NATIONAL TRANSPORTATION SAFETY BOARD

PIPELINE ACCIDENT REPORT
PHILLIPS PIPE LINE COMPANY
PROPANE GAS EXPLOSION
FRANKLIN COUNTY, MISSOURI
DECEMBER 9, 1970

NATIONAL TRANSPORTATION SAFETY BOARD

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NATIONAL TRANSPORTATION SAFETY BOARD
Washington, D. C. 20591
REPORT NUMBER: NTSB-PAR-72-1

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ADOPTED: MARCH 1, 1972

ERRATUM

Please make the following change to subject report:

Title Page - Change Adopted date from March 1, 1971, to read March 1, 1972.

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16. Abstract

On December 9, 1970, a rupture occurred in the Phillips Pipeline Company system in Franklin County, Missouri, which released 4,538 barrels of propane. An explosion, equivalent to 100,000 pounds of TNT, and a fire resulted in extensive property damage within a 2 mile radius. No fatalities occurred, but ten persons sutained injuries.

The probable cause of the accident was the rupture of an insufficiently bonded longitudinal weld, further weakened by internal corrosion. Contributing to the rupture was a pump station which shut down and produced a higher pressure on the failed pipeline section than it had been subjected to during recent operations. The explosion and fire were caused by the ignition of the released propane which had been confined in a concrete block building. The explosion inside the building initiated a shock wave which caused the detonation of the entire unconfined propane air cloud.

Contributing to the intensity of the explosion and fire were the weather inversion present at the time, which acted as a lid on the detonation and helped to deflect the resultant forces earthward, the delay in shutting down the pumping stations and the amount of time taken to close the manually operated valves on either side of the split.

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FOREWORD

The field investigation was conducted by the National Transportation Safety Board in cooperation with the Federal Railroad Administration (FRA). The investigation included a public hearing held by the Safety Board in St. Louis, Missouri, on February 2, 3, and 4, 1971. This report of facts and circumstances and the determination of probable cause by the Safety Board is based on the facts developed in the field investigation and public hearing.

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NATIONAL TRANSPORTATION SAFETY BOARD
Washington, D. C. 20591
PIPELINE ACCIDENT REPORT

Adopted: March 1, 1972

PHILLIPS PIPE LINE COMPANY PROPANE GAS EXPLOSION FRANKLIN COUNTY, MISSOURI December 9, 1970

I. SYNOPSIS

At 10:20 p.m., Wednesday, December 9, 1970, Phillips Pipe Line Company's 8-inch line ruptured and spilled propane in a rural area of Franklin County, Missouri. At 10:44 p.m, the propane-air mixture exploded, destroyed all buildings at the blast origin, extensively damaged 13 homes within a 2-mile radius, sheared telephone poles, snapped tree trunks, smashed windows 12 miles away, and registered its impact on a seismograph in St. Louis, 55 miles distant.

A resident living near the pipeline heard the roar of the escaping propane, saw a geyser, and a vaporlike cloud which flowed into the valley behind his house. He evacuated his family, warned the neighbors of the dangers, and telephoned the Sheriff's office. Minutes later, the valley erupted in an explosion which shattered houses and riddled them with glass.

A fire, fed by leaking propane, blazed at the point of rupture until 11 a.m. the next day. Phillips maintenance men closed valves on either side of the rupture, replaced the failed pipe, and put the pipeline in operation again about 18 hours after the accident.

The detonation and initial fire consumed 756 barrels of propane, giving rise to an estimated explosive force of 100,000 pounds of TNT. No fatalities resulted, but 10 persons were injured. The prompt, orderly evacuation by families in the area averted a tragedy.

The National Transportation Safety Board determines that the probable cause of the accident was the rupture of an insufficiently bonded longitudinal weld which had been further weakened by internal corrosion. Contributing to the rupture was a pump station which shut down and produced a higher pressure on the failed pipeline section than it had been subjected to during recent operations.

The explosion and fire were caused by the ignition of the released propane which had been confined in a concrete block building. The explosion inside the building initiated a shock wave which caused the detonation of the entire unconfined propane-air cloud.

Contributing to the intensity of the explosion and fire were the weather inversion present at the time, which acted as a lid on the detonation and helped to deflect the resultant forces earthward, the delay in shutting down the pumping stations, and the amount of time taken to close the manually operated valves on either side of the rupture.

FACTS

A. Background

1. Accident Site

This accident took place 7 miles south of the town of New Haven in Franklin County, Missouri, a rural, uncongested farm area. The terrain is rolling and falls away to the west and south to form a shallow valley. A few widely separated farmhouses are located in the valley itself and eight or more modern houses are on the rim of the valley along an east-west highway designated YY. An 8-inch pipeline, owned by the Phillips Pipe Line Company, extends through the area in an east-west direction roughly parallel to, and 500 feet south of highway YY at the point of the leak. (See Figure 1.)

2. Pipeline System Description

The original system, completed in 1931, extends over 680 miles from its origin in Borger, Texas, to a terminal at East St. Louis, Illinois.[1] The pipeline was one of the early refined products systems and all but 170 miles of it was constructed of 8-inch electric resistance weld pipe (ERW) manufactured in 1930-1931 by the Republic Steel Corporation at their Youngstown, Ohio, steel mill.

This line was constructed by acetylene welding each pipe to the next one and by lowering the bare pipeline into a ditch previously excavated to receive it. The individual longitudinal welds were located in a random manner such that some were placed on the top half and some on the botton half of the pipe.

After construction, the newly laid line was filled with water and subjected to a 1,200 p.s.i.g. hydrostatic test for 24 hours. This test encompassed some 668 miles of line from Borger to a gate valve approximately 2 miles east of the Meramec River near Fenton, Missouri. During the test, 17 longitudinal welds failed and many small flanges and fittings leaked. These failed sections were all removed, replaced with new pipe, and the line was retested. The failures were analyzed and found to be the result of imperfect fusion of the plate edges at the steel mill; a condition known as a cold-stitched longitudinal weld. A cold-stitched longitudinal weld is usually well defined; instead of a smooth, evenly placed, uniformly strong line of fused metal, it is broken by a series of partially fused or unfused areas which contain oxide pockets in the voids. The phenomena is caused by inadequate heat or pressure at the time the pipe edges are pushed together and welded, and results in the entrapment of oxides which prevents good fusion and causes a weak bond at frequent intervals all along the longitudinal weld. The cold-stitched weld derives its name from the uniformly interrupted, symetrically patterned appearance of the imperfectly fused metal. (See Figure 2.)

The completed pipeline system was placed in operation in the spring of 1931 with a company-imposed maximum discharge pressure limitation of 900 p.s.i.g. at the pump stations. There were no standards or regulations for pipeline pressure restrictions at that time. The initial system capacity was approximately 18,000 barrels per day (756,000 gallons). The pipeline capacity was soon reached, and increased capacity was obtained by raising the pump station discharge pressures from the initial limit of 900 p.s.i.g. to a new higher pressure of 1,080 p.s.i.g. and by the addition of more pump stations along the pipeline; no additional hydrostatic tests were performed. Again, more system capacity was required and more booster stations were constructed (See Figure 3). Then, as still more capacity was needed, a second line was constructed from each pump station parallel to and 4 or 5 feet away from the original line and welded back into the original line at a specified distance away from the pump stations. This newer, looped line provided the necessary capacity increase but was not hydrostatically tested as was the original system.

For approximately the first 10 years of operation the uncoated pipeline experienced an increasing number of leaks due to external corrosion; pitholes and pipe walls, thinned by

[1] An extension of the system northward to East Chicago, Indiana, was completed in 1939.

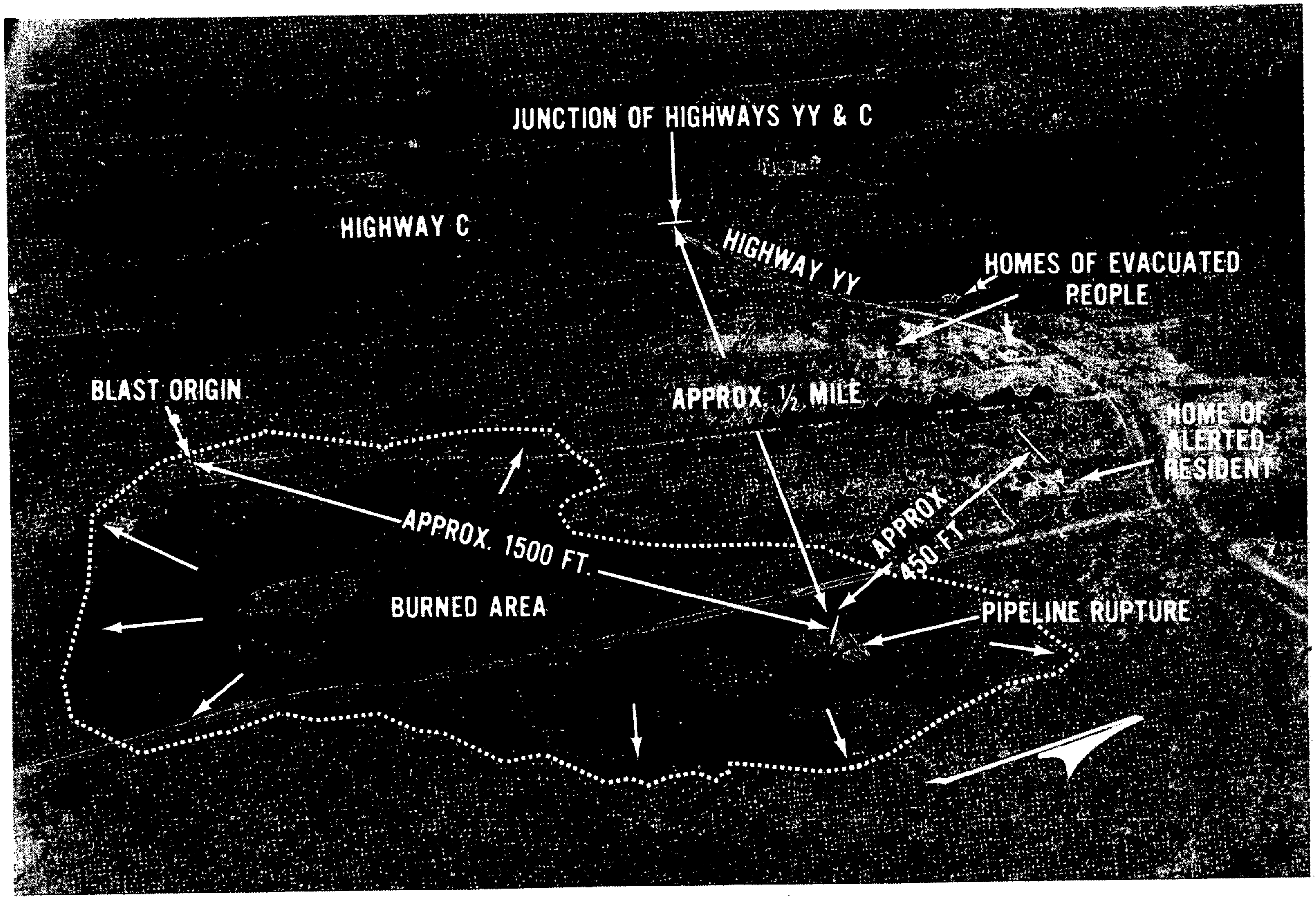


Figure 1 Overall View of Accident Area Showing Rupture Site, Explosion Origin and Residents' Houses

corrosion, were encountered[2]. Phillips, around 1941, initiated a plan to mitigate this external corrosion by the addition of anodes and rectifiers at various places along the pipeline, and the main line maintenance crews also repaired or replaced the pipe in the known leak areas. In addition to the numerous pithole leaks in the past, ten leaks of this type were reported by Phillips for 1970 and ten more were estimated to occur in 1971.

3. Pipe Wall Thickness Detection

As another means to locate the corroded pipe wall areas without the necessity to dig down and expose the pipe, Phillips used an instrument which detected and recorded these pipe abnormalities electronically. The instrument was placed inside the pipeline and performed its task while it was propelled by the stream of moving petroleum products. The pipe wall variations were noted and analyzed and the maintenance crews were advised of the locations of the defects to be repaired or removed. This tool has not been useful, nor was it so intended, to detect internal longitudinal weld problem areas.

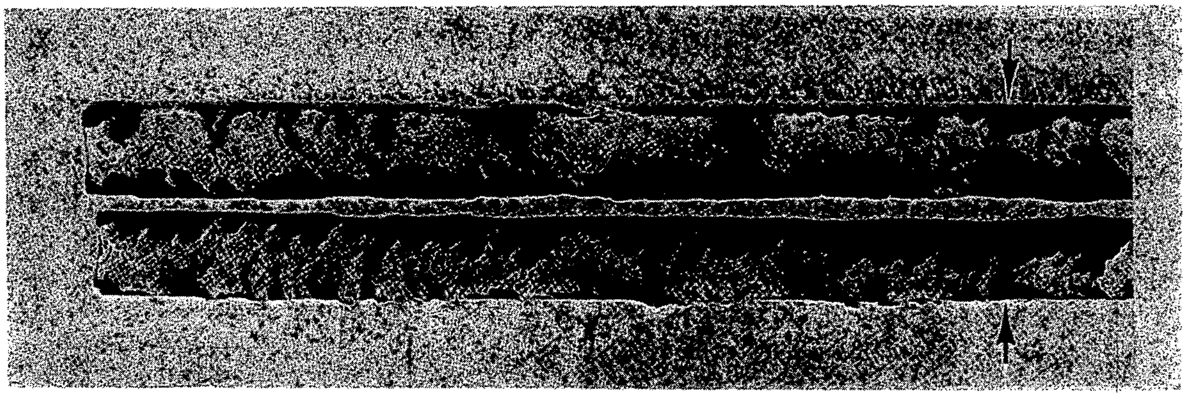
During the first 17 years of operation, this pipeline was also exposed to severe internal corrosion problems as well as to the external ones. Small amounts of entrained water and water absorbed in the petroleum products had entered the system. The water dropped out of suspension and lay on the bottom of the pipe causing corrosion, in varying degrees, to the inside walls of the pipe. Corrosion occurred where the 40-foot-long longitudinal welds had lain on the bottom and had been exposed to this free water. If the weld on the bottom was cold-stitched, the corrosion problem was compounded; oxides trapped in the weld voids were attacked by corrosion which successively weakened the weld until it failed and ruptured, or until the corrosion process was stopped. Phillips, between 1948 and 1950, acknowledged the severity of this problem and installed hay tanks and dehydration towers at strategic points along the pipeline to remove both the entrained and the absorbed water. The hay tanks were designed to remove the entrained water before it entered the system, and the dehydration towers were built to take out any water absorbed in the products by passing these products over a chemical bed. A check on the efficiency of this system is made periodically; corrosion coupons (metallic test strips), immersed in the product stream, are positioned at various locations along the pipeline. Periodic analysis of these test coupons for corrosion determines the efficiency of the dehydration system.

The extent of this internal corrosion is revealed by the pipeline leak records from 1965 to 1970 inclusive, wherein the "A" line from Borger to East St. Louis sustained 12 major longitudinal weld failures which released more than 39,000 barrels (1,638,000 gallons) of liquefied petroleum gas (LPG), and caused two deaths. Each rupture on this line averaged more than 3,200 barrels (134,400 gallons) of LPG released. In this same period, the newer, looped segments of this line experienced four longitudinal weld failures which spilled over 22,000 barrels (924,000 gallons) of propane, gasoline and other products. Each rupture on these looped segments averaged some 5,500 barrels (231,000 gallons) of spilled products.

4. Longitudinal Weld Detection

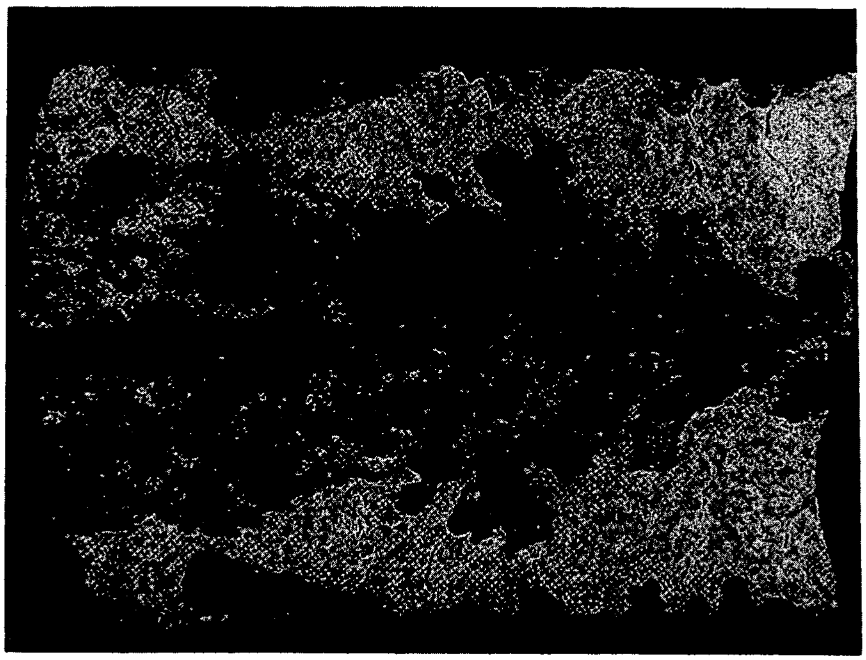
In an attempt to find these pipeline sections with longitudinal weld problems, Phillips, in 1969, began experiments with a newly developed instrument which is propelled through the pipeline by the product stream. Abnormalities in the longitudinal weld are detected and recorded electronically by this tool, and defects are marked so that the maintenance crews can then uncover the line at this point, examine the pipe, cut out the affected section and replace it with new pipe. The first complete run has recently been made with the in-

[2] Appendix I-Problems of Pipeline Corrosion.



1-1/2 X

Fracture faces of the electric resistance weld broken open by bending and the inside edges matched together. Specimen was located several inches beyond the east end of the split. Note the stitch pattern which has been accentuated by entrapped oxides and corrosion at the black areas. Also note entrapped oxides extending in from outside at spots. One of these spots is indicated by the arrows and is shown in greater detail below.



5 X

Detail of matched fracture faces at location indicated by arrows where entrapped oxides and corrosion extend practically across the wall.

Figure 2 Ruptured Pipe Section Showing Cold-Stitched Longitudinal Weld

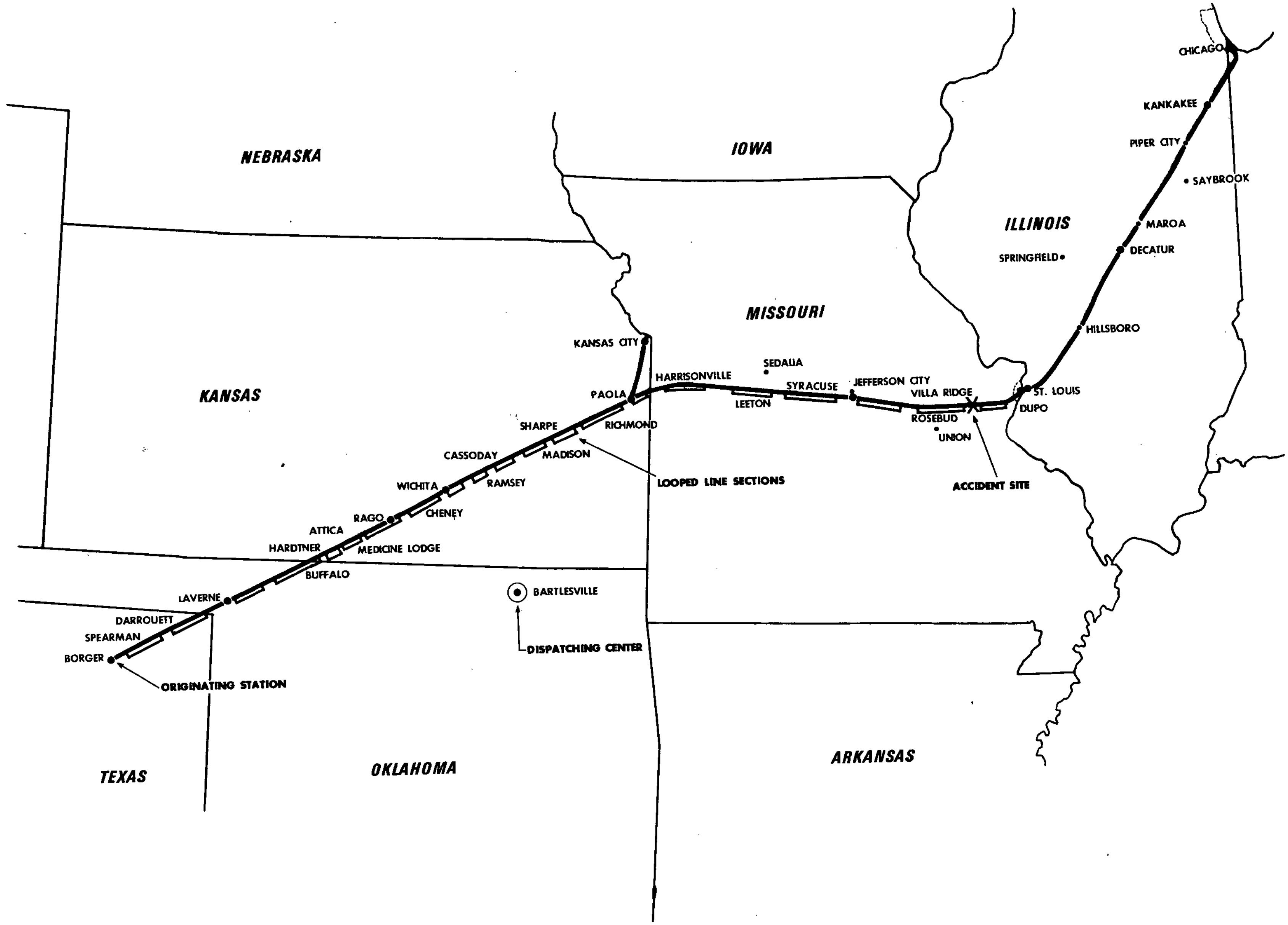
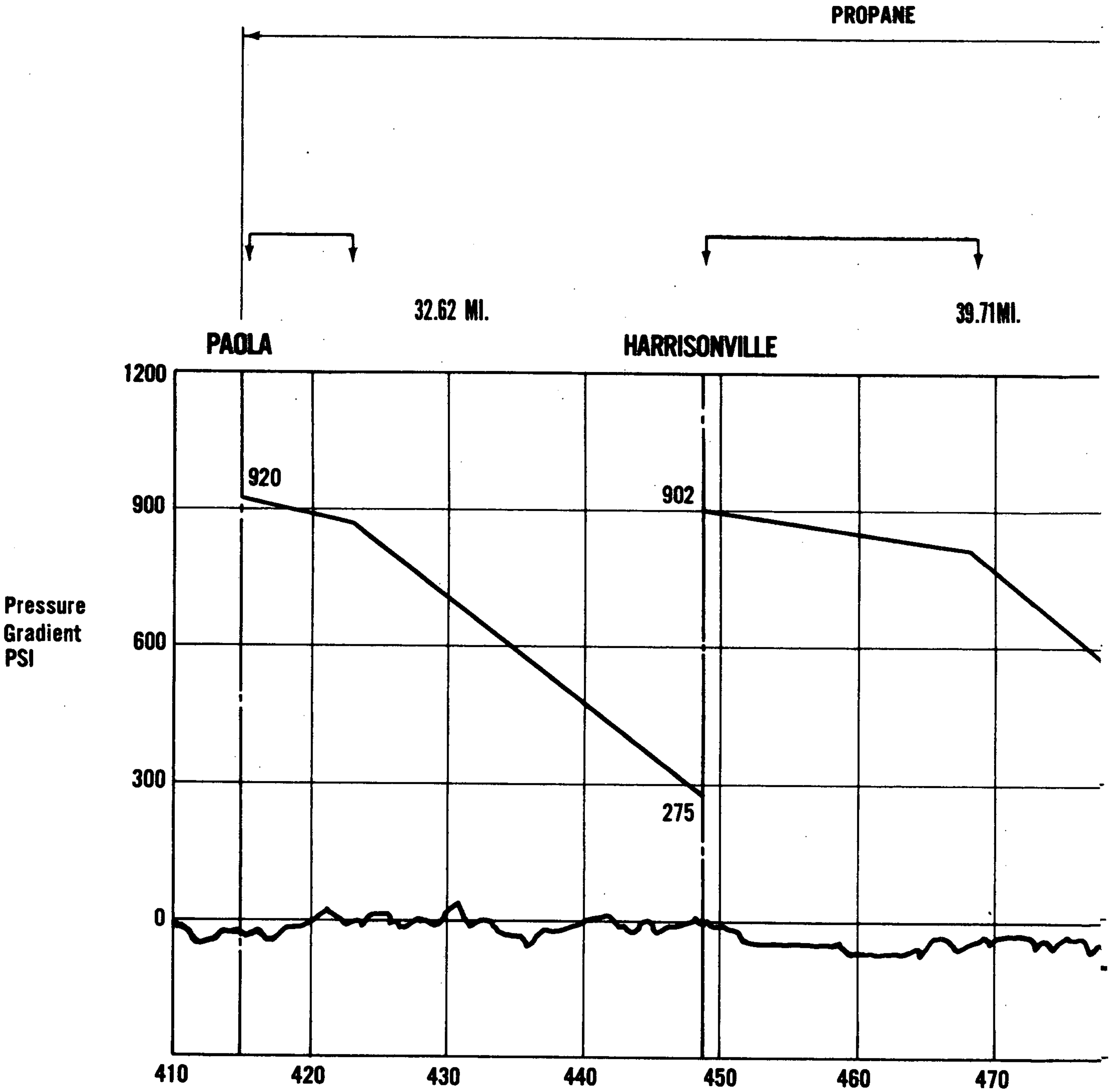
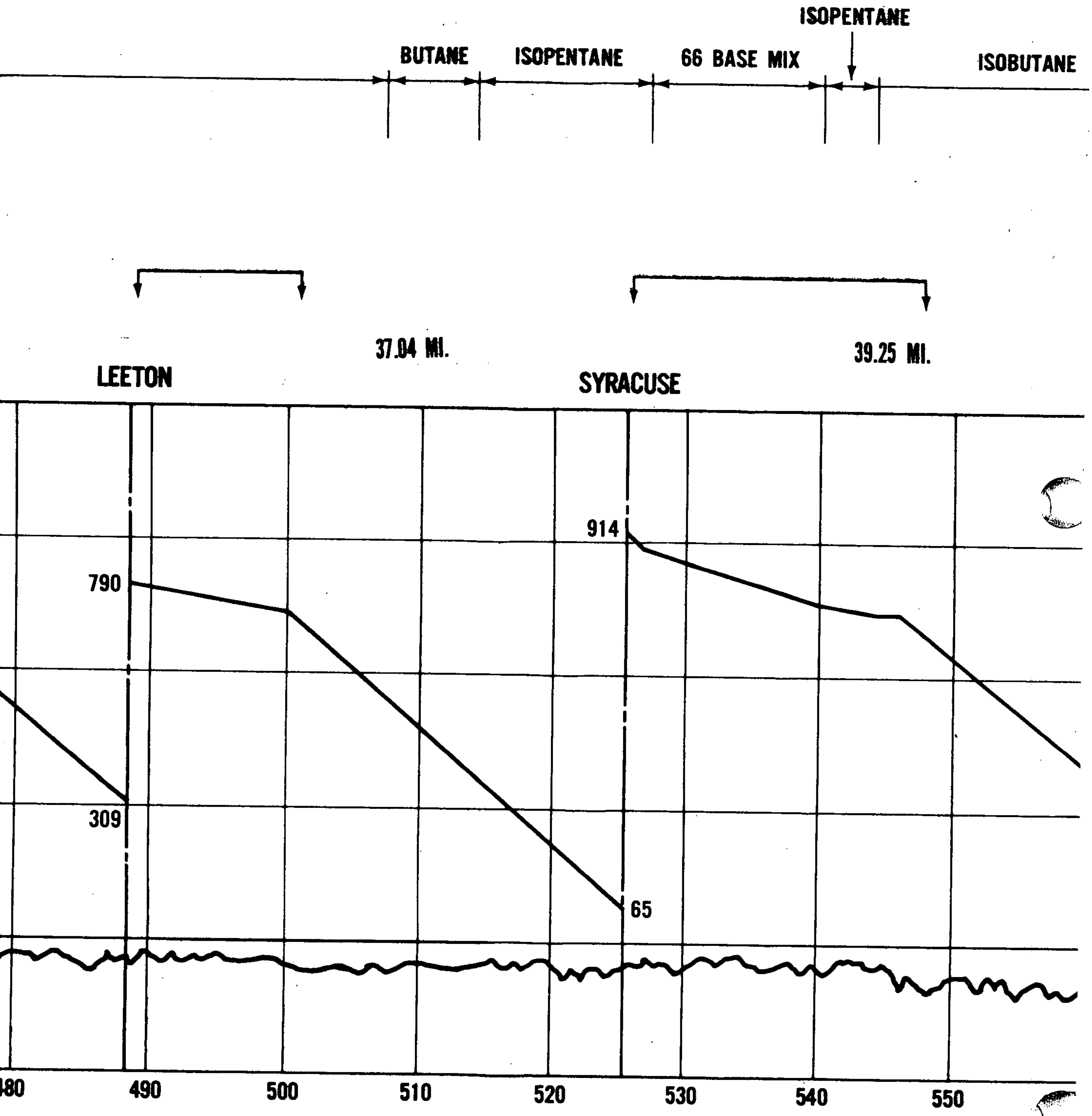


Figure 3 Phillips Pipe Line Company "A" Line System Map

The pressure changes between stations are calculated for points of product change and at loop ends with lines drawn between these points. The station pressures are the recorded pressures at the 10:00 P.M. reading.




ISOPENTANE
BUTANE
ISOPENTANE
66 BASE MIX
ISOBUTANE
37.04 MI.
39.25 MI.
LEETON
SYRACUSE
914
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309
65
480
490
500
510
520
530
540
550

PAOLA–E. ST. LOUIS 'A' PIPELINE

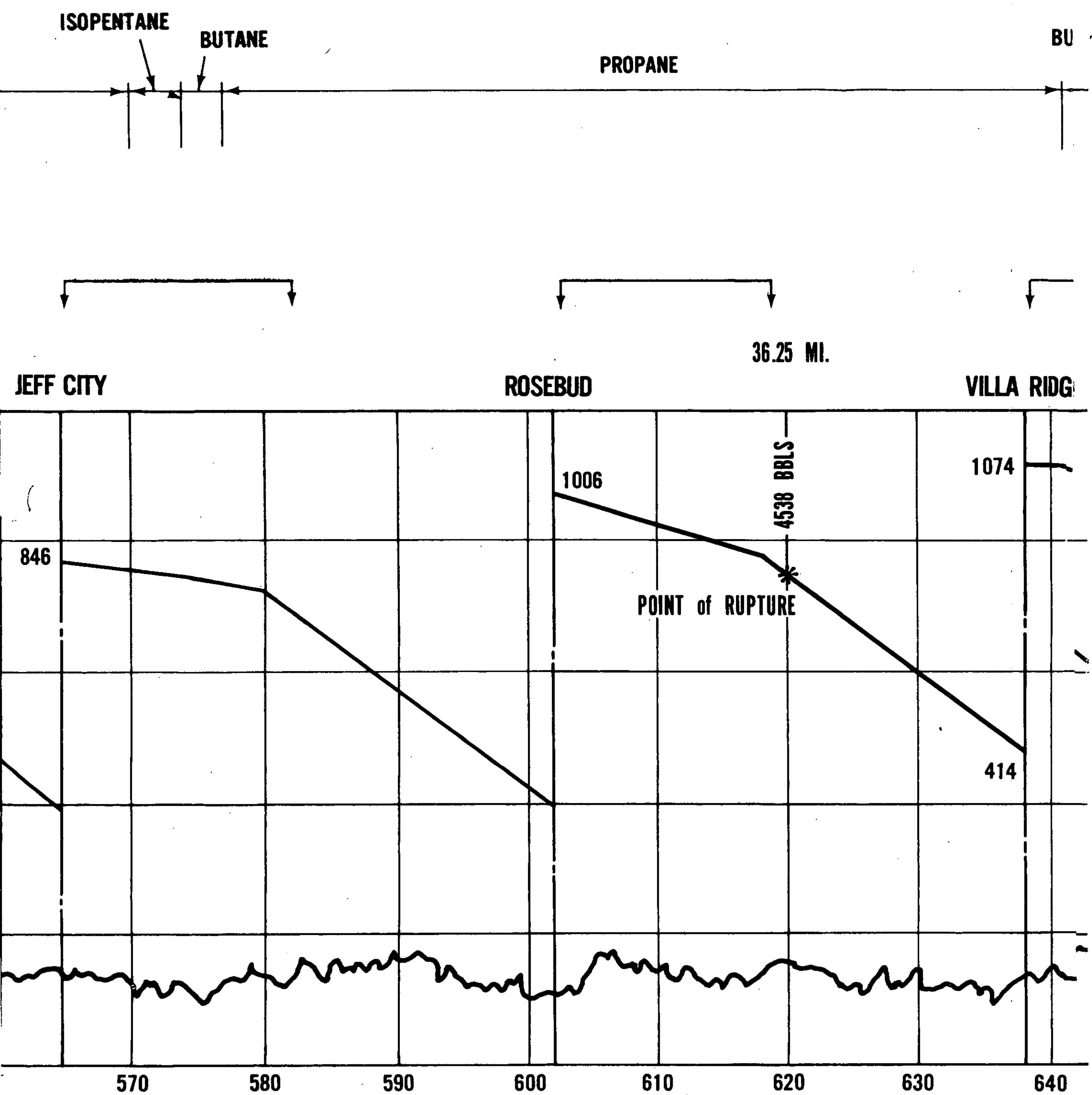
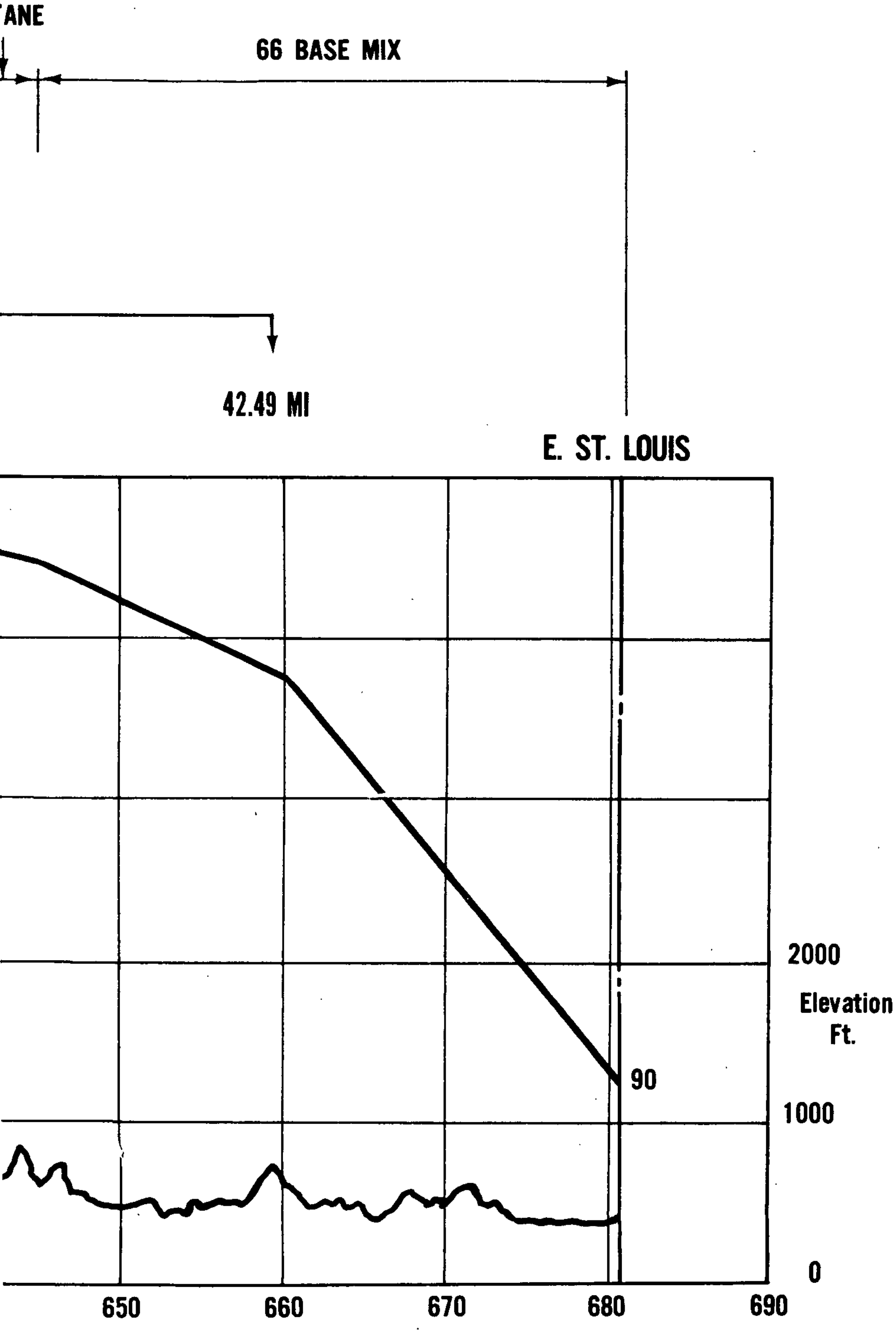


FIGURE 4

Pump Station and Line Fill, Paola to East St. Louis "A" Line Section



strument from Borger to East St. Louis, and the test results are being analyzed.

From its inception, this pipeline was intended to transport petroleum products which included propane, butane, gasoline, kerosene, diesel fuel and fuel oils. With the construction by Phillips of a separate new 10-inch line parallel to the original pipeline, the old system carried less of the fuels and more of the volatile, liquefied petroleum gases. During the 90-day period prior to the accident, the pipeline pumped LPG 69 percent of the time, and at the moment of failure the system carried an almost solid stream of LPG across the State of Missouri (See Figure 4.).

This pipeline system is operated on a "tight line" basis in order to handle these LPG products efficiently. Under this arrangement the number of barrels of product entering the system must equal the cumulative number of barrels leaving the system at the terminals; with some slight corrections made for temperature and pressure differences. To accomplish this "tight line" operation, all of the pump stations on the line must be hydraulically balanced with one another to stay within the pressure and flow conditions. These pumping stations are instrumented so that information is transmitted remotely to the dispatching center at Bartlesville, Oklahoma, where the entire system is monitored. Hourly checks on each pump station and the flow rate through the system are made and recorded. Most of the six intermediate pump stations between Paola and East St. Louis are unmanned and remotely controlled; station attendants are available when required, but their primary daylight activities are those of maintaining the facilities. Unlike those at fully manned pump stations, these men do not routinely control and monitor the station equipment.

5. Pipe Specifications

The pipe in this system was made in accordance with standards issued by Phillips Pipe Line Company, and it also conformed to the steel mill tolerance for pipe fabricated in that era; no industrywide codes or Federal regulations relating to line pipe manufacture were in existence. The low frequency, electric resistance weld process used in its manufacture had the following specifications:

8 5/8-inch outside diameter
0.277-inch wall thickness
52,000 p.s.i.g. tensile strength
30,000 p.s.i.g. yield point
3,080 p.s.i.g. ultimate bursting strength
1,930 p.s.i.g. internal pressure at minimum yield
334.12 barrels (14,033 gallons) per mile

This electric resistance weld (ERW) pipe was made from a steel plate of uniform grade and thickness and about 48 feet long. The flat steel plate was formed into a tubular or "O" shape and the unjoined edges of the "O" were then pressed together. An electric current, applied to these edges by special electrodes, provided the heat required to fuse the pipe together at a temperature slightly less than the melting point of the metal. Under this manufacturing process, no additional metal was added to make the weld; the union was accomplished solely by the pressure exerted on the pipe edges, forcing them together, and the heat supplied by the electrodes which made the plate edges soft enough for complete fusion. The ends of the pipe were then trimmed and squared, and filled with water, hydrostatically tested to 1,200 p.s.i.g., and the longitudinal weld struck with a hammer while the pipe was still under test pressure. Each finished 40 to 48-foot piece of pipe incorporates a longitudinal weld throughout its entire length.

6. Characteristics of Propane

Propane is one of a group of refined petroleum products categorized as Liquefied Petroleum Gas (LPG). The material is so classified because at atmospheric pressures and ambient temperatures it is gaseous, but it can be readily contained and stored as a liquid under increased pressure. When the pressure on propane is reduced below the critical point, the liquid vaporizes and forms a gas about 1½-times as heavy as air. Liquid propane has a direct pressure-temperature relationship; at minus 51° F. propane is a liquid under atmospheric pressure; at 100° F. propane is a liquid at 192 p.s.i.g. or more pressure. When propane vaporizes, it expands rapidly and absorbs a tremendous amount of heat from any substance with which it comes in contact. The whitish haze or fog commonly associated with spilled propane is not propane gas itself, but the frozen water vapor present in the surrounding air which has been chilled rapidly. Some additional properties of propane are:

vapor pressure p.s.i.g. at 100° F.	192
boiling point degrees F. at 14.7 p.s.i.g.	-51
cubic feet of vapor per gallon of liquid	36
specific gravity of the gas	1.554
flammable limits	
lower, percent by volume in air	2.4
upper, percent by volume in air	9.6

7. Liquefied Petroleum Gas Pipeline Accidents

A 3-year average taken from the "Summary of Liquid Pipeline Accidents," DOT Form 7000-1, for the fully reported years of 1968, 1969 and 1970, shows that although LPG was involved in only 9 percent of all the reported accidents during that period, it caused 71 percent of the deaths, 65 percent of the personal injuries and 26 percent of the property damage. During this 3-year period, a total of 115 LPG leaks were officially reported, involving the release to the atmosphere of 188,658 barrels (7,923,636 gallons) of LPG for an average of 1,640 barrels (68,880 gallons) per leak. Almost all of this flammable material vaporized or burned.

B. Description of the Accident

1. Events Preceding the Accident

The sky was partly covered with high, thin clouds, a breeze of 5 knots was blowing from the northeast and the temperature was about 34° F. A weak cold front had passed through earlier in the day leaving cold air at ground level capped by warmer air aloft at 2,000 to 2,500 feet. A well-defined temperature inversion existed with a very stable air condition on the ground.

At 10 p.m. the Phillips pipeline dispatcher in Bartlesville was making his routine hourly check on the "A" line to observe and record the flow rates and station pressures and verify normal operation. For the past several hours the pipeline had been running full; all booster stations from Paola eastward across the State of Missouri were running, near-maximum flow rates prevailed, and near-maximum pressures existed. Paola Station in Kansas was pumping at 920 p.s.i.g., Harrisonville Station in Missouri was pumping at 790 p.s.i.g., Syracuse Station in Missouri was pumping at 914 p.s.i.g., Jefferson City Station in Missouri was pumping at 846 p.s.i.g., Rosebud Station in Missouri was pumping at 1,006 p.s.i.g., and Villa Ridge Station in Missouri was pumping at 1,074 p.s.i.g. An almost solid stream of LPG was packed into the pipeline which was pumping at 1,500 barrels (63,000 gallons) per hour. (See Figure 5.)

At 10:07 p.m., a hazardous vapor alarm light flashed on the dispatcher's control console indicating that Villa Ridge Station in Franklin County, Missouri, had experienced a hazardous vapor condition in the pumproom and would automatically shut down within 3 minutes. At 10:10 p.m. when this occurred, the pipeline stream bypassed Villa Ridge Station and the pressure gradient changed rapidly from Rosebud Station to the terminal at East St. Louis. The pressure between Rosebud and Villa Ridge Stations increased, while that between Villa Ridge and East St. Louis decreased. The pressure at the point of rupture, about halfway between Rosebud and Villa Ridge, increased from 818 p.s.i.g. to 942 p.s.i.g. This section of the line had not been subjected to a pressure this high in the recent past.

The dispatcher notified Paola to slow one unit down and then, by remote control, he

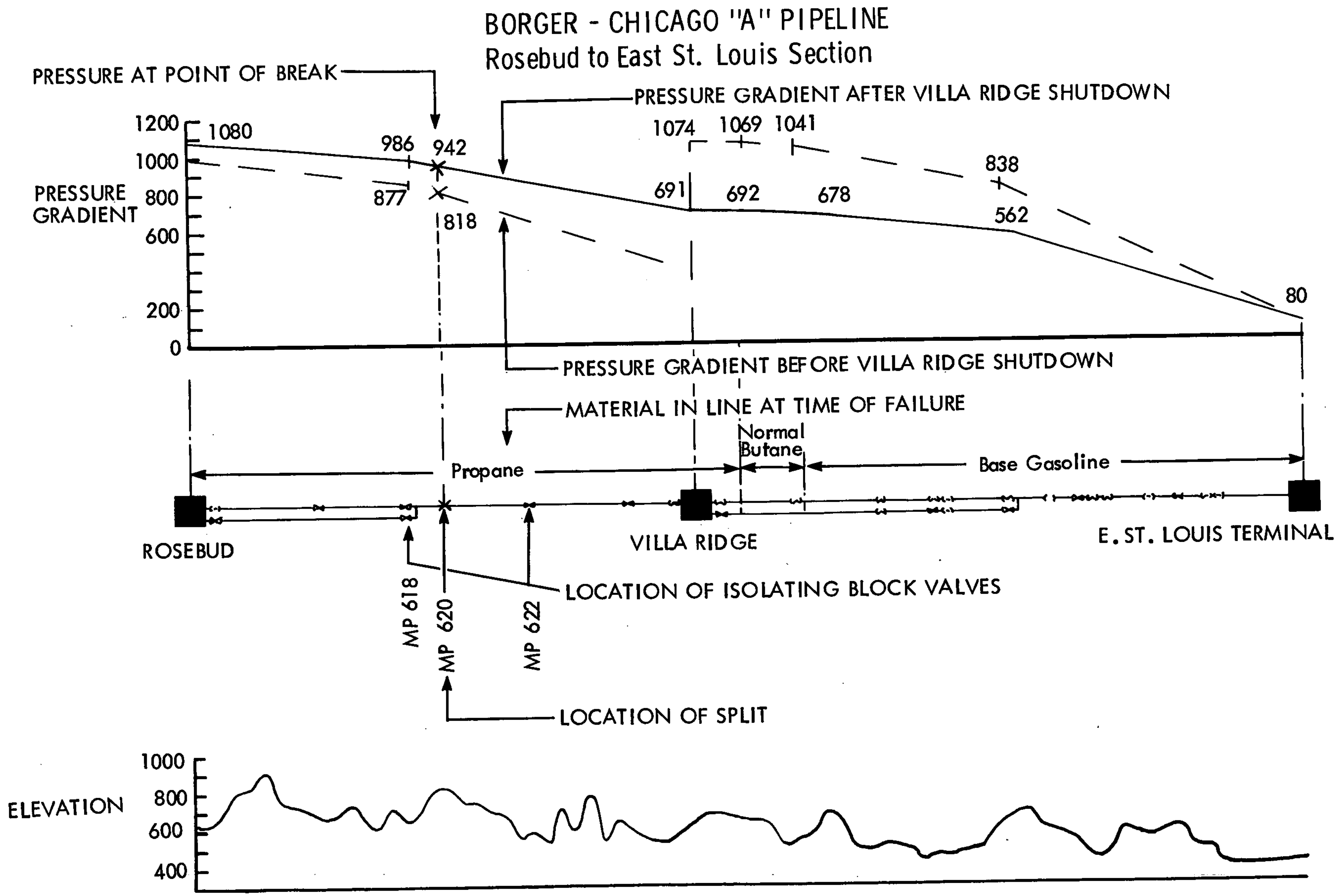


Figure 5 Hydraulic Gradient Between Rosebud and Villa Ridge Pump Stations

throttled back the diesel units at the unattended stations of Harrisonville and Leeton as much as possible without upsetting the line pressures He next directed Jefferson City to cut back on its pumping rate; he knew trouble existed on the line but not to what extent. At 10:10 p.m., Villa Ridge shut down automatically.

2. **The Accident**

At 10:20 p.m., 10 minutes after Villa Ridge had shut down, the dispatcher, still trying to reduce the pressure evenly at all points, saw the suction pressure at Rosebud drop off sharply, but the discharge pressure remained at approximately 1,000 p.s.i.g. The pipeline had burst approximately halfway between Rosebud and Villa Ridge. Propane, at approximately 942 p.s.i.g., escaping from a 6-foot split in the underside of the pipe, dug a 10-foot-diameter, 4-foot-deep crater and shot up into the air.

The dispatcher, now aware of new trouble somewhere between Rosebud and Villa Ridge, suspected a leak and commenced a normal shutdown procedure.

At 10:21 p.m., he called Paola and directed that station to shut down.

At 10:23 p.m., Jefferson City was ordered to send a man to Rosebud, 37 miles away, and close the pipeline there.

At 10:25 p.m., the dispatcher called a company man in the accident area to drive to Villa Ridge and check on the cause of shutdown.

At 10:26 p.m, the pressure at Harrisonville was checked to see if a unit could be shut down without causing undue pressure surges.

At 10:28 p.m., the No. 1 unit was shut down at Harrisonville.

At 10:30 p.m., both units at Rosebud and the No. 1 unit at Leeton were shut down.

At 10:30 p.m., Paola station shut the "A" line down.

At 10:34 p.m., the dispatcher was still checking the line pressure to see where additional pumps could be shut down.

At 10:35 p.m., the No. 2 unit was shut down at Harrisonville.

At 10:38 p.m., the No. 3 unit was shut down at Harrisonville.

At 10:39 p.m., the No. 1 unit was shut down at Syracuse.

At 10:42 p.m., both pumps were shut down at Jefferson City and the personnel were directed to block the line there as soon as possible.

Twenty-two minutes after the split occurred, all the pump stations had been shut down and instructions had been given to close the valves and isolate the line as soon as possible. At 10:45 p.m., Borger, the originating pump station in Texas, shut down the system to Paola, and the entire 946-mile pipeline from Texas to Indiana was idled 25 minutes after the failure.

A "crash down" procedure designed to shut down each unattended pump station in the event of fire was not utilized. This rapid shutdown procedure for the entire pipeline system requires between 20 and 30 seconds for each station so activated. The dispatcher had never been instructed in or studied this particular method of "crashing down" the entire pipeline. No procedure for shutting down the entire pipeline by using the station crash button was contemplated by Phillips and no instructions to that effect were issued. The intent of the crash button is for station shutdown due to fire. (See Figure 6.)

Shortly after 10:20 p.m., a man living along highway YY, approximately 450 feet from the pipeline, heard a loud roar similar to a jet aircraft. He and his wife went to their backyard to investigate and saw a geyser shooting 50 or 60 feet high, creating a heavy white fog which flowed downhill into the shallow valley behind the house and slowly filled the entire area. The man sensed imminent danger, aroused his five sleeping children, immediately left the house, ran for the car, and drove away. He stopped at his brother-in-law's house 200 or 300 feet down the road, alerted that family to the hazard, told them to evacuate the premises, and then telephoned the Sheriff's office advising it of the leak. By this time, another family from

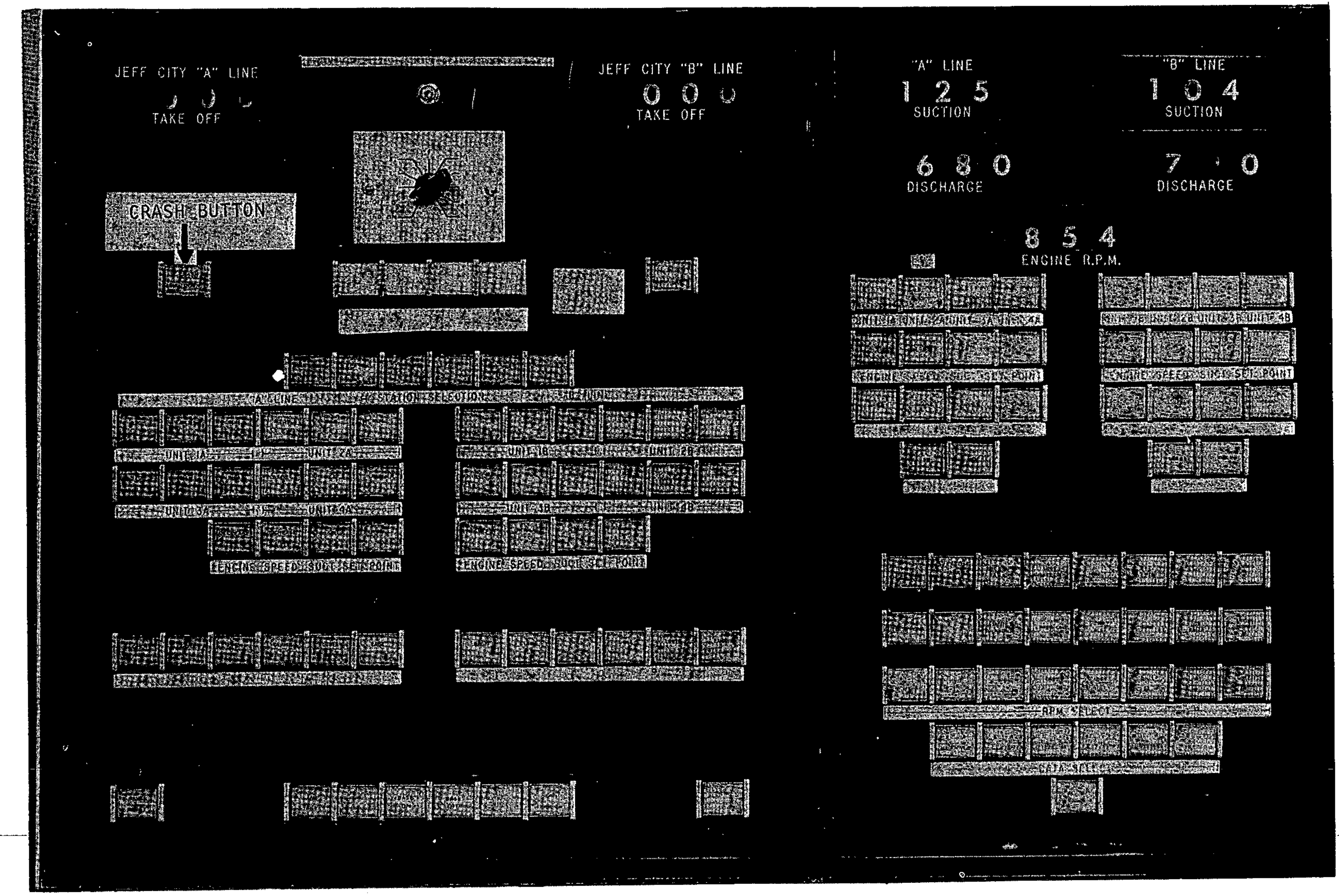


Figure 6 Dispatchers Control Console Showing the "Crash Button"

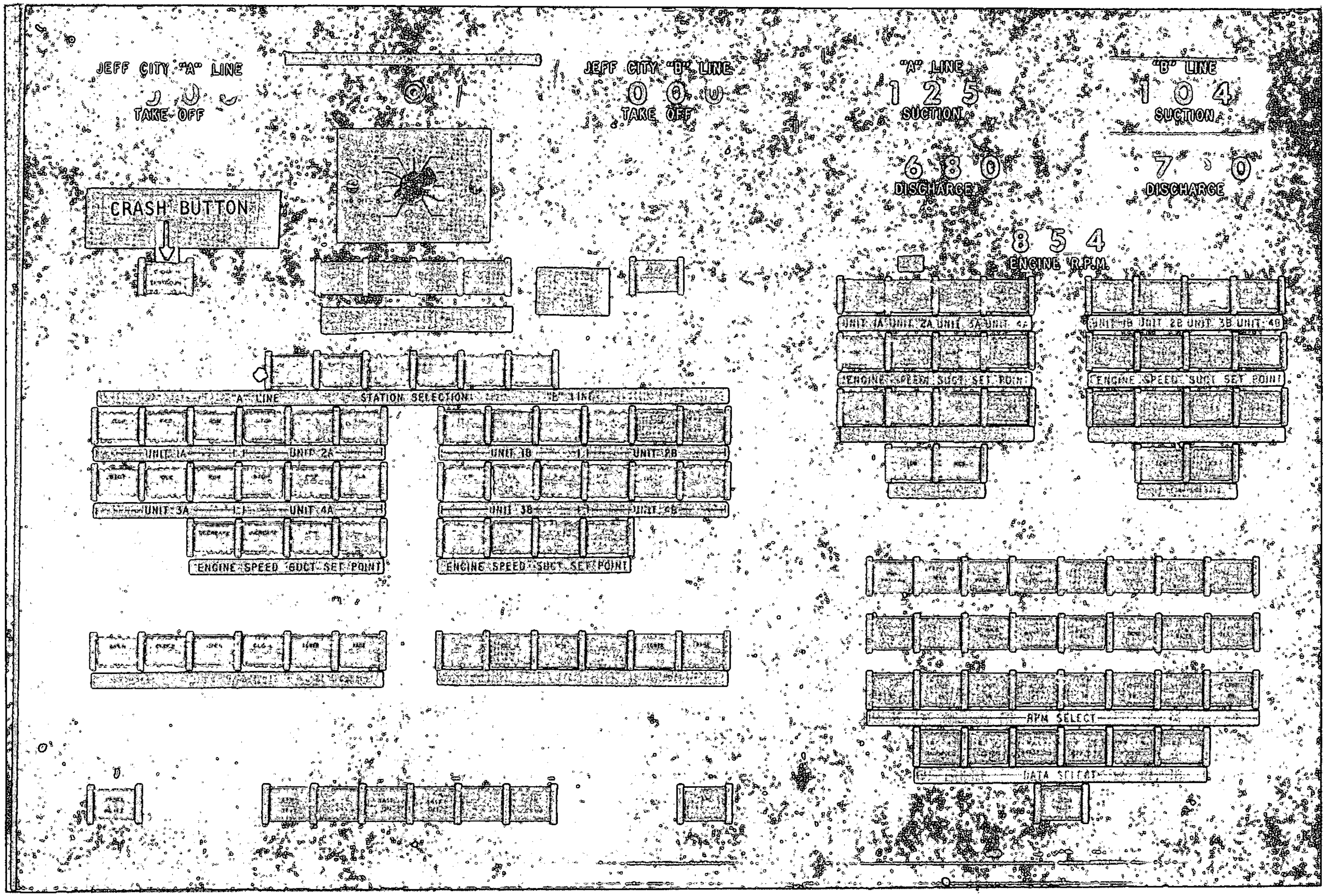


Figure 6 Dispatchers Control Console Showing the "Crash Button"

across highway YY had heard the noise, seen the haze caused by the escaping propane, and was in the process of leaving their house. Another next door neighbor was awakened by pounding on his door, warned of the increasing peril, and advised to leave everything and clear out. All the affected families retreated west down highway YY for about one half mile to its junction with highway C where they parked their cars (See Figure 1). The parking area at this intersection is 60 feet higher and overlooks the entire valley. This vantage point is about 3,000 feet from the rupture. The valley below was slowly filling with vaporizing propane gas during this time.

Some of the families were vaguely aware that a pipeline existed somewhere down in the valley, but no one had any idea of the material being transported; one even thought it carried crude oil. Phillips had a practice, when in communication with the land owners or residents along the pipeline right-of-way, of issuing a card containing information about the pipeline, the telephone numbers of personnel to call in an emergency, and an address where correspondence could be directed. None of these affected residents had seen or received this card.

At 10:44 p.m., 24 minutes after the rupture, the propane-air mixture detonated, and generated a double boom; the gaseous cloud ignited simultaneously at all points in the valley. One person was knocked down by the blast; the others, still in their cars, were seemingly unaffected. A huge ball of fire immediately followed the blast, mushroomed upward and enveloped the entire area. In the seconds that followed the ignition, the flame rolled from east to west across the valley bottom, up the sloping terrain toward the onlookers. The thermal column of fire was hundreds of feet high. The blast, the noise, and the pillar of fire passed over the area, and firebrands, broken boards, branches, rubble and debris fell on the countryside. The group quickly made their way along highway C to escape. One family stopped at a home along the way to telephone the fire department, but the telephone poles had been snapped off and broken and the lines were down. The ball of flame then subsided; it left one large conflagration which still roared at the pipe rupture and dozens of smaller blazes which dotted the entire valley. (See Figure 7.)

C. Activities After The Accident

1. Pipeline Personnel Activities

At 10:38 p.m., the Phillips Pipe Line Company area foreman received a telephone call from one of his maintenance crew members who informed him of a reported pipeline leak and trouble on the line. A Deputy Sheriff, who had learned of the leak from the phone call by the resident, had, in turn, called the maintenance man. The foreman called the dispatcher's office for verification of the leak and for any location details. At about 10:52 p.m., he began calling out as many of his maintenance crew as he could reach by telephone. He had been instructed by Bartlesville to close the main line valves on either side of the rupture as rapidly as possible. At 11 p.m. the foreman, together with the first two men who reported for duty, started for the valves. These main line gate valves, installed at the same time the line was constructed, are manually operated, hand-wheel type, requiring about 5 minutes to close. The men closed the first valve, located at milepost 626, approximately 6 miles downstream from the leak, at 11:30 p.m., 1 hour and 10 minutes after the rupture. The foreman had difficulty driving to the second set of valves. (See Figure 5) Crowds of sightseers, who had heard the explosion and seen the flames, converged upon the area, parked their cars, stood in knots on the road, and forced the foreman and his men to drive in a drainage ditch off the road, and alongside a fence before they could get to the valves. These two valves, located at milepost 618, 2 miles upstream from the rupture and 8 miles away from the first valve, were fully closed at 12 p.m., 30 minutes after the first

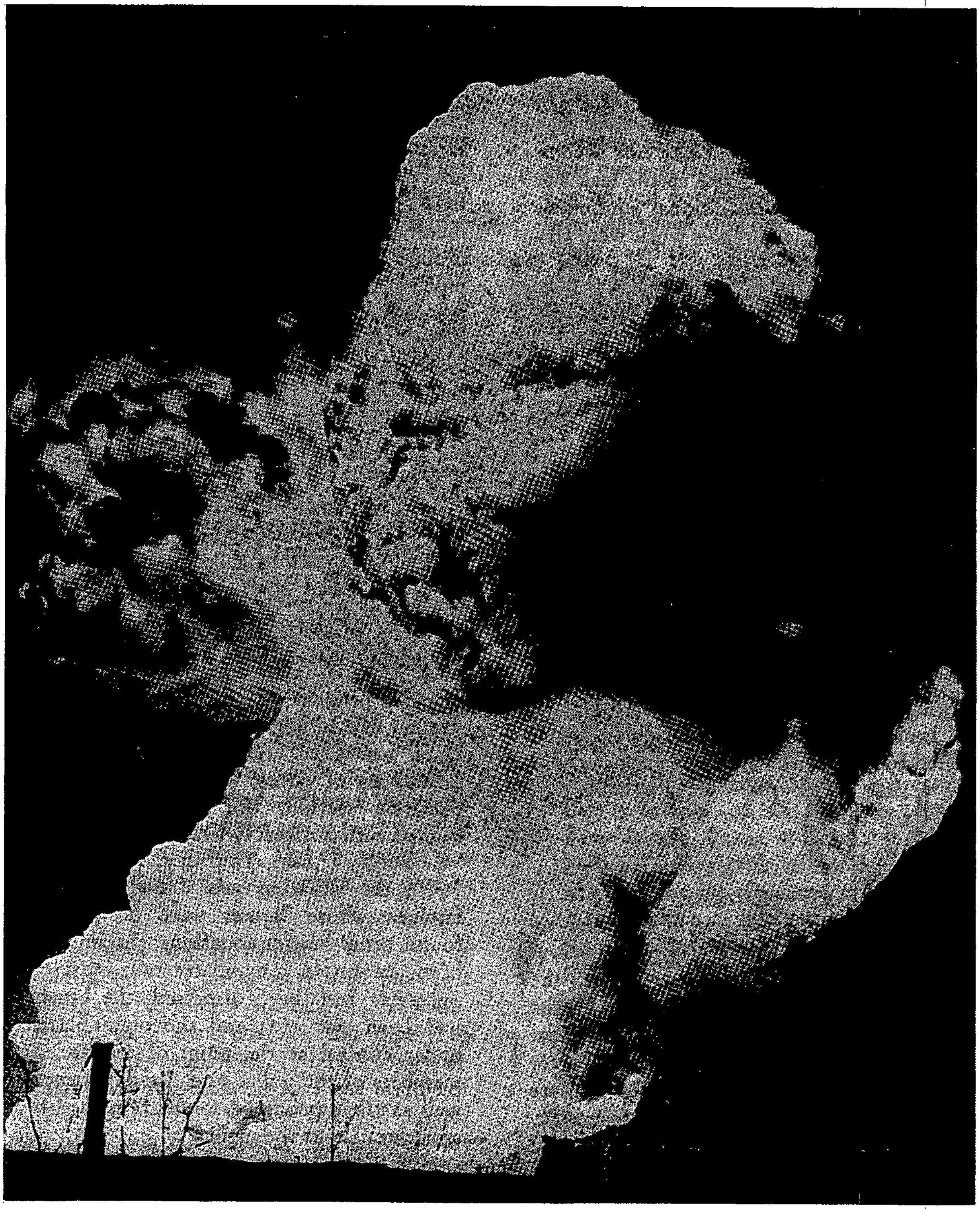


Figure 7 Propane Burning at Rupture Site

valve, and 1 hour and 40 minutes after the pipeline failure. This isolated pipeline section, 8 miles long, contained 2,673 barrels (112,266 gallons) of propane. With the line now blocked, the foreman headed for the leak area. The other maintenance men who had not accompanied the foreman, had gone to the leak site to prepare for repairs. Additional equipment and special tools for the repair work were also being dispatched to the scene.

Phillips indicated that a total of 4,538 barrels (190,596 gallons) of propane had escaped and burned as a result of this rupture. The amount of propane released from the moment of the split at 10:20 p.m., until the moment of the detonation at 10:44 p.m., was estimated to be approximately 756 barrels (31,752 gallons). The 756 barrels of propane, when converted to a gaseous state in the ratio of 36 cubic feet of vapor to 1 gallon of liquid, become 1,143,072 cubic feet of vapor.

2. State Police Activities

At 10:45 p.m., two Missouri State Policemen, on routine highway patrol about 25 miles from the explosion, felt two separate concussions, heard what sounded like a sonic boom, and then looked toward the west where flames where visible. The policemen immediately headed for the blaze.

3. County Sheriff's Activities

The Franklin County Sheriff's office, received the initial telephone call from the evacuating resident and dispatched ten men to the scene. Both groups, the State Police and the Sheriff's deputies, arrived at the site almost simultaneously at 11:10 p.m., 26 minutes after the explosion. Crowds had gathered and more were on the way; they choked the county roads and blocked traffic with their parked cars. Both police groups cordoned off the area against these sightseers, checked the blasted homes for injured, found shelter for the displaced, patrolled the area for possible looters, and checked with the local hospitals for those admitted for treatment.

4. Fire Department Activities

Volunteer fire companies proceeded to the scene; the first units arrived at 10:58 p.m., 14 minutes after the blast occurred. More firefighters arrived; some companies came from 25 miles away. The main blaze, still fueled by the propane which vented and vaporized out of the pipeline, had now retreated more than 1,000 feet back to the immediate leak area where it burned with considerable energy. These volunteer groups spent the initial hours putting out brush, grass, and tree fires. They then extinguished remaining fires in the house, warehouse, and outbuildings at the center of the detonation. As the fires were quenched or brought under control, the firemen aided the homeowners by clearing away glass and other debris, and administered first aid to the injured. Neither the volunteer fire companies nor the pipeline crews attempted to extinguish the main blaze which emanated from the pipeline split. This flame completely consumed the escaping propane and no hazardous vapors remained free to migrate and rekindle or explode again elsewhere. After the closure of the second set of valves, which isolated the failed pipeline section, the fire diminished and burned with noticeably less intensity.

At about 1 a.m., Thursday, December 10, 1970, the situation was under control. The families whose homes were destroyed had found other accommodations; the injured had been accounted for and treated; most of the sightseers had been dispersed; the brush fires had been put out; and the main blaze was under control at the point of rupture. Some members of the police and fire departments as well as the pipeline personnel remained in the area throughout the night.

5. Pipeline Repairs

By midmorning, the Phillips maintenance crew had installed two special plugs in the pipeline, several hundred feet apart, one on each end of the failure. The flame, which had now diminished considerably, was finally extinguished at 11 a.m. The ruptured pipe was cut out of the line and set aside for analysis by metallurgists (See Figure 8). The pipe had split in the longitudinal weld. This longitudinal weld had been on the bottom of the pipe and when it ruptured, a hole was blasted out underneath both sides and over the top of the pipe by the jetting action of the propane escaping under high pressure. The hole was 10 feet in diameter and 4 feet deep. A new section of pipe was installed and the ends were fastened with mechanical couplings. Welding was not attempted at this time for fear of reigniting any existing propane vapors. After the installation of the new pipe, the special plugs which had been positioned on either side of the failure were removed, the dispatcher in Bartlesville was notified, the main line valves were reopened, the empty line section was slowly filled, the pump stations were slowly brought back on the line, and the pipeline was back in operation again at 4 p.m., approximately 18 hours after the failure. The repaired section was carefully checked for leaks by the maintenance men as the pipeline came back up to operating pressure. The excavation was left open for several days to allow any propane vapors to dissipate. The mechanical couplings were later welded and the welds were x-rayed to check their soundness. This excavation was later backfilled and the surrounding area cleaned up.

6. Pipe Metallurgical Analysis:

Phillips sent the failed section of pipe to a metallurgical laboratory for analysis, and also conducted their own tests on this pipe (See Figure 9). The rupture was 77 inches long with a 4-inch maximum opening near the middle of the split. Examination showed that the longitudinal weld was defective at the time it was manufactured at the pipe mill. Inadequate heat and pressure had trapped oxides within the weld area, resulting in weak bonding of the pipe at frequent intervals rather than a universally strong, continuous, longitudinal weld. Internal corrosion had further weakened this weld by sharply reducing the pipe weld thickness along the weld line. Failure resulted when the pipe was subjected to higher than normal operating pressures. A test section of this failed pipe, cut out from beyond the end of the split, was broken open at the weld to check for defects. Although this test piece was back of the rupture and the weld was still intact, the black oxide spots, the corrosion, the stitch pattern and the variations in weld soundness were all apparent.[3]

7. Operating Pressure Reduction

After this accident, Phillips issued an order reducing the pressures on the pump stations at Syracuse, Jefferson City, Rosebud, and Villa Ridge from a maximum of 1,080 p.s.i.g. to 900 p.s.i.g. The three pump stations of Paola, Harrisonville, and Leeton were reduced from 1,080 p.s.i.g. to 980 p.s.i.g.

Subsequently, after the public hearing in St. Louis, Missouri, on February 2, 3, and 4, 1971, the National Transportation Safety Board, on April 27, 1971, issued Safety Recommendation P-71-6 which states, in part:

> The Phillips Pipe Line Company also place a restriction on the operating pressures of the remainder of the pipeline extending from Borger, Texas, to East St. Louis, Illinois. This restriction should have the effect of providing for a maximum discharge pressure of 900 p.s.i.g. at each of the pump stations on the line between Borger and East St. Louis. This restriction need not apply to the Borger pump station due to the fact that the pipe between Borger and the next pump station is of a newer and different type.[4]

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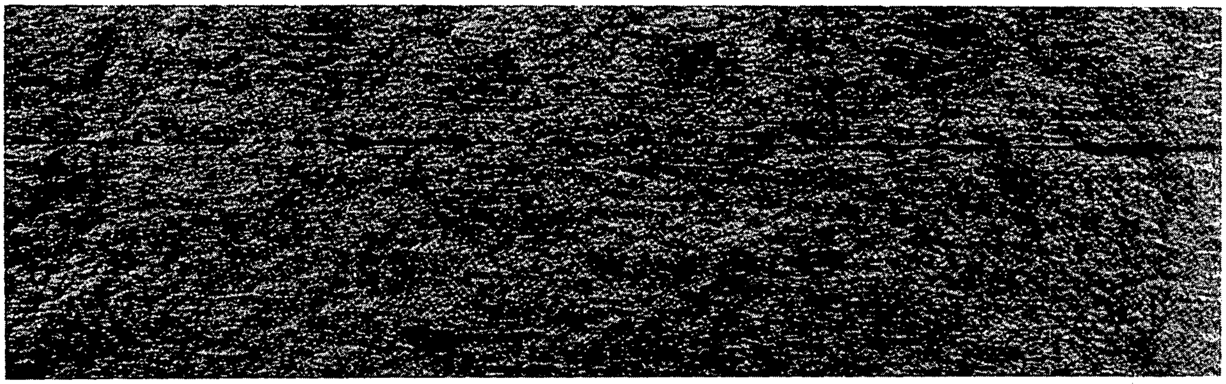
[3] Metallurgical Consultants, Inc. Failure In 8 5/8 Inch OD x 0.277 - Inch Wall Electric Resistance Welded Pipe In Phillips Pipeline "A" In Franklin County, Missouri, December 9, 1970. By M. E. Holmberg.

[4] Appendix II - Safety Recommendation P-71-6

Figure 8 Ruptured Pipe in the Ditch Prior to Removal. Split Was Facing Down



Detail of corroded inside surface showing variation in width of corrosion along the electric resistance weld. Note the short fine longitudinal grooves over the entire corroded surface.

Figure 9 Ruptured Pipe Interior Showing Internal Corrosion

By telegram dated May 4, 1971, Phillips Pipe Line Company advised that it had complied with this Safety Recommendation.

On August 2, 1971, Phillips Pipe Line Company, in a letter to the Chairman of the National Transportation Safety Board, advised that it intended to raise the discharge pressures of its pump stations on a 118-mile section between Borger, Texas, and Paola, Kansas, from 900 to 1,080 p.s.i.g.[5] The pipe in this line section, although manufactured by the same ERW process as that in the failed section, was made by a different pipe mill and had never experienced any cold stitched weld failures.

8. Subsequent Testing

After the accident, through the spring, summer, and fall of 1971, Phillips initiated hydrostatic tests on this pipeline between Syracuse and Jefferson City and Rosebud and Villa Ridge pump stations. There were a total of 11 in-place pipe failures, and four additional joints of pipe were removed from the line and purposely tested to failure. None of the failures that occurred either on the test block or during the hydrostatic testing of any line segment failed below 125 percent of the present operating pressure of 900 p.s.i.g. or below 110 percent of the original operating pressure of 1,100 p.s.i.g. which was the design criteria of the B31.4 code prior to 1966. The looped sections downstream from Syracuse and Rosebud pump stations later held 1,375 p.s.i.g. for 24 hours. The single line section through the accident area to Villa Ridge pump station was filled with water and hystrostatically tested. Three pipe failures resulted between 1,280 and 1,380 p.s.i.g., but this line was turned over to the dispatchers before a 24-hour test at 1,375 p.s.i.g. was completed.[6]

[5] Appendix III - Phillips Letter in Regard to Increased Station Pressures

[6] Appendix IV Phillips Pipe Line Company Letter on Hydrostatic Testing

D. Description of Damage

1. Overall View

On the day following the explosion and fire, evaluation of the damage began. Incredibly there were no fatalities; however, ten people had been treated for injuries. Within a 2-mile radius of the blast, major structural damage occurred to 14 houses, minor structural damage affected an additional 14 houses and windows were damaged in a total of 37 dwellings. Within a 7-mile radius, excluding the initial 2-mile section, some 17 houses sustained minor structural damage and 124 houses and other buildings had window damage. Within a 12-mile radius, which included the city of Washington, Missouri, 12 commercial buildings had windows blown out and 87 houses had broken windows (See Figure 10). The city of St. Louis, Missouri, 55 miles away, felt the detonation and a reading of 3.5 was recorded on a seismograph located there.

2. Detailed Damage

At the bottom of the valley, in the area assumed to be the origin of the detonation, the damage was extensive; trees were snapped off like matchsticks, burned, blackened, and strewn over the ground. In the open pastureland, many small evergreens were uprooted and large expanses of grass had been burned black. The uprooted trees and broken branches almost uniformly pointed toward the destroyed buildings – the center of the blast. The ranch-type stone farmhouse was incinerated, and debris of all varieties was scattered over the landscape (See figures 11 & 12). A black, charred stream bank traced one path of the fire for more than 1,000 feet to the southeast. The concrete block, two-story warehouse, located near the ranch-type stone house had been obliterated; this area was the origin of the blast. Another farmhouse, one-half mile southeast of the detonation origin, was destroyed (see Figure 13.) The windows were smashed, doors were broken and debris littered the interior.

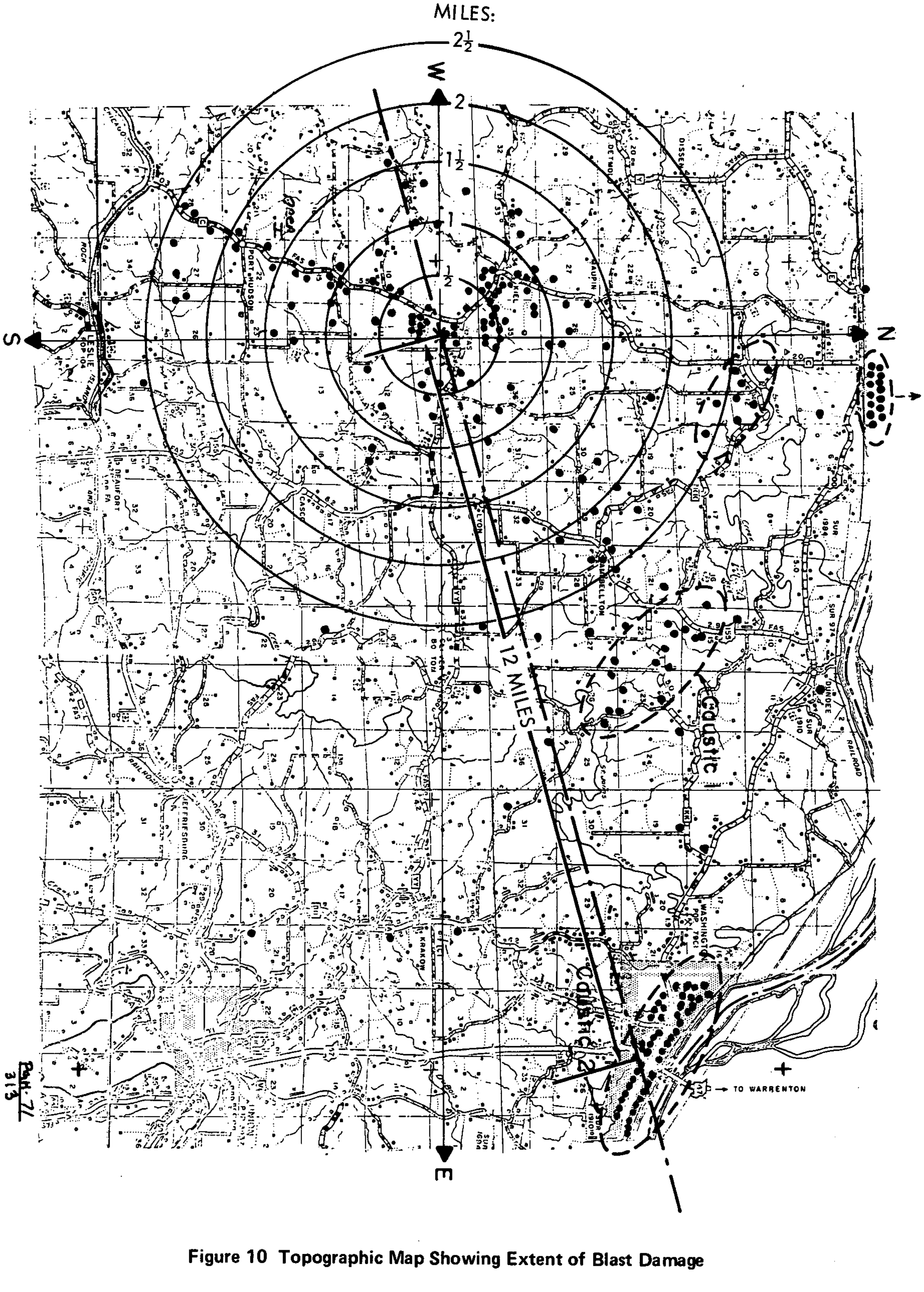


Figure 10 Topographic Map Showing Extent of Blast Damage

Figure 11 Detonation Site Showing Uprooted and Snapped Trees

Figure 12 Origin of Detonation

Figure 13 Farm House Located 1/2 Mile Southeast of Detonation Origin

Higher up along the rim of the valley, the houses along highway YY also took the full brunt of the explosion. Glass riddled walls, broken exposed roof beams, and blown-in window frames were in evidence. Sections of exterior brick and stone walls were torn from their sidings, and other adjacent frame houses were partially blown down.

An on-site inspection of the accident area by an explosives expert from the United States Department of the Interior, Bureau of Mines, revealed that the detonation was the result of ignition of at least 2 million cubic feet of propane and air—enough explosive material to cover a 10-acre tract to a depth of over 4 feet. The force of the blast was equivalent to 100,000 pounds of TNT; enough to create winds with minimum velocities of 70 to 140 m.p.h.; possibly exceeding 200 m.p.h. at the height, and strong enough to snap the handle of a rake. The origin of the blast was the double-walled concrete block warehouse which filled with the propane-air mixture and provided the container necessary for detonation. A contact made by an electric switch on one of the deep-freeze units located inside the warehouse provided the spark to initiate the blast.[7]

E. Standards

1. Industry Standards

At the time Phillips constructed this pipeline in 1931, there were no formal, published industrywide codes in existence for pressure piping, as applied to pipelines. In that era, pipelines were designed, constructed, and operated to the criteria of the respective oil or pipeline companies.

[7] Bureau of Mines, United States Department of the Interior; Detonation of a Flammable Cloud Following a Propane Pipeline Break: Investigation of the December 9, 1970, Explosion in Port Hudson, Missouri, by D. A. Burgess and M. G. Zabetakis.

In 1955 the liquid petroleum pipeline industry decided to develop and publish a separate code basically excerpted from the American Standard Code for Pressure Piping, B31. In 1959, the document became known as the American Standards Association, B31.4-1959, "Oil Transportation Piping" (B31.4 Code). In 1966, the code was again amended, updated and issued as the Code for Pressure Piping, Liquid Petroleum Transportation Piping Systems, USASI (United States of American Standards Institute) B31.4 1966, and was adopted as the industry wide guide for the design, construction, testing, operation and maintenance of pipelines.

The guidelines apply to the maintenance and operating procedures, and to an increase in the pressure used in existing pipelines but not to the design, construction and pressure testing of them.

The code makes no distinction or differentiation between liquefied petroleum products, and the more conventional petroleum products such as gasolines, kerosenes, fuel oils, and crude oils. The design, construction, testing, operation and maintenance guidelines for LPG are neither more nor less stringent than for other petroleum products.

The code was again revised and approved by the American National Standards Institute on January 12, 1971, approximately 1 month after this accident occurred. This new code, the American National Standards Code for Pressure Piping, Liquid Petroleum Transportation Piping Systems, ANSI B31.4-1971, is still not applicable to existing pipelines, as far as the design, construction, and pressure requirements are concerned, and still makes no distinction or differentiation between liquefied petroleum products and conventional petroleum products.

An additional industrywide guide to safe practices is the "Petroleum Safety Data Sheet," PSD 2200, June 1964. Although the material contained therein is not to be regarded as an industry standard, the information was formulated by the American Petroleum Institute for specific use in "Repairs to Crude Oil, Liquefied Petroleum Gas, and Products Pipelines." A special section is devoted solely to the characteristics and special handling required for LPG: pertinent parts from this section are stated in Appendix V.

2. Government Standards

On April 1, 1970, three subparts of the Code of Federal Regulations, (CFR) Title 49, Part 195, "Transportation of Liquids by Pipeline," became effective for the design, construction, operation and maintenance of pipelines. The design and construction sections of these regulations apply only to the pipelines constructed after the effective date of the regulation. The subpart on hydrostatic testing became effective on January 8, 1971.

A new section of 49 CFR 195, 195.406 *Maximum Operating Pressure*, was added, effective January 8, 1971, approximately 1 month after the accident, and states the following:

"195.406 maximum operating pressure.

(a) Except for surge pressures and other variations from normal operations, no carrier may operate a pipeline at a pressure that exceeds any of the following:

1. The internal design pressure of the pipe determined in accordance with 195.106
2. The design pressure of any other component of the pipeline.
3. Eighty percent of the test pressure for any part of the pipeline which has been hydrostatically tested under Subpart E of this part.
4. Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is excepted from testing under 195.304

(b) No carrier may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (a) of this section. Each carrier must provide adequate controls and protective equipment to control the pressure within this limit."

3. Request for Public Advice; Transportation of Highly Volatile Liquids by Pipeline

On April 18, 1969, the Hazardous Materials Regulations Board of the Department of Transportation issued a "Request for Public Advice; Advance Notice of Proposed Rule Making," under 49 CFR Part 180, Docket No. HM-6A, "Transportation of Highly Volatile Liquids By Pipeline." Seven areas for which regulatory actions might be appropriate were discussed. The intent of this request was to develop facts upon which to base rational rulemaking, and was basically twofold: (a) to classify and categorize highly volatile liquids such as LPG and anhydrous ammonia as more hazardous than less volatile petroleum products; and (b) to suggest higher safety standards for them. Among other proposals suggested by the Office of Hazardous Materials were requirements to lower the operating pressure in relation to the test pressure for lines carrying these highly volatile liquids, compared to that for lines carrying the less volatile liquids. Another proposal was to require that all main line valves on LPG systems be either automatic or remotely controlled from manned locations. The distance between valves was also considered a factor under these conditions. Interested persons were requested to submit their views by June 23, 1969, and some comments were received; however, no proposed regulations have been issued in regard to these items.

III ANALYSIS

A. Condition of the Pipeline

This 40-year old uncoated pipeline has been affected by three basic problems; external corrosion, internal corrosion and "cold-stitched" longitudinal welds apparently from its inception. The 680 miles of pipe, from Borger to East St. Louis, is still uncoated and although anodes and rectifiers will reduce the corrosion leak frequency on bare lines, they will not affect the existing pitholes or pipe walls thinned by corrosion—some number of corrosion leaks will probably continue. Additionally, the problem that remains is the unknown number and location of the remaining cold-stitched longitudinal welds in this pipeline which did not fail under the initial hydrostatic test, but which have been exposed to the water-caused internal corrosion for those first 17 years. There exist a number of cold-stitched longitudinal welds which have not failed, yet have progressively deteriorated, but not to the point of rupture. Some of these affected pipe sections may well be located near the discharge side of the pump stations under relatively high pressures, others may be in the lower pressure areas near the suction side of the stations or at the terminals; nevertheless, between failures, the pipeline system is operating in a precarious balance. If the pressures along the system remain relatively stable and do not surge above the normal pressure ranges, and if the internal and external corrosion, no matter how minute, does not continue, the line will probably maintain its integrity. Between 1965 and 1970, there were 12 pipe longitudinal weld failures in this system which show that, even after years of operating a dehydrated pipeline, cold-stitched longitudinal welds weakened by internal corrosion can and do fail.

B. Factors Affecting the Magnitude of the Accident

Conditions are present before an accident occurs which, if taken together with the introduction of a catalyst, become contributing factors to the magnitude of the accident. A series of these conditions were present prior to this pipeline accident.

1. Line Condition at the Time of the Leak

On December 9, 1970, all pump stations from Paola to East St. Louis were pumping on the line and the system was operating at a high pressure and capacity in relation to the past 90-day period. An almost solid stream of liquefied petroleum products was packed into the line and was being pumped at 1,500 barrels (63,000 gallons) per hour.

2. Material Being Pumped

When the line ruptured the pressure on the pipe at that moment blasted the propane out of the pipe and 50 or 60 feet into the air. This upward geyser action had a carburetion effect, mixing air with the pure propane spray, which moved into the valley below. In its pure gaseous state, the more than 1,000,000 cubic feet of highly flammable vapor would be too rich to burn, but the spraying action, the movement down the valley to the point of ignition, and the winds of 5 knots, blended the right amount of air into the vapor to make it explosive.

Liquefied petroleum gases are more hazardous materials than normal petroleum products such as gasoline, kerosene or fuel oil. If the pipeline had been pumping one of the above products other than propane, the initial rupture would have been no less severe, but the product, being a true liquid and almost incompressible, would have released all the pressure almost instantaneously. No continuing geyser, little carburetion effect, and no mass migration of fumes into the valley would have resulted. Even if the product had been gasoline, the number of barrels spilled out would have been fewer and a resultant explosion due to the detonation of the gas-air mixture would have been far less probable. With fuel oil or kerosene virtually no chance of fire or explosion would have existed under these same conditions.

3. Total Amount of Material Released

After the explosion the pipeline continued to leak for three main reasons: (a) some pump stations continued to pump on this line until about 2 minutes before the explosion; (b) the valves above and below the leak were not shut until well after the explosion; and (c) the vaporizing nature of propane enabled it to continue to leak out of the line even after the failed section was isolated.

The first valve was closed at 11:30 p.m., 1 hour and 10 minutes after the split, and the second set of two valves, which isolated the failed section, was closed at 12 p.m. These valves are manually operated and require about 5 minutes each to close. The foreman, together with two workers, drove to the first valve, closed it, and drove to the second set of valves and closed them. If these men had split up and gone as two separate groups in two separate cars to close off one set of valves each, all valves might then have been closed at 11:30 p.m., isolating the failed line section 30 minutes sooner.

4. Main Line Valves

All, or virtually all, of the product isolated between the closed valves, escaped from the pipe at the point of rupture, and burned. If check valves, or automatically or remotely operated valves had been in operation on this pipeline, the failed section would have been blocked off and isolated much sooner. The amount of propane released would have been reduced, and although the explosion may still have occurred, its intensity would have been reduced and the resultant fire would have burned out much sooner. There has been much commentary about allowing a propane pipeline fire, once ignited, to continue to burn, and it is true that this fire was allowed to burn out because (a) in its location it was not causing any additional damage; and (b) in allowing it to burn, all of the escaping propane was accounted for, leaving none to migrate and reignite elsewhere. This, however, was happenstance, instead of planned action, since there is no way available to contain and dispose of the propane. If this same type of fire occurred in a different location—in a small town, in a city suburb, or in the industrial pipeline terminal area, it would present a different situation. In that case, the amount of time required to shut the line down and close the valves could probably be related directly to the number of resultant fatalities and injuries, and to the extent of damage.

5. Delay In Pump Station Shutdown

The quantity of petroleum products lost as a result of a pipeline rupture is dependent on several conditions: the amount of pressure on the failed section, the length of time the pressure is maintained, the size of the rupture, the nature of the escaping material, the amount of this material in the failed pipeline section between the isolating valves and the length of time taken to close these valves. Some of these factors are controllable, some are not.

The amount of pressure exerted on a pipeline is controlled by the pump stations; the sooner the pump stations are shut down, the sooner the pressure drops. The sooner the line valves are closed, the less material escapes. The 22 minutes taken to shut down this failed 8-inch liquefied petroleum pipeline was excessive.

Phillips actually had an advantage in that they were already aware of trouble on the system 13 minutes before the split. At that time, Phillips started slowing the pumps down and adjusting pressures to avoid overstressing this pipe. When this split occurred, they were monitoring the pump stations and watching for pressure or flow abnormalities—they were alerted.

At 10:20 p.m. the pressure had built up between Rosebud and Villa Ridge stations and the pipeline ruptured. The pressure drop was observed at once because Rosebud's pressure happened to be monitored at that moment. Paola, the initial and controlling pump station on the line, did not shut down until 10:30 p.m., 10 minutes after the leak and 9 minutes after the shutdown order. Twelve additional minutes were taken to shut down the remaining pump stations.

A "crash" button, an emergency shutdown device, was installed on the control console at Bartlesville and was designed to shut down any pump station that was on fire. The dispatcher had not been trained in the use of this button and no one had ever practiced shutting down an entire pipeline with it. When the button is activated a pump station is shut down in about 20 seconds. The judgment of the Phillips personnel at the time of this rupture was not to use the "crash" button for shutting down all the pump stations.

When the initial pump station on a pipeline shuts down, the discharge pressure drops off rapidly, causing the next downstream station to lose its suction pressure and shut down. All other downstream pump stations, like falling dominoes, lose pressure and shut down without creating a pressure surge. However, if that initial controlling station does not shut down, care must be exercised in shutting down the downstream pump stations, and pressure must be dropped slowly at any one intermediate station to prevent a pressure surge which might split the line. The 9 minutes taken to get Paola, the initial pump station, off the line was critical in getting this pipeline shut down.

6. Action of The Affected Residents

Some fortunate circumstances occurred which were instrumental in averting fatalities and limiting the number of injured as a result of this accident.

The time of night at which the leak occured, 10:20 p.m., was fortuitous in that adult residents were not yet asleep and they heard the roar of escaping propane soon enough. If these people had not evacuated their homes, but had been indoors at the moment of detonation, the number of injured would have been greater and a number of fatalities probably would have occurred.

The family who owned the house and outbuildings where the detonation originated was not home at this time. Probably no one in that area would have survived the blast.

7. Physical Conditions and Prevailing Weather

Regarding the explosion itself, three factors combined to produce a special condition which intensified the explosion; the existing terrain, the prevailing weather, and the point of ignition. The accident site was similar to that of a shallow bowl with the houses along highway YY at the top and the warehouse at the explosion origin and the small stream at the bottom. The escaping propane flowed down into this bowl and along the stream bed, filled the valley and entered the warehouse. These vapors lay in a "V" shape on the valley floor, with one leg extending southeast along the stream and the other leg extending back northeast toward the split. An estimated 400,000 square feet of ground was covered by this flammable mixture.

A light surface wind helped push the propane down into the valley and on toward the warehouse where the combustible vapors dammed up inside. The wind was just strong enough to mix the vapors with air but not strong enough to dissipate the flammable mixture. The conditions were ideal; on the ground a propane vapor pool filled the valley and built up inside a concrete block warehouse while overhead a temperature inversion had effectively put a lid on the atmosphere which was capable of deflecting upward bound shock waves back to earth. A spark caused by an electrical contact in one of the deep-freeze units inside provided ignition and the entire cloud exploded.

IV CONCLUSIONS

The National Transportation Safety Board concludes that:

1. The Phillips Pipe Line Company's "A" line from Borger, Texas, to East St. Louis, Illinois, in its physical condition

was not safe for the transport of liquefied petroleum gas under the operating pressure in effect at the time of the rupture.

2. The pressure on the failed section of pipe at the time of rupture was higher than that pipe had been subjected to in the recent past.
3. After this accident, Phillips reduced the maximum allowable discharge pressures on this system. The National Transportation Safety Board, in its Safety Recommendation P-71-6 issued on April 27, 1971, recommended a further reduction in pressure. If these pressure reductions had been effected prior to this accident, it would not have occurred at this location.
4. During construction, the longitudinal welds were positioned in the pipeline ditch in a random manner; some were located on the bottom, some on the sides, and some on the top half of the pipe. For about the first 17 years of operation, free water and product-absorbed water were pumped through this pipeline. Some of this water initiated a corrosion attack on the bottom of this pipe, and on those longitudinal welds lying on the bottom.
5. This 40-year old bare pipeline, which contains many imperfectly made longitudinal welds and has internal corrosion problems, has had numerous longitudinal weld failures at various pressures and at various locations along its length. In the 6-year period from 1965 to 1970 inclusive, 12 longitudinal weld failures have occurred, which released more than 39,000 barrels (1,638,000 gallons) of liquefied petroleum products.
6. There remain in this pipeline system an unknown number of faulty longitudinal welds at unknown locations, and in varying stages of deterioration. A newly developed tool has been used by Phillips in an attempt to detect these defective welds. This tool is still in the experimental stage.
7. The delay in shutting down the pipeline and reducing the amount of escaping propane was due to (a) the excessive amount of time taken to shut down the initial pump station on this system; (b) the fear of rupturing the line again at another location by a rapid shutdown of a pump station, creating a pressure surge; and (c) lack of any automatically or remotely operated main line valves to close off and isolate the failed section rapidly.
8. Liquefied petroleum gases are more hazardous than crude oils or other refined products normally transported by pipelines. Little can be done to contain, dispose of, or dissipate the resulting flammable mixture after it leaks from a pipeline. Statistics for the 3 years of 1968, 1969, and 1970 show that LPG leaks represented only 9 percent of the total accidents, but they caused 71 percent of the total deaths, 65 percent of the personal injuries, and 26 percent of the property damage during this same period.
9. The greater hazards inherent in the transportation of LPG by pipeline require a higher degree of safety controls than other petroleum products. Currently there is no major distinction in the regulations.
10. If this type of accident, which consumed over 4,538 barrels of propane and detonated with a force equivalent to 100,000 pounds of TNT, had occurred in a more densely populated area, there would have been numerous fatalities, more injuries, and greater damage.
11. The alertness of a local resident, who heard the roar of escaping propane, and

his determination to warn his neighbors, prevented an accident of even more serious proportions.

12. The volunteer fire companies, the local Sheriff's officers, and the Missouri State Police combined effectively to extinguish the fire, aid and assist the displaced people, and restore and maintain order.

V. PROBABLE CAUSE

The National Transportation Safety Board determines that the probable cause of the accident was the rupture of an insufficiently bonded longitudinal weld, which had been further weakened by internal corrosion. Contributing to the rupture was a pump station which shut down and produced a higher pressure on the failed pipeline section than it had been subjected to during recent operations.

The explosion and fire were caused by the ignition of the released propane which had been confined in a concrete block building. The explosion inside the building initiated a shock wave which caused the detonation of the entire unconfined propane-air cloud.

Contributing to the intensity of the explosion and fire were the weather inversion present at the time, which acted as a lid on the detonation and helped to deflect the resultant forces earthward, the delay in shutting down the pumping stations, and the amount of time taken to close the manually operated valves on either side of the split.

VI RECOMMENDATIONS

The National Transportation Safety Board recommends that:

1. The Federal Railroad Administration of the Department of Transportation:

(a) Review the proposals made by the Hazardous Materials Regulation Board in Docket No. HM-6A on April 18, 1969. Rulemaking should be undertaken to provide for more complete controls for the transportation by pipeline of liquefied petroleum gas. These regulations should include minimum standards for the design, construction, testing, operation, and maintenance of both new and existing pipelines.

(b) Initiate an amendment to the Code of Federal Regulations, Title 49, Section 195.218 *Welding: Seam offset*, to require longitudinal welds to be placed in the upper half of the pipe during construction. Similarly, that in repairs to a pipeline involving pipe replacement, a requirement be issued that the longitudinal welds of replacement pipe be positioned in the upper half.

(c) Conduct a study, in cooperation with sources of qualified pipeline expertise, concerning minimum valve-spacing standards and the use of remotely operated valves, automatically operated valves, and check valves on all liquefied petroleum pipelines. As an adjunct to this, the Safety Board invites attention to a recommendation made in its special study of "Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown."[8]

(d) Undertake a study, in cooperation with sources of qualified pipeline expertise, of the various current practices in the handling, containing, and disposing of liquefied petroleum products resulting from pipeline failures. This study should include such external factors as weather conditions, leak site topography and population density in the vicinty of the leak. Based upon the

[8]Report Number NTSB-PSS-71-1.

results of this study, there should be formulated and added as an amendment to 49 CFR 195, minimum regulations regarding the handling of liquefied petroleum gas as a result of pipeline leaks.

2. The Phillips Pipe Line Company:

(a) Maintain as a maximum, the reduced pumping pressures recommended by the National Transportation Safety Board's Safety Recommendation P-71-6 issued April 27, 1971, which limits to 900 p.s.i.g. the maximum discharge pressures at each of the pump stations between Borger and East St. Louis, as well as Phillip's own pressure limitation of 900 p.s.i.g. on the four pump stations in the affected area; Syracuse, Jefferson City, Rosebud, and Villa Ridge. A 24-hour hydrostatic pressure test equal to 125 percent of the maximum anticipated pressure as specified in the CFR Title 49 Part 195 would be required before this line pressure could be again increased.

(b) Revise their pipeline operating procedures and initiate any equipment changes necessary to reduce substantially the time required to shut down the pump stations. Included in this review and revision should be explicit instructions to the dispatcher for the immediate emergency shutdown of all pump stations together with some means of practicing these procedures.

(c) Institute main line valve changes or modifications needed to reduce substantially the amount of time required to completely block off and isolate a failed pipeline section. Consideration should be given to the use of automatically operated valves, remotely operated valves, or check valves installed at strategic locations on this pipeline. Special consideration should be given to the concentration of population-at-risk along and adjacent to the pipeline right-of-way. The Safety Board invites Phillips attention to the section on the Public-at-Risk in the Safety Board's special study of "Effects of Delay in Shutting Down Failed Pipeline Systems and Methods of Providing Rapid Shutdown."

(d) Provide maps of their pipeline system in sufficient detail to establish clearly the system location with regard to the various affected civil agencies along the right-of-way. These maps should be kept current by the notations of pipeline additions or route changes as required. Specifically recommended to receive this information are the fire departments, both civil and volunteer, the state, county and local police departments, and other agencies concerned with hazardous materials.

(e) Establish a line of communication with the affected civil agencies and all residents along the pipeline right-of-way, by supplying a card or sticker with the names, addresses, and telephone numbers of pipeline personnel to be contacted during an emergency.

(f) Hold periodic meetings to include the local fire departments and other interested agencies, to inform further and educate the attending personnel as to basic pipeline operations, and materials pumped, hazards encountered, and procedures to follow during LPG leaks.

(g) Continue with the experimental work in cooperation with other qualified pipeline groups in testing and developing a tool to detect longitudinal weld defects and thin wall pipe caused by corrosion. Based on the findings, the methods of operation should be incorporated in the pipeline industry standards, as an additional tool for the detection of in-place line pipe flaws, but not as a substitute for hydrostatic testing.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD:

/s/ JOHN H. REED
Chairman

/s/ OSCAR M. LAUREL
Member

/s/ FRANCIS H. McADAMS
Member

/s/ LOUIS M. THAYER
Member

/s/ ISABEL A. BURGESS
Member

March 1, 1972

APPENDIX I

PROBLEMS OF PIPELINE CORROSION

Old, bare pipelines tend to have various kinds of corrosion problems. Pipeline corrosion is a continuing expensive phenomena which costs the industry millions of dollars annually. It is generally caused by the flow of direct current electricity, usually in small quantities. When this condition exists, the minute flow of current causes the metallic atoms to leave the pipe at variable rates, slowly thinning the pipe walls until finally, if the condition is left unchecked, a hole is corroded through the pipe and the petroleum inside escapes. This corrosion process may be fast or slow, depending upon the amount of current flow, and the environmental conditions around the buried line, such as moisture, soil type, and presence of nearby electrical facilities. Additionally, this process can be highly localized wherein the pipe is eaten away at one spot where the ultimate failure occurs in a "pithole," or it can occur over a large area of pipe where, instead of a single "pithole," the entire pipe surface is attacked, thinning the wall, weakening the pipe, and detracting from its pressure carrying capabilities.

The mitigation of this corrosion process is largely centered on controlling the rate of the causative direct current flow. Because it is not economically feasible to uncover an existing uncoated pipeline, clean it, coat it, relay it, and backfill it again, the alternative is to control this current flow by imposing a larger current in the opposite direction–from the surrounding soil back onto the pipe. There are two basic methods of doing this: (a) rectifiers, which use available alternating current and convert it to direct current, are attached to the uncoated pipeline to be protected and a current larger than the current leaving the pipe is generated back onto the pipe, and (b) anodes, usually magnesium ingots packed in an electrolyte are installed in the ground below and beside the pipeline and then wired to it causing a current flow from the soil to the pipe. However, when dealing with uncoated lines, there are some complications. When a current is imposed upon a pipeline by either anodes or rectifiers, the area of pipe protection may be quite small, sometimes only a few feet along the length of the line, thus necessitating many anode installations or more powerful rectifiers. Even when this is accomplished, there are instances where the "hot spot" is moved further on down the pipeline to some new point where the current will again flow from the pipe to the soil, causing a corrosive condition where none may have existed before. In addition to this, anodes after a period of time, are consumed. The situation demands continuous, regular monitoring to determine whether or not their electrical output is still effective and, eventually, it calls for replacement of the anode itself.

Uncoated pipeline systems protected by anodes and rectifiers years after their initial construction are, in a sense, in a delicate corrosion balance; the corrosion damage already done to the pipeline, the "pit holes" and the pipe wall thinning, cannot be undone by cathodic protection, and the moment the cathodic protection devices decrease their electrical output, pipe corrosion may recommence.

UNITED STATES OF AMERICA
NATIONAL TRANSPORTATION SAFETY BOARD
WASHINGTON, D.C.

ISSUED: April 27, 1971

Adopted by the NATIONAL TRANSPORTATION SAFETY BOARD
at its office in Washington, D. C.
on the 19th day of April, 1971.
(second revision)

FORWARDED TO:
Mr. Dean B. Taylor
Executive Vice President
Phillips Pipe Line Company
Bartlesville, Oklahoma 74003

SAFETY RECOMMENDATION P-71-6

This safety recommendation results from the investigation of a products pipeline accident in Franklin County, Missouri, on December 9, 1970, involving a pipeline owned and operated by the Phillips Pipe Line Company.

The National Transportation Safety Board has noted Phillips Pipe Line Company's decision to reduce the pressures on the "A" line between Paola, Kansas, and East St. Louis, Illinois, so that the maximum pressure which can be imposed at the point of the accident will be 777 p.s.i.g., instead of the 942 p.s.i.g. present at the time of failure on December 9, 1970. The Board concurs that the lower pressure should reduce the risk of seam splits in this part of the line, and tend to prevent repetition of the losses resulting from several fires and explosions that have occurred in this section between 1965 and 1970.

It is noted, however, that while the operating pressures on the Borger, Texas, to Paola, Kansas, section of the line have been lowered somewhat, necessitated by the reduced throughput in the Paola to East St. Louis section, the pressures are still above those in the latter section. This is so even though the pipe in both sections is the same age and most of it is of the same manufacture. We recognize that there were fewer split-seam failures per mile in the line between Borger and Paola than in the line between Paola and East St. Louis, both during the initial hydrostatic testing performed in 1931, and in the period between 1965 and 1970. However, the Board notes that the seam failure rate of the line between Borger and Paola for 1965 to 1970 is one failure per year for each 499 miles of line. This compares with an industrywide pipe seam failure rate for 1968 and 1969 of one failure per year for each 5,486 miles of pipe. These failure rates for this line and the industry have been determined by using the maximum number of years for which records of failure are available for each.

The seam failure rate of the Borger-Paola section is, therefore, much higher than that of the industry in general. Thus, even though the pressure has been reduced on the Paola-East St. Louis section where a still higher failure rate existed, the pressure remains at the higher level in the Borger-Paola section. Attached are data used in this comparison.

The Board therefore recommends, because of the risks involved, that:

> The Phillips Pipe Line Company also place a restriction on the operating pressures of the remainder of the pipeline extending from Borger, Texas, to East St. Louis, Illinois. This restriction should have the effect of providing for a maximum discharge pressure of 900 p.s.i.g. at each of the pump stations on the line between Borger and East St. Louis. This restriction need not apply to the Borger pump station due to the fact that the pipe between Borger and the next pump station is of a newer and different type.

The Safety Board considers this to be an interim recommendation pending completion of the Board's current investigation and until more permanent measures adequate to insure safe operations have been determined.

This recommendation will be released to the public on the issue date shown above. No public dissemination of the contents of this document should be made prior to that date. We are sending a copy of this letter to the Federal Railroad Administration and the Office of Pipeline Safety, Department of Transportation.

Reed, Chairman; Laurel, McAdams, Thayer and Burgess, Members, concurred in the above recommendation.

John H. Reed

By: John H. Reed
Chairman

Attachment

ATTACHMENT

1968 Statistics

Accidents resulting from defective pipe seams 1/	31
Number of miles of liquid petroleum pipelines 2/	169307
Resultant number of miles per defective pipe seam accident	5461

1969 Statistics

Accidents resulting from defective pipe seams 3/	31
Number of miles of liquid petroleum pipelines 2/	170824
Resultant number of miles per defective pipe seam accident	5510
Average annual industry-wide number of miles per defective pipe seam accident based on the calendar years of 1968 and 1969	5486
Accidents resulting from defective pipe seams in the Phillips Pipe Line Company's "A" line from Borger, Texas, to Paola, Kansas, from 1965 through 1970 inclusive 4/	5
Borger to Paola = 416 miles ÷ 5 defective pipe seam accidents x 6 years = 499 miles/defective pipe seam accident/year	
Average annual number of miles/defective pipe seam accident in the Borger to Paola section of Phillips Pipe Line Company's "A" line	499

The annual defective pipe seam accident rate in the Borger to Paola "A" line is 11 times that of the comparable industry-wide rate

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1/ Information obtained from exhibit 1G "Summary of Liquid Pipeline Accidents Reported On DOT Form 7000-1 From January 1, 1968, Through December 31, 1968.

2/ Information obtained from "Transportation Statistics, Part 6, Oil Pipe Lines", prepared by the Bureau of Accounts, Interstate Commerce Commission.

3/ Information obtained from exhibit 1G-1 "Summary of Liquid Pipeline Accidents Reported on DOT Form 7000-1 From January 1, 1969, Through December 31, 1969.

4/ Information obtained from exhibit 3E-2 "A Line Maintenance and Leak Reports Linalog" prepared by Phillips Pipe Line Company as part of the record "In the matter of the investigation of a Products Pipeline Accident in Franklin County, Missouri, on December 9, 1970."

PHILLIPS PIPE LINE COMPANY
BARTLESVILLE, OKLAHOMA 74003

August 2, 1971

National Transportation Safety Board
Department of Transportation
Washington, D. C. 20591

Attention: John H. Reed, Chairman

Gentlemen:

This is to advise you that Phillips Pipe Line Company is raising the discharge pressures at its pump stations between MP 195 and MP 313 on the "A" line products system between Borger, Texas, and East Chicago, Indiana, from 900 to 1080 psig.

This portion of the line is A. O. Smith pipe on which Phillips Pipe Line has never experienced any split or seam problems. After reviewing the operational history and inspecting portions of this section by a nondestructive type instrument or hydrostatic testing, Phillips Pipe Line is convinced that there is no risk of longitudinal seam splits on this portion of the line by operating the pump stations therein at 1080 psig discharge pressure.

Yours very truly,

D. B. Taylor

D. B. Taylor

DBT:rac

cc: Federal Railroad Administration

PHILLIPS PIPE LINE COMPANY

BARTLESVILLE, OKLAHOMA 74003

November 24, 1971

Department of Transportation
National Transportation Safety Board
Washington, D. C. 20591

Attention: Mr. Henry Shepard

Gentlemen:

Since 1969, Phillips Pipe Line Company (Phillips) has been embarked on a program of nondestructive testing of the products pipeline between Borger, Texas, and East Chicago, Indiana. As part of this program Phillips, in conjunction with AMF Tuboscope, Inc., has developed a tool for the purpose of locating longitudinal defects in the pipeline. The prototype of this tool was first field tested starting in September, 1969 and was operational in October, 1970. The tool is run through the pipeline and records on a tape longitudinal defects in the wall thickness of the pipe. The recordings on the tape have been correlated with hydrostatic testing in the following manner:

1. After the tool had been run through a test section of the pipeline in Franklin County, Missouri (the Rosebud Loop consisting of 16 miles), the tape was interpreted and where interpretations showed anomalies in the pipe, the pipeline was uncovered at such points and physically inspected visually, by X-Ray, with ultra-sonics and by magnetic particles to determine and classify the type of anomaly which had been recorded on the tape. Where these inspections indicated the need of repair the same was accomplished. Where such inspections would not reveal the degree of the anomaly for proper classification, joints of the pipe were physically removed from the pipeline and placed on a test block for hydrostatic pressure tests. The hydrostatic test pressure was increased up to the point of failure of the pipe joint and a direct correlation was made between the tape indication and the actual defect. The test section of the line was then hydrostatically tested before it was put back into operation.

2. After step one was completed the tape was interpreted on another test section of the pipeline in Franklin County, Missouri (the single line section from Rosebud to Villa Ridge consisting of 20 miles) and repairs were made only at the points where anomalies of the type discovered in step one showed repairs were indicated. The second test

section was then hydrostatically tested, but due to operational requirements a 24 hour test was not completed before it was put back into operation. When operational requirements permit, this section will be hydrostatically tested for a full 24 hour period.

3. After steps one and two had been completed, a third test section was selected where interpretations of the tape for that section showed that there were no defects which would prevent operating the line at a maximum operating pressure of 1,100 pounds. Hydrostatic testing of such section proved the tape interpretations, (Syracuse loop consisting of 20 miles).

4. Hydrostatic testing of the three test sections assures that those sections may be operated at a maximum operating pressure of 1,100 pounds. Tape interpretations for all other sections of the pipeline across the State of Missouri show that the pipeline is operating well within safety limits at anoperating pressure of 900 pounds, and probably would qualify for a operating pressure of 1,100 pounds.

Nevertheless, after consideration of all anomalies shown by the tape interpretations, and out of a sense of caution, repairs have been scheduled on other sections in Missouri so that, after such repairs have been made and based upon the correlation between hydrostatic testing and tape interpretations, all sections of the line in the State of Missouri will definitely qualify for a maximum operating pressure of 1,100 pounds and will withstand hydrostatic tests at 125% of the maximum operating pressure.

Because of the extensive block and hydrostatic testing done for the purpose of evaluating the tool, we pressured the line up to failure in several instances. However no failures occurred outside the range of 136% - 250% of the present maximum operating pressures of the line.

Tapes have been received in our office on all other sections of the "A" line containing ERW pipe. However, due to our concentration of testing and taping in the Missouri area, a detailed interpretation of such tapes has not been completed. But a preliminary review of such tapes does not indicate the need for any repair to maintain the present operating level.

The above information has been furnished you at your request to bring you up to date on our line testing. However, it is requested that no portion of this report be quoted out of context.

Very truly yours,

HLSparkes

H. L. Sparkes
Director Pipeline Protection

HLS:rac

APPENDIX V

CHARACTERISTICS AND SPECIAL HANDLING OF LIQUEFIED PETROLEUM PRODUCTS

THE PETROLEUM SAFETY DATA SHEET PSD 2200 JUNE 1964 CONTAINS A SPECIAL SECTION DELEGATED SOLELY TO LIQUEFIED PETROLEUM PRODUCTS; PERTINENT PARTS FROM THIS SECTION FOLLOW:

"4. Liquefied Petroleum Gas Pipelines

4.1 **General Conditions**

4.10 Methods and procedures set forth in the preceding sections are, in general applicable to the repair of pipelines handling liquefied petroleum gases, commonly referred to as LPG. However, as indicated by the following table of physical properties for propane and butane, these materials have substantially greater volatility than crude oil or gasoline, and additional precautions may be required when leaks occur."

"4.11 Because LPG materials have boiling points well below usual ambient temperatures, any liquid which is released as a result of a leak will almost immediately convert to vapor. Furthermore, the vapor equivalent of liquid for LPG materials is such that a flammable atmosphere can be created over a large area as the result of a relatively small release of liquid. For example, when vaporized and mixed with air in proportions corresponding to the lower flammable limit, 1 gallon of butane will create a flammable atmosphere to a depth of about 3 feet over an area 25 feet in diameter."

"4.13 Another important characteristic of LPG materials, from the standpoint of potential hazards associated with a leak is that their vapors, like those of gasoline, are heavier than air and thus tend to remain close to the ground. Therefore, the precautions outlined in paragraph 3.4 will be especially applicable with regard to LPG leaks."

"3.4 Surface terrain, direction and velocity of prevailing winds, and proximity to possible sources of ignition, such as may be found on highways, railroads, or in residences should be observed by the supervisor. Road blocks should be set up immediately if considered necessary in his judgment. A "wind sock" may be erected to assist in detecting changes in air currents."

"4.14 Vaporization of LPG issuing from a leak may freeze the surrounding ground and cause excavation to be difficult. This refrigerating effect can also cause a "freezing burn" or frostbite in the event of bodily contact with the escaping material."