

**Department of Mechanical & Manufacturing Engineering University of Calgary.**

**ENME628: Pipeline Coatings**

**Topic: Review on Elements of Pipeline Integrity Management**

(ILI inspection; Assessment; Mitigation; Prevention; Monitoring)

**Group 1**

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# **I Abstract**

Pipelines are known to be one of the most critical components of oil and gas industry for the transportation of products from both upstream and downstream operations. Pipeline integrity is important to ensure production operations maintenance in other to protect the environment and human life. The Integrity management programs (IMPs) operations are established and implemented for the pipeline industry in other to maintain a reliable and safe operation.

There are various elements of pipeline integrity management but in this project, we focused on the following: (ILI inspection; Assessment; Mitigation; Prevention; Monitoring). The in-depth discussions of these elements in this project emphasizes on the importance of these elements in terms of ensuring the minimization of failure, spills, and provision of a safe and reliable operation. Also, it is considered a known fact that pipelines used in the oil and gas, including other high hazardous industries must follow regular statutory inspections, verifications and certifications as this the point the elements of pipeline integrity management are applied..

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# **II Nomenclature**

(ILI) In-Line Inspections

(IM) Integrity Management

(HCAs) High Consequence Areas

(DOT) Department of Transportation

(NDT) Non Destructive Test

(MAOP) Maximum Allowable Operating Pressure

(IMPs) Integrity management programs

(MFL) Magnetic flux leakages

(UT) Ultrasonic Testing

(EMAT) Electromagnetic acoustic transducers

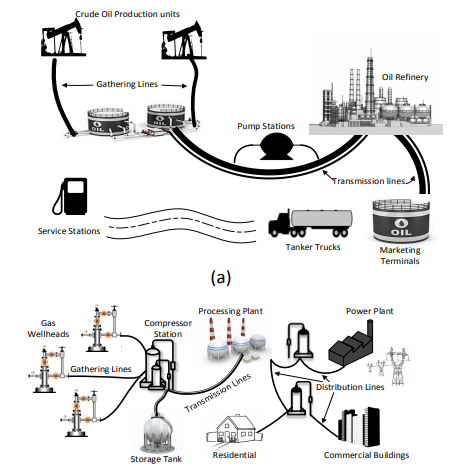
(ET) Eddy currents testing

# **Chapter 1- Introduction**

This chapter describes briefly on pipeline integrity management in conjunction with the aim and objectives of this project.

## **Introduction**

The transportation of oil and gas and other hazardous fluids from one place to another is efficiently done in several ways which include the following: through the use of pipelines, railroad tankers and road tanker trucks which are known as surface transports, over water transports which are executed with the use of ocean ship tankers, or smaller ships when in the coastal water regions (Singh & Ramesh, 2017). The oil and gas system was defined by the National Energy Board of Canada’s Act as “a line that is used for the transmission of oil, gas and other commodities and includes all branches, extensions, tanks, reservoirs, storage facilities, pumps, compressors, interstation systems of communication by telephone but does not include a sewer or water pipeline as that is used for municipal purposes only"(Board 2005). The Figure 1 shows the types of pipelines in a crude oil pipeline system which consist of the gathering lines and main transmission lines. On the other hand, a gas pipeline system consist of three types of pipelines which include: gathering lines, transmission lines, and distribution lines. Miesner & Leffler in 2006 stated that the sizes of the gathering lines ranges from about 2 to 12 inches, and the size of a transmission line is estimated to start from about 8 inches and higher. Definitely, the consequences of failure and associated costs of repair crucially depends on the location and pipe size.



**Figure 1: Oil & gas pipeline system: a) Oil pipeline system b) Gas pipeline system, CEPA (2015) (Iqbal, Tesfamariam, et al. 2016)**

Also, in other for the transportation of fluids or gas from one place to take place safely and efficiently, a term called Integrity Management is applied. Integrity management (IM) can be described as a performance-based and process-oriented program used in assuring safety management and environmental risks associated with oil and gas other hazardous liquid pipelines. These IM rules are much regimented as they specify how the operators of the pipelines must classify, prioritize, assess, evaluate, repair and validate the integrity of their pipelines. These rules are judiciously followed by the pipeline operators in other to prevent leakage or failure or hazardous substance polluting the environment especially in High Consequence Areas (HCAs). HCAs are classified as population areas, as these areas are sensitive to the damage of the environment or commercial waterways (Kowalewski, 2013).

## **1.2 Project structure**

Chapter 1 - Describes the Introduction in conjunction with the aim and objectives of this project.

Chapter 2 - Provides details on the background to the project, elements of pipeline integrity management. Focusing on the ILI inspection; Assessment; Mitigation; Prevention and Monitoring

Chapter 3 - Provides details of the legal and ethical issues of the project.

Chapter 4 - Conclusion on the project.

## **1.3 Project Aim and Objectives**

The aim of this project is to review the elements of pipeline integrity management and show an in-depth understanding of the ILI inspections, assessments, risk analysis and mitigations involved.

**Objectives:**

* Overview of the elements of pipeline integrity
* Understanding the ILI inspections, assessments, risk analysis and mitigations.

# **Chapter 2- Background**

This Chapter provides a brief introduction and an in-depth explanation on the elements of pipeline integrity.

## **2.1 Elements of Pipeline Integrity Management**

Pipeline Integrity was defined by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration as “The ability of a pipeline to work efficiently and safe by withstanding the stresses imposed during its operations” (Transportation Pipeline & Administration 2003). Integrity management aids the management priorities for the allocation of resources ensuring appropriate planning, actions to be taken, and tasks required to maintain integrity. The main drive of pipeline integrity management is to ensure an effective execution and quality control of the various technical processes all through the lifecycle phases of the pipeline (design, construction, maintenance, assessment, and abandonment) (Hassan & Khan 2012b).

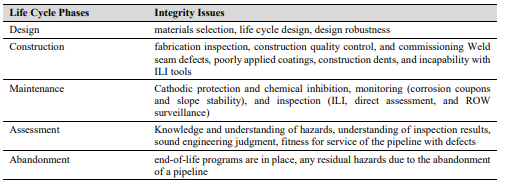
Kishawy & Gabbar in 2010, suggested that the main components of pipeline integrity managements include: pipeline failure identification process in high consequence areas, baseline assessment plan, failure consequences of pipeline integrity with an integrated analysis of defect information, keeping of records and documentation control, information analysis and integrity review, repair actions based on information analysis during assessment plan and mitigation measures to protect the high consequence areas.

In the same year 2010, Rahim et al added to this subject by stating that pipeline integrity can be improved by analyzing past accidents, inspection methods, various testing procedures, assessment methods, and a consistent long-term maintenance of a system.

### **2.1.1 Factors affecting Integrity**

Pipeline Integrity can be affected due to a material and construction defects, faulty job from a third party construction, operational errors, malfunctioning of devices, and Climate or environmental factors which include: corrosion, cracking, weather and sudden changes in temperature, movement of tectonic plates, floods etc (Adebayo & Dada 2008).

The Figure 2 below shows some integrity issues linked with pipeline lifecycle phases. After analyzing these issues, despite all the other factors, the human factor was seen to be very crucial, as this is impossible to be overlooked in the integrity management system. This is because the organization requires highly skilled workers in other to achieve a safe environment and also a high level of integrity (Chandima Ratnayake & Markeset 2010).



**Figure 2: Pipeline integrity issues related to lifecycle processes**

According to (Iqbal, 2004) the Elements of integrity management include:

1. Finding the potential pipeline effects to critical points.

2. Gathering of data, review and integration

3. Risk assessment

4. Pipeline integrity assessment plan development

5. Inspection and Mitigation

6. Assess continued periodically and Integrity assessment plan revised

7. Implement preventive and mitigative procedures

8. Update, integrate and review data

11. Reassess Risk

12. Pipeline stations and terminals integrity management

As seen, there are a lot of elements of pipeline integrity management. However, in this report we focused on a few of them which include: ILI inspection; Assessment; Mitigation; Monitoring.

### **2.1.2 In-Line Inspections (ILI)**

Pipelines are mostly used in transporting oil and gas products over long distances due to their safety, efficiency and low cost. Integrity is critical for reliable pipeline operations, for preventing expensive downtime and failures resulting in leaking or spilling oil and gas content to the environment. Pipeline integrity management is a program that manages methods, tools, and activities for assessing the health conditions of pipelines and scheduling inspection and maintenance activities to reduce the risks and costs (Mingjiang Xie & Zhigang Tian, 2018).

Pipelines are generally buried and therefore the outside pipe surface is not available for visual inspection. To overcome this restriction, tools have been developed to inspect the pipe wall thickness, position, and geometry from inside the pipeline, hence the reference to in-line inspection (ILI). A few ILI tools have been developed and are still being developed to inspect for specific types of anomalies. Generally, to obtain a complete assessment of the integrity of a pipeline, several ILI tools must be run in succession and then the inspection records compared to identify the types, location and severities of anomalies detected. Several types of internal ILI tools give a picture of the pipe wall and any corrosion or damage that has occurred throughout the service life. These tools allow the operator to be proactive, instead of reactive to potential CP shielding issues and corrosion (Cheng & Norsworthy, 2016).

There are ILI tools that are used to inspect for dents, corroded areas (metal loss), cracks both in the axial direction and in the circumferential direction, and tools that define the location and geometry of the pipeline. These tools are inserted into an operating pipeline and used to inspect the pipe from the inside. They are moved by the flow of the product in the pipeline and can generally be run without removing the line from service, although the inspections usually involve carefully controlled conditions, which may reduce the flow in a pipeline (Bob Eiber, 2003).

The general ILI system fundamental structure is illustrated in the figure below:



**Figure 3:Structure Schematic of ILI System (Source: Song Huadong et al, 2018)**

#### **2.1.2.1 In-Line Inspection Methods**

Due to possible pipeline leakage, environmental damage and high costs of repair and replacement, accurate pipeline monitoring and inspection becomes essential these days. Finding and recording data about pipeline integrity is the first step in pipeline integrity management, and there are a variety of ways to gather information about defects (Mingjiang Xie & Zhigang Tian, 2018). For external corrosion as well as other types of threats, there are various inspection techniques to record data on the defects. Pipeline inspection techniques include potential survey techniques, in-line inspection (ILI) tools, hydrostatic tests, tools for inspecting non-piggable pipelines like pipeline crawlers, etc. These pipeline inspection techniques were briefly introduced by (Song Huadong et al). ILI method is internationally recognized as the most effective way to protect the safety operations of pipeline. This project will focus on ILI tools.

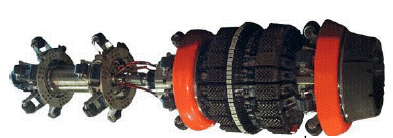
According to Mingjiang Xie and Zhigang Tian, a high-tech smart pigging device is utilized for in-line inspections, which is inserted in the pipeline and typically pushed through the pipe by the fluid flow from one compressor station to another. Such a smart electronic device is known as a smart pig in pipeline industry. This sophisticated electronic device is essentially a robotic computer that gathers all specific information related to the health condition of the pipeline. The ILI tools can classify the types of defect and their attributes including orientation of defects, size (length, width, depth) and specific location (Internal/External) of the defects (Shaik 2015). In-line inspection tools can also evaluate pipeline integrity in geohazard areas by mapping techniques (Yong A & Lockey A, 2013). How to get high-quality reports from ILI data was introduced in (Walker J. R et al, 2010).

Depending on the types of flaws they can detect, ILI tools can be classified as metal loss tools, crack tools, geometry detection tools, etc. Metal loss defects reported from an ILI inspection can be categorized into two main types: pressure based and depth-based defects (Shaik 2015).

In-line inspection are performed periodically using smart pigging tools to detect pipeline defects based on ILI data, predict defect such as corrosion and cracks. A variety of ILI technologies, which are examined below, are widely used in the pipeline field, and they include Magnetic flux leakages (MFL), Ultrasonic (UT) tools, Electromagnetic acoustic transducers (EMAT), Eddy currents testing (ET), etc.

#### **2.1.2.2 Magnetic Flux Leakage (MFL)**

The MFL tools were the first ILI tools to be developed and are most widely used tool for in-line inspection of pipeline. This technology can detect different types of defects, such as missing material and mechanical damage, and it is particularly widely used for metal loss inspection in a pipeline integrity management program. MFL inspection tools detect pipeline defects by sensing a local change in a saturating magnetic field, which is generated by huge magnets.As illustrated by Qingshan Feng et al, the principle of defect detecting and sizing of MFL inspection equipment is based on the varying magnetic lines of defect on the pipeline as shown in figure xx below; it can obtain the location, type, shape, dimension and other information of defects through the identification and judgement of MFL data. Three-axis high-resolution MFL in-line inspection utilizes the three-direction sensors inside the existing sensor to detect the size of the magnetic field in three directions. Therefore, it could measure the axial, circumferential and radial MFL data to determine the three-dimensional magnetic leakage field vector.



**Figure 4: A typical MFL Pig**



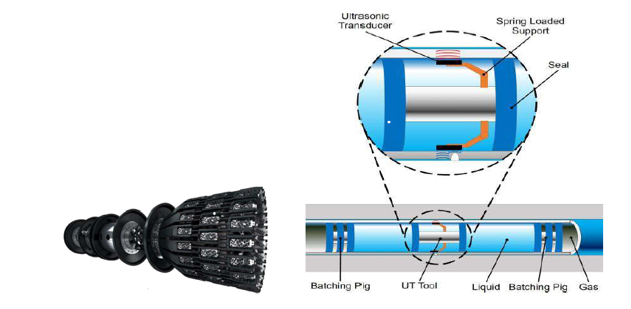
**Figure 5 : Schematic diagram of the magnetic flux leakage in-line Inspection Principle**

It has been demonstrated through various experimentation that the magnetic field profile is very complex and therefore there is need for researchers to pay careful attention to studying it in order to further develop MFL tools. Different sensitivity levels of the MFL tool can be chosen based on testing needs, such as low resolution, high resolution, and extra high resolution (Mingjiang Xie and Zhigang Tian, 2018).

The main merits of the MFL are its ability to operate without the need of pre-processing and the ease to detect signal (Song Huadong et al, 2018). Moreover, it can detect both internal and external surfaces and it is not affected by the transportation media. It also has the capability of easy online detection, high degree of automation for detecting many types of defects. All these advantages make the MFL inspection the most popular method of in-line inspection.

#### **2.1.2.3 Ultrasonic Testing**

Ultrasonic is one of the main areas of traditional NDT methods that uses guided waves and is the primary means of pipeline crack detection. Ultrasonic sensors typically refer to piezoelectric transducers (PZT), which converts AC into ultrasonic, as well as ultrasonic sound into AC, uses ultra-high-frequency sonic energy to identify discontinuities in materials that are both on and below the surface of the material (Song Huadong et al, 2018). The ultrasonic transducers generate a signal that is perpendicular to the pipe wall. The sound echoes and is received by the transducer. The timing of the return signal allows the tool to determine if there is wall loss from either the external or internal surfaces of the pipe wall. These transducers must have a liquid coolant between the transducer and the pipe wall for the sound-wave signal to be sent and received. If there is an air space between the transducer and the pipe wall, then the signal will not be sent. For this reason, UT tools are typically used in liquid lines, and in natural gas lines if water is used as a coolant (Cheng & Norsworthy 2016).

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**Figure 6: UT Detector (Left-Side) and Longitudinal Cross-Section of UT Transducer (Right-Side) (F. Varela et al 2015)**

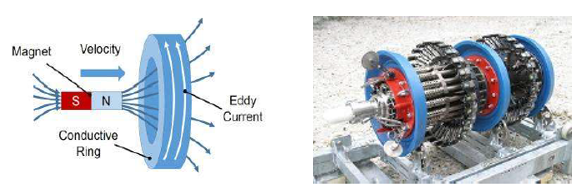
Currently, ultrasonic is the most reliable in-line inspection technology compared with the other technologies. Ultrasonic inspection generates ultrasonic pulses of high frequency and short wavelength to detect defects or measure pipeline wall thickness. In general, ultrasonic transducer tools have better detection capabilities than MFL tools and produce signals than can be directly related to defects sizes and quantities (Barbian & Beller, 2012). Nevertheless, this technology has a critical drawback in that it needs a homogeneous liquid coupling agent between the transducers and the pipe, which seriously limits its application on gas pipelines (Cordell & Vanzant, 2003).

#### **2.1.2.4 Electro-Magnetic Acoustic Transducer (EMAT)**

Electromagnetic acoustic transducer (EMAT) is a recently developed technology that generates and receives ultrasonic waves without requiring a liquid coupling agent. EMAT achieves this by means of Lorenz Force and magnetostriction (F. Varela et al 2015). Each transducer consists of a permanent magnet and a flat electrical coil. The ultrasonic wave is produced directly on the pipe wall when a burst high frequency signal is fed to the coil. These tools were initially designed to find various surface cracks in pipelines. As the technology has advanced, some companies have increased the number of sensors and can now locate where coating is either missing or disbanded from the external surfaces of the pipe. Most of the external corrosion, SCC, and bacteria problems occur on disbonded CP-shielding coatings, this tool now helps the operator find and correct these areas before they become a problem. The continued development and improvements of EMAT technology to locate and size disbonded coatings without the need to expose the pipeline gives operators economically sound information about their pipeline systems (Norsworthy et al 2013). As technology advances, these tools will locate smaller disbondment areas. At this time, some of these tools can also help to identify the type of coating used on the pipeline, providing the operator with critical information (Frank Cheng, Richard Norsworthy, 2016).

**2.1.2.5 Eddy Current Testing (EC)**

Eddy current testing (EC) is a widely used ILI tool in the automotive, aerospace and manufacturing industries. This tool operates on the principle of electromagnetic induction based on Faraday’s law, which states that when a conductor is placed in presence of a variable magnetic flux, an eddy current is induced in it as shown in figure xxx below.



**Figure 7: Graphical representation of Faraday’s law of Faradays’s law of Induction (Left-side) and Eddy current detector (Right-side)**

As an energized coil is brought close to the surface, the impedance of the coil is influenced by the nearness of the eddy current. When the eddy currents are affected by the defects, the impedance is also altered, and this change will be measured to detect defects (Mingjian Xie & Zhigang Tian, 2018). Eddy current can detect cracks and assess wall thickness and laminar defects. This technology has been used in ILI tools for pipeline for detection of internal anomalies because of the limited penetration of the signal through the pipe wall (J. Cordell & H. Vazant, 2003).

#### **2.1.2.6 Summary of In-Line Inspection Systems**

As presented above, each of the ILI tools has its advantages and limitations with respect to pipeline inspection applications. MFL system has the advantages of high sensitivity to pit corrosion, operation in hostile environment such as high temperature or cold, under water etc. It is also versatile and robust in operation and can be deployed at low cost. However, its limitations include sensitivity to pipe wall thickness, flow speed restriction, need for permanent magnetization saturation which determines its sensitivity and incapability of crack detection. UT system has high sensitivity and long-range inspection application like pipeline. It is good for crack, sizing and unlimited thickness of pipe wall. The major limitation is the need for coupling agent and flow restriction that turn down in gas pipeline. EMAT system has the advantages of UT plus the merit of operating without the need for coupling agent and thickness measurement. Its main limitation is low transduction efficiency, big size sensor hence consumes high energy. EC system is suitable for inner surface cracks and helps in the positioning and accurate detection. Suitable for wide range of defects regardless of size or material variation. Its limitation include sensitivity to lift-off and slow response to current pig speed (Song Huadong et al, 2018).

**2.1.2 Assessments**

According to (Cheng & Norsworthy 2016), a pipeline integrity management program (PIMP) can be defined as an engineering-based process designed to manage the integrity of a pipeline via the identification, susceptibility, assessment, prevention, mitigation and monitoring of the risks associated with the pipeline with the goal of protecting people and the environment while providing a reliable service to both shippers and customers. Based on this definition, it is clear that assessment is a key part of any PIMP. Assessment falls within the “Goals, Objectives and Targets” element of PIMP. This element deals with the integrity goals to be achieved as identified by the leadership of the organization. These goals comprise short, middle and long-term integrity goals for the organization as well as the targets that are set to ensure that such goals are accomplished. More specifically, this element also includes other components such as legal and regulatory requirements, pipeline threat assessment, risk assessment and integrity plan and schedule. In this section, a review of the various assessment types is provided.

A Pipeline Integrity Threat Assessment aims to accomplish 4 key goals: 1) Identify, 2) Classify, 3) Analyze and 4) Evaluate the susceptibility of a pipeline to integrity threats as well as the likelihood of any integrity threats to result in the failure of a pipeline. Once these goals are accomplished, pipeline integrity threat assessments go one step further to not only help outline risks to the pipeline but also to help with prioritizing the steps to remediate such risks. These steps include mitigation, prevention and any subsequent monitoring actions to avoid the risks (Cheng & Norsworthy 2016).

**How often should integrity threat assessments be performed on a pipeline?**

The frequency of this type of assessment is driven by either

* The need for a standard periodic assessment. For example, an assessment can be scheduled after a minimum fixed period of time has elapsed between consecutive assessments)

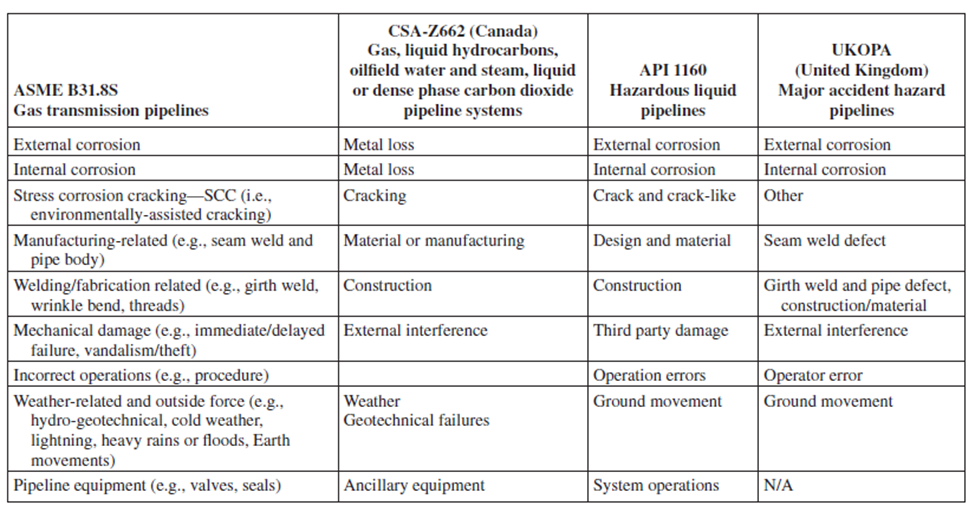
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* The need for an assessment predicated by a change in condition which increases the likelihood of a failure or the severity of integrity threats. For example, environmental or operational changes that lead to new hazards such as flooding or corrosivity.

Different industry standards and regulations such as ASME B31.8S, API RP 1160, CSA-Z662 (Canada) and UKOPA (United Kingdom) each specify integrity threats. Regardless of the standard, there are correlations between the integrity threats outlined. Examples of the pipeline integrity threats as well as the correlation between the different standards are as shown in the Figure 8.

Management System based approach to pipeline integrity threat assessment recommends a well-established process for implementing this assessment. This process can be applied by sequentially applying the steps below.

* **Assessment Planning and Scheduling**: This involves setting objectives, data gathering and identification of hazards, threats, failures or damage mechanisms
* **Threat Assessment**: This involves the actual hazard and threat identification susceptibility assessment
* **Threat Assessment Validation:** Here, the threats identified in step 2 are validated by SMEs. Beyond this, operations field verification also occurs.
* **Management Review**: This is the final step in the process. Management team prioritization of the integrity threats are completed and threat management plans are drawn up. The integrity hazard and threat management cycle is as follows – Identification -> Susceptibility -> Assessment -> Mitigation -> Prevention -> Monitoring



**Figure 8: Correlation between various Pipeline Integrity Threat Names across Multiple Industry Standards (Cheng & Norsworthy 2016).**

The Pipeline Consequence Assessment process is used to assess the severity as well as the extent of any consequence resulting from situations where a pipeline release occurs. Consequence assessments consider both leak and rupture scenarios to determine the impact they may have. This is done by considering the consequences from worse case scenarios assessed from multiple viewpoints. Within the Integrity Management Program (IMP) framework, consequence assessments are used to meet 2 key functions:

1. Identify direct areas that would be impacted by a pipeline release. Direct areas imply locations that run along the pipeline’s right-of-way.

2. Identify indirect areas that would be impacted by a pipeline release. Indirect areas imply locations which while they may be further away from any right-of-way areas could still be impacted due to water crossings, canyons or valleys.

A pipeline consequence assessment requires senior management commitment as well as a safety and environmental policy. This process can be applied by sequentially following the steps below (Cheng & Norsworthy 2016)

* Consequence Assessment Planning: This involves setting goals, targets and objectives. Other aspects of this step include data gathering and scheduling.
* Consequence Analysis: This involves assessing the extent of the consequence.
* Consequence Classification along the Pipeline: The results of the consequence analysis are evaluated. Based on this analysis, the consequences are classified quantitatively or qualitatively based on some predefined consequence criteria
* Results Validation: The field verification of the consequence analysis and classification occurs
* Management Review: This is the final step in the process and covers both assessment and implementation.

The purpose of a Pipeline Risk Assessment is to assign risk levels to pipelines and then determine if the level of risk assigned is acceptable or not. Risk assessment is achievable by first obtaining either an absolute or a relative value from the estimates of the probability, the consequence and the overall combined risk; and then once these values are obtained, then they are ranked. A risk assessment process collates pipeline risk factors such as their conditions, attributes and characteristics. These risk factors are then used to establish absolute or relative risk magnitudes. Based on the determined risk magnitude pipeline segments of interests can be identified and prioritized. Risk assessments can either be conducted at fixed intervals or based on any changes in risk factors or conditions. Other use cases for risk assessments include using the results from a risk assessment to optimize the scheduling of pipeline inspections, maintenance and replacement; increase the reliability and availability of pipelines; identify any changes in the operating conditions of pipelines e.g., changes in a pipeline’s operating temperature or pressure etc. Furthermore, risk magnitudes are used to categorize pipelines into one of the following categories for the purposes of risk management.

* Intolerable/unacceptable
* Tolerable
* Acceptable

There are 3 main risk assessment methods include:

* Quantitative
* Semi-Quantitative
* Qualitative

Selecting one method over the other is often governed by the answers to the questions below:

* How much time is available to conduct the risk assessment? For example, months, years etc.
* What is the expected level of effort to be expended gathering the data and processing the integrity of the data? For example, if there is limited data at hand, how much effort should be expended in getting additional data etc.
* What is the intended use of the resulting risk assessment results? For example, cost effective risk reduction efforts etc.

Pipeline risk assessment typically has an associated risk management process. Such risk management plan requires senior management commitment as well as a well-established risk policy. The risk assessment process has some sub processes (Cheng & Norsworthy 2016)

* **Risk Analysis and Risk Estimation**: This sub-process is initiated by establishing the goals, objectives and targets of the risk assessment. The system is also defined and data gathering occurs. Risk analysis is the first step of a risk assessment process and it assesses the probability of failures (i.e., integrity threats) as well as their consequences such as leaks or rupture for each segment being analyzed. Finally, the likelihood and consequences severity and extent are estimated and analyzed. In this context, risk drivers are defined as the risk factors that contribute the most to the estimated risk for the pipeline segment under consideration.
* **Risk Evaluation**: The results of the risk assessment are validated by a Subject Matter Expert as well as by personnel who work on the pipelines due to their familiarity with the pipelines. This would include integrity personnel, operators, inspectors or leak detection personnel. Next, the risk results are compared against the previously established acceptance criteria, after which the category of the risks present in the system is determined and the pipeline segments are prioritized into either acceptable, tolerable or unacceptable. This process of categorizing the pipeline segments is considered to be a ranking on the basis of the identified risks.
* **Risk Control**: The management review as well as mitigation, prevention and monitoring are prioritized. In determining the right mitigation or preventive actions to control the identified risks, legal, regulatory and any applicable company framework should be considered. The level of risks identified in the risk evaluation process above could either lead to a decision to perform more analysis to gain a better understanding of the risk results or a decision to manage the identified risks using risk reduction plans and controls. This decision is influenced by a cost benefit analysis. This analysis also helps management select a mitigation plan. Regardless of which decision is made, KPIs for risk reduction plans are eventually outlined and implemented.

Finally, the results of a conducted risk assessment should be documented. This documentation should detail the risk methodology, the sources of data used, any assumptions made, challenges encountered during the process and the results.

A Baseline Assessment offers an understanding of the integrity condition of a pipeline at the time t when the pipeline is being evaluated assuming that any limitations inherent in the applied integrity assessment methods used have been offset with matching integrity data. A baseline assessment is considered to have been completed for a pipeline if such a pipeline has been integrity assessed for every identified threat as well as for any vulnerable integrity threats (Cheng & Norsworthy 2016).

**How often should a baseline assessment be completed for a pipeline?**

A baseline assessment for a pipeline can be completed

* A few years after it has been commissioned
* Many years post commissioning if such assessment is initiated by the company responsible for the pipeline or
* Many years post commissioning if such assessment is now required by new pipeline regulations

In general, the decision about when a baseline assessment for a pipeline or pipeline segment should be completed should take into account the prioritization and/or the timing identified by any risk assessment conducted ahead of time.

**A baseline assessment of a pipeline is composed of the following key components:**

* An implementation of an integrity assessment method such as hydrostatic testing etc.
* The validation of the results obtained from the integrity assessment method of choice
* Data integration of the integrity assessment results with other non-integrity assessment data, thereby capturing all integrity threats that may increase the risk level of the pipeline

After an initial baseline assessment has been completed on a pipeline or pipeline segment, there may be a need to conduct a new Integrity Threat-Specific Baseline Assessment on the same pipeline if a new threat is identified or suspected. In this case, the results from this new assessment are used to supplement the results from the earlier assessment.

Fitness-for-Service Assessment (FFS) for pipelines is an engineering assessment that evaluates the integrity of a pipeline under both current conditions and under future conditions. The goal of such an assessment is to provide information required to safely and reliably operate the tested pipeline for a defined period of time. The identified or perceived threats to a pipeline are evaluated by an FFS assessment for the likelihood of the threats occurring, any associated consequences and risks (Cheng & Norsworthy 2016).

Similar to the risk assessment process, in FFS, regulatory, industry and company framework are also accounted for. The applicability and limitations of the results of any integrity threat assessments used to assess the pipelines in a company are also taken into consideration. By utilizing integrity data integration, an FFS assessment is able to provide a more rounded overview of the severity and potential consequences of integrity threats along with barriers that are already in place or need to be added to deal with them. Overtime, if the measures proposed by an FFS assessment are determined to be effective, then the FFS assessment provides a timeframe within which the integrity conditions of a pipeline are deemed to be acceptable.

**Advantages of FFS Assessments**

* They provide integrity mitigation, prevention and monitoring measures both for the short and long term.
* FFS Assessments identify potential system adjustments required to deliver a reliable, environmentally responsible and safe pipeline service for a defined time span until the next integrity assessment.

**An FFS assessment requires senior management commitment as well as an integrity policy. The FFS Assessment process is as follows** -

* Using best practice, select the assessment method as well as competent staff
* Collate all data, challenge assumptions and perform assessment with continuous checking
* Conduct quality assurance and sense check the results obtained
* Maintain integrity, document lessons learned and implement improvements

Continuous Assessment is conducted on a pipeline or pipeline segment to provide an update to the integrity condition information available from a previous assessment such as a baseline assessment. Continuous assessment is recommended in situations when a mix of different re-inspection timelines has been indicated by a previous integrity assessment leading to an inability to schedule all the next integrity assessments simultaneously. When faced with a situation such as this, pipeline operators may choose to continuously document the integrity information for their pipelines by conducting continuous assessment for all integrity threats. The advantage of this approach is that it enables the pipeline operator to integrate the information from all integrity threats into a single package thereby providing an accurate picture of the health of the pipelines while enabling the criticality of any threats identified to be correctly assessed (Cheng & Norsworthy 2016). As a result, continuous assessment can be integrated with other assessment processes such as consequence assessment etc. to develop a more robust process.

**2.1.3 Prevention**

Pipeline integrity prevention is a key component of pipeline integrity management system (PIMS) implementation management framework. Prevention implies an anticipatory counteraction requiring advance planning or action. Prevention is focused on hazards (e.g., coating damage) creating a barrier (e.g., coating selection) that would prevent the pipeline from having conditions leading to an integrity threat (e.g., external corrosion). Prevention of integrity threats can be applied in all stages of the pipeline life; however, their highest benefit/cost is achieved in the operational term.

Quality control and quality assurance during manufacturing and construction of pipeline can reduce the likelihood of defects being introduced into the system at the beginning of life. According to Khalid. F. et al (2019) in a report presented to California Energy Commission, technologies that focus on preventing pipeline failure include:

* In-line inspection tools that identify weld defects and line cracks,
* Real time monitoring of the system with devices that recognize and pinpoint the location of leaks to predict rupture and catastrophic failures. These devices include appropriately spaced flow and pressure transmitter along the length of covered lines,
* Real time monitoring of excavation damage using devices installed in the right-of-way and remote sensing technologies.
* Damage mitigation approaches, repairs, and procedures that prevent rupture and catastrophic failures.
* Effective materials characterization and failure prediction models; incorporating accurate operator’s data and output of accurate inspection protocols,
* Systems for emergency automatic shut off in high consequence areas.

### **2.1.4 Monitoring**

This is the act of ensuring that known threats do not increase in likelihood of failure Integrity monitoring is a process focused on determining either conditions or processes that may capture initiation and/or growth of integrity threats.

• Monitoring Integrity Conditions for New hazards (e.g., unauthorized RoW activity) and/or threats (e.g., Theft) and Changes in hazards (e.g., pressure cycling) and/or threats (e.g., crack growth)

• Monitoring Integrity Processes for Completeness and Effectiveness (e.g., corrosion growth after inhibition)

Integrity monitoring may trigger additional measures such as mitigation and prevention as well as focused inspections for dimensioning the extent of the findings.

Monitoring can serve two (2) purposes in integrity management. The first purpose is that it can determine when a threat or consequence has occurred (e.g., new corrosion or dwelling) or is likely to occur (e.g., new pressure cycling or new facility). The second purpose is to identify whether the threats or consequence have changed (e.g., crack or population growth). Early detection of a threat (e.g., ILI) or consequence (e.g., request for municipality approval) occurring or changing over time can lead to intervention at a more cost-effective stage of an asset’s lifecycle.

One limitation is that some threats may not be able to be monitored all of the time. A typical case is aerial or satellite monitoring of the right-of-way may not be available exactly when the excavation activity could be taking place over the pipeline.

Monitoring can also be used to predict or detect when a threat has or will occur. Some of the various examples of threat Integrity Monitoring Measures includes: Monitoring of External and Internal Corrosion, Monitoring of Stress Corrosion Cracking and Manufacturing Related Defects, Monitoring of Manufacturing Related: Seam Weld and Pipe Anomalies, Monitoring Welding/Fabrication Related Anomalies, Monitoring Equipment Failure, Monitoring Mechanical Damage, Monitoring Incorrect Operation, Monitoring Weather-Related and Outside Forces. (Cheng & Norsworthy 2016).

**Monitoring of External and Internal Corrosion:** MFL and CMFL surveys are the best ILI technologies to monitor external and internal corrosion. Performing run-to-run (i.e., comparing one survey to another) comparisons can give an estimated growth rate to features that are reported. If a high growth rate is determined to exist, that location can be prioritized for remediation. High growth rates may also lead to shortening of the time between integrity assessment methods. Pipelines with coatings that shield cathodic protection either at the girth welds or for the entire pipe length are good candidates for monitoring in this fashion.

For pipelines that are piggable, these assessments serve as monitoring for external and internal corrosion. External corrosion is usually monitored with cathodic protection surveys and corrosion coupons while Internal corrosion is monitored by corrosion coupons and analysis of any product expelled during maintenance pigging (Cheng & Norsworthy 2016).

**Monitoring of Stress Corrosion Cracking and Manufacturing Related Defects:** Crack detection ILI surveys are the best method for monitoring of cracks (i.e., SCC or manufacturing related). When monitoring cracks, the report from the vendor should be reviewed for locations of newly reported cracks and for crack features that increased in size. Most vendors that have crack detection tools report features in ranges of depth. If a feature moves up a range from one survey to the next, this could be an indication that the feature has grown.

Unlike MFL and CMFL surveys, it is difficult to accurately perform a signal comparison to determine if an individual crack has grown. Development of a unity plot to correlate reported feature size with field reported size could be useful in management of cracks (Cheng & Norsworthy 2016).

Monitoring of the cathodic protection system can be helpful in the management of SCC. SCC occurs in specific ranges of cathodic protection levels. Care should be taken to ensure that the cathodic protection levels on the pipeline are more negative than the –850 mV criteria that most pipeline operators aim to achieve.

**Monitoring of Manufacturing Related: Seam Weld and Pipe Anomalies:** Practice for Assessment and Management of Cracking in Pipelines to provide guidance on how to use pressure cycle analysis when monitoring crack-like defects and pressure cycle analysis to be performed on a regular bases (i.e., every one, three, or 5 years) to see how pressure cycles have changed over time were Recommended by API 1176. If pressure cycles become more aggressive, then the remaining life would be expected to shorten. Reassessment intervals should be determined based on the most conservative analysis performed. Monitoring pressure data also requires reviewing the pressure changes including shutdowns, spikes, abnormal operating conditions, and exceeding the maximum operating pressure of the pipeline. (Cheng & Norsworthy 2016). The operational effects in the integrity of pipeline should be monitored and tracked with key performance indicators (KPI).

**Monitoring Welding/Fabrication Related Anomalies:** Welding defects related to the girth weld are difficult to monitor other than by direct examination and inspection. If girth welds meet vintage criteria or similar welds have failed in service, it may be necessary to install pumpkin reinforcement sleeves to maintain the integrity of the weld. Traditional ILI methods cannot see defects in girth welds. Locations of high strain reported by strain measurement tools should be cross-referenced with locations of girth welds that may not have had sufficient quality assurance and quality control during construction. These locations should be monitored and mitigated as necessary.

Acceptable “imperfections” from construction may experience growth and failure during in-service in locations where thermal (e.g., temperature) or external force (e.g., displacement) changes may occur. It is important to monitor these locations with nondestructive methods and repair as necessary (Cheng & Norsworthy 2016).

Wrinkles and buckles that were introduced into the pipe that still allow passage of an ILI tool can be monitored with deformation detection surveys. When wrinkles or buckles are identified in a pipeline, they should be mitigated promptly as they are a threat to pipeline integrity.

**Monitoring Equipment Failure:** Equipment used in the oil and gas industry have design lives. Trending of the equipment used in the pipeline system versus the common performance life of equivalent equipment can be used for monitoring. As equipment nears the end of the expected life, the equipment can be budgeted for replacement if the equipment can no longer be effectively maintained. (Cheng & Norsworthy 2016).

**Monitoring Mechanical Damage:** Deformation surveys can be used to monitor for new excavation damage. New deformations reporting on the top half of the pipe should be prioritized for assessment even if they do not meet any of the regulatory required assessment criteria. Third party damage can fail immediately or they can have delayed failure from cracks that grow over time (Cheng & Norsworthy 2016). It is best to remediate these features as soon as they are reported by the deformation survey.Monitoring of right-of-way activity can anticipate first/second/ third party damage.

**Early detection can be performed by the following:**

• Aerial patrol,

• Walking/driving the right-of-way,

• Satellite monitoring, or other forms of remote monitoring such as

• Video surveillance

• Monitoring of acoustic frequencies of activity above the pipeline

• Fiber optic cable that sends an alert when it is disturbed

Aerial patrols and walking of the pipeline can identify activity over the line that is not included in the one-call. Density of right-of way activity can be used to identify areas for additional monitoring between deformation ILI surveys.

Monitoring also includes attending excavations that occur close to the operator’s pipeline but are not on the pipeline. Representatives of the potentially affected pipeline can watch and supervise excavations close to their pipeline to ensure they are not infringed upon. This individual can also enforce hand digging as they get close to the pipeline to prevent damage (Cheng & Norsworthy 2016). Monitoring of the installation of illegal taps or accessories for unauthorized extraction of pipeline fluids can be conducted using the following inspection, surveying, operational monitoring, and surveillance technologies.

• Axial or Circumferential MFL and Wall Measurement Ultrasonic in-line inspections have identified some type of illegal taps as a “metal loss” circumference resulting from the perforation or “round and isolated anomalies” located at periodic or aligned distances from each other as well as metal object in close proximity to the pipeline.

• Direct Current Voltage Gradient (DCVG) surveys are able to detect coating fault and buried metal object signals triggered by the installation of illegal taps.

• Operational monitoring with Leak detection systems and volume inventory checks have been able to identify variances in the transportation of the fluids (e.g., diesel, gasoline, jet fuel); however, gaseous fluids are more challenging to be verified.

• Right-Of-Way (ROW) surveillance via ground, aerial and Unmanned Aerial Vehicles (UAV) for detecting ground disturbance or the presence of unauthorized activities. Technology such as thermal infrared (i.e., electromagnetic energy) can be added for surveillance at night.

**Monitoring Incorrect Operation:** Pressure excursions or unplanned rises in operating pressures can be examples of incorrect operation. These instances can be monitored with the SCADA system. In some regulatory jurisdictions, exceeding the MOP, or a percentage of the MOP, is a reportable event. Pressure excursions can be leading indicators as to whether other integrity threats have become or could become a more significant threat to the pipeline. A number of the threats that we have discussed in this chapter are dependent upon consistent operation of the pipeline from a pressure perspective to avoid initiation and growth (Cheng & Norsworthy 2016)**.**Pipeline’s integrity can be protected by Monitoring of upset conditions and this will ensure maximum profit from shipping product.

### **2.1.5 Mitigation**

In order to regulate potential risks posed by the deterioration of the pipeline, identified defects through the monitoring procedure are categorized using a comprehensive fitness-for-service criteria. The need for repair work is based on the goal of ensuring a long-life service asset and failure prevention.

The ability to carry out an efficient operational repair method is very important for gas and liquid transmission lines which are said to be the subject requirements of the Department of Transportation (DOT). At this moment, in the CFR 49 Part 192 for transmission of natural gas, this suggest damaged pipelines to be cut out and replaced or repaired by methods which are not only reliable but engineering tested and analyzed (Farrag, 2013) .

Farrag also mentioned on the repair methods which are presently used to permanently restore serviceability of transmission pipes. These methods include full-encirclement steel reinforcing sleeves and composite wrap material.

They are a lot of methods presently used for external repair of corrosion and mechanical damage to permanently restore the serviceability of transmission pipes but in this report we will discuss on 3 methods which include:

**Composite Sleeve Repair:** A broad variety of composite materials are currently used in pipeline repair systems today. They mainly consist of glass or carbon fiber reinforcement in a thermoset polymer matrix (e.g., polyester, polyurethane). As seen in the Figure 9 below, the installation procedure results in a final composite material which covers the damaged area. The thickness of the composite material depends on the severity of the defect.

The composite material wrapped around the damaged area of the pipe works by distributing the hoop stress uniformly in the pipe wall so that the maximum allowable operating pressure can be safely maintained. The repair restores the strength of damaged pipeline as it increases the stiffness and acts as an external coating layer.



**Figure 9: Carbon fibre (left-side) and Glass fibre (Right-side) (Farrag, 2013)**

**Pipe Grinding and Recoating:** The pipe grinding method is mainly used to remove stress defects, micro cracks and provide a smooth surface. The repair of mechanical damage by using the grinding method has been approved by several standards. (Kiefner & Alexander 1999).

Certain restrictive conditions are also commonly applied for grinding method which include

* During the repair process, the pressure used for operating should be reduced to 80 percent.
* If the crack is not removed by grinding, an alternative repair technique must be applied.
* The removal of all cracks must be verified by non-destructive testing (NDT) after grinding.
* The removal of more than 40 percent of the wall thickness by grinding is not accepted.

**Metallic Sleeve Repair:** Mechanical sleeves mainly consist of the two types:

* **Steel Reinforcing Sleeves (Type A):** This consists of two halves of a steel cylinder which are positioned around the pipe and welded to fully fit the damaged area which in return improves the pipe strength. This type of sleeve (Type A) is not welded directly onto the pipe as it is not supposed to contain pressure or leakage. The main advantage of type A is that it does not require NDT inspection and also it can be used for both temporary and permanent repairs. However, this type is not used to repair leakage and circumferentially oriented defects.
* **Pressure Containing Sleeves (Type B):** This is similar to type A sleeves, but the only difference is that the sleeves are welded onto the pipe as seen in Figure 10. This type requires an appropriate procedure for welding and inspection when the sleeve is installed as the pipe is in service.

The thickness of the sleeve is designed to contain the Maximum Allowable Operating Pressure (MAOP) and the axial stresses imposed by secondary loads. Thus, type B sleeve can be used to repair leaks and to reinforce the circumferentially oriented defects.



**Figure 10: Steel Repair Sleeve (Farrag 2013)**

# **Chapter 3 – Specification**

## **3.1 Legal and Ethical Issues**

This project does not pose any trace of risk or danger to children or adults. However, we will take all responsibility to maintain Academic honesty for each resource used in this project. The public interest will be put into consideration while undertaking this project as there is no intention whatsoever to cause any potential harm and this project does not require storing personal or public data, therefore no privacy rights will be invaded. During the process of developing this project, the main aim is to gain an in-depth understanding in this subject area and therefore major steps will be taken in other to ensure the ethical rules are followed accordingly.

## **Chapter 4 – Conclusion**

Pipeline integrity management is a universal approach which also includes organizational elements. The traditional integrity assessment approaches, which only highlights inspection, testing, and analysis activities followed by maintenance. Pipelines are an integral asset to upstream operations pipeline integrity must reflect all design aspects, construction, and operating phases. Also, a formalized Operations of an Integrity Management System defines the management expectations of pipeline integrity and the procedure on how to meet management expectations by providing a proper documentation and stewarding integrity programs which a formally written by experts. Concisely, the implementation of these elements of pipeline integrity management practices improves the performance of pipeline operation system overall.

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