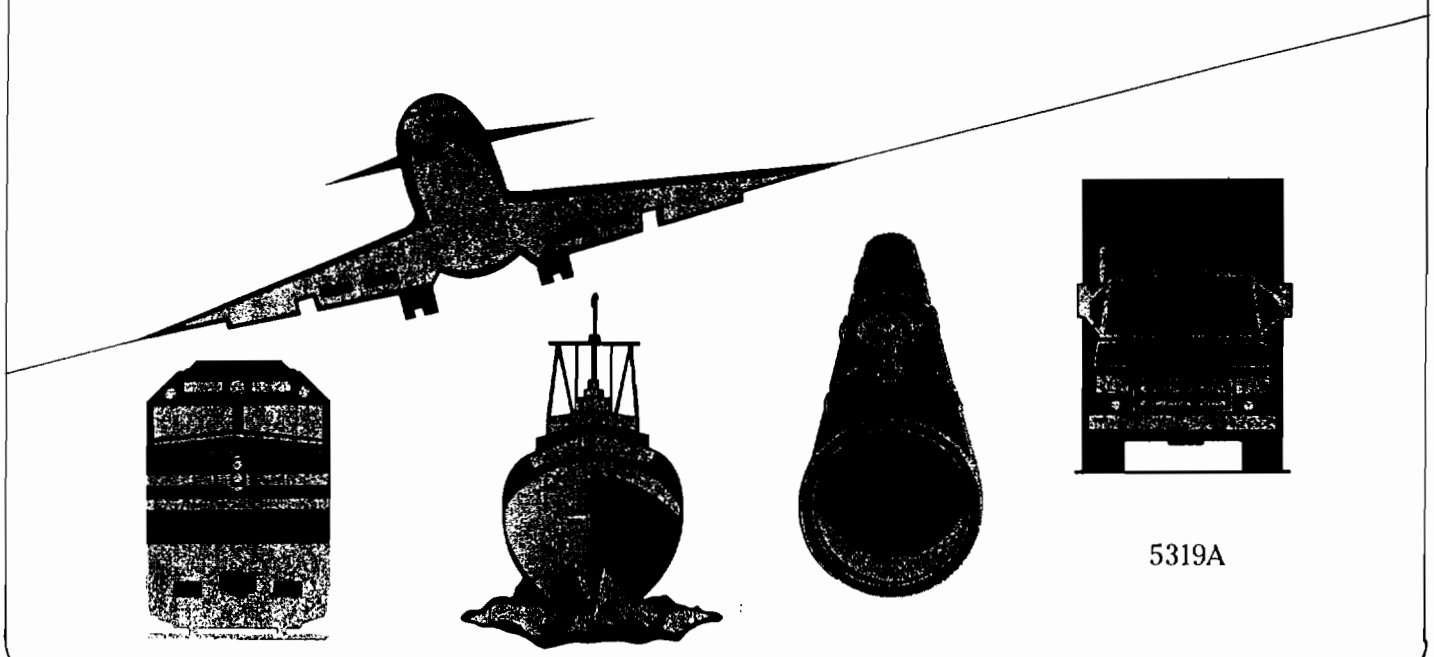
PB91-916501
NTSB/PAR-91/01

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

LIQUID PROPANE PIPELINE RUPTURE AND FIRE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY
NORTH BLENHEIM, NEW YORK
MARCH 13, 1990



5319A

U.S. GOVERNMENT PRINTING OFFICE: 1989 0—942-865

The National Transportation Safety Board is an independent Federal agency dedicated to promoting aviation, railroad, highway, marine, pipeline, and hazardous materials safety. Established in 1967, the agency is mandated by the Independent Safety Board Act of 1974 to investigate transportation accidents, determine the probable cause of accidents, issue safety recommendations, study transportation safety issues, and evaluate the safety effectiveness of government agencies involved in transportation. The Safety Board makes public its actions and decisions through accident reports, safety studies, special investigation reports, safety recommendations, and statistical reviews.

Information about available publications may be obtained by contacting:

National Transportation Safety Board
Public Inquiries Section, RE-51
800 Independence Avenue, S.W.
Washington, D.C. 20594
(202)382-6735

Safety Board publications may be purchased, by individual copy or by subscription, from:

National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161
(703)487-4600

NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

LIQUID PROPANE PIPELINE RUPTURE AND FIRE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY
NORTH BLENHEIM, NEW YORK
MARCH 13, 1990

ADOPTED: JUNE 11, 1991

NOTATION 5319A

Abstract: This report explains the Texas Eastern Products Pipeline Company pipe rupture, subsequent release of propane, and resultant explosion and fire at North Blenheim, New York, on March 13, 1990. The safety issues discussed in the report are pipeline employee qualification and training requirements; procedures to safely move pressurized pipe, especially those manufactured from steel with a high ductile-to-brittle transition temperature; pipeline monitoring requirements for detecting the existence and location of failed pipeline segments; valve requirements for rapidly shutting down failed pipeline segments; and public education and emergency preparedness liaison requirements. The National Transportation Safety Board made safety recommendations addressing these issues to the Research and Special Programs Administration of the U.S. Department of Transportation, the Texas Eastern Products Pipeline Company, the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association.

CONTENTS

On March 13, 1990, the Texas Eastern Products Pipeline Company line P-41, an 8-inch-diameter liquid propane pipeline, ruptured within a pipeline casing beneath County Road 43 near the Village of North Blenheim, New York. Liquid propane gas escaped from the ends of the casing, vaporized, and formed a white, heavier-than-air gas cloud. The gas cloud flowed downhill along County Road 43 until it entered North Blenheim and ignited. The fire quickly consumed the propane vapor and flashed back to the pipeline rupture. Two people were killed, seven persons injured, and more than $4 million in property damage and other costs resulted.

The National Transportation Safety Board determines that the probable cause of the Texas Eastern Products Pipeline Company pipe rupture, subsequent release of propane, and resultant explosion and fire at North Blenheim, New York, was the failure of the pipeline company to provide adequate procedures, equipment, training, and management oversight to ensure that maintenance on its pipelines was accomplished using methods and equipment that protected its employees and the public.

The following safety issues are discussed in this report:

- pipeline employee qualification and training requirements;
- procedures to safely move pressurized pipe, especially those manufactured from steel with a high ductile-to-brittle transition temperature;
- pipeline monitoring requirements for detecting the existence and location of failed pipeline segments;
- valve requirements for rapidly shutting down failed pipeline segments; and
- public education and emergency preparedness liaison requirements.

As a result of its investigation, the Safety Board issued safety recommendations to the Research and Special Programs Administration of the U.S. Department of Transportation, the Texas Eastern Products Pipeline Company, the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association. It also reiterated previously issued safety recommendations to the Research and Special Programs Administration.

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

LIQUID PROPANE PIPELINE RUPTURE AND FIRE
TEXAS EASTERN PRODUCTS PIPELINE COMPANY
NORTH BLENHEIM, NEW YORK
MARCH 13, 1990

INVESTIGATION

Accident

Pipeline Rupture.--About 7:32 a.m. on March 13, 1990, at Burnt Hill Road near its intersection with County Road 43 (CR 43) in Schoharie County, New York, a resident, walking to his barn, "heard an awful rumbling noise" and felt the ground shake. (See figure 1.) A Texas Eastern Products Pipeline Company (TEPPCO) propane pipeline crossed beneath CR 43 in that area. CR 43 was a two-lane macadamized road that ran north from State Route 30 (SR 30), an east/west oriented road that passed through the Village of North Blenheim (village), New York, about 32 miles southwest of Albany, New York. The resident then looked toward CR 43 and saw a large white cloud that appeared to be "about half a mile in the sky." He returned to his residence, obtained the TEPPCO's emergency telephone number from a TEPPCO brochure, and telephoned the TEPPCO to relate his observations. (The TEPPCO had hand delivered or mailed the brochure to all residents within 1/8 mile of its pipeline.) An employee in the TEPPCO's Northeast Region headquarters office at Watkins Glen, New York, received the call. The resident reported that he had observed the cloud and that it was moving rapidly downhill toward the village, which was about 3,000 feet south of his farm and 200 feet lower in elevation.

As soon as the TEPPCO employee learned about the emergency in progress, he transferred the resident's call to the control point operator (CPO),[1] and the resident advised the CPO of the situation. Using his cathodic ray tube (CRT) at his computer terminal, the CPO checked the supervisory control and data acquisition (SCADA) system for line P-41 for any abnormal pressure reduction or significant rate of pressure change. The CPO did not identify any abnormal condition, nor did he see any system alarms. While the CPO was further questioning the resident, at 7:39 a.m. the telephone disconnected without warning. The CPO immediately initiated the TEPPCO's procedures for shutting down line P-41 because he thought the abrupt disconnection might have been related to the information reported by the resident. (See appendix C for the TEPPCO operating procedures related to this accident.)

---

[1] A control point operator coordinates regional pipeline operations, consistent with directions provided by the dispatch center in Houston, Texas, and is in direct contact with regional and terminal managers.

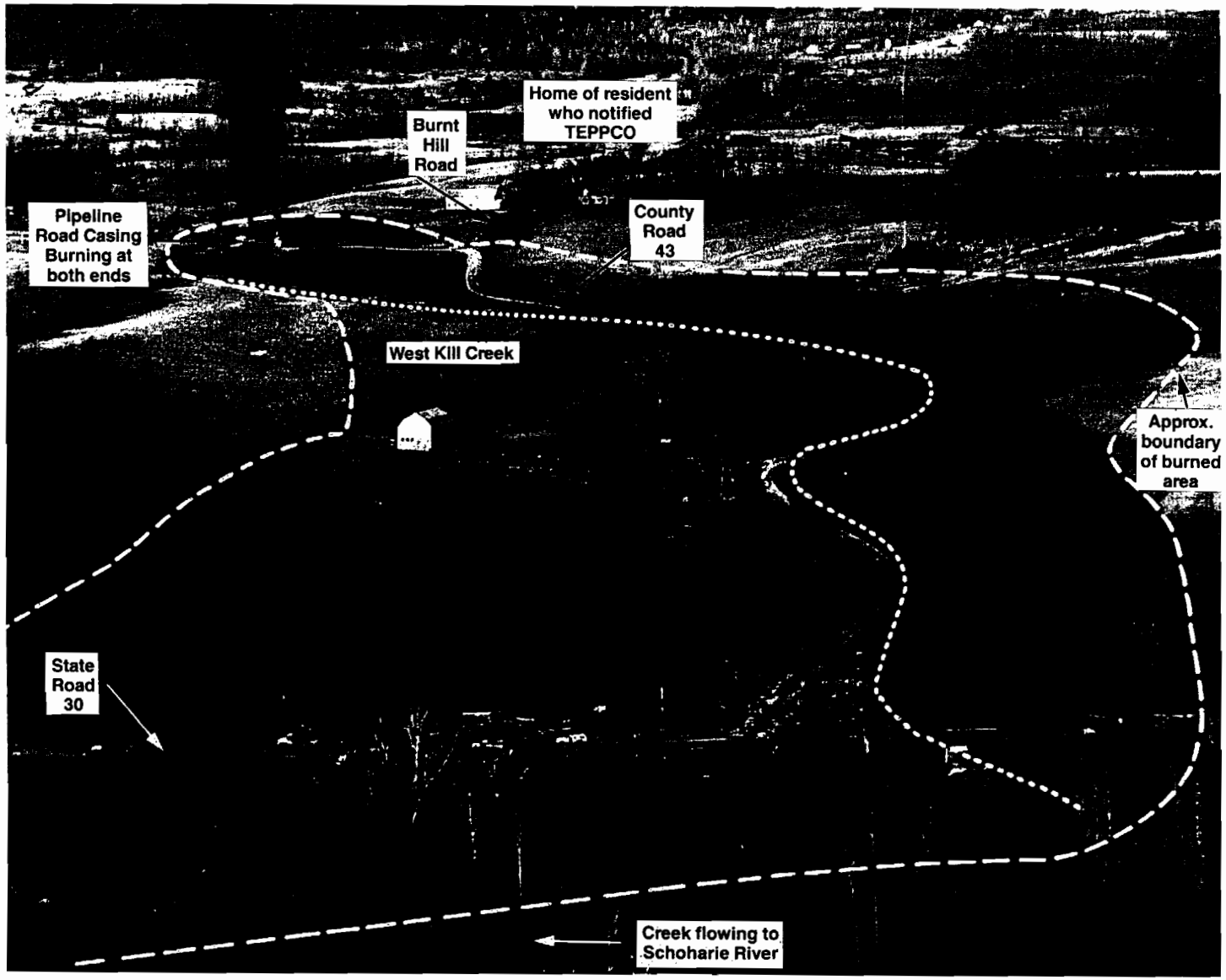


Figure 1.--Aerial view of the accident area.

In the village, motorists observed that moisture, believed to have been caused by fog, formed on their windshields as they drove along SR 30. Inside a house adjacent to SR 30, a resident observed a "dense fog" engulfing the house and obstructing his view of SR 30. This resident stated that because of his previous training as a volunteer firefighter, he recognized the fog as a gas vapor cloud and knew it was hazardous.

About the time that the resident on Burnt Hill Road was notifying the TEPPCO of the white cloud, another village resident telephoned the assistant chief of the village volunteer fire department (NBVFD) at his home in the village. The assistant chief began to evacuate nearby residences and a restaurant. He directed those he evacuated to go east on SR 30.

A third resident who was driving on CR 43 saw a fog and, as he neared the pipeline crossing, observed "a geyser" coming from the earth and shooting approximately 60 feet in the air.

Fire and Explosion.--Minutes after the vapor cloud was detected in the village, it ignited. No one reported observing the ignition, but many ignition sources were within the residential area. The Arson Bureau of the New York Department of State determined that the propane flowed downhill from the ruptured pipeline into the village and that ignition of the propane vapor occurred near the intersection of SR 30 and CR 43. The Arson Bureau personnel could not determine the specific ignition source. The ignited vapor cloud exploded, and the fire rapidly flashed back to the area where the pipeline crossed CR 43. The assistant chief, who had been evacuating the village, was fatally burned when the vapor cloud ignited.

Emergency Response

Community Activities.--Minutes after the explosion and fire, area residents telephoned the Schoharie County Sheriff's Department (SCSD) communications center to report their observations. Several persons reported feeling two concussions in rapid succession and seeing a large fireball. In accordance with the Schoharie County Emergency Management Office's (SCEMO) emergency response plan, the SCSD's communications center personnel dispatched deputies and volunteer fire and rescue companies to the village. About 8:14 a.m., the Schoharie Volunteer Fire Department arrived on scene with two engines and began search, rescue, and fire suppression operations.

The responding fire companies did not have information on either the product or the actions to take in response to a release of propane from a high pressure pipeline. Before this accident, the TEPPCO had not contacted the SCEMO or other local response agencies to coordinate emergency response activities or to advise them of the TEPPCO's response capabilities. The SCSD knew that the TEPPCO's pipeline was involved, but its communication center personnel did not immediately know how to contact the TEPPCO to report the emergency. At 7:57 a.m., a TEPPCO incident coordinator at Watkins Glen telephoned the SCSD to advise of the TEPPCO's activities and to obtain the location of the explosion and information then known about injuries. The TEPPCO incident coordinator provided his telephone number. At 8:40 a.m., the

SCSD telephoned the TEPPCO incident coordinator to advise that six structures were on fire. About noon, a TEPPCO regional manager arrived on scene, contacted the SCSD and the SCEMO, offered TEPPCO assistance, and committed TEPPCO resources to support actions already being taken by the public safety agencies and the community.

Additional area fire and rescue companies, as well as volunteers from the New York State Power Authority, arrived and assisted with emergency actions. Members of the SCSD and the New York State Police (NYSP) provided scene security and traffic and crowd control during the firefighting activities and for several days afterward. Several fire companies provided standby duty for 3 days following the explosion to fight recurring forest fires. Additionally, the New York State Disaster Preparedness Commission provided an on-scene mobile command post with radio and telephone equipment for all emergency responders to use. When rescue and fire suppression operations ceased about 9:00 p.m. on March 14, 1990, 15 fire and rescue companies from surrounding areas, using 37 pieces of fire apparatus, had participated in combating the dwelling and brush fires. Ten ambulances were used to transport the injured. About 300 emergency response personnel responded to this accident.

During their emergency response activities, several participating agencies experienced difficulty in communicating by VHF radio in the mountainous areas of Schoharie County. Additionally, some fire departments had old radio equipment that was of limited use. To overcome these communication difficulties, messengers conveyed information by driving from location to location. Communication by this method also proved difficult because fire and debris blocked the intersection of SR 30 and CR 43, requiring the messengers to take round-about, time-consuming routes between the response units located north, east, and west of the village.

TEPPCO Activities.--About 7:40 a.m. on the morning of the accident, the CPO began telephoning the TEPPCO employees at attended pump stations and instructing them to shut down. Using his CRT, the CPO shut down the pumps and closed the valves at the two pump stations equipped for remote operation. Additionally, he telephoned the TEPPCO employees at Watkins Glen, Oneonta, and Selkirk, New York, and instructed them to close manual mainline block valves along the pipeline and to proceed to the suspected rupture area. The pump at the attended Marathon pump station was the first one shut down. Then, the remote-controlled pump at the Gilbertsville pump station was stopped, and its remote-operated valve closed. Next, the TEPPCO maintenance employees at the Oneonta truck loading terminal manually closed its mainline block valve. Finally, the Watkins Glen pump station at mile post (MP) 0+00 was shut down. (See figure 2.) These actions stopped additional propane from being pumped through the pipeline to the accident site. All were accomplished, following the procedures and training provided CPOs, within 11 minutes after the CPO initiated the instruction to shut down the pipeline.

At the time of the accident, propane was being received at the Selkirk terminal station at MP 1+64.76. The TEPPCO employees at this terminal continued to withdraw propane from the pipeline to reduce the quantity

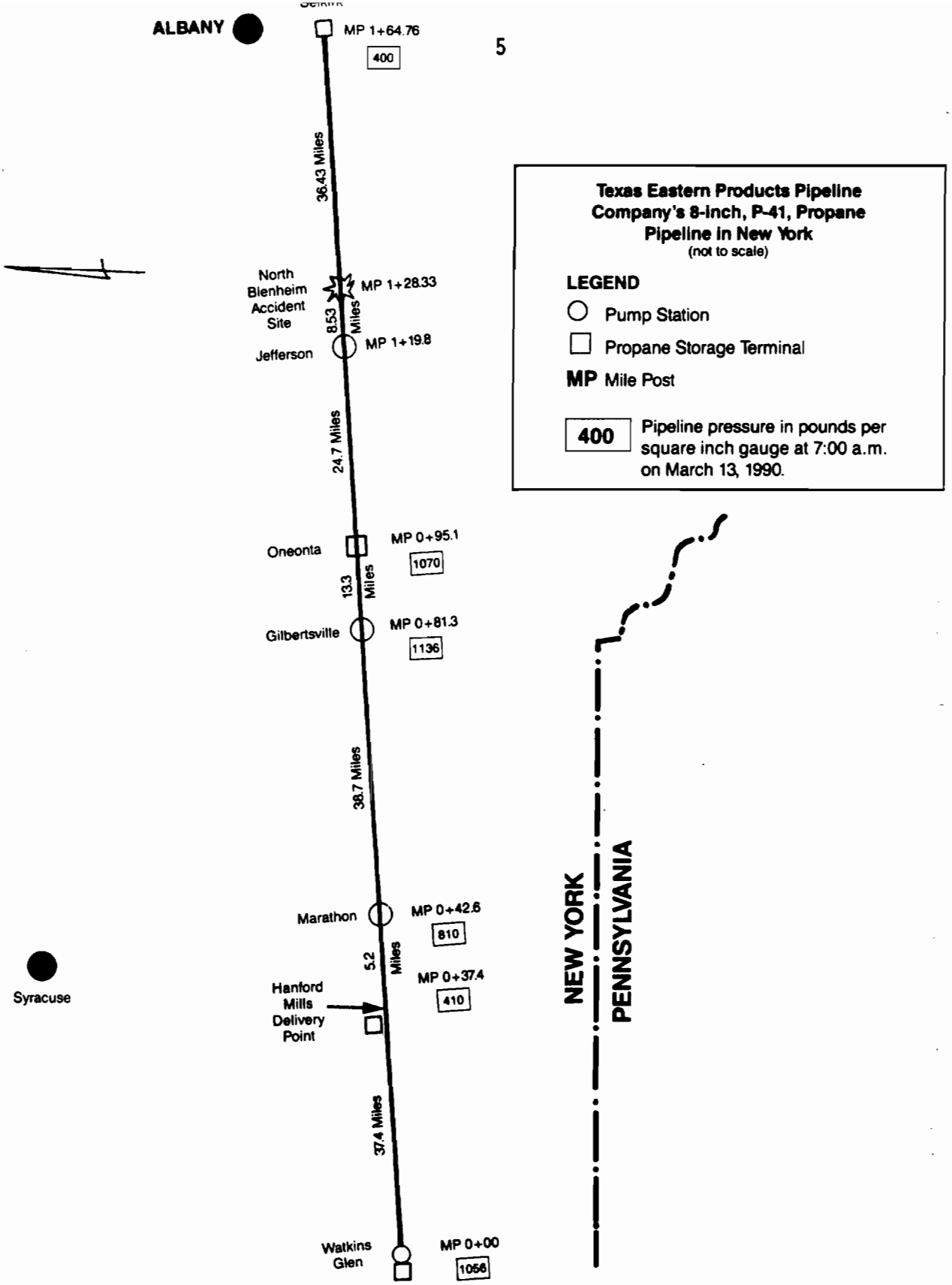


Figure 2.--Schematic of line P-41 showing pump stations and terminals.

available that could flow by gravity from the east to the rupture at CR 43. At 8:13 a.m., a TEPPCO terminal operations employee from Selkirk arrived at the block valve at MP 1+60.47 and closed it. At 8:46 a.m., several TEPPCO employees, who had earlier closed some of the mainline block valves, arrived at the accident site. A TEPPCO maintenance supervisor, who arrived at CR 43 north of the pipeline crossing, observed fire at each end of the casing pipe and numerous grass fires. He radioed this information to an employee at Selkirk who relayed the same information by telephone to the TEPPCO incident coordinator.

At 8:50 a.m., two TEPPCO maintenance employees, who earlier had been dispatched from Oneonta, arrived at the unattended Jefferson pump station and closed the east mainline block valve. This valve was nearest the west side of the rupture. During the next 18 minutes, these men closed four additional valves at that station. At 9:02 a.m., a TEPPCO employee arrived at MP 1+29.14 and closed a mainline block valve; another arrived at MP 1+29.79 on the opposite side of the Schoharie River and closed a mainline block valve. The valve at MP 1+29.14 was the closest east of the rupture. These actions isolated the ruptured pipeline section for 9.35 miles.

The now isolated 9.35 miles of pipeline contained about 129,000 gallons of propane with most at elevations higher than the rupture. Consequently, TEPPCO officials considered additional actions to decrease the time necessary to burn the propane in the pipeline. They decided to install a fitting that could be used as a temporary valve (stopple). The stopple was installed a few hundred feet west of the rupture to limit the flow of propane from an 8.53-mile segment of pipeline between the Jefferson valve and the rupture. This pipeline segment was at elevations higher than the rupture. (See figure 3.) The stopple fitting was installed at 4:40 a.m. on March 14. About 6:00 a.m., the fire self-extinguished.

The TEPPCO headquarters personnel stated that because of the mountainous terrain, they experienced difficulties in communicating with the TEPPCO personnel who responded to the emergency. The TEPPCO's radio transmitter at Watkins Glen, about 125 miles from the accident area, was not capable of directly transmitting to the TEPPCO emergency response personnel. The TEPPCO incident coordinator at Watkins Glen had to telephone a radio operator at the Selkirk terminal, and that operator then relayed messages to pipeline personnel who were about 36 miles away. Also, the radio frequency over which the TEPPCO personnel transmitted was different from those used by the county and the State emergency responders; consequently, direct radio communication between the TEPPCO personnel and government responders was not possible.

Preaccident Events.--Before 1987, the natural gas division of the Texas Eastern Transmission Corporation had performed all work on the TEPPCO pipe corrosion protection (CP) systems, including line P-41, but the TEPPCO did not eliminate the electrical shorts at casings identified by corrosion surveys. In 1986, the TEPPCO hired a corrosion technician for its Northeast Regional Division and made him responsible for corrosion control. That year, he initiated the first annual TEPPCO CP survey. From 1986 through 1989, an outside CP contractor performed surveys and was required, as a part of the

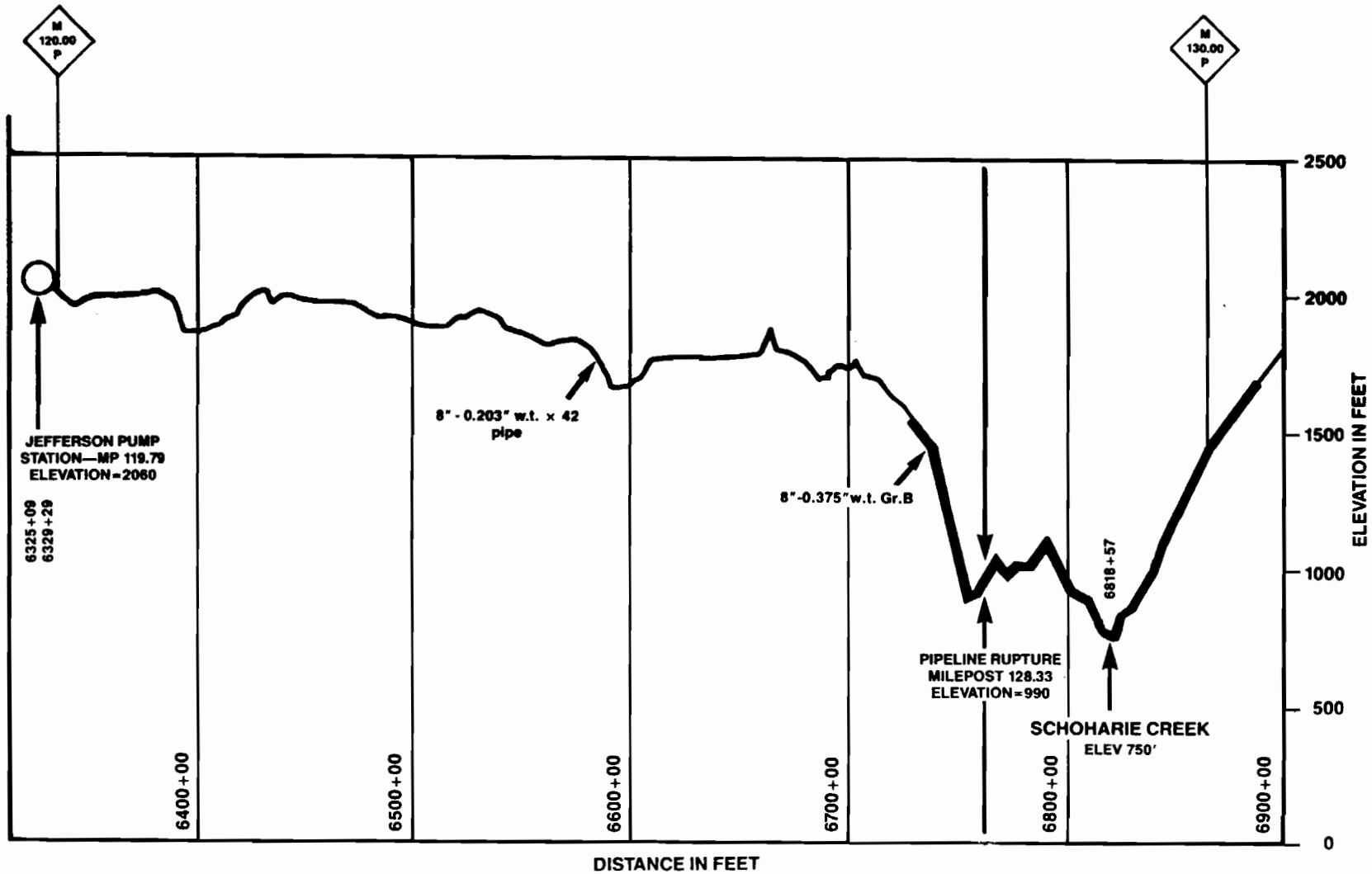


Figure 3.--Pipeline profile showing the location of the rupture.

surveys, to make pipeline-to-soil (P/S) and casing-to-soil (C/S) voltage readings at all locations where the pipeline passed through a casing.

The 1987 and the 1988 P/S and C/S readings for the pipeline at CR 43 were -1.19 volts, and in 1989, the readings were -1.22 volts. In accordance with the TEPPCO's operating and maintenance procedures for external corrosion control (procedure No. 100), whenever the difference between the pipeline and the casing readings were less than 0.10 volt, additional electrical testing was required to determine if a corrosion condition, such as the carrier pipe being electrically shorted to the casing pipe, existed. These initial readings, as well as the subsequent tests, met the criteria in procedure No. 100 that indicated that the pipeline was electrically shorted to the casing.

In 1989, after the corrosion technician had been promoted to engineer, he initiated a 3-year program to eliminate 30 electrical shorts at casings in the TEPPCO's Northeast Region. He ordered and had placed in the TEPPCO's supply inventory individual, interlocking rubber links that when joined by bolts and compressed by tightening, the bolts would form a watertight seal of an annulus (space) between a pipe and its casing. The manufacturer did not recommend these links as a substitute for pipe/casing spacers. The engineer had used these links during previous employment, but they had not been used by employees in the TEPPCO Northeast Region.

On February 16, 1990, the engineer prepared a maintenance request to "clear casing short at County Road 43," just north of the village and sent it to the district superintendent. The engineer met at the TEPPCO's warehouse in Watkins Glen with an employee who was the most experienced maintenance supervisor in the Northeast Region, furnished the equipment to perform P/S and C/S measurements, showed how to use it, and supplied the links from which to form a casing seal. The engineer did not discuss with the maintenance supervisor the procedures for clearing an electrical short, provide direction or guidance on how to eliminate the electrical short, give instruction on how to use the new type casing seal, or determine if the supervisor was experienced in moving pipe.

When the district superintendent received the maintenance request, he assigned the work to the maintenance supervisor who had previously met with the engineer. The district superintendent did not discuss with the maintenance supervisor the work to be performed, nor explain how it was to be performed, nor provide any instruction about the procedures to be followed.

The New York one-call excavation notification center[2] was advised that the work would begin on February 20, 1990. On that date, the TEPPCO maintenance supervisor and his three-member crew went to the pipeline crossing at CR 43. Using a small rubber-tired backhoe, they excavated the 12-inch-diameter steel pipe casing on the west side of CR 43. After exposing the west end of the casing, they cut and removed the rubber boot-type end seal used to keep water and other materials from the annulus between the casing and the pipe. (See figure 4.) Finding the annulus filled with water, the crew drained the water from the casing into the excavated trench and then pumped it from the trench. A plastic casing insulator[3] was found broken within 6 inches of the end of the casing, and the bottom of the pipe was in physical contact with the casing. Before ending work for the day, the maintenance supervisor recorded information about the condition of the pipe and its coating on the TEPPCO's Form 3458. He recorded that the coating condition was good and that he observed no evidence of corrosion pitting. The maintenance supervisor stated that he had not been instructed how to complete this form.

The next day, while the pipeline was being operated at a pressure between 400 and 600 pounds per square inch gauge (psig), the maintenance supervisor planned to raise the pipe just enough to remove the broken spacer and to install a new casing seal. The maintenance supervisor did not know the amount of stress he would impose on the pipe by raising it. He believed that if he uncovered about 70 feet of pipe adjacent to the crossing, he could raise it sufficiently to perform the work. He notified the CPO on duty of the work to be performed, including that the pipe would be raised. He did not request that the pressure in the pipeline be lowered nor did he ask that any mainline valves be closed.

The crew excavated a 72-foot-long trench, along the pipeline. At some locations, the excavation was 2 feet below the pipe, and at several locations, the excavation was enlarged and extended beneath the pipe to provide sufficient clearance for a man to work within the excavation (bell hole). One bell hole was near the west end of the casing, and another was

---

[2] A one-call excavation notification center is a service, normally jointly funded by operators of telephone, electric, pipeline, and other buried facilities to minimize excavation-caused damages to their facilities. It allows persons planning an excavation to notify by telephone, a single location of the planned excavation. Once notified, the center advises member-operators to locate and mark facilities in advance of the planned excavation. The one-call center for the State of New York is the underground facilities protection organization.

[3] Casing insulators serve to electrically isolate the casing from the carrier pipe and to center and support the carrier pipe within the casing. They are also called spacers.

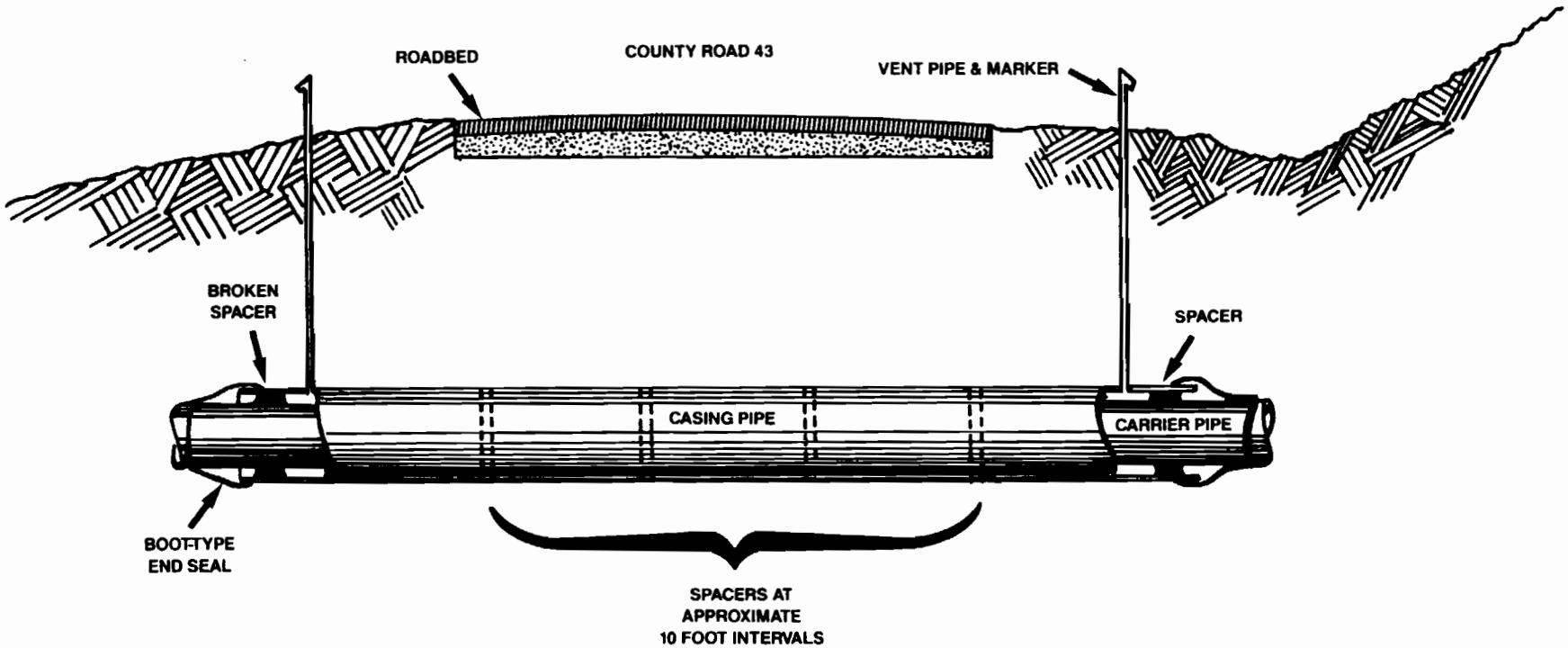


Figure 4.--Cross sections sketch of pipe crossing CR 43, looking North.

near the midpoint of the trench, about 30 feet west of the casing. In the midpoint bell hole, the crew placed a wooden timber (skid) on the soil below the pipe and positioned a hydraulic jack between the skid and the pipe. They raised the pipe several inches to obtain clearance (about 2 inches) between the pipe and the west end of the casing. The crew temporarily supported the pipe on skids, excavated another bell hole nearer the casing, and jacked the pipe upward at that location.

The crew then removed the broken insulator, but did not install a replacement. The maintenance supervisor stated that he did not believe there would be room to install both a spacer and a casing seal without blocking the casing vent line. They used 12 synthetic rubber links that were obtained from TEPPCO's supply inventory when the work was assigned, joined them into a "belt" using bolts, placed the belt around the pipe at the casing, connected its loose ends with a bolt, and positioned the assembly in the annulus between the pipe and the casing. The maintenance supervisor stated that he had not previously used these links to seal a casing annulus and had never been instructed in their use. He added that he used his "common sense" to complete the installation. In an alternating pattern, he tightened the bolts connecting the individual links until he thought the links had been expanded enough to provide a water-tight closure of the annulus. The maintenance supervisor believed that this installation would both seal the annulus and substitute for the broken insulator. The manufacturer's instructions for installing these links, which had not been provided to the crew, advised that the links should not be used to support the pipe and that the bolts should be sequentially tightened.

After the seal installation, the P/S reading was -1.187 volts, and the C/S reading was -1.014 volts (a difference of 0.173 volt or 0.073 volt greater than the 0.100 volt minimum allowed by procedure No. 100). Based on information from other employees, the maintenance supervisor thought that the present condition would be considered a casing short and would require correction within the next 3 years. He believed that it would be necessary to excavate the casing and the pipe on both sides of CR 43 to achieve a permanent correction. Because deeper excavations were needed to expose the casing and the pipe on the east side of CR 43, he had to defer the work until a larger track-type backhoe became available.

To temporarily support the pipe, the crew placed a 4-inch-high by 6-inch-wide by 4-foot-long skid beneath the pipe about 14 feet west of the casing's west end. They backfilled the excavation using the wet clay soil previously removed. Other than using the backhoe bucket to pack the soil, no attempt was made to compact or stabilize this soil. After backfilling the excavation, the P/S voltage was -1.152 volts, and the C/S voltage was -0.992 volt, a difference of 0.160 volt. From February 21, 1990, until March 13, 1990, the pipeline operated normally, and no additional work was performed. After completing this work, the maintenance supervisor again completed a TEPPCO Form 3458, providing information about the condition of the pipe that had been exposed.

Injuries

	Residents	Firefighters	Total
Fatal	1	1	2
Serious	2	0	2
Minor	5	0	5
None	Unknown	210*	210
Total	8	211	219

*Estimate provided by the SCEMO.

Pipeline Damages

The TEPPCO estimated its losses as a result of this accident as follows:

Propane	$ 40,000
Pipe, hydrostatic tests, test failures repair, and response	1,845,000
Revenue loss for 55 days	1,500,000
Total	$3,385,000

Other Damage

Fourteen houses were destroyed, 2 houses sustained major structural damage, and all sustained thermal damage. In addition, two automobiles were destroyed, telephone and electric facilities were severely damaged, and a 52-acre wooded area sustained significant fire damage. The SCEMO estimated the damage to the community at $654,000.

The TEPPCO contributed money to area communities. Part of the contribution was to be used for improving radio transmission capabilities. It also provided combustible gas indicators for their use. The TEPPCO estimated the value of these contributions at $485,000.

Personnel Information

The TEPPCO employee training program consists of 2-hour, video-taped computer-based training (CBT) sessions that cover a variety of safety subjects and 1/2-hour training sessions on selected Federal regulations that are provided at periodic shop safety meetings. Additionally, the TEPPCO requires managers to review annually all pipeline operating personnel to determine that job performance and training are adequate.

Control Point Operator.--The TEPPCO hired the CPO in 1971 as a maintenance employee. In 1974, he transferred to his current position and at the time of the accident was the senior operator in the TEPPCO Northeast

Region. The CPO successfully completed the TEPPCO's technical training and recurrent training for CPOs, including a program in the management of critical operating situations.

In the 4 years before March 13, 1990, the CPO had attended 28 training sessions. Eight were CBT sessions, and five were sessions on Federal regulations. Five of the eight CBT sessions specifically addressed the primary dispatching functions, and all CPOs were required to attend these sessions. However, the training for CPOs neither included information on TEPPCO procedure No. 70 that discusses the isolation of pipe and the lowering of pressure nor specifics on the SCADA system. The latter would inform and instruct CPOs on what operations might have caused the programmed set points[4] to send an alarm to the CRT or on the use of the computer's graphic capabilities as a tool for detecting release of products from the pipeline. The CPO's performance and training for the previous year was assessed by his supervisor as satisfactory.

Maintenance Supervisor.--The TEPPCO employed the maintenance supervisor in 1970 as a welder. He later became a senior welder and then a pipeline foreman. In 1986, he was promoted to pipeline maintenance supervisor. The maintenance supervisor stated that he had no experience in the repair of casing/pipe electrical shorts. His experience on casing repairs had been limited to installing vent lines and extensions; neither required the movement of an operating pipe. He had received no formal training from the TEPPCO on specific methods for repairing a casing/pipe electrical short or for installing a link-type casing seal nor on the provisions of procedure No. 100.

In the 4 years before the accident, the maintenance supervisor had attended 54 TEPPCO training sessions. Fifteen were CBT sessions, and 10 were sessions on Federal regulations. Included in his training was one CBT session on accident/incident reporting requirements and 49 Code of Federal Regulation (CFR) 195 and one training session each on 49 CFR 195.422 (pipeline repairs), 49 CFR 195.402 (operations and emergencies), and 49 CFR 195.424 (line markers and pipe movement). However, this training again did not include information on related TEPPCO procedures, specifically procedures Nos. 70 and 100. The maintenance supervisor's performance and training for the previous year was rated as satisfactory.

Engineer.--The engineer worked as a corrosion technician from 1977 to 1987. During that time, he designed and maintained CP systems for both oil and gas pipelines. In 1986, TEPPCO hired him as a corrosion technician and in 1990, made him responsible for pipeline engineering, maintenance, and corrosion control. He had a Bachelor of Science degree in Industrial Technology. In addition, he completed the National Association of Corrosion Engineers Corrosion Basic and Corrosion Control by Cathodic Protection

---

[4] Some operating parameter "set points" may be set by operating personnel to regulate, control, operate, or maintain the pipeline within safety operating limits.

courses and the Good-All Rectifier School. He had experience in the repair of shorted pipeline casings and in the use of the link seal from previous employment.

Pipeline Information

Ownership.--In 1957, the Texas Eastern Transmission Corporation purchased several pipelines constructed as World War II emergency pipelines, and it formed separate operating divisions for the gas and the liquid products pipelines. In 1964, the products division acquired staff to oversee the construction and operation of line P-41. In 1988, the Texas Eastern Transmission Corporation merged with the Panhandle Eastern Corporation (an operator of gas transmission pipelines), and the TEPPCO was formed as a limited partnership. On March 7, 1990, the ownership was organized into a partnership known as the TEPPCO Partners, L.P.; however, the TEPPCO continued to be responsible for operating the liquid products pipelines.

General Description.--The 165-mile line P-41, an 8-inch-diameter pipeline that transported liquefied petroleum gas (LPG), was constructed and hydrostatically tested in 1964. Originating at Watkins Glen and terminating at Selkirk, it was the northeasterly end of a 4,200-mile system that originated at Baytown, Texas, and supplied propane to several customers along its length. The delivery capacity of line P-41 was about 2 million gallons of propane per day at Selkirk. Facilities to insert cleaning and internal inspection equipment into the pipeline were at Watkins Glen, Marathon, and Gilbertsville; facilities to remove this equipment from the pipeline were at Marathon, Gilbertsville, and Selkirk. (See figure 2.)

Pump Stations and Terminals.--Propane for line P-41 was obtained at Watkins Glen either from an incoming 8-inch-diameter pipeline (the terminus of line P-40) or from nearby underground cavern storage reservoirs. Because this station was equipped with a remote terminal unit (RTU), the CPO could remotely start or stop the 1,250 horsepower (HP) electric motor that drives the centrifugal pump and could operate the remote-controlled mainline valve. A pressure control safety switch limited the pump discharge pressure to its maximum operating pressure (MOP) of 1,085 psig.

Between Watkins Glen and the Hanford Mills delivery point, approximately 37 miles, the area is mountainous and sparsely populated. The delivery point, attended only when product was being received, was not equipped with an RTU to transmit pressure or other information to the CPO.

Marathon, 5 miles east of Hanford Mills, is also in a remote, mountainous area. A 750 HP engine provided power to operate the pump; the engine had to be manually started and stopped. The station had neither an RTU nor any remote-operated valves. When this station operated, it was attended and operating data was provided to the CPO by telephone.

The 39-mile area between Marathon and Gilbertsville is relatively level although several 400- to 500-foot hills exist between the stations. This area is sparsely populated with a few small villages within 1/2 mile of the pipeline. A 1,200 HP electric motor drove the centrifugal pump at the

Gilbertsville station. Like the Watkins Glen station, a pressure safety switch in the pump system limited the pressure to the MOP for the line, and an RTU permitted the CPO to remotely control and monitor the station.

Fourteen miles east of Gilbertsville, the Oneonta truck terminal received propane but was not equipped with an RTU, remote-operated mainline valves, or a pressure recorder. The terminal, which served as a field maintenance office, was attended when propane was received. Several commercial and other buildings adjoined the terminal, but the area was sparsely populated.

About 25 miles east of Oneonta and 3/4 mile north of the village of Jefferson, the Jefferson pump station was equipped with a manually operated engine driven centrifugal pump. The station had neither an RTU nor a continuous pressure recording device.

The Selkirk terminal was approximately 15 miles south of Albany. A back pressure control valve near MP 1+40, 2,100 feet higher in elevation than the terminal, limited the pressure to prevent excessive static head pressure at Selkirk. The terminal had three 90,000-gallon storage tanks and loading facilities for both railroad and truck transportation. Selkirk was not equipped with an RTU to enable the CPO to remotely monitor the terminal. However, Selkirk was continuously attended, and the terminal operator periodically telephoned the CPO to provide operating data.

Pipeline Valves.--Line P-41 had 21 mainline valves, with an average distance of 8.25 miles between valves. At the time of the accident, the only remote-operated valves were at Gilbertsville and Watkins Glen. Check valves were installed only at the pumping stations; therefore, no check valves were between Jefferson and the highest pipeline elevation east of the rupture. In the 8.53 miles of pipeline between Jefferson (elevation 2,060 feet) and the rupture site (elevation 990 feet), the elevation drops 1,070 feet. In the approximate 4 miles of pipe from the highest point east of the rupture (elevation of 2,255 feet) to the rupture site, the elevation drops 1,265 feet. The lowest point in this segment is at the Schoharie River (elevation of 750 feet).

Pipe Specifications.--The pipe used to construct line P-41 was manufactured by Bethlehem Steel Corporation (Bethlehem), using a low-frequency electric resistance welding (ERW) process to make the longitudinal pipe seam, and by Jones and Laughlin (J&L), using a high-frequency ERW process. About 91 percent of line P-41 consisted of pipe, manufactured to meet the American Petroleum Institute (API) Standard 5LX, that had a specified minimum yield strength (SMYS) of 42,000 psi and a wall thickness of 0.203 inch. Bethlehem manufactured about 95 percent of this pipe and J&L manufactured the remainder. Nine percent of the 165 miles of pipe in line P-41 were manufactured to the API Standard 5L, Grade B standard and had a SMYS of 35,000 psi and a wall thickness of 0.375 inch. Bethlehem manufactured about 74 percent of this pipe and J&L manufactured the remainder. The Grade B pipe was generally used where the pipeline pressures were the greatest, at lower elevations or at crossings under creeks, roads,

and railroads. The pipeline was coated with a tape wrap with an overlay of felt.

At the rupture site, the J&L pipe was formed from steel plate, weighed 33.04 pounds per foot, and had an 8.625-inch outside diameter and a 0.375-inch wall thickness.

Hydrostatic Testing.--Between June 10 and September 21, 1964, the original pipeline construction was tested in 34 test sections. These tests were in accordance with Section 437.4.1 of the American Standard Code for Pressure Piping, B31.4-1959, that recommended the hydrostatic test pressure be at least 110 percent of the internal design pressure, but less than 90 percent of the SMYS. Most tests were conducted at pressures between 1,550 and 1,800 psig at the recording locations. Three pipe failures resulted from these tests. Each failure involved minor manufacturing defects, and all were on API Standard 5LX-42 pipe of 0.203-inch wall thickness.

The section of pipeline where the rupture occurred was pressure tested at 2,027 psig. Although the internal design pressure was 2,190 psig, the TEPPCO established a MOP for this section at 1,621 psig, using the accepted industry recommendation not to exceed 80 percent of the test pressure. A modification of 49 CFR 195.406(a)(5) required that highly volatile liquid (HVL) pipelines, such as those used to transport propane, constructed before January 8, 1971, and not previously tested as required by subpart E, should not be operated at pressures greater than 80 percent of the highest previous test pressure. Because the MOP of this section had been established as 80 percent of the 1964 test pressure, no additional testing was performed.

Pipeline Operating History.--The TEPPCO inspected the CP rectifiers on the pipeline six times each year. Also, P/S electrical inspections were conducted annually. Records for the 3 years before the rupture (the only available records) show that at a minimum, the pipeline had a negative (cathodic) voltage of more than -0.85 volts.[5] The P/S readings for the pipeline between Jefferson and Selkirk ranged from -0.88 to -2.47 volts. The C/S readings for the crossing at CR 43 and other casings were similar to the P/S readings. The TEPPCO did not maintain its CP inspection records for more than 3 years nor was this required by Federal regulations; therefore, the length of time before the rupture that the C/S and P/S readings at CR 43 were similar is not known.

Before the rupture, the pipeline had experienced only one other failure in its 26-year operating history. In 1980, a longitudinal weld seam, subjected to a 1,044 psig operating pressure, split near MP 31. The metallurgical report cited the cause as "selective seam weld corrosion." The failed pipe was manufactured by Bethlehem to meet API Standard 5LX-42 and had a 8 5/8-inch outside diameter and a 0.203-inch wall thickness. Although

---

[5]Although this CP criteria is not specifically addressed in 49 CFR 195, it is contained in appendix D of 49 CFR 192 and has been considered acceptable by the Office of Pipeline Safety for both gas and liquid pipelines.

no injuries resulted, the TEPPCO elected to reduce the MOP of its entire pipeline by 20 percent.

In 1985, the TEPPCO conducted an internal inspection of the pipeline to determine if additional corrosion damage was evident. All anomalies (corrosion pits) greater than 100 mils (one mil is one thousandth of an inch) indicated by the internal inspection instrument and any located inside a casing were investigated. Based on the investigation results, the TEPPCO replaced 3,363 feet of pipe (primarily API Standard 5LX-42, 0.203-inch wall thickness) with API Standard 5L, Grade B pipe that had a 0.280-inch wall thickness. It completed this pipe replacement in 1986, and the new pipe represented about 0.4 percent of the total length of the pipeline. The TEPPCO did not rescind the 20 percent reduction in operating pressure, voluntarily made after the 1980 failure, after it completed the repairs. The 1985 internal inspection did not identify any problems with the pipe within the casing at CR 43.

Supervisory Control and Data Acquisition System.--The TEPPCO pipeline dispatcher at Houston, Texas, and the CPO at Watkins Glen could monitor and control the 165-mile pipeline. RTUs were required to monitor, collect, and electronically transmit data to the SCADA computer. The information included such data as pump motor amperes, pumping station discharge and suction pressures, and station and tank valve positions (open or closed). Every 15 seconds, the computer scanned, received, and stored information from monitored locations. The collected data were then compared to programmed acceptance values for each monitored location, and if the data were not consistent with the programmed acceptance values, the computer generated an alert that was received and displayed on the CRTs of the CPO and the Houston dispatcher. If desired, the information could also be graphically displayed on the CRTs.

March 13, 1990, Pipeline Operations.--At 12:26 a.m., the pump at Watkins Glen was shut down because it was no longer needed. At that time, the pressure at Selkirk was 500 psig, and the discharge pressure at Gilbertsville was 533 psig. By 2:00 a.m., the Gilbertsville discharge pressure became a stable 475 psig, and the Selkirk pressure increased to 840 psig due to the 1,500-foot hydraulic elevation head. Based on the TEPPCO's calculations, the pressure at CR 43 was between 600 and 700 psig.

At 2:42 a.m., valves at Selkirk were opened to put propane into storage, and the pressure was reduced to 500 psig. At 2:48 a.m., the pump at Watkins Glen was started to increase the pressure in the pipeline. It operated about 30 minutes, and the pressure at Gilbertsville gradually increased. At 4:14 a.m., when the pressure at Gilbertsville reached 519 psig, the CPO remotely started its pump. At 5:00 a.m., the discharge pressure at Gilbertsville was 907 psig, and at Selkirk, it was 450 psig. The pump at Jefferson was not operating because the pipeline was not operating at capacity.

At 6:34 a.m., the Marathon pump was manually started. At 7:00 a.m., the line pressure at Marathon was 810 psig, the pump discharge pressure at Gilbertsville was 1,136 psig, and the line pressure at Selkirk was 400 psig.

When the rupture at CR 43 occurred, Hanford Mills was not receiving propane shipments, the pump at Marathon was operating attended, the pump at Gilbertsville was operating unattended, Oneonta was receiving and storing an estimated 8,400 gallons of propane per hour, and Selkirk was receiving about 61,000 gallons per hour. Based on the elevation differences and the operations of the pipeline, the pressure in the pipe at the rupture site was calculated by the TEPPCO at 682 psig.

The computer-stored data showed that at 7:32 a.m., the pressure at Gilbertsville began to drop. Over the next 5 minutes, the pressure dropped 39.75, 25.5, 12.75, 26.25, and 12 psig per minute. The average was 23 psig per minute, compared with the 80 psig per minute needed for the computer to alarm the CPO and the Houston dispatcher.

TEPPCO Operating and Maintenance Procedures

(See appendix C for more detailed information on procedures applicable to this accident.)

Aerial Patrols.--At least every 2 weeks, aerial patrols of line P-41 were performed by helicopter, and on-scene investigations were made of any unusual observations. Patrols were performed on February 5, 20, 28, and March 7. These revealed neither abnormal observations nor observations of operations, such as excavation or heavy equipment, near the pipeline at CR 43.

Emergency Plan.--Procedure No. 30 addressed the actions to be implemented to provide for the safety of the public and TEPPCO personnel, to protect property from damage, and to maintain continuity of service. The procedure stated, "It shall be the policy of Texas Eastern Products Pipeline Company to treat the failure or malfunction of any of its facilities as a potential hazard to the public and respond immediately." It noted that the type of response will vary depending on the nature of the failure, the proximity of the public, and the circumstances of the incident; consequently, a trained employee must evaluate these factors to ensure that a proper course of action is selected.

Pipeline Repairs.--Procedure No. 70 required that all pipe repairs be made in a safe manner to prevent injuries to persons or damage to property. This procedure reads:

> Facilities for repair shall include the necessary equipment, trained personnel aware of and familiar with the hazards to public and personnel safety, and appropriate repair materials. Temporary repairs may be necessary . . . for operating purposes and shall be made . . . permanent or replaced in a permanent manner as soon as practical. Pipelines containing liquefied gases shall not be moved unless the line section is isolated to prevent the flow of the product and the pressure in that line section is reduced to the lower of . . .

[f]ifty (50) percent or less of the maximum operating pressure or [t]he lowest practical level that will maintain the highly volatile liquid in a liquid state.

This procedure does not specify how temporary repairs are to be made or provide criteria for supporting pipe until permanent repairs are made. In addition, it does not explain how a pipe should be moved after the pressure is lowered and the section isolated, or include any limits on or require calculations to determine the distance a pipe can be moved.

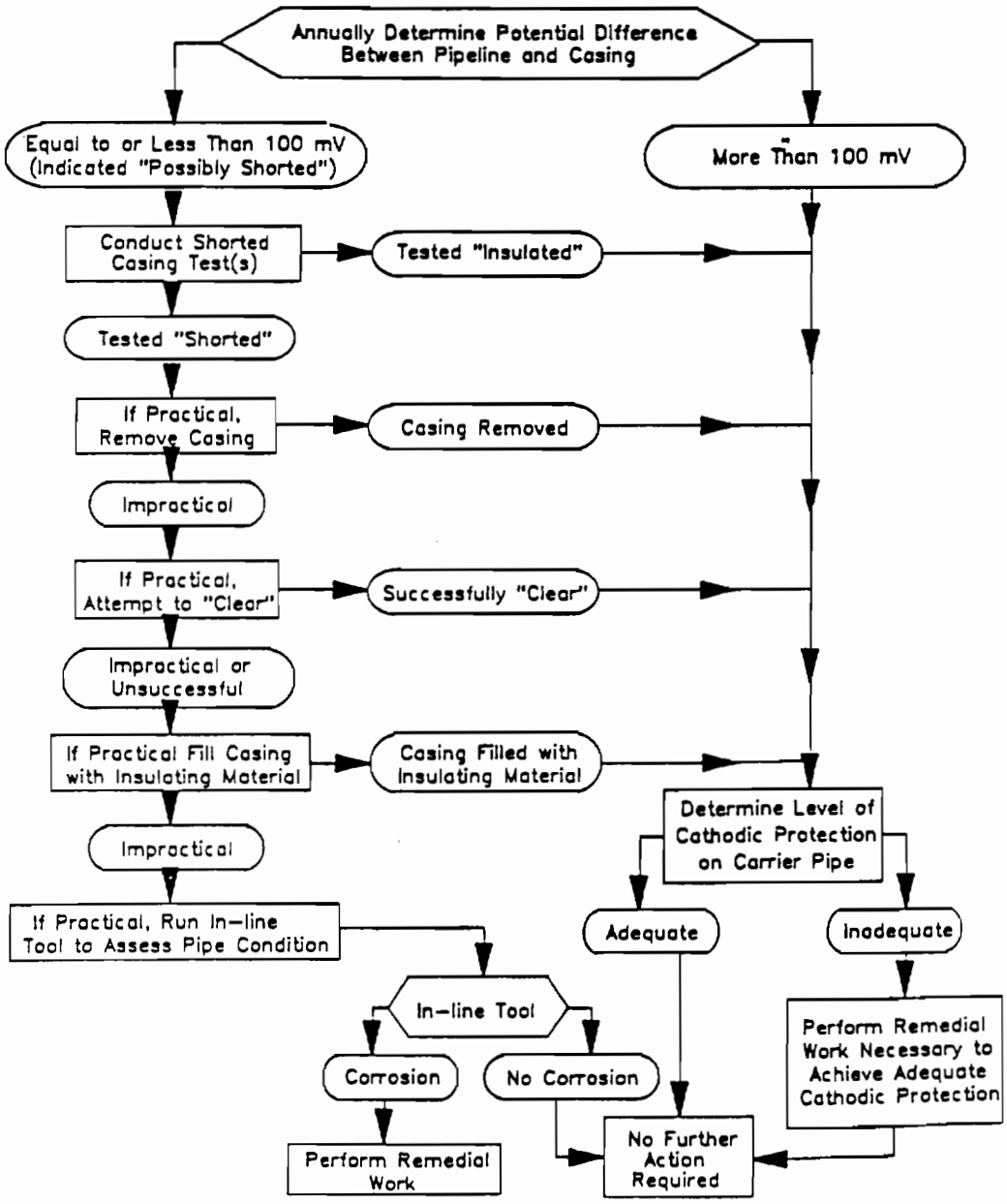
Corrosion Control.--Procedure No. 100 described the operations, surveillance, and maintenance of corrosion control systems. This procedure required annual inspections at each casing pipe to determine the voltage potential between the soil and the casing and the soil and the pipe. If the voltage potential readings differed by less than 0.10 volt, additional action was to be taken as outlined in the Shorted Casing Flow Chart. (See figure 5.) The procedure specified the actions to be taken, but it did not provide instructions on performing the required actions. For example, it did not instruct maintenance personnel on the actions to eliminate an electrical short once identified, and it did not address the need to replace broken spacers, the number and placement of spacers at the ends of casings, the use of end seals, the lifting or other movement of the pipe at casings, the backfilling and compaction of disturbed pipelines, or the procedures for temporarily supporting a pipe.

Minimizing Public Hazards.--Procedure No. 260 required the identification of pipeline facilities that would necessitate an immediate response to prevent hazards to the public and the environment in the event a release of product occurs. The criteria for identifying these areas were:

- all pipeline and other facilities within city limits;
- all pipeline crossings of navigable streams, lakes, and reservoirs;
- all pipeline and other facilities within 1/8 mile of a reservoir holding water for human consumption;
- pipelines and facilities within 1/8 mile of a church, school, hospital, or other place of public assembly; and
- pipelines and facilities within 1/8 mile of a residential subdivision.

The TEPPCO reported that it did not add an odorant to the propane in the pipeline because customers did not want mercaptan or other odorizing additives that might corrode certain storage facilities or "poison" the catalyst used in their manufacturing processes.

TEXAS EASTERN PRODUCTS PIPELINE COMPANY
CORROSION CONTROL PROGRAM
SHORTED CASING FLOW CHART



October 31, 1989

Figure 5.--TEPPCO's shorted casing flow chart.

The TEPPCO's manual on its public education program included a description of how to recognize by sight, sound, and smell a leak of any petroleum product. The manual advises that "any strange or unusual odor in the area may indicate a leak." It further notes that "hydrocarbon vapors are heavier than air and can accumulate in low areas." The TEPPCO provided a Material Safety Data Sheet (MSDS) for the product shipped to each TEPPCO customer for inclusion in this manual.

Public Officials Liaison.--Procedure No. 270 required that liaison be established and maintained with fire, police, and other appropriate officials, who may respond to an emergency involving TEPPCO pipelines, to learn each party's responsibilities and resources and to acquaint them with TEPPCO's response capabilities and means of communication. The TEPPCO operating personnel were responsible for conducting periodic briefings to provide public officials with information about the pipeline system, its operation, and current safety and emergency procedures. The TEPPCO had implemented these procedures only with public agencies located near pumping and receiving facilities. Before the accident, the TEPPCO representatives had not contacted the SCEMO to advise or to coordinate with them TEPPCO's response procedures.

Additionally, procedure No. 270 required that each region provide information to government agencies, excavators, and the public on recognizing an emergency condition that may involve a hazardous liquid (HL) pipeline and reporting it to the TEPPCO. The information distributed at least annually by the TEPPCO personnel included emergency telephone numbers, pocket calendars with emergency notification instructions, maps of the general location of TEPPCO's pipeline facilities in the region, and data sheets for the various liquids transported in the region. Only those residents within 1/8 mile of TEPPCO pipelines were provided this information.

Periodic Review.--Procedure No. 280 required that the work performed by operating personnel be reviewed by both regional and general office management to determine the effectiveness of the normal operations, maintenance, and emergency procedures. The TEPPCO requires its operations and maintenance (O&M) manual procedures be reviewed each calendar year with review intervals not to exceed 15 months. Corrective action is required for any procedure found deficient. The date of the O&M manual was October 31, 1989.

Meteorological Information

Weather observations for the North Blenheim area reported:

Date	Weather	Minimum °F temperature	Maximum °F temperature	Average °F temperature
February 20, 1990	Partly cloudy	13	47	30
February 21, 1990	Sunny	8	22	15
March 13, 1990	Partly cloudy	35	67	51

The temperatures between February 20, 1990, and March 13, 1990, varied with the lows from -8 to 44 °F and the highs from 15 to 67 °F. For the 3 days after the pipe at CR 43 was backfilled, the average daily temperatures were 33.5, 53, and 41 °F, respectively, and for the 3 days before the accident, they were 38.5, 43, and 47 °F, respectively. These two 3-day intervals were the warmest intervals between February 20 and March 13, 1990.

Little precipitation fell between February 20 and March 13, 1990, except for the 0.72 inches recorded on March 12, 1990. The local weather station did not record wind conditions; however, witnesses reported little wind at the time of the accident.

Medical, Pathological, and Toxicological Information

The two fatalities resulted from thermal injuries. Both persons were transported to a hospital that had a special burn unit; however, one died soon after arrival, and the other died the following day. Emergency medical technicians treated the seven injured residents on scene, and ambulances transported them to medical facilities.

At a local clinic about 10 hours after the accident, medical personnel took blood and urine specimens from the CPO. An analysis by a private laboratory found no evidence of alcohol or other drugs.

Tests and Research

Pipe and Casing Installation Documentation.--The TEPPCO had no detailed plans of the pipeline where it crossed CR 43 to show the casing insulators, pipe bends, or other as-built conditions. To establish these details, to determine the construction methods, and to understand the effect of the maintenance work of February 20 and 21, 1990, 130 feet of pipe, including the casing under CR 43, was excavated. The excavation revealed that the pipeline was the only utility at that location and had been placed beneath CR 43 by boring under the road for the casing. The casing pipe was a 51.8-foot-long steel pipe, externally coated with a mastic material, with a 12.75-inch outside diameter and a 0.250-inch wall thickness.

On the east side of CR 43, an approximate eight-degree bend upward had been made in the pipe as it exited the casing, about 8 feet of soil covered the casing, and the earth cover over the pipe 30 feet east of the casing was about 6 feet deep. The ground on the east side was higher than the road, and it sloped down to the road at an approximate 14-degree angle. The pipe was found centered within the casing, and a casing insulator was near the end of the casing. A synthetic rubber end seal had not been damaged by the fire, but it had been moved 2 to 3 inches from the casing; its stainless steel straps appeared in sufficiently tightened to hold the seal in place.

On the west side of CR 43, the casing was about a foot lower than on the east side, making the slope of the casing about one degree downward to the west. The ground west of the casing was lower than the road, and it sloped

downward at a four-degree angle. The pipe had no bends as it exited the casing and was buried about 6 feet below the surface. It exited the casing to the west at a downward angle about 3 1/2 degrees relative to the casing. (See figure 6.) Other than fire and rupture damage, no other damage was visible. At the point where the pipe exited the casing, it was in contact with the bottom of the casing. The link seal, installed in February, was found about 3 feet from the end of the casing, and one of the links was broken. No evidence was present of select backfill (such as sand), sand bags, or other support for the carrier pipe except for the single, wooden skid that had been installed on February 21, 1990.

Figure 6.--View of the excavated pipeline showing its position relative to the casing at the west end.

On March 15, 1990, a gauge was used to determine the moisture content and density of the soil beneath the pipe and the wooden skid. Five soil measurements were taken within 14 feet of the casing on the west, four were taken beneath the wooden skid, and two were taken from nearby undisturbed soil as a control. The results of these tests follow:

Location	Percent average moisture	Dry soil density pounds per cubic foot
Beneath pipe	26.5	94.0
Beneath skid	25.1	100.5
Control sample	22.0	104.0

A 2-inch-diameter steel pipe vent was installed on the top of the casing at both ends extending several feet above grade. A 2-inch-diameter steel pipe drain line was connected to the bottom of the casing at the west end. It was sealed with a 2-inch threaded plug. The pipe was found broken from the casing; it reportedly had been broken by excavation equipment after the accident.

The casing was cut longitudinally with a cutting torch, and the top section removed to reveal the pipe. A circumferential pipe fracture was found about 2 feet inside the west end of the casing and was 2 inches east of a pipe girth weld. The two fracture faces were found separated about 3/4 inch. Visual examination identified chevron marks on both fracture faces, indicating that the fracture was brittle and had initiated near the ERW longitudinal seam. When looking west, the longitudinal ERW seam weld was at the 11 o'clock position on the section of pipe that included the rupture. Five plastic casing insulators were installed on the pipe. The first at the west end was 13 feet 9 inches from the casing end, and the first at the east end was about 1 foot from the casing end.

The manufacturer's instructions recommended a maximum spacing of 10 feet between insulators, with the end insulators installed within 1 foot of each end and an extra insulator installed within 3 feet of each end. The manufacturer's catalog listed the compressive strength of any of the four polyethylene runners on the insulator as 3,200 psi. To conform to the recommendations, this installation would have required eight insulators.

After the rupture, the pipe-to-soil CP reading at the west end of the casing was -1.20 volts for both the casing and carrier pipes, indicating that the casing installation was "shorted." (These readings were about the same as those taken before the repair to the casing.)

On March 16, 1990, 115.6 feet of API Standard 5L, Grade B, 8.625-inch diameter pipe with a 0.500-inch wall thickness were installed at CR 43 to replace the removed pipe. This pipe was not cased beneath CR 43. The removed pipe was cut into 10 sections and shipped by the Safety Board to Battelle, a private research and testing company, for later examination.

The operating temperature of the propane in the pipeline was determined by TEPPCO to be about 50 oF at the time of the failure.

Metallurgical.--Battelle conducted physical testing and a chemical analysis of metal from the failed joint of pipe. It found that the composition met the 1963 API Standard 5L for Grade B line pipe, as well as the 1990 API standard. A 2-inch transverse sample, when subjected to a tensile test, elongated by 32 percent, yielded at 56,300 psi and fractured at

70,000 psi. A longitudinal sample and a sample taken across the weld seam produced even higher tensile strength values. All physical test values met or exceeded the applicable 1963 API Standard 5L.

Battelle conducted Charpy V-Notch tests to determine the impact energy to propagate a fracture in the steel from the pipe. At 50 °F, the approximate temperature at the time of failure, a 2/3-sized longitudinal Charpy V-Notch sample fractured at an average impact of 3.5 foot-pounds. This fracture contained no sheer features. Additional Charpy V-Notch tests determined the ductile-to-brittle transition temperature, the temperature below which a fracture absorbs substantially less energy, to be 150 °F. The energy required to fracture the metal at this temperature was measured at 32 foot-pounds. The API did not establish ductile-to-brittle transition temperatures nor require impact or toughness testing in its 1963 or 1990 standards for manufacturing line pipe.

Examination of the fracture origin with a scanning electron microscope disclosed shallow areas containing intergranular features. Longitudinal metallographic sections through the fracture origin identified several shallow intergranular cracks having a maximum depth of about 0.04 inch within 2 inches of either side of the pipe end girth weld near the fracture. The Battelle report characterized the intergranular cracks as stress-corrosion cracks (SCC). Metallographic microsections disclosed an altered (burned) microstructure in the areas corresponding to the areas of intergranular cracking. Hardness values obtained in the altered microstructure were much higher than the base material and were typical of steels having a tensile strength of 150,000 psi or greater. The intergranular cracks were circumferentially oriented and, for the most part, appeared to arrest as they entered the microstructure where the hardness values (tensile strengths) were lower. The Battelle analysis indicated that the hardened areas resulted from burns produced during pipe manufacturing, either from electrical arcs when the ERW longitudinal seam was made or when the seam weld was mechanically trimmed.

Stress Analysis.--Battelle performed a series of two-dimensional finite-element analyses to estimate the magnitude of the bending stresses in the pipe before, during, and after the repair work. Assumptions had to be made about the original pipe's raised positions and soil conditions. The analyses considered only bending stress. The calculations did not take into account any values for residual stress or axial stress from pressurization; these would have to be added. The analyses indicated that when the pipe was initially raised to remove the broken casing spacer, the maximum bending stress on the pipe increased from about 32,000 psi to about 53,000 psi. In addition, the point of the maximum stress moved from a few feet within the casing to about 30 feet west of the casing, where the jack lifted the pipe. After the link seal was installed in the annulus and the pipe lowered, the maximum bending stress was reduced to 43,000 psi at the end of the casing. At the point of failure, the bending stress was less than the maximum stress. (See figure 7.) The Battelle analyses indicated that the bending stress at the point of failure decreased from about 22,000 psi to 4,000 psi when the pipe was initially raised and increased to about 32,000 psi after the repair work. The net effect of the repair work performed on February 21, 1990,

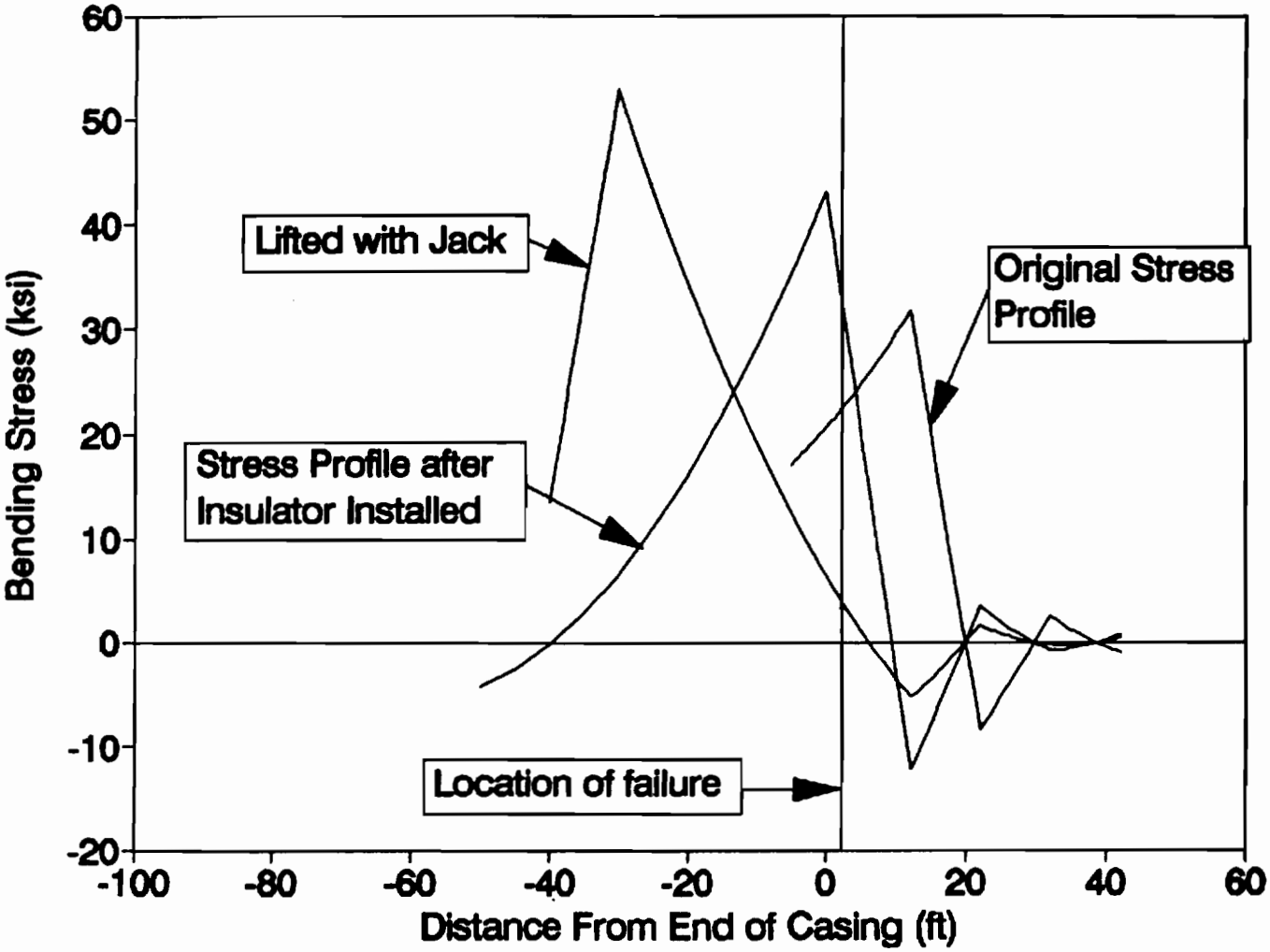


Figure 7.--Battelle's bending stress profiles showing the stresses before, during, and after repair.

increased the bending stress by 45 percent at the point of failure. These analyses also considered the effect of settlement after the repair on the pipe, and with a settlement of 15 inches, the increase in the bending stress at the failure would have been about 10,000 psi.

Postaccident Hydrostatic Tests.--After the accident, the 165 miles of pipeline was hydrostatically tested to stress the pipe to 100 percent of its SMYS at the lower elevations. This test level was selected by the TEPPCO to locate and remove any weak sections of pipe that might rupture when operation was resumed and also to allow the MOP to eventually be increased. The TEPPCO began tests on April 2, 1990, and the test pressures ranged from 1,599 psig to 2,342 psig. On April 5, 1990, a 66-inch-long section of the ERW seam failed at MP 93+96 when subjected to a pressure of 1,845 psig. This seam failure initiated at the end of the pipe in a 4-inch-long section where the ERW weld had not been fully fused. A second failure occurred on April 8, 1990, at MP 54+91. When subjected to a pressure of 1,796 psig, a 14.5-inch-long failure occurred in the pipe wall at a lamination in the steel plate which formed the pipe. Both failures occurred on pipe manufactured by Bethlehem to API Standard 5LX-42 with 0.203-inch wall thickness. After replacing the two failed pipe sections, the TEPPCO conducted a successful hydrostatic test of line P-41, and on May 6, 1990, the pipeline was placed into operation.

Other Information

Industry Standards.--The API standards (recommended practices) governed the manufacturing and testing of the pipe used to construct line P-41. These standards had no requirement either to normalize the longitudinal weld seam or to meet any material toughness for the steel used to form the pipe.

The only standard applicable to the design, construction, and initial testing of line P-41 was USA B31.4-1959, Code for Liquid Transportation Piping Systems, an industry recommended practice. This standard advised:

> The design requirements of this Code are considered to be adequate for public safety under all conditions usually encountered in oil transportation piping systems, including lines within villages, cities, and industrial areas. However, the design engineer should provide protection to prevent damage to the pipeline from unusual external conditions which may be encountered in river crossings, bridges, areas of heavy traffic, long self-supported spans, unstable ground, vibrations, weight of special attachments, or abnormal thermal forces. Some of the protective measures which the design engineer may provide are encasing with steel pipe of larger diameter, adding concrete protective coating, increasing the wall thickness to reduce the stress level using the established formula, lowering the line to a greater depth than normal, or indicating the presence of the line with additional markers. [Paragraph 402.1]

Internal Design Pressure (maximum internal liquid pressure) shall not be less than the Maximum Working Pressure plus allowances for surge pressure if anticipated. Suitable protection devices of such types as relief valves and automatic shutdown equipment shall be provided which will assure that the maximum internal design liquid pressure of the piping system and equipment is not exceeded by more than 10 percent. [Paragraph 402.2.2]

Piping systems shall be designed to have sufficient flexibility to prevent expansion or contraction from causing excessive stresses in the piping material, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment or at anchorage or guide points. [Paragraph 419.1(b)]

There are fundamental differences in loading conditions for the buried or otherwise restrained portions of the piping system and the above ground portions not subject to substantial axial restraints. Therefore different limits on allowable longitudinal expansion stresses are necessary. [Paragraph 419.6.4 (a)]

The equivalent tensile stress should not be allowed to exceed 90 percent of the specified minimum yield strength of the pipe. Beam bending stresses should be included in the longitudinal stress for those portions of the restrained line which are supported above ground. [Paragraph 419.6.4(b)]

Portions of oil transportation piping systems to be operated at hoop stress exceeding 30 percent of the specified minimum yield strength of the pipe shall be subjected to a hydrostatic test (oil or water) equivalent to not less than 1.1 times the internal design pressure. However, in no case shall it be required that the test pressure at any point of the line be such as to produce a hoop stress based on nominal wall thickness in excess of 90 percent of the specified minimum yield strength. [Paragraph 437.4.1(a)]

In 1985, Battelle issued "Guidelines for Lowering Pipelines While In Service." The guide stated that lowering [movement] of pipe should be limited to situations of moderate terrain and stable soils where the axial stress is likely to be in the range of -10,000 to +20,000 psi, and it recommended that the maximum stresses arising from supporting the pipeline and lowering it not be allowed to exceed 54 percent of the specified minimum yield strength of the pipe.

Table 3 of this guide provides the maximum distance in feet between supports to limit the total stress to 28,100 psi (54 percent of SMYS for a 52,000 SMYS). The maximum distance between supports to limit the stress to 54 percent SMYS for an 8 5/8-inch-diameter pipe in liquid service at 0 psi initial axial stress is 88 feet. The table also indicates that with supports 72 feet apart and a 6-inch differential in pipe support height, the stress imposed on the pipe at the supports would be a minimum of 43,300 psi if an initial axial stress in the pipe of 20,000 psi is assumed. (See figure 8.)

Table C-3 of the guide provides the maximum distance in feet between supports to limit the total stress to 18,900 psi (54 percent of SMYS for a Grade B pipe). For an 8 5/8-inch-diameter pipe in liquid service at 0 psi initial axial stress, the maximum distance between supports is 69 feet. The table also shows that with supports 68 feet apart and a 6-inch differential in pipe support height, the stress imposed on the pipe at the supports would be a minimum of 38,500 psi if an initial axial stress of 15,000 psi is assumed. (See figure 9.)

Federal Requirements.--In 1964, no Federal or State regulations applied to liquid pipelines. When Federal regulations, 49 CFR 195, were implemented on March 31, 1970, pipelines installed before that date were exempted from requirements directed to the design, materials, installation (including the location and spacing of valves and road crossings standards), and testing. The U.S. Department of Transportation's (DOT) Office of Pipeline Safety (OPS) in the Research and Special Programs Administration (RSPA) administers the requirements of 49 CFR 195. The State of New York has no regulatory authority over line P-41 because it is part of an interstate HL pipeline system subject only to Federal regulation.

The requirements of 49 CFR 195, applicable to factors addressed in this report, include hydrostatic testing of pipelines constructed before January 8, 1971, development of operation and maintenance procedures, review of the work performed by operator personnel, training of operator personnel, corrosion protection of buried pipelines, implementation of emergency procedures, monitoring of pipeline operations to detect abnormal conditions, shutdown of pipeline operations, educating the public to recognize and report leaks, repair of pipelines, and minimizing pipeline stress. At the time the TEPPCO repaired the casing in February 1990, the 1979 edition of the Code for Liquid Petroleum Transportation Piping Systems had been incorporated by reference in 49 CFR. Paragraph 451.6, "Pipeline Repairs," recommended that repairs be covered by a maintenance plan and be performed under qualified supervision by trained personnel aware of and familiar with the hazards to public safety. This paragraph stated that it is essential that all personnel working on pipeline repairs understand the need for careful planning on the job and be briefed on the procedures to be followed in accomplishing the repairs. (For Federal regulations applicable to this accident, see appendix D.)

TABLE 3. MAXIMUM DISTANCE IN FEET BETWEEN SUPPORTS TO LIMIT TOTAL STRESS TO 28,100 PSI (54 PERCENT OF SMYS FOR AN X52 MATERIAL)*

Initial Axial Stress, L, ksi	Empty Pipeline Sp. gr. = 0			Gas Pipeline Sp. gr. = 0.1			Liquid Pipeline Sp. gr. = 0.8		
	Differential Support Height, inches			Differential Support Height, inches			Differential Support Height, inches		
	0	3	6	0	3	6	0	3	6
8-5/8-inch diameter pipe									
0	155	148	142	138	132	125	88	82	75
5	161	153	143	143	135	125	88	79	60 (28.8)
10	156	143	125	138	125	105	83	66	64 (33.6)
15	136	113	91 (30.3)	120	95	85 (31.6)	72	53 (31.2)	68 (38.5)
20	101	74 (30.6)	98 (35.2)	90	70 (31.5)	93 (36.5)	55	55 (36.2)	72 (43.3)
16-inch diameter pipe									
0	186	181	175	167	162	156	111	105	96
5	189	181	172	168	160	151	106	97	75 (29.2)
10	180	167	150	159	146	126	98	79	78 (34.1)
15	156	133	108 (30.1)	138	112	102 (31.5)	84	67 (31.8)	81 (39.1)
20	118	89 (30.5)	113 (35.1)	105	84 (31.5)	107 (36.4)	65	67 (36.7)	83 (44.0)
30-inch diameter pipe									
0	244	239	233	217	212	206	141	132	119
5	238	230	221	210	202	191	131	118	97 (30.5)
10	221	208	191	194	180	157	119	89	99 (35.5)
15	191	166	136 (29.9)	167	138	128 (31.6)	102	83 (32.8)	101 (40.5)
20	147	113 (30.4)	142 (34.9)	129	107 (31.6)	132 (36.6)	79	84 (37.8)	102 (45.5)

* Underlined values represent conditions for which no span length exists which will give a stress level at the supports within the acceptable range. Values in parentheses are the stresses at the supports accompanying the corresponding span length and are the minimum possible values.

Figure 8.--Table 3 of "Guidelines for Lowering Pipelines While In Service" showing maximum distance between supports to limit total stress.

TABLE C-3. MAXIMUM DISTANCE IN FEET BETWEEN SUPPORTS TO LIMIT TOTAL STRESS TO 18,900 psi (54 PERCENT OF SMYS FOR AN GRADE B MATERIAL)*

Initial Axial Stress, L, ksi	Empty Pipeline Sp. gr. = 0						Gas Pipeline Sp. gr. = 0.1						Liquid Pipeline Sp. gr. = 0.8					
	Differential Support Height, inches						Differential Support Height, inches						Differential Support Height, inches					
	0	3		6			0	3		6			0	3		6		
8-5/8-inch diameter pipe																		
0	110	103		94			100	93		83			69	60		56	(24.0)	
5	108	94		76	(20.6)		97	83		73	(21.8)		64	48	(21.3)	60	(28.8)	
10	91	65	(20.7)	84	(25.5)		81	62	(21.5)	85	(26.7)		53	50	(26.3)	64	(33.6)	
15	56	70	(25.7)	91	(30.3)		51	66	(26.5)	93	(31.6)		34	53	(31.2)	68	(38.5)	
16-inch diameter pipe																		
0	145	138		128			132	125		113			90	77		73	(24.3)	
5	136	121		97	(20.2)		123	106		92	(21.6)		81	62	(21.8)	75	(29.2)	
10	112	83	(20.6)	102	(25.2)		101	79	(21.5)	97	(26.5)		65	64	(26.8)	78	(34.1)	
15	71	86	(25.5)	108	(30.1)		64	82	(26.5)	102	(31.5)		42	67	(26.8)	81	(39.1)	
30-inch diameter pipe																		
0	197	189		177			177	168		152			116	94		96	(25.5)	
5	179	161		129	(19.9)		159	139		122	(21.6)		101	82	(22.9)	97	(30.5)	
10	146	109	(20.4)	132	(24.9)		129	103	(21.6)	125	(26.6)		81	82	(27.8)	99	(35.5)	
15	94	112	(25.4)	136	(29.9)		84	105	(26.6)	128	(31.6)		53	83	(32.8)	101	(40.5)	

* Underlined values represent conditions for which no span length exists which will give a stress level at the supports within the acceptable range. Values in parentheses are the stresses at the supports accompanying the corresponding span length and are the minimum possible values.

Figure 9.--Table C-3 from "Guidelines for Lowering Pipelines While In Service" showing axial stresses on pipelines.

NTSB Pipeline Accident Reports.--Before the March 13, 1990, accident, the Safety Board had investigated six major LPG pipeline accidents.[6] In the accidents at Ruff Creek, Pennsylvania, and Donnellson, Iowa, pipe failed due to excessive stress. At Donnellson, an 8-inch-diameter steel propane pipe failed due to the combined stresses exerted when it was lowered into a trench 3 months before and from a dent and gouge caused during construction. At Ruff Creek, a 12-inch-diameter steel propane pipe failed due to stress-corrosion cracking when subjected to earth subsidence from previous coal mining in the area.

Pipeline Accident Data.--In a 1978 special study,[7] the Safety Board analyzed the DOT liquid pipeline accident and leak data for the period 1968 through 1976. The Safety Board determined from its analysis that although LPG was involved in only 10 percent of the reported 2,881 liquid pipeline accidents and leaks, it caused 62 percent of the 34 fatalities and 51 percent of the 65 injuries.

As a part of this investigation, the Safety Board analyzed the liquid pipeline accidents reported to the DOT from 1977 through 1989. Accidents that involved the transportation of LPG, natural gas liquids, and anhydrous ammonia are included in these latest data because the Federal regulations now address these products as HVLs. In the 13-year period, although HVLs were involved in only 13.7 percent of the 2,724 liquid pipeline accidents and leaks, they caused 61 percent of the 41 fatalities and 40 percent of the 228 injuries. These data are similar to those of the 1968-1976 period.

Analysis of the total 1968-89 period shows that the 669 accidents and leaks involving HVLs[8] resulted in:

- 66 fatalities;
- 156 injuries; and
- $19 million in reported property damage.

---

[6]"Pipeline Accident Reports--"Phillips Pipe Line Company Propane Gas Explosion, Franklin County, Missouri, December 9, 1970" (NTSB/PAR-72/01); "Phillips Pipe Line Company Natural Gas Liquid Fire, Austin, Texas, February 22, 1973" (NTSB/PAR-73/04); "Dow Chemical U.S.A. Natural Gas Liquid Explosion and Fire, Devers, Texas, May 12, 1975" (NTSB/PAR-76/05); "Sun Pipe Line Company Rupture of 8-inch Pipeline, Romulus, Michigan, August 2, 1975" (NTSB/PAR-76/07); "Consolidated Gas Supply Corporation Propane Pipeline Rupture and Fire, Ruff Creek, Pennsylvania, July 20, 1977" (NTSB/PAR-78/01); and "Mid American Pipeline System Liquefied Petroleum Gas Pipeline Rupture and Fire, Donnellson, Iowa, August 4, 1978" (NTSB/PAR-79/01).

[7]Safety Study Report--"Safe Service Life for Liquid Petroleum Pipelines (1978)" (NTSB/SS-78/01).

[8]This figure includes all materials now considered as HVLs; however, the statistics cited in the 1978 safety study report included only propane.

Interstate Hazardous Liquid Pipeline Data.--The July 1987 API research study, "The Safety of Interstate Liquid Pipeline: An Evaluation of Present Levels and Proposals for Change," contains the following data on liquid pipelines:

- The U.S. has about 220,000 miles of HL pipelines of which about 113,345 miles are interstate pipeline (as opposed to pipelines that begin and end in the same state).

- Eight-inch-diameter pipe represents more than 25 percent of the aggregate mileage, and pipe in the 6- to 12-inch-diameter range comprises over 70 percent of the total mileage.

- Adding dollar values of $2 million per life and $500,000 per injury to interstate HL pipeline accident damage figures, the annual average damage starting in 1968 was estimated at $19 million.

- Eighty-two percent of mainline block valves, used for purposes other than isolation of facilities, are manually operated and spaced approximately 13.6 miles apart; 7 percent are remote- or automatic-operated; and 11 percent are for one way isolation.

- Seventy-six percent of the deaths, 93 percent of the injuries, and 87 percent of the property damage occurred within 1/8 mile of the pipeline. The other deaths and injuries and most of the other property damage occurred between 1/8 and 1 mile of the pipeline.

- Forty-one percent of the total miles of pipeline were ERW and manufactured before 1970.

- Of the 52,400 casings used on pipelines, about 9 percent are metallic-shorted, and about 3.7 percent are electrolytic-shorted.

Propane Properties.--The TEPPCO's MSDS advised that the material transported in line P-41 was Propane HD-5 (also known as liquefied petroleum gas, LP-Gas, or LPG). The DOT classes it as a flammable gas, having a vapor pressure of 190 to 205 psia at 100 ^{o}F, a specific gravity in the liquid form of 0.52 and in the vapor form of 1.5, a gross heat of combustion of 2,550 BTU per cubic foot, a flash point of -45 ^{o}F, an autoignition temperature of 850 ^{o}F, a lower flammable limit of 2.1-percent gas-in-air, and an upper flammable limit of 9.5-percent gas-in-air.

The MSDS listed four hazard warnings as follows:

(1) Propane is extremely flammable, keep away from heat, sparks, and open flame.

(2) Propane vapor reduces oxygen available for breathing, use only with adequate ventilation.

(3) Propane may cause frostbite or freeze burns, avoid exposure to liquid or cryogenic gas vapor.

(4) The natural odor of propane is an inadequate warning of potentially hazardous air concentrations.

State and County Disaster Preparedness.--In the State of New York, the planning for and the response to catastrophic accidents and other disasters are handled at the State and county level. The New York State Emergency Management Office (NYSEMO) has the responsibility to supply communities with disaster relief and other required support, as well as to provide emergency response and incident command training for State and local officials. The NYSEMO subdivided the State into districts and requires that each district have a coordinator who serves on scene during emergencies. In addition, it requires each county within a district to have an emergency management office to provide on-scene support in emergencies and training for local emergency responders. The director of the SCEMO was designated as the district coordinator and assisted the on-scene commander.

All county and local public safety agencies participate in the Schoharie County Mutual Aid Agreement. This agreement governs the actions of all response agencies, and it is the countywide emergency planning document that guides each agency in the development of its response capabilities within the county.

ANALYSIS

General

The Safety Board's analysis of this accident and related issues includes the pipe failure mechanism, the repair work performed on the pipe before the rupture, the procedures and the employee qualifications applicable to the repair work, the pipeline monitoring and shutdown capabilities of the pipeline, and the knowledge of the public and community response agencies on recognizing and responding to emergencies involving a release of propane from a pipeline.

Accident

A finite-element analysis indicated that after the maintenance crew installed the end seal and lowered the pipe on February 21, 1990, the bending stress at the fracture origin was about 32,000 psi and the longitudinal tensile stress due to operating pressure was about 4,000 psi. The pipe was under greater bending stress and was less stable because it was supported only on a wooden skid that rested on moist, uncompacted soil.

Subsequent actions reduced the amount of support beneath the pipe and added weight to the soil above the pipe. Between the time of the

maintenance work and the time of the accident, the uncompacted soil beneath the pipe settled, and the rain that fell the day before the accident seeped into the ground and added weight to the soil above the pipe. These actions could have increased the bending stress at the fracture origin by 10,000 psi. Thus, the combined bending stress was calculated to be as high as 46,000 psi at the point of failure (about 80 percent of the measured longitudinal yield stress of the pipe metal).

Metallurgical examination found that the pipe failed in an area that had been weakened by small, shallow, SCC. The SCC were oriented circumferentially which is indicative of high bending stress promoting the cracking. Because SCC are strongly affected by both stress and environmental factors, the high bending stress applied to the outside circumference of the pipe in combination with the presence of water could have caused or accelerated the cracking process. The mechanism for the delayed fracture is not certain; however, at this higher-applied bending stress level, the Safety Board believes these cracks could have grown after the maintenance work, until the stress intensity at the crack tip was large enough to cause pipe failure. It is also possible that these cracks existed in the pipe and did not grow appreciably after the maintenance, but rather the stress level increased due to soil settlement. In either case, the excessively high bending stress was the primary cause of the fracture.

Pipeline Movement

Stress analyses determined that the loading of the pipe on February 21, 1990, increased the bending stress to 53,000 psi and possibly higher at the point where the pipe was jacked up. This substantially reduced the margin for error because the pipe was then stressed almost to its actual yield strength. With continued lifting, the pipe would probably have ruptured at that time. This work by an untrained TEPPCO crew unnecessarily threatened their safety and that of the public.

At the west end of the casing, the pipe was not aligned with the casing by transition bends nor was it independently supported to lessen the possibility of transferring loads to the pipe within the casing. These initial construction conditions and the subsequent settlement, in combination with the weight of the pipe and the propane, produced bending loads on the pipe within the casing that probably caused the failure of the insulator, allowing the pipe to contact the casing.

The TEPPCO procedure No. 70 on repairs to pipelines included the Federal requirement for lowering the pressure in the line section to be moved, and in addition, it required that the line section be isolated before movement. However, it did not include the Federal requirement for protecting the public, by adequate warning to evacuate, from the hazards of moving HVL pipelines. Additionally, neither this procedure nor the Federal regulations contain guidance or criteria on the extent that a pipe of specific strength, grade, diameter, and wall thickness that contains hazardous products may be safely moved, nor do the procedure and regulations require that this information to be calculated before movement. Although the pipe did not fail during its movement, additional elevation by jacking probably would have

caused a failure. Fortunately, the TEPPCO supervisor attained the clearance he needed between the pipe and its casing before the pipe failed. This was a fortuitous event rather than the result of a prudent judgment.

This accident shows that the stress limits can be easily exceeded during repairs. It underscores the need for operators to make site specific stress calculations relative to the pipe to determine how to move it safely. Because of the low fracture toughness of most pipe steel, pipes are most susceptible to failure at low ambient temperatures. Therefore, the RSPA should require pipeline operators, especially of HVL pipelines, to determine before pipe movement the amount of pipe to be uncovered, the proper site for force application, and the maximum movement a pipe can safely withstand.

Casing Repair Program and Procedures

The TEPPCO repair program did not incorporate several essential industry-recommended practices that: repairs be covered in the maintenance plan, they be performed under qualified supervision, they be performed by trained personnel, and all employees be briefed on the procedures to be followed for accomplishing the repairs. In deciding to implement a special program to correct longstanding deficiencies, the TEPPCO's management should have recognized that this program was different from routine maintenance work because the TEPPCO had not previously assigned such work to its employees. The TEPPCO then should have evaluated its procedures, supervision requirements, and the experience and training of its maintenance employees in light of the industry recommended practices.

Had the TEPPCO recognized that the casing repair program was different from routine maintenance and evaluated the procedures, maintenance personnel would have been better directed and guided to correctly perform the required work. A review of the experience and training of employees revealed that many had not been trained on applicable procedures or did not possess the work experience needed for moving pressurized pipe for the purpose of eliminating casing electrical shorts. These deficiencies should have been recognized by the TEPPCO's management and corrected before the program was implemented. At a minimum, the TEPPCO management should require that work be closely supervised by a person knowledgeable of the procedures and the methods to successfully perform the work. Also, employees should be briefed on the procedures they are to perform.

An evaluation might have made the TEPPCO management aware that the CPOs' responsibilities for operating line P-41 would be affected at times when a segment of pipe was to be moved. This should have prompted a review of the training and experience of the CPOs on the TEPPCO procedures and Federal requirements applicable to their responsibilities. This would identify whether the CPOs had been trained on the TEPPCO requirements for reducing the pressure and isolating pipe segments to be moved. By providing additional training to the CPOs, the TEPPCO would then be able to have them assist maintenance employees to comply with the TEPPCO procedures and the Federal requirements about work to be performed on the pipeline.

Although the crew, selected to perform the work at CR 43 in February 1990, did not possess the knowledge and experience to safely perform the work assigned, opportunities were available to correct this error. The maintenance supervisor should have acknowledged at the time the work was assigned that he was not experienced in moving pressurized pipes, that he had never been instructed on the use of the link seal, and that he had not received training for this work. Had he advised his supervisor of these facts, his supervisor might have delayed the work until a qualified person could perform the work or, at least, supervise it.

Although the maintenance supervisor may not have known at the time of the work assignment that the pipe required lifting to install the new casing seal, he should have recognized this when he inspected the casing and saw the broken insulator. At that time, he should have alerted his superintendent that he was not qualified to perform the work. Instead, he elected to use his "good judgment."

Although the Safety Board believes that the maintenance supervisor should have advised his superintendent that he needed assistance, it is not reasonable for management to rely on such notice to fulfill its supervisory responsibility. Rather, it is incumbent on the TEPPCO's management to assign work projects only to employees who possess the training and experience essential to the safe performance of the work, to determine that its employees are knowledgeable of the procedures applicable to the work assigned, and to periodically check that work has been completed correctly.

TEPPCO Employee Training and Supervision

The TEPPCO does not have a program to identify individual employee needs for initial or recurrent training. The TEPPCO's management failed to recognize the need to provide progressive technical training to supplement its employees' operational experience. In this accident, the TEPPCO misplaced its reliance on experience because the maintenance supervisor, with more than 20 years experience, had never performed the type of work required and had never seen the TEPPCO's written procedures for clearing casings, even if the usefulness of the procedures was limited.

The CPO's actions were also insufficient, which brings the adequacy of the TEPPCO's training for CPOs into question. The maintenance supervisor notified the CPO on duty of the work to be performed at CR 43, including the moving of the pipe. Had the CPO been trained on the TEPPCO procedure No. 70, he likely would have questioned the maintenance supervisor about performing such work without first isolating the pipe section and requesting a reduction in pressure. In addition, on the day of the accident when the resident's call alerted the CPO then on duty about the possibility of a rupture, that CPO did not effectively use available operating data within the SCADA system to determine if the pressure was dropping.

The TEPPCO's management believed that the maintenance supervisor's training was adequate because he had attended 54 training sessions in the previous 4 years. However, he had no experience in the work he performed on February 20-21, 1990; he had minimal training on applicable Federal

regulations; and he had no training on TEPPCO's procedures for clearing casing shorts. Likewise, management believed that the CPO's training was adequate. However, this training did not include either information on Federal regulations or on the TEPPCO procedures that required pipeline segments to be isolated and pressure reduced before work begins. Also, it did not adequately prepare the CPO to use the SCADA system computer capabilities to identify abnormal operating conditions.

The Safety Board has previously identified deficient pipeline operator training and employee selection practices in its February 18, 1987, report[9] on accidents at Beaumont and Lancaster, Kentucky. In that report, the Safety Board found that no requirement existed for operators of pipelines to develop and conduct training and testing programs to annually qualify their employees to perform assigned responsibilities, even though the incorrect performance of such work could adversely affect public safety. Additionally, Federal regulations do not provide criteria for assessing the adequacy of the experience and training of persons performing or directing actions required for corrosion control. Thus, the Safety Board recommended that the RSPA:

> P-87-2
>
> Amend 49 CFR Parts 192 and 195 to require that operators of pipelines develop and conduct selection, training, and testing programs to annually qualify employees for correctly carrying out each assigned responsibility which is necessary for complying with 49 CFR Parts 192 or 195 as appropriate.

On March 23, 1987, in response to this recommendation, the RSPA issued an Advance Notice of Proposed Rulemaking (ANPRM), "Pipeline Operator Qualifications," Docket No. PS-94, to obtain information on the need to establish employee qualification and training requirements. The Safety Board responded to the ANPRM on May 14, 1987, advising the RSPA that among other improvements needed, operators should be required to develop and, under the direction of a responsible person, implement an employee qualification and training program that includes the following activities:

> (a) Identification of each employee whose successful accomplishment of assigned responsibilities or tasks is a necessary part of an operator's actions for complying with Federal pipeline safety regulations.
>
> (b) Analyses sufficient to identify for each employee the individual jobs, tasks, and responsibilities necessary to be performed as a part of the operator's program for complying with Federal requirements. These

---

[9] Pipeline Accident Report--"Texas Eastern Gas Pipeline Company Ruptures and Fires, at Beaumont, Kentucky, April 27, 1985, and Lancaster, Kentucky, February 21, 1986" (NTSB/PAR-87/01).

analyses should be documented and should include routine job performance, in-plant emergency duties, and emergency responsibilities for events that occur along the pipeline right-of-way. Furthermore, these analyses should be used for establishing measurable performance standards.

(c) Identification and implementation of the specific training methods to be employed to provide adequate knowledge to each employee for effectively carrying out applicable jobs, tasks, and responsibilities identified in the analyses.

(d) Identification of the method(s) to be used in evaluating the effectiveness of the training including the identification of standard(s) for acceptance.

(e) Documentation for each employee of the training provided and the training evaluations.

Because the OPS informed the Safety Board that it intended to publish a Notice of Proposed Rulemaking (NPRM) in fall 1988, the Safety Board classified Safety Recommendation P-87-2 as "Open--Acceptable Action." However, the NPRM has not yet been published. Because of the time elapsed, the Safety Board now classifies this recommendation as "Open--Unacceptable Action" and urges the RSPA to expedite this rulemaking.

Pipeline Monitoring

The nearest monitoring location, Gibertsville, was about 47 miles from the rupture at CR 43, and its pressure differential alarm monitor was set to alert the CPO if pressure differentials were 80 psig pressure or more per minute. Because the average pressure drop per minute as the result of the rupture of CR 43 was only 23 psig, the monitor did not provide an alert to the CPO, and he was unaware of the rupture.

After the accident, the TEPPCO lowered the alarm point, to 20 psig pressure drop per minute on the pressure differential monitor at Gilbertsville. After Safety Board staff questioned the sensitivity of this monitor to detect similar or smaller releases along the 83 miles of pipeline between Gilbertsville and Selkirk, the TEPPCO installed RTUs to monitor the pressure at its pump stations and receiving terminals.

Although the operation of line P-41 is now better monitored, the Safety Board remains concerned about the adequacy of the monitoring system for protection of the public near this pipeline and other pipelines. Federal regulations require that, for facilities that are not designed to fail safely, pipeline operators must provide for the detection of abnormal operating conditions by monitoring appropriate operational data and transmitting it to an attended location. The regulations do not include any criteria on detection sensitivity or timeliness of detection. Consequently, the monitoring system installed by the TEPPCO before this accident complied with the requirement because eventually it would have detected an abnormal

pressure drop at Gilbertsville. However, the TEPPCO's monitoring system was not adequate to detect the March 13, 1990, release from line P-41 in a timely manner and to promptly alert the CPO. Moreover, because no performance criteria for monitoring systems have been established by the RSPA, the adequacy of the improved system is uncertain. Therefore, the Safety Board believes that the OPS should develop performance criteria for monitoring systems installed by pipeline operators to detect abnormal operating conditions and incorporate these criteria into its regulations.

Pipeline Shutdown

This accident released more than 100,000 gallons of propane before the pipeline could be shut down and the ruptured section isolated. When liquid propane and other HVLs are released, they vaporize rapidly, expand 200 to 300 times the liquid quantity, and form heavier-than-air vapors. These vapors can remain close to the ground for long periods. Gravity or wind can move the vapors from the area of release to areas of lower elevation and far from the pipeline. Although HVL pipelines are involved in only about 10 percent of liquid pipeline accidents, they have caused about 60 percent of the deaths and 40 percent of the injuries attributable to liquid pipeline operations. Contributing to the severity of HVL pipeline accidents is the lack of effective means to safely contain, dissipate, or otherwise reduce the threat when HVLs are released near populated areas.

In this accident, the volume of liquid propane in a 1-mile length of this pipeline would have provided a sufficient quantity of propane vapor to engulf the nearby village. Because ignition of the propane occurred within 10 minutes after the leak was detected, the delayed shutdown did not cause additional casualties or loss of property. However, prompt detection and isolation of a rupture would provide more time to evacuate residents if its location was farther from populated areas.

After the CPO was alerted about the release of propane, it required more than an hour to shut down the pumps and to close the mainline valves nearest the rupture. Although the CPO and the TEPPCO employees dispatched to close the valves did all they could to shut down the system, their actions were limited because of the distance of the valve from the rupture. The only remote-operated valve affecting this accident was at Gilbertsville. Consequently, in the mountainous terrain, propane flowed by gravity to the rupture for more than 21 hours.

The release of propane from TEPPCO's pipeline could have been substantially limited if remote- or automatic-operated valves were installed. After the CPO remotely closed the valve at Gilbertsville, a check valve located just east of the rupture could have prevented the release of propane from flowing to the rupture from pipe located at higher elevations. In recognition of this, the TEPPCO installed a check valve near the mainline block valve on the east side of the Schoharie Creek; a manual mainline valve on the west side of CR 43; remote-operated valves at Marathon, Jefferson, and Oneonta; and RTUs at Marathon, Jefferson, Oneonta, and Selkirk. Additionally, at all pump stations, the TEPPCO set the pressure differential monitor units to detect pressure loss rates of 20 psig per

minute instead of 80 psig per minute. Although these actions have improved the TEPPCO's overall monitoring and control capabilities, they have not improved its ability to remotely isolate a pipeline leak near the village. Because the valve at CR 43 must be manually operated, it would take more than an hour for an employee from the closest attended facility to arrive at this location to close it. The TEPPCO needs to modify the mainline valves near populated areas and remote- or automatic-operated valves should be installed to enable the rapid isolation of any failure in those sections.

The pipeline industry's 1979 standard, "ASME B31.4, Code for Liquid Petroleum Transportation Piping Systems," paragraph 434.15.2, "Mainline Valves," included a recommendation that on HVL pipelines in industrial, commercial, or residential areas, the mainline block valves be spaced at intervals no greater than 7.5 miles and that these valves be equipped for remote closure from an operated control location. Although the current edition of this code no longer contains these recommendations, the Safety Board believes they are needed. The code does address the use of check valves on HVL pipelines. It recommends that check valves, where applicable, be installed with each mainline block valve to provide the automatic block of a reverse flow in the piping system.

The Safety Board first addressed the issue of rapid shutdown of failed pipelines more than 20 years ago. In its 1970 report,[10] the Safety Board recommended that the OPS:

> P-71-01
>
> Conduct a study to develop standards for the rapid shutdown of failed natural gas pipelines and work in conjunction with the Federal Railroad Administration to develop similar standards for liquid pipelines.

In a 1972 report,[11] the Safety Board found that the delay in shutting down the failed pipeline to reduce the quantity of propane released was due in part to the lack of any remote- or automatic-operated mainline valves to rapidly close off and isolate the failed section. The Safety Board recommended that the Federal Railroad Administration (the agency then responsible for regulating liquid pipelines):

> P-72-10
>
> Conduct a study, in cooperation with sources of qualified pipeline expertise, concerning minimum valve-spacing standards and the use of remotely operated

---

[10] Special Study--"Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown, December 30, 1970" (NTSB/PSS-71/01).

[11] Pipeline Accident Report--"Phillips Pipe Line Company Propane Gas Explosion, Franklin County, Missouri, December 9, 1970" (NTSB/PAR-72/01).

valves, and check valves on all liquefied petroleum gas pipelines.

The recommended studies were conducted, and the Safety Board classified both recommendations as "Closed--Acceptable Action." However, no regulations were issued to require the use of remote-operated valves or other means to rapidly isolate failed segments of pipelines.

In the Safety Board report on a propane pipeline accident at West Odessa, Texas,[12] the Safety Board addressed the deficiencies in the liquid pipeline regulations compared with the natural gas pipeline regulations. On March 15, 1983, 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.

The Safety Board reiterated this recommendation on July 20, 1987, in its report on a products pipeline accident at Mounds View, Minnesota, on July 8, 1986.[13] Also in the report, the Safety Board recommended that the RSPA:

P-87-22

Require the installation of remote-operated valves on pipelines that transport hazardous liquids, and base the spacing of the remote-operated valves on the population at risk.

The RSPA responded to these recommendations in its June 8, 1990, "Proposals for Pipeline Safety; Disposition for Safety Proposals, Notice 2 of Docket PS-93." The RSPA contended that Part 195 now contains many safety standards that vary in stringency according to population characteristics even though a class location scheme is not used and that a study was underway to determine if further rulemaking on this issue was required. The Safety Board addressed the RSPA's comment on Safety Recommendations P-84-26 and P-87-22 in a 1990 accident report on a pipeline rupture in San Bernardino,

---

[12] Pipeline Accident Report--"Mid American Pipeline System Liquified Petroleum Gas Pipeline Rupture, West Odessa, Texas, March 15, 1983" (NTSB/PAR-84/01).

[13] Pipeline Accident Report--"Williams Pipe Line Company, Liquid Pipeline Rupture and Fire, Mounds View, Minnesota, July 8, 1986" (NTSB/PAR-87/01).

California.[14] The Safety Board stated that the RSPA's comments on Safety Recommendation P-84-26 were directed more at supporting existing regulations than at objectively assessing the need to improve the existing regulations. The Safety Board reclassified this recommendation as "Open-Unacceptable Action."

On the issue of more rapid shutdown of failed pipelines in populated areas, the RSPA proposal advised that a study, as required by the Congress, was being conducted to determine whether remote- or automatic-operated valves are needed to enhance safety. It stated that should this study provide a basis for improving pipeline safety, new rulemaking would be initiated.

Also in the San Bernardino accident report, the Safety Board addressed the usefulness of check valves in HL pipelines to limit the quantity of product released in the event of a rupture. From its review of Federal regulations and based on testimony from an OPS representative, the Safety Board determined that Federal regulations do not include specific requirements on the location, accessibility, and maintenance of valves and, in particular, do not address the need for check valves. In that report, the Safety Board once again cited the need for Federal regulations to include requirements for the prompt detection and shutdown of failed liquid pipelines and urged the RSPA to objectively assess the increased operating, maintenance, and emergency response requirements essential to public safety when populated areas are exposed to the risks of unintended releases of HLs from pipelines.

Because of the RSPA's reluctance to consider the Safety Board's recommendation until required to do so by the Congress and because of the time elapsed before the RSPA initiated action, the Safety Board affirmed the status of Safety Recommendation P-87-22 as "Open--Unacceptable Action."

Releases of HVLs from pipelines cause more than 60 percent of the fatalities attributable to HL pipeline operations; nevertheless, the OPS has not adequately addressed the additional hazards present from the operation of these pipelines. Federal regulations governing liquid pipeline operations do not include specific valve spacing requirements, as do the regulations governing natural gas pipelines; the need for check valves in pipelines that traverse areas with large variations in elevations; and the need for remote- or automatic-operated mainline valves to minimize the quantity of hazardous liquids released.

Consequently, the Safety Board believes that the RSPA should act promptly to establish performance standards for required monitoring to provide for the effective, timely detection of product releases and for the identification of the leak area. Further, the Safety Board urges the RSPA to

---

[14] Railroad Accident Report, "Derailment of Southern Pacific Transportation Company Freight Train on May 12, 1989, and Subsequent Rupture of Calnev Petroleum Pipeline on May 25, 1989, San Bernardino, California," (NTSB/RAR-90/02). Both Safety Recommendations P-84-26 and P-87-22 were reiterated in this report.

require pipeline operators to install remote- and automatic-operated valves (including check valves) sufficient to allow the rapid isolation of failed pipe, especially for pipelines located near populated areas.

Public Education and Release Detection

The TEPPCO information to educate the public about how to recognize and report leaks and the protective actions to take was provided to residents living within 1/8 mile of the pipeline. This action exceeded Federal requirements. The information appeared to be effective as it was used by the resident who first alerted the CPO of the leak. However, the residents injured in this accident lived beyond the 1/8-mile limit and had not received the information. Additionally, since the propane did not naturally have a distinctive odor, nor was the TEPPCO required to add one, the vapor cloud could be perceived as fog, a condition normal for that time of year and day, unless residents had knowledge of the characteristic of HVLs to form vapor clouds.

As a result of its investigation of the propane pipeline accident at Ruff Creek, Pennsylvania, the Safety Board issued to the Materials Transportation Bureau (MTB) (a former DOT organization that had included the OPS):

> P-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 liquefied petroleum gas pipeline, about the particular hazards of liquefied petroleum gas and how to contact emergency response personnel.

On August 3, 1978, the MTB issued an NPRM (Docket PS-51) that addressed the issue in Safety Recommendation P-78-10. On October 5, 1978, the Safety Board responded in support of the NPRM. On July 6, 1979, the MTB issued its final rule on Docket PS-51 but did not include this requirement. In its final rule, the MTB advised that eight commenters had recommended the deletion of the provision because they believed it would be impossible to accomplish. While the MTB eliminated the specific requirement to educate persons residing near HVL pipelines, it did require pipeline operators to conduct a program directed at the public, appropriate government organizations, and persons engaged in excavation-related activities to recognize an emergency and to report it to the pipeline operator and fire, police, and other appropriate officials.

On June 3, 1980, the Safety Board advised the RSPA that Safety Recommendation P-78-10 had been classified as "Closed--Acceptable Action" because the RSPA had included it in the proposed rulemaking as recommended. The Safety Board noted that educating persons residing near an HVL pipeline about the hazards associated with such a pipeline was not a closed issue and

that it would be addressed further when found in future accident investigations.

As noted in the 1987 API research study, 24 percent of the fatalities and 7 percent of the injuries caused by releases from liquid pipelines occurred between 1/8 and 1 mile of the pipeline. This accident again demonstrates the need to provide essential hazard recognition information to persons most likely to be harmed by a release of HVL from pipelines. The Safety Board urges the TEPPCO to extend its public education program to persons who reside at elevations lower than and within 1 mile of its pipelines, and the RSPA to require that all operators of HVL pipelines similarly extend their public education programs.

Emergency Response

Because of previous training, the NBVFD assistant chief correctly recognized the vapor cloud as hazardous, and his actions to immediately alert and evacuate others reduced the number of casualties. Similarly, the resident of Burnt Hill Road promptly recognized the noises he heard and the vapor cloud he observed as symptoms of a hazardous situation, and he promptly notified the TEPPCO's CPO. However, the short time between their observations and the ignition of the propane vapor cloud precluded the warning or evacuating of other residents.

Immediately after the explosion and fire, many residents telephoned the SCSD communications center. Its personnel promptly dispatched emergency response fire and rescue units and implemented the county's disaster response plan. The early arrival on scene of emergency response and rescue personnel, their prompt implementation of rescue and fire suppression operations, and the rescue actions taken by residents resulted in the effective evacuation and treatment of injured persons and held additional fire damage to a minimum. State, county, and local responders worked cooperatively and efficiently to implement the county disaster plan. The radio communication difficulties experienced during the emergency did not contribute to loss of life, but did impair coordination of activities and likely caused additional fire damage.

Representatives of each response agency participated in an after-action critique of the emergency operation response. The critique addressed the issue of deficient communications during the emergency, and a task group was formed to improve and standardize public safety communications within the county. The task group recommended the installation of an additional radio tower to provide better broadcast coverage in the mountainous terrain and the upgrading of older radio equipment.

As a result of the difficulties the TEPPCO experienced in communicating by radio with its response personnel, the TEPPCO recognized the need to improve its communication system between Watkins Glen and Schoharie County. It plans to install an additional radio tower to increase radio coverage in the mountainous terrain. To further improve the emergency response capabilities, the TEPPCO donated $400,000 to the area emergency response

agencies and supplied each of the 15 volunteer fire departments with a combustible gas indicator calibrated to detect propane.

CONCLUSIONS

Findings

1. The repair work on February 21, 1990, to clear an electrical short on the 8-inch steel propane pipe at County Road 43 left the pipe inadequately supported.

2. The improperly supported pipe imposed a high bending stress in the pipe at a location that contained numerous small, shallow, stress-corrosion cracks resulting in the pipe failure.

3. The steel pipe, weakened by cracks, failed catastrophically because the cracks grew from the bending stress and the corrosive environment and/or because of the excessive stress on the pipe from settlement of the soil.

4. The steel in the pipe had a high ductile-to-brittle transition temperature, which made it susceptible to brittle fracture at the normal operating temperatures of the pipe.

5. Explicit handling instructions should have been developed to move line P-41.

6. The TEPPCO written procedures applicable to the repair work did not provide adequate instruction and information for employees to correctly perform all required tasks.

7. The TEPPCO management assigned employees to perform the repair who were not sufficiently experienced or trained and did not require their work be supervised by a qualified employee.

8. The training provided to the maintenance supervisor and to the control point operators by the TEPPCO did not adequately prepare them to perform their assigned duties consistent with the TEPPCO written procedures, industry recommended standards, and Federal requirements.

9. The system the TEPPCO installed to monitor the operating conditions and to detect abnormal operations on the pipeline was not adequate to promptly detect and alert the TEPPCO personnel of the rupture. The 165-mile pipeline was monitored at an insufficient number of locations with an insufficient pressure-sensitive alarm setting.

10. The operation of the pipeline was promptly stopped once the control point operator suspected a failure had occurred; however, the flow of propane to the failed pipe could not be promptly stopped because the valves on each side of the rupture were not remote- or automatic-operated.

11. Insufficient time existed before the explosion and fire to evacuate all residents from the area of danger because the large volume of propane released from the pipeline rapidly vaporized and flowed to the lower elevations; however, one resident's early recognition of the propane vapor cloud as hazardous enabled the prompt evacuation of nearby persons which reduced the number of casualties in this accident.

12. Releases of highly volatile liquids, including propane, pose greater risks to public safety than other hazardous liquids transported by pipeline because they vaporize rapidly, are heavier-than-air, and are difficult to contain or control.

13. The Federal regulations do not include criteria for the monitoring systems now required to detect abnormal liquid pipeline operations and do not require the use of remote- or automatic-operated valves to rapidly isolate failures.

14. The TEPPCO procedures for educating the public within 1/8 mile of its pipeline to recognize hazards posed by liquid pipelines and to take appropriate actions were effective; however, they do not extend to persons who reside at elevations lower than and within 1 mile of highly volatile liquid pipelines.

15. The TEPPCO liaison with public safety officials on emergency preparedness was not adequate because it was limited to those public agencies located near line P-41 pump stations and terminals.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the Texas Eastern Products Pipeline Company pipe rupture, subsequent release of propane, and resultant explosion and fire at North Blenheim, New York, was the failure of the pipeline company to provide adequate procedures, equipment, training, and management oversight to ensure that maintenance on its pipelines was accomplished using methods and equipment that protected its employees and the public.

RECOMMENDATIONS

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

--to the Research and Special Programs Administration:

Define the operating parameters that must be monitored by pipeline operators to detect abnormal operations and establish performance standards that must be met by pipeline monitoring systems installed to detect and locate leaks. (Class II, Priority Action) (P-91-1)

Require pipeline operators to conduct analyses, before moving pressurized pipelines, to determine:

- o the extent to which the pipe may be safely moved,
- o the specific procedures required for the safe movement of the pipe, and
- o the actions to be taken for protection of the public. (Class III, Longer Term Action) (P-91-2)

Require operators of pipelines that transport highly volatile liquids to extend their public education program to include persons who reside at elevations lower than and within 1 mile of the pipeline. (Class III, Longer Term Action) (P-91-3)

Require pipeline operators to extend their emergency preparedness programs to include liaison with all community response agencies adjacent to their pipelines. (Class III, Longer Term Action) (P-91-4)

--to Texas Eastern Products Pipeline Company:

Develop and conduct employee training and testing programs to annually qualify employees to perform each responsibility assigned to them. (Class II, Priority Action) (P-91-5)

Develop explicit procedures on the physical movement of pipelines containing highly volatile liquids to require that, before movement, analyses be conducted to determine:

- o the extent to which the pipe may be safely moved,
- o the specific procedures for the safe movement of the pipe,
- o the actions to be taken for protection of the public.

Require that all employees be briefed on the work to be performed before work is begun. (Class II, Priority Action) (P-91-6)

Use only qualified employees to move pressurized liquid pipelines. (Class II, Priority Action) (P-91-7)

Install, at intervals sufficient to rapidly stop the flow of product in the event of a rupture, remote- and automatic-operated valves (including check valves) on pipeline segments that pass through or are adjacent to populated areas. (Class II, Priority Action) (P-91-8)

Extend your emergency preparedness liaison program to include all community response agencies adjacent to your pipelines. (Class II, Priority Action) (P-91-9)

Extend your public education program on recognizing and responding to highly volatile liquid pipeline emergencies to include all persons who reside at elevations lower than and within 1 mile of your pipelines. (Class II, Priority Action) (P-91-10)

--to the American Petroleum Institute, the Interstate Natural Gas Association of America, and the American Gas Association:

Notify your members of the circumstances of this accident and urge them to develop explicit procedures on the support, movement, and other handling of pressurized pipelines and to develop training and testing programs to annually qualify employees to perform each responsibility assigned to them. (Class II, Priority Action) (P-91-11)

Also, the Safety Board reiterated the following safety recommendations to the Research and Special Programs Administration:

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.

P-87-2

Amend 49 CFR Parts 192 and 195 to require that operators of pipelines develop and conduct selection, training, and testing programs to annually qualify employees for correctly carrying out each assigned responsibility which is necessary for complying with 49 CFR Parts 192 or 195 as appropriate.

P-87-22

Require the installation of remote-operated valves on pipelines that transport hazardous liquids, and base the spacing of the remote-operated valves on the population at risk.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ James L. Kolstad
Chairman

/s/ Susan M. Coughlin
Vice Chairman

/s/ Jim Burnett
Member

/s/ John K. Lauber
Member

/s/ Christopher A. Hart
Member

June 11, 1991

APPENDIXES

APPENDIX A

INVESTIGATION AND HEARING

Investigation

The National Transportation Safety Board was notified on March 13, 1991, of an explosion and fire involving a Texas Eastern Products Pipeline Company propane pipeline at North Blenheim, New York. The investigator-in-charge was dispatched from Denver, Colorado, and other members of the investigative team were dispatched from Washington, D.C. Investigative groups were established for pipeline operations, human performance, and survival factors.

Hearing

No public hearing was conducted in conjunction with this investigation.

APPENDIX B

PERSONNEL INFORMATION

Control Point Operator.--Mr. Stephen R. Westlake, 42 years old, was the control point operator on duty at the time of the accident. In 1971, the TEPPCO hired him as a maintenance employee, and before that, he had been employed as a machinist. In 1974, he transferred to pipeline operations as a control point operator. He was the senior operator in the TEPPCO's Northeast Region.

He had successfully completed the TEPPCO's technical training program and recurrent training for control point operators, including instruction in the management of critical operating situations. The investigation revealed no health or other factor that may have adversely affected his performance.

Maintenance Supervisor.--Mr. W. Palmer, 48 years old, was in charge of the work performed at CR 43 on February 21, 1990. In 1970, the TEPPCO hired him as a welder in the maintenance division. He progressed to the positions of senior welder and assistant pipeline foreman, and in 1986, the TEPPCO promoted him to the position of pipeline maintenance supervisor (foreman). During his years with the TEPPCO, he attended numerous training sessions; however, he had received no training on the procedures for removing electrical shorts between pipelines and casings or for installing link-type casing seals.

Corrosion Engineer.--Mr. Steven Rogers, 40 years old, was the TEPPCO engineer responsible for corrosion control. He received a Bachelor of Science degree in Industrial Technology. Between 1977 and 1987, he worked as a corrosion technician and designed and maintained cathodic protection systems in the oil and gas industries. He was hired by the TEPPCO in 1986 as a corrosion technician, and in 1990, he was promoted to the position of engineer.

APPENDIX C

APPLICABLE TEPPCO OPERATING AND MAINTENANCE PROCEDURES

The TEPPCO procedures applicable to the March 13, 1990, accident follow:

EXTERNAL CORROSION CONTROL--Procedure No. 100

This procedure provides for the operations, surveillance, and maintenance of corrosion control systems. It calls for corrosion control surveys to be conducted on subsurface piping systems under cathodic protection to determine the level of protection of each structure.

a. Annual Inspections

The annual inspection shall be made once each calendar year, but at intervals not to exceed 15 months. [Ref. 49 CFR 195.416]

b. Periodic Inspections

The periodic inspection shall be conducted a minimum of six times each calender year, but shall not exceed 2 1/2-month intervals. Critical bonds and rectifies shall be included in the periodic inspections. [Ref. 49 CFR 195.416(c)]

An as required periodic inspection is necessary whenever a buried pipe is exposed. The coating is to be inspected for damage or deterioration.

c. Pipeline Casings

During each annual pipeline survey, pipe-to-soil and casing-to-soil potentials shall be obtained at each location where casings are located. Should the difference between the potentials be less than 100 millivolts, additional testing is required to determine if the casing is directly or partially shorted to the carrier pipe.

Those casings which are found to be shorted to the pipeline shall be scheduled for corrective action, in accordance with the flow diagram in this section.

PIPELINE REPAIRS--Procedure No. 70
[Ref. 49 CFR 195.422 and 49 CFR 195.424]

a. All repairs to the pipeline system will be made in a manner which is safe and will prevent injury to persons or damage to property. All components must meet the standards for new construction as set forth in DOT regulations (49 CFR 195). Facilities for repair shall include the necessary equipment, trained personnel aware of and familiar with the hazards to public and personnel safety, and appropriate repair materials.

b. Temporary repairs may be necessary to protect the public and the property and for operating purposes and shall be made in a safe manner. Such temporary repairs shall be made permanent or replaced in a permanent manner as soon as practical.

c. Pipelines containing liquefied gases shall not be moved unless the line section is isolated to prevent the flow of the product and the pressure in that line section is reduced to the lower of the following:

1. Fifty percent or less of the maximum operating pressure or

2. The lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 psig above the vapor pressure of the commodity.

SYSTEM HAZARD TO THE PUBLIC--Procedure No. 260
[Ref. 49 CFR 195.402(c)(4)]

Pipeline facilities located in areas that would require an immediate response to prevent hazards to the public and the environment if the facilities failed or malfunctioned shall be determined by visual observation. The criteria for identifying these areas shall be as follows:

- All pipeline and other facilities within city limits.
- All pipeline crossings of navigable streams, lakes, and reservoirs.
- All pipeline and other facilities within 1/8 mile of a reservoir holding water for human consumption.
- Pipelines and facilities within 1/8 mile of a church, school, hospital or other place of public assembly.
- Pipelines and facilities within 1/8 mile of a residential subdivision.

The TEPPCO has also prepared a manual covering their Public Education Program for the Northeastern Region (Ohio, Pennsylvania, and New York). All customers using this common carrier pipeline have furnished Material Safety Data Sheets for their particular product being transferred, and these are included in the manual.

One page in the manual informs the public on how to recognize a pipeline leak by sight, sound, and smell and includes all petroleum products (besides propane carried in their entire pipeline systems). The manual informs that any strange or unusual odor in the area of a pipeline may indicate a leak. However, the relatively odorless smell of liquid propane would make it a difficult hazard for the public to recognize if it should leak from the pipeline.

LIAISON WITH PUBLIC OFFICIALS AND PUBLIC EDUCATION--Procedure No. 270
[Ref. 49 CFR 195.402(c)(12) & 49 CFR 195.440]

> Liaison with fire, police, and other appropriate public officials shall be established and maintained to learn the responsibility and the resources of each government organization that may respond to a hazardous liquid pipeline emergency and acquaint the officials with Texas Eastern's ability in responding to a hazardous liquid pipeline emergency and means of communication.
>
> Periodic emergency response agency briefings will be conducted by Texas Eastern Products Pipeline representatives. The purpose of these meetings will be to share information, to advise the public about our system and how it operates, our ongoing safety procedures, and the procedures we follow in the event an emergency occurs. Each party's capabilities and responsibilities in responding to emergencies will be discussed in order to ensure the safety of the public.
>
> A continuing education program shall be established to enable the public, appropriate government organizations, and persons engaged in excavation activities to recognize a hazardous liquid pipeline emergency and to report it to the Texas Eastern subsidiaries.
>
> Items to be distributed include Texas Eastern subsidiaries emergency telephone numbers, Texas Eastern memo pocket calendars, maps showing the general location of our facilities, and liquid petroleum safety data sheets.

The TEPPCO has included in its Public Education Manual vicinity maps for all of their terminals and pump stations.

EMERGENCY PLAN--Procedure No. 30
[Ref. 40 CFR 195.402(e)]

The Company Emergency Plan is to be implemented in the event of an emergency to provide for the safety of the general public and company personnel, protect property from damage, and maintain continuity of service. Ruptured or damaged pipeline or pipeline components, accidental releases of hazardous liquids, and fire or explosions, such as occurred in North Blenheim, are only three of the nine types of emergencies that will cause the procedure to implemented. The procedure states:

APPENDIX C

It shall be the policy of Texas Eastern Products Pipeline Company to treat the failure or malfunction of any of its facilities as a potential hazard to the public and respond immediately. The type of response will depend on the nature of the failure or malfunction and the particular circumstances involved. The proximity of the general public to the failure or malfunction is merely one of the factors a trained employee will evaluate in order to ensure that he makes a proper decision on a course of action.

PERIODIC REVIEW OF WORK--Procedure No. 280
[Ref. 49 CFR 195.402(a) & (c)(13)]

The work done by operating personnel shall be reviewed by Regional and General Office Management to determine the effectiveness of the procedure used in normal operation, maintenance, and emergencies. Corrective action shall be taken when deficiencies are found.

Procedures contained in the Operation and Maintenance (O&M) Manual for Products Pipelines shall be reviewed at intervals not exceeding 15 months but at least once each calendar year, and appropriate changes made as necessary to ensure that the manual is effective.

The O&M Manual is dated October 31, 1989, and had been reviewed approximately 5 months before the accident.

APPENDIX D

APPLICABLE FEDERAL REGULATIONS

When the Texas Eastern Products Pipeline was constructed in 1964, the provisions of 49 CFR 195 were not in effect, thus the design, materials, installation (including the location and spacing of valves and crossing of highways), and testing requirements did not initially apply to this pipeline. However, some testing requirements were retroactive. The reporting provisions on accidents and safety-related conditions and the operating and maintenance provisions were applicable when implemented. Requirements of 49 CFR 195 germane to this investigation include:

§ 195.242 Cathodic protection system.

(a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to determine whether adequate cathodic protection has been achieved.

(b) A cathodic protection system must be installed not later than 1 year after completing the construction.

§ 195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe.

(b) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipeline is supported by stanchions, held in place by anchors or heavy concrete coating, or an equivalent level of protection is provided.

§ 195.248 Cover over buried pipeline.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or sea bottom, as applicable, complies with the following table:

Location	Cover (inches)	
	For normal excavation	For rock excavation [1]
Industrial, commercial, and residential areas	36	30
Crossings of inland bodies of water with a width of at least 100 ft from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Deepwater port safety zone	48	24
Other offshore areas under water less than 12 ft-deep as measured from the mean low tide	36	18
Any other area	30	18

[1] Rock excavation is any excavation that requires blasting or removal by equivalent means.

(b) Less cover than the minimum required by paragraph (a) of this section and § 195.210 may be used if—

(1) It is impracticable to comply with the minimum cover requirements; and

(2) Additional protection is provided that is equivalent to the minimum required cover.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982]

APPENDIX D

§ 195.252 Backfilling.

Backfilling must be performed in a manner that protects any pipe coating and provides firm support for the pipe.

§ 195.258 Valves: General.

(a) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.

(b) Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

§ 195.260 Valves: Location.

A valve must be installed at each of the following locations:

(a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

(b) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.

(c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

(d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

(e) On each side of a water crossing that is more than 100 feet wide from high-water mark to high-water mark unless the Secretary finds in a particular case that valves are not justified.

(f) On each side of a reservoir holding water for human consumption.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982]

§ 195.262 Pumping equipment.

(a) Adequate ventilation must be provided in pump station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.

(b) The following must be provided in each pump station:

(1) Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.

(2) A device for the emergency shutdown of each pumping station.

(3) If power is necessary to actuate the safety devices, an auxiliary power supply.

(c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.

(d) Except for offshore pipelines pumping equipment may not be installed—

(1) On any property that will not be under the control of the operator; or

(2) Less than 50 feet from the boundary of the station.

(e) Adequate fire protection must be installed at each pump station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that is separate from the power that operates the station.

§ 195.302 General requirements.

(a) Each new pipeline system, each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be hydrostatically tested in accordance with this subpart without leakage.

(b) No person may transport a highly volatile liquid in an onshore steel interstate pipeline constructed before January 8, 1971, or an onshore steel intrastate pipeline constructed

before October 21, 1985, unless the pipeline has been hydrostatically tested in accordance with this subpart or, except for pipelines subject to § 195.5, its maximum operating pressure is established under § 195.406(a)(5). Dates to comply with this requirement are:

(1) For onshore steel interstate pipelines in highly volatile liquid service before September 8, 1980—

(i) Planning and scheduling of hydrostatic testing or actual reduction in maximum operating pressure to meet § 195.406(a)(5) must be completed before September 15, 1981; and

(ii) Hydrostatic testing must be completed before September 15, 1985, with at least 50 percent of the testing completed before September 15, 1983.

(2) For onshore steel intrastate pipelines in highly volatile liquid service before April 23, 1985—

(i) Planning and scheduling of hydrostatic testing or actual reduction in maximum operating pressure to meet § 195.406(a)(5) must be completed before April 23, 1986; and

(ii) Hydrostatic testing must be completed before April 23, 1990 with at least 50 percent of the testing completed before April 23, 1988.

(c) The test pressure for each hydrostatic test conducted under this section must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during test, for at least an additional 4 continuous hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-33, 50 FR 15899, Apr. 23, 1985; 50 FR 38660, Sept. 24, 1985]

Subpart F—Operation and Maintenance

§ 195.400 Scope.

This subpart prescribes minimum requirements for operating and maintaining pipeline systems constructed with steel pipe.

§ 195.401 General requirements.

(a) No operator may operate or maintain its pipeline systems at a level of safety lower than that required by this subpart and the procedures it is required to establish under § 195.402(a) of this subpart.

(b) Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it shall correct it within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.

(c) Except as provided by § 195.5, no operator may operate any part of any of the following pipelines unless it was designed and constructed as required by this part:

(1) An interstate pipeline on which construction was begun after March 31, 1970.

(2) An interstate offshore gathering line on which construction was begun after July 31, 1977.

(3) An intrastate pipeline on which construction was begun after October 20, 1985.

[Amdt. 195-22, 46 FR 38360, July 27, 1981, as amended by Amdt. 195-33, 50 FR 15899, Apr. 23, 1985; Amdt. 195-33A, 50 FR 39008, Sept. 26, 1985; Amdt. 195-36, 51 FR 15008, Apr. 22, 1986]

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

(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.

(b) *Amendments.* If the Secretary finds that an operator's procedures are inadequate to assure safe operation of the system or 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 15 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.

(c) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety during maintenance and normal operations:

(1) Making construction records, maps, and operating history available as necessary for safe operation and maintenance.

(2) Gathering of data needed for reporting accidents under Subpart B of this part in a timely and effective manner.

(3) Operating, maintaining, and repairing the pipeline system in accordance with each of the requirements of this subpart.

(4) Determining which pipeline facilities 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.

(5) Analyzing pipeline accidents to determine their causes.

(6) Minimizing the potential for hazards identified under paragraph (c)(4) of this section and the possibility of recurrence of accidents analyzed under paragraph (c)(5) of this section.

(7) Starting up and shutting down any part of the pipeline system in a manner designed to assure operation within the limits prescribed by § 195.406, consider the hazardous liquid in transportation, variations in altitude along the pipeline, and pressure monitoring and control devices.

(8) In the case of a pipeline that is not equipped to fail safe, monitoring from an attended location pipeline pressure during startup until steady state pressure and flow conditions are reached and during shut-in to assure operation within limits prescribed by § 195.406.

(9) In the case of facilities not equipped to fail safe that are identified under § 195.402(c)(4) or that control receipt and delivery of the hazardous liquid, detecting abnormal operating conditions by monitoring pressure, temperature, flow or other appropriate operational data and transmitting this data to an attended location.

(10) Abandoning pipeline facilities, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards.

(11) Minimizing the likelihood of accidental ignition of vapors in areas near facilities identified under paragraph (c)(4) of this section where the potential exists for the presence of flammable liquids or gases.

(12) Establishing and maintaining liaison with fire, police, and other appropriate public officials to learn the responsibility and resources of each government 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.

(13) Periodically reviewing the work done by operator personnel to determine the effectiveness of the procedures used in normal operation and maintenance and taking corrective action where deficiencies are found.

(d) *Abnormal operation.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device;

(v) Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Correcting variations from normal operation of pressure and flow equipment and controls.

(4) Notifying responsible operator personnel when notice of an abnormal operation is received.

(5) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(e) *Emergencies.* The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs:

(1) Receiving, identifying, and classifying notices of events which need immediate response by the operator or notice to fire, police, or other appropriate public officials and communicating this information to appropriate operator personnel for corrective action.

(2) Prompt and effective response to a notice of each type emergency, including fire or explosion occurring near or directly involving a pipeline facility, accidental release of hazardous liquid from a pipeline facility, operational failure causing a hazardous condition, and natural disaster affecting pipeline facilities.

(3) Having personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.

(4) Taking necessary action, such as emergency shutdown, or pressure reduction, to minimize the volume of hazardous liquid that is released from any section of a pipeline system in the event of a failure.

(5) Control of released hazardous liquid at an accident scene to minimize the hazard, including possible intentional ignition in the cases of flammable highly volatile liquid.

(6) Minimization of public exposure to injury and probability of accidental ignition by assisting with evacuation of residents and assisting with halting traffic on roads and railroads in the affected area, or taking other appropriate action.

(7) Notifying fire, police, and other appropriate public officials of hazardous liquid pipeline emergencies and coordinating with them preplanned and actual responses during an emergency, including additional precautions necessary for an emergency involving a pipeline system transporting a highly volatile liquid.

(8) In the case of failure of a pipeline system transporting a highly volatile liquid, use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas.

(9) Providing for a post accident review of employee activities to determine whether the procedures were effective in each emergency and taking corrective action where deficiencies are found.

(f) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 195.55.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982; Amdt. 195-39, 53 FR 24951, July 1, 1988]

§ 195.403 Training.

(a) Each operator shall establish and conduct a continuing training program to instruct operating and maintenance personnel to:

(1) Carry out the operating and maintenance, and emergency procedures established under § 195.402 that relate to their assignments;

(2) Know the characteristics and hazards of the hazardous liquids transported, including, in the case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions;

(3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquid spills, and to take appropriate corrective action;

(4) Take steps necessary to control any accidental release of hazardous liquid and to minimize the potential for fire, explosion, toxicity, or environmental damage;

(5) Learn the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition; and

(6) In the case of maintenance personnel, to safely repair facilities using appropriate special precautions, such as isolation and purging, when highly volatile liquids are involved.

(b) At intervals not exceeding 15 months, but at least once each calendar year, each operator shall:

(1) Review with personnel their performance in meeting the objectives of the training program set forth in paragraph (a) of this section; and

(2) Make appropriate changes to the training program as necessary to insure that it is effective.

(c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the procedures established under § 195.402 for which they are responsible to insure compliance.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 47 FR 32721, July 29, 1982, as amended by Amdt. 195-24, 47 FR 46852, Oct. 21, 1982]

§ 195.408 Communications.

(a) Each operator must have a communication system to provide for the transmission of information needed for the safe operation of its pipeline system.

(b) The communication system required by paragraph (a) of this section must, as a minimum, include means for:

(1) Monitoring operational data as required by § 195.402(c)(9);

(2) Receiving notices from operator personnel, the public, and public authorities of abnormal or emergency conditions and sending this information to appropriate personnel or government agencies for corrective action;

(3) Conducting two-way vocal communication between a control center and the scene of abnormal operations and emergencies; and

(4) Providing communication with fire, police, and other appropriate public officials during emergency conditions, including a natural disaster.

§ 195.414 Cathodic protection.

(a) No operator may operate an interstate pipeline after March 31, 1973, or an intrastate pipeline after October 19, 1988, that has an effective external surface coating material, unless that pipeline is cathodically protected. This paragraph does not apply to breakout tank areas and buried pumping station piping. For the purposes of this subpart, a pipeline does not have an effective external coating and shall be considered bare, if its cathodic protection current requirements are substantially the same as if it were bare.

(b) Each operator shall electrically inspect each bare interstate pipeline before April 1, 1975, and each bare intrastate pipeline before October 20, 1990 to determine any areas in which active corrosion is taking place. The operator may not increase its established operating pressure on a section of bare pipeline until the section has been so electrically inspected. In any areas where active corrosion is found, the operator shall provide cathodic protection. Section 195.416 (f) and (g) apply to all corroded pipe that is found.

(c) Each operator shall electrically inspect all breakout tank areas and buried pumping station piping on interstate pipelines before April 1, 1973, and on intrastate pipelines before October 20, 1988 as to the need for cathodic protection, and cathodic protection shall be provided where necessary.

[Amdt. 195-33, 50 FR 15899, Apr. 23, 1985; 50 FR 38660, Sept. 24, 1985]

§ 195.416 External corrosion control.

(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each underground facility in its pipeline systems that is under cathodic protection to determine whether the protection is adequate.

(b) Each operator shall maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.

(c) Each operator shall, at intervals not exceeding 2½ months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.

(d) Each operator shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.

(e) Whenever any buried pipe is exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.

(f) Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets the requirements of this part or, if the area is small, must be repaired. However, the operator need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure specified in this subpart, based on the actual remaining wall thickness.

(g) If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness in the pits.

(h) Each operator shall clean, coat with material suitable for the prevention of atmospheric corrosion, and maintain this protection for, each component in its pipeline system that is exposed to the atmosphere.

[Amdt. 195-22, 46 FR 38360, July 27, 1981 as amended by Amdt. 195-24, 47 FR 46852 Oct. 21, 1982; Amdt. 195-31, 49 FR 36384 Sept. 17, 1984]

§ 195.424 Pipe movement.

(a) No operator may move any line pipe, unless the pressure in the line section involved is reduced to not more than 50 percent of the maximum operating pressure.

(b) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are joined by welding unless—

(1) Movement when the pipeline does not contain highly volatile liquids is impractical;

(2) The procedures of the operator under § 195.402 contain precautions to protect the public against the hazard in moving pipelines containing highly volatile liquids, including the use of warnings, where necessary, to evacuate the area close to the pipeline; and

(3) The pressure in that line section is reduced to the lower of the following:

(i) Fifty percent or less of the maximum operating pressure; or

(ii) The lowest practical level that will maintain the highly volatile liquid in a liquid state with continuous flow, but not less than 50 p.s.i.g. above the vapor pressure of the commodity.

(c) No operator may move any pipeline containing highly volatile liquids where materials in the line section involved are not joined by welding unless—

(1) The operator complies with paragraphs (b) (1) and (2) of this section; and

(2) That line section is isolated to prevent the flow of highly volatile liquid.

[Amdt. 195-22, 46 FR 38360, July 27, 1981; 46 FR 38922, July 30, 1981]

§ 195.440 Public education.

Each operator shall 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. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of non-English speaking population in the operator's operating areas.