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A METHOD FOR THE MONITORING AND MANAGEMENT OF PIPELINE RISK – *A Simple Pipeline Risk Audit (SPRA)*

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ABSTRACT

This paper presents a summary of risk management methods used for pipelines. The use of surveillance methods for monitoring population encroachment along pipeline routes is covered. Methods for the assessment of risks associated with pipelines are presented.

The paper shows how the risk management of a pipeline needs to be audited on a continuous basis. The whole management system needs auditing, but two key elements – the pipeline operating parameters and pipeline route – can be quickly audited in a systematic and thorough manner, by a ***simple pipeline risk audit (SPRA)***.

This short audit allows operators to quickly demonstrate (to all stakeholders) that their pipeline is compliant with the requirments of the applicable design code, and poses negligible risk to the surrounding environment and population. It also allows operators to identify non-conformities in their operation and design, and quickly assess the requirement for remedial measures.

1. INTRODUCTION

Pipelines must provide a safe method of transporting energy, and pipeline operators must ensure that the public, the environment and property are protected from any associated risks.

Pipelines are safe because they are designed to recognised and proven design codes, and they are continually maintained and inspected during service. Operators are aware of the risks that a pipeline poses to the surrounding public and environment and take steps to ensure that the risk is kept to the lowest level that is reasonably practicable. This ‘risk management’ during service is usually focussed on preventing damage to the pipeline, and deterioration due to corrosion.

This paper starts with a brief summary of the safety of pipelines, identifying major risks, and then covers basic elements of risk management. It then discusses the role of surveillance in controlling risks around a pipeline, and how remedial measures can reduce this risk. It ends by introducing a simple and low cost method of monitoring and managing the risk associated with an onshore pipeline – the ***simple pipeline risk audit (SPRA)***.

2. SAFETY AND EFFICIENCY OF PIPELINES, AND THE CONTINUING NEED FOR RISK MANAGEMENT

Pipelines are both safe and efficient. This section gives an overview of their safety and efficiency, with an emphasis on onshore pipelines.

2.1 Safety.

Pipelines are very safe. A study in the 1980s showed that pipelines are 40 times safer than railroad tank cars and 100 times safer than highway tank trucks (1).

The 500,000 mile oil and gas pipeline system in the USA was mainly built between 1950 and 1980. In the 11 year period between 1986-96, accidents involving pipelines accounted for 63 deaths and 396 serious injuries. By comparison, in 1998 alone, 41,480 people died on that nation's highways, 831 in rail accidents, 808 in recreational boating accidents, and 621 in general (non-commercial) aviation accidents (1).

In Western Europe, the 300,000 oil pipeline system transports 634 million m^3 of product. Between 1971 and 1995 oil spillages from these lines caused 12 fatalities, mainly from the oil being subsequently ignited, rather than at the time of the spill. The cause of these spills are given in Table 1

Table 1. Onshore Oil Pipeline Incidents in Western Europe in 1995 (2)

CAUSE	NUMBER	ANNUAL AVERAGE (1991-95)		ANNUAL AVERAGE (1971-95)	
Mechanical Failure	4	5.2	38%	3.5	25%
Operational	1	1	7%	1	7%
Corrosion	1	2.6	19%	4.1	30%
Natural Hazard	0	0.4	3%	0.6	4%
Third Party Activity	4	4.2	31%	4.5	33%
Total	*10*	*13.2*		*13.7*	
Frequency *(no/year/1000km)*	*0.33*	*0.43*		*0.64*	

Clearly, third party activity (sometimes called 'external interference', or 'mechanical damage'), is the main cause of pipeline failures between 1971-95.

It is of interest to note that the failure rate from corrosion (the most likely failure mode from increasing age) has not increased with age up to at least 45 years (Figure 1), demonstrating that corrosion failure can be safeguarded against by inspection and maintenance measures (2).

Third party activities are also the major cause of failure in gas pipelines in the USA and Western Europe. Table 2 contains data from the European Gas Incident Group (EGIG), a group of onshore gas pipeline operators with over 2 million kilometre years exposure, and a database of about 1000 incidents. The database shows the average incident frequency decreasing from 0.56 incidents/1000 km year (1970-92) to 0.48 incidents/1000 km year (1970-97).

Figure 1. The Effect of Pipeline Age on Spills Caused by Corrosion (2)

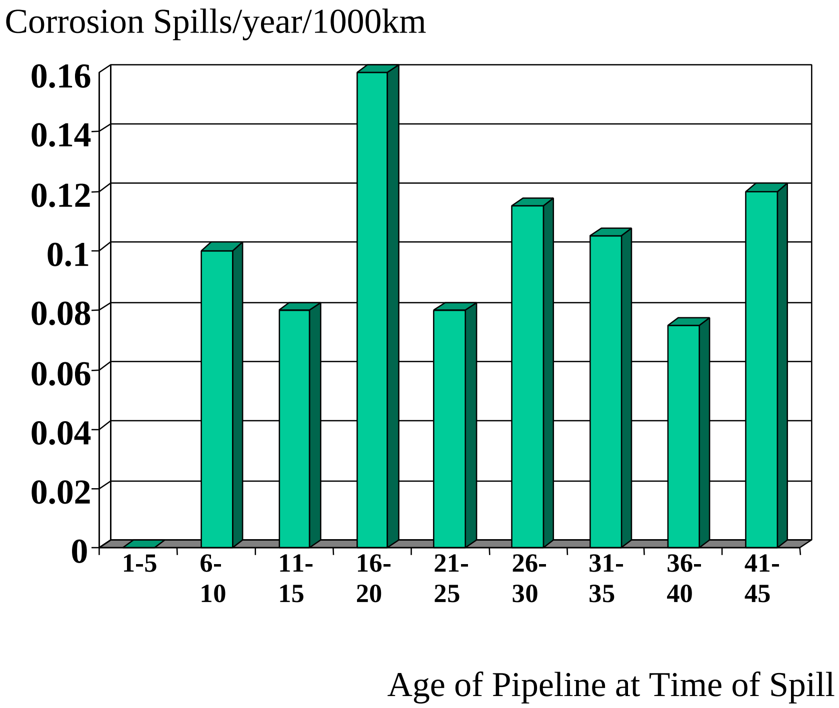


Table 2. Onshore Gas Pipeline Incidents in Western Europe in 1970-1997 (3)

CAUSE	Number
Hot Tap By Error	5%
Ground Movement	6%
Corrosion	15%
Construction/Material Defect	18%
Third Party Activity	50%
Other/Unknown	6%
Total Incidents	*945*
Frequency (No/Year/1000km)	*0.48*

2.2 Efficiency

Pipelines are both safe and economic. The economics of pipelines are impressive, Table 3.

Table 3. How far $1 will Transport 1 Ton of Petrochemical

MODE	DISTANCE, miles
Air	5
Truck	19
Rail	45
Ship	200
Pipeline	238

These efficiencies mean that the income (1997 figures) from liquid lines is typically $14,000/mile/year, and from gas lines it is typically $13,000/mile/year.

2.3 Increasing Pipeline Network

There are many millions of kilometres of pipelines around the world, and these systems are increasing. Approximately 18,000 miles of onshore pipelines have been constructed in 1998. Offshore pipelines amounted to about 3,500 miles. Similar figures were reported in 1997, and the majority of these onshore and offshore pipelines were designed to carry gas, particularly offshore where gas lines accounted for about 75% of the total constructed.

Most of the world’s pipelines are onshore gas pipelines. This environment (onshore) and product (gas) combine to give a risk to the population around the pipeline. Therefore, the greatest risk posed by our pipeline system is that of casualties caused by gas explosions.

2.4 Controlling Risks

An operator must have systems in place that minimise all pipeline risks. Good operational practices and maintenance procedures should reduce operator error, and mechanical failure (see Table 1). However, an operator must also have inspection and surveillance methods in place to reduce the risk of corrosion and third party activities (Tables 1 and 2, and see later).

This paper will later cover the control of third party activities. Control of corrosion involves external monitoring of the quality of the pipeline coating and protection system, and periodic internal inspections using smart pigs. The reader is directed towards the literature (e.g. Reference 4) for information concerning pigging, corrosion monitoring and control.

Most pipeline operators control risks by complying with their regulatory requirements and national codes, but regulatory regimes are generally ‘prescriptive’, and will not be adaptable to differing pipelines with differing needs and associated risks. This presents the dual problems of (i) potentially ‘missing’ new risks, and (ii) creating an inflexible environment, which prevents the application of new technologies that can both identify and mitigate the key risks.

The next section (and Section 5, later) gives a general overview of risk management in business today, then explains risk management, and its advantages, in the pipeline world.

3. RISK MANAGEMENT

3.1 Risk Management In The World Today - A General Overview

Risk management in industry today is very broad in scope; traditionally, companies have taken a narrow view on this, such as only considering risks to their business that can be insured against, principally in finance and credit management (5). This is due to a historical concern with interest rates, financial failure of customers, exchange rates, etc.. Hence, traditionally, the responsibility has fallen on the finance department.

The modern approach is broader and takes into account wider issues such as customer satisfaction and technology (e.g. pharmaceutical companies tend to carry a high risk by having a long product development cycle). Therefore, risk management now monitors and analyses all aspects of business risk, and this is why it is being introduced into pipeline operations.

Risk management responsibility always rests with the executives of the company (the 'board'). It starts at an operational level, being part of the day to day running of the company, and should be included in job descriptions.

3.2 The Move Towards Risk Management In The Pipeline World

Regulatory authorities (6-16) are moving away from prescriptive approaches in pipeline design and operation, to 'risk management' as the safest and most cost effective means of maintaining and improving safety levels in pipelines. Risk management recognises that it is not possible to eliminate all risks, and it recognises that the best way to control risks is the analytical and cost effective use of available resources, and not by simply following regulations and codes (14).

This means that the pipeline industry is changing, from prescriptive (some would say 'restrictive') methods of designing and operating pipelines, to 'goal setting'. Therefore, operators should be aware of these new management methods (17).

Many countries are actively using, or moving towards, risk management methods. The UK, USA, Canada, and Western Europe are all either working to, or developing, risk management approaches or programmes. Section 3.5 briefly covers risk management, and Reference 17 gives a fuller description.

3.3 What is 'Risk'?

All operators want a pipeline that is safe[1] (does not pose a major risk to the population and environment) and secure (does not pose a major risk to supplies). Therefore, they require high 'integrity' which is usually interpreted as a low probability of the pipeline failing.

Risk is calculated by combining the likelihood of a hazardous event, with its consequences:

RISK = f(Probability of Event, Consequence of the Event) … *1*

Therefore, risk is controlled by: controlling the probability of failure, or controlling the consequences of a failure (should it occur), or a combination of both.

3.4 How Do We Currently Deal With Risk?

Traditionally, transmission pipelines are designed in accordance with design codes such as the American Pipeline Standards ASME B31.4 or B31.8. Most national and international pipeline design codes are based on these ASME codes. They minimise risk by controlling factors such as the stress (and hence pressure) in the pipeline, and the population density in the vicinity of the pipeline.

3.4.1 Controlling Design Stresses

Design codes use 'deterministic' limits, e.g. a design stress limit of 72% of the specified minimum yield strength (SMYS), based on conservative assumptions such as minimum

[1] USA Office of Pipeline Safety (8) considers 'safety' as 'the protection of the public, the environment and property' and 'risk' is 'any threat to achieving these goals'.

wall thickness. Therefore, by limiting stress, we can control the probability of failure, and hence control risk, Equation 1.

3.4.2 Controlling Consequences

The pipeline risk is controlled by ensuring that we have a low failure probability in the case of liquid lines, but in the case of gas lines we also limit consequences by limiting the number of people (buildings) in the vicinity of the pipeline (‘population density’).

A first step in the process of setting an accpetable population density limit can be an assessment of the hazard potential of the substance in the pipeline. Some countries have different standards for different substances; for example, in the UK, BS 8010 covers most substances, and IGE TD/1 specialises in natural gas.

3.4.2.1 Controlling the Substance

Substances can be categorised or ranked according to their hazard potential, e.g.:

i. water-based fluids,
ii. flammable and toxic substances which are liquids at ambient temperature and atmospheric pressure conditions, e.g. oil,
iii. non-flammable substances which are gases at ambient temperature and atmospheric pressure conditions, e.g. nitrogen,
iv. flammable and toxic substances which are gases at ambient temperature and atmospheric pressure conditions and are conveyed as gases or liquids, e.g. methane.

all have differing consequences of failure, and can be ranked accordingly.

The design of pipelines carrying higher risk products (e.g. gas) is dependent on the population density along the route. This dictates the operating stress levels and proximity of buildings. Pipelines carrying low risk substances (e.g. water-based) are not limited in this way, and pipelines carrying substances such as oil are unlikely to be limited, but may require a safety evaluation or extra protection.

3.4.2.2 Classification of Location

3.4.2.2.1 General

Having ranked the hazard potential of the substance in the pipeline, it is now necessary to limit the consequences of any spillage or explosion, by limiting the location and density of the population around the pipeline. This is done by ensuring a pipeline route does not pass through areas of high buildings density, and for gas lines a minimum distance away from normally occupied buildings (Section 3.4.2.2.3).

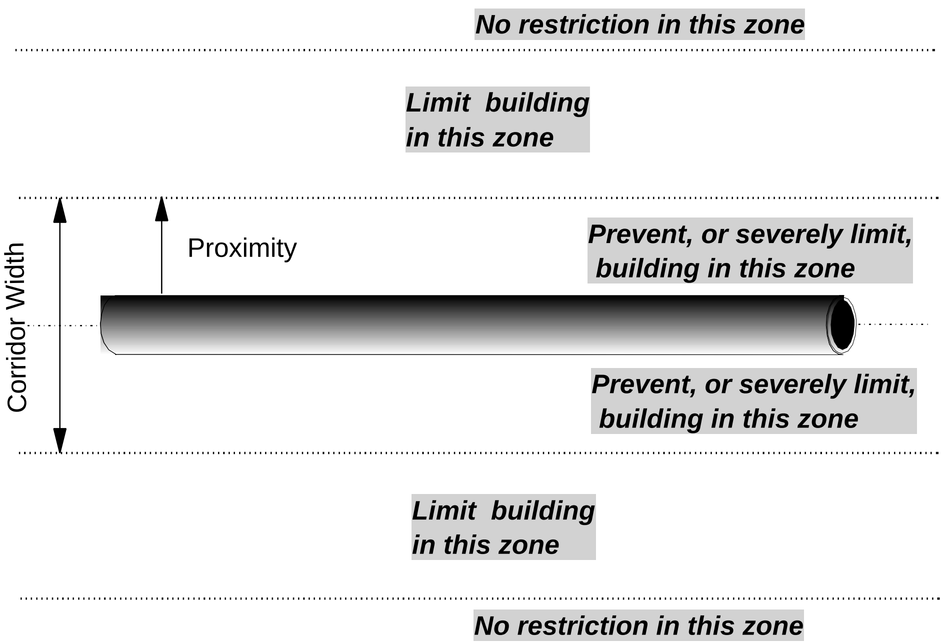
Buildings close to a pipeline will serve the dual effect of:

(a) putting persons in those building at risk, should a pipeline fail, and
(b) increasing the chance of the pipeline being damaged by excavating activities related to those buildings and their services.

Therefore, most pipeline standards require buildings to be either limited in number, or prevented, within a certain distance of the pipeline (see Figure 2). This distance is called a variety of names, typically 'corridor width', or 'proximity'.

Figure 2 shows how pipeline codes limit the consequences of a failure, by ensuring some control of building (and hence population) density around a pipeline.

Figure 2. Controlling Population Density Around a Pipeline



3.4.2.2.2 USA
ASME B31.8 has 'class locations' to minimise the risk to the surrounding population.

Table 4. Classification Scheme in ASME B31.8

CLASSIFICATION	**AREA**	**Design Factor (hoop stress/SMYS)**
Class 1 (Div 1)		0.80
Class 1 (Div 2)	0-10 buildings (rural)	0.72
Class 2	11-45 buildings (areas around towns)	0.60
Class 3	46+ dwellings (e.g. suburban)	0.50
Class 4	Multi-storey-type buildings	0.40

These class locations have their origins in work in 1955 (18) where aerial photographs of exsiting pipelines and their surrounding buildings were analysed and four location classes were established that closely resembled current practices in the design of pipelines. Originally, a 'corridor width' of 0.5 mile wide (now 0.25), with the pipeline at the centre, was used to determine the population density at risk.

It is of interest to note that a study of fires following a gas pipeline failure showed a clear trend between burn radius and pressure, but no correlation with pipe diameter (and hence considered a secondary effect). The study (19) plotted the radius of the burn area around a pipeline against pipeline pressure, and concluded that an upper bound existed between the two points in Table 5.

Table 5. Upper Bound Burn Radius for A Gas Pipeline (19)

Pressure	Radius
260 psi	92ft (28.1m)
987 psi	610ft (186m)

This Table gives a simple ‘rule of thumb’ for safe distances (ignoring wind speeds, terrain, etc.); for example, a pipeline at a pressure of 1000 psi would cause burn damage up to a distance of ~200m either side of its corridor, if it failed and the gas ignited. Most gas pipeline failures do not ignite; on average, ignition will occur in less than 4% of failures, although failures in larger diameter pipelines are more likely to ignite (21% of pipeline incidents on pipe of diameter >16” ignite) (3).

3.4.2.2.3 UK

In the UK the location of highly stressed natural gas pipelines is restricted by ‘proximity’ limits that are a function of pipeline pressure and diameter. These proximities are based on a simple (steady state) fire model using a radiation level of 32 kW/m^2, i.e. there will be very high thermal radiation at the proximity distance. This level was not chosen as a safe level (strong sunlight has a thermal radiation of 1 kW/m^2), but it reflected a judgement in the early 1970s that took account of the low frequencies of pipeline failure, the possibility of escape to take cover from direct radiation, the fact that the majority of the population is indoors most of the time, and the need to route pipelines in a densely populated country (20,21).

Indeed, persons exposed to a natural gas pipeline failure will be at risk up to 3 x the proximity distance if they are indoors, and 8 x the proximity distance if they are outdoors. This partly explains why the Institute of Gas Engineers in the UK bases its population density calculations on a strip centred on the pipeline of a width equal to 8 times the proximity distance.

These methods are all intended to limit the consequences of a failure and, as such, constitute the ‘consequence side of Equation 1.

3.5 Risk (and Integrity) Management

The above section has shown how current codes control risk by a combination of reducing the probability of failure (e.g. limiting operating stress) and limiting consequences of failure (e.g. controlling population densities). However, as stated in Section 3.2, there is a move away from these inflexible traditional approaches, to the more flexible ‘risk management’.

Risk management has been defined by the USA Office of Pipeline Safety as (6,7,11):

‘a comprehensive management decision support process, implemented as a program, integrated through defined roles and responsibilities into the day-to-day operations, maintenance, engineering management, and regulatory decisions of the operator’.

'Risk management' includes both risk (assessment and control) and integrity management aspects and covers three key areas (6,7,11)): Risk Assessment (Analysis), Risk Control and Decision Support, and Performance Monitoring and Feedback.

Reference 17 gives a full summary of risk management systems, and allows operators to develop a full risk management system for their own pipeline system. Section 5 (later) gives the key elements.

4. INSPECTION AND MAINTENANCE METHODS FOR REDUCING RISK.

There are various methods for reducing the probability of a pipeline failing. These methods wil now be summarised.

4.1 Aerial/Ground/Subsea Patrols

Offshore pipelines and river crossing are regularly surveyed either by divers or remotely operated vehicles ('ROVs').

Onshore pipelines are regularly surveyed either by air or ground patrol to ensure that no unauthorised activities such as excavating are taking place near a pipeline, or that building is not taking place within prescribed safety zones around the pipeline. Helicopter surveys and foot patrols can reduce the number of third party incidents, but will not detect corrosion problems. Helicopter surveys are typically carried out every two weeks. Foot patrols are typically undertaken at intervals of several years.

4.2 Awareness and Good Communications

Offshore pipeline operators can benefit from making shipping organisations aware of the location of their pipelines. Similarly, the close control and management of ships (e.g. supply ships) around offshore platforms can reduce the incidence of damage.

Landowners and construction companies should be continually monitored to ensure they are aware of the pipeline on their land, or in a development area. This awareness can be achieved by personal visits, letters, calendars, etc. Many third party incidents are caused by a pipeline owner's own staff, therefore good management procedures are always needed when working on or near a pipeline.

4.3 Leakage Surveys

Inevitably, pipelines will fail, and the scale of this failure varies, ranging from a small leak to a catastrophic rupture. In any event, an operator needs to know when and where his or her pipeline has failed. Therefore, a leak detection system should be considered. These systems can range from simple line walking exercises, to continuous mass balance of pipeline contents, and measurement of pipeline pressure and flow.

Clearly, there are degrees of leak. Large leaks will cause significant change in pressure gradient and differences in flowrates, and will be easily and quickly detected. However, 'small' leaks will be difficult to detect and locate, as the changes they cause to the usual process measurements will be very small, and within the 'noise' levels of the equipment measuring flow, etc..

4.3.1. Simple Systems (‘Seeing or Smelling’)

The simple systems involve flying, driving or walking along a pipeline and looking for evidence of discoloured vegetation around the pipeline, or hearing or smelling (if the fluid is odorized) a discharge. ‘Unofficial’ pipeline leak detection is performed by members of staff working near a pipeline (e.g. on an offshore platform) or members of the public living near, or passing, pipelines.

4.3.2. Flow Balance (‘What goes in, must come out’)

Simple line flow balances can be used to detect leakages. This involves measuring inputs and outputs of a pipeline. A loss of product is determined as the difference between the steady state inventory of the system and the instantaneous inlet and outlet flows.

4.3.3. Acoustic Methods (‘Leaks are noisy’)

Noise associated with a leak can be detected. These frequencies, caused by vibration, can have frequencies in excess of 20 kHz. Transducers can be clamped to a pipeline, and by noting signal strength, the source of the leak can be pinpointed.

4.3.4 Pipeline Modelling (‘Theory versus Operation’)

Real time pipeline modelling, which simulates the operation of the pipeline and continually compares the expected with the actual, can offer both detection and location. There are commercial packages on the market that may be appropriate to certain pipeline operations.

The model is a mathematical representation of the pipeline and will include such features as elevation data, valve and pump locations, etc.. The model can then calculate the expected pressures, flows etc., and compare them with what the measurements are showing. Any discrepancy may be a leak, and leak alarms can be triggered if this is the case.

4.5 Fluid Quality Control and Pipeline Corrosion Prevention

The substances in the pipeline can cause a pipeline to corrode internally, if their quality is not carefully monitored. The presence of other products, e.g. water, carbon dioxide and hydrogen sulphide can lead to corrosion.

Offshore pipelines are prone to internal corrosion because the control of product can be difficult, whereas onshore pipelines are more at risk from external corrosion. The pipelines are protected by coatings, but no coating is perfect, therefore pipelines are also cathodically protected (CP). The condition of both the coating and CP system must be periodically checked. The coating can be checked by impressing an electric signal onto the pipe and measuring its strength along the pipe. If the coating is uniform, the signal should decrease linearly along the pipeline. The CP system for onshore lines is regularly checked by 'CIPS' - a close interval potential survey which measures the pipe to soil potential.

It should be emphasised that the coating checks and CIPS do not give any indication of the condition of the internal surface of the pipe.

4.6 Inspection Using Pigs

Pigs have been in use in transmission pipelines for many years. The most sophisticated are called ‘intelligent’ (or ‘smart’) pigs, Table 6.

Table 6. Type of Pigs Available

INTELLIGENT PIGS	UTILITY PIGS
Geometry	Batching
Mapping	Gauging
Leak Detection	Cleaning
Loss of coating	Dewatering
Metal Loss	Meter Proving
Cracks	Tracking

Utility pigs are used to assist in the operation and maintenance of the pipeline. There are a variety of intelligent pigs that measure and retain pipeline data. Configuration and mapping pigs are used to check the geometry and location of a pipeline, but the most recent advances have produced smart pigs that can detect and measure pipe wall defects such as corrosion and cracks.

The most commonly used intelligent pigs for detecting metal loss defects use magnetic flux leakage techniques (MFL) to detect defects such as corrosion pits. MFL pigs detect metal loss defects, but most are unlikely to detect axially-orientated, planar defects such as cracks, although new developments (‘transverse field’) are now reaching the market that can detect these type of defects .

Other intelligent pigs use conventional ultrasonics to measure pipewall thickness. They require a liquid coupling between their transducers and the pipewall, which prohibits their use in gas lines, unless they are run in a slug of liquid or the coupling has been attached by other means. Some pigs using ultrasonics technology can detect cracks such as stress corrosion cracking.

4.7 The In-service Hydrotest

Pre-service hydrotesting has been used for many years to 'prove' a pipeline's integrity at the commencement of the pipeline’s life. The hydrotest can be used in-service. However, the in-service hydrotest only gives a demonstration of the pipeline's integrity on the day of the test. If there is an active deterioration mechanism operating (e.g. corrosion or fatigue) it cannot guarantee long term integrity, and also some defects that survive the hydrotest can fail at lower pressures at a later date.

The in-service hydrotest is generally acknowledged as expensive, and requires the shut-down of the pipeline for as much as several weeks.

4.8 Ground Movement

Ground can move due to geological faults, mining subsidence, sand erosion, etc. ROV surveys (offshore) and geotechnical surveys are the best methods for identifying potential ground movement problems.

Land surveying using sophisticated electronic distance measurement can be used to measure land movement in three dimensions. Remote sensing techniques such as radar and laser scanning can be used. Inclinometers measure local movement of land, and the resulting stresses and strains in the pipeline can be measured using strain gauges attached to the pipeline.

4.9 One-Call Systems

The major cause of damage to onshore pipelines is third party interference. This damage is often caused by contractors or farmers excavating earth, oblivious to the fact that a pipeline is below the surface.

Some countries are adopting single co-ordination points for the exchange of information on the location of underground plant. These ‘one call’ systems are commonplace in the USA, and is a legal requirement in the Netherlands.

The one call systems operate in a variety of ways, but a simple one would allow any contractor wishing to excavate the facility to call one telephone number, to alert all utilities who may have plant underground in the vicinity of the proposed excavation. The utilities will then have a short period to either contact the contractor or mark the area where the plant is (if they have plant underground). If the contractor does not hear from the utilities, or there are no markings in the area where the excavation is to take place, the excavation can take place.

There is no legal requirement for a one-call system in the UK. However, there is interest in these systems; a scheme operates in Scotland, and several utilities have joined to trial a system in Cheshire.

4.10 Supervisory Control And Data Acquisition (SCADA)

SCADA refers to the transmission of pipeline operational data (e.g. pressure and temperature) from points along the line, to allow monitoring from a single location. It also usually includes the transmission of data to allow remote operation of valves, etc..

4.11 Summary of Maintenance, Surveillance and Monitoring of Pipelines

Most pipelines are surveyed, maintained and monitored according to a code. This can be illustrated by showing the guidelines issued by the Institution of Gas Engineers in the UK for onshore gas lines.

Table 7. Inspection, Surveillance and Monitoring of Gas Pipelines in the UK

ACTIVITY	RECOMMENDED MAXIMUM INTERVAL
Aerial Survey, or Vantage Point Survey	2 weeks
Full Walking Survey	4 years
Leakage Survey	3-9 months*
Landowner/Authority Liaison	6 months (letter), 1 year (visit)
Internal Inspection, or Above Ground Survey (e.g. CIPS), or Hydrotest	10 years 5-10 years* 20 years
CP Systems	1-3 months*, 10 years (CIPS)

* - Depends on pipeline pressure, systems in use, etc.

The above are recommendations and minimum requirements and are based on previous 'good' practice in the industry.

The effectiveness of these methods can be compared against field data, Table 8.

Table 8. Detection of Incidents on Onshore Gas Pipelines (3)

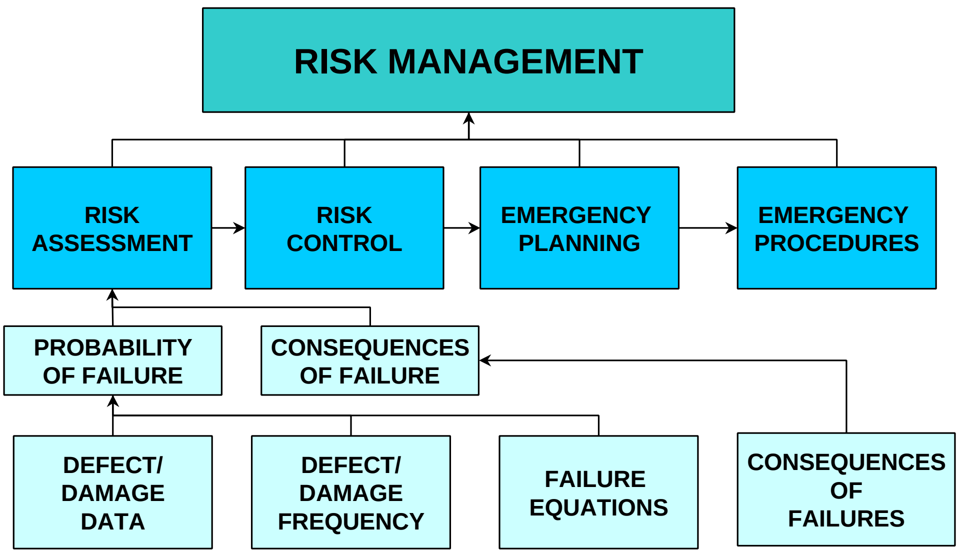
METHOD	%
Public	42
Patrol	21
Contractor	16
District Company	5
Company Staff	3
On Line Inspection	1
Client	1
Landowner	<1
Other	2
Unknown	8

5. THE SIMPLE PIPELINE RISK AUDIT - A Simple and Quick Method

5.1 Risk Management

Risk management covers four main aspects of a pipeline, Figure 3 (17). A pipeline operator must have policies and procedures in place to deal with all these aspects.

Figure 3. Key Elements of a Risk Management System (17)



The whole system must contain the following:

1. Description of pipeline system, legal & statutory duties
2. Organisation & control
3. Key personnel

4. Stakeholders
5. Documentation and communication systems
6. Management of change
7. Risk analysis, evaluation & control through whole life
8. Integrity management
9. Emergency planning
10. Emergency procedures
11. Performance measures
12. Management system review
13. Management review
14. Audit of all elements and processes

Section 4 has presented methods to help manage the integrity of the pipeline, and to minimise risks.

All aspects of a risk management programme must be regularly audited. A key part of this audit is an assessment of how an operator is monitoring key operating parameters and the pipeline route. This is known as a ***simple pipeline risk audit***. The following section explains this audit's drivers, benefits, and practice. Note that this is only one part of the total audit of the risk management system.

5.2 Basic Philosophy of a Simple Pipeline Risk Audit (SPRA)

All pipeline operators need to both demonstrate pipeline safety, and continually check safety. A complete audit of all the systems and practices of an operator is prudent and good practice (17). However, operators can conduct a simple pipeline risk audit (SPRA), focussed on key elements of the operation and design of the pipeline system. This short audit allows:

i. a verification of design parameters for the whole pipeline (e.g. pipeline identification, route, diameter),
ii. a quick and simple check of key operating parameters (e.g. operating pressure, pressure fluctuations),
iii. assessment of pipeline safety by reviewing pipeline route for building proximities and density, and comparing against code requirements and original pipeline design,
iv. identification of non-compliance in design and operation,
v. production of an action list

An in-house department can carry out the SPRA, but it is better conducted by an external organisation, to ensure an independent verification.

5.3 Drivers for SPRA

The drivers for an audit of a pipeline system are:

i. good operational practice,
ii. legal requirement,
iii. quality assurance requirement,
iv. demonstrate safety and code compliance to all stakeholders (company, staff, public, regulator).

The benefits are:

i. pipeline 'health' check,
ii. independent review of design and operation,
iii. confirmation of safe operating limits (e.g. pressure), and proximity limits,
iv. confirmation of safe operation for the period up to the date of the audit, and for the period up to the next audit,
v. opportunity to undertake remedial action before operational or design discrepancies develop into major problems.

5.4 SPRA Process

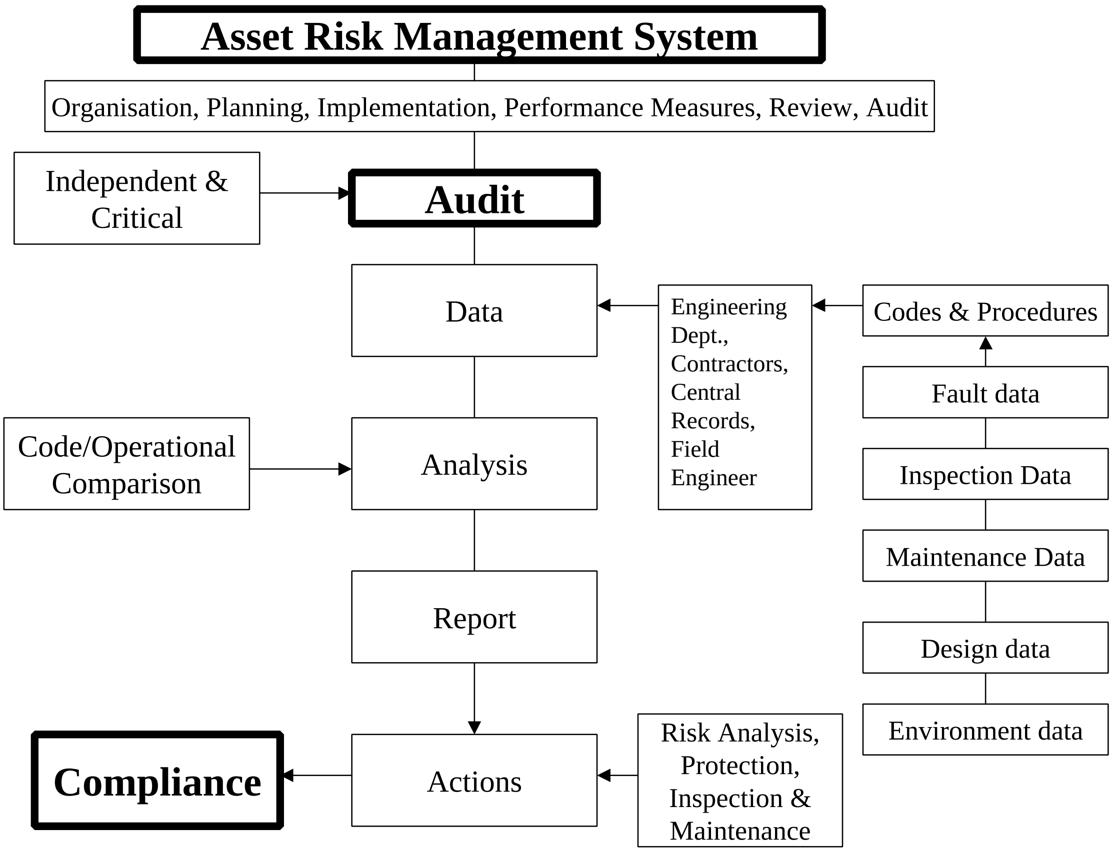
An audit is a simple procedure to identify operational and design non-compliances. It consists of two basic audits:

i. audit of pipeline design versus design code,
ii. audit of pipeline operation versus pipeline code and company procedures.

The process (Figure 4) is:

a. gather data (this is the most important part of the process, and often the most difficult)
b. identify non-compliances in operation and design,
c. quantify non-compliances and recommend changes,
d. implement any necessary changes or remedial work,
e. implement any new practices,
f. demonstrate compliance

Figure 4. The SPRA Process



It is important to emphasise that there is more benefit in performing a 'critical' audit (i.e. are the elements and processes correct and being followed?) rather than a purely 'compliance' audit (i.e. are the processes being followed?). However, the 'compliance' audit is a minimum requirement.

5.5 Scope of the SPRA

The scope of the SPRA is dependent on the operator. As a minimum, confirmation of all safe operating limits is needed, basic design parameters, and a complete audit of the pipeline route is required (see Appendix A). Therefore, the minimum audit would cover:

i. Pipeline design records,
ii. Pressure test records,
iii. Pipeline strip maps,
iv. Access to pipeline fault data,
v. Previous surveys and surveillance,
vi. Aerial photographs of pipeline route,
vii. Operational pressure records,
viii. Pipeline inspection and maintenance records,
ix. Modification records.

Figure 5. High Quality Aerial Photographs of a Pipeline Route

6. IDENTIFYING HIGH RISK AREAS DURING THE SPRA

The pipeline's design and operating parameters will usually be available from archives and field data (Figure 4). However, the pipeline route requires audit, and this is usually achieved by surveillance. This surveillance can be by walking, from aircraft, or (recently) using satellite images. However, permanent records are needed (e.g. still photographs or high quality video).

Figure 5 shows a pipeline route, and the buildings surrounding the pipeline can be both counted (to measure population density), and the distance from the pipeline measured to ensure the inhabitants are not at risk and the pipeline route is still acceptable to code.

Where there is doubt, or concern, foot patrols can be despatched for more detailed assessment and data.

Still photographs from aircraft currently offer the best balance of quality and cost, for these route audits. However, there are satellites now producing high quality images, that offer the potential for rapid, high resolution imagery for use on pipeline routes, Figure 6.

Figure 6. High Quality Satellite Photographs of a Pipeline Route

7. REPORTING AND MANAGEMENT OF DATA DURING THE SPRA

Figure 4 shows the importance of data in the audit process, and its various sources. The reporting and management of data are the most important elements of the audit and it is essential that complete records are collated, and that the collated data is both clearly presented, audited and reported.

Andrew Palmer and Associates has developed a comprehensive report format these audits, Appendix A. This structured approach allows a thorough and structured audit. The data are analysed and verified, and checked against code and company requirements. Non-compliances are highlighted and reported to the operator for action.

A major advantage of this formal process of logging data, is that repeat audits can be quickly conducted, as all previous data are both on file, and verified.

8. RISK ANALYSES AND REMEDIAL MEASURES AFTER THE SPRA

During the lifetime of a pipeline it is possible that both the population density around a pipeline may increase and violate code limits, or buildings may be erected within the code proximity limits.

There are four courses of action open to the operator:

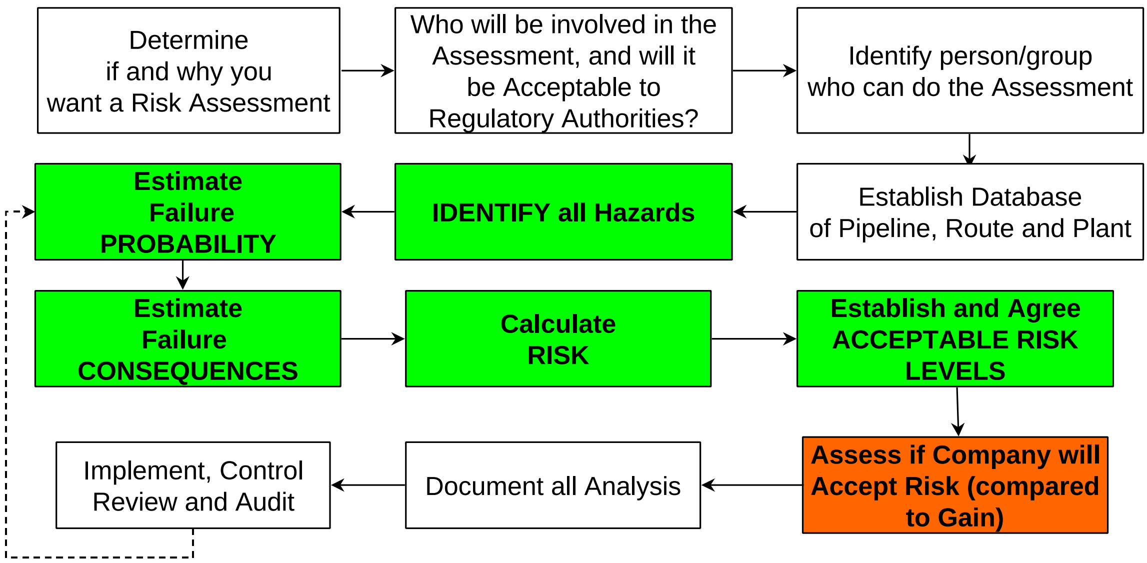
i. relocating the pipeline,
ii. downrating its pressure,
iii. conduct a risk analysis to determine if the inhabitants of the buildings are at risk
iv. remedial measures such as protecting the pipeline from damage.

Relocating the pipeline, or downrating its pressure, are high cost options, and should only be entertained if the latter two options are exhausted.

8.1 Risk Analysis

Section 3 covered pipeline risk. Risk analysis is a common technique in the pipeline industry, and there are software packages available to quantify risk associated with gas pipelines (17, 20).

Figure 7. A Pipeline Risk Analysis



The operator can quantify the risk associated with any non-conformity. If the risk is above an acceptable level, then he/she must consider re-routeing the pipeline, or remedial measures (see later). However, if the risk is low, then the pipeline can continue to operate, possibly with re-routeing or remedial measures.

The full risk analysis process is given in Figure 7 (6,7). One of the most difficult aspects of the risk analysis is determining 'acceptable' risk levels. The literature provides some guidance (e.g. 14), but any proposed level must have the agreement of all stakeholders, particularly the regulatory authority, and therefore they should be an integral part of the risk analysis process (Figure 7).

It is possible that the risk analysis will include a 'cost of life saved' assessment. This assessment compares the cost of any remedial action (including re-routeing the pipeline), with the number of lives that would notionally be saved by this action. This is a very delicate and sensitive issue, and requires a cost to be put on life. Again, the literature gives some guidance:

Table 9. Cost of Life[2] (14,17)

TRANSPORT	COST (£millions)
Air	17.5
Rail	1.7
Road	0.8
'Benchmark'	0.9

8.2 Remedial Measures

If a pipeline presents an unacceptably high risk to the surrounding population, it is possible to implement measures to reduce this risk. Measures such as increased inspection and surveillance can be easily and quickly applied. Additionally, pipelines can be protected, to reduce the risk of pipeline damage. Types of protection and warning are:

(a) concrete sections, channels, enclosure pipes or slabs,
(b) steel mesh or slab coverings or surrounds, and warning tapes
(c) depth of cover,
(d) wall thickness.

8.2.1 Enclosure

Where sleeves are used to enclose pipelines, they should have a minimum wall thickness to withstand damage. In the UK, IGE TD/1 recommends the use of sleeves 'to facilitate construction of carrier pipe'. Table 10 gives details of sleeve thicknesses.

8.2.2 Protection & Warning Tapes

The effectiveness of pipeline protection has been demonstrated by research work (21). Tests on buried pipe using earth excavating operators who did not know of the presence of the pipeline revealed that a combination of a strong barrier and warning tapes will reduce the risk of damage by >30, Table 11.

[2] 'How much would we be prepared to pay to reduce the risk of dying in an accident?'

Table 10. Sleeve Wall Thickness

Outside Diameter of Sleeve (mm)	Least Nominal Wall Thickness (mm)
≤457.2	6.35
457.2 - 609.6	7.92
609.6 - 914.4	9.52
914.4 - 1066.8	11.91
1066.8 - 1219.2	12.70
1219.2 - 1371.6	14.29

8.2.3 Depth of Cover

Depth of cover is also an effective method of protection. Research work reported with the work in Table 11 showed that the likelihood of damage is reduced by a factor of 10 as the depth of cover is increased from 1.1 m to 2.2 m.

Table 11. Effectiveness of Protective Measures (21)

Type of Protection	No. of tests	Summary of Tests	Damage Reduction Factor
No Protection	2	Pipeline damaged in both tests	1
Warning Tapes above the pipeline	5	Pipeline damaged in three tests	1.67
3 m wide concrete barrier above the pipeline	16	Pipeline damaged in three tests	5.33
3 m wide concrete barrier above the pipeline, combined with warning tapes	15	No pipeline damage observed in any test	>15
3 m wide yellow striped steel plate above the pipeline combined with warning tapes	15	No pipeline damage observed in any test	>15

8.2.4 Wall Thickness

Increased pipewall thickness offers protection against damage. For example very few (about 5%) of excavating machines used in suburban areas will be able to penetrate 11.9 mm wall.

9. CONCLUSIONS

1. Pipeline operators have a responsibilty to minimise the risk associated with their pipelines.
2. There are a large variety of inspection and monitoring methods that assist operators in both reducing and controlling the risks associated with their pipeline.
3. Risk management systems are rapidly gaining acceptance in the onshore and offshore pipeline industry, and requires continuous audit. The whole system needs audit, but one element – the key pipeline operating parameters and pipeline route – can be quickly audited in a systematic and thorough manner by a ***simple pipeline risk audit (SPRA)***.

4. A SPRA allows an operator to quickly demonstrate (to all stakeholders) that their pipeline is to code, and poses negligible risk to the surrounding environment and population. It also allows operators to identify non-conformities in their operation and design, and quickly assess the requirements for remedial measures.

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APPENDIX A

Example of Contents of an SPRA and Summary Pro Forma Used

A.1 CONTENTS

INTRODUCTION
ORIGINAL DESIGN DETAILS
GENERAL PIPELINE INFORMATION
INFORMATION SOURCES AND LOCATION
CONSTRUCTION DETAILS
ROUTING
CONSTRUCTION DETAILS
PRE-COMMISSIONING TESTING
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WATER CROSSINGS
EXPOSED AND OTHER SPECIAL CROSSINGS
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IMPACT PROTECTION
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OPERATION & MAINTENANCE DETAILS
OPERATION DETAILS
POPULATION DENSITY
AREA CLASSIFICATION
BUILDING PROXIMITY DISTANCES (BPDS)
SENSITIVE DEVELOPMENTS
SURVEILLANCE
ABANDONED SECTIONS
MODIFICATIONS AND REPAIRS
ANNUAL MPOP DECLARATIONS
FITTINGS
COATINGS
CONDITION MONITORING
FATIGUE
SUMMARY OF NON-CONFORMITIES
DEVIATIONS FROM DESIGN CODE
SUMMARY OF EXCEPTIONS TO ARCHIVED PIPELINE INFORMATION
EXCEPTIONS TO EXISTING PIPELINE INFORMATION
ADDITIONAL INFORMATION

A.2. SUMMARY PRO FORMA

SAIC *An Employee-Owned Company* Andrew Palmer and Associates	**SPRA SUMMARY DOCUMENT (for an IGE/TD/1 Line)**	Ref.: REF Date: DATE

Prepared by: ANDREW PALMER AND ASSOCIATES (N/cl)		Client:	
APA Contact		Client Contact	
APA Contact Location		Client Contact Location	
AUDIT SUMMARY:			
RECOMMENDATIONS:			

1. That the pipeline continues to be known as -	**Error! Reference source not found.**
2. That the MPOP be declared at -	
3. That the pipeline continues to be operated & maintained generally in accordance with the design code -	
4. That the condition of the pipeline continues to be monitored using -	
at intervals of -	
the next inspection being due in -	
5. That the pipeline is re-surveyed generally in accordance with -	
in -	
6. That the pipeline continues to form part of the pressure systems number	
7. That the pipeline Safe Operating Limit (SOL) is declared at	

RECOMMENDATIONS & CONCLUSIONS COMPILED BY:	
Name	
Position	Senior Engineer – APA Newcastle
Date	DATE
Signed	

RECOMMENDATIONS AND ACTIONS ACCEPTED BY:	
Name	
Position	
Date	
Signed	