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RESEARCH ARTICLE

Corrosion Rate Analysis in Material Selection for Tubing in CO_2 Injection Process at Well K-28

Salsabila Meiysa Disti [1,*], Rudi Rubiandini [1]
[1] Universitas Pertamina, Department of Petroleum Engineering, Jakarta, 12220, Indonesia

* Corresponding author : salsameisyadisti170520@gmail.com
Tel.: +62 822-8359-2387
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Abstract

This research aims to analyze the corrosion level of the tubing material used in CO_2 injection at well K-28. Four types of carbon steel tubing, 13Cr, super 13Cr, and super 15Cr, were analyzed under shut-in and injection conditions using experimental data from a previously published paper titled "Material Selection and Corrosion Rate Analysis for CO_2 Injection Well: A Case Study of K1 Field CO_2 Sequestration Project". The research results in eight corrosion rate equations for each condition and type of tubing. Based on the analysis, super 15Cr shows the best corrosion resistance, both in shut-in and injection conditions, with a corrosion rate ranging from 0.00053 mm/year to 0.00085 mm/year at temperatures of 25-35°C and pH 3.08-3.09. The research also showed that the temperature from the surface to the bottom hole and pH had a significant impact on the corrosion rate. Data was processed using Excel and StatsModels library of Python machine learning to estimate the corrosion rate based on these parameters.

Super 15Cr is recommended as the most corrosion-resistant tubing material for use in high corrosion potential environments during the CO_2 injection process in well K-28. This conclusion is based on a combination of literature studies, experiments, and regression analysis, which identify super 15Cr as the optimal choice for minimizing corrosion risk in this application.

Keywords: CO_2 Injection, Injection Tubing, Material Selection, Temperature, pH

1. Introduction

The oil and gas industry is known for its complex processes, involving various facilities influenced by multiple factors. One of the key challenges in modern oil fields is the high corrosion rate of production fluids, caused by dissolved gases, abrasive particles, and high water cut, leading to significant damage. Corrosion, driven by chemical or electrochemical reactions between corrosive fluids and metal surfaces, is a critical issue in advanced industries and a major cause of failure in flow components like pipes, pumps, valves, and impellers. In the oil and gas sector, corrosion in pipelines can be mitigated through the use of specialized materials, such as Corrosion Resistant Alloys (CRA) or epoxy-coated tubing. This study focuses on analyzing and simulating corrosion in different types of injection tubing, including carbon steel, 13Cr, super 13Cr, and super 15Cr, using OLI Studio Corrosion Analyzer, a specialized software for chemical and thermodynamic simulations in industrial applications. The research aims to identify key parameters influencing corrosion in injection tubing under shut-in and injection conditions, develop regression models for corrosion rates, and ultimately recommend the most corrosion-resistant material for CO_2 injection operations in oil fields.

1.1 Corrosion

As a global warming mitigation initiative, CO_2 storage projects have gained appeal, especially with tax incentives. However, maintaining well integrity during CO_2 injection and preventing leakage is challenging, primarily due to corrosion caused by the reaction of CO_2 with metal surfaces (Bakar et al., 2021). Unlike physical wear, corrosion exclusively affects metals, gradually compromising their structural integrity. Corrosion can be defined as the reverse of metal extraction or refining processes (Fontana, 1986). Factors such as temperature, reactant concentration, metal mass, and mechanical stress significantly influence the rate of corrosion.

Corrosion is a destructive process in which metals deteriorate through chemical or electrochemical reactions with their environment, forming ferric hydrogen oxide. It occurs when metal ions and electrons are released at the anode, where oxidation takes place, and hydrogen or oxygen is reduced at the cathode (Roberge, 2000). The terms "anode" and "cathode" describe the charge transfer between iron and the electrolyte. The electrochemical reactions at these sites can be represented by the following equations:

Anode reaction:

$$Fe_{(s)} \rightarrow Fe^{2+}{}_{(aq)} + 2\,e^-$$

Cathode reaction:

$$O_{2\,(g)} + 2\,H_2O_{(l)} + 4\,e^- \rightarrow 4\,OH^-{}_{(Aq)}$$

Based on these reactions, the overall chemical process of corrosion can be summarized as:

$$2\,Fe_{(s)} + O_{2\,(g)} + 2\,H_2O_{(l)} \rightarrow 2\,Fe(OH)_{2\,(s)}$$

In CO_2 injection wells, corrosion is exacerbated by the acidic environment created when CO_2 dissolves in formation water, forming carbonic acid, which accelerates metal degradation. If not properly managed, corrosion can result in equipment failure, environmental contamination, and significant operational downtime. Managing corrosion is critical for three main reasons such as reducing economic impact, ensuring operational safety, and conserving resources. Corrosion damages infrastructure such as pipelines, tanks, and offshore structures, leading to equipment failure and waste generation. Economic losses due to corrosion can be classified as direct, including the cost of replacing damaged infrastructure, repainting, maintaining cathodic protection systems, and adding corrosion inhibitors. Indirect losses involve production shutdowns, product loss, reduced equipment efficiency, and product contamination (Revie and Uhlig, 2008).

Corrosion in the oil and gas industry is caused by various factors, such as material properties, environmental conditions, and ineffective corrosion control methods. Uniform corrosion leads to an even thinning of the metal surface, which, although easier to predict, often begins with localized corrosion. Galvanic corrosion occurs when two metals with different electrochemical potentials are connected in a corrosive environment, causing the metal with lower potential to corrode more rapidly. Pitting corrosion creates small, deep pits in materials like stainless steel exposed to chloride ions, which can damage the protective passive layer.

Erosion corrosion, on the other hand, is caused by high fluid turbulence, stripping away the passive layer and accelerating corrosion. Stress corrosion cracking (SCC) is triggered by tensile stress and pressure, often affecting metals that have undergone cold working, with examples including hydrogen embrittlement and chloride stress cracking. Lastly, atmospheric corrosion occurs on metal surfaces exposed to open air, influenced by factors such as humidity, solar radiation, rainfall, wind, and air pollutants. These various forms of corrosion highlight the need for effective monitoring and prevention strategies in the oil and gas industry to protect equipment and ensure safety.

1.2 Factors Influencing Corrosion

Corrosion occurs due to the reaction between metals and reactive substances in liquid, solid, or gas forms, involving oxidation and reduction reactions. Metals tend to have very low energy in compound form but high energy as single elements due to their instability. Several substances that can cause corrosion in equipment include Hydrogen Sulfide (H_2S), which is sulfur found in oil and natural gas and is highly dangerous for metal and alloy corrosion, leading to sulfide stress corrosion cracking (SSCC). Chlorides, often present in mineralized water, cause intergranular corrosion and chloride stress corrosion cracking (CSCC). Carbon Dioxide (CO_2), typically responsible for sweet corrosion, is common in the oil and gas industry as it produces carbonic acid, lowering pH levels. Oxygen, one of the cathodic reaction agents, is a major corrosion driver as it easily reacts with metals and dissolves quickly in drilling fluids, accelerating the corrosion of drilling equipment.

In addition to these substances, corrosion rates are also influenced by several other factors. Pressure accelerates CO_2 corrosion by speeding up the corrosion process and indirectly affecting fluid flow. It increases the partial pressure of CO_2, enhancing the carbonic acid reaction at the cathode and accelerating corrosion (Bulyarskiĭ and Prikhod'ko, 1999). Temperature also increases corrosion rates due to the rise in chemical and electrochemical reactions, as higher temperatures provide more energy for molecules to collide. When pH levels are below neutral ($pH < 7$), the environment becomes acidic and corrosive. It is understood that higher pH values result in lower corrosion rates due to reduced carbonate solubility (Abd et al., 2019).

2. Data Sources and Parameters

The K-28 Field, located in the Central Luconia Basin of Sarawak, lies 281 km northwest of Bintulu at a water depth of 453 ft. It is part of a carbonate platform within the Mega Platform area. The estimated Gas Initially In-Place (GIIP) for this field is approximately 2,800 BScf. A feasibility study for CO_2 storage has identified the K-28 field as a suitable site for CO_2 sequestration. The plan is to inject and store CO_2 in one of the depleted carbonate reservoirs, either in the aquifer or hydrocarbon zone, until reservoir pressure returns to its original level of 3,440 psi. The reservoir temperature is around 120°C.

This study relies on data from a previously published paper titled "Material Selection and Corrosion Rate Analysis for CO_2 Injection Well: A Case Study of K1 Field CO_2 Sequestration Project" (Bakar et al., 2021) as the primary reference. The data utilized includes the composition of the

Table 1. Injection Fluid Composition

Compositions	Mol %
Carbon Dioxide	72
Hydrogen Sulfide	0.0409
Nitrogen	0.3914
Methane	27
Ethane	0.4908
Propane	0.0962
Butane	0.0323
Pentane	0.0083
Hexane	0.0004
Heptane Plus	0.3634
Water	0.0086

Table 2. Pressure and Temperature during Shut-in and Injection

Case	Location	Pressure, psi	Temperature, deg-C
Shut-in Case	Surface	1375	25
Shut-in Case	Bottomhole	3440	120
Injection Case	Surface	2850	25
Injection Case	Bottomhole	2850	25

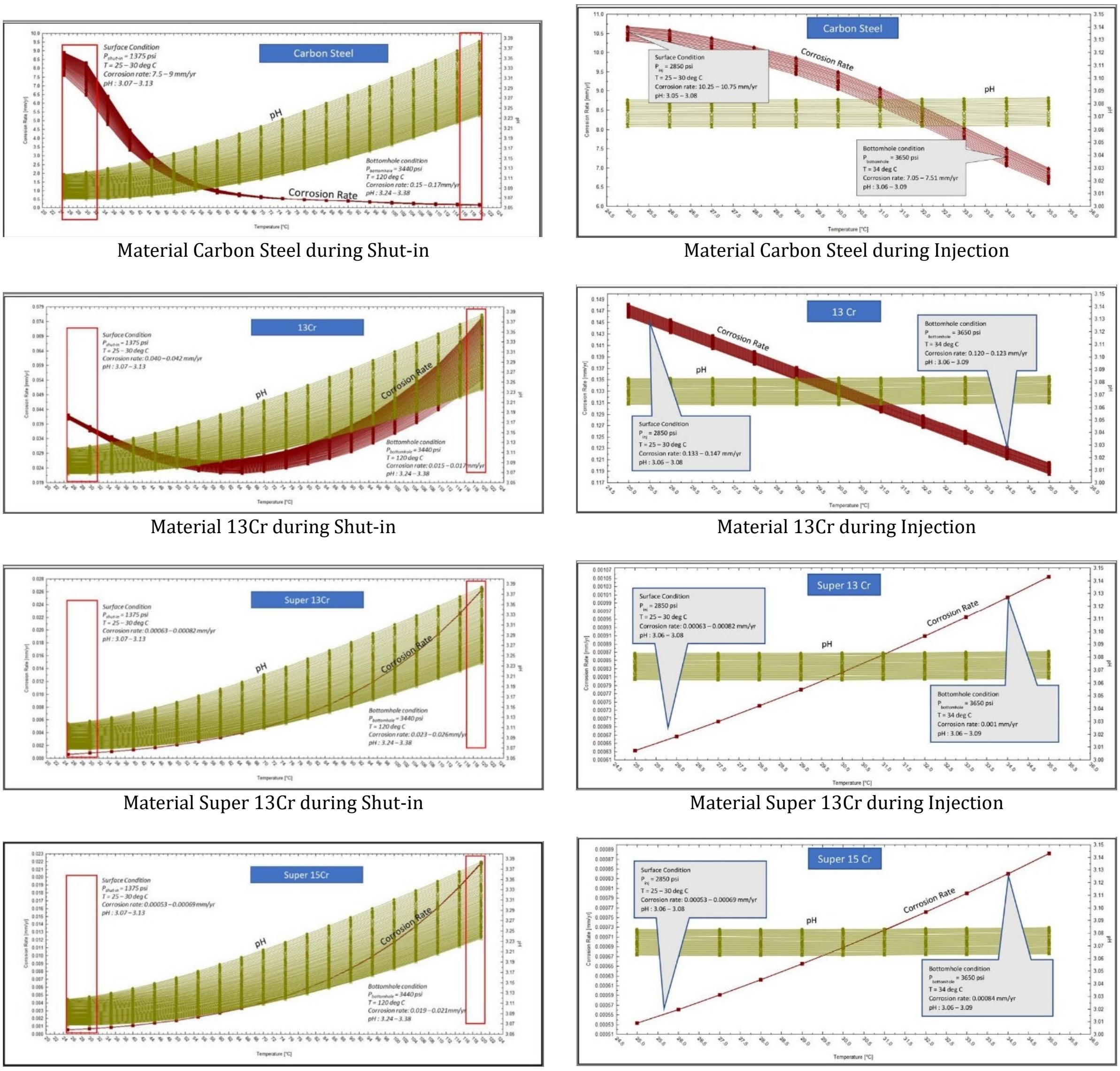
injection solution (**Table 1**), well pressure and temperature under both surface and downhole conditions (**Table 2**), as well as simulated corrosion rate graphs (**Figure 1**) based on temperature and pressure variations at each well condition.

3. Methodology

This study aims to select the optimal tubing material for the K-28 well, considering corrosion caused by CO_2 and H_2S. The methodology begins with a review of relevant literature and prior studies on injection well tubing corrosion, particularly focusing on CO_2 and H_2S-induced corrosion, to understand the latest developments and techniques in corrosion analysis. Geological data, including pressure, temperature, pH, and CO_2 and H_2S concentrations, are then collected from the K-28 Well as a basis for further analysis.

The raw data are processed using Excel, involving data organization, cleaning, and preliminary analysis. This processed data is then analyzed using machine learning methods on StatsModels library of Python to develop a model that predicts corrosion rates based on temperature and pH. The results of these simulations are used to establish corrosion rate equations, which serve as the foundation for determining the most suitable tubing material for the specific conditions of the K-28 well.

The output of this research includes corrosion rate equations based on temperature and pH, along with recommendations for optimal tubing materials to mitigate corrosion risks in the K-28 well. The study concludes with material recommendations and suggestions for future research, aiming to improve the accuracy and efficiency of tubing material selection, reduce corrosion risks, and extend the operational life of the well.



Material Carbon Steel during Shut-in

Material Carbon Steel during Injection

Material 13Cr during Shut-in

Material 13Cr during Injection

Material Super 13Cr during Shut-in

Material Super 13Cr during Injection

Material Super 15Cr during Shut-in

Material Super 15Cr during Injection

Fig 1. Simulated corrosion rate for various materials (modified from Bakar et al., 2021)

4. Results

4.1 Material Carbon Steel

Shut-in Case. Based on the model interpretation (**Figure 2**), an R-squared value of 0.956 was obtained, indicating that 95.6% of the variability in the corrosion rate (CR) is explained by this model. The analysis shows that temperature has a negative effect on CR, with each one-unit increase in temperature leading to a decrease in CR by 0.3554 units, assuming pH remains constant. This suggests that higher temperatures reduce the corrosion rate. Conversely, pH has a strong positive effect, with each one-unit increase in pH resulting in an increase in CR by 120.30 units, assuming constant temperature. This demonstrates that pH significantly increases the corrosion rate. Lastly, the intercept (const) value for CR when both temperature and pH are zero is -354.78; however, this condition is not practically relevant, as temperature and pH are never zero in real-world situations. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -354.7810 - 0.3554\,(t) + 120.3028\,(pH) \qquad (1)$$

Injection Case. The interpretation of results for carbon steel injection tubing revealed an R-squared value of 0.983, indicating that 98.3% of the variance in corrosion rate (CR) is explained by temperature and pH, with both predictors being statistically significant ($p < 0.05$). The analysis showed that each 1°C increase in temperature reduces the corrosion rate by 0.3360 units, suggesting that higher temperatures significantly decrease corrosion in the material analyzed. In practical terms, pipes operating at higher temperatures may have a longer lifespan. Additionally, each 1-unit increase in pH decreases the corrosion rate by 48.4545 units, indicating that more alkaline environments (higher pH) significantly reduce corrosion. This implies that pipes used in high-pH environments may require less maintenance. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -168.4188 - 0.3360\,(t) - 48.4545\,(pH) \qquad (2)$$

4.2 Material 13Cr

Shut-in Case. Based on the model interpretation (**Figure 3**), an R-squared value of 0.978 was obtained, indicating that 97.8% of the variability in the corrosion rate (CR) is explained by the model. The implications of the variables used in the model are as follows: each one-unit increase in temperature (t) results in a slight decrease in CR by 0.0018 units, assuming pH remains constant, indicating that temperature has a small negative effect on CR. Conversely, each one-unit increase in pH leads to a significant increase in CR by 0.8701 units, with temperature held constant, showing that pH has a positive and considerable impact on CR. The intercept (const) value of -2.6038 reflects the baseline CR when both temperature and pH are zero, though this condition is not practically relevant. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -2.6038 - 0.0018\,(t) + 0.8701\,(pH) \qquad (3)$$

```
                            OLS Regression Results
==============================================================================
Dep. Variable:                    CR1   R-squared:                       0.956
Model:                            OLS   Adj. R-squared:                  0.951
Method:                 Least Squares   F-statistic:                     183.8
Date:                Thu, 27 Jun 2024   Prob (F-statistic):           3.07e-12
Time:                        14:57:04   Log-Likelihood:                -15.070
No. Observations:                  20   AIC:                             36.14
Df Residuals:                      17   BIC:                             39.13
Df Model:                           2
Covariance Type:            nonrobust
==============================================================================
                 coef    std err          t      P>|t|      [0.025      0.975]
------------------------------------------------------------------------------
const       -354.7810     34.506    -10.282      0.000    -427.583    -281.979
T1            -0.3554      0.028    -12.865      0.000      -0.414      -0.297
PH1          120.3028     11.477     10.482      0.000      96.088     144.518
==============================================================================
Omnibus:                        3.067   Durbin-Watson:                   0.547
Prob(Omnibus):                  0.216   Jarque-Bera (JB):                1.310
Skew:                          -0.170   Prob(JB):                        0.519
Kurtosis:                       1.793   Cond. No.                     2.28e+04
==============================================================================
```

Shut-in Case

```
                            OLS Regression Results
==============================================================================
Dep. Variable:                    CR5   R-squared:                       0.983
Model:                            OLS   Adj. R-squared:                  0.979
Method:                 Least Squares   F-statistic:                     230.6
Date:                Fri, 28 Jun 2024   Prob (F-statistic):           8.44e-08
Time:                        18:58:26   Log-Likelihood:                 4.7239
No. Observations:                  11   AIC:                            -3.448
Df Residuals:                       8   BIC:                            -2.254
Df Model:                           2
Covariance Type:            nonrobust
==============================================================================
                 coef    std err          t      P>|t|      [0.025      0.975]
------------------------------------------------------------------------------
const        168.4188     59.517      2.830      0.022      31.173     305.665
T5            -0.3360      0.024    -14.151      0.000      -0.391      -0.281
PH5          -48.4545     19.467     -2.489      0.038     -93.344      -3.565
==============================================================================
Omnibus:                        0.758   Durbin-Watson:                   0.821
Prob(Omnibus):                  0.685   Jarque-Bera (JB):                0.661
Skew:                          -0.469   Prob(JB):                        0.719
Kurtosis:                       2.249   Cond. No.                     3.41e+04
==============================================================================
```

Injection Case

Fig 2. Multilinear Regression Results for Material Carbon Steel

```
                            OLS Regression Results
==============================================================================
Dep. Variable:                    CR2   R-squared:                       0.978
Model:                            OLS   Adj. R-squared:                  0.975
Method:                 Least Squares   F-statistic:                     369.5
Date:                Thu, 27 Jun 2024   Prob (F-statistic):           9.79e-15
Time:                        15:00:05   Log-Likelihood:                 98.540
No. Observations:                  20   AIC:                            -191.1
Df Residuals:                      17   BIC:                            -188.1
Df Model:                           2
Covariance Type:            nonrobust
==============================================================================
                 coef    std err          t      P>|t|      [0.025      0.975]
------------------------------------------------------------------------------
const         -2.6038      0.128    -20.350      0.000      -2.874      -2.334
T2            -0.0018      0.000    -17.633      0.000      -0.002      -0.002
PH2            0.8701      0.042     20.485      0.000       0.780       0.960
==============================================================================
Omnibus:                        1.725   Durbin-Watson:                   1.539
Prob(Omnibus):                  0.422   Jarque-Bera (JB):                1.460
Skew:                          -0.593   Prob(JB):                        0.482
Kurtosis:                       2.413   Cond. No.                     2.47e+04
==============================================================================
```

Shut-in Case

```
                            OLS Regression Results
==============================================================================
Dep. Variable:                    CR6   R-squared:                       0.999
Model:                            OLS   Adj. R-squared:                  0.999
Method:                 Least Squares   F-statistic:                     5959.
Date:                Fri, 28 Jun 2024   Prob (F-statistic):           2.02e-13
Time:                        18:58:32   Log-Likelihood:                 76.690
No. Observations:                  11   AIC:                            -147.4
Df Residuals:                       8   BIC:                            -146.2
Df Model:                           2
Covariance Type:            nonrobust
==============================================================================
                 coef    std err          t      P>|t|      [0.025      0.975]
------------------------------------------------------------------------------
const          0.5699      0.086      6.644      0.000       0.372       0.768
T6            -0.0027   3.42e-05    -78.142      0.000      -0.003      -0.003
PH6           -0.1157      0.028     -4.123      0.003      -0.180      -0.051
==============================================================================
Omnibus:                        0.100   Durbin-Watson:                   1.076
Prob(Omnibus):                  0.951   Jarque-Bera (JB):                0.268
Skew:                          -0.169   Prob(JB):                        0.875
Kurtosis:                       2.314   Cond. No.                     3.41e+04
==============================================================================
```

Injection Case

Fig 3. Multilinear Regression Results for Material 13Cr

Injection Case. The model interpretation for 13Cr injection tubing yielded an R-squared value of 0.999, indicating that 99.9% of the variability in the corrosion rate (CR) is explained by the model, with a significant predictor ($p < 0.05$) for temperature (t). The results show that each 1°C increase in temperature reduces the corrosion rate by 0.0027 units, suggesting that higher temperatures, though having a small effect, still contribute to reduced corrosion. Additionally, each 1-unit increase in pH decreases the corrosion rate by 0.1157 units, indicating that higher pH environments reduce corrosion, although the effect is smaller compared to the previous model. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = 0.5699 - 0.0027\,(t) - 0.1157\,(pH) \tag{4}$$

4.3 Material Super 13Cr

Shut-in Case. The model interpretation (**Figure 4**) resulted in an R-squared value of 0.992, indicating that 99.2% of the variability in the corrosion rate (CR) is explained by the model. The implications of the model are as follows: each one-unit increase in temperature (t) causes a slight decrease in CR by 0.0003 units, assuming pH remains constant, showing that temperature has a negative effect on CR. In contrast, each one-unit increase in pH results in an increase in CR by 0.2496 units, indicating a significant positive effect of pH on CR. The intercept (const) value of -0.7615 represents the baseline CR when both temperature and pH are zero, although this scenario is not practically relevant. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -0.7615 - 0.0003\,(t) + 0.2496\,(pH) \tag{5}$$

Injection Case. Based on the Super 13Cr injection tubing model (**Figure 4**), the R-squared value was 0.996, indicating that 99.6% of the variance in corrosion rate (CR) is explained by temperature (t) and pH. The model identified temperature as a significant predictor ($p < 0.05$), while pH was not significant ($p > 0.05$). The implications of the model are as follows: each 1°C increase in temperature raises the corrosion rate by 4.157 x 10^{-5} units, indicating a slight increase in corrosion with higher temperatures, though the effect is minimal. Since pH did not significantly affect the corrosion rate, it can be disregarded in certain predictive conditions. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -0.0061 + 4.157 \times 10^{-5}\,(t) + 0.0019\,(pH) \tag{6}$$

4.4 Material Super 15Cr

Shut-in Case. The model interpretation (**Figure 5**) yielded an R-squared value of 0.991, indicating that 99.1% of the variance in corrosion rate (CR) is explained by the variables. Temperature (t) was found to have a negative effect on CR, with each unit increase in temperature decreasing CR by 0.0003 units, assuming constant pH. In contrast, pH had a significant positive effect, with each unit increase in pH raising CR by 0.2082 units, again assuming constant temperature. The intercept (const) of -0.6350

OLS Regression Results

Dep. Variable:	CR3	R-squared:	0.992
Model:	OLS	Adj. R-squared:	0.991
Method:	Least Squares	F-statistic:	1015.
Date:	Thu, 27 Jun 2024	Prob (F-statistic):	2.06e-18
Time:	15:01:55	Log-Likelihood:	117.53
No. Observations:	20	AIC:	-229.1
Df Residuals:	17	BIC:	-226.1
Df Model:	2		
Covariance Type:	nonrobust		

	coef	std err	t	P>|t|	[0.025	0.975]
const	-0.7615	0.050	-15.383	0.000	-0.866	-0.657
T3	-0.0003	3.88e-05	-8.786	0.000	-0.000	-0.000
PH3	0.2496	0.016	15.192	0.000	0.215	0.284

Omnibus:	0.677	Durbin-Watson:	0.792
Prob(Omnibus):	0.713	Jarque-Bera (JB):	0.691
Skew:	-0.360	Prob(JB):	0.708
Kurtosis:	2.443	Cond. No.	2.47e+04

Shut-in Case

OLS Regression Results

Dep. Variable:	CR7	R-squared:	0.996
Model:	OLS	Adj. R-squared:	0.995
Method:	Least Squares	F-statistic:	955.5
Date:	Fri, 28 Jun 2024	Prob (F-statistic):	3.02e-10
Time:	18:58:37	Log-Likelihood:	112.41
No. Observations:	11	AIC:	-218.8
Df Residuals:	8	BIC:	-217.6
Df Model:	2		
Covariance Type:	nonrobust		

	coef	std err	t	P>|t|	[0.025	0.975]
const	-0.0061	0.003	-1.842	0.103	-0.014	0.002
T7	4.157e-05	1.33e-06	31.252	0.000	3.85e-05	4.46e-05
PH7	0.0019	0.001	1.704	0.127	-0.001	0.004

Omnibus:	1.858	Durbin-Watson:	2.222
Prob(Omnibus):	0.395	Jarque-Bera (JB):	0.828
Skew:	0.035	Prob(JB):	0.661
Kurtosis:	1.658	Cond. No.	3.41e+04

Injection Case

Fig 4. Multilinear Regression Results for Material Super 13Cr

OLS Regression Results

Dep. Variable:	CR4	R-squared:	0.991
Model:	OLS	Adj. R-squared:	0.990
Method:	Least Squares	F-statistic:	937.3
Date:	Thu, 27 Jun 2024	Prob (F-statistic):	4.03e-18
Time:	15:02:55	Log-Likelihood:	120.40
No. Observations:	20	AIC:	-234.8
Df Residuals:	17	BIC:	-231.8
Df Model:	2		
Covariance Type:	nonrobust		

	coef	std err	t	P>|t|	[0.025	0.975]
const	-0.6350	0.043	-14.800	0.000	-0.725	-0.544
T4	-0.0003	3.36e-05	-8.463	0.000	-0.000	-0.000
PH4	0.2082	0.014	14.618	0.000	0.178	0.238

Omnibus:	0.075	Durbin-Watson:	0.646
Prob(Omnibus):	0.963	Jarque-Bera (JB):	0.223
Skew:	-0.122	Prob(JB):	0.894
Kurtosis:	2.544	Cond. No.	2.47e+04

Shut-in Case

OLS Regression Results

Dep. Variable:	CR8	R-squared:	0.990
Model:	OLS	Adj. R-squared:	0.988
Method:	Least Squares	F-statistic:	416.9
Date:	Fri, 28 Jun 2024	Prob (F-statistic):	8.16e-09
Time:	18:58:41	Log-Likelihood:	109.96
No. Observations:	11	AIC:	-213.9
Df Residuals:	8	BIC:	-212.7
Df Model:	2		
Covariance Type:	nonrobust		

	coef	std err	t	P>|t|	[0.025	0.975]
const	-0.0066	0.004	-1.580	0.153	-0.016	0.003
T8	3.388e-05	1.66e-06	20.386	0.000	3.01e-05	3.77e-05
PH8	0.0020	0.001	1.490	0.175	-0.001	0.005

Omnibus:	4.255	Durbin-Watson:	1.216
Prob(Omnibus):	0.119	Jarque-Bera (JB):	2.174
Skew:	-1.089	Prob(JB):	0.337
Kurtosis:	2.972	Cond. No.	3.41e+04

Injection Case

Fig 5. Multilinear Regression Results for Material Super 15Cr represents the baseline CR when both temperature and pH are zero, though this scenario may not occur in practical situations. The high R-squared value demonstrates the model's strong predictive capability, with both temperature and pH serving as significant predictors of CR at a 99.1% confidence level. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -0.6350 - 0.0003\ (t) + 0.2082\ (pH) \tag{7}$$

Injection Case. The model interpretation for Super 1 Cr injection tubing (**Figure 5**) yielded an R-squared value of 0.990, indicating that 99.0% of the variance in corrosion rate (CR) is explained by temperature (t) and pH. Temperature was identified as a significant predictor ($p < 0.05$), while pH was not statistically significant ($p > 0.05$). The model implies that a 1°C increase in temperature leads to a slight increase in CR by 3.388×10^{-5} units, suggesting that higher temperatures marginally promote corrosion. However, changes in pH do not significantly affect the corrosion rate, and therefore, pH may be disregarded in certain predictive conditions. Based on the interpretation of this model, the following regression equation for the tubing can be derived:

$$CR = -0.0066 + 3.388 \times 10^{-5}\ (t) + 0.0020\ (pH) \tag{8}$$

5. Discussion

5.1 Shut-in Case

After successfully processing the data using StatsModels library of Python, four corrosion rate equations for shut-in conditions were derived from the results of multilinear regression, as shown in **Table 3**.

To validate that each equation accurately predicts the corrosion rate for the tested tubing materials, experiments will be conducted using a surface condition with a temperature of 30°C and pH of 3.1, as well as a downhole condition with a temperature of 120°C and pH of 3.3.

Based on **Table 4**, it is evident that the corrosion rates differ for each type of tubing used. This confirms that the derived equations are accurate and provide reliable results. The analysis concludes that corrosion rate is indeed influenced by temperature and pH, where an increase in both parameters leads to higher corrosion. Furthermore, the study shows that Super 15Cr tubing exhibits a significantly lower corrosion rate compared to other tubing types, indicating its superior corrosion resistance.

5.2 Injection Case

After successfully processing the data using StatsModels library of Python, four equations for calculating corrosion rates under shut-in conditions were obtained from the results of multiple linear regression, as shown in **Table 3**.

To validate that each equation accurately predicts the corrosion rate for each tested tubing type, testing will be conducted using a surface condition with a temperature of 27°C and pH of 3.06, and a downhole condition with a temperature of 32°C and pH of 3.08.

Based on **Table 4**, it is evident that the corrosion rates vary across different types of tubing, indicating that the developed equations are effective and produce reliable outcomes. The analysis confirms that the corrosion rate is influenced by temperature and pH, where increasing temperature and pH lead to an increase in corrosion. Furthermore, the analysis shows that Super 15Cr tubing exhibits a lower corrosion rate compared to other tubing types, indicating its superior corrosion resistance.

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Table 3. Summary of regression equations for various materials during shut-in and injection operations

Material	Shut-in Case	Injection Case
Carbon Steel	$CR = -354.7810 - 0.3554\ (t) + 120.3028\ (pH)$	$CR = 168.4188 - 0.3360\ (t) - 48.4545\ (pH)$
13Cr	$CR = -2.6038 - 0.0018\ (t) + 0.8701\ (pH)$	$CR = 0.5699 - 0.0027\ (t) - 0.1157\ (pH)$
Super13Cr	$CR = -0.7615 - 0.0003\ (t) + 0.2496\ (pH)$	$CR = -0.0061 + 4.157 \times 10^{-5}\ (t) + 0.0019\ (pH)$
Super15Cr	$CR = -0.6350 - 0.0003\ (t) + 0.2082\ (pH)$	$CR = -0.0066 + 3.388 \times 10^{-5}\ (t) + 0.0020\ (pH)$

Tabel 4. Corrosion rate (mm/year) determination at surface and downhole condition using regression equation

Material	At surface during shut-in	At bottomhole during shut-in	At surface during injection	At bottomhole during injection
Carbon Steel	7.49	0.429	11.076	8.426
13Cr	0.0395	0.0515	0.143	0.127
Super13Cr	0.00326	0.026	0.000836	0.00108
Super15Cr	0.00142	0.0161	0.000435	0.000644

acknowledges that this work may still have imperfections, and all constructive feedback is welcomed.

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