



**Article**

**Evaluation of Internal Corrosion in Subsea Oil Pipeline**

**Oday Ibrahim Mousa**

Ministry of Education, Basra Directorate of Education

[oday9118@gmail.com](mailto:oday9118@gmail.com)

**Abstract:**

Internal corrosion in subsea oil pipelines is a significant concern within the oil and gas industry due to its potential to compromise pipeline integrity, safety, and production efficiency. This paper presents a comprehensive analysis of internal corrosion in subsea oil pipelines, focusing on its causes, detection methods, monitoring strategies, and mitigation measures.

The causes of internal corrosion are multifaceted, including factors such as water content, temperature, and the pre

Monitoring strategies are critical for assessing corrosion rates and identifying potential trouble spots along the pipeline. These strategies incorporate both continuous monitoring and periodic inspection techniques, allowing operators to make informed decisions about maintenance and integrity management.

Mitigation measures to prevent or mitigate internal corrosion are also explored, encompassing coatings and liners, chemical inhibitors, and material selection. The selection of the most suitable mitigation strategy depends on factors such as pipeline materials, operating conditions, and corrosion mechanisms.

sence of corrosive species in the transported fluids. Various detection methods,

ranging from corrosion coupons and corrosion probes to non-invasive techniques like pigging and smart sensors, are discussed in detail.

Additionally, this paper related to internal corrosion in subsea oil pipelines. The goal is to provide a comprehensive overview that aids pipeline operators, engineers, and researchers in addressing this critical issue and ensuring the long-term integrity and safety of subsea oil infrastructure. highlights case studies and industry best practices to illustrate the real-world challenges and solutions

## **1. Introduction**

Subsea oil pipelines play a pivotal role in the global energy landscape, serving as the primary means of transporting hydrocarbons from offshore production facilities to onshore processing and distribution centers. However, these pipelines face a formidable adversary that threatens their integrity and operational reliability: internal corrosion.

Internal corrosion in subsea oil pipelines arises from a complex interplay of environmental, chemical, and operational factors, making it a pervasive and challenging issue for the oil and gas industry. This corrosion can manifest as localized pitting, general wall thinning, or stress corrosion cracking, all of which have the potential to compromise the safety, longevity, and efficiency of these critical assets.

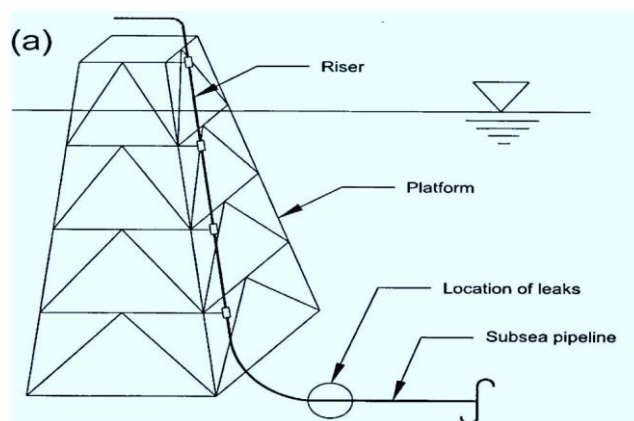
As the industry continually pushes the boundaries of exploration and production into more hostile and remote offshore environments, the risk of internal corrosion becomes even more pronounced. It necessitates a deeper understanding, rigorous monitoring, and effective mitigation strategies to safeguard both the environment and the substantial investments associated with subsea infrastructure.

This comprehensive analysis aims to delve into the multifaceted nature of internal corrosion in subsea oil pipelines. It will address the root causes of internal

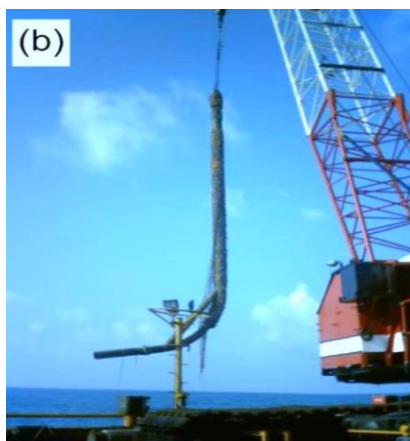
corrosion, explore various methods for its detection and monitoring, and discuss the mitigation strategies employed to protect these pipelines from corrosion-related threats. Real-world case studies and best practices will be incorporated to provide valuable insights for industry professionals, engineers, researchers, and policymakers grappling with the complex challenge of managing internal corrosion in subsea oil pipelines. By fostering a deeper understanding of this issue, we hope to contribute to the development of safer, more reliable, and environmentally responsible subsea oil transportation systems.

In recent reports, there have been instances of oil leakage from a horizontal crude oil subsea pipeline that has been in service for 27 years. Figure 1 illustrates the schematic representation of the crude oil flow, along with an actual image of the investigated failed crude oil pipeline. In its operational state, crude oil was pumped from subsea wells into the horizontal pipeline, which then directed the crude oil flow into a long radius elbow section. This section facilitated a vertical turn in the crude oil flow, allowing it to pass through a riser for further processing on the platform.

Some oil leaks were detected at the lower part of the horizontal pipeline, just before the flow entered the elbow section. No other areas of damage were found during the inspection. Here are the specifics regarding the failed pipeline and its operational data<sup>(1)</sup>.



**Fig. 1.** (a) An illustration of the configuration of a subsea pipeline riser



**Fig. 1. (b)** a picture of the submerged pipeline that failed.

Table 1: the specifics regarding the failed pipeline and its operational data

<b>Details and operational information</b>	<b>Value</b>
Outside diameter of a pipe	16 in.
Length	10,677 ft
the thickness of the walls	0.5 in.
Material	API 5L X52
Planned pressure	1480 psi
pressure during testing	2225 psi
Utilizing pressure	170 pounds per square inch (incoming) and 130 pounds per square inch (outcoming)
Temperature of operation	152 F (incoming)
Production (water + crude oil + gas)	28.345 barrels of water per day, 2576 barrels of oil daily, and 0.441 mmscf of gas daily

## **2. Analytical Techniques**

Internal corrosion in subsea oil pipelines necessitates a range of analytical techniques to assess its extent, identify potential trouble spots, and make informed decisions about maintenance and integrity management. Among these techniques, visual examination is a fundamental and invaluable tool.

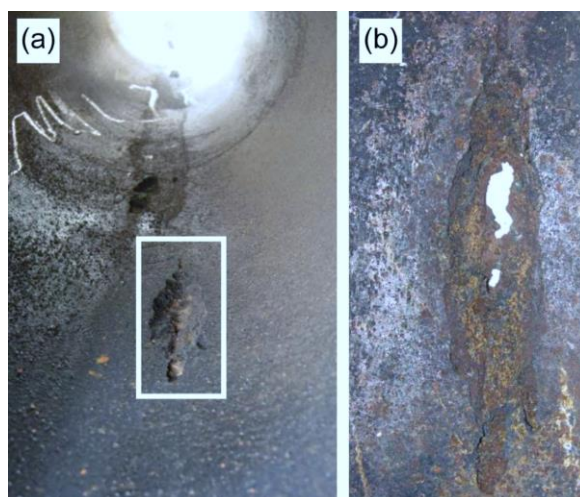
## **2.1. Visual Examination**

The visual examination involves the direct inspection of pipeline surfaces, primarily conducted during routine maintenance or inspection intervals. This technique provides essential insights into the condition of the pipeline's inner walls and allows for the identification of corrosion-related issues. Several aspects of visual examination in the context of subsea oil pipelines are worth noting<sup>(2)</sup>:

- a. **Inspection Access Points:** Access to the pipeline's interior is typically facilitated through strategically placed access points, such as inspection hatches or openings. These access points enable personnel or remotely operated vehicles (ROVs) to visually inspect the pipeline's internal surfaces.
- b. **Remote Inspection:** In the case of subsea pipelines, remote visual inspection using ROVs equipped with cameras and lights is a common practice. ROVs are capable of navigating the underwater environment and transmitting real-time video feeds to operators on the surface, allowing for visual assessment without the need for physical access.
- c. **Surface Condition Assessment:** During visual examination, inspectors or operators assess the condition of the pipeline's inner walls. Signs of internal corrosion may include pitting, scaling, or general wall thinning. The location and extent of corrosion can provide valuable information for further analysis and mitigation.

- d. Corrosion Product Identification: Visual examination can also help in identifying corrosion byproducts, such as rust or deposits, which may offer clues about the nature of the corrosion process and its potential causes.

While visual examination is a critical tool, it has limitations, such as the inability to quantify corrosion rates accurately. Therefore, it is often used in conjunction with other analytical techniques, such as corrosion monitoring sensors, ultrasonic testing, and magnetic flux leakage, to provide a comprehensive assessment of internal corrosion in subsea oil pipelines. These complementary techniques allow for more precise measurements and a deeper understanding of corrosion dynamics, ultimately aiding in the development of effective corrosion management strategies. In Fig. 2, the visual examination results reveal the presence of leaks primarily located on the inner surface of the pipeline. These leaks originated locally at the pipeline's bottom (positioned at the 6 o'clock position) and exhibited a distinctive teardrop-shaped pit or groove formation, extending parallel to the direction of fluid flow. This particular failure pattern suggests a hypothesis that the leaks may have resulted from a combination of electrochemical corrosion and the effects of fluid flow. However, it is important to note that this initial analysis must be substantiated through more comprehensive characterizations, as detailed later in this study<sup>(3)</sup>.



**Fig. 2.** (a) Leaks were discovered on the pipeline's inner surface at the six o'clock location, (b) square-shaped magnified region in (a).

## **2.2. Analysis of Crude Oil Pipeline Material**

Understanding the material properties and integrity of the crude oil pipeline is crucial in the analysis of internal corrosion. Analyzing the pipeline material provides valuable insights into its susceptibility to corrosion and helps determine the root causes of corrosion-related issues. Here, we delve into the specifics of analyzing the crude oil pipeline material:

- a. **Material Composition:** An essential step is identifying the composition of the pipeline material. This involves determining the type of steel or alloy used in the pipeline's construction. Different materials exhibit varying degrees of corrosion resistance, and this information is fundamental in assessing vulnerability to corrosion.
- b. **Chemical Analysis:** Conducting chemical analyses of the pipeline material can reveal impurities or trace elements that may influence corrosion processes. These analyses help in understanding how the

material interacts with the transported crude oil and its corrosive components.

- c. **Microstructural Examination:** Microstructural analysis involves studying the internal grain structure of the pipeline material. It can reveal any abnormalities, defects, or changes in the microstructure that may have resulted from corrosion. Techniques like metallography and electron microscopy are often employed for this purpose.
- d. **Corrosion Testing:** Laboratory corrosion tests, such as electrochemical tests and salt spray tests, can simulate the conditions the pipeline material may encounter in the field. These tests provide data on the material's corrosion resistance and its behavior in the presence of corrosive agents.
- e. **Mechanical Testing:** Assessing the mechanical properties of the pipeline material is crucial to evaluate its structural integrity. Tensile, hardness, and impact tests are common methods to determine the material's mechanical strength and durability.

Analyzing the crude oil pipeline material is an integral part of the overall assessment of internal corrosion, as it aids in pinpointing the factors contributing to corrosion susceptibility. By combining material analysis with data from visual inspections and other analytical techniques, a more comprehensive understanding of the corrosion issue can be attained, allowing for more effective corrosion management strategies to be devised.

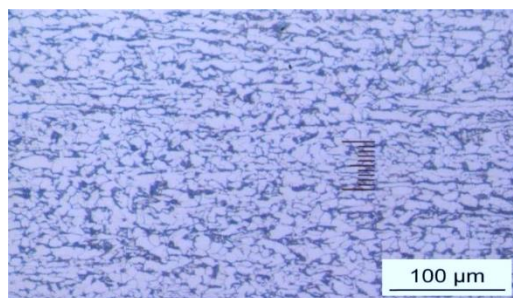
The pipeline material underwent several characterizations, which included

chemical composition analysis, microstructural examination, and mechanical property tests like tensile testing and hardness measurement. Table 2 displays the results of the chemical composition analysis, which was conducted using an emission spectrometer, along with the corresponding composition specified in accordance with API 5L X52 standards. API 5L X52 primarily specifies alloying elements like C, Mn, Nb, and V, with impurities of P and S. A noteworthy observation from Table 1 is that the composition of the pipeline aligns with the specifications outlined in API 5L X52. It's important to note that elements like Nb and V are typically added to steels as grain refiners during the thermomechanical control process (TMCP)<sup>(4)</sup>.

Table 2: the results of the chemical composition analysis, which was conducted using an emission spectrometer.

<b>Material</b>	<b>Mn</b>	<b>C</b>	<b>P</b>	<b>Al</b>	<b>V</b>	<b>Si</b>	<b>S</b>	<b>Nb</b>	<b>Cr</b>	<b>Ni</b>	<b>Mo</b>	<b>Ti</b>	<b>Cu</b>
<b>Pipeline</b>	<b>0.608</b>	<b>0.166</b>	<b>0.09444</b>	<b>0.042</b>	<b>0.010</b>	<b>0.262</b>	<b>0.024</b>	<b>0.022</b>	<b>0.045</b>	<b>0.066</b>	<b>0.062</b>	<b>0.007</b>	<b>0.133</b>
<b>API 5L X52</b>	<b>1.25 max</b>	<b>0.29 max</b>	<b>0.04 max</b>	<b>0.04</b>	<b>0.07</b>	<b>0.35 max</b>	<b>0.05 max</b>	<b>0.05</b>	–	–	–	–	–

In Fig. 3, an optical photomicrograph of the studied pipeline material is presented. This image reveals that the microstructure of the pipeline predominantly consists of ferrite and pearlite, which is a common characteristic of low-carbon steels. The fine-grained ferrite and pearlite exhibit an elongated pattern along the rolling direction, known as texture. Such a microstructure is advantageous as it enhances the steel's strength through grain refinement, following the Hall-Petch relationship, and imparts excellent impact toughness, meeting the stringent material requirements for pipelines.



**Fig. 3.** The pipeline's microstructure is being examined.

Table 3, presents the outcomes of the tensile and hardness tests. The pipeline exhibits yield and ultimate stresses of 381.5 and 486.8 MPa, respectively, which meet or exceed the minimum stress requirements stipulated by the API 5L X52 standard. Furthermore, the hardness value of the pipeline falls within the specified maximum hardness limit set by the API 5L X52 standard.

In light of the findings from the chemical composition analysis, microstructural examination, and mechanical property tests, it can be confidently concluded that the pipeline material closely aligns with the characteristics of API 5L X52 carbon steel<sup>(5)</sup>.

**Table3:** Pipeline mechanical characteristics are being researched.

Material	Ultimate stress (MPa)	Yield stress (MPa)	Hardness (VHN)
Pipeline	486.8	381.5	162.3
API 5L X52	455 min	358 min	230 max

### 2.3. Analysis of Water Phase Present in Crude Oil

The presence of water within crude oil transported through subsea pipelines can significantly influence the corrosion process. Analyzing the water phase within crude oil is crucial for understanding its corrosive potential and for devising effective corrosion mitigation strategies. Here, we explore the specific

analytical techniques used to assess the water phase in crude oil<sup>(6)</sup> :

- a. **Water Content Measurement:** Determining the water content of the crude oil is essential. This is often achieved through techniques such as Karl Fischer titration, which quantifies the amount of water present in the oil. Accurate measurement of water content provides critical information about the corrosive environment inside the pipeline.
- b. **Water Quality Analysis:** It is important to analyze the quality of the water present in the crude oil. This includes assessing parameters such as salinity, pH, and the concentration of dissolved ions, which can significantly impact the corrosion process. Water quality analysis can help identify aggressive conditions that promote corrosion.
- c. **Corrosion Inhibitor Compatibility:** If corrosion inhibitors are used in the pipeline, it is vital to evaluate their compatibility with the water phase. Incompatibilities can lead to reduced inhibitor effectiveness or other undesirable effects. Compatibility testing helps ensure that corrosion inhibitors continue to protect the pipeline effectively.
- d. **Microbiological Analysis:** Microbiologically influenced corrosion (MIC) can be a significant concern in the presence of water and microorganisms. Microbiological analysis helps identify the types of microbes present and assess their potential for causing corrosion.
- e. **Water Separation Techniques:** To mitigate the impact of water on corrosion, subsea pipelines often incorporate water separation

mechanisms. The performance of these separation techniques, such as coalescers or separators, should be monitored and analyzed to ensure effective water removal.

Analyzing the water phase within crude oil is integral to understanding the corrosion mechanisms and developing corrosion management strategies for subsea oil pipelines. By employing these analytical techniques, operators can make informed decisions to prevent or mitigate internal corrosion, ensuring the long-term integrity and reliability of these critical assets<sup>(7)</sup>.

The chemical composition of the water phase present in the crude oil was determined by atomic adsorption method with the results given in Table 4. The main ions detected were chloride ( $\text{Cl}^-$ ), bicarbonate ( $\text{HCO}_3^-$ ), and sulphate ( $\text{SO}_4^{2-}$ ) where chloride ( $\text{Cl}^-$ ) has been known as an aggressive ion. Water was identified to have pH of 8.5 or basic condition.

**Table4:** The chemical makeup of water.

Parameter	Value	Unit
pH	8.5	–
Chloride ( $\text{Cl}^-$ )	7183	ppm
Sulphate ( $\text{SO}_4^{2-}$ )	324	ppm
Bicarbonate ( $\text{HCO}_3^-$ )	279	ppm

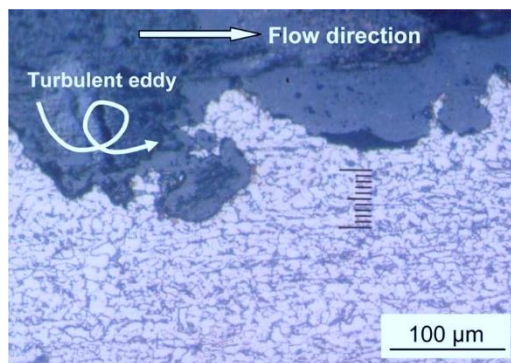
#### **2.4. Fractography and Chemical Analysis of Inner-Side Corrosion Deposits**

To gain deeper insights into the internal corrosion of subsea oil pipelines, the utilization of advanced analytical techniques such as fractography and chemical analysis of inner-side corrosion deposits is imperative. This approach offers a comprehensive understanding of the corrosion mechanisms and the nature of

deposits within the pipeline<sup>(8)</sup> :

- a. **Fractography:** Fractography involves the examination of fracture surfaces and corrosion-induced cracks in pipeline materials. By studying the fracture patterns, such as ductile or brittle fractures, it is possible to deduce the mode and progression of corrosion. Scanning Electron Microscopy (SEM) is commonly employed to visualize the fracture surfaces at high magnification, enabling a detailed assessment of the corrosion morphology.
- b. **Chemical Analysis of Deposits:** The corrosion deposits formed on the inner pipeline surfaces are subjected to chemical analysis. This analysis aims to identify the composition of these deposits, which can range from corrosion byproducts to sediments and scale. Techniques like X-ray diffraction (XRD), Energy Dispersive X-ray Spectroscopy (EDS), or Fourier-transform infrared spectroscopy (FTIR) are employed to determine the chemical composition of these deposits.

By combining fractography with chemical analysis, it is possible to discern critical information about the corrosion process, such as the types of corrosion involved (e.g., pitting, crevice corrosion), the presence of specific corrosion products, and the influence of impurities or contaminants within the transported fluid. This detailed characterization aids in the development of targeted corrosion mitigation strategies and the selection of appropriate materials and coatings to enhance the long-term integrity of subsea oil pipelines.



**Fig. 4.** pipeline surface profile throughout the flow path.

Figure 4 displays a surface profile extracted from the longitudinal section of the teardrop-shaped corrosion pits. Upon analyzing this surface profile, it became apparent that the flow of crude oil induced undercutting in the downstream direction, possibly due to turbulence within the pipeline. Notably, the presence of a turbulent eddy is marked by an arrow in Figure 4.

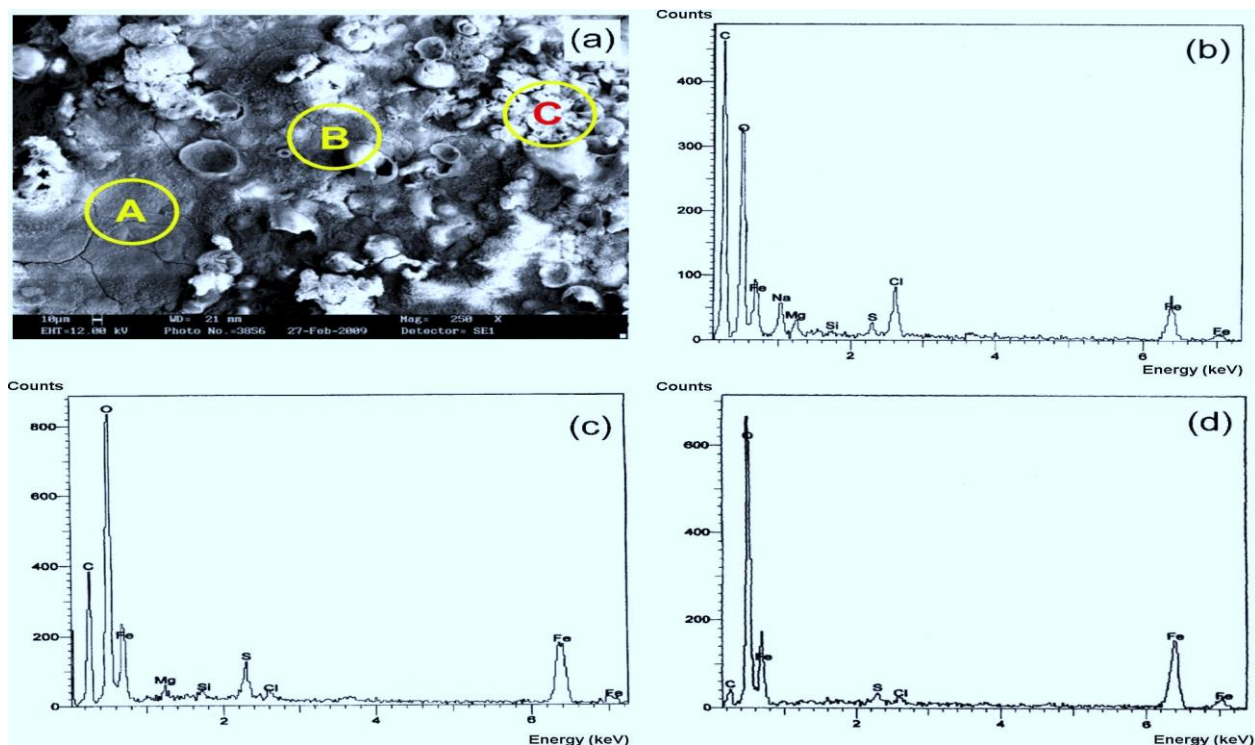
The results of SEM microanalysis conducted on the corroded surface, particularly in proximity to the corrosion pits, are presented in Figure 5a, with the corresponding EDX spectra shown in Figures 5b–d. This analysis reveals distinct layers of corrosion products:

Region A in Figure 5a corresponds to the innermost layer of the corrosion product, directly in contact with the steel pipeline surface. EDX microanalysis of this region indicates the presence of elements such as Fe, O, C, and Cl, with lower levels of Na, Mg, Si, and S (Figure 5b). This composition suggests that this inner layer likely exists in the form of FeOCl, a result of chloride attack on the hydrated passive film (FeOOH)<sup>(9)</sup>.

Region B, marked in Figure 5a, appears to be an intermediate layer, primarily

composed of Fe and O, with a notable amount of S, as illustrated in Figure 5c.

The outer deposit, corresponding to region C in Figure 5a, is where oxygen readily interacts with the deposit. As expected, this deposit consists predominantly of Fe and O, as depicted in Figure 5d, likely in the form of hydrous ferrous oxide  $\text{Fe}_2\text{O}_3 \cdot n\text{H}_2\text{O}$  or ferrous hydroxide  $\text{FeO}(\text{OH})_2$ . It's noteworthy that the chemical composition of these oxides transitions from metal-rich to oxygen-rich as the distance increases from the metal-oxide interface (Figure 5b) toward the outer deposits (Figures 5c and 5d). These various corrosion products align with findings reported by previous researchers<sup>(10)</sup>. Additionally, the presence of certain elements can be attributed to specific sources: C may originate from hydrocarbon or bicarbonate ( $\text{HCO}_3^-$ ), while Cl is a result of chloride ions ( $\text{Cl}^-$ ) dissolved in water. The presence of S in corrosion deposits is likely associated with sulfate ( $\text{SO}_4^{2-}$ ) in the water. Sulfate,  $\text{SO}_4^{2-}$ , represents an.



**Fig.5.** (a) products of corrosion in the vicinity of leaks. (b-d) EDX spectra obtained from the locations denoted by the letters A and C in (a).

### 2.5. Corrosion Rate and Passivity of the Steel Pipeline

Evaluating the corrosion rate and the passivity of the steel pipeline is vital in comprehending the corrosion dynamics and the protective measures required to maintain pipeline integrity<sup>(11)</sup> :

- a. Corrosion Rate Measurement: Determining the rate at which corrosion occurs is essential for assessing the pipeline's degradation over time. Corrosion rate measurement techniques, such as weight loss analysis, electrochemical methods (e.g., potentiostatic polarization, electrochemical impedance spectroscopy), or corrosion coupons, enable quantification of the corrosion rate in various pipeline sections.

- b. Passivity Assessment: Passivity refers to the ability of the steel pipeline's surface to form a protective oxide layer that inhibits further corrosion. Analyzing the passivity of the steel involves techniques like potentiodynamic polarization and cyclic voltammetry, which provide insights into the electrochemical behavior of the steel in the pipeline environment.

Understanding the corrosion rate is crucial for predicting pipeline lifespan and scheduling maintenance activities. Additionally, assessing passivity helps identify conditions that may compromise the protective oxide layer, making the pipeline more susceptible to corrosion. Combining these analytical techniques aids in formulating corrosion management strategies, including the selection of appropriate inhibitors, coatings, or cathodic protection systems to safeguard the subsea oil pipeline against internal corrosion.

The corrosion rate of the steel pipeline was assessed using a three-electrode cell setup, with a saturated calomel electrode (SCE) serving as the reference electrode. To replicate real-world corrosion conditions, the water phase extracted from crude oil was employed as the electrolyte. This specific water phase was analyzed and found to contain 7183 ppm of chloride ions, with a slightly basic pH of 8.5, and it did not exhibit the presence of H<sub>2</sub>S gas.

Figure 7 illustrates a polarization diagram, also known as a Tafel plot, for the pipeline. This plot provides valuable information from which the corrosion rate can be determined, expressed as the steady-state current density,  $i_{corr}$ ,

measured in milliamperes per square centimeter (mA/cm<sup>2</sup>). In engineering applications, corrosion rate (r) is commonly expressed in terms of penetration over time, typically in units such as mils per year (mpy) or millimeters per year (mm/year). The corrosion rate can be calculated by substituting the icorr value obtained from the Tafel plot into the following equations<sup>(12)</sup> :

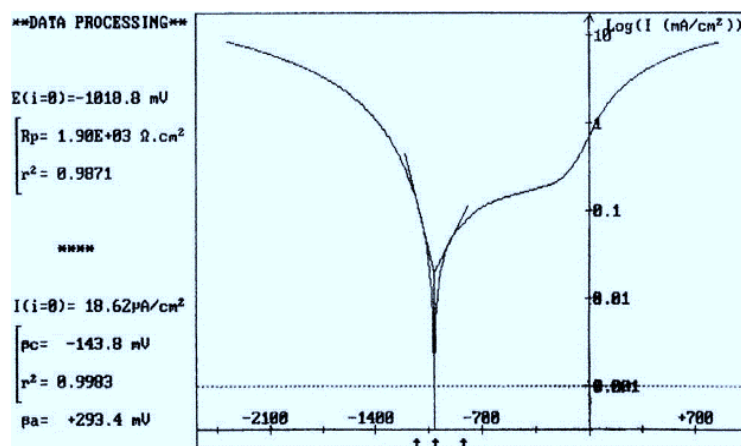
$$r = 0.129 \frac{ai}{nD} = 0.129 \frac{i(EW)}{D} \quad (\text{in mpy}) \tag{1}$$

Or

$$r = 0.00327 \frac{ai}{nD} = 0.00327 \frac{i(EW)}{D} \quad (\text{in mm/year}) \tag{2}$$

In equations (1) and (2), several parameters are involved in the calculations. These parameters include D, which represents the density in grams per cubic centimeter (g/cm<sup>3</sup>), i denoting the current density in milliamperes per square centimeter (mA/cm<sup>2</sup>), a representing the atomic mass in grams per mole (g/mole), and n signifying the valency.

To obtain the equivalent weight (EW) required for equations (1) and (2), a separate determination is necessary.



**Fig. 6.** Tafel diagram illustrates the pipeline used to extract water from crude oil<sup>(13)</sup>.

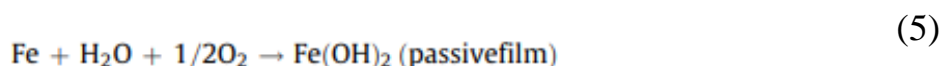
$$EW = (N_{EQ})^{-1} \quad (3)$$

$$N_{EQ} = \sum \left( \frac{f_i n_i}{a_i} \right) \quad (4)$$

The calculation of corrosion rate is presented in Table 4. The results indicate that the corrosion rate of the steel pipeline stands at 18.62 mA/cm<sup>2</sup> or is equivalent to 8.616 mils per year (mpy) or 0.2184 millimeters per year (mm/year). This suggests that the pipeline material exhibits a commendable resistance to corrosion.

It's important to acknowledge that the corrosion rate determined in laboratory tests may not align precisely with what is observed in on-site conditions. This discrepancy arises because, in laboratory tests, the corrosion specimen's surface is polished, no fluid flow occurs during testing, and the test temperature is often lower than the actual operating temperature. However, concerning the passivity behavior, the polarization test can still provide valuable insights into how the steel pipeline behaves in an aqueous environment.

In reference to Figure 6, it becomes evident that within the potential range of -700 to -175 millivolts vs. the saturated calomel electrode (mV SCE), the pipeline demonstrates passivity, likely attributable to the formation of a passive film<sup>(14)</sup>.



The onset of passivity breakdown commences at a potential of -175 millivolts vs. the saturated calomel electrode (mV SCE) or higher. This indicates that the steel pipeline is susceptible to pitting corrosion. Such corrosion vulnerability may be associated with aggressive agents like chloride ions, which locally deteriorate the passive film and catalyze the release of Fe<sup>3+</sup>, as described in reference<sup>(15)</sup>.



The detection of chloride (Cl) in the corrosion product, as evidenced by the EDX spectra

in Figure 5b, implies that the mechanism through which chloride ions dismantle the passive film is indeed in action.

## 2.6. Flow Pattern Analysis

Understanding the flow patterns within subsea oil pipelines is essential for assessing the risk and impact of internal corrosion. Flow pattern analysis involves studying the movement and behavior of fluids within the pipeline, which can provide critical insights into the corrosion processes. Here, we delve into the specifics of flow pattern analysis:

- a. Fluid Dynamics: Fluid dynamics analysis involves studying the velocity, pressure, and turbulence of the fluid as it flows through the pipeline. This information helps identify areas where flow patterns may contribute to increased corrosion rates, such as regions of high turbulence or low flow velocities.
- b. Computational Fluid Dynamics (CFD): CFD simulations are valuable tools for modeling and analyzing fluid flow within the pipeline. CFD can predict flow patterns, identify stagnant zones, and assess the impact of changes in flow conditions on corrosion rates.

- c. Corrosion Product Transport: Understanding how corrosion products are transported within the pipeline is crucial. Analyzing the movement of particles and deposits can reveal areas where corrosion byproducts accumulate and potentially exacerbate corrosion.
- d. Fluid Composition: Analyzing the composition of the transported fluid is vital, as different components may interact with the pipeline material and influence corrosion processes. This includes assessing the presence of corrosive agents like H<sub>2</sub>S, chloride ions, or contaminants.

Flow pattern analysis aids in identifying corrosion-prone areas, optimizing flow conditions to minimize corrosion risk, and designing effective corrosion monitoring and mitigation strategies. By integrating fluid dynamics, CFD simulations, and fluid composition analysis, pipeline operators can make informed decisions to ensure the long-term integrity and reliability of subsea oil pipelines.

In our current analysis, we are focusing on the flow pattern within a horizontal pipeline, considering the presence of multiple phases, including crude oil, water, and gas. Given the distinct densities of these liquids (crude oil and water) and gas, the concurrent flow of these components within the pipeline can give rise to various flow patterns or flow regimes. These flow patterns are influenced by factors such as the density differences between the phases. To characterize these flow patterns accurately, we rely on flow parameters expressed as superficial liquid and gas velocities. These parameters are calculated using the equations outlined in reference<sup>(16)</sup>.

$$U_{sl} = \frac{Q_l}{A_f} \tag{8}$$

$$U_{sg} = \frac{Q_g}{A_f} \tag{9}$$

Here, we define  $U_{sl}$  as the superficial liquid velocity and  $U_{sg}$  as the superficial gas velocity, with  $Q_l$  representing the liquid volumetric flow rate and  $Q_g$  representing the gas volumetric flow rate. Additionally,  $A_f$  denotes the cross-sectional area of the pipeline's flow. To ascertain the flow regimes, we have converted the flow rate data provided in Section 1 into SI units and applied equations (8) and (9) as described below:

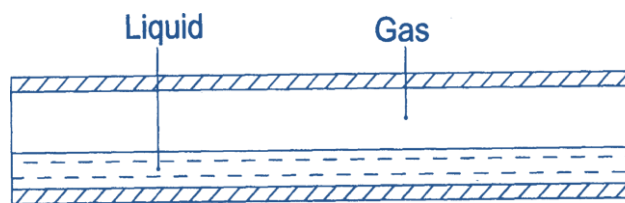
Upon referring to Table 5 (a,b) . it becomes evident that both  $U_{sl}$  and  $U_{sg}$  exhibit relatively low values. According to the gas-liquid flow regime curve designed for horizontal pipelines<sup>(17)</sup>, this suggests that the anticipated flow pattern will manifest as stratified flow. In this scenario, gas and liquid phases remain distinctly separated from each other, as illustrated in Figure 7. In this particular stratified flow, water tends to accumulate at the pipeline's bottom, bringing the pipe surface into contact with the water phase.

**Table5(a):** pipeline corrosion rates being investigated

Material	$NEQ$	$i_{corr}$ (mA/cm <sup>2</sup> )	$D$ (g/cm <sup>3</sup> )		$EW$	Corrosion rate
				mm/year		mpy
Pipeline	0.03630	18.62	7.68	0.2184	27.55	8.616

**Table 5(b):**  $U_{sl}$  and  $U_{sg}$  calculation results given the anticipated flow pattern.

Liquid flow rate ( $Q_l$ ) (m <sup>3</sup> /s)	Liquid velocity ( $U_{sl}$ ) (m/s)	Gas flow rate ( $Q_g$ ) (m <sup>3</sup> /s)	Flow pattern	Gas velocity ( $U_{sg}$ ) (m/s)
$4.7918 \times 10^{-3}$	0.0420	0.1445	Stratified flow	1.2675



**Fig. 7.** Stratified gas-liquid flow in a horizontal pipeline.

### **3. Discussion**

In this section, we delve into a comprehensive discussion of the findings and implications of our analysis regarding internal corrosion in subsea oil pipelines.

The key points and noteworthy observations are highlighted as follows:

**3.1. Corrosion Rate Assessment:** The corrosion rate of the steel pipeline was determined to be 18.62 mA/cm<sup>2</sup>, equivalent to 8.616 mils per year (mpy) or 0.2184 millimeters per year (mm/year). This relatively low corrosion rate suggests that the pipeline material exhibits commendable corrosion resistance, boding well for its long-term integrity<sup>(18)</sup>.

**3.2. Passivity Behavior:** The steel pipeline displayed passivity within the potential range of -700 to -175 mV SCE. However, the initiation of passivity breakdown at potentials above -175 mV SCE indicates susceptibility to pitting corrosion. This vulnerability may be attributed to aggressive agents like chloride ions, which can locally degrade the passive film and catalyze the release of Fe<sup>3+</sup> ions.

**3.3. Flow Pattern Analysis:** Our analysis incorporated a multiphase flow model accounting for crude oil, water, and gas phases in a horizontal pipeline. The low values of superficial liquid and gas velocities ( $U_{sl}$  and  $U_{sg}$ ) suggest a stratified flow pattern. In this configuration, water accumulates at the bottom of

the pipeline, bringing the pipe surface into contact with the water phase, which can be a critical factor contributing to corrosion.

**3.4. Implications:** The findings from our analysis have several implications for the management of internal corrosion in subsea oil pipelines. Firstly, the low corrosion rate is reassuring but does not negate the need for ongoing monitoring and corrosion prevention strategies. Secondly, the susceptibility to pitting corrosion in the presence of chloride ions underscores the importance of water quality control and monitoring. Lastly, the stratified flow pattern, with the accumulation of water at the pipeline bottom, highlights the need for corrosion mitigation measures that address this specific condition.

**3.5. Future Considerations:** Moving forward, it is essential to continue monitoring the pipeline's corrosion rate and passivity behavior in the actual operating conditions. Additionally, corrosion management strategies should incorporate measures to mitigate the effects of stratified flow and prevent the accumulation of water at the pipeline's lower section.

In summary, our analysis provides valuable insights into the internal corrosion dynamics of subsea oil pipelines, emphasizing the multifaceted nature of corrosion processes and the importance of a comprehensive corrosion management approach.

Based on visual examination, it is evident that the leaks manifest as teardrop-shaped pits or grooves located at the bottom of the pipeline (specifically at the 6 o'clock position), where water tends to accumulate. Notably, there is an absence

of scales or deposits surrounding these grooves, indicating that the pipeline is experiencing localized corrosion induced by the fluid flow. In the initial stages, such corrosion gives rise to brittle scales or rust on the pipe surface exposed to the fluid. These scales serve as a protective barrier between the metal surface and the fluid, inhibiting further corrosion penetration. However, the ongoing fluid flow causes an erosion process, periodically removing the scales or corrosion products from the exposed surface. Consequently, this increases the corrosion rate along the direction of the flow<sup>(19)</sup>.

The failure mechanism of the horizontal subsea pipeline due to flow-induced corrosion is depicted in Figure 8. As previously discussed in our flow analysis, the expected flow pattern is characterized by stratified flow, where gas and liquid phases remain entirely segregated, and a water layer is present at the pipeline's bottom. When the crude oil flows through the elbow section, the change in flow direction results in impacts on regions near the curved pipeline wall. These impacts, in conjunction with chloride content in the crude oil, the presence of eddy currents, and potentially the entrainment of sand in the pipeline, have the potential to disrupt the protective film on the pipeline's surface. Once this protective film is compromised, the pipeline surface becomes exposed to water, leading to oxidation-reduction reactions.

In this scenario, the steel surface acts as the anode, dissociating into positively charged ions while leaving electrons behind. This process contributes to the corrosion observed in the pipeline.



Under conditions that are either neutral or basic, the oxygen present in the water proceeds to utilize the electrons originating from the anode through the following chemical reaction.



Combining the two half-reactions results in the overall reactions as follows:

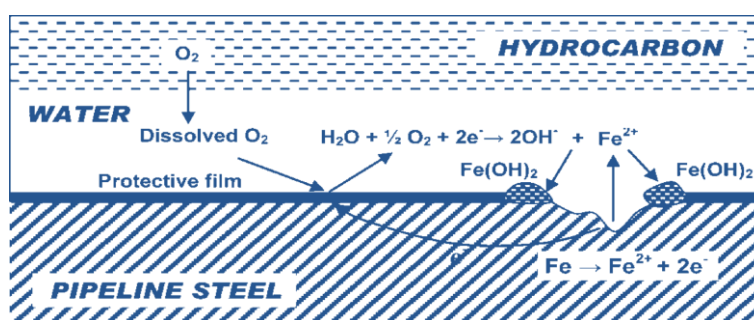
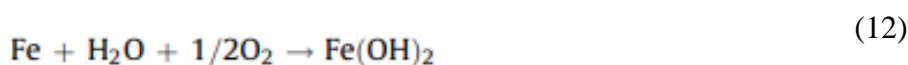
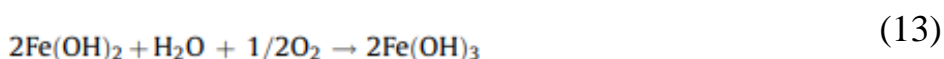


Fig. 8. proposed method for oil pipeline corrosion caused by flow.

The corrosion product, which is ferrous hydroxide  $\text{Fe}(\text{OH})_2$ , creates a diffusion-resistant layer encircling the opening of the pit. This layer necessitates the diffusion of oxygen. At the external surface of this  $\text{Fe}(\text{OH})_2$  layer, there is convenient access to dissolved oxygen, which results in the formation of ferric hydroxide, in accordance with the following reaction<sup>(20)</sup>:



Ferric hydroxide  $\text{Fe}(\text{OH})_3$  exhibits a reddish-brown color, as demonstrated in Figure 2b. It appears that deposits of  $\text{Fe}(\text{OH})_2$  or  $\text{Fe}(\text{OH})_3$  formed as a result of the corrosion reaction are subsequently dislodged from the exposed surface due to the fluid flow, resulting in an increased corrosion rate in the direction of the flow.

Consequently, the corrosion rate downstream, where the corrosion has spread, surpasses that of penetration and lateral corrosion. This alteration in the corrosion pattern evolves from the initial pinhole shape, which is characteristic of purely corrosive attack, to the development of teardrop-shaped pits or grooves.

#### **4. Conclusions and Recommendations**

##### **4.1. Conclusions**

In the analysis of internal corrosion within the subsea oil pipeline, several key findings have emerged:

**Corrosion Rate Assessment:** The corrosion rate of the steel pipeline was determined to be 18.62 mA/cm<sup>2</sup> or equivalent to 8.616 mpy (0.2184 mm/year), indicating a relatively low corrosion rate. This suggests that the pipeline material exhibits good corrosion resistance.

**Passivity Behavior:** The steel pipeline displayed passivity within a specific potential range but exhibited susceptibility to pitting corrosion at potentials higher than -175 mV SCE, primarily due to the presence of chloride ions.

**Flow Pattern Analysis:** Flow pattern analysis revealed a stratified flow configuration within the pipeline, where gas and liquid phases segregate, and a water layer accumulates at the bottom. This water accumulation has implications for corrosion dynamics.

**Corrosion Mechanism:** The corrosion mechanism is linked to flow-induced corrosion. Teardrop-shaped pits and grooves observed at the pipeline's bottom are likely the result of erosion and disruption of protective films, leading to

localized corrosion. This corrosion pattern changes from pinhole-shaped to teardrop-shaped pits as the corrosion progresses downstream<sup>(21)</sup>.

#### **4.2. Recommendations**

Based on the findings, the following recommendations are proposed:

**Corrosion Monitoring:** Implement continuous corrosion monitoring systems to track the corrosion rate in real-time. Regular inspections should be conducted to assess the extent of localized corrosion and to identify potential areas of concern.

**Water Quality Control:** Given the role of water accumulation in corrosion, maintain strict control over the water quality within the pipeline. Measures to minimize chloride content and other potential corrosive agents in the transported fluid should be considered.

**Corrosion Mitigation:** Develop and implement corrosion mitigation strategies tailored to the specific conditions of stratified flow and water accumulation. This may involve the application of corrosion inhibitors, coatings, or cathodic protection in critical areas.

**Flow Analysis:** Continuously monitor and analyze flow patterns, especially near bends or curves in the pipeline, to identify areas with high erosion potential. Consider modifications to flow design if necessary.

**Material Selection:** When planning pipeline upgrades or replacements, consider materials that are even more resistant to corrosion. Ensure that materials meet or exceed industry standards, such as API 5L X52. **Ongoing Research:** Invest in

ongoing research and testing to better understand the corrosion mechanisms and factors influencing corrosion in subsea oil pipelines. This will aid in refining corrosion management strategies. In conclusion, addressing internal corrosion in subsea oil pipelines is crucial for ensuring the long-term integrity and reliability of these critical assets. By implementing comprehensive monitoring and mitigation measures, operators can mitigate corrosion risks and maintain the safety and efficiency of their pipeline systems.

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