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Invited Paper

Predicting Corrosion in Pipelines, Oil Wells and Gas Wells; a Computer Modeling Approach

F.F. Farshad[1,*], J.D. Garber[2], H.H. Rieke[3] and Sh.G. Komaravelly[2]

Abstract. *Hostile oilfield corrosive environments have challenged the production and transportation operations of the petroleum industry. The estimated cost of corrosion on the U.S. economy in the year 2002 resulted in an expenditure of about 276 billion U.S. dollars. This amount was an increase of more than $100 billion over a previous five year period. Corrosion maintenance expenditures over this 5 year period were approximately 3.1% of the U.S. GDP, and stimulated congress to enact the Corrosion Prevention Act in 2007. One avenue available to successfully combat corrosion in the petroleum industry is the recent progress made in corrosion prediction applications for petroleum operations. Three such corrosion computer models have been developed at the University of Louisiana at Lafayette. These models are capable of predicting the physical conditions and corrosion rates inside pipelines and in producing oil and gas wells. The models are window based and described in this paper. An expert system module was developed, which adjusts the predicated corrosion rate based on various known reservoir and well subsurface parameters.*

Keywords: *Pipeline corrosion modeling; Oil and gas corrosion modeling; Flow assurance.*

INTRODUCTION

Corrosion can be defined as the destruction of a metal by chemical or electrochemical reactions, or microbial reaction with its environment. The principles of corrosion must be established in order to effectively select materials, and provide the design and fabrication of Oil Country Tubular Goods (OCTG) and production facilities in such a manner as to optimize their economic life and ensure safety in petroleum operations. Mitigation of corrosion is an important integral part of combating flow assurance problems [1]. Until recently, no single text book devoted to petroleum science and engineering aspects of corrosion was available until one was authored by Chilingar [2].

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The basic fundamentals of corrosion are the same for all metals and alloys, and differ in degree and not in kind [3]. The factors which influence corrosion are divided into two groups. Group one delineates factors associated mainly with metals. These include:

- Effective electrode potential of the metal.
- Overvoltage of hydrogen on the metal.
- Tendency of metal to form an insoluble protective film.
- Chemical and physical homogeneity of metal surface.
- Nature, concentration and distribution of electrolytes.
- Environmental tendency to deposit a protective film on the metal surface.
- Solution flow rate against metal.
- Environmental temperature and pressure.
- Static or cyclic stresses.
- Contact with dissimilar solutions.
- Contact with dissimilar metals.
- Microbial activity that forms H_2S, sulfur bearing proteins and sulfides.

During well drilling, general corrosion control practices in petroleum operations involve the use of a high pH mud containing a corrosive inhibitor. The well completion practice uses a cement sheath and bond between the pipe and the formation to protect the casing by controlling water inflow into the well. The pipe mill scale is controlled by pickling (5-10% H_2SO_4 or 5% HCl at 180°F with inhibitors) or by sand blasting [2]. Bactericides or oxygen scavengers are used to control corrosion in the subsurface. Cathodic protection is not a practical method for controlling corrosion of drill pipes or the internal surface of the well casing. Chilingar [2] pointed out that cathodic production is best used in the protection of pipelines and flowlines.

Today, newly developed computer models help combat corrosion and predict corrosion rates for a variety of petroleum production operations. Such computer models were developed at the University of Louisiana at Lafayette, Corrosion Research Center. The models are capable of predicting corrosion rates in oil wells, gas wells and pipelines. Development of the models was sponsored by industry and the United States Department Of Energy (DOE) [4]. The oil and gas modeling results provide a physical description of what is happing inside production wells, as a function of well depth [5,6]. An overview of the computer models is presented to demonstrate the technical advances in corrosion mitigation in vertical production hydrocarbon wells, pipelines and flowlines.

PIPELINE MODEL

A new pipeline model has been developed that can predict the corrosion rate in gas and oil flowlines and pipelines. The program describes the physical and chemical conditions inside a pipeline. This model predicts the corrosion rate in systems containing CO_2, H_2S, organic acid and bacteria. The above model predicts the occurrence of “top of the line” corrosion, internal wettability conditions and describes flow dynamics in large diameter pipelines. Furthermore, the model is capable of providing risk assessment which allows for integrity management of the system [7].

Physical Description

The first three modules shown in Figure 1 give the flowchart description of a process modeling. This includes a temperature/pressure profile, the phases present and the flow dynamics at each point in the pipe. In the case of CO_2 corrosion, the flow regime is very critical to the prediction of the corrosion rate. Typical horizontal flow regimes are described by the model in Figure 2. The flow dynamic model includes empirical corrosion rate prediction.

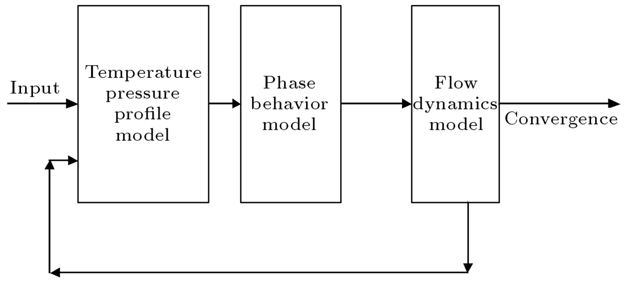

Figure 1. The three models that are looped for pressure convergence.

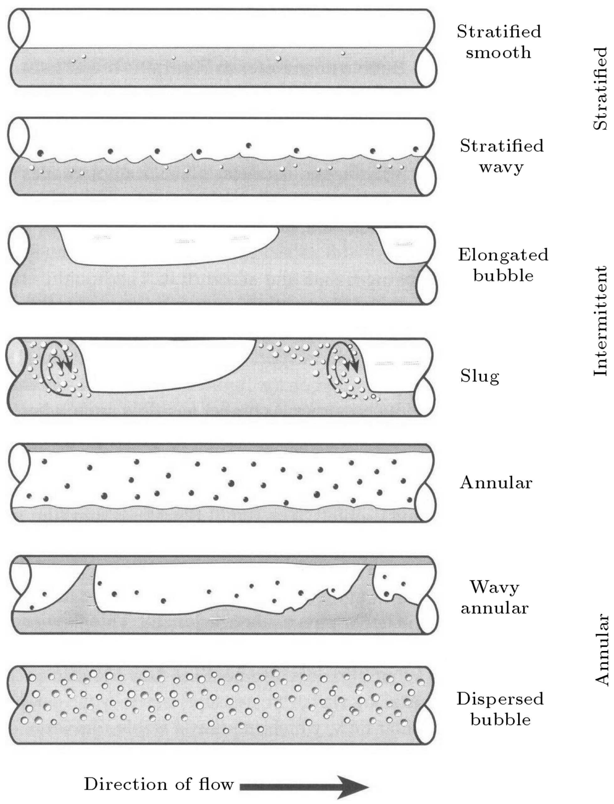

Figure 2. Flow pattern for horizontal two-phase flow.

Chemical Profile

The model is capable of predicting the chemical properties of the water in the system. In a system containing condensed water, the pH is low and so is the ion concentration. It is possible to track the location of organic acids entering the system, as well as bicarbonates and other ions. The potential for scale can be predicted by this model.

Corrosion Rate Profile

The final and most difficult part of the model is determination of the corrosion rate. Using equations developed in our previous models, we obtained accurate estimates of the corrosion rate at each point in the pipeline system. In addition to the more empirical models, a pitting corrosion model has also been included, which estimates the theoretical pitting rate. This model requires that a water analysis be available.

To provide the best estimate of the actual corrosion rate, an expert system has been developed. The parameters that are considered are temperature, water wetting, % inhibition, scaling and microbial effect.

Risk Assessment

Risk Assessment is useful in evaluating the life of various systems. General corrosion models predict the corrosion rate on a deterministic basis, namely all the input values are known and are fixed. However, in reality, each input will have some uncertainty associated with it because of the variation of production conditions and environment. This variation can have a significant impact on the corrosion rate prediction. One way to solve this problem is to calculate the range of corrosion rates based on the whole range of input values. This process can be time consuming if many inputs are involved.

Pitting Corrosion

There are, in total, 20 parameters used as inputs to determine corrosion rate in the pitting model. Variations of some of the 20 parameters have a significant impact on the predicted corrosion rate, and others have only a minor impact. Attaching a random number generator to all these variables will be time consuming and unnecessary. In this work, major variables are distinguished from minor variables in terms of their influence on the corrosion rate, and only major variables are considered to be associated with certain distribution types. The minor variables will be evaluated on their input basis.

Specifying the typical range of each variable in the field, the corrosion rate is calculated by continuously changing one variable in the range with others fixed. The resulting maximum and minimum corrosion rates are compared, giving the percent change of the corrosion rate for that particular variable. The effect of each variable on the corrosion rate was determined and it can be seen by our data that bicarbonate, temperature, CO_2 mole fraction, pipe wall thickness, chlorides, pressure and bulk iron have an effect on the corrosion rate in the range assigned [7].

MAJOR VARIABLES

In this work, field data and assumptions from the literature are combined to determine the distribution type of major variables. Based on 11,838 water analyses from oil and gas companies, distributions have been found for the following variables:

- Alkalinity (bicarbonate): log-normal.
- pH: normal.
- Chlorides: log-normal or normal.

A corrosion rate distribution of 20,000 iterations with assigned distribution type inputs resulted in a calculated mean corrosion rate of 20.7 mpy, and the standard deviation equals 9.54 mpy. The actual predicted corrosion rate was calculated to be 19.6 mpy by using the mean value for normal and log-normal type inputs and the average value between the lower and upper limit for uniform type inputs.

This ratio is the same as quoted by investigators of the Norsok and DeWaard Milliams [7] models for local corrosion. This result is encouraging, because it validates the random number generators and also the pitting model. In the model, due to time constraints, the standard deviation was fixed at 45% of the predicted corrosion rate, even though it will normally range from 35% to 55%, depending on input values.

CLASSIFICATION OF RISK ASSESSMENT

With the knowledge of probability of failure, the risk category of the pipe can be identified based on the criteria proposed in the DNV RP-G101 standard [7].

OIL WELL MODEL

An oil well computer model is developed that is capable of predicting physical conditions and corrosion rates inside a vertical or deviated well at various depths and under naturally flowing or gas lift conditions [4]. The model contains five specific parts. The following describes the five main parts of the model.

1. **Temperature/Pressure Profile**: This program calculates the temperature and pressure profile at various depths in an oil well. The model uses the method of Artificial Neural Networks (ANN) to establish the temperature profile. Farshad et al. [8] developed a neural network based methodology to predict the fluid temperature profile in producing multiphase oil wells. The initial values used in the pressure calculation assume a linear pressure profile between the wellhead and bottomhole pressure values. A looping routine was used to estimate the pressure drop in an oil well.
2. **Phase Behavior Profile**: Prediction of the hydrocarbon phases that are at equilibrium at various depths in the well was undertaken using the Peng-Robinson equation of state. This model first matches the flow rates of the gas-oil-water phases in the separator using gas composition, gravity of

oil, temperature and pressure. Once the flow rates in the separator are matched by looping, the overall composition of the full production stream can then be determined. The program then performs the phase equilibrium calculation to bottomhole.

3. **Flow Dynamics Profile**: Once the phase equilibrium information is known, it is possible to establish the flow dynamics at various depths in a [9] well. Figure 2 was used to provide the best overall description of the transition points between bubble, slug and churn flow regimes in an oil well. The three flow regimes are shown in Figure 3 for a non-annular flowing oil well. The liquid and gas [9] superficial velocities calculated in Figure 2 can be used to identify which regime occurs at any location in an oil well.

   The equations described by Fernandes [10] are the ones being used to physically describe the slug unit, as shown in Figure 4. One of the parameters that come from this calculation is the length of the liquid slug. Calculations have shown, in over 50 wells tested, that the void fraction at the point when the length of the Taylor bubble became negative was approximately 0.275. This value was, therefore, adopted as the point of slug to bubble transition.

4. **Corrosion Rate Profile**: Garber et al. [4] pointed out that the primary objective of this model was to use the physical parameters generated at each point in the production tubing to develop an empirical correlation with the corrosion rate. Inasmuch as oil inhibition is a problem in the prediction of the corrosion rate in oil wells, fluid data from non-annular gas condensate wells was used in the correlation. Four parameters, plus this one, were established to produce an empirical corrosion rate model for vertical flowing oil wells.

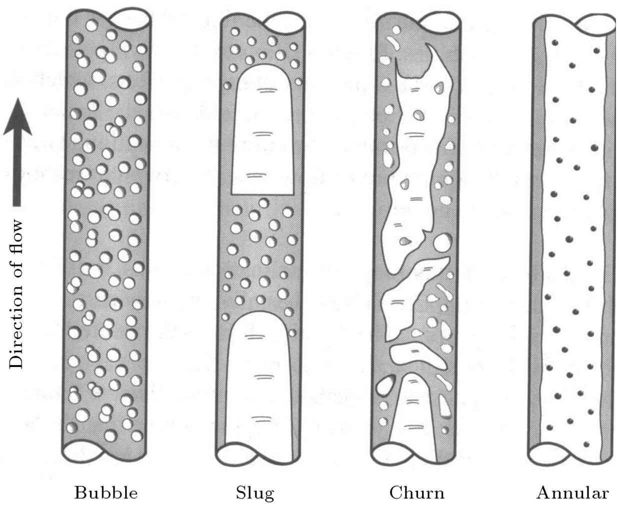

Figure 3. Flow pattern for vertical two-phase flow.

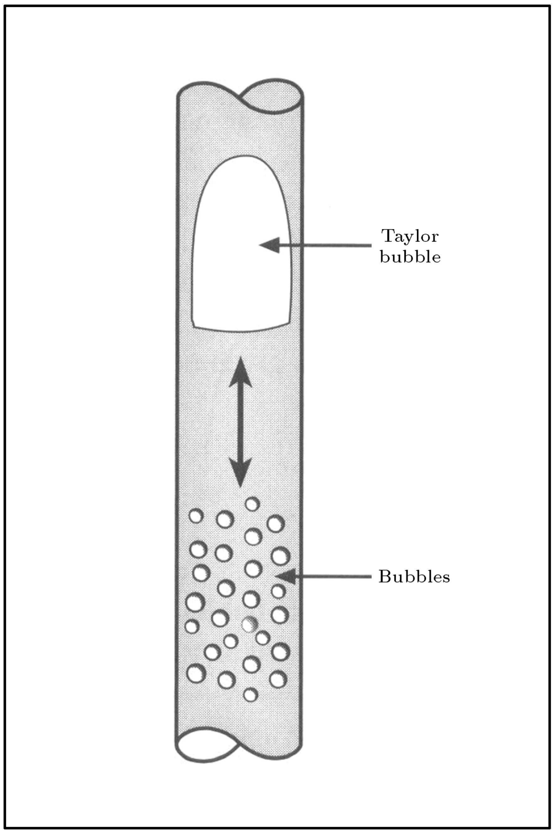

Figure 4. Slug unit in an oil well.

5. **Corrosion Rate Expert System Component**: Factors to be considered in developing a corrosion rate expert system for oil wells are:
   - Water wetting effect.
   - Effect of flow regime.
   - Temperature effect.
   - Inhibitive effect.

   These factors have been shown to be important by various investigators who have worked in the area of CO_2 corrosion for many years. The factors are used to adjust the predication rate for an oil well.

GAS WELL MODEL

A gas well computer model was developed [6], which can help predict the location of corrosion and the life of carbon steel tubular in a gas condensate well containing carbon dioxide. This model provides a physical description for the five different flow regimes that can occur in gas wells. This description has proven to be useful in the prediction of the corrosion rates of these wells. The model does not use the partial pressure of CO_2 in calculation of the corrosion rate. It has been found that the hydrodynamics and the amount of water present are the most important parameters in this type of corrosion. The model has an expert system associated with it, which takes into account the volume fraction of condensate and water in the tubing. When the water level reaches and exceeds 50% of the total volume, the tubing is completely water-wet and the corrosion rate is a maximum. At the point where 30% or less of the volume of the fluid is water, the corrosion rate is believed to be zero. Caliper surveys have played a role in our ability to establish these points of transition within the model. Farshad et al. [6] presented case histories that illustrate how the model can help in performing corrosion failure analysis and in the design of gas condensate wells.

The model provides a physical description of what is happening inside the production tubing as a function of well depth. This type of description has been found to be essential for an accurate prediction of corrosion rates in gas wells. Table 1 is a data sheet that presents the technical input into the model. Five categories of minimum requirements for data input are mandatory to successfully run the model. The minimum required data are:

- Completion information, such as true vertical depth, measured depth, size of tubing and casing data, is required.
- Temperature and pressure information at the separator wellhead and bottomhole is required.
- Separator production rates of the gas, condensate and oil are required.
- Analysis of the gas phase and gravity of the condensate are a minimum requirement for the input.
- A water analysis is needed if the in situ pH is to be calculated. The model corrects the pH for the presence of organic acid.

The required data, when used, is for a particular time period in the life of the gas wells. Producing gas wells can have compositions and flow rates that normally change with time. This requires multiple modeling of a gas well during its productive life to obtain the necessary picture for corrosion control. The model consists of five computer modules A, C, E, F and G.

Computer module A calculates the temperature and pressure profiles in a well based on computer module G, which produces the bottomhole flowing temperature for a given pressure drop as the gas exits through the casing perforations into the well. The phase behavior program which calculates the phases that exists at any point in the tubing is calculated by computer module C. Information from computer module C can help in deciding if the gas well tubing is oil wet or water wet. Computer module E is the flow dynamic model that describes the type of flow regimes present inside the well's tubing, and module F is the model for corrosion rate prediction.

COMPUTER MODULES' PHYSICAL DESCRIPTION

Physical Description Models

Models A and G

The first calculation made with the input data focuses on the temperature and pressure at each depth. Well configuration, number and length of casing and the casing fills constitute the information necessary to calculate the overall heat transfer coefficient vs. depth. If the geothermal gradient is known, the heat transfer rate can be determined. The fluids inside the well are flowing nonisothermally and a microscopic momentum and energy balance calculation on the flowing gas produces the equations necessary to calculate both the temperature and pressure drop. Physical properties of the gas and liquids produced inside the tubing are permanently stored in the program for use when needed.

The gas undergoes a substantial pressure drop through the perforations during production. It is possible to estimate the bottomhole flowing temperature using Model G. This model accounts for the adiabatic expansion of the gas using the Peng-Robinson equation of state. For a typical pressure drop, the temperature of the gas can drop as much as 25°F from its reservoir temperature value. Neglecting this factor can significantly affect the temperature profile and dew point location.

Model C

Since a gas condensate well is being modeled, one may expect that in addition to gas, both condensate and water could be present inside the tubing. Using the separator production rates and the gas composition, it is possible for the Peng-Robinson EOS to predict the phases present at every depth. If a well is producing formation water, it can be said with certainty that the tubing contains water from the bottomhole to the wellhead. Otherwise, the water may show a dew point somewhere up the tubing. The program can predict this water dew point location. Likewise, the location of condensate inside the tubing is equally important and the model can predict the location of the condensate as well. Therefore, unlike oil wells which produce oil from bottomhole to wellhead, condensate wells may or may not have condensate inside the tubing. Previous work at the center [11] showed that approximately 55% of condensate wells had no condensate inside the tubing, even though there was a substantial amount of condensate in the separator.

Model E

Once it has been established that there is liquid inside the production tubing, it is important to know what type of flow pattern exists at each depth. Figure 3

Table 1. Standard input data sheet.

Field/Lease/Well# ____________________

Separator Production Information :

Gas Rate at Separator = __________ MMSCF/D

Condensate Rate at Separator = __________ BBLS/D

Water Rate at Separator = __________ BBLS/D

Temperature __________°F, Pressure __________ psig

Gas (y)/Condensate (x) composition - mole fraction or mole percent

Nitrogen	______/______	n-Pentane	______/______
CO_2	______/______	Hexane	______/______
H_2S	______/______	Heptane	______/______
Methane	______/______	i-Octane	______/______
Ethane	______/______	Nonane	______/______
Propane	______/______	Decane	______/______
i-Butane	______/______	Formic Acid	______/______
n-Butane	______/______	Acetic Acid	______/______
i-Pentane	______/______	User Defined	______/______

Heavy Component C_plus __________/__________

Condensate Properties, API Gravity __________ at __________ °F or

Specific Gravity ______, Molecular Weight ______

Density of water (default = 62.4 lb./cu.ft.) ______

Heavy Component Properties, Specific Gravity ______, Molecular Weight ______

Well Information:

Type of Well: On-shore ______ Off-shore ______

Depth of Well to mid-perfs : True Vertical Depth ______ ft, Measured Depth ____ ft

Offshore Well Only:

Depth of Water ______ ft

Sea Level to Wellhead - Length of wellbore exposed to air ______ ft

Temperature of Air ______ °F

Wellhead Temperature (flowing) ______ °F, Pressure (flowing) ______ psig

Bottomhole Temperature (static) ______ °F, Pressure (static) ______ psig

Production Tubing inside Diameter (ID) ______ inches, Thickness ______ inches

Coated Tubing ____Yes ____No

Casing Size ______ inches, Length ______ ft, Annulus Fill ______

Casing Size ______ inches, Length ______ ft, Annulus Fill ______

Casing Size ______ inches, Length ______ ft, Annulus Fill ______

Casing Size ______ inches, Length ______ ft, Annulus Fill ______

Casing Size ______ inches, Length ______ ft, Annulus Fill ______

Water Analysis (Optional)

Ion Concentration (mg/l)

shows the five types of flow pattern that can exist in vertical flow. Sixty percent of gas wells studied using Model E were found to be in annular flow at all points in the tubing. Of the remaining wells, 20% were found to be in mist flow at various points in the tubing and 20% were in churn-, slug- or bubble-type flow. A description of how the various flow regimes are modeled follows.

Annular Flow

This type of flow is defined as having the bulk of the liquid flowing upward against the pipe wall as a film. The gas phase is flowing in the center of the pipe with some entrained liquid droplets in the gas phase. As described earlier [12], to obtain the liquid film thickness, it is necessary to calculate the entrained liquid. Then, using a microscopic momentum balance on an element in gas-liquid two-phase flow, it is possible to develop a triangular relationship between pressure gradient, flow rate of liquid film and liquid film thickness [12].

Mist Flow

In high velocity wells, the corrosion rate can become activation controlled due to a disturbance of the liquid film. This has been found to occur whenever (1) the annular flow program calculates that the liquid film is more than 50% turbulent, or (2) when the liquid droplets become large enough and of sufficient velocity to disturb the liquid film. A paper by Kocamustafaogullari et al. [13] gives an equation for the maximum stable droplet size, in terms of dimensional groups, such as liquid-and gas-phase Reynolds number, modified Weber number and dimensionless physical property groups. Using this concept, a paper [14] on the generation of droplets has shown that for gas condensate wells, the droplets are about 12 times larger in diameter than the thickness of the liquid film. Their velocities are somewhat less than that of the gas, but it is clear that these are high energy projectiles than can impact the liquid film causing it to become increasingly turbulent.

The ability to identify mist flow wells based on their abnormally high corrosion rates has been made possible, using a discriminate analysis method [15]. A probability equation has been developed which uses four parameters:

1. Mixture superficial velocity.
2. Reynolds number of liquid.
3. Percent of liquid film in turbulent flow.
4. Liquid pressure drop.

Based on this relationship, at every depth in an annular flow well, the equation is checked to determine if mist flow exists.

Slug/Churn/Bubble

The remaining 20% of gas wells exist in a flow pattern described as churn, slug or bubble. The approach used in this work was based on considering the slug unit as consisting of one Taylor bubble, its surrounding liquid film and a liquid pad between the bubbles. Several important parameters, such as the length of the Taylor bubble and the average void fraction of the Taylor bubble and the slug unit were all calculated to within 5 to 10% of the measured values. The void fraction of the slug unit is equivalent to the liquid holdup at each point in the tubing.

This model has also proven to be useful in defining the slug/ churn transition point. Mashima and Ishii [16] postulated that direct geometrical parameters, such as the void fraction are conceptually simpler and yet more reliable parameters to be used in flow regime criteria than the traditional parameters such as gas and liquid superficial velocities. With this in mind, other work [17] has shown that the vast majority of void fractions for churn flow had a slug unit void fraction of greater than 0.73. None of the reported values below 0.73 were in churn flow [18]. This parameter and its value of 0.73 were selected in this work as the basis of the slug/churn transition point.

Corrosion Rate Model

Since a physical description of each flow regime has been developed, attempts have been made to use these flow parameters to predict corrosion rates in these wells. The following corrosion rate models have been developed.

Annular Flow

As described previously, a well that is in the annular flow regime is usually found to exhibit a liquid film of a given thickness that can be divided into laminar, buffer and turbulent components. Table 2 shows the results of modeling 12 gas wells [12] that had known corrosion rates. The three wells with the thickest film failed in the shortest period of time. From these data, an excellent tubing life correlation [12,19] based on the first principle, known as Model F, was developed, which uses the film thickness and liquid velocity.

Mist Flow

If a well is found to be in mist flow by the previously mentioned discriminate analysis equation, a fundamental change is made to the above corrosion rate correlation. The velocity of the droplet is used in place of the liquid velocity. In most cases, the droplet velocity is within 90% of the gas velocity value. This approach is theoretically more sensible, because it is believed by some investigators that the corrosion rate in mist flow is controlled by droplet impingement [20]. The corrosion under this condition is believed to be

Table 2. Calculated film thickness in a gas condensate well.

Well No.	Actual Life (months)	Entrainment %	Calculated Film Thickness (mils)			
			Laminar	Buffer	Turbulent	Total
1	44	0.21	1.0	5.0	0.4	6.5
2	117	1.04	0.5	1.6	...	2.1
3	113	0.28	1.2	3.5	...	4.7
4	59	0.60	0.5	2.4	...	3.0
5	71	0.25	1.0	4.5	...	5.5
6	116	0.62	0.8	2.9	...	3.6
7	62	0.49	1.0	4.4	...	5.4
8	91	0.63	1.5	4.2	...	5.7
9	97	0.26	1.3	4.1	...	5.5
10	32	0.27	1.2	6.1	3.8	11.1
11	41	0.33	0.8	3.8	2.1	6.7
12	66	0.14	1.1	5.0	...	6.2

partially activation and mass transfer controlled. In other words, a protective iron carbonates film forms, which is then physically removed by impingement or by dissolution.

The accuracy of the two above-mentioned corrosion rate correlations can be seen in Figure 5. The time to failure of 53 gas condensate wells that were in annular or mist flow has been shown to correlate well with the field data [21]. The average percent difference between predicted and actual corrosion rates was ±18%.

Slug Flow

What has made this model comprehensive is inclusion of the physical description and corrosion prediction for the nonannular flow regime. At this time, a total of only eight gas condensate wells in slug flow with known production and corrosion rates have been documented.

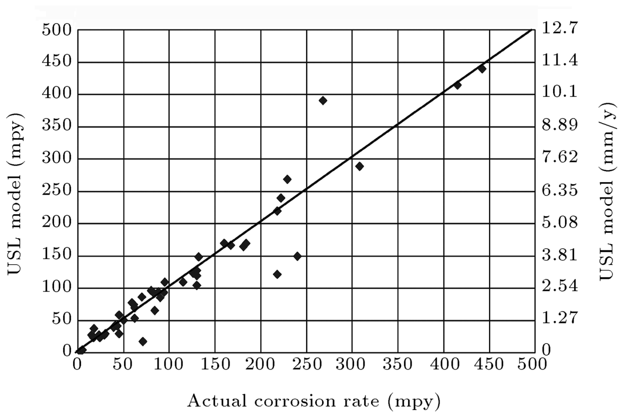

Figure 5. USL model results compared to actual corrosion.

All eight wells contained CO_2 as the corrosion specie, and failed due to internal penetration. The wells were found to be in slug flow at the depth of the failure.

Corrosion rates in slug flow have been experimentally determined in the laboratory [22] to be higher than churn flow.

It was decided to develop a correlation for slug flow wells by performing a regression on several of the calculated parameters [5]. The four parameters selected were (1) length of the Taylor bubble, (2) velocity of the Taylor bubble, (3) water rate, and (4) gas superficial velocity. The resulting equation showed an average percent difference of ±14% from the actual value.

To this date, no field data have been found for the corrosion rate of churn flow wells. It is proposed that the same slug flow regression equation be used and that an experimental factor be applied. The corrosion rate for churn flow gas wells has been found experimentally to be consistently 15% less than slug flow on the experiments conducted [22]. Therefore, at the present time for churn flow wells, the slug parameters are calculated and a 15% reduction factor is applied to the slug corrosion rate equation.

CONCLUSIONS

Pipeline Model

The pipeline computer model contains a physical description of large diameter pipes with the modification of the Dukler flow regime maps [23]. Within the flow regime area, the modeling of slug flow has been the most difficult flow regime to describe. A change in the calculation of the height of the liquid film has given reasonable slug lengths and liquid hold up values.

The accurate prediction of the wettability of a three-phase of gas-oil-water is important for the determination of the final corrosion rate. Describing "top of the line" corrosion in a condensing pipeline requires an accurate calculation of the physical system, as well as an accurate knowledge of the flow regime involved. The model is capable of determining if the "top of the line" corrosion can occur and what the pH value is at the top and bottom of the line. By incorporating the effect of organic acid in the calculations, it is possible to predict how seriously it would affect the pipe.

Experimental data has verified that, initially, the CO_2 will dominate the corrosion process and a small amount of H_2S will contribute to an increase in corrosion. However, when the H_2S species become dominant, then, there is usually a drop in the corrosion rate. Using the pitting model developed at UL Lafayette, it has been possible to model the effect of H_2S on CO_2 corrosion.

The pipeline model includes an internal risk assessment module. The risk assessment module is used to calculate the probability of failure (pof) and provide a risk classification using a 1-5 rating (with 1 the best) as a function of years of use. From this information, a plot of risk classification versus years, to determine the expected time of failure, can be developed. The effect of inhibitors on this classification can also be described. This pipeline program is the "state-of-art" computer model for predicting corrosion in pipelines and flowlines with the capability of risk assessment. This program has achieved accurate corrosion rate predictions.

Oil Well Model

An updated computer model was developed that physically describes flowing or gas lifted vertical or deviated wells. The model is capable of predicting temperature, pressure, phase behavior and flow dynamics at each depth inside a flowing well. The flow regime has a pronounced affect on the pressure drop and corrosion rate inside a well. It was found that the physical description of the Taylor Bubble gave the best indication of when the transition from slug to bubble flow occurred.

Corrosion rates in gas condensate wells correlated well to five physical parameters for vertical wells. These wells are believed to represent a higher corrosion rate than oil wells due to the inhibitive effect of the crude. The expert system developed for oil wells uses the factors of water cut, flow regime, temperature and inhibitive effect to adjust the predicted corrosion rate.

The model was tested on several wells in the field and in these cases the predicted value of corrosion rate was close to the actual corrosion rate.

Gas Well Model

A computer model has been developed for gas condensate wells and a number of conclusions can be made.

- The Corrosion Research Center at the University of Louisiana at Lafayette has developed a computer model which provides a comprehensive physical description of gas wells.
- This physical description which includes temperature-pressure profile, phase behavior and flow dynamics can be useful in the design and production of these wells.
- The non-annular model completes the description of the five different types of flow regime possible in a gas well.
- The equations of Fernandes [10] are able not only to describe slug flow, but to provide a means by which the slug/churn transition and the bubble/slug transition can be defined.
- The corrosion rates of wells operating in annular flow have been shown to be mass transfer controlled.
- Using a discriminate analysis method, the occurrence of mist flow in a gas well can be predicted.
- Using the velocity of the droplets instead of the liquid velocity appears to provide a better estimate of corrosion rate in the mist flow regime.
- Model F which predicts the corrosion rate for annular and mist type wells is accurate to within $\pm18\%$.
- The same wells were shown to show no correlation between partial pressure of CO_2 and the corrosion rate.
- Based on laboratory experiments, wells in slug flow are 15% more corrosive than churn flow wells.
- Field data on nonannular flow wells show that the shorter the Taylor bubble, the more corrosive is the well. This may be due to the washing effect of the slug.
- A statistical equation to predict the corrosion rate of nonannular gas wells has been developed, which has an accuracy of $\pm14\%$.

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