UKOPA
United Kingdom Onshore Pipeline Operators' Association

Good Practice Guide

Remaining Life Assessment

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GUIDANCE ISSUED BY UKOPA:

The guidance in this document identifies what is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered guidance and should not be considered obligatory against the judgement of the Pipeline Owner/Operator. Where new and better techniques are developed and proved, they should be adopted without waiting for modifications to the guidance in this document.

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CONTENTS

1. EXECUTIVE SUMMARY

This UKOPA good practice guide has been developed by the UKOPA Pipeline Integrity Working Group to provide guidance on assessing the remaining life of pipelines. The guidance within the document is applicable to assets operated by the UKOPA member companies.

The document provides advice on the assessments and studies that should be carried out in accordance with the recommended practice presented in the Technical Specification ISO/TS/12747 Petroleum and natural gas industries - Pipeline Transportation systems – Recommended practice for pipeline life extension.

The document considers the assessment process and requirements recommended in ISO/TS/12747 and provides guidance on the requirements for data compilation and the assessment of the technical integrity of the pipeline system and future threats to onshore pipeline systems. The document then provides advice and guidance based on UK pipeline codes and standards for on the assessment of:

- Risk
- System design
- Integrity management during extended life
- Update of systems and procedures

2. OBJECTIVE

The objective of this good practice guide (GPG) is to provide guidance to pipeline operators on a consistent approach to the assessment of the remaining life of UK onshore pipelines based on the assessment process and requirements recommended in ISO/TS/12747, and the requirements of UK pipeline codes and standards.

3. INTRODUCTION

3.1 Background

Pipelines are long life assets and their safe operation is controlled by legislation which requires integrity assessments to confirm fitness for operation. Some UK pipelines were constructed in the 1950s, and more than 50% by length of pipelines operating in the UK are over 50 years old. There have been a number of changes in the design, construction, operation and maintenance requirements of the pipeline codes and standards in this period.

The requirement for an operator GPG for the life extension of pipelines and associated installations was identified in the UKOPA Strategy Review carried out in 2015.

3.2 Scope

This GPG provides guidance on assessing the remaining life of onshore UK pipelines and their associated installations. The scope of the assets covered is shown in

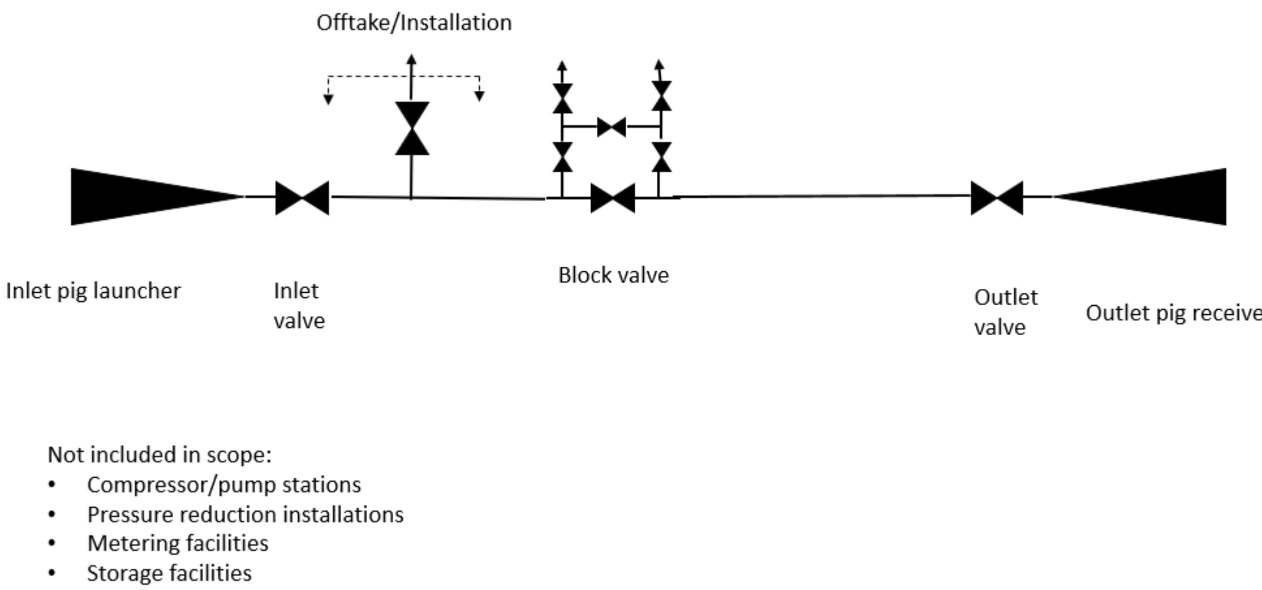


Figure 1.

3.3 Application

The guidance in this document is applicable to assets within the scope shown in

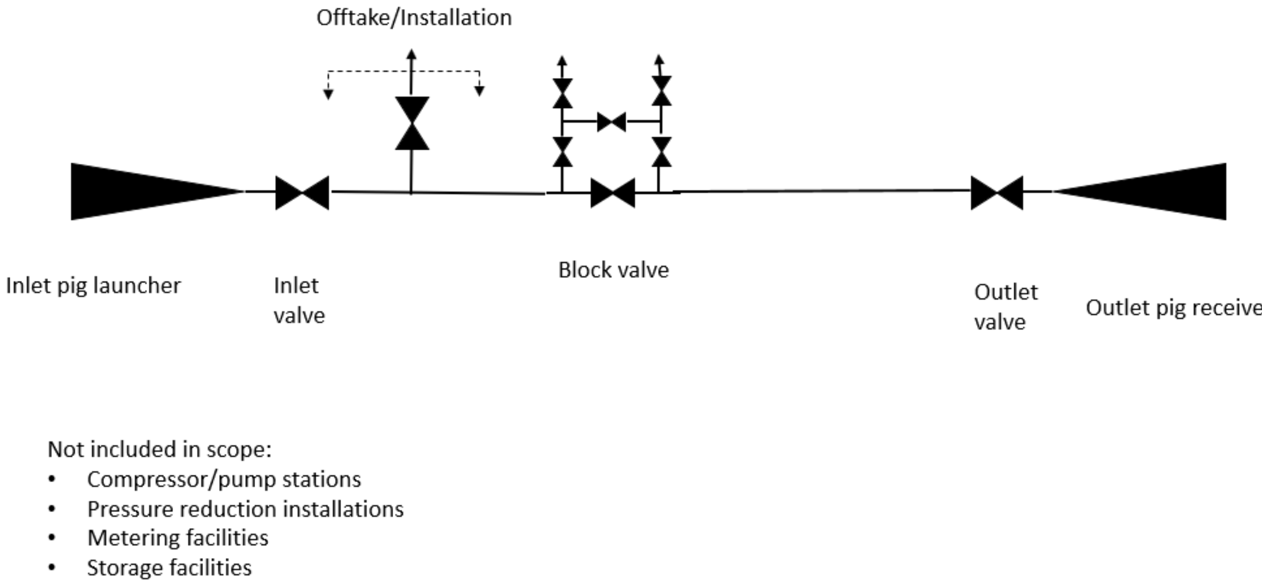


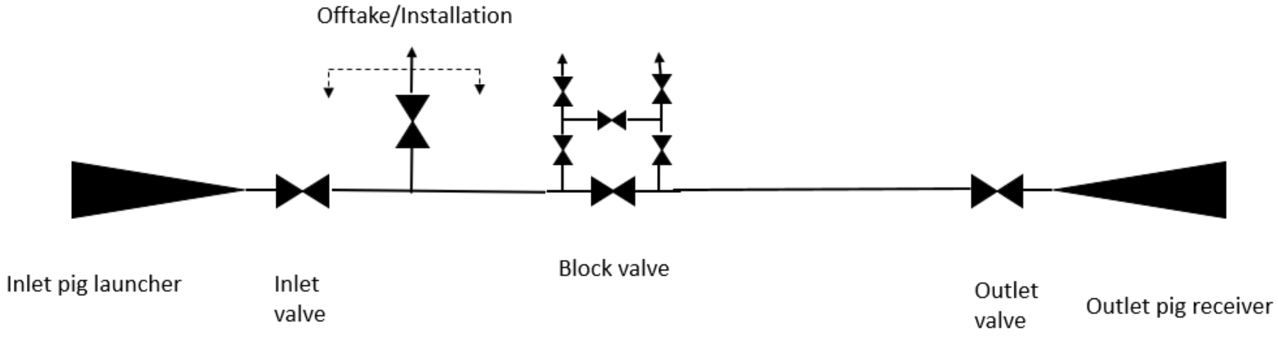
Figure 1 operated by the UKOPA member companies, including:

- Above 7 barg natural gas pipelines
- Petrochemical liquids and gas pipelines
- Oil and refined liquid pipelines

Within this document:

Shall: indicates a mandatory requirement.

Should: indicates good practice and is the preferred option.



Not included in scope:

- Compressor/pump stations
- Pressure reduction installations
- Metering facilities
- Storage facilities

Figure 1 Extent of Pipeline System covered by GPG

4. METHODOLOGY

Guidance on the remaining life assessment is presented in this GPG is informed by the methodology presented in ISO/TS/12747.

The design life of pipelines and installations is specified to prevent failure due to time and duty dependant degradation mechanisms such as corrosion and fatigue. As operator pipeline integrity management systems (PIMS) control the integrity of the system through inspection, maintenance and repair throughout the operating life, the pipeline and installations are likely to be fit for purpose at the end of the design life, and formal extension of the design life will be desirable if there is a continued need for the assets.

4.1 Remaining Life Assessment Process

Where the pipeline system is to be operated beyond the original design life, an assessment of the remaining life should be performed. A flowchart for the remaining life assessment of the pipeline system is given in Figure 2. This includes:

1. Requirements for initiating the remaining life assessment
2. Identification of time and duty dependent threats
3. Identification and screening of existing defects, repairs and features
4. Methods and guidance for assessment of fatigue, corrosion and vibration
5. Assessment of remaining life and remediation actions

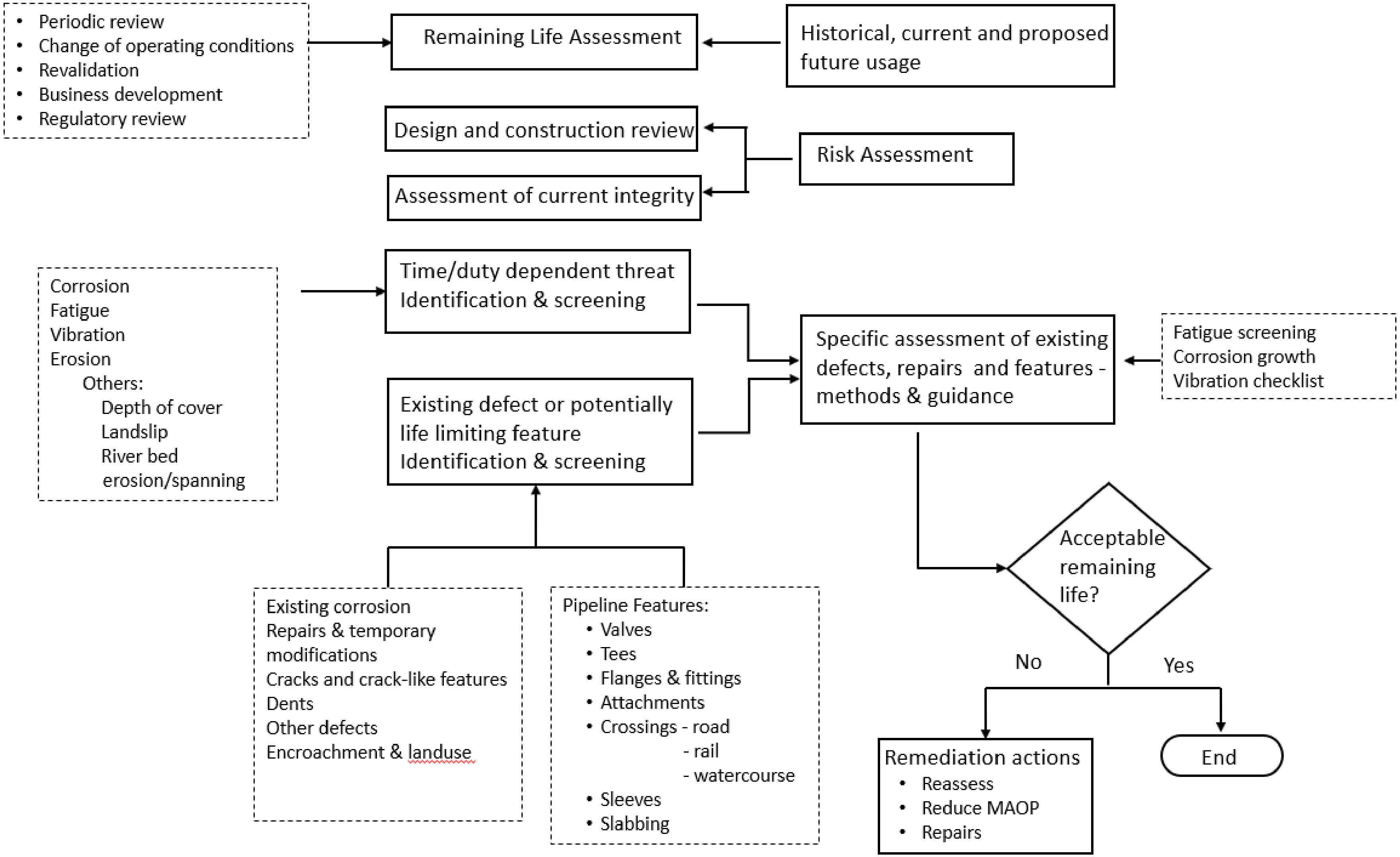


Figure 2 Process for Assessment of Remaining Life

4.2 Assessment Requirements

The assessment requirements are summarised below taking account of the relevant requirements of UK pipeline codes and standards, and UKOPA GPGs.

4.2.1 Historical, Current and Propose Futured Usage

Life extension of pipelines may be required for one of several reasons:

1. Continued operation for transport of the same product (or product group) at the same operating conditions
2. Future operation for transport of the same product (or product group) at different operating conditions
3. Future operation for transport of a different product (or product group) at the same or different operating conditions

This document addresses 1) and 2) above where the future operating pressure and temperature range do not exceed historical values. Where future operating pressure and temperature range exceed the historical values, pipeline uprating in accordance with IGEM/TD/1 or PD 8010-1 is required. Where future operation is required for a different product or product group at the same or different operating conditions, pipeline change of use and possible uprating in accordance with PD 8010-1 is required.

4.2.2 Risk Assessment

The purpose of the risk assessment is to evaluate the risk posed by the pipeline and associated installations to population and infrastructure in the vicinity. The risk assessment shall take into account developments which have occurred over the life of the pipeline system and the occupancy of these developments.

Risk assessment of pipelines must be conducted in accordance with the UK risk assessment standards IGEM/TD/2 for natural gas pipelines, and PD 8010-3 for other pipelines. The failure frequencies due to damage mechanisms should be taken from the latest issue of the UKOPA Pipeline Product Loss Incidents and Faults Report. The assessment of age and duty-based damage mechanisms (corrosion, fatigue and vibration) should be reviewed taking into consideration the results of the integrity assessment described in Section 4.2.4.

The pipeline risk assessment should take into consideration the deterioration of control measures such as loss of depth of cover, marker post degradation etc. which may not be directly linked to time. Reference should be made to published UKOPA GPGs.

Risk assessment of installations should be conducted in accordance with the principles of IGEM/TD/2 and PD 8010-3. Specific consideration shall be given to:

- Identification of generic loss of containment events and relevant failure rate databases
- The scenarios for significant product release from above ground pipework and vessels, below ground pipework, and the potential impact of releases on adjacent pipework, vessels and equipment
- The contribution of equipment failures and reliability
- Releases in enclosed and congested spaces
- The assessment of dispersion, fire and explosion of all release scenarios

- The impact of external events, including intentional damage
- Assessment of domino events;
- The calculation of individual and societal risk levels inside the site security fence and the impact on personnel outside the site security fence and the impact on members of the public

Risk levels for installations should be assessed using the individual and societal risk criteria given in IGEM/TD/2 and PD 8010-3.

Guidance on the acceptability of risk and target Probability of Failures (PoFs) given in ISO 16708 should be applied.

4.2.3 Design and Construction Review

Design and construction details for the pipeline and installations should be reviewed against the requirements of the current pipeline standards IGEM/TD/1 and PD 8010-1. As a minimum the review should take account of:

- Material properties, design criteria and testing of the pipeline.
- Pipeline as-laid route maps
- Installation of isolation valves
- Pressure control and emergency shut down systems
- Depth of cover
- Pipeline sleeves
- Pipeline and pipework support and anchors
- Road, rail and water crossings (including any changes to traffic routes and reassessment of traffic volumes)
- Above ground crossings
- Evaluation and mitigation of internal corrosion
- Evaluation and mitigation of external corrosion (including AC and DC induced corrosion, SCC, MIC)
- External coating integrity
- Proximity to and crossing of other pipelines and services
- Pipeline protection measures
- Assessment of changes in environmental loading, including effect of adverse ground conditions, ground movement (due to land sliding, subsidence and settlement), frost heave, buoyancy due to changes in the water table and erosion at riverbanks, vehicle loading and seismic events

- Route survey to identify any infrastructure and population density infringements, and risk assessment of identified infringements

The above assessments should include a review of original design and construction records. Where primary records (material certificates, pressure test records, Original Equipment Manufacturer (OEM) records, construction inspection records) are not available, secondary records (other construction records such as data sheets or material orders, company database entries, primary records for equivalent materials/components from the same manufacturer procured at the same time, evidence of company quality control procedures in place at the time) may be considered.

Where secondary records are used for the design and construction review, the effect of data uncertainty should be taken into account and demonstration of the acceptability of the data assessment should be documented based on:

- A cautious best estimate quantification of the uncertainty associated with each source of data, and combination of uncertainties for comparison with a justified acceptable limit, or

- A qualitative algorithm or semi-quantitative ‘points-scoring’ model developed to evaluate the adequacy of given levels of available data

A documented fitness for purpose assessment should be carried out on any features or components which do not meet current design and construction standards.

Reference should be made to the pipeline standards IGEM/TD/1, PD 8010-1, IGEM/TD/2 and PD 8010-3, and published UKOPA GPGs.

4.2.4 Current Integrity of the Pipeline System

The current integrity of the pipeline and associated installations should be evaluated against the operation and maintenance requirements of the current pipeline standards IGEM/TD/1 and PD 8010-1. A full operations and maintenance review shall be undertaken including:

- Modifications and repairs since construction
- Operating service history
- Product quality records
- Cathodic Protection (CP) monitoring results and actions
- Condition monitoring (CIPS, DCVG) results and actions
- Inspection results and actions
- Assessment of defects
- Maintenance results and actions
- Leak detection records
- Pressure cycling/fatigue history

- Proximity and population density infringements and area classification
- Operating temperature history
- Products carried previously in the pipeline
- Susceptibility to stress corrosion cracking
- Residual construction and operating stresses, including those due to ground movement (e.g. associated with deep mining, quarrying and landslips)
- Stress analysis of any associated installation and components included in, or attached to, the pipeline
- Proximity of third-party equipment
- Inspection of special crossings (road, rail, water)
- Condition of aerial and pipeline markers
- Condition and performance of primary protection devices, isolation valves and isolation valve actuators
- Condition of pipework, pig traps and pressure vessels
- Condition of anchors and supports
- Condition and performance of electrical, instrumentation and control equipment
- Condition of the pipeline route (including recording of encroachments, damage to above ground or exposed assets, evidence of third-party activities, change in land use, adverse ground conditions)
- Condition of installation sites (including land, buildings, security fence and gates)

It is noted that the majority of essential information should be recorded in the operator's PIMS.

Reference should be made to the pipeline standard for integrity management, PD 8010-4, and published UKOPA GPGs.

4.2.4.1 Corrosion Assessment

A corrosion assessment should be carried out using the inline inspection (ILI) records for piggable pipelines and Close Interval Potential Survey (CIPS) and/or Direct Current Voltage Gradient (DCVG) (as appropriate) data for non piggable pipelines and buried pipework at installations to assess the incidence of corrosion, and the historical Cathodic Protection (CP) performance to assess the corrosion rate.

Any detected ILI corrosion feature, CIPS indication that CP current is being drawn, or DCVG indication that a coating defect exists should be investigated. Where corrosion is indicated, the recommended corrosion rates derived from UKOPA data to be applied to estimate the remaining life are given in Table 1.

Corrosion Rate	Rate (mm/year)
Low	0.05
Medium	0.12
High	0.27

Note: Corrosion rates derived from UKOPA data and applied in Intervals2 model used by the UK gas networks

Table 1 Recommended Corrosion Rates for Buried Pipelines and Pipework

The time for corrosion to grow to an appropriate maximum allowable depth (e.g. 80% wall thickness, ref ASME B31G) should be used to predict the remaining life or the time at which a detailed corrosion assessment of the pipeline or pipework, including repair, should be scheduled. In cases where there are no indications of corrosion features, it is recommended that the remaining life is estimated from the date of the assessment assuming a low corrosion rate.

Guidance on corrosion assessment of buried pipelines and an example is given in Appendix 1. Note, if detailed data for buried pipework at block valves is not available, relevant data for the inlet and outlet pipelines should be used. In addition, relevant fault rates for pipelines can be derived from the UKOPA pipeline database.

An assessment of the susceptibility of buried pipelines and buried pipework to Stress Corrosion Cracking (SCC) should be carried out in accordance with the UKOPA GPG 9 – Managing stress corrosion cracking.

4.2.4.2 Fatigue Assessment

A fatigue assessment to determine the fatigue damage which has occurred on the pipeline since commissioning and to predict the fatigue damage for future operation is required.

The assessment will involve analysis of variable magnitude pressure cycles recorded for the pipeline and installations to identify:

- Cyclic pressures resulting in hoop stresses ≥ 30% SMYS
- Rainflow or reservoir counting of pressure cycles recorded over a relevant operating period, which should include maximum pressure cycling
- Construction of a historical and future fatigue cycle spectra.

The pipeline fatigue assessment shall take account of the fatigue assessment of pipeline dents as detailed in UKOPA GPG 04 – Managing Pipeline Dents.

Guidance on pipeline fatigue assessment and an example is given in Appendix 2.

The fatigue assessment of pipelines should be based on hoop stress cycles assessed using an appropriate S-N model. Reference should be made to UKOPA GPG 04 – Managing Pipeline Dents and TBN 14 Application of S-N Curves to Fatigue Assessment of Pipeline Dents.

4.2.4.3 Vibration Assessment

An assessment of the occurrence of and/or potential for vibration fatigue at pipeline attachments should be carried out, particularly where vibration during operation has been observed. The assessment should take into account any monitoring and assessment of vibration, and/or should recommend whether future monitoring and assessment is required. If required, vibration mitigation measures shall be identified and installed.

Vibration assessment should be carried out in accordance with the guidance given in UKOPA GPG Management of Pipework Vibration GPG 30.

4.2.5 Requirements for Future Integrity Management

The requirements for future integrity management shall be based on the results of the assessments detailed in sections 4.2.1 to 4.2.4 above.

4.2.6 Update of Systems and Procedures

The update of systems and procedures shall include:

- PIMS update, including revision of inspection, surveillance monitoring and maintenance schedules
- Update of control procedures
- Scheduling of specific corrosion assessments of non piggable pipelines and buried pipework at block valves
- Scheduling of specific fatigue assessments of pipelines
- Update of emergency response procedures.

5. RESULTS OF REMAINING LIFE ASSESSMENT

The results of the life extension assessment shall include:

- The remaining life
- Any required approvals
- Details of deviations from the original design basis, and non-conformances with current standards
- Wall thickness assessment results
- Details of corrosion, fatigue and vibration assessments
- Details of residual risks and risk mitigation measures

The results shall be documented in a remaining life assessment report, which shall include recommendations for any required remedial measures or additional inspection and assessment necessary to justify future operation.

6. REFERENCES

ISO TS 12747 Petroleum and natural gas industries - Pipeline Transportation systems – Recommended practice for pipeline life extension.

IGEM/TD/1 Steel pipelines and associated installations for high pressure gas transmission. Edition 5 with amendments 2016.

PD 8010 Pipeline Systems – Part 1: Streel Pipelines on land – Code of Practice 2015+A1:2016

IGEM/TD/2 Assessing the risks from high pressure Natural Gas pipelines Edition 2 2013.

PD 8010-3 Pipeline Systems – Part 3 Steel pipelines on land Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables. 2009+A1:2013.

PD 8010-4 Pipeline Systems Part 4: Steel pipelines on land and subsea pipelines – Code of Practice for integrity management. 2012.

ISO 16708 Petroleum and natural gas industries - Pipeline Transportation systems – Reliability-based limit state methods.

ASME B31.G Manual for Determining the Remaining Strength of Corroded Pipelines

ASTM E1049-85 (2017) Standard Practices for Cycle Counting in Fatigue Analysis

APPENDIX 1 CORROSION ASSESSMENT METHODOLOGY

A simple methodology for the assessment of the probability of corrosion on non piggable buried pipelines and buried pipework at block valves is described below.

Corrosion failure is defined as a leak. The assessment methodology involves:

- Assessment of the corrosion incident probability, taking account of CP, CIPS and/or DCVG data (as appropriate)
- Application of a corrosion growth model based on UK corrosion growth rate distributions for buried pipelines
- Application of a corrosion failure model

Corrosion Remaining Life Example – Non-Piggable Pipeline

The aim of this example is to stimulate thinking when assessing the remaining life of a non-piggable pipeline. The pipeline is based on a typical UK onshore pipeline, but the specifics are for illustrative purposes only. Operators own policy, procedures, experience and knowledge should be applied when carrying out any assessment. There are other published corrosion rates and assessment methodologies which can be applied depending on the situation. In certain circumstances a probabilistic assessment may be more appropriate.

An onshore pipeline operator transports refined product. The pipeline details are described in Table 2.

Property	Detail	Units
Nominal Bore	8	inch
Wall thickness	7.04	mm
Length	16	km
Maximum Operating Pressure	47	barg
Commissioning Year	1964	-
Material	Grade B	-
External Coating	Coal Tar Enamel	-
Corrosion Protection System	Impressed Current	-

Table 2 Corrosion Assessment Example Pipeline Details

The pipeline is non-piggable and there are no plans to modify the pipeline to carry out an internal inspection. Internal corrosion is mitigated via fluid specification and process control. External corrosion is controlled with an impressed current CP system. This is monitored though the pipeline operator's pipeline integrity management system (PIMS).

A detailed record check of test post monitoring and CIPS was undertaken to determine the operating history of the CP system. The results were grouped into three categories based on the potential readings recorded. The results were:

- Between 1984 and 1986 there were three years where CP potentials were between -850 and -550 mV

- Between 1987 and 1996 there were seven years where CP potentials were less negative than -550 mV
- All other years the CP potentials were more negative than -850 mV.

At the maximum operating pressure, the pipeline experiences a stress of 30% SMYS. To determine a remaining life, a limiting feature depth of 80% wall thickness was selected from the ASME B31G methodology. The pipeline operator selected an initial starting depth for a potential feature which had been in the pipeline since commissioning of 10% of the wall thickness. No wall thickness tolerance was considered in the assessment. Table 3 details the applied corrosion rates:

Potential (mV)	Corrosion Rate	Rate (mm/year)
< -850	Low	0.05
-550 to -850	Medium	0.12
> -550	High	0.27

Table 3 Applied corrosion rates

To evaluate the remaining life, the following equation was solved to calculate the potential feature depth in 2019 when the initial feature has grown by the applied corrosion rates:

$$d_f = d_i + N_H \times CR_H + N_M \times CR_M + N_L \times CR_L$$

Where: d_f= final feature depth

d_i= initial feature depth

N_H= number of years at a high corrosion rate

N_M= number of years at a medium corrosion rate

N_L= number of years at a low corrosion rate

CR_H= high corrosion rate

CR_M= medium corrosion rate

CR_L= low corrosion rate

The calculated feature depth to the end of 2019 was 5.25 mm. To predict the remaining life, the pipeline operator applied the low corrosion rate of 0.05 mm/year to subsequent years of operation and determined it would take 8 years for the feature to exceed the 80% wall thickness limit of 5.63 mm.

These results could then be used to inform the decision on how to manage the pipeline's future operations and highlights the importance of maintaining an effective CP system to control external corrosion.

Note: in the event that the predicted remaining life due to corrosion is zero or negative, a detailed corrosion assessment must be actioned immediately.

APPENDIX 2 FATIGUE ASSESSMENT METHODOLOGY

Assessment of Pipeline Pressure Cycle History

Where pressure cycle data is recorded:

Use recorded pressure cycles to assess pressure cycle and number of cycles vs time. Where a complete record is not available, use analysis of recent data. Analysis of the most recent full annual history should be carried out to assess the variation in the cyclic history.

Where there is a high variation in the cyclic pressure loading, it is recommended that 1 year in two over 6 years is used to assess variation.

Where the variation in cyclic pressure loading is low, it is recommended that the maximum annual loading over the previous 5 years is used.

Note – guidance for judgement of high and low cyclic variation to be developed.

Where pressure cycle history is not recorded:

1. Install pressure monitoring equipment and commence recording of data at the earliest opportunity
2. Apply cycle counting method
3. Build cycle history using operational knowledge.

Reasonable assumptions for immediate assessment of fatigue life to be assessed and included, based on

- Cycles per day/month/year for gas pipelines
- Cycles per day/month/year for liquid pipelines

The fatigue calculation methodology is given in Figure A2.1. This methodology assumes three annual pressure ranges which can be extended as required.

It is recommended that factors to account for uncertainty in the estimated number of historical and future cycles are included.

The recommended safety factor to be applied to the calculated fatigue life for buried pipelines and pipework is 10.

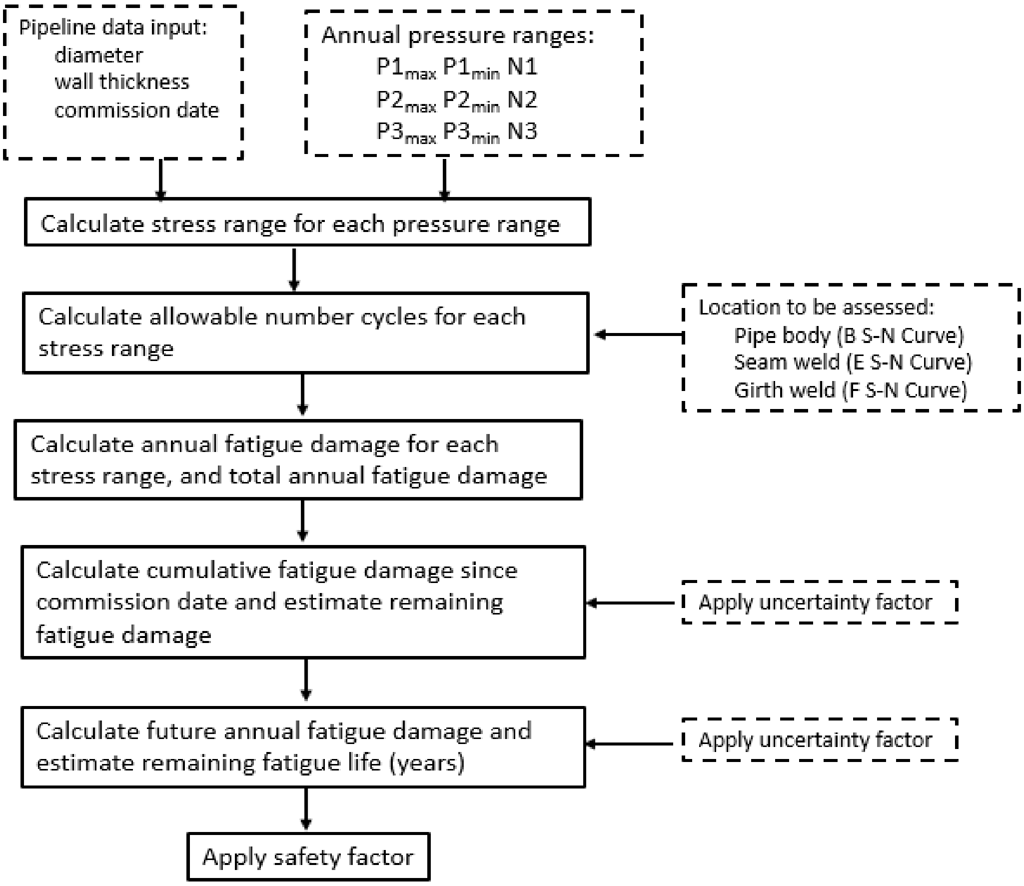


Figure A2.1 Fatigue Calculation Methodology

Fatigue Remaining Life Example

The aim of this example is to stimulate thinking when assessing the remaining fatigue life of a pipeline. The pipeline is based on a typical UK onshore pipeline, but the specifics are for illustrative purposes only. Operators own policy, procedures, experience and knowledge should be applied when carrying out any assessment. This example applies the fatigue calculation methodology given in Figure A2.1. There are other published fatigue models and assessment methodologies which can be applied depending on the situation. In certain circumstances a probabilistic assessment may be more appropriate.

The details of an onshore pipeline are described in Table 4:

Property	Detail	Units
Nominal Bore	10	inch
Wall thickness	5.6	mm
Type	Seam welded	-
Maximum Operating Pressure	100	barg
Commissioning Year	1991	-
Material	X52	-
External Coating	Fusion Bonded Epoxy	-

Table 4 Fatigue Assessment Example Pipeline Details

Pressure monitoring equipment has recently been installed on the pipeline and one complete year of data was available for evaluation. Pressure cycles were broadly split into three categories as shown in Table 5:

Range	Maximum Pressure	Minimum Pressure	Number of Cycles
1	100	92	730
2	100	50	100
3	100	25	365

Table 5 Fatigue Assessment Example Pressure Cycles

The fatigue calculation methodology was used to calculate the remaining life for the seam weld. The same pressure cycling was assumed to have occurred each year of operation. An estimated remaining life of 40 years from 2019 was calculated.

Note: in the event that the predicted remaining fatigue life is zero or negative, a detailed fatigue assessment must be actioned immediately.

Questions to build historical pressure cycling history

A pipeline operator may not have evidence of historical operations. The following questions may be asked to personnel who have worked in the operation or management of the pipeline and have historical knowledge of the system:

Are you aware of any time in the past where the pipeline was operated differently to its current operation? Areas to consider are:

- Different fluids transported
- Changes to normal operating pressures or safe operating limits
- Use of the pipeline for line packing, storage
- Any periods of mothballing / temporary cessation of operation
- Any major changes to the pipeline e.g. cut-outs, diversions, replacements, extensions
- Different wall thickness or material grade sections e.g. crossings, diversions, replacements, extensions
- Equipment operations e.g. pumps, compressors, valves
- Variations to the pipeline's current operations.

Note: It is recommended that fatigue calculations are carried out assuming the minimum wall thickness

Any information gathered can be used to build a more appropriate pressure cycling history. Any information should be cross referenced as appropriate. If the information is used in any modelling, appropriate safety factors should be applied.