International Journal of Software Engineering & Applications (IJSEA), Vol.15, No.4, July 2024

EVALUATING THE IMPACT OF ENVIRONMENTAL FACTORS ON CORROSION RATES IN OFFSHORE OIL AND GAS PIPELINES: INSIGHTS FROM THE LEVANTINE BASIN

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ABSTRACT

The Levantine Basin is an important area for oil and gas exploration. However, the region's high salinity and corrosive conditions significantly threaten the durability of pipelines and equipment, resulting in substantial maintenance and repair expenses. This study seeks to evaluate the environmental and industrial influences on the corrosion rates of different oil and gas streams within the Levantine Basin.

This study collected and analyzed data from the Levantine Basin, including physical and chemical properties of the streams, environmental factors such as temperature, pressure, and humidity. The Larkton corrosion software was utilized to simulate and predict corrosion rates under various conditions. Findings of this experiment demonstrate the significance of temperature on corrosion rates, showing a marked increase as temperatures rise. At lower temperatures, H_2S corrosion is more prominent, whereas CO_2 corrosion becomes the dominant factor at medium to high temperatures, especially when coupled with high CO_2 concentrations.

KEYWORDS

Corrosion Rates, Levantine Basin, Oil and Gas Streams, Environmental Factors, Industrial Factors, H_2S, CO_2, Temperature, Corrosion Inhibitors

1. INTRODUCTION

Situated in the eastern Mediterranean Sea, the Levantine Basin has emerged as a key area for oil and gas exploration and production, thanks to its abundant hydrocarbon reserves.However, the high saline and corrosive environment of the Mediterranean Sea presents significant challenges to the integrity of pipelines and equipment. Corrosion is a major concern in the oil and gas industry, leading to substantial maintenance and repair costs. Historical accidents, such as the BP oil spill in the Gulf of Mexico and the Exxon Valdez oil spill, highlight the devastating consequences of corrosion-related failures [1].

To address these challenges, this research aims to assess the environmental and industrial factors affecting corrosion rates in the Levantine Basin and monitor the economic impact of the results. The study focuses on various oil and gas streams, considering factors such as temperature, pressure, humidity, and the materials used in pipelines and equipment [2][3].

The Larkton corrosion software was used in the experimental part of this study to simulate and predict corrosion rates under various conditions. The software considers multiple factors, including temperature, pressure, pH, and the presence of CO_2 and H_2S, to provide accurate corrosion rate predictions [4]. This tool is essential for comprehending the intricate interactions between environmental and industrial factors that impact corrosion rates.

Data from various oil and gas fields in the Levantine Basin were gathered and analyzed, with a focus on the physical and chemical properties of the streams, as well as environmental factors like temperature, pressure, and humidity. The Larkton corrosion software played a vital role in predicting and analyzing these corrosion rates under different conditions [5].

2. LARKTON SOFTWARE

Larkton Corrosion Software: This software was launched by Larkton LTd, a company found in 2018 in UK, for the aim of reaching new standards in analysing corrosion rates. For this aim to be reached, the development team of this software was consistent on re-analysing carbon dioxide and hydrogen sulfide corrosion models and recent experiments and data. Moreover, revision of recent industry experience and information inspection was applied. Furthermore, they overtook the business processes and essentials for material and corrosion engineers in the modern industrial epoch; where their focus was on productivity and efficiency advancing. This software offers its user many editing choices in the input section; where many accurate data can be entered in each section as verified in table (1).[6]

Table 1. Alloy Select Software Sections and Components.

Section	Components
Pipeline Design	Distance Elevation Outside Diameter Total Wall Thickness Temperature Pressure Carbon Content Steel
Fluid Parameters	Water Flow Rate Oil or Condensate Flow Rate Gas Flow Rate CO2 in Gas CO2 in water H2S in Gas H2S in Water Glycol Injection Rate Oil Density Standard Gas Density Z- Factor Erosional Factor
Water Analysis	Bicarbonate Ions Acetic Acid NaCl in water Iron Saturation Lithium Sodium Pottasium Magnesium Calcium

3. EXPERIMENTAL:

3.1. Input Data:

3.1.1. Concerning the Pipeline Design:

- Distance: 10 kms
- Elevation: 1200 m
- Outside Diameter: 0.3556 m
- Total Wall Thickness: 9.53 mm
- Temperature: • Pressure: 955 psi(a)
- Carbon Content of steel: 0.31 wt%

3.1.2. Concerning the Fluid Parameters, Formulas & Calculations:

-Formulas:

a) Q (gas)= mRTZ/144P
b) M= rVA
c) r=m/v

2.2. Calculations:

By using compressibility table :
Z= (1.0210+1.0234+1.0287+1.0323)/4= 1.02635
R= 8.20573 m^3atm/mol/k
m= dxVxA
Water flow rate= 360∏xVx (d/2) ^2
Density of natural gas= 0.8 kg/m3

- Water Flow Rate: 19.285008 sm3/d
- Oil or Condensate Flow Rate: 17.531832 sm3/d
- Gas Flow Rate: 250 MMSCFD • CO2 in Gas: variable
- CO2 in water: 0 ppmw
- H2S in Gas: variable
- H2S in Water: 0 ppmw
- Glycol Injection Rate: 250000 kg/MMSm3
- Oil Density: 0.8 g/cm3
- Standard Gas Density: 0.8 kg/m3
- Z- Factor: 1.02635 (based on Z-factor graph)
- Erosional Factor: 90 (kg/m)^0.5/s (minimum value, in order not to influence corrosion rates)
- Distance= 20 km
- Elevation= 200m
- Outside Diameter: 0.3556 (Based on ASME standard Parameter)
- Z= 1.0263075
- Pipe Grade: JIS
- Pipe Size= 13.124

Note that Pipe Size, Diameter, Temperature and Pressure are set based on Pipe ASME Chart and Carbon Steel Pipeline Pressure Temperature Charts.

3.2. Water Analysis

- Bicarbonate Ions: 0 ppmw
- Acetic Acid: 0 ppmw
- NaCl in water: 0.38803 g/L
- Lithium: 0.170 ppmw
- Sodium: 11.800 ppmw
- Pottasium: 463 ppmw
- Magnesium: 1.403 ppmw
- Calcium: 423 ppmw

In the upcoming parts, different cases were taken; where the first part represents the results of the obtained corrosion rates at elevated temperature and CO2 percentages, where there is no H2S present(H2S=0%). On the other hand, the 2nd part represents the results of corrosion rates for the case were no CO2 is present and results are obtained under elevated temperature and H2S percentages. Note that these 2 cases were taken in the aim of restricting the effect of temperature on H2S and CO2 corrosion rates individually.

The rest of the cases are about different combinations for different percentages of each of CO2 and H2S in order to reveal the effect of temperature on these different cases of mixtures.

3.3. Experiment 1

H2S is set at 0 mol%, and a gradual increase in CO2 % was done at gradual increased values of temperature that ranges between 0˚C and 200˚ C. The results are illustrated by curves in the graph of figure (1).

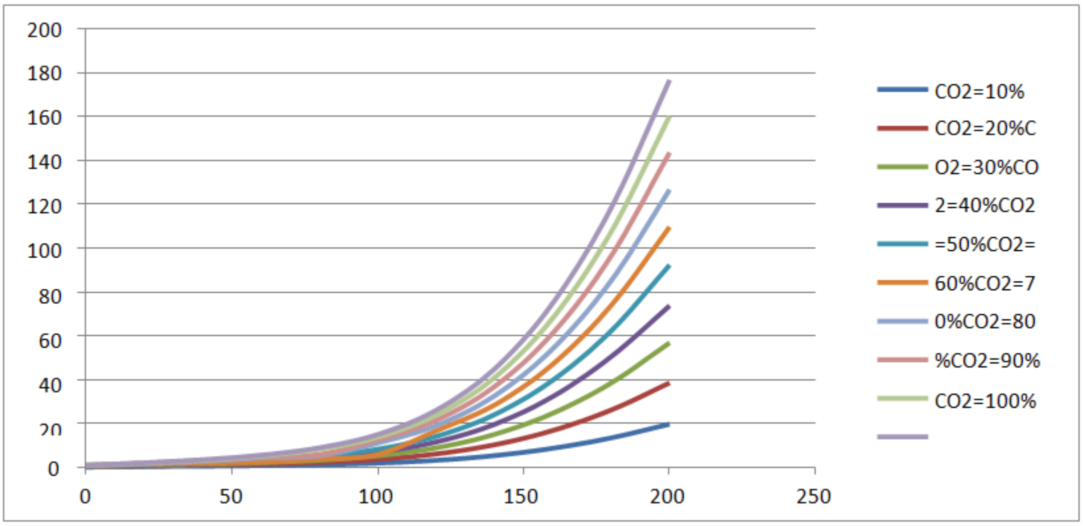


Figure 1. Graph representing inlet corrosion rate variation as a function of temperature and CO2 %s at H2S%= 0%.

3.3.1.Analysis

As figure (1), representing pipeline inlet corrosion rate variation as temperature increases from 0 till 200˚ C for different cases of CO2 percentages (from 0% up to 100%), where H2S percentage is fixed at zero, reveals, when CO2 percentage is 10%, and as temperature increases from 0˚C to 10˚C, inlet corrosion rate increases from 0.16 mm/year to 0.33 mm/year, where a very slight increase is noticed as temperature increases from 15˚C till 60˚C. However, when reaching 80˚C, corrosion rate encounters a noticeable increase where it reaches 1.28 mm/year. Yet, this increase rate is reduced when temperature increases from 80˚C to 100˚C, but is then regained as temperature increases from 100˚C to 120˚C all the way till 200˚C, where as temperature increases from 120˚C to 140˚C, corrosion rate increases from 3.28 mm/year to 5.42 mm/year, and as temperature increases from 160˚C to 180˚C to 200˚C, corrosion rate increases from 8.77mm/year to 13.52mm/year till reaching 19.80mm/year. Moving to the next case, 0 20 40 60 80 100 120 140 160 180 200 0 50 100 150 200 250 CO2 =10% CO2=20% CO2=30% CO2=40% CO2=50% CO2=60% CO2=70% CO2=80% CO2=90% CO2=100% 133 | P a g e where CO2 percentage is increased to 20%, similar results were noticed but with higher rates; where when temperature increases from 0˚C to 20˚C, slight corrosion rate increase was noticed, where it increases from 0.41 mm/year to 0.62 mm/year at 10˚C, then reaches 0.55 mm/year and 0.70 mm/year as the temperature increases from 15˚C to 20˚C. Then, as temperature rises till 40 ˚C, corrosion rate increases to reach 1.07 mm/year. Corrosion rate keeps increasing correspondingly to reach 1.57 mm/year, 2.36 mm/year and 3.75 mm/year at 60˚C, 80˚C and 100˚C correspondingly. However, corrosion rate increase doubles when reaching 120˚C, where it records 6.23 mm/year, then re-decreases at 140˚C, but remains higher than the previous rate, , where the recorded corrosion rate is 10.40 mm/year. Nevertheless, this increasing rate re1increases when temperature reaches 160˚C; where corrosion rate reaches 16.95 mm/year, followed by 26.28 mm/year and 38.64 mm/year at 180˚C and 200˚C. The increase in corrosion rates is proportional to that obtained in CO2; where as shown in the adjacent figure, as temperature increases, corrosion rates increase for all percentages of CO2, and as CO2 percentages increase, corrosion rate increase becomes more rapid. Thus, as temperature increases, rate of increase of corrosion is experiencing a noticeable increase.

3.4. Experiment 2

CO2 is set at 0 mol%, and a gradual increase in H2S % was done at gradual increasing values of temperature that ranges between 0˚C and 200˚ C. The results are represented by table not by graph since the obtained values are so close and indistinct in the form of curves.

Table 2. Inlet Corrosion Rate Variation as a Function of Temperature and CO2 %s at H2S%= 0%

	CR (mm/year)									
	H2S%									
Temperature	10	20	30	40	50	60	70	80	90	100
0	0.37	0.44	0.48	0.52	0.55	0.57	0.59	0.60	0.62	0.63
10	0.46	0.53	0.58	0.62	0.64	0.66	0.68	0.70	0.71	0.72
15	0.51	0.58	0.63	0.66	0.69	0.71	0.73	0.74	0.75	0.77
20	0.56	0.63	0.68	0.71	0.74	0.76	0.77	0.79	0.80	0.81
40	0.77	0.84	0.88	0.91	0.93	0.95	0.96	0.97	0.98	0.99
60	1.04	1.11	1.14	1.17	1.19	1.20	1.21	1.22	1.22	1.23
80	1.46	1.53	1.57	1.59	1.61	1.62	1.63	1.64	1.64	1.65
100	2.22	2.29	2.33	2.36	2.37	2.39	2.40	2.41	2.41	2.42
120	3.57	3.65	3.70	3.73	3.75	3.76	3.78	3.78	3.79	3.80
140	5.80	5.91	5.97	6	6.03	6.05	6.06	6.07	5.67	6.09
160	9.28	9.42	9.49	9.53	9.56	9.59	9.60	9.62	8.89	9.64
180	14.19	14.36	14.44	14.50	14.54	14.57	14.59	14.61	13.33	14.63
200	20.64	20.84	20.95	21.01	21.06	21.09	21.12	21.14	19.02	21.17

3.4.1. Analysis

As shown in table (2), and in comparison with the previous case (figure 1), it's noticed that in the 1st 2 cases; where H2S= 10% and 20% and in the absence of H2S, the obtained corrosion rates are higher than the ones obtained in the same temperature conditions in the previous case; where are higher than the opposite previous case when H2S= 10% and 20%, corrosion rates obtained are way less than the opposite previous case; where for example the obtained corrosion rate when H2S= 10% at a temperature of 10˚C, 60˚C, 140˚C and 200˚C are correspondingly 0.46 mm/year, 1.04 mm/year, 5.80 mm/year and 20.64 mm/year. Conversely, in the previous scenario with opposite conditions (20% CO2 and 0% H2S) and the same temperature settings, higher corrosion rates were observed. The corrosion rates at 10˚C, 60˚C, 140˚C, and 200˚C were 0.16 mm/year, 0.88 mm/year, 5.42 mm/year, and 19.80 mm/year, respectively.

Also, for the case where H2S= 20% & CO2= 0%, corrosion rate obtained at 0˚C (0.44 mm/year) is greater than that obtained corrosion rate in the case where CO2= 20% & H2S= 0% (0.41 mm/year). Yet, after this temperature value, all the remaining cases witnessed higher corrosion rates in the presence of CO2. For example, when CO2= 30% at 100˚C, the recorded corrosion rate is 5.38 mm/year, whereas that recorded at the same temperature at 30% of H2S is 2.33 mm/year. This case continues as the values of H2S and CO2 increase in parallel with increasing temperature.

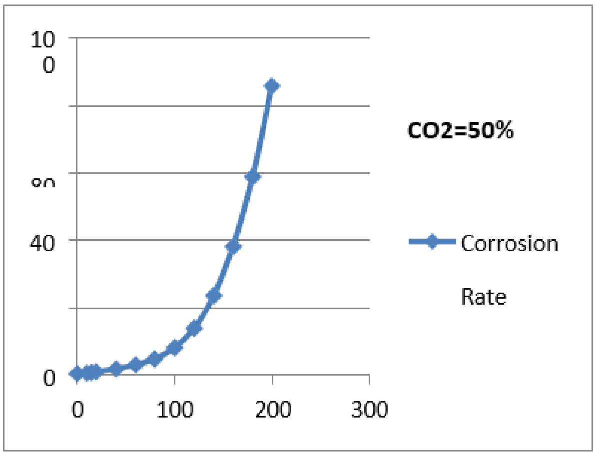
Thus, at very low temperature, and in the presence of very concentrations of H2S and CO2, H2S corrosion is being more effective than CO2 corrosion. On the other hand, CO2 corrosion is way more effective than H2S corrosion at medium and high temperature ranges.

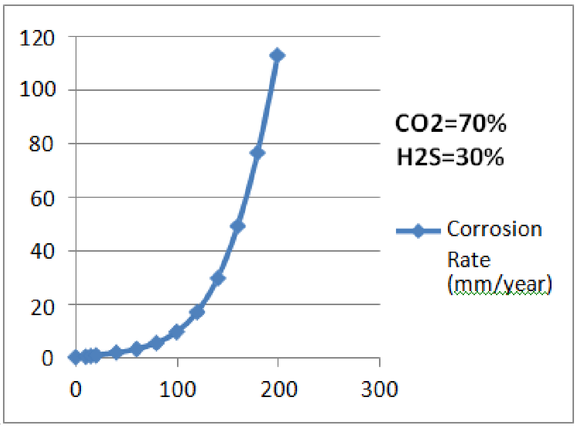
3.5. Experiment 3

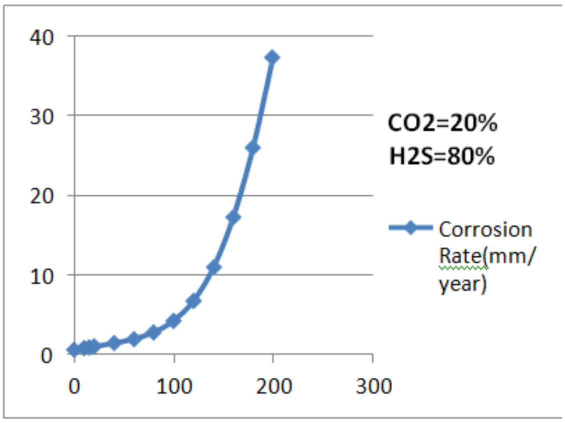
Fourcases of a plenty of compositions were taken. Each composition contains different % combinations of CO2 & H2S; where there are cases with:

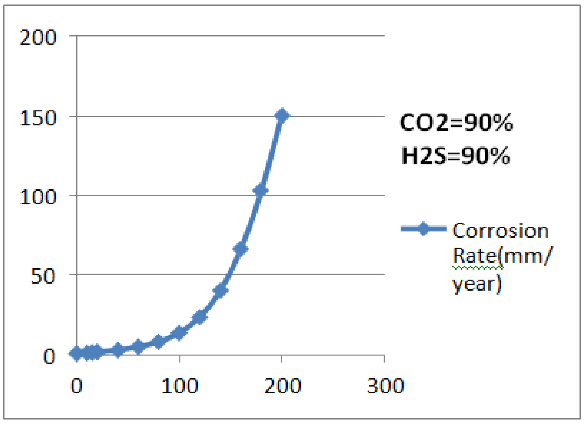
1- Low percentage of H2S with high CO2 percentage
2- Low percentage of H2S with low CO2 percentage
3- High percentage of H2S with low CO2 percentage
4- High percentage of H2S with high CO2 percentage

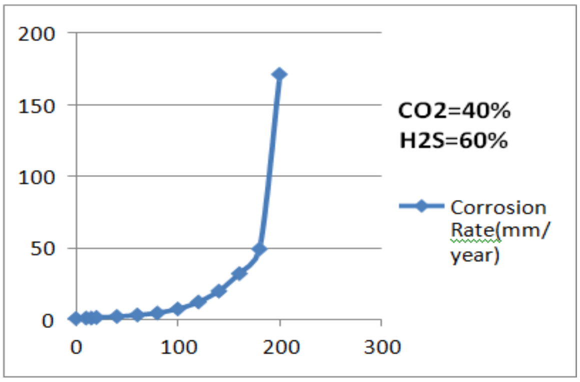
Resulted corrosion rates of each composition mixture are represented individually by a graph. The following graphs represent the obtained corrosion rates as a function of temperature (from 0˚C till 200˚C).

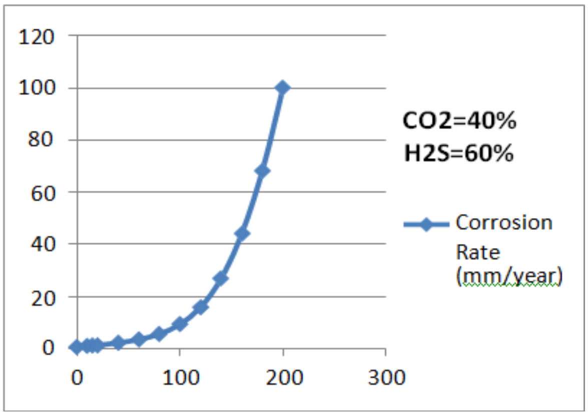


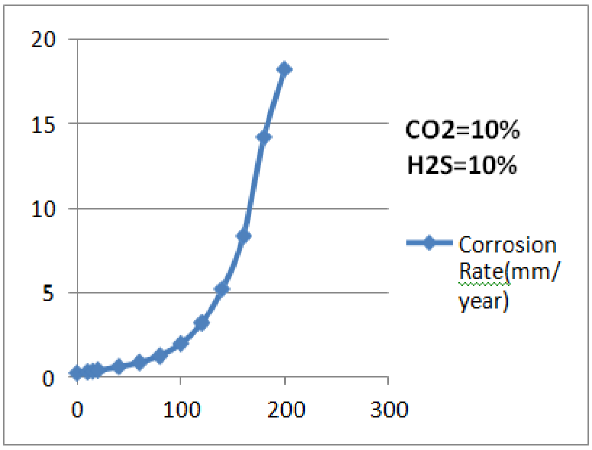

120
100
80
60
40
20
0
0
100
200
300
CO2=70%
H2S=30%
Corrosion Rate (mm/year)


40
30
20
10
0
0
100
200
300
CO2=20%
H2S=80%
Corrosion Rate(mm/year)


200
150
100
50
0
0
100
200
300
CO2=90%
H2S=90%
Corrosion Rate(mm/year)


200
150
100
50
0
0
100
200
300
CO2=40%
H2S=60%
Corrosion Rate(mm/year)





3.5.1. Analysis

Among the results designated by the tables, the lowest recorded corrosion rates values were noticed in the composition where 10% of each of CO2 and H2S is present from temperature 0 till 200, where the minimum attained corrosion rate is 0.23 mm/year at 0 ˚C and 18.17 mm/year at 200˚C, followed by the case where the composition contains 80% H2S and 20% CO2, where the minimum attained corrosion rate is 0.64 mm/year at 0˚C and a maximum corrosion rate of 37.22 mm/year at 200˚C. Then comes the case where the composition is about 70% H2S and 30% CO2, and the recorded maximum and minimum corrosion rates are 0.69 mm/year and 54.49 mm/year at 0˚C and 200 ˚C correspondingly. On the same trend, as H2S % decreases till 60% and CO2 % increases till 40%, the obtained corrosion rates are in a continuous increasing matter; where the maximum and minimum recorded corrosion rates are 81.22 mm/year and 0.71 mm/year. Following this case, is the case where 50% of each of CO2 and H2S is present in the composition; where the minimum recorded corrosion rates are so close to the ones recorded in the previous case. Yet, when the temperature exceeds 120 ˚C, corrosion rates start to vary noticeably from the ones in the previous case; to record a maximum corrosion rate of 98.81 mm/year. Subsequently, as CO2 % continues in increasing to reach 60% and that of H2S continues in decreasing to reach 40%, corrosion rate at 0˚C slightly decreases, to re-increase but in an inappreciable manner. This situation pursue until temperature exceeds 120˚C, where corrosion rate expansion starts to take place gradually with temperature increase, till it reaches a maximum corrosion rate at 200˚C equivalent to 117.77 mm/year. Next comes the cases where the compositions components are of continuous CO2 increase and H2S decrease summed up by 3 cases of composition mixtures of CO2 and H2S percentages correspondingly follows: with ratios of 70%-30%, 80%-20%, and 90%-10%, there is an increase in corrosion rates. The increase is minimal at low and medium temperatures, similar to previous cases, but becomes significant only after reaching 120°C. Yet, it's noticed that moving from the 2nd to the final case involves distinguishable increase in corrosion rates at lower degrees of temperature.

Therefore, at high temperatures, CO2 becomes the primary factor in increasing the corrosion rate. It is evident that high corrosion rates occur in the presence of both high temperatures and high CO2 levels. On the contrary, at low temperature, H2S is being more effective than CO2.

4. CONCLUSION:

This research aimed to evaluate the impact of environmental factors on corrosion rates in offshore oil and gas pipelines within the Levantine Basin through three key experiments.

The initial experiment examined the impact of temperature on corrosion rates.It was found that temperature plays a critical role in the corrosion process, with higher temperatures significantly increasing corrosion rates. At lower temperatures, H_2S corrosion was more prevalent, whereas at medium to high temperatures, CO_2 corrosion became the dominant factor, particularly when coupled with high CO_2 concentrations.

The second experiment focused on the influence of pressure on corrosion rates. The findings indicated that increased pressure exacerbates corrosion, particularly in environments with high levels of CO_2 and H_2S. The pressure-induced acceleration of corrosive reactions highlighted the need for robust pipeline materials and coatings to withstand high-pressure conditions.

The third experiment examined the combined effects of temperature, pressure, and other environmental factors such as humidity and salinity on corrosion rates. The results demonstrated that these factors interact synergistically to influence corrosion. For instance, high humidity and salinity levels, when combined with elevated temperatures and pressures, significantly intensified the corrosion rates.

Overall, the experiments underscored the complex interplay between various environmental factors in determining corrosion rates in offshore pipelines. The use of the Larkton corrosion software proved invaluable in simulating and predicting these rates under different conditions. The software's ability to account for multiple variables provided a comprehensive understanding of the corrosion mechanisms at play.

In conclusion, this research underscores the importance of ongoing monitoring and customized corrosion management strategies to mitigate the detrimental impacts of environmental factors on offshore oil and gas pipelines.The insights gained from these experiments contribute to improving the safety, reliability, and longevity of pipeline infrastructure in the Levantine Basin and similar environments.

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