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MINERALS MANAGEMENT SERVICES

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APPRAISAL AND DEVELOPMENT OF PIPELINE DEFECT ASSESSMENT METHODOLOGIES

FINAL REPORT FOR PHASE 1

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MSL Engineering Limited
MSL House
5-7 High Street, Sunninghill
Ascot, Berkshire. SL5 9NQ

Tel: +44 (0)1344-874424
Fax: +44 (0)1344-874338
E-mail: MSLCENG@aol.com

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1. INTRODUCTION

1.1 General

Offshore pipelines transport enormous quantities of oil and gas vital to the economies of virtually all nations. Any failure to ensure safe and continuous operation of these pipelines can have serious economic implications and possibly damage to the environment and cause fatalities. A prerequisite to pipeline safe operation is to ensure their structural integrity to a high level of reliability throughout their operational lives. Such integrity may be threatened by defects introduced into a pipeline system during its construction or operation. Since it is virtually impossible to prevent such defects from occurring and because not all defects are harmful to pipeline integrity, it is essential to be able to distinguish defects which can be tolerated from those which can not.

A large number of empirical and/or analytical tools for the assessment of pipeline defects are available. The project **Appraisal and Development of Pipeline Defect Assessment Methodologies** is to evaluate thoroughly all available methods for assessing offshore pipeline defects. The objective of this project is to establish a firm basis on all the major aspects of the methodology needed to assess the safety of offshore pipelines with geometric and material defects. Furthermore, it performs the necessary development to cover the remaining gaps in the state-of-the-art.

Based on the project proposal, the main tasks in this Phase 1 of the project was the collation of pipeline defect related literature, including all available codes, standards, published reports and published papers. From the review of collated documents and interviews with Operators, a critical appraisal of current industry practice and code provisions has been undertaken. A database of screened test results for different defect forms has been created, and present-day inspection methodologies of offshore pipeline defects established.

This report represents a review of the progress of the project in Phase 1 of the above mentioned four aspects: Collation of pipeline defect related literature, Current industry practice, Code provisions, and Database of test results for different pipeline defect forms.

1.2 Background

A number of studies on the failure/loss of containment of pipelines have been conducted. Based on statistical analysis of information usually held by Regulatory Authorities and/or Pipeline Operators, these studies provide indications of the level of reliability achieved in the operation of pipelines. They also provide information on the likely level of failure frequency for an individual pipeline depending on factors such as:

- Cause of Failure
- Location of Pipeline
- Diameter of Pipeline

- Length of Pipeline
- Contents of Pipeline.

The most recent published studies on pipeline failures are as follows:

- Mandke - evaluation of failure rate data for Gulf of Mexico using the US office of Minerals and Management Service (MMS) database. This covered 690 incidents that occurred during the Period 1967-87. Information from 1987- onwards is currently not available.

- HSE/UKOOA commissioned a number of studies of pipeline failures in the North Sea. Some results of the study are reported by Williams et al covering the period up to 1989. Further reports covering periods 1989 to 1992, and 1992 to 1994 have been released by the HSE (PARLOC) and findings 1994 to 1996 have been released recently by the HSE.

- The Office of Pipeline Safety (OPS) of US Department of Transport (DOT) collected all pipeline incident data from 1968-1999.

Comparison of Gulf of Mexico (Mandke) and North Sea Pipeline failure studies indicated that the primary cause of failures listed in decreasing frequency of occurrence/detection were as follows:

Gulf of Mexico:	Corrosion, third party, storm and slides, material and equipment failure.
North Sea:	Third Party, corrosion, material failure.

Data extracted from the Office of Pipeline Safety Database on incident and accident statistics for the period covering 1984-1999 is presented in Table 1.1 for hazardous liquids and Gas transportation/Distribution. It can be observed from Table 1.1 that the number of incidents and number of accidents etc are generally similar with no apparent decrease with time being noted. The primary cause for the incidents are presented in Tables 1.2 to 1.4. The tables indicate that the cause of damage resulted from a number of causes including the following:

- Corrosion (internal and external)
- Damage from outside forces (ie. mechanical damage)
- Defective weld and pipe
- Construction/material

The primary cause of failure listed in decreasing frequency of occurrence in general appears to be as follows:

- Damage from outside forces/outside damage, Corrosion (internal and external), defective pipe/weld.

Although the above information is incomplete and further information (eg. MMS Hurricane Andrew, HSE PARLOC updates) could be considered, there is sufficient evidence that damage which require defect assessment procedures to be considered are required.

Year	Hazardous Liquid Pipeline Operators			Natural Gas Pipeline Operators Transmission			Natural Gas Pipeline Distribution		
	No. of Incidents	Fatalities	Injuries	No. of Incidents	Fatalities	Injuries	No. of Incidents	Fatalities	Injuries
1984	186	0	17	NA	NA	NA	NA	NA	NA
1985	183	5	18	NA	NA	NA	NA	NA	NA
1986	209	4	32	83	6	20	142	29	104
1987	237	3	20	70	0	15	164	11	115
1988	193	2	19	89	2	11	201	23	114
1989	163	3	38	103	22	28	177	20	91
1990	180	3	7	89	0	17	109	6	52
1991	216	0	9	71	0	12	162	14	77
1992	212	5	38	74	3	15	103	7	65
1993	230	0	10	96	1	18	121	16	84
1994	243	1	7	81	0	22	141	21	91
1995	188	3	11	64	2	10	97	16	43
1996	195	5	13	77	1	5	110	47	109
1997	175	0	5	73	1	5	108	10	83
1998	151	1	2	96	1	10	132	16	62
1999	2	0	0	2	0	0	8	0	2

Table 1.1: Offshore Pipeline Safety Summary of Incident/Accident Statistics by Year

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	0 (0)	0 (0)	1 (0.92)	0 (0)	0 (0)
External Corrosion	5 (3.55)	3 (3.09)	1 (0.92)	3 (2.78)	5 (3.79)
Damage From Outside Forces	79 (56.03)	66 (68.04)	64 (58.72)	59 (54.63)	86 (65.15)
Construction/ Operating Error	13 (9.22)	5 (5.15)	6 (5.50)	4 (3.70)	5 (3.79)
Operator Error	10 (7.09)	6 (6.19)	6 (5.50)	6 (5.56)	8 (6.06)
Other	34 (24.11)	17 (17.53)	21 (28.44)	36 (33.33)	28 (21.21)
Total	141	97	109	108	132

Values in Bracket % of Total Incidents

Table 1.2: Office of Pipeline Safety – Gas Distribution Pipeline Accident Summary by Cause

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	20 (25)	5 (7.81)	6 (8.22)	16 (23.88)	13 (13.54)
External Corrosion	13 (16.25)	4 (6.25)	7 (9.59)	5 (7.46)	7 (7.29)
Damaged From Outside Forces	23 (28.75)	27 (42.19)	37 (50.68)	28 (41.79)	36 (37.50)
Constructional/ Material/Defect	9 (11.25)	13 (20.31)	7 (9.59)	8 (11.94)	19 (19.79)
Other	15 (18.75)	15 (23.44)	16 (21.42)	10 (14.93)	21 (21.88)
Total	80	64	73	67	96

Values in Bracket % of Total Incidents

Table 1.3: Office of Pipeline Safety – Transmission and Gathering Pipeline Accident Summary by Cause

Cause	Year				
	1994	1995	1996	1997	1998
Internal Corrosion	10 (4.1)	13 (6.81)	21 (10.99)	18 (10.2)	19 (12.5)
External Corrosion	38 (15.57)	21 (12.04)	38 (19.90	34 (19.4)	17 (11.2)
Defective Weld	21 (8.61)	9 (4.71)	9 (4.71)	3 (1.7)	7 (4.6)
Incorrect Operation	8 (3.28)	26 (13.61)	11 (5.76)	11 (6.2)	7 (4.6)
Defective Pipe	11 (4.51)	14 (7.33)	9 (4.71)	11 (6.2)	6 (3.9)
Outside Damage	57 (23.36)	54 (28.27)	48 (25.13)	40 (22.8)	40 (26.4)
Malfunction of Equipment	22 (9.02)	5 (2.62)	6 (3.14)	7 (4.0)	9 (5.9)
Other	77 (31.56)	47 (24.61)	49 (25.65)	51 (29.1)	46 (30.4)
Total	244	191	191	175	151

Values in Bracket % of Total Incidents

Table 1.4: Office of Pipeline Safety – Hazardous Liquid Pipeline Accident Summary by Cause

1.3 Definition of Defects

A defect is an imperfection of sufficient magnitude to warrant rejection based on the requirements of the codes or standards. An imperfection is a material discontinuity or irregularity that is detectable by inspection in accordance with the requirements of the codes and standards. Different codes and standards give different warranty of rejection of the defects.

Pipeline defects can be grouped into three categories according to their cause: mechanical damage, weld defects and corrosion defects.

Mechanical Damage:

Dent: A depression caused by an event that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.

Gouge: A surface imperfection caused by mechanical removal or displacement of metal that reduces the wall thickness of a pipe or component.

Groove: Groove can cause stress concentration at the point and can be considered as a defect.

Surface Cracks: Pipe body surface cracks shall be considered defects.

Weld Defects:

Arc Burn: A localised condition or deposit that is caused by an electric arc and consists of remelted metal, heat-affected metal, a change in the surface profile, or a combination thereof.

Incomplete Penetration: The root head of weld does not completely fill the root of the joint.

Incomplete Fusion: There is lack of bond between the weld metal and the base metal at the root or top of the joint.

Internal Concavity: Incomplete filling of the joint.

Undercut: A groove melted into the base metal adjacent to a weld toe at the root or top of the joint.

Slag Inclusions: Non-metallic solid entrapped in the weld metal or between the weld metal and the base metal.

Hollow Bead: Linear porosity or cylindrical gas pockets occurring in the root bead.

Corrosion Defect:

General Corrosion: Uniform or gradually varying loss of the wall thickness over the area.

Localised Corrosion Pitting: Localised corrosion pitting can reduce the wall thickness to be less than the design thickness.

Stress Corrosion Crack: There are two kinds of stress corrosion cracking: sulphide stress corrosion cracking and hydrogen induced cracking. Suphide stress corrosion cracking occurs primarily in steels at a region subjected to applied or residual tensile stresses. Hydrogen induced cracking occurs at low stresses or even in the absence of stresses or under external compressive stresses.

The above types of damage are illustrated in Figure 1.1 and Figure 1.2.

2. DATA CAPTURE

2.1 Literature

2.1.1 Methodology

The basic literature survey is the main task conducted in phase I of this project. There is a significant amount of literature on pipeline defect assessment. The literature search was performed in three categories. Category I includes codes and standards on offshore pipeline design and defects assessment. Category II includes all the technical papers relevant to defect assessment methodologies. Category III collects all the possible technical reports from governments and companies. The most popular and used codes and standards from different countries are also collected. The reference sources are identified in Section 2.1.2.

A literature database from all the collected codes, standards, technical papers from conference proceedings or journals was created which includes almost 400 references.

For each reference the following information has been recorded: Reference number, Title of paper, Author(s), organisation, date of publication, document reference (ie. conference, code, etc.). In addition, to enable searching of the database to be undertaken more efficiently, particularly in identifying those references which contain defect data, a number of key words have been identified (eg. defect assessment, code, corrosion damage, mechanical damage, weld damage, material, inspection, etc.).

In this project, the emphasis was confined to offshore pipeline defect assessment and in particular to those types of defect damage which commonly occur. The range of defect types is presented in Section 1.3.

2.1.2 Reference Sources

The following lists of reference sources were identified:

General Design Codes and Standards:

- Pipeline Transportation System for Liquid Hydrocarbons and other Liquids, ASME B31.4, 1998, US
- Gas Transmission and Distribution Piping Systems, ASME B31.8, 1995, US
- Code of Practice for Pipelines, BSI 8010, Part3, 1993, UK
- Oil and Gas Pipeline Systems, CAS-Z662-99, 1999, Canada
- Rules for Submarine Pipeline Systems, DnV 1996, 1996, Norway
- Rules for Subsea Pipelines and Risers, GL 1995, Germany

- Pipeline Transportation System for the Petroleum and Natural Gas Industries, ISO 13623, 1996

- Design of Long Distance Transmission Pipelines, SniP2.05.06-85, 1985, Russian

Codes and Standards on Pipeline Defect Assessment:

- Welding of Pipelines and Related Facilities, API - 1104, 1994, US

- Pipeline Maintenance Welding Practices, API – 1107, 1991, US

- Manual for Determining the Remaining Strength of Corroded Pipelines, ASME B31G, 1991, US

- Guide on Methods for Assessing the Acceptability of Flaws in Structures, BS 7910, 1999, UK

- Specification for Welding of Steel Pipelines on Land and Offshore, BS 4515, 1996, UK

- Assessment of the Integrity of Structures Containing Defects, R/H/R6 Revision 3, 1997, Nuclear Electric, UK

- Oil and Gas Pipeline Systems, CSA-Z662-99, 1999, Canada

The Specification and standards of the following organisations appear in the above codes and standards.

API American Petroleum Institute, USA

ASME American Society of Mechanical Engineers, USA

BSI British Standards Institute, UK

CEGB Central Electricity Generating Board, UK

CSA Canadian Standards Association, Canada

GL Germanischer Lloyd, Germany

ISO International Standards Organisation

The majority of sources concerning offshore pipeline defect assessment are the specific conferences and seminars. The following conferences and seminars are covered in the literature database.

- Offshore Technology Conference, API, 1985 – 1999

- International Pipeline Conference, ASME, 1996, 1998

- International Conference on Offshore Mechanics and Arctic Engineering, ASME, 1990 - 1998
- International Pressure Vessel Technology Conference, ASME 1990-1998
- Pressure and Piping Conference, ASME 1990 –1998
- International Offshore and Polar Engineering Conference, ISOPE, 1997, 1998
- API Pipeline Conference, API, 1990-1998
- Pipeline Engineering Symposium, ASME, 1985-1990
- Pipeline Engineering, ASME, 1991-1995
- International Conference on Pipeline Protection, MEP, 1991-1997
- Advances in Subsea Pipeline Engineering, ASPECT, 1994
- International Workshop on Offshore Pipeline Safety, MMS, 1991
- Pipeline Crossing, ASCE, 1996
- Deepwater Pipeline Technology Conference and Exhibition, Clarion, 1997-1999

In addition, the following Journals were sourced.

- International Journal of Pressure Vessels and Piping, ASME
- Oil And Gas Journal, OGJ
- Civil engineering, ASCE
- Welding Journal, AWS
- World Oil, Gulf

Several technical reports from government and companies such MMS, BP, EXXON, API are also reviewed.

To illustrate how the reference source database has been used to identify information on available data, Tables 2.1 to 2.6 provide extracts of information obtained from those references which contain data for different defect damage types. It can be observed that there is a significant number of references which contain data particularly for corrosion damage.

Ref No.	Author	Main Topic.	General Description
267	Chouchaoui and Pick	Interaction of Corrosion Pits	Describes results of experimental and finite element studies on burst strength of pipes with multiple corrosion pits
268	Chouchaoui and Pick	Corrosion assessment procedures	Proposes a comprehensive 3 level corrosion procedure drawn from series of burst tests on pipe sections with both service and simulated corrosion and a complementary series of FE analyses.
222	Roberts and Picks	Longitudinal stress assessment of corroded line pipe	Most techniques consider only the circumferential stress in the pipe in predicting the burst pressure of corroded pipe. Tests on experimental pipe sections and FE analyses to investigate longitudinal stress are assessed.
223	Wang, Smith, Popelar and Maple	Assessment procedure for corrosion under combined loading	Full scale tests of 48 inch diameter corroded pipe with FE data under combination of bending and other secondary loads.
140	Smith and Grigory	Assessment procedure of corrosion under combined loading	Full scale, small scale and FE studies on corroded pipes subjected to combined loading.
141	Cronin, Roberts and Pick	Assessment procedure for long corrosion grooves in pipes	Measured burst pipe tests with various corrosion geometries compared with FE analyses for long corrosion grooves.
284	Bubenik	Corrosion under combing loading	Combination of linear and non-linear FE studies supported by experiments under internal pressure and axial loading.
278	Stewart, Klever and Ritchie	Burst strength intact and corroded pipes	Validation of model against limited set of burst tests on uncorroded and corroded pipes.
273	Kanninen, Grigory et al.	Corrosion assessment procedure under combined loading	Validation of FE data against existing experimental data.
308	Hopkins and Jones	General corrosion assessments	Extensive full scale burst test experimental study into the behaviour of long and complex shaped corrosion and interacting corrosion. Results compared with other data.

Table 2.1: Summary of Relevant References for Data on Corrosion (continued…)

Ref No.	Author	Main Topic	General Description
330	Wang	Corrosion method (combined loading)	Finite element analyses conducted for combined loading compared to existing database of 86 burst tests on corroded pipes.
320	Kiefner and Vieth	Remaining strength of corroded pipe lines	Experimental database of burst tests on corroded pipe
317	Jones et al.	General corrosion assessment	Results of experimental and finite element study under internal pressure with corrosion occurring at bottom of pipe.
280	Andrews	Effect of corrosion on fracture/fatigue resistance	Results in heat affected zone of girth weld seam examined using FE and experimental data.
74	Rosenfeld et al.	Corrosion assessment procedure	A proposed corrosion procedure is compared with full scale burst tests of 168 pipes containing actual or simulated metal loss corrosion of various configurations

Table 2.1: Summary of Relevant References for Data on Corrosion (...continued)

Ref No.	Author	Main Topic	General Description
192	Stevick, Haart and Flanders	Fatigue assessment of dented pipelines	Fatigue assessments of damages pipeline. Data compared with S-N predictions.
194	Hagiwarara et al	Fatigue assessment of severely gouged line pipes	Fatigue tests on ERW line pipes with severe denting/gouge carried out.
195	Rosenfeld and Kiefner	Fatigue behaviour of dented pipes	Dent fatigue tests compared with analytical model. Influence of dent geometry, pipe strength and pipeline operation on fatigue life estimated.
268	Fowler et al.	Fatigue of dented pipe	Describes an S-N based procedure for fatigue assessment of plain dents including stress concentration factors, based on FE and experimental validation.
307, 309, 311	Hopkins et al.	Fatigue/burst pressure of dented pipes	Experimental research on plain dents, combined dents carried out to provide guidelines for treatment of dents and combination of dents and defects.
55	Rosenfeld et al.	Fatigue of shallow dents in girth welds	Predicted fatigue lives compared with 5 experimental pipe tests with dents in girth welds.
50	Fowler et al.	Fatigue of pipes with dents/gouges	Further assessment of experimental data/FE data (i.e. above reference 268)

Table 2.2: Summary of Relevant References for Data on Mechanical Damage Defects

Ref No.	Author	Main Topic	General Description
275	Leggatt and Challenger	Weld defect assessment procedure	Validation of PD 6493 approach for assessment of girth weld defects against Canadian database of full scale pipe bend tests.
351	Roodbergen and Denys	Fracture methodology for assessing girth weld defects	Application of various methodologies (i.e. codes) to a variety of girth weld defects for different pipe diameter/wall thickness combinations and line pipe grades.
286	Coote et al.	Avoidance of brittle failure	Full scale tests on girth welds and pipes containing failure circumferential defects compared with Canadian code and PD 6493.
298, 299	Glover et al.	Fracture methodology	Extension of work undertaken by Coote et al.
283	Broekhoven and Rongen	Verification of fracture analysis	Structures of various degree of complexity were tested including forty-three full scale pipeline sections tested with internal pressure and wide plate tests. Failure data compared to various codes.
52	Pistone et al.	Assessment of girth weld defects in ductile/brittle transition zone	Full scale bend and wide plate tension tests on X65 pipe material compared with PD 6493 predictions
82	Balsara	Application of advance fracture mechanics	Results from a series of seven pipe ring tests using sections from 36" diameter, 15.9 mm nominal wall thickness, API 5 LX material with different notches, compared with PD 6493 and R6 procedures.

Table 2.3: Summary of Relevant References for Data on Girth Weld Defects

Ref No.	Author	Main Topic	General Description
46	Buitrago et al.	S-N data on critical girth weld components	Fatigue data on critical welds, development of S-N curves and methodology for assessment.
319	Jutta et al.	Review of S-N curves and data for pipelines	Derivation of S-N design curves from limited data.
326, 328, 329	Vosikovsky	Fatigue crack growth data	Fatigue crack growth data on several API pipeline steels for various environmental test conditions.
327	Vosikovsky et al.	Fatigue crack growth data	Fatigue crack growth data on API 5L X65 pipeline steel in crude oil saturated with H_2S.
319	Jutla et al.	Review of crack growth data	Fatigue crack growth data from various programs with additional data assessed for developing crack growth modes.
297	Ebara et al.	Fatigue crack growth data	Derivation of crack growth rates for HT50 TMCP steel in sour crude oil and comparison with other data.
44	Robinson et al.	Fatigue crack growth data	Derivation of crack growth and thresholds for high strength steel up to 700 MPa in sulphate reducing bacteria environment.

Table 2.4: Summary of Relevant References for S-N (Fatigue) and Crack Growth Data

Ref No.	Author	Main Topic	General Description
208	Willmot M. et al.	Growth of SCC under fluctuating load	Experiments to determine crack growth rates under different corrosion environments for pipe line steels.
212	Zheng W et al.	Growth of SCC under hydro-testing	Experiments on X52 pipeline steel with different coating conditions, crack lengths and depths.
151	Krishnamurthy et al.	Methodology procedure to manage SCC on X52 pipeline	Experiment on in-service X52 pipeline steel and methodology (fracture model) developed.
157	Plumtree	SCC, crack growth monitoring under field conditions	Experiments on API X60 grade pipeline steel placed in service in 1972 and removed in 1988. Measurements of crack growth rates and model to assist inspection monitoring.
150	Zheng	SCC crack growth subject to fluctuating pressure	Experiments on range of pipeline steels (X52, X60, X65 and X70) under different pressure fluctuations with range of different cracks.

Table 2.5: Summary of Relevant References for Stress Corrosion Cracking Data

Ref No.	Author	Main Topic	General Description
53	Irisarri et al.	Fracture behaviour of high strength pipeline steel	CTOD and Charpy impact tests on API 5L grade X70 pipeline steel.
237	Kostic et al.	Material aspects of X-80 pipeline steel	Metallurgical examination, fracture toughness of X-80 steel compared with other grades.
242	Mak and Tyson	Material assessment of pipeline steel	Eight pipes in service over a period of 30 years have been tested to evaluate toughness properties. Range of steel grades X52 – X70.
298, 299	Glover et al.	Pipeline using high strength steels	Toughness data on MMA girth welds for a 914 mm 11.1mm thick grade 50X pipeline steel evaluated.
310	Hopkins et al	Toughness data for different welding processes	Extensive program of CTOD tests from two pipelines.
288	Slater and Davey (OTH 86233)	Statistical assessment of weld fracture toughness data	Comprehensive analysis of pipeline girth weld data based on information gathered from nine offshore operators and other sources.
365	McKeehan et al.	High yield to tensile ratio assessment	Evaluation of higher strength steel pipeline material (ref. yield to tensile ratio)

Table 2.6: Summary of Relevant References for Data on Material CTOD/Fracture Toughness

2.2 Interviews with Operators

A number of interviews were held with major operators having pipelines in UK, Norwegian and US waters. The main objectives of these interviews were to identify their current approach to pipeline inspection, the perceived trends in technology development, and their views on inspection techniques.

Detailed notes of meetings are provided in Appendix A. Here, only a summary of the main points are given. It should be noted that at the time of writing, not all interviews had been undertaken and therefore the following observations should be taken as being tentative.

- European interviewees reported very few problems had been experienced with their pipelines. This was thought to reflect benign sweet gas conditions. In GOM waters, loss of inventory was mainly due to third party interference (eg. anchor drag).

- In-service anomalies found during inspections tend to be related to internal corrosion.

- It would appear to be cost effective to impose high standards of inspection during pipeline manufacture. One operator has gone even further in stipulating stricter (than code) requirements on steel chemistry (to improve weldability) and dimensions (to facilitate fabrication).

- Operators, at least those in Europe, would like to dispense with the need to conduct hydrotesting of new pipelines. This is seen as expensive, time-consuming and of doubtful benefit, particularly when the longitudinal seam welds, which experience most of the stress imposed in such tests, have already been pressure tested at steel mills during pipe manufacture.

- Intelligent pigs are used for inspection, but are regarded as an expensive option and carry attendant risks (ie. stuck pigs). Therefore, they are increasingly tending to be only used when there are other indications of degradation in pipeline integrity.

- The recommendations of ASME B31G are commonly used for defect assessment. These were acknowledged as being conservative.

3. OVERVIEW OF CODES/PRACTICES

3.1 General

The development of pipeline standards started in the US in the 1930's with the issue of the first B31 Code. Pipelines at that time were exclusively onshore pipelines. Later updating has resulted in a separation into a number of codes, in particular B31.4 for transportation of hydrocarbon liquids and B31.8 for transportation of natural gas. Amendments to cover offshore pipelines have been developed and issued. The ASME B31.4 and B31.8 codes, together with API 5L and API 1104 specifications for line pipe and pipeline welding, respectively, have been used and referenced by the petroleum and natural gas industries worldwide.

However, the development of significant hydrocarbon reserves in Europe and other parts of the world since the sixties has lead to diversity of pipeline standards and specifications on a national or company level. Many industrialised countries developed their own pipeline standards including the prevailing requirements of their own experts and approving authorities. Thus significant differences in safety and technical requirements for pipelines developed between the various national codes. On a company level a similar process took place. This resulted in an increasing volume of standards and specifications with differences in their requirements not always relevant for the final product.

In recognition of this, the Technical Committee 67 of ISO (ISO/TC 67) was set up with the objective to develop truly international standards for the petroleum and natural gas industries. In parallel to the ISO work, Norway decided to establish the NORSOK organisation with the objective to establish common industry standards. Similar initiatives have been seen in other countries.

One operator which is strongly supporting the ISO work is STATOIL, because of its position as operator of the largest gas transmission system in the world. Statoil has clearly seen the consequences of different pipeline standards between neighbouring countries (ie. Gas transport pipelines like Zeepipe 1, Europipe I and NorFRa cross different national sectors along their routes from the North Sea to continental Europe). National pipeline regulations and industry standards apply within the sectors resulting in, for example, varying wall thickness for the same pipeline from one sector to the next.

Pipeline technology has improved over the years resulting in improved fabrication tolerances, and better welding and NDT techniques. Furthermore, improved knowledge of pressure behaviour, external loads, corrosion protection and operational aspects have also taken place. These improvements have contributed to a need to update existing codes and standards.

Offshore pipeline system can be grouped into two categories based upon their usage, oil industry pipeline systems and gas industry pipeline systems. The design, installation, inspection, repair and maintenance of offshore pipelines are covered by a number of national codes and standards, which include the following:

- Pipeline Transportation System for Liquid Hydrocarbons and other Liquids, ASME B31.4, 1998, US
- Gas Transmission and Distribution Piping Systems, ASME B31.8, 1995, US
- Code of Practice for Pipelines, BSI 8010, Part3, 1993, UK
- Oil and Gas Pipeline systems, CAS-Z662-99, 1999, Canada
- Rules for Submarine Pipeline Systems, DNV 1996, 1996, Norway
- Rules for Subsea Pipelines and Risers, GL 1995, Germany
- Pipeline Transportation System for the Petroleum and Natural Gas Industries, ISO 13623, 1995
- Design of Long Distance Transmission Pipelines, SniP2.05.06-85, 1985, Russian

These codes and standards specify minimum requirements for the design, fabrication, installation, operation, re-qualification and abandonment of offshore pipeline systems. They serve, as guidelines for designers, clients, contractors and others not directly involved in the certification process. These codes and standards are not design handbooks, and the exercise of competent engineering judgement is a necessary requirement to be employed concurrently with their use.

To design an offshore pipeline system, hydraulic, mechanical and structural design manuals, even textbooks, are required besides the above mentioned codes and standards. The design process of offshore pipeline system is typified in Figure 3.1. The required design checks are typically as shown in Figure 3.2.

3.2 Probabilistic Design Methods

A pipeline shall fulfill two basic functional requirements: the individual probabilities of excessive deformations, resulting in an unserviceable line, and burst, resulting in loss of contents, must be sufficiently low. The probabilities of excessive deformations and burst can be assessed using reliability analysis. There are generally three levels of such analysis at which structural safety may be treated.

Level 1. A semi-probabilistic design process in which the probabilistic aspects are treated specifically in defining partial safety factors to be applied to characteristic values of loads and structural resistances. A level 1 structural design is what is now commonly called a limit state design. It is used as a practical method of incorporating reliability methods in the normal design process.

Level 2. A probabilistic design process with some approximation. In this process, the loads and the strengths of materials and section are represented by their known or postulated distributions (defined in terms of relative parameters such as type, mean, and standard deviation) and some reliability level is accepted. Level 2 methods are not necessary for component designs (handled by level 1 limit state design) but are valuable for economic planning, monitoring, and maintenance decision-making and structural integrity evaluations.

Level 3. A design process based upon full probabilistic analysis for the entire structural system. Level 3 methods, which take into account joint probabilistic distributions of load and strength parameters and uncertainties in the analysis, are extremely complex and limited in practicality. They are used in special circumstances where the environment is particularly sensitive or where cost savings justify the additional expense of complex analysis.

Situations where probabilistic methods might be used include the determination of the factored resistance of new systems and materials and the levels of safety to control new hazards.

3.3 Reliability-Based Calibration

Any design code provides a certain safety margin against failure in design. This inherent safety margin is mainly related to the choice of safety factors sometimes selected on a more or less arbitrary basis. This has caused different safety levels for different design checks.

Limit state design implies that the performance of the pipelines is described in terms of a set of limit states for which adequate safety margins are quantified. For the entire limit states, a set of safety factors are calibrated for each safety class using a structural reliability approach. It introduces flexibility in specific conditions and provides design with a consistent safety level without compromising the safety objective. However, in a sound calibration process a varying degree of conservatism needs to be introduced for individual design scenarios depending on the knowledge of the prevailing loads, pipe capacities, etc. Thus, the calibrated design criteria being generally applicable may be expected to be conservative on average.

3.4 Design Criteria and Methods in Codes

3.4.1 ASME B31.4 1998 and B31.8 1995

ASME B31.4 and ASME B31.8, together with the API 5L and API 1104 specifications for line pipe and pipeline welding, respectively, are the most widely applied pipeline codes for the Petroleum and Natural Gas Industries.

The Codes are based on traditional allowable stress design methods. The design factor for general route pipelines is 0.72 for liquid pipelines based on nominal wall thickness. In setting the design factor, due consideration has been given to and allowance has been made for the under-thickness tolerance and maximum allowable depth of imperfections provided for in the specification approved by the code.

For the gas transmission and distribution piping systems, the code specifies a Location Class as follows:

- Location Class 1 is any l mile section that has 10 or fewer buildings intended for human occupancy. Location Class 1 is intended to reflect areas such as wasteland, desert, mountains, grazing land, farmland, and sparsely populated areas.

- Location Class 2 is any 1-mile section that has more than 10 but fewer than 46 buildings intended for human occupancy. Location Class 2 is intended to reflect areas where the degree of population is intermediate between location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates.

- Location Class 3 is any 1 mile section that has 46 or more buildings intended for human occupancy except when a location Class 4 prevails. Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas.

- Location Class 4 includes areas where multi-story buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multi-storey means 4 or more floors above ground, including the first or ground floors.

Allowable tensile and compressive stress values for materials used in structural supports and restraints shall not exceed 66% of the specified minimum yield strength. Allowable stress values in shear and bearing shall not exceed 45% and 90% of the specified minimum yield strength, respectively.

3.4.2 BS 8010

The code takes the allowable stress design method as the basic design method as in other codes. The design factors, appropriate to the assessment of allowable stress, are given below in Table 3.1.

Hoop stress		**Equivalent stress resulting from functional and environmental or accidental loads**		**Equivalent stresses arising from construction or hydrotest loads**	
Riser	**Seabed**	**Riser**	**Seabed**	**Riser**	**Seabed**
0.6	0.72	0.72	0.96	1.0	1.0

Table 3.1: Design factors f_d

Alternatively, the code allows that the acceptability of construction loads may be assessed on an allowable strain basis. The limit on equivalent stress may be replaced by a limit on allowable strain, provided that all the following conditions are met:

- Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.001. The reference state for zero strain is the as-built state.
- Any plastic deformation occurs only when the pipeline is first raised to its maximum operating pressure and temperature, but not during subsequent cycles of depressurisation, or reduction in temperature to the minimum operating temperature.
- The D/t ratio does not exceed 60.
- Welds have adequate ductility to accept plastic deformation.
- Plastic deformation reduces pipeline flexural rigidity; this effect may reduce resistance to upheaval buckling and should be checked if upheaval buckling might occur.

This approach is only permissible where geometric considerations limit the maximum strain to which the pipeline can be subjected and where the controlled strain is not of a cyclic or repeated nature.

3.4.3 DNV 1996

The DNV Rules for Submarine Pipeline Systems were first issued in 1976 and have since been updated in 1981 and most recently in 1996. It has as one of the basic objectives to "Provide an internationally acceptable standard of safety with respect to strength and performance by defining minimum requirements for the design, material selection, fabrication, installation, commissioning, operation, maintenance, re-qualification and abandonment of submarine pipeline systems".

In DNV '96 limit state design principles are adopted but it allows, as an alternative, probabilistic design provided an acceptable reliability method is applied by competent personnel. The design format of the DNV '96 Rules is called a Load and Resistance Factor Design (LRFD) except for the requirement for pressure containment which is given in the traditional Allowable Stress Design (ASD) format.

The principle of the LRFD design format is to ensure that the level of structural safety is such that the design load on the pipeline does not exceed the design resistance of the pipeline except for a stated level of failure probability.

The acceptable target failure probabilities should be in compliance with the implied safety in the rules. By performing a reliability analysis for a specific design case or for a more restrictive scope of scenarios the inherent conservatism may be reduced.

In DNV '96, a novel safety class concept is introduced. Based on the fluid category, location class and phase, the pipeline is classified into a safety class. See Tables 3.2 to 3.4.

Category	Description
A.	Typical non-flammable water-based fluids.
B.	Flammable and/or toxic substances which are liquids at ambient temperature and atmospheric pressure conditions. Typical examples would be oil, petroleum products, toxic liquids and other liquids which could have an adverse effect on the environment if released.
C.	Non-flammable substances which are gases at ambient temperature and atmospheric pressure conditions. Typical examples would be nitrogen, carbon dioxide, argon and air.
D.	Non-toxic, single-phase gas which is mainly methane.
E.	Flammable and toxic substances which are gases at ambient temperature and atmospheric pressure conditions and which are conveyed as gases or liquids. Typical examples would be hydrogen, methane (not otherwise covered under category D), ethane, ethylene, propane, butane, liquefied petroleum gas, natural gas liquids, ammonia, and chlorine.

Table 3.2: Categorisation of Fluids

Location Class	Description
1	The zone where no frequent human activity is anticipated along the Pipeline route
2	The part of the Pipeline/Riser in the near platform (manned) zone or in areas with frequent human activity. The extent of zone 2 should be based on appropriate risk analyses. If no such analyses are performed a minimum distance of 500 m could be adopted.

Table 3.3: Definitions of Location Classes

Phase	Fluid Category A and C		Fluid Category B, D and E	
	Location Class		Location Class	
	1	2	1	2
Temporary	Low	Low	Low	Low
Operational	Low	Low	Normal	High

Table 3.4: Normal Classification of Safety Classes

Determination of appropriate target safety levels is fundamental to the process of developing new design criteria through the application of reliability methods. A target safety level is defined as the maximum acceptable failure probability level for a particular limit state design to be accepted, see Table 3.5 below:

Limit State Category	Probability Bases	Safety Classes		
		Low	Normal	High
Serviceability	Annual per Pipeline[1)]	10^{-2}	10^{-3}	10^{-3}
Ultimate	Annual per Pipeline[1)]	10^{-3}	10^{-4}	10^{-5}
Fatigue	Lifetime probability per Pipeline[2)]	10^{-3}	10^{-4}	10^{-5}
Accidental	Annual per km[3)]	10^{-4}	10^{-5}	10^{-6}

1 Or the length of the period in the temporary phase

2 No inspection and repair is assumed, temporary and in-service conditions considered together

3 Refers to the overall allowable probability of severe consequences.

Table 3.5: Recommended Target Safety Levels

The evaluation of the target safety level for pipelines should primarily be based on the implied safety in currently accepted design practice, using uncertainty measures representative at the time when the code was made. Further, the nature of failure and the actual consequence potential in terms of hazard to human health and safety, damage to the environment, economic losses, and the amount of expense and effort required to reduce such hazard potential should be take into account.

With no implicit safety level available, the rules provide recommendations on target failure probabilities versus safety class and limit state category. The base for the values of safety factor rely on a conservative assessment of implied safety in current accepted design practice guided by accident statistics and engineering judgement.

Limit State Categories:

Typical Limit States and corresponding limit state categories for a pipeline may be:

Serviceability/Limit State (SLS) Category

- Ovality / ratcheting Limit State
- Accumulated plastic strain Limit State

- Damage due to or loss of weight coating
- Yielding

Ultimate Limit Sate (ULS) Category

- Bursting Limit State
- Local buckling Limit State (pipe wall Limit State)
- Global buckling Limit State (normally for load-controlled condition)
- Unstable fracture and plastic collapse Limit State

Fatigue Limit State (FLS)

- Fatigue due to cyclic loading

Accidental Limit State (ALS) Category

- Dropped objects
- Trawl gear hooking
- Earthquake.

The hoop stress formula in the DNV rules is the same as in the ISO standard. The design factor requirements for pressure containment is, however, formulated as a dual requirement, namely as a check against yielding and a check against bursting as shown in Table 3.6

Safety Class	**Low**	**Normal**	**High**
Yielding	0.83	0.77	0.77
Bursting	0.72	0.67	0.64

Table 3.6: DNV '96 Hoop Stress Design Factors

A further possibility to benefit the designer is in the application of high quality material. The design factors given in Table 3.7 below apply when specified material quality requirements are satisfied.

Safety Class	**Low**	**Normal**	**High**
Yielding	0.85	0.80	0.80
Bursting	0.74	0.70	0.67

Table 3.7: DNV '96 Hoop Stress Design Factors, best material

Differences can be noted when comparing DNV with ISO as follows:

- The design requirements of ISO are based on yielding exclusively, whilst DNV '96 applies both yielding and bursting as actual failure modes and presents a dual requirement for both.
- The design factors specified by DNV '96 for yielding are generally the same as the ones specified by ISO. Whilst the factors in ISO basically rest on ASME B31.4/B31.8 and long term industry practice, the design factors in DNV are supported by extensive research programmes.
- The design factors in ISO are specified depending on fluid category and location, whilst those of DNV '96 are given by safety Class and in spite of the fact that the two standards generally specify the same design factors for the yielding criterion, the two design formats are basically different and may give different results in some cases.

3.4.4 CSA Z662-1999

In the code CSA Z662-99, allowable stress design is still used for the design criteria. The stress design requirements are considered to be adequate under conditions usually encountered and for general stress design of conventional pipeline systems. The design factors are given in Table 3.8

System	Load condition		
	A	B	Pressure Testing
Pipelines	0.72	1.00	1.00
Risers	0.60	0.80	1.00

Table 3.8: Design Factors

As an alternative, it permits oil and gas pipelines to be designed in accordance with the requirement of limit state design methods given in Appendix C of the code as illustrated in Figure 3.3, provided that the designer is satisfied that such designs are suitable for the conditions to which the pipelines are to be subjected.

3.4.5 ISO/DIS 13623-1996

The standard uses maximum permissible stresses as the basic concept for ensuring pipeline integrity and serviceability. Formulas and design factors are given for hoop stress and equivalent stress. Strain based design is allowed in specific cases.

The use of the reliability based limit state design method may be applied with one important exception, namely that of design for pressure containment for the general route part of the pipeline.

The hoop stress formula of the ISO standard is based on the average between the inner and outer diameters of the pipeline and on the minimum wall thickness. This is different from the traditional formulation (i.e. ASME) which is based on nominal outer-diameter and nominal wall thickness. The traditional formulation was established for thin wall pipelines, whilst modern offshore gas trunklines are designed to much higher pressures giving thicker walls.

It may also be noted that European standards vary between the countries. Statoil for example has used a formulation based on inner diameter and minimum wall thickness. The result of the different formulations is that different standards in reality express different levels of steel utilisation for pressure containment in spite of the fact that they all prescribe the same design (ie. utilisation factor of 72% of yield strength).

Another effect inherent in the traditional design formulation for pressure containment is that the real steel strength utilisation expressed by the formulation is different when applied to pipelines with highly different design pressures. Thus the requirement works differently for an onshore gas pipeline with a design pressure typically in the range 60-80 bar and a flowline with a design pressure of say 400 bar both fabricated with the same wall thickness tolerances (eg. API 8%).

The practical consequences are such that the requirement for pressure containment normally determines the wall thickness of the pipeline steel. Therefore for the above example this would mean that the flowline would need relatively more steel than an onshore gas line in order to meet the same requirements when using the traditional formulation.

The hoop stress factors were calibrated to lead to the same wall thickness as required in ASME B31.4 and B31.8 for an average pipeline with a D/T of 60 and a 8% wall thickness tolerance. These factors are given in Table 3.9 below:

Location	Design factor u
General Route*	0.77
Shipping Lanes, designated anchoring areas and harbour entrances	0.77
Landfalls	0.67
Pig traps and multipipe slug catchers	0.67
Risers and station piping	0.67

* The factor may be increased to 0.83 for pipelines conveying category C and D fluids as defined in the code.

Table 3.9: ISO Hoop stress design factors for offshore pipelines

4. PIPELINE INSPECTION TECHNIQUES

4.1 Introduction

As the international pipeline system are growing in age it is of ever increasing importance that operators are supplied with the technology to inspect and assess the state of their pipeline. It is for this reason that inspection tools have been developed and introduced into the market utilising non-destructive testing techniques (NDT) to inspect pipelines without the need of a shut down during the survey. These vehicles are generally known as on-line inspection tools or intelligent pigs. Furthermore with the introduction of large diameter, high pressure offshore lines for oil or gas in the last twenty years and constant addition to this offshore network on a worldwide scale intelligent pigs are increasingly being used in the commissioning stage in order to perform base-line surveys.

Information on inspection techniques and pigging can be found in both codes/standards and in the open literature. These were examined and the findings are reported in this Section 4. Summaries of the content of individual papers on inspection techniques are given in Appendix B.

Basically flaws and defects in pipelines can be distinguished into one of the following categories: Geometric Anomalies; Metal Loss; Cracks or Crack like Defects.

Geometric anomalies related to any change in the geometry of a pipe such as dents, ovalities or wrinkles etc. Two reasons why these may be important are a critical reduction in free internal diameter and the formation of locally acting stress concentrations. Regular or intelligent pigs are used.

Metal Loss features usually relate to internal or external corrosion although sometimes mechanical damage is involved. Intelligent corrosion detection pigs must therefore be able to reliably detect and measure corrosion flaws and to accurately locate them.

The following types of cracks can be found in pipelines: fatigue cracks, stress corrosion cracks (SCC); sulfide stress corrosion cracks. The types of potential defects for onshore and offshore installations are similar, although the frequencies with which they occur are different.

Whilst most failure of onshore pipelines is attributed to third party mechanical interference, most defects in offshore lines are caused by corrosion.

4.2 Conventional Non-destructive Techniques

The following techniques are addressed in various codes as summarised below:

A. **(Manual/mechanised) Liquid Penetrant Testing (PT)**

Environmental Cracking including chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Fatigue cracking; Creep Cracking; Surface imperfection detection for ferromagnetic materials; Crater cracks or star crack.

Codes:

API 570: Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Fatigue cracking; Creep Cracking.

DNV 96: Surface imperfection detection for ferromagnetic materials.

API 1104: Crater cracks or star cracks.

B. **(Manual/Auto) Magnetic Particle Testing (WFMT)**

Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking, Fatigue cracking; Creep Cracking; Surface imperfection detection for ferromagnetic materials; Discontinuity (crack).

Codes:

API 570: Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking, Fatigue cracking; Creep Cracking.

DNV 96: Surface imperfection detection for ferromagnetic materials.

API 1104: discontinuity (crack).

C. **(Auto/Manual)Ultrasonics (UT)**

Environmental Cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydro blistering and hydro induced cracking; Creep Cracking; Weld corrosion; Internal imperfection detection; Preferred for planar imperfections; Weld imperfections including partial penetration butt welds, weld crown, elongated surface imperfections, elongated internal imperfections, isolated surface imperfections, isolated internal imperfections, crack burns, unequal leg length-fillet welds, accumulation of imperfections.

CSA Z662: Weld imperfections including partial penetration butt welds, weld crown, elongated surface imperfections, elongated internal imperfections, isolated surface imperfections, isolated internal imperfections, crack burns, unequal leg length-fillet welds, accumulation of imperfections.

G. **Eddy Current**

Erosion and corrosion, Surface imperfection detection for ferromagnetic materials.

Codes:

API 570: Erosion and corrosion.

DNV 96: Surface imperfection detection for ferromagnetic materials.

H. **Acoustic Emission**

Fatigue cracking; Creep Cracking; Remote leak detection.

Codes:

API 570: Fatigue cracking; Creep Cracking. Remote leak detection.

I. **In-situ Metallography**

Creep Cracking.

Codes:

API 570: Creep Cracking.

J. **Thermography**

Leak detection; Hot spots.

Codes:

API 570: Leak detection; Hot spots.

In addition to the above, further information on selected techniques can be found in the following standards and codes:

Radiography: ISO 1106-1, ISO 1106-2, ISO 1106-3, ISO 5579.

Ultrasonic: ASME boiler and Pressure Vessel Code.

Magnetic Particle: ASTM E709, ASTM E1444.

Dye Penetrant: ASTM E1417.

4.3 In-Service Internal Inspection

The use of in-line inspection techniques (Smart pigs) to detect and quantify the pipeline defect has gained wide acceptance in recent years.

Basically flaws and defects in pipelines can be distinguished into one of the following categories: Geometric Anomalies; Metal Loss; Cracks or Crack like Defects. While there are several different technologies available for each of the first categories, cracks have proven to be the most difficult type of defect to detect, and there is currently no commercially available in-line inspection system with proven crack detection capability.

A. Geometry Pigs:

Geometry pigs are used to measure pipe internal geometry in order to detect imperfections such as ovality or dents and to ensure that a pipeline has a full round opening for its entire length. The inspection needs to determine the exact location of any point where the diameter of the pipeline is less than a predetermined dimension, and the magnitude of the reduction.

1. **Mechanical geometry Pigs**: the most widely used mechanical tool is the Kaliper Pig. As the pig travels through the pipeline, the deflection of the levers is recorded. The results can show up details such as girth weld penetration, pipe ovality, and dents.

2. **Electric Geometry Pigs**: they record, analyse and display the data from an inspection run using electronic instrumentation. As a result, the data can be manipulated and massaged to greatly expand the information from a single pipeline run.

B. Corrosion Defect Detection Pig:

1. **Laser-Based Pipeline Corrosion Assessment System**

   The system consists of a laser-based range sensor, signal processing computer, and a frame. It is designed to improve the assessment of the extent of external corrosion on exposed natural gas and oil pipelines (pit gauge, depth micrometers). The data gathered by laser can be readily digitised to provide a permanent record and colour map of corrosion defects.

2. **Semi Automatic Ultrasonic System – Mapscaner**

   To obtain quantitative results to establish the severity of metal loss or to determine the suitability of a pipe segment for continued use, RTD Mapscan, a tool which uses a small ultrasonic probe.

3. Magnetic Flux Leakage Scanner – Pipescaner

The MFL technique provides qualitative results and can give a good indication of general condition of a pipeline section. MFL is a well known mature technique, extensively used in self-contained intelligent pigs. A permanent magnet generates a magnetic field in the pipe wall. Internal and external volumetric defects, general corrosion or pitting, cause disturbance in the magnetic field flow, which can be detected by a Hall effect sensor.

C. Crack Detection:

Cracks in pipelines are among the most severe and potentially dangerous defects in pipelines. The mechanisms of initiation and growth in particular of the so called near neutral SCC are still not fully understood and are the subject of ongoing research. SCC can occur in various forms from small isolated cracks to large crack fields containing hundreds of cracks. Since the hoop stress is usually the driving force, SCC is normally axially orientated. SCC is generally found on the external pipe surface with some preference in the longitudinal weld area but also in the base material. Its occurrence is observed to be largely associated with coating failure.

For a long time, the use of hydrostatic testing was considered the only reliable way to prove the integrity of a pipeline that was a candidate for SCC attack. This type of test is expected to show all critical cracks, i.e. cracks that could cause failure under normal operating conditions. However, since no information on sub-critical cracks is obtained the estimation of the safe future service life becomes rather uncertain. Moreover, hydrostatic testing can cause crack growth of near critical cracks thus reducing the expected safety margin. Additionally, hydrostatic tests are expensive and time consuming, as the line has to be taken out of service.

Cracks have proved to be the most difficult to detect. There currently is no commercially available in-line inspection system with proved crack detection capacity. However, BG (formerly British Gas) has developed a pig-based system to detect and size longitudinal cracks and has reported some success.

MFL Pigs: Longitudinal flaws are difficult to detect by MFL due to the physical principle used.

UT Pigs: Ultrasonic tools cannot recognise cracks oriented in a radial direction and can only detect cracks in a circumferential and longitudinal direction if the defect size is larger than about 5 mm long and wide.

A method, which utilises elastic waves at ultrasonic frequency, was selected as the basis for development. Ultrasonic waves are injected into the pipe wall so that they travel circumferentially around the pipe and are detected when they are reflected from axial cracks. Elastic waves are transmitted in both directions to allow a comparison of echoes from both sides of the reflector.

D. **Smart Pig Evaluation:**

1. **Low Resolution Magnetic Leakage Tools:**

These smart pigs have been around for some time, and have produced satisfactory results for many pipeline operator. While unable to differentiate between internal and external defects, they can detect the majority of defects in pipelines. Costs for this tool typically run between $600 and $1200 per mile.

2. **High Resolution Magnetic Leakage Tools:**

A more costly new alternative for pipeline operators, "high-resolution" MFL tools come in limited sizes. Cost for this tool typically will cost $1500 to $4000 per mile.

3. **Ultrasonic Tools:**

These smart pigs use ultrasonic technology to measure remaining pipe wall thickness. Until very recently these smart pigs have not been able to inspect thin-wall pipe (≤0.25 inches). Even now, the technology for inspecting thin walls is somewhat difficult. There are other limitations with this type of tool, such as requiring a couplant, being unable to detect small pits with sharp wall shapes, etc., which may be a factor for operators.

E. **Research:**

An Ultrasonic guided wave inspection technique to detect and locate defects in pipes using SH (Horizontally Polarised Shear) plane Waves.

Standard ultrasonic techniques applied for the non-destructive testing (NDT) of pipes include the straight beam method using longitudinal waves and the angle beam method using vertical shear (SV) waves.

SH plate waves are a family of Lamb waves. These waves can propagate in plate-like structures of a few wavelengths thick or even of the order of one wavelength. They are two dimensional stress waves in infinite plate structures whose surfaces are free of stresses. Their propagation characteristics are tailored to the geometry of the structure inspected. Their elastic motion covers the whole thickness of the structures (wave-guided) due to the guiding effect of the inner and outer surfaces of the pipe. SH-plate waves have small divergence losses and are attenuated less rapidly than bulk waves, resulting in longer propagation ranges than those for bulk wave with the same frequency and higher sensitivity for defect detection. Furthermore, SH-plate waves can follow curvature thus enabling inspection along bends and other irregular geometry.

The Alternating Current Field Measurement (ACFM) crack detection and sizing technique has demonstrated its potential as a stress corrosion cracking (SCC) characterisation tool.

The techniques currently under development are ultrasonic and electromagnetic, specially the Remote Field Eddy Current (RFEC) method. In gas lines it is difficult to couple ultrasonic energy efficiently into and from the pipe wall; signal processing, or rather discrimination, is also proving to be a serious problem, partly because of the relatively small number of sensors which can be used. Whilst results from high resolution ultrasonic detection tools in liquid lines are encouraging, there is resistance to the use of liquid slugs in gas lines, although more valuable data is obtained than from a simple hydrostatic test.

The SwRI techniques are termed SLIC, which refers to the simultaneous use of shear and longitudinal waves to inspect and characterised flaws. The techniques were developed in the 1980s and early 1990s.

Four techniques using the SLIC systems were evaluated for sizing cracks: amplitude-drop, phase-comparison, peak-echo, and satellite-pulse. Each technique was calibrated against four electro-discharge machined (EDM) axial notches placed in one of the test specimens. The amplitude drop technique was used for estimating the crack lengths. The phase-comparison technique in conjunction with the peak-echo and satellite-pulse techniques were used for depth.

MFL has been shown to be capable of detecting some mechanical damage. Part of the signal generated at mechanical damage is due to geometric change – for example, a reduction in wall thickness due to metal loss causes an increase in measured flux and sensor/pipe separation. Other parts of the signal are due to change in magnetic properties that result from stresses, strains, or damage to the microstructure of the steel.

4.4 In-Service External Inspection

External surveillance of pipelines can provide a wide range of data on various parameters that may affect pipeline integrity. A surveillance operation may involve the inspection of an entire pipeline using side scan sonar for example, or it may be restricted to monitoring a known critical area by a diver or a ROV.

From the external surveillance the following parameters can be inspected:

Location of pipelines
Sea bed movement
Concrete weight coating condition
Corrosion protection system, and
Detection and location of leaks.

Visual observation is the most obvious form of external surveillance. The common equipment and techniques of external surveillance are as follows:

A. **Magnetometer and gradiometers**: they are mainly used for locating and tracking pipelines.

B. **Acoustics**: Typical applications include side scan sonar and sub-bottom profilers which are primarily used for the location and tracking of pipeline.

C. **Conventional Optics**: These include direct visual contact through the eyes of a diver and indirect contact through still photography and/or video cameras. Both direct and indirect visual contacts can be significantly affected by the underwater environmental, such as lighting and turbidity conditions.

D. **Unconventional Optics**: It uses a scanning laser light beam and is characterised by greater independence from underwater visibility conditions than conventional optic system.

E. **Cathodic Protection Survey Methods**: They include fish/trailing wire, ROV assisted remote electrode; ROV assisted trailing wire and electric field gradient.

In addition, a pig-based system using neutron absorption is being developed to find free spans and loss of concrete coating (see Reference 259, summarised in Appendix B).

4.5 Codes and Standards

4.5.1 API 570

API 570 covers inspection, repair, alteration, and rerating procedures for metallic piping system that have been in-service. API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. It is intended for use by organisations that maintain or have access to an authorised inspection agency, a repair organisation, and technically qualified piping engineers, inspectors, and examiners.

Risk-Based Inspection:

Identifying and evaluating potential degradation mechanisms are important steps in an assessment of the likelihood of a piping failure. However, adjustments to inspection strategy and tactics to account for consequences of a failure should also be considered. Combining the assessment of likelihood of failure and the consequence of failure are essential elements of risk-based inspection (RBI). The likelihood assessment must be based on all forms of degradation that could be expected to affect piping circuits in any particular service. The effectiveness of the inspection practices, tools and techniques utilised for finding the expected and potential degradation mechanism must be evaluated.

Specific attention is needed for inspection of piping systems that are susceptible to the following types and areas of deterioration:

A. Injection point

Injection points are sometimes subjected to accelerated or localised corrosion from normal or abnormal operating conditions. The preferred methods of inspecting injection point are radiography and/or ultrasonics, as appropriate, to establish the minimum thickness at each thickness measurement location (TML). Close grid ultrasonic measurement or scanning may be used, as long as temperatures are appropriate.

B. Deadlegs

The corrosion rate in deadlegs can vary significantly from adjacent active piping. The wall thickness on selected deadlegs should be monitored.

C. Corrosion Under Insulation

The most common forms of CUI are localised corrosion of carbon steel and chloride stress corrosion cracking of austenitic stainless steels. Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed.

D. Soil-to-air interfaces

Soil-to-air interfaces for buried piping without adequate cathodic protection shall be included in scheduled external piping inspections. Inspection at grade should check for coating damage, bare pipe, and pit depth measurement.

E. Service-Specific and Localised Corrosion

An effective inspection program help to identify the potential for service-specific and localised corrosion and select appropriate TML's.

F. Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles. It can be characterised by grooves, round holes, waves, and valleys in a directional pattern. A combination of erosion and corrosion results in significantly greater metal loss than can be expected from corrosion or erosion alone. Area suspected of having localised corrosion/ erosion should be inspected, using appropriate NDE methods that will yield thickness data over the wide area, such as ultrasonic scanning, radiographic profile, or eddy current.

G. Environmental Cracking

Environmental cracking includes chloride SCC, polythionic acid SCC, caustic SCC, amine SCC, hydrogen blistering and hydrogen induced cracking (HIC). The inspection can take the form of surface NDE [liquid penetrant testing (PT), wet fluorescent magnetic-particle testing (WFMT) or ultrasonics (UT).

H. Corrosion Beneath Linings and Deposits

The effectiveness of corrosion-resistant lining is greatly reduced if there are breaks or holes in the lining. The linings should be inspected for separation, breaks, holes, and blisters. Large lines should have the deposits removed in selected critical areas for spot examination. Smaller lines may require that selected spools be removed or that NDE methods, such as radiography, be performed in selected areas.

I. Fatigue Cracking

Fatigue cracking of a piping system may result from excessive cyclic stress that are often well below that static yield strength of the material. Preferred NDE methods of detecting fatigue cracking include liquid-penetrant testing, or magnetic-particle testing. Acoustic emission also may be used to detect the presence of cracks that are activated by test pressure or stresses generated during the test.

J. Creep Cracking

Creep is dependent on time, temperature, and stress. Creep cracking may eventually occur at design conditions, since some piping codes allowable stresses are in the creep range. NDE methods of detecting creep cracking include liquid-penetrant testing, magnetic-particle testing, ultrasonic testing, radiographic testing and in-situ metallography. Acoustic emission testing also may be used to detect the presence of cracks that are activated by test pressures or stresses generated during the test.

Types of Inspection and Surveillance

a. Internal visual Inspection
b. Thickness measurement Inspection
c. External visual Inspection
d. Vibrating piping Inspection
e. Supplemental Inspection

Internal Visual Inspection

Internal visual inspections are not normally performed on piping. When possible and practical, internal visual inspection may be schedule for systems such as large-diameter transfer lines, ducts, catalyst lines, or other large-diameter piping lines.

Thickness Measurement Inspection

A thickness measurement inspection is performed to determine the internal condition and remaining thickness of the piping components. Ultrasonic thickness measuring instruments usually are the most accurate means for obtaining thickness measurements on installed pipe larger than NPS 1. Radiographic profile techniques are preferred for pipe diameter of NPS 1 and smaller. Radiographic profile techniques may be used for locating areas to be measured, particularly in insulated systems or where non-uniform or localised corrosion is suspected. Where practical, ultrasonics can then be used to obtain the actual thickness of the area to be recorded.

When corrosion in a piping system is nonuniform or the remaining thickness is approaching the minimum required thickness, additional thickness measuring may be required. Radiography or ultrasonic scanning are the preferred methods in such cases. Eddy current devices also may be used.

External Visual Inspection

An external visual inspection is performed to determine the condition of the outsides of the piping, insulation system, painting and coating systems, and associated hardware; and to check for signs of misalignment, vibration, and leakage.

Vibrating Piping and Line Movement Surveillance

Vibrating or swaying piping, and other significant line movements should be reported that may have resulted from liquid hammer or liquid slugging in vapour lines.

Supplemental Inspection

Other inspection may be schedule as appropriate or necessary. Periodic use of radiography and/or thermography to check for fouling or internal plugging, thermography to check for the hot spots in refractory lined system, or inspection for environmental cracking. Acoustic emission, acoustic leak detection, and thermography can be used for remote leak detection and surveillance. Ultrasonics and/or radiography can be used for detecting localized corrosion.

Inspection of Welds In Service

Inspection for piping weld quality is normally accomplished as a part of the requirements for new construction, repairs, or alterations. However, welds are often inspected for corrosion as part of a radiographic profile inspection or as part of internal inspection. On occasion, radiographic profile examinations may reveal what appear to be imperfections in the weld. If crack-like imperfections are detected while the piping system is in operation, further inspection with weld quality radiography and/or ultrasonics may be used to assess the magnitude of the imperfections.

Inspection of Buried Piping

Inspection of buried process piping is different from other process piping inspection because significant external deterioration can be caused by corrosive soil conditions. Since the inspection is hindered by the inaccessibility of the affected area of the piping, the inspection of buried piping is treated in a separation section.

Intelligent pigging, Video Camera, Excavation are inspection methods.

4.5.2 DNV 1966

The in-service inspections are to be carried out according to accepted procedures. A long term inspection program is to be established for the whole pipeline system. The program is to take into account the following:

- Inspection type
- Design and function of the pipeline system
- Seabed and environmental conditions
- Protection and burial requirements
- Corrosion and erosion condition
- Third party traffic density and extent
- Experience from previous inspections
- Possible consequences of failure.

Both external and internal inspection by intelligent pigging, if selected for metal loss inspection or other reasons, shall be included in the long term inspection program. The inspection program and further updating is to be agreed for each pipeline system.

External Corrosion Inspection

For risers, corrosion damage may occur in the splash zone and atmosphere zone due to damaged and/or disbonded coatings. Risers carrying hot fluids are most exposed to corrosion. In the submerged zone, certain coating malfunctions are not critical unless they are combined with deficiency in the cathodic protection system.

Inspection by special internal tools may be used to detect severe external corrosion of riser in all three zones. To a large extent external corrosion protection of pipeline and risers with sacrificial anodes can be limited to monitoring the condition of anodes. Electric field gradient measurements in the vicinity of anodes may be used for semi-quantitative assessments of anode current outputs.

Internal Corrosion Inspection

Inspection of internal corrosion is carried out in order to confirm the integrity of the pipeline system. Corrosion monitoring does not normally give any quantitative information of critical loss of wall thickness. Internal corrosion inspection of pipeline is typically carried out using an instrumented pipeline Inspection Gauge. Systems for wall thickness measurement based on magnetic flux leakage detection, ultrasonic examination, or eddy current techniques may be considered.

4.5.3 API 1104

The company shall have the right to inspect all welds by nondestructive means or by removing welds and subjecting them to mechanical tests. The inspection may be made during or after the welds has been completed.

Nondestructive testing may consist of radiographic inspection or other methods. The method used shall produce indications of defects that can be accurately interpreted and evaluated.

Nondestructive testing method:

Radiographic, magnetic particle, liquid penetrant, and ultrasonic test. The acceptance standards for the methods are different to different testing methods.

Acceptance standards given in Section 6 of the code are based on empirical criteria for workmanship and place primary importance on flaw length. Such criteria have provided an excellent record of reliability in pipeline service for many years. The use of fracture mechanics analysis and fitness-for-purpose criteria is an alternative method of determining acceptance standards and incorporates evaluation of the significance of both flaw depth and flaw lengths. The fitness-for-purpose criteria provide more generous allowable flaw sizes, but only when additional procedure qualification tests, stress analysis, and inspections are performed.

4.5.4 ASME B31.8

Welding and Inspection Tests

100% of the total number of circumferential field butt welds on offshore pipelines shall be non-destructively inspected, if practical, but in no case shall less than 90% of such welds be inspected.

All welds which are inspected must meet the standards of acceptability of API Standard 1104. For girth welds on a pipeline, alternative flaw acceptance limits may be established based upon fracture mechanics analysis and fitness-for-purpose criteria as describe in API Standard 1104. Such alternative acceptance limits shall be supported by appropriate stress analysis, supplementary welding procedure test requirements, and non-destructive examination beyond the minimum requirements specified in API 1104.

4.5.5 BS 8010

Weld Inspection

Selection of the appropriate weld inspection technique, acceptance criteria and the frequency of inspection should conform to the relevant welding standard. Typical inspection techniques and standards are visual inspection (BS 5289); Magnetic Particle Inspection (BS 6072); Dye Penetrant (BS 6443); Radiographic Inspection (BS 2600); Ultrasonic Inspection (BS 3923).

4.5.6 CSA Z662

Inspection:

Pipe and components shall be inspected for defects. Such inspection shall include, but not necessarily be limited to, inspection for flattening, ovality, straightness, pits, slivers, cracks, gouges, dents, defective weld seams, and defective field welds.

Where the pipe is field-coated, inspection shall be carried out to determine that the cleaning/coating machine is not creating defects in the pipe.

Where necessary and as appropriate, nondestructive inspection of piping shall be performed using one or more of the following:

a. Radiographic inspection of welds
b. Ultrasonic inspection of welds
c. Ultrasonic inspection of pipe
d. Electrical inspection of protective coatings
e. Inspection using internal inspection devices
f. Other methods capable of achieving appropriate results.

Inspection and Testing of Production Welds

All welds within the limits of uncased road and railway crossings, all welds within the limits of water crossings, all pressure-containing welds that will not be pressure tested in place, and a minimum of 15% of all production welds made each day shall be non-destructively inspected: 1) for 100% of their lengths; 2) in accordance with the requirements of Clause 7.2.8.3; and 3) where such welds are butt welds, using radiographic or ultrasonic methods, or a combination of such methods.

Radiography

Source of radiation shall be X-ray machines or radioisotopes. The radiation source shall be located either inside or outside the pipe or component. Where radiation sources are located on the outside, the image of one or both walls shall be acceptable for interpretation.

Ultrasonic Inspection of Pipeline Girth Welds

Imperfections recorded by ultrasonic inspection (ie. weld conditions giving indications that exceed the recording level) shall be as follows:

1. Imperfections characterised as cracks shall be unacceptable regardless of length or location.

2. Individual imperfections that are determined not to extend into the weld beads closest to the surfaces of the pipe shall not exceed 50 mm in length, the cumulative length of such imperfection in any 300 mm length of welds shall not exceed 50 mm, except that for welds less than 300mm long, the cumulative length of such imperfection shall not exceed 16% of the weld length.

3. Individual imperfections other than those covered by Items 1,2 shall not exceed 12 mm in length, and the cumulative length of such imperfections in any 300 mm length of weld shall not exceed 25 mm, except that welds less than 300 mm long, the cumulative length of such imperfections shall not exceed 8% of the weld length.

Guidelines for In-Line Inspection of Piping for Corrosion Imperfections

The factors to be reviewed when considering such inspection techniques should include, but not necessarily be limited to, the following:

a. the availability and capability of the equipment
b. the age, condition, and configuration of the piping
c. the service, leak, and corrosion mitigation history of the piping
d. population density and environmental concerns.

5. DEFECT ASSESSMENT METHODS IN CODES

5.1 Assessment of Weld Defects

5.1.1 API 1104

This standard covers the gas and arc welding of butt, fillet, and socket welds in carbon and low alloy steel piping used in the compression, pumping, and transmission of crude petroleum products and fuel gases and, where applicable, covers welding on distribution systems. This standard also covers the acceptance standards to be applied to production welds tested to destruction or inspected by radiography. It includes the procedure for radiographic inspection.

The standard presents the acceptance standards for non-destructive testing, which apply to discontinuities located by radiographic, magnetic particle, liquid penetrant, and ultrasonic test methods. These acceptance standards are based on empirical criteria for workmanship and place primary importance on flaw length. Such criteria have provided an excellent record of reliability in pipeline service for many years.

In addition, API 1104 allows the use of alternative fitness-for-purpose criteria based on fracture mechanics analysis, which incorporates evaluation of the significance of both flaw depth and flaw length. The fit-for-purpose criteria provide more generous allowable flaw sizes, but only when additional procedure qualification tests, stress analysis, and inspections are performed.

The method requires that the welding procedures are qualified for either of two minimum CTOD toughness levels: 0.005 inch or 0.010 inch. Then, for a given maximum applied strain, the allowable defect depth is inferred. Limits on defect length are dependent on defect depth.

A residual strain of 0.2% has been included in developing the acceptance criteria in order to account for postulated residual stresses of yield magnitude. Defect depth may be determined by NDT techniques or by consideration of inherent size limitations due to weld pass geometry.

5.1.2 BS 7910

As the replacement of PD 6493 and PD 6539, this code outlines methods for assessing the acceptability of flaws in all types of structures and components. Although emphasis is placed on welded fabrications in ferritic and austenitic steels and aluminium alloys, the procedures developed can be used for analysing flaws in other materials and in non welded applications.

The fracture assessment procedures described in this guide are a development of the 1991 edition of PD 6493. Although there are continuing advances and improvements in fracture assessment methods, the procedures presented are felt to represent approaches which have been validated extensively and are intended to provide consistently accurate and safe predictions. They combine the Crack Tip Opening

Displacement Methods introduced by the Welding Institute via the 1980 edition of PD6493 with approaches based on the R6 procedures published by Nuclear Electric/Magnox Electric (formerly Central Electricity Generating Board) in the UK.

The code contains improvements to the approaches in PD6493:1991 based on user experience, additional solutions and improved guidance from various literature sources, and a fuller integration of R6 Rev 3 procedures.

As in the 1991 edition of PD 6493, three levels of fracture assessment are available to the user. All levels refer to tensile Mode I failure only. Shear failure is dealt with the method in Annex B. All three levels of assessment use a Failure Assessment Diagram (FAD) which combines consideration of fracture and local plastic collapse. The choice of level depends on the input data available, the level of conservatism and the degree of complexity required.

Level I: this is the screening level introduced into the 1991 version of PD6493 and broadly compatible with the 1980 edition of the document. This level provides a conservative estimate from its use of the simplified FAD with in built safety factors and required conservative estimates of the applied stress, residual stress and fracture toughness.

Level II: this is considered to be the normal assessment route applicable for general structural steel application and makes use of a more accurate FAD with no inherent safety factors. The procedure permits the prediction of acceptability of the structure when all three input parameters are known and also allow limiting values of any one parameter to be predicted.

Level III: This level employs a full tearing instability approach and therefore provides a more accurate description of the performance of ductile materials.

5.1.3 CSA Z662-99

Work quality standards of acceptability have been based on experience with traditional welding and inspection practices. This experience has indicated the capabilities of welding procedures and personnel in minimising the incidence of welding imperfections during production welding of pipe girth welds.

Appendix J of the code outlines the application of the concept of engineering critical assessment to fusion welds. Standards of acceptability based on Engineering Critical Assessment (ECA) include consideration of the measured weld properties and intended service conditions for a specific application. Alternatives to the work quality standards of acceptability can be derived for sections of a new pipeline.

Appendix K of the code provides the analytical methods that shall be used to derive standards of acceptability for weld imperfections, which may be used as an alternative to the standards. The standards of acceptability that are derived are based on engineering critical assessment and include consideration of the measured weld properties and the intended service conditions.

5.1.4 R/H/R6 Revision 3

R/H/R6 was originally published as a Central Electricity Generating Board (CEGB) Report entitled " Assessment of the Integrity of Structures Containing Defects" in 1976.

The R6 defect assessment procedure uses the concept of a failure assessment diagram (FAD) to define the boundary between the safe and unsafe operating conditions of the flawed structures.

The procedure described in the main document adopts a deterministic approach in which specific combinations of defect size and material property values are chosen to ensure a conservative result in the assessment of defect structures. The elastic-plastic assessment procedure used in the R6 approach can form the basis of a probabilistic assessment procedure where the uncertainties in the main assessment parameters are included. In Appendix 10 of R6, a probabilistic assessment procedure based on the R6 analysis is described which takes account of developments in probabilistic fracture mechanics in recent years. This extends previous applications of probabilistic fracture mechanics, which have been based mainly on linear elastic fracture mechanics, to elastic-plastic fracture analysis more appropriate for the assessment of general engineering structures.

5.2 Corrosion Defect Assessment

5.2.1 ASME B31G

This is a supplement to the ASME B31 code for pressure piping. It provides a semi-empirical procedure for the assessment of corroded pipes. The procedure was developed in the late sixties and early seventies at Battelle Memorial Institute.

Based on an extensive series of full-scale tests on corroded pipe sections, it was concluded that the experiments on corroded pipe indicated that line pipe steels have adequate toughness and that the toughness is not a significant factor. The failure of blunt corrosion flaws is controlled by their size and the flow stresses or yield stresses of the materials.

Limitations on the use of the B31G procedure include:

1. It applies to corrosion defects only in the body of the pipe which have relatively smooth contours and cause low stress concentration

2. It applies to pipes under internal pressure loading only.

The assessment procedure considers the maximum depth and longitudinal extent of the corroded area, but ignores the circumferential extent and the actual profile.

If the corroded region is found to be unacceptable, B31G allows the use of more rigorous analysis or a hydrostatic pressure test in order to determine the pipe remaining strength. Alternatively, a lower maximum allowable operating pressure may be imposed.

6. DATABASE

6.1 Database Requirements

A prime deliverable from this project is a database on the strength of pipelines containing defects. The usefulness of any database is very dependent on the care exercised during its development, particularly with such issues as completeness of captured data, quality assurance and database structure.

MSL's experience in the area of database preparation would indicate that time spent during the initial set-up (i.e. in defining the fields of the database) pays dividends during data entry, data checking and eventual use. As an example, different source documents will use different units (e.g. inches v. millimetres) whereas the data in the database needs presenting in consistent units. However, to facilitate the checking of data entry against the source documents, it is easier to use the original unit systems of those documents. The database therefore contains a degree of duplicated columns; one set based on original units and the other with consistent units. After data entry checking, the columns with original units can then be hidden for presentation purposes.

It is important to capture the data fully. For instance, the pipe thickness will normally be quoted but it may be relevant in subsequent analyses to know whether this value was nominal, measured or inferred (from other variables such as D and D/T). This information has therefore been carefully recorded. In a similar vein, the steel yield stress is preferably a measured value but may have been given in terms of the specified minimum value. Again, such information needs to be recorded, including both measured and specified values if available. The inclusion of a 'comment' field is essential for recording peculiar testing characteristics. In all cases, tabular information in the source documents is to be preferred over graphical information as the latter may introduce scaling errors when extracting data.

Consideration was given to setting up a number of separate databases according to defect type: dent, gouge, cracks, corrosion, etc. However, many of the fields would be common, e.g. fields describing pipe geometry, materials, loading, etc. It was therefore decided to generate a Master Database, subsets of which could be extracted later for subsequent appraisal. A detailed description of all fields is given in the next subsection.

6.2 Description of Fields

The fields defined in the Master Database are reproduced in Table 6.1. In the actual database, the field headings stretch along one horizontal line. The numbers in the first row refer to Notes given in Table 6.2.

See Note:					1	2	3			3			3	3			
SPECIMEN IDENTIFICATION							PIPE GEOMETRY										
Ref No	Author	Spec ID	Sequence No.	Type	Screening Level	Type of Defect	Dia (source)			Thk. (source)			D [mm]	T [mm]	D/T	L [mm]	L/D
								Unit	Type		Unit	Type					

4			3			3			3			3				
PIPE SPECIFICATION			MATERIAL PROPERTIES													
Manufac. Process	Material Grade	SMYS	σ_{yhoop} (source)			σ_{uthoop} (source)			σ_{ylong} (source)			σ_{utlong} (source)			σ_y [N/mm^2]	σ_u [N/mm^2]
				Unit	Type		Unit	Type		Unit	Type		Unit	Type		

LOADING						
Load Type	Loading (source)			Loading Stress Range		No. of Cycles
	Min	Max	Unit	Min	Max	

Table 6.1: Database fields (continued...)

MATERIAL PARAMETERS																		
Fracture Parameters									Residual Stresses			FM Parameters				
Charpy	Unit	Temp	CTOD	Unit	J_{IC}	Unit	K_{IC}	Unit	σ_{rhoop}	σ_{rlong}	Failure Mode	A_a	A_b	m_a	m_b	K_{th}

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MECHANICAL DAMAGE																	
Type	DENT								GOUGE								
	Shape	d_d	Unit	l_d	Unit	d_d [mm]	l_d [mm]	Location	d_g	Unit	l_g	Unit	d_g [mm]	l_g [mm]	Orientation	Finish	SCF

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CORROSION											CRACK							COMMENTS
Corrosion Type	Length	Unit	Width	Unit	Depth	Unit	L_c [mm]	W_c [mm]	d_c [mm]	Surface Finish	Location	depth (a)	Unit	length (2c)	Unit	a [mm]	2c [mm]	

Table 6.1: Database fields (...continued)

Notes:

1 SL1 = Fully acceptable data
SL2 = Acceptable data but some nominal values used
SL3 = Acceptable data but peculiarities
SL4 = Incomplete data, reject

2 M = Mechanical damage (dent and/or gouge)
C = Corrosion
F = Fatigue crack
W = Weld defect
O = Other

3 N = Nominal
M = Measured
C = Calculated
U = Unknown

4 SMLS = Seamless
SAW = Submerged Arc Welding
ERS = Electric Resistance Welding
N/A = Not applicable (for FE data)

5 Sq = Square indentor
Cyl1 = Cylinder transverse to pipe
Cyl2 = Cylinder longitudinal to pipe
Sph + Spherical indentor
O = Other

6 GW = Girth weld
LW = Longitudinal weld
P = Parent material

7 G = General
I = Internal
E = External
P = Pit
L = Localised

Table 6.2: Database notes

Inspection of Table 6.1 shows that the data has been entered under ten main headings, with sub-headings as follows:

i) Specimen Identification

The 'reference number' and 'author' are the same as in the list of References herein. The 'spec ID' is the specimen identification as used in the source document. The author and spec ID fields are useful in weeding out duplicate sets of data. Each specimen is given a unique 'sequence number' to facilitate traceability following screening and the creation of data subsets. Where a specimen requires multi-row entries (e.g. for the recording of crack growth data) then letters a, b, c etc. are used after the sequence number to distinguish the row entries. The 'type' column refers to whether the data are test data or finite element (FE) data. The entries under 'screening level' and 'type of defect' are defined in Notes 1 and 2 in Table 6.2 respectively. The latter will be useful for sorting the database and in preparing data subsets.

ii) Pipe Geometry

The sub-headings under this grouping are self-explanatory especially when read in conjunction with Note 3 in Table 6.2. As explained above, the 'source' columns are used for data entry purposes and are hidden following data checking.

iii) Pipe Specification

The three sub-headings under 'pipe specification' record the pipe manufacturing process and the type of material.

iv) Material Properties

Again, these sub-headings are self-explanatory.

v) Loading

The 'load type' identifies the loading regime as appropriate, e.g. pressure, axial, bending, etc. The loading range (or ranges if multi-row entries are being used for crack growth tests) is entered under the 'source' column in the original units. The 'number of cycles' is only relevant for fatigue or crack growth tests, otherwise N/A is entered.

vi) Material Parameters

Sub-headings are provided for brittle fracture parameters, Fracture Mechanics parameters and residual stresses. These parameters might be given in some source documents and will become relevant during appraisals of the various defect assessment methodologies.

vii) Mechanical Damage

The entries under this heading are to characterise the shape, size and location/orientation of dents and gouges. Once again, duplicate columns allow for data entry using source document units and then transposition to a consistent set. The first column under this heading, 'type', allows for subsequent sorting.

viii) Corrosion

The corrosion section allows data pertaining to the nature and extent of any corrosion to be entered. The 'corrosion type' is a qualitative field and is used to define whether the corrosion is internal or external, localised or general, etc.

ix) Crack

The location, depth and length of a crack are entered here.

x) Comments

This section allows the embellishment of any noteworthy aspects gleaned from the source document. It is particularly useful for recording any peculiar testing procedure or observation that is not addressed in other fields.

REFERENCES

No.	Title	Main Author	Conference	Ref
1	Rules for Submarine Pipeline System	Det Norske Veritas		DNV 96
2	Oil and Gas Pipeline System	Canadian Standard Association		CSA Z662-99
3	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	American Society of Mechanical Engineer		ASME B31.4
4	Manual for Determining the Remaining Strength of Corroded Pipelines	American Society of Mechanical Engineer		ASME B31G
5	Gas Transmission and Distribution Piping Systems	American Society of Mechanical Engineer		ASME B31.8
6	Welding of Pipelines and Related Facilities	American Petroleum Institute		API RP 1104
7	Piping Inspection Code	American Petroleum Institute		API 570
8	Piping Maintenance Welding Practice	American Petroleum Institute		API RP 1107
9	Rules for Submarine Pipeline System	Det Norske Veritas		DNV 81
10	Code of Practice for Pipelines	British Standards Institute		BS 8010
11	Guidance on Methods for Assessing the Acceptability of Flaws in fusion welded structures	British Standards Institute		BS 6493
12	Guidance on Methods for Assessing the Acceptability of Flaws in fusion welded structures	British Standards Institute		BS 7910
13	Petroleum and National Gas Industries - Pipeline Transportation Systems	International Organization for Standardization		ISO/TC67/SC2
14	Code of Federal Regulations, Title 49 Transportation	National Register		CFR 40
15	A Review of Current Practice in Pipeline Defect Assessment	Billington Osborne Moss engineering Ltd		OTO 1999 002
16	A Review of Current Practice in Pipeline Defect Assessment - User Guide	Billington Osborne Moss engineering Ltd		OTO 1999 003
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18	GL Rules for Subsea Pipelines and Risers	Thomas Plonski	Pipeline Technology	OMAE
19	An Introduction to the DNV 1996 Rules for Submarine Pipeline Systems	Leif Collberg	7th International Offshore and Polar Engineering Conference	ISOPE
20	R6 Developments in the Treatment of Secondary Stresses	Dennis G Hooton	Pressure Vessels and Piping	ASME
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24	The Development and Implementation of a Strain Methodology for Installation of Pipelines on Uneven Seabeds	Kyriacou A.	Pipeline Technology	OMAE
25	Reliability Based Calibration of Partial Safety Factors For Design of Free Pipeline Spans	Knut O. Ronold	Pipeline Technology	OMAE
26	Comparison Between Limit State Equations for Deepwater Pipelines Under External Pressure and Longitudinal Bending	Segen F. Estefen	Pipeline Technology	OMAE
27	Compressive Strain Limits for Buried Pipelines	T.J.E. Zimmerman	Pipeline Technology	OMAE
28	Strain Based Design of Pipelines	Alastair C Walker	Pipeline Technology	OMAE
29	New Test Data on Structural Behavior of Gre Pipe and Joint Systems	A Ma	Pipeline Technology	OMAE
30	The Superb Project: A New Safety Philosophy for Submarine Pipeline Design	Torbjorn Sotberg	Pipeline Technology	OMAE
31	Reliability-Based Limit-State Design and Re-Qualification of Pipelines	Yong Bai	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
32	System Reliability of Offshore Structures	Alberto C. Morandi	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
33	Expansion of Pipelines Under Cyclic Operational Conditions: Formulation of Problem and Development of Solution Algorithm	Ibrahim Konuk	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
34	Probabilistic Design of Burial Depth for Offshore Pipelines and Cables in Dynamic Seabed	Zhiwen Chen	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
35	A Limit States Approach to the Design of Pipelines for Mechanical Damage	Robert G. Driver	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
36	Reliability-Based Approach to the Operation of Gas Transmission Pipelines at Design Factors Greater than 0.72	Andrew Francis	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
37	Technical Basis for the Extension of ASME Code Case N-494 for Assessment of Austenitic Piping	Joseph M. Bloom	Pressure Vessels and Piping	ASME
38	The Use of GE-EPRI Handbook Solutions in ETA Factor Methodologies for Determing J Crack Growth Resistance Curves	E. Smith	Pressure Vessels and Piping	ASME
39	Modifications to the GE/EPRI J-Estimation Scheme Using Reference Stress Methods	Robert A Ainsworth	Pressure Vessels and Piping	ASME
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43	Detection of Fatigue Crack Closure Using Thermoelastic Stress	Hannah Batchelor	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
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46	Fatigue Design of Critical Girth Welds for Deepwater Applications	Jaime Buitrago	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
47	A Model for Predicting Vessel Failure Probabilities due to Fatigue Crack Growth	F. A. Simonen	Pressure Vessels and Piping	ASME
48	Fracture Behavior Under Low Cycle Fatigue Loadings in Japanese Carbon Steel Welded Pipe Joints with a Defect	Katsumasa Miyazaki	Pressure Vessels and Piping	ASME
49	Fatigue Risk Assessment Procedures	Achintya Haldar	Pressure Vessels and Piping	ASME
50	Fatigue Life of Pipelines with Dents and Gouges Subjected to Cyclic Internal Pressure	J. R. Fowler	Pipeline Engineering	ASME
51	Some Test Results for Wrinkling of Girth-Welded Line Pipe	Nader Yoosef-Ghodsi	Pipeline Technology	ASME
52	Assessment of Girth Weld Defects in Transmission Pipelines in the Ductile to Brittle Transition Region	Valentino Pistone	Pipeline Technology	ASME
53	Fracture Behavior of Overmatched Girth Welds	Angel M. Irisarri	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
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55	Toward and Acceptance Criterion for Shallow Dents Affecting Girth Welds in Gas Transmission Pipelines	M. J. Rosenfeld	Pressure Vessels and Piping	ASME
56	Fracture Toughness Estimation Methodology in the 'SINTAP' Procedure	Pekka Nevasmaa	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
57	Practical Application of Fracture Mechanics with Consideration of Multiaxiality of Stress State to Degraded Nuclear Piping	K. Kussmaul	Pressure Vessels and Piping	ASME
58	A Fracture Strength Evaluation Method for Carbon Steel Pipes Subjected to Dynamic/Cyclic Loadings - Evaluation of Dynamic/Cyclic Pipe Fracture Tests at Elevated Temperature	Terutaka Fujioka	Pressure Vessels and Piping	ASME
59	The Application of Local Approach To Assess the Influence of In-Plane Constraint on Cleavage Fracture	Andrew H Sherry	Pressure Vessels and Piping	ASME
60	The Effect of Crack Location on the Net Section Stress Criterion for Failure of a Cracked Piping System	E. Smith	Pressure Vessels and Piping	ASME
61	Experience with Corrosion Resistant Pipelines	Liane M. Smith	Pipeline Technology	OMAE
62	Non-Linear Finite Element Prediction of Wrinkling in Corroded Pipe	Daniel P. Nicolella	7th International Offshore and Polar Engineering Conference	ISOPE
63	Corrosion Resistance Evaluation of 22Cr Duplex Stainless Steel Weldments	A. Kopliku	Pipeline Technology	OMAE
64	Reliability Prediction of Corroding Pipelines	John E Strutt	Pipeline Technology	OMAE
65	Corrosion Risk Assessment and Planned Maintenance for Corrosion Control: An Application to an Oil Field in Egypt	Sayed Abdel Hameed	17th International Concerence on Offshore Mechanics and Arctic Engineering	ISOPE
66	Pipeline Buckling, Corrosion and Low Cycle Fatigue	Roland Palmer-Jones	17th International Concerence on Offshore Mechanics and Arctic Engineering	ISOPE
67	Comprehensive Overline Diagnostics to Determine Actual Pipeline and Protective Coating Condition	G. A. Euwe	Pipeline Technology	OMAE
68	Predicting Failure Pressure of Internally Corroded Linepipe using the Finite Element Method	Bin Fu	Pipeline Technology	OMAE
69	New Developments in Burst Strength Predictions for Locally Corroded Pipelines	Frans J. Klever	Pipeline Technology	OMAE
70	Prevention of Hydrate Formation in Pipelines by Electrical Methods	Jens Kristian	7th International Offshore and Polar Engineering Conference	ISOPE
71	Internal Corrosion Monitoring of Subsea Production Flowlines - Probe Design, Testing, and Operational Results	M. W. Joosten	Offshore Technology Conference	OTC
72	Deep Water: Considerations of the Cathodic Protection Design Basis	K. P. Fischer	Offshore Technology Conference	OTC
73	Overview of Britannia Subsea Corrosion-Control Philosophy	J. Kolts	Offshore Technology Conference	OTC
74	A Proposed Corrosion Assessment Method and In-service Safety Factors for Process and Power Piping Facilities	M. J. Rosenfeld	N/A	N/A
75	Pipeline Inspection Using an Autonomous Underwater Vehicle	Per Egeskov	Pipeline Technology	OMAE
76	A New Ultrasonic Long-Range Imaging Scheme for Defect Characterization in Steel Structures	M.C.M. Bakker	17th International Concerence on Offshore Mechanics and Arctic Engineering	ISOPE
77	Probabilistic Tools for Planning of Inspection and Repair of Corroded Pipelines	D. Ritchie	17th International Concerence on Offshore Mechanics and Arctic Engineering	ISOPE
78	Insulated Pipe-In-Pipe Subsea Hydrocarbon Flowlines	Robert H. Nuttall	17th International Concerence on Offshore Mechanics and Arctic Engineering	ISOPE
79	Development and Application of Proposed ASME Section XI Code Changes for Risk-Based Inspection of Piping	Raymond A. West	Pressure Vessels and Piping	ASME

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80	Application of Risk-Based Methods to In-service Inspection of Piping Systems	Nancy B. Closky	Pressure Vessels and Piping	ASME
81	34" Onshore Gasoline: Integrity Assessment and Rehabilitation Costs	A. Amorelli	Pipeline Technology	ASME
82	Application of Advanced Fracture Mechanics to the Assessment of Linepipe Defects**	Mukesh N. Balsara	Pipeline Technology	ASME
83	Advantages of a Rational Assessment of the Offshore Structure Behavior	A. Della Greca	17th International Concerence on Offshore Mechanics and Arctic Engineering	ASME
84	Comparison of Deterministic and Probabilistic CTOD Flaw Assessment Procedures	Henryk G Pisarski	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
85	Incorporation of Residual Stresses into the Sintap Defect Assessment Procedure	A. Stacey	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
86	Driving Force and Failure Assessment Diagram Methods for Defect Assessment	R. A. Ainsworth	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
87	A Review of Current Defect Assessment Procedures	J. Ruiz Ocejo	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
88	Alternative Approaches to Pipeline Rehabilitation	Alan C. Coates	Pipeline Technology	ASME
89	Update on Pipeline Repair Methods	John F. Kiefner	Pipeline Engineering	ASME
90	Development and Implementation of a Pipeline Integrity Management Program in Russia	V.V. Kharionovski	Pipeline Technology	ASME
91	Risk-Based Optimization of Pipeline Integrity Maintenance	Maher A. Nessim	Pipeline Technology	ASME
92	The Evaluation of Advanced Remote Sensing Methods for Ground Movement Monitoring in Pipeline Integrity Management	Moness Rizkalla	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
93	New Technologies in Underwater Pipeline Management	Stefano Dicorrado	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
94	Arctic Pipeline Limit States for Secondary Loadings	I.F. Kharib	2nd International Offshore and Polar Engineering Conference	ISOPE
95	Plastic Buckling of Pipes Under Bending and Internal Pressure	H.O. Kim	2nd International Offshore and Polar Engineering Conference	ISOPE
96	Correlation between Analytical and Experimental Results for Propagation Buckling	S. F. Estefen	Pipeline Technology	ASME
97	Analytical Methods for the Determination of Allowable Free Span Lengths of Subsea Pipelines	H.I. Park	7th International Offshore and Polar Engineering Conference	ISOPE
98	The Behavior of High Pressure, High Temperature Flowlines on Very Uneven Seabed	Knut Tornes	7th International Offshore and Polar Engineering Conference	ISOPE
99	Intrinsic Coordinate Elements for Large Deflection of Offshore Pipelines	Poh C. Andrew Ngiam	7th International Offshore and Polar Engineering Conference	ISOPE
100	3-D Dynamic Buckling and Cyclic Behavior of HP/HT Flowlines	Per R. Nystrom	7th International Offshore and Polar Engineering Conference	ISOPE
101	A Simplified Analysis of Imperfect Thermally Buckled Subsea Pipelines	James G.A. Croll	7th International Offshore and Polar Engineering Conference	ISOPE
102	Reeline of Pipelines with Thick Insulation Coating, Finite-Element Analysis of Local Buckling	Tim Crome	Offshore Technology Conference	OTC
103	Buckle Arrestors for Deepwater Pipelines	Carl G. Langner	Offshore Technology Conference	OTC
104	Seismic Qualification of Existing Pipeline Systems	G. M. Manfredini	Pipeline Technology	ASME
105	Structural Integrity of Offshore Pipelines in Seismic Conditions	R. Bruschi	Pipeline Technology	ASME
106	Field Experiences of Pipelines in Geologically Unstable Areas	Giuseppe Scarpelli	Pipeline Technology	ASME
107	Failure Modes for Pipelines in Landslide Areas	R. Bruschi	Pipeline Technology	ASME
108	Ground Movement Hazards to Pipeline Integrity: Quantifying the Effect of Snowmelt	Dimitri A. Grivas	17th International Concerence on Offshore Mechanics and Arctic Engineering	OMAE
109	How to Avoid Major Hazards From Oil and Gas Pipelines in the Coastal and Inner Waters of Denmark	Jens Erik Thygesen	Pipeline Technology	ASME
110	Scour around Pipelines in Combined Waves and Current	B. M. Summer	Pipeline Technology	ASME
111	Materials Selection for Offshore Pipelines	Liane M. Smith	Pipeline Technology	ASME
112	Expansion Analysis of Subsea Pipe-In-Pipe Flowline	Gary E. Harrison	7th International Offshore and Polar Engineering Conference	ISOPE
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114	Force and Vortex Shedding Characteristics of a Circular Cylinder Near a Plane Boundary	C. Lei	7th International Offshore and Polar Engineering Conference	ISOPE
115	Stability of Pipeline in Curved Routed During Offshore Pipeline Installation	H. Shin	7th International Offshore and Polar Engineering Conference	ISOPE
116	Arctic Linepipe with High Resistance to Crack Propagation and Hic	Gregorio R. Murtagian	First International Pipeline Conference 1996	IPC
117	Quantitative Examination of Segregation in Slabs for the Production of Sour Service Linepipe	Bernhard Hoh	First International Pipeline Conference 1996	IPC
118	Dynamic Ductile Tearing in High Strength Pipeline Steels	F. Rivalin	First International Pipeline Conference 1998	IPC
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121	Comparison of Ring Expansion vs Flat Tensile Testing for Determining Linepipe Yield Strength	Wahib E. Saikaly	First International Pipeline Conference 1996	IPC
122	A Simple Procedure for Synthesizing Charpy Impact Energy Transition Curves from Limited Test Data	Michael J. Rosenfeld, PE	First International Pipeline Conference 1996	IPC
123	Tar-Polyurethane Joint Coating for the Three-Layer Polyethylene Pipeline Coating	Robert H. Rogers, P.E.	First International Pipeline Conference 1996	IPC
124	External Pipeline Coating Selection for New and Existing Buried Pipelines	Mick D. Brown, Ph.D.	First International Pipeline Conference 1996	IPC
125	Material Technology Trends to Improve Multi-Layer Coatings: Challenges to Traditional Thinking	Jamie W. Cox	First International Pipeline Conference 1996	IPC
126	High Temperature Pipeline Coatings Using Polypropylene over Fusion Bonded Epoxy	Richard Norsworthy	First International Pipeline Conference 1996	IPC
127	The Use of Thermoplastic Lined Pipelines for Aggressive Hydrocarbon Service	Eur Ing Kenneth A. Woodward	First International Pipeline Conference 1996	IPC
128	Effect of Asphaltene Deposition on the Internal Corrosion in Transmission Lines	Jose L. Morales	First International Pipeline Conference 1996	IPC
129	Limit Loads for Pipelines with Axial Surface Flaws	G. Shen	First International Pipeline Conference 1996	IPC
130	Practical Diagnostics of Russian Gas Transmission Pipelines	V. Kharionovsky	First International Pipeline Conference 1996	IPC
131	Predictive and Preventive Maintenance of Oil and Gas Production Pipelines in the Area North Monagas-Venezuela	Miguel Angel Lugo Perez	First International Pipeline Conference 1996	IPC
132	Validating the Serviceability of IPL's Line 13	John F. Kiefner	First International Pipeline Conference 1996	IPC
133	Pipeline Accident Statistics: Base to Pipeline Rehabilitation	Chris Timur	First International Pipeline Conference 1996	IPC
134	R&D Advances in Corrosion and Crack Monitoring for Oil and Gas Lines	D.L. Atherton	First International Pipeline Conference 1996	IPC
135	Measuring Pipeline Movement in Geotechnically Unstable Areas Using an Inertial Geometry Pipeline Inspection Pig	Jaroslaw A Czyz	First International Pipeline Conference 1996	IPC
136	Internal Inspection Device for Detection of Longitudinal Cracks in Oil and Gas Pipelines - Results from an Operational Experience	H. H. Willems	First International Pipeline Conference 1996	IPC
137	Inspection Challenges - Pigs versus Pipes	E. M. Holden	First International Pipeline Conference 1996	IPC
138	Colonial's Experience with Finding Longitudinal Defects with Internal Inspection Devices	Dennis C. Johnston	First International Pipeline Conference 1996	IPC
139	Residual Strength of 48-Inch Diameter Corroded Pipe Determined by Full Scale Combined Loading Experiments	Stephen C. Grigory	First International Pipeline Conference 1996	IPC
140	New Procedures for the Residual Strength Assessment of Corroded Pipe Subjected to Combined Loads	Marina Q. Smith	First International Pipeline Conference 1996	IPC
141	Assessment of Long Corrosion Grooves in Line Pipe	Duane S. Cronin	First International Pipeline Conference 1996	IPC
142	Pipeline Failure Investigations: Analytical Techniques and Case Studies	Brian R. Wilson	First International Pipeline Conference 1996	IPC
143	Life After Inspection	Keith Grimes	First International Pipeline Conference 1996	IPC
144	The Evaluation and Restoration of a Deteriorated Buried Gas Pipeline	Ricardo Dovico	First International Pipeline Conference 1996	IPC
145	AC Corrosion: A New Threat to Pipeline Integrity?	Robert A. Gummow	First International Pipeline Conference 1996	IPC
146	Evaluation of Stray Current Effect on the Cathodic Protection of Underground Pipeline	K. W. Park	First International Pipeline Conference 1996	IPC
147	Coating Integrity Survey Using DC Voltage Gradient Technique at Korea Gas Corporation	Y. B. Cho	First International Pipeline Conference 1996	IPC
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149	Stress and Strain State of a Gas Pipeline in Conditions of stress-Corrosion	V. V. Kharionovsky	First International Pipeline Conference 1996	IPC
150	Pipeline SCC in Near-Neutral pH Environment: Recent Progress	W. Zheng	First International Pipeline Conference 1996	IPC
151	Stress Corrosion Cracking of a Liquid Transmission Line	Ravi M. Krishnamurthy	First International Pipeline Conference 1996	IPC
152	Factors Influencing Stress Corrosion Cracking of Gas Transmission Pipelines: Detailed Studies Following a Pipeline Failure: Part 1, Environmental Considerations	Martyn J. wilmott	First International Pipeline Conference 1996	IPC
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157	Stress Corrosion Crack Growth of Pipeline Steels in NS4 Solution	A. Plumtree	First International Pipeline Conference 1996	IPC
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160	Risk Management at TransCanada Pipelines	Kevin Cicansky	International Pipeline Conference 1998	IPC
161	Relative Risk Assessment - The Competitive Advantage	Bruce D. Beighle	International Pipeline Conference 1998	IPC
162	Risk Assessment of Gas Transmission Pipelines in Mexico	Jose L. Martinez	International Pipeline Conference 1998	IPC
163	Safe Separation Distances: Natural Gas Transmission Pipeline Incidents	Eugene Golub	International Pipeline Conference 1998	IPC
164	Progress of the US Department of Transportation Risk Management as a Regulatory Alternative	Keith G. Lewis	International Pipeline Conference 1998	IPC
165	Geologic Hazards Reconnaissance and Mitigation, and Implications to Natural Gas Pipeline Operations and Risk Management	Jill Braun	International Pipeline Conference 1998	IPC
166	A Survey of Pipelines in the North Sea Incidents During Installation, Testing and Operation	Strating, J	OTC Paper 4069	OTC
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172	Bursting of Line Pipe with Long External Corrosion	Mok,D.H et al	International Journal Pressure Vessel and Piping, 46, pp 195-215	Pressure Vessel &Piping
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178	Behavior of Circumferentially Aligned Corrosion Pits	Chouchaoui,B.A. and Pick,R.J	International Journal Pressure Vessel and Piping	Pressure Vessel & Piping
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181	Floating-Roof Tank Heel Reduction Options and Heel Turnover Emissions	Terry A. Gallagher	International Pipeline Conference 1998	IPC
182	Maintenance Plan for 1958 Vintage Storage Tank Facility	Brian S. Buck	International Pipeline Conference 1998	IPC
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184	Reengineering Maintenance for Dependability	Daniel J. Risdon	International Pipeline Conference 1998	IPC
185	Application of the Quartz Crystal Microbalance to Corrosion Investigation	Heijan Sun	International Pipeline Conference 1998	IPC
186	Inhibitor Selection for Internal corrosion Control of Pipelines	S. Papavinasam	International Pipeline Conference 1998	IPC
187	Repairing Pipe Defects (Cracking, Arc Burns, Corrosion, Dents) Without Operational Outages Using the Petroseleve Compression Sleeve Repair Technique	Robert J. Smyth	International Pipeline Conference 1998	IPC
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190	Strain-Based Failure Criteria For Sharp Part-Wall Defects in Pipelines	Aaron S. Dinovitzer	International Pipeline Conference 1998	IPC
191	Fatigue Damage Calculations for a Dented and Ovalled Section of the TransAlaska Pipeline System at Thompson Pass	James D. Hart	International Pipeline Conference 1998	IPC
192	Fatigue Curves for Damage Calculations for a Dented and Ovalled Section of the TransAlaska Pipeline System	Glen R. Stevick	International Pipeline Conference 1998	IPC
193	TransAlaska Pipeline System Linewide Slackline Investigations for Potential Pipe Vibrations	W. G. Tonkins	International Pipeline Conference 1998	IPC
194	Fatigue Behavior of Line Pipes Subjected to Severe Mechanical Damage	Naoto Hagiwara	International Pipeline Conference 1998	IPC
195	Investigations of Dent Rerounding Behavior	Michael J. Rosenfeld	International Pipeline Conference 1998	IPC
196	Non-Destructive Techniques for Measurement and Assessment of Corrosion Damage on Pipelines	Richard Kania	International Pipeline Conference 1998	IPC
197	Estimation of Measurement Errors	Arti Bhatia	International Pipeline Conference 1998	IPC

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198	EMAT Generation of Horizontally Polarized Guided Shear Waves for Ultrasonic Pipe Inspection	Julie Gauthier	International Pipeline Conference 1998	IPC
199	An Automated ACFM Peak Detection Algorithm With Potential for Locating SCC Clusters on Transmission Pipelines	L. Blair Carroll	International Pipeline Conference 1998	IPC
200	High-Temperature, High-Pressure Rotating Electrode System	S. Papavinasam	International Pipeline Conference 1998	IPC
201	Mechanical Development of a NPS 36 Speed Controlled Pipeline Corrosion Measurement Tool	Robert S. Evenson	International Pipeline Conference 1998	IPC
202	TCPL In-Line Inspection Management Program	Patrick H. Vieth	International Pipeline Conference 1998	IPC
203	The Operational Experience and Advantages of Using Speed Control Technology for Internal Inspection	Reena Sahney	International Pipeline Conference 1998	IPC
204	NPS 8 Geopig: Inertial Measurement and Mechanical Caliper Technology	Phil Michailides	International Pipeline Conference 1998	IPC
205	The Changing Role of Inspection	Keith Grimes	International Pipeline Conference 1998	IPC
206	Strain Estimation Using VTCO Deformation Tool Data	Michael J. Rosenfeld	International Pipeline Conference 1998	IPC
207	The Role of Coatings in the Development of Corrosion and Stress Corrosion Cracking on Gas Transmission Pipelines	Martyn Wilmott	International Pipeline Conference 1998	IPC
208	The Role of Pressure and Pressure Fluctuations in the Growth of Stress Corrosion Cracks in Line Pipe Steels	Martyn Wilmott	International Pipeline Conference 1998	IPC
209	High-pH SCC: Temperature and Potential Dependence for Cracking in Field Environments	John A. Beavers	International Pipeline Conference 1998	IPC
210	Review and Proposed Improvement of a Failure Model for SCC of Pipelines	Carl E. Jaske	International Pipeline Conference 1998	IPC
211	A Review of the Concept of Mildly Sour Environments	Richard J. Pargeter	International Pipeline Conference 1998	IPC
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214	Hydrogen Effects in Gas Transmission Pipeline Steels	T. M. Maccagno	International Pipeline Conference 1998	IPC
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217	Variations in Stress Concentration Factors Near Simulated Corrosion Pits as Monitored by Magnetic Clux Leakage, Magnetic Barkhausen Noise and Neutron Diffraction	L. Clapham	International Pipeline Conference 1998	IPC
218	Prediction of Maximum Time for Delayed Cracking in a Simulated Girth Weld Repair	Lalit Malik	International Pipeline Conference 1998	IPC
219	An Instrumented Field Corrosion Test Loop	Alebachew Demoz	International Pipeline Conference 1998	IPC
220	Imitation of Environment Induced Cracking in Pipeline Steel: Microstructural Correlations	Y.-Z. Wang	International Pipeline Conference 1998	IPC
221	Full-Scale Wrinkling Tests and Analyses of Large Diameter Corroded Pipes	Marina Q. Smith	International Pipeline Conference 1998	IPC
222	Correction for Longitudinal Stress in the Assessment of Corroded Line Pipe	K. Andrew Roberts	International Pipeline Conference 1998	IPC
223	A New Rupture Prediction Model for Corroded Pipelines Under Combined Loadings	Wei Wang	International Pipeline Conference 1998	IPC
224	The Use of Reliability Based Limit State Methods in Uprating High Pressure Pipelines	Andrew Francis	International Pipeline Conference 1998	IPC
225	Pipeline Repair Based on Diagnostic Inspection - Investment Return	Barnabas Pallaghy	International Pipeline Conference 1998	IPC
226	The Canadian Energy Pipeline Association Stress Corrosion Cracking Database	Bruce R. Dupuis	International Pipeline Conference 1998	IPC
227	Use of the Elastic Wave Tool to Located Cracks Along the DSAW Seam Welds in a 32-inch (812.8-mm) OD Products Pipeline	Willard A. Maxey	International Pipeline Conference 1998	IPC
228	In-Line Inspection Tools for Crack detection in Gas and Liquid Pipelines	H. H. Willems	International Pipeline Conference 1998	IPC
229	Comparison Between In-Line Crack Detection and Hydrostatic Testing in IPL's Line 3	Michael A. Gardiner	International Pipeline Conference 1998	IPC
230	Application of Material Standards & ISO Quality Management Systems	Keith E. W. Coulson	International Pipeline Conference 1998	IPC
231	The Australian Petroleum Pipeline Code AS 2885 - 1997	Ken J. Bilston	International Pipeline Conference 1998	IPC
232	Reliability of Mechanised UT Systems to Inspect Girth Welds During Pipeline Construction	Jan A. de Raad	International Pipeline Conference 1998	IPC
233	Customized Ultrasonic Systems for Gas Pipeline Girth Weld Inspections	Michael D. C. Moles	International Pipeline Conference 1998	IPC
234	Three Layer Epoxy/Polyethylene Side Extruded Coatings for Pipe for High Temperature Application	Mike Alexander	International Pipeline Conference 1998	IPC
235	Deformation and Fracture Behaviors of Polyethylene Coatings on the Natural Gas Transmission Line With Ultraviolet Exposure	Seong-Min Lee	International Pipeline Conference 1998	IPC
236	Pipeline Design and Construction Using Higher Strength Steels	Alan G. Glover	International Pipeline Conference 1998	IPC

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238	An Investigation of the Factors Influencing the Formation of Hollow Bead Bores in Pipeline Girth Welds	Gersende M. Delphine Cantin	International Pipeline Conference 1998	IPC
239	Quality and Productivity Improvements in the Field Welding of High Strength Thin Walled Pipelines	Frank J. Barbaro	International Pipeline Conference 1998	IPC
240	Transition Temperature Determination for Thick Wall Line Pipe	G. Demofonti	International Pipeline Conference 1998	IPC
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256	A Survey of Plastic Collapse Solutions used in Failure assessment of part wall defects	Willoughby, A.A	The Welding Institute Research Report No. 191/1982, Sep 1982	TWI report
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258	Stress Corrosion Crack In-Line Pig Shows Promise in Tests	Keith Grimes	Pipe line & Gas Industry	Pipeline & Gas Industry
259	Inspection Technologies for a Wide Range of Pipeline Defects	Keith Grimes	Pipeline Pigging and Inspection Technology Conference	Pipe line Industry
260	Development of a Smart Pig for Pipeline Crack Detection : An Upgrade	Keith Grimes		
261	Use of In-Line Inspection Data for Integrity Management	Patrick H. Vieth	Corrosion 99	NACE
262	Which Smart Pig do I Choose ? A Comparison of Magnetic Flux Technologies from an Operator's Viewpoint	Ken Plaizier		
263	In-Line Inspection Technologies for Mechanical Damage and SCC in Pipeline- Final Report on Task 1 and 2	T.A. Bubenik		Battelle Columbus Laboratories
264	Offshore Pipeline Girth Welds: Non-Destructive Testing	P.J. Mudge		OTI
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266	Evaluating the Remaining Strength of Corroded Pipelines	Chouchaoui B A.	Ontario	
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270	Failure of Spiral Corrosion in Linepipe	Fu B.	13th Offshore Mechanics and Arctic Engineering Conference, Houston	
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272	The European Pipeline Research Groups Guidelines on Acceptable Girth Weld Defects in Transmission Pipelines	Hopkins P	8th Annual Symposium on Line Pipe Research,Texas,1993	Sponsored by AGA
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317	Failure Behavior of Internally Corroded Line Pipe	Jones, D Get al	11th International Conference on Offshore Mechanics and Arctic Engineering	
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319	A Review of Fatigue Assessment Methods for Pipelay Operations	Jutla, T	5th International Conference on Offshore Mechanics and Arctic Engineering	
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333	New International Standards for Offshore Pipelines	Herman Moshagen, Erling giertvert	Internatinal offshore and Polar engineering Conference	ISOPE
334	Design Through Analysis Applying Limit-State Concepts and Reliability Method	Yong Bai and Per Damsleth	Internatinal offshore and Polar engineering Conference	ISOPE
335	Experience from Operation, Inspection and Monitoring of Offshore Pipeline System on the Norwegian Continental Shelf	Ase Katrine Thomsen	Internatinal offshore and Polar engineering Conference	ISOPE
336	Realtime Monitoring to Detect Third-Party Damage	B.N. Leis, R.B. Francini	Internatinal offshore and Polar engineering Conference	ISOPE
337	Direct Electrical heating of Pipelines as a Method of Preventing Hydrate and Wax Plugs	Jens Kristian Lervik	Internatinal offshore and Polar engineering Conference	ISOPE
338	Pressure-Displacement Behavior of Transmission Pipelines under Outside Forces--Towards a Services Criterion for Mechanical damage	B.N. Leis, R.B. Francini	Internatinal offshore and Polar engineering Conference	ISOPE
339	Assessment of Free Spanning Pipelines Using the DnV guideline	Olav Fyrileiv and Kim Mork	Internatinal offshore and Polar engineering Conference	ISOPE
340	Plastic Failure of Pipelines	Michelle S. Hoo Fatt	Internatinal offshore and Polar engineering Conference	ISOPE
341	Plastic Deformation and Local Buckling of Pipelines Loaded by Bending and Torsion	A. M. Gresnigt	Internatinal offshore and Polar engineering Conference	ISOPE
342	The effect of Tension-Fractured and Compression-Crushed Zones on Pipe Uplift Resistance in Frozen Soil	A. Foriero	Internatinal offshore and Polar engineering Conference	ISOPE
343	Analytical Collapse Capacity of Corroded Pipes	Yong Bai and Soren Hauch	Internatinal offshore and Polar engineering Conference	ISOPE
344	Pipeline Design Strategies for Deep Water	Andrew palmer	Deepwater Pipeline Technology Conference	
345	Strength Design of Deepwater Pipelines	Yong Bai, Per Damsleth	Deepwater Pipeline Technology Conference	
346	Integrity Assessment of Deep Water Pipelines	Majid Al Sharif	Deepwater Pipeline Technology Conference	
347	External Corrosion Control and Corrosion Inspection of deepwater Pipelines	Jim Britton	Deepwater Pipeline Technology Conference	
348	The Effect of Plastic Deformation on the Fatigue Performance of Steel Catenary Risers	Elie Kodaissi	Deepwater Pipeline Technology Conference	
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352	Integrity Assessment of Offshore Pipelines by Use of Intelligent Inspection Tools	M. Beller and W. Garrow	12th International Conference on Offshore Mechanics and Arctic Engineering	OMAE
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No.	Title	Main Author	Conference	Ref
356	Non-Linear Finite Element Prediction of Wrinkling in Corroded Pipe	Daniel P. Nocolella	7th International Offshore and Polar Engineering Conference	ISOPE
357	Limit-State Design of High-Temperature Pipelines	Frans J. Klever	13th Offshore Mechanics and Arctic Engineering Conference, Houston	
358	Wall Thickness Design for High Pressure Offshore Gas Pipelines	Richard Verley	13th Offshore Mechanics and Arctic Engineering Conference, Houston	
359	Submarine Pipeline Inspection: The 12 Years Experience of Transmet and Future Developments	Luigi Ioveniti	13th Offshore Mechanics and Arctic Engineering Conference, Houston	
360	TMCP - Application for Production of High Strength, High Toughness Line Pipe Steels	A. Streibelberger	10th Offshore Mechanics and Arctic Engineering Conference	
361	Development and Mass Production of X80 Line Pipe	Shigeru Endo	10th Offshore Mechanics and Arctic Engineering Conference	
362	Sour Service Large-Diameter Line Pipe Having Good Field Weldability and Sulphide Stress Corrosion Cracking Resistance	H. Tamehiro	10th Offshore Mechanics and Arctic Engineering Conference	
363	Future Needs for Integrity Evaluation	Andrew Palmer	International Workshop on Offshore Pipeline Safety	
364	Design and Installation issues for integrity	Dave McKeehan	International Workshop on Offshore Pipeline Safety	
365	Evaluation of Integrity, Reliability Assessment	Tom Zimmerman	International Workshop on Offshore Pipeline Safety	
366	Appendix A - Inspection Considerations	D. W. Barry	International Workshop on Offshore Pipeline Safety	
367	Corrosion Control Survey Methods for Offshore Pipelines	Clark Weldon	International Workshop on Offshore Pipeline Safety	
368	Recent Developments in Pipeline Integrity Technology	Tom Bubenik	International Workshop on Offshore Pipeline Safety	
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370	An Analysis of Crack Extension by Corrosion Fatigue in a Crude Oil Pipeline	Vosikovsky, O	International Journal of Pressure Vessels and Piping	

FIGURES

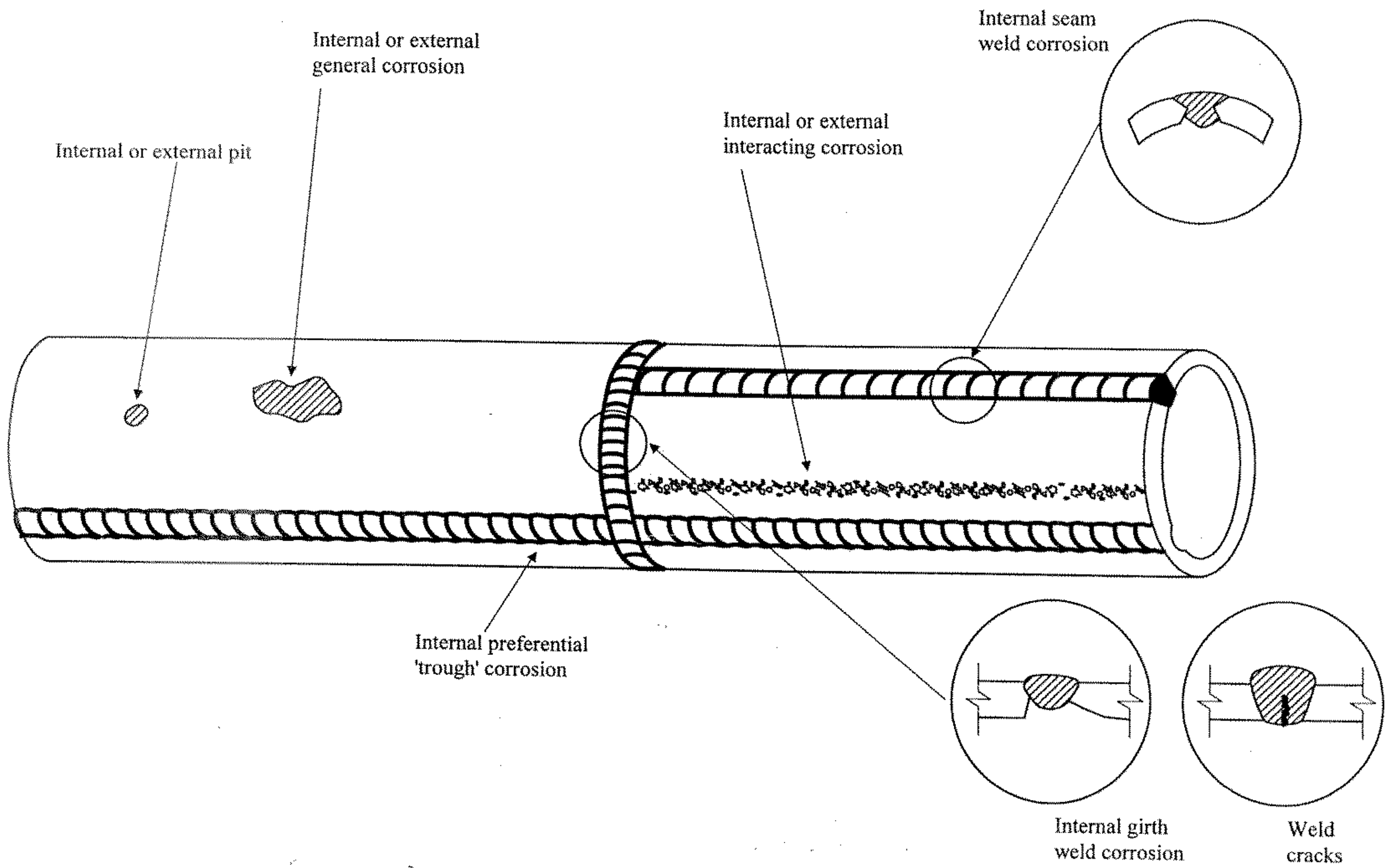

Figure 1.1: Some types of corrosion and cracking found in pipelines

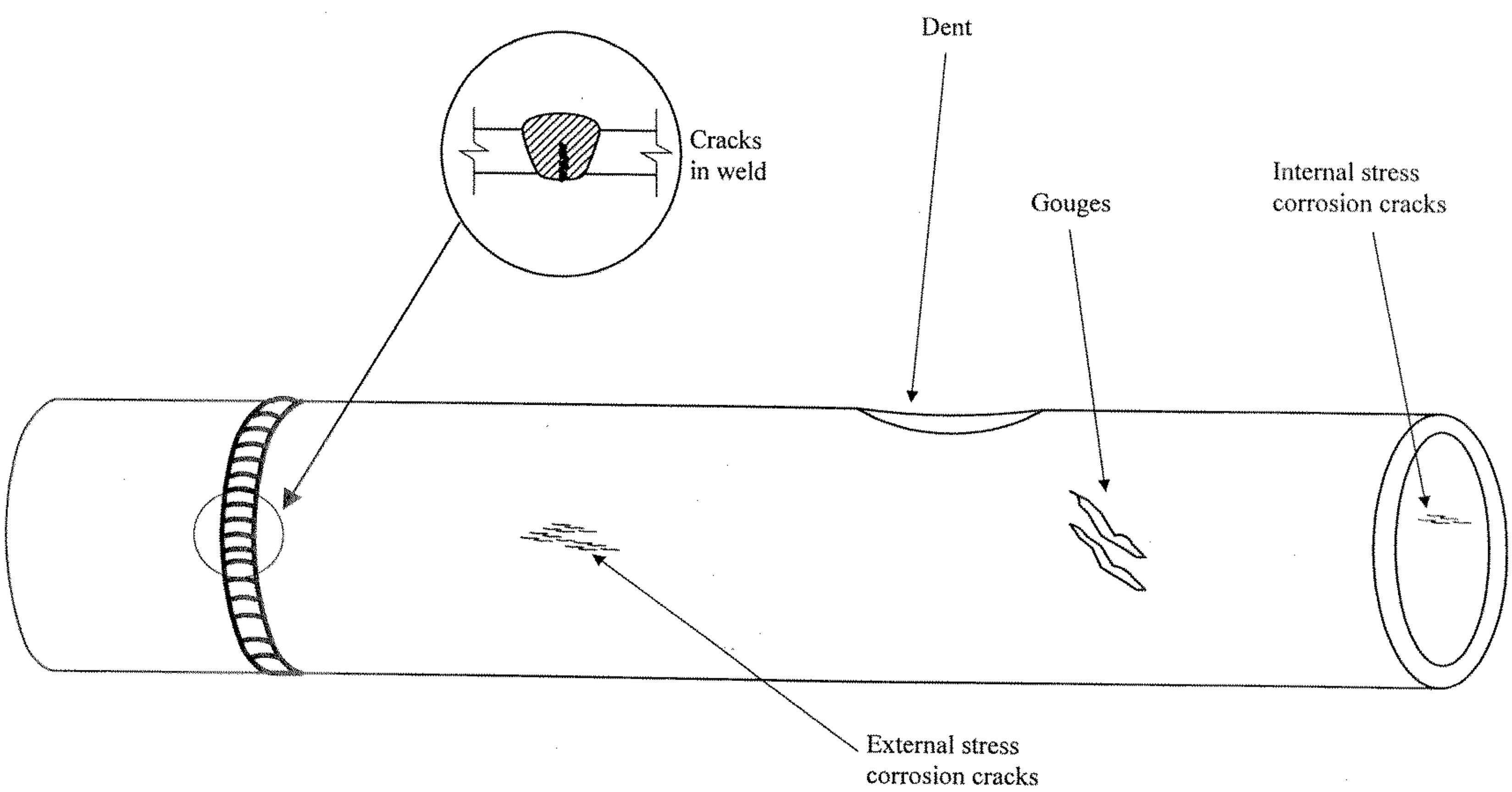

Figure 1.2: Mechanical damage and cracks found in pipelines

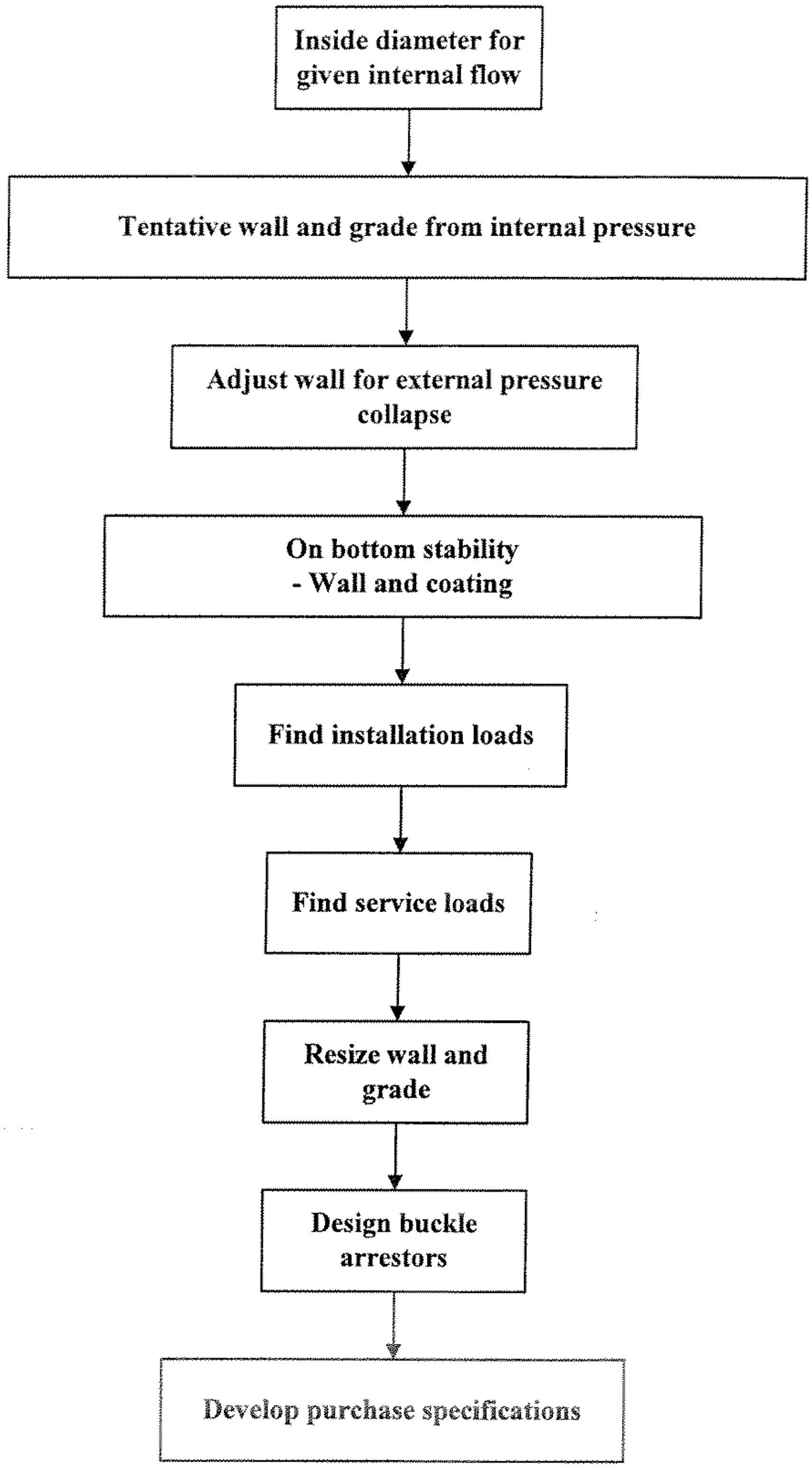

Figure 3.1: Offshore pipelines design flow chart

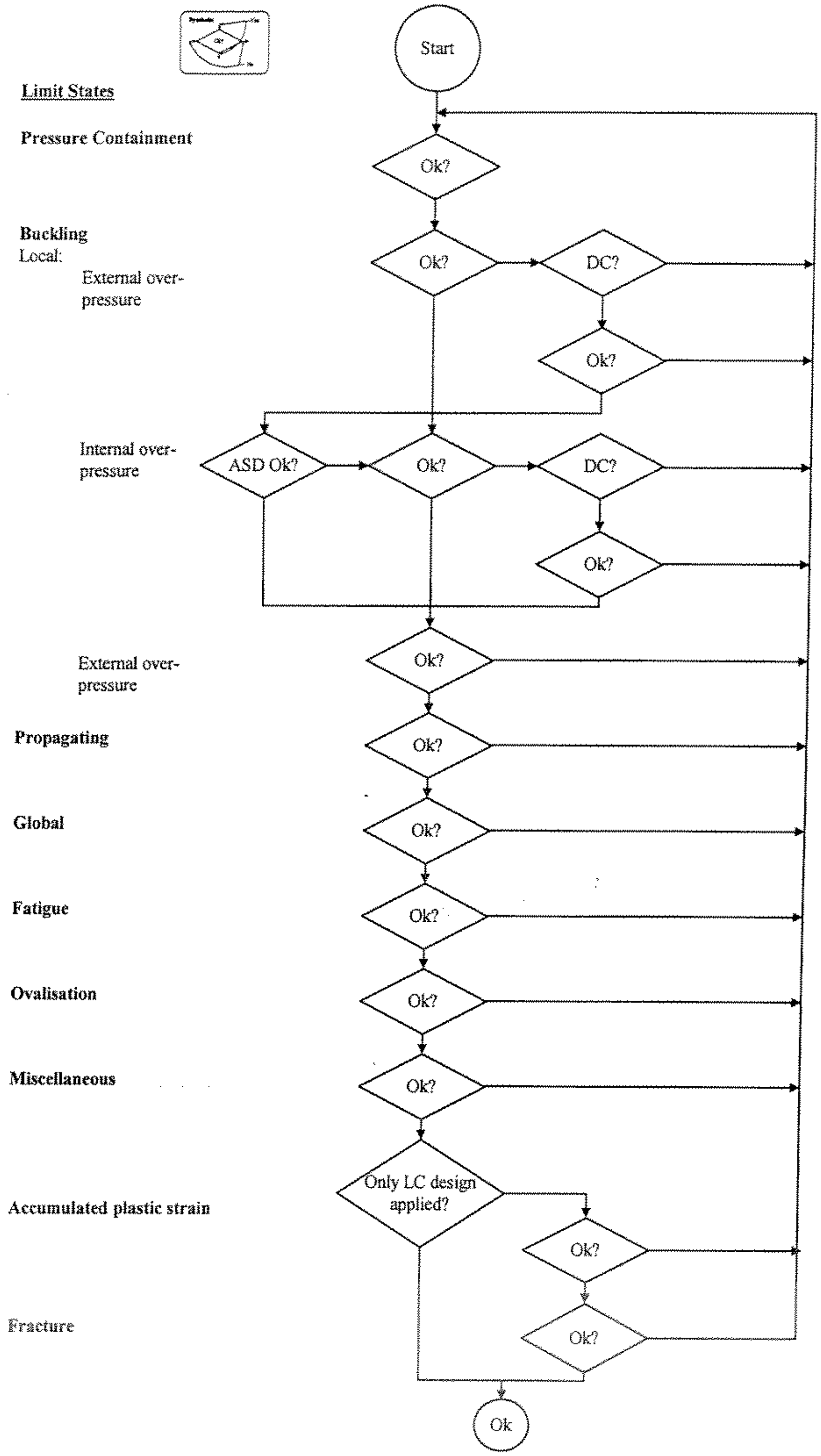

Figure 3.2: Typical flow diagram for design checks

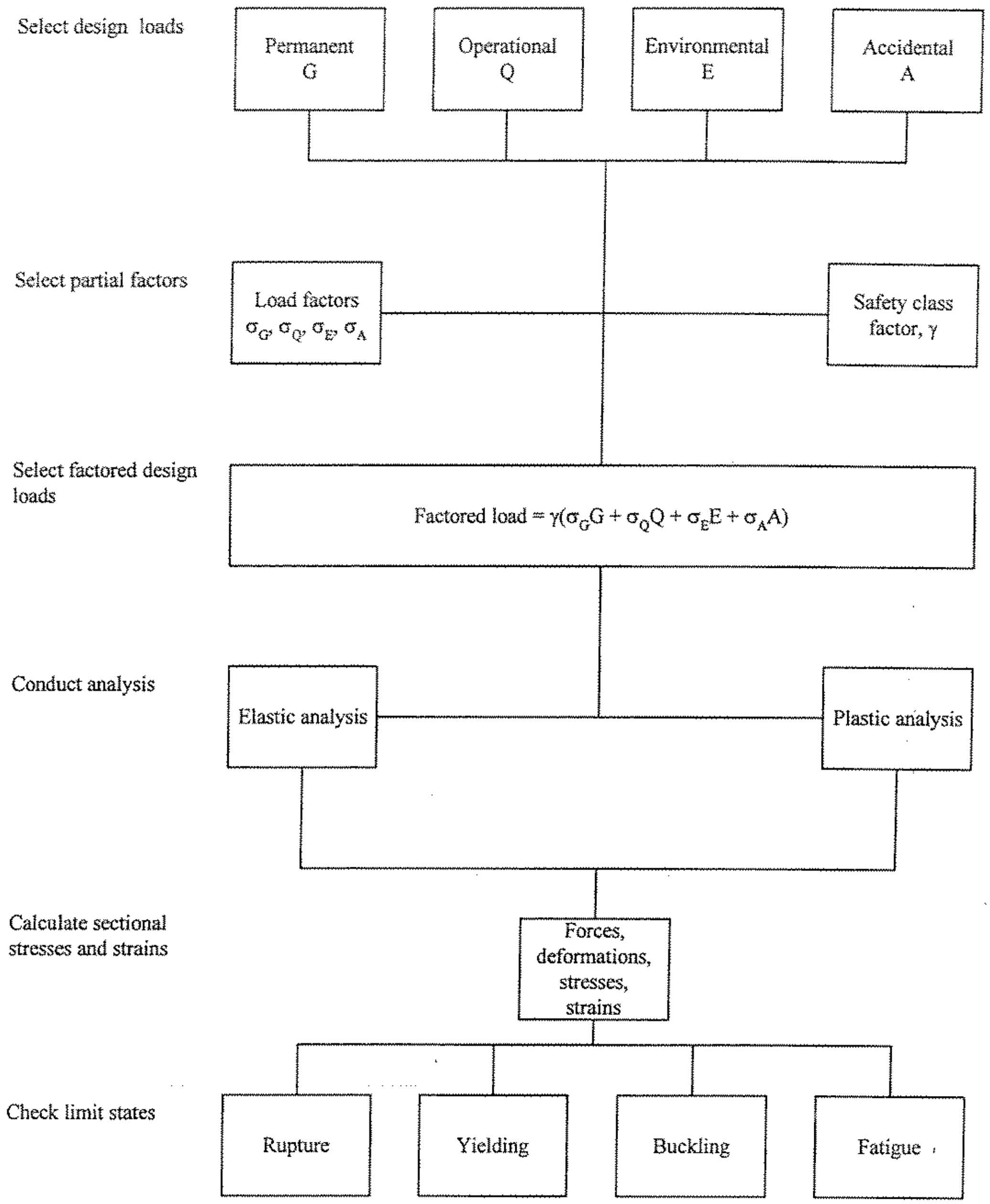

Figure 3.3: Limit state design methodology (CSA Z662-99)

APPENDIX A

Notes of Meetings with Operators

INTERVIEW: Operator No. 1

Operator No. 1 owns a number of pipelines in the North Sea. Most of the pipelines are large diameter (up to 42 inch) high pressure gas lines; the oil lines tend to be short in-field (eg. subsea wellhead to platform) flowlines of small diameter.

The interviewee stated that very few problems had been experienced with the pipelines. This good operational history may be due to at least three factors that were discussed during the course of the interview:

- The gas is generally sweet and is carefully dried before it is conveyed.
- The pipeline systems are not old, typically being less than 15 years.
- Meticulous procedures are used for steel, pipe and pipeline manufacture as discussed below.

Problems during the manufacturing stage are relatively easily identified and corrected. In-service anomalies would appear to be confined to a few instances of internal corrosion at the 6 o'clock position due to dampness caused by process irregularities, the corrosion being within the first km from the platform.

Interestingly, this Operator has its own specifications for steel grades. The preferred strength is 450MPa and in this respect it is equivalent to API X65. However the Operator's specification has stricter requirements on steel chemistry and geometric tolerances than the API specifications. The improved weldability of the steel leads to fewer defects during pipe/pipeline manufacture and also to fast production rates (eg. a 42" dia. x 30mm pipeline could be produced at a rate of 4.5km/day from a lay barge). The Operator is involved in steel production to ensure compliance with its specification.

The steel plate is rolled and welded to form 12.2m (40') lengths. Ultrasonic inspection is used on the longitudinal weld and the ends are x-rayed over a 300mm length. At this stage welds rarely present problems; defects tend to consist of mechanical surface damage (ie. minor dents, scratches). Any scratch is removed by grinding and the area examined by MPI or dye penetrant methods. The remaining wall thickness is checked using ultrasonics. The pipe lengths may then be subjected to a pressure test. The internal surface is grit blasted, visually inspected for defects, painted and then inspected again for continuity of the paint coating. (The paint coating is applied to improve gas flow only, and not for corrosion protection. It was claimed that flow rates are improved by 5 to 10%.) The external surface is also grit blasted, inspected and either a 6mm asphalt or a 3mm three-layer system (fusion bonded epoxy/glue/poly-propolyne) is applied. A 40 to 100mm thick reinforced concrete coating is used for protection against mechanical damage and for weighting purposes.

The prepared pipe lengths are stored around the coating yard until required. At that time they are washed internally and subjected to a visual inspection to check for any damage incurred during storage.

On the lay barge, the SAW welding process is used at the double jointing station to produce 24.4m pipe lengths. The double jointed pipes are then transferred to the main line which consists of several MIG welding stations, the first laying the root pass and the last the capping runs. After these stations comes the NDT, repair and field coating stations. The pipeline then travels down the stinger. Usually, only spot checks are carried out between the MIG stations. However, for one project involving a duplex stainless steel line, a full inspection using ultrasonics (TOF) was conducted after only two weld beads had been laid. At the NDT station, x-ray inspection techniques have tended to be used. This will size the length of any defect but not the depth. The Operator therefore assumes a depth equivalent to the height of two weld beads when comparing the defect against normal workmanship criteria. More recently, AUT (automatic ultrasonic testing) has been used at the NDT station which can size length and depth. An Engineering Critical Assessment is used to set acceptable defect size.

Whenever possible, the Operator prefers to let the pipeline lie on the seabed. But where uneven topography could leave unacceptable free spans or where fishing activity is likely, trenching or rock dumping is employed. A survey vessel aft of the lay barge conducts a visual inspection of the pipeline by ROV.

After pipeline completion, a hydrostatic pressure test is conducted, followed by cleaning with pigs and drying. The Operator would like to dispense with the pressure test as it is time-consuming and expensive. It was also noted that longitudinal welds are more critical than girth welds as hoop stresses are generally higher than longitudinal stresses, and that all longitudinal welds are pressure tested at the mill.

In-service inspection has relied on British Gas' intelligent pigs using MFL (magnetic flux leakage) techniques. The good inspection history of the gas lines has allowed a relaxation of inspection intervals. Indeed, the only incidences of defects are the corrosion patches near the platform mentioned above. Defect assessment has been based on PD 6493 and, more recently, BS 7910. Preliminary assessment would be based on the 'RSTRING' package.

It was concluded that the care exercised in steel, pipe and pipeline manufacture, coupled with sweet gas conditions, has led to the good operational record for the Operator's pipelines.

INTERVIEW: Operator No. 2

Operator No. 2 is responsible for pipelines across all sectors of the UK continental shelf. Those in the southern North Sea are likely to be gas lines, elsewhere they tend to convey multi-phase products. The Operator classifies the pipelines into the following three categories, although it was recognised that there may be overlap amongst the categories:

1) In-field lines

   These tend to be short (ie. less than 1.5km) and of small diameter (ie. typically 6″ to 8″). They carry unprocessed fluids at pressures up to 200 bar in normal operating conditions but pressures approaching 800 bar can arise when High Pressure wells are shut in, generally over short lengths (say up to 100m).

2) Inter-field lines

   These are of intermediate lengths (ie. up to about 25km) and diameters (typically around 12"). Maximum pressures are about 200 bar. Fluids can be processed or unprocessed.

3) Trunk lines

   These can be long (100km plus) and are of large diameter. Operating pressures are generally in the range of 100 to 200 bar. The fluids are processed.

Good operational history has been experienced with all pipelines. Lines are subject to hydro-testing followed by external and internal inspections at periodic intervals. For external inspections, a towed vehicle housing side scan sonar equipment is used to look for scour, pipe spanning, burial due to slip, evidence of fishing activity (eg. by tracks) or lateral movement of the pipe. If evidence of disturbance is found, an ROV camera may be deployed to investigate further.

For internal inspections, pigs are used. Generally, the in-field lines can not be pigged due to a lack of arrangements to launch and catch pigs and because of the small diameter of the lines. Inter-field lines can be pigged if they are looped; if they are single lines then sometimes arrangements are made for a ROV-installed temporary pig launcher/trap, Other possibilities were discussed for pigging single lines including crawler pigs with umbilicals (with ultrasonic equipment or camera mounted on the crawler), and contra-flow pigs using the flow for motive power (akin to sailing against the wind). Although bi-directional cleaning pigs exist, the interviewee was not aware of any bi-directional intelligent pigs. Trunk lines can generally be pigged.

The UK pipeline safety regulations have, over the last three years, prompted a change to a risk-based approach in defining inspection plans; inspection intervals greater than one year are now common. It was stated that the regulations assign responsibility for a pipeline to the operator who actually controls the valves. For certain inter-field lines running between installations (platform, subsea manifolds, etc.) owned by different operators, the pipeline owner may not, in fact, be the operator who controls the valves. This is a slightly unsatisfactory state of affairs as the owner, after all, decides what will flow through the line, and has made the investment in the line that he will want to protect (by integrity management).

The Operator uses 2nd generation intelligent pigs where other inspection data indicates better information is required. Instrumentation that can be included in cleaning pigs was discussed. This is a relatively new development that should provide cheaper/lower risk alternatives to full scale intelligent pigging, though it is not currently in common use and certainly not by the operator. In some respects, the use of large intelligent pigs presents additional risks, most notably in the possibility of the pig getting stuck in the pipeline. Cost was also another factor cited as a disadvantage.

Local corrosion rates are measured in line by corrosion coupons and corrosion probes. Corrosion coupons are sacrificial elements, held into the pipe wall by special housings, and removed at intervals to measure weight loss. Corrosion probes indicate corrosion rates by a change in electrical resistance.

It was believed that the internal and external inspections are generally sufficient to allow the state of the pipeline to be inferred.

For defect assessment the Operator uses in-house procedures. These are based on ASME B31G but with modifications to make the requirements less conservative but still remaining robust.

INTERVIEW: Operator No. 3

This Operator owns almost 1000 miles of sub sea hydrocarbon pipelines in the waters of the Gulf of Mexico. The Pipeline Department of the company is responsible for the pipeline from the export riser to the beach; the Production Department of the company operates the flow-lines and local jumpers from the wells to the platform. The hydrocarbon inventory is about 20% gas and about 80% crude oil. The gas is generally fairly sweet and dry and requires minimal offshore processing. The pipelines range in size from 6 inches to 20 inches.

The company uses API 5L as the standard for line-pipe specification, however, more rigorous inspection requirements are stipulated by the company for pipe with longitudinal seam welds, including 100% UT. This is reflective of in-service experience and a lack of faith in the ability of inspection systems to reliably detect defects of this nature. Materials from Gr. B to X60 are typical and, hence, the operator had no experience of defect issues pertaining to high strength steels.

Routine inspections are not implemented for the pipeline system although the company estimates that approximately 80% of the pipelines (from the export riser to the beach) are piggable. A deterministic risk assessment technique is used to rank the pipelines by potential to fail and by consequence of failure. The risk assessment is based on field experience and is repeated every few years or as operational conditions change.

Inspections, when performed, are seeking mainly corrosion defects, which are the most prevalent based on operational experience. The company does have some experience with MFL Smart Pigs in the Gulf of Mexico, deployed for purposes of corrosion defect detection. Dents cannot generally be detected by the systems that have been employed to date, unless the tool is physically impeded. The Pigs used by the company do not differentiate between internal and external defects; however, in the experience of the company this is often discernable from the nature and, in particular, the location of the defect.

The company does not perform external pipeline inspections in the Gulf of Mexico due to the low visibility and the fact that the pipelines are generally buried.

The major cause of loss of pipeline integrity, resulting in loss of inventory, was stated to be third party interference. This included general shipping and, in particular, the influence of vessels/barges experiencing mooring failures during hurricanes and dragging anchors through pipelines.

Of other potential pipeline defects, the operator advised that corrosion was the most significant. The company reported that their crude oil lines, where the consequence of loss of inventory was greatest, were more susceptible (than the gas lines) to corrosion defects. The reasons for the increased propensity for internal corrosion were cited as higher water content, periods of low flow rate, inadequate or insufficient inhibitors and/or insufficient pigging (cleaning).

The philosophy of the company with regard to defect assessment was to apply the recommendations of ASME/ANSI B31G to detected corrosion defects. For defects failing the acceptance criteria contained in the code the company policy was to either repair/replace the line segment or to closely monitor for leaks. It was felt that the codified assessment criteria were conservative; but that the code was a tool representing operational field experience and that recourse to more sophisticated assessment was not cost effective due to the requirement for greater inspection reliability/accuracy.

APPENDIX B

Summaries of Papers on Inspection Techniques

IPC 98- 309 (Ref. 196)

NON-DESTRUCTIVE TECHNIQUES FOR MEASUREMENT AND ASSESSMENT OF CORROSION DAMAGE ON PIPELINES

Richard Kania
RTD Quality Services Inc.

Three systems are discussed:

1. Laser-Based Pipeline Corrosion Assessment System

   The system consists of a laser-based range sensor, signal processing computer, and a gantry frame. It was designed to improve assessing the extent of external corrosion on exposed natural gas and oil pipeline (pit gauge, depth micrometers). The data gathered by laser can be readily digitized to provide a permanent record and colour map of corrosion defects.

2. Semi Automatic Ultrasonic System –Mapscaner

   To obtain quantitative results to establish the severity of metal loss or to determine the suitability of a pipe segment for continued use, RTD Mapscan, a tool which use a hand held ultrasonic probe

3. Magnetic Flux Leakage Scanner – Pipescaner

   MFL technique provides qualitative results and can give a good indication of general condition of a pipeline section, MFL is a well known mature technique, extensively used in self-contained intelligent pigs. A permanent magnet generates a magnetic field in the pipe wall. Internal and external volumetric defects, general corrosion or pitting, cause disturbance in the magnetic field flow, which can be detected by a Hall effect sensor.

Corrosion assessment procedures use the RSTRENG program.

IPC 98 – 335 (Ref. 199)

An Automatic ACFM peak Detection algorithm with Potential for Locating SCC Clusters on Transmission Pipelines

L. Blair Carroll

The Alternating Current Field Measurement (ACFM) crack detection and sizing technique has demonstrated its potential as a stress corrosion cracking (SCC) characterization tool.

ACFM is a commercially available NDT technology that was developed for surface crack detection and sizing on coated carbon steel weldments. It was first introduced in the early 1990's by Technical Software Consultants of the UK. The scope of its application has since spread to include sub-surface crack detection in stainless steels up to 30 mm thick, the detection and sizing of corrosion pitting, airframe inspection and drill thread inspection.

IPC-98 - 351 (Ref. 201)

Mechanical Development of a NPS 36 Speed Controlled Pipeline Corrosion Measurement Tool

Robert S Evenson
BJ Pipeline Inspection Services

A large bypass, variable speed NPS 36 MFL, corrosion inspection tool has been developed and run successfully in several high-pressure natural gas pipelines without noticeable impact on operational throughput.

Since the first in-line MFL tool was introduced in 1965, a variety of conventional (low) and high-resolution MFL tools have been devised for measuring pipeline corrosion. A slow MFL tool speed, normally less than 4 m/s, is required. Reducing pipeline flow throughput velocity to provide an optimum MFL measurement was accepted standard for MFL corrosion measurement. Low MFL tool measurement speed and lack of active speed control bypass capacities generally resulted in a plethora of economic and operational problems for high-pressure natural gas pipeline operators.

Tool speed reduction in a pressure gas pipeline can be accomplished through a combination of flow bypass and tool drag. Adequate friction must be introduced to counteract the force created by the differential pressure across the tool. A fixed bypass (Passive speed control) can achieve the desired effect; however, variations in flow, pipe slope and wall thickness cannot be adjusted for. Constant inspection velocity is fundamental for enduring accurate evaluation and sizing of corrosion defects. This can be realized using a variable bypass (Active speed control).

IPC-98 - 367 (Ref. 203)

The Operational Experience and Advantages of using Speed control Technology for Internal Inspection

Reena Sahney
TransCanada Pipelines
Calgary AB T2P 3Y6

Speed control technology was still in the early stages of development and performance testing. The purpose of speed control is to reduce capacity restrictions while maintaining the optimal speed for data collection. Constant tool speed also improves data quality, as MFL signals are asymmetric under dynamic conditions. The basic mechanism of speed control involves bypassing gas such that the tool speed is slower than the gas speed. This is accomplished through a valve and controller that respond to changes in gas velocity in order to maintain a pre-set tool speed. The amount of gas being bypassed is obviously sensitive to pressure and temperature.

By mid 1997, two vendors had successfully completed MFL inspections on the TCPL system with speed control technology.

IPC-98 - 379 (Ref. 205)

The Change Role of Inspection

Keith Grimes
Pipeline Integrity International, Inc
7105 Business park Drive, Houston, TX 77041

The changing role of Inspection and industry's expectations of it are addressed in the paper.

Tuboscope were pioneers of intelligent pigging with their Linalog Magnetic Flux Leakage (MFL) pigs for pipeline surveys from the mid 1960's onward. This was a remarkably advanced technology for its day, giving pipeline operators their first early warning of major pipeline problem. The inspection log was essentially qualitative, with some degree of defect severity grading. In the mid 1970's British Gas and Battelle had completed major investigation programs on pipeline material properties and failure mechanisms. This work lead to the definition of quantitative performance requirements for intelligent pigs to be able to reliably replace hydrotesting as a means of revalidating pipelines. British Gas developed its first high-resolution inspection tools, operating to these specifications, in the late 1970's. Some years later, during the mid 1980's, Pipetronix and NKK developed the alternative ultrasonic technique (UT) using liquid coupling.

Where industry is now:

Inspection specifications: 10/20 sizing specifications. Defects above these depths are detected and sized to +/- 10% wall thickness.

Girthweld Defects: Corrosion problems often occur preferentially at girth welds due to failure of field coatings at joints or preferential internal corrosion/erosion at the girth weld. The ability to inspect girth welds has been taken further to detect and size circumferential cracking.

Long Axial Corrosion including channeling: this form of corrosion is often seen alongside the seam weld in tape wrapped pipe. Conventional MFL has a limited sensitivity to such features. Normal wave ultrasonic has the ability to see the plateau corrosion but has problems in gauging the depth of narrow channels and can be troubled by variable geometry at the corroded seam weld. BG's solution is to produce a Transverse Field Inspection (TFI) system where the magnetic flux path is circumferential around the pipe. This system is now tuned to give preferential detection of axial/channeling defects.

The Poor field Coating Problem: Inspection system was re-calibrated to look specifically for the onset of low level corrosion around the pipe joints.

The Highly Stressed Pipeline: The MFL interpretation task gives an indication of these high stress levels. It does not provide a high resolution mapping of detailed stress pattern in the pipeline. Other techniques under development may be able to provide this information in the future.

Hard spot Inspection: BG's work has demonstrated the ability to detect and size the extent of hard spots using low saturation magnetic techniques.

Inspection for Stress Corrosion Cracking (SCC): Longitudinally aligned planar defects such as SCC cracking and longitudinal internal Seam Fatigue cracking pose particular problems for on-line inspection technologies because of the inherent variability of the defect, and the presence in many pipeline steels of benign defects which can be confused with cracks.

Ultrasonic techniques are very sensitive to planar defects such as cracks and laminations. A major operational problem with ultrasonic pigs in gas pipelines is the necessity for a liquid couplant, meaning that either the line has to be flooded or a liquid slug introduced to carry the tool. One remarkable feature of the BG crack tool is the use of transducers mounted within special probe wheels, which provide acoustic coupling without the need for flooding or liquid slug in the pipeline. By looking around the pipe circumference, these sensors provide 100% high-resolution coverage of the whole pipe wall, including the seam weld.

In addition to ultrasonics as a solution to the SCC inspection problem, work performed on the Transverse field MFL inspection system has shown some ability to detect colonies of SCC in line pipe magnetically, although the full capacity is not yet established.

IPC-98 – 589 (Ref. 226)

The Canadian Energy Pipeline Association Stress Corrosion Cracking Database

Bruce R. Dupuis
Foothill Pipe Lines Ltd.

The SCC database was initiated by the CEPA(Canadian Energy Pipeline Association). The current generation of the database has a broad scope, containing detailed data for every colony and its associated environmental conditions. The database also includes corrosion and dents amongst other integrity concerns to identify any correlation with SCC and provide a common industry data format to investigate these and other integrity issues.

IPC-98 – 595 (No. 227)

Use of the Elastic Wave Tool to Locate Cracks Along the DSAW Welds in a 32 Inch OD Products Pipeline

Willard A. Maxey, Raymond E. Mesloh
Kiefner and Associates, Inc

The effectiveness of the British Gas elastic wave in-line inspection tool for finding and characterizing along DSAW seams was clearly demonstrated by its use.

IPC-98 - 605 (Ref. 228)

In-line Inspection tools for Cracks Detection in Gas and Liquid Pipelines

H.H Willems, and O.A. Barbian
Pipetronix GmbH

Cracks in pipelines are among the most severe and potentially dangerous defects in pipelines. The mechanism of initiation and growth in particular of the so called near neutral SCC are still not fully understood and are the subject of ongoing research. SCC can occur in various forms from small isolated cracks to large crack fields containing hundreds of cracks. Since the hoop stress is usually the driving force, SCC is normally axially orientated. SCC is generally found on the external pipe surface with some preference in the longitudinal weld area but also in the base material. Its occurrence is observed largely concerning coating failure.

For a long time, the use of hydrostatic testing was considered the only reliable way to prove the integrity of a pipeline that was a candidate for SCC attack. This type of test is expected to remove all critical cracks, i.e. cracks that could cause failure under normal operating conditions. However, since no information on sub-critical cracks is obtained the estimation of the safe future service life becomes rather uncertain. Moreover, hydrostatic testing can cause crack growth of near critical cracks thus reducing the expected safety margin. Additionally, hydrostatic tests are expensive and time consuming, as the line has to be taken out of service.

Another approach to find SCC in pipelines relies on predictive models and investigative excavation. The effectiveness of predictive models (soil models) for finding sites assumed to be susceptible to significant SCC depends on a number of parameters thus making this method unsuitable for detection and prioritization of SCC.

The UltraScan CD is an in-line inspection tool developed with the goal to reliably detect and size cracks and related crack-like defects in pipelines. It is a superior alternative to hydrostatic retesting and the other approaches mentioned.

The UltraScan CD is based on using 45° shear waves, which are generated in the pipe wall by angular transmission of ultrasonic pulses through a liquid coupling medium. This is a standard technique for ultrasonic crack inspection established many years ago (Krautkramer, 1986)

Because SCC is generally oriented perpendicularly to the main stress components, i.e, to the hoop stress, the ultrasonic pulses are injected in a circumferential direction to obtain maximum acoustic response.

IPC -96- 345 (Ref. 136)

Internal Inspection Device for Detection of Longitudinal Cracks in Oil and Gas Pipelines - Results from an Operational Experience

H.H. Willems
PipeTronix, Germany

Pipetronix has develop a new generation of internal inspection device for the detection of cracks in pipelines. Since its commercial introduction in October 1994 the tool, UltraScan CD, has successfully inspected nearly 1,000 km of operating oil and gas pipelines. The performance has proved the UltraScan CD to be a reliable internal inspection device for the detection of Cracks (SCC, Fatigue and other crack like defects) in pipelines. As a result, the German TUV has approved the use of UltraScan CD as a substitute for hydrostatic pressure testing of pipeline.

The new tool is based on the ultrasonic technique since only ultrasonic allows for the in-line detection of external as well as internal cracks with the necessary sensitivity and high resolution. The technique applied uses shear waves, which are generated in the pipe wall by angular transmission of the ultrasonic pulses through a liquid coupling medium (oil, water etc). The angle of incidence is adjusted such that a propagation angle of 45 is obtained in pipeline steel. This technique has proven appropriate for crack inspection and it is established as one of the standard techniques in ultrasonic testing.

IPC 1996 – 329 (Ref. 134)

R&D Advance in Corrosion and Crack Monitoring for Oil and Gas Lines

D.L. Atherton
Queen's University

Magnetic Flux Leakage (MFL) inspection techniques for in-line corrosion monitoring of pipelines continue to evolve rapidly. Current R&D is aimed at improving the accuracy and reliability and consequent need to characterize the magnetic properties of the pipes and effects of line pressure, residual and bending stresses on MFL signals. Magnetic Barkhausen Noise (MBN) measurements are being used to study the stress-induced changes in magnetic anisotropy. Remote Field Eddy Current (RFEC) Techniques are being investigated for detection and measurement of stress corrosion cracking in gas pipelines.

Smart pigs using MFL detectors are still the most cost-effective method of inspecting pipelines for corrosion. The general advent of high-resolution tools and the introduction of extra high-resolution tools have more precise defect sizing. Depth indications correct to 5% are desired so that accurate fracture mechanics calculations of maximum allowable operating pressure can be made. The MFL signal depends not only on the defect and tool characteristics but also on the running conditions, such as line pressure stress, and on the magnetic properties of the particular line pipe, which vary greatly.

Crack detection and measurement are much more difficult challenges than corrosion monitoring. The techniques currently under development are ultrasonic and electromagnetic, specially the Remote Field Eddy Current (RFEC) method. In gas lines it is difficult to couple ultrasonic energy efficiently into and from the pipe wall; signal processing, or rather discrimination, is also proving to be a serious problem, partly because of the relatively small number of sensors which can be used. Whilst results from high resolution ultrasonic detection tools in liquid lines are encouraging, there is resistance to the use of liquid slugs in gas lines, although more valuable data is obtained than from a simple hydrostatic test.

An RFEC tool uses a relatively large internal coaxial solenoidal exciter coil driven with low frequency AC. They can detect defects on the inside or the outside of the pipe wall with approximately equal sensitivity. RFEC probes use both phase and amplitude information to give both signal discrimination and defect measurement.

OMAE Piping Technology 1993 (Ref. 352)

Integrity Assessment of Offshore Pipelines by Use of Intelligent Inspection Tools

M. Beller And W. Garrow
Pipetronix GmbH

As the international pipeline systems are growing in age it is of ever increasing importance that operators are supplied with the technology to inspect and assess the state of their pipeline. It is for this reason that inspection tools have been developed and introduced into the market utilizing non-destructive testing techniques (NDT) to inspect pipelines without the need of a shut down during the survey. These vehicles are generally known as on-line inspection tools or intelligent pigs. Furthermore with the introduction of large diameter, high pressure offshore lines for oil or gas in the last twenty years and constant addition to this offshore network on a worldwide scale intelligent pigs are increasingly being used in the commissioning stage in order to perform base-line surveys.

Basically flaws and defects in pipelines can be distinguished into one of the following categories: Geometric Anomalies; Metal Loss; Cracks or Crack like Defects.

Geometric anomalies related to any change in the geometry of a pipe such as dents, ovalities or wrinkles etc. Two of reasons are a critical reduction in free internal diameter and the formation of locally acting stress concentrations. Regular or intelligent pigs are used.

Metal Loss features usually relate to internal or external corrosion. Intelligent corrosion detection pigs must therefore be able to reliably detect and measure corrosion flaws and to accurately locate them.

The following types of cracks can be found in pipelines: Fatigue cracks; Stress Corrosion Cracks; Sulfide Stress Corrosion Cracks. The types of potential defects for onshore and offshore installations are similar, although the frequencies with which they occur are different. Whilst most failures of onshore pipelines are attributed to third party mechanical interference, most defects in offshore lines are caused by corrosion.

Pipeline & Gas Industry (Ref. 258)

Stress Corrosion Crack In-Line Pig Shows Promise in Tests

Keith Grimes
British Gas, Inspection Services, Inc., Houston

Stress corrosion cracks, the most difficult pipeline defect to detect with a survey pig, may soon yield to in-line inspection technology.

Inline inspection techniques - smart pigs - to detect and quantify the first two defect categories (Geometric Deformation: dents, ovality; Metal Loss: corrosion, mechanical damage), have gained wide acceptance in recent years and many pipeline operators have instituted regular inspection programmes to aid maintenance and assure pipe integrity.

Cracks have proved to be the most difficult to detect. There currently is no commercially available in-line inspection system with proven crack detection capacity. BG developed a pig-based system to detect and size longitudinal cracks.

Technique:

A method, which utilizes elastic waves at ultrasonic frequency, was selected as the basis for development. Ultrasonic waves are injected into the pipe wall so that they travel circumferentially around the pipe and are detected when they are reflected from axial cracks. Elastic waves are transmitted in both directions to allow a comparison of echoes from both sides of the reflector.

Because high frequency elastic waves will not propagate through gas, the essential requirement is for some means of transmitting the energy into the pipe wall without excessive attenuation.

(Ref. 262)

Which Smart Pig Do I Choose? A Comparison of Magnetic Flux Leakage Technologies From an Operator's Viewpoint

Ken Plaizier

We used hydro testing as an inspection method every five years up to the mid-1980's. Without hydro testing as an inspection option, smart pigs become the option of choice.

Our division began using magnetic flux leakage (MFL) smart pigs in the early 1980's to assess pipeline integrity. Low resolution MFL tool in 1989.

To know the priority in which lines should be inspected, a risk assessment first needs to be developed by each pipeline company. Each pipeline segment we operate was evaluated as to the probability and consequence of a leak, and numerical values assigned to each segment.

Smart Pig Evaluation:

Low Resolution Magnetic Leakage Tools:

These smart pigs have been around for some time, and have produced satisfactory results for many pipeline operators. While unable to differentiate between internal and external defects, they can detect the majority of defects in pipelines. Costs for this tool typically run between $600 and $1200 per mile.

High Resolution Magnetic Leakage Tools:

An exciting and more costly new alternative for pipeline operators, "high-resolution" MFL tools come in limited sizes. Cost for this tool typically will cost $1500 to $4000 per mile.

Ultrasonic Tools:

These smart pigs use ultrasonic technology to measure remaining pipe wall thickness. Until very recently these smart pigs have not been able to inspect thin-wall pipe (≤0.250). Even now, the technology for inspecting thin walls is somewhat difficult, if not untested, using third-wave processing. There are other limitations with this type of tool, such as requiring a couplant, being able to detect small pits with sharp wall shapes, etc., which may be a factor for the operator.

PPITC-1992 (Ref. 259)

Inspection Technologies for a Wide Range of Pipeline Defects

Keith Grimes

The main investment has been concerned with metal loss inspection using highly developed magnetic flux leakage technology. British gas has developed two unique systems for the detection and measurement of the other major causes of pipeline failure.

The elastic wave system is designed to detect longitudinal cracks, while the burial and coating system inspects offshore pipelines for free spanning, pipeline exposure and damage to the weight coating.

Metal Loss:

In common with most other pipeline operators, British Gas identified metal loss, cause by mechanical interference and corrosion mechanisms, to be the most likely cause of pipeline failure. British Gas took MFL basic techniques and introduced major refinements and engineering innovations.

Crack Detection:

Of all the forms of planar defect that can occur in a pipeline, those oriented radially and longitudinally have the greatest structural significance. Two such types of crack are the result of fatigue and stress corrosion.

A method, which utilizes elastic waves at ultrasonic frequencies, was selected as the basis for development.

Burial and Coating:

Offshore pipeline operators have adopted sub sea surveillance methods to inspect for the following threats to pipeline integrity:

1. Exposure of the pipeline on the seabed
2. Damage to, or loss of, concrete weight coatings;
3. Presence and nature of unsupported spans.

Current techniques employ such methods as sidescan sonar, sub-bottom profilers, ROV and diver visual survey. These techniques, particularly diver and ROV survey are expensive.

A pig-based system has obviously advantages. Firstly the pig cannot drift unknowingly off the pipeline. Secondly, the quality and timing of the inspection are not affected by sub sea visibility or weather conditions, and thirdly, shallow waters and intertidal area can all be inspected in the same inspection mission.

The inspection technique employed is based on a neutron-interrogation method. The core of the vehicle holds a neutron source, normally held within a radiation shield, but capable of being exposed when required. Once the source is exposed, neutrons pass through the pipeline steel and the concrete coating into the surrounding medium.

The neutrons interact with the surrounding material, producing radiation characteristic of the composition of that material. Some of the characteristic radiation travels back into the pipeline and is detected by sensing units mounted circumferentially around the pig. The data is then recorded by the on board electronics.

(Ref. 263)

In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines

Final Report on Tasks 1 and 2

T. A. Bubenik, J.B. Nestleroth
Battelle

This report is a summary of work conducted for the U.S. Department of Transportation Office of Pipeline Safety under a research and development contract entitled "In-Line Inspection Technologies for Mechanical Damage and SCC in Pipelines". This project is evaluating and developing in-line inspection technologies for detecting mechanical damage and cracking in natural gas transmission and hazardous liquid pipelines.

Task 1: Mechanical Damage

Mechanical damage is the single largest cause of failure on gas-transmission pipelines today and a leading cause of failures on liquid transmission lines. Mechanical damage defects typically show a number of features, such as denting, metal movement, and cold working. The most significant of these features from the perspective of defect severity are the size and extent of the cold worked region.

From an inspection perspective, cold work and residual stresses and strains change the magnetic properties of the steel, confounding inspection results. Denting changes the orientation of the pipe wall with respect to the fixed orientation of sensors on an inspection tool. And removed metal produces a signal of its own, adding further complexity.

MFL has been shown to be capable of detecting some mechanical damage. Part of the signal generated at the site of the mechanical damage is due to geometric change – for example, a reduction in wall thickness due to metal loss causes an increase in measured flux and sensor/pipe separation. Other parts of the signal are due to change in magnetic properties that result from stresses, strains, or damage to the microstructure of the steel.

Inspection-tool variables, such as the strength of the applied magnetic field, impact the ability to detect and characterized defects.

Inspection –run variables, such as tool velocity and line pressure, also impact the results. Velocity reduces the strength of MFL signals. Pressure affects the stresses in the pipe wall (and adds stresses around dents and gouges), which in turn change the magnetic properties of the pipe steel.

MFL signals for metal loss, dents, cold work, residual stress, and plastic strains are fundamentally different signal components as a means of assessing the severity of mechanical damage defect.

MFL inspection tools that are designed to detect metal-loss corrosion are not optimized for detecting mechanical damage. These tools use high magnetic fields to suppress noise sources due to stresses and micro structural change, such as cold work, which diminish sizing accuracy for corrosion. However, a mechanical-damage tool needs to detect changes in microstructure and stress.

MFL is the most commonly used in-line inspection method for the detection of corrosion in pipelines, extending this technology for mechanical damage would simplify and have many practical and economic benefits.

Analysis Methodologies:

a. Feature Based Analysis Methods

Feature-based analysis methods make use of discrete signal parameters, such as peak amplitude or peak-to-peak amplitude. Peak amplitude is tha maximum recorded value in an inspection signal, and peak-to-peak amplitude is the difference between the maximum and minimum recorded value in an inspection signal.

To improve the ability to reliably detect, classify, and size mechanical damage defects, Battelle developed a multiple magnetization approach. The approach requires two magnetizing levels: high level for detecting geometric deformation and low level for detecting both magnetic and geometric deformation. Classifying and determining the severity of the damage requires additional signal processing. Decoupling is used to extract unique signal due to geometric and magnetic deformation. Using the geometric and magnetic signal, different types of damage become apparent.

b. Nonlinear harmonic Methodologies

The nonlinear harmonic method is an electro-magnetic technique that is sensitive to the state of applied stress and plastic deformation in steel. A sinusoidal magnetic field is applied at a fixed frequency. Odd-numbered harmonic of that frequency are generated because of the nonlinear magnetic characteristics of ferromagnetic materials. Detecting and measuring the harmonic signal can infer changes in magnetic properties.

c. Neural Network analysis Methods

A neutral network analysis method used a large number of relatively simple calculations to make a prediction. As an example, a neutral network might be designed to predict the shape of a corrosion detect or classify a possible defect based on information contained in the MFL signal.

Three kinds of neutral networks for characterizing mechanical damage were developed and evaluated at Iowa State University. The results from this work demonstrate the feasibility of using a neutral network approach for differentiating between mechanical damage and corrosion, characterizing defect profiles from MFL signals.

Task 2: Cracking

Stress-corrosion cracking (SCC) is a complex phenomenon associated with several in service and hydrostatic restest failures on gas and liquid pipelines. The exact mechanisms that lead to SCC and the field and operating conditions that affect cracking are the subject of ongoing research.

Intergranular SCC usually occurs in colonies, where the cracks are often branched and irregular at their tips. As a result, using ultrasonic techniques to measure crack-tip signals for sizing is difficult. The difficulty is compounded by the presence of background signal from ultrasonic energy that are scattered by the crack face reflected off the nearby pipe surface, and converted from one mode to another at interface.

Inspection Techniques:

There are a number of problems associated with sizing near-surface axial cracks from the out side surface of the pipe. A primary difficulty is the inability of conventional ultrasonic procedure, such as shear-wave and amplitude based techniques, to locate the end points of the flaw in both the axial and through wall direction.

The SwRI techniques are termed SLIC, which refers to the simultaneous use of shear and longitudinal waves to inspect and characterized flaws. The techniques were developed in the 1980s and early 1990s.

Four techniques using the SLIC systems were evaluated for sizing cracks: amplitude-drop, phase-comparison, peak-each, and satellite-pulse. Each technique was calibrated against four electro-discharge machine (EDM) axial notches placed in one of the test specimens. The amplitude drop technique was used for estimating the crack lengths. The phase-comparison technique in conjunction with the peak-echo and satellite-pull techniques were used for depth.

One of the reasons that many cracks cannot be effectively detected and characterized by current MFL tools is that the applied magnetic field has an orientation parallel to axial cracks, such as those due to SCC. Velocity-induced remote-field effects and current perturbation has strong components that are oriented preferentially for detecting axial cracks.

In order to investigate the feasibility of the technique, a three-dimensional finite element model for simulating the velocity-induced fields in the remote region and the effect of cracks on these fields was developed.

Like velocity-induced remote-field techniques, remote-field eddy-current techniques are sensitive to axial crack-like defects. The fundamental difference between this technique and the one discussed above is in the generation of the source electromagnetic field. The remote-field eddy-current technique uses a sinusoidal current flowing in an exciter coil to induce currents in the pipe, while the velocity-induced remote-filed technique uses the permanent magnets on the inspection tool.

(Ref. 264)

Offshore Pipeline Girth Welds: Non-Destructive Testing

P.J. Mudge
Welding Institute

Non destructive testing is an important activity in the pipe laying process, it being applied to prevent defects in girth welds made in the field, which are outside the limits imposed by the appropriate code, being present when the pipeline enters service. Consequently, the purpose of this programme was to provide sufficient information about both conventional NDT techniques already in use. In order to enable recommendations to be made concerning optimum use of NDT, the performance of NDT has been examined in the context of ensuring that girth welds meet the requirement of the specified standards.

Four techniques have been considered:

(i) The widely used panoramic radiography, with an X-ray crawler inside the pipe and a film wrapped around the joint on the outside.

(ii) Manual ultrasonics, which in some instances is used for localized testing;

(iii) Mechanized ultrasonics, which is capable of scanning the whole weld, but which has yet to gain wide acceptance; and

(iv) Real time filmless radiography, which is under development, but has the advantage of eliminating the difficulties of rapid film processing and viewing and has the potential to make interpretation easier.

To achieve 100% examination of the weld volume, panoramic X-radiography is widely used, with the source situation inside the pipe and positioned on the axis, and the film wrapped around the outside of the joint.

For small diameter pipes (usually less than around 250mm diameter), a gamma ray-emitting isotope placed inside the pipe is used as the source of radiation, or alternatively a double wall exposure is taken with both film and radiation source (X or gamma) outside the pipe.

Manual ultrasonics is employed in some cases for localized testing where the radiography has detected a discontinuity, which is marginally acceptable or reject able according to code requirements. Magnetic particle inspection is used on a similar basis when surface breaking defects are suspected.

A device has been built which allow ultrasonic probes to be transported around the joint circumference by a mechanized scanner, so that the entire weld can be tested ultrasonically.