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PIPELINE INTEGRITY: SOME LESSONS LEARNT

Hopkins, P[1]

ABSTRACT

The pipeline business now has many years of operational experience. This, combined with access to sophisticated inspection tools such as intelligent pigs, improved coatings and protection, and advanced calculation methods for the assessment of defects, should ensure that pipelines are both safe and secure. However, there continues to be frequent and tragic pipeline failures around the world. What lessons can we learn from these inspections, assessments and failures?

This paper considers some of the lessons learnt from recent failures and field experiences, and concludes with some guidance for all engineers in the pipeline business.

KEYWORDS

Pipeline, integrity, safety, management, pipeline failures, intelligent pigs, corrosion, outside force, surveillance, data management, metal loss, cracks, dents, standardisation, errors, lessons learnt.

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1. INTRODUCTION

We are experiencing change in the pipeline business [1,2]: poor quality materials and a lack of understanding of major risk meant that 30 years ago, and before, we needed standards that ensured we had good quality pipe, careful routeing, etc.. But now we know that in-service defects (damage, corrosion) fail pipelines and cause casualties [3]. Hence, a pipeline's 'integrity' is dependent on the design, operation and management of a pipeline

Consequently, we are now seeing the publication of regulations and standards that formally require pipeline operators to 'manage' their pipeline's integrity and have in place formal risk management plans that clearly mitigate and control risks.

Recent failures in the USA [4], Figure 1, have resulted in the U.S. Department of Transportation issuing regulations that require pipeline integrity validation through inspection, testing, and analysis of pipelines that run through or near high consequence areas[2] (HCAs). Operators are required to perform a 'baseline' assessment of pipeline systems by specified dates, e.g. by intelligent pig inspection, hydrotesting, etc., and operators must maintain a written integrity management plan. In Texas[3], the state regulator requires that an operator, who chooses not to develop this type of assessment program, must carry out pressure testing or in-line inspection at 5 to 10 year intervals.

It is not only the regulators in the USA who are changing pipeline management requirements [5-7]:
- In the UK, the Pipelines Safety Regulations issued in 1996 are goal-setting, not prescriptive, and they require a 'major accident prevention document', where all risks are identified, and also require a safety management system.
- The European Commission is reviewing 'major accident' pipelines, and by about 2006 is likely to enforce legislation requiring operators to have a 'major accident prevention policy' and a pipeline management system that ensures the policy is applied.

Figure 1. Recent failures of pipelines in the USA [4] (images courtesy of the Office of Pipeline Safety, USA).

[2] 'HCAs' are defined for liquid lines as populated areas, commercially navigable waterways, and areas that are unusually sensitive to environmental damage.

[3] www.rrc.state.tx.us

The intentions of formalised pipeline integrity management are [4]:

i. accelerating the integrity assessment of pipelines in areas where failures would have a high consequence,

ii. improving operator integrity management systems,

iii. improving government's role in reviewing the adequacy of integrity programs and plans, and

iv. providing increased public assurance in pipeline safety.

In the USA, the American Petroleum Institute [8] and the American Society of Mechanical Engineers [9] have published guidelines on how operators can satisfy the new integrity management rules in the USA.

It is very important to operate a safe pipeline and satisfy regulations: as engineers and competent operators we want to protect people and the environment, but we also need to protect ourselves from litigation. In the USA there have been settlements approaching $100,000,000 in recent pipeline failures, and operating staff and management are facing imprisonment for mistakes made.

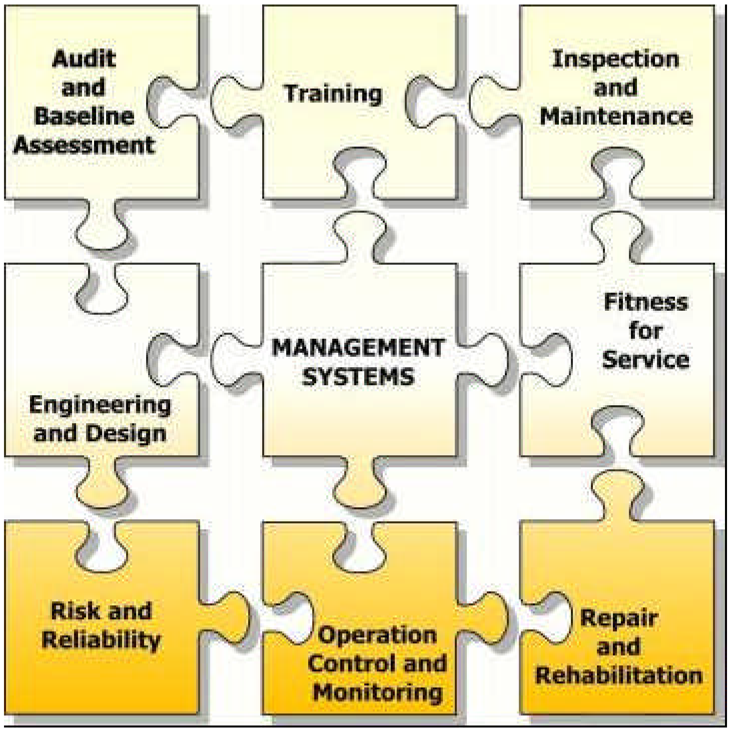

Figure 2. The pipeline integrity 'jigsaw'.

This paper is aimed at providing managers in pipeline companies with some recent 'lessons learnt' in the pipeline integrity management area, to help them prevent failures.

Engineers have always learned from their failures, sometimes with extreme consequences. For example, 3000 years ago, Hammurabi the greatest ruler (1795-1750) of Babylon, produced a remarkable list of codes and laws for his people. One of these laws was… *'If a builder builds a house for some one, and does not construct it properly, and the house which he built falls in and kills its owner, then that builder shall be put to death'.*

There are many more recent publications on 'lessons learnt' from engineering failures. Many state that most failures could be avoided. An article in the New Scientist (June 1991) by A Anderson states: *'The relevant information is almost always available: the problem is that it is either not known to the right people or its significance is not appreciated. Far from each failure or disaster* *being unique, there is usually a past history of similar events that could have resulted in failure but which for some reason didn't'.*

This paper will first of all consider pipeline integrity and list some lessons learnt over the past 20 years. Pipeline integrity also involves careful consideration of staff and their training needs [10-12], but another paper at this conference will consider these aspects [13].

2. PIPELINE INTEGRITY

In the past we have assumed that if we maintain our pipeline to the minimum requirements in codes or our company manuals, the pipeline will be safe. Recent failures have confirmed this approach as naï ve, and any engineer will tell you that an ageing asset requires increasing care, not constant care.

Pipeline integrity is ensuring a pipeline is safe and secure. It starts with a good design and construction, but it involves all of a pipeline's inspection, management and maintenance. This presents an operator with a complex 'jigsaw' to solve if they are to maintain high integrity, Figure 2

Pipeline integrity management is the management of all the elements of this complex jigsaw. The management brings all these pieces of the jigsaw together.

A key lesson learnt from integrity management is that we cannot eliminate pipeline failures: natural disasters, gross human error, sabotage/wars, etc., will all cause failures. Engineers can do little to prevent these events; however, engineers can prevent or reduce defects in pipelines. Defects such as corrosion, dents, gouges, etc., are a major cause of pipeline failures. Therefore, the key to pipeline integrity is to prevent or detect or mitigate defects in the pipeline.

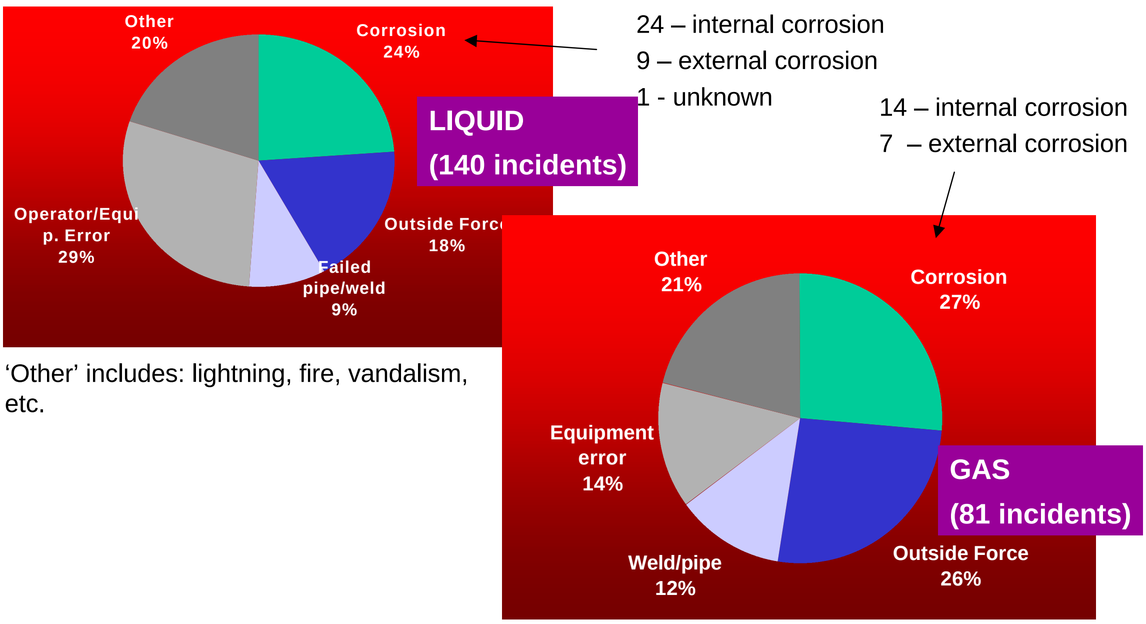

Figure 3. Pipeline failure data (2002) from USA (http://ops.dot.gov/stats).

3. LESSONS LEARNT FROM PIPELINE FAILURES

3.1 What are the major causes?

Failure data from regions such as Western Europe and USA show third party damage ('outside force') and corrosion to be the major causes of failure. Therefore, if we are to improve the integrity of our pipelines we need to reduce third party damage and corrosion, and focus our design and operation on achieving this reduction.

Figure 3 presents the latest failure data (for 2002) for pipelines in the USA. These data are freely available and updated by the USA Office of Pipeline Safety

Pipeline failures are usually related to a breakdown in a 'system', e.g. the corrosion protection 'system' has become faulty, and a combination of ageing coating, aggressive environment, and rapid corrosion growth may lead to a corrosion failure. This type of failure is not simply a 'corrosion' failure, but a 'corrosion control system' failure. Therefore, an engineer must appreciate the system to prevent failure; understanding the equation that quantifies failure pressure is just one aspect.

3.2 What causes corrosion?

Pipeline protection starts with a good design and construction, but our pipelines are surrounded by hostile environments, and this can lead to corrosion.

We need to separate our pipe steel from the soil or water environment otherwise it will corrode. Usually, there is no corrosion allowance for external corrosion in pipelines; hence we need to protect our outside surface. The pipe coating is the primary protection, and cathodic protection (CP) system is the secondary protection.

Coatings will not be perfect. On new pipelines there will be several damaged areas/km [14], and the coatings can break down. The major causes in Australia are given in Figure 4 [15].

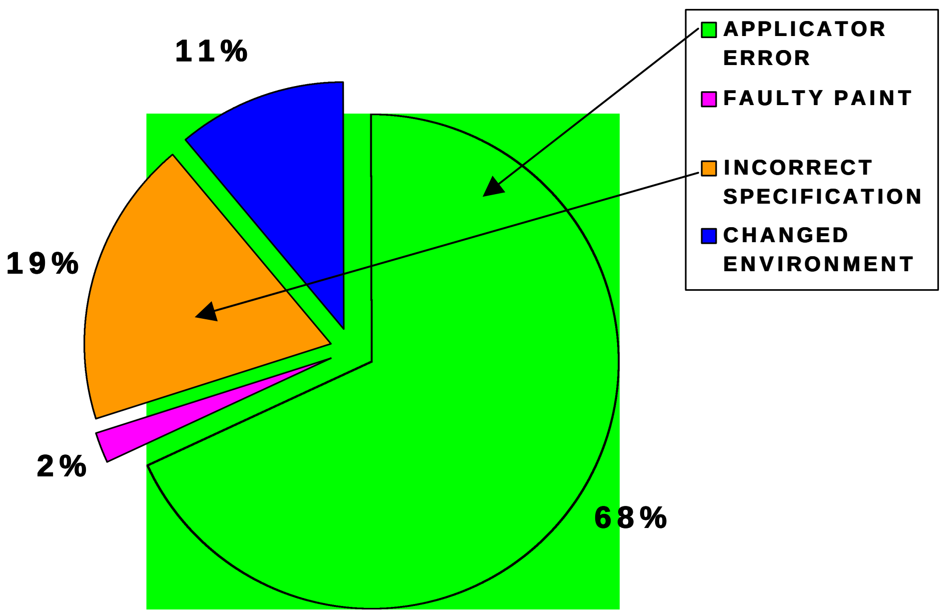

Figure 4. Cause of pipeline coating breakdown in Australian pipelines.

3.3 What causes failures from 'outside force'?

Both onshore and offshore pipelines can be damaged by outside force. Offshore lines can be damaged by supply boats colliding with risers, or anchors being dragged across a seabed line.

Onshore lines can be damaged by a variety of machines. A review [16] of UK experience is summarized in Table 1.

It can be seen that certain types of operation around an onshore line (e.g. power drilling) has a high chance of damaging a pipeline. Operators can use the data in Table 1 to assess the highest risk operations around their pipelines, and allocate the necessary supervisory resources.

Table 1.

Causes of damage to UK onshore pipelines [16].

Type of machine	No. of damage incidents	No. of failures	Failures: Incidents
Back Acter	165	3	0.02
Digger	137	6	0.04
Others	60	4	0.07
Powerdrill	21	9	0.43
Plough	11	3	0.27
Trencher	10	2	0.2
Drainline	9	1	0.11
None	7	0	0
Spike	6	0	0
Tracks	6	1	0.17
Scraper	4	1	0.25
Bull Dozer Blade	4	2	0.5
Dragline	4	0	0
Unknown	110	0	0

3.4 Learning from failures

We can learn from pipeline failures. The National Transportation Safety Board of the Department of Transportation in the USA publishes pipeline failure reports that offer significant lessons for pipeline managers. A selection of these failures, and some lessons learnt, are summarised below, but the reader is directed to the original reports (available on the NTSB website: www.ntsb.gov) for full accounts. We will briefly review some failures, summarise key lessons learnt, then conclude how a manager can ensure he/she does not have similar failures.

3.4.1 Use all data, and manage data effectively

A 40” diameter, 0.344” wall-thickness, gasolene line commissioned in 1978 was constructed at a depth of 4 feet, through an active landfill site. The operator’s construction specifications did not include special requirements for pipeline construction through landfills. Landfill material consisting of trash and other materials extended to more than 10 ft deep at places under the pipeline. The section of the landfill where the pipeline was located remained in use until about 1980, and was officially closed in 1987.

Up to 1980, additional debris was placed over the pipeline and by 1998 about 8-10 ft of debris and earth covered the pipeline at the point of failure.

The pipeline failed in 1998. Two weeks before the accident, a Recycle Plant near the pipeline began using an area over the pipeline to generate and stockpile ‘mulch’. At the time of the accident, the mulch pile height was 17 feet. The centre of the mulch pile was over the pipeline, and about 80 feet from the point of failure. A heavy vehicle occasionally traversed the pipeline right-of-way while moving equipment around the site. Crossing the pipeline right-of-way with heavy equipment and storing materials on or near the right-of-way were against an agreement between the operator and the Recycle Plant.

The pipeline operator had ran an intelligent pig (metal loss) through the pipeline in 1993 and found no significant anomalies. Also, the aerial pipeline patrol pilot noted the mulch stockpile on the right-of-way during patrols, but did not believe this to be of concern. He further believed that the appropriate operator's employees were aware of the mulch pile on the right-of-way. Finally, six months prior to the pipeline failure, a 'concerned citizen' living in the community wrote to her congressman and expressed concerns about the safety and vulnerability of the pipeline in the landfill. The Congressman wrote to the regional regulator (Office of Pipeline Safety (OPS)) asking to address these concerns. An inspector interviewed operator personnel and visited the landfill site, but noted no code violations; however, the visit by the engineer was made prior to the activities of Recycle Plant and the mulch being placed on the line.

The pipeline failed [17][4] with an operating pressure at the time of accident of 384psi. A visual examination of the pipe segment revealed a circumferential buckle deformation on the upper side of the pipe, Figure 5. No damage such as dents, gouges, or corrosion was noted on the outside surface of the pipe in the area of these cracks. The cracking in the pipe was consistent with stress damage due to soil settlement underneath the pipe.

The probable cause of the pipeline rupture was settlement of soil and compacted trash underneath the pipeline. The activities of the Recycling Plant subjected the pipeline to additional stresses at and near the site of the rupture; and, the aerial patrols failed to report to the operator that recycling activities were ongoing on the pipeline right-of-way.

Lessons:

- Inadequate design/construction practices can cause failures many decades after construction.
- Use ALL data available (surveillance and public reports were not co-ordinated).
- Have a data management system that highlights major integrity issues and reports.
- Select a pig that can detect the major threats to a pipeline (a metal loss pig was run in 1993, but the buckle would only be detected and sized by a geometry pig).

Figure 5. Settlement buckle (taken from The National Transportation Safety Board website: www.ntsb.gov).

[4] Other failure reports are not referenced. See National Transportation Safety Board Website for other reports. Visit www.ntsb.gov.

3.4.2 Select the correct pig and beware of dents in liquid lines

A 24” diameter, 0.25” wall thickness crude oil line, constructed in 1975 failed in 2000 at a pressure of 606 psi, Figure 6, causing $7million damage/clean up costs.

Previously, in 1997, a contractor's magnetic flux standard resolution inline inspection tool was run through the entire pipeline. Excavations were then made at locations along the pipeline where the inspection tool indicated significant anomalies. At the site where the pipeline ruptured, the 1997 inspection data showed an anomaly that the contractor had interpreted as a "dent." The pipeline had not been excavated at this location because the dent did not appear to meet the repair criteria being used at the time. The repair criteria used required that, for a dent to be repaired, it had to be deeper than 2 percent of the outside diameter of the pipe.

The rupture was on the bottom of the pipe, and the fracture surface showed transgranular cracks that had the appearance typical of fatigue along the edges of a dent in the pipe wall. The dent was consistent with contact with a hard object, although no hard object likely to have caused it (such as a rock) was found during the investigation. The NTSB report does not state that the dent may have been from construction, but its position at the bottom of the pipe and the absence of any rock or denting object suggests a construction defect.

NTSB concluded that the pipeline failed due to fatigue cracking, due to a dent in the pipe in combination with fluctuating pressures within the pipe, producing high local stresses in the pipe wall.

Lessons:

- Dents in liquid pipelines can be a source of fatigue initiation and failure.
- Inspection methods should focus on detecting dents in these liquid lines.
- Damage introduced during construction may cause failure later in service.

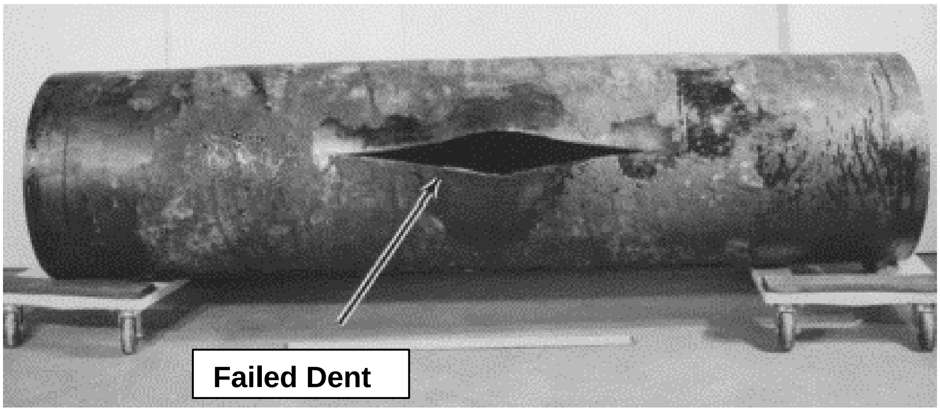

Figure 6. Ruptured dent in a liquid pipeline (taken from The National Transportation Safety Board website: www.ntsb.gov).

3.4.3 Identify the threats to your pipeline

A gasolene pipeline, 28” diameter, 0.281” wall thickness, built in 1970 failed in 2000 resulting in an $18 million clean up/damage bill, Figure 7. The pressure at the time of the failure was 705psi.

An in-line inspection tool was run through the failed section of the line in 1997. Anomalies meeting the operator’s criteria were excavated, evaluated, and repaired. No anomalies meeting their criteria were reported in the area of the 2000 failure, so the pipe was not visually examined at this location. The NTSB concluded the probable cause of the pipeline failure was corrosion-low cycle fatigue cracking that initiated at the edge of the longitudinal seam weld at a likely pre-existing weld defect. Contributing to the failure was the loss of pipe coating integrity.

Lesson:

- Inspection methods should focus on the actual threats to the pipeline (seam defects, fatigue cracks), and not expected threats.

Figure 7. Rupture along defective seam weld (taken from The National Transportation Safety Board website: www.ntsb.gov).

3.4.4 Cyclic stresses can cause failures

A 12.75”, 0.2” wall thickness, fuel oil line, built in 1972-3, failed in 2000, Figure 8. The failure resulted in a $71million clean-up bill. The line had previously (1995) been in-line inspected using a geometry tool and a magnetic flux leakage tool. The data from the magnetic flux inspection did not correlate well with field measurements for either wall loss data or odometer readings, hence the operator decided to conduct an additional in-line inspection in 1997 using ultrasonic inspection tool technology.

This 1997 in-line inspection was accompanied with an in-line caliper tool survey to confirm that there were no obstructions in the pipeline that could prevent the passage of the ultrasonic inspection tool.

After excavations, the operator determined that the in-line inspection data correlated relatively well with field measurements; however, some locations had more severe corrosion than had been indicated by the ultrasonic inspection.

The pipeline ruptured at a wrinkle in a section of pipe that had been field-bent during initial construction of the pipeline in the early 1970s. The deformation, or wrinkle, that failed was a single outward deflection of the pipe wall, commonly described as a buckle. The NTSB concluded that the cause of failure were the forces imposed on the deformed area of the bend, including the normal operating pressure and thermal cycles in the pipeline, causing repeated straining and eventual cracking until the pipe at the deformed area failed. Contributing to the magnitude of the fuel oil release were inadequate operating procedures and practices for monitoring the flow of fuel oil through the pipeline to ensure timely leak detection. It is of interest to note that the buckle was undiscovered because the data from the in-line inspection tool were interpreted inaccurately as representing a T-piece.

Lessons:

- Select inspection methods that will identify key threats to a pipeline.
- Buckles in pipelines can be difficult to interpret with inspection tools.

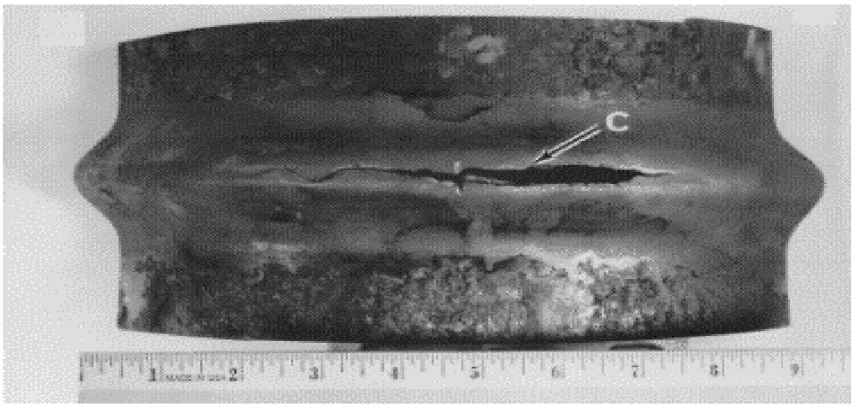

Figure 8. Failure from deformation and fatigue at a pipe bend (taken from The National Transportation Safety Board website: www.ntsb.gov).

3.4.5 Summary

A review of pipeline failures gives us two clear 'lessons learnt':

i. Failures usually have a number of contributory factors, hence…

ii. We must conduct a thorough risk assessment of our pipeline to identify the threats to it, and the consequences of failure. This is the approach now being universally adopted – it is pipeline integrity management.

Reference 8 (API 1160) considers an integrity management program as one that:

- Identifies & analyses all events that could lead to failure.
- Examines likelihood and consequences of potential pipeline incidents.
- Examines and compares all risks.
- Provides a framework to select and implement risk mitigation measures.
- Establishes and Tracks performance, with the goal of improvement.

Reference 9 (ASME B31.8S) presents a simple schematic of how a pipeline management program is structured, Figure 9.

We must assess risk in our pipeline, and manage this risk effectively. Key components of the above integrity/risk management programs are:

- In line inspection using intelligent pigs,
- Data management.

The following sections present some lessons learnt recently on intelligent pigs and data management.

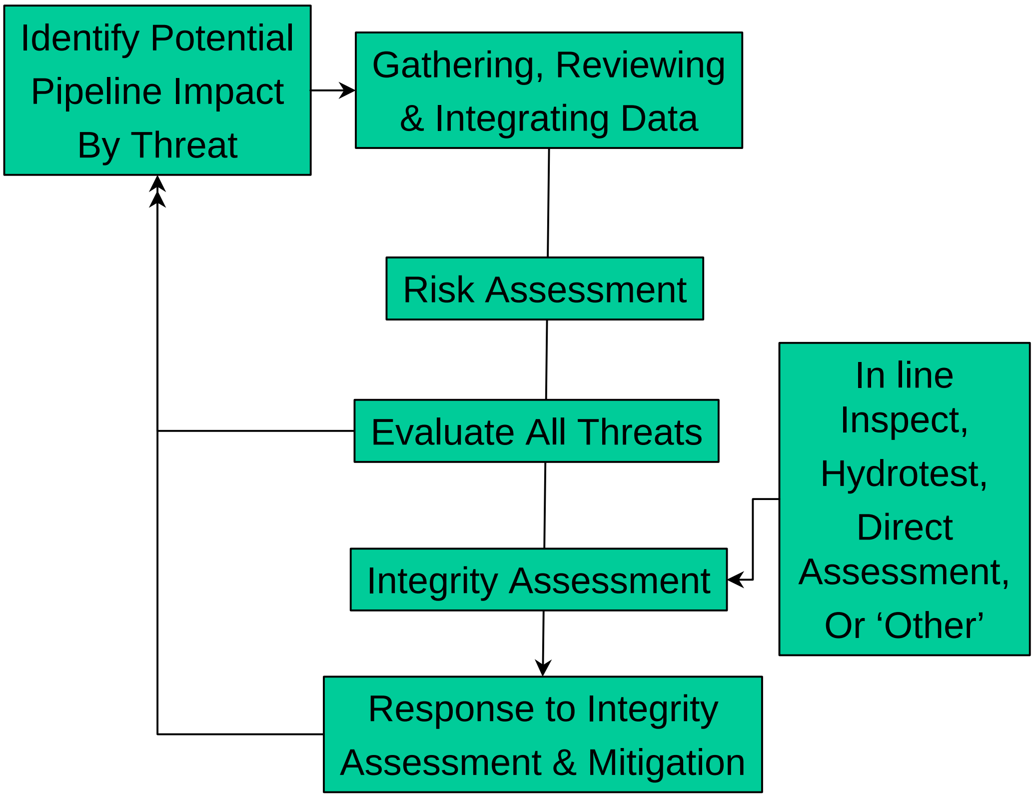

Figure 9. Integrity management program, from ASME B31.8S [9].

4. LESSONS LEARNT FROM INTELLIGENT (SMART) PIG INSPECTION

Intelligent pigs are used extensively for inspecting pipelines. Their use will increase rapidly due to their proven benefits, expanding capabilities, and legislative requirements. The result of an intelligent pig inspection is an inspection report with a list of defects. Therefore, these pigs are useless unless the pipeline operator understands the reliability and accuracy of the report, and has methods for assessing the significance of the defects detected.

There are a number of recognised defect-acceptance (or ‘fitness-for-purpose’) methods available for assessing these defects, for example ASME B31G and API 579, but these methods are simply calculation methodologies; there are many issues related to the input data and the engineering assessment that also need to be resolved. These include tolerances on pig data, variability in pipeline operational data, and differing defect types.

It is good practice to approach fitness-for-purpose assessments holistically. This means that all aspects of the pipeline's integrity is taken into account and it is not simply an exercise of inputting intelligent pig data into an equation, then obtaining a predicted failure stress for the defect.

This section covers some lessons learnt in dealing with both intelligent pig data and associated fitness-for-purpose assessments [18].

4.1 General

The most popular technologies used for intelligent pigs to detect defects in the pipewall (often called ‘metal loss’ defects) are ‘magnetic flux leakage (MFL)’ and ‘ultrasonics (UT)’. These technologies are attached to the pig, and it becomes ‘intelligent’ or ‘smart’.

We have had these metal loss detection tools available since the mid-1960s: the early pigs were MFL and had limited capabilities and were known as ‘standard resolution (SR)’ tools. More recent MFL tools are known as ’high resolution (HR)’ as they have more sensors on board and can detect smaller detects with increased accuracy and reliability.

Intelligent pigs that could detect cracks were introduced into the pipeline business in the 1990s. These tools initially used ultrasonics to detect the cracks, but vendors are now introducing MFL crack detection tools.

It is important for pipeline operators to realize that intelligent pigs cannot detect all defects; they are designed to detect certain defects of a certain size. Table 2 [8] is taken from an American Petroleum Institute's standard and gives guidance on what pigs cannot and can detect.

Table 2.

API 1160 Information on pig capabilities (D=detect, S=Size).

Defect	**Metal Loss Tools**			**Crack tools**	
	MFL – SR[5]	MFL - HR[5]	UT	UT	MFL
Corrosion	D&S[1]	D&S	D&S	D&S	D&S
Cracks - axial	NO	NO	NO	D&S	D&S
Cracks - circumferential	NO	D[3]&s[4]	NO	D&S[2]	NO
Dents	d	d&s	d&s	d&s	d&s
Laminations	d	d	D&S	D&S	NO
Mill defects	d	d	D	D	d
Ovality	NO	NO	NO	NO	NO

Notes:

1 – No internal/external diameter discrimination.

2 – Modification needed (sensors need rotating 90 deg).

3 – Lower case d means limited or unreliable detection.

4 – Lower case s means limited or unreliable sizing.

5 – HR = high resolution. SR = standard resolution.

Also, intelligent pigs will have errors associated with their measurements, as with all engineering tools. MFL pigs have the following sizing capabilities [19]:

- Low ('standard') resolution tools can size anomalies to a minimum of 20% wall thickness, with 15-20% accuracy,
- High resolution tools can size anomalies to a minimum of within 10% wall thickness, with 10-15% accuracy,
- Extra high resolution tools can detect corrosion to less than 10% wall thickness.

4.2 Dents

Caliper pigs are used to detect and size dents in pipelines. Figure 10 [20] plots the results of a caliper run on a 16" liquid line in the USA between 2000-3. It can be seen that the caliper pig can detect dents much smaller than the stated limits, and there is reasonable agreement between pig measurement and subsequent field measurement.

However, a major observation made from this study was that more than half of the dents contained gouges: this is very significant, as a combined dent and gouge is considered the most severe form of damage in a pipeline, and this combination can record very low failure stresses and fatigue lives [26].

The orientation of the dent can also be used to give an indication of the likely source and severity of the dent. Dents on the top of the pipe line are most likely to have been caused by external interference; on the bottom of the pipeline they are more likely to be the result of rocks in the bottom of the trench the pipe was laid in, and will have been there since the pipeline was built.

Consequently, any dent detected in the field, if it is in the top half of the pipeline (09.00 to 03.00 o'clock) (see next section), will require close investigation.

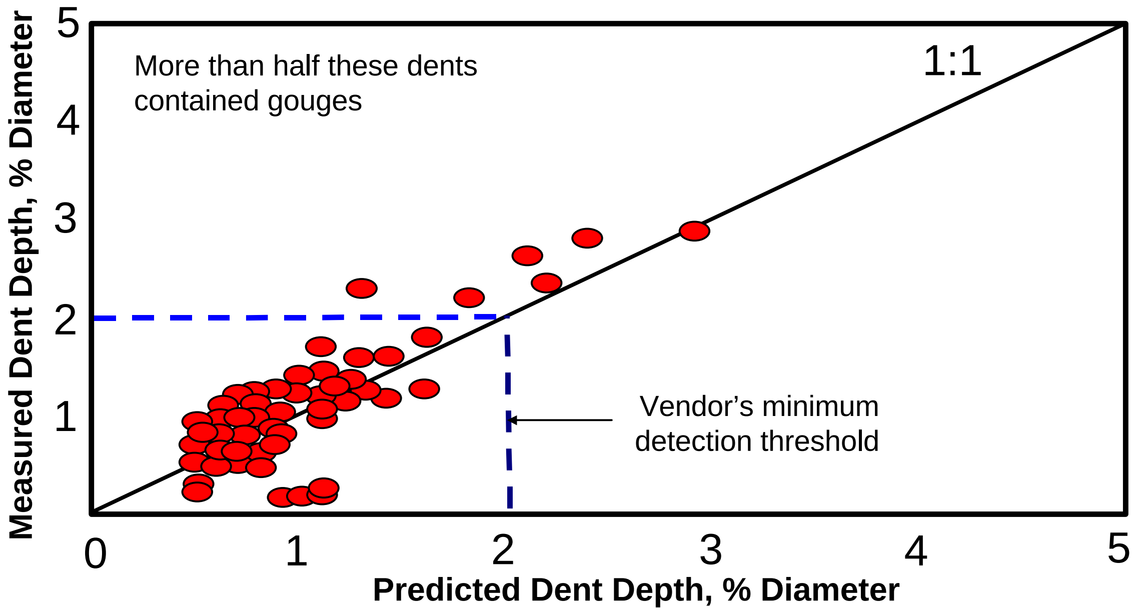

Figure 10. Comparison of dents detected ('predicted') and measured by a pig, with subsequent field measurement [20].

4.3 Defects at girth welds

MFL pigs are affected at girth welds by the change in metallurgy and the sensor may lose contact with the pipe surface due to the root penetration of the weld. This can prevent the detection of defects. In a recent case, an intelligent pig inspection of an oil pipeline in an environmentally sensitive area identified a number of internal corrosion defects all in the pipe body. Soon after the inspection, the pipeline leaked at a girth weld [21]. Severe localised pitting at a girth weld had not been detected by the intelligent pig inspection. Subsequent NDT of 30% of the girth welds on the pipeline provided data that allowed the intelligent pig vendor to review the inspection data and categorise the remaining welds.

So what does this tell us about how to assess inspection data? It tells us that all defects may not be detected and it tells us the importance of working with the intelligent pig supplier before the inspection to warn him/her of all possible defects.

4.4 'False positive'

Debris and other features in a pipeline can lead to the inspection tools reporting defects where there are none – 'false positives'. This misinterpretation can lead to pipeline derating, or even shutdown and repair, which can be very costly, particularly for trunk lines and offshore pipelines.

In a recent case in the UK North Sea, the need to remove a defect to allow a pipeline to be used at its original design pressure required the temporary shutdown of a major trunk line and a very costly subsea pipeline section replacement exercise [22]. This defect, which had been reported as slowly growing by repeat intelligent pig inspections, did not exist. Some scale containing iron grit was found at the location where the metal loss had been reported. The pipeline in question carried dry gas and had always been operated responsibly.

This again emphasizes the importance of identifying the root cause of a defect, and using more inputs that just the intelligent pig data when undertaking an assessment.

4.5 Growth rate analysis

The estimation of corrosion growth rates based on intelligent pig data is increasingly common (see previous section). Corrosion defects reported by two pig runs can be compared and a corrosion rate estimated. This is done using processed data, comparing reported defect sizes or using the sensor signal data, and comparing signals to derive a change in signal and hence a change in defect depth [23]. These defects can then be assessed using 'fitness for purpose' methods [24, 26].

This type of pig data analysis is extremely valuable for predicting when repairs should be done, when the pipeline should be re-inspected, and helps extend the economic life of the line. However, it must be treated with caution, and knowledge of corrosion processes and pipeline operation must be incorporated into any assessment. For example, pig accuracy and tolerances will invariably produce anomalies such as negative corrosion rates (the corrosion is decreasing in size) for some locations.

Where an analysis is based on an unprocessed signal, the legitimacy of this method must be demonstrated with practical test results (signals from a sample of defects before and after a known increase used to give an estimated growth that can be compared with the actual growth): to date the author has seen no such validation. Methods based on the sized defects must consider the corrosion process, treat the data consistently, and consider the sizing issues discussed above.

A publication later this year [25], shows the errors associated with calculating corrosion rates from successive pig runs, and demonstrates the benefits of both improved pig accuracies and rational statistical analysis. Reference 26 gives the methods for assessing al types of pipeline defects, including corrosion.

4.6 Contract inspection accuracy and significant figures in reporting

Inspection tolerances agreed and quoted in an inspection contract can affect the way that inspection companies report detected defects.

In a recent assessment of intelligent pig data, the accuracy quoted for the axial position of a feature was within 1% of the distance from the nearest reference weld. As most pipe spools in this pipeline were 12m long, the position of the features was typically given to the nearest 0.1m. This kept the positional accuracy within the quoted accuracy and did not give the appearance of a better accuracy. For excavation and repair this level of accuracy is sufficient. However, in this particular case, where there were numerous very short defects (less than 0.05m long), the 'rounding' of the axial position to the nearest 0.1m led to many defects being reported at the same position, Figure 11 [18].

In addition, and even more serious, there were external defects reported exactly coincident with the internal defects, with a combined depth greater than 100% of the pipe wall thickness. Based on this information, the pipeline should have been leaking. The measurements were queried with the inspection company and they supplied data giving the axial positions of the defects to the nearest millimetre. Obviously, the inspection vehicle cannot locate the feature with this level of accuracy relative to a reference weld up to 12m away. However, the relative positional accuracy from one defect to the next is very good and it is reasonable to use measurements that give the position to the nearest millimetre. This higher resolution data showed that the features were not coincident and allowed a reasonable assessment to be made.

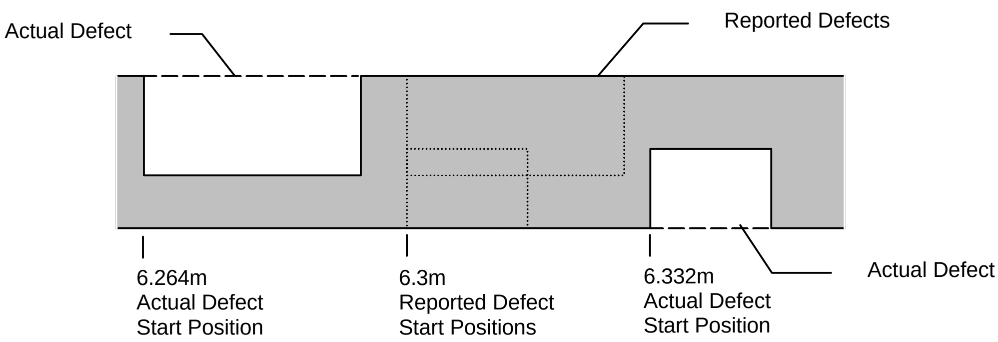

Figure 11. Example of defects reported as coincident due to reporting tolerances.

4.7 Shallow defects (less than 10% of the pipe wall)

Both old and new pipelines will inevitably contain some defects. This is reflected in the codes, i.e. the API line pipe specification allows some defects, and ASME B31 allows defect up to 10% below nominal wall thickness. These defects may have escaped detection at the pipe mill or may have been introduced during transportation, storage or construction, or be due to a corrosion mechanism. The manufacturing wall thickness tolerances in API 5L are given in Table 3 [27].

Table 3.

Manufacturing wall thickness tolerances from API 5L [27].

Size Diameter, in.	Type of Pipe	Tolerance (percent of specified wall thickness)	
		Grade B or Lower	Grade X42 or Higher
> 2.875 and < 20	All	+15.0, –12.5	+15.0, –12.5
≥ 20	Welded	+17.5, –12.5	+19.5, –8.0
≥ 20	Seamless	+15.0, –12.5	+15.0, –10.0

The new generation of intelligent pigs will detect some of these defects since the new pigs can detect defects of depth below 10% wall thickness, whereas the older generation of pigs could not. In a thin-walled pipeline (<10mm) this means that defects less than 1mm deep will be detected. This can cause problems.

i. FINGERPRINT RUNS. Intelligent pigs are increasingly being used to ‘fingerprint’ new pipelines. A fingerprint run is a pig run shortly (e.g. within one year) after commissioning, to check the quality of the new build. There has been a recent case of a new pipeline that has been superficially corroded during storage and transportation, and contained many thousands of small internal corrosion pits (all below 1mm). Following a fingerprint run it was ‘condemned’ because the intelligent pig reported all these corrosion defects. However, this pipeline had passed the pre-service hydrotest, the corrosion was not active or growing, and it did not affect the pipeline’s fitness for purpose. The defects detected may not have been desirable but they are likely to be ‘custom and practice’ storage and/or construction defects, mostly within ASME tolerances. The operator only became aware of them because of the new and very intelligent pigs.

ii. REPEAT RUNS. The above has also been found to cause problems when comparing old pig runs with new pig runs:

   a. older generation pigs would only detect defects greater than 30% wall thickness;

b. later generations of pigs could detect defects that where 20% of wall-thickness;

c. the current generation are capable of detecting defects less than 10% of wall thickness.

Therefore a pipeline that was fingerprinted using old technology and passed as 'defect free' (i.e. no defect above 20% wall thickness), may (on a new run today) have 10,000 defects reported, all under 20% wall thickness, but nevertheless reportable using new technology.

Clearly, there is a need to quantify the 'workmanship' level of defects on a fingerprint run, otherwise perfectly acceptable new constructions containing 'custom and practice' defects, will be the subject of lengthy arguments between operator and constructor [28].

Therefore, it is necessary to consider the following factors when dealing with inspection data with modern intelligent pigs. These factors will influence the way that the available data is assessed:

- **Defect Cause** - It is necessary to determine the cause of the reported defects. This helps us to understand the nature of the defects and to determine their likely development over time. Are the reported defects due to storage and transportation, or are they caused by in-service corrosion?
- **Defect Size** - Account needs to be taken of the reported defect size. An intelligent pig that can detect defects that are less than 10% wall thickness is likely to report many thousands of defects, many of which are likely to be shallow – it is important to decide which of the reported defects are significant and need to be assessed.
- **Defect Location** - The location of the reported defects within the pipeline gives a good indication of the nature of the defects. For example, internal defects consistently located at low-points in the pipeline in the 6 o'clock position are likely to be due to corrosion. Therefore, the location of the defects can help us to interpret the cause of reported defects.

4.8 Standardisation and accreditation

We have many excellent and reputable intelligent pigs on the market, and intelligent pig companies are to be congratulated in their commitment to improving both the pig technology and supporting services.

Unfortunately, the industry is not keeping pace! We have insufficient standardisation, quality accreditation, minimum requirements, or accreditation schemes for these pigs [29]. The standards that do exist, such as the Pipeline Open Data Standard[5] are not yet widely used, and whilst they give some guidance as to what should be reported, they do not and cannot give full details of the parameters (reporting levels, clustering rules, etc.) that should be used for particular situations.

Similarly, we are assessing the significance of defects detected by pigs with very few approved fitness for purpose methods, and no formal training requirements or accreditation of those conducting the assessments.

Compare the above lack of standardisation and control with that which we apply to the simple pipeline girth weld (in its fabrication, materials, inspection and certification)!

There is a need for standardisation bodies, regulators, pipeline operators and pig companies to work together and resolve the above, and there is some good news;

i. Intelligent Pigging: The American Petroleum Institute is working on a standard for intelligent pigging (API 1163) which should help all operators start to standardize on pigging inspections, but standardization of data and formats is still a long way off (see Section 8.3, later).

[5] for more information see Section 8 or visit www.pods.org

ii. Defect Assessment: Reference 26 details a pipeline defect assessment manual that was sponsored by 15 major companies in the oil and gas pipeline business. This manual could be the basis of a defect assessment standard.

iii. Data Management: See Section 8.

5. LESSONS LEARNT FROM LEAK DETECTION

It is important that pipeline companies can respond to leaks in pipelines both quickly and effectively. A key element of this response is a leak detection system. These systems range from simple patrols looking for leaks, to measuring the pipelines flow balance (comparing inputs to outputs), to detecting pressure decays, to sophisticated real-time dynamic computer modeling of the pipeline system. These systems vary in cost, efficiency and reliability, and pipeline operators are faced with a difficult choice. Older (pre1970s) onshore pipelines have limited leak detection systems, e.g. some form of 'static' leak detection (pressure decay) and/or volume balance – based on flow metering. New pipelines in most countries are required to have some form of active/dynamic leak detection system: the majority of new pipelines will have leak detection by dynamic modeling. But the question is… *'who/what currently detects most leaks in a pipeline?'*

Table 4.

Detection of Leaks in European Pipelines [30, 31].

Leaks Detected in European Gas Pipelines	
Detected by:	***%***
Public	42
Patrol	21
Contactor	16
District company	5
Company staff	3
On-line inspection	1
Client	1
Landowner	<1
Other	2
Unknown	8

Leaks[6] Detected in European Liquid Pipelines		
Detected by:	***No (average spill size, m^3)***	***%***
Third party passer-by	144 (120)	45
Routine monitoring by operator	64 (388)	20
Right of Way survey by operator	29 (229)	9
Automatic detection system	25 (188)	8
Third party worker	20 (110)	6
Hydrotest	17 (157)	5
Operator maintenance staff	13 (60)	4
Contractor working on line	5 (482)	2
Internal inspection survey	3 (6)	1

There are two major reviews of pipeline failures in Western European liquid and gas pipelines [30, 31]. The reader is directed towards these reviews for definitions of 'failure' etc., but the main conclusion from both these reviews is that the majority of pipeline leaks are detected by the general public, Table 4.

[6] Not including leaks in pump stations

Many of the pipelines included in both of these reviews will be old and may not have active or dynamic leak detection systems fitted, and therefore it is not possible to draw conclusions on their effectiveness.

However, the lesson learnt from pipeline leaks is that they are more likely to be detected by a passer-by, than by the pipeline company.

Additionally, pipeline failures can take several hours for the pipeline operator to detect: following a pipeline rupture, controllers often continue to operate a pipeline or restart a system that had shut down, rather than promptly shutting the system down and isolating the leak.

6. LESSONS LEARNT FROM PIPELINE SURVEILLANCE

Most pipeline operators survey their pipelines by air, usually every two weeks. This survey ensures that the building density around a pipeline is not contravening limits set in codes and regulations, and – more important – checks that work is not taking place on or around (‘encroaching’) the pipeline that might damage it.

This air patrol gave the ‘first sighting’ of any activity in 30 – 60% of incidents [16], but many are missed because of their short duration (between 60% and 90% of the total encroachment activities lasted less than 2 weeks).

A recent report presented the results of a number of trials on the effectiveness of air patrols and compared their effectiveness with that of modern satellites [32]

The report states that air patrols (using helicopters) are between 66 and 89% efficient at detecting ‘targets’ (these were small polythene sheets located along the pipeline route, or excavations), Table 5. It is interesting to note that the new, high resolution satellites can give similar detection rates, but the current cost of satellite images is much higher than the cost of air patrols.

Table 5.

Effectiveness of helicopter surveillance compared to modern satellites [32].

	Helicopter test (Netherlands)	**Helicopter test (France)**	**Satellite test (France)**
No. of Targets	77	28	28
Targets Detected Correctly	51	25	22
% Targets Detected	66%	89%	795
Location Accuracy (m)	43m	unknown	29m

The lesson from Table 5 is that air patrols are not perfect, and we should not rely solely on this type of surveillance to control activities around our pipelines.

7. LESSONS LEARNT FROM USING SOFTWARE/HARDWARE IN ENGINEERING

Engineers rely on computer software and hardware for both communications and calculations. Pipeline companies are increasingly eager to purchase software that will help them manage data (see next Section) and also conduct engineering calculations such as design.

We all know that as we use new tools in engineering, we introduce the chance of new errors. The American Society of Civil Engineers [33] reviewed failures in 52 structures attributable to computer errors. Table 6 summarises their findings. It is interesting to note that the major cause of 'failures'[7] was poor solutions being chosen by the software users.

Table 6.

Cause and Effect of Engineering Structural Failures due to 'Computer' Errors [33].

Effect of Error	%
'Poor solutions' to problems in engineering	63%
Poor performance	6%
Catastrophic failures	4%
Unknown effect	27%

Cause	%
Computer Hardware	13%
Software	25%
Users	58%
Others	4%

The lessons learnt were:

i. computer hardware and software (operating system, general, and civil engineering) are not infallible;

ii. diagnostic software used to check flaws is not infallible;

iii. no amount of testing by the vendor or user will assure that hardware and software will be flawless, but testing does help reduce the number of flaws;

iv. newer versions of software, because of bugs, do not always perform as well as older and tested versions; and

v. the owner, engineer-of-record, supervisor, etc., should not accept computer-aided analysis and design conducted by any user, unless the results have been shown to be verified by independent methods.

Clearly, computers (hardware, operating systems software, and engineering software) can be defective, and only competent engineers can use computers effectively.

8. PIPELINE DATA MANAGEMENT

A key part of risk and integrity management is data management. We all need data to make decisions: in business we need market data to manage financial risk, and in the pipeline business we need data to help us manage all the risks associated with a pipeline.

So… we collect data. Engineers love data as much as the old bits of wood and wire we store and treasure in our garages, but we collect and store data the same way – chaotically - in differing locations, in differing boxes, etc.. We also collect useless data, and store it in the same careful manner as the useful data: how many of us have totally useless items in our garage that we know will never be of any use to anyone?

This section explains why we need to change how we deal with, and manage, data to help us effectively manage pipeline risk.

[7] Failures are defined as: 'Poor solutions' to problems in engineering; Poor performance; Catastrophic failures. The software being used ranged from spreadsheets to specific software such as structural engineering, geo-technics, hydraulics, etc..

8.1 Data management overview

Let us start this section with some simple questions:

- Is the bulk of the data you collect today, of use today?
- Does the data you collect today, address future issues?
- Are you prepared for tomorrow?

Collating data is relatively easy – we have large database packages that allow us to store anything and everything. But data alone is useless – it is when it is transferred into knowledge and facilitates decision-making that it becomes of use.

To allow our data to become knowledge we need databases that are easily accessible and easily analysed, but one of our biggest problems is incompatibility between the databases we use: these huge data warehouses that store our data are often incompatible.

Pipeline companies will have a number of databases where they store data. These databases can reside in different departments/locations, and may not compatible or be easily accessible.

Pipeline companies are good at systematically recording component and assembly drawings (documents), but often do not keep comprehensive records of their attributes such as 'size', 'weight', 'where used‘, etc.. As a result, engineers often have problems accessing the detailed information they need. This leaves an unfortunate gap in their ability to manage their pipeline effectively: it has been estimated that engineers spend 25% of their working day searching for data….

Data management systems should be able to manage both attribute and documentary product data, as well as relationships between them, through a relational database system.

8.2 Data management in the pipeline business

The solution for the pipeline business is to systematically organise our data in our database:

i. DATA – Are essential to the safe management of our pipelines, and we are gathering more and more data.

ii. COMPUTERISATION – Companies are now spending time and money to integrate all aspects of the business & datasets, and are creating large…

iii. DATABASES – These are large, and can be used across a company, and resemble a ‘warehouse’ (or ‘marts’) where we can collect our data.

iv. APPLICATIONS – The companies are using these data in ‘*Applications’* such as GIS, and risk analysis programs: these Applications are constantly changing and improving, but our data must remain constant. As an industry, we will not develop Applications, so we need not concern ourselves with them, but we must organise our data for their use.

v. JARGON, DIFFERING FORMATS & DIFFERING DATA REQUIREMENTS – But our applications all have differing data needs and formats.

vi. DATABASE DESIGN – Therefore, we need a standardised database design that organises all our business data requirements and formats, and it must be an…

vii. ‘OPEN’ ‘STANDARD’[8] – it must be freely available to all, and adopted as a standard by all parties, including Applications and the Service Sector.

This sounds very easy… but it is not:

i. COMPATIBILITY – Transfer of data across companies is often not possible due to differing formats, etc.. For example, the data a pipeline company receives from differing

[8] ‘Open standard’ – a standard set of data structures and formats in the public domain available for all to use, preferably recognised by an International Standards body such as ISO.

inspection companies (above ground inspections, river crossings, intelligent pigs, etc.) will all be presented in different formats.

ii. TRANSFERABILITY – As assets are bought and sold, the bought asset data has to be incorporated into the new owner's systems – consistent data models, languages and formats are needed.

iii. INPUT/OUTPUT FOR APPLICATIONS – We need to be able to input data to our databases, so we need consistency. When we access our databases through Applications (e.g. GIS), we need to ensure the data can be uploaded AND we can then download results into our database.

iv. SERVICE SECTOR – We need to specify the data we need from our inspection companies, surveyors, etc., to allow easy storage. Also, when we ask our service sector to use our data (e.g. audits), we need the data to be easily transferable into their own Applications.

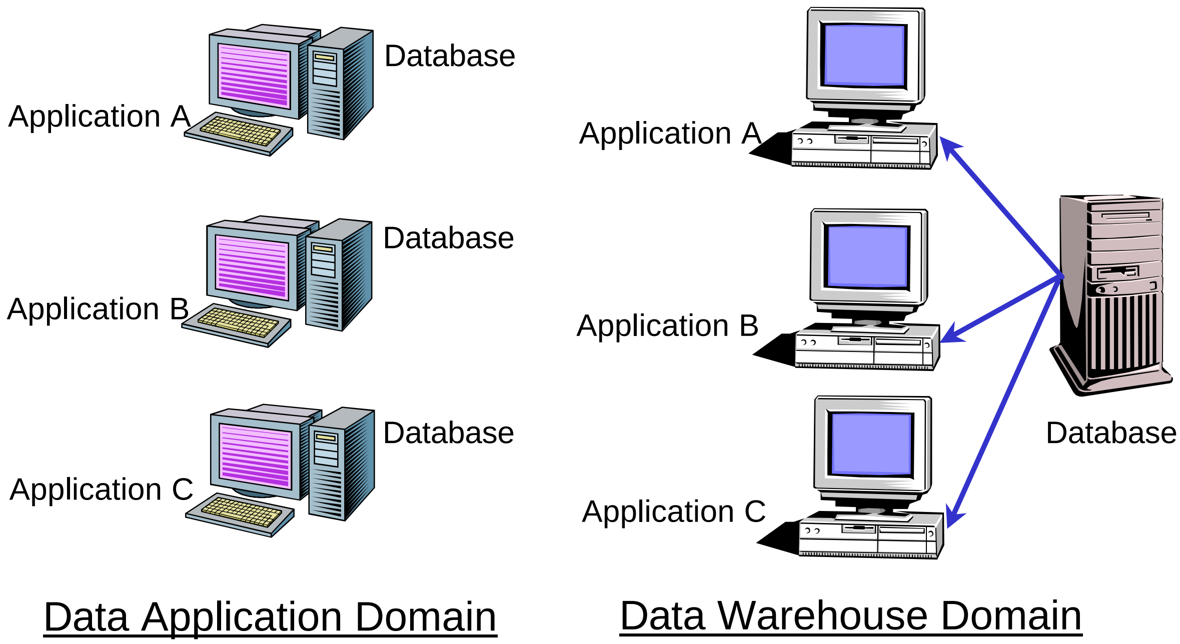

Figure 11. Data Management Domains [34].

8.3 The way forward

If we want to effectively manage our pipeline risk we need to both organize and standardise our data management, otherwise we will not be able to assess, monitor or control risk.

Currently, there are two basic data management approaches ('domains'), Figure 11:

i. In the *application domain* the database and data management functions are dependent on, and an integral part, of an application, (e.g. a Geographic Information Systems (GIS)), where special software uses the data. The data reside within the application. These are the most common in our business.

ii. In the *warehouse domain* the database and data management function is independent of any application. The data is contained in a 'warehouse' that can be accessed by any application.

The pipeline business is dominated by the former approach. For example, a brief WEB search using the key words "pipeline+database" returned information on 68 organisations that operated some 100 software packages that utilised some form of database containing pipeline information. These are summarised in Table 7 [34].

Table 7.

Summary of pipeline databases [34].

Type of database system	% of total systems
Databases with limited or no applications	15%
GIS, Mapping & Imagery Applications	38%
National / Regional Databases[1]	10%
Corrosion Protection / Pigging Systems	10%
Engineering Applications[2]	27%
[1] In the main these are GIS-based systems. [2] These include Risk, Integrity, Asset, Facilities and Project Management Applications.	

The application domain creates a situation whereby data is "locked in" to an application and cannot be accessed by other applications. For example a database built up in a GIS application, may not easily be accessed by a risk assessment application. This may also 'lock' a pipeline operator to the application vendor: a situation many now find unacceptable.

The solution, to the inherent failings of application domain data management, is to manage information independent of any application so that it is available to a wide variety of users and applications. This approach is the *data warehouse domain data management environment*. It is based on the simple principal that (software) applications and pipeline data have differing ownership and life spans: data must last forever and resides within a pipeline operator, whereas applications are continually being updated/changed and are the property of a software vendor. This also means the skills and knowledge base of the people responsible for each will also reside in different locations.

There are now two major initiatives in the pipeline business that are attempting to standardize how we manage our data:

i. The 'PODS'[9] initiative in the USA [35] was the first step: the USA pipeline industry is building its databases in accordance with a company-wide or industry-wide standard 'to allow operators to compare their own performance with comparable companies or across the pipeline industry'. The Pipeline Open Data Standard (PODS) is managed by, and for, the pipeline industry [35].

ii. The 'ISPDM'[10] initiative in Europe is providing further (similar) advances [34]. This industry standard pipeline data management project was a $1milllion project supported by the European Union, and finished at the end of 2002.

9. AFFIRMATION OF MAXIMUM ALLOWABLE OERATING PRESSURE (MAOP) AND AUDITS

Some pipeline codes require regular, formal audits of pipelines to ensure they are operating at pressures within code requirements; for example, pipeline codes in the UK and Australia require pipeline operators to regularly review their MAOP. This is important, as infrastructure changes, or pipeline condition, may require a reduction in MAOP.

[9] www.pods.org
[10] www.ispdm.org.

All pipelines should be the subject of regular risk reviews [8,9], regardless of their age This should include regular independent audits, and also include a thorough evaluation of the condition of a pipeline if it is to be:

- uprated beyond its original design pressure, or extended beyond its design life,
- operated at a higher pressure than it has experienced in, say, the past four years,
- change of product,
- change ownership: many pipelines are now either being transferred to new owners (e.g. by acquisition or mergers), or are under scrutiny by third parties wanting to use them to transmit their product. An integrity review is appropriate both for due diligence reasons and also for demonstrating security of (third party) supplies [12].

10. CONCLUDING REMARKS

i. The pipeline industry is changing: its plant is ageing, and new regulations are being introduced to force operators to effectively manage their pipeline's integrity. The regulations require the integrity management process to be included in a 'Pipeline (Integrity) Management System', which ensures all processes and procedures are applied, and performance measured, reviewed and audited. Operators in other parts of the world, who are not covered by such regulations, should learn from the lessons in the USA: as our systems age, we must invest more in pipeline integrity. A good safety record, or a dismissal of the experiences in USA as 'unrepresentative', is not an excuse to avoid this investment: this type of complacency and naivety will lead to failures.

ii. A key element of managing a pipeline's integrity is a risk assessment (Figure 9), to identify the major threats to a pipelines safety and security. Managers need to ensure that their staff are suitably trained to do this work, have an efficient data management system, but – more important – are aware of lessons being learnt by other operators through failures, inspection, etc..

iii. We can learn clear lessons from reviewing pipeline failures: Section 3 indicates that failures can be caused by inadequate co-ordination of data and staff, and inadequate appreciation of risks.

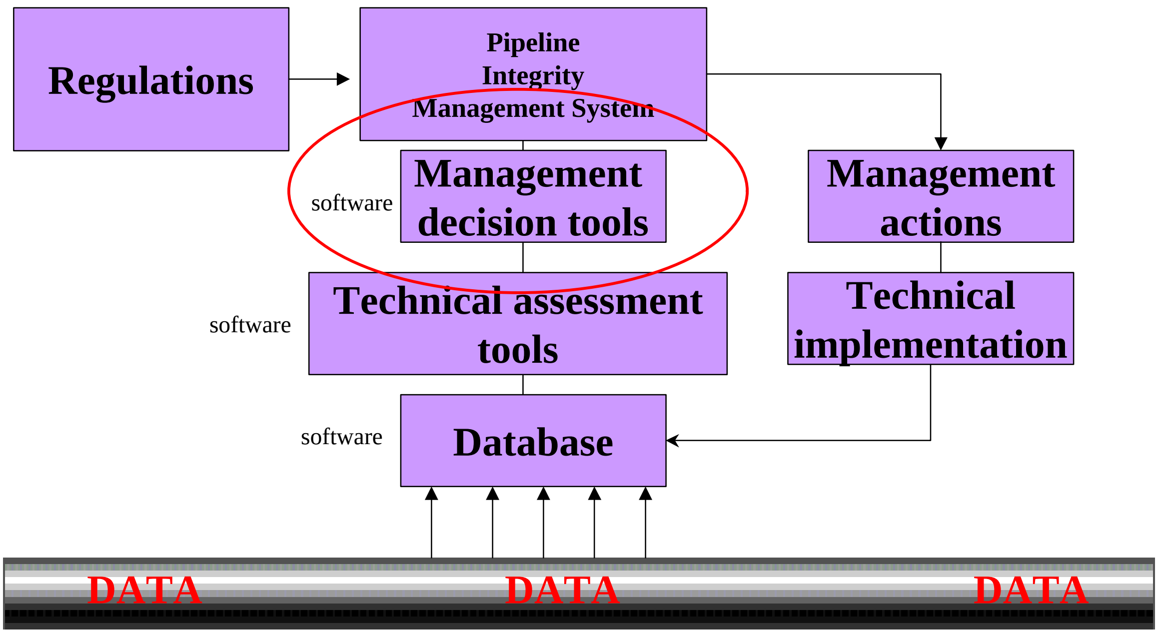

Figure 12. Position of technical and decision tools in pipeline integrity management.

iv. It is also clear now that in the modern day, pipeline managers will need access to large sets of data, technical tools (such as risk assessment software), and management decision tools, Figure 12, to allow them to operate their pipeline safely.

   a. It is not sufficient to purely have a risk analysis software package, or a defect assessment model, and managers need to be careful with the use of software packages (see Section 7 [33]). Figure 12 shows that it is not sufficient to have technical assessment packages: these merely give numbers. Management must make the final decision on any technical assessment, using their experience of software tools. It is management that manages integrity, not a risk assessment software tool.

   b. We have many databases and many technical tools available to us, but we do not have the management decision tools that allow a manager to bring together al the data and technical assessments: these types of decision tool would have avoided the failures mentioned in this paper. A complete package of tools is required to allow a pipeline integrity management system to function, and this is the major lesson learnt.

   c. It is interesting that pipeline operators will spend $millions on hiring intelligent pigs, but spend little on databases to manage the masses of data obtained from the pig.

v. It is clear that we are living in rapidly changing times. A pipeline engineer will come under increasing pressure, as companies 'downsize', and our engineering workforce retire in large numbers due to a high average ages, and our pipeline operators are 'stretched' to record higher profits. It is essential that we aid our engineers and provide them with all the tools they need.

   a. One important aid is a formal 'lessons learnt' procedure where engineers record and circulate lessons learnt from both failures and 'near misses'. This can be a simple folder on the company's main server, or a collection of technical notes easily accessible to all staff. Additionally, all companies should encourage staff to publish 'lessons learnt', even if the failures being reported show deficiencies in company practices.

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