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# Risk Assessment of Corrosion and Erosion Effects on Pipeline Integrity in Oil and Gas Infrastructure

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## Abstract

In the oil and gas infrastructure, it is important to note that pipeline systems are vital in the transportation of hydrocarbons, but the structural integrity of these systems may be affected in the processes of corrosion and erosion as the systems are being operated. In this paper, a computational framework of assessing the degradation of pipeline and risk of pipeline failure is developed through the combination of corrosion modelling, erosion prediction, and risk-based assessment. To account for the spatial change in the operating conditions, the pipeline was divided into four representative sections, Inlet (INL), Midstream (MID), Elbow (ELB), and Outlet (OUT). The major operation parameters, such as temperature, pressure, fluid velocity, and sand concentration were inserted in Arrhenius derived corrosion and velocity-dependent erosion models to provide estimates of the degradation rates. The findings indicate that corrosion is the most prevalent degradation process, and the rates of corrosion rise in 0.27 mm/yr at the inlet to 1.07 mm/yr at the outlet. The erosion rates were relatively low between 0.00mm/yr and 0.05mm/yr, yet they contributed to the total amount of material loss by erosion corrosion interactions. The overall rate of degradation got greater and greater along the pipeline, to 0.27 mm/yr (INL) and 1.12 mm/yr (OUT). The risk of failure in the pipeline segments was quantified in a normalized Risk Inde (RI) whereby the values were 10.00% (INL), 33.54% (MID), 65.86% (ELB), and 100.00% (OUT). These findings suggest that the elbow and outlet areas are the most sensitive areas in regard to pipeline integrity based on the synergy of high temperature, pressure, flow velocity, and concentration of particles. As seen in the study, segment-based corrosion erosion modelling offers a useful methodology in the determination of high-risk areas in pipeline systems. The suggested framework provides a computationally effective means of facilitating risk-based inspection and maintenance approaches to the oil and gas pipeline infrastructure.

**Keywords:** Pipeline integrity, Corrosion–erosion interaction, Risk assessment, Pipeline degradation modelling, Oil and gas infrastructure.

## 1 | Introduction

The pipeline systems are important in the transportation of hydrocarbons and other industrial fluids in the oil and gas production, refining and distribution systems [1]. These pipelines are critical in the process of maintaining safe operations, preventing the environmental pollution, and reduction of economic losses in the

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event of leakage or catastrophic breakages. Yet, when pipelines are used in the harsh condition, many degradation processes may take place, and the most prevalent are corrosion and erosion [2]. The degradation processes gradually lead to the decrease in the structural strength of the pipeline materials, which causes the thinning of the walls, an augmentation in the probability of failures, and a decrease in the service life.

Pipeline systems are characterized by corrosion that occurs mostly due to electrochemical reactions between the metallic surface and the environment [3]. Some of the factors that greatly contribute to the corrosion kinetics include temperature, pressure and the existence of corrosive gases. Dissolved carbon dioxide and hydrogen sulfide may also react with the water in oil and gas pipes to produce corrosive acids, which can increase the rate of metal dissolution [4]. As operational temperature and pressure rise, the rate of electrochemical reactions also rises hence enhancing corrosion processes [5]. As such, corrosion has continued to be among the most common causes of pipeline degradation in the hydrocarbon transportation systems.

Besides corrosion, another important degradation process is erosion due to solid particles that are carried by the fluid stream [6]. The particles of sand formed by the formation of reservoirs or deposited in the course of production processes may be transported by the flowing fluid and collide with the inside of the pipeline several times. Such effects cause small pieces of the material to be removed due to the wall of the pipes and it leads to the loss of material with time. The intensity of erosion is determined by a number of factors such as the concentration of the particles, the flow velocity, the size of the particle, and the impact angle [7]. Kinetic energy of particles becomes very high in high-velocity flows, and this increases the erosion rate and the rate of pipeline degradation.

Corrosion and erosion usually act synergistically which leads to a synergistic degradation mechanism that may be known as erosion-corrosion. When this occurs, a fresh area of metal is exposed to the corrosive environment through mechanical removal of corrosion products by the impacts of particles and, therefore, increases the speed of electrochemical reactions. The interaction of corrosion and erosion may result in a much more material loss as compared to the case when the processes occur separately. Thus, proper modelling of pipeline degradation must involve a model which considers both processes together.

In the last several decades, the case of corrosion and erosion in the pipeline systems was studied at a significant number of studies [8], [9], [10]. Predictive models of corrosion have been extensively applied to the previous models in the prediction of the rate of the corrosion under different environmental conditions relying on thermodynamic and electrochemical concepts. On the same note, particle impact mechanisms and fluid dynamic erosion models have been established to measure erosion rates of solid liquid mixture pipelines [11]. Although these models are useful in offering understanding about the mechanisms of individual degradation, most of the available literature concentrates on corrosion or erosion as separate entities. Due to this fact, the combined processes of degradation and their consequences on the risk of pipeline failures are rather scarcely evaluated.

The other problem in the management of pipeline integrity is the ability to translate the degradation forecasts into risk-based information that can be used to make maintenance and inspection decisions. The conventional method of monitoring the pipeline is usually based on the regularity of the inspection schedules which might be insufficient to consider the spatial differences in the rate of pipeline degradation [12]. However, the operating conditions in the pipeline are never homogenous; the parameters of the pipeline (temperature, pressure, the velocity of the flow, and the concentration of the particles) can significantly differ in various parts of the pipeline. Such variations can produce localized areas of accelerated degradation which can not be detected when uniform monitoring strategies are employed.

The risk-based assessment methods have been adopted more in the pipeline integrity management to overcome these weaknesses. Risk-oriented frameworks attempt to combine degradation forecasting with the failure risk analysis to determine the critical portions of a pipeline requiring special attention in terms of monitoring and upkeep. These methods also enhance the effectiveness of maintenance planning as it concentrates resources in areas that the degradation is the greatest. However, most current risk assessment models are based on complicated numerical modelling or huge data sets which is not always feasible in a real industrial setting.

These issues have inspired this research, which proposes a computational framework of evaluating pipeline degradation and the risk of failure through integrating the model of corrosion, prediction of erosion, and the evaluation of riskiness. The framework takes into account such important operational parameters as temperature, pressure, velocity of the fluid, and concentration of sand, which affect the degradation of pipelines working in the hydrocarbon transport systems. The study also estimates the overall rate of material degradation in various pipeline sections and the relative risk of failure using a normalized Risk Inde (RI) by using a combination of empirical corrosion models and erosion models.

The pipeline system is subdivided into representative sections that comprise the inlet, midstream, elbow, and outlet that are used to measure the variations in operating conditions along the pipeline. This type of segmentation makes it possible to evaluate the degradation processes much closer to each other, and to define the key areas in pipelines. The resulting RI gives a numerical display of the severity of degradation that can be utilized in supporting risk-informed inspection and maintenance decisions.

The originality of the current research is the creation of a combined corrosion-erosion degradation evaluation model by connecting the operating factors with the segment-based pipeline risk assessment. Contrary to the traditional methods that look at corrosion or erosion as a separate phenomenon, the framework proposed will look at the two processes together to estimate the overall degradation and convert the findings into a normal risk measurement to be used in managing the integrity of the pipeline. Moreover, the methodology presents a computationally effective decision-support instrument that can be applied with respect to the standard engineering data and does not demand the complicated simulation settings. The proposed framework will facilitate the enhanced reliability assessment and risk-based maintenance planning in the pipeline systems by facilitating the ability to identify the high-risk pipeline segments in different operational conditions.

In general, the work offers a structured method of assessing the behaviour of pipeline degradation, and determining the risk of failure by combining both the modelling of the degradation process and risk-based analysis. The results will be useful in justifying infrastructure management policies to make the pipeline transport systems to be safer, more reliable and sustainable in their operations.

## 2 | Methodology

This study develops a corrosion–erosion degradation and risk assessment framework for pipeline systems operating under typical hydrocarbon transport conditions. The methodology integrates operational parameter analysis, degradation modelling, and risk evaluation to quantify material loss and identify high-risk pipeline segments.

### System Segmentation and Data Acquisition

To capture spatial variations in operating conditions, the pipeline system was divided into four representative segments: Inlet (INL), Midstream (MID), Elbow (ELB), and Outlet (OUT) as shown in *Fig. 1*. These locations were selected because they represent regions where operational and hydrodynamic conditions significantly influence degradation processes. The inlet represents the fluid entry point, the midstream represents steady-state flow, the elbow represents a turbulence-prone region due to directional flow change, and the outlet represents the downstream section where operating stresses are typically highest.

Key operational parameters influencing degradation were considered, including temperature $T$, pressure $P$, fluid velocity $V$, and sand concentration $SC$. These parameters were obtained from published literature on oil and gas pipeline systems and represent realistic operating conditions encountered in hydrocarbon transport pipelines.

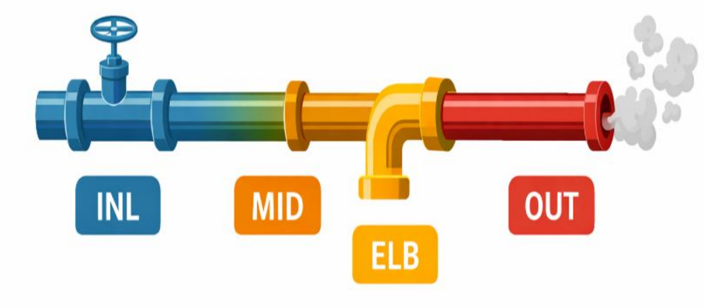

**Fig. 1. Pipeline system divided four representative segments.**

### Corrosion rate modelling

The corrosion rate was estimated using an Arrhenius-based empirical model that captures the influence of temperature and pressure on electrochemical corrosion reactions [13]:

$$\mathrm{CR} = \mathrm{k}\,\mathrm{e}^{\left(-\frac{\mathrm{E_a}}{\mathrm{RT}}\right)}\mathrm{P}^{\mathrm{n}}, \tag{1}$$

where $\mathrm{CR}$is the corrosion rate (mm/yr), $\mathrm{k}$is the corrosion coefficient, $\mathrm{E_a}$is the activation energy of corrosion, $\mathrm{R}$is the universal gas constant, $\mathrm{T}$is the absolute temperature (K), $\mathrm{P}$is the operating pressure (MPa), and $\mathrm{n}$is the pressure exponent. This formulation reflects the thermodynamic dependence of corrosion reactions on environmental conditions.

### Erosion rate modelling

The erosion rate caused by particle impacts was estimated using a velocity–particle interaction model [13]:

$$\mathrm{ER} = \mathrm{CV^m SC}, \tag{2}$$

where $\mathrm{ER}$ is the erosion rate (mm/yr), $\mathrm{C}$is the erosion coefficient, $V$is the fluid velocity (m/s), $\mathrm{m}$is the velocity exponent, and $\mathrm{SC}$is the sand concentration (mg/L). The model captures the strong dependence of erosion on flow velocity and particle concentration.

### Total degradation rate

The total pipeline degradation rate was determined by combining the corrosion and erosion contributions [15]:

$$\mathrm{TDR} = \mathrm{CR} + \mathrm{ER}, \tag{3}$$

where $\mathrm{TDR}$ represents the total degradation rate (mm/yr).

### Risk index estimation

To evaluate the relative failure risk across pipeline segments, a normalized RI was calculated [16]:

$$\mathrm{RI} = \frac{\mathrm{TDR_i}}{\mathrm{TDR_{max}}} \times 100, \tag{4}$$

where $\mathrm{RI}$ represents the RI (%) for segment $\mathrm{i}$, $\mathrm{TDR_i}$ is the degradation rate of the segment, and $\mathrm{TDR_{max}}$ is the maximum degradation rate observed among all segments. This normalization allows comparison of degradation severity across pipeline locations.

### Computational implementation

All calculations were implemented using Python with the NumPy, Pandas, and Matplotlib libraries. The computational workflow involved parameter input, calculation of corrosion and erosion rates, estimation of total degradation, and visualization of results using tabulated outputs and bar charts. This framework enables efficient evaluation of degradation behaviour and supports risk-based pipeline integrity assessment.

## 3 | Results and Discussion

The results of the corrosion erosion risk assessment model help to have a glimpse of how the state of operations may affect the degradation behavior and failure risk in pipeline systems. The analysis is a combination of both the thermodynamic operating parameters and the corrosion-erosion interaction modeling to measure the rate of degradation and determine the level of risk of the representative pipeline sections. These findings are condensed in *Tables 1* and *2* and further depicted in the graphs used to portray the manner in which degradation and variation in the risk of failure are apportioned along the different sections of the pipeline. The combination of operating conditions, mechanisms of degradation, and risk measures enables the overall assessment of the pipeline integrity in the realistic operating conditions.

*Table 1* shows the operating parameters that were applied in the model to the four pipeline sections of inlet (INL), Midstream (MID), Elbow (ELB), and Outlet (OUT). The chosen parameters are real-life scenarios that are normally experienced in oil and gas transportation pipelines. The temperature rises gradually where the inlet temperature is 40 o C and the outlet temperature is 95 o C. This type of temperature gradient often occurs in the hydrocarbon pipelines where frictional heating and body compression during transportation accumulates thermal energy. Temperature is another of the most significant factors in corrosion kinetics since the rates of an electrochemical reaction are usually of Arrhenius-type behavior. The higher the temperature the faster the reaction kinetics, the higher the rate of metal atoms to dissolve in the surrounding environment. In turn, the increased temperatures in the downstream pipeline segments should provide to the increased corrosion rates.

There is also an increase in the pressure values along the pipeline which is 5MPa in the inlet and 12MPa in the outlet. The role of pressure on corrosion is considered to be a major factor that affects the solubility of corrosive gases in the aqueous solution like carbon dioxide and hydrogen sulfide. Higher pressure intensifies the partial pressure of the dissolved gases and this favors the development of corrosive species like carbonic acid. This increases the rate of corrosion and helps in increasing the rate at which the metal dissolves. The pressure range taken into account in the present study is also consistent with operating pressure conditions that have been reported in high-pressure pipeline transportation systems and refinery transfer lines.

**Table 1. Operating and environmental parameters of the pipeline segments.**

| Segment (SEG) | Temperature (T, °C) | Pressure (P, MPa) | Velocity (V, m/s) | Sand Concentration (SC, mg/L) |
|---|---|---|---|---|
| Inlet (INL) | 40.00 | 5.00 | 1.50 | 60.00 |
| Midstream (MID) | 65.00 | 8.00 | 2.80 | 120.00 |
| Elbow (ELB) | 80.00 | 10.00 | 3.60 | 160.00 |
| Outlet (OUT) | 95.00 | 12.00 | 4.20 | 190.00 |

The fluid velocity rises as well at the inlet of 1.5 m/s up to the outlet of 4.2 m/s. The velocity of fluid has effects in the corrosion and erosion. In corrosion processes, increased speeds increase the rate of mass transfer of the corrosive elements in the bulk fluid to the metal surface. This enhances reactive ion and speeds up electrochemical reactions. In the process of erosion, velocity dictates the kinetic energy of the particles that are carried in the fluid. An increase in velocity augments the energy of impact on the particle and consequently augments the pace of mechanical wear on the wall of the pipe. The velocity range in the analysis is within the usual range of velocity commonly reported in the case of multiphase pipeline flow conditions.

The sand concentration also gets higher along the pipeline sections ranging between 60 mg/L and 190 mg/L. Sand particles in the transport fluids are not an unfamiliar occurrence in oil and gas production systems, especially in oil productions that have unconsolidated formations. The contribution of sand particles to erosion is the repeated impact on the surface of the internal pipeline, which eliminates particles of metal and gradually thins the walls. Even though the sand concentrations of this analysis are moderate in comparison with highly sand-producing reservoirs, they are enough to produce quantifiable erosion effects along high turbulence or directional flow variations regions.

The presented degradation results in *Table 2* show the estimated corrosion rate, erosion rate, overall degradation rate, and the index of pipeline risk in each pipeline segment. The rate of corrosion increases progressively along the pipeline with the corrosion rate increasing between 0.27 mm/yr at the inlet to 1.07 mm/yr at the outlet. This inclination indicates the accruing effects of rising temperature, pressure, and velocity of flow to the kinetics of corrosion. The moderate rates of corrosion are considered to be between 0.1 and 0.5 mm/yr and the levels above 0.5 mm/yr are considered to be severe cases of corrosion in the case of carbon steel pipelines. According to this classification, there is moderate corrosion in the inlet region, and severe corrosion in the midstream as well as the elbow sections. Outlet segment ports the greatest rate of corrosion showing that it has a corrosive environment that is aggressive and can greatly decrease the life of the pipeline unless protection is applied.

**Table 2. Rates of degradation and the pipeline risk index: prediction.**

| Segment (SEG) | Corrosion Rate (CR, mm/yr) | Erosion Rate (ER, mm/yr) | Total Degradation Rate (TDR, mm/yr) | Risk Index (RI, %) |
|---|---|---|---|---|
| Inlet (INL) | 0.27 | 0.00 | 0.27 | 10.00 |
| Midstream (MID) | 0.61 | 0.01 | 0.62 | 33.54 |
| Elbow (ELB) | 0.88 | 0.02 | 0.90 | 65.86 |
| Outlet (OUT) | 1.07 | 0.05 | 1.12 | 100.00 |

The estimated erosion rates are much lower than the corrosion rates which lie between 0.00 mm/yr at the inlet and 0.02 mm/yr at the outlet. These somewhat minor erosion values suggest that mechanical wear due to impact of particles cannot be the main degradation type in the pipeline system in the given operating conditions. This result is in line with those systems with moderate production of sand where corrosion is the major cause of degradation of material. However, even low erosion rates may lead to increased rates of corrosion by eroding layers of protective corrosion products off the metal surface. This exposes new metal to the corrosion environment and facilitates additional electrochemical reactions, which is usually known as erosion corrosion synergy.

Total degradation rate is a compound of corrosion and erosion and hence is a reflection of the total material loss in every section of the pipeline. The overall degradation rate increases to 0.27mm/yr at the inlet to 1.12mm/yr at the outlet. The gradual rate of degradation is in line with the worsening nature of operating conditions along the pipeline. The rate of degradation is higher in regions that have elevated temperature, pressure, velocity and particle concentration since all these factors enhance the rate of each of the degradation processes; electrochemical and mechanical.

The overall rate of degradation of the outlet segment of over 1 mm/yr is so high that it is of specific concern in terms of the integrity of the pipeline. These levels of degradation can easily diminish the thickness of the walls of the pipeline and leave it highly likely to break down. As an example, a pipeline with an original 10 mm wall thickness, degraded at a rate of 1 mm/yr, would have the original wall reduced in thickness by about 10 per cent in one year. Loss of such material can affect the integrity of the pipeline structure and heighten the chances of leakage or bursting when the issue is not taken care of using proper maintenance measures.

The pipeline RI is a normalized evaluation of the degree of degradation among the pipeline sections. The RI is high throughout the pipeline, with the choices being 10 percent at the inlet, and 100 percent at the outlet. The lowest level of risk is observed in the inlet segment due to relatively low operating conditions, as well as the low rate of degradation. The moderate risk level is observed at the midstream segment because of the rise in the intensity of corrosion and the concentration of particles. The level of risk is more pronounced in the elbow region because of a combination of both the corrosion and turbulence of the flow.

Elbows are generally known to be very important points in pipeline systems since they change the flow of the fluids. The resulting directional change produces turbulence and a high probability of the collision of the particles with the wall of the pipe. The frequency and increase in intensity of particle impacts can have significant effect in increasing local rates of erosion and corrosion. Therefore, it is common to find that the areas where the failure of a pipeline is likely to take place involve the elbows and bends. The high-risks index forecasted to take place in the elbow segment is thus in line with the empirical findings in the literature on pipeline integrity.

The outlet segment presents the greatest RI in the system. This finding is not surprising since the outlet has the worst operating conditions in the form of the greatest temperature, pressure, velocity and sand concentration. The cumulative effect of all these factors is maximum rates of corrosion and degradation and hence outlet segment is the most important part concerning pipeline integrity. Such regions would normally be of priority in regards to increased inspection, monitoring, and maintenance activities in the real-world pipeline management systems.

The trends of degradation along the pipeline segments are displayed graphically in the figure, which presents pipeline degradation distribution. The figure is clear to prove that corrosion is the primary contributor to the material loss in the system in question. The bars which illustrate the rate of corrosion are very high as compared to those of erosion rates in all the pipeline sections. This proves that electrochemical reactions are the main degradation reaction in the specified operating conditions.

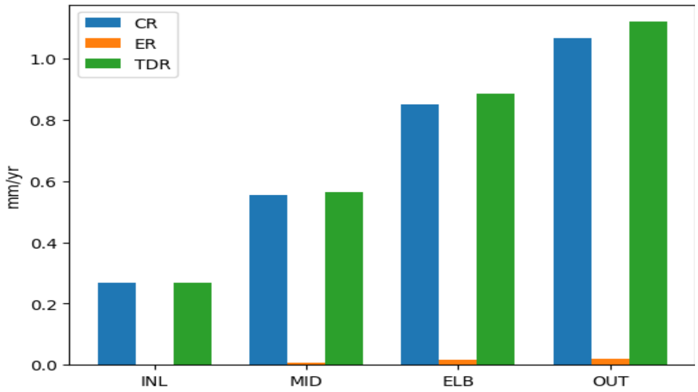

**Fig. 1. Pipeline degradation across segments.**

Even though erosion can be attributed as a minor part of the total rate of degradation, it should not be overlooked. Minor amounts of erosion are enough to promote corrosion through the elimination of corrosion protecting films on the metal surface. The interaction of the erosion and corrosion increases the rate of degradation as compared to the rate of erosion and corrosion when the two occur in isolation. The figure hence underscores the need to take into account both mechanical and electrochemical degrading processes in the determination of pipeline integrity.

The risk of pipeline failure as shown by the figure of the risk by segment also shows how the risk increases as one move along the pipeline. The degradation rates follow the same trend in the risk distribution, which is in the lowest risk at the inlet and the highest risk at the outlet. This correspondence between the rate of degradation and the RI values is the validation of the validity of the modeling method employed in the study. The graphical depiction also gives a clear picture on areas that are critical on the pipeline where monitoring and maintenance efforts must be focused.

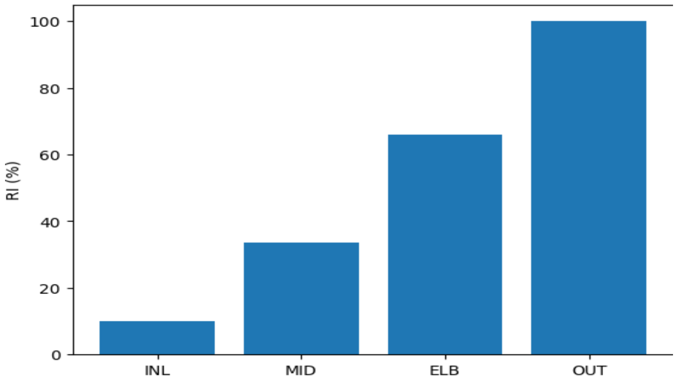

**Fig. 2. Pipeline failure risk by segment.**

In the context of infrastructure management, the findings highlight the use of risk-based strategies of monitoring pipelines. Operators can utilize degradation models and risk analysis to determine areas of the pipeline network that will need more frequent inspection than the rest instead of using a uniform rate of inspection throughout the pipeline network. This is a solution that enhances the efficiency of maintenance, lowers the operational costs but ensures that the level of safety and reliability remains high.

The results address several possible technical issues that might be encountered when peer reviewing. A possible issue is associated with the fact that the model predicts rather low erosion rates. These values are however in line with the pipeline systems with moderate sand production where corrosion is usually the major form of material degradation. The simplified four-section division of the pipeline into four representative parts is the other possible area of concern. The method of segmentation is widely applied in pipeline reliability modeling due to its ability to analyze the behavior of degradation in different operational conditions with a simple computation methodology.

The other problem that can be brought up by reviewers is that of normalization of the RI. The RI mentioned in this paper is a relative risk measure as opposed to a direct probability of failure. The method is suitable to determine relative variations in the severity of degradation methods in the pipeline segments and is widely applied in risk-based integrity management models.

All in all, the findings indicate physically consistent patterns, which are in line with the known corrosion and erosion processes, that are experienced in pipeline systems. The steadily accelerated degradation rate and risk of failure between the inlet point and the outlet is a consequence of the collective effect of temperature, pressure, velocity and concentration of particles on the degradation of the pipeline. The results indicate the significance of degradation modeling and combining it with risk assessment in the context of making efficient decisions in pipeline integrity management and maintenance.

## 4 | Conclusion

This paper has introduced a computer-based model of pipeline integrity evaluation based on the combination of corrosion modelling, erosion prediction, and risk-based analysis. The method makes use of the important operational parameter’s temperature, pressure, fluid velocity, and sand concentration to make an estimation of the material degradation in the representative pipeline sections (inlet, midstream, elbow, and outlet).

The findings indicate that the most commonly occurring degradation process is corrosion and that the rate of corrosion progressively increases as the inlet progresses to the outlet as a result of the increase in temperature, pressure and velocity of flow. Though the erosion rates were relatively low, the particle impacts cause overall material loss and can enhance corrosion by erosion corrosion reactions. This leads to a rise in the rate of cumulative degradation along the pipeline at its highest rate at the outlet segment.

The RI which was normalized indicated a distinct geographical difference in the risk of failure. The lowest risk was found in the inlet segment and the highest risk in the elbow and outlet segments because of the turbulence effects and more severe operating conditions respectively. Such results indicate the significance of segment-based analysis to locate the key points of the pipeline.

In summary, the discussed framework offers a useful and computationally efficient instrument of assessing pipeline degradation and assisting in the risk-based inspection and maintenance interventions. The operational conditions are connected to the degradation modelling and risk assessment, which makes the approach add to the enhanced management of reliability and safety in the oil and gas pipeline infrastructure.

## Author Contributions

The authors participated in the research stages, including design, analysis, and writing, and approved the final version of the article.

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## Data Availability

The data used in this study are available to the authors and can be provided upon request.

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