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Article

Probabilistic Finite Element Analysis of Temperature-Dependent Corrosion in Oil and Gas Pipelines

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Abstract: Marine pipeline systems are continually exposed to operating conditions that accelerate internal corrosion, posing risks to flow assurance and structural integrity. This study applies finite element modelling to evaluate the influence of operating temperature on corrosion progression and pipeline performance. The study addressed gaps in temperature-based corrosion propagation in a pipeline using ANSYS Design Modeler, meshing, and exporting for flow-corrosion modelling in ANSYS Fluent. A one-way coupling was established between Fluent and ANSYS Mechanical to assess the mechanical response under operating conditions. The base case at 62 °C showed a corrosion rate of 6.0 mm/year. To investigate the role of temperature, simulations were conducted at 30 °C, 50 °C, 62 °C, and 70 °C, representing the typical temperature range of Niger Delta fluid systems. Results indicate that lower temperatures significantly increase corrosion rates, leading to pronounced wall thinning and elevated stress concentrations. Conversely, higher temperatures reduce corrosion intensity by promoting the formation of protective corrosion films. However, localized stress elevations at higher temperatures were also observed, which may be attributed to combined thermal expansion effects and residual corrosion-induced weakening. This demonstrates a non-linear interaction between temperature, corrosion progression, and stress response. The study recommends maintaining sufficiently high fluid temperatures to mitigate corrosion. Further studies are needed to define the temperature range where corrosion behaves linearly, to support optimal design and operation while preventing conditions that could impair system performance and flow assurance. The result provides technical insight for the development of an integrity management strategy for optimum pipeline safety.

Keywords: Niger Delta; Temperature-Dependent Corrosion; Oil and Gas Pipelines; Fluid System Temperature; Structural Integrity.

1. Introduction

Pipelines are a critical infrastructure in the oil and gas industry, enabling the efficient, continuous transportation of crude oil, natural gas, and refined petroleum products over long distances. These structures are important in meeting the world's energy demand and ensuring economic stability and development. The significance of pipelines extends beyond energy supply; they are useful to industrial operations in the chemical and petrochemical sectors where large volumes of hazardous or volatile fluids are transported [1]. In Nigeria and across other petroleum-producing nations, pipelines traverse diverse geographical terrains, including swamps, deserts, offshore basins, and urban settlements. This widespread usage, coupled with the vital nature of their function, elevates the need for high operational reliability and structural soundness. As noted by [2], pipelines in complex terrains require context-specific strategies to ensure integrity and safety.

Pipelines, no matter how advanced their design or how carefully they're installed, still end up suffer some pretty harsh realities in service. Pipelines endure extreme pressure fluctuations, high temperatures, and exposure to corrosive media. These factors are particularly serious in offshore and subsea environments, where saltwater ingress, microbiological activity, and complex fluid compositions accelerate degradation. According to [3], localized environmental variability significantly affects the propagation of corrosion in buried pipelines. Soil types, moisture levels, electrical interference, mechanical damage during installation, and aging of protective coatings also contribute to its vulnerability. For example, in gas pipelines, changes in temperature and fluid flow composition can cause condensation and accumulation of corrosive elements within the pipeline. These operational and environmental interactions pose serious threats to the integrity and longevity of pipeline systems.

The concept of pipeline integrity concerns the technical, operational, and management activities undertaken to ensure that a pipeline system continues to perform its designed function effectively and safely throughout its life cycle. Pipeline integrity management is a structured, systematic approach to preventing failures by integrating data acquisition, risk assessment, inspection, and mitigation strategies. As highlighted by [4], dynamic modelling of coating degradation enhances predictive accuracy in pipeline risk assessment. The importance of pipeline integrity stems from the need to prevent catastrophic incidents such as explosions, leakages, and oil spills, which may result in loss of human lives, environmental degradation, disruption in energy supply, and massive economic losses. These incidents often attract heavy penalties from regulators and result in loss of social license to operate [5].

Corrosion remains the most persistent and damaging threat to oil and gas pipeline integrity. It is an electrochemical process in which metal atoms lose electrons and convert to ions, gradually degrading the pipeline material. This process is driven by the interaction of the pipeline metal with water, oxygen, acids, and other ionic species. Internal corrosion occurs due to transported fluids, especially when they contain corrosive gases such as CO_2 and H_2S. CO_2 reacts with water to form carbonic acid, leading to sweet corrosion, whereas H_2S causes sour corrosion and sulfide stress cracking. [6] reported that external coatings, when degraded, significantly increase the susceptibility of pipelines to localized corrosion under variable environmental stresses. The severity of internal corrosion increases with factors such as flow velocity, temperature, water cut, and the presence of entrained solids. On the other hand, external corrosion results from the interaction between the pipeline's outer surface and its surrounding environment, such as soil or seawater. Failures in coating systems or cathodic protection exacerbate the rate of external corrosion. Furthermore, AC interference from nearby power lines introduces additional electrochemical reactions that accelerate the corrosion of buried pipelines [7].

Corrosion-induced degradation can lead to several physical changes in pipeline structure. One of the most negative consequences is wall thinning, which reduces the mechanical strength and pressure-bearing capacity of the pipe. This makes the structure prone to deformation and leakage under operational stresses. In many cases, localized corrosion, such as pitting and crevice corrosion, results in sharp notches that act as stress concentrators. These sites are particularly vulnerable during high-pressure operations, where minor defects can propagate into long cracks, eventually leading to pipeline rupture [8].

[9] emphasized that machine-learning-enhanced inspection data can detect early-stage colony interactions that often precede catastrophic failures. The development of corrosion colonies, where multiple defects are located in close proximity, poses a much greater risk, as interactions among defects intensify the stress field and complicate failure analysis [10].

Pipeline integrity checks have often relied on deterministic models. In these, fixed, conservative values are plugged in for factors such as corrosion rate, wall thickness, and pressure. The problem is, real-world conditions don't stay fixed. By ignoring that variability, these models can swing in either direction; sometimes they overshoot, making maintenance more expensive than it needs to be; other times they miss the mark, leaving the system exposed to failure. [11] note that approaches like FORM or Monte Carlo Simulation tend to capture better reality, and provide estimates that come with clear confidence bounds. That's why probabilistic assessments have been gaining ground. Rather than assuming one fixed value, they treat key parameters, material properties, loads, corrosion rates, and defect shapes as variables that follow statistical distributions. Methods such as Bayesian inference, MCS, and FORM can provide a fuller picture of reliability, showing the probability of failure along with confidence intervals for quantities such as burst pressure. This way, decisions can be made with risk in mind, and maintenance can be planned more efficiently [12].

The increasing adoption of smart sensing technologies in corrosion monitoring is transforming integrity management from reactive to proactive. These systems enable continuous, real-time monitoring of structural health, allowing operators to detect early signs of corrosion and intervene before damage escalates. For instance, piezoelectric sensors are employed to detect acoustic emissions and vibrations associated with corrosion activity. Electromechanical impedance (EMI) sensors measure changes in material impedance caused by corrosion-induced stiffness loss. Fiber Bragg Grating (FBG) sensors are embedded along pipelines to monitor strain and temperature distribution, while guided wave ultrasonic sensors are used to inspect inaccessible regions. According to [13], integrating AI-enabled analytics with sensor data significantly improves fault detection accuracy and predictive capability. These sensing technologies, when integrated with digital platforms, artificial intelligence, and machine learning algorithms, enhance data interpretation, fault localization, and predictive analytics. Such systems form the backbone of predictive maintenance regimes, ultimately reducing operational cost, minimizing environmental risks, and increasing system uptime [14].

Corrosion growth modelling has come a long way and now plays a central role in assessing pipeline integrity. At its core, the idea is simple: it takes what is known from current inspections, factors in environmental influences, and projects how corrosion depth will change over time. Some models are built on fixed assumptions, while others lean on probabilistic thinking. The probabilistic ones go further, allowing for time-based changes and random effects that bring the predictions closer to how things actually happen in the field. Well-structured probabilistic growth models can sharpen the measurement of failure margins. With tools like copula functions, stochastic differential equations, and reliability-based methods, it's now possible to describe the full probability profile of a pipeline's failure risk.

In addition to temperature, the composition of the transported fluid directly affects the development of corrosion. High CO_2 partial pressures, water cut, and dissolved salts significantly enhance the electrochemical reactions that drive corrosion in carbon-steel pipelines [15], [16]. Multiphase flow patterns, which mix oil, gas, and produced water, further complicate the problem by generating turbulent regions and wall shear stresses, thereby increasing localized attack [17]. Recent numerical modelling efforts using CFD and finite element methods have highlighted how these coupled factors interact: temperature controls corrosion kinetics, fluid composition dictates the availability of corrosive species, and flow conditions determine transport and deposition on the pipe wall [18], [19].

Although CFD-driven corrosion prediction, probabilistic integrity analysis, and finite element stress evaluation have each been studied individually, their direct integration into a single workflow for a temperature-dependent operating pipeline remains limited [20], [21].

However, there is still no detailed finite element analysis that directly simulates fluid flow under the actual operating conditions of a pipeline, accounting for internal pressure, fluid composition, and the true temperature range of the flowing system [22].

Moreover, no study has generated spatial corrosion rate fields (corrosion grids) that clearly show how corrosion rate changes with temperature variation, and then linked this to the pipeline's mechanical integrity in terms of stress distribution and possible failure.

The current study presents the application of an integrated probabilistic-numerical model for pipeline integrity assessment under corrosion effects. The numerical model directly simulates fluid flow under the actual operating conditions of a pipeline, accounting for internal pressure, fluid composition, and the true temperature range of the flowing system. The stress distribution along the corroded pipeline is assessed and compared with the material yield stress, thereby predicting the likelihood of failure under progressive corrosion. The probability distribution is used to develop the corrosion rate profile under varying operation conditions of the pipeline. The result provides technical insight for the development of an optimum integrity management strategy for sustainable operation.

The remaining part of the paper is structured as follows: Section 2 briefly describes the research methodology. Section 3 provides the research results and discussion, and Section 4 concludes the study.

2. Methodology

The study employs an integrated approach for the integrity assessment of the corroded pipeline. The following explains the mathematical formulation, probabilistic and numerical concepts of the study.

2.1. Differential Form of Parsons' Law

The differential form of Parson's Law describes how the thickness (or cross-section) of a metal pipeline decreases over time due to corrosion. This law is particularly useful in predicting wall loss progression, which is essential in pipeline integrity assessment. In the differential form, the law relates the instantaneous rate of corrosion penetration to time and other environmental or material parameters. This helps determine remaining wall thickness, time-to-failure, and reliability under probabilistic modelling frameworks. The generalized differential form can be expressed as:

$$\frac{dW(t)}{dt} = -k\,W(t)^n \quad (1)$$

Where:

- $W(t)$ = wall thickness at time t (mm)
- k = corrosion rate constant (mm/year or mm/s, depending on units)
- n = corrosion reaction order (dimensionless, typically $0 \le n \le 2$)
- t = time (years or seconds)

Integrated Form (For Practical Prediction):

By solving the differential equation:

If $n \neq 1$:

$$W(t) = [W_0^{1-n} - k(1-n)t]^{\frac{1}{1-n}} \quad (2)$$

If $n = 1$:

$$W(t) = W_0\,e^{-kt} \quad (3)$$

Where:

W_0 = initial wall thickness at $t = 0$

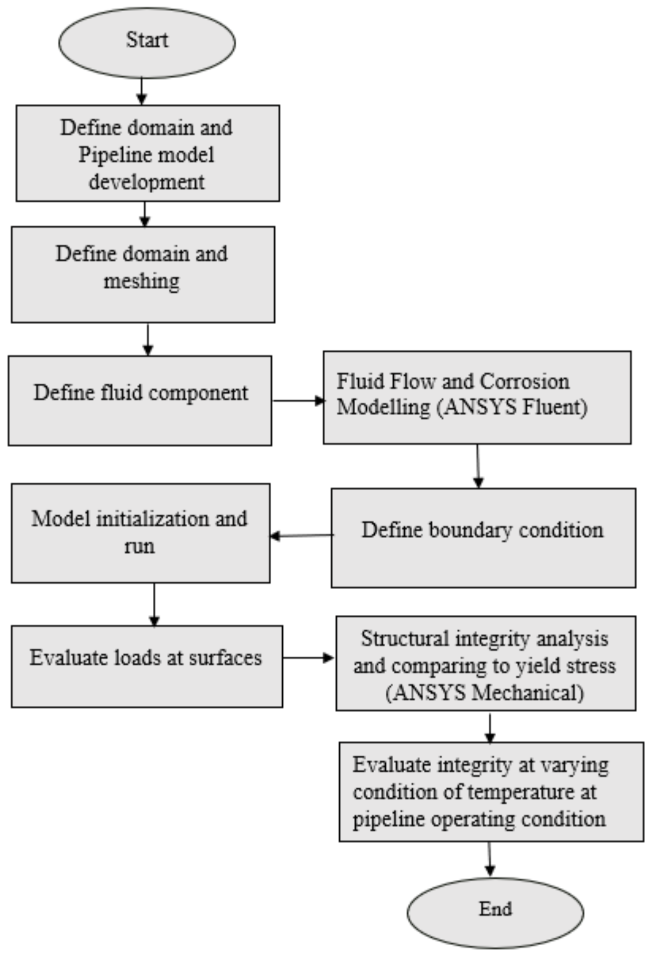

Figure 1. Simulation work flow.

Table 1. Pipeline Characteristics.

Parameter	Value
Inner Diameter (ID)	244.5 mm
Wall Thickness	14.275 mm
Yield Strength (YS)	448 MPa
Tensile Strength (TS)	531 MPa
Young's Modulus (E)	207 GPa
Poisson's Ratio (v)	0.3
Density (ϱ)	7850 kg/m³
Roughness	0.000028 m
Specific heat	500 J/Kg K
Operating pressure	197.7bar
Operating temperature	(30-70) °C

Von Mises stress:

$$\sigma_{vm} = \sqrt{\begin{matrix} 1/2\left[(\sigma_x - \sigma_y)^2 + (\sigma_y - \sigma_z)^2 + (\sigma_z - \sigma_x)^2\right] + \\ 3(\tau_{xy}^2 + \tau_{yz}^2 + \tau_{zx}^2) \end{matrix}} \quad (4)$$

Where:

$\sigma_x, \sigma_y, \sigma_z$ = normal stresses in x, y, z directions (MPa or N/mm²)
$\tau_{xy}, \tau_{yz}, \tau_{zx}$ = shear stresses in xy, yz, zx planes (MPa)
σ_{vm} = von Mises equivalent stress (MPa), used for yield/failure criterion.

2.2. Time-to-Failure Estimation (Using Corrosion Growth Rate)

Time-to-failure (TTF) is crucial for planning inspections and mitigation before corrosion progression leads to failure. It offers a time-based prediction of pipeline failure if corrosion continues at the current rate. This is critical in risk-based maintenance planning.

$$\mathrm{TTF} = \frac{t_r - t_{crit}}{\mathrm{CR}} \quad (5)$$

Where:

TTF = Estimated time to failure (years),
Tr = Current wall thickness (mm),
t_{crit} = Critical wall thickness below which failure is expected (mm), CR = Corrosion rate (mm/year)

2.3. ANSYS-based Simulation procedure

The CFD simulation was conducted under steady-state conditions to capture the flow and mass transfer characteristics governing corrosion behavior within the pipeline. The simulation procedure used in the simulation is highlighted thus: The simulation procedure began by modelling a pipeline segment in Design Modeller, with a length of 10 m, an inner diameter of 244.5mm, and a wall thickness of 14.275 mm. The chosen 10 m length represents about 0.23% of the actual pipeline length and was adopted to reduce computational demand in ANSYS. After geometry creation, the fluid domain was generated, and the model was transferred to the meshing module, where suitable meshing was applied. The pipe geometry was then imported into ANSYS Fluent for CFD computation, with the solid body suppressed to focus on fluid–structure interaction. Within Fluent, the corrosion model was defined, the Ω-based viscosity model was applied, the flow components were set, and the corrosion reaction equation was embedded in the material properties. The model was initialized from the inlet conditions, with 100s of computational time required for the solver to reach convergence and obtain a stable solution, and CFD simulations were performed to capture both fluid flow and corrosion behaviour.

The results from Fluent were subsequently transferred into ANSYS Mechanical (Static Structural) for one-way coupling analysis, where the fluid body was suppressed, the mesh was refined, pipe material properties were defined, and all structural settings were applied. The simulation was run for 100 seconds, with solver convergence time, to evaluate the stress distribution on the pipeline wall. Finally, the entire procedure was repeated at 30°C, 50°C, and 62°C (the base case) to assess how varying temperature affects corrosion intensity and pipeline stress response.

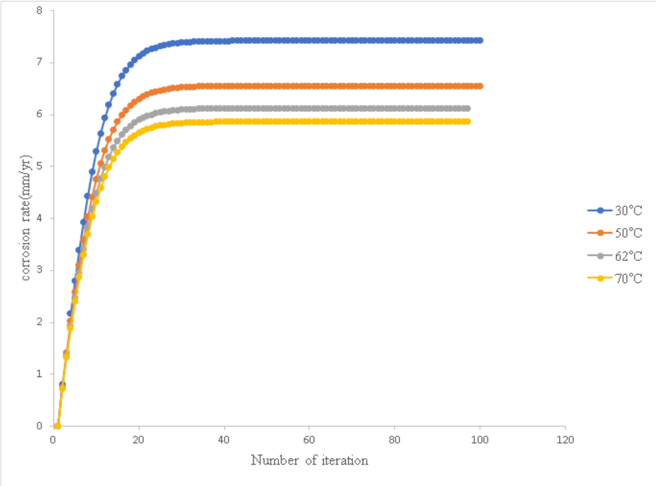

Figure 2. Corrosion Rate Under Varying Temperature.

Table 2. Fluid Composition.

Component	Molar %
C1	72.3926
C2	3.9559
C3	1.9255
iC4	0.4267
nC4	0.8707
iC5	0.2657
nC5	0.3694
C6	0.6521
C7	0.8089
C8	0.9728
C9	0.9472
C10	0.8035
C11	0.8183
C12	0.7203
C13	0.6129
C14	0.6856
C15	0.7077
C16	0.5276
C17	0.4486
C18	0.4802
C19	0.4234
$C20^+$	8.0818
N_2	0.1026
CO_2	2.0000

The simulation for this research work shall follow a stepwise procedure, as illustrated in the flowchart in Figure 1. The parameters used in this study are categorized as shown in Table 1 and 2.

3. Results and Discussions

3.1. Corrosion Rate of Pipeline at Varying Fluid Temperature

Figure 2 illustrates the corrosion rate profile at the pipe wall across distinct conditions. At 30°C, the corrosion rate reaches the highest steady-state value of approximately 7.4–7.5 mm/yr, consistent with higher CO_2 solubility and more aggressive acidic conditions at lower temperature. The curve shows a fast rise and early convergence, indicating stable reaction kinetics and strong driving forces for metal dissolution. At 50°C, the corrosion rate stabilizes around 6.5–6.6 mm/yr. Although still relatively high, it is lower than in the 30°C case, indicating reduced CO_2 solubility and the onset of a protective $FeCO_3$ film that slightly suppresses wall dissolution. At 62°C, the corrosion rate further decreases to approximately 6.0 mm/yr due to protective films formed by corrosion products. This trend reflects a more pronounced formation of iron carbonate ($FeCO_3$) layers at higher temperatures, which limits the active surface area exposed to corrosive species. The 70°C case shows the lowest steady-state corrosion rate at approximately 5.8–5.9 mm/yr. This behaviour is consistent with thermodynamic and kinetic predictions of CO_2 corrosion: at higher temperatures, protective films form more rapidly and adhere better, thereby decreasing corrosion severity despite elevated fluid temperature. The analysis was validated and its follow similar trends to the work of [23], [24].

3.2. Equivalent (Von Mises) Stress Distribution on the Pipeline at Different Fluid Temperatures

The plot in Figure 3 illustrates the variation of equivalent (Von Mises) stress in the pipeline system at operating temperatures of 30°C, 50°C, 62°C, and 70°C, and the trend reflects the combined influence of temperature-dependent corrosion behaviour and thermomechanical loading on the pipe wall. At 30°C, the stress level is approximately 20.394 MPa, which corresponds to a condition where the corrosion rate is at its peak due to high CO_2 solubility and unstable $FeCO_3$ film formation. The high corrosion rate at this temperature results in measurable wall thinning, thereby elevating mechanical stress, even though the temperature is relatively low. As the temperature increases to 50°C, the equivalent stress decreases to 17.999 MPa, the lowest observed in the analysis. This reduction is consistent with the previously observed corrosion trend in this temperature range, partial stabilization of $FeCO_3$ films reduces metal dissolution, resulting in a slower corrosion rate and, consequently, lower wall degradation. The structural response at 50°C, therefore, represents a transition zone in which the pipeline experiences minimal combined corrosive and thermal effects.

However, as the operating temperature increases to 62°C, the equivalent stress rises sharply to 25.524 MPa, the highest recorded in the simulation. This increase occurs despite the corrosion rate being significantly lower at high temperatures, indicating that the dominant factor in this regime is the steel's thermomechanical response. At elevated temperatures, steel undergoes reduced stiffness (lower modulus), increased thermal expansion, and amplified internal pressure effects, all of which contribute to

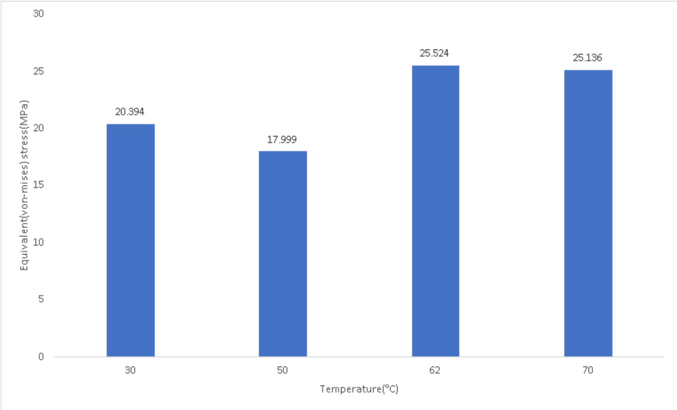

Figure 3. Stress with Varying Temperature.

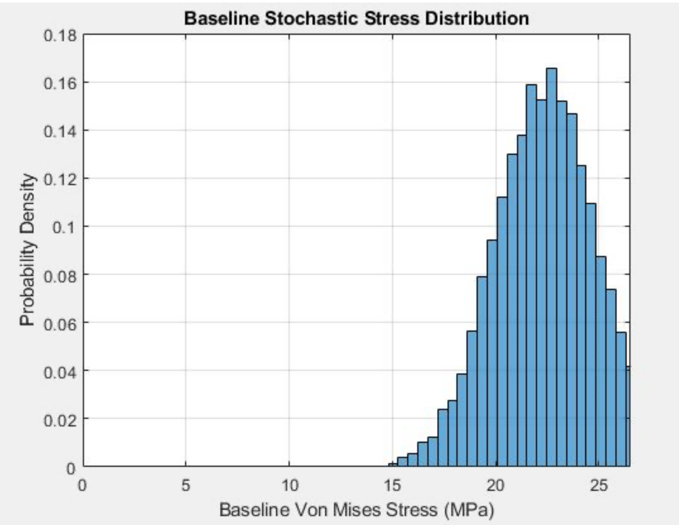

Figure 4. Equivalent stress distribution on the pipeline.

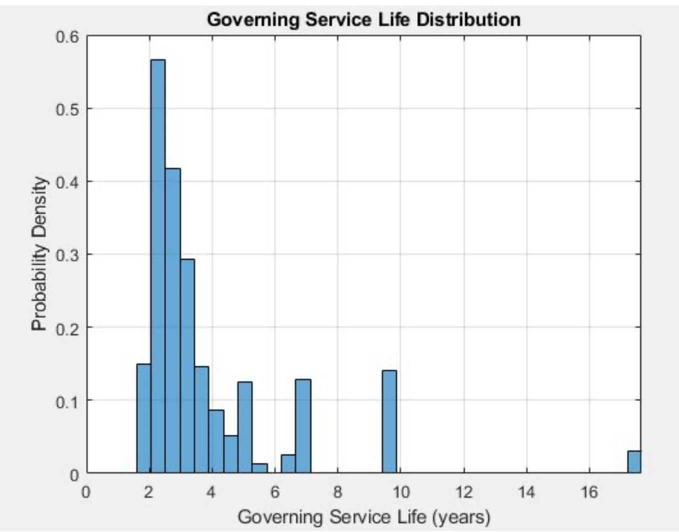

Figure 5. Remaining service life of the pipeline.

higher Von Mises stress even in the presence of a more protective and stable $FeCO_3$ layer. A similar pattern is observed at 70°C, where the stress reaches 25.136 MPa. Although marginally lower than the stress at 62°C, it remains high, confirming that thermal effects overshadow corrosion mechanisms at elevated temperatures.

3.3. Probabilistic Pipeline Integrity Assessment

3.3.1. Von Mises Stress Distribution

The stochastic Von Mises stress distribution shown in Figure 4 exhibits a relatively narrow probability spread, ranging from approximately 14.9 MPa to about 27 MPa. This indicates that under the combined influence of corrosion variability, temperature fluctuations, and internal pressure, the pipeline operates within a stable stress regime.

The highest probability density occurs around 22–23 MPa, representing the most probable stress state of the pipeline. This region reflects moderate corrosion, with wall thinning that has not significantly compromised the pipeline's structural capacity. A smaller fraction of realizations is observed within the lower stress band of 14.9–20 MPa, corresponding to conditions of relatively low corrosion rates and higher effective wall thickness.

On the upper end, the distribution extends toward approximately 24–27 MPa, indicating less frequent but more severe operating conditions characterized by increased corrosion penetration and reduced wall thickness. These higher stress values result from the amplification of internal pressure effects caused by material loss along the pipeline wall. However, the occurrence of such conditions remains limited, as reflected by the lower probability density in this region.

The relatively compact distribution suggests that the pipeline response is not highly sensitive to variations in the governing parameters within the investigated range. While corrosion contributes to increased stress through wall thinning, the magnitude of this increase remains moderate across most realizations. This indicates that the pipeline's structural behaviour remains stable under varying operating conditions.

All stress values from the probabilistic analysis remain significantly below the material yield strength of 448 MPa, indicating that failure by yielding is unlikely within the current operating envelope. Nevertheless, the presence of higher stress realizations highlights the progressive impact of corrosion on structural integrity, emphasizing the need for continuous monitoring and maintenance

3.3.2. Estimation of Life Distribution

Figure 5 presents the stochastic remaining life distribution of the pipeline, illustrating the probabilistic outcomes of its expected service duration under varying operating conditions and corrosion scenarios. The distribution is noticeably right-skewed, with a strong concentration of results in the lower service-life range.

The highest probability density is observed at approximately 2–3 years, indicating that this represents the most probable service life of the pipeline under the simulated conditions. This peak reflects the dominance of relatively high corrosion rates, which accelerate wall thinning and shorten the time to critical failure conditions.

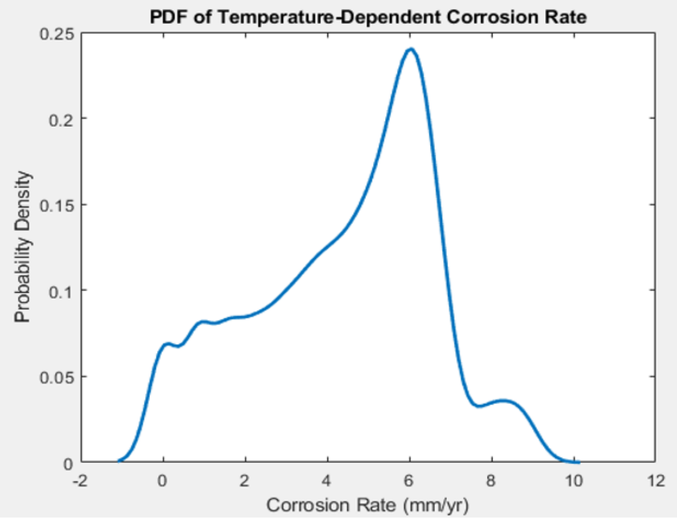

Figure 6. Corrosion Rate Probability Density Function (PDF).

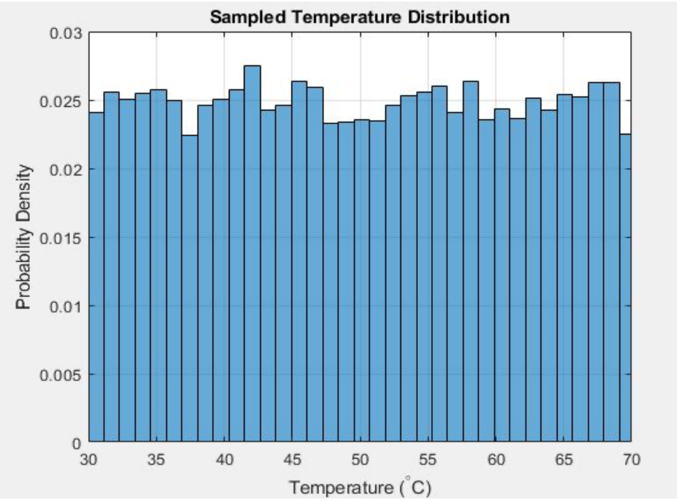

Figure 7: Temperature Distribution.

A significant portion of the realizations falls within the range of approximately 1 to 4 years, suggesting that the majority of operating scenarios result in relatively short service durations. This concentration highlights the severity of the corrosion environment and its strong influence on pipeline longevity.

The distribution exhibits a diminishing tail extending beyond 4 years, with very few realizations reaching higher service life values. These outcomes are associated with lower corrosion rates and more favourable operating conditions, where material degradation progresses more slowly. However, the low probability density in this region indicates that extended service life is unlikely under typical conditions.

3.3.3. Corrosion Rate Probability Density Function (PDF)

Figure 6 illustrates the probability density function (PDF) of the temperature-dependent corrosion rates sampled during the Monte Carlo simulations. The PDF reveals an initial sharp increase in the lower corrosion rate range (0–2 mm/year), suggesting a large fraction of pipe segments are exposed to mild corrosion conditions. The distribution then peaks around 6–6.5 mm/year, corresponding to higher temperatures and more aggressive corrosive conditions. Beyond this peak, the density gradually decreases, indicating that extremely high corrosion rates are less probable. The analysis results resonate with previous research conducted by [25]. This profile provides insight into the most likely corrosion scenarios affecting the pipeline, enabling focused maintenance planning and validating the current research outcomes.

3.3.4. Temperature Distribution

Figure 7 presents the distribution of temperatures sampled across all Monte Carlo realizations, illustrating the variability of thermal conditions within the pipeline system. The distribution appears approximately uniform across the 30–70°C range, reflecting the sampling strategy used in the probabilistic analysis. The relatively even spread of temperature values indicates that all operating conditions within the specified range are equally represented in the simulation. This ensures that the analysis captures both low-temperature and high-temperature scenarios without bias toward any specific condition. As a result, the probabilistic framework provides a comprehensive assessment of the thermal influence on corrosion behaviour and structural response.

Despite the overall uniformity, minor fluctuations in frequency may be observed across certain temperature intervals. These variations are attributed to the randomness inherent in the sampling process and do not indicate any dominant temperature regime. Instead, they reflect the stochastic nature of the Monte Carlo simulation. The temperature distribution plays a critical role in interpreting both the corrosion rate and the resulting structural behaviour of the pipeline. As temperature influences reaction kinetics and mass transfer, variations within this range directly contribute to the observed spread in corrosion rates. In particular, higher temperatures tend to enhance corrosion activity under certain conditions, while also influencing the formation of protective surface films that may reduce corrosion rates at elevated levels.

4. Conclusion

The current study demonstrates the application of an integrated probabilistic finite element method to predict corrosion rates and assess the integrity of a corroded oil and gas pipeline. Intelligent pig surveys and modelling indicate that pipeline wall loss in certain sections exceeds 5 mm, corresponding to an average corrosion rate exceeding 4 mm/year. This observation closely aligns with the corrosion rates obtained in the current ANSYS Fluent simulation, providing a credible benchmark for model validation. The study further highlights that corrosion rates are influenced by factors such as CO_2 partial pressure and temperature, which are also accounted for in the parametric impacts on pipeline integrity. The following are key outcomes of the model application.

1) The pipeline was accurately modelled and meshed in ANSYS, achieving high mesh quality and stable element behaviour, which ensured reliable numerical convergence during the coupled Fluent–Mechanical analysis.
2) Corrosion showed a non-linear temperature dependence: it increased sharply at 30–50°C due to incomplete protective film formation, but decreased at 62–70°C as stable $FeCO_3$ layers developed, aligning with known CO_2 corrosion behaviour in carbon steel pipelines.
3) The equivalent stress also varied non-linearly, ranging from 17.99 MPa at high corrosion to about 2.5.524 MPa at low corrosion, confirming that uniform wall thinning significantly influences structural loading even under constant internal pressure.
4) Probabilistic stress evaluation indicates the pipeline remains within safe limits but with rising uncertainty at higher corrosion levels, suggesting the need for frequent inspection; with corrosion reaching up to 7.4 mm/year, maintenance should occur within a one-year operational cycle.

The proposed model provides a technical insight into the development of the pipeline management strategy for sustainable operation. Nevertheless, the model can be improved in future research by considering a dynamic algorithm that integrates the nonlinearity in the corrosion influencing parameters for an improved integrity management.

5. Nomenclature and Abbreviations

Abbreviations	Meaning
(NPS)	Nominal Pipe Size
(OD)	Actual Outside Diameter
(YS)	Yield Strength
(TS)	Tensile Strength
(E)	Young’s Modulus
(v)	Poisson’s Ratio
(ϱ)	Density
API	American Petroleum Institute
VIV	Vortex Induced Vibration
3D	3 – Dimensional

6. Declarations

6.1. Author Contributions

Million Matthew Nrior: Conceptualization, Methodology, Software, Validation, Writing - Original Draft, Formal analysis, Investigation, Resources; **Samson Nitonye:** Formal analysis, Investigation, Resources, Writing - Review & Editing, Visualization, Supervision, Project administration; **Sidum Adumene:** Formal analysis, Investigation, Resources, Writing - Review & Editing, Visualization, Supervision, Project administration; **Charles Ugochukwu Orji:** Writing - Review & Editing, Visualization, Supervision, Project administration.

6.2. Institutional Review Board Statement

Not applicable.

6.3. Informed Consent Statement

Not applicable.

6.4. Data Availability Statement

The data presented in this study are available on request from the corresponding author.

6.5. Acknowledgment

Not applicable.

6.6. Conflicts of Interest

The authors declare no conflicts of interest.

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