1920s 1930s 1940s 1950s 1960s 1970s 1980s 1990s

Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction

A Report Prepared by

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FOREWORD

Our vision is an oil pipeline industry that –

- *Conducts operations safely and with respect for the environment;*
- *Respects the privilege to operate granted to it by the public; and*
- *Provides reliable transportation of crude oil and refined products upon which America and all Americans rely.*

This report, sponsored by the oil pipeline industry, provides new information on the characteristics of the national oil pipeline network and puts that information in context so that operators can use it to assess risk factors in their systems and improve safety performance.

To achieve improved performance, the oil pipeline industry agreed on the need to develop a better understanding of the safety record, including how it has changed and why and what that implies for further improvement; expand the reporting of incidents; and develop materials (reports and presentations) that the oil pipeline industry can use to improve performance.

One key component of the oil pipeline industry's work was the implementation of the Pipeline Performance Tracking System (PPTS), a voluntary and comprehensive reporting system that began receiving data on spills and pipeline infrastructure in 1999. The PPTS form for reporting incidents was carefully crafted to assess the implications for operations and the impacts of incidents, as well as prioritize risk mitigation strategies. PPTS also includes the first-ever survey of the oil pipeline industry's infrastructure, including onshore and offshore mileage, mileage by decade of construction, mileage by diameter and other features of the infrastructure.

This report integrates one aspect of the infrastructure survey – mileage by decade of construction – with 15 years of accident data reported to the federal government. We chose to conduct this particular analysis because the topic of aging of various parts of the U.S. infrastructure – bridges, highways, airports and pipelines – is on the minds of many Americans, including those who manage pipeline operations.

This report, *Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction*, provides a description of the technologies, materials and construction practices and their evolution over time, including a discussion of the physical properties of steel. It describes and analyzes the safety performance of today's nationwide oil pipeline system as a function of the decade in which various portions of that system were originally constructed. Importantly, the report provides a set of findings and recommendations that pipeline operators can use to assess pipeline characteristics and develop strategies to reduce risk over time.

EXECUTIVE SUMMARY

This report uses newly available data on pipeline mileage by decade of construction to illustrate the impact of various advances in pipeline construction and maintenance over time and it discusses the testing and maintenance practices that allow pipelines to provide safe and reliable performance.

Over the decades, technological advances or changes in practices have eliminated or reduced risks associated with specific characteristics in operations (or pipe manufacturing technology or pipe installation practices). Some of these advances have occurred during a relatively short window of time, so pipelines constructed after the advance exhibit markedly improved performance. With the perspective of these advances, one can adequately assess the pipeline-specific risk factors, and with the information on when the advances occurred, one can illustrate the impact of the advance on performance. The combination can provide a tool for pipeline operators to assess risk factors in their systems and to prioritize mitigation programs.

This study provides an analysis of the advances and their impacts, including:

- The history of pipe and pipeline technology, techniques and practices, highlighting developments across the decades;
- New data on pipeline mileage by decade of construction collected in the oil pipeline industry's voluntary reporting initiative;
- Analysis of existing data on safety incidents by decade of construction relative to the new data on mileage and the historical perspective on technology and practices.

The oil pipeline industry began a voluntary reporting initiative, the "Pipeline Performance Tracking System" (PPTS), in 1998. The oil pipeline industry's goal in implementing the reporting initiative was to create a tool for achieving improved safety performance and a reduction in operational errors. Accurate and detailed data are key both to learning from incidents so operations can be modified for prevention and to tracking progress over time.

This groundbreaking reporting regime collects data on spills as small as 5 gallons, marking the first time that information on such small releases has been collected industry-wide. It also collected new information on the industry's infrastructure, including the mileage by decade of construction, the mileage by state, the mileage by diameter, as well as other features of the infrastructure. The availability of PPTS mileage information presented a first-ever opportunity to analyze existing, publicly available incident data, illustrating the impact of the advances in technology and practices on performance.

The broad outline of the risk factors and historical advances in addressing them fall into just a few categories: the properties of steel, developments in pipe manufacture (forming a piece of steel into a cylinder with a defect-free longitudinal seam), developments in joining segments of pipe (girth welds), developments in corrosion control, developments in inspection and maintenance practices, and developments in industry standards and government regulations. There are other risk factors, of course, ranging from human error to acts of God. These apply to all pipelines, regardless of when the systems were constructed.

Why Steel?

The first section of the study addresses the unique qualities of steel that make it the best choice for pipe manufacture. The low carbon or low alloy steel used for pipelines is strong, resistant to defects, and relatively easy to fabricate into pipes and pipelines. In ideal conditions, the properties of steel do not degrade with the passage of time. However, steel pipe can corrode in service and may suffer degradation from defects created during manufacturing or construction, or from the effects of careless excavations. It is also possible to prevent spills related to these factors by inspecting and testing pipe as it is being made and installed, by protecting it from corrosion, by protecting it from excavation damage and by performing periodic in-service inspections or tests to locate damaged areas and repair them.

Evolution of Pipeline Technology

The second section of the study reviews the development in pipe manufacture, pipeline construction, and operating practices. ***In the late 1920s***, when the first major pipeline construction boom began, manufacturers began to form pipe with electric resistance-welded or flash-welded processes, a significant advance in the reliability of the longitudinal seam, and the electric arc girth weld was developed, a significant improvement over acetylene girth welds in use previously. Simultaneously, the industry began to develop material-quality standards and consensus standards for the safe design, construction, operation, and maintenance of pipelines. ***In the late 1940s***, pipeline operators began to employ cathodic protection for new pipeline construction, a breakthrough in the understanding and control of corrosion. ***By the late 1950s***, even the older existing pipelines were equipped with cathodic-protection systems to mitigate corrosion. Operators began to radiograph girth welds as the pipeline was being installed, and imposed welder qualification and procedure qualification standards, both measures improving the reliability of the girth welds.

By the late 1960s, manufacturers began to use low alloy or low carbon steels exclusively, in tougher grades, resulting in steel with fewer defects. They also began to form the pipe using a high frequency electric resistance weld, increasing the reliability of the longitudinal seam. Pipeline operators began to test all new construction with a hydrostatic pressure test, assuring the soundness of the pipe before it was put into service. Manufacturers universally applied improved coatings to new pipe, another advance in corrosion control. New "in-line" tools became available that allowed inspection for corrosion and other developing defects while the pipeline remained in service. The "smart pig," first introduced in 1965, is now a generic name for a number of in-line inspection tools that have become increasingly sophisticated over the years, targeting specific types of defects with more accuracy.

By the late 1990s, anti-corrosion coatings had improved further, and are tested before being placed in service to ensure that they have not been damaged during transport and construction. Pipelines are now installed with deeper cover, and bored crossings under highways and rivers provide greater protection and less potential for damage during installation. In-line inspection tools have evolved to locate corroded areas before they fail, and technology for finding and evaluating other types of defects is evolving rapidly. These advances improve the performance of pipelines of any age. It is now possible to ensure the continuing integrity of a pipeline by means of periodic tests and inspections where pipeline attributes and service histories indicate there is a need.

Safety Performance by Decade of Construction

The third section of the study compares the safety incident record by decade of construction with the pipeline mileage submitted to the voluntary reporting initiative, PPTS. Thirty-three pipeline operators submitted decade of construction detail on 143,647 miles of pipelines (more than 90 percent of the pipeline mileage on which the Office of Pipeline Safety collects User Fee Assessments, and about 72 percent of the U.S. total mileage for oil pipelines). As shown in the table below, the most important decades for the construction of the pipelines currently in service were the 1950s (22% of the total in service) and the 1960s (23%). The development of long-distance, large-diameter pipelines during and after World War II placed the pipeline industry in a position to fuel the post-War boom. The third-ranked decade was the 1970s (17% of the total). These three largest decades account for the construction of more than 60% of the miles of pipeline in service.

Operators of hazardous liquid pipelines – those transporting crude oil, refined petroleum products, and highly volatile liquids such as propane – are subject to regulation by the Department of Transportation's Office of Pipeline Safety (OPS) with respect to safety and operations. They file reports of safety incidents with OPS on Form 7000-1. The American Society of Mechanical Engineers' B31.4 Committee on oil pipeline operations audits these submissions and reclassifies incident causes from the seven broad categories required by the Office of Pipeline Safety to 20 narrower categories capturing the operations implications of the hazards represented. This report uses the OPS database of incidents as reclassified by the ASME's B31.4 Committee over the 1986-99 period, the period during which the data are available on a consistent annual basis. The comparison uses only those incidents that occurred on line pipe, as opposed to other parts of the system such as tank farms or pumping stations, and only those incidents where the year of installation was reported. Over the 1986-99 period, there were 1,788 line pipe incidents reported and the year of installation was reported on 1,669 (93%) of them. The total number of incidents used for comparison is thus 1,669.

As shown in the table, third party damage – damage inflicted by excavation or construction activity, farming, or other digging or boring activities – accounts for the largest share of the incidents, 29%. The second largest cause is external corrosion at 27%. In this report, specific causes have been tested against the mileage data by decade of construction. For instance, defective pipe and defective pipe seam failures generally reflect pre-service conditions, in that the defect is related to the manufacture of the pipe; as pipe manufacture and pre-service testing improves, so should the performance of pipe manufactured and tested with advanced techniques. External corrosion, in contrast, reflects both pre-service conditions such as the control measures originally installed, and in-service conditions, including repair and renovation.

We compared the share of miles for a given decade with the share of incidents for that decade. If the shares were the same, such as 22% of the mileage and 22% of the incidents, the ratio of the two shares would be 1.0, indicating performance commensurate with the decade's miles. A ratio higher than 1.0 indicates relatively more incidents per mile than commensurate and a ratio lower than 1.0 indicates relatively fewer incidents per mile than commensurate.

In summary,

- Only the earliest pipe – that installed before 1930 – shows a consistently higher number of incidents per mile than commensurate with its miles across causes.

- Pipe installed in the 1950s and 1960s – the most important decades for pipeline construction – shows a number of spills per mile that is about commensurate.

- Pipe installed since 1970 shows a lower number of spills than commensurate.

There are a variety of factors that support these broad conclusions. With respect to the pipelines installed prior to 1930, for instance, pipe manufacturers had not developed a seam that would be as strong as the pipe's steel until the end of the 1920s, contributing to failures due to "defective pipe" and "defective pipe seam" in the earlier pipe. The end of 1920s also saw the development of electric arc girth welds for connecting one pipe segment to another, replacing use of collars or the relatively less satisfactory acetylene girth welds. Pipelines constructed during the early period were also generally installed without coatings and cathodic protection, contributing to failures due to external corrosion. In fact, the performance by decade for external corrosion is worthy of particular note. Pipelines installed in the 1950s – now 40-50 years old – do not show a high rate of corrosion. Instead, the construction periods that exhibit the higher rates of external corrosion were decades when prevailing practices did not include corrosion control, pre-1930s, 1930s, and 1940s. (Most went through subsequent reconditioning and upgrades, however, and OPS regulations now require that pipeline systems have a cathodic protection system installed.)

In the most recent decades, pipe manufacture, construction and maintenance have embraced a number of improvements that make the pipe less likely to fail and the system less vulnerable. These include: more thorough use of non-destructive testing during construction, such as radiography and coating inspection; greater depth of cover; greater use of boring or directional drilling; greater use of pipeline corridors; backfilling techniques to protect the pipeline while filling the trench; more effective, less vulnerable coatings; and more identifying markers along pipeline rights of way.

Comparison of Pipeline Performance by Decade of Construction by Cause of Incident

		Pre 1930s	1930s	1940s	1950s	1960s	1970s	1980s	1990s
Share of Miles	%	2	7	13	22	23	17	9	7
All Incidents (1,669)	Incident %/ Miles %	>4.0	1.2	1.1	0.9	1.0	0.7	0.8	0.5
External Corrosion Incidents (450)	Incident %/ Miles %	>4.0	2.2	1.4	0.7	0.9	0.5	0.6	0.1
Internal Corrosion Incidents (85)	Incident %/ Miles %	>4.0	1.2	0.3	1.1	0.8	0.9	1.4	0.7
Defective Pipe/Seam Incidents (128)	Incident %/ Miles %	3.1	0.5	0.7	1.7	1.6	0.1	0.3	0.0
Defective Weld Incidents (53)	Incident %/ Miles %	>4.0	1.2	1.1	1.2	0.8	0.7	0.7	0.5
Third-Party Damage Incidents (476)	Incident %/ Miles %	4.0	1.0	1.5	1.0	1.0	0.7	0.6	0.3

Values shown should be interpreted as relative indicators because of data limitations. Values for the 1990s are understated because all pipe was not in place for all years.

General Findings

This examination of the industry's advances in technology and practices has resulted in some specific guidelines that operators can use to prioritize their risk assessment and mitigation efforts. These targeted recommendations are shown in the section *Findings and Recommendations.* The general findings are as follows:

- Age – the number of years a pipeline has been in service – is an unreliable indicator of the condition of a pipeline system. A better first indicator is the technologies that are represented in the manufacture and construction of the system when it was first placed in service. Even the decade of original construction, however, is only a first indicator. Also critical to a pipeline's condition are the renovation, inspection, and maintenance practices that have been applied since construction.

- Industry-wide information comparing the performance of pipeline systems based on the decade in which a system was constructed provides important broad indicators for operators to examine further in assessing their own systems.

- Specific techniques can prevent or slow deterioration in pipeline systems. Hence, determining the specific types of deterioration that a pipeline system or pipeline segment may experience over time is an important aspect of conducting pipeline-specific risk assessments.

- Pipeline systems constructed in any decade can provide safe and reliable performance with the application of current testing and monitoring techniques, and with an appropriate program of assessment and mitigation as necessary.

INTRODUCTION

The topic of aging of various parts of the U.S. infrastructure – bridges, highways, airports and pipelines – is on the minds of many Americans, including those who manage pipeline operations. This report is part of the oil pipeline industry's continuing effort to assist operators in evaluating pipeline systems and improving performance.

The oil pipeline industry, as individual operators and as a whole, has instituted a number of programs to improve its safety performance. Some of these have included increased and more sophisticated inspection to evaluate the condition of pipe in the ground, prevention programs to reduce the risk of excavation and other third party damage, and construction practices that better protect the lines from damage during and after construction. In addition, oil pipeline operators have committed themselves to a new generation of integrity management programs, using cross-cutting information about all aspects of their operations to assess and reduce the risk of failures in their systems.

The oil pipeline industry began a voluntary reporting initiative, the "Pipeline Performance Tracking System" (PPTS), in 1998. The industry's goal in implementing the reporting program was to create a tool for achieving improved safety performance using the information to drive to zero spills. Accurate and detailed data are key both to learning from incidents so operations can be modified for prevention and to tracking progress over time. This groundbreaking reporting regime collects data on spills as small as 5 gallons, marking the first time that information on such small releases has been collected industry-wide.[1] It also collected new information on the industry's infrastructure, including the mileage by decade of construction, the mileage by state, the mileage by diameter, as well as other features of the infrastructure.

[1] As of early 2002, the U.S. Department of Transportation's Office of Pipeline Safety has lowered the federal reporting threshold to 5 gallons and will collect significantly more detail than in the past.

This report is one of the first efforts to provide this new information to a wide audience, allowing operators to integrate new understanding into their risk assessments and therefore better prioritize mitigation and improvement programs.

Over the decades, the oil pipeline industry has reduced the risk of operations by advances in pipe manufacturing technology and changes in pipeline construction practices. Some of these advances have occurred during a relatively short window of time, so pipelines constructed after the advance exhibit markedly improved performance. Without the perspective of these advances one cannot adequately assess the pipeline-specific risk factors, and without the information on when the advances occurred, one cannot illustrate the impact of the advance on performance. The availability of PPTS mileage information presented a first-ever opportunity to analyze existing, publicly available incident data, illustrating the impact of the advances in technology and practices on performance.

This report provides new perspective on the timing of the advances and their impact on risk in several ways.

- In the section *Why Steel*, we discuss the properties of steel and its use in pipe manufacture.

- In the section *Evolution of Pipeline Technology*, we offer a narrative on the most important advances in technology and practices and their timing over the decades. This discourse explores the developments in pipe manufacture, pipeline construction practices, corrosion control, inspection, maintenance, as well as industry and regulatory standards.

- In the section *Safety Performance by Decade of Construction*, we illustrate the impact of technological advances by comparing the pipeline mileage data submitted to the industry's voluntary initiative with the record of accidents reported to the U.S. Department of Transportation's Office of Pipeline Safety. These incident data, covering incidents that occurred over the 1986-99 period, reflect the ongoing review by a committee of experts from the American Society of Mechanical Engineers, B31.4 Committee. [2] This review included classification of accidents into the 20 risk factors recognized by ASME.

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[2] ASME is a professional engineering society and the B31.4 Committee is responsible for maintaining the basic design, construction, operations and maintenance code for hazardous liquid pipelines systems. The results of this review for incidents occurring from 1986-1996 have been published previously in a report funded jointly by the Office of Pipeline Safety and the American Petroleum Institute. See J.F. Kiefner, B.A. Kiefner and P.H. Vieth, "Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996," API Publication 1158, 1999.

- To aid the reader in navigating this crosscutting approach, we have provided a *Summary of Practices and Developments*.

- In addition, we have provided an appendix of the technological milestones and a glossary.

The analyses presented in this report were conducted and authored by Cheryl J. Trench, Allegro Energy Group, and John F. Kiefner, Kiefner & Associates.

For additional information on the safety incident record of oil pipelines, the reader may see

- J. F. Kiefner, B. A. Kiefner and P. H. Vieth, "Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996," API Publication 1158, 1999. This report is available from API's Global Engineering Documents at 1-800-854-7179 or at http://www.global.ihs.com/.

- C. J. Trench, "The U.S. Oil Pipeline Industry's Safety Performance," December 2001. This report is available at http://www.aopl.org/.

WHY STEEL: STRENGTH, TOUGHNESS, DUCTILITY AND WELDABILITY

Low-carbon or low-alloy steel for pipelines

Line pipe for constructing oil and gas pipelines is made from steel, and in particular, either low-carbon steel or low-alloy steel. These two types of materials are primarily composed of iron (98 to 99 percent iron), but small amounts of carbon (0.001 to 0.30 percent by weight), manganese (0.30 to 1.50 percent by weight), and other intentionally added alloying elements in small amounts (columbium, molybdenum, vanadium, titanium) can have beneficial effects on the strength and toughness of steel. ("Toughness" is the ability to resist crack propagation.) Low-carbon or low-alloy steels are suitable for line-pipe materials and most other steel structures such as buildings or bridges because they provide a durable, strong material to withstand the service loads imposed on such structures. Other iron-based materials such as wrought iron (almost pure iron) and cast iron (usually a relatively high-carbon material) are either too low strength or too brittle to function well as structural materials. Stainless or high-alloy steels are essential for special applications such as in high-temperature piping and pressure vessels or tool steels, but they are not suitable and cannot be made economically in the quantities needed for use in structures including pipelines. Only low-carbon steels or low-alloy steels offer the appropriate ranges of desirable properties (*i.e.*, strength, toughness, ductility, and weldability) that are required for structural applications.

Time and Steel

Line-pipe steels, that is, low-carbon or low-alloy steels, are durable. Over the ranges of temperatures in which they are commonly utilized (-20°F to +250°F), these materials are stable: their properties do not change with the passage of time. Tensile tests or toughness tests conducted today on a low-carbon-steel material manufactured in 1910 will yield the similar results as tests that might have been conducted on the same material back in 1910.

Corrosion Control

Low-carbon and low-alloy steels are susceptible to oxidation (*i.e.*, corrosion) in air, water, or soil environments. They can be satisfactorily protected from corrosion by suitable coatings and by the application of an appropriate level of electrical direct current referred to as cathodic protection (when buried in soils or submerged in water). Corrosion takes place when electrons in the steel flow away from an exposed surface causing the iron to become oxidized. The oxides of iron are weak and brittle, and cannot carry the loads that are successfully borne by the steel structure; hence, corrosion can reduce the strength of a low-carbon or low-alloy steel structure such as a pipeline. Supplying a proper amount of cathodic protection to an exposed steel surface, however, mitigates the loss of electrons, slowing the corrosion to an insignificant rate. A protective coating applied to steel also prevents corrosion by eliminating exposed surfaces. Periodic pipe-to-soil potential surveys are used to measure the level of cathodic protection. Thus, pipe that is adequately coated and cathodically protected, as well as properly inspected and maintained, will not be degraded by corrosion.

Stress Cycles

Low-carbon and low-alloy steels can survive unlimited numbers of cycles of loading and unloading within design stress limits. In the presence of a flaw or defect, however, the application of repeated loadings – typically many thousands of cycles – may cause fatigue crack growth that may lead to an eventual failure of the structure. The phenomenon is controlled through design codes, initial manufacturing quality-assurance measures, and pre-service hydrostatic testing. In-service inspections (discussed below) can detect the presence and indicate the size of many types of flaws, which can then be removed or repaired before they become severe enough to cause an in-service failure.

Manufacture and Fabrication

Methods for making line-pipe steels and line pipe have evolved over the years such that the levels of strength, toughness, ductility and weldability have increased. Improved materials manufacturing processes and quality-assurance measures have resulted in very few, and even less injurious, manufacturing defects. Since the late 1960s, pipeline operators have routinely conducted pre-service hydrostatic pressure tests of newly constructed pipelines to demonstrate their fitness for service. In addition, by regulation, pipelines that were not tested at the time of installation have been temporarily taken out of service so that they can be pressure tested. Hydrostatic testing is a destructive test that either exposes defects that result in a failure at the test pressure or proves that those flaws remaining after the test are small enough to withstand the maximum operating pressure level. (Future inspection and testing may be necessary to detect imperfections that may become enlarged by fatigue cracking, however.)

Inspection and Testing

In the last four decades, the pipeline industry has developed a battery of non-destructive tests and “in-line” inspection tools to identify anomalies and flaws in the pipe or the coating. Prior to burying a new line, for instance, the operator tests the coating for any damage that may have occurred during installation. The first of the in-line inspection tools was the so-called “smart pig,” developed in the mid-1960s. Smart pigs are a series of instrumented modules that travel through the pipeline with the oil. The instruments record corrosion pitting, dents, and other imperfections based either on ultrasonic wall thickness measurements or disturbances in an induced magnetic field. Computer and other technological improvements have made instrumented pigs smarter, both increasing the data points available and the ability to interpret them. GPS positioning can now help pinpoint the location of a pipeline wall anomaly, indicating where increased cathodic protection or even repair may be warranted. Additional enhanced tools now can identify specialized anomalies such as fatigue cracks, and others can examine whether a pipe has been dented or damaged.

Implications for Pipeline Safety

The main points concerning the durability of steel as it affects pipeline safety are as follows. First, as noted above, the steel itself does not degrade with the passage of time. Eighty-year-old pipe, if properly protected, exhibits the same properties if tested today as it would have if tested 80 years ago.

Technological advances ensure that a line-pipe material made with modern technology has performance characteristics superior to that manufactured with techniques in use 80 years ago, however, and superior maintenance strategies have emerged in the intervening years. Second, while the lower initial performance characteristics of older materials and their possible exposure to in-service degradation (before cathodic protection, for instance) is a concern, current inspections and/or testing of pipelines comprised of older materials are used to detect potential problems before failure. Third, the continued satisfactory performance of any pipeline, old or new, requires levels of inspection and maintenance appropriate to the performance characteristics of the materials and the severity of degrading factors to which the pipeline has been exposed in its operating environment. Finally, new technology can identify and characterize ever-smaller defects, thus improving performance further.

EVOLUTION OF PIPELINE TECHNOLOGY

An Abbreviated History of Advances in

Oil Pipeline Manufacture, Construction, and Inspection

Early pipelines in the United States were installed to carry manufactured gas for gas lighting purposes in major cities. These systems appeared early in the 19th century. The systems were often comprised of cast-iron pipe (first made in the U.S. in 1834) with bell-and-spigot joints sealed with rope or jute packing and molten lead. Pipes made of wrought iron and joined by screwed collars were also used in gas applications.

After oil was discovered in Pennsylvania in 1858, a new use for pipe and pipelines soon emerged. The first successful oil pipeline, a 2-1/2-mile-long 2-inch-diameter pipeline was laid in 1863. It moved 800 barrels (33,600 gallons) of oil per day. The threaded pieces of pipe were joined end-to-end by screwed collars.

Over the years, manufacturing and construction practices effectively addressed and reduced a variety of risk factors. These include:

- Improvements in the performance of the material and in manufacturing pipe (forming the cylinder) reduced the likelihood of failures in the pipe material or the manufactured longitudinal seam;

- Improvements in installing pipelines (*i.e.*, connecting one piece of pipe to the next) reduced the likelihood of failures in the weld around the circumference of the pipe;

- Improvements in controlling the factors that cause defects and degradation in the service environment reduced the likelihood of failures due to external corrosion; and

- Improvements in testing, inspecting, protecting, and maintaining pipelines reduced the likelihood of failures due to a variety of causes, even third party damage, the largest cause of line pipe safety incidents.

Some of these advances were developed and proven over relatively short periods, and were thus quickly adopted. The performance of advanced systems is demonstrably improved over systems not utilizing the newer technology or practice. Understanding the advances and eras during which they were adopted can help operators assess their system's risks and prioritize mitigation measures.

This section discusses the advances in manufacturing, construction, corrosion control, and testing and inspection over the last century. There are hyperlinks in the text to more technical explanations of manufacturing techniques, and there is a glossary at the end of this paper for the reader's reference.

Early Challenge: Forming the Cylinder

One of the earliest challenges facing the industry was how to create a cylinder from flat steel sheets that could be used for pipe. The quality of the resulting "longitudinal seam" depended on the successful bonding of the abutted edges. In early pipe, this longitudinal seam was not consistently reliable, creating a risk factor for failure.

Manufacturers used a process called furnace butt-welding (see explanation in the adjacent text box) to form the early pipe, using 20-foot lengths of wrought iron tube. Burst tests of furnace butt-welded tubes revealed that the bondline – the longitudinal seam – on the average would fail at about 70 percent of the burst strength of the pipe material itself (determined on the basis of burst tests of samples with "perfect" bondlines, which failed somewhere other than the bondline). Thus, the early pipeline builders used a "joint factor" of 0.6 to provide a safety factor on operating pressure for furnace butt-welded tubing. The minimum yield strength level of the wrought-iron tubes was 25,000 psi. Following the development of Bessemer steel in 1856, pipe manufacturers increasingly turned to

Pipeline Manufacturing Methods at a Glance

In the ***furnace butt-welding process***, the wrought-iron tubes were hot formed from 20-foot-long (random lengths) of flat stock (called skelp) into round "cans" by drawing the red-hot pieces through a "welding bell." The tapered bore of the bell progressively forced the flat plate into a circular shape. The end diameter of the bell was slightly smaller than the outside diameter of the can such that it forced together the abutting edges of the can as the piece was pulled through the bell with "tongs." (Back to text.)

Instead of using a welding bell, the ***furnace lap-welding process*** relied upon hot forming 20-foot-long plates (skelp) of appropriate widths for a particular pipe size on pyramid rolls. Prior to forming, the long edges of the plates were flame-scarfed to a tapered shape. The pyramid rolls were then used to shape almost complete circles (cans). The red-hot cans were then reheated; streams of compressed air were directed to the tapered edges to provide exothermic local heating to a suitable "welding" temperature. Each can was then forced between two rolls, which together formed the shape of a circle. Centered between the rolls was a stationary "ball" supported on a cantilevered arm. The diameter of the ball was equal to the inside diameter of the pipe. Upon passing of the can through the concentric space between the rolls and the ball, the tapered extra-hot edges were forced to bond to one another. Bonding was successful if all oxide was hot enough to be extruded from the bondline region. (Back to text.)

Electric-resistance-welded (ERW) pipe was made from plates or coils of steel strip (skelp). All forming for ERW was done at room temperature. The edges of the skelp were sheared to a width appropriate to that particular pipe circumference. Large mills with mechanical rolls progressively shaped the skelp into round cans (cylinders). As the cans were completed and the

Continued, next page

steel to make furnace butt-welded pipe due to its lower hot working temperature and its superior minimum yield strength of 30,000 psi. By 1900, nearly all line pipe was made from steel.

Butt-welded tubes were made in sizes ranging from 1/2 inch to 4-1/2 inches, but as the need to transport crude oil grew, it became apparent that larger diameter pipelines would be needed. Because the technology for making butt-welded pipe appeared to be unsuitable for making the larger diameter materials, pipe manufacturers turned to the process of making pipe by means of furnace lap welding.

Burst tests of furnace lap-welded materials revealed a joint efficiency of about 90 percent, so pipe designers chose a joint factor of 0.8, an improvement over the 0.6 joint factor of butt-welded pipe.

Lap-welded pipe could readily be made in sizes larger than 4-inch diameter and by 1897 sizes up to 30-inch diameter were made. By 1900, most lap-welded pipe was made from steel, and the gradual replacement of Bessemer steel with steel made with fewer impurities by the open-hearth process had begun.

Three New Seam Types, All Improvements

In the 1920s, the rate of pipeline construction increased sharply as natural gas was discovered in the Great Plains, and the need for it as a heating fuel developed in large Midwestern cities. The stimulus of increased pipe production led to significant improvements in pipe manufacturing. The first electric-resistance-welded pipe (ERW) appeared in 1924. The first large-diameter seamless pipe (up to 24 inches) appeared in 1925. In 1927 the process of making pipe with electric-flash-welded seams was introduced.

All three of these products proved to be superior to the earlier furnace butt-welded and furnace lap-

(Pipeline Manufacturing, continued)

abutting edges were brought into contact with one another, electric current locally heated the edges to near-melting temperature. Because the edges were being mechanically forced together, the hot metal bonded. Excess material was extruded both to the outside and the inside of the pipe. The excess metal was trimmed off, leaving a smooth or near-smooth surface. (Back to text.)

Seamless pipe was typically hot formed from a solid round "billet." The billet was ovalized between two rolls that progressively "spiraled" the billet between them. The billet was forced onto and around a stationary piercing mandrel as a tensile-stress-induced separation developed in the center of the ovalized billet. The resulting thick-walled "round" was then reheated and pushed over a solid plug, reducing the wall thickness nearly to that requested by the purchaser. The plug mill also stretched the length of the round. A final internal finishing pass reduced surface irregularities in the still-hot tube. The tube, now approximately 40 feet in length, was run through external sizing and straightening rolls and allowed to cool. (Back to text.)

Electric flash-welded pipe was made by cold forming 40-foot-long skelp into cans. The entire length of the abutting edges was forced together with mechanical pressure as an applied electric current locally heated it. Excess hot material was extruded to the inside and outside of the pipe. Most of this excess material was then trimmed leaving a slightly raised "flash" at both the outside and inside surfaces. Flash-welded pipe had some similarities to ERW pipe: both types of seams were comprised of a bondline region and a heat-affected zone with microstructures that differed from that of the parent metal, and neither contained added filler metal. (Back to text.)

Continued, next page

welded techniques. For one thing, these newer materials could be made in 40-foot lengths (double random lengths), a factor that cut in half the number of field girth welds or joints required during construction. Secondly, and more importantly, the transverse strength of the longitudinal seam, when made reasonably free of defects, exceeded the strength of the parent metal; *i.e.*, the longitudinal seam was not the weak link. Thus, there was no longer a need to apply a safety factor for seam design. A joint factor of 1.0 (*i.e.*, no penalty for the effect of the seam) was applied to the design of the pipe.

Improving the Longitudinal Seam Further: Submerged-Arc Welding

In the decade after World War II (1946 to 1956), many large pipeline systems were constructed. The boom in pipeline construction brought a number of technological advances in pipe manufacturing and pipeline construction. The submerged-arc weld process for making longitudinal seams became the most common means of making large-diameter pipe (24-inch and up). By 1948, this process was superceded by the double submerged-arc process. The double submerged-arc process proved more reliable and was quickly adopted as the exclusive means of making submerged-arc-welded pipe.

After being welded, each piece of submerged-arc-welded pipe is typically subjected to "cold expansion" to achieve uniform pipe diameter. This is important for large-diameter pipe, ensuring that one piece can be readily joined to an adjacent piece. Submerged-arc-welded pipe typically is made in sizes ranging from 24-inch to 48-inch diameter, though a few mills can make it as small as 16-inch and as large as 56-inch.

In the 1950s, there were significant advances in pipe manufacturing and testing. High strength grades of line pipe (42,000 psi to 52,000 psi minimum yield

(Pipeline Manufacturing, continued)

Straight-seam submerged-arc welded pipe is made by cold-forming 40-foot-long steel plates into cans and joining the edges of the cans by means of an added filler metal weld. The process is termed submerged-arc because the arc is created between a continuously supplied filler metal and the can and maintained within a bed of powdered flux. The heat of the arc melts the flux and the filler metal. The filler metal bonds the edges of the weldment together and the gas generated by melting the flux and the flux blanket shields the molten metal from the atmosphere. The first such pipe materials produced in commercial quantities appeared in 1946. The process at that time involved depositing the weld only from one side (the outside surface of the can). The molten metal was contained in the joint by a copper backing bar at the inside surface. (Back to text.)

By 1948, the ***double submerged-arc process***, in which both an inside and an outside weld bead is deposited, superceded the submerged-arc process, with its weld bead only on the outside. The double submerged arc process proved more reliable and was quickly adopted as the exclusive means of making submerged-arc-welded pipe. After being welded, each piece of submerged-arc welded pipe is typically subjected to "cold expansion." Either internal hydraulic pressure is used to plastically deform the pipe against an external die or an internal mechanical device is used to plastically deform the pipe a fixed radial amount. (Back to text.)

Submerged-arc-welding is also used to make "spiral" seam pipe. In that case, a coil of skelp is formed into a helix and the edges of the helix are joined to one another by means of a double submerged-arc-weld.

strengths) became available. These new grades were covered by a new API Standard, which also required the manufacturer to test each segment to 90 percent of its specified minimum yield strength.

1960s: Better Steel, Pre-Service Testing

In the 1960s, steel making underwent further significant improvements, pipe manufacturing technology continued to evolve, and pipeline operators instituted the practice of high-pressure hydrostatic testing. By the end of the decade, most manufacturers had converted their ERW processes from direct current or low-frequency-alternating current welders (60-360 cycles) to high-frequency welders (450 kilocycles), resulting in consistently better quality seams.

Manufacturers introduced steel with improved properties, including minimum yield strength levels of 60,000 psi and 65,000 psi.[3] Low carbon and low alloy steels also came into wide use. Supplemental (non-mandatory) requirements for minimum toughness levels were introduced into the API Specification 5LX. The latter development is particularly significant because assuring a minimum level of toughness is the key to obtaining line pipe with greatly improved resistance to defects and rapid crack propagation. In the year 2000, a mandatory minimum toughness level was introduced in API Specification 5L.

Perhaps of greatest significance is the fact that during the 1960s, pipeline operators instituted the practice of high-pressure hydrostatic testing of a newly-completed pipeline (not just a piece of pipe) prior to placing it in service. (Prior to this time individual segments of pipe were tested to 90% of their maximum operating pressure.) By the late 1960s, all new pipelines were tested in this manner to pressure levels of at least 1.25 times their maximum operating pressure. This practice nearly eliminated manufacturing and construction defects as a cause of pipeline failures. (More recently, U.S. Department of Transportation regulations required that pipeline operators hydrotest any pipeline system made with pre-1970 ERW pipe or lap-welded pipe that had a leak history, thus applying the benefit of this testing practice to pipelines constructed in earlier decades.)

An important issue arose in the 1960s that became increasingly important over the next 30 years: non-destructive testing of line pipe and pipelines. Up to the 1960s, pipe manufacturers relied upon destructive testing of samples and a hydrostatic pressure test of each pipe to a level between 60 percent and 90 percent of the specified minimum yield strength to control the quality of the material. As early as the 1940s, manufacturers began to apply non-destructive methods to inspect the seam welds of each pipe. In 1963, however, mandatory requirements for such inspections were introduced into API Specification 5L. The methods included fluoroscopy, film-radiography, magnetic particle inspection, and ultrasonic inspection. Any or all of these techniques were useful for detecting and eliminating manufacturing defects. By the late 1980s,

[3] The 1970s saw the development of 70,000 minimum yield strength line pipe.

the ultrasonic inspections used by the manufacturers had advanced to the point where it was extremely unlikely that an injurious defect could escape detection.

Also in the 1960s, the manufacture of furnace butt-welded and furnace lap-welded pipe was discontinued. The basic oxygen process for steel making, resulting in cleaner, higher-quality steel, was accepted for making line pipe while the Bessemer process was discontinued.

Another Early Challenge: Joining the Segments

Innovations in manufacturing pipe were accompanied by improvements in joining segments of pipe together to construct a pipeline. While pipes as large as 12-inch diameter could be joined by means of screwed collars, the joining of larger pipes required more effective methods. As early at the late 1800s, mechanical joints began to appear. These included bolted flanged pipe, but more commonly, concentric metal rings and bolts were used to compress packing materials around the ends to two adjacent pieces ("joints") of pipe. The packing seals provided pressure containment but no significant resistance to the axial thrust generated by internal pressure. Hence, mechanically coupled lines had to be buried in order for soil pressure and friction to resist the thrust. Bolted flanges or other means of connection to carry the thrust force were necessary for joining aboveground piping. In 1911, a 1-mile line was installed by means of joining the pieces of pipe with a circumferential (or girth) weld; in this case acetylene girth welds. In 1914, a 35-mile pipeline was installed using that process. Electric arc girth welding was first used in 1917 on an 11-mile pipeline. (See the Glossary for additional information on how these welds were formed and explanations of terms used.)

Typically, it was difficult if not impossible to make either acetylene welds and the early electric arc welds in vertical or overhead positions. Therefore, long segments had to be created by "roll" welding, that is, rotating the segment as the weld was formed so that the welding was always performed in a "flat" position. Also, it was difficult to bridge gaps (especially with early electric welding), so backing rings were often used resulting in restrictions on the inside surface of the pipeline. Sometimes the ends of the pipes were "belled" to accommodate the backing rings so that the internal restrictions were eliminated. By 1930, the techniques and consumables for electric arc girth welding had evolved to the point where all-position welds could be made, and the "keyhole" welding technique permitted "root" beads to be deposited in the gaps between pipes. Electric arc girth welding became and remains the most widely used means of constructing a pipeline.

Radiographic inspection of girth welds, introduced in 1948, soon became the universal tool for inspecting a portion of all field girth welds, and became mandatory under API Standard 5L in 1963. For some pipeline projects, such as the TransAlaska Pipeline, all girth welds were radiographed. By the 1990s, the portion of welds inspected in this manner typically approached 100 percent on all pipelines. Radiography is one of a battery of non-destructive tests that pipeline operators now utilize for testing the soundness of the pipe and its installation. Others include fluoroscopy, film-radiography, magnetic particle inspection, and ultrasonic inspection.

Another advance in improving the reliability of the girth weld was the adoption in the 1950s of the new industry standard, API Standard 1104 (Standard for Welding Pipelines and Related Facilities). The standard requires that the company develop specific welding procedures and prove them by destructive tests, and qualify the welders by testing their sample weldments.

Advances in Corrosion Control

The early pipeline operators became aware of the fact that corrosion of pipe buried in soil could be quite aggressive. By the 1920s, some operators began to coat the pipe as it was being laid in the ditch in an attempt to protect it from corrosion. The idea was to place a barrier between the pipe and the corrosive conditions in the soil. A common early coating was coal tar.

By 1945 both government and industry studies revealed that corrosion of underground steel structures was an electro-chemical process in which the flow of electrons away from the soil-pipe interface could cause rapid, localized metal-dissolution leading to leaks. These studies showed that some soils were more corrosive than others (*i.e.*, the rate of corrosion varied with soil resistivity). It also became apparent that damaged coating could result in concentrated corrosion where the coating was incomplete, as where it was disbonded or contained holes.

Once the electro-chemical nature of corrosion was understood, a major breakthrough was the recognition that corrosion could be mitigated (slowed to an insignificant rate) if electric current sufficient to offset the inherent corrosion current of a particular environment were caused to flow in the opposite direction (*i.e.*, to supply electrons to the soil-pipe interface). The applied direct current was termed "cathodic" protection because it made the pipe the cathode in a galvanic cell. The required current could be supplied by connecting a "sacrificial" anode (*i.e.*, a metal with a higher oxidation potential than iron) in an electrical circuit where soil acted as the "electrolyte." Alternatively, commercial current could be directed to the pipe via an anode bed.

The application of sufficient cathodic protection was found to mitigate corrosion successfully. While bare (non-coated) pipeline could be protected in this manner, a sound corrosion-resistant coating applied to the pipe greatly reduced the amount of current required. By the late 1940s when a tremendous boom in pipeline construction began, pipeline builders and operators recognized the need to coat pipelines and to install cathodic protection systems. Cathodic protection systems were retrofit to many existing pipelines thereafter.

Further advances in coating technology occurred in the 1960s, 1970s, and 1980s. Whereas the early coatings had been mostly coal-tar enamel or asphalt enamel, the 1960s and 1970s saw the development of and increasing use of polyethylene tape coatings, extruded polyethylene coatings, and fusion-bonded epoxies. In the 1980s, three-layer systems comprised of polyethylene tape and fusion-bonded epoxies were developed.

Over the period of the '60s, '70s, and '80s, operators developed aboveground survey techniques to locate holes in the coatings of buried pipelines and to make electric measurements on the surface over or near a buried pipeline. Pipeline operators were able to use such techniques to find and repair coating faults and to determine whether the cathodic protection being applied was adequate. By the 1990s, these techniques had evolved to the point where stray electric currents that might potentially cause corrosion (electric currents outside of the cathodic protection system) could be detected so that appropriate remedial action could be taken. Also, by the 1990s, the use of coaxial casings at road and railroad crossings was being phased out in favor of alternative methods of physical protection in such areas. The casings, once used routinely, were found to interfere significantly with corrosion-prevention techniques.

The technology of in-line inspection has also developed significantly since the introduction of the "smart pig" in 1965. A smart pig, as noted above, is propelled through the pipeline by the transported commodity, such as oil. It is instrumented to return readings about anomalies in wall thickness, pipe deformation, or a host of other characteristics that may indicate existing corrosion or damage to the pipe that may invite corrosion. The use of the smart pig has been an important tool in finding corrosion before failure, and successive generations of the smart pig now return more detailed information. Other in-line inspection tools have been designed to detect specific types of other defects.

Advances in Standards for Manufacturing and Design

With the growth in line-pipe manufacturing, the increased utilization of pipelines, and the advent of new types of line pipe in the 1920s, the need for line-pipe standardization became apparent. This is not to say that standards and quality assurance measures in the manufacture of line pipe did not exist. As early as 1869, manufacturers were performing hydrostatic tests of each piece of pipe. By the early 1900s, each manufacturer listed the standard test pressures used for each size and grade of pipe. Typically these test pressures were well in excess of operating pressure levels so that each piece of pipe was proven fit for service. All manufacturers made certain standard sizes and used common threading configurations as well. Nevertheless, the purchasers of line pipe and the manufacturers saw the need to develop a uniform standard to specify acceptable manufacturing processes, quality-control tests, sampling rates, standard sizes, standard marking techniques, and a certification process.

In answer to these needs, a committee of pipe users and manufacturers issued the first edition of API Standard 5L for the manufacture of line pipe in 1928. The first edition of the standard listed pipe sizes, minimum tensile and chemical content requirements, sampling rates, internal pressure tests, thread configurations, identifying marks to be stamped on each pipe, and a list of approved manufacturers who were to be licensed to "monogram" pipe as API Line Pipe. Subsequent editions of the standard as well as supplements were published periodically to reflect changes and technological advances. Over the years, the API standard gained worldwide acceptance. The 42nd Edition of API Specification 5L[4] was issued in January 2000.

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[4] API's Standard was called 5-L during some periods. It is currently API Specification 5L. API also adopted an API Specification 5LX for X-grade steels (newer, tougher, stronger steels); it too is now part of API Specification 5L.

Pipeline design also generated high interest in standardization not only in the oil and gas pipeline industry but also in refineries, chemical plants, and power plants, all of which depended on pressure piping for their processes. These industries recognized the clear connection between adequate piping design and safety. Both pipeliners and plant operators desired to prevent injuries, loss of life, and property damage that could result from the failure of a pressurized system. They formed a committee that produced the first standard code for the design of pressure piping in 1935. The code specified how much wall thickness was required, the allowable stress limits on the materials, the allowable types of materials that could be used, and the factors that pipeline designers must consider in designing a pressure piping system.

The emphasis was on safety. Stress limits were set conservatively with the aim of preventing in-service failures. In 1942, this became the American Standard Code for Pressure Piping. The code was reissued in 1951 as the ASA (American Standards Association) B31.1 Code. In recognition of the increasing complexity and diversity of pipe needs in the various industries, separate codes for each industry evolved. The first code exclusively dedicated to the transportation of liquid petroleum products and crude oil (ASA B31.4) was published in 1959. Currently this code is referred to as ASME (American Society of Mechanical Engineers) B31.4, 1998 Edition.

In 1970, federal safety regulations for pipelines went into effect. In Title 49 of the Code of Federal Regulations, Part 192 was created to regulate natural gas pipeline safety and Part 195 was created to regulate hazardous liquids pipeline safety. In many ways, these regulations were like the industry's voluntary consensus pipeline code, ASME B31.4 (and analogously, ASME B31.8 for natural gas pipelines).

Today, the technology exists to manufacture and install pipe that is virtually free of injurious defects. Techniques and equipment for preventing deterioration of pipelines in service are widely used. Smart pigs are widely available to inspect most of the older systems (and the newer systems as they become older) to ensure that they remain safe.

Maintaining System Integrity

Pipeline operators employ a number of techniques to monitor and maintain the integrity of their pipeline systems to protect the public and the environment from accidental releases of oil. One way they do this is by making routine periodic inspections and measurements of system components and parameters. Examples include bi-weekly aerial patrols of rights-of-way, biennial measurements of pipe-to-soil potentials, annual checks of block valve functioning, and once-every-five-year inspections of pipelines at river crossings. They may also conduct pipeline integrity assessments on an as-needed basis or as required by federal regulations.

To schedule integrity assessments, most operators use risk assessment models that identify pipeline segments that may be at risk from some form of time-dependent deterioration or exposure to development and encroachment along the pipeline right of way. In most cases the models are used to rank the segments in descending order of risk so that inspections and remedial actions can be applied first where the need is greatest. The risk models typically take into account such factors as age, pipe diameter, pipe wall thickness, type of product, operating pressure, history and causes of any releases, proximity to populated areas or environmentally sensitive areas, and the findings of prior tests and inspections. The operator then develops an integrity assessment plan to address segments perceived to be at risk. The integrity assessments may consist of conducting in-line inspections with "smart pigs" to detect corrosion-caused metal loss or to detect injurious dents or cracks. The results of such inspections are typically followed up with excavations of areas where the smart pigs have identified anomalies, followed by repairs, pipe replacement, or other mitigative actions, where necessary. Proven repair criteria and repair methods are available through written industry standards such as ASME B31.4. Alternatively, an operator may use a hydrotest (filling a pipeline with water and testing it to an internal pressure level significantly above its maximum operating pressure) to demonstrate that it is free of injurious defects.

A group of pipeline industry experts including personnel from operating companies, service vendors, the Office of Pipeline Safety, API, and industry consultants has completed a comprehensive standard, API Standard 1160, Managing System Integrity for Hazardous Liquid Pipelines, to provide guidance for integrity inspections of pipelines that affect high-consequence areas.[5] This new standard provides guidance to operators for managing integrity, conducting risk assessments, planning and conducting tests and inspections, implementing repair and mitigative actions, and measuring performance.

[5] "High-consequence areas" are defined in 49 CFR 195.450 as a *high population area* (an urbanized area based on population and population density); *another populated area* (a place that contains a concentrated population, such as an incorporated or unincorporated city, town, village, etc.); a *commercially navigable waterway* (a waterway where a substantial likelihood of commercial navigation exists); or *an area of the environment that has been designated as unusually sensitive to oil spills* (an "unusually sensitive area" or USA, defined in 49 CFR 195.6).

SAFETY PERFORMANCE BY DECADE OF CONSTRUCTION

As noted throughout, manufacturing, construction, and maintenance practices have evolved over the decades to improve performance. The industry's voluntary reporting initiative, Pipeline Performance Tracking System or PPTS, has provided the first opportunity to examine industry-wide data related to pipeline age and decade of construction. Prior to the availability of PPTS, mileage data by decade of construction, the industry, its observers, and its regulators were limited to information about the decade of construction of the pipelines that experienced a reportable safety incident, but did not have any information about incident-free pipe. For the first time, we can explore meaningfully the pipeline performance by decade as reflected in the safety incident data. We do so by comparing the inventory of pipelines in service at this time with the record of safety incidents by decade of construction. Using the insight gained in examining pipeline technology and characteristics by decade of construction in previous chapters of this report, we can offer perspective on the result.

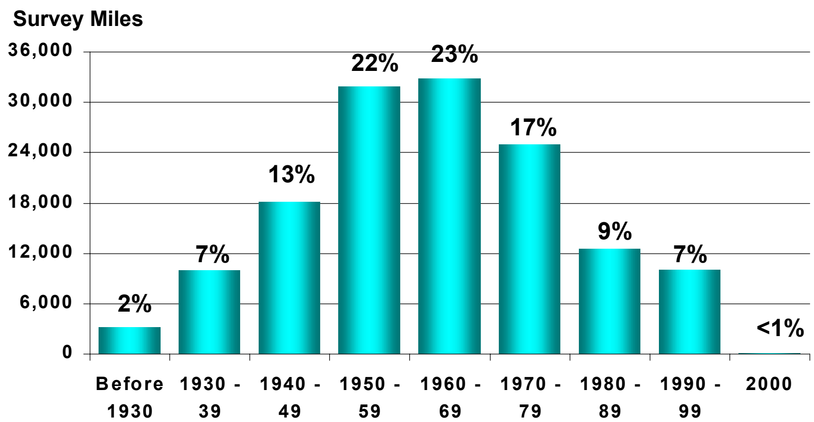
Miles of Pipeline in PPTS

Pipeline companies participating in PPTS submitted mileage detail by decade of construction for 143,647 miles of pipeline. The submissions, from 33 operators, cover the 1999-2001 period and represent in-service mileage as of mid-2001. With responses from a subset of a group – as PPTS participants are a subset of all pipeline operators – one of the first questions to examine is whether the sample is appropriate to represent the group. All available measures indicate that the PPTS submissions represent most, almost three-quarters of the miles, of pipeline in service. For instance, the Office of Pipeline Safety collects User Fee Assessments on 157,000 miles of pipelines under its jurisdiction[6]; thus the PPTS total is equal to more than 90% of this OPS total. Participants in PPTS report all the miles of hazardous liquid pipelines they operate, regardless of whether the

[6] The Office of Pipeline Safety does not collect User Fee Assessments on onshore gathering pipelines in rural areas, non-HVL hazardous liquid pipelines located outside populated areas and navigable waterways that operate at low stress (less than 20% of specified minimum yield strength), and other pipelines excluded from regulation by 49 CFR Part 195.

lines are subject to the operations and safety regulations of the Department of Transportation's Part 195. While there is no authoritative data on the total miles of oil pipeline in service both in and out of Federal jurisdiction, by common estimate[7], this total is approximately 200,000 miles. The PPTS total approaches three-quarters of this most inclusive estimate. In addition, in this comparison of safety incidents with pipeline mileage, we have relied on the only set of data on safety incidents available over an extended period of time, that from the Office of Pipeline Safety. The PPTS participants represent a high share of the universe of operators subject to the reporting requirements of the Office of Pipeline Safety. For these reasons, we are confident that the PPTS sample is a reasonable one to use for the comparisons discussed here.

Pipeline Mileage by Decade of Construction



Decade of construction data from Pipeline Performance Tracking System

Profile of Decade of Construction

While PPTS provides the first time we can use data to construct this industry-wide picture of construction by decade, the pattern is as expected given industry experience. The 1940s, the fourth-ranked decade, were an important period of construction as the advent of World War II brought an increasing need for the secure (*i.e.*, overland) transportation of petroleum and refined products. One private system was begun as the War threatened, and was completed by 1941, providing transport of refined petroleum products from the Gulf Coast to the Mid-Atlantic seaboard. In 1942 and 1943, the U.S. government underwrote construction of a 24-inch crude oil pipeline and a 20-inch refined products pipeline between Texas and New Jersey. The

[7] See, for instance, National Petroleum Council, *Petroleum Transportation & Storage*, Volume V: Petroleum Liquids Transportation, 1989, p. 15.

system was called the War Emergency Pipelines. After the war, these pipelines were sold to a private operator. Portions of these pipelines are in service today. The breakthrough in the construction of long-distance, large-diameter pipelines during World War II placed the pipeline industry in a position to fuel the post-War boom and the burgeoning oil demand that accompanied it.

As shown in the graph above, the most important decades for the construction of the pipelines currently in service were the 1950s (some 22% of the total in service) and the 1960s (23%). The growth included longer distance crude oil pipelines to supply refineries and refined product pipelines to distribute product. The largest pipeline system, Colonial Pipeline, was begun in the 1960s, for instance. This system, now more than 5,300 miles of line pipe, includes main lines that extend from Houston to New York Harbor. It transports more than 2 million barrels per day of refined products and has by far the highest throughput in terms of barrel-miles (one barrel transported one mile is a barrel-mile). Also constructed in the 1960s was the Capline system. Originating at the Louisiana Gulf Coast, this system carries more than one million barrels of crude oil per day to the Midwest for the region's refineries. It is the major conduit for the transport of non-Canadian crude oil imports destined for these facilities. The third-ranked decade was the 1970s (17% of the total). The Trans-Alaskan Pipeline was built during the 1970s (completed in 1977), and at its peak transported about 2 million barrels per day of crude oil, but at 800 miles, even this critical carrier is a small share of the decade's total miles of pipeline. Explorer Pipeline (1,400 miles), a vital link for refined products supply from the Gulf Coast to the Midwest, was also constructed during the 1970s. Pipelines constructed during the 1950s, 1960s, and 1970s together comprise more than 60% of the miles of pipeline in service.

Incident Data from OPS

Operators of "hazardous liquid" pipelines – those transporting crude oil, refined petroleum products and highly volatile liquids such as propane – are subject to regulation by the Department of Transportation's Office of Pipeline Safety (OPS) with respect to safety and operations, maintenance and construction. Operators file reports of safety incidents with OPS on Form 7000-1, as required by 49 CFR Part 195:

"An accident report is required for each failure in a pipeline system subject to this part in which there is a release of the hazardous liquid or carbon dioxide transported resulting in any of the following:

(a) Explosion or fire not intentionally set by the operator.
(b) Loss of 50 or more barrels (8 or more cubic meters) of hazardous liquid or carbon dioxide.
(c) Escape to the atmosphere of more than 5 barrels (0.8 cubic meters) a day of highly volatile liquids.
(d) Death of any person.
(e) Bodily harm to any person resulting in one or more of the following:
    (1) Loss of consciousness.
    (2) Necessity to carry the person from the scene.

(3) Necessity for medical treatment.
(4) Disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident.

(f) Estimated property damage, including cost of clean-up and recovery, value of lost product, and damage to the property of the operator or others, or both, exceeding $50,000."

Form 7000-1[8] requests information on the operator's identity, the location of the incident, the part of the system involved (line pipe, tank farm or pumping station), the commodity spilled, the volume lost, the volume recovered, the cause of the incident, and a host of other details. The current Form 7000-1 has been in use since late 1985, with 1986 being the first year in which it was in use throughout the year. A database of the information filed on Form 7000-1 is available incident-by-incident on the Office of Pipeline Safety website, http://ops.dot.gov/.

Form 7000-1 uses seven causes to categorize incidents: corrosion, failed weld, failed pipe, incorrect operation by operator personnel, malfunction of control or relief equipment, outside force damage, and "other." These broad categories have frustrated analysis for the pipeline industry, its observers and its regulators. For instance, "outside force damage" includes failures due to excavation damage where a pipe is ruptured by heavy equipment or pierced by an augur, as well as failures due to weather, earthquakes and flooding. The hazards and risks of one type of failure are significantly different, and the appropriate mitigation measures are also different. The catchall category "other" is a similar frustration for analysts.

ASME's B31.4 Committee's Causes

To avoid failures, the industry needed to understand the risk factors that were causing the incidents, and then to adjust operations and maintenance practices accordingly. Confronted with the overly broad cause categories in the published data, a committee of experts from the American Society of Mechanical Engineers, B31.4 Committee[9] reviewed the Form 7000-1 submissions, form-by-form. Based on the narrative provided, the review committee classified incidents into the 20 causes recognized by ASME (see table, next page). The cause categories were chosen to reflect the risk factors identified by the incidents and to help the B31.4 Committee formulate any needed changes to the ASME code. This reclassification has been an ongoing process, repeated periodically to analyze new submissions. The Office of Pipeline Safety participated in the development and funding of a joint report with the American Petroleum Institute using ASME's

[8] The U.S. Department of Transportation's Office of Pipeline Safety has lowered the federal reporting threshold to 5 gallons and will collect significantly more detail than in the past.

[9] The American Society of Mechanical Engineers (ASME) is a professional engineering society and the B31.4 Committee is responsible for maintaining the basic design, construction, operations and maintenance code for hazardous liquid pipelines systems.

in-depth and more definitive set of causes.[10] Here, we have incorporated B31.4/Kiefner & Associates' reclassifications of incidents for the 1997-99 period.

Cause Categories of ASME's B31.4 Committee	
Cold Weather	Lightning
Corrosion-Related Failures - External	Malfunction of Control or Relief Equipment
Corrosion-Related Failures - Internal	Miscellaneous Causes
Defective Fabrication Weld	Other (insufficient information to be classified)
Defective Girth Weld	Ruptured or Leaking Gasket or O-ring
Defective Pipe	Ruptured or Leaking Seal or Pump Packing
Defective Pipe Seam	Rupture of Previously Damaged Pipe
Defective Repair Weld	Third Party Inflicted Damage
Heavy Rains or Floods	Threads Stripped, Broken Pipe, or Coupling Failure
Incorrect Operation by Carrier Personnel	Vandalism

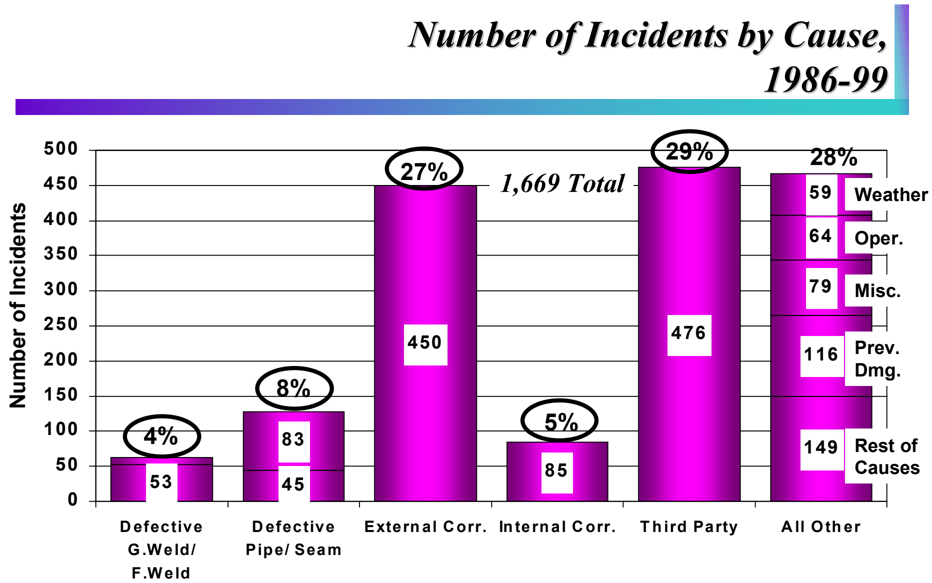
The Incident Data and Cause Patterns

For this study, we only used those incidents that occurred on line pipe, as opposed to other parts of the system such as tank farms or pumping stations, and only those incidents where the year of installation was reported. Over the 1986-99 period, there were 1,788 line pipe incidents reported and the year of installation was reported on 1,669 (93%) of them. The total number of incidents used for comparison is thus 1,669.

The graph on the next page shows the number of incidents by cause, with the risk factors generally specified or grouped to test them against the mileage data for decade of construction. For instance, defective pipe and defective pipe seam failures generally reflect pre-service conditions related to the manufacture of the pipe. Later pipe, manufactured and tested with improved techniques, should show improved performance over the earlier pipe. Defective girth weld and defective fabrication weld are similar, in that they relate to pre-service conditions, in this instance related to the construction of the pipeline – joining the segments of pipe one to the other. Again, the improvements in techniques and testing as they evolve in later periods would be assumed to lead to improved performance for pipelines constructed later. External corrosion, in contrast, reflects both pre-service conditions and in-service conditions; as discussed extensively in this paper, the application of cathodic protection, coatings and a variety of mitigation measures reduce the likelihood of a failure due to external corrosion. Incorrect

[10] J.F. Kiefner, B.A. Kiefner and P.H. Vieth, "Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996," API Publication 1158, 1999.

operation by carrier personnel was specifically excluded from the analysis since it was deemed to be unrelated to the decade of construction for any pipeline system.



Incidents 1986-99 from Kiefner & Associates for ASME B31.4 Committee. Includes only incidents involving line pipe (1,788) where year of installation was specified (1,669).

As shown in the graph, third party damage – damage inflicted by excavation or construction activity, farming, or other digging or boring activities – accounts for the largest share of the incidents, 29%. The second largest cause is external corrosion at 27%. A number of causes have been grouped to create the “All Other" category; together these causes account for 28% of the incidents. Examples of incidents in this category include weather, operator error, previously damaged pipe[11], etc. However, because these causes are neither typically time-dependent nor large components of the total number of incidents, testing against the decade of construction data does not provide illumination. It should be noted that the appropriateness of drawing conclusions from a small number of incidents is also a concern with respect to some of the causes where improved practices would logically have led to improved performance for later installations. Defective girth and fabrication welds are such an example.

[11] Damage inflicted when a pipe is struck or dented by outside force may not cause a failure at the time, but may be the prime cause of a later failure at the damaged or weakened location. Dings to coatings can also lead to increased corrosion at the site of the ding.

The Methodology

To compare the *mileage* by decade of construction with the *incidents* by decade of construction, we compared the *share* of mileage to the share of incidents by decade for all incidents and for selected incident causes. By this test, a decade where the incident share equaled the mileage share would be showing performance commensurate with its representation in the overall system. Similarly, if the decade's share of incidents is higher than its share of mileage, the systems constructed during the period are showing a relatively higher rate of incidents per mile, and if the incident share is lower than the mileage share, the systems are showing a relatively lower rate of incidents per mile. The left-hand graph in each of the ensuing charts illustrates.

To make the relative performance clearer, we also divided the share of incidents by the share of miles. If the shares were the same, such as 22% of the mileage and 22% of the incidents, this ratio would be 1.0, indicating performance commensurate with the decade's miles. A ratio higher than 1.0 indicates relatively higher rate of incidents per mile and a ratio lower than 1.0 indicates relatively lower rate of incidents per mile. The right-hand graph in each of the charts illustrates.

Because there are limitations in the data, it is important to recognize the conclusions here as relative indicators. For instance, while we could calculate the number of incidents per mile, we know that we do not have 100% of the pipeline mileage in our PPTS sample. A rate calculated from the sample would be overstated. The relative performance, however, is probably reasonable because it is more likely that the pattern of construction by decade is approximately correct. Similarly, as noted above, the conclusions drawn from a small number of incidents are less robust than those drawn on larger numbers of incidents. In addition, not every assumption can be tested statistically, because the detailed data are not available.

Again, the comparisons presented here provide indicators of relative performance, especially in light of the evolution of pipeline technology, but are less helpful in establishing a single definitive value. Of particular note are the decades before 1930 and the 1990s.

- The number of incidents per mile for the earliest pipeline systems (those that are still in service from before 1930) is relatively high for nearly every risk factor examined. With such a small number of miles reported for the period in the infrastructure inventory, a very small undercount could markedly sway the result. For instance, if the decade profile for the operators not participating in PPTS were heavily weighted to this early period, the share of mileage would grow. An increase from the current 2.3% of the total miles to 3.0% of the total would have a minor impact on the other decades, but would shift the ratio of the share of incidents to the share of miles incidents for these early decades. For instance, this change would shift the ratio from 5.4 (as now) to 4.0 for the total number of incidents. Even while substantially reduced, however, the ratio would remain higher than that for any other period of construction. Because of the uncertainty over the exact values for this small amount of pipe, we have truncated the y-axis scale at 4.0 in the remaining graphs showing the ratio between the share of incidents and the share of miles.

- Another data limitation exists for pipe installed in the 1990s. This pipe was in place for only a portion of the period for which we are examining incidents. The values shown for 1990s pipe therefore show the decade in a more favorable light than would be the case if a precise adjustment for the temporal under-representation were possible.

Finally, it is important for the reader to understand that even the relative indicators do not mean that every system that was constructed in a given period is going to have the same characteristics, or has been operated under the same conditions with the same maintenance practices. In fact, many operators have tested and reconditioned older pipelines, returning them to service with renewed reliability. The comparisons provided here are broad indicators, not definitive conclusions.

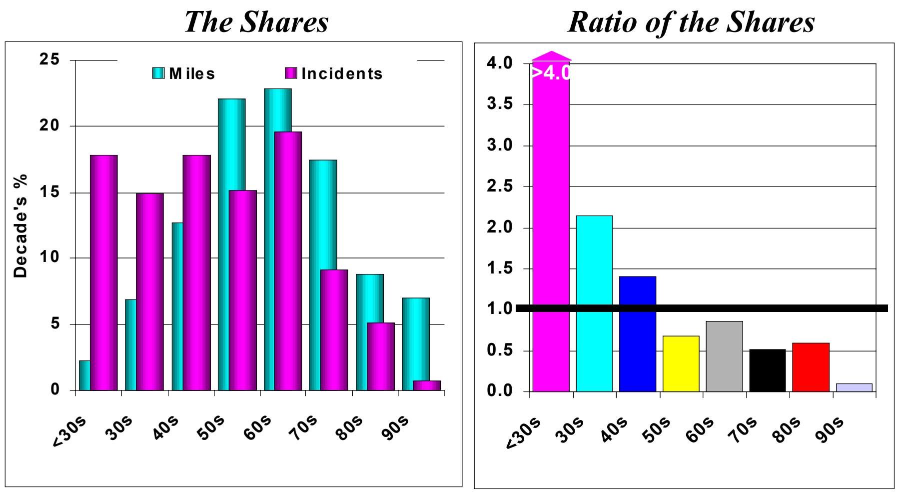
External Corrosion

As noted previously, some risk factors are tied to pre-service conditions and some to practices prevailing at the time of construction. It is widely assumed that some causes are time-dependent, with the likelihood of a failure increasing as the pipeline remains in service longer. External corrosion, the second largest cause of accidents (450 incidents or 27% of the total over the 1986-99 period), is clearly one of the risk factors that many assume is time-dependent. Uncontrolled, it would be. While this examination may not silence the debate authoritatively, the pattern shown in the graph is of considerable interest. Pipelines installed in the 1950s – now 40-50 years old – do not show a high rate of corrosion incidents. Instead, the construction periods that exhibit the higher rates of external corrosion were decades when prevailing practices did not include corrosion control.

The periods of construction reflecting the highest relative rates of external corrosion incidents are the period before 1930, the 1930s, and the 1940s – the decades before cathodic protection became universal for new construction. In the earliest period, pipe was buried without coating and cathodic protection was little known. By the 1930s, some pipelines were coated after being laid in the ditch with sprayed-on coal tar. While this was an improvement in technology, cathodic protection was still not widely utilized. Cathodic protection came into general use after World War II, in time for the boom in pipeline construction.

Coating practices and methods have continued to evolve. By the 1960s, coatings were applied to pipe before installation, for instance. Fusion-bonded epoxy coatings, which first appeared in the 1960s, have continued to improve through the 1990s. In addition, pipelines are now better protected from dings and damage during construction that may result in corrosion later. The pipe is also tested for any damage to the coating that may have occurred during transport and installation.

Illustrating Advances in External Corrosion Control with Decade of Construction



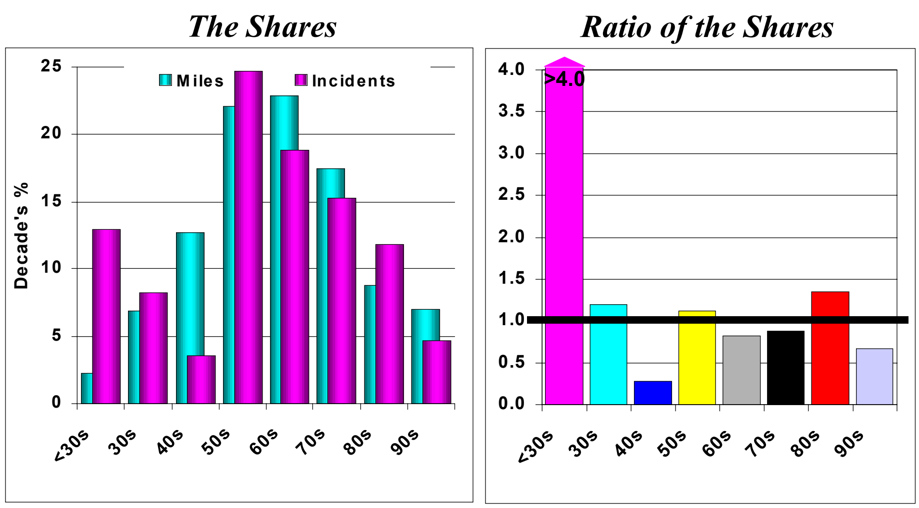
"External corrosion" accounts for 27% of line pipe incidents for the period from 1996-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

Many systems have undergone extensive reconditioning and upgrade. For instance, cathodic protection systems were installed on existing systems when the evidence of their benefits became compelling. When retrofitting a system with cathodic protection, many operators also examine it for existing corrosion, repairing as necessary and applying the level of cathodic protection appropriate for the condition of the pipe.

Internal Corrosion

Internal corrosion is the cause of relatively few incidents on line pipe, just 85 or 5% of the total over the 1986-99 period. As shown in the graph, only the earliest decades show a significantly higher rate than expected from the decade's importance in the mileage profile. Internal corrosion is not mitigated by cathodic protection, as external corrosion is, and is largely a result of in-service conditions. Produced water in a crude oil line, for instance, was the cause of many of the incidents. As fields mature and output declines, many operators install waterflood projects to maintain production. The produced water and the low volume flow from these older fields contribute to the likelihood of internal corrosion. Sulfate-reducing bacteria are another factor. While nearly all of the incidents involved crude oil, a few refined product incidents showed microbiological corrosion. The reason for the very low rate of internal corrosion in 1940s pipe is not readily apparent with the information available.

Illustrating Risks from Internal Corrosion with Decade of Construction

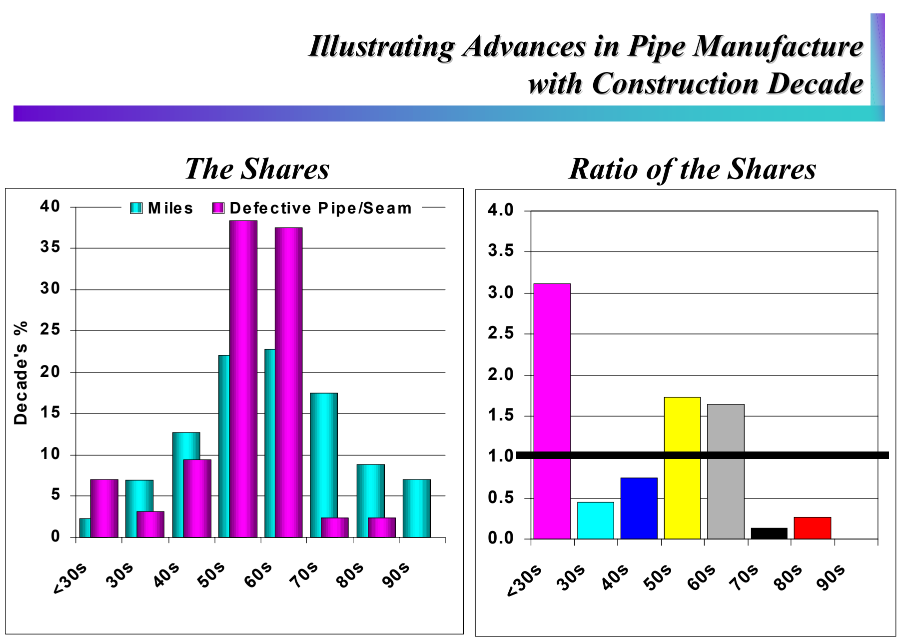


"Internal corrosion" accounts for 5% of line pipe incidents for the period from 1986-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

Defective Pipe/Defective Pipe Seam

As discussed extensively in the section on the *Evolution of Pipeline Technology*, forming steel into a cylinder for use as pipe was one of the earliest challenges for the industry. The vulnerability of the seam to failure made it the weak point in the early pipe. More recent developments, however, have nearly eliminated manufacturing defects such as defective pipe and defective pipe seam as risk factors. Pipelines constructed after the 1960s show few of these incidents, for instance, and pipe manufactured in the 1990s has not had any pipe seam or defective pipe failures. The graph below illustrates the pattern for the 128 incidents (8% of the total) occurring over the 1986-99 period. Although not shown in the graph, testing has helped eliminate these failures even in early pipe: incidents due to defective pipe and defective pipe seam occurring on pipe of any decade have averaged only 5 incidents per year over the most recent 5-year period.

In the early decades, pipe was formed with a butt-welded or lap-welded seam. There was limited pre-service testing and there were no industry-wide manufacturing standards until late in the 1920s. The development of pipe made with electric resistance welds (ERW) and seamless pipe in the later 1920s was a significant advance. Over time, it became apparent that the electric resistance weld, when made with a low-frequency process, could also be a point of vulnerability.



"Defective pipe/defective pipe seam" accounts for 8% of line pipe incidents for the period from 1986-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

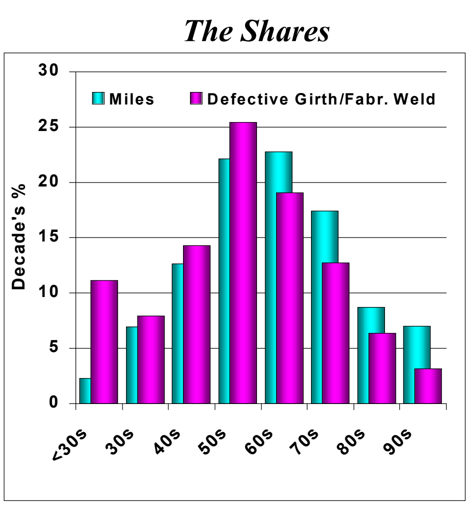
(The data records do not specify the detail necessary to explain the lower rate in 1930s and 1940s pipe versus the higher rate in the 1950s and 1960s pipe.)

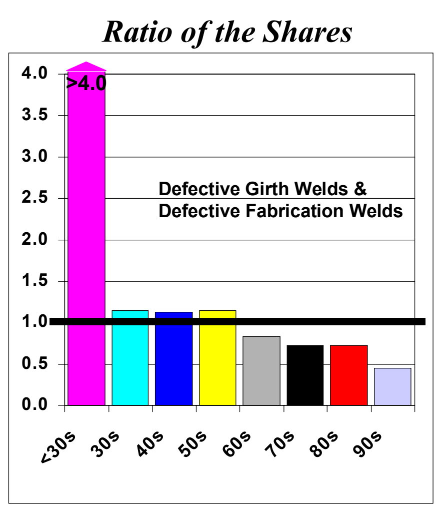
Beginning in the late 1960s, the electric resistance welds were made exclusively with a high-frequency process. In addition, the use of pre-service hydrotesting to a pressure level well above in-service conditions became universal in the 1960s. (OPS has required that operators hydrostatically test any pre-1970 ERW or lap-welded pipe with a leak history. Most of these tests took place over a 5-year period ending in 2000. It is therefore likely that these failures will fall even further in the future for the pre-1970 pipe as well.) Finally, newer grades of steel are tougher and "cleaner" (subject to more and better processing, and thus have fewer defects), and are therefore less vulnerable to failure. As shown in the graph, no pipeline constructed during the 1990s has experienced a defective pipe or pipe seam failure.

Defective Girth Welds

The weld joining two segments of line pipe, the girth weld (or fabrication weld), is the cause of relatively few incidents as well, just 4% of the total over the period under examination. Two of the significant advances took place in the late 1920s: the introduction of electric arc welds and the development of welding techniques that allowed the welds to be produced successfully on all positions around

Illustrating Advances in Girth/Fabrication Welds with Construction Decade



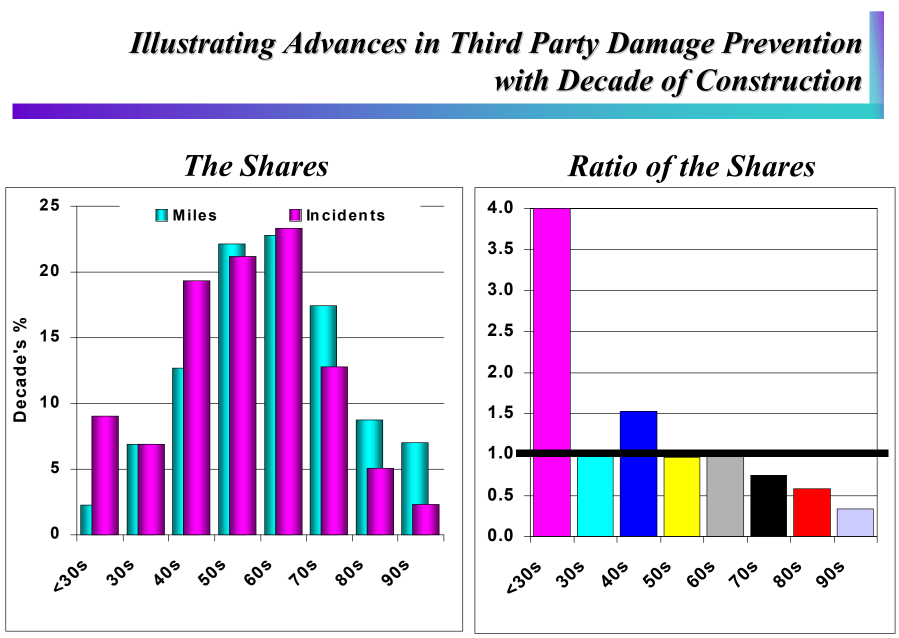


"Defective girth/fabrication weld" account for 4% of line pipe incidents for the period from 1996-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

the girth of the pipeline. Later, increased qualification programs for welders and weld procedures (API Standard 1104) improved the quality of welds. The use of radiographic and other non-destructive inspection methods such as magnetic flux and dye penetrant tests on new welds contributed to eliminating defects.

Third Party Damage

Damage from a third party, including excavation damage or damage from farm equipment, is the largest cause of line pipe incidents, accounting for 476 or 29% of the total from 1986-99. Of all the causes, third party damage would seem not to be time-dependent; an accident caused by a third party would have nothing to do with the age of the pipe. Thus, differences between the performances in different decades might appear to be anomalous. In fact, third party incidents provide another illustration that the issue is not the age of the pipe, but the practices prevailing when the pipeline was installed.



"Third party damage" accounts for 29% of line pipe incidents for the period from 1986-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

An issue with the earliest pipe, for instance, is that the steel was more brittle. A hit of the same force may cause a rupture on this early steel where it would not on newer grades. The early pipe was also laid before encroachment from a number of sources, including suburban development and more intensive and invasive farming methods, and was generally installed with relatively shallow cover. In the 1940s, the War effort had a considerable impact, including the competing uses for steel for the war materiel. In addition, the need to switch quickly from waterborne transportation to overland transportation for oil to avoid submarine attacks required a massive effort to construct pipelines. The prevailing industry standard for steel manufacture, API Specification 5L, was suspended for the duration of the War, and to speed construction, many of the lines were installed with relatively shallow cover. Later, the move to suburbia was a post-War phenomenon, with encroachment of residential and commercial activity on formerly unoccupied spaces. More recently, the industry has implemented safety initiatives on a number of fronts, including the need to reduce likelihood of third party damage to a line. Pipelines constructed in recent decades are more likely to have deeper cover.

Preventing third party accidents, the single largest cause of pipeline accidents and the largest volumes released, continues to be a major focus of the pipeline industry. In 2000, a new private sector organization, the Common Ground Alliance, was created to bring underground facility operators, one-call centers, locate services, excavators, and federal, state, and local government agencies together to identify best practices and promote damage prevention.

Conclusions on Performance by Decade

The graph below shows the result of a comparison of all incidents, regardless of risk factor or cause, with the mileage data. As discussed throughout this report, there were several periods that were watersheds for advances in pipeline technology and operating practices. (Both the Appendix and Summary of Practices and Developments help illustrate.) ***In the late 1920s***, when the first major pipeline construction boom began, manufacturers began to form pipe with electric resistance-welded or flash-welded processes, a significant advance in the reliability of the longitudinal seam. Also, the electric arc girth weld was developed, a significant improvement over acetylene girth welds in use previously. Simultaneously the industry began to develop material-quality standards, and consensus standards for the safe design, construction, operating, and maintenance of pipelines. ***In the late 1940s***, pipeline operators began to employ cathodic protection for new pipeline construction, a breakthrough in the understanding and control of corrosion. ***By the late 1950s***, even the older existing pipelines were equipped with cathodic-protection systems to mitigate corrosion. Operators began to radiograph girth welds, and imposed welder qualification and procedure qualification standards, both measures improving the reliability of the girth welds.

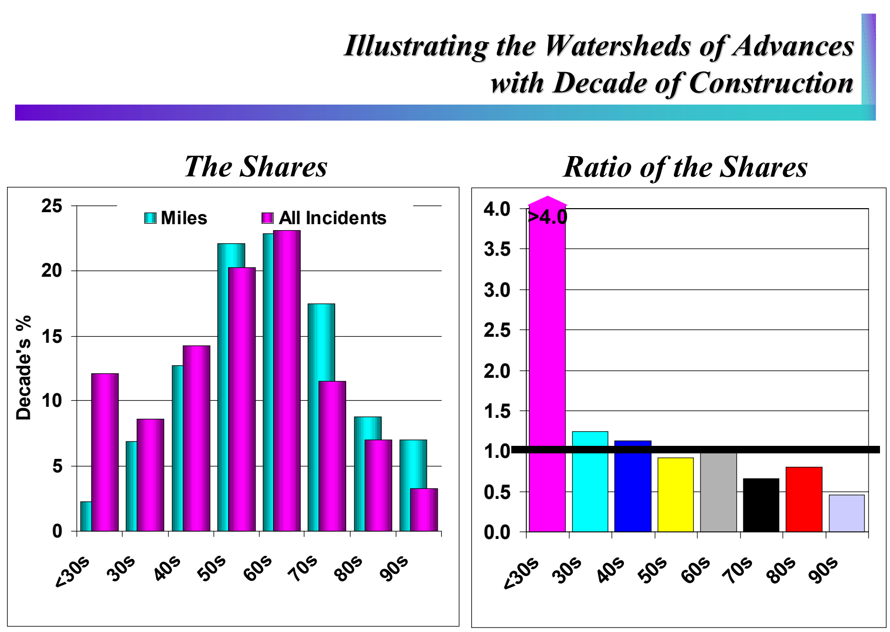
By the late 1960s, manufacturers began to use low alloy or low carbon steel widely, in tougher grades, resulting in steel with fewer defects; and to form the pipe a high frequency electric resistance weld, another improvement in the reliability of the longitudinal seam. Pipeline operators began to test all new construction with a hydrostatic pressure test, assuring the soundness of the pipe before it was put into service. (Older pipe with a low frequency electric resistance weld and a leak history has subsequently been taken out of service temporarily and subjected to a hydrotest.) Manufacturers universally applied improved coatings to new pipe, another advance in corrosion control. New "in-line" tools became available that allowed inspection for corrosion and other developing defects while the pipeline remained in service.

The "smart pig," first introduced in 1965, is now a generic name for a number of in-line inspection tools that have become increasingly sophisticated over the years, targeting specific types of defects with more accuracy.

By the late 1990s, anti-corrosion coatings had improved further, and were tested before being placed in service to ensure that they were not damaged during transport and construction. Pipelines are now installed with deeper cover, and bored crossings under highways and waterways provide greater protection and less potential for damage during installation. In-line inspection tools have evolved to locate corroded areas before they fail, and technology for finding and evaluating other types of defects is evolving rapidly. These advances improve the performance of pipelines of any age. It is now possible to ensure the continuing integrity of a pipeline by means of periodic tests and inspections where pipeline attributes and service histories indicate there is a need.

As shown in the graph,

- The performance of pipe installed before the advances of the late 1920s (now 70 years old and older) shows more incidents per mile than other decades.



Incidents for line pipe from all causes for the period from 1986-1999. Pipeline mileage collected in Pipeline Performance Tracking System and incident data submitted to the Office of Pipeline Safety on Form 7000-1. Incident data, covering the period 1986-99, reflect the ongoing review by ASME B31.4 Committee. Source: Allegro Energy Group and Kiefner & Associates.

- The performance of pipe installed after the advances of the late 1960s (now 30 years old and younger) shows fewer incidents per mile than other decades.

- The performance of pipe installed after the late 1920s but before the universal application of cathodic protection (that installed in the 1930s and 1940s, so now between 50 and 70 years old) shows a marginally higher rate of incidents per mile than the average. This result is solely due to the higher rate of external corrosion incidents for these decades. Isolating the external corrosion incidents from other causes and risk factors, these decades do not generally show a high rate of incidents.

- The performance of pipe installed after the universal application of cathodic protection but before the advances of the late 1960s (that installed in the 1950s and 1960s, so now between 30 and 50 years old) shows about the same number of incidents per mile as the average.

FINDINGS AND RECOMMENDATIONS

Throughout its history, the oil pipeline industry has focused on improving safety performance through a variety of initiatives, and its record demonstrates success. The number of safety incidents reported to the Office of Pipeline Safety was almost 25% lower in 2000 than in 1995, for instance. Looking at three-year averages to smooth out year-to-year fluctuations, the annual number of incidents went from 184 in 1995-97 to 154 in 1998-2000, a 16% decline. The number of incidents and the volume released were both at historical annual lows in 2000.

The industry's initiatives have included those undertaken by individual firms, such as risk management programs and aggressive inspection using increasingly targeted and sophisticated in-line inspection tools. Initiatives have also included industry-wide efforts, such as the voluntary reporting regime called Pipeline Performance Tracking System, and the adoption of a new industry standard for integrity management.

The industry's multi-faceted approach reflects the realization that improving safety performance is not a one-dimensional task, but an all-encompassing effort. To be successful, operators (and their trade associations and regulators) must process and understand – must *integrate* – each piece of information available about a pipeline system and risk factors facing it. The availability of new and detailed information from the Pipeline Performance Tracking System marks a turning point in this effort, providing industry-wide information where each operator formerly was forced to rely on only its own, less complete, record.[12] Integration of this data into pipeline risk management programs will further improve performance.

[12]New detailed information will also be available from the Office of Pipeline Safety's Form 7000-1 in the coming years. The Office of Pipeline Safety has instituted a 5 gallon reporting threshold and the collection of much more comprehensive information on each incident.

General Findings

This examination of the industry's advances in technology and practices has resulted in some general findings and some specific recommendations that operators can use to prioritize their risk assessment and mitigation efforts.

- Age – the number of years a pipeline has been in service – is an unreliable indicator of the condition of a pipeline system. A better first indicator is the technologies that are represented in the manufacture and construction of the system when it was first placed in service. Even the decade of original construction, however, is only a first indicator. Also critical to a pipeline's condition are the renovation, inspection, and maintenance practices that have been applied since construction.

- Industry-wide information comparing the performance of pipeline systems based on the decade in which a system was constructed provides important broad indicators for operators to examine further in assessing their own systems.

- Specific techniques can prevent or slow deterioration in pipeline systems. Hence, determining the specific types of deterioration that a pipeline system or pipeline segment may experience over time is an important aspect of conducting pipeline-specific risk assessments.

- In recent years, the industry has developed specific techniques that contribute to the overall improved performance of pipe and pipelines installed since 1970, including:

  Universal use of non-destructive testing during construction, such as radiography and coating inspection

  Greater depth of cover

  Greater use of boring or directional drilling

  Greater use of pipeline corridors

  Improved backfilling techniques

  More effective, less vulnerable coatings

  More identifying markers along pipeline rights-of-way

- Other techniques have contributed to the overall improved performance of pipe and pipelines installed in any decade, including:

  Universal pipeline industry support of one-call centers

  Greater use of risk management techniques

  Improved training

Specific Recommendations for Some Pipe

The process of examining the advances in technology and practices and overlaying them on the decade of construction mileage and incident data brought some specific recommendations to the forefront. These recommendations may help operators to assess the characteristics and hence the risks in their own pipeline systems and to establish mitigation priorities accordingly. As is always the case, assessing risk and planning mitigation strategies requires that operators integrate information from a variety of sources. The information in this report and the recommendations below should be evaluated in light of the operator's knowledge of its system and the in-service conditions, inspection, and mitigation already applied.

Findings for Pre-1930s Pipe

- About 2% or about 4,500 miles of oil pipeline mileage nationwide is pre-1930s pipe.

- The performance of pipelines installed before 1930 shows a higher rate of incidents per mile than any other decade, across a variety of risk factors.

Recommendations for Pre-1930s Pipe

- Because the late 1920s was a watershed period in advances, operators should carefully evaluate pipelines constructed prior to 1930 against a number of risk factors that pre-date the advances.

- Cathodic protection and coatings were essentially unknown in the period during which this pipe was installed. Operators should give specific attention to risk of external corrosion. When developing risk factors or risk indexes, pre-1930s pipe should be rated along a continuum depending on when corrosion protection was first applied and its adequacy over time. The following conditions should be assigned relatively greater weight during risk assessment unless specific renovation or mitigation has been conducted:

  The pipeline system is not now under cathodic protection.

  The length of time the pipe remained without cathodic protection and what testing and renovation was conducted at the time cathodic protection was installed.

  The length of time the pipe has lacked adequate cathodic protection without hydrostatic testing or inspection using in-line inspection tools suitable for identifying corrosion.

  The pipeline remains uncoated.

- Before the late 1920s, pipeline designers recognized the greater likelihood of failure of the pipe material or the longitudinal seam. When developing risk factors or risk indexes for pre-1930s pipe, the following conditions should be assigned relatively greater weight during risk assessment unless specific renovation or mitigation has been conducted:

Pipe has not been pressure tested.

- Before the late 1920s, pipe segments may have been joined with early, less reliable methods. When developing risk factors or risk indexes for pre-1930s pipe, the following conditions should be assigned relatively greater weight during risk assessment unless specific renovation or mitigation has been conducted:

  Pipe is still joined with threaded collars, mechanical couplings and or acetylene girth welds.

  Electric arc girth welds were not made from "all positions."

- Early pipe may have been manufactured from more brittle steels and may have been installed with shallower cover. Pre-1930s pipe should be evaluated with special consideration for protection from excavation damage, including the use of depth-of-cover surveys in populated areas or in areas subject to modern deep plowing techniques or drainage tiling.

Findings for 1930s and 1940s Pipe

- 1930s and 1940s pipe is almost 20% or about 19,000 miles of the nation's oil pipeline system.
- The overall performance of 1930s and 1940s pipe is comparable to later decades, except for external corrosion incidents.
- 1940s pipe has a higher rate of accidents from third party (excavation, farming) damage than other decades of construction.

Recommendations for 1930s and 1940s Pipe

- Because corrosion protection technology was in the early stages of development, 1930s and 1940s pipe should be evaluated for corrosion damage that may have occurred prior to the application of cathodic protection. When developing risk factors or risk indexes for 1930s and 1940s pipe, the following conditions should be assigned relatively greater weight during risk assessment unless specific renovation or mitigation has been conducted:

  The pipeline system is not now under cathodic protection.

  The length of time the pipe remained without cathodic protection and what testing and renovation was conducted at the time cathodic protection was installed.

The length of time the pipe has lacked adequate cathodic protection without hydrostatic testing or inspection using in-line inspection tools suitable for identifying corrosion.

The pipeline remains uncoated.

- Because of conditions specifically related to the construction of pipelines during World War II (availability and quality of steel, shallow pipeline cover), 1940s pipe should be evaluated with special consideration for protection from excavation damage, including the use of depth-of-cover surveys in populated areas or in areas subject to modern deep plowing techniques or drainage tiling.

Findings for 1950s and 1960s Pipe

- 1950s and 1960s pipe is about 45% or about 90,000 miles of nation's oil pipeline system.
- The overall performance of 1950s and 1960s pipe is comparable to later decades.
- Although overall defective pipe and pipe seams comprise only 8% of all failures, such failures are over-represented in 1950s and 1960s pipelines.

Recommendations for 1950s and 1960s Pipe

- 1950s and 1960s pipe should be rated along a continuum for pipe and pipe seam and pipe weld failures. The following conditions should be assigned relatively greater weight during risk assessment unless specific mitigative actions have been conducted:

  Pipe has not undergone a hydrostatic test and has had seam failures

  Pipeline system operates at high pressure versus minimum yield strength

Findings for 1970s, 1980s, 1990s Pipe

- 1970s, 1980s, and 1990s pipe is about 33% or 66,000 miles of the nation's oil pipeline system.
- Pipeline constructed since 1970 represents the current state of the art in the metallurgy of steel, pipe mill practices, and construction techniques.

- All pipelines constructed since 1970 have been hydrostatically tested at the time of initial construction.

Recommendations for 1970s, 1980s, 1990s Pipe

- Follow established industry procedures and practices.

- Utilize risk management and integrity management programs

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Over time, advances in pipe manufacturing and pipeline construction have made pipelines of more recent decades superior in design to early pipelines. However, the specific characteristics or shortcomings of the early decades can be identified and managed. Pipeline systems constructed in any decade can provide safe and reliable performance with the application of the newest testing and monitoring techniques, and with an appropriate program of assessment and mitigation as required.

Operators can use the information developed in this report to understand the advances in technology and practices that have occurred in over the decades and when they occurred. Without the perspective of these advances one cannot adequately assess the pipeline-specific risk factors, and without the information on when the advances occurred, one cannot illustrate the impact of the advance on performance. The combination can provide a tool for pipeline operators to assess risk factors in their systems and to prioritize mitigation programs.
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APPENDIX: PIPELINE MILESTONES

1834	first U.S. cast iron pipe made at Millville, NJ
1856	Bessemer steel is developed
1858	first successful oil well - Titusville, PA
1863	first successful oil pipeline moved 800 barrels of crude oil per day
1863	pipelines joined by screwed couplings
1863	pipe is wrought iron with furnace lap-welded seams
1869	hydraulic testing of pipe begins as a quality assurance test
1871	Bessemer steel begins to displace wrought iron
1891	Dresser coupling is developed to join pieces of pipe end-to-end mechanically
1897	first 30” diameter lap-welded pipe is made
1899	first large diameter (20”) seamless pipe is made, 5/8” wall thickness
1900	most lap-welded pipe is made from steel; open hearth steel making is the predominant process
1904	first major gas transmission pipeline, 16” diameter
1911	one-mile pipeline constructed with oxy-acetylene girth welds
1914	35-mile pipeline constructed with oxy-acetylene girth welds
1917	11-mile pipeline is welded with electric metal arc welding
1919	American Petroleum Institute chartered
1924	a process for making line pipe by electric resistance welding with direct or low frequency current is invented
1925	large diameter seamless pipe (made by the plug mill process) becomes available (24” diameter)

1927	electric flash-welded pipe is developed
1928	first API Standard 5L for making line pipe appears, covers furnace butt-welded pipe, furnace lap-welded pipe, and seamless pipe. Minimum yield strength 25,000 psi, maximum yield strength 45,000 psi. Manufacturers hydrostatic test to a maximum of 60% of the specified minimum yield strength
1930	first long distance pipeline (1000 mile, 24” diameter) is constructed primarily with electric arc girth welding
1931	API Standard 5L modified to include electric resistance-welded pipe (ERW)
1933	most large diameter pipelines are welded with electric arc girth welding
1935	publication of first standard code for design of pressure piping
1942	API Standard 5L now includes hydrostatic testing of pipe to a minimum of 60% of SMYS and a maximum of 80% of SMYS
1942	American standard code for pressure piping appears
1942-1943	War emergency pipelines, 20” and 24” diameter, constructed between Texas and New Jersey
1944	electric flash-welded pipe included in API Standard 5L
1946	manufacture of large diameter (30”) single submerged-arc-welded pipe begins
1948	radiographic inspection of girth welds is introduced
1948	double submerged-arc-welded pipe is introduced
1948	first tentative Standard 5LX introduced, covers 42,000 psi minimum yield strength material
1951	ASA B31.1 Code supercedes the American Standard Code for Pressure Piping
1953	line pipe Grades X46 and X52 are introduced
1956	mill hydrostatic testing to 90% of SMYS introduced
1959	ASA B31.4 appears as a separate code for oil transportation piping systems
1962	furnace lap-welded pipe deleted from API Specification 5L
1962	basic oxygen steel-making method accepted in API Specification 5L
1963	nondestructive inspection of line pipe under API Specification 5L begins
1965	first use of “smart pig” in pipeline
1966	Grade X60 line pipe appears

1967	Grade X65 line pipe appears
1969	last manufacturer of furnace lap-welded pipe goes out of business
1969	supplemental requirements for toughness testing introduced in API Specification 5L
1970	Bessemer steel dropped from API Specification 5L
1970	Code of Federal Regulations Title 49 Part 195, mandatory federal safety regulations for liquid petroleum pipelines
1973	Grade X70 line pipe appears
1977	TransAlaska pipeline begins operating, eventually carries 15% of the nation’s crude oil supply (2 million barrels per day) at its peak
1980	high-resolution smart pig becomes available
1982	experimental smart pig for crack detection is tested
1983	API 5L and 5LX combined in API 5L, applying to all grades of steel.
1985	Grade X80 line pipe appears
1992-95	crack detection tools are proven for some applications
2000	minimum level fracture toughness made mandatory in API Specification 5L
2001	publication of API Standard 1160, Managing System Integrity fro Hazardous Liquid Pipelines

SUMMARY OF PRACTICES AND DEVELOPMENTS

(Follow color and position to track practices from decade to decade)

- **Pipe Manufacture**
  - **Pipeline Construction Practices**
    - **Corrosion Control**
      - **Inspection and Maintenance**
        - **Common Upgrades (Later Years)**
          - **Industry & Regulatory Standards**

Pre-1920

- Lap-welded and butt-welded longitudinal seams (recognized as less than 100% efficient)
  - 20-ft segments joined by threaded collars, mechanical couplings or acetylene girth welds
    - It was assumed that bare unprotected pipe would last as long as needed but no criteria for useful life existed
      - Probably limited to responding to leaks
        - Collars or welds replaced with electric arc girth welds; corrosion pits identified and removed or repaired; pipe cleaned and coated; cathodic protection applied
          - American Petroleum Institute chartered

1920s

- Large diameter electric-welded and seamless pipe developed, significantly more reliable than lap-welded or butt-welded pipe
  - Segments still joined by collars, couplings or acetylene girth welds
    - Pipe still installed bare
      - Probably limited to responding to leaks
        - Pipe made with low-frequency electric resistance welds subjected to testing or inspection for seam defects; collars or welds replaced with electric arc girth welds; corrosion pits identified and removed or repaired, pipe cleaned and coated; cathodic protection applied.
          - API 5L for pipe manufacturing; includes yield strength standards and hydrostatic testing provisions

(Cont'd)

Decade	Pipe Manufacture	Pipeline Construction Practices	Corrosion Control	Inspection and Maintenance	Common Upgrades (Later Years)	Industry & Regulatory Standards
1930s	Many systems made with seamless or electric-welded pipe (increasingly supplanting the use of lap- or butt-welded pipe)	Electric arc welds becoming common	Use of coatings began (coal-tar applied during installation); cathodic protection seldom if ever applied	Practice of visual right-of-way inspection becomes more common	Pipe made with low-frequency electric resistance welds subjected to testing or inspection for seam defects; collars or welds replaced with electric arc girth welds; corrosion pits identified and removed or repaired, pipe cleaned and coated; cathodic protection applied.	First design standard for pressure piping; electric resistance-welded pipe added to API Standard 5L
1940s	Most systems made with seamless or electric-welded pipe	Electric arc girth welding became the norm	Most pipelines had coating applied during installation; many had cathodic protection installed from the outset or within the first year	Radiographic inspection of girth welds introduced	Pipe made with low-frequency electric resistance welds subjected to testing or inspection for seam defects; corrosion pits identified and removed or repaired, pipe cleaned; cathodic protection applied if not in place.	Code for pressure piping; API Standard 5L covers more pipe with more requirements
1950s	Majority of systems used electric resistance- or flash-welded pipe; new high-strength steel grades, double-submerged-arc seam process becomes common for pipe of 20-inch diameter and up	All systems constructed with electric arc girth welds	All had coating (coal-tar or asphalt enamel) applied during installation; most installed with cathodic protection from the beginning	Additional nondestructive testing introduced	Pipe made with low-frequency electric resistance welds subjected to testing or inspection for seam defects; corrosion pits identified and removed or repaired.	New industry codes for oil transportation piping

(Cont'd)

	Pipe Manufacture	**Pipeline Construction** Practices	**Corrosion Control**	**Inspection and Maintenance**	**Common Upgrades (Later Years)**	**Industry & Regulatory Standards**
1960s	Improved grades; ERW made with high frequency welds		Coatings applied to pipe before installation including polyethylene jackets, tape and the first fusion-bonded epoxies; use of cathodic protection becomes universal	Smart pigs for in-line inspection introduced	Corrosion pits identified and removed or repaired.	More stringent pre-service hydrostatic testing; nondestructive inspection methods made mandatory part of line pipe manufacturing
1970s	Steel made from basic-oxygen process for "cleaner" steel; ERW made with high frequency welds and substantially improved reliability		Increased use of fusion-bonded epoxy coatings			Bessemer steel dropped from API 5L; mandatory federal safety regulations for liquid petroleum pipelines implemented (CFR Title 49 Part 195)
Post 1980				Internal inspection tools evolve: high-resolution smart pigs, crack detection tools, ultrasonic tools, and deformation tools		Line pipe minimum toughness requirement made mandatory, integrity assessment for high-consequence areas becomes mandatory

GLOSSARY

Steel	A form of iron in which specific amounts of carbon and, in some cases, other alloying elements are used to obtain specific sets of useful properties. Steel is relatively easy to form into useful shapes at high temperatures by mechanical means. By controlling the amounts of alloying elements and the rates of cooling, manufacturers can produce wide varieties of useful materials.
Carbon Steel	A type of steel in which the only element intentionally added to iron is carbon. Low to medium carbon steels with carbon contents of 0.05 to 0.40 percent by weight or less were the first steels used for structural applications (*i.e.*, building frames, bridges, pipelines). High carbon steels (0.40 percent to 1.0 percent by weight) were generally used for non-structural applications such as tools and mechanical devices.
Alloy Steel	A steel in which both carbon and other elements such as manganese, nickel, chromium, molybdenum, vanadium, titanium, or columbium are added in small amounts to enhance strength and toughness. Low-alloy steels are most often used for structural applications. High-alloy steels tend to be used for tools and mechanical devices.
Stainless Steel	A class of steels in which significant amounts (eight to 20 percent) of chromium or nickel are added to achieve a combination of strength, toughness, and corrosion resistance. Because these materials require special facilities to manufacture, form, and fabricate, their use is reserved for special applications, such as where high- or low-temperature resistance is prized.
Hot Working (or hot forming)	A term applied to the process in which steel is formed from a cast ingot or slab into a structural shape such as a beam or column, a tube (as in seamless pipe), or a flat plate or elongated flat strip. Hot working generally is carried out when the steel is at a temperature between 1,432°F and 2,300°F.
Cold Working (or cold forming)	A term applied to the process in which steel is formed into useful shapes without being heated. Generally, cold working or forming is done at ambient (i.e., room) temperature. Technically, any working that takes place below 1,432°F, the temperature at which low-carbon or low-alloy steels undergo a solid-state phase transformation induces "cold work."
Heat Treatment	A process for changing the strength, hardness, or toughness of iron or steel by heating it to a high temperature to achieve the desired ranges of these properties.

Strength	A property of steel usually defined either as yield strength or ultimate tensile strength. The yield strength corresponds to the level of applied stress at which the material begins to exhibit permanent distortion; tensile yield strength being the point at which elongation induced by tensile load is no longer recoverable upon unloading. The ultimate tensile strength is the highest level of applied tensile stress that the material can tolerate. Any additional load produces failure.
Specified Minimum Yield Strength (SMYS)	The minimum yield strength guaranteed by the manufacturer for a particular grade of material.
Ductility	The ability of a material to deform irreversibly under load without failing.
Toughness	The ability to resist crack propagation under increasing tensile stress.
Brittleness	The inability of a material to deform irreversibly under load without failing. In other words, the tendency to fail suddenly without appreciable deformation when the applied stress reaches a certain level.
Seamless Pipe	A type of line pipe made by "piercing" a hot (2,200°F to 2,700°F) solid, round billet of steel as it is ovalized by being spiraled between two skewed-axis spirally rolls. After being pierced, the resulting "round" is reheated and formed to near-final pipe size in a "plug mill." Final steps in forming seamless pipe include "reeling" in which the pipe is passed over another smooth plug to give it its final wall thickness, and passing it through external sizing and straightening rolls.
Electric-Resistance-Welded (ERW) Pipe	A type of line pipe made by progressively cold forming a flat strip of steel into a cylindrical shape and passing the resulting cylinder through a cluster of rolls forming a circular opening equal to the outside diameter of the finished pipe while the edges of the cylinder are simultaneously heated by means of electric current. At the instant the converging edges are forced together by the mechanical pressure of the rolls, the short circuit current heats a narrow zone of material at each edge to a temperature suitable for bonding. As the bond is being formed, heat-softened material is extruded radially outward and radially inward from the pipe wall thickness. The excess material at both surfaces is immediately trimmed off. The bondline region is then given a post-weld heat treatment by means of induced electric-current resistance heating.
Low-Frequency or d.c.-Welded ERW Process	An obsolete process for making ERW pipe where in the electric current was either direct current or low-frequency alternating current (60 to 360 cycles).
High-Frequency-Welded ERW Process	A contemporary process for making ERW pipe using an alternating current at a frequency of 450 kilocycles.

Electric-Flash-Welded (EFW) Pipe	A type of pipe made in the past but which is no longer made. EFW pipe was made from 40-foot steel plates by cold forming the plates into "cans." The abutting longitudinal edges were then brought together with mechanical pressure while electric current was caused to flow, heating the edges to a suitable temperature for bonding. The excess metal was extruded radially inward and outward. In EFW pipe, this extra metal was not trimmed flush with the pipe surface. Instead, a raised flat-topped "flash" remained at both the outside and inside surfaces. This distinctive appearance makes flash-welded pipe easily recognizable.
Submerged-Arc-Welded Pipe (straight seam)	A type of line pipe made by cold forming 40-foot-long steel plates into cans. The longitudinal edges of the can are then joined by a two-pass submerged-arc weld, one made along the inside surface, and one made along the outside surface. To make each weld, an electric arc is used to melt filler metal in the form of wires that fuses with and joins the edges of the plate.
Submerged-Arc-Welded Pipe (spiral seam)	A type of line pipe made by cold forming a strip of steel into a helix such that the edge of the helix is progressively joined to itself by a two-pass submerged-arc weld in much the same manner as the two-pass weld used to form the longitudinal seam of straight-seam submerged-arc-welded pipe.
Bondline	The boundary between the two formed edges of a steel plate or strip that have been brought together after the plate or strip has been formed into a cylinder and the edges have been mechanically forced together while hot enough to form a solid metal-to-metal bond.
Parent Metal	That portion of a piece of line pipe that consists entirely of the original steel plate or strip unchanged by heat from any welding process.
Heat-Affected Zone	That portion of a piece of line pipe that consists entirely of the original steel plate or strip but which has been altered in terms of its microstructure by the heat of a welding process.
Weld Metal	The as-deposited added filler metal that results from the melting of a wire or electrode that was not part of the original pipe steel.
Longitudinal Seam	The region of a pipe where the edges of a steel plate or strip have been joined to one another after the originally flat plate or strip has been reshaped to form a cylinder.
Microstructure	The nature of the grain structure of steel as it appears under a microscope after having been suitably prepared.
Joint	Term often used to refer to a single piece of line pipe. Alternatively, joint may refer to the location where one pipe is joined end to end with another.

Girth Weld (Back to text)	The circumferential weld made to join one piece of line pipe to another.
Acetylene (girth) Weld	A weld formed by using an oxy-acetylene flame to melt a steel rod, filling the gap between the ends of two pieces of line pipe with the molten metal such that a solidly fused weldment joins one pipe to another.
Electric Arc (girth) Weld	A circumferential weld formed by melting steel electrodes to produce added filler metal to join one piece of line pipe end to end with another. An electric arc is established by passage of electric current through the electrode either to or from pieces of pipe to be joined and the heat of the arc melts the electrode so that the gap between the two pipes can be filled with solid metal fused soundly to each piece of the pipe.
(all) Position Weld	A technique for joining one piece of pipe end-to-end to another without moving or rotating the pipes. A position weld requires the ability to deposit the filler metal in all clock positions, even when the molten metal must be directed vertically upward against the force of gravity. This is accomplished by utilizing the "pressure" derived from the force of the electric arc (or the combustion gases in the case of acetylene welding). This technique is essential in pipeline construction since an entire pipeline cannot be "rolled" to accommodate 360-degree welding in a downward metal-deposition mode.
Roll Weld	A technique for joining one piece of pipe end-to-end with another while continually rolling the pieces of pipe so as to accommodate welding entirely in a downward metal-deposition mode. Obviously, an entire pipeline cannot be constructed by roll welding.
Keyhole Welding	The technique used to deposit the first pass of weld metal between the two adjacent but not touching ends of two pieces of line pipe.