NATIONAL TRANSPORTATION SAFETY BOARD

WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

TEXAS EASTERN GAS PIPELINE COMPANY RUPTURES AND FIRES
AT BEAUMONT, KENTUCKY, ON APRIL 27, 1985, AND
LANCASTER, KENTUCKY, ON FEBRUARY 21, 1986

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16. Abstract About 9:10 p.m. c.s.t. on April 27, 1985 natural gas under 990 psig ruptured the No. 10, 30-inch-diameter pipeline of the Texas Eastern Gas Pipeline Company. The pipeline was located 2 miles east of Beaumont, Kentucky, under Kentucky State highway 90. The force of the escaping high-pressure gas ripped open 30 feet of pipe, blasted an opening across Kentucky State highway 90, and dug out a crater 90 feet long, 38 feet wide, and 12 feet deep. The escaping gas ignited and incinerated an area about 700 feet long and about 500 feet wide. Five persons in a house 318 feet north of the rupture were killed and three persons 320 feet south of the rupture were burned as they ran from their house trailer. Two houses, three house trailers, a sawmill, two barns, numerous parked cars and abandoned vehicles, and nine pieces of road construction equipment were destroyed.

At 2:05 a.m. c.s.t., on February 21, 1986, natural gas under 987 psig ruptured the No. 15, 30-inch-diameter pipeline of the Texas Eastern Gas Pipeline Company 50 feet south of State highway 52 near Lancaster, Kentucky. The force of the escaping gas ripped 480 feet of pipe out of the ground, exposed 40 feet of an adjacent parallel pipeline, ignited and destroyed two houses, one house trailer, six automobiles, and damaged other buildings. Three persons were injured, 2 of them seriously, and 77 other persons were evacuated from the area.

17. Key Words in-line inspection equipment; corrosion inspection; corrosion detection; shielding; corrosion control monitoring; cathodic protection; grandfather clauses; liaison and coordination; specified minimum yield strength; maximum allowable operating pressure; pressure reduction; line valves; pipe wall thickness; requalification; hydrostatic testing; personnel training

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The National Transportation Safety Board determines that the probable cause of the pipeline accident near Beaumont, Kentucky, was the unsuspected and undetected atmospheric corrosion of Texas Eastern Gas Pipeline Company's 30-inch-diameter pipeline in a casing under State highway 90. Contributing to the accident was the failure of the pipeline industry and of the Office of Pipeline Safety to recognize the need for and to require the use of in-line corrosion detection techniques for identifying and monitoring the existence and severity of corrosion in casings and other areas shielded from corrosion protection.

The probable cause of the pipeline accident near Lancaster, Kentucky, was the failure of the Texas Eastern Gas Pipeline Company to fully investigate the extent and severity of previously detected and inspected corrosion-caused damage and to replace the damaged segment of pipeline before its failure. Contributing to the accident was the lack of gas company guidelines for its personnel for further inspection and the shut down or reduction in line pressure upon detecting corrosion damage on its pipelines.

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EXECUTIVE SUMMARY

On April 27, 1985, natural gas under 990 psig ruptured the No. 10 pipeline of the Texas Eastern Gas Pipeline Company system. The rupture was in an area weakened by atmospheric corrosion that was located within the pipeline's casing under Kentucky State highway 90 near Beaumont, Kentucky. The ensuing fire killed five persons in a house located north of the rupture, injured three persons as they fled from their house located south of the rupture, and destroyed substantial amounts of property.

On February 21, 1986, natural gas under 987 psig ruptured the no. 15 pipeline of the Texas Eastern Gas Pipeline system. The rupture was in an area weakened by galvanic corrosion and was located south of Kentucky State highway 52 near Lancaster, Kentucky. The force of the escaping gas and the ensuing fire injured three persons as they fled from their houses, resulted in the evacuation of 77 other persons, and destroyed substantial amounts of property.

The major safety issues addressed in this report concern the gas company's inspection and monitoring procedures of its pipelines for corrosion, the adequacy of guidance developed by industry-related organizations, and the adequacy of Federal regulations for assisting operators of pipelines in protecting pipelines against corrosion and for identifying areas of corrosion-caused damage. Other safety issues identified during the investigation were the inadequacy of training by the gas company of employees responsible for performing inspections and for coordinating with local emergency response agencies, and deficiencies in the Federal regulations for qualifying and training gas company employees in carrying out responsibilities mandated by those regulations.

The National Transportation Safety Board determines that the probable cause of the pipeline accident near Beaumont, Kentucky, was the unsuspected and undetected atmospheric corrosion of Texas Eastern Gas Pipeline Company's 30-inch-diameter pipeline in a casing under State highway 90. Contributing to the accident was the failure of the pipeline industry and of the Office of Pipeline Safety to recognize the need for and to require the use of in-line corrosion detection techniques for identifying and monitoring the existence and severity of corrosion in casings and other areas shielded from corrosion protection.

The probable cause of the pipeline accident near Lancaster, Kentucky, was the failure of the Texas Eastern Gas Pipeline Company to fully investigate the extent and severity of previously detected and inspected corrosion-caused damage and to replace the damaged segment of pipeline before its failure. Contributing to the accident was the lack of gas company guidelines for its personnel for further inspection and the shut down or reduction in line pressure upon detecting corrosion damage on its pipelines.

As a result of its investigations of these accidents, the Safety Board issued recommendations to upgrade the qualifications and training of gas company employees, to require complete inspections for corrosion-caused damage to buried pipelines that have been excavated to require periodic affirmation through inspections and tests of the maximum allowable operating pressure of pipelines, to require periodic inspections for corrosion damage of pipelines installed in vented casings, to require changes in pipelines to facilitate use of in-line inspection equipment, and to provide additional and more specific guidance on corrosion control practices and corrosion monitoring procedures.

NATIONAL TRANSPORTATION SAFETY BOARD
WASHINGTON, D.C. 20594

PIPELINE ACCIDENT REPORT

Adopted: February 18, 1987

TEXAS EASTERN GAS PIPELINE COMPANY PIPELINE RUPTURES AND FIRES BEAUMONT, KENTUCKY, ON APRIL 27, 1985, AND LANCASTER, KENTUCKY, ON FEBRUARY 21, 1986

INVESTIGATION

The Accident at Beaumont, Kentucky

In September 1983, in anticipation of the widening and straightening of Kentucky State highway 90 near Beaumont, Kentucky, the Texas Eastern Gas Pipeline Company (gas company) excavated and extended the casing 1/ on two of its three pipelines under the road--line No. 15, a 30-inch-diameter pipeline and line No. 25, a 36-inch-diameter pipeline. To extend the casing on lines No. 15 and 25, both lines were fully exposed. While exposed, they were examined and found to be in good condition; their coatings were in good condition and no corrosion was found.

Line No. 10, a 30-inch-diameter pipeline which was located between lines No. 15 and 25, had a sufficient length of casing to accommodate the road construction project, therefore no additional casing was added. Line No. 10 was not exposed, but was excavated to within 1 foot of the top of the casing so that its casing vent pipe could be extended to the edge of the new, wider right-of-way. After the additional casing had been added to lines No. 15 and 25, the area was backfilled, leaving all three pipelines with 6 feet of cover over them.

On April 27, 1985, at its Tompkinsville compressor station near Beaumont, the gas company was compressing natural gas to 1,000 psig in three parallel pipelines extending northward from the station. The compressor station had been operating steadily at this pressure for more than a year and had experienced no pressure upsets or rapid pressure changes. This compressor station contained two electric motor-driven compressors.

At 9:10 p.m. c.s.t. 2/ the compressor station operator noticed a sudden drop in discharge pressure on the No. 10 pipeline pressure gauge. In compliance with gas company emergency procedures, he immediately telephoned the gas company's dispatching headquarters in Houston, Texas. (See appendix B.) The control panel at the dispatching headquarters displayed the pressure drop a minute later. The station operator then

1/ Lengths of pipe, generally two sizes larger than that of the pipeline, installed beneath highways and railroads through which the pipeline is inserted. The pipeline is electrically isolated from the casing by installing spacers made of electrically nonconductive material at intervals along the pipeline. Generally, the space between the casing and the pipeline at the ends of the casing are sealed by a gasket to keep water and dirt out and atmospheric vents are installed near each end of the casing. Casings are installed to facilitate replacement, to comply with requirements imposed by owners of property crossed by the pipeline, or to provide structural strength for withstanding superimposed traffic loads.

2/ All times are central standard time excepted where noted.

telephoned his supervisor and advised him of the drop in pressure (see figure 1). The supervisor directed the station operator to shut down the No. 1 compressor which was compressing gas into the No. 10 pipeline and told the station operator that he would come to the compressor station and close the valve on the No. 10 pipeline in the compressor yard. The station operator ran toward the compressor to shut it down, and on the way he saw a large orange glow in the sky north of the compressor station indicating to him that the No. 10 pipeline had ruptured and that the escaping gas had ignited. The station operator shut down the No. 1 compressor at 9:15 p.m.

The gas company's dispatching department in Houston, Texas, is the central control point for the operation of the pipeline system. The dispatchers have the responsibility to control and to monitor the entire pipeline system, to maintain its continuous operation and to monitor the gas intake into the system and the gas discharged from the system. During emergencies involving system disruption, the dispatchers have the responsibility for determining which compressor stations to shut down or to slow down and which valves to close to eliminate or mitigate the emergency conditions while holding the pipeline upset condition to a minimum. Uncontrolled or unreported compressor station shutdowns can result in line pressure surges which could cut off gas supplies to communities and possibly rupture other sections of the pipeline system.

As the station operator was shutting down the compressor, the supervisor arrived at the station at 9:23 p.m. and closed the power-operated valve on the No. 10 pipeline which was located outside the compressor building. This action stopped the flow of gas from the compressor station to line No. 10. He then telephoned the gas company maintenance crew to alert them about the rupture and to instruct them to close the main line valves at a location 18 miles north of the compressor station.

To reach the mainline valves, the maintenance crew had to drive near the area of the rupture. Their trip was impeded by the automobiles converging on the accident site. Although the congestion slowed them considerably, they were able to close the mainline valves at 10:31 p.m. isolating the rupture within an 18-mile section of the pipeline. (See figure 2.) Immediately after closing the last of the mainline valves, the flames decreased, and by 11:43 p.m. the major fire was out with only small fires burning at each end of the ruptured pipeline and at isolated grassy areas.

Investigation of the accident site revealed that at 9:10 p.m., while operating in a Class I location at 992 psig or at 76.3 percent of its specified minimum yield strength (SMYS) 3/ the No. 10 pipeline had ruptured within its casing beneath Kentucky State highway 90 at a location about 2 miles east of Beaumont, Kentucky. The force of the natural gas escaping from the rupture ripped 30 feet of the No. 10 pipeline out of the ground, tore an opening across State highway 90, and blasted out a pear-shaped crater 90 feet long, 38 feet wide, and 12 feet deep. The escaping gas ignited and incinerated an area 700 feet long by 500 feet wide. The fire was ignited either by sparks created by the tearing of the metal pipe or by rocks or other debris striking the metal pipe.

3/ Pipelines constructed and in operation after 49 Code of Federal Regulations Part 192 became effective in 1971 are required to operate at a maximum pressure of 72 percent of SMYS in a Class I, rural area. Pipelines constructed and in operation before the effective date of the Federal regulations are allowed to operate above 72 percent of SMYS if they had safely done so for the 5 years before 1971. A Class I location is defined as ". . .any class location unit that has 10 or less buildings intended for human occupancy." The class location unit "is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. . . ."

Figure 1.— Tompkinsville pressure recording chart.

Figure 2.—Schematic diagram of the pipeline system.

Five persons in a house 318 feet north of the rupture were killed and three other persons were burned while fleeing from a house trailer 320 feet south of the rupture. The gas-fueled fire destroyed two houses, three house trailers, a sawmill, two barns, a school bus, numerous parked and abandoned automobiles, nine pieces of road construction equipment, and other items. (See figure 3.)

Events Preceding the Accident at Lancaster, Kentucky

After the accident at Beaumont, the Kentucky State Public Service Commissioner requested the gas company conduct an in-line inspection of all of its pipelines (Nos. 10, 15, and 25) in Kentucky. Later, the in-line inspection was enlarged to include the gas company's entire system at the direction of the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation (DOT). The OPS, the State of Kentucky, and the gas company were concerned that the cathodic protection monitoring system used by the gas company in compliance with Federal regulations, and the close interval corrosion survey, which was not specifically required by Federal regulations, were not depicting the true condition of the cathodic protection at all locations along the pipeline. They wanted to determine if any other undetected pipe corrosion conditions existed, and, if so, where they were located and how critical they were.

The in-line inspection program began in May 1985 on line No. 10 and was completed in November 1985. Gas company personnel worked with the in-line instrument inspection company personnel to verify each instrument run and analyze the graphs. At the end of each instrument run, the instrument was removed from the pipeline and the information on its magnetic tape was used to make a temporary working graph. The magnetic tape was then mailed to the instrument company's office for refining, editing, and enlarging. In about 4 to 6 weeks, the completed, permanent graph was sent to the gas company's measurement and corrosion department in Houston, Texas. The in-line inspection instrument identified several locations where previously undetected corrosion was present. Thirty-five sections of pipe at various locations between Beaumont and Owingsville were replaced and additional pipe replacements were scheduled. (See figure 2.)

In September 1985, the in-line inspection instrument was run through the No. 15 pipeline in the Lancaster, Kentucky, area. The instrument indicated an area of possible corrosion damage on the pipeline outside of and just south of the casing pipe beneath State highway 52; this area was selected for excavation and inspection to verify that the instrument operated correctly throughout the run (instrument verification excavation). On September 12, 1985, the No. 15 pipeline at State highway 52 was excavated and examined by two gas company employees, a corrosion control department representative from the gas company's Measurement and Corrosion Department in Houston, and a measurement and corrosion technician from the gas company's pipeline department area office. The representative's primary responsibility at these instrument verification excavations was to make sure that the in-line instrument functioned accurately and that the anomalies which the instrument indicated in the pipe wall were identifiable where the pipe was excavated. This information was later taken to the gas company's Houston office by the representative from that office. The local area corrosion technician was at the excavation to help with the instrument verification work and reported to the gas company's area manager, not to the Houston office representative. The local technician and the Houston representative documented the corrosion found on the pipe by tracing the corrosion areas, prepared a diagram of the corroded areas, and noted the location and depths of corrosion. (See figures 4a through 4d.) Both employees stated that the corrosion appeared to be inactive at this location because no bright metal was observed which would indicate active corrosion.

Figure 3.—Diagram of the accident site at Kentucky State highway 90.

Figure 4a.—Texas Eastern Gas Pipeline Company report of pipe and coating inspection.

Figure 4b.—Tracing made of area and depth of corrosion at the south end of the casing under State highway 52.

Figure 4c.—Drawing of area and deepest penetration of corrosion in No. 15 pipeline south of State highway 52.

Figure 4d.—Drawing of overall corrosion areas and depths of penetration on No. 15 pipeline south of State highway 52.

The pipe could not be easily inspected completely because it was resting on a rock ledge. This prevented the gas company's personnel from determining whether the corrosion extended further along the underside of the pipe and it prevented their measuring the depths of pits close to the rock. The gas company personnel did make a notation on the "instrument verification" report that said "unable to gauge center, probably deeper than 190 mils." However, some information required to be entered on the report form used for the "instrument verification" was not provided, the report was not signed, and the company's personnel did not describe the condition of the pipe or the degree of corrosion. The corroded areas that were measured for depth and traced for area and configuration ranged from a 260 mil pit (55.4 percent of the 0.469 inch pipe wall thickness) at the girth weld joining the 0.469 inch wall thickness pipe to the 0.375 inch wall thickness pipe, to a 190 mil pit (50.7 percent of the 0.375 inch wall thickness pipe). In addition, a band of general corrosion on the bottom of the pipe about 5 feet in circumferential length and 1 foot in longitudinal length was located between the 260 mil and 190 mile pits.

At that time, the gas company had no written criteria or company guidelines for categorizing various degrees of pipeline corrosion, i.e., light, moderate, severe, or critical. Based on his knowledge and experience, each corrosion technician was expected to make his own judgment as to the severity of the corrosion. The representative from the corrosion control department from Houston and the local measurement and corrosion technician had different opinions about the effect of the corrosion. The representative from Houston considered what he saw to be "severe but not critical" corrosion; however, he believed the corroded pipe would eventually have to be replaced. The local measurement and corrosion technician, when questioned about the corroded pipe during the Safety Board's investigation stated, "I would say in the medium, possibly medium heavy, however [sic] terms you want to use, not all that critical, nothing to cause any great alarm."

After the instrument verification had been made and the corroded areas of the pipe measured and recorded, the pipe was recoated, but the excavation was left open for several days. During that period the excavation filled with water before the backfill was completed.

The "instrument verification" report and the diagrams of the corroded area of the pipe were taken to the gas company's Measurement and Corrosion Department office in Houston, Texas. These actual corrosion measurements were compared with the indications shown on the permanent graph prepared by the instrument company. Copies of the "instrument verification" report were also sent to the gas company's Pipeline Department in Houston which was responsible for determining which corroded areas would be repaired or replaced and when such work should be done. The area of corrosion at State highway 52, documented on the "instrument verification" report and three other areas were listed in a September 23, 1985, memorandum from the Measurement and Corrosion Department to the Pipeline Department as candidates for further investigation by the Pipeline Department. The State highway 52 "instrument verification" report was referenced in the memorandum as "also included is an excerpt of the verification digout on the upstream side of highway 52 which has already been excavated and investigated."

The normal procedure for the Pipeline Department was to examine the instrument verification reports and other indications of corrosion and to calculate the safe operating pressure of the pipe at the remaining uncorroded wall thickness. Many of these reports were being received by the Pipeline Department due to the intensified in-line inspection program. The "instrument verification" report and the September 23, 1985, memorandum were assigned to an engineer in the gas company's pipeline department in Houston, Texas, for further evaluation. The engineer retired before completing the assignment. The pipeline department did not examine the instrument verification report for Kentucky State highway 52 and did not calculate the pressure. No further work was done on line No. 15 at State highway 52.

By February 1986, based on its inspection data, the gas company had excavated and replaced 35 sections of pipe between its Tompkinsville and Owingsville compressor stations because of corrosion damage. Twenty-five replacements were made on the No. 10 pipeline on the discharge (downstream) side of the Tompkinsville compressor station, seven replacements were made on the No. 15 pipeline on the suction side (upstream) of the Danville compressor station, and three replacements were made on the No. 10 pipeline on the discharge side of the Danville compressor station. (See figure 2.) No pipe had been replaced on the No. 15 pipeline on the discharge side of the Danville compressor station at that time. After all postaccident in-line inspections had been completed and analyzed, the gas company removed more than 400 sections of corroded pipe from its system in Kentucky alone. Although the majority the of 400 sections replaced were not critically corroded, the gas company considered the corrosion to be serious enough for the pipe sections to be replaced. The gas company had been unaware of the corroded areas before using the in-line inspection equipment even though the Federal regulation for inspection for corrosion was being met.

The Accident at Lancaster, Kentucky

On February 21, 1986, at its Danville compressor station near Lancaster, the gas company was compressing natural gas to 1,000 psig in three parallel pipelines extending northward from the station. This compressor station contained 10 gas engine-driven compressors and 2 electric motor-driven compressors. The compressor station had been operating steadily at this pressure and had experienced no pressure upsets or rapid pressure changes. At 2:05 a.m., the station operator noticed a sudden drop in the discharge pressure on the No. 15 pipeline. As the pressure in the No. 15 pipeline dropped, the engine-driven compressors automatically speeded up in an attempt to maintain the 1,000 psig set pressure. In so doing all 10 engine-driven compressors exceeded the engine overspeed limitation and were shut down automatically by the speed control. In compliance with gas company emergency procedures, the station operator immediately telephoned the gas company's dispatchers in Houston, informed them of the problem, and then closed the station valve on the No. 15 pipeline. (See appendix B.) Natural gas under 987 psig (75.9 percent of SMYS) ruptured the gas company's 30-inch-diameter No. 15 pipeline about 30 feet south of the casing pipe that crossed under State highway 52, about 7 miles from Lancaster. The force of the escaping gas tore 480 feet of the pipeline out of the ground and excavated an area 500 feet long, 30 feet wide, and 6 feet deep.

The escaping natural gas ignited almost immediately and incinerated an area extending more than 900 feet north and south and 1,000 feet east and west. Three persons were burned as they escaped from their frame house located 280 feet west of the rupture and five other persons suffered minor injuries; two persons were burned as they ran from a trailer house located 525 feet north of the rupture and three persons were burned as they ran from a brick house located 200 feet southwest of the rupture. The two houses were destroyed by fire and the house trailer was damaged beyond repair due to the heat of the fire and by debris propelled by the force of the escaping gas. Two barns, several small buildings, and four automobiles were destroyed and about 15 acres of pasture and woodland were burned. Seventy-seven persons were initially evacuated from the area, but were allowed to return to their homes later the following day. (See figure 5.)

Figure 5.—Diagram of the accident site at Kentucky State highway 52.

Valves at the Danville compressor station located 7 miles south of the accident, were closed by gas company personnel at 2:15 a.m. The mainline valve on line No. 15, 11 miles north of the accident, was closed at 2:46 a.m., thus isolating the rupture within an 18-mile section. The gas-fed fires burned out at 3:14 a.m., about 28 minutes after the rupture was isolated.

Emergency Response

<u>Beaumont, Kentucky.</u>—The Kentucky State Fire Marshal (fire marshal), the Kentucky State Disaster and Emergency Services (DES), the Kentucky State Police (State police), and the local police and volunteer fire departments promptly responded to the accident. These civil agencies and the gas company personnel coordinated and cooperated with each other at the accident site to control the emergency; no complaints or recommendations for more effective action were profferred by any group.

<u>Lancaster, Kentucky.</u>—The fire marshal, DES, the State police, and the local area police and volunteer fire departments promptly responded to the accident. Spokespersons for the fire marshal and the DES stated that it was difficult to take emergency measures because they were unable to obtain the necessary information about the pipeline from local gas company personnel. The adjacent exposed pipeline was the greatest source of concern to the civil agencies.

In the early morning light, emergency personnel could see a 40-foot long section of line No. 10 which had been uncovered by the force of the escaping gas. This section had been exposed to the heat and flames of the ignited gas. The civil agencies wanted to know if the exposed, heat-affected pipeline was still operating under pressure and if so, under what pressure and was it safe. The civil agencies reported that the local gas company personnel would not give them the information requested. The civil agencies needed the information to determine if the evacuated area should be extended and to determine if there was any danger to the civil agency personnel in the area attempting to locate missing persons and to make certain that all houses had been evacuated. Without the necessary information the civil agencies were reluctant to commit their personnel to a potentially dangerous area.

Eight hours elapsed after the gas ignited before some of the requested information was provided by the gas company. The compressor station supervisor had never been involved in an accident of such serious proportions, but was well aware of the previous accident at Beaumont. In an affidavit filed with the Safety Board after its public hearing, the gas company supervisor stated that a person approached him at the accident site stating that he was from the Fire Marshal's office, but presented no identification. In addition, that same person had a tape recorder and told the gas company supervisor that he needed some information for the media. The Kentucky Fire Marshal at the Safety Board's public hearing held in Danville, Kentucky, on April 30 and May 1, 1986, stated:

> I do not recall presenting my credentials. I do recall that I did, definitely, identify myself. I was wearing a uniform that we wear that would make it obvious to anybody, I believe, who we were. But I certainly identified myself, why I was there, and why I wanted the information.

The gas company supervisor indicated to the Safety Board that he did not want to give out information which might be misinterpreted by the news media or others; he wanted to clear the release of information with his supervisor first.

The gas company supervisor took no action to identify himself to any of the civil agency personnel on site nor did he report to the civil agency command post. However, he was wearing a "hard hat" and driving a radio-equipped pickup truck both of which displayed the gas company logo. The gas company supervisor was satisfied that all of the major damage to the area that could be done had been done because he knew that the compressor was shut down, the pipeline block valves had been closed isolating the failed section of pipe, and the pressure had been reduced to 900 psig in the adjacent, exposed, and heat-affected pipeline. He had also radioed his supervisor in the Lebanon, Tennessee, pipeline office and had been told that the exposed pipeline would not fail at the reduced pressure of 900 psig. In his mind the area had been secured and it was now just a matter of waiting for daylight to begin repairs. Although he was confident that the area was safe, the gas company supervisor did not provide the civil agencies on site with any information or assurance to alleviate their concerns about extending the evacuation area or ordering their personnel into a potentially hazardous area.

After the accident the gas company revised its Emergency Procedures (No. 40). Excerpts from the revised procedures follow:

> Emergency procedures shall be implemented in the event of an emergency to provide for the safety of the general public and company personnel, protect public and company property from damage, and maintain continuity of gas service.
>
> Continuity of management shall be maintained during emergencies, insofar as possible. When continuity of management cannot be maintained due to communications failure or other extenuating circumstances, the highest level of management will assume supervision and control.
>
> *　　*　　*　　*　　*
>
> Emergencies that involve the general public and outside authorities such as police, fire, and emergency response personnel may require immediate on-site answers to the authority. Additionally, reporters from newspapers, radio, or television must also be handled in a responsible manner. Until top Company management can be fully briefed and take overall control of the emergency, the following line of succession should be followed to establish the person responsible for initial response to the authorities and media:
>
> 1. The Station Supervisor (or Station Supervisor designee) at the closest compressor station.
>
> 2. The appropriate Area General Manager (or Area General Manager designee) as soon as he can arrive and be available.
>
> 3. The on-site Public Affairs Division representative.
>
> As each of the above personnel becomes briefed on the incident, he will in turn become responsible for responses to the authorities and media.

The following general answers can be given by the responsible person:

1. What happened and when.
2. Whether there are injuries and/or missing persons and, if so, how many.
3. What Texas Eastern has done or is doing to end the emergency.
4. That Texas Eastern is investigating or will investigate the cause of the emergency.
5. That you have no further information, but that Texas Eastern will release more information as it becomes available.

The responsible person should be prepared and may give the following information to identified police, fire, and emergency response authorities with respect to Texas facilities involved with the incident:

1. Identify whether facility is or is not Texas Eastern's.
2. The number and size of pipelines at the location.
3. The line number and size of the pipeline involved in the emergency.
4. The approximate distance between pipelines and their location with respect to each other where multiple lines exist.
5. The approximate operating range (or Maximum Allowable Operating Pressure).
6. The approximate soil cover.
7. The product being transported (i.e., dry natural gas, non-toxic, specific gravity about 0.6 [lighter than air], odorized or non-odorized).
8. The length of line to be isolated and time when isolated (last valve closed).
9. The on-site Texas Eastern representative's name and job title.
10. Name and phone number of Texas Eastern's personnel to be contacted for further information:

a. By fire, police, and emergency response type agency representatives (also General Manager, or as otherwise advised).

b. By news media (Public Relations Department).

Injuries to Persons

Beaumont, Kentucky

	Company Employees	Area Residents	Total
Fatal	0	5	5
Nonfatal	0	3	3
Total	0	8	8

The five fatally injured persons were found at the north wall of their house. The Metcalf County Coroners report indicated that their deaths occurred as a result of smoke inhalation with post mortem incineration. The manner of death was listed as accidental.

The three injured persons sustained burns; two were treated and released, one was hospitalized for a short period of time with second degree burns on his back.

Lancaster, Kentucky

	Company Employees	Area Residents	Civil Agencies	Total
Fatal	0	0	0	0
Nonfatal	0	8	0	8
Total	0	8	0	8

Five of the eight area residents who were injured, sustained minor injuries and were treated and released. Three other persons fleeing from their house sustained burns on their backs and legs and were hospitalized under observation.

Pipeline Damage

Beaumont, Kentucky.—For several hours after the accident, gas company maintenance personnel were unable to conduct repairs because the ground temperature was estimated to have been 150 -170° F. Lines No. 15 and 25 had not been exposed to the forces of the escaping gas or the heat of the flames since the 6 feet of compacted soil protected the lines. After the area had cooled, the fragments of line No. 10 and its casing were collected by investigators, measured, marked for reference, and removed from the road crossing.

Approximately 120 feet of 30-inch diameter, 0.469-inch wall thickness, API Specification 5L, X-65 grade pipe (API 5L, X-65) 4/ was installed across the road to

4/ API, the American Petroleum Institute, is a trade association. Among its activities, it issues standards for the manufacture of pipe used for constructing pipelines that transport hazardous liquids and gases. Specification 5L, X-65 is one such standard for pipe with a specified minimum yield strength of 65,000 psi.

replace the ruptured and damaged section of line No. 10. The Kentucky State Highway Department authorized the gas company to use uncased, heavy-wall pipe to make this repair. The gas company estimated it cost $757,000 for replaced pipe, for the lost gas (116,000 cubic feet), for the materials used, and for the labor required to install the pipe and restore the area. The estimated cost does not include loss of gas sales when line No. 10 was not in operation and other business interruption costs.

Lancaster, Kentucky.—Approximately 480 feet of the No. 15 pipeline, constructed of 30-inch diameter, 0.375-inch wall thickness, API 5LX-52 pipe, was blown out of the ground and torn into 25 pieces by the force of the escaping gas. In addition, about 40 feet of the No. 10 pipeline, constructed of 30-inch diameter, 0.375-inch wall thickness, API 5LX-52 pipe, which lay 25 feet to the east of the No. 15 pipeline, was uncovered by the force of the escaping gas and exposed to the fire. Although only 40 feet of the No. 10 pipeline had been exposed to the fire, the gas company replaced it with 61.1 feet of pipe to be sure that all of the heat-affected pipe was removed. While excavating for this pipe replacement, an area of corrosion was found 57 feet away from the heat-affected pipe. The corroded pipe was replaced with 22.5 feet of new pipe.

The gas company replaced 763 feet of line No. 15 (including the road crossing at highway 52) to return this pipeline to service. The gas company estimated the costs of damage to its pipeline including the natural gas lost to be about $1 million. This estimate does not include the cost of business interruption, lost gas sales during the time these pipelines were out of service, nor the extended interval that all three pipelines were operated at reduced rates of flow until other corroded sections of these pipelines were replaced.

Other Damage

Beaumont, Kentucky.—After the accident, the Kentucky State Police estimated property damage at approximately $1 million. This does not include the costs of the emergency agencies response to the rupture, of evacuation, of damage to the highway, or of the time and expense of highway users for the days alternate routes were required. The items listed as destroyed included:

- 2 one-story frame houses plus contents
- 3 house trailers plus contents
- 3 wood frame storage barns plus contents
- 1 school bus-1975 model
- 15 non-operable vehicles
- 8 pieces of road construction equipment
- 1 fuel oil tank-full
- plastic piping

Lancaster, Kentucky.—After the accident the Kentucky State Police estimated the damage to adjacent property to be $500,000. This loss estimate does not include costs incurred by local agencies in responding to this emergency or by evacuated area residents. These items listed as destroyed were:

- 2 brick houses
- 1 house trailer
- 5 damaged buildings
- 6 automobiles

Meteorological Information

Beaumont, Kentucky.—At the time of the accident, Beaumont, Kentucky, was in a warm sector, east of a slow easterly moving frontal system. Weather conditions included overcast skies and scattered rain showers; the temperature was 66° F with winds at 7 mph from the southwest.

Lancaster, Kentucky.—At the time of the accident, the weather conditions at the Blue Grass Airport in Lexington, approximately 31 miles from Lancaster and the closest weather recording station, were low scattered clouds and a high overcast sky. The wind was blowing about 6 mph from the southeast, the temperature was 55° F, the relative humidity was 64 percent, and the barometric pressure was 29.71 inches.

Tests and Research

Beaumont, Kentucky.—After the accident, the Safety Board's metallurgist and a metallurgist from the Battelle Petroleum Technology Center recovered six pieces of the line pipe and three pieces of the casing pipe; all pipe fragments were not recovered. The recovered pipe fragments were segregated by casing pipe and line pipe; the pipes were measured, photographed, and examined at the accident site. Similar documentation also was performed on the damaged casing pipe and line pipe remaining in the ground.

Visual examination of both the inside and outside of the line pipe which had been installed in the casing revealed extensive areas of corrosion on the outside surface; corrosion had significantly reduced the pipe wall thickness. Further laboratory metallurgical examination revealed that the fracture originated at the top of the line pipe inside the casing at the road crossing of Kentucky highway 90 at MP 354.40 approximately 17 feet north of the south end of the casing. The fractured area was associated with an extensive amount of external corrosion with a minimum remaining wall thickness of about 0.130 inch at one point.

The facilities of the Battelle Petroleum Technology Center in Houston, Texas, were used to perform the metallurgical tests.

The metallurgical report included the following information:

> Calculations have shown that the loss of pipe wall arising from corrosion reduced the strength of the pipe inside the casing to a value below the stress generated by the operating pressure. The corrosion is believed to have been caused by atmospheric corrosion accelerated by alternating condensation/evaporation cycles. We speculate that the water entered the casing annulus by condensation in the vent pipes.
>
> A summary of the recent cathodic protection data indicates that a small fraction of current from the cathodic protection system was flowing to the casing. However, the difference between the pipe to soil potential of the carrier pipe and the casing suggests that this was due to a high resistance electrolytic path such as would occur with mud or water rather than direct short between the casing and pipe. Under such conditions, any current flow from the casing to the pipe would be so small as to result in very little corrosion of the inside surface of the casing, which is consistent with the observations. Even though the

casing may have been in some kind of electrical contact with the carrier pipe, it does not appear to have had an effect on the failure. Cathodic protection would be ineffective at mitigating atmospheric corrosion in this case because of the thin discontinuous films of water present.

The failure pressure calculated by using the actual wall thickness profile would only be reduced by 5 psig. This would be negligible considering it is only 0.5 percent less than the value calculated from the operating pressure alone and also within the scatter of the calculations.

Scraping and residue taken from the bottom of the casing pipe after the accident were analyzed by an independent laboratory. The results showed that:

The base material in all samples was iron oxide.

*   *   *   *   *

The presence of sulfates in the corrosion products is of major significance. The very low concentration of strong base cations and relatively low concentration of alkaline earth cations insure that in the presence of water, the sulfate ions would have the corrosive effect of dilute sulfuric acid.

<u>Lancaster, Kentucky.</u>—The affected area of the pipeline was fractured into 25 pieces along approximately 480 linear feet of original pipe. Metallurgists visually examined the fracture surfaces to determine the origin of the rupture. The damaged pipe segments were classified by geometry, weld configurations, and other surface conditions to determine their position at the time of rupture. These efforts established that 16 girth welds and 17 pipe sections of line No. 15 were included in the damaged pipe. One piece of the pipe, containing about 28 inches of girth weld near the south end of the failed pipe, was never recovered.

The origin of the fracture was determined to be in an area of corrosion on the outer surface of a 0.375-inch wall thickness pipe section. The origin was determined to be at the bottom of the pipe approximately 14 feet south of the girth weld joining the 0.375-wall thickness pipe to a section of 0.469-inch wall thickness pipe (transition weld). The location of the corroded area roughly corresponds to the edge of the large rock ledge in the bottom of the pipeline trench as noted in the September 14, 1985, "instrument verification" report. Thirteen areas of corrosion were found on the outer surface of the first pipe length south of the transition girth weld. The failure initiation point was approximately 14 inches south (upstream) of the last pit that the corrosion technicians were able to measure (the 190 mil depth pit).

The area of initial fracture and its related area of corrosion together with other specimens of the same pipe length were removed and sent to Battelle Columbus Laboratories, Columbus, Ohio, for more detailed tests, measurements, and examinations by Safety Board and Battelle metallurgists. The report of the tests and analysis indicated that:

The failure initiated at an area of corrosion that was 26 inches in longitudinal extent and 10 inches in circumferential extent. Within this region, more than half of the wall thickness had been lost for a distance of 9 inches along the fracture path. This corroded region was located almost on the bottom of the pipeline at a point where the pipeline may have been resting on a solid rock ledge. Calculations using the A.G.A. (American Gas Association) surface flaw equation revealed that the region of metal loss would have been expected to fail at a pressure level of 962 psig. Thus, it is reasonable to believe that the failure was the result of the observed corrosion.

It could not be determined whether active corrosion was occurring in the 26-inch by 10-inch failure initiation area. The corroded section had been scoured by the force of the escaping gas and the heat of the flames; the failed pipe surfaces were clean.

Pipeline System Description

Texas Eastern Gas Pipeline Company, a division of the Texas Eastern Transmission Corporation, operates a natural gas pipeline system consisting of 9,538 miles of pipelines. The system begins in Texas at the Mexican border near McAllen and extends to the New York City area. The system provides a major portion of the natural gas supply for the northeastern part of the United States. (See figure 6.) The gas company operates 76 compressor stations with a total main line horsepower of 1,229,160 to provide a maximum capacity of about 5.2 billion cubic feet of natural gas per day.

There are 5,400 casings installed in the system—an average of one casing in each 1.77 miles of pipeline. At the time of the accident approximately 150 (2.8 percent) of these casings were known by the gas company to be electrically shorted to the pipeline. However, before this accident, the gas company had never experienced a corrosion-caused failure of a line pipe which was electrically short circuited to the casing pipe.

The compressing of gas to high pressures results in heat being induced into the gas and in turn into the pipe and its coating. Some of the early pipeline coatings deteriorated or became disbonded from the pipe for as far as 10 miles downstream of the compressor stations because of these temperatures, which may reach 160° F or more.

Line No. 10 was constructed in 1952 in the center of the right-of-way acquired by the gas company for its pipeline system. It was constructed of 30-inch diameter API 5L X52 pipe with a wall thickness of 0.375 inch. Line No. 15 was constructed in 1957 on the west side of the right-of-way and was the same size and met the same API standard as line No. 10. Line No. 25 was constructed in 1967 on the east side of the right-of-way. This pipeline was made of 36-inch diameter API 5L X52 pipe with a wall thickness of 0.390 inch. (See figure 2.) The SMYS, wall thickness, and other pipe properties of each pipeline were selected to provide a design internal pressure of 1,300 psig. Each pipeline was permitted by the Federal regulations to be operated at a maximum pressure of 1,000 psig or 76.9 percent of the SMYS at the compressor station.

The industry guidelines in effect at the time of the gas company's three pipelines were constructed was the Gas Transmission and Distribution Piping System ASA B31.1.8-1952 (for the No. 10 pipeline), ASA B31.1.8-1985 (for the No. 15 pipeline), and ASA B31.8-1958 (for the No. 25 pipeline), published by the American Society of Mechanical Engineers (ASME). All three editions of this industry guide recommended that the maximum allowable operating pressure of gas transmission pipelines in Class I locations be limited to 72 percent of SMYS, 936 psig in the case of the gas company's three pipelines. However, the gas company hydrostatically tested all three of its pipelines to the yield strength of the pipes (and slightly above that point) because:

Figure 6.—Texas Eastern Gas pipeline system map.

Texas Eastern believes very strongly in high pressure hydrostatic testing to verify the structural integrity of pipelines. We hydrostatically test pipelines to the actual yield level of the steel. When the yield level is reached the steel begins to deform plastically. At this point the volume of water injected into the pipeline per unit increase in pressure goes up significantly and pressurization is stopped. The test pressure is then maintained within a narrow range below this yield pressure for the duration of the test.

Hydrostatically testing a pipeline to its actual yield strength confirms the actual strength of the pipeline as constructed. Hydrostatically testing to a certain percentage of the specified minimum yield strength of the pipe, or of the proposed operating pressure of the pipeline, does not confirm the actual strength of the pipeline. The specified minimum yield strength is the minimum yield strength which is called for in the specification under which the pipe is manufactured.

* * * * *

Operating a pipeline at a certain percentage of the specified minimum yield strength of the pipe or to the mill test pressure level does not confirm a known factor of safety in the pipeline. Under these conditions, the actual strength of the constructed pipeline is not known. The pipe mill hydrostatic test is not representative of the actual strength of a completed pipeline. The only method of determining the actual yield strength of a pipeline is in-place hydrostatic testing of the pipeline to yield. In-place hydrostatic testing to actual yield allows a known factor of safety to be determined.

* * * * *

The gas company's Pipeline Department headquartered in Houston, Texas, is responsible for technical oversight of the operation and maintenance of system pipelines. It is responsible for reviewing all information concerning the physical condition of the pipelines including reports on corrosion damage and inspections of pipeline segments exposed, for evaluating the affect upon the pipelines of any damages noted, for excavating and inspecting areas of suspected damages identified by the in-line inspection instrument, and as applicable, for replacing, repairing, and requiring pressure reductions on segments of pipelines where remedial measures are required.

The gas company's Measurement and Corrosion Control Department headquartered in Houston, Texas, among other responsibilities, has overall responsibility for controlling corrosion of the pipelines and for monitoring the effectiveness of procedures and facilities used in the corrosion control program. In carrying out its responsibilities, this department selected the pipeline segments to be inspected using the in-line inspection instrument, selected the segments of pipelines to be excavated and inspected to verify the adequacy of the in-line inspection, analyzed the graphs produced from the in-line inspection to identify additional areas on the pipelines suspected of being damaged by corrosion to such an extent that physical inspection was warranted, and provided its findings to the Pipeline Department for its use in performing the physical inspections and evaluations.

Personnel Information and Training

Compressor Station Supervisor Training.—The Tompkinsville compressor station supervisor had been employed by the gas company for 33 years; he had been a compressor station supervisor for 4 years. He qualified for this position through seniority with the gas company and on-the-job training. The previous compressor station supervisor acted as his instructor before retirement.

The Danville compressor station supervisor had been employed by the gas company for 32 years. He had served as a supervisor for approximately 5 years, the last year at Danville. He qualified for this position through seniority with the gas company and on-the-job training.

Gas company compressor station supervisors, in addition to on-the-job training, were to attend occasional roundtable discussions at Baton Rouge, Louisiana, or at Morgantown, West Virginia. Supervisory personnel from other gas pipeline companies also attended these sessions at which general pipeline and compressor station problems were discussed. There are no records to indicate that the Tompkinsville Compressor Station supervisor had ever attended these roundtable discussions. The Danville Compressor Station supervisor had last attended a session on May 10 through 12, 1977.

Other Employee Training.—The gas company tests its compressor station personnel in several ways to determine their ability to properly carry out their responsibilities. Once each year, all compressor station operators are taken to the first set of valves on the suction and discharge sides of the station. At these locations, which are about 18 miles on either side of the station, the operators are tested to determine if they know which mainline valves to operate for separating, for connecting, or for isolating the three pipelines. According to the gas company training manual, other training includes monthly safety meetings at which work area safety requirements, operations, and maintenance and emergency procedures are discussed. Personal health habits such as diet, rest, cleanliness, and personal appearance are also discussed. Every 2 years all pipeline, compressor station, and maintenance personnel are given a job review based on job duties and related responsibilities. This job review is performed during the year by the supervisor observing employees in performing tasks required. For each employee, the supervisor notes on the employee job review form each task observed and his assessment as to whether the employee is properly trained for performing that task. At the end of the review period, all tasks listed on an employee's review form which have not been observed and rated by the supervisor are discussed between the supervisor and the employee. Based on the responses given by the employee, the supervisor determines if the employee is adequately trained to perform each task. Once each year the compressor station is shut down under a mock emergency condition and the compressor station operators and other maintenance personnel on duty are evaluated on how they responded to the emergency condition.

Gas company measurement and corrosion technicians are qualified for their positions by on-the-job training. A trainee learns the procedures for which he is responsible by actually performing the duties under the supervision of a more senior technician. In addition to the on-the-job training, technicians may periodically attend continuing education programs, seminars, and roundtable discussions with other company technicians. One such corrosion course attended is given by The National Association of Corrosion Engineers (NACE), at the University of West Virginia. On average, a company technician attends a NACE course on corrosion once every 3 to 5 years. No tests are given at any of the above training sessions.

The measurement and corrosion technician involved in the instrument verification at Kentucky State highway 52 had attended nine corrosion training sessions from 1958 through 1980, five of which were the Underground Corrosion Short Course sponsored by the NACE and held at West Virginia University (WVU). The corrosion control representative from Houston attended seven company-sponsored seminars and several NACE-sponsored Underground Corrosion Short Courses at WVU. These courses encompassed all aspects of pipeline corrosion from system design to corrosion detection, including pipeline corrosion control, pipeline coating, anode installation, rectifier installation, and maintenance.

Pipeline Corrosion

Practically all corrosion encountered in pipeline systems is galvanic in nature, wherein the chemical change is accompanied by a transfer of electrical energy. Such reactions are called electrochemical. In galvanic corrosion, the area from which current flows is called the anode; the area to which the current flows is called the cathode. Two types of galvanic corrosion exist—one in which dissimilar metals are in a common electrolyte and one in which a common metal is in dissimilar electrolytes. (Dissimilar metals could be new and old pipe, pipe and casing pipe, or mill scale and clean pipe. Dissimilar electrolytes could be differences in soils or soil conditions.)

Atmospheric corrosion occurs on pipelines when moisture from the air, along with any contaminates contained therein, comes into contact with exposed metal and a combination of electro-chemical and direct chemical attack occurs. The rate of corrosion is influenced by the temperature, the type of chemicals contained in the moisture, and the rate at which corrosion products are removed by any washing action produced as moisture moves across the exposed metal. Washing of the corrosion products from an area exposes additional pipe metal to moisture for further attack.

Monitoring of Cathodic Protection

The gas company annually checked the level of cathodic protection on its pipelines by measuring the pipe-to-soil (p/s) and casing-to-soil (c/s) potential differences at test stations installed at intervals averaging about 3/4 of a mile apart. Using a saturated copper-copper sulfate half cell as required by Federal regulations 49 CFR Part 192, the gas company had measured and recorded these readings since 1952 when the No. 10 line was installed.

The readings from the test station at State highway 90 near the accident site at Beaumont, Kentucky, are shown in figure 7. From 1960 to 1971 the p/s and c/s readings were identical indicating that the pipe was electrically short-circuited to the casing. Many other readings were either identical or nearly the same including one taken 1 month before the accident. Since 1953 the gas company had suspected that the pipe was electrically shorted to the casing pipe and, in 1954, 1956, and 1964 it tried to eliminate the condition by replacing the casing seals and by clearing out the mud and debris in the casing annulus. The condition was never fully corrected. In addition, in July 1973 a 20-foot, close-interval corrosion survey was conducted at State highway 90. All readings were more negative than the -0.85 volt minimum specified by Federal regulations.

Figure 7.—Annual cathodic protection survey on State route 90.

Close Interval Surveys

To supplement its annual monitoring of the cathodic protection system at permanent test stations, the gas company began a close interval p/s potential survey (close interval survey) program in the mid-1970's. The gas company performed these surveys to better determine the effectiveness of its cathodic protection system.

At the Safety Board's public hearing on the accident at Lancaster, on April 30 and May 1, 1986, a pipeline corrosion consultant, who is a member of the NACE, testified that close interval surveys were a valuable method of determining the effectiveness of a pipeline's cathodic protection system at points between the permanent test stations. He stated that in selecting the interval at which readings are to be taken, the added costs for closer intervals must be weighed against the value of the additional information obtained about the cathodic protection of the pipeline. It was the consultant's opinion that the most cost-effective distance between readings is 30 inches. The consultant also stated that although the close interval survey was quite accurate, it could not always detect areas where a pipeline was subject to a "shielding effect." The consultant described a "shielding effect" as an obstruction that prevents or hinders the desired flow of current onto a pipeline which is to be protected cathodically. Such obstructions could be casing, areas of rock adjacent to a segment of a pipeline, disbonded pipe coatings, or other large objects buried near pipelines.

At the accident site at Lancaster, the annual p/s and c/s potentials were all well above -0.85 volt. In addition in 1980, the gas company conducted a 20-foot, close interval survey at State highway 52 (the accident site); the p/s potentials were well above -0.85 volt, indicating that the No. 15 line was cathodically protected.

In-Line Inspections

In 1967 the gas company began to supplement the monitoring of its cathodic protection system with in-line inspections using an electromagnetic in-line pipeline inspection instrument. In the earlier years of the in-line pipe inspection program, the correlation between the location of pipe wall variations as indicated by the instrument as a result of the inspections and their actual locations along the route of the pipeline, often was not good. However, as more operational experience with the technique has been gained and as refinements have been made in the equipment, the technique now provides acceptable accuracy in locating pipe wall deficiencies. Using field measurements to verify corrosion depths, the gas company estimated that it could be about 95 percent accurate in estimating the depth of corrosion identified by the in-line inspection.

The company's in-line inspection program began in 1967 and 50 miles of its pipeline were inspected using the technique. The following table shows the number of miles of the pipeline system which was inspected each year.

Year	Inspected Pipeline
1967	50
1968	250
1969	150
1970	350
1971	250
1972	275
1973-1978	180
1979	280
1980	210
1981	375
1982	250
1983	150
1984	490
1985	1,470
1986	4,050
	8,780

Other Information

New Company Guidelines for Corrosion Assessment and Establishment of Removal or Repair Program.--After the Lancaster accident the company instituted new procedures and guidelines for determining the area and extent of corrosion damage, for immediately assessing the need to reduce the internal pressure in pipelines, and for establishing a priority for repair or replacement. The new procedures require that whenever any portion of the pipeline is excavated and exposed (for maintenance work, new construction, or instrument verification), the exposed pipe is to be inspected for corrosion. When corrosion is found, the excavation will be continued until no corrosion is evident and then all corrosion damage will be fully documented. A company engineer at the site will calculate 5/ the safe pipeline operating pressure, using the information on the depth and spacing of the corrosion damage. If the calculation indicates that the pipeline pressure is too high for the pit depths and spacing, the pipeline pressure will be immediately reduced or, if extreme corrosion is encountered, the affected line section will be shut down. Recently the gas company corrosion technicians have been trained and qualified to perform this duty.

The Effect of Casings on Cathodic Protection.—To explore further the reasons for using casings on pipelines and to determine what adverse effects the use of casings may have on the safety of pipelines, the Safety Board received testimony from several agencies and organizations during its October 9 and 10, 1985, public hearing on the Beaumont accident. Federal, State, and private organizations testified; however, the pipeline industry organizations (the Interstate Natural Gas Association of America, the American Gas Association, and the American Petroleum Institute) did not accept the Safety Board's invitation to participate.

The gas company representatives stated that many sections of pipe had been removed from casings when pipe was being relocated because of road construction and other activities. Inspection of the removed pipe sections showed that the pipe was in good

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5/ This involves entering data on the depth of corrosion pits and the distance between pits into a programmed portable calculator. The formula programmed into the calculator is that included in appendixes G-6, G-7, and G-8 of the ASME Guide for Gas Transmission and Distribution Pipeline Systems (1984).

condition with only minor areas of corrosion discovered. Furthermore, minor leakage of gas has been the worst result experienced due to corrosion of pipe installed within casings; no major ruptures had ever been experienced before these accidents by any of the gas companies.

The representative of the OPS stated that he knew of no statistics on pipeline failures directly applicable for assessing the effect, if any, casings may have upon the overall safety of buried pipelines. However, from the records of OPS there is no indication that the failure of pipelines which are encased has resulted in a significant threat to public safety. The OPS does not require the casing of pipelines for crossing roads or for any other reason; however, if a casing is used, its regulations incorporate specific actions which must be taken (49 CFR 192.323).

Representatives of the Federal Highway Administration (FHWA), DOT, and the American Association of State Highway and Transportation Officials (AASHTO) commented that before 1959 the Federal government and most of the States favored the use of casings for pipeline crossing under highways. Since 1959 there has been no policy specifically requiring the use of casing; rather, the policy has been to leave the decision concerning the use of casings up to the individual State highway department.

The representative of the Kentucky State Highway Department concurred with the FHWA and AASHTO representatives. He stated that Kentucky had a policy in the 1950's which generally required the casing of pipeline crossings under highways; however, this policy was changed to allow the uncased crossing of pipelines where heavier pipe wall and improved insulating coatings were used. The change in policy came about because pipeline companies have been able to demonstrate that the heavier wall pipelines could safely withstand the forces imposed by the highway and vehicular traffic and in so doing the pipeline could be better protected against corrosion within the highway right-of-way.

The representative of the American Railway Engineering Association (AREA) stated that it endorses the casing of pipelines crossing under railroads to protect against damaging the railroad should the pipe leak or rupture. While individual railroads are not mandated to follow this policy, in practice most railroads do require the use of casings for pipelines crossing their rights-of-way. The representative further stated that by following good construction and inspection practices, operators of pipelines should experience no problems as a result of these casings.

Other Gas Company Corrosion Surveillance Procedures.—The Safety Board obtained information about corrosion monitoring practices and experiences with corrosion-caused failures from four additional operators of pipelines in Kentucky. The representative for the Tennessee Gas Pipeline Company (TGP) stated that TGP operates approximately 14,000 miles of pipelines with 1,618 miles (11 percent) located in Kentucky. He reported that TGP has experienced only one electrolytic corrosion-related rupture in Kentucky. TGP believes that all the corrosion monitoring practices it uses are required by Federal regulations. The annual monitoring of corrosion test stations is the primary method used for assessing the adequacy of its cathodic protection. This basic monitoring is supplemented as necessary by conducting close interval surveys, in-line inspections where possible, and hydrostatic testing. TGP uses 2 1/2- to 3-foot spacing between readings when performing close interval surveys which it believes is effective. Also, it has performed in-line inspection of 250 miles of its pipeline and obtained good results.

The representative for the American Natural Resource Pipeline Company (ANR) stated that ANR operates 12,600 miles of pipeline with 274 miles (2.2 percent) located in Kentucky. The ANR has not experienced a corrosion-caused rupture of its pipeline in

Kentucky. Like the TGP, ANR believes it complies with the Federal requirements for corrosion monitoring and in addition to the annual monitoring of test stations, ANR supplements its surveillance by use of close interval surveys (10-foot spacing), in-line inspections where possible, and hydrostatic testing. A total of 1,800 miles of its pipeline system has been inspected using in-line inspection equipment.

The representative of the Columbia Gulf Transmission Company (CG) stated that CG operates 4,243 miles of pipeline with 715 miles (17 percent) located in Kentucky. The CG has experienced no corrosion-caused ruptures since it began in 1954. In addition to its annual monitoring of corrosion test stations, CG also uses close interval surveys (2-foot spacing) and in-line inspection equipment as a part of its corrosion control surveillance.

The representative of the Texas Gas Transmission Corporation (TGT) stated that TGT operates 5,656 miles of pipeline with 1,324 miles (23 percent) located in Kentucky. The TGT has not experienced a corrosion-caused rupture of its pipeline in Kentucky and has experienced only one such rupture within its total system. The TGT also uses close interval surveys and in-line inspection equipment to supplement its annual monitoring of corrosion test stations. It has used in-line inspection equipment on 160 miles of its system; this includes 38 miles located in Kentucky.

In-line Electromagnetic Inspection.—The instrument used for an in-line inspection resembles a scraper 6/ and is inserted into a launching facility at one end of the pipeline. It is propelled through the pipeline by the flow of the gas or liquid and is recovered in a receiving facility at the other end of the pipeline. As the instrument progresses through a pipeline it induces a magnetic field into the pipe wall. Variations in the wall thickness of the pipe alter the magnetic field and these changes are electronically recorded on a magnetic tape. The instrument does not detect corrosion per se; rather, it detects any variance in the wall thickness as it travels through the pipe. Consequently, changes in the magnetic field will occur at welds, connections with other pipe, gouges or dents in the pipe, as well as areas where corrosion has thinned the pipe wall. To determine what caused the changes in the magnetic field, the pattern of the changes formed on a graph made from a magnetic tape are interpreted. The instrument also records the linear distances from known points such as launching and receiving facilities and valves.

To check the instrument for accuracy in locating pipe wall anomalies and depicting the extent and depth of those anomalies, an excavation and inspection of a section of pipe is performed at the end of each run through the pipeline to verify that the instrument was operating properly. A point on the graph which indicates pronounced pipe wall anomalies is selected and the pipeline is excavated at that point. The area and depth of any corrosion found is measured, sketched, and compared with the indications on the graph. Using this verification, a technician can then interpret with reasonable accuracy the location, and the area and the depth of corrosion for other indications on the graph.

Many liquid petroleum and natural gas pipelines companies that use this instrument have installed both launching and receiving facilities in their pipelines to periodically clean the pipelines. Special provisions must be made to launch, to receive, and to transmit the instrument through each section of a pipeline not so equipped. In addition to the launching and receiving facilities, pipelines must have full opening valves to allow the instrument's passage and must have a radius large enough to allow the instrument to pass through the bends without jamming. Generally, field bends with large radii and without undue ovality will allow the instrument to pass, whereas short radius bends will not. The manufacturer of one such in-line instrument claims that its instrument will negotiate bends with radii as small as 3 pipe diameters (90-inch radius for 30-inch diameter pipe.)

6/ Internal pipeline cleaning tools designed to scrape accumulated foreign material off the pipe wall, clean out foreign material in the pipeline, etc.

The in-line inspection instrument is capable of accurately locating welds, fittings, locations where different pipe wall thicknesses were installed, and locations of defects where the pipe wall thickness has been reduced by gouges and corrosion damage or where the pipe has been dented. The extent of defects identified during an inspection of many miles of pipeline is provided as a relative measure. However, the actual extent of all defects can be closely approximated based on actual measurements of damages taken at one or more locations. The instrument is unable to identify corrosion damage which occurs within a weld area, to determine the quality of welds, or to identify other defects in a pipe such as hydrogen stress cracking or defects in the protective coating of a pipeline.

Safety Requirements and Guidance

Federal Pipeline Safety Standards.—The minimum safety standards for transporting natural and other gases by pipeline are contained in Part 192, Title 49 Code of Federal Regulations. The development and enforcement of these standards are the responsibility of the OPS of the DOT's Research and Special Programs Administration (RSPA). (See appendix C for applicable requirements.) These regulations require numerous actions on the part of pipeline operators to protect their pipeline from corrosion. They include the annual monitoring and evaluation of pipelines to determine the effectiveness of corrosion control methods in use.

These regulations do not provide criteria against which to measure or otherwise assess the adequacy of the "experience and training" of persons performing or directing the performance of the actions required for corrosion control. The regulations also do not specify criteria with which to assess the effectiveness of employee training required by the regulations. They do not address actions to be taken for preventing corrosion of pipelines installed in casings when the casing is vented to the atmosphere or when liquid and other materials can enter the casing and fill part or all of the space between the casing and the pipe. There is no specific requirement to continue to excavate and expose pipe found to be corroded until no further evidence of corrosion exists. Furthermore, the regulations do not establish a time frame for ending, or cite other conditions for removing, the "grandfather" clause which permits older pipelines to operate at pressures higher than allowed for newly installed pipelines.

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

In August 1969, NACE approved Standard RP-01-69 as a Recommended Practice. It was used extensively by OPS in 1971 for developing the Federal requirements for corrosion control. This Recommended Practice provides corrosion prevention standards on pipeline system design, pipe coatings, design, installation, operation, maintenance, and monitoring of cathodic protection systems, control of interference currents, and levels of cathodic protection. NACE has continued to revise this Recommended Practice; the latest edition was issued in 1983. (See appendix D.)

The Recommended Practice contains valuable guidance for protecting pipelines from corrosion; yet it is incomplete in several significant areas. It provides no guidance for the user to determine the conditions under which the various cathodic protection criteria should be used or when a combination of such criteria should be used in determining the type and extent of cathodic protection necessary for protecting a buried pipeline. The practice is neither clear about what voltage drops must be considered when using the negative 0.85 volt criterion nor does it describe how to evaluate the affects of such voltage drops. It does not provides any method for identifying segments of pipe which may be shielded from cathodic protection systems. It does not provide any method for assessing the extent of corrosion damage to pipe installed in casings when the pipe is not fully electrically isolated or when pipe is installed in vented casings and is in contact with the atmosphere. It also does not provide any guidance about when close interval surveys, in-line instrument inspections, or other techniques should be used for identifying areas of corrosion damage. Furthermore, NACE has not developed a systematic process for obtaining data on the results realized by persons using the NACE practice for protecting pipelines; therefore, it is not able to determine either the effectiveness of the practice or the necessity for developing improvements in its recommended practices.

The American Society of Mechanical Engineers Guide for Transmission and Distribution Piping Systems.—This guide, first published on December 15, 1970, recommends to the gas pipeline industry methods to enable the operator to comply with the intent of the performance standards contained in the Federal Safety Standards. The guide material provides "how to" information to assist operators of gas pipeline systems in complying with the intent of the Federal regulations. (See appendix E for selected guide material.)

While there is a great deal of information in the guide, there are no specifics on the use or usefulness of in-line, internal inspection equipment for assessing the condition of a pipeline or for locating areas of corrosion. There is also no warning or other information on the potential for atmospheric corrosion of pipes installed in vented casings, on the conditions which may cause shielding of pipe segments from cathodic protection, on how to assess the extent or affect of corrosion which may be occurring when a casing is electrically shorted to the pipe, or about the conditions under which the various cathodic protection criterion should be used to protect buried pipelines from corrosion.

Office of Pipeline Safety Activities

Interpretations and Compliance Guidance.--In January 1979, the OPS published its Pipeline Safety Enforcement Manual to provide procedures and guidance for enforcement activities of the Office of Operations and Enforcement, OPS. The most recent revision was published on January 19, 1981.

A section of this manual lists selected regulations contained in 49 CFR 192, provides guidance about what constitutes a violation of the listed regulation, and provides information about documents or actions which would constitute a violation of the regulation. Since not all regulations are listed, it appears that the regulations listed were ones which, according to experience, required more direction.

The manual contained no guidance for enforcing the requirements for continuing surveillance of pipelines by gas operators. However in performing a Congressionally mandated review of pipeline facilities constructed before January 1, 1940, the OPS concluded that "the physical environment and construction type, not age, were the significant factors contributing to leakage of products from pipelines." As a result of this finding, the OPS issued guidelines to its regional offices for its inspector's monitoring of pipeline operators for compliance with the requirements for continuing surveillance of pipelines (49 CFR 192.613).

These new guidelines were issued to explain that each operator must have a procedure for continuing surveillance of its facilities in order to determine the condition of the pipelines and take appropriate action regarding failures, leakage history, corrosion, and substantial changes in cathodic protection requirements. Further, it was pointed out that it is intended that each problem encountered by an operator (or deviation from the accepted norm) shall be evaluated and appropriate corrective action shall be initiated. Included as examples of additional actions which an operator may take to assist in evaluating a problem were more detailed corrosion surveys, pressure testing, and use of non-destructive testing equipment or instruments.

While not a part of the manual, the Transportation Safety Institute, DOT, has published enforcement guidelines in a format similar to the manual for most of the requirements contained in 49 CFR 192. These guidelines are used to train new Federal and State investigators and to conduct refresher courses. The information contained in these guidelines are written in an easily understood style and often provide additional information to aid in understanding the action(s) required.

Inspections and Enforcement.—From 1970 to the present, inspections of the gas company's pipeline system have been performed. Most often these inspections have been performed by State public service commissions acting as agents of the OPS. In Kentucky the OPS agent is the Kentucky Public Service Commission.

During May 1977 through March 1, 1986, OPS personnel or its agents conducted 192 inspections of the gas company's pipeline system in various States. As a result of its investigation OPS issued 17 citations for failing to comply with required safety standards. Each citation involved different requirements and the gas company corrected each item cited. No citations were issued to the gas company for failure to comply with the cathodic protection requirements for that portion of its system located in Kentucky. For that matter, during this entire time only one citation pertaining to the cathodic protection of the entire pipeline system was issued; it was issued in March 1985 for failure to provide an adequate level of cathodic protection at a compressor station located in Pennsylvania.

Following the accident at Lancaster, Kentucky, the Kentucky Public Service Commission, an agent for the OPS, recommended on February 28, 1986, that OPS require the gas company to reduce by 10 percent the maximum allowable operating pressure of its pipelines in Kentucky until it could demonstrate that the system could be operated safely at higher levels. Further, the commission recommended that the gas company establish a test program to annually evaluate the integrity of the pipeline system.

On March 6, 1986, OPS responded to the commission's request, advising the commission that on March 4, 1986, it had issued a notice of probable violation, a proposed civil penalty of $160,000, and a proposed compliance order to the gas company.

To assess the gas company's state of compliance with the Federal requirements, the OPS ordered a systemwide review of the gas company's operations. To accomplish this, OPS formed a task force of OPS personnel from four of its regional offices; the review was accomplished during March through June 1986. The review focused on factors similar to the recent pipeline ruptures that occurred in Kentucky.

On June 12, 1986, the OPS issued its Final Order 2320 which determined that the gas company had violated the requirements of 49 CFR 192.13 and 192.485(a). The order stated that:

> . . . a failure to repair a corrosion defect in a high pressure line which lasts over a significant amount of time is a violation which justifies a substantial

penalty. The violation, however, occurred in the course of a rehabilitation program and appears to have been inadvertent. Respondent's compliance record is good. Furthermore, Respondent has initiated a program for the rehabilitation of the lines involved. The program will be finalized by actions contemplated by the agreement incorporated herein. Respondent has cooperated in investigating the rupture involved here and has voluntarily reduced its operating pressure pending rehabilitation.

The gas company was assessed a civil penalty of $100,000.

In the agreement referenced in the Final Order, the gas company denied it had violated the requirements of 49 CFR 192.613 concerning its responsibility to conduct continuing surveillance of its pipelines. However, it agreed to submit a plan to the OPS for the continued surveillance and rehabilitation of its total system of pipelines numbered 10, 15, and 25 to include:

1. A schedule of in-line electromagnetic inspections to reveal loss of pipe wall thickness due to corrosion;

2. A schedule of evaluations of the electromagnetic or other corrosion inspection results and possible replacement of pipe and the definition of criteria for determination of repair or replacement of pipe; and

3. A schedule of hydrostatic retesting adequate to substantiate the acceptability of the in-line electromagnetic inspection and pipe replacement rehabilitation program.

In its November 1986 report on this review, the OPS developed several conclusions about the gas company's compliance with Federal pipeline safety regulations and recent failures which occurred in the gas company's pipeline system. The gas company stated that it had no opportunity to review these conclusions before the report was published and had no opportunity to confirm the accuracy of the conclusions. Essentially, the OPS concluded that:

1. The gas company's record for complying with Federal requirements was not significantly different from the other six principal gas transmission companies operating pipelines in Kentucky;

2. The gas company had the second lowest ratio of reportable corrosion incidents per mile of pipeline and the fifth lowest ratio of corrosion leaks per mile of the 12 gas transmission pipelines operating in Kentucky.

3. Each of the gas company's recent accidents occurred on pipelines that operated above 72 percent of the pipe metal's specified minimum yield strength;

4. Each failure occurred in pipe segments located downstream of a compressor station and before the first mainline valve where the pipe and its coating is subject to high temperatures and pressures;

5. The gas company has pipe located in areas such as rock formations and in casings where segments of pipe are shielded from the effects of the cathodic protection system and the gas company's pre-1985 corrosion

monitoring program did not detect these locations nor did the corrosion control program fully protect these shielded areas from corrosion; the in-line instrument inspections conducted by the gas company does identify areas of corrosion on the pipeline which previously were not detected by the required annual corrosion monitoring and by the use of close interval pipe-to-soil voltage potential surveys; and

6. The gas company did not provide in its corrosion control program sufficiently detailed procedures for its employees for satisfactorily operating and maintaining the pipeline.

Based on its findings and conclusions, the OPS task force recommended four actions to be taken:

1. That the gas company revise its operating and maintenance procedures to include specific guidance to its field personnel regarding corrosion, delination of responsibility and accountability for personnel performing corrosion inspections, and establishment of procedures for conducting close-interval surveys, consideration of voltage (IR) drop, and identification of areas of corrosion where shielding of the cathodic protection current is likely to occur.

2. That OPS revise 49 CFR 192.605, Essentials of operating and maintenance plan, to provide more guidance. 7/

3. That OPS initiate research to evaluate when in-line inspections should be conducted, when close interval pipe-to-soil surveys should be conducted, and when the use of special corrosion control provisions are necessary given conditions such as shielding.

4. That OPS initiate research to evaluate limiting to 72 percent of SMYS the maximum allowable operating pressure of pipelines installed before 1970 in Class I Locations.

The OPS, although citing the gas company for failure to repair a corrosion defect and for failure to have a comprehensive plan for corrosion control, neither commented on nor cited the gas company about its emergency response actions during the Lancaster, Kentucky accident.

7/ Section 192.605 provides that each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.
(b) Items required to be included by the provisions of Subpart M of this part.
(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.
(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.
(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

Initial Safety Recommendations and Responses

The Accident at Beaumont.—Early information obtained during the investigation of the accident at Beaumont, Kentucky, indicated that for many years the pipe may have been corroding because the pipe within the casing was electrically shorted to the casing. Additionally, review of the gas company records revealed that there were many additional segments of pipe within the pipeline system shorted to their casings. Because the Safety Board was concerned that similar conditions may have existed elsewhere on this and other pipeline systems, on June 10, 1985, it issued Safety Recommendation P-85-6 to the Texas Eastern Gas Pipeline Company:

> Review all cathodic protection test station readings for pipe installed in casing to identify those locations where there is the possibility of a direct or partial electrical short circuit, conduct necessary inspections and tests to confirm or reject the existence of corrosion, and take corrective action to restore cathodic protection and to eliminate unsafe conditions.

The Safety Board also issued Safety Recommendation P-85-7 to the Interstate Natural Gas Association of America (INGAA), the American Gas Association (AGA), and the American Petroleum Institute (API):

> Notify member companies of the circumstances of the pipeline accident at Beaumont, Kentucky, on April 27, 1985, and urge them to review their cathodic protection test station records for pipe installed in casing, to identify those locations where there is the possibility of a direct or partial electrical short circuit, to conduct necessary inspections and tests to confirm or reject the existence of corrosion, and to take corrective action to restore cathodic protection and to eliminate unsafe conditions.

The gas company responded to Safety Recommendation P-85-6 twice, the first time on June 28, 1985, and the second time on March 18, 1986. The gas company advised that in keeping with its policy, it conducts a corrosion control program which includes inspecting, testing, and monitoring cased pipeline crossings to determine if an uninsulated condition or other conditions exist which could indicate or contribute to the possible existence of corrosion. Use of the in-line inspection instrument was cited as an important part of this program because of its capability to detect variations in the pipe wall thickness at cased crossings, at buried river crossings, and at other locations where physical inspection is difficult. (From 1967 through 1984 the gas company had inspected 3,260 miles of its pipeline system.) In 1985 before the failure, the gas company had used the in-line instrument to inspect about 79 miles of pipeline containing 38 cased crossings, 2 of which were identified as possibly shorted. After the accident, the in-line inspection program was accelerated and an additional 1,391 miles of pipeline containing 807 cased crossings were inspected, 51 of which were identified as possibly shorted. In 1986, the in-line inspection program was to be further accelerated with plans to inspect an additional 4,537 miles of pipeline containing about 3,350 cased crossings. (The gas company actually inspected 4,050 miles of its pipeline in 1986. A total of 1,844 excavations were made where the in-line inspection instrument indicated moderate to severe corrosion; 1,472 of these excavations were made in the State of Kentucky. A total of 1,463 pipe replacements were made as a result of the excavations; 1,157 of these replacements were made in the State of Kentucky.)

Remedial actions taken as a result of the in-line inspections which were completed through February 15, 1986, included the replacement of pipe at two cased crossings where the pipe was corroded to the extent that repair was not justified, the removal of casings at 13 locations, the installation of insulating material to fill the casing annulus at 12 locations, and the clearing of electrical shorts and cleaning or replacing of casing end seals at more than 19 locations. Completion of the in-line inspection program was expected by December 31, 1986, and at that time all pipe 12 inches nominal size and larger in which it is possible to run the in-line inspection instrument will have been inspected. Based on these responses, on July 1, 1986, the Safety Board classified the recommendation to the gas company as "Closed—Acceptable Action."

The INGAA and the API responded to Safety Recommendation P-85-7 on June 18, 1985, and June 20, 1985, respectively that they had notified their member companies of the circumstances of the accident as recommended by the Safety Board. The recommendations to these two organizations were classified as "Closed—Acceptable Action" on November 13, 1985, and August 19, 1985, respectively.

The AGA responded to Safety Recommendation P-85-7 on October 25, 1985, advising that, as worded, it would be difficult to comply with the recommendation and that the recommendation raised technical questions concerning shorted casings. It pointed out that most corrosion control personnel will argue that commonly used electrical test methods are not conclusive and that evaluation as to whether a pipeline was electrically shorted to a casing must be made on a case-by-case basis. It further stated that restoration of cathodic protection is not the only acceptable corrosion control measure available and cited the filling of the shorted casing with a high dielectric material as another acceptable measure. Because it had reservations about the safety recommendation, the AGA did not notify its member companies.

On February 5, 1986, the Safety Board replied to the AGA advising that it was aware of the diversity of opinion among corrosion engineers concerning what constituted an electrical short between pipelines and their casings. The Safety Board also generally agreed with the AGA's position that "commonly used electrical test methods are not conclusive," that such information must be reviewed on a case-by-case basis, and that the "restoration of cathodic protection is not the only acceptable corrosion control measure available." However, the Safety Board pointed out that the language used in its safety recommendation did not preclude AGA member companies from using any method found to be effective in achieving its safety intent. The safety recommendation to the AGA was classified on February 5, 1986, as "Open—Acceptable Action" and the AGA again was requested to notify its member companies as recommended. At the time of this writing the AGA has not responded to the Safety Board's latest request and therefore, Safety Recommendation P-85-7 is now classified as "Open—Unacceptable Action" pending notification of action by the AGA.

<u>The Accident at Lancaster.</u>—Because of its concern that other gas operators may also have experienced damage on their pipelines from corrosion in areas shielded from cathodic protection systems which had not been detected through analysis of the annual corrosion monitoring at test stations, on July 8, 1986, the Safety Board issued Safety Recommendation P-86-14 to the AGA and the INGAA:

> Urge its member companies to review their systems where cathodic protection shielding conditions could exist (casing, rocky environs, buried structures, etc.), advise them to use methods such as in-line inspection techniques and close interval (2.5-foot) corrosion surveys to determine if corrosive conditions exist, and, where such conditions are identified, urge that prompt corrective action be taken.

The AGA responded on November 4, 1986, advising that it concurred with the intent of the recommendation although it did not believe it should endorse the use of any specific method for determining if corrosive conditions exist. It pointed out that in-line inspection has been used successfully in some transmission lines; however, for many gas systems—particularly distribution systems which have smaller diameter pipelines—in-line inspection generally is not feasible. It further noted that while close interval corrosion surveys using a 2 1/2-foot interval is not totally conclusive for identifying areas of corrosion, it has been found by some companies to be an effective method. The AGA also stated that some AGA-member companies had conducted close interval surveys at 2 1/2-foot intervals and found this method to be expensive and the results to be disappointing. The AGA forwarded to its member companies its letter to the Safety Board together with the Safety Board's letter of recommendation. The action taken complied with the intent of the safety recommendation and on February 18, 1987, the recommendation was classified as "Closed—Acceptable Action."

The INGAA responded to the Safety Recommendation P-86-14 on October 29, 1986, advising that the use of close interval (2 1/2-foot) surveys or in-line inspection neither individually nor collectively are conclusive for identifying corrosion. It concluded that the only method for conclusively determining the existence of corrosion is to excavate the pipeline for visual and other inspection. Since in its judgment recommending the use of close interval survey or in-line inspection to a person not knowledgeable could result in erroneous conclusions, without providing any advice, it transmitted to its member companies its letter to the Safety Board and the Safety Board's letter of recommendation. The Safety Board replied on March 20, 1987, that it recommended only that INGAA urge its member companies to use inspection methods advocated by INGAA to review their systems where shielding of the cathodic protection systems may be allowing corrosion to occur and that INGAA urge its member companies to take prompt remedial action where such conditions were identified. The Safety Board did not recommend the use of any specific inspection method primarily because it believed that the INGAA possessed more complete information on the available methods and their effectiveness. The INGAA was requested to prepare and provide to its member companies the information and guidance necessary for them to understand the potential hazard addressed by this safety recommendation and to take necessary corrective measures. The safety recommendation was classified as "Closed—Unacceptable Action."

ANALYSIS

The Accident at Beaumont, Kentucky

Over an extended period of time atmospheric corrosion, and possibly electrolytic corrosion to a lesser degree, reduced the wall thickness of the pipeline within the casing under State highway 90 until the pipe could no longer contain the internal pressure whereupon it ruptured suddenly and violently.

Since 1953 the gas company suspected that the pipeline was electrically shorted to the casing at State highway 90 and it had made several unsuccessful attempts in 1954, 1956, and 1964 to eliminate or overcome the effect of the electrical short and to prevent entry of water into the casing. However, the motivation for these actions was to maintain adequate cathodic protection for the pipeline by removing a direct electrical drain on the cathodic protection system. The gas company did not suspect nor did its corrosion monitoring of the pipeline indicate that atmospheric corrosion on the pipe inside the casing was occurring.

The gas company did not believe the electrically shorted casing to be a problem affecting the integrity of the pipeline. It had operated its pipeline system for many years during which time more than 150 casings had been found to be electrically shorted to the pipeline and it had never experienced leaks or ruptures at these locations. The experience of other operators of pipelines and of the OPS indicate that the gas company's assessment about the dangers posed by its electrically shorted casing was not unreasonable. For example, the OPS's guidance to its investigators advise that where it is not practical to eliminate the electrical short, the operator may chose to monitor for gas leakage within the casing and if such leakage were detected, immediate corrective action then would be required; the gas company did not do this. Had the gas company believed that the electrically shorted casing posed a threat either to public safety or to its pipeline, it would have been prudent to have corrected this problem at the time it modified its pipeline crossings of State highway 90. However, the gas company did not do this because it did not consider the electrical short to be a problem to the pipeline and it had no evidence to suggest that its pipeline was being damaged by atmospheric corrosion.

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

The Accident at Lancaster, Kentucky

For an extended period of time, the pipeline segment which lay south of State highway 52 near Lancaster had not received an adequate level of protection against corrosion. This segment was shielded from the cathodic protection system by a rock formation below the pipeline and this allowed galvanic corrosion to reduce the wall thickness of the pipe until it could no longer contain the internal pressure whereupon the pipe ruptured suddenly and violently.

The gas company's annual corrosion monitoring at test stations and its previous close interval survey provided no indication that corrosion of the pipe was occurring. In fact, the corrosion monitoring actually showed higher negative voltages than the required negative 0.85 volt, which indicated to the gas company that the pipe was well protected against corrosion. The corroded segment was identified on September 12, 1985, 5 months before the accident, through the gas company's use of an in-line inspection instrument; however, no corrective action was taken at that time.

The gas company personnel who excavated the corroded area to document the extent of the corrosion did so primarily to confirm that the in-line instrument was functioning properly during the inspection run and to gather data to assist other gas company personnel in the interpretation of the permanent graph. The gas company personnel were expected to identify any seriously corroded segments of pipe and to alert the gas company when they believed remedial measures should be taken. However, the pipe was not further excavated so that the full extent of the corrosion damage could be documented and thus, its potential for failure could not be assessed. As a result, these employees determined, based on insufficient data, that no immediate corrective action was required.

Other factors also were involved in the failure of gas company personnel to recognize the threat posed to public safety, to themselves, and to the pipeline. The gas company, without knowing or taking action to determine the ability of its corrosion technicians for assessing the affect of corrosion damage on its pipelines, depended upon the varying experience of each of its employees to support them in making critical decisions relative to the safety of the pipeline. No specific training or analytical guidance on methods for assessing the affect of corrosion damage was provided to its personnel by the gas company to support them in performing this responsibility.

Also, neither the gas company procedures at that time nor the Federal regulations specifically required continued excavation and inspection of areas of corrosion damage until corrosion was no longer evident. Had this been required and had the pipe been fully examined for evidence of corrosion damage, the corrosion technicians then would have obtained sufficient information about the extent of corrosion damage to have indicated that immediate action was necessary to prevent the rupture of the pipeline at State highway 52.

Additionally, because of the earlier pipeline rupture at Beaumont, Kentucky, the gas company had embarked upon a greater than normal in-line inspection program which imposed increased workloads on key personnel charged with corrosion control and monitoring responsibilities. The incomplete preparation of the field inspection report on this corrosion damage, the failure to fully document and properly assess the extent of corrosion damage during the field examination, and the less than adequate attention given by the Corrosion and Pipeline Departments located in Houston, Texas, to this report of corrosion damage probably were adversely influenced by the large influx of information on the condition of the pipeline. These factors resulted in the gas company not taking action to prevent the rupture of a segment of pipeline even though the information on the corrosion damage obtained 5 months previous was sufficient to have raised serious concern about the consequences of continuing operations without taking remedial action to either reduce the pressure or replace the damaged section of pipeline at State highway 52.

To overcome deficiencies identified after this accident, the gas company developed procedures requiring exposed pipelines to be excavated until no corrosion effects are evident, to document fully the extent of corrosion damage to its pipelines, and to assess the effect of this damage on the continued operation of its pipelines by performing the ASME-recommended calculations. The gas company has equipped its corrosion technicians with preprogrammed calculators and has trained and tested the technicians in the application of these procedures.

Corrosion Monitoring Practices

Information developed during the investigations of these accidents and the reviews of regulations and recommended practices for monitoring the effectiveness of corrosion control methods makes it clear that improvements in this area are necessary. The accident at Beaumont indicates that pipelines installed in vented casings are subject to damage by atmospheric corrosion; however, this potential hazard is not addressed in the Federal regulations, in the NACE corrosion control practices, or in the ASME guidance to operators of pipelines. No guidance is provided by the OPS, ASME, or NACE by which data obtained from p/s and c/s measurements depicting an electrical short circuit can be used to estimate the amount of corrosion damage which has already occurred on the encased pipe. In fact, no guidance is provided to show that corrosion of any kind is occurring in these situations. The information obtained during the investigation about the affects on safety of pipelines being electrically shorted to a casing indicates that this condition has not caused a significant number of pipeline ruptures; however, damage from this condition, as with atmospheric corrosion, is dependent upon many factors of which the most important may be the duration of exposure. Periodic inspection is needed to determine the damage corrosion already has caused to pipelines installed within casings or to determine when corrosion on pipelines has progressed to the extent the pipe should be replaced.

Information gathered as a result of the accident at Lancaster indicates that the corrosion monitoring method specifically required by the Federal regulations—annual readings taken at corrosion test stations—often is insufficient for identifying areas of corrosion on pipelines. This accident and information obtained during the investigation, demonstrated that pipeline segments installed upon or over large rock formations or installed over or adjacent to other large buried structures can be shielded from the protection of corrosion mitigation systems. More important, however, is the fact that segments of pipelines unprotected because of shielding are difficult if not impossible to detect using conventional corrosion monitoring methods. It was only through the gas company's use of the in-line inspection instrument that the hundreds of corrosion damaged segments finally were detected, providing an opportunity for the gas company to take remedial action.

Moreover, neither the Federal regulations, the NACE recommended practice, or the ASME guidelines provide specific criteria or other guidance to assist gas pipeline operators in determining when the annual test station monitoring may not be effective for identifying areas of corrosion. They do not advise about the use of close interval surveys, hydrostatic testing, or in-line instrument inspection and their usefulness in identifying areas of corrosion. They do not require or recommend that operators of pipelines, when modifying existing pipelines or constructing new pipelines, make provision for the use of in-line inspection instruments.

OPS has developed the most comprehensive guidance concerning the actions a pipeline operator should take for identifying corrosion damage and other deficiencies on its pipeline and for responding to the identified deficiencies. However, this guidance has been developed for and provided to its personnel for their use in uniformly carrying out regulatory compliance inspections. The OPS guidelines better define the intent of specific regulations and provide information on the types of actions which may be taken to comply with the requirements. The Safety Board believes that these guidelines also would benefit the regulated pipeline industry much in the same manner it assists OPS's personnel in administering these primarily performance-type regulations. Moreover, it seems reasonable that by having access to these OPS guidelines, the pipeline industry would be better able to conform with the OPS interpretation of the regulations.

Operating Pressures in Excess of 72 Percent SMYS

When the ruptures occurred at Beaumont and Lancaster, the operating pressure of both pipelines was above that allowed for pipelines newly constructed using improved steels, improved electrical insulation materials, and many additional improved procedures and materials. This higher operating pressure has been allowed for many pipeline companies without limitation through a "grandfather" provision incorporated in the Federal pipeline standards when they were promulgated in 1970. Had the pressure been limited to 936 psig (72 percent of the SMYS), the allowable pressure if it had been a newly constructed similar pipeline, the accident at Beaumont would still have occurred, although probably at a later date, because it is unlikely that the ongoing atmospheric corrosion would have been detected. However, at Lancaster, the accident probably would not have occurred until a later date had the maximum allowable operating pressure for the pipeline been limited to 72 percent of the SMYS. This limitation would have resulted in an operating pressure of 924 psig at the area where the pipe was found to be damaged by corrosion rather than the 965 psig pressure at the time of the failure. This difference in pressure may well have allowed the gas company to have replaced the damaged segment before the accident.

The net effect of a lower maximum allowable operating pressure on the corroded areas of these pipelines would depend upon many variables. However, the Safety Board does not believe it is sound engineering practice to allow older pipelines, constructed with materials and procedures inferior to those used in new pipelines, to operate at SMYS levels greater than those new pipelines. At the time the Federal requirements were promulgated, it may not have been practical to have required all existing pipelines to immediately conform to the new maximum pressure standard (72 percent of SMYS). Thus it would have been reasonable to have provided a "grandfather" provision to allow continued operation of existing pipeline at the higher pressures. However, the regulations should have established a time by which all existing pipelines would be required to adhere to the new standard. The OPS should take action expeditiously to correct this longstanding deficiency.

Employee Training

The gas company's program for training its compressor station personnel and for reviewing these employees' knowledge about actions to take during emergencies apparently was adequate in that these employees did take prompt, effective action in responding to both the Beaumont and Lancaster accidents. Additionally, during the Beaumont accident the implementation of its procedures for coordinating with response personnel during the emergency was effective.

There were, however, deficiencies which were identified in other procedures and employee activities. The gas company emergency procedures were not followed explicitly during the emergency at Lancaster apparently because the compressor station supervisor did not understand why emergency response personnel needed the requested information and because he was concerned that the information provided would be made available to the news media. He knew that according to the gas company procedures, providing information to the news media was reserved for higher level company representatives. This failure to provide the requested information to emergency response personnel did not in this instance cause or contribute to any greater loss; however, it did greatly hamper the civil agencies in carrying out their duties to assure the safety of their own personnel and it did nothing to ease the concern of the evacuated citizenry about the safety of their homes and possessions and their inconvenience in having to find temporary shelter. It does demonstrate that the gas company should improve its training and testing of supervisory personnel to be certain that they know what types of information should be provided to emergency response agencies and that they understand why full cooperation should be extended to these agencies.

Additionally, the gas company did not train its corrosion technicians in making critical assessments about the affect of corrosion damage on its pipelines rather, the gas company relied heavily upon the undefined and differing experiences of its corrosion technicians for making judgments about the effect of corosion-damaged areas on the continued safety of its pipelines. As demonstrated by the actions taken by these technicians before the accident at Lancaster, the experience of these gas company personnel was not adequate to access the danger posed by the corrosion of the excavated pipe. While this specific deficiency may have been corrected by implementing new procedures and training for its corrossion technicians, this and the previously discussed training deficiency indicates that improvement is needed in the area of employee qualifications and training. To assist the gas company in making necessary improvements, it should develop proper selection and qualification criteria to implement effective training and testing programs on normal and emergency operations.

The need for improvements in a gas company's employee selection, training, and testing programs has been addressed frequently in Safety Board reports of pipeline accidents. The reason deficiencies in employee qualification and training continue to be identified during the investigations of accidents is because the OPS has not yet fully developed and incorporated comprehensive requirements for the qualification and training of pipeline operator employees who perform the various functions required by the regulations. The most complete requirement about training included in the regulations applies to the gas company's emergency plans. Section 49 CFR 192.615 requires the gas company to train appropriate operating personnel on the procedures to be used during emergencies, to verify in some manner that the training was effective, and to review employee activities after an emergency to determine if the procedures were effectively followed.

Proper planning for emergencies, training of employees responsible for carrying out actions during emergencies, and a review of activities after the emergency all are important tasks. However, preventing emergencies from occurring through proper operation and maintenance of pipeline systems is equally important. Therefore, the OPS should require for all activities addressed by the regulations that employee qualifications be developed through job/task analyses, that employees be trained in the proper performance of assigned tasks, and that employees be periodically tested to demonstrate that they understand and are able to perform their assigned responsibilities.

CONCLUSIONS

Findings

1. The No. 10 pipeline ruptured within its vented casing at Beaumont, Kentucky, because atmospheric corrosion reduced the thickness of the pipe wall to a point where it no longer could contain the internal pressure.

2. The No. 15 pipeline ruptured at Lancaster, Kentucky, because galvanic corrosion reduced the thickness of the pipe wall to a point where it no longer could contain the internal pressure.

3. The shutdown of the compressors and the closing of valves to isolate the failed pipe sections in both accidents was timely.

4. The gas company was not aware before the accident at Beaumont, Kentucky, of the atmospheric corrosion damage to its pipeline within the casing that crossed under State highway 90 because no inspection capable of detecting the corrosion damage had been performed.

5. The potential of atmospheric corrosion damaging pipelines installed in casing is not addressed by existing Federal pipeline safety requirements, probably because this problem previously has not resulted in a major accident.

6. The gas company was not aware of the true condition of its pipelines because its annual monitoring by making tests at corrosion test stations and by conducting close interval surveys did not identify many areas of corrosion damage to its pipelines.

7. Existing electrical test methods for monitoring the effectiveness of cathodic protection systems are unable to fully detect corrosive conditions, particularly in areas where a pipeline is shielded from cathodic protection systems.

8. The gas company failed when it excavated its No. 15 pipeline at Kentucky State highway 52, to investigate the full extent of the corrosion-caused damage to the pipeline.

9 The corrosion-caused damage to the No. 15 pipeline was not fully identified because gas company procedures did not require its employees to fully expose and inspect the pipeline until no further corrosion damage was evident.

10. Gas company employees who performed the inspection of corrosion-caused damage had not been adequately trained to assess the affects of corrosion damage on pipelines.

11. It was not possible to determine if active corrosion was occurring on the pipeline at Lancaster at the time of the rupture because gas under pressure and heat from the fire cleaned the pipe and fracture surfaces and removed any evidence that may have existed.

12. Civil agencies responding to the accident at Lancaster, were unable at an early time to obtain information they needed about the operating status and condition of the three adjacent pipelines from an on-scene gas company supervisor.

13. The gas company procedures and training did not properly prepare the supervisor for cooperating with local officials during emergencies.

14. There is no general requirement for operators of pipelines to develop and conduct selection, training, and testing programs to qualify their employees for correctly carrying out each assigned responsibility necessary for the operator to comply with the Federal pipeline regulations.

15. The Federal regulations concerning pipeline corrosion are not adequate for preventing all corrosion-caused damage to pipelines which may be detrimental to public safety.

16. The Federal regulations concerning the inspection and monitoring of pipelines for evidence of corrosion are not adequate for identifying all corrosion-caused damage to pipelines which may be detrimental to public safety.

17. The only present, practical method of detecting corrosion-caused damage on pipelines is an in-line instrument inspection.

18. Federal regulations do not explicitly require the use of in-line instrument inspections of pipelines.

19. There is no Federal requirement for periodic requalification of gas and liquid pipelines either through hydrostatic testing to verify that continued operation is safe or through in-line inspection to verify the condition of the pipe.

20. Many miles of gas and liquid transmission pipelines are or with minor modification can be equipped to facilitate the use of in-line inspection instruments; however, other pipelines would require major modifications to make possible the use of in-line inspection instruments.

21. Existing Federal regulations do not require newly constructed gas and liquid transmission pipelines or existing pipelines undergoing major modifications to be designed to facilitate the use of in-line inspection instruments.

22. There is no sound engineering basis for allowing pipelines constructed before promulgation of the Federal regulations to continue to operate at pressures which result in a higher pipe wall stress than that allowed for pipelines designed and installed in accordance with the Federal regulations.

Probable Cause

The National Transportation Safety Board determines that the probable cause of the pipeline accident near Beaumont, Kentucky, was the unsuspected and undetected atmospheric corrosion of Texas Eastern Gas Pipeline Company's 30-inch-diameter pipeline in a casing under State highway 90. Contributing to the accident was the failure of the pipeline industry and of the Office of Pipeline Safety to recognize the need for and to require the use of in-line corrosion detection techniques for identifying and monitoring the existence and severity of corrosion in casings and other areas shielded from corrosion protection.

The probable cause of the pipeline accident near Lancaster, Kentucky, was the failure of the Texas Eastern Gas Pipeline Company to fully investigate the extent and severity of previously detected and inspected corrosion-caused damage and to replace the damaged segment of pipeline before its failure. Contributing to the accident was the lack of gas company guidelines for its personnel for further inspection and the shut down or reduction in line pressure upon detecting corrosion damage on its pipelines.

RECOMMENDATIONS

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

—to the Texas Eastern Gas Pipeline Company:

> 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 the requirements of 49 CFR Part 192 and 195. (Class II, Priority Action) (P-87-1)

—to the Research and Special Programs Administration of the U.S. Department of Transportation:

> 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. (Class III, Longer Term Action) (P-87-2)

Amend 49 CFR 192.459, External corrosion control, Examination of buried pipeline when exposed, to require pipeline operators to fully expose and fully examine pipelines exposed for any reason. The exposure and examination should continue until corroded or other damaged areas are no longer encountered. (Class III, Longer Term Action) (P-87-3)

Require operators of both gas and liquid transmission pipelines to periodically determine the adequacy of their pipelines to operate at established maximum allowable pressures by performing inspections or tests capable of identifying corrosion-caused and other time-dependent damages that may be detrimental to the continued safe operation of these pipelines and require necessary remedial action. (Class III, Longer Term Action) (P-87-4)

Establish criteria for use by operators of pipelines in determining the frequency for performing inspections and tests conducted to determine the appropriateness of established maximum allowable operating pressures. (Class III, Longer Term Action) (P-87-5)

Require existing natural gas transmission and liquid petroleum pipeline operators when repairing or modifying their systems, to install facilities to incorporate the use of in-line inspection equipment. (Class III, Longer Term Action) (P-87-6)

Require that all new gas and liquid transmission pipelines be constructed to facilitate the use of in-line instrument inspection equipment. (Class III, Longer Term Action) (P-87-7)

Make available to the regulated gas and liquid pipeline industries the guidance information OPS provides to its inspectors for determining compliance with the pipeline safety regulations. (Class II, Priority Action) (P-87-8)

Revise 49 CFR 192 and, if necessary, request legislative authority to amend 49 CFR 192 to eliminate the "grandfather clause" which permits operators of pipelines installed before November 12, 1970, to operate at levels of stress that exceed those levels permitted for pipeline installed after the effective date of 49 CFR 192. (Class II, Longer-Term Action) (P-87-9)

—to the National Association of Corrosion Engineers:

Revise Recommended Practice RP-01-69 to incorporate specific guidance on the conditions under which each of the cathodic protection criterion should be used, on the conditions under which the internal resistance drop should be considered in pipe-to-soil voltage potential measurements, on the conditions which may shield buried pipe from the benefits of cathodic protection systems, on the effective use of available methods for identifying areas of active cathodic and atmospheric corrosion, and on effective methods for identifying previous corrosion damage to buried pipelines. (Class III, Longer Term Action) (P-87-10)

Develop a system for collecting information on corrosion-caused pipeline failures and leaks to evaluate the adequacy of criteria and procedures included in its recommended practices for controlling the corrosion of buried pipelines. (Class III, Longer Term Action) (P-87-11)

—to the American Society of Mechanical Engineers Gas Piping Standards Committee:

Revise its guidelines to assist operators of gas pipelines in determining when annual test station monitoring may not be effective for identifying areas of corrosion, in determining where segments of pipeline may be shielded from the affects of cathodic protection systems, in determining how and when to inspect pipes installed in casings for evidence of atmospheric corrosion, and in determining when hydrostatic testing or in-line instrument inspections should be used for identifying areas of corrosion. (Class III, Longer Term Action) (P-87-12)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

/s/ JIM BURNETT
Chairman

/s/ PATRICIA A. GOLDMAN
Vice Chairman

/s/ JOHN K. LAUBER
Member

/s/ JOSEPH T. NALL
Member

February 18, 1987

APPENDIXES

APPENDIX A

INVESTIGATION

The National Transportation Safety Board was notified at 4 a.m. on April 28, 1985, of the accident near Beaumont, Kentucky, by the National Response Center in Washington, D.C. Two investigators were dispatched to the accident site from the Safety Board's Washington, D.C., headquarters and arrived at 3:15 p.m. on April 28, 1985.

Parties to the investigation were the Texas Eastern Gas Pipeline Company, the Kentucky State Public Service Commission, the Kentucky State Fire Marshal, the Kentucky State Police, the Metcalf County Coroner's Office, and the U.S. Department of Transportation, Office of Pipeline Safety.

A public hearing concerning this accident was held in Houston, Texas, on October 9 and 10, 1985.

The National Transportation Safety Board learned of the accident near Lancaster, Kentucky at 9:15 a.m. on February 21, 1986, from an Associated Press news release. Three accident investigators were dispatched from the Safety Board's headquarters in Washington, D.C., and arrived on site at 11:30 p.m. on February 21, 1986.

Parties to the investigation were the Texas Eastern Gas Pipeline Company, the Kentucky State Public Service Commission, the Kentucky State Fire Marshal, the Garrard County Disaster Emergency Service, and the U.S. Department of Transportation, Office of Pipeline Safety.

A public hearing concerning this accident was held in Danville, Kentucky, on April 30 and May 1, 1986.

A technical review of the factual section of the report on both the Beaumont and Lancaster accidents was conducted on December 3, 1986. In attendance at this review were the Texas Eastern Gas Pipeline Company, the Kentucky State Public Service Commission, and the U.S. Department of Transportation, Office of Pipeline Safety.

APPENDIX B

EXCERPTS FROM THE GAS COMPANY PROCEDURES FOR EMERGENCY RESPONSE IN EFFECT AT THE TIME OF THE RUPTURES

Employees located at the scene of an emergency, or the first employees to arrive at the scene of an emergency, shall take necessary actions insofar as possible, to eliminate, insolate, or minimize the conditions causing or contributing to the emergency situation and take steps to prevent possible further injury or damage. Some possible actions that may be taken are as follows:

1. Eliminate or control gas escape or leakage by closing valves, blowing down, or other means.

2. Evacuate employees and/or public from premises which are or may be affected.

3. Block off the area or restrict unauthorized access, insofar as possible.

4. De-energize or arrange to have de-energized live electrical circuits creating a hazard.

5. Utilize available fire extinguishing equipment as necessary.

6. Eliminate possible sources of ignition and/or take precaution to prevent accidental ignition within the area of hazard.

7. Ventilate affected premises if necessary.

8. Administer first aid as necessary.

9. Request fire, police, or medical help if necessary.

10. Notify General Office Dispatching of such situations as soon as possible so gas flow conditions can be evaluated and necessary steps can be taken to continue or resume gas flow.

Local authorities or services such as fire departments, law enforcement agencies, medical or ambulance services, telephone company (for restoration or addition of communication service), electric power company, etc. shall be notified as required and with the expediency as warranted by the nature of the emergency. Emergency activities shall be coordinated with such agencies or service parties responding to emergencies on the system insofar as practical.

Liaison with public officials along the pipeline system, including fire and police officials, shall be established with respect to emergency procedure by personal or telephone contact with dissemination of business cards and other printed information.

The Public Relations Department shall be consulted on situations involving dissemination of information to the news media.

It shall be the responsibility of the Field Office Manager to see that appropriate personnel are aquainted with emergency procedures and that liaison is established with appropriate public officials, including fire and police officials. The Field Office Manager shall be responsible for seeing that the educating of customers and the general public along the route of the pipeline in how to recognize and report a gas emergency is carried out.

APPENDIX C

SELECTED FEDERAL PIPELINE SAFETY STANDARDS AND FEDERAL COMPLIANCE GUIDANCE

The minimum safety standards for transporting natural and other gases by pipeline are contained in Title 49, Part 192, Code of Federal Regulations. The development and enforcement of these standards are the responsibility of the Office of Pipeline Safety (OPS) which is a part of the Research and Special Programs Administration (RSPA) of the Department of Transportation (DOT). In part, these requirements provided that:

> An operator of a pipeline must establish procedures for complying with the cathodic protection requirements, including the design, installation, operation, and maintenance of such systems and that such procedures must be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.
>
> Pipelines that have effective external coatings, even if installed before the effective date of the Federal standards, must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with the corrosion control requirements. The cathodic protection provided must comply with one or more of the applicable criteria contained in Appendix D.
>
> Section I of Appendix D contains criteria for cathodic protection and for steel pipe, there are listed five criterion which, for all intents, are the same five criterion incorporated in NACE's Recommended Practice. This included the criterion of a negative voltage of at least 0.85 volts with the current applied. Section II of Appendix D states that voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement.
>
> To monitor the effectiveness of the corrosion control, once each year tests must be performed to determine if the cathodic protection meets the requirements (criterion included in Appendix D). Should these tests indicate any deficiency in the cathodic protection, prompt remedial corrective action is required.
>
> Buried or submerged pipelines must be electrically isolated from other underground metallic structures unless the pipeline and the other structures are electrically interconnected and protected as a single unit. This requirement is further refined to state that each pipeline must be electrically isolated from metallic casings that are a part of the underground system or, if impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
>
> Inspection and electrical tests are required to assure that electrical isolation is adequate.
>
> A sufficient number of test stations or other contact points must be available for performing electrical measurements to determine the adequacy of the cathodic protection.

When a segment of buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if bare or if the coating is deteriorated.

Pipeline segments installed above ground must be protected from atmospheric corrosion and at intervals not to exceed 3 years; pipelines exposed to the atmosphere must be evaluated and remedical action, if necessary, must be taken to maintain protection against atmospheric corrosion.

Pipelines found to contain general corrosion (corrosion pitting so closely grouped as to affect the overall strength of the pipe) to the extent that the remaining wall thickness is less than that required for the maximum allowable operating pressure must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on the actual remaining wall thickness. If the operator considers the area of general corrosion to be small, then the corroded pipe can be repaired.

Pipelines found to contain localized corrosion pitting to a degree where leakage might result must be replaced, 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.

An operator must have a procedure procedure for the continuing surveillance of its facilities to determine and take appropriate action concerning changes in areas such as corrosion and substantial changes in cathodic protection requirements. For a segment of pipeline determined to be in unsatisfactory condition but where no immediate hazard exists, the operator is required to initiate a program to recondition or phase out the unsatisfactory segment or to reduce the pressure to a safe level commensurate with the deficient condition.

Except for pipelines installed before the effective date of the Federal regulations, the maximum allowable pressure cannot exceed a pressure that would result in a stress equal to 72 percent of the specified minimum yield strength of the pipe metal. Pipelines operating before the existence of the Federal requirements can continue to operate at the highest pressure to which they have been subjected during the 5 years preceding July 1, 1970.

All operators are required to have written procedures to minimize the hazard resulting from a gas pipeline emergency. Among the requirements included are emergency shutdown and pressure reduction to minimize hazards to life and; coordinating with fire, police, and other public agencies planned responses and actual responses during an emergency; and the training of appropriate operating personnel to assure they are knowledgeable of emergency procedures and verifying that the training is effective.

On March 18, 1985, in a letter to the Interstate Natural Gas Association of America, the OPS advised that it was rescinding an earlier policy concerning the measurement of internal resistance drop when operators performed their pipe-to-soil potential surveys.

The OPS found that most operators are considering the IR drop in their voltage readings of impressed current corrosion protection systems sufficient to meet the intent of the wording in appendix D, Title 49, Part 192. OPS found that these operators were assuming that there is a margin of safety built into the cathodic protection criteria and thus, measuring the exact amount of the IR drop was not necessary. OPS further advised that this type consideration would be accepted with one exception. That exception was that whenever a leak related to inadequate cathodic protection occurs, the operator must measure the level of cathodic protection at the soil to metallic structure interface. Should this measurement show a level of protection less than required by the regulations, then it would become obvious that the consideration to IR drop was inadequate and such a showing would constitute the basis of a possible enforcement action against the operator.

Later in 1985, the OPS issued to its regional offices revised guidelines for monitoring compliance with the requirements for continuing surveillance of pipelines by operators (49 CFR 192.613). Pipeline industry representatives are consulted by OPS during the development of such guidelines; however, copies of the final guidelines are distributed only to OPS personnel and some State pipeline safety personnel. The need for this revision became apparent to the OPS after it completed a Congressionally mandated review of pipeline facilities constructed before January 1, 1940. Based on its review, the OPS concluded that "the physical environment and construction type, not age, are the significant factors contributing to leakage of products from pipelines."

The guidelines developed explain that each operator must have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning several factors, including failures, leakage history, corrosion, and substantial changes in cathodic protection requirements. Further, it is intended that each problem (or deviation from the accepted norm) shall be evaluated by the operator and that appropriate one-time or continuing corrective action shall be initiated. Included as examples of additional procedures which an operator may take to assist in evaluating a problem were more detailed corrosion surveys, pressure testing, and use of non-destructive testing equipment or instruments.

APPENDIX D

SELECTED RECOMMENDATIONS FROM THE NATIONAL ASSOCIATION OF CORROSION ENGINEERS (NACE) STANDARD RP-01-69

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

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

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

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

APPENDIX E

SELECTED RECOMMENDATIONS FROM THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS GUIDE FOR TRANSMISSION AND DISTRIBUTION PIPING SYSTEMS

This guide, first published on December 15, 1979, recommend some suitable methods to the gas pipeline industry to enable the operator to comply with the intent of the performance standards contained in the Federal safety standards. The function of the guide material is to provide "how to" information to assist operators of gas systems in complying with the intent of the Federal regulations. In part, this guide recommends:

> That NACE RP-01-69 (as revised in 1972) is a useful reference for carrying out cathodic protection.
>
> That the most effective, practical, and reliable methods to evaluate or determine areas of corrosion on gas facilities will vary with the type and location of facilities. Historically, electrical-type surveys have been practical and effective on transmission pipelines and other pipelines in rural areas. Where electrical surveys are considered impractical or ineffectual, leak surveys and a review of leak survey results, corrosion leak repair history and records of exposed pipe examinations are the most effective means of determining corrosion areas. On-stream corrosion detectors, pressure tests, ultrasonic, accoustical or other methods may be applicable in special cases.
>
> Where there is an indication on existing installations that corrosion is occurring on the carrier pipe or where a cathodic protection installation is rendered inadequate as a result of low resistance between the casing and the carrier pipe, practical measures to help insure adequate protection on the pipeline may be filling the annular space between the carrier pipe and the casing with a nonconductive filler, applying additional cathodic protection to the pipe, or in some cases where the carrier pipe is shorted to the casing near the end of the casing, exposing the ends of the casing and physically lifting the carrier pipe to provide proper clearance for inserting electric insulating material in a sheet form between the carrier pipe and the casing.
>
> The monitoring of cathodic protection required by Federal regulations and the evaluation of such test data is generally sufficient for assuring the adequacy of the electrical isolation on cathodically protected pipe. Additionally, where deemed necessary by the operator, specific electrical tests on isolating devices should be made to assure adequacy of the isolation and to pinpoint operational problems on cathodic protection systems.
>
> Any contact point location which is electrically continuous to the structure under test may be chosen as a test station for determining the level of cathodic protection. Examples of such contact points are provided. No guidance is given to assist in selecting the spacing of these contact points so that the test data collected will be appropriate for evaluating the adequacy of the cathodic protection system.

The evaluation of the pressure strength of a corroded region on a transmission pipeline can be accomplished by use of an analytical method included in the guide or by pressure testing or other alternate methods. In using the analytical method the pipe can be continued in service at the established maximum allowable operating pressure if the depth of the corrosion is 10 percent or less of the specified wall thickness. However, should the depth of corrosion exceed 10 percent but be less than 80 percent of the specified wall thickness, a detailed procedure is provided for determining the safe pressure for the continued operation of the pipeline. For greater depths of corrosion, repair or replacement of the corroded area is recommended.

Continuing surveillance of the pipeline should be conducted to identify facilities experiencing unusual or abnormal operating and maintenance conditions Such surveillance can be accomplished through on-site inspection and periodic review and analysis of records such as leakage surveys, corrosion control inspections, and facility failure investigations.

Guidance is provided for actions necessary during an emergency to be included in the written procedures, including the coordination with fire, police, and other public officials of actions to be taken for making safe any actual or potential hazard. Additionally, specific guidance is given on the training of employees for the specific actions each may be required to take.