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NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

WILLIAMS PIPE LINE COMPANY LIQUID PIPELINE RUPTURE AND FIRE MOUNDS VIEW, MINNESOTA JULY 8, 1986

NTSB/PAR-87/02

UNITED STATES GOVERNMENT

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16. Abstract

About 4:20 a.m., on July 8, 1986, line 2N, an 8-inch products pipeline at Mounds View, Minnesota, operated by Williams Pipe Line Company ruptured. Unleaded gasoline under 1,434 psig spewed from a 7 1/2-foot-long opening along the longitudinal seam of the pipe. Vaporized gasoline combined with air and liquid gasoline flowed along neighborhood streets. About 20 minutes later, the gasoline vapor was ignited when an automobile entered the area. Following an explosion-like noise, fire spread rapidly along the path of the liquid gasoline. Two persons were burned severely and later died, and one person suffered serious burns. There was substantial property damage and soil and water pollution.

The National Transportation Safety Board determines that the probable cause of the rupture at Mounds View, Minnesota, was the failure of Williams Pipe Line Company to correct known deficiencies in the cathodic protection applied to the first 10 miles of line 2N. Contributing to the failure of the pipeline was the susceptibility of the low frequency, electric resistance welded pipe to weld seam corrosion and the Department of Transportation's ineffective inspection and enforcement program. Contributing to the extent of the damages was the failure of the pipeline company to provide adequate direction, through its procedures and training, for its employees to effectively respond to emergencies involving failed sections of its pipeline and the nonavailability of remotely operated valves or automatic shutdown capability on the pipeline.

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EXECUTIVE SUMMARY

About 4:20 a.m. on July 8, 1986, line 2N, an 8-inch products pipeline operated by Williams Pipe Line Company at Mounds View, Minnesota, ruptured. Unleaded gasoline under 1,434 psig spewed from a 7 1/2-foot-long opening along the longitudinal seam of the pipe. Vaporized gasoline combined with air and liquid gasoline flowed along neighborhood streets. About 20 minutes later, the gasoline vapor was ignited when an automobile entered the area. Following an explosion-like noise, fire spread rapidly along the path of the liquid gasoline. Two persons were burned severely and later died, and one person suffered serious burns. There was substantial property damage and soil and water pollution.

The safety issues discussed in this report are:

(1) Shutdown of the pipeline;
(2) Operating personnel training;
(3) Office of Pipeline Safety enforcement;
(4) Liquid pipeline safety regulations; and
(5) Public awareness of the pipeline.

Recommendations concerning these issues were made to the Williams Pipe Line Company, the American Petroleum Institute, and the Office of Pipeline Safety, and the Department of Transportation, Safety Recommendation P-84-26 regarding a level of hazardous liquid pipeline safety for the public comparable to that required for natural gas pipelines was reiterated to the Research and Special Programs Administration.

The National Transportation Safety Board determines that the probable cause of the rupture at Mounds View, Minnesota, was the failure of Williams Pipe Line Company to correct known deficiencies in the cathodic protection applied to the first 10 miles of line 2N. Contributing to the failure of the pipeline was the susceptibility of the low frequency, electric resistance welded pipe to weld seam corrosion and the Department of Transportation's ineffective inspection and enforcement program. Contributing to the extent of the damages was the failure of the pipeline company to provide adequate direction, through its procedures and training, for its employees to effectively respond to emergencies involving failed sections of its pipeline and the nonavailability of remotely operated valves or automatic shutdown capability on the pipeline.

NATIONAL TRANSPORTATION SAFETY BOARD
WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

Adopted: July 20, 1987

WILLIAMS PIPE LINE COMPANY LIQUID PIPELINE RUPTURE AND FIRE MOUNDS VIEW, MINNESOTA JULY 8, 1986

INVESTIGATION

The Accident

Pipeline Rupture.—At 1:36 a.m. on July 7, 1986, the Williams Pipe Line Company (WPL) dispatcher at Tulsa, Oklahoma, remotely opened a valve at Wrenshall, Minnesota, to receive unleaded gasoline from line 2N. (See figure 1.) At the time, line 2N was not in operation, and the unleaded gasoline in the pipeline was at a pressure of about 90 psig. At 1:38 a.m., the dispatcher remotely opened the main gate valve at the Minneapolis terminal, and at 1:39 a.m., he remotely started the pump at the Minneapolis terminal for delivery of unleaded gasoline from tank 805 to Wrenshall. The pressure in line 2N at the Minneapolis terminal was about 1,290 psig, and the flow rate was 965 barrels per hour (bph). (See figure 2.) The dispatcher set a parameter alarm 1/ at 1,200 psig.

On July 8, 1986, the terminal operator (TO) at the Minneapolis Terminal prepared to change the product being pumped into line 2N. He positioned the valves on the suction line for tank 823, which contained fuel oil, to allow the dispatcher to make a switch 2/ from unleaded gasoline in tank 805. The switch was made at 4 a.m., and the pressure controller equipment at the pump automatically increased the pressure over the next several minutes to about 1,490 psig to obtain the desired flow rate for the heavier material now being pumped. Pressure charts indicate that the pipeline stabilized at a pressure of 1,480 psig. The flow rate remained at 965 bph, and the operating conditions were normal for the product being transported.

About 4:10 a.m., in accordance with normal practice, the TO positioned a valve upstream of the pump to direct the flow of the product through a prover. 3/ Other than minor pressure fluctuations resulting from the reduction in product flow, pumping operations remained stable for about 10 minutes until about 4:20 a.m., when large, rapid drops in the pressures occurred. At that time, the suction pressure dropped from 56 psig to between 10 and 15 psig, the pump case pressure dropped from 1,486 psig to between 65 and 70 psig, and the discharge pressure dropped sharply from 1,480 psig to about zero psig. The Minneapolis TO said that at the time he was in the pump control room and that he heard "some clicking noises," which he interpreted as an indication that something had changed. He said that he believed the noises were caused by the operation of breakers or relays and that he checked the pressure chart on his console. He stated that the pressure

1/ An alarm which can be set by the dispatcher to alert him should the pressure in the pipeline reach the preset pressure.
2/ A change in product being pumped without interrupting the operation of the pipeline.
3/ A device to calibrate the pipeline's flow meter. Flowing the product through the prover is routinely done when the product in the pipeline is changed to determine a correction factor to apply to the reading of the in-line meter for the specific product being pumped.

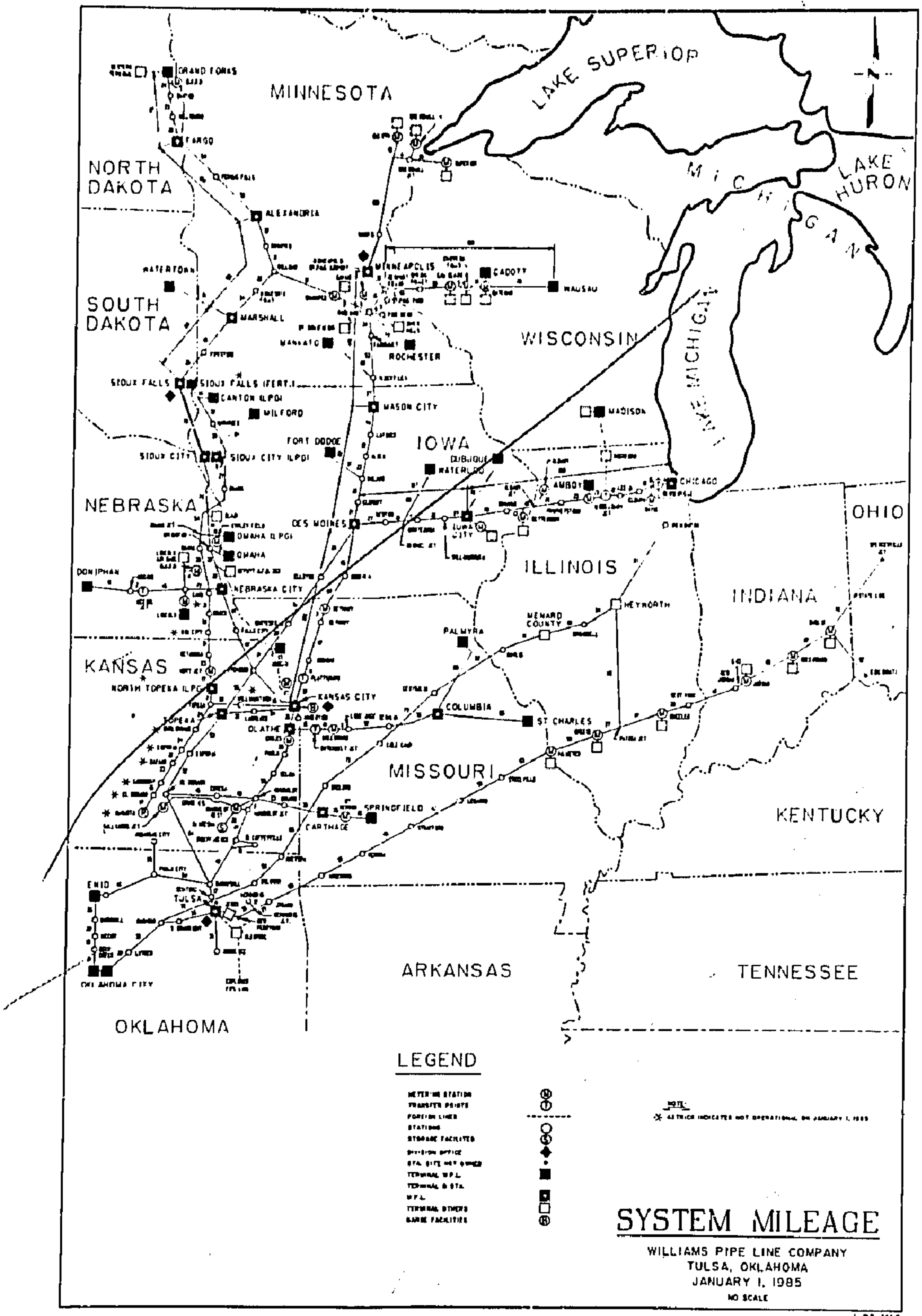


Figure 1.—Williams Pipe Line Company system map.

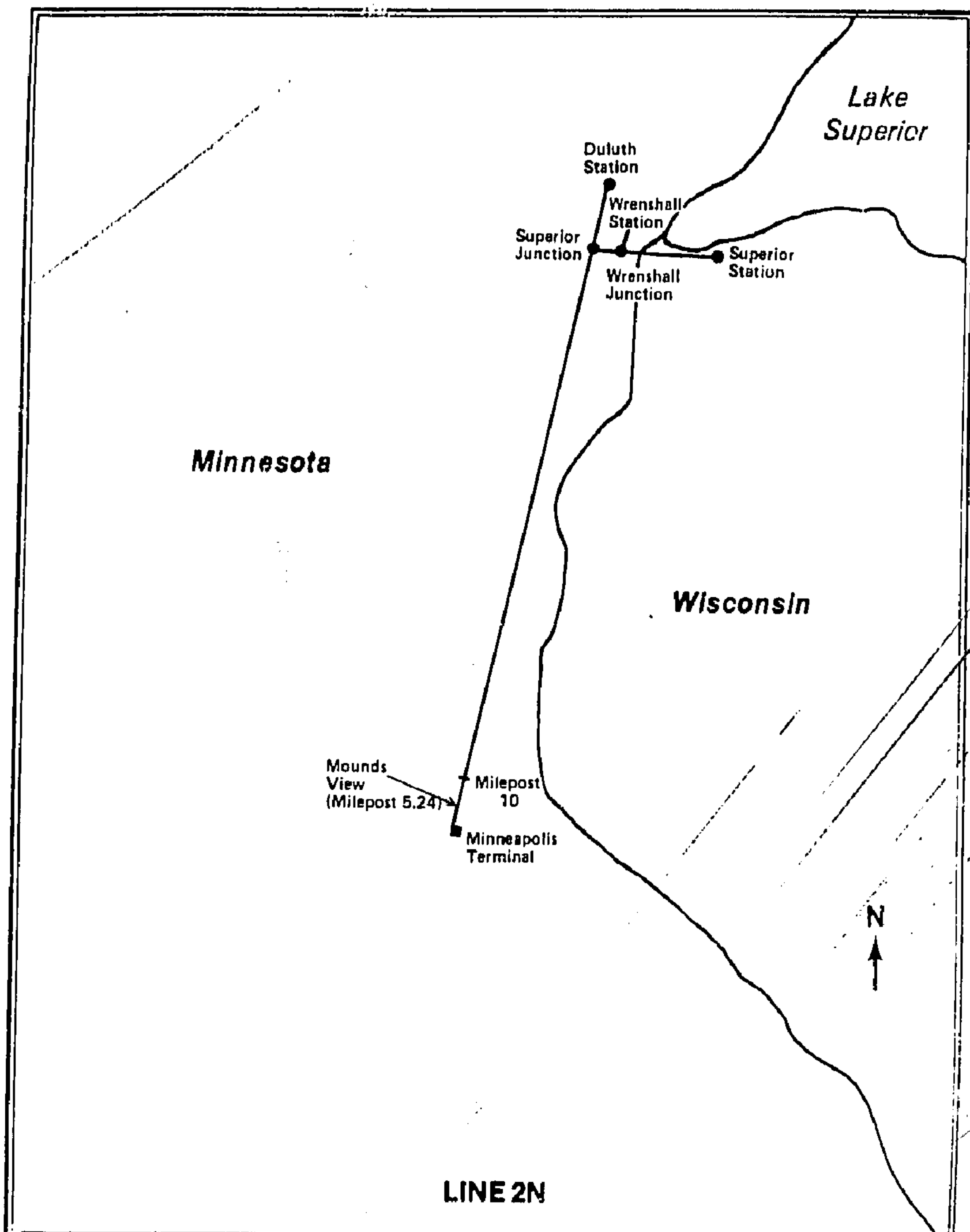


Figure 2.—Line 2N in Minnesota.

on line 2N had dropped considerably; however, he did not immediately consider this to be a problem. The TO then headed outside to the area of the pump to check the valve configuration and pump operations.

The dispatcher in Tulsa said that about 4:21 a.m., an alarm sounded and the parameter alarm flashed on his monitor indicating that the pressure on line 2N had dropped below the 1,200 psig setting. The dispatcher said that he promptly reviewed the operating data for line 2N and saw that the discharge pressure was reading 37 psig. The dispatcher telephoned the TO in Minneapolis to confirm the information; he reached the TO on his portable telephone as the TO was on his way to the area of the pump. The dispatcher advised the TO that there was an abnormal condition on line 2N; the TO acknowledged that he was aware that an abnormal condition existed. The dispatcher also advised the TO that his information indicated the product flow was high (slightly above the previous flow rate) but that the discharge pressure was low. The TO advised the dispatcher that the discharge pressure gauge at the pump read 200 psig.

The dispatcher stated that he did not know what condition may have existed on line 2N since several things may have given somewhat similar readings: a break may have occurred, the power may have failed, the strainers may have become plugged, the valving may have been changed at the receiving location, or a problem may have occurred in the telephone system used for the transmission of operating data on the pipeline system. The dispatcher said, however, that had the power failed, the pump unit should have shut down, and that had there been a problem with the pump, he would have received other alarms. At 4:24 a.m., the dispatcher entered a computer command to remotely shut down the pump; pump shutdown was confirmed by the computer at 4:25 a.m.

At 4:26 a.m., according to WPL records, the pressure dropped and the flow rate increased to 1,539 bph. At 4:27 a.m., believing that the problem was with the equipment rather than a line break, the dispatcher, in accordance with WPL operating procedures for such a problem, remotely closed the block valves at Wrenshall and Superior Junctions. The TO at the Minneapolis terminal said that at 4:28 a.m., the flow through the pipeline was 60 percent (about 1,200 bph). He said that he shutdown the tank pump at tank 823 and that, at the time, the flow had reduced to about 20 percent flow (about 400 bph). The TO relayed this information to the dispatcher in Tulsa. The dispatcher then entered a computer command to remotely close the main valve on line 2N at the Minneapolis terminal. The TO stated that once this was done, the indications of flow ceased.

Meanwhile, about 4:27 a.m., the TO telephoned the dispatch shift supervisor in Tulsa and informed him of the actions that had been taken and of the flow rates. The dispatch shift supervisor said that based on the pressure readings along the pipeline, he believed that the line had ruptured, probably within 10 miles of the Minneapolis terminal. The dispatch shift supervisor advised the dispatcher to open the block valves at Wrenshall and Superior Junctions to relieve pressure on the pipeline. This was in accordance with the WPL operating procedures on handling ruptures. The procedures did not contain information on recognizing the causes of abnormal conditions. The dispatcher issued the command to open the valves and the valves at Wrenshall and Superior Junctions were opened at 4:31 a.m. and 4:32 a.m., respectively.

About 4:28 a.m, the dispatch shift supervisor notified the on-call district manager 4/ at his home in Minnesota that line 2N was experiencing an abnormal operating

4/ One of three persons in the northern division who, on a rotating basis, serves as the after hours emergency contact. The northern division's headquarters is in Minneapolis, Minnesota, area.

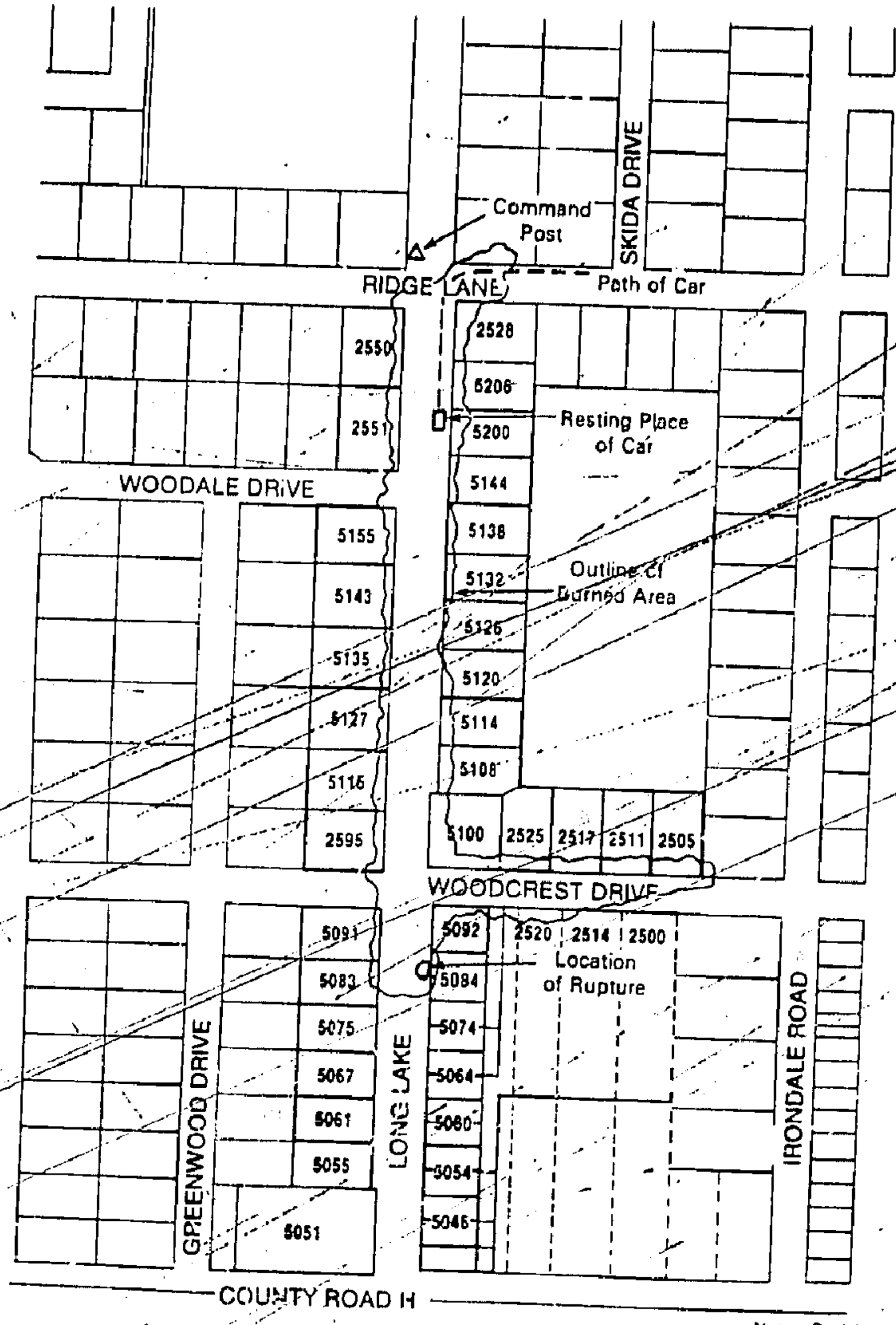
condition. The dispatch shift supervisor said that he believed the problem was a rupture, probably within 10 miles of the Minneapolis terminal. The dispatch shift supervisor who was not familiar with the environment along line 2N had maps which showed the pipe's profile and included aerial photographs of the area around the pipeline right-of-way; however, he did not use them to determine the direction of flow in the pipeline when not under pressure or to determine the population exposure along the first 10 miles of line 2N.

At 4:30 a.m., the on-call district manager, in accordance with WPL procedures, notified the area maintenance supervisor of the possibility of a leak and directed the area maintenance supervisor to mobilize a crew at the Minneapolis Terminal and to prepare to search for a possible leak. The on-call district manager then called the line supervisor and directed him to locate a helicopter and to begin an aerial search for the problem.

At 4:50 a.m., the WPL on-call district manager notified the district manager (northern district manager) who was responsible for line 2N. He advised the northern district manager of the pressure drop on the line and that the area maintenance supervisor and the line patrol supervisor both had been called and alerted.

Explosion and Fire.—About 4:40 a.m., a resident of 5114 Long Lake Road, Mounds View, Minnesota, was awakened by an odor which he believed to be natural gas. He checked his appliances and determined that the source of the odor was not in the house. He then went outside where he found the odor to be stronger. After examining and finding no leaks of any kind from his cars, the resident looked into the street and saw that the west side of the road was covered with a pool of liquid. Shortly afterward, a car turned left from Ridge Lane, onto Long Lake Road (see figure 3), and stopped in front of the residence at 5200 Long Lake Road. The resident stated that he saw a fireball in the front of the car, heard a loud noise, saw the liquid in the street ignite, and then saw a person run from the car to the house at 5200 Long Lake Road. The flames traveled south on Long Lake Road and east on Woodcrest Drive. At 4:44 a.m., a resident on Woodale Drive notified the Ramsey County Sheriff's Office (RCSO), via the 911 emergency number, of an explosion and fire in the area. The RCSO contacted the Anoka County Central Dispatch which, in turn, dispatched the Spring Lake Park, Blaine, and Mounds View Fire Department (fire department) to the scene.

The first fire department unit arrived onscene about 4:50 a.m. At that time, flames covered two blocks of Long Lake Road and one block of Woodcrest Drive. Shortly afterward, a fire department district fire chief set up a command post marked with a flashing blue light at the intersection of Ridge Lane and Long Lake Road, just north of the burning area. The district fire chief surveyed the scene and instructed firefighters to lay hose lines to extinguish any structural or related fires and to protect all exposures. Due to the characteristics of the fire, fire department officers believed gasoline was involved; however, they did not know whether a tank truck or a pipeline was the source of the gasoline. Firefighters at the south end of the fire informed the officers at the command post that a tank truck was not involved. After finding a pipeline marker, which contained local and out-of-state numbers for WPL, onscene firefighters requested the fire department dispatcher to notify WPL that its line probably was involved and to shut down the pipeline. The request was transferred to the RCSO dispatchers. About 5 a.m, the RCSO notified the Minneapolis terminal of the fire and injuries on Long Lake Road. The RCSO then reported the accident to the WPL dispatch center in Tulsa, Oklahoma, by dialing the out-of-state telephone number listed on the pipeline marker. While WPL had the general information provided by the dispatch shift supervisor that the rupture was within 10 miles of the Minneapolis Terminal, this information was the first notification that WPL had concerning the exact location of the leak.



Plan View of Accident Site

Figure 3.—Accident area.

The Minnesota Highway Patrol, the Mounds View Police Department, and the fire department evacuated residents in a 10-block area around the accident scene. Initially, the residents were not instructed to report to a specific area although later the evacuees were directed to go to the Mounds View City Hall.

The fire chief requested that representatives of the Minnesota Pollution Control Agency (MPCA), WPL, and Northern States Power report to the command post. At 5:20 a.m., the fire department dispatcher informed the command post that line 2N had been shut down. According to WPL records, the pump unit had been shut down at 4:25 a.m., about an hour earlier. At 5:20 a.m., when the northern district manager learned the exact location of the accident, he called the area maintenance supervisor from his mobile telephone and instructed him to close the manually operated gate valve at milepost 10.

The WPL northern district manager arrived onscene about 5:30 a.m. and reported to the command post as the RCSO had instructed him. He confirmed that the product was gasoline, that the Minneapolis terminal had been shut down, and that a WPL employee had been dispatched to close the gate valve at milepost 10. At the time, the northern district manager was not able to provide any other information on the closure of the gate valve on the line at milepost 10 or on the profile of the pipeline; he had neither received nor requested any updated information from other WPL personnel. About 6 a.m., the intensity of the fire decreased and the northern district manager remarked to the fire chief that the valve at milepost 10 must have been closed. By this time, only the area in front of 5064 Long Lake Road, near the rupture, was burning; the fire department had extinguished the fires on Woodcrest Drive and elsewhere on Long Lake Road.

About 6:10 a.m., the fire chief ordered the evacuation area to be expanded to the southeast because of concerns over the presence of gasoline in the storm sewers and the path of the sewers. Gasoline had entered the storm sewer system, and sewer covers in the area were occasionally being blown into the air by explosions in the sewer system. Personnel at the command post, in discussion with the WPL representative, decided that the best option was to allow the gasoline to burn itself out because there was a possibility that vapors from the residual gasoline could ignite and create a new hazard.

The fire at the rupture site burned out about 7:35 a.m. About 1 hour later, fire department personnel tested the storm and sanitary sewers for the presence of flammable atmospheres along Long Lake Road and Woodcrest Drive. The only place where vapors were found was at a storm sewer on Woodcrest Drive. About 11 a.m., the search for flammable vapors was expanded to include the residences on these streets. No flammable atmospheres were found. The evacuees were allowed to return to their residences about noon. The fire department remained onscene until 11:08 p.m.

Closing of Valve at Milepost 10.--At the time of the accident, the northern district manager lived about 12 miles away from the milepost 10 valve. He said that he was notified by the on-call district manager of the accident about 4:50 a.m., and that he left his residence at 5:09 a.m. While en route to the district office, about 5:15 a.m., he spoke to the RCSO and learned the exact location of the accident; he had not received any updates since his initial conversation with the on-call district manager. The northern district manager then called the area maintenance supervisor, directed him to close the valve at milepost 10, and then proceeded to the scene. The area maintenance supervisor, who lived more than 40 miles south of the valve, left a telephone message at the Minneapolis terminal for members of his work crew to close the milepost 10 valve and then he proceeded to milepost 10. A crewmember who had received the message at the Minneapolis terminal went to the valve and closed it about 6 a.m.; the area maintenance supervisor arrived at milepost 10 shortly thereafter.

Injuries to Persons

	Pipeline Company	Civil Agencies	Residents	Total
Fatal	0	0	2	2
Nonfatal	0	1	2	3
Total	0	1	4	5

Two residents suffered fatal burns while escaping from their home on Woodcrest Drive. The driver of the car suffered second-degree burns on her arms and legs. One resident broke her toe while escaping from her house, and a firefighter suffered a muscular injury during the emergency response.

Damage Information

One house sustained moderate damage; its exterior was charred and fire had burned through the front door. A garage attached to one house sustained structural damage, and three other houses sustained minor exterior damage. Five vehicles sustained damages ranging from paint damage to complete destruction. Twenty-three residences suffered landscape damage. The damage to both public and private property was estimated to be $250,000.

The accident also caused environmental damage. Approximately 600 fish and other animals were killed as a result of the gasoline that entered Rice Creek from the storm sewer system. Gasoline also entered the shallow ground water aquifer on Long Lake Road. WPL is still involved in clean up of the aquifer. WPL estimated that it lost approximately 30,000 gallons of gasoline. The cost of the emergency response was estimated to be $14,000.

Personnel Information

Terminal Operator.—The TO had been employed by WPL for 6 years and had been in his current position since 1984. Before becoming TO, he had worked on the loading rack and in the terminal gauging area. Before his employment at WPL, he served about 4 years in the U.S. Air Force where he stored, issued, and transferred fuel. He stated that his training at WPL had been on-the-job. Each year the TO's area supervisor evaluated his performance using a WPL checklist. The checklist rates the quality and quantity of the employee's work, his dependability, initiative, and knowledge of the job, as well as the employee's planning and communication skills. The TO had never taken any formal written tests to determine his knowledge of operations or procedures.

The TO was responsible for observing tanks, changes in the transmission of product, changes in the receipt of product, monitoring the pipeline equipment, checking the tank farm, and assisting in the loading of tank trucks.

WPL Dispatcher.—The dispatcher had been employed by WPL since 1972, and had been a dispatcher since October 1981. He worked the 11 p.m. to 7 a.m. shift July 7-8. 1986. WPL stated that the dispatcher had received on-the-job training.

The dispatcher received his orders from the dispatch shift supervisor. He then coordinated with employees at WPL terminals and stations along the pipeline activities involving deliveries, changes of product, valve alignments, and the times for these operations.

On-Call District Manager.—The on-call district manager began working for WPL in June 1976 as a pipeliner, 5/ and had worked in various operating positions through terminal manager to district manager. He had held the position of district manager since May 1984. During the summers of 1972 through 1975, he had worked as a pipeliner for Amoco Pipeline Company. His personnel records indicated that he had attended numerous job-related training sessions and seminars, some of which dealt with WPL operating procedures.

The district manager was responsible for coordinating operations and maintenance within a district. As the on-call district manager he was responsible for coordinating response to trouble calls, obtaining information, and notifying the emergency task force, applicable government agencies, and service contractors as necessary.

Northern District Manager.—The northern district manager had been employed by WPL since June 1979. He became district manager in May 1984. He began his employment at WPL as assistant to the vice president of operations. Eight months later, he was promoted to the position of supervisor, terminals/stations. Before 1977, he had worked with Shell Oil Company primarily in the areas of auditing and accounting. Between 1977 and 1979, the northern district manager was employed by the Williams Company 6/ as an internal auditor. His duties as the northern district manager were the same as the on-call district manager's.

WPL had provided the northern district manager on-the-job training. In addition, he had attended management training sessions similar to those provided to the on-call district manager.

Training

WPL has two different training programs for employees involved in the operation of the pipeline. WPL hourly workers receive mostly on-the-job training. Hourly workers at WPL terminals also are trained in the use of fire extinguishers and other emergency equipment used to extinguish fires at a pump station or terminal. District managers and other management employees are provided classroom training.

Samples of the district manager training program showed that managers received classroom training consisting of lectures on such topics as union contracts, Federal standards, corrosion, tank cleaning, and financial management. There was no evidence that the managers were tested to determine the effectiveness of this training. A manager in the Northern Division stated that, in addition to the classroom training, employees also read the WPL operating procedures.

In 1985, WPL contracted a consultant to prepare a training plan to enhance WPL's hourly workers' knowledge of common operations. The training plan set up a nine-module program designed to supplement the training conducted at each terminal and station. The training plan allows employees to work at their individual pace on portable computers. Program topics include use of the computer, the nature of petroleum products, station and terminal operations, quality control procedures, and occupational safety. Two modules were completed in June 1986, and at the time of the accident, the contract for the remaining seven modules was up for bid.

5/ A laborer on a maintenance crew.
6/ WPL is a subsidiary of the Williams Company.

WPL provides training to emergency response agencies whose response area includes a WPL terminal or pump station. WPL representatives said that the company believes its employees are more qualified than anyone else to locate pipeline leaks and that they can best determine the assistance needed from fire departments and other emergency response personnel.

The WPL Emergency and Insurance Guide lists instructions for company personnel to follow in case of a fire or other emergency. Also, Federal and State emergency contact numbers for WPL personnel are listed in the guide. Emergency numbers are posted in WPL terminals and pump stations in addition to an emergency call list containing telephone numbers for the local fire departments and other persons to contact in case of an emergency. Safety Board investigators were unable to find any record of emergency drills that had been conducted at WPL facilities or along the pipeline right-of-way.

Pipeline Operations

Description of Line 2N.—Line 2N, which was constructed by the Great Lakes Pipeline Company in 1957, consisted of pipe lengths with low frequency electric resistance welded (ERW) longitudinal seams. The pipe lengths were manufactured by Jones and Laughlin Steel Company. Federal regulations governing pipeline design, testing, or construction did not exist at the time.

At the time of construction, the area surrounding the pipeline's right-of-way was in an unincorporated area of Ramsey County which was planned as a residential area. Residences had been built along Long Lake Road at the time the pipeline was installed. Great Lakes Pipeline Company obtained the right to construct the pipeline from Ramsey County. Operation of the pipeline began in 1958. In 1966, Great Lakes Pipeline sold the pipeline to WPL.

The 8-inch, bi-directional flow line extends between the Minneapolis Terminal at the south end and the Duluth, Wrenshall, and Superior stations at the north end. The line allows WPL to deliver products to each station; however, products can be pumped from the Minneapolis and Superior stations only. When not under pressure, liquid in the line drains south toward the Minneapolis Terminal.

Pipeline Failures.—WPL records showed that since 1958 line 2N had experienced 23 seam failures; 7 occurred during operation (see table 1) and 16 during hydrostatic testing in 1984. According to WPL, only the 1983 pipeline failure was subjected to metallurgical analysis.

Table 1.--Seam failures during pipeline operation.

Date	Branch	Milepost	BBLs	Product
1/14/58	Superior Jct	12+3486	42	Fuel oil
6/19/58	Minn/Duluth	134+0063	75	Unidentified
5/27/59	Superior Jct	13+4164	1	Gasoline
4/02/68	Minn/Duluth	0+0009	42	Fuel oil
12/29/68	Minn/Duluth	10+2132	300	Fuel oil
12/09/83	Minn/Duluth	102+29	659	Gasoline
7/08/86	Minn/Duluth	5+24	478	Gasoline

The 1983 failure occurred when the pipeline was pumped against a closed valve. The failure resulted in the discharge of gasoline into the watertable. The line failed at 1,253 psig. As a result of an agreement between WPL and the MPCA, in return for no further enforcement action relating to this spill being taken by the MPCA, WPL agreed to clean up the spill site and to metallurgically test the pipe. The metallurgical consultant contracted by WPL reported that the failed section of ERW pipe had split along the full length of the weld seam. Examination of the fracture surfaces indicated a brittle failure. A metallographic examination conducted by the consultant indicated a defective weld as the cause of the failure.

Following the consultant's report, WPL hydrostatically tested the entire pipeline. During August 1984, the pipeline was subjected to hydrostatic testing at pressures up to 2,125 psig; the pipeline experienced 16 seam failures, some occurring at pressures as low as 1,700 psig. WPL then lowered the test pressure to 1,900 psig. The tests were completed, thus allowing WPL to set a maximum allowable operating pressure of 1,500 psig.

Other WPL pipelines which have experienced longitudinal ERW seam failures include the 8-inch fuel oil pipeline at Newport Villas, Minnesota, and the No. 4, 12-inch pipeline out of Tulsa, Oklahoma. The ERW seam failures that have been tested have been attributed to manufacturing defects. Each of these lines is about 30 years old.

Cathodic Protection System for Line 2N.--Title 49 CFR 195 requires that line 2N be cathodically protected but does not specify a level of cathodic protection. The Department of Transportation (DOT), however, enforces the cathodic protection regulations using NACE Standard RP-01-69. (See appendix E.) WPL manuals state that the acceptable level of cathodic protection for the line is -0.85 volt (the same level as for all of its other lines).

The cathodic protection system for WPL's pipelines is administered from the Tulsa headquarters office. WPL divisions currently responsible for other maintenance of the pipelines are not responsible for maintaining or monitoring the level of cathodic protection on the pipeline. Since 1982, WPL has used contractors to test the cathodic protection system. The results of the tests are sent to WPL's Tulsa headquarters. Pipe-to-soil (p/s) readings for 1980 through 1985 show that the level of cathodic protection was usually substandard for most of the first 10 miles of line 2N. (See table 2.) The p/s readings for the rest of line 2N met WPL's standard of -0.85 volt.

WPL's senior corrosion technician first became aware of problems with the cathodic protection system on line 2N in 1981 through the p/s reports taken each fall. In early 1982, WPL hired a consultant, the recently retired head of WPL's corrosion department, to determine the reason the p/s potential readings on line 2N failed to meet WPL's standard. The consultant concluded that the coating on the pipe had been damaged, and he recommended that anodes be installed. WPL disagreed with the consultant's assessment of the situation because WPL believed the coating would not fail as quickly as the p/s readings had dropped. WPL attempted to correct the problem by installing an insulating flange at the Minneapolis terminal; however, the problem worsened and WPL bypassed the insulating effects of the flange by installing bonding cables on the line across the flange. In 1983, WPL hired another consultant who was requested to identify the problem and to determine if it was related to an AC power line that paralleled part of line 2N. After completion of his initial studies, the second consultant recommended more testing. In 1984, a third consultant was hired because the second consultant had not determined the reason for the low p/s readings. Like the first consultant, the third consultant

Table 2.—Pipe-to-soil potentials, line 2N.
(The boldface numbers indicate p/s readings that met or exceeded WPL's standard.)

	Test Station	1981	1982	1983	1984(1)	1984(2)	1985
	0+00		−0.73	−0.06	−0.73	−0.49	−0.05
	0+02	−0.60	**−0.86**	−0.27	**−1.08**	−0.60	−0.16
Mile 1	0+23	**−1.25**	**−1.61**	−0.78	**−1.42**	**−1.09**	−0.84
	0+52	**−1.10**				**−1.07**	**−0.92**
	1+11	−0.20		−0.58	**−1.46**	−0.83	−0.64
Mile 2	1+44	**−0.90**		−0.76	**−1.18**	**−0.93**	−0.66
	1+48	**−0.80**				−0.84	−0.62
	2+03	−0.80	**−1.03**	−0.61	**−1.18**	**−0.86**	−0.60
	2+07	−0.70	**−0.99**	−0.61	**−1.22**	−0.84	−0.59
	2+11	−0.70	**−0.97**				
	2+13				**−1.38**		
Mile 3	2+16				**−1.33**		
	2+34		**−1.03**	−0.80	**−1.26**	**−0.91**	−0.63
	2+40		**−1.07**	−0.79	**−1.29**	−0.77	−0.61
	2+50	**−0.95**					−0.69
Mile 4	3+96/11	**−1.00**	**−1.00**	[illegible]	**−1.30**	−0.71	−0.65
Mile 5	4+14	−0.70	−0.64	[illegible].55	**−0.97**	−0.56	−0.51
	4+46	−0.80	**−0.91**	−0.67	**−1.14**	−0.67	−0.68
Mile 6	5+26	−0.65	−0.82	−0.65	**−0.98**	−0.61	−0.60
	5+46	−0.75	**−0.92**	−0.70	**−1.14**	−0.68	−0.67
	6+08			−0.36	**−1.08**	−0.67	−0.65
Mile 7	6+20	−0.70	−0.82	−0.68	**−1.04**	−0.64	−0.61
	6+33	−0.65	−0.80	−0.67	**−1.07**	−0.68	−0.64
	6+40	−0.60	−0.79	−0.63	**−1.07**	−0.60	−0.60
Mile 8	7+20	**−0.90**	**−0.97**	−0.81	**−1.21**	−0.80	−0.67
	7+26	**−0.95**	**−1.00**	**−0.86**	**−1.23**	**−0.87**	**−0.87**
Mile 9	8+26	**−1.05**	**−1.07**	**−0.94**	**−1.39**	**−0.89**	**−0.93**
Mile 10	9+33	**−0.95**	**−1.02**	**−1.03**	**−1.60**	**−0.99**	−0.81
	9+51	**−0.85**	**−0.88**	−0.82	·	**−0.90**	
Mile 11	10+24	**−1.05**	**−1.13**	**−0.97**	**−1.15**	**−0.98**	**−0.90**

1984(1)--P/s readings done by contractor unrelated to annual readings.
1984(2)--Annual p/s test reading.

recommended that anodes be installed on the pipeline. However, no action was taken at that time since the p/s readings conducted by this consultant for the section of line 2N in question showed that the company's standard of cathodic protection was being met. A second set of p/s readings taken in 1984 showed the potentials no longer complied with WPL's standard; however, no corrective action was scheduled. After the annual p/s potential readings taken in the fall of 1985 failed to meet WPL's standards, the third consultant again recommended the installation of anodes; the work was scheduled for July 1986.

A corrosion consultant contracted by WPL after the accident stated that cathodic protection can mitigate continuing corrosion on a pipe as long as the corrosion has not penetrated to a critical depth, commonly believed in the cathodic protection industry to be 70 percent of the pipe wall. Once corrosion has penetrated to a critical depth, cathodic protection can no longer mitigate corrosion because the walls of the pipe effectively shield the bottom of the defect from the cathodic protection system. This same phenomenon also will occur in defects that are not caused by corrosion.

An industry-accepted level of cathodic protection is -0.85 volt when measured in p/s readings. However, according to the WPL consultant, just because the -0.85 volt criteria is not being met does not mean that corrosion is occurring. Other factors, such as the corrosivity of the soil and the condition of the pipe's coating also affect the degree of cathodic protection and corrosion. The WPL consultant stated that because p/s readings give a fairly accurate picture of the degree of corrosion on a pipe, a p/s reading is the usual method of identifying corrosion on a pipeline.

In October 1986, an impressed current system was installed at the Minneapolis terminal. The activation of the impressed current system brought the p/s readings on the first 10 miles of line 2N to a level equal to or more negative than -0.85 volt.

Rapid Shutdown.--The Minneapolis terminal is equipped with alarms to alert the TO of fires, problems with the tank levels, and manifold overpressurization. The terminal is not equipped to monitor the pipeline outside its boundaries. Only the dispatcher has information on the operating status of the pipeline outside the terminal. The Minneapolis terminal has automatic shutdown controls for the main line pump which activates in the event of high discharge pressure, low suction, high sump, or high amps. There is no automatic shutdown control for low discharge pressure. The main line pump is equipped with a low suction shutoff control. The suction pumps located at the tanks that feed the main line pump are capable of supplying pressure in excess of that for which the low suction shutoff is set.

Remote-operated valves (ROV), which are controlled by the dispatchers in Tulsa, are installed on WPL's main lines. ROVs are used to assist in the movement of product. At the time of the accident, the valves were located only at terminals, pump stations, and receive locations. In October 1986, WPL installed two ROVs on line 2N; one at milepost 2.67 and one at milepost 8.38, to the south and north of Mounds View. The valves were operationally checked on January 29, 1987, and were put into service on February 2, 1987, when the line was returned to service at 900 psig.

Meteorological Information

At 4:50 a.m., visibility at the Minneapolis/St. Paul airport, approximately 13 miles southeast of the accident site, was reported to be 7 miles. The temperature was 69° F with the wind out of the east-southeast at 6 knots. Sunrise was at 4:35 a.m.

DOT Pipeline Safety Program

Pipeline Monitoring and Inspection.--At the time of the accident, the Office of Pipeline Safety (OPS), an office within the Research and Special Programs Administration (RSPA) of DOT, had 16 inspectors nationwide, divided among five regional offices. OPS has sole authority over approximately 600 natural gas and hazardous liquid transmission pipeline operators, and is responsible for monitoring State gas distribution inspection programs. Only 11 States now serve as agents for the OPS for inspecting interstate natural gas pipelines, while 49 States have been certified under Section 5(a) or 5(b) of the Natural Gas Pipeline Safety Act for regulating the safety of intrastate natural gas lines. Two have been certified under the Hazardous Liquid Pipeline Safety Act for enforcing the safety standards on intrastate liquid pipelines. In part, because of the proximity of State inspectors to the regulated pipeline operators, State inspectors, on the average perform two to three times more inspections than do their Federal counterparts. Additionally, the OPS statistics on State operations for 1985 indicate that State inspection programs are more aggressive than OPS in identifying violations. An OPS representative testified that approximately 50 percent of an inspector's time is spent in the field conducting inspections and investigations of pipeline operator's facilities. The remaining time is spent in the office doing followup work on the investigations and performing paperwork. Nationwide, OPS devotes about 16 percent of its total inspection time (2.5 inspector-years) to inspecting the more than 154,000 miles of hazardous liquid pipelines and investigating accidents related to these lines.

The OPS central region is responsible for operations in 10 States 7/ and all of WPL's system, part of which is located outside the central region. Its two inspectors inspect the 113 interstate operators in the central region (of which 84 are liquid pipeline operators) and monitor the operations of the 10 States for inspections of gas distribution systems. Three States--Ohio, Iowa, and Michigan—act as agents for OPS to inspect interstate natural gas pipeline facilities; no State has authority to inspect liquid interstate pipeline facilities. The region has divided each pipeline company into inspection units 8/. The chief of the central region stated that the inspectors devote, on the average, about 2 1/2 days per year to each inspection unit. An inspection of any unit or any function of a unit of a pipeline company is counted as an inspection of the pipeline company. Accident investigations also are counted as inspections of the company. The central region had divided WPL into four inspection units. In December 1986, the central region further divided WPL into nine inspection units. Inspections of WPL facilities have averaged approximately four per year over a 12-year period.

In its enforcement procedures training course, OPS states that an inspection "will consist of an onsite evaluation of an operator and any requests for records or other information needed to determine whether the operator has acted or is acting in violation of any regulation . . . "

Enforcement.—Title 49 CFR 190, Subpart B, describes the enforcement authority and sanctions available to the OPS. Once probable violations have been identified, enforcement proceedings may begin. This involves notifying the operator and providing it the opportunity to respond to the notice of probable violation. An operator may agree with the notice or it may request a hearing. After the operator has responded, the

7/ Iowa, Illinois, Indiana, Kansas, Michigan, Minnesota, Missouri, Nebraska, Ohio, and Wisconsin.
8/ An inspection unit is an operating area within a company that has responsibility for a particular segment of a pipeline.

Director of OPS will issue a final order which includes determinations on the probable violations and any civil penalties and compliance orders that may be issued or assessed. Before issuing the final order, the Director does not involve himself with the actions of his enforcement staff relevant to the enforcement action. Before the enactment of the Hazardous Liquid Pipeline Safety Act of 1979, only criminal penalties could be taken against hazardous liquid pipeline operators. When assessing a civil penalty, OPS must consider the nature, circumstances and gravity of the violation, the operator's "degree of culpability," the operator's compliance history, the operator's ability to pay any fine and remain in business, and any good faith actions taken by the operator when attempting to achieve compliance. In practice, civil penalties are assessed infrequently.

Enforcement actions may be in the form of consent orders, in which the operator does not contest the facts presented and waives the right for further action; compliance orders, which direct compliance with a section of the regulations; or hazardous facility orders, which require the operator to cease or restrict operations of specified facilities until specified tests or repairs are performed.

RSPA officials have made the following statements about OPS's enforcement philosophy:

> ... Enforcement should be considered as one end of a continuum of efforts necessary to achieve regulatory compliance and in consequence, enhance safety. It is essential that we pursue effective complementary programs all along that continuum. This involves making operators fully aware of our regulations and then assuring that their level of understanding is converted into safe practices. This process maximizes the likelihood of compliance with the regulations currently in existence, and serves as a primary and effective resource for identifying whatever new regulatory initiatives may be necessary. 9/

> The term enforcement has a broad meaning and encompasses those acts leading to and including injunctive and monetary sanctions. To enforce the pipeline safety regulations is to compel observance of them. In this context, acts which urge, suggest, or recommend observance are not acts of enforcement. They may be acts which improve the level of safety but by definition they are not included in the term enforcement... Enforcement, then is an act of prevention and the final goal of all enforcement activities is safety. 10/

After the accident in Mounds View, the central region chief testified that OPS believes civil penalties do not contribute to public safety and that it would rather an operator put its money into making its system safe than paying a civil penalty. The central region chief also said that OPS' "mere presence is enough for operators to want to comply (with the pipeline safety regulations)." OPS officials stated that it could not both issue a civil penalty for a specific violation and order the violation corrected since this would subject the operator to double jeopardy. When questioned as to when civil penalties are issued, the director of OPS said it is their policy that if there is no remedy that can be taken because of a chronological event then the most "equitable action" is to issue a civil penalty. However, if a remedy can be taken then the most "equitable action" is to issue a

9/ From the Statement of the Administrator, RSPA (1977-1985) before house committee on Public Works and Transportation, March 21, 1984.
10/ From OPS "Pipeline Safety Enforcement Philosophy and Policy," RSPA, June 1984.

compliance order. The director agreed with the central region chief's statements regarding OPS's general enforcement policy. In addition, the director said that DOT considers the pipeline safety regulations the minimum standard for safety but as long as those regulations are adhered to the pipeline is safe to operate. (In a letter dated May 15, 1987, the new director of OPS stated that "The OPS will now consider, and if appropriate, issue a civil penalty and a compliance order for a single act of noncompliance with a regulation.")

OPS annual reports were examined to obtain an overview of OPS enforcement activities. Each year OPS includes in its annual report summaries of its inspection and enforcement activities. The three most recent years were reviewed and the following information was found. In 1983, OPS inspected 416 operators, initiated 111 enforcement actions, and assessed 4 civil penalties for a total of $26,000. In 1984, OPS inspected 360 operators, initiated 143 enforcement actions, and assessed 2 civil penalties totaling $2,600. In 1985, the most recent year for which data is available, 317 operators were inspected, 154 enforcement actions were initiated, and 8 civil penalties totalling $12,000 were assessed.

Inspections of WPL.--Safety Board investigators reviewed OPS' inspection records of WPL since 1980. Only those cases in which all compliance actions were completed were made available for review. 11/ The 1980 date was chosen to allow for the adoption of the Hazardous Liquid Pipeline Safety Act of 1979 which governs the current enforcement program. The Safety Board identified 17 distinct initial inspections. Of these inspections, five were regularly scheduled inspections, five were "inspections" to gather data on an incident, and seven were accident investigations. In addition, the inspector may have made several additional trips to gather related information or to observe testing. Each of WPL's four inspection units were visited at least once in the 6-year period although two of the units accounted for most of the inspections because of accident investigations. The records showed that the onscene phase of the inspections typically lasted 1 to 2 days; however, followup action related to the inspection, such as requests for information or testing, may have continued for more than a year. According to the records, during an accident inspection, the OPS inspector would examine the records related to the accident only; other records for the same inspection unit would go unexamined. The inspection records do not reflect any effort on the part of the central region to examine during each inspection any records or operations consistently nor do they reflect consistently which records or operations were examined. While the central region had developed forms to use during inspections, not all inspection files contained the forms. The central region chief said the forms were used during routine inspections only. However, in those files that did contain the forms, the forms did not show that any operational areas were examined consistently.

In July 1981, OPS investigated an accident in Minnesota involving corrosion leaks on two WPL lines (neither was line 2N). As a result of this investigation, OPS ordered WPL to repair the lines and cathodically protect them. Action on this accident, which included a 1982 visit to WPL's Tulsa headquarters to review the corrosion control on the two lines continued into March 1986. During this period of nearly 5 years, OPS investigated accidents in States other than Minnesota that involved corrosion. Safety Board investigators found no evidence of any effort on OPS's part to examine WPL systematically for problems with its corrosion control (cathodic protection) program.

11/ There were three cases that were not available for review. The OPS denied Safety Board investigators' request to review these cases because disclosure of information related to an enforcement case before its closing might prejudice the parties involved.

The 17 inspections resulted in the initiation of 12 compliance cases: 6 warning letters, 5 compliance orders, and 1 civil penalty. Four of the six warning letters were a result of routine investigations, and all five compliance orders were developed from accident investigations. Although WPL was never cited for the same violation twice, four compliance orders related to deficiencies in WPL's operating and maintenance (O&M) plans.

OPS records indicate that WPL was not always responsive to OPS direction. In April 1981 during repair work to its Minneapolis terminal, WPL was informed by OPS that all manifold and piping welds done by WPL must be x-rayed. The following month, OPS inspected the terminal and discovered that all the welds had not been nondestructively tested as required by the pipeline safety regulations. The pipeline safety regulations state that all welds must be nondestructively tested, i.e., inspected by a method which will clearly indicate any defects that may affect the integrity of the pipe. OPS has further interpreted a nondestructive test as a method that cannot harm the component being tested. Instead, WPL had tested the welds hydrostatically, which is not a nondestructive test method. On September 21, 1981, OPS issued a compliance order requiring WPL to nondestructively test the manifold welds at its Minneapolis terminal. As a result of this testing, 10.5 percent of the welds were rejected. The compliance case was closed in October 1982 with no further OPS action.

The above instance was not an isolated case. In March 1984, after an inspection of WPL's O&M plan at its Tulsa headquarters, OPS issued a warning letter to WPL regarding deficiencies in its O&M plan. (See appendix G.) WPL replied that it was reviewing its O&M plan, that revisions should be completed by May 1984, and that it would send OPS a copy at that time. In July 1984, OPS contacted WPL regarding the revisions and WPL stated that the revisions had been made but that they were still under review. Two months later, an OPS memorandum indicated it had not yet received the revised manual and was waiting for WPL to submit it to them following WPL's internal review. A handwritten note on the memorandum indicated that WPL's response is taking too long and that some action should have been taken to ensure prompt response by WPL. Although WPL's O&M plan had an effective date of May 1984, OPS did not receive the revised manual until August 1986.

The warning letters examined by the Safety Board investigators contained a section stating what further action would be taken by the OPS. The typical statement was "We have reviewed the circumstances and supporting documents in this case and have decided not to assess you a civil penalty. We advise you, however, that should you not correct the circumstances leading to the violations we will take enforcement action when and if the continued violation comes to our attention." This phrase also was found in sample "warning letters" in the notebook for the OPS enforcement procedures training course.

The one violation for which WPL paid a civil penalty was the failure to telephonically report a meter rupture that resulted in a spill of 2,249 barrels of gasoline into Lake Superior. On January 11, 1982, OPS preliminarily assessed WPL a civil penalty of $1,000. WPL responded that the failure to report was simply an oversight and requested that the penalty be withdrawn. WPL contended that the requirement for notification was based upon the need for emergency response. OPS stated that this was not so and that, in fact, it had rejected that argument when adopting the final rule. In response to WPL's request for withdrawal of the penalty, OPS noted that WPL's "history of compliance with the regulations has not been a shining example of 'strict compliance.'" The OPS found that WPL had violated the regulation and upheld the penalty assessment.

The OPS policy regarding release of information concerning ongoing enforcement cases prompted the Safety Board to examine the rationale in support of this policy. Through testimony and examination of OPS records, the Safety Board determined that all information related to an enforcement case, including proposed violations and operator responses, is withheld from public scrutiny until the case has been closed. Thus, the public, including local agencies concerned with public safety, cannot obtain any information on enforcement actions being taken by OPS in the name of public safety until the case is closed. OPS policy officials stated that disclosure of any information relevant to an ongoing enforcement case before its closure might prejudice the outcome of the case. OPS counsel stated that its investigations were protected under an exemption to the Freedom of Information Act. 12/ Counsel further stated it believed that public presence and participation at enforcement hearings could dampen the operator's spirit of cooperation with the OPS.

On July 11, 1986, the OPS issued a hazardous facility order requiring WPL to hydrostatically test line 2N to 1,900 psig before returning it to service and to metallurgically examine all seam failures to identify their causes. Failures which could be attributed to the visual detection of corrosion were expected from this requirement. The OPS found that neither corrosion nor overpressure was a significant factor in the failure.

The Safety Board had several areas of concern in regard to the OPS final order of July 11, 1986. The initial examination of the failed area of the pipeline by Safety Board personnel revealed the presence of corrosion on the external surface of the pipe adjacent to the split seam. Therefore, the Safety Board believed that the final order should have required that failures attributable to corrosion be examined. The Safety Board also was aware that the phenomenon of pressure reversal 13/ can occur in ERW pipe, and that this issue was not addressed in the OPS final order.

The Safety Board held discussions with the RSPA to explain the Safety Board's concerns with the July 11, 1986, final order. The discussions focused on the pressure reversal phenomenon and the presence of corrosion on the pipe. As a result of the discussions, the administrator sent the Safety Board a document to explain the testing to be done. However, after the document and the final order had been reviewed, the Safety Board remained concerned that the OPS final order contained what appeared to be arbitrary test and operating pressures. As a result of these concerns, on August 13, 1986, the Safety Board recommended that the RSPA:

P-86-15

> Amend Final Order CPF No. 3541-H to Williams Pipe Line Company: (1) to require the development and the submission to the Research and Special Programs Administration for its approval of a plan for testing line 2N that incorporates the findings of research into the pressure reversal phenomenon and that includes a test pressure level capable of eliminating potentially harmful defects; (2) to require metallurgical

12/ Exemption 7 of the Freedom of Information Act allows agencies to withhold from the public any investigative records related to an enforcement case if their disclosure might interfere with the enforcement proceedings. However, there is no requirement that these documents be withheld.

13/ Failure of a pipeline at a pressure below a previously conducted hydrostatic test pressure as a result of the extension of near-critical size defects.

testing of all seam failures unless the failure mechanism is determined by an independent metallurgist; and (3) to establish a maximum allowable operating pressure based on the results of the tests.

On August 18, 1986, officials of the City of Mounds View, Minnesota, and representatives of the DOT (the RSPA administrator, the OPS director, and the central region chief) met to discuss among other issues, the final order and the Safety Board's recommendation for amending the final order. During this meeting, the OPS director acknowledged that before developing the final order it met with WPL officials to discuss what actions would have to be taken before line 2N could be returned to service. He pointed out that he attempted to obtain an agreement with WPL to test the line to 2,200 psig as one condition; however, he was not successful. He stated further that while WPL did not explain its objection to the 2,200 psig test pressure, he was able to obtain WPL's agreement to test the line to 1,900 psig, the test pressure required by the final order. He explained that he felt confident that WPL would carry out the provisions of the final order because WPL had agreed to it and, in effect, what they did was to have WPL waive its rights to any hearing relative to the final order.

Also during this meeting, DOT representative and Mounds View officials discussed the provisions of the Safety Board's recommendation for amending the final order and other concerns about deficiencies it believe existed in the final order. As a result of these discussions, the DOT representatives agreed to several modifications to the final order, indicating that WPL was willing to consider additional requirements and that the DOT would work with WPL to try to get it to accept modification of the final order.

On August 22, 1986, OPS issued an amended final order to require that WPL: (1) metallurgically examine all failures that occurred during the hydrostatic test, (2) not operate the line without the approval of the OPS and the completion of an operational reliability analysis, and (3) operate the line at a pressure no greater than 900 psig. The amended order did not exclude corrosion as a causal factor. The operational reliability analysis was designed to perform six functions: (1) establish the causes of any failures due to the hydrostatic test, (2) establish a relationship between defect size and pressure at failure, (3) establish representative fracture toughness and crack growth rate, (4) review research on pipeline monitoring inspection methods, (5) develop a basis upon which to establish a maximum operating pressure (MOP), and (6) estimate the safe operating life at this MOP.

Three seam failures occurred during the hydrostatic testing ordered by OPS. All occurred at pressures greater than 1,900 psig. The failures occurred at milepost 14.00 on the Superior branch and mileposts 101.15, and 125.16 on the Minneapolis to Duluth main line.

As a result of its investigation of the Mounds View accident, on October 3, 1986, OPS issued a Notice of Probable Violation and Proposed Civil Penalty. This notice stated that "It appears you have committed probable violations. . . ." The violations were listed as: (1) 195.401, failure to correct a situation that could adversely affect the safe operation of the pipeline within a reasonable period of time. OPS stated that p/s potentials for the first 7.5 miles of line 2N illustrated such a condition; (2) 195.402, preparing and following a manual of procedures. OPS stated that WPL had failed to follow its procedures by allowing the p/s potentials on line 2N to fall below -0.85 volt; (3) 195.402, procedures for establishing and maintaining liaison with public officials. OPS stated that WPL's procedures did not include provisions for this; and (4) 195.414, operating a pipeline without cathodic protection as required. P/s readings indicated that the cathodic protection levels did not meet the accepted levels. A preliminary civil penalty of $30,000 was proposed.

On October 29, 1986, WPL requested a hearing to discuss the probable violations; a hearing was scheduled for December 18, 1986. On December 12, 1986, OPS issued an amendment to the notice. The notice stated that additional information had become available which indicated that corrosion might have played a part in the failure of the pipe. Based on this information and information it had reviewed earlier, OPS increased the amount of the proposed civil penalty to $200,000. The hearing was postponed to allow WPL the required amount of response time.

A hearing was conducted on February 5, 1987. WPL contended that the probable violations regarding its cathodic protection system should be combined into one violation. In addition, regarding the probable violation of 195.402(c)(12), WPL stated that it "does not believe that the Office of Pipeline Safety or the Department of Transportation has ever acknowledged or enforced a requirement that police and fire departments in every town and county along an interstate pipeline have to be contacted. . . . WPL does not believe that its written procedures are in violation . . . but . . . in the event that said procedures are found to be inadequate, WPL should not be cited. 195.402(b) requires the Secretary of the DOT to issue a notice of amendment — not a citation for probable violation."

On March 11, 1987, WPL withdrew its contest of the violations and requested that the department consider the evidence presented at the February hearing when considering the assessment of any civil penalty. At the hearing, WPL presented testimony and exhibits that had been presented at the Safety Board's hearing. In addition, WPL presented a listing of the p/s potentials for line 2N. (See table 2.)

On March 13, 1987, OPS issued a final order on the case and assessed WPL a civil penalty of $115,000. In the final order, the director of OPS adopted WPL's argument that it should have notified WPL of the alleged inadequacy and allowed correction in accordance with the procedure provided in that section. The director stated that "since it has been OPS' policy to follow that procedure, it should do so in this case instead of alleging violation. Accordingly, I do not find the Respondent in violation of 195.402." Also, the final order noted that WPL's "compliance history has not been out of line with that of other hazardous liquid operators. WPL paid the civil penalty on March 27, 1987, but stated that it did not admit to any of the violations.

Tests and Research

A 40-foot 3-inch section which contained the failure was removed from the pipeline and taken to a metallurgical laboratory in Minnesota for testing. The pipe was subjected to dimensional analysis, an evaluation of the crack surfaces, radiography of the uncracked portion of the electric resistance weld, metallographic evaluation, and chemical and mechanical testing of the pipe metal properties. The pipe complied with the 1968 edition of the American Petroleum Institute's (API) specification 5LX, grade 42 for ERW pipe.

The pipe contained a crack, approximately 90 inches long, which was located along the electric resistance weld. The maximum opening of the crack was measured at two locations near the midpoint of the length of the crack and found to be 0.31 inch. The pipe was cut so that the fracture surfaces could be examined. Over most of its length, the crack surface was flat and perpendicular to both the interior and exterior pipe surfaces, typical of a brittle fracture mode.

The center portion of the length of the crack contained dark discolored areas on the fracture faces nearest to the exterior surface of the pipe. Chevron markings on the fracture pointed back to a discolored area located at one of the positions of greatest crack opening, indicating that this area was the origin of the crack.

Electron microscopic examinations of the origin area and other portions of the crack face revealed that the darkly discolored areas were relatively smooth and contained no fracture features. All areas outside the discolored areas contained at least some cleavage features, typical of a brittle overstress separation. No evidence of fatigue cracking was found, although corrosion may have eliminated evidence of other failure mechanisms.

Metallographic examination of various sections of the electric resistance weld showed that the dark discolored areas on the mating faces of the crack formed a V-notch. (See figures 4 and 5.) Metal flow lines beneath portions of the dark discolored areas could only have been produced during the welding process, indicating that the mating faces of the crack in the discolored areas were in close contact at the time of welding. The loss ofmaterial from the dark discolored areas appeared to be the result of corrosion. Corrosion also was noted on the exterior surface of the pipe in the vicinity of the discolored areas of the crack.

Impact testing indicated relatively low toughness across the weld seam. Low toughness in the weld contributes to a brittle fracture mode.

Radiographic examination of unfailed sections of the weld seam revealed 17 minor defect indications within a 30-foot section of the weld seam. Two sections with defect indications were hydrostatically tested. The test pressures were far above the maximum allowable operating pressure of 1,500 psig. One section was tested to 4,450 psi, at which point the test equipment began to leak and the test was stopped. The other section was pressurized to 4,250 psi, at which point the seam ruptured. The fracture along the ruptured seam was examined. The fracture appeared to stem from a small area of incomplete fusion of the weld seam.

Other Information

Hydrostatic Testing and the Safe Service Life of Pipelines.—At a recent symposium on line pipe research, Battelle Laboratories (Battelle) reported that:

> Hydrostatic testing is a general means of demonstrating pipeline integrity. It validates, in both a legal and a practical sense, the maximum allowable operating pressure of a new pipeline. It can also be used to revalidate the maximum allowable operating pressure of an existing pipeline. The potential for service growth of environmentally caused defects makes the control of such defects by hydrostatic testing less reliable than for defects that do not grow. 14/

The report prepared by Battelle indicates that the effectiveness of hydrostatic testing is related to the ratio of the test pressure to the operating pressure. The theory is that testing a pipeline to a pressure higher than its maximum operating pressure will eliminate all defects which would cause the pipeline to fail at normal operating

14/ Kiefner, J.F., "Evaluating Pipeline Integrity-Flaw Behavior During and Following High Pressure Testing," 7th Symposium on Line Pipe Research, Pipeline Research Committee of the American Gas Association, Houston, Texas, November 1986.

Figure 4.—Cross-sections of pipe near fracture origin.

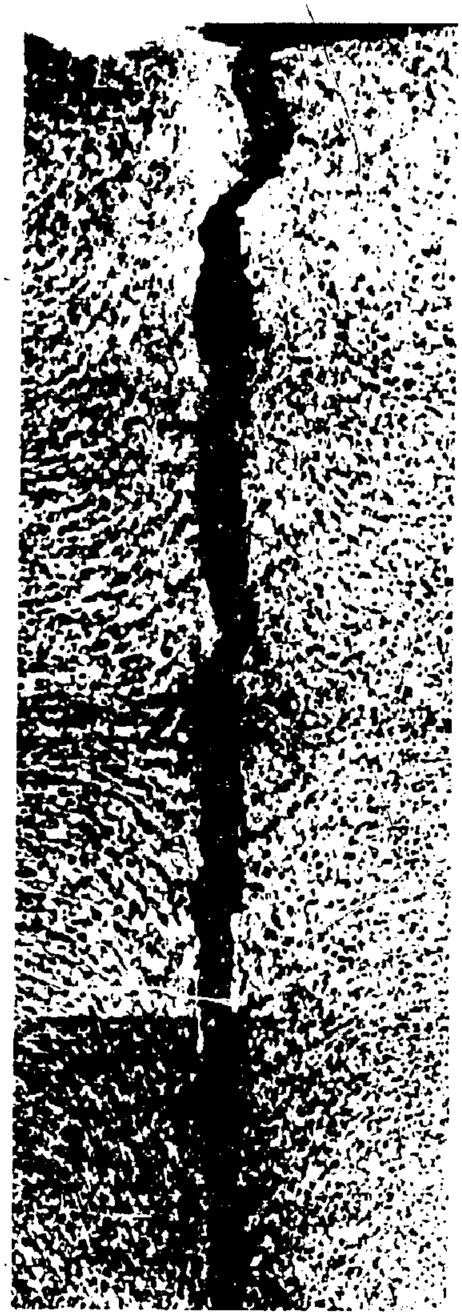


Figure 5.—Cross-section of pipe at section without defects.

pressures. The greater the ratio of the test pressure to the operating pressure, the greater the assurance that the pipeline will not fail during normal operations. The report states that a defect may grow as the pressure on it is increased and decreased. As a result of this growth, the pipeline may eventually fail at a pressure lower than its previous operating pressure (pressure reversal). The report also states that by testing (or retesting) the pipe to a sufficiently high hydrostatic test pressure the likelihood of a pressure reversal failure during normal operation can be dramatically reduced. However, the growth of any remaining defects either by cycling or from environmental factors can reduce the effectiveness of hydrostatic tests. Consequently, pipelines may need to undergo hydrostatic retesting or be nondestructively examined at regular intervals.

In 1985, Battelle reported on a model it had developed to predict the intervals at which a pipeline should be retested based on the hydrostatic test pressure and the number and range of pressure cycles under which it operates. 15/ The model considers fatigue crack growth from pressure cycles but not defect growth mechanisms, such as corrosion or stress corrosion cracking.

If a pipeline is subject to frequent and large pressure cycles, crack growth can be a factor in pipeline serviceability. For a given hydrostatic test pressure, the safe service life (that period of time between hydrostatic tests for which it can be assumed that the pipe will not fail) is inversely proportional to the number and range of pressure cycles. The greater the ratio of hydrostatic test pressure to operating pressure (the model gives its examples as percent of the Specified Minimum Yield Strength (SMYS) of the pipe), the longer the service life of the pipe. Thus, for some pipelines, given their operating characteristics, pressure cycles would not be expected to cause crack growth induced failures during the useful life of the pipe, while other pipelines might need periodic hydrostatic retesting to ensure continued safe service.

In an example, Battelle calculated the time to failure for a hypothetical pipeline operating at 72 percent of its SMYS. The pipe was tested to 90 percent of its SMYS, 100 percent of its SMYS, and 110 percent of its SMYS. The model predicted that the higher the hydrostatic test pressure, the longer the safe service period between retests. For a frequency of 200 cycles per year at 250 psi variation per cycle, the retest period for a pipe tested to 90 percent SMYS was 33.5 years; however, for a pipe tested to 100 percent of its SMYS, the retest period was 120 years. Battelle stated that the results appear to be conservative. The greater the pressure range in a cycle, the shorter the time between retests. For the same cycle frequency but with a range of 850 psig, the retest interval for a 90 percent test drops to 2.8 years and for a 100 percent test, to 9 years.

Battelle's testing showed that the data generated by the model agreed with actual pressure cycle data. However, the model does not account for environmentally caused growth of flaws which would decrease the safe time between hydrostatic tests.

<u>ERW Pipe.</u>—ERW is a welding process in the manufacturing of pipe which uses electric resistance on the longitudinal edges of the pipe shaped parent metal to heat the edges. The longitudinal edges are then bonded together under pressure to create the pipe. ERW pipe can be manufactured using high frequency (450 kilo hertz) or low frequency (up to 240 hertz) electrical alternating currents. Low frequency welding requires greater care in maintaining the electrodes and in keeping the edges of the steel free of scale. The presence of scale on the edges of a metal to be bonded using low frequency ERW can cause incomplete bonding.

15/ Kiefner, J. F. and Forte, T. C., "Hydrostatic Retesting," Oil & Gas Journal, January 7, 1985 and January 14, 1985.

A retired electric weld manufacturing foreman and supervisor of J & L stated that after constructing the pipe lengths the weld seams were annealed and a section of each length of pipe was flattened to check the strength of the weld. According to the retired supervisor, after annealing "you forget that it was ever welded because it's now treated as if it were seamless." In addition, the supervisor stated that J & L hydrostatically tested each length of pipe. Of approximately 30,000 miles of ERW pipe manufactured by J & L between 1957 and 1984, about 15,000 miles were low frequency ERW pipe. 16/

About 59 percent of WPL's active pipelines are constructed of a combination of low and high frequency ERW pipe. WPL has ERW pipe from more than 14 different companies. (See appendix C.)

On July 9, 1986, the OPS reviewed its files for information on the frequency and number of ERW seam failures. The review revealed that between 1968 and October 1986, 79 hazardous liquid pipeline ERW seam failures occurred which involved 12 fatalities and 5 injuries. These accidents account for 2 percent of the total number of hazardous liquid pipelines accidents that have been reported since 1968 and represent 13 percent of the fatalities.

According to the director of OPS, its data on ERW seam failures was "somewhat meager." The present forms used for reporting accidents do not specifically ask if the failure involved an ERW weld seam. Because it did not have complete or accurate data, OPS, in cooperation with the API, planned to solicit information from gas and liquid pipeline operators on the amount and characteristics of their ERW pipe. On January 20, 1987, the API informed OPS that its members could not provide any information to OPS on the amount and characteristics of any pre-1970 pipe in use as the OPS had requested. The 1970 date was chosen, according to OPS, because its data showed that most of the accidents involving ERW pipe involved pipe installed in 1970 or earlier. OPS has yet to require operators to submit this data or to obtain it through other means.

Research at Battelle on ERW pipe (unrelated to this accident) revealed evidence of selective corrosion which forms an axial V-shaped groove in the weld seams. According to Battelle researchers, the corrosion is caused by differences in the metal structure between the weld seam and the parent metal, thus creating a local corrosion cell. 17/

Causes of Failures.—In 1962, the American Gas Association published research on the failure modes of pipelines. 18/ The summary of this work stated that:

> . . . there is always a gross defect of some kind at the origin of a leak or a break. The more prominent types were identified as defects in welds, [emphasis added], external damage to the pipe wall, . . . hard spots in the pipe wall . . . and fatigue cracks produced by cyclic stresses during shipment of the pipe from the mill to the job site. A few operational failures have been observed which occurred after several years of operation. These initiated at a defect that existed at the time of construction, and the specific reasons for the time delay are not known at the present time.

16/ Neither the DOT nor any other organization collects data on the types of materials installed in pipeline sufficient to determine the miles of ERW pipe (either low or high frequency) in use in gas and liquid pipelines.
17/ Metals Handbook, Vol. 10, 9th Edition, 1986, Failure Analysis and Prevention, "Failures of Pipelines" Eiber, R. J. and Kiefner, J. F., Battelle Columbus Laboratories.
18/ "Research on the Properties of Line Pipe," American Gas Association, 1962.

WPL Public Education Program.—In 1981, WPL began using an educational program which had been developed by the API in cooperation with WPL and other hazardous liquid pipeline operators. WPL stated that in 1981 it provided pipeline system maps and two API publications to landowners/tenants along the WPL pipeline right-of-way. One publication identified pipeline markers and the second, a general brochure, discussed what to do in the event of a pipeline leak. Between 1980 and 1983, advertisements which provided information on pipeline markers and the actions to take in the event of a suspected pipeline leak were placed in city newspapers along the pipeline route, including newspapers in the Twin Cities area. (See figure 6.) In 1984 and 1985, public service announcements, similar in content to the API pamphlets and the newspaper ads, were broadcast on television. Except for some of the information distributed in 1981, none of the printed educational materials mentioned WPL.

WPL pipeline markers are located at points where pipelines cross roads and occasionally, in the middle of blocks. The markers are checked on a regular basis, and they also are checked by WPL personnel when work is being performed in the area. The markers provide the name of the pipeline owner, corporate and local telephone numbers to be called before beginning excavating activities or in the event of an emergency, the milepost location, and the information that petroleum is carried in the line. (See figure 7.)

Safety Board investigators interviewed the residents of the accident area shortly after the accident. The interviews revealed that, despite WPL's public education program, 24 of the 39 persons interviewed were not aware of the presence of the pipeline. One third of the persons not aware of the presence of the pipeline had seen the markers but had not paid attention to what they represented. Of the 15 who were aware of the pipeline, 7 knew of the pipeline because they remembered its construction rather than because of the presence of the pipeline markers.

WPL Liaison with the Fire Department.—The Spring Lake Park, Blaine, Mounds View fire department is a volunteer department with a paid chief. There are 78 persons in the department at five stations.

In addition to general hazardous materials training, the fire department has received training on responding to natural gas emergencies from Northern States Power, the local natural gas distribution company. The fire department involved in the accident had not received any training from WPL nor had WPL coordinated any emergency plans with the fire department because its jurisdiction did not include a WPL pump station or terminal. The fire department did not have a map showing the route of the WPL pipeline through the community. However, the chief said that he knew of the presence of the line because of his many years of service with the fire department.

ANALYSIS

Pipeline Rupture

The initial examination of the failed pipe revealed that corrosion had been active on the exterior surface of the pipe in the vicinity of the fracture initiation. Also, metallographic sections throughout the mating faces of the crack showed that the dark discolored V-notch areas had been in contact with each other when originally manufactured, and that corrosive attack from the exterior of the pipe was most likely the mechanism which produced the V-notch areas. The external surface and V notch corrosion areas were most likely located at a breech in the protective coating of the pipeline. The corrosion occurred as a result of an inadequate level of cathodic protection. WPL's annual

The Minneapolis Star 9C
Thursday, Nov. 13, 1980

Pipelines...
make good neighbors

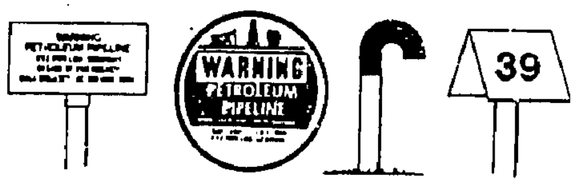
America has over 220,000 miles of petroleum pipelines carrying crude oil and products to refineries and storage terminals across the United States. Each day, more than 1.5 billion ton/miles of crude oil and products move through this network. These pipelines have a safety record *second to none* in the transportation industry . . . and we want you to help us keep it that way.

liquids on or a mist above the ground in the area of a pipeline

- Flames originating from an opening in the ground

If you become aware of a pipeline leak . . .

- LEAVE THE LEAK AREA IMMEDIATELY.
- Avoid driving into vapor clouds.
- Avoid direct contact with the escaping liquids.



GROUND MARKER | GROUND MARKER | CASING VENT | AERIAL MARKER

When you see signs like those shown above, they tell you that there's a pipeline nearby. If it's underground, you can't see it, of course. But it's there, working quietly to provide energy for you and other consumers throughout this nation.

Some of these signs list the commodity transported in the pipeline, the name of the operator and a telephone number where the operator's representative can be reached at all times.

Although pipelines have an exceptionally good safety record, once in a while a leak can occur. Indications of a leak might include:

- A strange or unusual odor in the vicinity of a pipeline
- A hissing or roaring sound (caused by petroleum or product escaping from a pipeline)
- A dense white cloud or fog
- A spot of dead or discolored vegetation
- An accumulation of petroleum
- Avoid creating sparks or sources of heat which could cause the liquids or vapor to ignite and burn. If you find yourself in a suspected vapor area, do not light a match, start an engine or even switch on an electric light.
- Notify the pipeline operator as soon as you reach a safe area. Call collect. Give your name, a description of the leak and its location. If you do not know who the pipeline operator is, call your local fire, police or sheriff's department, or the state police. Advise them of the nature and location of the emergency.

If you see someone digging near a pipeline or doing other construction work . . . or if you plan to do such work near a pipeline yourself . . . please call the telephone number shown on the sign and let the pipeline company know so damage can be avoided. It's in your interest . . . and the nation's.

America's Petroleum Pipelines

Pipelines are the safest way to move petroleum and products and you can help keep it that way!

Figure 6.—Newspaper advertisement on pipeline safety.

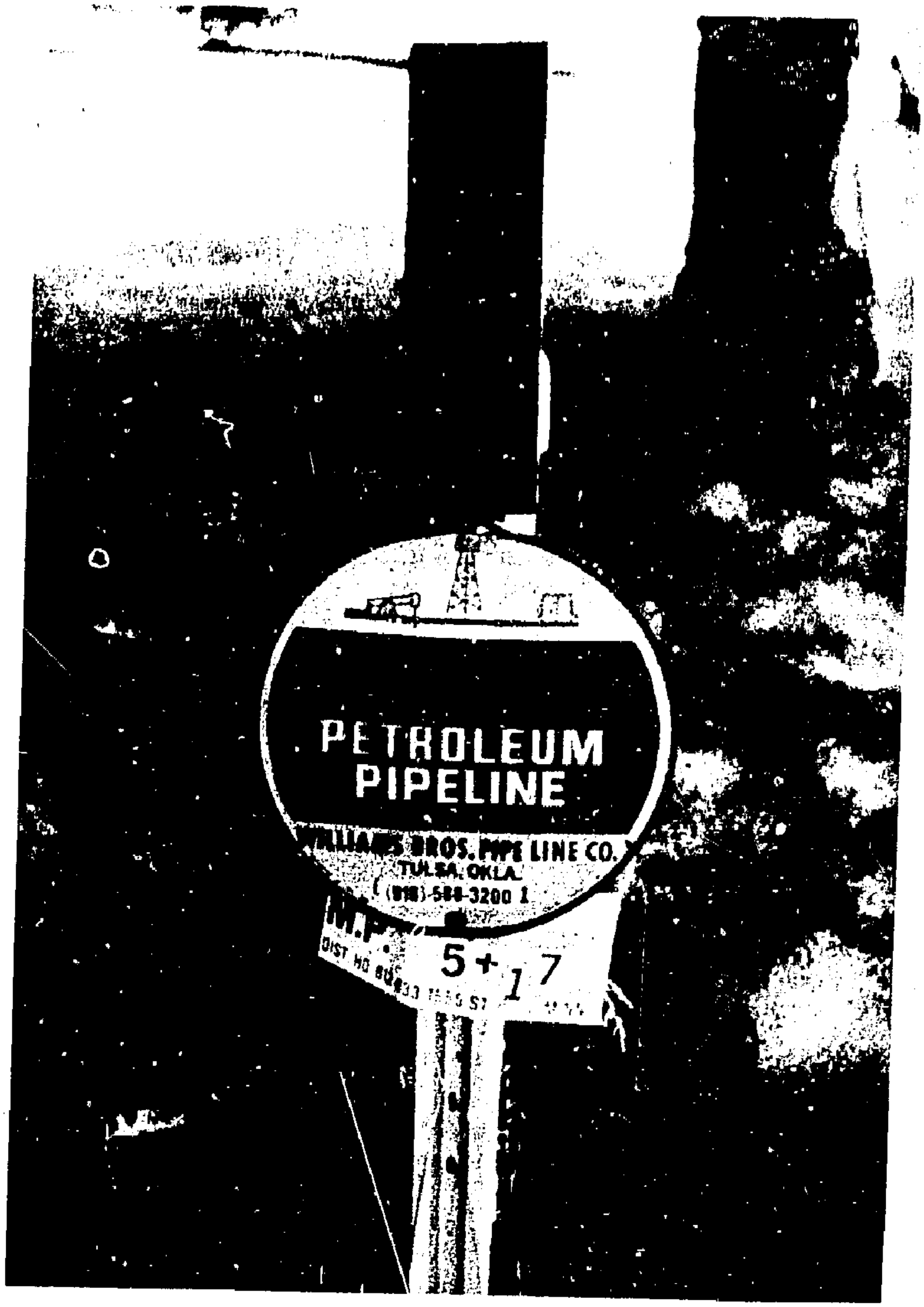


Figure 7.—Pipeline marker.

p/s surveys indicated that the level of cathodic protection was inadequate over a 5-year period and that the lowest levels of cathodic protection occurred during 1984 and 1985. The operating pressure at the time of the accident was below the line's MOP and would have been insufficient to cause an undamaged, defect free pipe to fail.

The corrosive attack in the failed pipe was concentrated along the weld line of the ERW seam, resulting in V-shaped notches along the seam. The corrosion notches in the seam were deep enough at some locations that the walls of the notches may have shielded the tip of the notch from whatever cathodic protection may have existed. Although the failed section of the pipe survived the 1984 hydrostatic test which was conducted at 1,900 psig, it ruptured while under a pressure of about 1,480 psig on the day of the accident. Therefore, the corrosion notches along the weld seam must have grown a significant amount from 1984 to the date of the accident. The pipe failed when the pressure exerted on it exceeded the remaining strength of the pipe within the corrosion damaged weld seam.

Although the metallurgical examination on the failed section of the pipe indicated that there was no evidence of fatigue cracking, corrosion may have eliminated any evidence. Therefore, the hydrostatic testing and the cyclic operations of the pipeline may have contributed to extensions of the corrosion notches in the weld seam.

When the pipeline ruptured, it allowed gasoline being pumped at about 1,480 psig to be released into the residential neighborhood. Even after the Minneapolis terminal was shutdown, gasoline under the head pressure of the remaining gasoline in the line continued to flow onto the residential streets. The car turning onto Long Lake Road provided the ignition source. Ignition had not occurred earlier because the expanding cloud of flammable vapor had not yet reached any of the many potential ignition sources in the neighborhood.

Cathodic Protection

In 1981, WPL was aware that line 2N was proving difficult to cathodically protect to a satisfactory level. Yet despite the p/s readings, WPL took 5 years to schedule corrective action for the line. While the Safety Board cannot say that there was no cathodic protection on the line, whatever protection was provided did not meet even WPL's own standard of -0.85 volt. The Safety Board is concerned about the amount of time it took for corrective action to be scheduled. Previous accidents investigated by the Safety Board have shown that substantial corrosion can be occurring even when the level of cathodic protection meets prescribed levels. For this reason, p/s readings should not be the only data considered by a pipeline company when assessing the effectiveness of its cathodic protection system.

On April 27, 1985, natural gas under 990 psig ruptured the No. 10 pipeline of the Texas Eastern Gas Pipeline Company system. The rupture was in an area weakened by atmospheric corrosion that was located within the pipeline's casing under Kentucky State highway 90 near Beaumont, Kentucky. On February 21, 1986, natural gas under 987 psig ruptured the No. 15 pipeline of the Texas Eastern Gas Pipeline system. The rupture was in an area weakened by galvanic corrosion and was located south of Kentucky State highway 52 near Lancaster, Kentucky. 19/ The Safety Board stated that in the Beaumont accident:

19/ Pipeline Accident Report—"Texas Eastern Pipeline Ruptures and Fires at Beaumont, Kentucky, on April 27, 1985, and at Lancaster, Kentucky, on February 21, 1986" (NTSB/PAR-87/1)

> The only practical methods available to the gas company for detecting the atmospheric corrosion damage to the pipeline within the casing were periodic hydrostatic testing of the pipeline to confirm its integrity and the use of in-line inspection equipment. It was already performing in-line inspections of its pipelines in areas where its annual corrosion test station monitoring or close interval surveys indicated unusual or abnormal conditions. The pipeline crossing under State highway 90 had not been subject to an in-line inspection because its corrosion monitoring indicated that the protection level of the line coming into and going out of the casing was in excess of that required by Federal regulations.

Regarding the Lancaster accident, the Board stated that:

> The gas company's annual corrosion monitoring at test stations and its previous close interval survey provided no indication that corrosion of the pipe was occurring. In fact, the corrosion monitoring actually showed higher negative voltages than the required negative 0.85 volt, which indicated to the gas company that the pipe was well protected against corrosion. The corroded segment was identified . . . 5 months before the accident through the gas company's use of an in-line inspection.

Corrosion can even be more severe when the level of cathodic protection does not meet recognized standards. Thus, the detection of corrosion becomes the challenge. The use of p/s readings is one accepted method of monitoring for corrosion and, in this accident, the low potential readings should have led WPL to suspect corrosion and to have taken corrective action.

In addition to pipe-to-soil readings, in-line inspection equipment is used to detect corrosion. The accidents in Beaumont and Lancaster, Kentucky show the advantage of using this method. However, when dealing with corrosion within the weld seam of a pipe, a problem occurs. The design of in-line inspection equipment limits the detection of corrosion in the weld seam because the internal weld seam disturbs the sensors of in-line inspection equipment. Because corrosion in or closely adjacent to weld seams cannot readily be detected by in-line inspection tools and because low frequency ERW weld seams are known to be subject to preferential corrosion, the Board is concerned that there may be other areas on the first 10 miles of line 2N where the low frequency weld seam has been and may now be subject to corrosion.

Rapid Shutdown

WPL personnel recognized the need to isolate the section of the pipeline involving the failure and did shut down the line. However, they did not take the most expeditious method of accomplishing the task. The first indication of the failure occurred at 4:20 a.m.; however, the section of the pipeline containing the failure was not isolated until 6 a.m., about 1 1/2 hours after the failure was first identified.

Although the dispatcher shut down the pump station within 8 minutes after the rapid pressure drop, he did not know the cause of the pressure drop. Neither the TO nor the dispatcher had the operating experience or the training to realize that line 2N had ruptured. Further, WPL's operating procedures did not provide any guidance for recognizing a pipeline rupture. The most appropriate response to the alarms alerting the employees to the low discharge pressure condition would have been to consult the flow meter, to determine that product was continuing to flow through the pipeline, and to initiate an emergency shutdown of the pumping system. The TO testified that he was not immediately aware that the low discharge pressure indicated any abnormal operational situation. His attributing the pressure loss to a plugged strainer may have been a reasonable initial response considering that his interpretation was based upon his previously having experienced problems with plugged strainers and his never having experienced a rupture of the pipeline. However, reasonable expectations and prudent cautionary actions are two different things. The consequences to public safety of a plugged strainer are far less than those of a line rupture. To minimize the damage to the pipeline and danger to the public, WPL should revise its operating procedures to include information sufficient for TOs and other operational employees to quickly determine the appropriate actions to take in the event of abnormal operating conditions or emergency conditions.

Once a rupture was suspected, none of the WPL personnel considered the effect the rupture would have on the area surrounding the pipeline. This could have been done easily in the dispatch center in Tulsa by consulting the company's profile map which contained aerial photographs of the pipeline right-of-way. The local northern division personnel should have been familiar with the environment surrounding the first 10 miles of line 2N due to living and working in the general area. While most of the line is in rural areas, the first 10 miles of the line passes through commercial and residential areas where quick response is needed to minimize the danger to the public. While the dispatch shift supervisor had advised that the rupture was within 10 miles of the Minneapolis terminal, it was not until WPL was notified by the RCSO that actions were initiated to close the valve at milepost 10. Even then, it was not closed with the urgency it deserved. Up to that time, the WPL actions were the same as they would have been if the line had ruptured in a rural area. During the 1 hour 40 minutes between the time the line ruptured and the valve at milepost 10 was closed, gasoline flowed uncontrolled into the residential neighborhood. Had WPL personnel considered the occupancy of the area surrounding the line earlier, action might have been taken to close the milepost 10 valve and reduce the potential risks to the public despite any doubts as to the exact location of the pipeline rupture.

The delay in closing the milepost 10 line valve allowed fuel to continue flowing to the residential area after the Minneapolis terminal was shut down because the slope of the line allowed liquid not being pumped to drain south toward the Minneapolis Terminal. Key WPL personnel knew the approximate location of the leak, but they did not take the most expeditious action to close the valve. Although the exact location of the leak was not known until 5 a.m., WPL could have sent someone to close the milepost 10 valve around 4:30 a.m., thus greatly decreasing the amount of gasoline released. Further, the northern district manager could have proceeded from his residence directly to milepost 10 and closed the valve at least 1/2 hour earlier. WPL should examine its emergency procedures regarding the closing of line valves during emergencies and should revise them as necessary so that failed sections of its pipelines will be isolated as rapidly as possible.

Had the valve at milepost 10 been remotely operable or had ROVs been installed on the line at the time of the accident, the pipeline could have been shut down by the dispatcher soon after the failure was detected, thereby decreasing substantially the amount of product released into the neighborhoods. Ignition of the fuel may not have been prevented; however, the extent and severity of the damage could have been reduced. With the exception of the ROVs installed after the accident at mileposts 2.67 and 8.38 to the north and south of Mounds View, WPL currently uses ROVs only where they will be of assistance in controlling product movement. WPL should examine the need for installing ROVs on its pipeline to isolate sections of the pipeline in populated areas in the event of a failure.

In its 1971 study on the rapid shutdown of pipelines, 20/ the Safety Board found that "By reducing the time required to shutdown a failed pipeline system to minimize the loss of materials, the hazardous effects to the public, to persons working near a pipeline, and to property can be minimized or eliminated." Since 1971, the Safety Board has made several recommendations to the DOT regarding the need for regulations on rapid shutdown systems. In response to these recommendations, the DOT has stated that studies show that the installation of rapid shutdown systems or closely spaced valves along the entire pipeline length is not cost effective and thus it will not order them. The Safety Board believes, however, that installation of such equipment should be based on the population at risk, i.e., those persons who live or work near a pipeline. Failures of pipelines in residential or business areas expose large numbers of persons and thus present far greater risks to public safety than do similar failures in remote, sparsely populated areas. Therefore, an operator's ability to minimize the consequences of a failure in highly populated areas should be correspondingly greater. The Safety Board remains concerned about the rapid isolation of failed sections of pipelines and urges the DOT to require the installation of ROVs on pipelines that pass through or near highly populated areas.

Training

WPL's training program depends heavily on work experience, supervision, generic (general pipeline topics not specific to WPL) training courses, and unsupervised readings of its operations manuals. This type of training program is based on activities that occur within the context of daily work routines, and it provides little or no learning about actions to take in response to emergencies or other abnormal events. The Safety Board believes that such training has serious deficiencies. Work experience, supervision, and nonevaluated readings are typically undertaken without specific learning objectives or without measurement to evaluate the accomplishment of these objectives. Thus, only when there is an accident do employees have an opportunity to learn what is required during abnormal events, such as pipe failures. Proper training could have enabled the TO and the dispatcher to quickly recognize that a rupture had occurred as the dispatch shift supervisor did.

Work experience is not an adequate substitute for training which includes guidelines for what is to be accomplished and a means of evaluating what has been learned. WPL needs a planned, coordinated approach for preparing its employees to accomplish work tasks and to cope with emergencies. Its current training programs, with the exception of the computer modules developed by the consultant, lack continuity. Although the training and evaluation programs for hourly employes reflect an awareness of management for addressing employee needs, there is no apparent organization in administering or conducting training to address those needs.

In addition, the generic training courses offered by WPL, while well structured, did little to acquaint WPL employees with the necessary actions to take in the event of an emergency. Learning to extinguish small fires using fire extinguishers is necessary but has little application to fires and other accidents which may occur outside station or terminal boundaries. Generic training, by itself, provides no way to assure that transfer of that learning to normal operations or emergencies will occur. WPL should practice emergency scenarios through drills or other means to ensure that personnel involved in the operation of the pipeline know the proper actions to take in the event of a failure. Such training also will improve the transfer of learning from generic training to the actions required during an actual emergency. Had WPL employees received training to prepare

20/ "Special Study of the Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown" (NTSB-PSS-71-1).

them to respond to pipeline ruptures, there might not have been such a delay in closing the valve at milepost 10 because the consequences of a delay would have been made known to them.

On March 23, 1987, the RSPA issued an advance notice of proposed rulemaking (ANPRM) on pipeline operator qualifications, Docket No. PS-94. The ANPRM requested comments on the need for regulations or a certification program regarding the qualifications of personnel who operate and maintain pipelines. The ANPRM requested comments on: (1) whether the competency of operator personnel provides a threat to public safety; (2) if so, where should Federal action be applied; (3) what additional training regulations should be developed; and (4) what should a licensing or certification program cover. The Safety Board provided comments to the docket based on its previous investigations. The Board urges the RSPA to complete this rulemaking by establishing guidelines or other criteria for operators to use when developing, conducting, and evaluating their training programs.

DOT Pipeline Safety Program

Monitoring and Inspection.—Although OPS has devoted a considerable amount of its available time to working with WPL, it appears that much of its effort has been in the form of reaction to accidents and not proactive efforts to ensure that WPL operations uniformly comply with the established safety regulations. Accident related inspections have been so focused on operational aspects related to the accidents that inspectors have ignored all others. As the Safety Board's review of the OPS files on WPL showed, there were no common factors examined in all of the inspections. The Safety Board believes that this lack of common factors between inspections denied OPS the opportunity to compare the results of various inspections and prevented it from identifying company-wide problems within WPL.

If OPS had a more thorough inspection program, the Safety Board believes that it might have discovered the problems with WPL's cathodic protection of line 2N before this accident. OPS investigated at least two accidents involving WPL in which corrosion was the cause (one in Minnesota), and several other accidents in which past corrosion problems were discovered; yet, it never examined WPL's overall cathodic protection program for systematic problems.

Lack of thoroughness in its inspections is not the only problem. Disregarding past violations appeared to be a problem as well. While OPS has recognized that WPL's "history of compliance with the regulations has not been a shining example of 'strict compliance'" it appears to have had no effect on the level of successive enforcement cases. Although the OPS central region initiated enforcement actions as a result of 12 of the 17 initial inspections, there was no apparent increase in the severity of these actions. For example, warning letters, the lowest level of enforcement action, continued to be the primary enforcement action taken by OPS even after it levied the civil penalty in which WPL's compliance history was criticized. The Safety Board believes that this type of action did not give WPL any motivation to comply with the regulations in the future. In reviewing WPL's response to previous OPS enforcement actions, it is clear that WPL was not concerned about any actions OPS might take if it discovered violations of the Federal pipeline safety regulations. In the 1981 enforcement case involving nondestructive testing, WPL was told explicitly that the welds it made must be tested in a certain manner, yet WPL did not perform the required tests. In the 1984 enforcement case, it delayed for more than 2 years sending OPS a copy of the revised operating procedures.

The Safety Board does not believe that the problems identified in the OPS enforcement program are limited entirely to WPL or to the OPS central region. In the enforcement action related to this accident, OPS stated that, at present, WPL's compliance history is similar to that of other hazardous liquid pipeline operators. Regarding the OPS problems, the forms and policies used by the central region follow those given in OPS' enforcement procedures training course. In addition, the director of OPS stated that he agreed with central region chief's policies, indicating that those policies are, indeed, OPS policies.

The Safety Board does not agree with the OPS policy of not disclosing any information on enforcement actions before closure of a case. OPS enforcement proceedings should be conducted in the public view. At a minimum, OPS should provide public notice of proposed charges and remedies before the case is resolved. OPS' accountability for its enforcement actions would be increased, and persons directly at risk from pipeline operations would be aware of OPS actions to protect public safety.

Compliance with Federal Regulations.—At present, OPS must depend on voluntary compliance with the Federal regulations to ensure the safety of the public from pipeline accidents. There simply are not enough pipeline investigators to effectively inspect every operator annually and to perform their other duties. To perform inspections of each operator in the central region each year would require 272 inspection days, 47 days more than the approximately 225 inspection days the central region had available. (The number of available inspection days was determined based on two inspectors devoting 50 percent of their time.) If the "mere presence" of OPS is to have the effect of encouraging operators to comply with the pipeline safety regulations, then its efforts need to call more attention to its presence. Therefore, its efforts must motivate compliance by operators with the pipeline safety regulations.

The manner in which OPS has used its sanctions has been insufficient to motivate compliance with the pipeline safety regulations. For any regulatory program to be effective, it must have and use sanctions designed to motivate compliance. An understaffed program, such as that of OPS, cannot realistically expect to be effective without the use of sanctions to the extent that such sanctions motivate operators to implement aggressive internal compliance assurance programs. While the number of enforcement actions initiated has risen, the OPS has increased its use of enforcement actions, such as warning letters, while the average civil penalty assessed has fallen. Also, as demonstrated by OPS actions related to the order issued to WPL shortly after this accident, OPS negotiates with pipeline operators about its enforcement action.

Although OPS assessed a large civil penalty against WPL, it was only after its investigation of this accident involving loss of life. If pipeline operators were concerned that similarly severe actions might be taken against them for major violations discovered during routine inspections, the Safety Board believes there would be greater compliance with the pipeline safety regulations. The Safety Board believes that OPS should modify its enforcement policy to more effectively use its sanctions to motivate operator compliance and, without negotiation with the regulated operator before issuing any orders, to develop corrective actions which must be taken as part of the sanctions to protect the public's safety.

While a change in OPS' enforcement policy is necessary, that alone will not correct all the problems with the enforcement program. To adequately protect public safety, OPS staffing needs to be augmented. At the time of the accident at Mounds View, the OPS had only 16 inspectors nationwide. In the central region, which has complete responsibility for the WPL pipeline system, there were two inspectors available to inspect 113 interstate pipeline operators and to monitor the intrastate pipeline safety inspection and enforcement program for 10 States.

The Safety Board believes this number of inspectors is insufficient to allow thorough, periodic reviews of each operator. Additionally. just performing the initial review would allow no time for analyses of the various operators' performances to determine which ones require comprehensive monitoring, to actually perform any comprehensive monitoring, to participate in investigations of accidents and incidents, or to respond to public reports of potentially unsafe conditions.

Considering that only 11 States now serve as agents for the OPS in inspecting interstate natural gas pipelines, finding ways to obtain similar status for the other States would greatly expand the number of inspectors available to the OPS. Similarly, consideration should be given to providing inspection powers to the States for interstate liquid pipeline operations.

Liquid Pipeline Regulations.—The Safety Board has long been concerned about the adequacy of the liquid pipeline safety regulations. Between 1970 and 1979, the Board made 19 recommendations (see appendix F) concerning the transportation of highly volatile liquids (HVL). Some of the recommendations were implemented and others were not. An accident investigation in 1983 brought to light many of the continuing problems with the regulations for the transportation of HVL by pipeline.

In 1983, the Safety Board investigated a liquefied petroleum gas pipeline rupture in West Odessa, Texas. 21/ As a result of the investigation, the Safety Board examined the development of 49 CFR 195. The Safety Board found that: 49 CFR Part 192 and 49 CFR Part 195 were primarily based on industry codes (ASA B31.8 for natural gas pipelines and ASA B31.4 for liquid pipelines). The gas code took into account population densities for the construction of pipelines while the liquid code did not. Furthermore, it found that 49 CFR Part 192 requires operators of natural gas pipelines that are located in areas where the population has increased significantly since the pipeline's installation to reevaluate and/or retest the pipeline to confirm that its margin of safety is adequate to reduce the maximum allowable operating pressure such that an adequate margin of safety is achieved. However, Part 195 does not require operators of liquid pipelines to take comparable action and, consequently, many liquid pipelines continue to operate without increasing the margin of safety even though the land adjacent to the pipeline may have become more densely populated. The margin of safety provided for liquid pipelines, especially for those that transport highly volatile liquids or liquids which possess toxic materials should be reevaluated periodically. Provisions for reevaluating safety factors, such as the provisions contained in 49 CFR 192.611 for natural gas pipeline, should be established for liquid pipelines which transport highly volatile or toxic liquids.

As a result of its findings in the West Odessa accident, the Safety Board recommended that the RSPA:

P-84-26

Amend Federal regulations governing pipelines that transport highly volatile liquids to require a level of safety for the public comparable to that now required for natural gas pipelines.

21/ Pipeline Accident Report--"Mid America Pipeline System Liquefied Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983" (NTSB/PAR-84/1).

On April 7, 1986, the RSPA responded that the maximum allowable operating pressure of gas pipelines was based on the maximum hoop stress levels corresponding to population densities. This was done, according to the response, to prevent long running fractures. The letter further stated that "In contrast, stress level does not appear to be a significant factor in HVL pipeline accidents. In fact, we are not aware of any HVL pipeline accident that has involved a long-running fracture . . ."

In a letter to the RSPA, the Board stated on August 20, 1986, that:

> . . . the Research and Special Programs Administration (RSPA) may have missed the thrust of this recommendation. The Safety Board is recommending that the safety standards for liquid pipelines be equivalent to natural gas pipeline standards . . . Based on our knowledge of the history of the ANSI B31.8 Code, the industry rationale for development of the population based class location criteria was not solely in response to its concern about fracture propagation; it was also in response to industry's over all concern about the increasing populations residing adjacent to its pipelines which initially were located in noninhabited areas . . . Furthermore, the Board did not make its assessment solely on the basis that the gas standards contained requirements tied to class locations rather its assessment was that the overall standards were not as stringent in many respects as those for gas pipelines.

The Board classified Safety Recommendation P-84-26 as "Open—Unacceptable Action."

In a letter dated March 2, 1987, the RSPA stated that it had issued an ANPRM on amendments to the safety standards for gas and hazardous liquid pipelines. The ANPRM issued at 52 FR 4361 on February 11, 1987, Docket P-92, was based, according to the RSPA, on various proposed legislative bills on pipeline safety. The Safety Board provided comments to the docket for this ANPRM. The Safety Board is pleased that the RSPA has issued this ANPRM and will look forward to the results of this action. The Board reclassified Safety Recommendation P-84-26 as "Open—Acceptable Action."

In the same letter, the RSPA informed the Safety Board that it is planning a research study in fiscal year 1988 to determine whether there is a difference in the levels of safety provided for liquid pipelines and for gas pipelines. The Safety Board believes that there is a difference and that the RSPA should take action to eliminate the difference in the levels of safety.

While the WPL pipeline did not transport a material classified by 49 CFR Part 195 as highly volatile or toxic, this accident demonstrates the need for an increased level of safety in 49 CFR Part 195. Although the area in Mounds View around the pipeline was populated when the pipeline was installed, the population increased without a corresponding change in the pipeline's level of safety. Residents of the accident area who were interviewed were relatively unaware of the pipeline's presence and hazards. The level of safety cannot be defined by one factor alone; it is the combination of several. An increase in the population around a pipeline should effect not only its operating pressure but such facets of pipeline operation as the development of emergency plans and surveillance. Pipeline failures in populated areas require a different response than similar failures in rural areas because of the increase in the population at risk. As populated areas expand, the need for surveillance will be greater than it is in remote areas. The Safety Board believes that this accident again demonstrates the need for more stringent liquid pipeline regulations.

ERW Pipe

In 1976, the Safety Board investigated an accident involving the release of liquefied petroleum gas near Whitharral, Texas. 22/ The pipeline, constructed of ERW pipe manufactured by Jones and Laughlin Steel Corporation, failed along a longitudinal weld seam. The pipe had been hydrostatically tested to a pressure of 1,660 psig, in 1960, and it failed at a pressure of 1,570. The pipeline company had experienced 14 longitudinal seam failures in the 8 years before the accident.

As a result of its investigation, on June 14, 1976, the Safety Board recommended that the DOT:

P-76-20

Review all pertinent data such as leak and failure reports submitted by liquid pipeline carriers to determine if longitudinal weld failures constitute a recurrent safety problem and take appropriate regulatory action if they do.

P-76-21

Request all pipeline companies which have installed ERW pipe manufactured by the Jones and Laughlin Steel Corporation to review their records on longitudinal seam failures and determine if the number of such failures is abnormally high. After DOT reviews these data, it should take necessary corrective actions.

In its response to Safety Recommendation P-76-20, the MTB stated that a review of its records on longitudinal weld seam failures found that statistically longitudinal weld seam failures have caused a very small percentage of failures and continue to become even more insignificant. The MTB also stated that regulatory action as appropriate for the problems identified would be taken. The recommendation was classified as "Closed—Acceptable Action."

In response to Safety Recommendation P-76-21, the MTB stated that it would not conduct the requested review since sufficient data were not available to perform a meaningful review of the performance of ERW pipe. Instead, MTB advised that it would ask all operators to conduct a thorough evaluation of the physical condition of their pipelines through a rulemaking. OPS has yet to issue such a rulemaking.

Comments received on the 1980 MTB ANPRM titled "Placing Longitudinal Welds Seams in Upper Half of Pipe," indicated that there were no problems with internal corrosion of ERW weld seams and that improved manufacturing techniques prevented the occurrence of insufficiently bonded weld seams. Safety Recommendation P-76-21 was closed at this time. The Board stated that, "Based on the information gathered . . . in your ANPRM it has been determined that further action on P-76-21 would no longer be productive. Therefore, this recommendation has also been classified as "Closed-No Longer Applicable."

22/ Brief of Accident Report, DCA-76-FP-016, Mid American Pipe Line System Pipeline Rupture and Fire, Whitharral, Texas, February 25, 1976.

The Safety Board again became concerned about the safety of ERW pipe when on February 24, 1986, a 40-foot section of a natural gas transmission pipeline operating at 750 psig ruptured near Cale, Arkansas. 23/ The line, which consisted of low frequency ERW pipe manufactured by Youngstown Sheet and Tube Company, had been installed in 1950 and had been hydrostatically tested to 960 psig in May 1977. Segments of the ruptured pipe were metallurgically examined. According to the metallurgy report, the fracture initiated in an area of the weld seam with a lack of fusion. The report stated that "The basic defect is believed to have been present from the manufacture of the pipe but may have since been sharpened and become more severe due to pressure fluctuations caused by the normal operation of the pipeline." However, the examination showed no obvious fatigue marks. Investigation of the accident in Cale showed that the operator had experienced three seam failures on this same line since 1975. In addition, some of its other lines also had experienced operating failures.

The Safety Board believes that the accidents in Whitharral, Cale, and Mounds View illustrate a safety problem that must be addressed. While the change from the use of low frequency to high frequency in ERW welding may have eliminated many of the weld defects that were found, low frequency pipe remains in use and continues to be an issue of concern in pipeline safety. The Safety Board believes that the OPS, with its admission that its ERW pipe data is meager, had no valid basis for determining that longitudinal weld seam failures in ERW pipe constituted an insignificant safety problem. Therefore, the Safety Board believes that OPS should seek out information from pipeline operators sufficient for determining the relative safety of low frequency ERW pipe.

Emergency Response

The emergency situation that existed in Mounds View was handled well and efficiently by the fire department. The Spring Lake, Blaine, Mounds View Fire Department was well prepared to respond to this accident. Its members had received prior general hazardous materials training, knew generally of the potential dangers, and had conducted drills to coordinate their response. At the accident scene, the fire department quickly established a marked command post and began an organized response to the situation. Fire department personnel identified the product involved; contacted the shipper (WPL), as well as other groups which were needed for an effective response; and took prompt actions to protect the public. In addition, WPL was able to provide some helpful, but limited, information on the characteristics and status of the pipeline through its representative once on scene. However, had this accident happened in a community where the emergency response personnel had not been as well trained, the severity of the accident would have depended on the assistance and direction given by on-scene WPL personnel.

Although WPL conducts training with local emergency response agencies, the training is limited to those agencies in which the response areas include a WPL terminal or pump station. This apparently reflects WPL's interpretation of 49 CFR 195.402c(4) & (12), which requires a pipeline company to determine areas that require an immediate response and which requires the pipeline company to maintain a liaison with local emergency response agencies that may respond to a hazardous liquid pipeline emergency. The Safety Board believes that WPL's interpretation is far too limited and consequently its actions for compliance with these regulations are insufficient.

23/ Brief of Accident Report, DCA-86-FP-009. Arkla Energy Resources Pipeline Rupture and Fire Near Cale, Arkansas, February 24, 1986.

Populated areas around a pipeline, such as Mounds View, require an immediate response to protect the public. As such, WPL should modify its liaison policy with the emergency response agencies in such areas. Coordinating responses to emergencies on the pipeline right-of-way will not only aid the local emergency responders in refining their response plans but will enable WPL to evaluate and correct any deficiencies with its emergency procedures before an actual emergency occurs. However, not all areas would require the same degree of liaison as those areas that surround a tank farm or areas where the pipeline right-of-way is under a heavily traveled street. By working through organizations, such as State fire marshal's offices, WPL could reach a wide range of emergency response agencies to develop improved emergency preparedness within each State WPL operates. Additionally, through cooperating with State fire marshal's offices, WPL could identify the types and extent of training which should be provided for all emergency response agencies that might have to respond to hazardous liquid pipeline accidents. Certainly, such training should include information, such as the products transported, the location of the line through their community, actions to take in the event of an emergency, WPL personnel to contact in the event of an accident involving a pipeline, and what assistance to expect from WPL to aid in resolving the emergency.

Hydrostatic Testing

In 1978, the Safety Board, issued a special study on the safe service life of liquid petroleum pipelines. 24/ At that time, the Board concluded that there was no way to predict the safe service life of liquid pipelines using the data reported to the OPS. The Safety Board recommended that the Office of Pipeline Safety Operations (now OPS):

P-78-58

> Publish a plan that describes how the OPSO will use accident report data to formulate safety regulations and to develop a safe service life model for pipelines.

OPSO responded on February 1, 1979, that it was computerizing the pipeline accident data and that it believed this action would increase the utility of the data. The OPSO stated that it would publish a plan in its Pipeline Safety Advisory Bulletin. OPSO would not "speculate in a published plan as to how the accident report data might be used to develop a service life model for pipelines. . . . When we are convinced that model development efforts will have a satisfactory probability of success, we will, of course, document the efforts in a plan and publish it." OPS has yet to publish or develop any model. The recommendation has been classified as "Closed—Superseded," based on a safety recommendation issued as a result of this investigation.

The Board believes that the development of such a model is important especially since the potential for manufacturing defects to grow to critical failure size has been shown by actual operating failures. The Safety Board is pleased that someone has had the initiative to develop a service life model. Battelle's model has the benefit that it is not dependent on accident data. The Board believes that OPS must take advantage of this study and include in its regulations criteria for periodic hydrostatic restesting of all pipelines based on operating parameters. Such criteria also could be used to minimize the likelihood of ERW pipe failures during operations due to growth of manufacturing related defects.

24/ Special Study—"Safe Service Life for Liquid Petroleum Pipelines" (NTSB-PSS-78-1).

CONCLUSIONS

Findings

1. The operating pressure at the time of the accident would have been insufficient to cause an undamaged, defect free pipe to fail.

2. The failure initiated in an area of the electric resistance weld seam which had been severely weakened by corrosion

3. Fatigue resulting from pressure cycles normal to liquid pipeline operations may have contributed to the failure; however, this could not be conclusively determined because corrosion damaged the failure surface.

4. Between 1980 and 1986, there were long periods when the level of cathodic protection on the first 10 miles of line 2N did not meet the standard required by WPL.

5. The Federal requirements for cathodic protection on pipelines transporting hazardous liquids provide no guidance other than requiring its existence.

6. The corrosion at the origin of the failure probably had been active before the 1984 hydrostatic test and probably continued to be active after the test.

7. The valve at milepost 10 was not closed expeditiously because WPL procedures were not adequate for recognizing and responding to a pipeline failure, and its employees were not trained sufficiently to effectively use early information about the location of the failure.

8. Delay in closing the valve at milepost 10 increased the amount of product released into the residential neighborhood.

9. With the exception of the computer modules developed by a consultant, WPL training programs lack continuity and apparent organization in administering and conducting training to address employees' needs.

10. WPL training programs for employees involved with the operation of the pipeline did not include preparedness for accidents on the pipeline right-of-way.

11. OPS' present enforcement program lacks thoroughness in its inspections of operators and primarily is reactive to accidents.

12. Lack of thoroughness in its inspections handicaps OPS' ability to identify safety problems between inspection units of an operator and between operators.

13. OPS' present use of its enforcement sanctions does not motivate operators to comply with the Federal pipeline safety standards.

14. The provisions of OPS' final order for actions to be taken to protect public safety before allowing WPL to return line 2N to service were developed through negotiations with WPL rather than through its independent review.

15. OPS' use of punitive sanctions is not based on either the severity of the violation or the operator's past compliance history.

16. OPS should use its punitive sanctions more effectively to motivate compliance by pipeline operators.

17. Opening OPS' ongoing enforcement proceedings to public scrutiny would have a positive effect on public safety.

18. Present OPS staffing is insufficient to adequately monitor all pipeline operations directly subject to its review.

19. Cooperative programs with the States offer a good method for meeting much of the OPS' interstate liquid and natural gas pipeline safety inspection requirements.

20. The population around liquid pipelines is increasing without commensurate increases in the level of safety for liquid pipelines.

21. Populated areas along a pipeline right-of-way require immediate response in the event of a pipeline emergency.

22. The level of safety for liquid pipelines, as established by 49 CFR Part 195 is less than that for natural gas pipelines established by 49 CFR Part 192.

23. The use of remote-operated valves on sections of liquid pipelines that pass through populated areas could decrease the severity of the effects of pipeline failures in these areas.

24. Title 49 CFR Part 195 does not require changes in the operation of a pipeline when the population density along the pipeline's right-of-way changes.

25. Manufacturing defects can grow due to normal cyclic pipeline operations thus decreasing the pipe's safe service life.

26. Title 49 CFR Parts 195 and 192 do not consider the effects of pressure cycles on the safe service life of pipelines.

27. Data on pipelines currently required to be reported to OPS by the pipeline industry is not adequate to determine if low frequency ERW pipe presents an unreasonable hazard to public safety.

28. Injuries resulting from this accident were limited due to the relative lack of pedestrian and vehicular traffic along Long Lake Road at the time of the accident.

29. The Spring Lake Park, Blaine, Mounds View Fire Department was well prepared to respond to this accident.

30. WPL's public education program was not effective in providing information for the majority of residents of the accident area to enable them to identify the location of the pipeline, to identify the hazards of the products transported, to recognize an emergency situation involving the pipeline, or to know the actions to take during such an emergency.

31. Title 49 CFR 195.402c(4) & (12) and 195.440 do not provide criteria for operators to measure the effectiveness of their public education and liaison programs.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the rupture at Mounds View, Minnesota, was the failure of Williams Pipe Line Company to correct known deficiencies in the cathodic protection applied to the first 10 miles of line 2N. Contributing to the failure of the pipeline was the susceptibility of the low frequency, electric resistance welded pipe to weld seam corrosion and the Department of Transportation's ineffective inspection and enforcement program. Contributing to the extent of the damages was the failure of the pipeline company to provide adequate direction, through its procedures and training, for its employees to effectively respond to emergencies involving failed sections of its pipeline and the nonavailability of remotely operated valves or automatic shutdown capability on the pipeline.

RECOMMENDATIONS

As a result of its investigation, the National Transportation Safety Board made the following safety recommendations:

—to the Williams Pipe Line Company:

Revise the operating procedures to place greater emphasis on isolating sections of its pipelines in the event of a failure, and train employees on the procedures established. (Class II, Priority Action) (P-87-13)

Revise the operating procedures to include populated areas along the pipeline as areas requiring an immediate response for emergencies involving the release of product from its pipeline. (Class II, Priority Action) (P-87-14)

Develop emergency response preparedness plans in coordination with local emergency response agencies in populated areas along its pipelines. (Class II, Priority Action) (P-87-15)

Identify for each employee involved in the operation of the pipeline the proper actions to take in the event of a pipeline failure, and provide to each employee adequate knowledge to carry out the actions required through training and other means, as necessary. (Class II, Priority Action) (P-87-16)

Conduct a review of training needs, and based upon that review, develop and implement training programs to enable employees to correctly carry out each assigned responsibility which is necessary to comply with the requirements of 49 CFR Part 195. (Class II, Priority Action) (P-87-17)

Install remote-operated valves on pipeline to allow prompt isolation of those sections that pass through highly populated areas. (Class II, Priority Action) (P-87-18)

Add a low discharge pressure automatic shutdown control to automatic shutdown controls at the Minneapolis terminal, as well as at other terminals. (Class II, Priority Action) (P-87-19)

—to the American Petroleum Institute:

In coordination with member companies, develop guidelines for preparing coordinated emergency preparedness plans with communities. (Class II, Priority Action) (P-87-20)

—to the Office of Pipeline Safety:

Increase the use of sanctions which reflect the gravity of the violation and the operator's compliance history as a means for motivating operator compliance with Federal pipeline safety standards. (Class II, Priority Action (P-87-21)

Require the installation of remote-operated valves on pipelines that transport hazardous liquids, and base the spacing of remote-operated valves on the population at risk. (Class II, Priority Action) (P-87-22)

Revise 49 CFR Parts 192 and 195 to include operational based criteria for determining safe service intervals for pipelines between hydrostatic retests. (Class II, Priority Action) (P-87-23)

Revise 49 CFR Part 195 to include criteria, similar to those found in Part 192, for liquid pipeline operators to evaluate their cathodic protection systems. (Class II, Priority Action) (P-87-24)

Before allowing Williams Pipe Line Company to increase the operating pressure on line 2N, require the company to provide scientifically based evidence through inspection and testing that corrosion, which could contribute to future failures, does not remain on the line. (Class II, Priority Action) (P-87-25)

Obtain sufficient data on low frequency, electric resistance welded pipe and determine if its continued use presents an unreasonable hazard to public safety, and take appropriate regulatory action for identified deficiencies. (Class II, Priority Action) (P-87-26)

Revise its policy on the release of information concerning ongoing enforcement cases to keep the public aware of the Office of Pipeline Safety actions being taken during enforcement proceedings. (Class II, Priority Action) (P-87-27)

--to the Department of Transportation:

Increase, through the use of State inspection personnel and by increasing the number of Office of Pipeline Safety (OPS) inspectors, the OPS pipeline inspection capability sufficient to perform thorough, periodic safety reviews of all pipeline operations directly subject to OPS monitoring and to perform timely, effective, followup compliance reviews of those operations in which compliance deficiencies are identified. (Class II, Priority Action) (P-87-28)

Also, the Safety Board reiterated Safety Recommendation P-84-26 to the Research and Special Programs Administration:

> Amend Federal regulation governing pipelines that transport highly volatile liquids to require a level of safety for the public comparable to that now required for natural gas pipelines.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ JIM BURNETT
Chairman

/s/ PATRICIA A. GOLDMAN
Vice Chairman

/s/ JOHN K. LAUBER
Member

/s/ JOSEPH T. NALL
Member

/s/ JAMES L. KOLSTAD
Member

July 20, 1987

APPENDIXES

APPENDIX A

INVESTIGATION AND HEARING

1. Investigation

The National Transportation Safety Board was notified of the accident by the Office of Pipeline Safety at 10:30 a.m. on July 8, 1986. A Safety Board team, including two investigators and a member from the Washington, D.C. headquarters, arrived on the scene of the accident about 8 p.m., on July 8, 1986

Parties to the investigation included the Williams Pipe Line Company; the city of Mounds View, Minnesota; the Minnesota Pollution Control Agency; Ramsey County, Minnesota; and the Office of Pipeline Safety, U.S. Department of Transportation.

2. Public Hearing

A public hearing was held October 22 and 23, 1986 in St. Paul, Minnesota.

APPENDIX B

FEDERAL PIPELINE SAFETY STANDARDS

The minimum safety standards for transporting hazardous liquids by pipeline are contained in 49 CFR Part 195. The development and enforcement of these standards are the responsibility of the Office of Pipeline Safety which is a part of the Research and Special Programs Administration of the Department of Transportation. In part, these regulations are:

> 195.401 (b) requires an operator aware of any condition which could adversely affect the safety of the system to correct the deficient condition within a reasonable time; however, if the condition presents an immediate hazard to persons or property, then the operator is not allowed to operate the affected part of the system until the deficient condition is corrected.
>
> 195.402 requires each operator to have a written manual for operations, maintenance, and emergencies. Some of the purposes of this manual are to establish procedures for:
>
> - determining which pipeline facilities are located in areas that would require immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned.
> - analyzing accidents to determine their causes.
> - minimizing the potential of identified hazards to public safety and the possibility of recurrence of accidents analyzed.
> - establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibilities and resources of each governmental organization that may respond to a hazardous liquid pipeline emergency and acquaint the officials with the operator's ability in responding to a hazardous liquid pipeline emergency and means of communication.
> - establishing procedures for emergency conditions as specified in subparagraph (e).
>
> 195.403 requires each operator to establish and conduct a training program to instruct operating and maintenance personnel to, among other items, carry out the operating and maintenance, and emergency procedures established under 195.402. The operator is further required to review with personnel their performance in meeting the objectives of the training program, make changes in the training program as appropriate, and verify that its supervisors maintain a thorough knowledge of the procedures for which each has responsibility.

195.408 requires each operator communication system to provide for the transmission of information needed for the safe operation of its pipeline. Areas specific included are monitoring operation data, receiving notices of abnormal or emergency conditions and sending this data to appropriate personnel for corrective action, providing two-way communication between control centers and locations of abnormal or emergency conditions, and communicating with emergency response and other public officials during emergencies.

195.410 specifies specific information, letter size, and color contrast requirements for markers which must be installed over each buried pipeline at public road and railroad crossings and at other locations as to accurately make known the location of the pipeline.

195.414, among other requirements, requires each operator to cathodically protect all pipelines which have an effective external surface coating material, to annually conduct tests to determine if the cathodic protection is adequate, and to inspect at least 6 times per year its cathodic protection rectifiers. No standards for the level of cathodic protection is specified nor do the regulations make reference to any industry or other cathodic protection standards.

195.440, among other requirements, requires each operator to establish a continuing educational program to enable the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a hazardous liquid pipeline emergency and to report it to the operator or the fire, police, or other appropriate public officials.

APPENDIX C

WPL MAINLINE PIPE DATA SUMMARY
ERW PIPE ACTIVE LINES ONLY

MANUFACTURER	FEET	MILES	% OF TOTAL SYSTEM	% OF EW BY MANUFACTURER	1962 & PRIOR	1963 & LATER
J & L	3,161,388	599	8	13	2,580,455	580,933
REPUBLIC	4,091,860	775	10	17	4,074,838	17,022
YOUNGSTOWN	3,495,229	662	10	15	3,487,700	7,529
A. O. SMITH	4,348,366	824	10	18	4,348,366	0
U.S.S.	3,533,114	669	8	15	0	3,533,114
LONESTAR	2,272,570	430	6	9	84,158	2,188,412
COMBINED: A. O. SMITH & YOUNGSTOWN	307,180	58	1	1	307,180	0
KAISER	688,164	130	2	3	681,594	6,570
BETHLEHEM	410,550	78	1	2	0	410,550
STUPP	389,519	74	1	2	0	389,519
AMERICAN	601,985	114	1	3	0	601,985
INTERLAKE	21,284	4	--	--	0	21,284
IPSCO.	43,105	12	--	--	0	43,105
SOUTHWEST	83,092	16	--	--	0	83,092
OTHER	4,442	1			0	4,442
UNKNOWN	556,149*	105	1	2	210,390	135,750
TOTALS	24,007,997*	4,551	59	100	15,774,681	8,023,307

*Includes 210,009 feet of unknown pipe manufacturer and unknown date.

MAINLINE PIPE DATA SUMMARY
ELECTRIC RESISTANCE WELDED (ERW) PIPE
ACTIVE LINES ONLY

MANUFACTURER	FEET	MILES	% OF TOTAL SYSTEM	% OF EW BY MANUFACTURER	1962 & PRIOR	1963 & LATER
J & L	3,161,388	599	8	13	2,580,455	580,933
REPUBLIC	4,091,860	775	10	17	4,074,838	17,022
YOUNGSTOWN	3,495,229	662	10	15	3,487,700	7,529
A. O. SMITH	4,348,366	824	10	18	4,348,366	0
U.S.S.	3,533,114	669	8	15	0	3,533,114
LONESTAR	2,272,570	430	6	9	84,158	2,188,412
COMBINED: A. O. SMITH & YOUNGSTOWN	307,180	58	1	1	307,180	0
KAISER	688,164	130	2	3	681,594	6,570
BETHLEHEM	410,550	78	1	2	0	410,550
STUPP	389,519	74	1	2	0	389,519
AMERICAN	601,985	114	1	3	0	601,985
INTERLAKE	21,284	4	--	--	0	21,284
IPSCO.	43,105	12	--	--	0	43,105
SOUTHWEST	83,092	16	--	--	0	83,092
OTHER	4,442	1			0	4,442
UNKNOWN	556,149*	105	1	2	210,390	135,750
TOTALS	24,007,997*	4,551	59	100	15,774,681	8,023,307

*Includes 210,009 feet of unknown pipe manufacturer and unknown date.

APPENDIX D

RAPID SHUTDOWN RECOMMENDATIONS

P-71-001 — Office of Pipeline Safety:
Conduct a study to develop standards for the rapid shutdown of failed natural gas pipelines and work in conjunction with Federal Railroad Administration to develop similar standards for liquid pipelines.
Status: Closed—Acceptable Action

P-72-10 — Conduct a study in cooperation with sources of qualified pipeline expertise, of the various current practices in the handling, containing, and disposal of liquefied petroleum products resulting from pipeline failures. This study should include such external factors as weather conditions, leak site topography and population density in the vicinity of the leak. Based upon the results of this study, there should be formulated and added as an amendment to 49 CFR 195, minimum regulations regarding the handling of liquefied petroleum gas as a result of pipeline leaks.
Status: Closed—Acceptable Action

P-74-18 — Require that designated emergency valves be the valves closed initially when a section of main is required to be isolated in an emergency.
Status: Closed—Acceptable Alternate Action

P-79-30 — Establish minimum performance standards for the prompt detection and rapid isolation of failed sections of highly volatile liquid pipelines.
Status: Closed—Superseded.

APPENDIX E

RECOMMENDATIONS FROM NACE STANDARD RP-01-69

NACE, a technical society concerned with corrosion and its prevention, was founded in 1943. This society develops standards, conducts research sponsors training courses, and develops and administers programs for testing and certifying the qualifications of persons to perform corrosion prevention practices at both the technician and engineer levels.

NACE Standard RP-01-69, approved in August 1969 as a Recommended Practice, was used extensively in 1971 by the Office of Pipeline Safety for developing the Federal requirements for corrosion control. Among other provisions, this Recommended Practice advised:

> That application of the provisions should be directed by a person who by reason of his knowledge of the physical sciences and the principles of engineering and mathematics, acquired by professional education and related experience, is qualified to engage in the practice of corrosion control on buried or submerged metallic piping systems. Such persons may be licensed professional engineers or other persons certified as being qualified by the National Association of Corrosion Engineers if such licensing or certification includes suitable experience in corrosion control on buried or submerged metallic piping systems.
>
> Where metallic casings are required as part of the underground piping system, the pipe should be electrically isolated from such casings. The term "electrical isolation" is defined to mean the condition of being electrically separate from other metallic structures or the environment.
>
> That the objective of cathodic protection is to control the corrosion of metallic surfaces in contact with electrolytes. It defined the term "electrolyte" as a chemical substance or mixture, usually liquid, containing ions that migrate in an electric field. The example given of an electrolyte or soil or liquid adjacent to and in contact with a buried or submerged metallic structure, including the moisture and other chemicals contained therein.
>
> Criteria, when complied with either separately or collectively, was specified for indicating that adequate cathodic protection of a metallic system in its electrolyte had been achieved. For steel structures, five criterion were specified including the achievement of a negative voltage of at least 0.85 volts as measured between the structure surface and a standard copper-copper sulfate half cell contacting the electrolyte. In applying this criterion, two requirements were imposed. First, determination of this voltage must be made with the protective current applied. Second, the corrosion engineer was required to consider voltage drops due to internal resistance (IR) other than those across the structure-electrolyte boundary for valid interpretation of the voltage measurement.

NACE published the most recent revised Recommended Practice in 1983. A proposed new edition of this Recommended Practice is under review.

APPENDIX F

SAFETY BOARD RECOMMENDATIONS TO THE DOT FOR IMPROVED HVL PIPELINE SAFETY

No.	Recommendation and Status
72-8	Review the proposals made by the Hazardous Materials Regulation Board in Docket No. HM-6A on April 28, 1969. Rulemaking should be undertaken to provide for more complete controls for the transportation by pipeline of liquified petroleum gas. These regulations should include minimum standards for the design, construction, testing, operation, and maintenance of both new and existing pipelines. Status: Closed--Superseded
72-9	Initiate an amendment to the Code of Federal Regulations, Tile 49, Section 195.218 Welding: Seam offset, to require longitudinal welds to be placed in the upper half of the pipe during construction. Similarly, that in repairs to a pipeline involving pipe replacement, a requirement be issued that the longitudinal welds of replacement pipe be positioned in the upper half. Status: Closed—No Longer Applicable
72-10	Conduct a study in cooperation with sources of qualified pipeline expertise, concerning minimum valve-spacing standards and the use of remotely operated valves, and check valves on all liquefied petroleum pipelines. As an adjunct to this, the Safety Board invites attention to a recommendation made in its special study of "Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown." Status: Closed—Acceptable Action
72-11	Undertake a study, in cooperation with sources of qualified pipeline expertise, of the various current practices in the handling, containing, and disposing of liquefied petroleum products resulting from pipeline failures. This study should include such external factors as weather conditions, leak site topography and population density in the vicinity of the leak. Based upon the results of this study, there should be formulated and added as an amendment to 49 CFR 195, minimum regulations regarding the handling of liquefied petroleum gas as a result of pipeline leaks. Status: Closed—Acceptable Action
73-47	Expedite rulemaking currently under study to provide for more complete and effective controls over the transportation by pipeline of liquefied petroleum gases, which would include natural gas liquids. These regulations should contain minimum standards for the design, construction, testing, operation, and maintenance of both new and existing pipelines. Status: Open—Acceptable Action

No.	Recommendation and Status
73-48	Undertake rulemaking concerning methods of handling, containing, and disposing of liquefied petroleum gases involved in pipeline failure. This rulemaking should take into account such external factors as weather conditions, leak site topography, and population density. Status: Open—Acceptable Action
73-49	Amend 49 CFR 195 to establish an educational program to enable customers and the general public to recognize and report liquefied petroleum gas leaks to appropriate officials. These regulations should be similar to those which appear in 49 CFR 192, "Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards." Status: Open—Acceptable Action
73-50	Undertake a study of the effects of pipe stress concentration caused by improper weld positioning and improper welding techniques. Based on the results of this study, incorporate into 49 CFR 195 specifications for pipeline repair-welding procedures designed to avoid stress concentrations. Status: Closed—Unacceptable Action
74-50	In its upcoming rulemaking action for the transportation of highly volatile, toxic, or corrosive liquids, include anhydrous ammonia pipeline systems. Particular emphasis should be placed on a reduction of the maximum allowable pressures for NH3 systems, more closely spaced valves, and more remotely or automatically operated valves. Status: Closed—Unacceptable Action
74-51	In its consideration to take regulatory action concerning the methods of handling, containing, and disposing of liquefied petroleum gases, include NH3. Necessary information should be obtained from the OPS study on highly volatile, toxic and/or corrosive liquids currently underway. Rulemaking should take into account such external factors as weather conditions, leak site topography, and population density. Attention should be given to the local temperature inversions caused by the rapid expansion of the escaping NH3 and the possible use of externally supplied heat and air blowers to force the NH3 vapors to rise and dissipate. Status: Closed—Unacceptable Action
74-52	Amend CFR 49 195.404(b), Maps and Records, to provide for pressure recording instruments to be installed and properly maintained at each pump station and each pipeline terminal and that these recorded pressures be retained at a central location for at least 3 years. Status: Closed—Acceptable Action

No.	Recommendation and Status
74-53	Amend 49 CFR 195 to require liquid petroleum pipeline operators to establish liaison with appropriate public officials, including fire and police officials, to better inform them of the characteristics and hazards of liquid petroleum and related products. These regulations should include anhydrous ammonia and should be similar to those which appear in 49 CFR 192, "Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards." Status: Closed—Acceptable Action
76-20	Review all pertinent data such as leak and failure reports submitted by liquid pipeline carriers to determine if longitudinal weld failures constitute a recurrent safety problem, and take appropriate regulatory action if they do. Status: Closed—Acceptable Action
76-21	Request all pipeline companies which have installed ERW pipe manufactured by the Jones and Lauglin Steel Corporation to review their records on longitudinal seam failures and determine if the number of such failures is abnormally high. After DOT reviews these data it should take necessary corrective action. Status: Closed—No Longer Applicable
78-1	Include in proposed 49 CFR 195 regulations, provisions for checking natural gas pipelines that are being converted to liquefied petroleum gas (LPG) service for stress-corrosion cracking. Status: Closed—Acceptable Action
78-9	Expedite the publishing of the Notice of Proposed Rulemaking on regulations for the safe transportation of pipelines of liquefied petroleum gases (LPG). Include a comprehensive section on the communications required for the safe operation of LPG pipelines. Status: Closed—Acceptable Action
78-10	Include in proposed regulations a section similar to the emergency plan section of the natural gas code (49 CFR 192.615) that will require operators to provide information to persons who live or work within 220 yards of a propane pipeline, and up to 1 mile if located downhill of a LPG pipeline, about the particular hazards of LPG and how to contact emergency response personnel. Status: Closed—Acceptable Action
78-63	Expedite completion of the rulemaking to strengthen the Federal regulations concerning LPG pipelines. Status: Closed—Unacceptable Action
79-6	Reevaluate all recommendations made by the Safety Board concerning LPG, and expedite those that require rulemaking. Status: Open—Acceptable Action

APPENDIX G

OPS WARNING LETTER TO WPL

US Department of Transportation
Research and Special Programs Administration

Central Region

Materials Transportation Bureau
Room 1802
911 Walnut Street
Kansas City, Missouri 64106

WARNING LETTER

March 8, 1984

Mr. R.A. Wilkens
President
Williams Pipe Line Company
Post Office Box 3448
Tulsa, Oklahoma 74101

Dear Mr. Wilkens:

On December 12-13, 1983, a representative of the Central Region, accompanied by the Chief of the Southwest Region, Pipeline Safety, Office of Operations and Enforcement (OOE), pursuant to Section 211(c) of the Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA) (Title II of P.L. 96-129), conducted a pipeline safety inspection at your Tulsa, Oklahoma headquarters. This inspection consisted of a review of your written procedures for the operation and control of your pipeline system.

As a result of the inspection, it appears that Williams Pipe Line Company (Williams) is not in compliance with pipeline safety regulations (Title 49, Code of Federal Regulations Part 195). This non-compliance is based on the inadequacy of the procedures reviewed, "Dispatching Procedures: Emergencies, Mainline Start Up, Mainline Shut Down".

Section 195.402 Procedural manual for operations, maintenance, and emergencies, requires that each operator prepare and follow a manual of written procedures (O&M Plan) for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. 195.402(c),(d), and (e) list specific procedures which must be included in the O&M Plan. The procedures reviewed appear to be inadequate, as noted below, insofar as the specific requirements of the regulations apply to this set of dispatching procedures. The procedures require amendment as prescribed in 49 CFR, Section 195.402(b).

1. 195.402(c) Maintenance and Normal Operations.

   (a) The plan does not contain any reference to specific pipeline facilities which are located in areas that would require an immediate response by the operator to prevent hazards to the public if the facilities failed or malfunctioned, per 195.402(c)(4).

(c)
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(b) Also-relating to these "sensitive areas", there is no provision for minimizing the potential for hazards in the areas identified under 192.402(a)(4), per 195.402(c)(6).

(c) The procedures for starting up and shutting down a pipeline system require expanding to satisfy the requirements of 192.402(c)(7).

(d) The procedures do not contain provisions for periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures, per 195.402-(c)(13).

2. 195.402(d) Abnormal Operation.

The procedures do not address abnormal operations in the same context as do the regulations. Per the regulations, abnormal operation occurs when the design limits of the pipeline have been exceeded. In the sense that abnormal operation is addressed in your plan, an abnormal operation is a planned event. This also can be included, but those situations specifically noted in 195.402(d) must be covered. Many of those items appear to be addressed as emergencies in your procedures.

a) 195.402(d)(1) lists specific events for which procedures must be included in the Plan. Your procedures do not cover some items and are inadequate in regard to others. No reference to "unintended valve closures" could be located. Coverage of "exceeding pressure limits" does not appear adequate. No reference to "flow rate" was noted. There is no coverage of procedures for responding to high pressure shutdown alarms or no-flow shutdowns or alarms. A low-level tank alarm could indicate a leaking tank or tank failure. After notice of alarms is turned over to your Division personnel, what follow-up by Dispatching is required? Is response from Division to be received within a certain time frame, otherwise is shutdown required?

b) No provision for monitoring pipeline operations after an abnormal operation has ended, per 195.402(d)(2), could be located.

c) Procedures for correcting variations from normal operation of pressure and flow equipment and controls are not adequate and require expanding to satisfy 195.402(d)(3).

d) Provisions for periodic reviews of operator response to determine the effectiveness of the procedures, per 195.402-(d)(5) were not noted in your procedures.

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3. 195.402(e) Emergencies.

a) The procedures do not provide instruction in regard to "classifying" notices of events which need immediate response, per 195.402(e)(1). Instruction in this area should be expanded.

b) The procedures need to be more specific in regard to the handling of the types of emergency noted in 195.402(e)(2).

c) No provision for a post accident review of personnel action during an emergency to determine the effectiveness of the procedures, per 195.402(e)(9) was noted in your procedures.

A copy of Section 195.402(b) is attached to this notice and prescribes your rights under that section. If you elect to request a hearing, it will be provided as prescribed in CFR, Section 190.

Please respond within thirty days of your receipt of this letter, explaining the actions you have taken to correct these inadequacies.

Sincerely,

Edward J. Ondak

Edward J. Ondak, P.E., Chief,
Central Region, Pipeline Safety
Office of Operations & Enforcement

§195.402 Procedural manual for operations, maintenance, and emergencies.

... (b) Amendments. If the Secretary finds that an operator's procedures are inadequate to assure safe operation of the system to minimize hazards in an emergency, the Secretary may, after issuing a notice of amendment and providing an opportunity for an informal hearing, require the operator to amend the procedures. In determining the adequacy of the procedures, the Secretary considers pipeline safety data, the feasibility of the procedures, and whether the procedures are appropriate for the pipeline system involved. Each notice of amendment shall allow the operator at least fifteen days after receipt of such notice to submit written comments or request an informal hearing. After considering all material presented, the Secretary shall notify the operator of the required amendment or withdraw the notice proposing the amendment. ...

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