OPERATIONAL PIGGING – A FRONTLINE TOOL TO CONTROL INTERNAL CORROSION OF PIPELINES

Paul Birkinshaw, Jozef Soltis and Daniel Sandana
Macaw Engineering Limited, UK

Abstract
In this paper, we provide a Corrosion Engineer's perspective on developing corrosion management systems for the oil and gas industry assets, highlighting organisational and technical challenges and the importance of operational pigging, *i.e.* utilisation of cleaning and sealing pigs, and in-line inspection (ILI) tools, and how it may fit within an overall corrosion management strategy.

Based on actual results obtained through assessments and investigations conducted on a wide range of pipelines, the impact and effectiveness of typical current operating practices are critically reviewed. Suggestions and recommendations are then put forward for discussion with regard to improvements and/or alternative pigging strategies which may be beneficial and provide practical solutions against a range of internal pipeline corrosion threats.

1 Introduction

Corrosion remains a dominant causal factor that compromises reliability and service life of pipelines and industrial assets, in general[1,2]. For example, as illustrated in Figure 1, in the province of Alberta (Canada), up to 70% of the incidents that resulted in pipeline failures were associated with corrosion[3].

At the very least, demonstrating the integrity of assets requires both the development and effective implementation of a corrosion management system. Within MACAW we have already stressed[1] on the importance of adopting a holistic approach that brings together individual components into an integrated corrosion management system. However, even with the existence of an over-arching corrosion management system, it is its implementation and the correct application of processes and tools that is critical; we find this often misunderstood.

It is also now widely acknowledged[4] within the oil and gas industry that operational (production) pigging is a key frontline operational and maintenance (O&M) activity for controlling internal corrosion in upstream production pipelines. As a member of the Rosen Group of companies, we are at the forefront of this battle, helping operators with assets' inspection, development of corrosion management strategies and implementation of effective corrosion control schemes[5].

This paper seeks to provide a Corrosion Engineer's perspective on developing corrosion management systems for oil and gas pipeline assets, highlighting organisational and technical challenges and the importance of operational pigging (*i.e.* utilisation of production pigs and ILI tools) and demonstrates how operational pigging fits within an overall corrosion management strategy.

2 Corrosion Management in Pipelines

2.1 Background

Controlling pipeline corrosion is one of the biggest challenges faced by operators of pipelines. Meeting this challenge proactively is essential to ensure that pipeline systems are maintained in an efficient state and working order, and in good repair. It should also be noted that in the UK this is an obligation under the Pipelines Safety Regulations 1996.

The obvious benefit is ensuring the integrity of pipeline assets, and thus avoiding a loss of containment incident (an uncontrolled release of hazardous fluid) and any associated consequences.

In the context of hydrocarbon production pipelines, the consequence of such incidents can be significant and will usually fall into one of the following general categories:

- Unsafe/hazardous conditions.
- Pollution / environmental damage.
- Loss of service (economic impact).
- Reputational damage.

In general, corrosion management includes all activities throughout the lifetime of an asset – pipelines in this specific case – which are performed to mitigate corrosion, and repair or replace components which, as a result of in service corrosion, become unusable. Unarguably, the overall goal is to achieve the desired level of service at the least cost.

In our approach to pipeline corrosion management, we put emphasis on four main components:

(i) Corrosion Risk Assessment (CRA), focused on corrosion threats.
(ii) Pipeline Risk Assessment (PRA), focused on wider threats including corrosion.
(iii) In-line Inspection (ILI), incorporating fitness for purpose and corrosion growth assessment.
(iv) Corrosion Control Strategy (CCS), which defines the overall strategy for identified corrosion threats, and establishes control and mitigation measures / procedures.

As already discussed elsewhere[5], the principal objective of the risk assessments (CRA and PRA) is to encourage a balanced approach to risk management by ensuring that inspection and monitoring resources are commensurate with the degree of identified risks and components criticality. As part of the integrity review process, the risk assessments thus drive future monitoring and inspection strategies (including ILI requirements, prioritisation and tool selection). The outputs from corrosion growth and fitness for purpose assessments also provide important indicators which can be used to validate and optimise CRA.

It is important to stress, however, that even with such an over-arching corrosion management plan or system in place, it is the implementation which should be critically evaluated. Our experience (in MACAW) suggests that obstacles to effective implementation of integrity management systems are often attributed to: excessive paper work; lack of visibility, readability of integrity status, awareness in regard to implementation of actions; communication between different organisation groups; prioritisation; disjointed decisions across organisation; duplication of actions; and lack of transparency and consistency in design, operations, inspection, monitoring, *etc.*

2.2 The UK Regulatory Framework Governing Pipelines

In the UK from a HSE and regulatory perspective, the key instruments that govern pipelines include the Pressure Systems Safety Regulations 2000 (PSSR) and the Pipeline Safety Regulations 1996 (PSR).

Additional provisions are made (within the PSR) for so call Major Accident Hazard (MAH) Pipelines which includes the majority of offshore and production pipelines (and the UK onshore gas transmission network). The additional provisions for MAH pipelines include HSE Notification and a requirement for a detailed Major Accident Prevention Document (MAPD) together with a documented emergency response plan. For offshore pipelines, the installation of Emergency Shut-down Valves (ESDVs) is also mandated.

The UK PSR were implemented in the wake of the Piper Alpha incident, implementing a goal setting approach to ensure that operators are managing pipelines safely and effectively while the associated risks are controlled and kept as low as reasonably practical (ALARP). The document is very concise with 31 Clauses over only 8.5 pages. To illustrate the HSE's approach, two of the main clauses covering design (one of the longest) and maintenance are presented below.

<u>Clause 5 (Design)</u>

The operator shall ensure that no fluid is conveyed in a pipeline unless it has been so designed that, so far as is reasonably practicable, it can withstand:

(i) The forces arising from its operation;
(ii) The fluids that may be conveyed in it; and
(iii) The external forces and chemical process to which it may be subjected.

<u>Clause 13 (Maintenance)</u>

The operator shall ensure that a pipeline is maintained in an efficient state, in efficient working order and in good repair.

2.3 Managing Internal Corrosion in Pipelines

Internal corrosion is recognised as one of the principal threats in upstream production and export pipelines, where the fluids transported are often unprocessed hydrocarbon containing some produced water.

The principal internal pipeline corrosion threats include:

- Sweet (CO_2) Corrosion.
- Sour (H_2S) Corrosion.
- Microbiologically Influenced Corrosion (MIC).
- Erosion Corrosion.
- O_2 Corrosion.

Internal corrosion is arguably not one of the main causes of pipeline failures, even in offshore pipelines. Available failure statistics does highlight that corrosion accounts for about 40-50% of pipeline failures in the UK, but there is limited data separating out those attributed to either internal or external corrosion. The general consensus within MACAW is that the majority of corrosion failures in offshore pipelines can be attributed to external atmospheric corrosion associated with the riser and splash zone segment of a pipeline.

However, while internal corrosion might not be the dominant immediate integrity threat to pipelines, it is undoubtedly a more difficult integrity threat to manage and probably the main reason why upstream production and transmission pipelines are ultimately retired from service or need to be replaced (partially or wholly). Internal corrosion, therefore, will rank at or near the top in terms of cost impact to industry when compared with the other major integrity threats (considering the share of OPEX disbursed and/or CAPEX for rejuvenation/repair).

3 The Role of Pigging Within a CCS

Pigging is an important tool in managing the threat of internal corrosion, whether it be routine operational or ILI pigging. Operators invest significant time and resource in carrying out a range of pigging tasks.

3.1 Operational Pigging

The term operational pigging (also referred to as routine, production and maintenance pigging, or any combination of these) can cover a wide range of operations. In general, it can be interpreted as activities which are regularly carried out on an in-service pipeline (*i.e.* during normal operations) as part of an established maintenance routine. This will usually be driven by the need to maintain efficient pipeline throughput and/or prescribed for corrosion management.

A quick web search yields a good number of references to operational pigging, which mostly originate from pigging vendors and emphasise on benefits to operators. However, at this level, little thought is given to the discrete sets of circumstances that might exist in individual pipelines, where different scenarios might arise and what inspection (pigging) options may (or may not) be appropriate.

In order to understand particular requirements of an individual pipeline system, the additional wisdom of wider disciplines (typically including a production chemist and/or an experienced corrosion engineer) are essential to help understand key corrosion threats and to identify appropriate methods of control.

Operational pigging in pipelines is usually only considered necessary and/or beneficial in upstream hydrocarbon production pipeline lines or in main (crude) export transmission pipelines. The benefits of (and in some cases the need for) operational pigging in such pipeline assets is generally well understood by operators, with routine pigging programmes established for many pipeline systems.

For many new production pipeline systems it is recognised from the outset that some routine pigging will be a necessary part of the normal operating regime. In other cases it may have been adopted at a later time, as a reaction to a change in operating circumstances in an existing pipeline system.

The principal challenges faced by operators, and main reasons for establishing such programmes typically include:

- Dewaxing – preventing wax build-up on the pipe wall.
- Descaling – helping preventing scale formation and build-up.
- Liquids removal in gas pipelines (condensates / produced water).
- Dewatering – preventing produced water holdup in oil or multiphase pipelines.
- Removal of corrosion products.
- Removal of sand / sediments.
- To help prevent hydrate formation.

Where these pigging routines are adopted, they are often defined as part of an established and documented CCS and will often sit as an operating procedure within a wider pipeline integrity management system (PIMS). As such, operational pigging is also usually subject to some form of Key Performance Indicators (KPIs), typically monitoring actual *vs.* planned pig run frequency.

3.2 Operational Pigging – a Tool to Control Internal Corrosion

In the context of managing the threat of internal corrosion, operational pigging can often play a crucial role. In reality the role of pigging is generally simple, with the main objective usually ether to prevent a build-up of deposits under which certain corrosion mechanisms may develop (*e.g.* under-deposit corrosion) and/or for the removal of any free water in a pipeline (one of the key elements required for aqueous corrosion to occur).

It is important to note, however, that pigging is usually only one part of the solution, with chemicals introduced into the product stream also playing a major part in limiting and controlling corrosion. Common production pipeline chemical treatments include:

- Corrosion Inhibitors (CI).
- Scale Inhibitors.
- Wax Inhibitors.
- Biocides.

Upstream pipeline operators invest considerable sums in using CI and other chemicals treatments to help combat corrosion and maintain healthy internal pipeline environment. The chemicals and injection dosage rates can vary considerably depending on the fluids carried and the prevailing pipeline operating conditions.

Pigging does however play a significant role in helping to maintain a clean internal surface in pipelines, which in turn means that, where applied to help combat corrosion, expensive chemical treatments will be more effective. This in turn will allow for the injection dosage rates or frequency of deployment (*e.g.* biocide batching) can be optimised. With some specific corrosion threats (*e.g.* MIC) there is anecdotal evidence that routine pigging can play a much more significant role in prevent active corrosion than with chemical treatment alone.

On a cautionary note, there are some cases where more aggressive pigging can upset the natural balance in a pipeline and exacerbate internal corrosion.

Table 1 summarises the main objectives of operational pigging together with the principal benefits to the operator. This illustrates that an effective operational pigging strategy when deployed as part of an overall CCS can result in significant reductions in both operating costs and environmental impact; while maintaining integrity, and efficient and reliable pipeline operation.

Table 1: Role and Benefits of Operational Pigging Within a CCS.

<table>
<tr><th>Key Function / Task</th><th>Main Benefit</th><th colspan="2">Additional Benefits</th></tr>
<tr><td rowspan="5">Prevention of Deposit Build-up</td><td>Elimination of habitat for onset of associated corrosion mechanisms</td><td>Allows for optimisation of CCS elements</td><td rowspan="11">Allows for optimisation of established CCS

Can reduce both operating costs and environmental impact while maintaining integrity, and efficient and reliable operation</td></tr>
<tr><td>Improved CI effectiveness</td><td>Optimisation of chemical dosage rates</td></tr>
<tr><td>Improves effectiveness of chemical treatment</td><td>Optimisation of biocide deployment strategy</td></tr>
<tr><td rowspan="2">Reduction in pre-ILI cleaning requirements</td><td>Reduction of future cost and operational risks associated with ILI</td></tr>
<tr><td>Improved ILI data quality</td></tr>
<tr><td rowspan="2">Prevention of Water Hold-up</td><td>Elimination of a key element required for a corrosion process</td><td>Allows for optimisation of other CCS elements</td></tr>
<tr><td>Reduced burden on topsides processing facilities (avoids slugging)</td><td>Reduced risk of carry-over to vulnerable downstream assets</td></tr>
<tr><td rowspan="2">Maintenance of Asset Operability</td><td rowspan="2">Maintains operators familiarity with asset and operating procedures</td><td>Regular maintenance of pig traps and valves</td></tr>
<tr><td>Active engagement of operators in CM process</td></tr>
<tr><td rowspan="2">Deposit / Debris Sampling</td><td>Monitoring for presence / type of corrosion products and bacteria</td><td>Leading indicator for the internal condition of pipelines</td></tr>
<tr><td>Monitoring for changes in pipeline operating conditions</td><td>Leading indicator for correct CCS set-up</td></tr>
</table>

3.3 The Role of In-Line Inspection Pigging

In-Line Inspection (ILI) pigging (where it can be conducted) forms another key pillar of a CCS. An individual ILI tool run not only detects and reports metal loss (often attributed to corrosion), but further analysis of the reported results (typically done as part of a post inspection FFP study) can help to identify the nature of corrosion and therefore diagnose the likely cause (*i.e.* what corrosion mechanisms maybe at play).

The evidence gathered from a thorough analysis of the reported ILI results are a key ‘lagging’ indicator of the effectiveness of the implemented CCS, helping to confirm whether or not the prescribed mitigation measures are appropriate and effective.

In the case of a repeat ILI tool run, a comparison of two data sets acquired between a known inspection intervals can be used to measure observed corrosion growth rates (refer to Figure 13). A detailed CGA provides another confirmatory indicator of CCS effectiveness and can also help with corrosion diagnosis, predict future degradation rates, estimated pipeline remnant life when the next inspection should be planned.

An important consideration with ILI pigging is to make sure that the correct ILI tools is selected to address the anticipated corrosion threat. For example, a conventional ‘Axial’ MFL (magnetic flux leakage) ILI tool might not be considered the best solution for chandelling corrosion where it is suspected. The CRA in this case can provide an important input to ILI tool selection to ensure the best technology option is chosen based on the perceived threat. Figure 2 demonstrates that there is now a wide range of ILI tools and technology options at the disposal of the operator today. This demonstrates that over recent years the major vendors have shown significant technological advances[7].

4 Concluding Remarks

In this work we provide a Corrosion Engineer’s perspective on developing corrosion management systems for the oil and gas industry assets. We highlight organisational and technical challenges and the importance of operational pigging, *i.e.* utilisation of cleaning and sealing pigs, and in-line inspection tools, and how these fit within an overall corrosion management strategy. More specifically, it is emphasised on the fact that pipelines’ internal corrosion provides operators with challenges and requires a robust and diligent approach. Implementation of an effective corrosion management system can reduce operational costs and environmental impact, while maintaining both integrity, and efficient and reliable pipeline operation. Operational pigging plays a very important role in effective management of pipelines.

References

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Figures

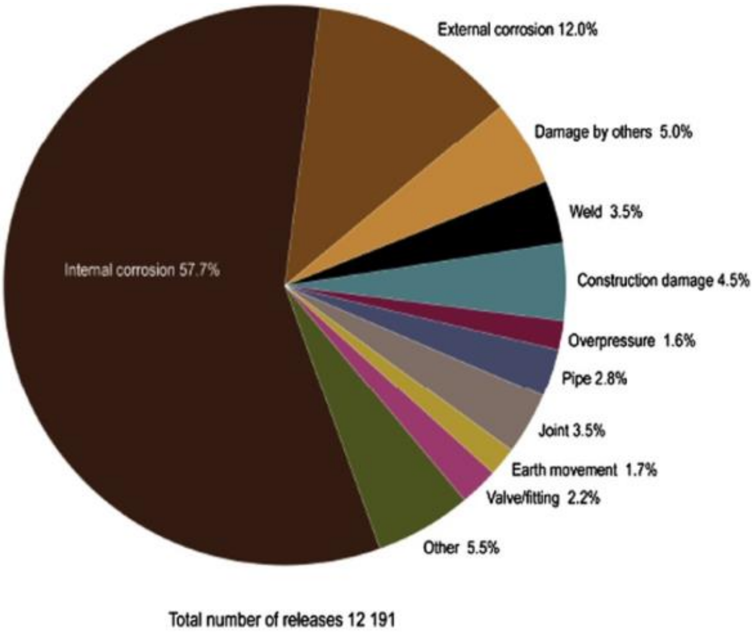

Figure 1. Pipeline main cause of failures, Canada, Alberta (1980-2005).

	GEOMETRY		METAL LOSS			CRACK DETECTION		COMBO	
	RoGeo EC	RoGeo XT	RoCorr MFL-A	RoCorr MFL-C	RoCorr UT	RoCD UT-C	RoCD EMAT-C	RoCombo MFL-A/UT	RoCombo MFL-A/IEC
Corrosion Growth Assessment			●	●	●			●	●
Fitness for Purpose Assessment	●	●	●	●	●	●	●	●	●
Dent Strain / Stress	●	●							
Crack Assessment						●	●		
Bending Strain*	●	●	●	●	●	●	●	●	●

*inertial measurement unit (IMU) is prerequisite

Figure 2: Rosen ILI Tools Options.

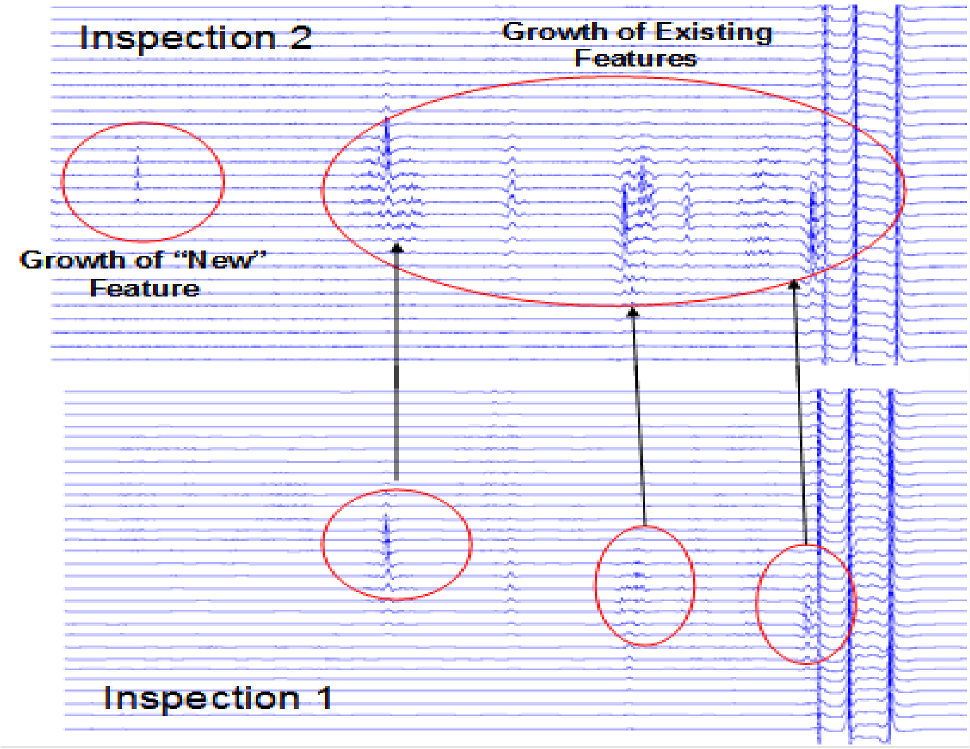

Figure 3: Detailed Corrosion Growth Assessment