Pipeline Integrity Management – The Rise of Non-Intrusive Area Corrosion Monitoring
Pipeline Integrity Management – Growth & Threats

When it comes to the safe transportation of gases and other fluids, the integrity of pipelines and the ability to operate such infrastructure in a safe and reliable manner is paramount. It’s for this reason that corrosion and pipeline integrity remain an ongoing issue.

Hydrocarbons – oil, gas or condensate – have been transported through pipelines since the beginning of the twentieth century. The American Engineering Standards Committee played a fundamental role when it initiated the B31 project in 1926, developing stringent pipeline standards that ensured consistency in safe design and operation. The project evolved into several codes and sections that are relevant today not only in the United States but also around the world.

The context for pipelines has changed as well. While rising energy consumption required the highest possible pipeline utilization rates, aging infrastructure, population density, environmental concerns, company liabilities and local community intolerance to incidents and accidents have all influenced pipeline integrity management programs today.

Today, there are 2,175,000 miles of pipeline in 120 countries around the world, complex regulation structures and thousands of highly specialized technicians and engineers that need to meet high utilization rates and safety requirements, while ensuring an efficient cost structure.

While the effectiveness of a pipeline integrity management programs depends on many factors, it is the ability to identify threats, estimate risks and integrate and act upon data to reduce systemic risk successfully that are perhaps the most important.

What are these threats? In the United States, pipeline operators are required to abide by regulations put forth by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA). Two standards widely used by the PHMSA are ASME B31.8S and ASME 2012c, which identify three key threats to pipeline integrity.

These consist of: i) stable, resident threats – threats that do not change over time and tend to be influenced by another condition or failure mechanism and cover areas such as manufacturing and construction; ii) threats that are time-independent and could be down to human error or outside factors, such as weather: and iii) time-dependent threats – threats that can grow over time and cover issues, such as external corrosion, stress corrosion cracking, and internal corrosion.

This white paper will focus specifically on the issue of internal corrosion. In a recent 2016 National Association of Corrosion Engineers (NACE) Impact study, the global cost of corrosion was estimated at US$2.5 trillion.

Furthermore, according to the United States Pipeline and Hazardous Materials Safety Administration (PHMSA), corrosion has been responsible for 18% of significant pipeline safety incidents (both onshore and offshore) in the 20-year period from 1988 through 2008, with 40 to 65 significant corrosion incidents per year.

The white paper will look at the challenges of internal corrosion and its impact; the failures and successes of the technologies used to address it; and new innovations – in particular, non-intrusive area corrosion monitoring based on the Field Signature Method (FSM™) – that can form a key cornerstone of pipeline integrity management strategies in the future.

Internal Corrosion – Causes and Challenges

Internal corrosion - the deterioration of the metallic structure of the pipe due to an electrochemical reaction between the pipe material and the environment inside the pipe – is a leading cause of incidents in pipelines with – in the case of liquid pipelines – the maximum rates occurring at the 6 o’clock position of the pipeline.

Despite the 2002 US Pipeline Safety Improvement Act and the increased emphasis on integrity management, pipeline failures due to internal corrosion continue to occur in the United States, Canada and worldwide. Operators of pipelines installed before the 1970s, which account for more than half of the total installed base in the US alone, identify internal corrosion as the leading cause of incidents.

According to the Alberta Energy Regulator (AER) and their 2018 Pipeline Performance Report, internal corrosion remains the leading cause of pipeline failures representing 37% of such failures in 2017 with 92% of high-consequence incidents occurring on pipelines that carry corrosive substances such as salt water or oil well effluent (although the report goes on to state that the number of pipeline incidents have dropped by almost half over the past 10 years).
There are a wide variety of causes for internal corrosion and can include fluid corrosivity, flow velocity, deposit of water accumulation, \(\text{H}_2\text{S}\) or \(\text{CO}_2\), or other pipeline impurities.

Yet while corrosion inhibitors can help control internal corrosion, how can the referenced threats be assessed?

There are a number of challenges here. For example, there is the need to identify between localized corrosion – corrosion in small areas or zones on the metal surface – and generalized corrosion where corrosion is uniformly distributed over a much larger area. Inorganic acids, salts, \(\text{CO}_2\), \(\text{H}_2\text{S}\) and other components that generate localized corrosion and possible leaks are also often difficult to track with pipeline failure carrying significant financial risk.

There are also the challenges of sourcing cost-effective pipeline monitoring over large and remote areas which come with their own challenges from communications to cost to power, transportation and logistics.

In this white paper, we will examine three types of integrity assessment methods - In-Line Inspection (ILI); Direct Assessment; and a new non-intrusive online corrosion monitoring method – and how these technologies are addressing the challenges above.

**In-Line Inspection (ILI)**

From the mid-1960s onwards, pipeline operators began to use a form of instrumented inspection technology that has evolved into what is known today as In-Line Inspection (ILI). The goal of ILI is to assess the health of the pipeline, assess corrosion rate growth, put in place a strategy for rehabilitation work, and outline plans for future inspection needs.

ILI covers a wide variety of tools and techniques, such as ultrasonic inspection, magnetic flux inspection, metal loss tools and pigging. Smart pigs, for example, have continued to grow and are playing a key role in detecting stress cracking, and general and pitting corrosion, with their highly tuned sensors gauging the thickness of pipes and identifying integrity issues, such as cracks, fissures, erosion and other problems.

There’s no doubt that ILI techniques can be highly effective. A 2015 report by the National Transportation Safety Board (NTSB)\(^4\), for example, that evaluated the need for improvements to gas transmission integrity management programs and requirements for gas transmission pipelines, confirmed that ILI yields the highest per-mile discovery of pipe anomalies.

Yet, ILI techniques come with their own challenges as well. For example, ILI technologies need to have pipelines configured to accommodate their tools and often a wide range of specifications. Such specifications can be related to pressure, temperature and flow range, tool length and weight, minimum bend ratios, and much more.

The result is that – even if the pipeline segment is ready to accept the ILI tools – the operators may still choose not to use them due to operational complications, such as low operating pressure, low flow, or even absence of flow. There are also often access issues, particularly in the lower parts of underground pipelines, and the possibility that transportation in the pipeline might have to be halted.

Many regions also rely on single source lines, which can be defined as the only source of hydrocarbons to customers and communities. This type of pipeline cannot be shut down without disrupting customer supply. Based on this, operators may limit the use of ILI due to potential operational complications.

It’s also worth noting that ILI doesn’t provide continuous online information and that some pipelines are ‘unpiggable’ due to their small diameters, bends and connections, and low flow that can cause the pig to get stuck.

Finally, there are the issues of cost and logistics – especially when large areas have to be monitored. With many pipelines in some of the world’s most remote locations, there can be significant cost and transportation implications with pigs not cheap and also labor intensive. Each pig can only handle a few miles on average, require multiple launches, and total smart pigging can be as much as US$35,000 per mile!

**Direct Assessment**

Direct Assessment is another means of analysing pipeline integrity.

Direct Assessment consists of three key areas: External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Direct Assessment (SCCDA) and is designed to complement detailed ILI-based inspections.

Direct Assessment also has four phases – the pre-assessment phase of the inspection where all pipeline...
data is collected to determine whether direct assessment is feasible; the inspection and pre-direct examination phase that involves the use of non-intrusive techniques to assess the buried pipelines and possible excavation; the direct examination stage; and the post-assessment and continuing evaluation stage.

Direct Assessment is popular today. In the case of internal corrosion, for example, NACE has ratified Internal Corrosion Direct Assessment (ICDA) methods for dry gas, wet gas and liquid product pipelines to meet the need for pipeline integrity with respect to likelihood of internal corrosion.

Limitations of direct assessment, however, include but are not limited to very short pipeline sub-segments coverage; the subjective operator selection of the excavation location; the levels of expertise during direct examination; the low anomaly identification yield; and the discrete nature of the data points.

In effect, inspection data from a selected few locations along the pipeline is used to characterize integrity of the entire pipeline. Performing successful ICDA applications therefore relies heavily on the ability to model flow and accurately quantify/predict corrosion damage along the pipeline.

It’s for this reason that several regulatory bodies have already recommended implementing a plan for eliminating the use of direct assessment as the sole integrity assessment method.

The already cited National Transportation Safety Board (NTSB) 2015 report into gas transmission integrity management programs found that “the use of direct assessment as the sole integrity assessment method has numerous limitations.”

The Emergence of Non-Intrusive, Online Corrosion Monitoring

It’s against this context and when evaluating the relative merits of In-Line Inspection and Direct Assessment as well as the growth in digitalization that we turn to an alternative form of integrity assessment - non-intrusive, online corrosion monitoring.

It is the authors’ belief that online corrosion area monitoring enhances both ILI and Direct Assessment by providing continuous information of selected points from virtually all pipeline segments.

Figure 1 illustrates how successful pipeline integrity management programs are dependent on continuous monitoring to identify internal corrosion.

There are significant benefits to the ability to monitor continuous select points across several pipeline segments.

An efficient monitoring strategy, for example, would ideally consist of three monitoring locations between compressors or pump stations, thereby establishing two locations above ground and one underground location at the pipeline’s lowest point and leveraging the myriad of data points provided. In this way, operators can identify threats early and learn to calculate risk through the likelihood of potential incidents - the plausibility of a model parameter value given specific observed data.
Figure 2 shows the differences in corrosion monitoring based on interval-based data monitoring and continuous corrosion monitoring based around non-intrusive corrosion monitoring and the Field Signature Method (FSM). It is this complimentary technology to traditional In-Line Inspection and Direct Assessment technologies that will be highlighted in the rest of the article, providing a highly effective way to monitor new and existing uncovered or buried pipelines across several segments.
The Field Signature Method (FSM)

The Field Signature Method (FSM) is based on feeding an electric current through a monitored section of a pipe, pipeline or vessel. The applied current sets up an electric field that is monitored as voltage drop values between a set of sensing pins installed on the external pipe wall.

The initial measurement sequence measures the voltage drop between all pairs of sensing pins and is called the Field Signature. Later measurements are compared to the Field Signature, where general corrosion can be seen as a uniform increase in voltage drops between all pin pairs, and localized corrosion can be seen as a local increase in the values.

It is important to note that corrosion is measured between the sensing pins meaning that the complete monitored area is covered, not only under each sensing pin. This is particularly important for monitoring localized corrosion, such as naphthenic acid corrosion.

FSM data can then be plotted as metal loss versus time for the efficient tracking of changes in metal loss or in 3D plots that show the distribution of corrosion over the monitored area. Typical sensitivity for FSM is 0.1% of wall thickness for general corrosion, corresponding to 10-20 micrometer in most cases.

Figure 3 shows how the corrosion monitoring data from the Roxar FSM Log is being presented in the Roxar Fieldwatch software.

FSM also fits into the growth of the industrial internet of the things, with pervasive sensors proving continuous online, data trending as well as communicating with each other seamlessly.

A New Corrosion Monitor

Utilizing this technology, Emerson has developed the Roxar FSM Log 48 Area Corrosion Monitor™, a vital new tool in pipeline integrity management that delivers permanent, cost-effective and online area corrosion & erosion monitoring for remote and large area pipelines. Figure 4 illustrates the recommended locations for Roxar FSM Log 48 installation to monitor high risk areas of internal corrosion. The final Number of positions will depend on required coverage, pipeline length and topography.

The monitor is not only suitable for unpiggable pipes but also for high consequence areas, reducing Direct Assessment and aerial surveillance costs. It also has a total cost of ownership less than just one typical smart pig run of up to 10 kilometers, although this can vary according to the pig technology.

The monitor is a variant of the already established potential drop technique and monitors a pre-defined area with the ability through the sensing pins to distinguish between localized corrosion and generalized corrosion.

Inorganic acids, salts, CO$_2$, H$_2$S and other components that generate localized corrosion and that can only be monitored through area measurement technologies can also be tracked in real-time. To this end, the Roxar FSM Log 48 provides a tomographic image that depicts a full insight of the pipeline’s internal corrosion status.

The monitor can also be easily retrofitted to any uncovered or buried onshore pipeline segment and, because of its cellular communication and solar power capabilities, can autonomously function in the most remote locations, enabling more data points across several pipeline segments and forming a key element of future digitalization strategies. The fact that several can be located over a pipeline minimizes the need of assessing the pipeline integrity through pigging and increases transportation capacity.
Emerson has also developed a data management solution that can interface with SCADA systems through Modbus TCP/IP or OPC, performing complex analytics and providing advanced data trending capabilities, alarm setting, information sharing options and output selected values to the operator's SCADA system.

It is this information sharing that can increase pipeline integrity and also optimize pig runs (when pipe bends, valve restrictions and contaminant build-up are restricting pigs from moving through pipelines), integrity digs and hydrostatic pressure tests.

This continuous monitoring of general and localized internal corrosion allows early threat identification and improved risk assessment, and avoids unnecessary pipeline shutdowns, costly hydrostatic pressure tests, and repairs because of leaks.

Meeting CAPEX, OPEX and Maintenance Costs

Every pipeline brings with it a unique sense of circumstances that lends itself to specific technologies covering everything from the inspection environment to pipeline conditions.

However, the cost of conducting pipeline integrity management activities, such as pressure tests (which cost US$163,000 per 1000 feet versus $34,000 per mile for in-line inspection and $85,000 per mile through direct assessment) significantly impact pipeline operators’ bottom line. Pressure test operations also require extensive planning well as the halting of hydrocarbon transportation activities.

Increasing corrosion monitoring locations provides real time 24/7 information as well as the ability to comply with regulatory frameworks without jeopardizing transportation operations. For a fraction of the cost of integrity dig activities, operators can enhance their current integrity management techniques with the FSM monitor and constantly receive internal corrosion information to selectively schedule their integrity digs or aerial surveillance. This data-driven proactive maintenance strategy also reduces both unplanned and planned downtime.

As well as decreased inspection costs, non-intrusive online corrosion monitoring is also leading to decreased pipeline lifecycle costs.

Pipeline construction is a CAPEX-intensive endeavour that can cost, on average, $4.5 million per mile. As a result, material selection plays a fundamental role in customizing the right life cycle costs for the selected project. To conduct this analysis, operators must identify corrosion threats, calculate the corrosion rate per year, and define the right material for each segment. Depending on the application, operators can select not only carbon steel with a corrosion allowance and/or coating but also expensive materials, such as duplex or super duplex.

Balancing such material decisions with other parameters such as inhibitor injection requires continuous actionable information. To this end, the new FSM monitor can trend not only general but also localized corrosion through its tomographic technology and avoid unnecessary pipe replacements and excess of chemical inhibitors injection. All this forms part of the growing digitalization of the midstream sector.
And as we know, the costs of inaction are huge. Uncontrolled internal corrosion can severely impair the integrity of pipelines beyond the point of no-repair, generating pipeline replacement costs that can range up to $4.2 million for a 24-inch pipe\(^\text{10}\).

**Conclusion**

Meeting increased pipeline integrity management requirements can be best achieved through the deployment of remote corrosion monitoring locations throughout several pipeline segments that enhance current threat identification methods.

This also lays the foundation for a wider digitalization strategy, with the Roxar FSM Log 48 Area Corrosion Monitor and its internal corrosion monitoring, remote communications, scalability and data intelligence forming a central part of it.

In this way, operators can gain control of their pipelines, increase the pipeline area monitored, deliver accurate corrosion and erosion monitoring in the most remote of areas, and provide operators with increased pipeline capacity, reduced risks of failure and the very best in cost-effective, data-driven pipeline integrity management.

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5. Digital Transformation Initiative Oil and Gas Industry – World Economic Forum
9. Safety of Gas Transmission pipeline rule – INGAA