

PIPELINE INDUSTRY

- **COMPARISON OF U.S. WITH FOREIGN PIPELINE LAND USE AND SITING STANDARDS**
- **MAINTENANCE, REHABILITATION AND RETROFITTING POLICIES AND PRACTICES**

F.H. (Bud) Griffis
Robert Dresnack
Sophia Evans
Eugene Golub
Joshua Greenfeld
Louis J. Pignataro
Luz Vega

NEW JERSEY INSTITUTE OF TECHNOLOGY
Institute for Transportation
323 Martin Luther King Boulevard
Newark, NJ 07102



APRIL 1996

FINAL REPORT

This document is available through the
National Technical Information Service,
Springfield, Virginia 22161

Prepared for

U.S. DEPARTMENT OF TRANSPORTATION
Research and Special Programs Administration
Office of Pipeline Safety
Washington, DC 20590

Technical Report Documentation Page

1. Report No. DTRS56-94-C-0006		2. Government Accession No.		3. Recipient's Catalog No.	
4. Title and Subtitle PIPELINE INDUSTRY: • Comparison of U.S. with Foreign Pipeline Land Use and Siting Standards • Maintenance, Rehabilitation and Retrofitting Policies and Practices				5. Report Date April 1996	
				6. Performing Organization Code DOT/RSPA/OPS	
7. Authors F.H. (Bud) Griffis, Robert Dresnack, Sophia Evans, Eugene Golub, Joshua Greenfeld, Louis J. Pignataro, Luz Vega				8. Performing Organization Report No.	
9. Performing Organization Name and Address NEW JERSEY INSTITUTE OF TECHNOLOGY Institute for Transportation 323 Martin Luther King Blvd. Newark, NJ 07102				10. Work Unit No. (TRAIS)	
				11. Contract or Grant No. DTRS 56-94-C-0006	
12. Sponsoring Agency Name and Address U.S. DEPARTMENT OF TRANSPORTATION Research and Special Programs Administration/Office of Pipeline Safety 400 7th St. S.W., Rm. 2335 Washington, D.C. 20590				13. Type of Report and Period Covered Final Report	
				14. Sponsoring Agency Code OPS	
15. Supplementary Notes					
16. Abstract <p>This report documents results from the analysis of maintenance, rehabilitation and retrofitting policies and practices of the gas and hazardous liquids pipeline industry, and their comparison with the Federal Pipeline Safety Regulations (i.e. 49 CFR Parts 191, 192, 194 and 195) as they apply to these areas. The report also compares the above-noted regulations with counterparts in Canada, Australia, Germany, Japan and the United Kingdom as they relate specifically to the land use and siting of pipelines in close proximity to urban (i.e. densely populated) and/or environmentally sensitive areas.</p> <p>A comparison of siting and land use policies in urban and/or environmentally sensitive areas for the six nations analyzed indicates that the regulations are written in a very similar manner. A few issues specifically addressed in some foreign regulations and not found currently in the United States regulations include the concepts of pipeline life, fatigue life, third-party factors, and use of on-line instrumentation for leak detection and earthquake impacts.</p> <p>Industry interviews, examination of internal documents and literature reviews were performed to develop and analyze current industry policies and practices. Seven operators were surveyed. Gas transmission pipeline operators generally exceed the regulatory requirements with regard to welding practices as a matter of good business. Their operating procedures for general construction requirements generally conform to the regulations; however, operators prefer replacement of damaged pipe even though repairs are allowed. Industry practices in corrosion control are extensive and discussed in the report. Testing practices meet and usually exceed those required by the regulations. Unanimously, the industry feels that the best preventive maintenance measure is quality control during construction. The analysis of the hazardous liquid pipeline operators revealed similar policies and practices to those of the gas operators. A special commentary on the state-of-the-art in pipeline maintenance, rehabilitation and retrofitting is contained in the report.</p>					
17. Key Words U.S. AND FOREIGN PIPELINE REGULATIONS, REHABILITATION, RETROFITTING, REPAIR, GAS, HAZARDOUS LIQUIDS, PIPELINE, SAFETY, MAINTENANCE, TRANSMISSION LINES, OPERATOR, CORROSION, WELDING, URBAN AREAS, SITING, LAND USE, ENVIRONMENTAL IMPACT.			18. Distribution Statement		
19. Security Classification (of this report) Unclassified		20. Security Classification (of this page) Unclassified		21. No. of Pages 22	22. Price

NOTICE

This document is disseminated under the sponsorship of the Department of Transportation in the interest of information exchange. The United States Government assumes no liability for the contents or use thereof.

PREFACE

The research associated with this report was performed under contract to the Office of Pipeline Safety of the Research and Special Programs Administration of the U.S. Department of Transportation procured by solicitation # DTRS56-94-R-0006. This study compares the United States Pipeline Safety Regulations (i.e., 49 CFR Parts 191, 192, 194, and 195) with the pipeline safety regulations of Canada, Australia, Germany, Japan and the United Kingdom as they relate specifically to the land use and siting of pipelines in close proximity to urban (i.e., densely populated) and/or environmentally sensitive areas. The similarities and differences in the respective regulations are noted in the text herein.

In addition, the objective of this report is to present the results of the analyses of the rehabilitation and retrofitting policies and practices of the gas transmission and hazardous liquid pipeline industry in the United States and to identify the Federal pipeline safety regulations promulgated in these areas. The research also provides insights into the state-of-the-art techniques either being presently utilized or being investigated at present by the pipeline industry.

METRIC CONVERSION FACTORS

Approximate Conversions to Metric Measures

Symbol	Quantity	Multiply by	To Find	Symbol
LENGTH				
in.	inches	2.54	centimeters	cm
ft.	feet	30.00	centimeters	cm
yd.	yards	0.90	meters	m
mi.	miles	1.60	kilometers	km
AREA				
in.'	square inches	6.50	square centimeters	cm ²
ft.'	square feet	0.09	square meters	m ²
yd.'	square yards	0.80	square meters	m ²
mi.'	square miles	2.60	square kilometers	km ²
	acres	0.40	hectares	he
MASS (weight)				
oz.	ounces	28.00	grams	g
lb.	pounds	0.45	kilograms	kg
	short tons (2000 lb.)	0.90	tonnes	t
VOLUME				
tsp.	teaspoons	5.00	milliliters	ml
Tbsp.	tablespoons	15.00	milliliters	ml
fl. oz.	fluid ounces	30.00	milliliters	ml
c.	cups	0.24	liters	l
pt.	pints	0.47	liters	l
gal.	gallons	3.80	liters	l
ft. ³	cubic feet	0.03	cubic meters	m ³
yd. ³	cubic yards	0.76	cubic meters	m ³
TEMPERATURE (exact)				
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius Temperature	°C
PRESSURE				
bars	bars	14.50	pounds/sq. in.	psi

METRIC CONVERSION FACTORS

Approximate Conversions from Metric Measures

Symbol	Quantity	Multiply by	To Find	Symbol
LENGTH				
mm	millimeters	0.04	inches	in.
cm	centimeters	0.40	inches	in.
m	meters	3.30	feet	ft.
m	meters	1.10	yards	yd.
km	kilometers	0.60	miles	mi.
AREA				
cm ²	square centimeters	0.16	square inches	in. ²
m ²	square meters	1.20	square yards	yd. ²
km ²	square kilometers	0.40	square miles	mi. ²
he	hectares (10000 m ²)	2.50	acres	
MASS (weight)				
g	grams	0.035	ounces	oz.
kg	kilograms	2.20	pounds	lb.
t	tonnes	1.10	short tons (2000 lb.)	
VOLUME				
ml	milliliters		fluid ounces	fl. oz.
l	liters		pints	pt.
l	liters		quarts	qt.
l	liters		gallons	gal.
m ³	cubic meters		cubic feet	ft. ³
m ³	cubic meters		cubic yards	yd. ³
TEMPERATURE (exact)				
°C	Celsius Temperature	9/5 (then add 32)	Fahrenheit Temperature	°F
PRESSURE				
psi	pounds/sq.in.	0.069	bars	bars

TABLE OF CONTENTS

INTRODUCTION	1
PART 1 COMPARISON OF UNITED STATES AND FOREIGN SITING PIPELINE SAFETY REGULATIONS	4
1.1 EXAMPLES OF SPECIFIC COMMON ISSUES INVESTIGATED IN THE PIPELINE REGULATIONS REVIEWED.....	4
1.2 COMMON CATEGORIES TABULATED IN THE APPENDIX TO THIS REPORT	6
1.2.1 Applicability of Regulations	7
1.2.2 Classification of Locations	7
1.2.3 Pressure Design Formulation for Steel Pipelines	7
1.2.4 Transmission Line Valve Spacing Requirements	7
1.2.5 Cover Requirements.....	7
1.2.6 Criteria and Regulators for Siting Pipelines	8
1.2.7 Patrolling of Pipelines	8
1.2.8 Maximum Allowable Operating Pressures	8
1.3 SECTIONS IN FOREIGN REGULATIONS NOT SPECIFICALLY ADDRESSED IN THE UNITED STATES REGULATIONS	9
1.3.1 Issue of a Design Life for a Pipeline	9
1.3.2 Australian Standards - Section 3.2 Design Life	9
1.3.3 Third-party Damage Provision.....	9
1.4 CONCEPT OF FATIGUE LIFE	10
1.5 USE OF IN-LINE MONITORING DEVICES	11
1.6 THE RATIONALE BEHIND THE DIFFERENCES BETWEEN FOREIGN AND UNITED STATES STANDARDS	11
1.7 CONCLUSIONS - BASIC DIFFERENCES IN THE REGULATIONS COMPARED TO THE UNITED STATES REGULATIONS	11
1.8 GENERAL CONCLUSIONS.....	12
PART 2 GAS TRANSMISSION PIPELINES AND PRACTICE IN THE UNITED STATES	13
2.1 WELDING • SUBPART E OF 49 CFR 192.....	14
2.1.1 Current Industry Policies.....	14
2.1.2 Industry Practices.....	14
2.2 GENERAL CONSTRUCTION REQUIREMENTS • SUBPART G OF 49 CFR 192	14
2.2.1 Current Industry Policies.....	14
2.2.2 Industry Practices	14
2.3 CORROSION CONTROL • SUBPART I OF 49 CFR 192	15
2.3.1 Industry Policies Associated With Corrosion - External Corrosion Control.	15
2.3.1.1 Corrosion Evaluation - External	15
2.3.1.2 Coatings and Coating Repair	17
2.3.1.3 Cathodic Protection.....	18
2.3.2 Industry Practices Associated With Corrosion Control - External Corrosion.	18
2.3.2.1 Corrosion Evaluation - External	19
2.3.2.2 Coatings and Coating Repair	19
2.3.2.3 Cathodic Protection.....	20
2.4 TEST REQUIREMENTS • SUBPART J OF 49 CFR 192.....	21
2.4.1 Current Industry Policies.....	21
2.4.2 Industry Practices.....	21
2.5 MAINTENANCE • SUBPART M OF 49 CFR 192	21
2.5.1 Current Industry Policies.....	21
2.5.2 Industry Practices.....	24

PART 3 UNITED STATES OIL AND HAZARDOUS LIQUID PIPELINES.....	25
3.1 CONSTRUCTION • SUBPART D OF 49 CFR 195.....	25
3.1.1 Current Industry Policies.....	25
3.1.2 Industry Practice	26
3.2 HYDROSTATIC TESTING • SUBPART D OF 49 CFR 195	26
3.2.1 Current Industry Policies.....	26
3.2.2 Industry Practice	26
3.3 OPERATION AND MAINTENANCE • SUBPART F OF 49 CFR 195.....	27
3.3.1 Current Industry Policies.....	27
3.3.2 Industry Practice	27
PART 4 COMMENTARY ON THE STATE-OF-THE ART IN UNITED STATES STEEL PIPELINE MAINTENANCE, REHABILITATION AND RETROFITTING	29
4.1 INTRODUCTION.....	29
4.2 PIPELINE SURVEILLANCE AND INSPECTION.....	30
4.3 LEAK DETECTION	30
4.3.1 Acoustic Monitoring Systems.....	31
4.3.2 Computer Based Monitoring Systems	31
4.3.3 Mathematical Modeling Systems	31
4.3.4 Recent Improvements in Leak Detection Software.....	31
4.4 IN-LINE INSPECTION	31
4.5 CATHODIC PROTECTION INVESTIGATIONS.....	32
4.6 PIPELINE MAINTENANCE	34
4.6.1 Preventive Maintenance.....	34
4.6.2 Routine Field Repairs.....	35
4.7 PIPELINE REHABILITATION	35
4.7.1 Determination of the Need for Rehabilitation.....	35
4.7.2 Design of a Pipeline Rehabilitation Program	36
4.7.2.1 Temporary Pipe Repair	36
4.7.2.2 Coating Repair and Replacement	37
4.7.2.3 Pipe Replacement Program	38
BIBLIOGRAPHY	39
APPENDIX A.....	A
APPENDIX B.....	B
APPENDIX C.....	C

LIST OF ILLUSTRATIONS

Figure 2.3.1.1 Classification of in-line devices 16

Figure 2.5.1 Preferred repair of imperfections, damages and leaks 23

Figure 3.2.2 Hydrotest layout 27

Figure 4.6.1 Assumed failure rate function 34

LIST OF TABLES

Table 2.0 Regulations and their relationship with maintenance, rehabilitation and retrofitting. 13

Table 2.3.2.3 Basic corrosion troubleshooting. 20

Table 3.0 Regulations and their relationships with maintenance, rehabilitation and retrofitting 25

Table 4.7.2.3 Pipe replacement program 38

LIST OF ABBREVIATIONS AND SYMBOLS

ABB	AIR ABRASIVE BLAST SYSTEM
AGA	AMERICAN GAS ASSOCIATION
API	AMERICAN PETROLEUM INSTITUTE
ASME	AMERICAN SOCIETY OF MECHANICAL ENGINEERS
DCVG	DIRECT CURRENT VOLTAGE GRADIENT
GPTC	GAS PIPELINE TECHNOLOGY COMMITTEE
GRI	GAS RESEARCH INSTITUTE
MAOP	MAXIMUM ALLOWABLE OPERATING PRESSURE
MFL	MAGNETIC FLUX LOSS
MR&R	MAINTENANCE, REHABILITATION AND RETROFITTING
MSVP	MAGNETIC SPHERE VALVE POSITIONING SYSTEM
NACE	NATIONAL ASSOCIATION OF CORROSION ENGINEERS
NEPA	NATIONAL ENVIRONMENTAL POLICY ACT
OPS	OFFICE OF PIPELINE SAFETY
SCADA	SUPERVISORY CONTROL AND DATA ACQUISITION
SMYS	SPECIFIED MINIMUM YIELD STRENGTH

INTRODUCTION

Part 1 of this report compares the United States Regulations (i.e. 49 CFR Parts 191, 192, 194 and 195) with the regulations in Canada, Australia, Germany, Japan, and the United Kingdom as they relate specifically to the land use and siting of pipelines in close proximity to urban (i.e. densely populated) and/or environmentally sensitive areas. Parts 2, 3 and 4 of the report document the results from the review and analysis of the routine maintenance, rehabilitation and retrofitting policies and practices of the United States gas transmission and hazardous liquid pipeline industry, and identify with the Federal pipeline safety regulations applicable to these issues.

The report is organized around the Pipeline Safety Regulations, specifically, Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards and Part 195 - Transportation of Hazardous Liquids by Pipeline AS THESE REGULATIONS APPLY TO THE ROUTINE MAINTENANCE, REHABILITATION, AND RETROFITTING OF PIPELINES. As a point of reference, the major subpart of the regulation is followed by a comprehensive description of the policies and practices as required by regulation and as practiced in the industry. (Note: Operator names are used only if information was obtained through public documentation). Current policies are taken from those documents that are prevalent in the industry that elaborate upon the intent of the regulation and the processes for complying with the regulation. The initial document used in this process is ASME B31.8 - 1992 for gas transmission pipelines and ASME 831.4 - 1992 for hazardous liquid pipelines. Finally, the current practices of the industry are investigated. Initial interviews with four gas and three hazardous liquid pipeline companies were held. Interviews with individual operators resulted primarily in generalities; they all profess to following the regulations. Lengthy discussions were held with a board of experts made up of experts from the gas and liquid pipeline industry and a board of experts on environmental matters. In addition, this report was reviewed by expert consultants assigned to this project. Papers presented at conferences, published articles and other discussions are used to add more depth to the industry practices and to look toward the state of the art.

In order to select the regulations to analyze with respect to maintenance, rehabilitation and retrofitting, it was necessary to decide just what each of the terms meant. Maintenance is the attempt to keep the pipeline at the state of service for which it was designed. For a buried or submerged gas or hazardous liquid pipeline, the best preventive maintenance that can be applied to the pipe is to ensure that quality control is in place when a pipeline is installed. Rehabilitation is the action taken to restore to the former level of service. Retrofitting is the upgrading of the pipeline by replacement of a portion of the pipeline system. The functions of these activities as they relate to the 49 CFR Parts 191, 192, 193, 194, and 195 are as follows:

MAINTENANCE

- Patrolling and inspection
- Maintenance of right of ways
- Maintenance of above ground structures
- Maintenance of valves
- Inspection of cathodic protection

- Routine maintenance of cathodic protection systems
- Welding
- General repair

REHABILITATION

- Close interval surveys
- In-line inspections
- Leakage surveys
- Cathodic protection system repair
- Coating repair and replacement
- Permanent pipeline repair
- Pipeline segment replacement
- Welding

RETROFITTING

- Pipeline system replacement
- Welding

The rationale for placing surveys and inspections under rehabilitation was simply that these functions are generally part of an operator's surveillance program for rehabilitation. They can just as easily be categorized as part of maintenance. These functions will form part of the criteria in selecting the regulations to discuss in this report.

In preparing Part 1 of this report, the following documents were reviewed:

-
1. Pipeline Safety Regulations- **49 CFR Parts 191, 192, 194, and 195**, revised as of October 1, **1995**.
 2. Environmental Impact Regulations promulgated by the Federal Energy Regulatory Commission (FERC).

-
1. Recommendations on Transmission and Distribution Practice - **IGE/TD/1 Edition 3: 1993 Communication 1530** - "Steel Pipelines for High Pressure Gas Transmission" published by the Institution of Gas Engineers.
 2. "Guidelines for the Environmental Assessment of Cross-Country Pipelines," published by the Department of Trade and Industry - **1992 (ISBN No. 0114142866)**.
 3. Code of Practice for Pipelines Part 2. Pipelines on Land: Design, Construction and Installation: Section **2.8**: Steel for *Oil and Gas*. **BS 8010**: Section **2.8**: **1992 [ISBN 05802099621]**, published by the British Standards Institution.

Australia

1. "Pipelines - Gas and Liquid Petroleum," published by Standards Australia (**No. AS 2885 - 1987**) in **1987**, and prepared by Committee **ME/38**, Gas and Liquid Petroleum Piping Systems.

Canada

1. Standard Z662-94, "Oil and Gas Pipeline Systems," published in 1994 by the Canadian Standards Association (CSA).
2. National Energy Board Onshore Pipeline Regulations as per the National Energy Board Act - June 8, 1989.

Japan

1. The Japanese Pipeline Safety Standards are entitled, "Tsusho Sangyo Roppo," published by MITI (Ministry of Industry and Trade).

Germany

1. DVGW - Standards G463 - "Steel Gas Service Mains With an Operating Pressure Exceeding 16 Bar; Construction," and G466/1 - "Gas Steel Pipeline Systems With an Operating Pressure Exceeding 4 Bar. Both of the above documents were published in 1989 by DVGW (Deutscher Verein des Gas- und Wasserfaches e.V.).
2. TrbF301 and TrbF302: Technische Regeln für brennbare Flüssigkeiten: Richtlinie für Fernleitungen zum Befördern gefährdender Flüssigkeiten (pipelines for hazardous liquids) and Richtlinie für Verbindungsleitungen zum Befördern gefährdender Flüssigkeiten (connecting piping for hazardous liquids).

At this writing, to the best knowledge of the authors, the above documents define the current safety regulations employed by the respective nations as they relate to gas and hazardous liquid pipelines.

As a general note, in analyzing the publication dates for the above-mentioned documents, it appears that the regulations in each foreign country are reviewed and updated periodically. However, the respective updates occur at different time intervals, and at different time horizons. As such, to remain current with the respective regulations cited herein, it will be necessary to contact the various governments periodically to be apprised of any updates. Also, the International Standards Organization (ISO), located in The Netherlands, through its Technical Committee No. 67 - Subcommittee No. 2 (i.e., TC67/SC2), has a group working on a draft of ISO regulations related to pipeline safety due to be completed this year. Thus, this organization should be contacted to ascertain when (and if) the above subcommittee will be reviewing the concept of developing unifying standards related to siting and land use issues.

The report and its findings are presented below in four specific parts as previously identified.

PART 1

COMPARISON OF UNITED STATES AND FOREIGN SITING PIPELINE SAFETY REGULATIONS

An analysis of the literature noted herein indicates that all of the respective nations involved in this study require that potential environmental impact issues be addressed as part of the siting process. The assessment requirements, where specifically stated (i.e., United States', United Kingdom, and Canadian Regulations), are quite similar; they generally involve an environmental inventory of the proposed alignment without the proposal, an evaluation of potential impacts associated with the proposal, consideration of specific mitigative methods that could be employed to minimize impact, and investigation of potential alternative alignments either initiated by the assessment preparer or by the regulatory agency reviewing the environmental assessment report. Once a proposed alignment has been selected, public hearings are generally conducted in the impact areas in order to elicit comments and questions from the public.

Issues of proximity of the proposed pipeline alignment to environmentally sensitive areas and/or to population centers are considered in the assessment preparation and review process prior to final selection of the pipeline alignment. The concept of risk assessment (i.e. risk assessment analysis), however, is not utilized directly as part of the siting process.

Tabulated in Appendix A to this report is information related to the regulatory agencies and/or specific regulations which oversee the siting of gas and hazardous liquid pipelines in the respective countries. In addition, numerous other "general categories" (e.g., cover requirements, patrolling requirements, class location definitions, etc.) are listed in the Appendix as they relate to regulating the pipeline industry for the various countries reviewed. The material in Appendix A provides an overview of citations listed in the respective regulations for many categories. However, the reviewers are cautioned to review the various regulations cited herein in their entirety for completeness because of the complexity of the regulations, and the numerous cross-referencing which often occurs in the documents which precludes their being extracted completely in simplified, tabulated form. The intent of the presentation herein is not to replace the need for reading the specific documents, but rather to provide an overview of how the regulations respond to issues common to all pipeline regulators.

1.1 EXAMPLES OF SPECIFIC COMMON ISSUES INVESTIGATED IN THE PIPELINE REGULATIONS REVIEWED

Whereas environmental assessments are basically utilized in the siting process by the nations evaluated to rationalize the ultimate selection of alignments (where unavoidable) in proximity to

*In the United States, site selection for gas transmission pipeline corridors are determined in accordance with the National Environmental Policy Act (NEPA) of 1969, and requirements for environmental impact reporting described therein (in Section 102C of the Act). The Federal Agency which oversees the process and grants approvals is the Federal Energy Regulatory Commission (i.e., FERC). Also see Appendix A and the Table entitled "Siting of Pipelines" for further information.

environmentally sensitive and/or densely populated areas, the regulation of the pipelines thereafter (i.e. in their construction and operational phases) is governed by the respective regulations cited in this report to insure the safety of such siting by providing more stringent design criteria and monitoring requirements in the most sensitive locations.

The regulations, with the exception of the German and Japanese regulations, initially develop a series of classifications of locations (normally between four and five) which are differentiated on the basis of either allowable (by zoning purposes) or actual population densities either stipulated within a specified distance from the pipeline or described as adjacent to the vicinity of the pipeline. Utilizing the aforementioned classification system, a number of design and/or construction criteria are established in the regulations (e.g., maximum spacing between valve locations, minimum cover requirements, etc.) and monitoring requirements (e.g., patrolling of lines, leakage surveys, etc.) which take into account the proximity of the pipeline to densely populated areas.

As previously noted, tabulated in Appendix A for each country analyzed is a brief description of the wording of the appropriate sections in the respective regulations for a specified category which describes its approach to various design, construction, or monitoring strategies as they relate specifically to proximity to densely populated and/or environmentally sensitive areas. One of the categories noted in the Appendix is the classification of locations system developed by each country. It, like many other categories analyzed (and appended herein) is handled in a similar fashion, but shows slight differences in its requirements, probably because of differences in defining its classification of locations.

As an example, a review of the classification of locations by the respective countries reveals the following:

- The Canadian system is virtually (i.e., with minimal differences as shown in the Table) the identical criteria that is utilized in the United States for gas pipelines (**49 CFR Part 192**). It is obvious that the United States and Canada either jointly developed the criteria, or one followed the other's lead in this category.

The main distinction between the two nations for this category is that the Canadian classifications apply to both natural gas and hazardous liquid transmission lines, whereas, in the United States regulations, location classifications apply only to natural gas pipelines.

- In the United Kingdom, the closest allowable proximity of a gas pipeline to existing occupied structures is a function of the classification category, the operating pressure in the pipeline, and the outside diameter of the pipe. In essence, the minimum separation distance required for each specific population density classification category defined (see Appendix A under class locations - United Kingdom for categories R, **S**, & T and their definitions) increases with increased diameter of the pipe, and increased maximum operating pressure. However, minimum separation distance requirements decrease with increased population density. As such, the regulations seemingly recognize the difficulty in establishing clearance in heavily populated areas, but compensate for same by reducing the design pressure in type **S** (i.e., more densely populated) areas compared to type R (i.e., less densely populated) areas.

lated) areas (See category of steel pressure design for the United Kingdom in the Appendix).

- In the German regulations for gas pipelines, the allowable proximity of pipelines to structures is a function of the nominal diameter of the pipe (i.e., the larger the pipeline, the greater the distance required). However, the regulations set forth in TRbF 301 clearly indicate, in section 2.3.2, that the right of way requirement “is to protect the pipeline”. For Canada, the United States, and Australia, there isn’t any minimum separation distance requirement between pipelines and neighboring structures. Although a minimum fifty-foot requirement is noted in the United States regulations for hazardous liquid pipelines (i.e., in Section 195.210 (b)), the requirement may be waived in lieu of providing an additional 12 inches of cover for the pipeline above the normal cover stipulated in Section 195.248 of the regulations.
- In the Japanese regulations, only above ground pipeline installations have minimum separation distance requirements from sensitive receptors (e.g. railroads, schools, nursing homes, hospitals, landmark properties, city water resources, etc.). See Appendix A under class locations for specific values.

As can be seen from the above examples, it is difficult to compare a specific category when analyzing the pipeline safety regulations of one nation versus another. Frequently, a combination of categories must be reviewed jointly because pipeline safety is often regulated through a combination of factors (Le., design, construction, operational) which are often interrelated and compensating.

1.2 COMMON CATEGORIES TABULATED IN APPENDIX A TO THIS REPORT

Provided in Appendix A are a number of different categories which are basically common to all the standards reviewed herein. Categories noted include those that pertain to design, construction, and operational policies associated with pipelines located in proximity to densely populated and/or environmentally sensitive areas, and which are categories addressed in most of the regulations reviewed. Specifically, the general categories listed are as follows:

- Where the regulations are applicable
- Classification of locations
- Pressure design formulation for steel pipeline
- Transmission line valve spacing criteria
- Cover requirements
- Criteria and regulators for siting pipelines
- Patrolling of pipeline criteria
- Maximum allowable operating pressures.

In reviewing the tabulated data noted above, there are many similarities noted insofar as the various categories are addressed. They are shown below for each category noted.

1.2.1 APPLICABILITY OF REGULATIONS

The regulations (i.e., except for Canada and Japan) generally include either pipelines that operate within an operating pressure range, exceed a certain operating pressure level, or have a hoop stress above 20 percent of SMYS (i.e., specified minimum yield strength).

1.2.2 CLASSIFICATION OF LOCATIONS

This category was previously addressed. All of the regulations except Germany and Japan develop a classification system based upon density of population within proximity to the pipeline alignment.

1.2.3 PRESSURE DESIGN FORMULATION FOR STEEL PIPELINES

Most of the countries utilize formulas, shown directly in their regulations, which relate the design pressure to the yield strength of the pipe, the design wall thickness, and a design factor which is related to a class location designation. Other variables utilized by some of the regulations include the outside diameter of the pipe (i.e., the United Kingdom and Australia), and a longitudinal joint factor and temperature derating factor (i.e., the United States and Canada). The Japanese regulations specify the minimum thickness requirements for pipelines of varying outside diameters.

1.2.4 TRANSMISSION LINE VALVE SPACING REQUIREMENTS

Spacing of valves is generally based upon class locations (i.e., the United States, Canada, and Australia) for gas pipelines. The German regulations stipulate a recommended range of spacing intervals for gas pipelines. For hazardous liquids, Canada and Australia specify valve spacing for high vapor liquids and generally leave it to designer judgment for low vapor liquids. However, Australia requires valves within public water supply reserve areas. The United Kingdom leaves it to the designer judgment for gas pipelines, and the United States leaves it mainly to designer judgment for hazardous liquid pipelines, with exceptions noted in section 195.260 of the regulations (e.g. section 195.260 (f) requirements on either side of a reservoir used for human consumption). The Japanese regulations require spacing of emergency valves every kilometer. In addition, normal operating valve spacing in proximity to pipe bends is based upon pipeline diameter (i.e., the larger the diameter, the greater the spacing intervals). Most regulations specify the need for valves on both sides of a water crossing.

1.2.5 COVER REQUIREMENTS

The United States, Canada, and Australia specify minimum depth of cover requirements based upon class locations, nature of material in the pipeline (e.g., gas, high vapor pressure liquid, low vapor pressure liquid) and nature of excavation (e.g., normal, rock). Cover requirements are also stipulated for on-shore and off-shore pipelines. The United Kingdom leaves the cover requirements to design judgment; however, it recommends that various forms of protection listed and illustrated in the regulations be considered to reduce the likelihood of pipeline damage. Germany and Japan have normal cover requirements of 1 meter, however, under city streets, the Japanese regulations require a cover of 1.8 meters.

1.2.6 CRITERIA AND REGULATORS FOR SITING PIPELINES

This category was previously described in the report. All the countries require environmental impact reviews and/or assessments be performed in planning the alignment for the pipeline. In most countries, a formal review process is employed by a regulator prior to the granting of approval of a proposed alignment.

1.2.7 PATROLLING OF PIPELINES

The regulations vary considerably on this issue. The United States regulations specify intervals between patrols as a function of class location; the United Kingdom specifies intervals for all but water crossings, and all are independent of class location. Canadian regulations allow for operator judgment, but list factors that should influence frequency of intervals to be employed; and Australia also allows for operator judgment subject to approval by the Statutory Authority where this is legally required. The German regulations do not appear to respond directly to this issue; however, in Regulation TRbF 301, Sections 2.3.1 and 2.3.2 respectively, it states that “the pipeline must be protected by a clearly marked right of way”, and “the right of way is to protect the pipeline”. Since the Japanese regulations specifically require the installation of leakage detection devices, there is no specific foot patrolling or frequency requirement.

1.2.8 MAXIMUM ALLOWABLE OPERATING PRESSURES

The United States, Canada, and Australia relate the maximum allowable operating pressure to the test pressure for the pipeline divided by a design factor varying between values of 1.1 to 1.5. The United States and Canadian regulations relate the design factor to class location and/or service fluid (i.e., gas, liquid), whereas the Australian regulations utilize design factors independent of class locations. The United Kingdom requires operators to go through a decision algorithm to establish the maximum operating pressure allowed. They also require that the value be determined and declared annually by the responsible engineer. The German regulations (i.e. TRbF 301, section 4.3.3) specify that the solidity of the pipeline is to be calculated for the worst pressure (plus 10 bar over pressure) and unfavorable temperatures. The standard safety factor is 1.6; in sensitive areas, it is 2.0. The Japanese regulations require the installation of pressure safety control devices in order to insure that the maximum operating pressure does not exceed ten percent (10%) above the design pressure.

In summary, review of a number of regulated categories related to pipelines in proximity to densely populated and/or environmentally sensitive areas from the various regulations examined, demonstrates a great degree of similarity in how the countries regulate the categories examined. The regulations of Canada, the United States and Australia are quite similar in their approaches, whereas the United Kingdom and Germany generally allow more designer and operator judgment rather than consistently quantify each category requirement. The Japanese regulations are quite specific in their requirements.

1.3 SECTIONS IN SOME FOREIGN REGULATIONS NOT SPECIFICALLY ADDRESSED IN THE UNITED STATES REGULATIONS

In reviewing the foreign regulations noted in this study, a number of sections included in other regulations and not specifically found in the United States regulations are indicated below for reference purposes.

1.3.1 ISSUE OF A DESIGN LIFE FOR A PIPELINE

The Australian Standards have developed a concept of a design life for a pipeline which is initially selected by the pipeline company.

At the time when the design life is reached, it is incumbent upon the pipeline company to conduct a study to evaluate whether the pipeline can continue to operate or not. The specific sections in the Australian Standards which refer to this concept are noted below.

1.3.2 AUSTRALIAN STANDARDS- SECTION 3.2 DESIGN LIFE

A design life nominated by the Operating Authority (i.e., the pipeline operator) is used as a basis for the design. At the end of the design life, the pipeline is abandoned unless an operator-directed approved engineering investigation determines that its continued operation is safe. Although not specifically defined, the engineering investigation would be expected to involve a strength test, an approved leak test, and a determination of the MAOP (Maximum Allowable Operating Pressure) of the pipeline in accordance with provisions in Section 9 of the regulations entitled "Inspection and Testing".

1.3.3 THIRD-PARTY DAMAGE PROVISION

The Australian Standards also have a section (i.e., Section 3.7) entitled "Third-party Damage" in which the concept is to protect against third-party damage by a combination of methods.

The recommended methods of protection are as follows:

- (a) DESIGN REQUIREMENTS
 - 1. Nominal wall thickness
 - 2. Depth of cover
- (b) ACCESS RESTRICTION
 - 1. Fencing the route
 - 2. Pipeline patrols
- (c) WARNINGS
 - 1. Pipeline marker
 - 2. Buried marker
- (d) PROTECTIVE BARRIER
 - 1. Concrete coating
 - 2. Concrete encasement
 - 3. Covering slab
 - 4. Casing
 - 5. Box culvert
- (e) OTHER APPROVED METHODS

The standard further stipulates that “if wall thickness and depth of cover are the only methods of protection, the nominal wall thickness shall be not less than the lesser of”

(a) 10mm; and

(b) $A \times F_v$ where

A = pressure design wall thickness (mm)

F_v = third-party factor

The third-party factor is evaluated as a function of class location and nature of carrier fluid as show below:

<u>Location Class</u> ²	<u>THIRD-PARTY FACTOR (Fv)</u>	
	<u>Liquids</u>	<u>Gas or High Vapor Pressure Liquid</u> ³
R1	1	1
R2	1	1.2
T1	1	1.44
T2	1	1.8
S	1	1

In analyzing the above concept, it can be argued that the United States regulations presently require a number of protection methods other than wall thickness and cover to protect the pipe, and, as such, the need to consider the implementation of this section may be a moot point. However, the concept may still be interesting to review in that it specifies a number of damage protection methods listed under Section 3.7d and entitled “Protective Barrier”.

1.4 CONCEPT OF FATIGUE LIFE

Section 6.7 of the United Kingdom’s gas pipeline safety regulations and section 2.12 of the British Standards Institute’s Code of Practice for Pipelines (i.e. section, 2.8 - Steel for Oil and Gas) utilizes a heading entitled “Fatigue Life.” The purpose of the section is for operators to give consideration to “the fatigue life of a steel pipeline, in order to insure that minor defects, associated with any welded structure, which survive the proof test, do not grow to a critical size under the influence of pressure cycling.”

In order to test the fatigue life, a “life” of 15,000 stress cycles is utilized (equivalent to one cycle per day over 40 years based upon a maximum daily variation in hoop stress being limited to 125N/mm²⁴). A determination is then made to assess the actual daily variation in hoop stress under operating conditions, and if the cumulative combination of daily varying stresses and time sum to 15,000 stress cycles, the pipeline should be revalidated for its integrity and effectiveness.

The above concept suggests that pipelines subjected to considerable variation in daily operating pressures have a finite life which must be re-tested when it approaches its “life cycle.” It

² See Appendix A under class locations- Australia for definition of each category.

³ The numerical values are derived by dividing 0.72 by 0.72, 0.6, 0.5, 0.4, and 0.72, respectively

⁴ Note: 125N/mm² = 18,130 psi

should be noted, however, that one would have to have huge variations in daily operating pressures for the fatigue life of a pipeline to be reached within a century or two based upon the criteria utilized in the regulations.

1.5 USE OF IN-LINE MONITORING DEVICES

The Japanese regulations require the installation of automatic leakage detection devices every 10 kilometers along the pipeline. In addition, they require earthquake magnitude measuring devices every 25 kilometers to assess the potential degree of damage to pipelines due to earthquake activities.

Regarding leak detection systems, the United Kingdom's Regulation **BS8010: Section 2.8 - Steel for Oil and Gas under Section 2.6.14** entitled "Leak Detection" says the following: "Consideration should be given to the incorporation of a leak detection system into the design of a pipeline. The method chosen for leak detection should be appropriate and **effective** for the substance to be conveyed. Typical leak detection methods include continuous mass balance of pipeline contents, detection of pressure waves, monitoring of rate of change of pressure and flow, and dynamic modeling by computer. The leak detection system should be part of the overall pipeline management system which should incorporate route inspection in accordance with **BS8010: Part 1, 1989.**"

1.6 THE RATIONALE BEHIND THE DIFFERENCES BETWEEN FOREIGN AND UNITED STATES STANDARDS

As noted above, although there are great similarities in the respective regulations reviewed and assessed herein, there are a few issues specifically noted in the Australian, Japanese, and the United Kingdom's regulations which do not exist in the United States regulations. In order to attempt to ascertain the rationale for these differences, a number of qualified spokesmen have been contacted in the above-mentioned countries who are familiar with the regulations and who have been asked to address the rationale for the incorporation of specific concepts in the Australian, Japanese and United Kingdom regulations. The questions posed and their responses are provided in Appendix B to this report.

1.7 CONCLUSIONS - BASIC DIFFERENCES IN THE REGULATIONS COMPARED TO THE UNITED STATES REGULATIONS

The major differences between the United States pipeline safety regulations and some of the other foreign regulations are the concepts of pipeline life, fatigue life, and third-party factors which are found in the Australian or United Kingdom's regulations, and the employment of on-line leak detection equipment and earthquake impact measuring equipment in the Japanese regulations. Although the concepts of pipeline life, fatigue life, and third-party factors are not explicitly noted in the United States regulations, one can argue that **third-party** factors are indirectly accounted for through the requirements for patrolling and the use of **markers** along pipelines, as well as the damage prevention programs required in the regulations. Also, the concepts of design life and fatigue life of pipelines, while not directly articulated in the United States

regulations, can be indirectly tested through findings from the use of leakage surveys (as required in the regulations), or if there are any changes required or requested in the class location with time and/or a desire for operators to upgrade the pipeline which would necessitate pressure testing of the lines. However, if no leakage is noted, and no changes are contemplated in the operation of the pipeline, the concept of the "life" of the pipe is not directly or indirectly addressed in the United States pipeline safety regulations.

1.8 GENERAL CONCLUSIONS

The report herein, which compares pipeline safety regulations from Canada, Australia, the United Kingdom, Germany and Japan with the United States Regulations, demonstrates that the regulations are quite similar in their approach to the design, construction, and operation of pipelines located in close proximity to densely populated and/or environmentally sensitive areas.

The different concepts found in other foreign regulations but not in the United States regulations such as life of pipeline, fatigue life, third-party factors and use of on-line instrumentation for leak detection and earthquake movement are addressed herein for consideration by a reviewer.

PART 2

GAS TRANSMISSION PIPELINES AND PRACTICE IN THE UNITED STATES

The basis for regulations concerning the technical aspects of gas transmission pipelines is the document developed by the ANSI 831.8 Committee that is published as *Gas Transmission and Distribution Piping Systems, ASME B31.8- 1992 Edition* and other technical references. This document will discuss these references as they apply to maintenance, rehabilitation, and retrofitting of gas transmission pipelines. Several gas pipeline operators were interviewed in order to determine the current state of practice in the industry as they expand upon the minimum acceptable standards as required by regulation. An extensive literature review was undertaken and current publications were used to supplement operator interviews.

Table 2.0 lists the regulations considered as having a significant impact on the functions of maintenance, rehabilitation and retrofitting.

Regulation		Maint	Rehab	Retro
1. WELDING				
192.225	Welding Procedures	x	x	x
192.241	Inspection and Testing of Welds	x	x	x
182.243	Nondestructive Testing	x	x	x
192.245	Removal of Defects	x	x	x
2. GENERAL CONSTRUCTION				
192.309	Repair of Steel Pipe			x
192.313	Bends and Elbows			x
192.319	Installation of Pipe in a Ditch		x	x
192.327	Cover		x	x
3. CORROSION CONTROL				
192.455	External Corrosion Control: Pipe Post July 31, 1971		x	x
192.457	External Corrosion Control: Pipe Pre August 1, 1971		x	x
192.461	External Corrosion Control: Protective Coatings		x	x
192.463	External Corrosion Control: Cathodic Protection	x	x	x
192.465	External Corrosion Control: Monitoring	x		
192.467	External Corrosion Control: Electric Isolation	x	x	x
192.475	Internal Corrosion Control: General		x	x
192.479	Atmospheric Corrosion	x	x	x
4. TEST REQUIREMENTS				
192.503	General Requirements		x	x
192.505	Strength Test Requirements (Hoop Stress > 30% SMYS)		x	x
192.507	Strength Tests Requirement (Hoop Stress < 30% SMYS)		x	x
5. MAINTENANCE				
192.705	Transmission Lines: Patrolling	x		
192.706	Transmission Lines: Leakage Surveys	x		
192.711	Transmission Lines: General Requirements for Repair	x	x	
192.713	Transmission Lines: Permanent Field Repair of Damages		x	
192.714	Transmission Lines: Permanent Field Repair of Welds		x	
192.717	Transmission Lines: Permanent Field Repair of Leaks		x	
192.719	Transmission Lines: Testing of Repairs		x	

Table 2.0 Regulations and their relationships with maintenance, rehabilitation and retrofitting

2.1 WELDING • SUBPART E OF 49 CFR PART 192

Welding is involved in most maintenance, rehabilitation and retrofitting activities involving steel pipelines. The regulations to be addressed include procedures, inspection and testing, nondestructive testing and repair and removal of defects.

2.1.1 CURRENT INDUSTRY POLICIES

ASME B31.8 Paragraph 826.2 is less restrictive than 192.243 in that it requires only 40% of field butt welds in Class 3 locations and 75% of welds in Class 4 locations to be nondestructively tested. Section 192.243 in Class 3 and 4 locations requires 100% nondestructive testing of field girth welds, if practicable, but no less than 90%. It does call for all welds to be acceptable in accordance with API Standards 1104. Neither policies nor regulations specify the type of nondestructive testing to be performed. All allow radiographic, magnetic particle, ultrasonic or dye penetration tests.

2.1.2 INDUSTRY PRACTICES

Several of the companies surveyed produced their welding and inspection manuals. The manuals are detailed, describing all aspects of individual welds. The following quotation was in a welding manual: "It should further be noted that the Company standards spelled out in the welding and weld inspection manual may exceed minimum regulatory requirements". In fact, their nondestructive testing requirements necessitate that all butt-welds that are not subject to hydrostatic tests be inspected by radiography.

2.2 GENERAL CONSTRUCTION REQUIREMENTS • SUBPART G OF 49 CFR PART 192

2.2.1 CURRENT INDUSTRY POLICIES

ASME B31.8 - 1992 forms the basis for these regulations. It goes into detail defining dents, gouges, grooves and arc burns, and details their repair. The industry-wide preference for repair of a pipe is to remove a cylindrical section and replace it.

2.2.2 INDUSTRY PRACTICES

- (a) PIPELINE REPAIR. Every operator interviewed repeated section 192.309 in his maintenance manuals. Each operator interviewed addresses all but the most minor repairs and prefers replacement in lieu of repair.
- (b) BENDS AND ELBOWS. Operators are now specifying that bends and elbows be constructed in such a manner as to allow in-line inspections.

When bending pipe for a line to be laid, all necessary pipe bends required in the rerouting, replacing or reconditioning of the line normally are made in the field. However, fabricated bends may be used for installation at points where the use of such bends is preferable. Bending is held to a minimum and is required only where changes in the grade are such that the pipe will not lay naturally on the bottom of the ditch. The use of mitered bends is not permitted at any time. Buckled pipe is cut out and replaced (operator's manual).

- (c) **INSTALLATION OF PIPE INTO A DITCH.** The use of a nonabrasive canvas padded sling or a rubber cradle-type sling for lowering coated sections of pipe into a ditch is to protect the coating. The necessary amount of slack is to be obtained without injury to the protective coating. Any coating that is damaged in the handling or lowering of the pipe into the ditch is repaired so as to leave it in a condition equal to that of the undamaged coating. When coated pipe is to be lowered in rock areas, dirt cushions are placed in the bottom of the ditch or, the ditch is padded above and below the pipe with loose dirt to protect the coating against damage. Rock shields are used if approved by the corrosion specialist. Slack loops are left on skids at approximate 700-foot intervals, and that part of the line between each slack loop is covered immediately with sufficient dirt to hold the pipe in place. Slack loops are to be lowered only when weather and temperature are suitable for such operation (operator's manual).

2.3 CORROSION CONTROL • SUBPART I OF 49 CFR PART 192

Corrosion accounts for approximately 24% of the incidents related to natural gas pipelines. Corrosion is an environmentally-driven condition that can be protected against. The purpose of this part of the regulations is to protect the public against corrosion-related incidents.

2.3.1 INDUSTRY POLICIES ASSOCIATED WITH CORROSION- EXTERNAL CORROSION CONTROL

ASME 831.8 requires procedures to be established for evaluating the need for corrosion control. It gives general guidance for the evaluation, corrective measures, repair of corroded pipe, and cathodic protection criteria. There is a plethora of information concerning corrosive deterioration of pipe. Rather than discuss policies on corrosion in general, consider the following breakdown of the issue:

CORROSION EVALUATION- EXTERNAL

- Inspection
 - » Visual and Electrical Surveys
 - » In-line Inspection Using Pigs
- Extent of Damage
 - » Coatings and Coating Repair
 - » Cathodic Protection

2.3.1.1 Corrosion Evaluation • External

- (a) **INSPECTION.** Here are a number of suggested methods of inspecting buried pipelines in ASME B31.8, "Guide for Gas Transmission and Distribution Systems" by the Gas Piping Technology Committee of the American Gas Association (GPTC Manual), and other publications.
- (1) **VISUAL AND ELECTRICAL SURVEYS.** An operator continuously monitors records from leakage surveys and normal maintenance work for evidence of corrosion. Electrical survey methods are used in areas where surface conditions permit accurate measurements.

- (2) **IN-LINE INSPECTION USING PIGS.** There are two general types of pigs. One type is a common utility pig for performing some task inside of a pipeline and the other is an instrumented pig, used to determine the condition of the pipeline. In-line inspection is accomplished by the instrumented pig, a self contained vehicle named such because of the squealing noise it produces as it travels through the pipeline. Figure 2.3.1.1 shows the classification of in-line devices.

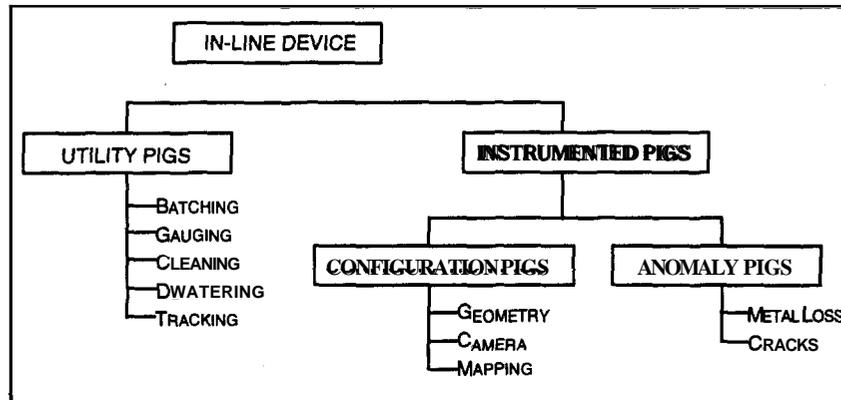


Figure 2.3.1.1 Classification of in-line devices (GRI 1995)

The instrumented pig records the existence, location and severity of anomalies through the use of recording equipment carried on board the pig. The industry uses instrumented pigs extensively to detect changes in wall thickness due to corrosion or mechanical damage. Instrumented pigs may also be used to detect geometric deformation such as dents and ovality (OPS 1995).

There are several types of instrumented pigs. The most common metal-loss detecting pig uses a technology known as magnetic flux leakage (**MFL**). Basically this pig generates an induced magnetic flux field and searches for distortion of that field on the surface of the pipe. A distortion of the magnetic field indicates an anomaly which probably resulted from metal **loss**. A second type of instrumented pig that uses ultrasonic technology has been developed and is gaining acceptance in the industry. This technology is expected to eventually be able to detect cracks as well as metal **loss** in the pipe.

Some operating constraints limit the use of pigs for in-line inspection. A pipeline with tight bend radii, varying wall thickness, varying diameter or with check or reduced bore valves may prohibit the use of pigs for pipeline inspection. Only about 30% of gas transmission pipelines are presently equipped with permanent facilities for launching and receiving pigs (GRI 1992).

OPS has recently published a regulation requiring that all new and replaced pipeline segments be designed to allow passage of in-line inspection tools (OPS 1995).

- (b) **EXTENT OF DAMAGE DETERMINATIONS.** Each inspection program must have an accompanying maintenance verification plan to check each anomaly found and determine the course of action to be followed. A GRI report characterizes anomalies as either imperfections,

- (b) **EXTENT OF DAMAGE DETERMINATIONS.** Each inspection program must have an accompanying maintenance verification plan to check each anomaly found and determine the course of action to be followed. A GRI report characterizes anomalies as either imperfections, defects or critical defects. "Critical defects" are those which could cause failure when the pipeline is operating to its MAOP and require immediate repair or replacement. "Defects" are those which will require repair but not necessarily immediately. "Imperfections" may only require monitoring or remediation to prevent growth (GRI 1992).

2.3.1.2 Coatings and Coating Repair

Approximately 95% of all gas transmission pipelines have some type of protective coating; approximately 85% of these lines are coated with coal tar or asphaltic enamels. These coatings are usually reinforced with an outer wrapping to provide additional resistance from soil and other stresses. Other types of coatings in use include fusion-bonded epoxy, polyethylene, polyurethane and waxes. Coal tar enamels and polyethylene tape are usually the coatings applied in the field for coating replacement (Croch, GRI 1993).

However, a new process that will allow 3-layer polyethylene (3LPE) coatings to be applied in the field has been recently developed. These coatings could previously be accomplished in a factory setting. The 3LPE provides high disbondment and "cathodic shielding" resistance due to the epoxy bonds to steel and chemical bonds set-up between epoxy and the copolymer layer, both of which are mechanically and environmentally protected by the tough outer layer of polyethylene. This new field application depends upon the quality of the removal of the old coating and the pipe preparation (John 1995). A new method of removing old coatings, the Borehole Reconditioning System (**BRS**), has been developed. This machine encircles the pipe between cribs and blasts the surface to near white metal. It incorporates high power water blasting and automated air abrasive blasts to remove the old coatings and to prepare the pipe surface to attain the maximum life out of any coating applied to the pipeline. This procedure takes place in the ditch while the pipeline is in-service operating at a reduced pressure. The BRS machine operates between support cribs. It is remotely controlled. Its high pressure water blasting unit can remove almost any coating in one pass. It has a water blast capacity of 20,000 psi with water consumption of 12 gallons per minute and a cleaning rate of 25 square feet per minute. It removes heavy rust (1/4 to 3/8 inches thick) and cleans the surface of any residual corrosion but will not deform or damage the surface of the pipeline. With asbestos coatings, this machine will allow safe and easy removal of asbestos without having to be in contact with the material. With the **BRS**, asbestos coatings can be blasted off the pipeline and contained in an OSHA approved container without having to be handled. The **BRS** has a containment chamber with vacuum power and a filter to remove the asbestos from the water. It is then pumped into a certified disposal container where it is held until turned over to a disposal company. The **BRS** prepares the bare pipe surface to a point that it virtually insures the success of the coating application. The BRS is an automated abrasive air blast unit which provides a uniform steel color and anchor pattern prepared by oscillating head. This process creates a high quality surface for any type of coating to be applied. For a commercial grade surface, the BRS can finish up to 15 square feet per minute and for a near white grade, 5.5 square feet per minute (Fluharty 1995). It should be noted that coating selection and application interacts with the cathodic protection system and the two must be considered together. Quality must be controlled in the application of coatings to allow the cathodic protection system to function properly.

2.3.1.3 Cathodic Protection

Tests on buried and submerged structures are conducted to verify that the corrosion control system is functioning properly and the structure to soils potential is within the criteria set forth in the NACE International's recommended practice RP 0169 - 92 (Bauer 1995). Analog type voltmeters and ammeters are standard equipment in cathodic protection rectifiers. Readings of rectifier gauges are made every two months to ensure that they are providing the proper output. These readings are also checked occasionally using a portable multimeter since analog gauges have a tendency to stick after operating a long time. There are many methods for monitoring the structure - soil potential and the rectifier output. These methods vary from analog gauge to automated data collection (Bauer 1995).

OPS addressed the problems with determining true cathodic protection in their Comprehensive Inspection Report of New Jersey Interstate Natural Gas Transmission Pipeline Operators (OPS 1995):

Federal pipeline safety regulations require operators to provide cathodic protection for their pipelines and check the adequacy of this protection on a yearly basis. This is accomplished primarily by reading the electric potential difference, or voltage, between the pipe and the soil directly above the pipeline: these readings are commonly called pipe/soil potentials and are taken at test stations installed along the pipeline.

To determine the true cathodic protection at any point, a pipe/soil reading must be taken in the soil close to the steel pipeline. In actuality, the reading is taken at the soil surface, often several feet above the pipeline. The intervening distance provides an additional potential difference (called IR drop, $V=IR$, Ohm's Law, when V is voltage, I is current, and R is resistance) to the pipe/soil reading. Because this additional potential drop cannot be reasonably measured at every reading, some interstate natural gas transmission pipeline operators in New Jersey have added a safety factor to the target pipe/soil reading. For example, if the operator believes that a "true" pipe/soil reading of -0.85 volts will prevent the pipeline from corroding, the target pipe/soil reading may be established at -1.10 volts with rectified current applied. The extra -0.25 volts is a safety factor added to account for IR drop. Federal pipeline safety regulations require pipeline operators to account for IR drop when applying this criteria method in the cathodic protection program. The method listed above is one way IR has historically been taken into consideration (OPS 1995).

It should be noted that when coatings and cathodic protection are used together, the coating is the primary corrosion inhibitor. The cathodic protection is the secondary inhibitor in that it protects only at breaks and other defects in the coating. This gives the quality of the coating greater importance.

2.3.2 INDUSTRY PRACTICES ASSOCIATED WITH CORROSION CONTROL - EXTERNAL CORROSION

This section references the actual practices of a number of operators. The references indicate that operator practice often exceeds operational requirements as mandated in the Federal Pipeline Safety Regulations.

2.3.2.1 Corrosion Evaluation - External

OPS investigated six operators in the State of New Jersey in its comprehensive report (OPS 1995). They found that five of the six operators had used instrumented pigs to inspect some, if not all, of their pipelines. Magnetic flux leakage technology was used in each. The use of instrumented pigs is growing and will continue to grow in the industry.

There are other data that enter into an evaluation of a pipeline, particularly when determining whether to rehabilitate or replace the pipeline. The data used are leak/failure history, historical cathodic protection data, test point or close interval survey data, and results of bellhole examinations as well as in-line inspection data. Synthesizing these data is difficult and complex. There is no method currently in use that will combine these data and result in a model.

2.3.2.2 Coatings and Coating Repair

The coating rehabilitation process of the Interprovincial Pipeline Inc., Edmonton, Alberta, was described in a recent paper (Lesic 1995) as follows:

- (1) TOP SOIL STRIPPING AND EXCAVATION. Machine excavation is allowed within one foot of the top of a pipeline and within 6 inches of its sides.
- (2) LINE LIFTING. Total stresses (internal and external) must remain less than 30% **SMYS**. Lifts use inflatable air bags in combination with sideboom tractors. Lifts are to 32 inches in 4 lifts of 8 inches each. The line is supported every 45 feet with skid mats of Styrofoam and lumber. Pipe is laterally supported every 180 feet.
- (3) HYDROBLASTING. High pressure water pulverizes the tape and other coatings. They use a brand, HydroKleaner, which is a clamp-on unit containing water jets that sit directly on the pipe. A sideboom tractor supports the pipe just ahead of the instrument.
- (4) INTEGRITY ASSESSMENT. Once the steel is exposed, a non-destructive testing of the line using eddy current inspection is performed. Long seams and girth welds are inspected and a visual corrosion inspection made.
- (5) ABRASIVE BLASTING. An air abrasive blast (ABB) system using steel grit is used to prepare the surface. As in the hydro blasting, sidebooms are used ahead of the machine to lift the pipe while work crews move the supports. The **ABB** system weighs 6,500 pounds. The entire **ABB** train is 130 feet long. Production rates approached 3.5 feet per minute. The specification calls for near white metal (**SSPC⁵ SP10**) finish with an average anchor of 4 mils. (The anchor makes the surface of the pipe rough to improve the adhesion of the coatings.) Missed areas are touched up by hand units.
- (6) COATING APPLICATION. In 1992, a tar extended polyurethane was used. In 1993, however, a 100% polyurethane was selected partly because of quicker curing capabilities. The coatings are preheated and spray applied using a CRC Line Travel Coater (CPCL). This is a clamp-on assembly that contains spray tips and rests on the pipe. The coating machine follows the **ABB** machine closely in order to minimize flash rusting. Rust spots are hand blasted. The optimal procedure was determined to be as follows:

⁵ Structural Steel Painting Code

- (i) Coat entirely between a set of support stations using a 90 foot unsupported length. Stop adjacent to the next support station.
- (ii) Allow approximately 15 minutes cure time.
- (7) Remove obstacle support station and repeat the process.
- (8) Specified thickness is not always uniform. Require at least 25 mil thickness.

2.3.2.3 Cathodic Protection

A number of operators were interviewed and questioned about industry practices with respect to cathodic protection. The responses were more or less uniform, especially in the types of systems and frequency of inspections. Each quoted the regulatory requirements.

Table 2.3.2.3, taken from a paper by Marquez, Rubenstahl and Tencer, is an example of a corrosion troubleshooting guide (Marquez, et. al. 1995).

C	Coat	CP	Diagnosis	Action
O	OK	OK	CP System is operating properly	Maintain corrosion systems
O	OK	X	CP system is not operating properly	Repair or replace CP materials as required
O	X	OK	Coating holidays exist but CP system is mitigating corrosion	No coating repairs required. Maintain corrosion control system.
I	OK	OK	Internal corrosion control program is not effective due to difference in product or ineffective inhibitor program	Determine cause and adjust inhibitor program, pigging schedule or product as necessary .
E	OK	OK	External wall loss could be old damage or corrosive disbonded coating which is not apparent from CP potentials	Determine whether coating has disbonded or if wall loss is old. Repair disbonded coating as required. Perform close interval surveys to determine that CP potentials are good between test stations.
O	X	X	Coating has holidays and CP system does not satisfy CP criteria but detectable wall loss has not occurred.	Investigate to determine whether coating repair and/or adjustment of CP system is the most cost effective method to achieve a CP criterion.
I	OK	X	Internal and external corrosion control system operating properly. The unsatisfactory CP potentials have not resulted in metal loss at this time	Investigate internal corrosion control program as above. Determine cause of CP potentials, then repair and/or replace CP materials.
E	OK	X	CP system is not operating properly and wall loss has occurred.	Determine cause, then repair, replace or modify the CP system.
I	X	OK	Internal corrosion control program is not effective as above. The external coating has holidays but the CP system is satisfactory.	Investigate internal corrosion control program. No coating repairs are required because CP potentials are satisfactory. Certain CP systems perform close interval survey to determine that CP potentials are good between test stations.
E	X	OK	The external wall loss could be old damage or corrosion could be active under disbonded coating.	Determine whether the coating has disbonded, the wall loss is old, and the CP system is controlling corrosion. Perform interval surveys to determine that CP potentials are good between test stations.
I	X	X	The internal and external corrosion control systems are not effective. The failure of the internal corrosion control system has often resulted in wall loss.	Investigate internal corrosion control program. Determine whether coating repairs and/or modifications to the CP system are the most cost effective method to satisfy a CP criterion.
E	X	X	CP system and coating are not effective resulting in pipe wall loss.	Perform close interval surveys. Determine whether coating repairs and/or adjustments to the CP system are the most cost effective method of satisfying a CP criterion.

2.3.2. Basic (O: no corrosion; I: internal corrosion; E: external corrosion; X: item not functioning properly)

2.4 TEST REQUIREMENTS • SUBPART J OF 49 CFR PART 192

2.4.1 CURRENT INDUSTRY POLICIES

The current policy for conducting hydrostatic tests conforms closely to the regulations in 192.503, 505, and 507. They are based on Paragraph 845 of ASME B31.8 - 1992 which outlines procedures for pipelines with proposed MAOP's that cause hoop stress greater than 30% SMYS, those with a proposed operating pressure that produces hoop stresses between 100 psig and 30% of SMYS, and those intended to operate at operating pressures that cause hoop stresses less than 100 psig. The testing of off-shore transmission lines is specified in part A847 of ASME B31.8 - 1992. The recommended practice for hydrostatic testing of transmission pipelines in-place is contained in Appendix N of ASME 831.8 - 1992. This appendix *is* intended only as a recommended practice.

The procedure for hydrostatic testing is straightforward. Basically, the pipeline segment is filled to a fraction of the test pressure and checked for leaks. Leaks, if any, are repaired. The pipeline segment is re-pressurized and the test pressure maintained for at least **8** hours in the pipeline (some companies hold the pressure for a longer period) before the line is drained. The medium must be removed after the test either by gravity or by a purge pig. Ethylene glycol or alcohol can be mixed with water to prevent freezing if the volume of water is small. For larger pipe, ethylene glycol or alcohol can be used between pigs to absorb the water (AGA 1986).

2.4.2 INDUSTRY PRACTICES

The practices of the companies interviewed followed the regulation and Appendix N of ASME B31.8 - 1992 precisely. All had procedure manuals that contained detailed instruction for controlling tests, leaving little leeway for the personnel performing the testing.

OPS found in its New Jersey study that two companies routinely performed hydrostatic tests along with in-line inspections.

In discussions with industry experts, some companies hold the hydrostatic tests for 24 hours in order to get a complete temperature cycle and allow sun-to-sun test. However, there is little consistency between companies.

2.5 MAINTENANCE • SUBPART M OF 49 CFR PART 192

2.5.1 CURRENT INDUSTRY POLICIES

This Subpart deals primarily with inspection, identification and repair of pipelines.

(a) INSPECTION.

- (1) PATROLLING. The regulations specify the minimum frequency for patrolling a pipeline right-of-way. Operators patrol more frequently since the frequency is based on a number of variables associated with the pipelines. Much patrolling is accomplished by aircraft. The purpose of patrolling is to detect third party encroachment and possible leaks. Examples include observation of earth moving equipment or excava-

tions in the right-of-way, dead vegetation that can indicate gas leakage, and exposed pipe due to landslides, frost heaves, and washouts (GRI - 1992).

- (2) **LEAKAGE SURVEYS.** Natural gas in transmission lines is not normally odorized except where it passes through populated centers. This makes detection difficult since natural gas is virtually odorless. In addition, small gas leaks dissipate as gas flows through the soil above the pipe. This adds to the difficulty involved in leak detection. Gas leakage detectors, or sniffers, for pipelines that are not odorized are designed to detect the presence of hydrocarbons rather than sulfur-based odorants used for transmission lines in populated areas. Detectors for odorized or unodorized gas may be hand held or mounted on vehicles for rapid surveys. As mentioned before, ground observations are also an effective means for locating potential leakage sites (GRI 1992). **ASME B31.8 - 1992** in appendix **M** outlines leakage surveys and test methods.

(a) **APPROVED METHODS:**

- (1) **SURFACE GAS DETECTION SURVEY.** This survey continuously monitors the air in the vicinity of a pipeline with a device capable of detecting concentrations as low as 50 ppm of gas in air at any sampling point. The detection device should be within 2 inches of the ground. This survey technique may be limited by adverse conditions (such as excessive wind, excessive soil moisture, or surface sealing by ice or water).
- (2) **SUBSURFACE GAS DETECTION SURVEY.** This technique involves sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.5% gas in air at the sample point. This technique involves a geographic sampling plan. Tests are made in small openings or substructure or bar holes over or adjacent to the gas facility. The location of the gas facility and its proximity to buildings and other structures should be considered in spacing sampling points. Good judgment should be used in selecting existing valves, manholes, etc., as sampling stations.
- (3) **VEGETATION SURVEY.** This involves visual observation for abnormal or unusual vegetation indications. All visual indications should be evaluated using a CGI. The survey should be limited to areas with adequate vegetation. This survey should be replaced by other forms of leakage surveys when soil moisture content is abnormally high, vegetation is dormant, or vegetation is in an accelerated growth period such as early spring.
- (4) **PRESSURE DROP TEST.** This test will determine whether or not an isolated pipeline segment has a leak by observing a pressure drop. The facility tested should be isolated then tested. The test pressure should be performed at a pressure at least equal to the operating pressure. This test is performed only to determine if there is a leak. It will not usually locate the leak.

(5) **BUBBLE LEAKAGE TEST.** This test involves the application of soap water or other bubble-forming solutions on exposed piping to determine the existence of a leak. The piping system must be exposed to use this test. It is usually used to test a tie-in joint or leak repair which is not included in a pressure test.

(6) **ULTRASONIC LEAKAGE TEST.** This test involves the testing of exposed piping with an instrument capable of detecting the ultrasonic energy generated by escaping gas. Ultrasonic indications of leakage should be verified or pinpointed by some other survey method.

(b) **MARKING.** The policies are the same as the regulation. The objective is clear but implementation is difficult. Marking of pipelines, especially in urban areas, is difficult since markers are subject to vandalism.

(c) **REPAIRS.** The policy prescribed in **ASME 831.8 - 1992** appears more liberal than the regulations which govern transmission lines. **ASME 931.8 - 1992** elaborates on damages by categorizing them as gouges, grooves and dents. In all cases, the preferred method of repair is as shown in figure 2.5.1, e.g. take the line out of service, remove the damaged section, and replace with a pipe segment of equal strength.

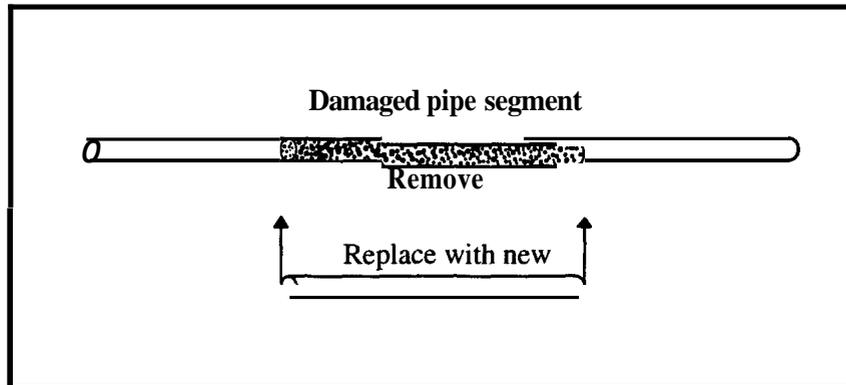


Figure 2.5.1 Preferred repair of imperfections, damages and leaks.

For transmission lines, the only other major method of repair allowed is a full encirclement weld split sleeve. **OPS** has issued over 30 waivers for the use of a “clock-spring” repair that uses composite material of polyester resin reinforced by glass filament as a repair process. On installation, it is tightly wound and adhesively bonded to the damaged pipe. Tests have shown that repairs using this technique are stronger than the pipe itself. This technique may replace or supplement full encirclement weld split sleeves. It has the advantage of not requiring welding crews and equipment on site for repairs.

2.5.2 INDUSTRY PRACTICES

- (a) INSPECTION. All operators questioned patrol their pipelines more frequently than the minimum required by the regulations. All use aerial, vehicular, and foot patrols. Some operators perform aerial inspections as often as 3 times per week. Pilots usually are on the operator's radio frequency. When a problem is detected, it can be addressed immediately. All operators perform leakage surveys more frequently than required by the regulations. All use above-ground man and vehicle transported hydrogen flame ionization detectors with sensitivities in the range of 5 ppm.

- (b) REPAIRS. All operators prefer to replace the damaged pipeline segment. If any other method of repair is used, that repaired pipe segment will be replaced as soon as possible. Operators do not like to have patched pipelines in the ground. One operator specified that 90% of his repairs consist of pipe segment replacement; 8% consist of full encirclement weld split sleeve; and now, perhaps 2% use the "clock-spring" technology. A major operator has the following policy: if the malfunction is a leak or a stress concentration, the pipe is replaced; if it is corrosion or a dent, he will consider a welded split sleeve as a temporary repair. No operator interviewed considers any repair other than pipe segment replacement as permanent.

PART 3

UNITED STATES OIL AND HAZARDOUS LIQUID PIPELINES

Table 3.0 contains a listing of those hazardous liquid regulations that pertain to maintenance, rehabilitation and retrofitting.

Regulation		Maint	Rehab	Retro
1. CONSTRUCTION				
195.228	Welds and Welding Inspection: Standards of Acceptability	x	x	x
195.230	Welds: Repair or Removal of Defects	x	x	x
195.234	Welds: Nondestructive Testing	x	x	x
195.236	External Corrosion Protection		x	x
195.238	External Coating		x	x
195.242	Cathodic Protection System	x	x	x
195.158	Valves: General			x
195.260	Valves: Location			x
2. HYDROSTATIC TESTING				
195.300	Scope	x	x	x
195.302	General Requirements	x	x	x
195.304	Testing of Components	x	x	x
195.306	Test Medium	x	x	x
3. OPERATION AND MAINTENANCE				
195.403	Training	x	x	x
195.406	Maximum Operating Pressure		x	x
195.416	External Corrosion Control	x	x	x
195.418	Internal Corrosion Control	x	x	x
195.420	Valve Maintenance	x		
195.422	Pipeline Repairs	x	x	
195.428	Overpressure Safety Devices	x	x	
195.436	Security of Facilities	x		
195.440	Public Education	x		

Table 3.0 Regulations and their relationships with maintenance, rehabilitation and retrofitting

3.1 CONSTRUCTION • SUBPART D OF 49 CFR PART 195

3.1.1 CURRENT INDUSTRY POLICIES

WELDS. ASME B31.4 elaborates on weld standards. This guide discusses welding processes and metal, welder qualifications, standards, quality control and inspection procedures, types of welds, repair or removal of defects, and stress relieving. However, it does refer to API 1104 for the specific requirements. API Recommended Practice 1107, "Pipe Maintenance Welding Practice, 3rd Edition" dated April 1991 relates API 1104 to maintenance and rehabilitation practice. This publication covers recommended maintenance welding practices that may be used when making repairs to or installing appurtenances on piping systems which are or have been in service in the transmission of hazardous liquid. It suggests that the welding be done by shielded metal-arc, gas tungsten-arc, gas metal-arc, flux-cored arc, or oxyacetylene welding using manual or semi-automatic techniques. It varies slightly from API 1104 by including a sec-

tion on suggested maintenance welding practices. In this section, it alerts the welders to the safety aspects of welding a pipeline that is or has been in use. It alerts the welder that particular consideration should be given to the fillet weld used to join a sleeve to a carrier pipe because the fillet weld will tend to underbead or have delayed hydrogen cracking. With welds on pressurized and flowing piping systems, success has been achieved using low-hydrogen welding processes or electrodes with appropriately high-heat input that slows the cooling rate. This document also contains suggested welding sequences for reinforcing pads, reinforcing saddles, encirclement sleeves, encirclement tees, encirclement sleeves and saddle combinations and encirclement saddles.

CORROSION CONTROL SYSTEMS. Corrosion control systems were discussed in Part 2 and will be discussed further in Section 3.3.

3.1.2 INDUSTRY PRACTICE

WELDING. All of the seven operators surveyed required 100% radiographic inspection for all butt or girth welds on pipe with diameters exceeding 2 inches. All operators surveyed had extensive welding manuals and numerous certification requirements.

CORROSION CONTROL. Corrosion control was discussed in Part 2 and will be discussed in Section 3.3.

3.2 HYDROSTATIC TESTING • SUBPART E TO 49 CFR PART 195

3.2.1 CURRENT INDUSTRY POLICIES

ASME B31.4 is the basis for the regulations. This code references API Recommended Practices 1110 for guidance in performing the tests. The code warns that if the test medium is subject to thermal expansion pressure relief valves must be installed. It is very important to rid the pipeline of test water after the test, especially in cold climates. Some operator policies are to remove the water by running a pig or sphere followed by product through the line to purge the system.

3.2.2 INDUSTRY PRACTICE

Operators surveyed varied in their approach to hydrostatic tests. Most tested their pipelines for a continuous 24 hours in order to observe a complete temperature cycle. One company surveyed tested their pipeline segments for 1 hour at 100% **SMYS** and 90% **SMYS** for 24 hours. Most monitor with dead weight monitors, continuous pressure and temperature gauges at distances of no more than 10 miles apart. Pigging is often done in conjunction with these tests. Scrapers, poly-pigs, or spheres are used to purge the system. Figure 3.2.2 shows a typical hydrostatic test layout.

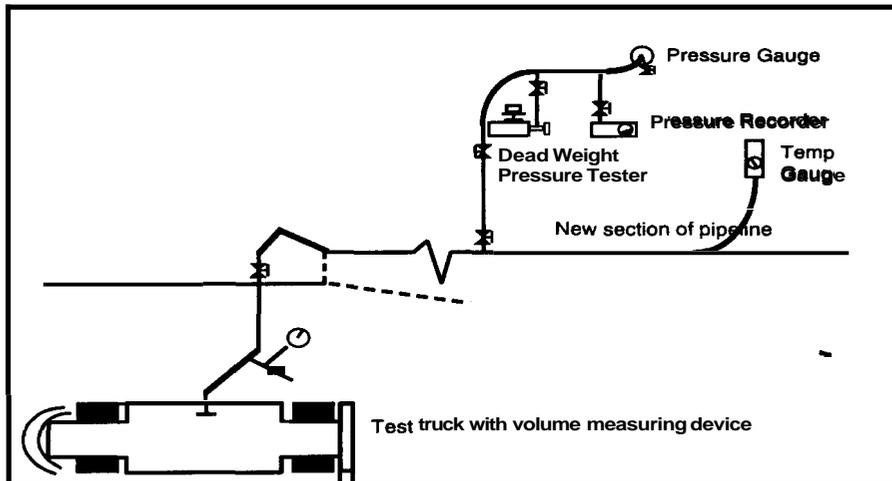


Figure 3.2.2 Hydrotest layout

3.3 OPERATION AND MAINTENANCE • SUBPART F TO 49 CFR PART 195

3.3.1 CURRENT INDUSTRY POLICIES

Policies associated with corrosion control outlined in Part 2.3.1 of this report also pertain to hazardous liquids pipelines.

3.3.2 INDUSTRY PRACTICE

- (a) **ROW PATROLLING.** Operators use aerial, vehicular, and foot patrols. They often patrol pipelines more often than the minimum regulatory standards. Aerial investigations allow easy and rapid visual observation of the right-of-ways and an early indication of third party activity or damage; however aerial patrols are costly, provide no corrosion information, require at least two trained observers per patrol, and require a ground response team. Ground patrolling may employ less costly transportation platforms but be more costly in expended man-hours. It requires more time, may provide detection of small leaks through subsurface tests, and may provide immediate response to **ROW** encroachment.
- (b) **CORROSION CONTROL.** Operators almost universally apply cathodic protection to their pipelines, usually in combination with protective coatings. Operators inspect cathodic protection systems every two months and routinely evaluate external corrosion whenever they expose pipe. NACE International RP 0169-92 is a common reference guide for structure-to-soil potentials. Analog voltmeters and ammeters are often used in cathodic protection rectifiers and are inspected using a portable multimeter because analog meters may be stuck if operating for a long time. Operators conduct corrosion and cathodic protection surveys on all pipelines via portable high impedance voltmeters and portable copper/copper sulfate reference electrodes. As these surveys are more difficult on submerged pipelines, these pipelines are typically inspected less frequently than buried pipelines. Some operators use field computers with multiple reference electrodes in addition

to portable measuring devices. In order to improve inspection of cathodic protection, some operators are installing pipeline-to-soil potential test stations at road crossings and at areas with known corrosion. In-line inspection pigs are used to augment cathodic protection systems in locating internal and external corrosion pits. The accuracy of pig data varies by contractor and by type of pig. The ultrasonic pig provides extremely precise information on remaining pipe wall thickness, but it is costly relative to MFL pigging and not yet widely available. MFL pigging provides data on the general magnitude of anomalies to within feet dependent upon the vendor, is less costly than ultrasonic pigging, and is widely used and accepted by the industry. Caliper pigging is less expensive and locates geometric distortions in pipelines; however, it is not suitable for identifying corrosion. Its best use appears to be as a lead pig for a subsequent anomaly pig run. Corrosion coupons may indicate a trend in internal corrosion, but they provide limited point information, can disturb flow thereby causing problems, and are subject to misinterpretation.

There are portable and external means for monitoring above-ground pipe. Portable ultrasonics provide point information but are expensive and not readily available. Automated ultrasonic external scanners provide accurate wall thickness data and allow calibration of other methods; however, they are costly and slow. Operators are also employing remote leak detection equipment. While this equipment will not prevent a leak, it will prevent the extent of damage, thereby reducing risk. Leak detectors will provide alarm before major ruptures occur. Disadvantages are that the pipelines must be pressurized and packed with fluid, sensors must be properly located, and they require communications devices/lines. Integrating the variety of cathodic protection systems, cathodic protection test equipment, internal inspection pigs, remote leak sensors, coatings, historical leak databases, bellhole digs, and coupon sampling tests is a complex task that is highly situation dependent. The attributes of the pipe, transported commodity, operating conditions, and external environment all interact to exhibit varying corrosion prevention requirements.

PART 4

COMMENTARY ON THE STATE-OF-THE ART IN UNITED STATES STEEL PIPELINE MAINTENANCE, REHABILITATION AND RETROFITTING

4.1 INTRODUCTION

The approach taken in this commentary on the state-of-the-art in steel pipeline maintenance, rehabilitation and retrofitting is to consider gas transmission pipelines and hazardous liquid pipelines together. The reader is cautioned that gas transmission pipelines are regulated by 49 CFR Part 192 which is in part based on ASME 831.8 *Gas Transmission and Distribution Piping Systems* (current edition 1992). Hazardous liquid pipelines are regulated by 49 CFR Part 195 which is in part based on ASME 831.4 *Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols* (current edition 1992). The outline of this commentary is first to discuss inspection and surveillance practices, pipeline maintenance, and pipeline rehabilitation. The purpose of this commentary is to discuss industry practices and the state-of-the-art.

The emphasis on regulating gas and liquids differs in that gas regulations are directed primarily at public safety and to a lesser degree, environmental damage. A defect in a gas transmission pipeline can result in catastrophic consequences of explosion and fire. A leak in a buried gas pipeline may kill some vegetation but will probably not leave lasting environmental impacts. Hazardous liquid pipelines, on the other hand, can and do cause major environmental impacts. Historically, gas transmission pipelines have been more regulated than hazardous liquid pipelines. However, since the passage of the National Environmental Policy Act (NEPA) in 1969, the Federal Water Pollution Control Act Amendments of 1972, subsequent legislation and some major impactive hazardous liquid spills in the last two decades, hazardous liquid pipelines are seeing more and more environmental regulation.

Regulations, policies and industry operators aim at making pipelines safer and more economical. Therefore, before any maintenance, rehabilitation or retrofitting can take place, the defects or potential defects in pipelines must be detected. Battelle, in a study for the AGA (Kiefner and Eiber 1987) found that the cause of pipeline incidents could be categorized as:

1. DEFECTS IN THE PIPE BODY
 - Mechanical damage
 - Material defects
 - Environmental effects
 - Corrosion
 - Hydrogen-stress cracks
 - Stress-corrosion cracks
 - Sulfide-stress cracks
 - Step-wise cracks

2. LONGITUDINALWELD DEFECTS
 - Submerged arc
 - Toe cracks
 - Fatigue cracks from cyclic loading
 - Electric weld
 - Selective corrosion
 - Hydrogen stress cracks

3. FIELDWELD DEFECTS
 - Lack of penetration
 - Corrosion

SPECIAL CAUSES

- Secondary loads from soil movement
- Earthquake loads
- Wrinkle bends
- Internal combustion
- Sabotage.

4.2 PIPELINE SURVEILLANCE AND INSPECTION

Operators are required by both gas and liquid regulations to maintain surveillance over their pipelines. **ASME 831.8** requires studies to be undertaken on gas pipelines where unusual operating and maintenance conditions occur, such as failures, leakage history, drop in flow efficiency due to internal corrosion or substantial changes in cathodic protection parameters. The frequency of patrolling gas pipelines is determined by class location of the pipeline. The patrols attempt to limit third party encroachment and to locate leaks. Leaks are located by observing dead vegetation and by using several of the approved leak detection methods as described in section 4.3.

Liquid pipeline regulations require that pipelines be inspected approximately twice monthly and a thorough condition survey every 5 years where the pipeline transverses navigable waters. **ASME 831.4** emphasizes the inspection of the pipeline material prior to placement. Most operators are very conscientious about inspecting their right-of-way. One operator has aerial surveys 3 days per week. They use aerial patrols, vehicular patrols, and foot patrols. These inspections, for both gas and liquid operators are important in detecting potential defects that affect the integrity of pipeline segments, especially third party mechanical damage and leaks.

4.3 LEAK DETECTION

There are many systems available for leak detection. These range from visual checking of the pipeline to more sophisticated hardware-software combination techniques. The following are some of the available technologies:

4.3.1 ACOUSTIC MONITORING SYSTEMS

When a pipeline leak occurs, a rapid drop in pressure occurs at the leak site creating a low pressure rarefaction wave. This wave propagates at the velocity of sound both upstream and downstream from the leak site. The placing of acoustic signal measurement devices, such as wave alert monitors, at strategic locations along the pipeline will permit the detection of such a wave. The time required to detect a leak is related directly to the time taken for the acoustic signal generated by the leak to traverse the distance from the leak site to the acoustic monitor. In natural gas, for example, the leak signal travels at a velocity in excess of 400 meters per second. Therefore, a line break occurring 60 kilometers from an acoustic monitor would be detected by the monitor in less than three minutes.

4.3.2 COMPUTER BASED MONITORING SYSTEMS

Monitoring systems based on the real time acquisition of data from pipelines are among the more functional, efficient and cost-effective systems available. Data pertaining to flow, pressure and temperature, as well as fluid composition, are transmitted from various locations along the pipeline network via satellite, microwave, radio or telephone links to a central control location housing a Supervisory Control and Data Acquisition (SCADA) system. The basic function of such a computer-based SCADA system is to provide the network operator with the facility to immediately access the current state of any region within the network. The stage is therefore set for a high level pipeline integrity monitoring system. The methodology adopted within the system derives from the mathematical modeling of transient flow in pipeline networks.

4.3.3 MATHEMATICAL MODELING SYSTEMS

A pipeline network, however complex, may be treated as a series of inter-connected single pipeline branches together with the ancillary equipment components that are required to operate the network such as regulators and compressors. The transient flow of the fluid through each branch may therefore be simulated independently and coupled with the characteristics of the various equipment devices through the connection points or nodes within the network (Ellul 1994).

4.3.4 RECENT IMPROVEMENTS IN LEAK DETECTION SOFTWARE

Recent developments in computer software have overcome some of the previous shortcomings of leak detection systems in that they now:

- (a) Allow the ability to model slack line flow,
- (b) Allow the ability to model drag reducing agents, and
- (c) Allow the reduction of false alarms through leak sensitivity (correspondence with Scientific Software-Intercomp, Inc.).

4.4 IN-LINE INSPECTION

Section 1.2.3.1 discussed the classification of in-line inspection devices. Utility pigs are used primarily for maintenance of pipelines. Instrumented pigs are used for defect detection. The least complex of the instrumented pigs is the caliper pig. This device measures the geometric

distortions in a pipeline. It is not suitable to measure corrosion. It should be used prior to an intelligent pig inspection. Its major advantage is that its cost to run is relatively low (\$15k to \$30k per run) (Smollen 1995).

The most common intelligent pigging technology is the magnetic flux loss (MFL) technology. This technology detects distortion in a magnetic flux field due to changes in metal wall thickness. It will locate the precise location (within feet) of an anomaly and can predict the general magnitude of such an anomaly. It allows planning of preventive steps and for repairs. The cost ranges from \$75k to \$100k per run (Smollen 1995). This technology is preferred by most operators. The quality of the inspection varies with the vendor performing the tests.

The most promising intelligent pigging technology being developed is ultrasonic pigging. This new technology is evolving and its availability is limited to a few vendors. It is expensive (\$150k to \$350k per run for oil pipelines; more for gas) (Smollen 1995). However, the proponents of the technology assert that it can precisely locate and determine the magnitude of wall thickness remaining within fractions of an inch. It can produce a color graphic image to show detailed pictures of each pipe joint. It is easy to understand. This technology is now used in non-destructive testing of welds. One vendor claims that it can detect extremely small stress cracks (Willems 1995).

A problem common to liquid petroleum pipelines, particularly near the refinery end and as the warm product cools as it enters an offshore pipeline, is the buildup of paraffin wax or asphaltine on the inside of the pipe wall. Since this wax buildup can hamper the flow and can plug the pipeline, its detection is critical. Once the buildup starts to restrict flow, the pipe is cleaned by a utility pig and deposited in a clean-out chamber. A new type of magnetic sphere and valve positioning (MSVP) system has been developed to improve the buildup detection. This MSVP system interfaces with the operators SCADA system and provides for automatic early detection (Casey 1994).

4.5 CATHODIC PROTECTION INVESTIGATIONS

Corrosion prevention of a pipeline depends on coatings and cathodic protection. The two systems are complementary, neither is effective without the other. The coating is the primary corrosion protection, with cathodic protection being the secondary system. Coating permits the effective use of cathodic protection within practical limits, and coating without cathodic protection can cause accelerated attack at areas of coating damage by concentration of anodic current discharge.

Routine testing of cathodic protection level is relatively simple. Up to a point, the protection level can be adjusted to overcome a developing problem and the results of the adjustment are immediately apparent. However, coating defect detection is not always accurate or even quantifiable. Thus, coating surveys and repairs are often considered only as a last resort.

Developments in semiconductor manufacturing technology have allowed the practical design of field instruments which significantly improve the reliability, accuracy, and speed of coating de-

fect surveys. This means that increased attention to coating defect repair as a means of maintaining corrosion protection status is now a viable option.

The concept of cathodic protection is simple but its application can be complex. If current flow is from the environment to the pipe, no corrosion occurs. If current flow is from the pipe to the environment, corrosion occurs at a rate that can be calculated. The condition of the system is predicted by the measurement of the electric potential from the pipe to the soil interface and from the soil interface to its surrounding environment. It is generally accepted that an adequate current flow will occur to the pipe if there is a difference in potential of -850 mV from the soil to the pipe. The -850 mV is measured relative to a copper/copper sulfate reference. The following are typical routine testing techniques:

- (a) **ROUTINE POTENTIAL SURVEYS.** These tests generally involve pipe-to-soil potential measurement at installed test points of 1 to 2 km spacing. This test can predict the condition of the cathodic protection but not the coating condition.
- (b) **CLOSE INTERVAL OVERLINE POTENTIAL SURVEYS.** These tests are tailored according to the information required and can vary considerably in cost. The "on" potential of the pipeline is measured at close intervals using a long wire reeled out from available test points. Readings are taken over the pipeline and also at some distance perpendicular to the pipeline. The measurements can be used to calculate the true potential and the defect severity at each defect located.
- (c) **COUPONS OR POLARIZATION PROBES.** These probes of selected size distributed as artificial defects at representative locations along the pipeline can give accurate true potential levels. For this information to be useful, a realistic assessment of coating condition or defect size is required.
- (d) **INSTANT OFF POTENTIAL.** This test compares the pipeline on potential with the polarized potential immediately following cathodic protection system switch off to indicate the protection status and general condition of the coating.
- (e) **COATING DEFECT SURVEYS.** Pearson surveying is the usual method of locating coating defects or areas of coating damage. Other techniques must be used to determine the severity of each defect found.

The costs of the various techniques can be calculated by using the following production rates:

- Routine potential surveys: 50 km/man-day
- Close interval overline potential surveys: 1 km/man-day
- Pearson survey: 5 km/man-day.

These production rates allow cost comparisons to be made

A relatively new testing technique using the "DC pulse" technique has been developed. Direct current techniques have long been recognized as having some advantages over the conven-

tional Pearson technique. The main drawback to the DC survey was that the survey speed compared to the AC Pearson technique was much slower. However, recent improvements in instrument component manufacturing have allowed the development of DC survey equipment that exceeds the survey speed of Pearson gear and provides much of the information afforded by close interval overline potential surveys. See Mulvany²⁹ for a description of the technique.

4.6 PIPELINE MAINTENANCE

4.6.1 PREVENTIVE MAINTENANCE

The most effective preventive maintenance that can be done to a buried pipeline or submerged pipeline is CARE IN THE INITIAL CONSTRUCTION OF THE PIPELINE. The theoretical failure rate of a pipeline will follow a typical “bath-tub” graph as shown in figure 4.6.1.

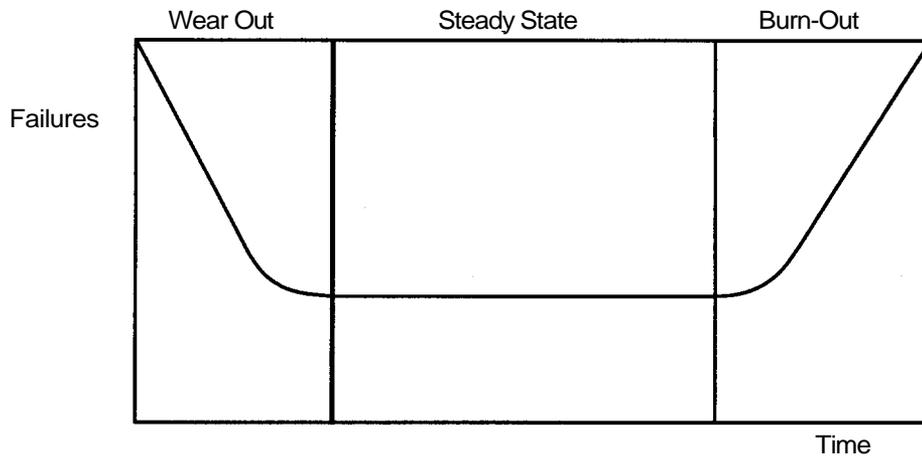


Figure 4.6.1 Assumed failure rate function.

Many of the early failures are due to construction and installation quality. This results in an initially high component failure rate as shown in the “installation” portion of the curve. Controlling construction quality is the most important preventive maintenance action an operator can take. Many operators have extensive manuals to account for this quality. For instance, the following is an excerpt from an operator’s manual:

“A non-abrasive canvas padded sling or rubber cradle-type sling is to be used for placing the pipe in the ditch. The necessary amount of slack is to be obtained without injury to the protective coating. Any coating damaged is to be repaired to the condition equal to that of the undamaged coating” (Operator Manual 1995).

The “steady state” portion of the curve in figure 4.6.1 shows that there will be a very low failure rate for a long period of time for a well-installed pipeline. With the exception of third party damage, this represents the experience of the industry. The final part of the curve in figure 4.6.1 is the “wear-out” phase of the pipeline. This represents an increased failure rate due to the age of the pipeline and might be represented by internal or external corrosion, fatigue, or brittleness. The wear-out phase, if quantified, would represent the design life of a pipeline.

4.6.2 ROUTINE FIELD REPAIRS

There are few field repairs to transmission pipelines that can be categorized as maintenance. Routine repairs to markers, right-of-way area, valve protection fences and structures are accomplished in accordance with operator's maintenance manuals. Repair of coatings, leaks or other defects are not routine repairs and are categorized as pipeline rehabilitation.

4.7 PIPELINE REHABILITATION

4.7.1 DETERMINATION OF THE NEED FOR REHABILITATION

There are four steps in determining a pipeline rehabilitation strategy:

- (a) Define the pipeline integrity requirement
- (b) Identify the pipeline integrity threats
- (c) Identify the rehabilitation strategy, and
- (d) Verify the strategy's applicability (Coates 1995).

In defining the pipeline integrity requirement, strategies other than repair or replacement of the pipeline or coatings may be in order. It may be that the MAOP may be derated, e.g., the required present operating pressure may be less than the design MAOP. Given a derated MAOP, the minimum allowable wall thickness may be less than the original design. The pipeline lifetime requirement may be recalculated, and the leak tolerance might be reinvestigated.

The threats to the pipeline must be evaluated. Third-party damage and corrosion are the major causes of concern. Since third-party damage is impossible to predict through routine inspections and is dealt with from a preventive point-of-view, the threat of corrosion usually drives a rehabilitation program. The deterioration mechanism must be evaluated, and all places on a pipeline where deterioration is taking place must be investigated. The only effective way of assessing corrosion threats to pipeline integrity is the use of an in-line pig.

The operator must identify rehabilitation strategies. The strategies may be long term or short term. For short term strategies, the objective is to establish the minimum integrity level required by pipeline repairs and thus the capability of meeting the derated MAOP. This will require additional work in terms of mitigation, based on indicated or verified worst case corrosion pitting rates to allow for the time lag between the intelligent pigging operations and the long term rehabilitation strategies. Most operators interviewed for this study consider all repairs temporary and plan pipe segment replacement to restore the pipeline. For the long term strategy, the objective is to maintain the pipeline over time at the established integrity level, mitigating deterioration by replacement of defective pipe, upgrading of CP systems (for external corrosion) and chemical inhibition regimes and, perhaps, dewatering programs to meet changing demands (for internal corrosion) (Coates 1995). Long term rehabilitation also includes pipeline segment replacement.

In preparing pipeline rehabilitation strategies operators count on in-line inspection to determine the basis of the repair program, close interval surveys to determine the coating conditions, and

cathodic protection surveys as part of normal maintenance. To develop rehab strategies, one should investigate the following:

- (a) Alignment sheets
- (b) Fabrication drawings
- (c) Leak and repair history,
- (d) Hydrostatic test records
- (e) Previous in-line inspection records, and
- (f) Cathodic protection system records (Tencer 1995).

One should note that no techniques for integrating these data currently exist. There is a need for research to develop a way to analyze the above information, synthesize it into a form that would prioritize and lay out a set of economic risk variables that could be used to evaluate a rehab program.

Finally, one must verify the applicability of the strategy employed. Inspection and maintenance programs are an integral part of the management and operation of pipelines and they must be able to verify the pipeline integrity. The level of inspection and investigation involves economic trade-offs (Coates 1995).

4.7.2 DESIGN OF A PIPELINE REHABILITATION PROGRAM

There are three major activities in a pipeline rehabilitation program. These include temporary pipe repair, coating repair and replacement, and pipe segment replacement.

4.7.2.1 Temporary Pipe Repair

Sections 192.713 and 192.715 of the gas pipeline safety regulations require full encirclement split sleeves for field repair of imperfections, damages and welds except for some specific exclusions. In some instances, 192.717 allows leaks to be repaired by using a bolt-on leak clamp or a fillet welded steel plate patch with rounded corners over corrosion pits. However, a full encirclement split-sleeve is the repair of choice.

Liquid pipelines are governed by Paragraph 195.422. ASME 831.4 discusses the safety aspects of repairs to liquid pipelines and refers the reader to API Publications 2200 and 2201 and to API Recommended Practices 1107 and 1111. There are several new types of repair methods being developed which have not been approved for high pressure gas transmission pipelines. Some involve prestressing the split sleeve, filling a sleeve with epoxy, etc. There is one non-welded repair technique that is receiving good marks by the industry. It is called the "Clock Spring" method, developed by the Clock Spring Company, L.P. This consists of a composite coil that is equivalent to a structural reinforcement sleeve wrapped about the pipe in the defect zone, an adhesive system that bonds the coil to the pipe on each layer of the coil, filler material that is the load transferring agent placed to fill an annular gap, a starter pad that anchors lead edge to coil to the pipe to allow cinching, and an external coating system that provides additional environmental protection. There is no restriction for liquid pipeline repair by the hazard-

ous liquid pipeline regulations in Part 195. A waiver is required before this technology can be used on a gas transmission pipeline. Several gas pipeline operators have received waivers to use this repair method. The ASME 631.8 committee determined that no change in the code was required to use this technology (Keltly 1995).

4.7.2.2 Coating Repair and Replacement

A valid way to inspect the condition of pipeline coatings is to use close interval surveys. There are two basic types of close interval surveys: a pipe-to-soil potential survey and a direct current voltage gradient (DCVG) survey. A close interval pipe-to-soil potential survey requires a connection to the pipeline and collection of pipe-to-soil data at approximate 0.75 meter (2.5 feet) intervals over the entire route of the pipeline. The survey can be conducted with rectifier units on, or with interrupters in the rectifier units to obtain on and off potential readings. Data from the survey can be plotted to observe:

- (a) Whether a criterion for cathodic protection has been satisfied between the test station locations
- (b) Sharp dips in the pipe-to-soil readings, which are indicative of coating holidays or interference from a crossing pipeline, and
- (c) Gradual depressions in the pipe-to-soil potential level, which can be indicative of general deterioration of the pipeline coating, excessive spacing between impressed current sources, or a need to adjust the output of the impressed current sources.

A close-interval DCVG survey involves measuring the voltage between two reference electrodes, located over the pipeline, that are set a distance apart. The cathodic protection current flowing to the pipeline at the holiday location creates a voltage gradient that is detected by the reference electrodes. A DCVG survey can determine the location of coating holidays and the relative size of the coating holiday.

The DCVG survey is more sensitive than the pipe-to-soil potential survey for locating holidays, and also locates small holidays that the pipe-to-soil potential survey would miss. However, the DCVG survey does not indicate whether the pipeline is cathodically protected at the holiday location. If the pipeline is protected from corrosion by the cathodic protection system, there may be no reason to repair the coating holiday. The DCVG and pipe-to-soil potential surveys can be performed concurrently at a relatively small increase in cost, and the advantages of both surveys can be realized. These surveys work best when there is only one pipeline in the right-of-way. Once the close interval surveys are performed, corrosion can be mitigated through a systematic approach as in Table 2.3.4.3 (Tencer 1995).

If coating rehabilitation is considered necessary after an economic and technical analysis, one should carefully select the new coating material. Daniel Werner (1995) presented information excerpted from a current draft of a NACE State of the Art report prepared by Task Group T-6a-63. In that paper he describes the desirable physical/chemical properties and performance criteria for coating material. In addition to the listed 13 specifications to consider, he presented 11 factors to be considered in the design of new coatings. The key factors in pipeline recoating are ensuring adequate surface preparation and maximizing the production rate of the coating

process. He goes on to discuss the strengths and weaknesses of the following generic coating materials:

- Coal tar enamels
- Hot-applied wax
- Cold-applied wax tapes
- Tape coatings
- Coal tar epoxy
- Epoxy coatings
- Urethanes
- Coal tar urethanes
- Vinyl esters.

Processes are available to rehabilitate pipeline coatings. There have been recent advances in several techniques for applying in-place pipeline coatings. These were discussed in section 2.3.1.2.

4.7.2.3 Pipe Replacement Program

A pipe replacement program is designed to remove critical anomalies, temporary repairs and unnecessary fittings. Pipeline replacement requires taking the system out of service and replacing the existing pipe with new pipe. Table 4.7.2.3 shows a description of the features replaced along with the corresponding justifications (Tencer 1995).

FEATURES INCLUDED IN THE PIPE REPLACEMENT PROGRAM

Description	Justification
Corroded pipe having a wall thickness loss equal to or greater than 50%	Usually cost-effective due to the high corrosion rates measured.
Corroded pipe having a Safe Pressure equal to or less than the MAOP	ASME 831G-1991.
Reinforcing sleeves left in the pipelines as a result of emergency repair work	ASME B31.4-1989 Section 451.6.2 (c) (4).
Stopples left in the pipelines as a result of previous pipe replacement work	To minimize the number of locations exposed to tampering and third party damage.
Defective girth welds	ASME B31.4-1989 Section 451.6.2 (a) (5).
Mechanically damaged pipe having wall thickness loss equal to or greater than 12%	ASME B31.4-1989 Section 451.6.2 (a) (1).
Half soles and patches	ASME B31.4-1989 Section 451.6.2 (c) (13).
Unclassified defects	Replacement recommended as preventive measure.

Table 4.7.2.3 Pipe Replacement Program

BIBLIOGRAPHY

- Ahmed, Syed., "Geoenvironmental Considerations in Pipeline Construction and Rehabilitation", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.
2. Alyeska, "Alyeska Evaluates Corrosion Repair Program on Trans-Alaska Crude Line", *Materials Performance*, December, 1990. Pp. 26-29.
 3. American Petroleum Institute, API Specification Practice 5L, "Specification for Line Pipe", (40th Edition, 1992).
 4. American Petroleum Institute, API Standard 1104, "Welding of Pipelines and Related Facilities", (18th Edition, 1994).
 5. American Petroleum Institute, API Standard 1107, "Pipeline Maintenance Welding Practices", (3rd Edition, 1991).
 6. American Society of Mechanical Engineers/American Society of Testing and Materials, Standard B31.4, "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols", (1989 with ASME B31.4a -1991 Addenda).
 7. American Society of Mechanical Engineers/American Society of Testing and Materials, Standard B31.8, "Gas Transmission and Distribution Piping Systems", (1990 with ASME/ANSI B31.3a-1990, B31.3b-1991, and 831.1c-1992 Addenda and Special Errata issued December 31, 1990).
 - a. Bario, Thomas, J. and Berry, Warren, E., "An Assessment of the Current Criteria for Cathodic Protection of Buried Steel Pipelines", *National Association of Corrosion Engineers*, September, 1984. Pp. 9-16, 50-51, 55.
 9. Bauer, D., "Cathodic Protection Considerations in the Rehabilitation of Buried and Submerged Pipelines", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.
 10. Casey, Ernest, D., "New Magnetic Sphere and Valve Positioning System Improve Pipeline Operations", *Pipeline & Gas Journal*, December 1994. Pp. 56-60.
 11. Cherry, B.W. and Gould, A.N., "Pitting Corrosion of Nominally Protected Land-Based Pipelines", *Materials Performance*, August, 1990. Pp. 22-26.
 12. Croch, A.E., "In-Line Inspection of Natural Gas Pipelines", *Gas Research Institute*, May, 1993.
 13. Fluharty, John, II., "Advances in Bell-Hole Rehabilitation Equipment", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.

14. Friedel, T., "Practical Application of a Composite Repair Sleeve", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
15. Friedrich, J., "Repair of Pipeline Defects With Pre-Stressed Sleeves", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
16. Gaudioso, Charles, P., "Corrosion-Resistant Composite Sleeve for the Pipeline Industry", *Chemical Engineering Progress*, November, **1985**. Pp. **40-42**.
17. Gimelfarb, Mikhael, N., "Corrosion Prediction for Underground Pipelines", *Materials Performance*, February, **1990**. Pp. **18-20**.
18. Gundry, Ronald, D., "Underground Pipeline Corrosion Control", *National Association of Corrosion Engineers*, April, **1988**. Pp. **9**.
19. Hamilton, J.C., "Statistical Model", *Oil & Gas Journal*, Sept. **11, 1989**. Pp. **42-46**.
20. Hussain, K., Shaukat, A. and Hassan, F., "Corrosion Cracking of Gas-Carrying Pipelines. Does Cathodic Protection Contribute?", *Materials Performance*, February, **1989**. Pp. **13-15**.
21. John, Robin., "Field Recoating Using the 3 Layer System", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
22. Kellner, Jordan, D., "Laboratory Evaluation of In-Ground Cathodic Disbondment of Pipeline Coatings", *National Association of Corrosion Engineers*, September, **1986**. Pp. **20-24**.
23. Kelty, W., Paul., "Composite Sleeves for Pipeline Integrity: Part II", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
24. Kiefner, John, F. and Eiber, Robert, J., "Study Shows Shift in Line Pipe Service Problems", *Oil & Gas Journal*, Mar. **30, 1987**. Pp. **98-100**.
25. Kresic, Walter., "Coating Rehabilitation of a Large Diameter In-Service Crude Oil Pipeline", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
26. Kresse, Thomas, J., "CO₂-Removal Reduces Pipeline Corrosion at Two Storage Sites", *Oil & Gas Journal*, Oct. **12, 1987**. Pp. **77-79**.
27. LaCasse, Gary, A. and Ingvordsen, Torben., "Desiccant Drying of Gas Pipelines", *Materials Performance*, September, **1988**. Pp. **48-51**.
28. Maddox, R.N., Shariat, Ahmad and Moshfeghain, Mahmood., "Program for TI-59 Calculator Helps Locate Position of Leaks on a Liquids Pipeline", *Oil & Gas Journal*, Dec. **10, 1989**. Pp. **104-110**.

29. Muhlbauer, Kent, W., "Pipeline Risk Management and Operating Discipline", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.
30. Mulvany, John., "New Pipeline Coating Defect Surveying Equipment for Corrosion Protection Assessment", *Materials Performance*, April, 1991. Pp. 17-21.
31. Nicholas, R., Edward., "Leak Detection and Location Sensitivity Analysis", *Pipeline Engineering '92*, ASME, PD-Vol. 46. 1992. Pp. 11-19.
32. Norsworthy, Richard., "Testing of Pipeline Maintenance and Rehabilitation Coatings", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.
33. Nyborg, Rolf., Dugstad, Arne., and Lunde, Liv., "Corrosion and Glycol Distribution in a Large Wet-Gas Pipeline", *Materials Performance*, September, 1993. Pp. 57-61.
34. Office of Pipeline Safety, "Comprehensive Inspection Report of New Jersey Interstate Natural Gas Transmission Pipeline Operators", Office of Pipeline Safety, February 22, 1995.
35. Partidge, Paul, E., "Testing Methods for Underground Pipeline Coatings", *Materials Performance*, December, 1991. Pp. 22-24.
36. Punter, A., Fikkers, A.T. and Vanstaen, G., "Hydrogen-Induced Stress Corrosion Cracking on a Pipeline", *Materials Performance*, June, 1992. Pp. 24-28.
37. Rapaport, Diane., "Tracer Compounds Help Find Tank and Pipeline Leaks", *Materials Performance*, February, 1992. Pp. 40-41.
38. Rhea, S.W. and Grimes, K., "Case Study: In-Situ Rehabilitation of Pipeline Defects Using Epoxy Filled Repair Sleeves": *Seventh Annual International Pipeline Monitoring and Rehabilitation Seminar*, February 6-9, 1995.
39. Robinson, Ronald, C., "Computerized Corrosion Monitoring for Metallic Pipeline Structures", *Materials Performance*, February, 1993. Pp. 30-34.
40. Roche, Marcel., "Coating Disbondment Leads Causes of External Pipeline Corrosion", *Oil & Gas Journal*, Apr. 1, 1991. Pp. 49-53.
41. Rusin, Michael and Sawides-Gellerson, Evi., "The Safety of Interstate Liquid Pipelines: An Evaluation of Present Levels and Proposals for Change", American Petroleum Institute, Research Study #040, July, 1987.
42. Smart, John, S. and Smith, Gary, L., "Pigging and Chemical Treatment for Oil and Gas Pipelines", *Materials Performance*, January, 1992. Pp. 47-50.
43. Smollen, J., III., "Pipeline Leak Detection in the Strategic Petroleum Reserve", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February 6-9, 1995.

44. Stretch, Paul., "Developing a Rehabilitation Strategy: *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
45. Strinvasan, R., Murphy, J.C., and Lillard, R.S. ;"Corrosion Detection on Underground Gas Pipeline by Magnetically Assisted AC Impedance", *Materials Performance*, March, **1991**. Pp. **14-18**.
46. Tensor, G. and Marquez, M., "Pipeline Rehabilitation Investigation Parameters", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
47. U.S. Department of Transportation, "A Review of Pipeline Facilities Constructed Before January 1, **1947**", Research and Special Programs Administration, August, **1985**.
48. U.S. Department of Transportation, "Comprehensive Inspection Report of New Jersey Interstate Natural Gas Transmission Pipeline Operators", The Joint Inspection Task Force, February **22, 1995**.
49. Vasilyev, Gennady., "SCC in the Russian Pipeline System", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
50. Werner, Daniel, P., "Perspectives in Pipeline Rehabilitation", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
51. Willems, H., "A New Tool for Crack Detection in Pipelines", *Proceedings of the Seventh Annual Pipeline Monitoring & Rehabilitation Seminar*, February **6-9, 1995**.
52. Wu, Yulin., McSperitt, Kenneth, E. and Harris, George, D., "Corrosion Inhibition and Monitoring in Sea Gas Pipeline Systems", *Materials Performance*, December, **1988**. Pp. **29-34**.

APPENDIX A

SYNOPSIS OF INFORMATION FOR VARIOUS COMMON CATEGORIES RESPONDED TO IN THE FOREIGN REGULATIONS REVIEWED IN THIS STUDY

● SOURCE OF MATERIAL	A1
● WHERE REGULATIONS ARE APPLICABLE	A2
● CLASS LOCATIONS CATEGORIES	A3, A4
● PRESSURE DESIGN FOR STEEL PIPE LINE	A5, A6, A7
● TRANSMISSION LINE VALVE SPACING	A8
● COVER REQUIREMENTS (OVER BURIED PIPELINE)	A9, A10
● SITING OF PIPELINES	A11
● MAXIMUM ALLOWABLE OPERATING PRESSURE	A12, A13
● PATROLLING OF LINES	A14

COUNTRY	SOURCE OF MATERIAL
UNITED STATES	U.S. Pipeline Safety Regulations U.S. DOT, Research and Special Programs Administration (10/1/93) - Natural Gas Parts 191-2, Oil Pipelines Response Plans Part 194, Hazardous Liquids Part 195
UNITED KINGDOM	<p>United Kingdom • Institution of Gas Engineers Steel Pipeline for High Pressure Gas Transmission, Recommendations on Transmission and Distribution Practice • IGE/TD/1 Edition 3: 1993 Communication 1530. Department of Trade and Industry</p> <p>(a) Guidelines for the Assessment of Cross-County Pipelines • 1992 HMSO-ISBN014142866</p> <p>(b) Guidance Notes for Applications and Notifications for Onshore Pipelines Under the Pipe-Lines Act 1962-1993; HMSO-ISBN0014142890</p> <p>Code of Practice for Pipelines Part 2 • Pipelines on land: design, construction and installation • Section 2.8 (BS8010): 1992, published by British Standards Institute</p>
CANADA	<p>Canada - Z662-94- "Oil and Gas Pipeline Systems" ISSN 0317-5669 • Sept. 1994 by Canadian Standards Association</p> <p>This suersedes: CAN/CSA • Z183-M90 - Oil Pipeline Systems and CAN/CSA - Z184-M92 - Gas Pipeline Systems</p>
AUSTRALIA	Australia - AS2885-1987 Pipelines • Gas and Liquid Petroleum by Standards Australia
GERMANY	<p>Germany - DVGW Arbeitsblatt G463 - July 1989 & G466/1 - July 1989</p> <p>TRbF 301 and 302 - Rules for Long Distance Transport of Hazardous Liquids</p>
JAPAN	Japan • Tsusho Sangyo Roppo (MITI Regulation Code) MITI is the Ministry of Industry and Trade

COUNTRY	WHERE REGULATIONS ARE APPLICABLE
UNITED STATES	Transmission line is a pipeline that operates at a hoop stress of 20% or more of SMYS (specified minimum yield strength) - (Part 19 3); • natural gas 195.1 - hazardous liquids • regulations only apply to hazardous liquids that operate at a stress level of 20% or more of SMYS.
UNITED KINGDOM	Regulations (i.e. IGE/TD/1) apply to the transmission of natural gas at pressures exceeding 7 bar and not exceeding 100 bar and at temperatures between • 25°C and 120°C inclusive (section 2 • scope; 2.1). They pertain to on-land pipes and water crossings (sect. 2.2); for offshore pipes, additional guidance may be required, however, many recommendations will remain valid. Section 2.8 (BS8010): applies to steel pipelines constructed with butt welded joints and are generally suitable for conveying oil, gas and toxic fluids. EDITOR'S NOTE: THE PASCAL (PA) IS 1N/M ² ; 1BAR=10 ⁵ PA; 1PSI=6.895KPA; ∴ 7BAR≅101.5PSI AND 100BAR≅1,450PSI
CANADA	Scope (section 1.1) • covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems which convey liquid hydrocarbons, including crude oil, natural gas liquids, liquid petroleum products,.....
AUSTRALIA	1.1 Scope - covers the design, construction, installation, inspection, testing, operation, and maintenance of pipelines used to convey hydrocarbon fluids such as natural and manufactured gas, natural gasoline, crude oil, natural gas liquids and liquid petroleum products in either a single-phase or multiphase condition for steel pipes . Temp. between - 30°C and 200°C Operating pressure is above 1050k Pa or the hoop stress is above 20% of SMYS or for interconnecting liquid pipeline is above 2000k Pa or 20% of SMYS EDITOR'S NOTE: 1050K PA IS 10.5BAR (IS -152 P.S.I.)
GERMANY	Steel Gas Pipelines with Service Pressures over 16 Bar. Steel Pipelines conveying Hazardous Liquid TRbF 301: Lists various regulations pertaining to obtaining proper permission/certification for constructing and operating hazardous liquids pipelines.
JAPAN	Steel Pipeline conveying Gas or Hazardous Liquids. Chapter 4, Section 2 specifically regulates the installation of LP, gas and oil pipeline systems, licensing and testing standards for engineers and technicians under the joint supervision of the Governor and MITI.

COUNTRY	CLASS LOCATIONS CATEGORIES
UNITED STATES	<p><u>GAS ONLY</u> <u>192.5</u>: offshore is Class 1 location. Class location onshore is an area that extends 220 yards (Editors Note: 1/8 mile) on either side of the centerline of any continuous 1 mile length of pipeline. For this section, each separate dwelling unit in a multiple dwelling unit building is considered as a separate building. <u>Class 1 location</u>: has 10 or less buildings intended for human occupancy. <u>Class 2 location</u>: has more than 10 but less than 46 buildings intended for human occupancy. <u>Class 3 location</u>: (a) has more than 46 buildings intended for human occupancy, or (b) an area where pipeline lies within 100 yards of either a building or a small, well-defined outside area occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12 month period. <u>Class 4 location</u>: any class location unit where buildings with 4 or more stories above ground are prevalent.</p> <p><u>OIL: Sect 195.210</u>. No pipeline may be located within 50 feet of any private dwelling, industrial building or place of public assembly unless provided with at least 12 inches of cover in addition to that prescribed in 195.248.</p>
UNITED KINGDOM	<p><u>Section 6.8</u> Classification of Area Types and Design Criteria (IGE/TD/1 Edition 3:1993) Three distinct types of area, designated R, S and T, represent locations adjacent to a pipeline. The area types require different design criteria, with particular reference to operating stress level and proximity. <u>TvDe R</u> - Rural areas with a population density not exceeding 2.5 persons per hectare (ha). <u>TvDe S</u> - Areas intermediate in character between types R & T in which population density exceeds 2.5 persons per hectare and which may be extensively developed with residential properties, schools, shops, etc. <u>TvDe T</u> - Central areas of towns or cities, with a high population density, many multistory buildings, dense traffic and numerous underground services.</p> <p>Figures 2 & 3 in the document provide minimum distances from normally occupied buildings of pipelines designed to operate in Type R & S areas, respectively. Design of pipeline in T areas shown in IGE/TD/3. Minimum distances are functions of operating pressures (R & S); outside diameters (R) and wall thickness (S).</p> <p>BSI - Section 2.8 (BS8010):1992: developed in the document are three class locations, namely, Class 1, Class 2, and Class 3 which are defined exactly as Type R, Type S, and Type T, respectively, as defined above in document IGE/TD/1. In addition, substances to be conveyed are categorized in four categories (i.e. Category A, B, C or D). Category A includes typically water based fluids. Category B includes flammable and toxic substances which are liquids at ambient temperature and atmospheric pressure conditions (e.g. oil, petroleum products, toxic liquids). Category C are non-flammable substances which are gases at ambient temperature and atmospheric pressure conditions (e.g. oxygen, nitrogen, carbon dioxide). Category D are flammable and toxic substances which are gases at ambient temperature and atmospheric pressure and are conveyed as gases or liquids (e.g. methane, ethane, propane, butane, LPG, ammonia, and chlorine).</p> <p>Minimum distances from normally occupied buildings for Category B substances is a function of access requirements for construction and operation. For Categories C and D, the minimum distances are a function of the design factor (i.e. 0.72 or 0.3) used, the outside pipe diameter, the maximum operating pressure, and the substance carried.</p>

Continued on Next Page

COUNTRY	CLASS LOCATIONS CATEGORIES																		
CANADA	<p><u>Sect. 4.3.2 for Oil & Gas Pipelines</u>: prior to '94 regs, gas lines had Class Locations and oil lines had Zone Locations.</p> <p>Class Location areas shall extend 200 m on both sides of C of any continuous 1.6 km length of pipeline (EDITOR'S NOTE: SAME AS U. S. • 200M≅220YARDS; 1.6KM≅1 MILE)</p> <p>Class 1: >10 dwelling units for human occupancy. Class 2: >10 and <46 dwelling units or a building occupied by 20 or more persons during normal use or a small well defined outside area occupied by 20 or more persons during normal use, or an industrial installation such as a chemical plant or hazardous substance storage area, where release of products from a pipeline could cause the industrial installation to produce a hazardous condition. Class 3: >46d.u.'s; also where rapid evacuation needed such as hospitals and nursing homes. Class 4: >4 story buildings or more are prevalent.</p>																		
AUSTRALIA	<p><u>Sect. 3.5.2</u> Class R1 - broad rural -- sparsely populated - undeveloped area or broadly farmed area. Area of average allotment is greater than 5ha (EDITOR'S NOTE: 1HA=2.47 ACRES) Class R2 - semi-rural -- small farms or rural residential use where average allotment is between 1 and 5ha. Class T1 - suburban -- developed for residential, commercial, or industrial use where majority of buildings have less than four floors, and where, typically, the area of the average allotment is less than 1ha. Class T? - high-rise -- allotment < 1ha; used for residential, commercial, or industrial use, but majority of buildings have four or more floors. Class S - submarine -- a location on or in the bed of the sea, bay or estuary up to the highest watermark.</p>																		
GERMANY	<p><u>Section 3.1.2 Right of Way (G463)</u> Building over or within the "Safety Zone" is not allowed. The "Safety Zone" is dependent on pipe diameter and type of service. The normal Safety Zones are:</p> <table border="0" data-bbox="602 1176 1120 1308"> <thead> <tr> <th style="text-align: left;"><u>Pipe Diameter</u></th> <th style="text-align: left;"><u>Zone Width (m)</u></th> </tr> </thead> <tbody> <tr> <td>up to DN 150</td> <td>2-4 m</td> </tr> <tr> <td>DN 150 - DN 300</td> <td>4-6m</td> </tr> <tr> <td>DN 300 - DN 500</td> <td>6-Em</td> </tr> <tr> <td>Over DN 500</td> <td>8-10m</td> </tr> </tbody> </table> <p>Exceptions due to planning or construction techniques can, in special circumstances cause the Zone to be either smaller or larger than specified. TRbF3d: Section 2.3 - Protective Right of Way; 2.3.2 - The right of way is to protect the pipeline; 2.3.4 - The right of way must be sufficiently large to prevent encroachment by deep plant roots; 2.3.6 - Right of ways must be from 4m to 10m wide depending upon the pipe size; 2.3.8 - Exceptions to policy for right of way sizes may be granted in special cases. EDITOR'S NOTE: DN = NOMINAL DIAMETER (MM)</p>	<u>Pipe Diameter</u>	<u>Zone Width (m)</u>	up to DN 150	2-4 m	DN 150 - DN 300	4-6m	DN 300 - DN 500	6-Em	Over DN 500	8-10m								
<u>Pipe Diameter</u>	<u>Zone Width (m)</u>																		
up to DN 150	2-4 m																		
DN 150 - DN 300	4-6m																		
DN 300 - DN 500	6-Em																		
Over DN 500	8-10m																		
JAPAN	<p>Above ground pipeline installations must comply with the following minimum horizontal distances from the items listed:</p> <table border="0" data-bbox="475 1549 1131 1793"> <tbody> <tr> <td>Railroad</td> <td>25 meters</td> </tr> <tr> <td>LP Gas Storage Tank</td> <td>35 meters</td> </tr> <tr> <td>Schools (up to High Schools)</td> <td>45 meters</td> </tr> <tr> <td>Children's Welfare, Nursing Homes and Hospitals</td> <td>45 meters</td> </tr> <tr> <td>Theater and Movie Theaters</td> <td>45 meters</td> </tr> <tr> <td>Department Stores</td> <td>45 meters</td> </tr> <tr> <td>Commuter Train Stations</td> <td>45 meters</td> </tr> <tr> <td>Landmark Properties</td> <td>65 meters</td> </tr> <tr> <td>City Water Resources</td> <td>300 meters</td> </tr> </tbody> </table>	Railroad	25 meters	LP Gas Storage Tank	35 meters	Schools (up to High Schools)	45 meters	Children's Welfare, Nursing Homes and Hospitals	45 meters	Theater and Movie Theaters	45 meters	Department Stores	45 meters	Commuter Train Stations	45 meters	Landmark Properties	65 meters	City Water Resources	300 meters
Railroad	25 meters																		
LP Gas Storage Tank	35 meters																		
Schools (up to High Schools)	45 meters																		
Children's Welfare, Nursing Homes and Hospitals	45 meters																		
Theater and Movie Theaters	45 meters																		
Department Stores	45 meters																		
Commuter Train Stations	45 meters																		
Landmark Properties	65 meters																		
City Water Resources	300 meters																		

COUNTRY	PRESSURE DESIGN FOR STEEL LINE PIPE																					
UNITED STATES	<p>GAS Formula Sec 197.105</p> $P = \left(\frac{2St}{D} \right) \times F \times E \times T$ <p>P=design pressure in (p.s.i.g.) S=Yield Strength (in p.s.i.) as per 192.107 D=Nominal outside diameter of the pipe (in.) t =Nominal wall thickness of the pipe (in.) F=design factor determined as per 192.111 E=longitudinal joint factor as per 192.113 T=temperature derating factor as per 192.115 Design factor (F) for steel pipe is a function of class location as follows:</p> <table border="1" data-bbox="584 697 1141 832"> <thead> <tr> <th>CLASS LOCATION</th> <th>DESIGN FACTOR (F)</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>0.72</td> </tr> <tr> <td>2</td> <td>0.60</td> </tr> <tr> <td>3</td> <td>0.50</td> </tr> <tr> <td>4</td> <td>0.40</td> </tr> </tbody> </table> <p>Hazardous Liquids</p> <p>OIL: $P = \left(\frac{2St}{D} \right) \times E \times F$ - same units as above</p> <p>F=design factor = 0.72, except 0.60 is used for pipe on a platform located offshore or on a platform in inland navigable waters.</p>	CLASS LOCATION	DESIGN FACTOR (F)	1	0.72	2	0.60	3	0.50	4	0.40											
CLASS LOCATION	DESIGN FACTOR (F)																					
1	0.72																					
2	0.60																					
3	0.50																					
4	0.40																					
UNITED KINGDOM	<p>Sec. 6.4 Wall Thickness of Linepipe (IGE/TD/1)</p> $t = \frac{P \cdot D}{20f \cdot S}$ <p>where t =design thickness of pipewall (mm) P=design pressure (bar), at the relevant design temperature. D=outside diameter of the pipe (mm) S=specified minimum yield strength (N/mm²) f =a factor that should not exceed 0.72 in type R areas, and 0.3 in Type S areas. In any event, the nominal thickness of steel pipe should not be less than indicated in Table 3.</p> <p style="text-align: center;">TABLE 3</p> <table border="1" data-bbox="551 1389 1409 1661"> <thead> <tr> <th colspan="2">Outside Diameter of Pipe (mm)</th> <th>Least Nominal Wall Thickness (mm)</th> </tr> </thead> <tbody> <tr> <td>exceeding</td> <td>but not exceeding</td> <td></td> </tr> <tr> <td>---</td> <td>168.3</td> <td>4.78</td> </tr> <tr> <td>168.3</td> <td>457.2</td> <td>6.35</td> </tr> <tr> <td>457.2</td> <td>609.6</td> <td>7.92</td> </tr> <tr> <td>609.6</td> <td>914.4</td> <td>9.52</td> </tr> <tr> <td>914.4</td> <td>1066.8</td> <td>11.91</td> </tr> </tbody> </table> <p>Editor's Note: 25.4 mm=1 inch</p>	Outside Diameter of Pipe (mm)		Least Nominal Wall Thickness (mm)	exceeding	but not exceeding		---	168.3	4.78	168.3	457.2	6.35	457.2	609.6	7.92	609.6	914.4	9.52	914.4	1066.8	11.91
Outside Diameter of Pipe (mm)		Least Nominal Wall Thickness (mm)																				
exceeding	but not exceeding																					
---	168.3	4.78																				
168.3	457.2	6.35																				
457.2	609.6	7.92																				
609.6	914.4	9.52																				
914.4	1066.8	11.91																				

Continued on Next Page

COUNTRY	PRESSURE DESIGN FOR STEEL LINE PIPE																											
UNITED KINGDOM	<p data-bbox="475 272 1395 389">BSI - Section 2.8 - Part 2 (BS8010) - Section 2.9.2 Hoop stress - The hoop stress (S_h) developed in the pipe wall at the internal design pressure should not exceed the allowable hoop stress (S_{ah}) given in 2.10.1. The hoop stress should be calculated by using either the thin wall or thick wall design equations:</p> <p data-bbox="475 406 669 480">Thin wall $S_h = \frac{pD}{20t}$</p> <p data-bbox="475 491 1020 549">Thick wall (maybe used when the $\frac{D}{t}$ ratio is ≤ 20)</p> <p data-bbox="475 559 735 644">Then, $S_h = \frac{p(D^2 + D_i^2)}{10(D^2 - D_i^2)}$</p> <p data-bbox="475 655 900 800">where S_h is the hoop stress (N/mm²) p is the internal design pressure (in bar) D is outside diameter (mm) t is design thickness (mm) D_i is the inside diameter $(D-2t)$ (in mm)</p> <p data-bbox="475 832 1412 1034">Section 2.10.1 Allowable hoop stress - The allowable hoop stress (S_{ah}) should be calculated as follows: $S_{ah} = a e S_y$ where S_{ah} = the allowable hoop stress (N/mm²) a = the design factor (.72 in Category B substances); .72 in Class 1 and 0.30 in Class 2 and Class 3 locations in Category C and category D substances e = weld joint factor (equals 1.0 for pipe conforming to API 5L). If pipe history unknown, $e = 0.6$ for pipe of 4.5 in. outer diameter or smaller, or 0.8 for pipe larger than 4.5 inches. S_y = specified minimum yield strength of pipe (N/mm²) as for Table 3</p> <table border="1" data-bbox="464 1093 1394 1391"> <thead> <tr> <th data-bbox="464 1093 789 1155">Pipe Spec.</th> <th data-bbox="789 1093 1053 1155">Type of grade of pipe</th> <th data-bbox="1053 1093 1394 1155">Specified Min. yield strength N/mm²</th> </tr> </thead> <tbody> <tr> <td data-bbox="464 1155 789 1187">API 5L: 1991</td> <td data-bbox="789 1155 1053 1187">B</td> <td data-bbox="1053 1155 1394 1187">241</td> </tr> <tr> <td></td> <td data-bbox="789 1187 1053 1219">X42</td> <td data-bbox="1053 1187 1394 1219">289</td> </tr> <tr> <td></td> <td data-bbox="789 1219 1053 1251">X46</td> <td data-bbox="1053 1219 1394 1251">317</td> </tr> <tr> <td></td> <td data-bbox="789 1251 1053 1283">X52</td> <td data-bbox="1053 1251 1394 1283">358</td> </tr> <tr> <td></td> <td data-bbox="789 1283 1053 1315">X56</td> <td data-bbox="1053 1283 1394 1315">386</td> </tr> <tr> <td></td> <td data-bbox="789 1315 1053 1347">X60</td> <td data-bbox="1053 1315 1394 1347">413</td> </tr> <tr> <td></td> <td data-bbox="789 1347 1053 1378">X65</td> <td data-bbox="1053 1347 1394 1378">448</td> </tr> <tr> <td></td> <td data-bbox="789 1378 1053 1391">X70</td> <td data-bbox="1053 1378 1394 1391">482</td> </tr> </tbody> </table>	Pipe Spec.	Type of grade of pipe	Specified Min. yield strength N/mm ²	API 5L: 1991	B	241		X42	289		X46	317		X52	358		X56	386		X60	413		X65	448		X70	482
Pipe Spec.	Type of grade of pipe	Specified Min. yield strength N/mm ²																										
API 5L: 1991	B	241																										
	X42	289																										
	X46	317																										
	X52	358																										
	X56	386																										
	X60	413																										
	X65	448																										
	X70	482																										

Continued on Next Page

COUNTRY																												
CANADA																												
AUSTRALIA	<div style="text-align: center;"> <hr style="width: 10%; margin: 0 auto;"/> <hr style="width: 10%; margin: 10px auto 0 auto;"/> </div>																											
GERMANY																												
JAPAN	<table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th colspan="2" style="text-align: left;"><u>Outside Diameter of Pipe (mm)</u></th> <th style="text-align: left;"><u>Least Nominal Wall Thickness (mm)</u></th> </tr> <tr> <th style="text-align: left;"><u>Exceeding</u></th> <th style="text-align: left;"><u>But Not Exceeding</u></th> <th></th> </tr> </thead> <tbody> <tr> <td style="text-align: center;">--</td> <td style="text-align: center;">114.3</td> <td style="text-align: center;">4.5</td> </tr> <tr> <td style="text-align: center;">114.3</td> <td style="text-align: center;">139.8</td> <td style="text-align: center;">4.9</td> </tr> <tr> <td style="text-align: center;">139.8</td> <td style="text-align: center;">165.2</td> <td style="text-align: center;">5.1</td> </tr> <tr> <td style="text-align: center;">165.2</td> <td style="text-align: center;">216.3</td> <td style="text-align: center;">5.5</td> </tr> <tr> <td style="text-align: center;">216.3</td> <td style="text-align: center;">355.6</td> <td style="text-align: center;">6.4</td> </tr> <tr> <td style="text-align: center;">355.6</td> <td style="text-align: center;">508.0</td> <td style="text-align: center;">7.9</td> </tr> <tr> <td style="text-align: center;">508.0</td> <td></td> <td style="text-align: center;">9.5</td> </tr> </tbody> </table>	<u>Outside Diameter of Pipe (mm)</u>		<u>Least Nominal Wall Thickness (mm)</u>	<u>Exceeding</u>	<u>But Not Exceeding</u>		--	114.3	4.5	114.3	139.8	4.9	139.8	165.2	5.1	165.2	216.3	5.5	216.3	355.6	6.4	355.6	508.0	7.9	508.0		9.5
<u>Outside Diameter of Pipe (mm)</u>		<u>Least Nominal Wall Thickness (mm)</u>																										
<u>Exceeding</u>	<u>But Not Exceeding</u>																											
--	114.3	4.5																										
114.3	139.8	4.9																										
139.8	165.2	5.1																										
165.2	216.3	5.5																										
216.3	355.6	6.4																										
355.6	508.0	7.9																										
508.0		9.5																										

COUNTRY	TRANSMISSION LINE VALVE SPACING																				
UNITED STATES	<p><u>GAS: Sect. 192.179</u> Each point on a transmission line, other than offshore segments, must have a sectionalizing block valve spaced as follows: Class 4 - within 2 1/2 miles of each point Class 3 - within 4 miles of each point Class 2 - within 7 1/2 miles of each point Class 1 - within 10 miles of each point Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency <u>OIL - Sect 195.260</u> - no set distance criteria except for water crossings 100 feet wide, then on both sides.</p>																				
UNITED KINGDOM	<p><u>Sect. 6.13 VALVE INSTALLATIONS (IG/ETD/1)</u> <u>NOT SPECIFIED</u> "In a cross-country (i.e. exceeding 10 miles in length) pipeline, valves should be provided at periodic intervals and may be hand-operated, automatic or remotely controlled." In built-up areas, the spacing of valves should be reduced. <u>Sect. 2.6.12 - LOCATION OF SECTION ISOLATING VALVES (BSI 8010)</u> Valves should be installed at the beginning and end of the pipeline and at a spacing along the pipeline appropriate to the substance being conveyed to limit the extent of a possible leak. Proximity to normally occupied buildings should be considered in valve selection. Also, valves should be installed at either side of a major river or estuary crossing where damage due to anchors or scouring of the riverbed may occur.</p>																				
CANADA	<p><u>Section 4.4 Valve Location and Spacing</u> Valve Spacing, KM (Table 4.6)</p> <table border="1" data-bbox="553 889 1169 1053"> <thead> <tr> <th>Class</th> <th>Gas Pipelines</th> <th>HVP Pipelines</th> <th>LVP Pipelines</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>NR</td> <td>NR</td> <td>NR</td> </tr> <tr> <td>2</td> <td>25</td> <td>15</td> <td>NR</td> </tr> <tr> <td>3</td> <td>13</td> <td>15</td> <td>NR</td> </tr> <tr> <td>4</td> <td>8</td> <td>15</td> <td>NR</td> </tr> </tbody> </table> <p>NR=not required <u>Section 4.4.8</u> For HVP and LVP pipelines valves shall be installed on both sides of major water crossings.</p>	Class	Gas Pipelines	HVP Pipelines	LVP Pipelines	1	NR	NR	NR	2	25	15	NR	3	13	15	NR	4	8	15	NR
Class	Gas Pipelines	HVP Pipelines	LVP Pipelines																		
1	NR	NR	NR																		
2	25	15	NR																		
3	13	15	NR																		
4	8	15	NR																		
AUSTRALIA	<p><u>Section 3.23 - Table 3.4 (Values in Kilometers)</u> Spacing of Valves (max.) - KM</p> <table border="1" data-bbox="569 1187 1131 1351"> <thead> <tr> <th>Location</th> <th>Gas</th> <th>Liquid</th> </tr> <tr> <th>Class</th> <th>HVPL</th> <th>Hydrocarbon</th> </tr> </thead> <tbody> <tr> <td>R1</td> <td>As required</td> <td>As required</td> </tr> <tr> <td>R2</td> <td>30</td> <td>As required</td> </tr> <tr> <td>T1 & T2</td> <td>15</td> <td>15</td> </tr> <tr> <td>S</td> <td>See clause 3.23.4</td> <td></td> </tr> </tbody> </table> <p><u>3.23.2</u> Valves for Liquid Hydrocarbon Pipeline at River Crossings and within Public Water Supply Reserve Upstream - A mainline valve Downstream - A mainline valve or non-return valve <u>3.23.4</u> Submarine Pipeline- Valves not used in a submerged location</p>	Location	Gas	Liquid	Class	HVPL	Hydrocarbon	R1	As required	As required	R2	30	As required	T1 & T2	15	15	S	See clause 3.23.4			
Location	Gas	Liquid																			
Class	HVPL	Hydrocarbon																			
R1	As required	As required																			
R2	30	As required																			
T1 & T2	15	15																			
S	See clause 3.23.4																				
GERMANY	<p><u>Section 3.2.2</u> Shutoff Devices The distance between main shutoff devices depends upon location and the required supply demand. In general, a distance of 10-18 km will suffice.</p>																				
JAPAN	<p>Section 33 of the regulations requires the installation of emergency valves every 1 km. The emergency valve should be equipped with a remote or a manual control device. In addition, valve spacing should be maintained as follows in the vicinity of pipe bends:</p> <table border="1" data-bbox="487 1670 1131 1840"> <thead> <tr> <th>Pipe Diameter, D, (mm)</th> <th>Spacing (mm)</th> </tr> </thead> <tbody> <tr> <td>D ≤ 318.5</td> <td>18D</td> </tr> <tr> <td>318.5 < D ≤ 355.6</td> <td>21D</td> </tr> <tr> <td>355.6 < D ≤ 406.4</td> <td>24D</td> </tr> <tr> <td>406.4 < D ≤ 508.0</td> <td>27D</td> </tr> <tr> <td>508.0 ≤ D</td> <td>30D</td> </tr> </tbody> </table>	Pipe Diameter, D, (mm)	Spacing (mm)	D ≤ 318.5	18D	318.5 < D ≤ 355.6	21D	355.6 < D ≤ 406.4	24D	406.4 < D ≤ 508.0	27D	508.0 ≤ D	30D								
Pipe Diameter, D, (mm)	Spacing (mm)																				
D ≤ 318.5	18D																				
318.5 < D ≤ 355.6	21D																				
355.6 < D ≤ 406.4	24D																				
406.4 < D ≤ 508.0	27D																				
508.0 ≤ D	30D																				

COUNTRY	COVER REQUIREMENTS (OVER BURIED PIPELINE)																																				
UNITED STATES	<p data-bbox="520 300 814 325"><u>Section 192.327 (Natural Gas)</u></p> <table border="1" data-bbox="520 325 1475 538"> <thead> <tr> <th data-bbox="520 325 867 351">Location</th> <th data-bbox="867 325 1065 351">Normal Soil</th> <th data-bbox="1065 325 1475 378">Consolidated Rock</th> </tr> <tr> <td colspan="3" data-bbox="1007 378 1073 404" style="text-align: center;">Inches</td> </tr> </thead> <tbody> <tr> <td data-bbox="520 404 867 429">Class 1</td> <td data-bbox="867 404 1065 429" style="text-align: center;">30</td> <td data-bbox="1065 404 1475 429" style="text-align: center;">18</td> </tr> <tr> <td data-bbox="520 429 867 455">Class 2,3, & 4</td> <td data-bbox="867 429 1065 455" style="text-align: center;">36</td> <td data-bbox="1065 429 1475 455" style="text-align: center;">24</td> </tr> <tr> <td data-bbox="520 455 867 538">Drainage ditches of public roads and railroad crossings</td> <td data-bbox="867 455 1065 538" style="text-align: center;">36</td> <td data-bbox="1065 455 1475 538" style="text-align: center;">24</td> </tr> </tbody> </table> <p data-bbox="520 538 690 563"><u>Section 192.327e</u></p> <p data-bbox="520 563 1475 670">All pipe in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock. If installed offshore underwater less than 12 feet deep, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of pipe and the natural bottom.</p> <p data-bbox="520 670 875 695"><u>Section 195.248 (Hazardous Liquids)</u></p> <table border="1" data-bbox="520 695 1475 1038"> <thead> <tr> <th data-bbox="520 695 1032 742">Location</th> <th data-bbox="1032 695 1296 783">Normal Excavation Cover (inches)</th> <th data-bbox="1296 695 1475 742">Rocky Excavation</th> </tr> </thead> <tbody> <tr> <td data-bbox="520 783 1032 808">Industrial, commercial and residential areas</td> <td data-bbox="1032 783 1296 808" style="text-align: center;">36</td> <td data-bbox="1296 783 1475 808" style="text-align: center;">30</td> </tr> <tr> <td data-bbox="520 808 1032 861">Crossings of inland bodies of water with a width of at least 100ft.</td> <td data-bbox="1032 808 1296 861" style="text-align: center;">48</td> <td data-bbox="1296 808 1475 861" style="text-align: center;">18</td> </tr> <tr> <td data-bbox="520 861 1032 887">Drainage ditches at public roads and railroad crossings</td> <td data-bbox="1032 861 1296 887" style="text-align: center;">36</td> <td data-bbox="1296 861 1475 887" style="text-align: center;">36</td> </tr> <tr> <td data-bbox="520 887 1032 912">Deep water port safety zone</td> <td data-bbox="1032 887 1296 912" style="text-align: center;">48</td> <td data-bbox="1296 887 1475 912" style="text-align: center;">24</td> </tr> <tr> <td data-bbox="520 912 1032 966">Other offshore areas under water less than 12 feet deep</td> <td data-bbox="1032 912 1296 966" style="text-align: center;">36</td> <td data-bbox="1296 912 1475 966" style="text-align: center;">18</td> </tr> <tr> <td data-bbox="520 966 1032 991">Any other area</td> <td data-bbox="1032 966 1296 991" style="text-align: center;">30</td> <td data-bbox="1296 966 1475 991" style="text-align: center;">18</td> </tr> </tbody> </table>	Location	Normal Soil	Consolidated Rock	Inches			Class 1	30	18	Class 2,3, & 4	36	24	Drainage ditches of public roads and railroad crossings	36	24	Location	Normal Excavation Cover (inches)	Rocky Excavation	Industrial, commercial and residential areas	36	30	Crossings of inland bodies of water with a width of at least 100ft.	48	18	Drainage ditches at public roads and railroad crossings	36	36	Deep water port safety zone	48	24	Other offshore areas under water less than 12 feet deep	36	18	Any other area	30	18
Location	Normal Soil	Consolidated Rock																																			
Inches																																					
Class 1	30	18																																			
Class 2,3, & 4	36	24																																			
Drainage ditches of public roads and railroad crossings	36	24																																			
Location	Normal Excavation Cover (inches)	Rocky Excavation																																			
Industrial, commercial and residential areas	36	30																																			
Crossings of inland bodies of water with a width of at least 100ft.	48	18																																			
Drainage ditches at public roads and railroad crossings	36	36																																			
Deep water port safety zone	48	24																																			
Other offshore areas under water less than 12 feet deep	36	18																																			
Any other area	30	18																																			
UNITED KINGDOM	<p data-bbox="520 1066 916 1091"><u>Section 6.9</u> Methods of Impact Protection</p> <p data-bbox="520 1091 1428 1144">The use of one of the forms of protection listed below and illustrated in Figure 4, reduces the likelihood of pipeline damage.</p> <p data-bbox="520 1144 949 1170">Acceptable forms of additional protection are:</p> <ul style="list-style-type: none"> <li data-bbox="578 1170 1065 1195">(a) Reinforced concrete inverted • U sections (4a) <li data-bbox="578 1195 1115 1221">(b) Curved steel capping plate on concrete bed (4b) <li data-bbox="578 1221 933 1247">(c) Weld mesh inverted channel (4c) <li data-bbox="578 1247 1024 1272">(d) Reinforced concrete inverted channel (4d) <li data-bbox="578 1272 949 1298">(e) Weld mesh and concrete slab (4e) <li data-bbox="578 1298 883 1323">(f) Concrete slab covering (4f) <p data-bbox="520 1323 883 1349">For Figure 4, the following notes apply:</p> <ul style="list-style-type: none"> <li data-bbox="578 1349 1049 1434">(a) The form of protection should be selected by the responsible engineer to suit the circumstances. <li data-bbox="578 1434 1049 1489">(b) The dimension "h" should be greater than the length of a pneumatic drill steel. <li data-bbox="578 1489 1049 1566">(c) The overall width of the protection should be adequate to guard against lateral encroachment. <p data-bbox="520 1566 908 1591"><u>Section 7.20</u> Bedding and Covering Pipe</p> <p data-bbox="520 1591 1437 1676">Backfilling should follow closely on the lowering in of the pipe and fine-grade material free from sharp edged stones should be filled and carefully compacted round the side of the pipe to a minimum consolidated height of 150mm above the pipe.</p> <p data-bbox="520 1676 826 1702"><u>Section 7.22.2</u> Water Crossings</p> <p data-bbox="520 1702 1462 1808">Where water crossings are installed by the open cut method, the pipeline should be laid at a cover allowing for future bed movement, dredging operations and the like. Consideration should be given to the application of a weight coating such as concrete to maintain negative buoyancy of the pipe during construction and when in service.</p>																																				

Continued on Next Page

COUNTRY	COVER REQUIREMENTS(OVER BURIED PIPELINE)																																											
CANADA	<p>Section 4.7 Cover Requirements</p> <p style="text-align: center;">Table 4.8 Minimum Cover for Pipelines, cm (measured to top of carrier or casing pipe, as applicable)</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="text-align: left;">Location</th> <th style="text-align: center;">Type of Pipeline</th> <th style="text-align: center;">Normal Excavation</th> <th style="text-align: center;">Rock Excavation</th> </tr> </thead> <tbody> <tr> <td rowspan="3" style="vertical-align: top;">General</td> <td>LVP and gas</td> <td style="text-align: center;">60</td> <td style="text-align: center;">60</td> </tr> <tr> <td>HVP Class 1</td> <td style="text-align: center;">90</td> <td style="text-align: center;">60</td> </tr> <tr> <td>HVP Class 2,3,4</td> <td style="text-align: center;">120</td> <td style="text-align: center;">60</td> </tr> <tr> <td rowspan="2" style="vertical-align: top;">Rights-of way (roads and railways)</td> <td>All</td> <td style="text-align: center;">75</td> <td style="text-align: center;">75</td> </tr> <tr> <td></td> <td></td> <td></td> </tr> <tr> <td style="vertical-align: top;">Below traveled surface (roads)</td> <td>All</td> <td style="text-align: center;">120</td> <td style="text-align: center;">120</td> </tr> <tr> <td rowspan="3" style="vertical-align: top;">Below base of rail (railways)</td> <td>All</td> <td></td> <td></td> </tr> <tr> <td>Cased</td> <td style="text-align: center;">120</td> <td style="text-align: center;">120</td> </tr> <tr> <td>Uncased</td> <td style="text-align: center;">200</td> <td style="text-align: center;">200</td> </tr> <tr> <td style="vertical-align: top;">Water Crossing</td> <td>All</td> <td style="text-align: center;">120‡</td> <td style="text-align: center;">60</td> </tr> <tr> <td style="vertical-align: top;">Drainage and irrigation ditch inverts</td> <td>All</td> <td style="text-align: center;">75</td> <td style="text-align: center;">60</td> </tr> </tbody> </table> <p>‡ Cover not less than 60 cm shall be permissible where analysis indicates the potential for erosion is minimal.</p>	Location	Type of Pipeline	Normal Excavation	Rock Excavation	General	LVP and gas	60	60	HVP Class 1	90	60	HVP Class 2,3,4	120	60	Rights-of way (roads and railways)	All	75	75				Below traveled surface (roads)	All	120	120	Below base of rail (railways)	All			Cased	120	120	Uncased	200	200	Water Crossing	All	120‡	60	Drainage and irrigation ditch inverts	All	75	60
Location	Type of Pipeline	Normal Excavation	Rock Excavation																																									
General	LVP and gas	60	60																																									
	HVP Class 1	90	60																																									
	HVP Class 2,3,4	120	60																																									
Rights-of way (roads and railways)	All	75	75																																									
Below traveled surface (roads)	All	120	120																																									
Below base of rail (railways)	All																																											
	Cased	120	120																																									
	Uncased	200	200																																									
Water Crossing	All	120‡	60																																									
Drainage and irrigation ditch inverts	All	75	60																																									
AUSTRALIA	<p>Section 3.11.4 Depth of cover of buried land pipelines (other than within a road or railway reserve) given in Table 3.3</p> <p style="text-align: center;">Minimum Depth of Cover for Land Pipelines</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th rowspan="2" style="text-align: left;">Location Class</th> <th rowspan="2" style="text-align: left;">Application</th> <th colspan="2" style="text-align: center;">Depth of Cover, mm</th> </tr> <tr> <th style="text-align: center;">Normal Excavation</th> <th style="text-align: center;">Rock Excavation</th> </tr> </thead> <tbody> <tr> <td rowspan="2" style="vertical-align: top;">R1, R2</td> <td>HVPL</td> <td style="text-align: center;">900</td> <td style="text-align: center;">600</td> </tr> <tr> <td>other than HVPL</td> <td style="text-align: center;">750</td> <td style="text-align: center;">450</td> </tr> <tr> <td rowspan="2" style="vertical-align: top;">T1, T2</td> <td>HVPL</td> <td style="text-align: center;">1200</td> <td style="text-align: center;">900</td> </tr> <tr> <td>other than HVPL</td> <td style="text-align: center;">900</td> <td style="text-align: center;">600</td> </tr> </tbody> </table> <p>HVPL is High Vapor Pressure Liquid (at atmospheric pressure)</p> <p>Section 3.11.5 Submarine Pipeline Cover not specified. The depth of cover should be determined during the design when account should be taken of the stability of the pipeline, the need for protection against third-party interference, and the requirements of authorities having jurisdiction over the water.</p> <p>Section 3.12.9.5 Depth of Cover within a Road or Railway Reserve It shall not be less than that illustrated in Figure 3.2 or Figure 3.3 as appropriate.</p>	Location Class	Application	Depth of Cover, mm		Normal Excavation	Rock Excavation	R1, R2	HVPL	900	600	other than HVPL	750	450	T1, T2	HVPL	1200	900	other than HVPL	900	600																							
Location Class	Application			Depth of Cover, mm																																								
		Normal Excavation	Rock Excavation																																									
R1, R2	HVPL	900	600																																									
	other than HVPL	750	450																																									
T1, T2	HVPL	1200	900																																									
	other than HVPL	900	600																																									
GERMANY	<p>TrbF 301 : Section 4.2 Plans</p> <p>4.2.1 Pipelines are normally laid below the ground. The depth of cover must meet local ordinances, but, is routinely 1.0 meter. Depth of covers may be as little as 0.6 meters in isolated areas of special zoning.</p> <p>G463: Pipe cover should be at least 0.8-1.0 meters. Only in special circumstances should the cover be deeper than 2.0 meters.</p>																																											
JAPAN	<table border="1" style="width: 100%; border-collapse: collapse;"> <tbody> <tr> <td style="width: 50%;">Normal Underground</td> <td style="width: 50%;">1 meter(m)</td> </tr> <tr> <td>Wooded or forest areas</td> <td>0.9 m</td> </tr> <tr> <td>City Street</td> <td>1.0 m</td> </tr> <tr> <td>Suburban Street</td> <td>1.0 m</td> </tr> <tr> <td>Heavily paved street</td> <td>1.0 m</td> </tr> <tr> <td>From other Electr. Gas Lines</td> <td>0.3 m</td> </tr> </tbody> </table>	Normal Underground	1 meter(m)	Wooded or forest areas	0.9 m	City Street	1.0 m	Suburban Street	1.0 m	Heavily paved street	1.0 m	From other Electr. Gas Lines	0.3 m																															
Normal Underground	1 meter(m)																																											
Wooded or forest areas	0.9 m																																											
City Street	1.0 m																																											
Suburban Street	1.0 m																																											
Heavily paved street	1.0 m																																											
From other Electr. Gas Lines	0.3 m																																											

COUNTRY	SITING OF PIPELINES
UNITED STATES	<p>Siting approvals granted by the Federal Energy Regulatory Commission (FERC) for interstate transmission gas pipelines and state agencies for interstate hazardous liquid pipelines. Approvals are based upon environmental impact assessment which examine, in part, factors such as proximity to populated areas and sensitive receptors (e.g. neighboring water courses and public water supply sources).</p> <p>The environmental impact regulations are promulgated and enforced by FERC.</p>
UNITED KINGDOM	<p>The planning and construction of cross-country* pipelines is regulated by the Department of Trade and Industry under the powers of the Pipe-lines Act of 1962.</p> <p>Environmental assessments are required in accordance with "Guidelines for the Environmental Assessment of Cross-Country Pipelines", published in 1992 (ISBN 01 14142866) by the Department of Trade and Industry.</p> <p>The following policy statement is from Section 4.3, Project Definition of the Guidelines.</p> <p>"In general, the minimum distance route between A and B, avoiding areas of high construction cost, will be preferred. However, other criteria, such as the location of environmental constraints, centers of population, and nearness to markets, will, in reality affect routing."</p> <p>*Pipelines exceeding ten miles in length, and all those which connect into an existing cross country pipeline system regardless of length.</p>
CANADA	<p>The National Energy Board Onshore Pipeline Regulations, developed in the National Energy Board Act of 1989, oversee the design, construction, operation and abandonment of onshore pipelines.</p> <p>In that capacity, the NEB can require impact analysis to verify the appropriate procedures to be followed by companies in respect of the design, construction, operation and abandonment of pipelines under the Board's jurisdiction.</p>
AUSTRALIA	<p>In Australian Standard AS 2885-1987 entitled "Pipelines-Gas and Liquid Petroleum", the following sections are applicable:</p> <p><u>Section 3.3</u> Environmental Data</p> <p>3.3.1 Investigations: A detailed investigation of the route and environment in which a pipeline is to be installed shall be made. The appropriate authorities should be contacted to obtain details of any known or expected development or encroachment along the route,....</p> <p>3.3.4 Environmental Studies: Attention is drawn to the environmental studies which may be required by the relevant authority.</p> <p>3.5 Location of a Pipeline</p> <p>3.5.1 Route. The route of a pipeline shall be selected having regard to public safety, pipeline reliability, environmental impact and other important factors including the following:</p> <p>(b) Present land use and any expected change of land use.</p> <p>(d) Proximity of any populated areas.</p>
GERMANY	<p>TrbF 301:</p> <p>Sect. 2.1.3 The siting of pipelines must take into account land use planning, city planning, traffic, water sources, nature and agricultural demands, home construction, military defense plans, and environmental considerations.</p> <p>Sect. 2.1.4 If possible, pipelines should not be built in urban zones or areas in which large-scale construction is planned. If that is not possible, pipeline operators must plan for special safety and response measures.</p> <p>Section 2.2 Water Protection</p> <p>2.2.1 Pipelines may not traverse watersheds, storage areas, and spa springs. Exceptions are possible for limited areas as defined in DVGW Papers W101, W102, and W103.</p> <p>2.2.2 Pipelines may not traverse areas that are significant water sources: if they do, special precautions are required.</p> <p>G463: Sections 6, 7, and 8 of the regulations relate to pre-permitting in accordance with Section 6 (1) of the Regulations for High Pressure Gaslines: standards for coming on-line; and final permitting in accordance with section 6 (2) of the regulations for high pressure gaslines.</p>
JAPAN	<p>MITI, the DOT and the Fire Department jointly regulate and oversee the siting aspects of pipelines. Regulation 3162-5 provides detailed guidelines for siting.</p>

COUNTRY	MAXIMUM ALLOWABLE OPERATING PRESSURE																		
UNITED STATES	<p><u>Natural Gas: Section 192.619</u> EDITOR'S NOTE: THIS SECTION SHOULD BE REVIEWED BY REVIEWERS BECAUSE OF NUMEROUS CLAUSES THEREIN. For steel pipe operated at 100 p.s.i.g. or the test pressure* is divided by a factor determined in accordance with the following table:</p> <table border="1" data-bbox="566 385 1144 570"> <thead> <tr> <th>Class Location</th> <th>Installed before 11/12/70</th> <th>Installed after 11/12/70</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>1.1</td> <td>1.1</td> </tr> <tr> <td>2</td> <td>1.25</td> <td>1.25</td> </tr> <tr> <td>3</td> <td>1.4</td> <td>1.5</td> </tr> <tr> <td>4</td> <td>1.4</td> <td>1.5</td> </tr> </tbody> </table> <p>*based on section 192.507 requirements. <u>Hazardous Liquids: Section 195.406</u> specifies the conditions in detail and should be reviewed in detail. Generally, however, the pressure cannot exceed the internal design pressure of the pipe (as per section 195.106), or eighty percent of the test pressure for any pipeline which has been hydrostatically tested based upon subpart E of this part.</p>	Class Location	Installed before 11/12/70	Installed after 11/12/70	1	1.1	1.1	2	1.25	1.25	3	1.4	1.5	4	1.4	1.5			
Class Location	Installed before 11/12/70	Installed after 11/12/70																	
1	1.1	1.1																	
2	1.25	1.25																	
3	1.4	1.5																	
4	1.4	1.5																	
UNITED KINGDOM	<p><u>IGF/TD/1 Section 11.4 Operational Pressure Limits and Section 11.4.1 Maximum Permissible Operating Pressure.</u> The procedure herein is detailed and is a function of what edition of the regulations that the pipeline originally had to meet. The maximum permissible operating pressure (MPOP) is the maximum pressure at which a pipeline can be operated by design, construction, testing, downrating or uprating in accordance with these Recommendations or prior Editions. <u>Section 11.4.1.2</u> The MPOP should be determined and declared annually by the responsible engineer. <u>Section 4.2.1</u> An audit of the pipeline should be carried out at intervals of not more than four years to confirm the MPOP. BS1 - Part 2 - Section 2.8 (BS8010): Section 2.7.3 Maximum Allowable Operating Pressure The MAOP is related to the test pressure established by carrying out a hydrostatic or pneumatic test in the pipeline in accordance with section 8 of the regulations. It is essential that the MAOP does not exceed the internal design pressure. Section 8: The <u>hydrostatic test pressure</u> should not be less than the lower of: (a) 150% of the maximum operating pressure; or (b) that pressure which will induce a hoop stress as defined in 2.9.2 of 90% of the specified minimum yield strength of the pipeline material. The <u>pneumatic test pressure</u> only for Category C substances operated at a design factor of not more than 0.3. The pneumatic test pressure should not be less than 1.25 times the maximum operating pressure.</p>																		
CANADA	<p><u>Section 8.5 Maximum Operating Pressures</u> <u>Section 8.5.1 Piping Intended to be Operated at Pressures Greater than 700 kPa</u> * - Table 8.1 applies</p> <table border="1" data-bbox="459 1421 1420 1755"> <caption>Table 8.1</caption> <thead> <tr> <th>Service Fluid</th> <th>Class Location</th> <th>Maximum Operating Pressure (MOP)</th> </tr> </thead> <tbody> <tr> <td>LVP</td> <td>All</td> <td>Lesser of minimum strength test pressure achieved divided by 1.25 and design pressure</td> </tr> <tr> <td>HVP</td> <td>1</td> <td>Lesser of minimum strength test pressure achieved divided by 1.4 and design pressure</td> </tr> <tr> <td>Gas</td> <td>1 or 2</td> <td>Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure</td> </tr> <tr> <td>Gas</td> <td>3 or 4</td> <td>Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure</td> </tr> <tr> <td>HVP</td> <td>2, 3 or 4</td> <td>Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure</td> </tr> </tbody> </table> <p><u>Section 8.5.7 Piping Intended to be Operated at Pressures of 700 kPa or less</u> - the maximum operating pressure shall be established by the operating company and shall not exceed 700 kPa. EDITOR'S NOTE: 1 P.S.I. = 6.895 KPA</p>	Service Fluid	Class Location	Maximum Operating Pressure (MOP)	LVP	All	Lesser of minimum strength test pressure achieved divided by 1.25 and design pressure	HVP	1	Lesser of minimum strength test pressure achieved divided by 1.4 and design pressure	Gas	1 or 2	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure	Gas	3 or 4	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure	HVP	2, 3 or 4	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure
Service Fluid	Class Location	Maximum Operating Pressure (MOP)																	
LVP	All	Lesser of minimum strength test pressure achieved divided by 1.25 and design pressure																	
HVP	1	Lesser of minimum strength test pressure achieved divided by 1.4 and design pressure																	
Gas	1 or 2	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure																	
Gas	3 or 4	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure																	
HVP	2, 3 or 4	Lesser of minimum strength test pressure achieved divided by 1.5 and design pressure																	

Continued on Next Page

COUNTRY	MAXIMUM ALLOWABLE OPERATING PRESSURE
AUSTRALIA	<p><u>Section 10</u> The MAOP of a pipeline shall not exceed: (a) design pressure (pd) or (b) test pressure limit at any point (pt)</p> <p><u>Section 10.2 2 Design Pressure.</u> The design pressure (pd) shall be equal to the design pressure determined in accordance with this standard. Where the actual yield strength is used to calculate a design pressure, the engineering design shall be critically reviewed.....</p> <p>Section 10.2 3 Test Pressure. The test pressure limit (pt) shall be derived from $Pt = \frac{Pst}{Ftp}$</p> <p>where Pst = minimum strength test pressure, in megapascals Ftp = test pressure factor (see clause 10.3)</p> <p><u>Section 10.3 Test Pressure Factor</u> The test pressure factor (Ftp) shall be 1.25 unless 100% radiographic examination has been applied, the value may be reduced to 1.1.</p> <p><u>Section 10.5</u> The MAOP shall be reviewed at least every 5 years.</p>
GERMANY	<p>TRbF 301: Section 4.3 Calculations Section 4.32 - Operating and Test Pressures and Temperatures. The highest expected operating pressures under unfavorable conditions are to be considered in the design of the entire length of the pipeline. 4.3.3. The solidity of the pipeline is to be calculated for the worst pressure (plus 10 bar over pressure) and unfavorable temperatures. The wall thicknesses are to be calculated per DIN2413. The standard safety factor is 1.6; in sensitive areas it is 2.0.</p> <p>G463: Section 3.2.1 Pressure Regulation The installation of regulation controls must be chosen so that its tolerances will not permit pressures above the allowable service pressure.</p>
JAPAN	<p>The regulations specifically require the installation of pressure safety control devices in order to ensure that the operating pressure does not exceed the design pressure by ten percent (i.e., 1.1).</p>

COUNTRY	PATROLLING OF LINES												
UNITED STATES	<p>Section 192.705 (Natural Gas) Frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be larger than prescribed in the following table: Maximum Interval Between Patrols</p> <table border="1" data-bbox="480 406 1424 693"> <thead> <tr> <th data-bbox="480 406 783 438">Class location of Line</th> <th data-bbox="783 406 1174 438">At Highway and Railroad Crossings</th> <th data-bbox="1174 406 1424 438">At All Other Places</th> </tr> </thead> <tbody> <tr> <td data-bbox="480 438 783 523">1, 2</td> <td data-bbox="783 438 1174 523">7 1/2 months; but at least twice each calendar year</td> <td data-bbox="1174 438 1424 523">15 months; but at least each calendar year</td> </tr> <tr> <td data-bbox="480 523 783 608">3</td> <td data-bbox="783 523 1174 608">4 11/2 months; but at least four times each calendar year</td> <td data-bbox="1174 523 1424 608">7 11/2 months; but at least twice each calendar year</td> </tr> <tr> <td data-bbox="480 608 783 693">4</td> <td data-bbox="783 608 1174 693">4 11/2 months; but at least four times each calendar year</td> <td data-bbox="1174 608 1424 693">4 1/2 months; but at least four times per calendar year</td> </tr> </tbody> </table> <p>Section 195.417 (Hazardous Liquids) R.O.W. Inspections and crossing under navigable waters surface line * at least 26 times per year; intervals not exceeding 3 weeks. Offshore pipelines: not exceeding every 5 years.</p>	Class location of Line	At Highway and Railroad Crossings	At All Other Places	1, 2	7 1/2 months; but at least twice each calendar year	15 months; but at least each calendar year	3	4 11/2 months; but at least four times each calendar year	7 11/2 months; but at least twice each calendar year	4	4 11/2 months; but at least four times each calendar year	4 1/2 months; but at least four times per calendar year
Class location of Line	At Highway and Railroad Crossings	At All Other Places											
1, 2	7 1/2 months; but at least twice each calendar year	15 months; but at least each calendar year											
3	4 11/2 months; but at least four times each calendar year	7 11/2 months; but at least twice each calendar year											
4	4 11/2 months; but at least four times each calendar year	4 1/2 months; but at least four times per calendar year											
UNITED KINGDOM	<p>IGE/TD/1: Section 11.5 Inspection and Surveillance Aerial Patrols of all Pipelines 11.5.1 Should be undertaken every 2 weeks. 11.5.3 Full walking surveys for the entire system should be walked at least once every 4 years. 11.5.5 Monitoring of third party activities-- A system should be established to collect information on third party activities and assess the impact of such activities on pipelines. 11.5.6 Liaison with owners/occupiers, tenants and other authorities- regular contact should be maintained on at least an annual basis. Best achieved by depositing, with the occupier, a plan showing the pipeline location and the easement width and by personal visits. 11.5.8 Exposed crossing points should be examined at least annually 11.5.9 Minor water course crossings should be surveyed periodically 11.5.10 Major water course crossings should be surveyed regularly.</p>												
CANADA	<p>Section 10.5.1 Pipeline Patrolling Operating companies shall periodically patrol their pipelines in order to observe surface conditions on or adjacent to their rights-of-way, indication of leaks, construction activity performed by others, and other conditions affecting the safety and operation of the pipelines. Section 10.5.1.7 The frequency of pipeline patrolling shall be determined by considering such factors as (a) operating pressure (b) pipeline size (c) population density (d) service fluid (e) terrain (f) weather</p>												
AUSTRALIA	<p>Section 9.5 and clause 13.4 z Patrolling of the pipeline shall commence immediately following completion of the leak and strength tests. The route shall be inspected regularly at * approved intervals, and whenever it is considered that damage or threats to the integrity of the pipeline may have occurred. *approved by the Operation Authority and includes obtaining the approval of the relevant statutory authority where this is legally required. Approval requires a conscious act and is generally given in writing. Operating Authority the organization responsible for the design, construction, testing, inspection, operation, and maintenance of facilities within the scope of the standards. Statutory Authority The Commonwealth or State body empowered by an Act of Parliament to exercise jurisdiction over facilities within the scope of the standard.</p>												
GERMANY													
JAPAN	<p>No specific patrolling requirements are mandated. In lieu of same, the Japanese regulatory requirements include: 1-the installation of automatic leakage detection devices every 10 kilometers along the pipelines. 2-earthquake rector cale devices every 25 kilometers to measure the degree of damages to pipelines due to earthquake activities.</p>												

APPENDIX B

QUESTIONS AND RESPONSES RELATED TO THE CONCEPTS OF PIPELINE DESIGN LIFE, FATIGUE LIFE, THIRD-PARTY FACTORS AND REQUIREMENTS OF ON-LINE LEAK DETECTION AND EARTHQUAKE IMPACT MEASURING EQUIPMENT IN VARIOUS FOREIGN PIPELINE REGULATIONS

- DESIGN LIFE (SECTION 3.2) AND THIRD-PARTY DAMAGE (AUSTRALIAN).....B1
- FATIGUE LIFE (SECTION 6.7) (UNITED KINGDOM) B5
- USE OF ON-LINE LEAK DETECTION AND EARTHQUAKE IMPACT MEASURING EQUIPMENT (JAPANESE)..... B6

ISSUE: DESIGN LIFE (SECTION 3.2) AND THIRD-PARTY DAMAGE (SECTION 3.7)

STANDARD: AUSTRALIAN STANDARD - AS 2885:1987

PRELIMINARY COMMENTS BY THE RESPONDER:

EDITORS NOTE: The responder is a member of the committee which drafted the above standard in 1987 and is redrafting the standard presently.

Before answering the specific questions, a little bit of background:

1. In Australia, petroleum pipelines are licensed by State Government authorities except for offshore pipelines outside the 3-mile limit, which are a Federal Responsibility, but the Feds subcontract to the state in any case.
2. There is no equivalent Australian organization to DOT and no equivalent Australian organization to **FERC**. Individual pipelines operate under licenses. Virtually all pipeline licenses nominate the Australian Standard in force *at* the time of construction and renewals of licenses may also nominate elements of subsequent issues of the Australian Standard(s), where the requirements are seen as superseding the original. Australian Standards have the force of law **ONLY** if nominated in legislation and/or called up in regulations of licenses. Thus, for us, **REGULATIONS** are quite different from **STANDARDS** or **CODES**. Standards and codes are prepared by the industry as a whole. Regulations and Licenses are issued on a case-by-case basis by the relevant government authority.

Australian Standards are produced by voluntary committees made up of representatives of industry organizations and individuals with particular expertise. Balanced representation of all interests is required by Standards Australia; pipeline owners, pipeline constructors, pipeline designers, pipeline materials suppliers, corrosion and welding industry specialists and state regulatory bodies are all represented and active. Standards are produced by a consensus process in which a minimum of 85% of voting committee members must approve the document. (It used to be 100% and was 100% in 1987). New standards must be published in draft form for public comment. Once the public comment has been assessed by the committee, the publication draft **is** prepared and all committee members must vote on it before it **is** published.

The first major review and rewrite of AS 2885:1987 is currently in progress and the new Standard will likely issue in several parts in early 1996. This is relevant to your questions as the current Australian thinking in relation to Section 3.7 has advanced considerably from 1987.

QUESTIONS AND RESPONSES (SECTION 3.2)

Q1. When was *this* concept *initially* incorporated into *your* regulations?

A1. The concept of Design Life was first introduced into Australian Standards for Petroleum Pipelines in AS 2885:1987.

Q2. What was the rationale for including the concept in your regulations?

- A2. The rationale was that some pipelines are built for a limited life and others for a virtually indefinite life. Some pipelines have a life defined by specific provisions for corrosion or erosion and it was considered that AS 2885 should have a mandatory requirement for review when the originally defined Design Life expires. The Design Life provides a basis for setting corrosion allowances, where these are used, and can be used to limit the provisions which might otherwise be made for future land use changes which might affect the design and thus the cost.

Q3. What is a typical “design life” nominated by the Operating Authority? What is a typical range of “design life” that the Statutory Authority deems appropriate? What authority do they have in insuring that the Operating Authority nominates a reasonable design life?

- A3. There is no typical Design Life. An Operating Authority building a pipeline project which has an essentially indefinite life will nominate an unlimited design life and engineer the pipeline accordingly. An Operating Authority building a pipeline to drain a particular oil field over ten years may nominate ten years or, perhaps fifteen years. An Operating Authority building a pipeline to carry wet CO₂ rich gas from an offshore field to processing facilities on shore may nominate a design life based on the projected rate of corrosion of the pipeline.

We have a generally very cooperative relationship between Operating and Regulatory authorities. The Regulatory Authority has the authority to enforce a reasonable or, indeed, an unreasonable Design Life because it issues the License, but I have no knowledge that this has ever been a matter of dispute.

Q4. If the concept has been in force a sufficient time to respond, what percentage of pipelines reaching their design life are abandoned, continue to operate as is, or continue to operate under reduced operating conditions? If the above doesn't apply, what are the anticipated impacts from a percentage standpoint?

- A4. I am not aware of any pipelines built since AS 2885:1987 was issued being abandoned, but there are a few small oilfield pipelines which must be getting close to their original 10 years.

The majority of high pressure petroleum pipelines in Australia and, certainly, all new pipelines larger than 6-inch, are required by their License to have facilities for intelligent pig inspection and are required to conduct intelligent pig inspections at intervals from 5-10 years as a condition of their License. This practice has not been forced on the industry, which had largely adopted the practice before Licenses were amended to make it mandatory. Consequently, a pipeline operator approaching the end of the original Design Life will have access to objective information on the current state of the pipeline on which to base any application for extension of the license. I would not anticipate any modern high pressure pipeline being abandoned except for:

- No further use because the resource it served was fully drained
- Corrosion and/or erosion or similar allowances have been fully used up

- Some other factor has made the pipeline no longer comply with its license conditions and rectification of the deficiency is not economic.

Q5. *Is there ultimately a plan to abandon pipelines, on average, after a prescribed “life”?*

- A5. In theory yes, but in fact such abandonment will be very much the exception. The Operating Authority would not be required to prepare such a plan until a decision is made to abandon the pipeline.

QUESTIONS AND RESPONSES (SECTION 3.7)

Q1. *When was this concept initially incorporated into your regulations?*

- A1. The specific provisions of Section 3.7 dealing with Third Party Protection were new in AS 2885:1987. They will be substantially changed when AS 2885 Part 1 is issued in 1996.

Q2. *What was the rationale for including the concept in your regulations?*

- A2. Our experience of high pressure pipelines (and AS 2885 covers all high pressure petroleum pipelines) is relatively young compared with the USA. Consequently, we have only a few pipelines built before modern pipe steels were available and before modern high-performance corrosion coatings dramatically reduced the incidence of corrosion as a failure mechanism. Third Party interference is therefore, by far, the Australian industry’s major concern on pipeline safety. This concern is enhanced because, with our small population and long distances between source and user, all our major cities have a single-pipeline supply of gas.

The industry here, including the regulatory authorities, is firmly of the view that the real issue is the safety of the pipeline since pipelines are demonstrated not to be a risk to the public unless the public interferes with the pipeline. This is a somewhat different view from that taken by some other countries. The result of that view is that protection of the pipeline is regarded as a primary design and operating issue.

Q3. *Why was a nominal wall thickness of 10mm chosen if cover and wall thickness are the only methods of protection?*

- A3. You may have noted in AS 2885:1987 that we have a more practical Location Class system based on Land Use, rather than Building Density as in ANSI 631.8 and that it applies equally to gas and liquid pipelines. You may also have noted that, unlike ANSI B31.8, the design factor for the calculation of wall thickness is the same for all class locations and the same for all fluids. We took the view that 72% is fully adequate to contain the pressure. We further took the view that the marginal increases in wall thickness which result from changing from 72% to 60% or from 60% to 50% following the ANSI 831.8 method add nothing real to the protection of the pipeline and therefore nothing real to the safety of the public.

We build a lot of smaller diameter pipelines in Australia and we use high strength steels and very thin walls. For example, a 6-inch pipeline operating at ANSI Class 600 pressure

in X56 steel requires a wall thickness of only 1/8 inch. We have thousands of kilometers of pipelines with thicknesses between 1/8 inch and 1/4 inch - most of the pipelines in Australia. In 1987, the available research work, primarily by British Gas but supplemented by a substantial program in Australia, indicated that only substantial excavation equipment would succeed in damaging pipelines with a wall thickness of more than 10mm and this was the source of the 10mm value in Section 3.7. Subsequent research and the increase in the size and effectiveness of digging equipment would suggest 12mm is a better number than 10mm in 1995.

Since most of the pipelines we build or expect to build are NOT thicker than 10mm or 12mm, it was necessary to define in Section 3.7 the level of protection required for such pipelines against Third Party damage. In 1987, we simply did not have the data. The Third party Factor was introduced as a mechanism to ensure that such pipelines were no less protected by wall thickness than pipelines designed to early standards AS 1697, AS 2018, etc. which had used the ANSI B31.8 or ANSI 631.4 requirements. It was a back door method of keeping the single design factor for all location classes and fluids while providing some additional protection against Third Party Damage.

In the revision currently nearing completion, the mechanism of "deeming protection" by the use of the Third Party Factor and all reference to the Third Party Factor has been deleted. This means that all high pressure pipelines in all class locations will be designed with the single 72% design factor and additional wall thickness will be used honestly to deal with Third Party damage only where it will genuinely provide protection. This has two effects:

- Wall thickness will not be added in Location Classes 2,3 and 4 except where it is clearly required to improve protection of the pipeline from Third Party damage.
- Where wall thickness alone does not provide adequate protection, other protection measures are required.

We anticipate that the savings in wall thickness in Location Classes 2, 3, and 4 will, if applied to situations where the pipeline is at high risk, substantially improve pipeline safety. We anticipate that measures other than increased wall thickness will be more effective in many, if not most, cases.

Q4. What percentage of accidents do you find occur due to third-party damage? How has it changed since incorporation of this concept in your regulations?

- A4. There is no DOT in Australia, so the collection and collation of pipeline incident statistics is not centralized. I do not have definite figures for the percentage of third-party damage. We have very, very few incidents of any kind. There has never been a fatality associated with pipeline transport of petroleum fluids in Australia. The total number of what would be reportable incidents to DOT in the thirty years of the industry is probably fewer than 1 per year for the whole country and, of these, all but a handful are related to third-party damage. I do not think the performance has changed since 1987; it was already excellent before 1987.

Q5. It appears you have no minimum right-of-way requirements for pipelines in proximity to population centers or environmentally sensitive areas (e.g., public water supplies)

in your regulations. Am I correct? If not, could you kindly cite the appropriate sections in your regulations to review?

- A5. By minimum right-of-way, I assume you mean width of controls on development. Our actual pipeline easements (right-of-way) for high pressure pipelines vary from 25 meters wide with the pipeline approximately 8 meters from one side down to as narrow as 7 meters. Buildings may not be actually constructed on the easement, but are permitted right up to the edge.

We have addressed the issue of utility corridors and separation distances and have followed the debate and practices in the United Kingdom and Europe with interest, but have decided that our overall philosophy stated above of protecting the pipeline is more valid than arbitrary “separation distances” no matter what technical basis they are calculated on and no matter that they appear to protect the public (but actually do not). By conscious decision of the committee, the revised AS 2885 will not contain provisions for separation distances.

We are, however, beginning to see planning authorities in major cities implementing new suburban developments incorporating provision of “separation distances” to high pressure pipelines by allocation of public space. This is desirable, provided the reverse is not attempted; that of preventing high pressure pipelines from being built within similar distances from existing developments or of requiring the owner of a high pressure pipeline to acquire a band of land with a width equal to twice some arbitrary separation distance.

The literal answer to your question is that AS 2885 does not deal with either easement widths or separation distances. We have relatively few liquids pipelines in Australia. so the issue of liquids pipelines’ potential to foul public water supplies has not arisen. We would maintain that the above philosophy of protecting (and regularly inspecting) the pipeline is a more effective means of protecting public water supplies from fouling than “separation”.

ISSUE: FATIGUE LIFE (SECTION 6.7)

STANDARD: UNITED KINGDOM STANDARD IGE/TD/1 - EDITION 3 (1993)

EDITORS NOTE: The responder was a member of the committee which drafted the above standard and its prior editions.

QUESTIONS AND RESPONSES (SECTION 6.7)

Q1. When was the concept of fatigue life initially incorporated into your regulations?

- A1. The concept of fatigue life was initially introduced into TD/1 Edition 2 (1984) in recognition of the fact that U.K. gas transmission pipelines at that time were becoming widely used for linepack storage.

Q2. What was the rationale for including the concept in your regulations?

A2. The basic need was for consideration of fatigue due to the effect of diurnal fluctuations of line pressure on possible defects in the longitudinal pipeline welds. **At** the time (and still largely true today) there was no practical means of inspecting the longitudinal weld for part wall defects susceptible to fatigue growth. It was therefore considered necessary to impose safe fatigue limits based on initial defects of the maximum size which could be left by the pre-commissioning high level pressure test.

Q3. Approximately what percentage of your pipelines in operation would be potentially impacted by this requirement over a 50 or 100 year life? It appears to me that unless huge variations in pressure occur within the pipeline on a regular basis, it might take centuries to reach the 15,000 stress cycle criteria? Am I incorrect?

A3. The 15,000 cycle limit is approximately one cycle each day for 15 years. I understand that some of our pipelines have cyclic stress ranges in the order of 10,000 lbf/in² each day and a large proportion of our pipeline is becoming a real issue for the British Gas pipeline system as the company looks to improve utilization efficiency of the pipeline system by increasing linepack storage.

Q4. Does your Institute have any statistical data which might indicate the percentage of pipeline failures in the UK attributed to pipeline fatigue, and the distribution of age of pipeline at failure?

A4. I am not aware of any failure in the pipeline system which can be attributed to the growth of defects due to fatigue as a result of fluctuations in internal pressure. We are, however, reaching the point at which, unless suitable controls are imposed or the appropriate inspection is carried out and remedial action taken where necessary, fatigue failures could be expected.

ISSUE: USE OF ON-LINE LEAK DETECTION AND EARTHQUAKE IMPACT MEASURING EQUIPMENT

STANDARD: JAPANESE STANDARD (REGULATION 3162-5) - "TSUSHO SANGYO ROPPO"

EDITORS NOTE: The responder is an official in the Ministry of Industry and Trade (MITI), the agency which developed the above standard..

QUESTIONS AND RESPON

Q1. Why do the Japanese Regulations require on-line leak detection and earthquake impact measuring equipment?

A1. The requirements are based upon the potential vulnerability of gas and hazardous liquid pipelines in Japan to earthquakes. This necessitates the need for early detection of leaks (ruptures) in the system.

APPENDIX C

REGULATIONS

REGULATIONS

1.1 WELDING • SUBPART E OF 49 CFR PART 192

Welding is involved in most maintenance, rehabilitation and retrofitting activities involving steel pipelines. The regulations to be analyzed include procedures, inspection and testing, nondestructive testing and repair and removal of defects.

1.1.1 Regulations

192.225 WELDING PROCEDURES

- (a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this Subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.
- (b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

192.241 INSPECTION AND TESTING OF WELDS

- (a) Visual inspection of welding must be conducted to insure that --
 - (1) The welding is performed in accordance with the welding procedure: and
 - (2) The weld is acceptable under paragraph (c) of this section.
- (b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if --
 - (1) The pipe has a nominal diameter of less than 6 inches; or
 - (2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.
- (c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of API Standard 1104.

192.243 NONDESTRUCTIVE TESTING

- (a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.
- (b) Nondestructive testing of welds must be performed --
 - (1) In accordance with written procedures; and
 - (2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.
- (c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under 192.241(c).
- (d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:
 - (1) In Class 1 locations, except offshore, at least 10 percent.
 - (2) In Class 2 locations, at least 15 percent.
 - (3) In Class 3 and Class 4 locations, at crossing of major or navigable rivers, offshore, and within railroad or public highway rights-of way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.
 - (4) At pipeline tie-ins, 100 percent.
- (e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241 (b).
- (f) When nondestructive testing is required under § 192.241 (b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

192.246 REPAIR OR REMOVAL OF DEFECTS

- (a) Each weld that is unacceptable under § 192.241 (c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.
- (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely effect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.
- (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

1.2 GENERAL CONSTRUCTION REQUIREMENTS • SUBPART G OF 49 CFR PART 192

1.2.1 Regulations

192.309 REPAIR OF STEEL PIPE

- (a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:
 - (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS;
 - (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
 - (2) A dent that affects the longitudinal weld or a circumferential weld.
 - (3) In pipe to be operated at a pressure that produces a hoop stress of 40% or more of SMYS, a dent that has a depth of:
 - (i) More than one-quarter inch in pipe 12 3/4 inches or less in outer diameter; or
 - (ii) More than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches in outer diameter.For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.
- (c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40%, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:
 - (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
 - (2) The nominal wall thickness required for the design pressure of the pipeline.
- (d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.
- (e) Each gouge, groove, arc burn or dent that is removed from a length of pipe must be removed by *curring* out the damaged portion as a cylinder.

192.313 BENDS AND ELBOWS

- (a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with paragraph 192.315, must comply with the following:
 - (1) A bend must not impair the serviceability of the pipe.
 - (2) Each bend must have a smooth contour and be free from buckling cracks, or any other mechanical damage.
 - (3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:
 - (I) Bend is made with an internal bending mandrel; or
 - (ii) Pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

- (b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.
- (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length as measured along the crotch, is at least 1 inch.

192.319 INSTALLATION OF PIPE IN A DITCH

- (a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 % or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.
- (b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:
 - (1) Provides firm support under the pipe; and
 - (2) Prevents damage to the pipe and pipe coating from equipment or from backfill material.
- (c) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

192.327 COVER

- (a) Except as provided in paragraphs (c) and (e) of this section, each buried transmission line must be installed with a minimum cover as follows:
 - Class 1 locations: 30 inches in normal soil and 18 inches in rock
 - Class 2, 3, or 4 locations: 36 inches in normal soil and 24 inches in rock.
 - Drainage ditches of public roads and railroad crossings: 36 inches in normal soil and 24 inches in rock.
- (b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches of cover.
- (c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
- (d) A main may be installed with less than 24 inches of cover if the law of the state or municipality:
 - (1) Establishes a minimum cover of less than 24 inches;
 - (2) Requires that mains be installed in a common trench with other utility lines; and
 - (3) Provides adequately for prevention of damage to the pipe by external forces.
- (e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

1.3 CORROSION CONTROL • SUBPART I OF 49 CFR PART 192

Corrosion accounts for approximately 24% of the incidents related to natural gas pipelines. Corrosion is an environmentally-driven condition that can be protected against. The purpose of this part of the regulations is to protect the public against corrosion related incidences.

1.3.1 Regulations

192.453 GENERAL

Each operator shall establish procedures to implement the requirements of this Subpart. These procedures, including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

192.455 EXTERNAL CORROSION CONTROL: BURIED OR SUBMERGED PIPELINES INSTALLED AFTER JULY 31, 1971

- (a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
 - (1) It must have an external protective coating meeting the requirements of 192.461.

- (2) It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this Subpart, installed and placed in operation within one year after completion of construction.
- (b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with subparagraph (a) (2) of this section.
- (c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by test investigation, or experience that --
 - (1) For a copper pipeline, a corrosive environment does not exist; or
 - (2) For a temporary pipeline with an operating period of service not to exceed five years beyond installation, corrosion during the five-year period of service of the pipeline will not be detrimental to public safety.
- (d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with subparagraph (a) (2) of this section.
- (e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8.0, unless tests or experience indicate its suitability in the particular environment involved.
- (f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if --
 - (1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application that adequate corrosion control is provided by alloys; and
 - (2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

192.457 EXTERNAL CORROSION CONTROL: BURIED OR SUBMERGED PIPELINES INSTALLED BEFORE AUGUST 1, 1971

- (a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this Subpart. For the purposes of this Subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.
- (b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this Subpart in areas in which active corrosion is found:
 - (1) Bare or ineffectively coated transmission lines.
 - (2) Bare or coated pipe at compressor, regulator, and measuring stations.
 - (3) Bare or coated distribution lines.

The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.
- (c) For the purpose of this Subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

192.461 EXTERNAL CORROSION CONTROL: PROTECTIVE COATING

- (a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must -
 - (1) Be applied on a properly prepared surface;
 - (2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;
 - (3) Be sufficiently ductile to resist cracking;
 - (4) Have sufficient strength to resist damage due to handling and soil stress; and
 - (5) Have properties compatible with any supplemental cathodic protection.
- (b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

- (c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.
- (d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
- (e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

192.463 EXTERNAL CORROSION CONTROL: CATHODIC PROTECTION

- (a) Each cathodic protection system required by this Subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this Subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.
- (b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential--
 - (1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or
 - (2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.
- (c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

192.465 EXTERNAL CORROSION CONTROL: MONITORING

- (a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10 year period.
- (b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 months, to ensure that it is operating.
- (c) Each reverse current switch, each diode, and each interference bend whose failure would jeopardize structure protection, must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bend must be checked at least once each calendar year, but with intervals not exceeding 15 months.
- (d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.
- (e) After the initial evaluation required by paragraphs (b) and (c) of 192.455 and paragraph (b) of 192.457, each operator shall, at intervals not exceeding three years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this Subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

192.467 EXTERNAL CORROSION CONTROL: ELECTRIC ISOLATION

- (a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.
- (b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
- (c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.
- (d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.
- (e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.
- (f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

192.475 INTERNAL CORROSION CONTROL: GENERAL.

- (a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.
- (b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found --
 - (1) The adjacent pipe must be investigated to determine the extent of internal corrosion;
 - (2) Replacement must be made to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and
 - (3) Steps must be taken to minimize the internal corrosion.
- (c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type or bottle-type holders.

192.479 INTERNAL CORROSION CONTROL: ATMOSPHERIC CORROSION.

- (a) PIPELINES INSTALLED AFTER JULY 31, 1971. Each above ground pipeline or portion of a pipeline installed after July 31, 1971, that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.
- (b) PIPELINES INSTALLED BEFORE AUGUST 1, 1971. Each operator having an above ground pipeline or portion of a pipeline installed before August 1, 1971, that is exposed to the atmosphere, shall --
 - (1) Determine the areas of atmospheric corrosion on the pipeline;
 - (2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489, and
 - (3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

1.4 TEST REQUIREMENTS • SUBPART J OF 49 CFR PART 192

1.4.1 Regulations

192.503 GENERAL REQUIREMENTS

- (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until--
 - (1) It has been tested in accordance with this Subpart and paragraph 192.619 to substantiate the maximum allowable operating pressure; and
 - (2) Each potentially hazardous leak has been located and eliminated.
- (b) The test medium must be liquid, air, natural gas, or inert gas that is--
 - (1) Compatible with the material of which the pipeline is constructed;
 - (2) Relatively free of sedimentary materials; and
 - (3) Except for natural gas, nonflammable.
- (c) Except as provided in paragraph 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Natural Gas	Air or inert gas
1.	80	80
2	30	75
3.	30	50
4	30	40

- (d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this Subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

192.505 STRENGTH TEST REQUIREMENTS FOR STEEL PIPELINE TO OPERATE AT A HOOP STRESS OF 30 PERCENT OR MORE OF SMYS

- a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.
- (b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements.
- (c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.
- (d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that --
 - (1) The component was tested to at least the pressure required for the pipeline to which it is being added; or
 - (2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.
- (e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

192.507 TEST REQUIREMENTS FOR PIPELINES TO OPERATE AT A HOOP STRESS LESS THAN 30 PERCENT OF SMYS AND AT OR ABOVE 100 PSIG

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 psig. must be tested in accordance with the following:

- (a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.
- (b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium --
 - (1) A leak test must be made at a pressure between 100 psig. and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.

1.5 MAINTENANCE • SUBPART M OF 49 CFR PART 192

1.5.1 Regulations

Maintenance of gas transmission pipelines consists of preventive maintenance and routine repair. There is little one can do in the way of preventive maintenance on a buried or submerged pipeline. The best prevention is quality control during installation. Therefore, most of the maintenance in gas transmission lines involves inspection for defects, repair of those defects and tests of the repairs. Therefore the regulations that pertain to maintenance, rehabilitation and retrofitting are:

- Inspection
 - Patrolling
 - » Leak detection
 - » Field markers
 - Repair
 - » General requirements
 - » Permanent repair of defects
 - » Permanent repair of welds
 - » Permanent repair of leaks
- Testing.

192.705 TRANSMISSIONLINES: PATROLLING

- a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.
- (b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Class Location	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1, 2	7½ months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4½ months; but at least four times each calendar year	7½ months; but at least twice each calendar year
4	4½ months; but at least four times each calendar year	4½ months; but at least four times each calendar year

192.706 TRANSMISSIONLINES: LEAKAGE SURVEYS

- (a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.
- (b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted --
 - (1) In Class 3 locations, at intervals not exceeding 7 1/2 months, but at least twice each calendar year; and
 - (2) In Class 4 locations, at intervals not exceeding 4 1/2 months, but at least four times each calendar year.

192.707 LINE MARKERS FOR MAINS AND TRANSMISSION LINES

- (a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:
 - (1) At each crossing of a public road and railroad; and
 - (2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.
- (b) Exceptions for buried pipelines. Line markers are not required for buried mains and transmission lines --
 - (1) Located offshore or at crossings of or under waterways and other bodies of water; or
 - (2) In class 3 or Class 4 locations --
 - (i) Where placement of a marker is impractical; or
 - (ii) Where a damage prevention program is in effect under paragraph 192.614.
- (c) Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located above ground in an area accessible to the public.
- (d) Marker warning. Must be written legible on a background of sharply contrasting color on each line marker:
 - (1) The work "Warning", "Caution" or "Danger" followed by the words "Gas" (or name of gas transported) "Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.
 - (2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

192.711 TRANSMISSION LINES: GENERAL REQUIREMENTS FOR REPAIR PROCEDURES

- (a) Each operator shall take immediate temporary measures to protect the public whenever:
 - (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
 - (2) It is not feasible to make a permanent repair at the time of discovery. As soon as feasible, the operator shall make permanent repairs.
- (b) Except as provided in paragraph 192.717(a)(3), no operator may use a welded patch as a means of repair.

192.713 TRANSMISSIONLINES: PERMANENT FIELD REPAIR OF IMPERFECTIONS AND DAMAGES

- (a) Except as provided in paragraph (b) of this section, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of SMYS must be repaired as follows:

- (1) If it is feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.
 - (2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.
 - (3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.
- (b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

192.715 TRANSMISSION LINES: PERMANENT FIELD REPAIR OF WELDS

Each weld that is unacceptable under § 192.241 (c) must be repaired as follows:

- (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.
- (b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:
 - (1) The weld is not leaking;
 - (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and
 - (3) Grinding of the defective area can be limited so that at least 1/8-inch thickness in the pipe weld remains.
- (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

192.717 TRANSMISSION LINES: PERMANENT FIELD REPAIR OF LEAKS

- (a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:
 - (1) If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.
 - (2) If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line:
 - (i) Is joined by mechanical couplings; and
 - (ii) Operates at less than 40 percent of SMYS.
 - (3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
- (b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

192.719 TRANSMISSION LINES: TESTING OF REPAIRS

- (a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.
- (b) Testing of repairs made by *welding*. Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

192.727 ABANDONMENT OR INACTIVATION OF FACILITIES

- (a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.
- (b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
- (c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.
- (d) Whenever service to a customer is discontinued, one of the following must be complied with:

- (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.
- (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.
- (e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.
- (f) Each abandoned vault must be filled with a suitable compacted material.

2.1.1 Regulations

195.228 WELDS AND WELDING INSPECTION: STANDARDS OF ACCEPTABILITY

- (a) Each weld and welding must be inspected to insure compliance with the requirements of this Subpart. Visual inspection must be supplemented by nondestructive testing.
- (b) The acceptability of a weld is determined according to the standards in section 6 of API Standard 1104.

195.230 WELDS: REPAIR OR REMOVAL OF DEFECTS

- (a) Each weld that is unacceptable under §195.228 must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.
- (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.
- (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §195.214. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met in completion of the final weld repair.

195.234 WELDS: NONDESTRUCTIVE TESTING

- (a) A weld may be nondestructively tested by any process that will clearly indicate any defects that may affect the integrity of the weld.
- (b) Any nondestructive testing of welds must be performed.
 - (1) In accordance with a written set of procedures for nondestructive testing; and
 - (2) With personnel that have been trained in the established procedures and the use of the equipment employed in the testing.
- (c) Procedures for the proper interpretation of each weld inspection must be established to ensure that acceptability of the weld under §195.228.
- (d) During construction, at least 10 percent of the girth welds made by each welder during each welding day must be nondestructively tested over the entire circumference of the weld.
- (e) 100 percent of each day's girth welds installed in the following location must be nondestructively tested 100 percent unless impracticable, in which case at least 90 percent must be tested. Nondestructive testing must be impracticable for each girth weld not tested:
 - (1) At any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water, and any offshore area;
 - (2) Within railroad or public road rights-of-way;
 - (3) At overhead road crossings and within tunnels;
 - (4) Within the limits of any incorporated subdivision of a state government and
 - (5) Within populated areas, including, but not limited to residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.
- (f) When installing used pipe, 10 percent of the old girth welds must be nondestructively tested.
- (g) At pipeline repairs 100 percent of the girth welds must be nondestructively tested.

195.236 EXTERNAL CORROSION PROTECTION

Each component in the pipeline system must be provided with protection against external corrosion.

195.238 EXTERNAL COATING

- (a) No pipeline system component may be buried or submerged unless that component has an external protective coating that-
 - (1) Is designed to mitigate corrosion of the buried or submerged component;
 - (2) Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture;
 - (3) Is sufficiently ductile to resist cracking;
 - (4) Has enough strength to resist damage due to handling and soil stress; and
 - (5) Supports any supplemental cathodic protection. In addition, if an insulation-type coating is used it must have low moisture absorption and provide high electrical resistance.
- (b) All pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe, and any damage discovered must be repaired.

195.242 CATHODIC PROTECTION SYSTEM

- (a) A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to determine whether adequate cathodic protection has been achieved.
- (b) A cathodic protection system must be installed not later than 1 year after completing the construction.

195.258 VALVES: GENERAL

- (a) Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering.
- (b) Each submerged valve located offshore or in inland navigable waters must be marked or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.

195.260 VALVES: LOCATION

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

- (a) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.
- (b) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.
- (c) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.
- (d) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.
- (e) On each side of a water crossing that is more than 100 feet wide from high-water mark to high-water mark unless the Secretary finds in a particular case that valves are not justified.
- (f) In each side of a reservoir holding water for human consumption.

195.262 PUMPING EQUIPMENT

- (a) Adequate ventilation must be provided in pump station buildings to prevent an accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in the pumping station building.
- (b) The following must be provided in each pump station:
 - (1) Safety devices that prevent overpressuring of pumping equipment, including the auxiliary pumping equipment within the pumping station.
 - (2) A device for the emergency shutdown of each pumping station.
 - (3) If power is necessary to actuate the safety devices, an auxiliary power supply.
- (c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pumping station may be used.
- (d) Except for offshore pipeline pumping equipment may not be installed-
 - (1) On any property that will not be under the control of the operator; or
 - (2) Less than 50 feet from the boundary of the station.
- (e) Adequate fire protection must be installed at each pump station. If the fire protection system installed required the use of pumps, motive power must be provided for those pumps that are separated from the power that operates the station.

2.2 HYDROSTATIC TESTING • SUBPART D TO 49 CFR PART 195

2.2.1 Regulations

195.300 OPE

This Subpart prescribes minimum requirements for hydrostatic testing of the following. It does not apply to movement of pipe covered by Para. 195.424.

- (a) Newly constructed steel pipeline systems;
- (b) Existing steel pipeline systems that are relocated, replaced, or otherwise changed;
- (c) Onshore steel interstate pipelines constructed before January 8, 1971, that transport highly volatile liquids; and
- (d) Onshore steel intrastate pipelines constructed before October 21, 1985, that transport highly volatile liquids.

195.302 GENERAL REQUIREMENTS

- (a) Each new pipeline system, each pipeline system in which pipe has been relocated or replaced, or that part of a pipeline system that has been relocated or replaced, must be hydrostatically tested in accordance with this Subpart without leakage.
- (b) No person may transport a highly volatile liquid in an onshore steel interstate pipeline constructed before January 8, 1971, or an onshore steel intrastate pipeline constructed before October 21, 1985, unless the pipeline has been hydrostatically tested in accordance with this Subpart or, except for pipelines subject to 195.5, its maximum operating pressure is established under 195.406(a)(5). Dates to comply with this requirement are:
 - (1) For onshore steel interstate pipelines in highly volatile liquid service before September 8, 1980:
 - (i) Planning and scheduling of hydrostatic testing or actual reduction in maximum operating pressure to meet §195.406(a)(5) must be completed before September 15, 1981; and
 - (ii) Hydrostatic testing must be completed before September 15, 1985, with at least 50 percent of the testing completed before September 1, 1983.
 - (2) For onshore steel intrastate pipelines in highly volatile liquid service before April 23, 1985:
 - (i) Planning and scheduling of hydrostatic testing or actual reduction in maximum operating pressure to meet 195.406(a)(5) must be completed before April 23, 1986; and
 - (ii) Hydrostatic testing must be completed before April 23, 1990 with at least 50 percent of the testing completed before April 23, 1988.
- (c) The test pressure for each hydrostatic test conducted under this section must be maintained throughout the part of the system being tested for at least 4 continuous hours at a pressure equal to 125 percent, or more, of the maximum operating pressure and, in the case of a pipeline that is not visually inspected for leakage during a test, for at least an additional 4 continuously hours at a pressure equal to 110 percent, or more, of the maximum operating pressure.

195.304 TESTING OF COMPONENTS

- (a) Each hydrostatic test under §195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section.
- (b) A component that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either:
 - (1) The component was hydrostatically tested at the factory; or
 - (2) The component was manufactured under a quality control system that ensured each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

195.306 TEST MEDIUM (MONITORING INCLUDED IN REGULATION)

- (a) Except as provided in paragraphs (b) and (c) of this section, water must be used as the test medium.
- (b) Except for offshore pipelines, liquid petroleum that does not vaporize rapidly may be used as the test medium if:
 - (1) The entire pipeline section under test is outside of cities and other populated areas;
 - (2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure which produces a hoop stress of 50 percent of specified minimum yield strength;
 - (3) The test section is kept under surveillance by regular patrols during the test; and

- (4) Continuous communication is maintained along entire test section.
- (c) Carbon dioxide pipelines may use inert gas or carbon dioxide as the test medium if-
 - (1) The entire pipeline section under test is outside of cities and other populated areas;
 - (2) Each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure that produces a hoop stress of 50 percent of specified minimum yield strength;
 - (3) Continuous communication is maintained along entire test section: and
 - (4) The pipe involved is new pipe having a longitudinal joint factor of 1.00.

2.3 OPERATION AND MAINTENANCE • SUBPART F TO 49 CFR PART 195

2.3.1 Regulations

195.403 TRAINING

- (a) Each operator shall establish and conduct a continuing training program to instruct operation and maintenance personnel to:
 - (1) Carry out the operating, maintenance, and emergency procedures established under §195.402 that relate to their assignments;
 - (2) Know the characteristics and hazards of the hazardous liquids or carbon dioxide transported, including, in the case of flammable HVL, flammability of mixtures with air, odorless vapors, and water reactions;
 - (3) Recognize conditions that are likely to cause emergencies, predict the consequences of facility malfunctions or failures and hazardous liquid or carbon dioxide spills, and to take appropriate corrective action;
 - (4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, or environmental damage;
 - (5) Learn the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition; and
 - (6) In case of maintenance personnel, to safely repair facilities using appropriate special precautions, such as isolation and urging, when highly volatile liquids are involved.
- (b) At intervals not exceeding 15 months, but at least once each calendar year, each operator shall:
 - (1) Review with personnel their performance in meeting the objectives of the training program set forth in paragraph (a) of this section; and
 - (2) Make appropriate changes to the training program as necessary to insure that it is effective.
- (c) Each operator shall require and verify that its supervisors maintain a thorough knowledge of that portion of the procedures established under §195.402 for which they are responsible to insure compliance.

195.406 MAXIMUM OPERATING PRESSURE

- (a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:
 - (1) The internal design pressure of the pipe determined in accordance with 9195.106.
 - (2) The design pressure of any other component of the pipeline.
 - (3) Eighty percent of the test pressure for any part of the pipeline which has been hydrostatically tested under Subpart E of this part.
 - (4) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is exempted from testing under §195.304.
 - (5) In the case of onshore HVL interstate pipelines constructed before January 8, 1971, or onshore HVL intrastate pipelines constructed before October 21, 1985, that have not been tested under Subpart E of this part, 80 percent of the test pressure or highest operation pressure to which the pipeline was subjected for four or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted. (See 9195.302 (b) for compliance schedules for HVL interstate pipelines in service before September 8, 1980, and for HVL intrastate pipelines in services before April 23, 1985.)
- (b) No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (A) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

195.412 INSPECTION OF RIGHTS-OF-WAY AND CROSSINGS UNDER NAVIGABLE WATERS

- (a) Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions in or adjacent to each pipeline right-of-way.
- (b) Except for offshore pipelines, each operator shall, at intervals not exceeding 5 years, inspect each crossing under a navigable waterway to determine the condition of the crossing.

195.416 EXTERNAL CORROSION CONTROL

- (a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, conduct tests on each underground facility in its pipeline systems that is under cathodic protection to determine whether the protection is adequate.
- (b) Each operator shall maintain the test leads required for cathodic protection in such a condition that electrical measurements can be obtained to ensure adequate protection.
- (c) Each operator shall, at intervals not exceeding 2-1/2 months, but at least six times each calendar year, inspect each of its cathodic protection rectifiers.
- (d) Each operator shall, at intervals not exceeding 5 years, electrically inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed.
- (e) Whenever any buried pipelines are exposed for any reason, the operator shall examine the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, it shall investigate further to determine the extent of the corrosion.
- (f) Any pipe that is found to be generally corroded so that the remaining wall thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets the requirements of this part or, if the area is small, must be repaired. However, the operator need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure specified in this Subpart, based on the actual remaining wall thickness.
- (g) If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, and the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness in the pits.
- (h) Each operator shall clean, coat with material suitable for the prevention of atmospheric corrosion, and, maintain this protection for, each component on its pipeline system that is exposed to the atmosphere.

195.418 INTERNAL CORROSION CONTROL

- (a) No operator may transport any hazardous liquid or carbon dioxide that would corrode the pipe or other components of its pipeline system, unless it has investigated the corrosive effect of the hazardous liquid or carbon dioxide on the system and has taken adequate steps to mitigate corrosion.
- (b) If corrosion inhibitors are used to mitigate internal corrosion the operator shall use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect and shall also use coupons or other monitoring equipment to determine their effectiveness.
- (c) The operator shall, at intervals not exceeding 7-1/2 months, but at least twice each calendar year, examine coupons or other types of monitoring equipment to determine the effectiveness of the inhibitors or the extent of any corrosion.
- (d) Whenever any pipe is removed from the pipeline for any reason, the operator must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the operator shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets the requirements of this part or, based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits in operating pressure specified in the Subpart.

195.420 VALVE MAINTENANCE

- (a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.
- (b) Each operator shall, at intervals not exceeding 7-1/2 months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.
- (c) Each operator shall provide for each valve from unauthorized operation and from vandalism.

195.422 PIPELINE REPAIRS

- (a) Each operator shall, in repairing its pipeline systems, insure that the repairs are made in a safe manner and are made so as to prevent damage to persons or property.
- (b) No operator may use any pipe, valve, or fitting, for replacement in repairing pipeline facilities, unless it is designed and constructed as required by this part.

195.428 OVERPRESSURE SAFETY DEVICES

- (a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7-1/2 months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure control equipment to determine that it is functioning properly, is in good condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.
- (b) In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years.

195.436 SECURITY OF FACILITIES

Each operator shall provide protection for each pumping station and breakout tank and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.

195.440 PUBLIC EDUCATION

Each operator shall establish a continuing program to enable the public, appropriate government organizations and persons engaged in excavation-related activities to recognize a hazardous liquid or a carbon dioxide pipeline emergency and to report it to the operator to the fire, police, or other appropriate public officials. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of non-English speaking population in the operator's operating areas.