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Development of Twelve Parameter Prediction Model for Examining the Under-Pipe Corrosion Deposit Condition of Localized Carbon Steel in Acidic Media

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ABSTRACT: This paper presents an under deposit condition of localized carbon steel in acidic gas solutions by developing and using a twelve parameters condition prediction model. The proposed analytical model was tested against De Waard models, neural network model and experimental result and found to have an accuracy of 82.4% against 23%, 53.3%, 95.6% of De Waard Lotz and Milliams models and NN mode and was found to give reasonably accurate results. It had root mean square error (RMSE) of 0.024, mean absolute error (MAE) 0.019, scattered index (SI) 0.371 and with coefficient of determination (R^2) of 82.4% in the validation series. The method is useful for introducing nonlinear conditions prediction in undergraduate/postgraduate engineering with manual computation coupled with lesser error and very simple method in application for better corrosion management than the existing manual traditional models.

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Oil, gas and other petroleum products are mostly produced in large expanses situated far from consumption middles. This implies that the oil and gas must be transferred to refineries, and their refined products moved from producing regions to utilization centers. Conversely, pipeline substructure is the primary means of conveying this natural gas and the crude oil. Furthermore, pipelines play important role in modern societies like Nigeria and are crucial in providing needed fuels for sustaining vital functions such as transportation, power generation, cooking and heating supplies (Tawancy *et al*., 2013). Petrochemical processes companies also use oil and gas to make useful products. Additionally, pipelines are recognized as the safest and most economical mode of petroleum products transportation across far distances and over difficult terrains (Tawancy *et al*., 2013; Teixeira *et al*., 2008).
Pipelines as an engineering facility do fail in-service owing to deterioration. This is mostly climaxed by the environmental factors such as; moisture, oxygen, temperature and even intensive property like pressure. However, the latter factors put together on the exposed facility leads to a complex scenario termed corrosion (Ahammed, 1998; Mohitpour *et al*., 2007). Corrosion is a major problem in pipeline engineering and materials transportation as it may result to high maintenance cost, and in some case huge, financial and economic loses. Oil and gas steel pipeline buried underground deteriorate because of an electrochemical reaction with the environment. Corrosion is the deterioration of material, usually a metal, because of a reaction with its environment and which requires the presence of an anode, a cathode, an electrolyte, and an electronically circuit which important of corrosion is in economic, safety, and conservation of resources (Revie and Uhlig, 2008). In addition, if no proper preventive maintenance is carried out, and there is leakage, it tends to cost the operators huge cost of replacement that lead to production shutdown, loss of fluid, loss of efficiency and high cost of fuel and energy as a result of leakage of corroded pipeline (Mohitpour *et al*., 2007). Corrosion is a major potential problem in the oil and gas industry and is more significant in aged pipeline (Netto *et al*., 2005). The practical techniques of identifying rate of corrosion in oil and gas pipeline are the use of high-resolution magnetic flux leakage (MFL) or ultrasonic technology (UT) tools (Ahammed, 1998; Mohitpour *et al*., 2007; Caleyo *et al*., 2002; EL-Abbasy et al., 2014). Furthermore, with all these procedures, there exist two challenges that include; the inability to estimate when an affected pipeline is expected to fail in service due to corrosion defect and understanding the physic/mechanism of corrosion growth rate as it affects the integrity of a pipeline. These challenges have generated different theories leading to various predictive approaches and models (Caleyo *et al*., 2002; Hallen *et al*., 2002). De Waard and Milliams (1975), study shown that rate of corrosion increases with CO_2

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partial pressure and temperature until it approaches a maximum value at temperature 60-70°C and then decreases until 90°C. De Waard *et al*. (1995) developed a semi-empirical model with the application of data acquired from a high-pressure test facility. The model they proposed incorporate the contributions of kinetics of corrosion reaction and mass transfer of dissolved carbon dioxide. The model, however, fall to account for the oil composition. Jepson *et al*. (1996) came up with an empirical model for rate of corrosion prediction in horizontal multiphase slug flow pipelines. In their model relates the rate of corrosion to the pressure gradient across the mixing zone, temperature, CO_2 partial pressure and water cut. In addition, the model has been enhanced in 1997 to further account for the effect of slug frequency and oil type (Jepson *et al*., 1997). Xiao *et al*. (2002) in their study a mechanistic model was proposed for CO_2 corrosion in horizontal multiphase slug flow in 2002. The study covers the electrochemical reactions on steel surface, the chemistry of fluid, and mass transfer between the metal surface and the fluid. Nesic *et al*. (1995) in their investigation a comprehensive model was develop for internal corrosion prediction in mild steel pipelines. Several factors affecting the rate of corrosion include H_2S, water entrainment in multiphase flow, corrosion inhibition by crude oil components and localized attack have been examine into account in the model.

However, the results of the respective internal corrosion predictive method may deviate from the realistic corrosion rates when the internal environmental parameters of the inspection segments are outside the scope of the prediction model. Hence, the objective of this study is to develop a twelve-parameter prediction model for investigating the under-pipe corrosion deposit condition of localized carbon steel in acidic media.

MATERIALS AND METHOD

Model Formulation and Governing Equations: The modeling of under deposit corrosion in oil and gas pipeline prediction were developed following the iterative steps involved from the theoretical and experimental background/understanding physics/corrosion mechanism of the study. The developed model equation can be solve manually or with any spreadsheet package unlike the neural network model which can only be solved by programming software that support neural network tools. The performance of the proposed model was determined by running a repeated test with experimentally determined corrosion rates for the given conditions. The twelve listed factors represent the main operational parameters in the model are individually analyzed. In analyzing the rate of corrosion through an oil and gas pipeline, the following assumptions were adopted: (i.) CO_2 is the corrosive species present in the fluid flow (oil and gas) industry (ii.) The pH of the system varies with dependent on temperature (iii.) Corrosion is localized over the target surface of the oil and gas pipeline (iv.) Fluid viscosity and density varies with temperature dependent (v.) Sand deposit production is not negligible

The proposed Model takes the form below as;

$$\log(CR) = \beta[K\bar{P} + \alpha] + M \qquad (1)$$

Where; CR = corrosion rate in [mm/year]

$$\bar{P} = \log(inputs\ matrix) \qquad (2)$$

$$inputs\ matrix = \begin{bmatrix} L \\ D \\ A \\ T \\ P \\ V \\ P_{CO_2} \\ pH \\ Cl \\ SF \\ \rho \\ \mu \end{bmatrix} \qquad (3)$$

The original governing equation of the developed model thus depends on L = spool length [mm], D = diameter of pipe [mm], A = age of pipe [years], T = Temperature of fluid [^{0}C], P = Flow Pressure [bar], V = Flow velocity [m/s], P_{CO_2}= Partial Pressure of CO_2 [bar], pH = oil pH [-], Cl = Chloride content [mg/kg], SF = Sand flow Deposit [m/s], ρ = Oil Density [Kg/m^3], μ = Oil viscosity [cP].

K, α, β and M are constants matrices given as follows;

$$K = \begin{bmatrix} K_{1,1}K_{1,2}K_{1,3}K_{1,4}K_{1,5}K_{1,6}K_{1,7}K_{1,8}K_{1,9}K_{1,10}K_{1,11}K_{1,12} \\ K_{2,1}K_{2,2}\ K_{2,3}K_{2,4}K_{2,5}\ K_{2,6}\ K_{2,7}\ K_{2,8}\ K_{2,9}\ K_{2,10}\ K_{2,11}\ K_{2,12} \end{bmatrix} \qquad (4)$$

$$\alpha = \begin{bmatrix} \alpha_1 \\ \alpha_2 \end{bmatrix} \qquad (5)$$

$$\beta = [\beta_{11}\ \beta_{12}] \qquad (6)$$

The constant K[-] is the input parameters exponent factors,α[-] is the correlation factors and β[-] is the transformed parameter coefficients. M is the error correction constant. This constant reduces the error in the calculation of the corrosion rate. M is a matrix of a single constant defined as;

$$M = [M] \qquad (7)$$

Table 1: Constants of the model

S/N	K_1	K_2	α	β_1
1	-0.0149	-0.0016	-1.6284	3.5677
2	0.0754	0.0075	-1.2582	6.9925
3	0.0793	0.0145		
4	-1.0542	-0.4340		
5	0.0953	0.0458		
6	0.1341	0.0160	$M = 0.5679$	
7	0.0453	0.0126		
8	-0.0909	0.0569		
9	0.5379	0.4765		
10	0.0047	0.0060		
11	0.8456	0.4839		
12	-0.6520	-0.2381		

Table 2: Inputs Field Data

Pipe length (mm)	Diameter (mm)	Pipe age (year)	Fluid temp (oC)	Pressure (bar)	Velocity (m/s)	CO_2 partial pressure (bar)	pH	Chloride (mg/Kg)	Sand flow (m/s)	Oil density	Oil viscosity
211	304.8	6	44	55	2.7	4.5	5.6	34.6	1.67	832.60	24.81
45	508	37	67	70	1.2	2.5	3.9	36.5	1.04	818.80	10.73
121	609.6	19	69	52	1.02	3.8	3.5	35.9	0.98	817.54	10.00
300	400	16	35	64	1.81	6.0	6.4	30.7	0.92	838.18	37.18
700	610	29	70	36	1.01	4.6	5.2	36.1	0.58	816.88	9.65
500	600	32	69	62.8	0.92	5.4	3.8	35.3	0.45	817.59	10.03
60	609	25	55	70	0.82	2.2	5.6	34.7	0.43	825.98	16.28
500	192.7	8	35	39	2.85	2.2	5.8	32.9	1.83	838.07	36.95
242	406.4	26	67	56	1.85	5.8	3.4	37.1	0.98	818.74	10.70
119	914	28	45.5	59	0.98	4.9	5.1	34.8	0.67	831.69	23.36
55	305	40	70	60	2.71	5.3	6.4	35.2	2.01	816.98	9.70
100	508	30	48	64	1.56	2.5	4.3	36.9	1.02	830.19	21.17
1000	225	13	55	40	2.2	2.0	5.24	33.8	1.97	825.85	16.17
45	508	41	67	30	1.95	3.4	5.86	37.9	1.04	818.63	10.63
60	609	15	53	45	1.08	2.9	5.34	34.3	0.69	827.08	17.42
500	192.7	11	45	37	2.92	2.2	5.23	31.7	1.56	831.91	23.71
121	609.6	6	70	67	0.76	2.6	3.6	38.7	0.41	817.01	9.71
211	304.8	31	45	45	2.62	5.4	5.7	34.5	1.78	831.94	23.76
210	304.8	27	66.5	69	1.75	4.3	5.45	34.7	1.08	819.09	10.91
250	406.4	8	63	49.5	2.85	3.4	5.67	30.1	1.12	821.09	12.22

RESULTS AND DISSUSION

Using data from a particular field Z in the Niger Delta region of Nigeria for twenty different cases to first validate the proposed model for uniform/localized corrosion, the results gotten from both field and the one predicted by the proposed model are as shown in Table 3.

Table 3: Comparison of Field, DeWaard and ANN with the proposed model

Pipeline	Field value CR[mm/yr]	DeWaard Lotz CR[mm/yr]	DeWaard Milliams CR[mm/yr]	AAN Model CR[mm/yr]	This Study CR[mm/yr]
1	0.020	0.060	0.068	0.030	0.038
2	0.141	0.012	0.106	0.190	0.115
3	0.035	0.014	0.151	0.040	0.071
4	0.028	0.047	0.057	0.030	0.028
5	0.060	0.017	0.177	0.060	0.065
6	0.134	0.018	0.191	0.140	0.080
7	0.025	0.007	0.064	0.030	0.045
8	0.022	0.043	0.029	0.020	0.018
9	0.123	0.047	0.187	0.110	0.125
10	0.046	0.013	0.076	0.050	0.058
11	0.216	0.072	0.195	0.210	0.171
12	0.062	0.015	0.054	0.070	0.082
13	0.031	0.029	0.06	0.030	0.025
14	0.143	0.024	0.131	0.150	0.127
15	0.045	0.011	0.072	0.030	0.033
16	0.026	0.045	0.044	0.030	0.017
17	0.054	0.008	0.121	0.060	0.059
18	0.035	0.070	0.080	0.030	0.064
19	0.136	0.042	0.151	0.140	0.086
20	0.044	0.039	0.114	0.050	0.026

From the validation set of the proposed model shown in table 3, the error resulting is analyzed using Root mean square error (RMSE), Mean absolute error (MAE), Scattered index (SI) and Coefficient of determination (R^2) parameters. Fig 1 depicts the variation of this proposed model and the field data. Having compared the propose and other models, other commonly used empirical correlations are also compared with the developed model in order to check its performance as shown in Table 4.

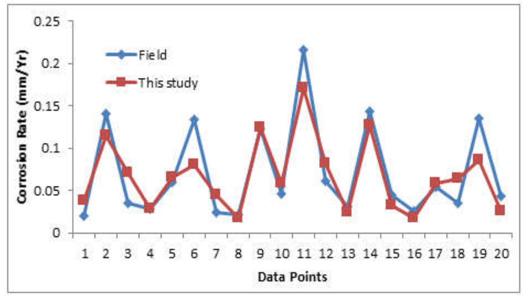

Fig 1: Variation of Proposed Model and Field Data

Table 4: Comparison of Proposed model with other empirical models

Measurement	WAARD LOTZ	WAARD MILLIAM	ANN MODEL	This study (Model)
RMSE	0.068	0.052	0.012	0.024
MAE	0.053	0.042	0.007	0.019
SI	2.160	0.495	0.170	0.371
R^2	0.023	0.533	0.956	0.824

The developed model equation can be solve manually or with any spreadsheet package unlike the neural network model which can only be solved by programming software that support neural network tools. The performance of the developed model was determined by running a repeated test with experimentally determined corrosion rates for the given conditions. The table 4 shows that neural network performed best with minimum errors and scatter index. The proposed model performed better than the rest apart from neural network model, but the rational here the proposed model can be computed manually or with any spreadsheet with easy, without undergoing the constrain of training and re-training, testing and validation regression plots. The figure 2 is the plots of predicted corrosion rate result versus field results for the model.

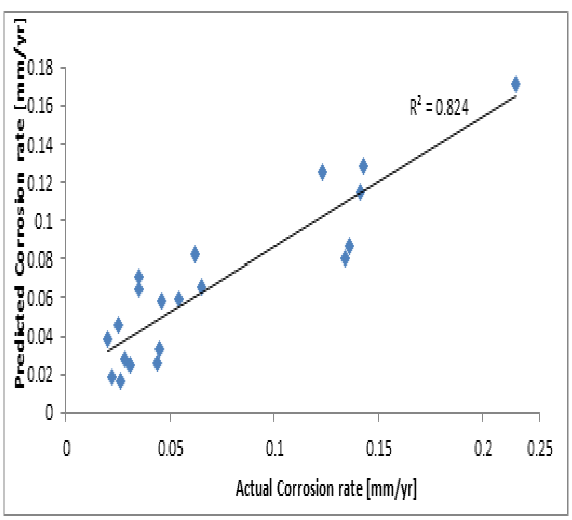

Fig 2: Proposed Model Performance plot

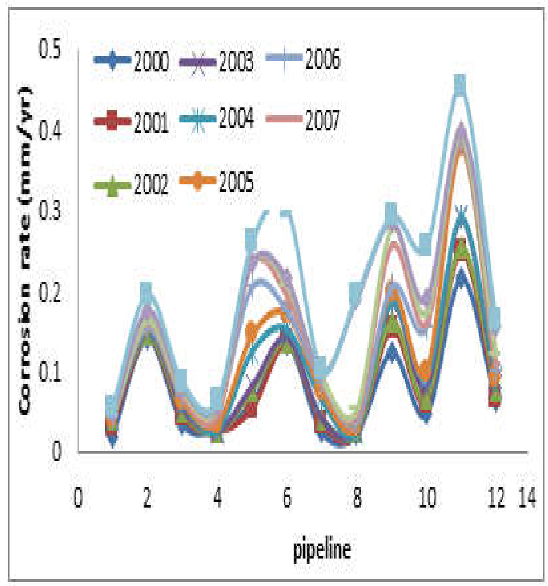

Fig 3: corrosion rate against pipeline for 2000–2010

To further investigate the effect of pipe age on the corrosion rate of pipes, the following graphs (Fig 3-Fig 15) were plotted for the first 12 pipelines. The pipeline ages were varied while all other parameters kept constant; the predicted corrosion rates were therefore a function of pipe age and so deviate a little from the corrosion rate obtained from the field, which is the combined effect of all the parameters put together. The results show that corrosion rate increase with increase in the age of installation of the pipes. This is in agreement with the work of Netto *et al*. (2005). The predicted rates of corrosion also show the same trend.

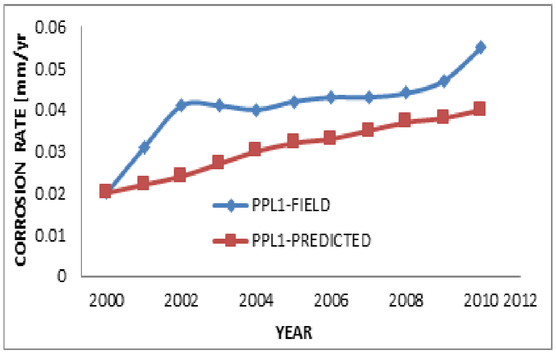

Fig 4: corrosion rate against time for pipeline 1

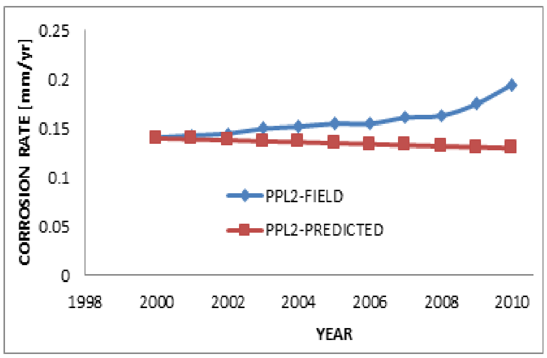

Fig 5: corrosion rate against time for pipeline 2

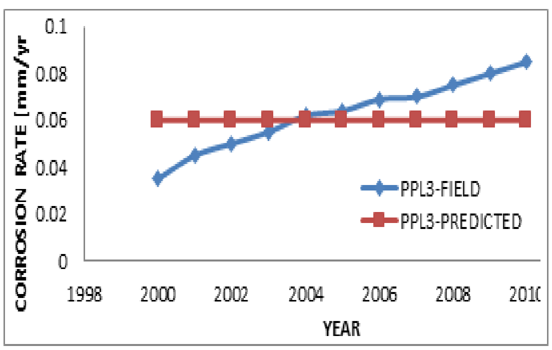

Fig 6: corrosion rate against time for pipeline 3

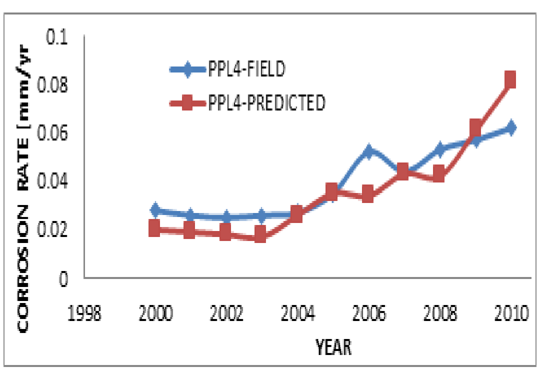

Fig 7: corrosion rate against time for pipeline 4

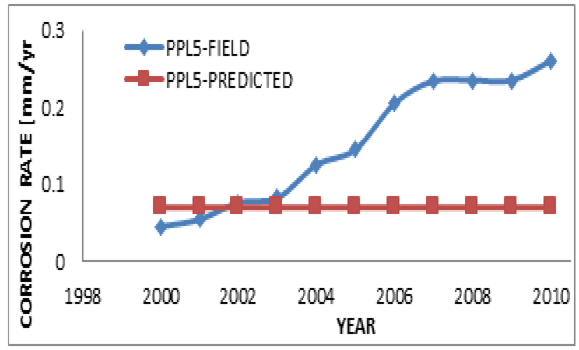

Fig 8: corrosion rate against time for pipeline 5

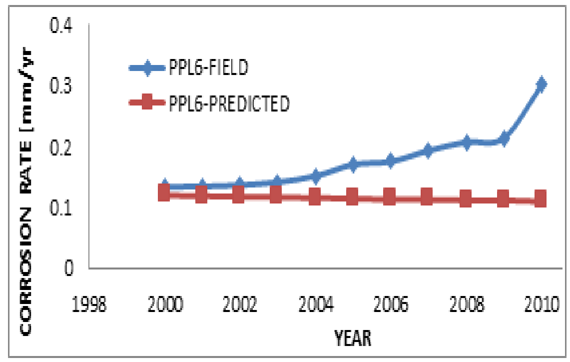

Fig 9: corrosion rate against time for pipeline 6

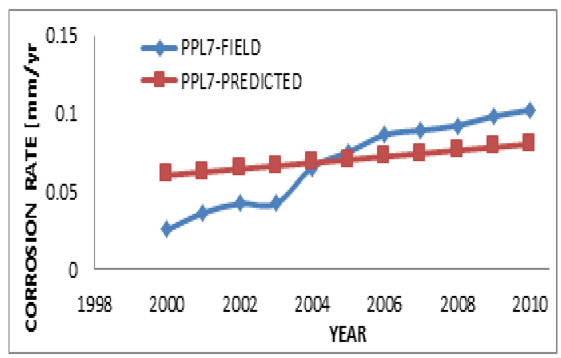

Fig 10: corrosion rate against time for pipeline 7

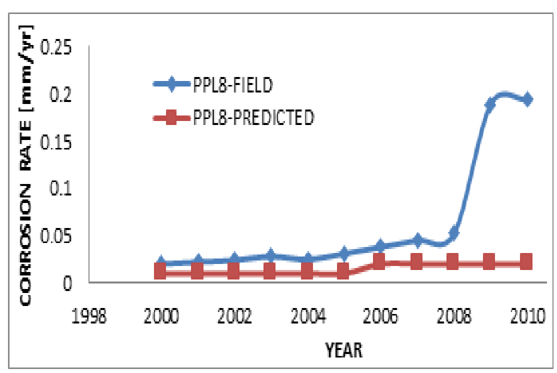

Fig 11: corrosion rate against time for pipeline 8

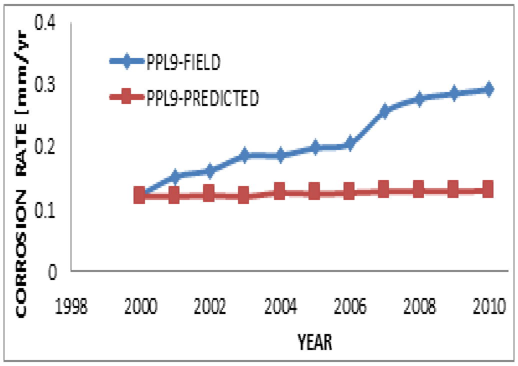

Fig 12: corrosion rate against time for pipeline 9

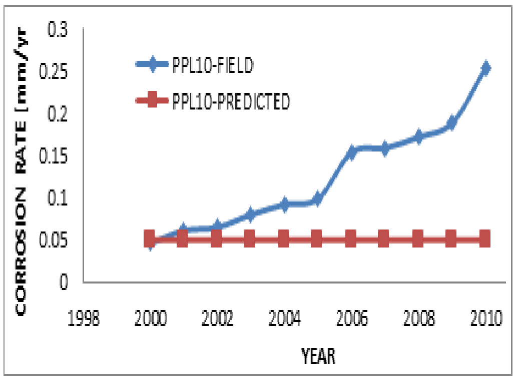

Fig 13: corrosion rate against time for pipeline 10

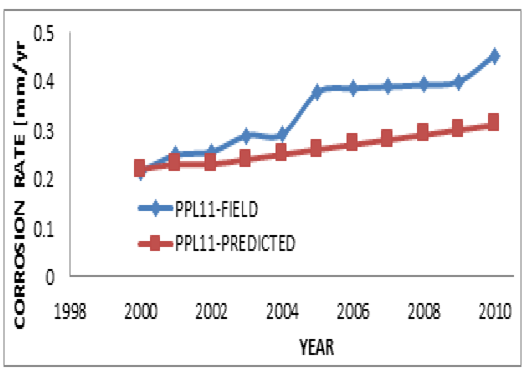

Fig 14: corrosion rate against time for pipeline 11

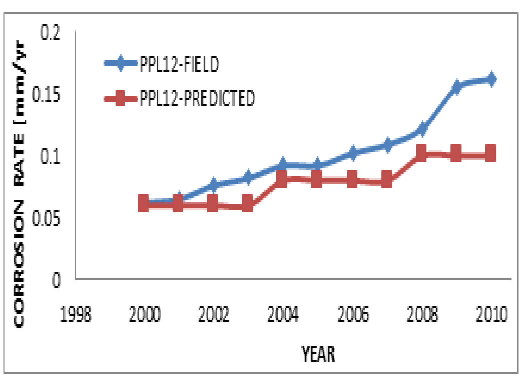

Fig 15: corrosion rate against time for pipeline 12

Conclusion: This study presents development of twelve-parameter prediction model for examining the under-pipe corrosion deposit condition of localized carbon steel in acidic media. The proposed analytical model was tested against De Waard Lotz, Milliams models and experimental result and found to give reasonably accurate results. The intention of this paper is to present a method that can be used to easily introduce complex nonlinear condition in relevant undergraduate/postgraduate engineering with manual computation coupled with less error and very simple method in application for better corrosion management.

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