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Influence of Temperature on CO_2 and H_2S Corrosion Rates of Steel Pipelines Using Alloy-Select Software in the Lebanese Oil and Gas Offshore Environment

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Abstract

By referring to the fact that corrosion rates alter upon variation of different conditions and no research relevant to Lebanon address corrosion issues yet, this study was conducted based on accurate Lebanese offshore data and water composition. Based on "Alloy Select Software", identifying the most suitable material from different alloys was revealed, which turned out to be Copper and Aluminum based alloys. Moreover, corrosion rates were detected under different conditions of Temperature, CO_2, and H_2S and then repeated in the presence of a corrosion inhibitor. Results of these studies proved the significant influence of high temperature accompanied with high CO_2 percentage. However, different results concerning low temperature with different percentages of H_2S were obtained.

Paper type: Research paper

Keywords: Corrosion, Lebanese offshore, CO_2, H_2S, temperature, oil, and gas industry.

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Introduction

Corrosion is a spontaneous type of attack on specific types of material (iron, steel, etc.), taking place due to different types of interactions between metals and the surrounding corrosive environment. What makes these environments corrosive is the presence of several factors, including organic and inorganic acids, high temperature and pressure, moisture, and so many other affecting factors (Kermani and Smith, 1997; Popov , 2008). The presence of these corrosion-leading conditions reduces the life span of equipment and compromise's structure safety. Moreover, it is considered a leading factor in the failure of many scopes' components such as chemical, petrochemical, transportation, and petroleum domains. These components include pipelines, casing, and pipes (Wood *et al*., 2013; Oyelami and Asere, 1999). This scenario is illustrated by petroleum companies losing up to several billions of dollars each year just because of corrosion. Oil and gas industries face many corrosion problems throughout all three stages (downstream, midstream, and upstream).

Furthermore, many reports worldwide have confirmed several losses in oil companies worldwide; these companies faced pipeline rupturing due to corrosion, leading to significant financial losses. It is proved that corrosion is considered one of the most dangerous problems in many industries, resulting in monumental economic sequels (Roberge, 2000; Cote *et al*., 2014). Many similar accidents occur each year in many places, where it's appraised that costs due to corrosion vary between 3% to 5% of the countries' gross national product. Moreover, the oil and gas industries are obliged to pay annually almost 1.4 billion dollars to compensate for the losses caused by corrosion. Almost pure 600 million dollars are due to the portion of losses taking place in pipelines.

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In the US, corrosion causes industries about 170 billion dollars/year, where oil and gas industries are mainly the cause of half of these costs (Golden, 1992; Revie, 1992; Trethewey *et al*., 1995). Besides, recently conducted studies revealed that the second leading cause of OGP failure between 2009 and 2018 was corrosion, forming 17% of these causes, as shown in **Figure 1**. (PHMSA, 2018). Furthermore, the second most fatal OGP accident, through history was due to corrosion, particularly pitting corrosion, where the accident took place in San Juanico, Mexico where this accident resulted in 650 fatalities, as shown in **Table 1** (Bhandari, 2015; Arturson, 1987; Jimenez, 2019).

Table 1 OGP top five most fatal accidents through history.

Date	Location	Fatalities	Root cause	Substance	Sources
October 1998	Lagos, Nigeria	1078	Vandalism	Gasoline	*(Sovacool, 2008); (The Associated Press, 1998);(BBC News, 2003).*
November 1984	San Juanico, Mexico	650	Pitting corrosion	LPG	*(Bhandari, 2015); (Arturson, 1987); (Jimenez, 2019).*
June 1989	Ufa, Russia	643	Mismanagement	Natural Gas	(Sovacool, 2008); (J. Nevett, 2019); (The Moscow Times, 2019).
December 2006	Lagos, Nigeria	466	Vandalism	Oil	*(Sovacool, 2008); (BBC News, 2006); (The Associated Press, 20016).*
March 1937	Texas, USA	309	ND	Natural Gas	*(B.K. Sovacool, 2008); (Aoghs.org Editors, 2011); (History.com Editors, 2009).*

Moreover, the type of equipment composition plays an influential role in mitigating or increasing the risk of corrosion; generally, different steel grades are the most common type of metal used to form the facilities for marine life. One of the most convenient types of used metal is stainless steel. However, stainless steel is considered very expensive to be used in all applications; thus, carbon steel is being widely used instead. This type of metal can satisfy almost all the demands and place stainless steel in all situations. Carbon steel is an alloy of iron with up to 2% of carbon. The strength and corrosive resistance are provided to the material. In addition to other additives such as cobalt, manganese, nickel, and tungsten, they play a significant role in enhancing the material's performance in the oil and gas industry. Even though corrosion of carbon steel facilities is minimized by many methods, including paint, cathodic protection, coating, etc, nevertheless, this problem is still considered an omnipresent problem in an offshore environment due to the presence of many sources of corrosion, where a notable amount of corrosion is actuated by Hydrogen Sulfide (H_2S) and Carbon Dioxide (CO_2) (Revie et al., 1992). One of the challenging causes that make this topic essential to discuss is that Lebanon is on the verge of producing its very first well in the upcoming months. It is most likely that there are 1.7 billion barrels of recoverable oil that may be found in the Levant Basin province and 122 trillion cubic feet of recoverable natural gas (SCM Daleel Admin, 2020). So, the oil and gas sector is considered a big hope of revival for Lebanon. This is what makes it essential to study corrosion and take into consideration mitigating it. This study was carried out to understand the effect some factors have on triggering corrosion.

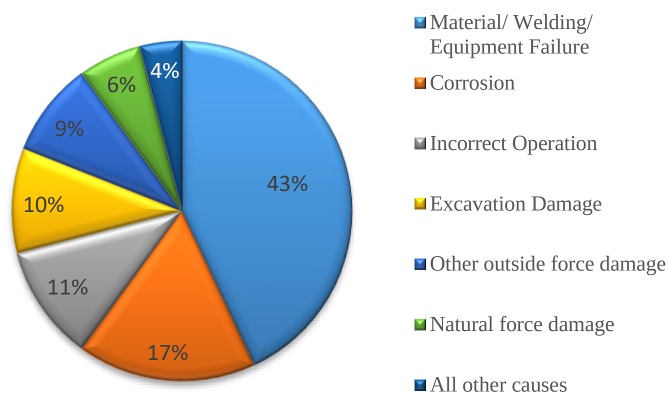

Fig.1 Incident distribution per cause in 2009–2018. (PHMSA,2018).

1 Materials and Methods

1.1 Oil and Gas in Lebanon

On 29th January 2018, the Minister of Energy and Water, with the contribution of Right-holders, signed the Exploration and Production Agreement (EPAs) for blocks 4 and 9. After almost a year, in 2019, the Environmental Baseline Survey for Lebanese Offshore was conducted, which covered Blocks 4 and 9. The survey aimed to identify environmental and archeological sensitive areas offshore to identify and characterize chemical, physical, and biological marine conditions. Moreover, the first Environmental Impact Assessment (EIA) study was conducted in parallel with Lebanese regulations and was approved in February 2020. This Assessment's role is the evaluation of the likely environmental impacts of all involved activities planned. In February 2020, the drilling campaign of the first exploration well in block four was conducted to a total depth of 4,076 meters from sea level in a water depth of almost 1500 meters (LPA, 2021). However, on 27th April, Total E&P Liban announced the results of Byblos Exploration Well 16/1 drilled in Block 4, where the report mentions that only traces of gas were observed. However, no reservoirs exist in the main target of the explored well. It also mentioned that further studies would analyze the recent results and study other block's explorations (LPA, 2020).

1.2 Alloy Select Software

This Software was launched by Oil and Gas Corrosion Ltd.; it is a cloud-based material selection software; whose goals are: the estimation of carbon steel corrosion rates upon different input data and process conditions, the verification of the most suitable material selection under different temperatures, pressure, and partial pressures of carbon dioxide and hydrogen sulfide. It is a corrosion model based on laboratory data and validated with actual life oilfield data. Operators of this Software are provided with experts by expertise in the oil and gas industry to assure meeting regulatory compliance and optimization. It uses (Al) algorithm to determine corrosion rates with or without the availability of a corrosion inhibitor.
This Software is divided into three main sections:

I. Evaluate: Allows the user to select his/her convenient data from the reservoir and process conditions, determining pH, service severity, corrosion rates, and any threats to the integrity of his/her asset. Moreover, it can determine the suitability of carbon steel and any requirements for corrosion allowance.
II. Select: by the assistance of algorithm, identification of the most suitable material from a library including more than 300 materials of different carbon steels, cast irons, low alloy steels, and corrosive resistant alloys; where this library is in the continuous progress of updating in the aim of complying with regulatory requirements.
III. Verify: where the user is asked to confirm material compliance from a group of available ones.
IV. Experiments of this research will be based only on the Evaluate and the Select sections. The components of these sections are illustrated in **Table 2** (Alloy Select Software, 2020).

Table 2 Alloy select software sections and components.

Section	Component	
	Input	Output
Evaluate	• Temperature • Pressure • Percentage of H_2S • Percentage of CO_2 • Cl Concentration • HCO3 Concentration • Design Life • Corrosion Inhibitor Availability(Yes/No)	• Corrosion Rate(mm/year) • Inhibited Corrosion Rate • Corrosion Allowance • Severity Region
Select	• Temperature • Pressure • Percentage of H_2S • Percentage of CO_2 • Cl Concentration • HCO3 Concentration • Equipment • Material Group • Materials	• Accepted or not Material Group • Notes
Verify	Verification of compliance with code and standards will be encountered after choosing the	

1.3 Methods

Three studies were conducted using this Software. The first aim was to check what type of material best suits a chosen case study and designates optimal material for Lebanese offshore operations in a worst-case scenario. The second is to check the effect of temperature on corrosion rate under different carbon dioxide and hydrogen sulfide concentrations. The final study is to study the effect of a 90% efficiency corrosion inhibitor on corrosion rates of the previous study cases. This corrosion inhibitor is an option found in the Software with a 90% efficiency, where the user chooses if he/she wants to include it in the input data. Note that the Software does not specify the corrosion inhibitor type.

2 Results and Discussion

2.1 Material Selection:

Starting with the first study, the "*select*" section was used to aim for material selection. Filling the input data, in this case, was applied based on a worst-case, with a maximum temperature, pressure, and percentages of H_2S and CO_2 in the aim of making sure that the selected material can handle the uttermost cases. On the other hand, HCO_3 and NaCl concentrations were filled based on Lebanese offshore data. After filling these data, selecting several types of material groups will be applied; this will be either accepted with a note or notice or rejected with a justification for the cause of this rejection. The data was filled in as designated in **Table 3**. Note that Cl and HCO_3 concentrations were measured by a Lebanese seawater sample in the laboratory. However, values of temperature, pressure, H_2S, and CO_2 are not based on any real or oil and gas field data. However, they are taken to confirm a worst-case scenario based on the Software's capabilities and value limitations. The results of material selection for the worst-case scenario in Lebanese Offshore Operations are as follows: (for more info concerning the below-mentioned steel grades, refer to the table in (McHone Industries, 2017). Starting with the first chosen material, S66286, which belongs to the Precipitation Handled Stainless Steel group, is rejected due to its inability to handle the maximum temperature and H_2S partial pressure in the worst scenario under Lebanese conditions. The second material group chosen was Titanium alloys, which have 4 grades. Three out of these 4 grades are accepted but with limitations, where R50250 and R50400 cannot have a maximum hardness of 100 HRC, and R53400 should be annealed while heat treatment followed by air cooling, and also has a maximum hardness of 92 HRC. On the other hand, R55400 is rejected since it could handle neither the partial pressure of H_2S nor that of CO_2. Moving to the Highly Alloyed Austenitic Stainless Steel, all 13 grades are accepted, but with many limitations and conditions. Where: J93254 should be following ASTMA351, ASTMA743, or ASTMA744 in the cast, in addition to its need to be in a solution heat-treated and water-quenched condition to a maximum hardness of 100 HRB. This last condition is applied to J95370 but has a maximum hardness of 94 HRB. However, N08007, N08020, N08320, and S32200 are to be in a solution annealed condition and chemical composition such that Ni+2MO should be greater than 30.0, where the minimum MO percentage is 2. Similarly, N08367, N08925, N08925, and S32166 are in a solution annealed condition but with a chemical condition of having PREN greater than 40.0. This last condition applies to S31254 and S32654 but with an additional condition of their susceptibility to CISCC in offshore applications. However, Copper and Aluminum Based Alloys, encompassing grades C63200, C72900, C95400, C95500, C695800, and C96900, are accepted with no limitations or conditions. These are resistant to sulfide stress cracking but may be exposed to general external corrosion at the production stage. Furthermore, regarding Cobalt Based Alloys, all of its corresponding grades are accepted with conditions as well. Where, as obtained, each of R30003, R30004, and R30035 has a maximum hardness of 36, 35, 35, and 35 correspondingly; except that the last can have a maximum hardness of 51 HRC if it is in the cold-reduced and high temperature aged, heat-treated condition following a minimum time. Regarding R31233, the solution shall be annealed to a maximum of 22 HRC. Additionally, R31233 should be solution annealed to a maximum value of 22 HRC. Moreover, Cold Worked Solid Solution Nickel Based Alloy grades witnessed dominance in rejection; where N06002+cw, N06007+cw, N06030+cw, N6625+cw, etc. N06952+cw, N06975+cw, and N06985+cw are rejected because they cannot handle the full temperature set. Similarly, N06022+cw, N06110+cw, N06250+cw, N06255+cw, N06686+cw also cannot hold this temperature does not handle the partial pressure of H_2S. On the other hand, grades N06059+cw and N06060+cw are accepted with a condition which states that wrought or cast material shall be annealed and cold worked to a maximum hardness of 40 HRC and maximum yield strength of 1240 MPa. Also, Martensitic Stainless Steel with grades J91150, J91151, J91540, S41425, and S42000 are all rejected since they cannot handle the partial pressure of H_2S set in this case. Moving to Precipitation Hardened Nickel Based Alloys, grades N07031 and N07048 are rejected since both cannot handle the maximum temperature they are exposed to. Whereas N07626 and N07716 are rejected due to their inability to handle the partial pressure of the H_2S set. Moreover, N09925 and N09946 can handle neither the maximum temperature nor the partial pressure of hydrogen sulfide they are exposed to. On the other hand, N07022 is accepted with a condition of annealing and aging, where its maximum hardness is 39 HRC. Likewise, Tantalum Alloys, R05200 grade, is accepted, but with a maximum hardness of 55 HRB in annealed or gas tungsten arc welded and annealed. Concerning Solid Solution Nickel Based Alloys, all of its grades (including N06002, N06686, N07022, and N08020) are accepted. However, these wrought and cast products should be annealed or solution annealed, and no limit condition for their compliance with NACE MR0175 ISO10423/API6A compliance is required for wellhead and Christmas tree components. Despite the material results, all of the Ferric Stainless-Steel grades are rejected since they cannot handle the partial pressure of hydrogen sulfide. These grades are S405000, S40900, S43000, S43600, S44200, S44400, S44626 and S44800. Finally, most grades of Duplex Stainless Steel, including J93345, J93370, J93280, J93404,

Table 3 Input data for select section.

Input	Temperature (˚C)	Pressure (psi)	Hydrogen Sulfide (H_2S) Percentage	Carbon Dioxide (CO_2) Percentage	Cl Concentration (mg/L)	HCO_3 Concentration (mg/L)
Value	165	1062	30	30	38.830	140

S312200, S39274, and S39277, are accepted but with many conditions, such as rapid cooling of the liquid. Equally important, the ferrite content must be between 35% and 65%, aging heat treatments are forbidden, and no hardness limits exist in the case of NACE MR0175, but other standards have precise hardness requirements.

However, S31803 is rejected because it cannot handle the partial pressure of hydrogen sulfide. Thus, to sum it up, we can say that all of the materials mentioned above have grades either rejected in our case or accepted but have many limitations especially concerning the hardness. It is essential to mention that offshore operations and applications require materials with a hardness range between 32 and 39 HRC, which is unattainable in many accepted grades. On the contrary, all grades of Copper and Aluminum Based Alloys are accepted, with no limitations or significant dangers, except that they are exposed to external corrosion with time, which is affected by many conditions. Therefore, copper and aluminum-based alloys are the best choices to be added to carbon steel pipelines, which can bear the worst conditions of temperature, CO_2, and H_2S corrosions. However, the Software does not choose the mixture of alloys within the carbon steel. That is why the upcoming study cases will be applied on pure carbon steel pipelines with no additions.

Table 4 Results of material selection for the worst-case scenario in the Lebanese offshore operations.

Material Group	Result	Justification for Rejection	Limitations for Accepted Grades
Precipitation Handled Stainless Steel	Rejected	-Cannot handle partial pressure of H_2S -Cannot handle temperature	-
Titanium Alloys	3 out of 4 types of grades are accepted	Cannot handle maximum pressure of H_2S and CO_2	-Cannot handle H_2S and CO_2 concentrations -Heat treatment should be annealing followed by air cooling -Maximum hardness of 92 HRB
Highly Alloyed Austenitic Stainless Steel	Accepted	-	-Should be in a solution heat-treated and water quenched condition -Should have a maximum hardness of 94 HRB
Copper and Aluminum Based Alloys	Accepted	-	-
Cobalt Based Alloy	Accepted	-	-Maximum hardness of 35 HRC, except that it can have a maximum hardness of 51 HRC if it is in the cold-reduced and high temperature aged, heat-treated condition following a minimum time
Cold Worked Solid Solution Nickel Based Alloy	Rejected	-Cannot handle the maximum temperature - Cannot handle the partial pressure of H_2S	-
Martensitic Stainless Steel	Rejected	Cannot handle the partial pressure of H_2S	-
Precipitation Hardened Nickel Based Alloys	Rejected	Cannot handle partial pressures of CO_2 and H_2S	-
Tantalum Alloys	Accepted	-	Max hardness is 55 HRB in annealed or gas tungsten arc welded and annealed
Duplex Stainless Steel	Rejected	Cannot handle the partial pressure of H_2S	-
Ferritic Stainless Steels	Rejected	Cannot handle partial pressures of H_2S	-
Solid Solution Nickel Based Alloys	Accepted	-	- Should be in a wrought or cast form -Should be annealed liquid quenched -The ferrite content should be 35%-65% -Ageing heat treatments aren't allowed -Rapid cooling is required

2.2 Corrosion rates at different conditions of temperature, H_2S, and CO_2 without a corrosion inhibitor

Moving to the second study conducted in Alloy Select software, the input data is designated in T**able 5**. Values of Cl & HCO_3 are based on accurate Lebanese offshore data that was detected at the laboratory. Three levels of temperature were taken, low (0-30˚C), medium (30-60˚C), and high temperature (70-100˚C) values. These values were correlated with four combination conditions between H_2S and CO_2 levels (high=90, low=10), and the corrosion rates of these cases were then obtained.

Table 5 Input data for evaluation section.

Input	Value
Temperature (˚C)	Variable
Pressure (bar)	1.0132
Hydrogen Sulfide (H2S) Percentage	Variable
Carbon Dioxide (CO2) Percentage	Variable
Cl Concentration (mg/L)	38.830
HCO_3 Concentration (mg/L)	140

The logged data in **Table 6** sum up correlations of these values, and the results are illustrated by **Table 7**. These values of corrosion rates are considered exaggerated ones in comparison to actual oil and gas field data. However, they have been used because the Software allows access to this limit of values in the input data. Therefore, we can view the effect of temperature on corrosion rates more clearly when the image is magnified. Referencing tables 6 and 7, starting with the first case, where a high percentage of H_2S and a high percentage of CO_2 were present, and when the temperature is low, the corrosion rate is 1.81 mm/year. However, as the temperature is increased to the medium range, the corrosion rate increases till reaching 140.24 mm/year.

Similarly, as temperature increases to the high range, the corrosion rate reaches 1969.37 mm/year. On the contrary, when setting low percentages of H_2S and CO_2, the second case at a low-temperature range obtained a corrosion rate of 0.47 mm/year. Moving to the medium temperature range, the corrosion rate increases till reaching 36.4 mm/year. Likewise, as moving to the maximum range of temperature, the elevation of corrosion rate takes place, where it recorded 502.46 mm/year. Moving to the third case, where a high percentage of H_2S and a low one of CO_2 are set, at a low range of temperature, the obtained corrosion rate is 0.13 mm/year, and that at medium temperature level is 10.23 mm/year. However, corrosion rates witness inflation in corrosion at the high-temperature range, recording 139.2 mm of corrosion per year. Putting forward the fourth case, where low H_2S percentage and high CO_2 percentage were set, the recorded corrosion rate at a low-temperature range was 2.96 mm/year. As the elevation of temperature range takes place, 228.87 mm/year and 3,237.05 mm/year of corrosion rates were recorded for medium and high-temperature ranges. As noticed, in all of the temperature ranges, the maximum recorded corrosion rate was when the mixture contains a high CO_2 percentage with a low H_2S percentage. Finally, the lowest recorded corrosion rate went where the mixture is composed of a low CO_2 with high H_2S percentages. The low corrosion rates obtained in cases of having low CO2 in compliance with high H_2S are that H_2S corrosion reaction leads to the formation of $Fe(HS)_2$. This formation, in turn, leads to the formation of thermodynamically stable iron sulfide, leading to the reduction of corrosion rates observed.

Table 6 Correlations between levels of temperature, H_2S, and CO_2, represent the taken cases' input data.

Case	Case (1)				Case (2)				Case (3)			
Temperature Range	Low				Medium				High			
Designation	A	B	C	D	A’	B’	C’	D’	A’’	B’’	C’’	D’’
H_2S Percentage	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
CO_2 Percentage	High	Low	Low	High	High	Low	Low	High	High	Low	Low	High

Table.7 Corrosion rates (mm/year) and allowance rates obtained under different conditions of temperature levels and percentages of H_2S and CO_2. (See table 5 for conditions)

Case	A	B	C	D	A’	B’	C’	D’	A’’	B’’	C’’	D’’
Corrosion Rate(mm/year)	1.81	0.47	0.13	2.96	140	36.4	10.23	228	1969	502	139.2	3,237

In order to detect the effect of temperature on these cases and point out where the temperature had the most and most minor practical function on these CO_2 and H_2S combination cases, the medium temperature range is taken as the reference and percentages of variation concerning this reference for each composition case is calculated. From these calculations, we can say that the higher percentage chance of corrosion rate was detected when moving from low to medium temperature range, where a 98.7% increase in corrosion rate was recorded. On the other side, when moving from medium to high-temperature range, an average of 93% increase was noticed for all combinations. This is because at very high temperatures, the solubility of CO_2 in water decreases, which leads to the formation of compact and adherent product layers on the steel surface. This layer acts as a protective layer, which inhibits corrosion, leading to reduced corrosion rates.

2.3 Corrosion rates at different conditions of temperature, H_2S and CO_2 with a corrosion inhibitor

The same conditions were set, but adding a corrosion inhibitor, which is type is not specified by the Software. However, it has an efficiency of 90%. The results obtained are characterized in **Table 8**.

Table.8 Inhibited corrosion rates (mm/year) and % of corrosion reduction obtained under different conditions of temperature levels and percentages of H_2S and CO_2 in the presence of a corrosion inhibitor

Case	**A**	**B**	**C**	**D**	**A'**	**B'**	**C'**	**D'**	**A''**	**B''**	**C''**	**D''**
Corrosion Rate(mm/year)	0.2	0.05	0.01	0.32	15.29	3.97	1.11	24.95	214.66	54.77	15.17	352.84

The addition of a corrosion inhibitor with an efficiency of 90% (specified by the Software) to the same previous conditions was applied. As table 8 reveals, concerning the low-temperature range, the inhibited corrosion rates recorded for cases A, B, C, and D are 0.2 mm/year, 0.05 mm/year, 0.01 mm/year, and 0.32 mm/year. Concerning the medium temperature range, the inhibited corrosion ranges increase to 15.29 mm/year, 3.97 mm/year, 1.11 mm/year, and 24.95 mm/year. Finally, at a high-temperature range, the inhibited corrosion rates noted are 214.66 mm/year, 54.77 mm/year, 15.17 mm/year, and 352.84 mm/year. These results assure the role of corrosion inhibitors in warding off carbon pipeline corrosion in the presence of high temperature, CO_2, and H_2S values. These results confirm recent related studies (Li, *et al*., 2014; Liu, *et al*., 2013). Further studies are to be done to specify what other corrosive environmental factors are behind the observed results concerning H_2S.

Conclusions

Copper and aluminum-based alloys are the best choices to be added to carbon steel pipelines, where they can handle all the Lebanese offshore corrosive conditions with no limitations. Furthermore, "*Evaluation Section*" studies reveal that the CO_2 dominant system is more corrosive than H_2S dominant system, specifically in compliance with high temperature. This is explained by the fact that more water is being evaporated at high temperatures, which releases more CO_2, leading to higher corrosion rates. On the other side, H_2S dominant system is the weakest among all cases, which is explained by the formation of thermodynamically stable iron sulfide, acting as protective films. However, in the case of the CO_2 dominant system, and when moving to higher temperature values, the increase in the percentage of corrosion rates witness reduction due to forming the protective layers on the steel surface. Finally, the importance of adding a corrosion inhibitor to carbon pipelines was revealed by its act of reducing corrosion rates, especially in the presence of high temperature, CO_2, and H_2S values.

Nomenclature

CO_2	=Carbon Dioxide	[mole]
H_2S	=Hydrogen Sulfide	[mole]
PHMSA	=Pipeline and Hazardous Materials Safety	[-]
IOGP	=International Association of Oil and Gas Producers	[-]
EPAs	=Exploration and Production Agreements	[-]
EIA	=Energy Information Administration	[-]
LPA	=Lebanese Petroleum Administration	[-]
Ltd	=Limited Company	[-]
NaCl	=Sodium Chloride	[mole]
HRB	=Hardness Rockwell	[B]
HRC	=Hardness Rockwell	[C]
T	=Temperature	[˚C]
P	=Pressure	[psi]
Cl	=Chloride	[mole/L]
HCO_3	=Bicarbonate	[mole]
pH	=potential of Hydrogen	[-]

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