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Internal Corrosion Assessment for Dry Gas and Multiphase Pipelines using Corrosion Prediction Models

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Abstract

The significant problem posed by internal corrosion in dry gas and multiphase transmission pipelines has been highlighted in many recent publications, and the internal corrosion direct assessment (ICDA) methodology has been shown to be an effective tool in addressing corrosion in nominally dry or dehydrated gas pipelines. An efficient corrosion assessment methodology must also aim at quantifying corrosion damage in multiphase (liquid-gas) systems to facilitate development of pro-active inspection and maintenance programs for safe operation of pipelines. The objective of this paper is to highlight the importance of using current technologies and software models to effectively quantify the possibility of corrosion damage. This approach needs be evaluated alongside propensity in a pipeline system for water retention and consequently identify critical pipeline segments with real potential for damage and failure.

Keywords: Corrosion prediction, dry gas, dehydrated pipelines, multiphase pipelines, ICDA, internal corrosion direct assessment.

Introduction

Internal corrosion has been one of the most significant causes for reported natural gas pipeline failures, causing substantial property damages. Accident reports over the last 30 years highlight the significantly increasing problem posed by internal corrosion in natural gas transmission pipelines. ICDA [1, 2, 3] provides an enhanced framework of complementary solution systems, using latest technologies to implement a successful and comprehensive strategy of direct assessment methodology to help ensure pipeline integrity.

Work Body

Current ICDA methods primarily deal with determining conditions that favor formation of liquid water in a specific pipeline segment, and whether the pipeline segment *inclination* is adequately low to support water *carry through*. If the flowing multiphase gas/water fluid has inertial and viscous characteristics that do not support carry through of water, then the segment is labeled as 'critical' for further inspection, and integrity analysis. *While this approach is*

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better than operating pipelines without a basis for ICDA, it only identifies potential for water hold up, but does not address the more relevant questions of quantification of water hold up and potential for ***corrosion damage***. Assessment of the extent of corrosion damage due to availability of an aqueous phase in the presence of CO_2, H_2S etc. is a complex task essential for effective ICDA, but typically beyond the scope and/or capabilities for rigorous quantification of most present-day ICDA models.

PredictPipe [TM(1)], an easy to use software system, has been developed and is capable of not only determining propensity for water retention, but also the *corrosivity* of the environment in the presence of the aqueous medium for the identified critical segment. In fact, the software model will not only perform conventional ICDA, but also *generate actual corrosion rate predictions for any point along a pipeline segment.* The system integrates a number of key functionalities, including water phase behavior determination, pH computation, corrosion modeling, flow modeling and comprehensive pipeline analyses based on lab and field data.

The methodology encapsulated within this software system is hence termed as '*Advanced'* ICDA. The rest of the paper provides an overview of the various modules in the software, including technical overview of corrosivity prediction, as well as a brief description of the system interface. Efficacy of the approach has been validated through representative case studies.

CO_2/H_2S-based Corrosion: Technical Background

CO_2-based corrosion has been one of the most active areas of research, with several predictive models for carbon steel corrosion assessment. These efforts range from a predictive model that begins with CO_2 corrosion [4,5, 6,7] to models that focus on specific aspects of the corrosion phenomena (such as flow-induced corrosion or erosion corrosion) [8,9] to models that empirically relate corrosion rates to gas production and water production rates [10]. Crolet et al. [11] use the physical chemistry of the corrosive medium as the key notion and take into account ionic strength, pH and specific ionic species as relevant factors. Other relevant efforts include those by Ikeda et al. [12] that look at the influence of H_2S and O_2 on CO_2-based corrosion as well as those by Adams et al.[13]. Many of these efforts suffer from significant drawbacks in that,

- they focus on a narrow range of parametric effects, for e.g., there is relatively little published data on the effects of H_2S in production systems and on how sulfide scaling can affect the CO_2 corrosion process
- Some models focus just on one component of serviceability, such as erosional effects, wall shear stress effects or flow effects and have opted to ignore effects of chemical species (factors such as pH, H_2S, CO_2 etc.)
- Other models totally rely on lab data for predictive modeling, with the consequence that the simplifying assumptions made in developing laboratory models often lead to results that can be far removed from what is observed in the field.

Some other electrochemical models utilize thermodynamics and first principle models based on solution chemistry and mixed potentials to predict corrosion rates but such models however do not represent real life scenarios in most cases and utilize esoteric input parameters that may not be easily available to users.

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The current model integrates lab data and field experience within the framework of relevant controlling parameters that are most prominent in oil and gas production.

While there have been several studies focusing on the exact mechanism of metal dissolution in CO_2 containing waters, the efforts of De Waard and Milliams and others [4,5,7] present a commonly accepted representation wherein anodic dissolution of iron is a pH dependent mechanism as given by Bockris [2], the cathodic process is driven by the direct reduction of undissociated carbonic acid. Iron carbonate solubility, which decreases with increasing temperature and pH, and the consequent precipitation of iron carbonate is a significant factor in assessing corrosivity. The charge transfer controlled reaction involving carbonic acid and carbon steel (or Fe) can be represented in terms of the concentration or partial pressure of dissolved CO_2 in the medium (pCO_2, bar) and the operating temperature (T, °K) to arrive at an equation for corrosion rate (V_{cor}, mm/yr) as [7],

$$\log (V_{cor}) = 5.8 - 1710/T + 0.67 \log (pCO_2) \text{ ------ (1)}$$

The corrosion rate obtained by equation (1) has typically been often seen as the maximum possible corrosion rate without accounting for iron carbonate scaling.

The above correlation describes CO_2-based corrosion in pure CO_2 systems. There have been other significant efforts to demonstrate the effects of other environmental variables such as pH, H_2S, chlorides, bicarbonates, condensate type, oil wettability, velocity etc [14-19]. Ikeda's work [12] indicates that the preferential formation of an Iron sulfide film can decelerate the corrosion rate, especially at temperatures above 20 °C and extending up to 60 °C. Above 150 °C, the corrosion reaction falls back to the standard CO_2-based corrosion with an $FeCO_3$ film that is more stable than the FeS film.

The primary objective of the corrosivity prediction model described in this paper is to address the importance and complexity of corrosion prediction, and the need to synthesize different parametric relationships based on information from literature, lab research/data and practical experience/expertise.[17]. It has often been observed that lab data and the ensuing models represent poor and often inadequate simulation of field conditions.

ICDA SYSTEM Corrosivity Prediction Model Description

A more detailed description of the Predict®[1] model, which forms the foundation for corrosion predictions in PredictPipe, can be found elsewhere [20-22]. The first step in corrosivity determination is computation of the system pH, since it is the hydrogen ion concentration that drives the anodic dissolution. Further, the role of pH in promoting or mitigating CO_2-based corrosion has been extensively chronicled [23-25].

For production environments, where it is the dissolved CO_2 or H_2S that contribute significantly to a suppressed pH, accurate pH determination is critical since precipitation of corrosion products that form scales (such as $FeCO_3$ in CO_2 only systems) or lack of it is determined by the saturation pH for the scale component and the bulk pH. In this model, if the bulk pH is higher than the saturation pH for FeCO3, scaling and the ensuing protection is permitted. Otherwise, no allowance is provided for protection due to scaling. pH can be determined as a function of acid gas partial pressures, bicarbonates and temperature [23]. From a practical stand

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point, the contribution of H_2S or HCO_3 or temperature to pH determination is another way of representing effective levels of CO_2 that would have produced a given level of pH.

While it has been documented that the CO_2 corrosion mechanism is dissimilar to that of strong acids like HCl (where as CO_2 corrosion is now understood to progress through direct reduction of H_2CO_3 to HCO_3^- rather than reduction of H^+ ions), and that carbonic acid corrosion is much more corrosive than that obtained from a strong acid such as HCl at the same pH [24], there is also significant agreement that lower pH levels obtained from higher acid gas presence leads to higher corrosion rates. Conversely, higher levels of pH obtained through buffering in simulated production formation water solutions have been shown to produce significantly lower corrosion rates even at higher levels of CO_2 and/or H_2S. Hence, it is more meaningful to determine the effective CO_2 partial pressure from the system pH. A numerical computer model has also been developed to compute pH for different values of HCO_3 and temperature in the current prediction scheme. The flow chart in Figure 1 provides the lists sequential effects that are important from a stand point of corrosivity determination.

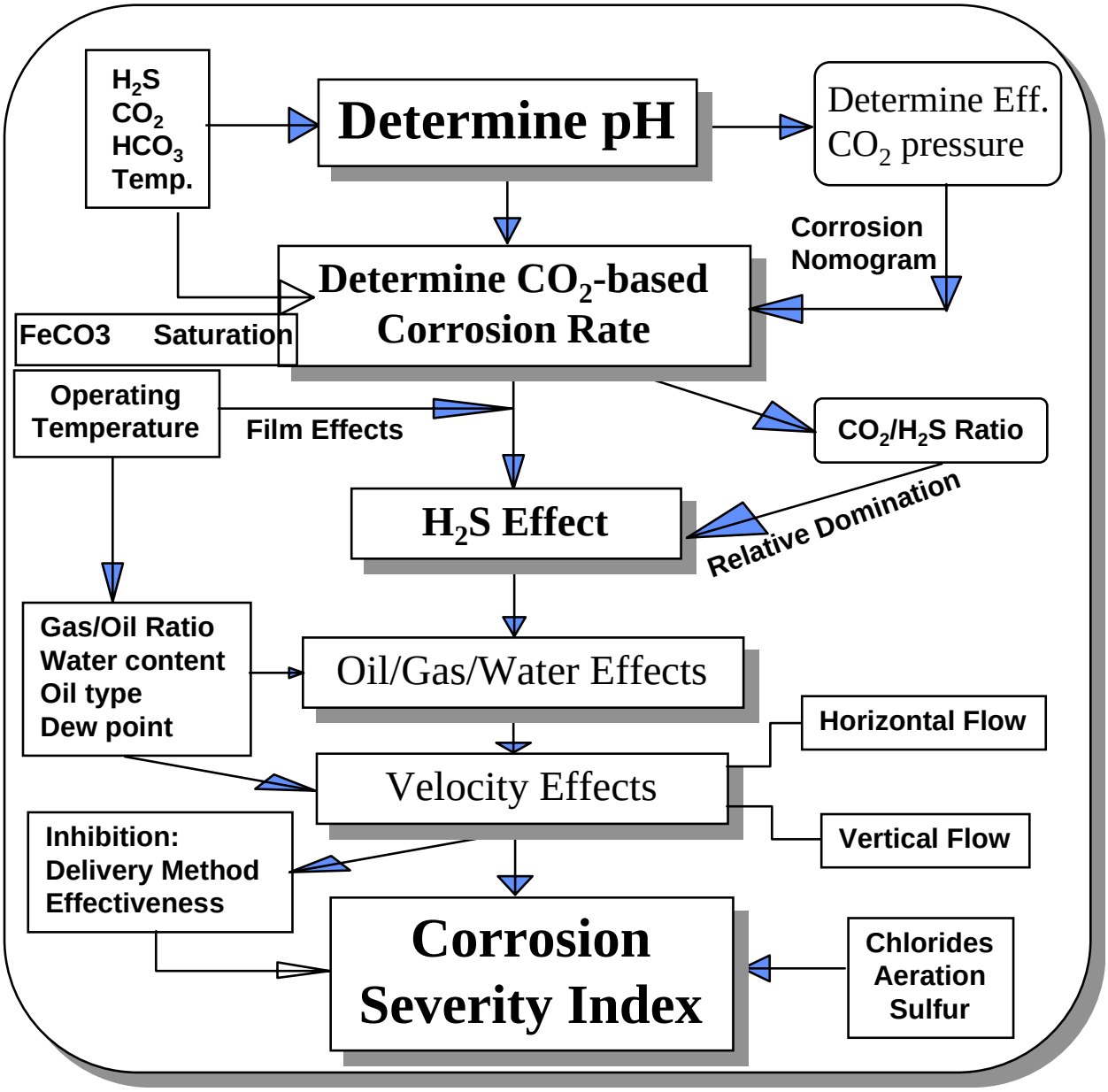

Figure 1: Corrosivity Prediction Flow Chart in ICDA system

Other critical corrosivity assessment parameters include H_2S partial pressure, operating temperature, Dissolved chlorides, Gas to oil ratio, water to gas ratio/water cut, Oil type and its persistence, elemental sulfur/aeration, and fluid velocity. The following sections discuss the effects of some of these parameters on corrosivity. A detailed description of the role of all the parameters is given in earlier works of S. Srinivasan [20].

Role of H_2S - Even though H_2S is probably the most significant concern in current day corrosion and cracking evaluation, the role of H_2S in corrosion in steels has received much less attention when compared to the widely studied CO_2 corrosion. However, H_2S related corrosion and cracking has remained one of the biggest concerns for operators involved in production because of the significance of H_2S related damage. The current modeling effort, in addition to its contribution in pH reduction, H_2S has a three fold role:

(1) At very low levels of H_2S (< 0.01 psia, 68.95 Pa), CO_2 is the dominant corrosive species, and at temperatures above 60 °C, corrosion and any passivity is a function of $FeCO_3$ formation related phenomenon and the presence of H_2S has no realistic significance.
(2) In CO_2 dominated systems [26-28], presence of even small amounts of H_2S (ratio of $pCO_2/pH_2S > 200$), can lead to the formation of an iron sulfide scale called mackinawite at temperatures below 120 °C. However, this particular form of scaling, which is produced on the metal surface directly as a function of a reaction between Fe^{++} and S^{--} is influenced by pH and temperature [26]. This surface reaction can lead to the formation of a thin surface film that can mitigate corrosion. The authors are currently pursuing laboratory studies to characterize the stability and formation of mackinawite in sour multiphase systems.
(3) In H_2S dominated systems (ratio of $pCO_2/pH_2S < 200$), there is a preferential formation of a meta-stable sulfide film in preference to the $FeCO_3$ scale; hence, there is protection available due to the presence of the sulfide film in the range of temperatures 60 to 240 °C. Here, initially it is the mackinawite form of H_2S that is formed as a surface adsorption phenomenon. At higher concentrations and temperatures, mackinawite becomes the more stable pyrhotite. Further, in H_2S dominated systems, scaling protection from the more stable $FeCO_3$ scale is not available to mitigate corrosion.

Figure 2 [28] shows the combined effects of temperature and gas composition on corrosion rate of carbon steels.

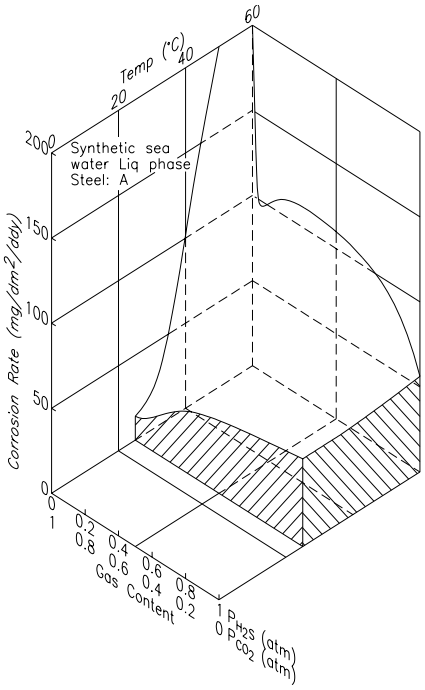

Figure 2: Effect of gas composition and temperature on corrosion rate [28]

Figure 3 [12] shows the effect of varying degrees of H_2S contamination on CO_2 corrosion. It is to be noted that the role of H_2S in CO_2 corrosion is a complex issue governed by film stability of FeS and $FeCO_3$ at varying temperatures and is an area further active research by the authors.

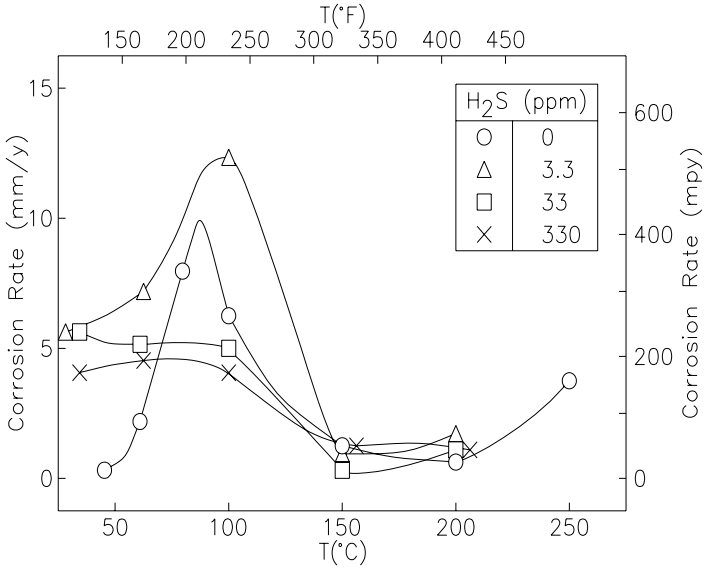

Figure 3: Effect of H_2S and temperature on corrosion rate in pure iron [12]

Temperature Effects - Temperature has a significant impact on corrosivity in CO_2/H_2S systems. Corrosion rate as a function of different levels of CO_2 and temperature are given in Figure 4 [7]. It has to be noted that once the corrosion products are formed, there is a significant mitigation in corrosivity.

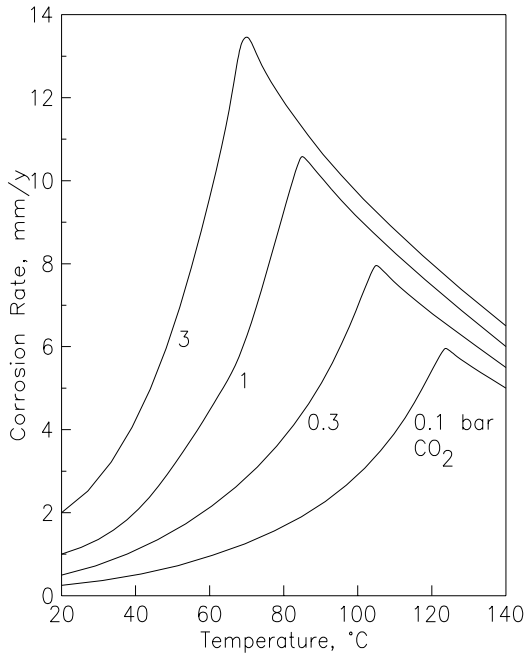

Figure 4: Corrosion rate as a function of temperature and CO_2 pressure [7]

It is also apparent that the carbonate film is more stable at higher temperatures and affords greater protection at higher temperatures. In H_2S dominated systems, because of the fact that no carbonate scale may be formed and that the FeS film becomes porous and unstable at temperatures beyond 120 °C, significant localized corrosion may be observed.

Velocity - Next to the corrosive species that instigate corrosion, velocity is probably the most significant parameter in determining corrosivity of production systems. Fluid flow velocities affect both the composition and extent of corrosion product films. Typically, high velocities (> 4 m/s for non-inhibited systems) in the production stream leads to mechanical removal of corrosion films and the ensuing exposure of the fresh metal surface to the corrosive medium leads to significantly higher corrosion rates.

Data shown in Figure 5 [29] demonstrates the effects of velocity on corrosion rate for both inhibited and non-inhibited systems.

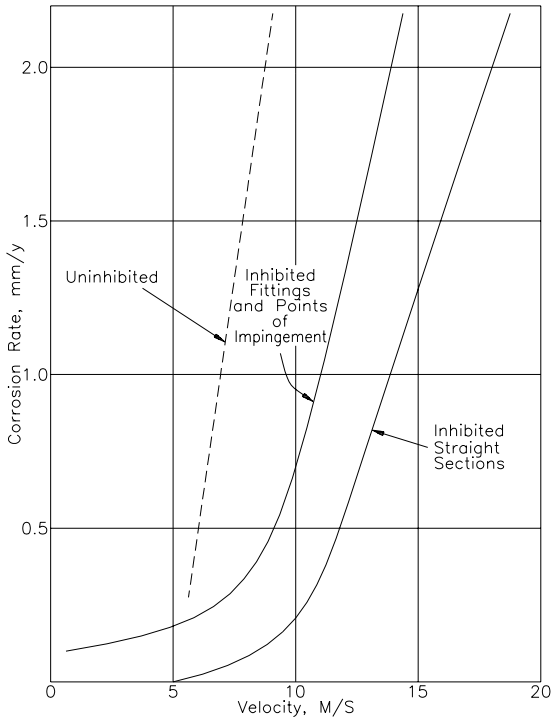

Figure 5: Effect of gas velocity on corrosion rate [29]

Flow related effects on corrosivity have been linked to the wall shear stress developed and is an area of intense research [30]. Guidelines for velocity limits with respect to erosional considerations are given in API-14E in terms of the density of the fluid medium.[31]

Importance of Water/Gas/Oil ratios - The predictive model classifies systems as oil dominated or gas dominated on the basis of the gas/oil ratio (GOR) of the production environment. If the environment has a significant condensate phase, the tendency for corrosion and environmental cracking is often substantially reduced.

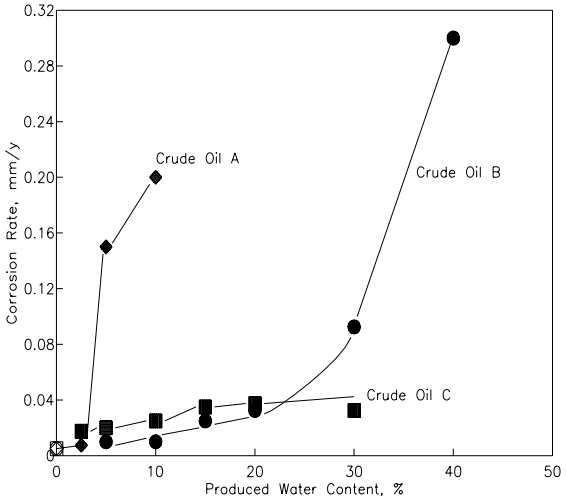

Figure 6: Effect of crude oil type on corrosion rate as a function of water content [32]

This is caused by the possible inhibiting effect of the oil film on the metal surface, which effectively reduces the corrosivity of the environment. See Figure 6 [32] above.

Aeration/Sulfur - Presence of oxygen significantly alters the corrosivity of the environment in production systems. Oldfield [33] has chronicled how presence of oxygen can significantly increase corrosion rates due to acceleration of anodic oxidation. Data showing increases in corrosion rate as a function of oxygen concentration for differing temperatures is shown in Figure 7 [29]. Presence of elemental sulfur is similar to that of free oxygen since elemental sulfur also acts as a strong oxidizing agent.

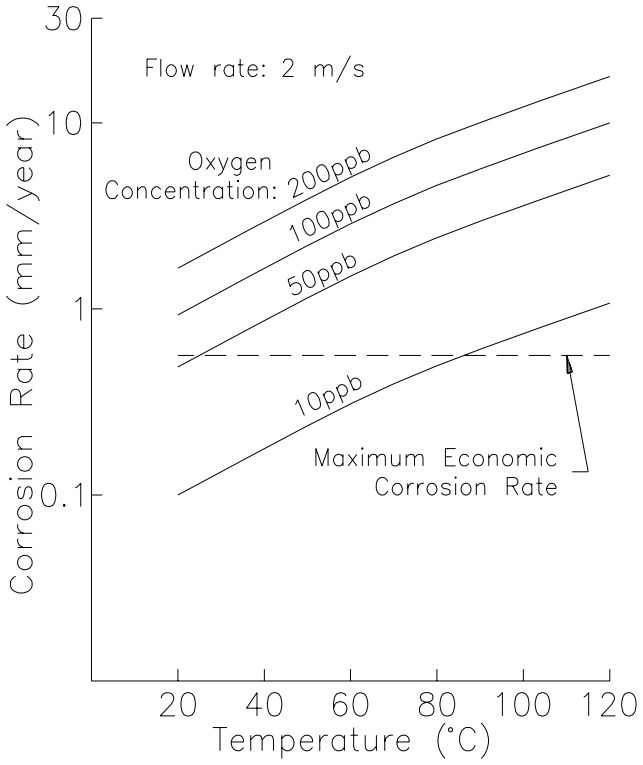

Figure 7: Effect of oxygen concentration as a function of temperature on corrosion [29]

The prediction model discussed in this paper has shown itself to be quite accurate when used to compare against field corrosion rates from different fields [22]. Data showing the accuracy of the model's prediction with respect to field data is shown in Figure 8.

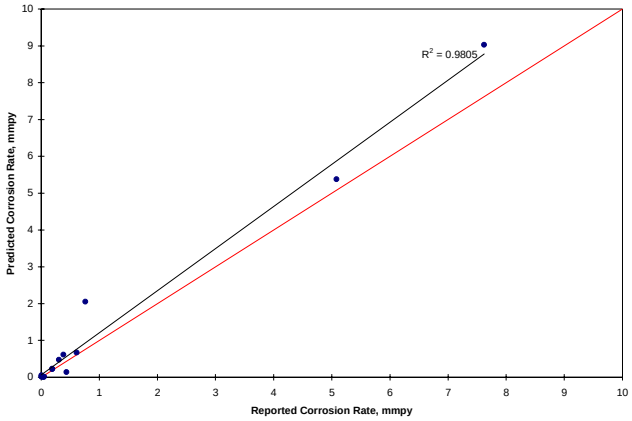

Figure 8: Predicted Vs. Field Corrosion Rate for the Predict System

MULTIPHASE PIPELINES

In oil and gas pipeline and gathering systems, a three phase system comprising of crude oil and water along with produced gases and corrosive acid-gas species such as carbon dioxide (CO2) and hydrogen sulfide (H2S) is commonly observed. Various oil-gas-water flow patterns that lead to varying distributions of liquid (mixed oil and water) phases on the cross-section of pipe often exist in such scenarios. It is widely known that the dissolution of such corrosive gases into the water phase forms a corrosive environment that often attacks steel pipe walls. It has been reported that at lower water cuts corrosion is not a significant issue because in such cases a water-in-oil dispersion is observed or most of the water is entrained by the flowing oil. With increasing water cut and stratified flow conditions water separation may occur, leading to segregated flow conditions of separate water and oil phase layers. Once water separates the likelihood of water wetting the pipe wall substantially increases leading to higher corrosion susceptibility.

The wetting of the pipe wall by the water phase and subsequently internal corrosion rates are affected by various factors described below.

Water cut – With higher water cuts water and oil phase separation is more likely to occur, leading to wetting of the pipe inner wall. Lower water cuts do not necessarily mean absence of corrosion since depending of flow conditions and pipe geometry it may be possible for water to separate out at low points in the pipeline and flow conditions cause the water to stagnate for a prolonged period.

Type of oil – Hydrocarbon properties such as density (API gravity) and viscosity affect the ability of the oil phase to entrain the water phase and prevent it from wetting the pipe wall. An experimental study by S. Nesic et. al. [34] presents the effect of various oil types and water cut on phase separation and corrosion in multiphase flowing systems.

Flow regime – Multiphase pipelines operating under varying flow conditions and pipe inclinations lead to differing flow regions along the length of the pipeline. Some flow regimes and superficial liquid velocities are conducive to phase separation. Both Predict and PredictPipe systems utilize comprehensive flow modeling methodologies to compute various fluid dynamic parameters and wall shear stress. The wall shear stress is consequently correlated to corrosion rate, based on laboratory data developed for multiphase pipeline applications. An example of such data built into the Predict system, derived from a Joint Industry Project on corrosion in multiphase pipelines is given in Figure 9 [35].

Water phase behavior – Operating conditions across the length of a pipeline vary significantly in some cases leading to phase behavior changes of water and in some cases hydrocarbons as well. It is essential to consider the effect of such changes in water phase behavior.

Pipeline inclination – The pipeline layout also is a major factor for correctly assessing corrosion in multiphase flowing systems. Due to high segment inclinations some low points along the pipeline may be susceptible to water holdup and stagnation. Under certain flow conditions such a separated phase of water may remain stagnant for extended periods of time leading to high corrosion at such localized regions of water and solids accumulation.

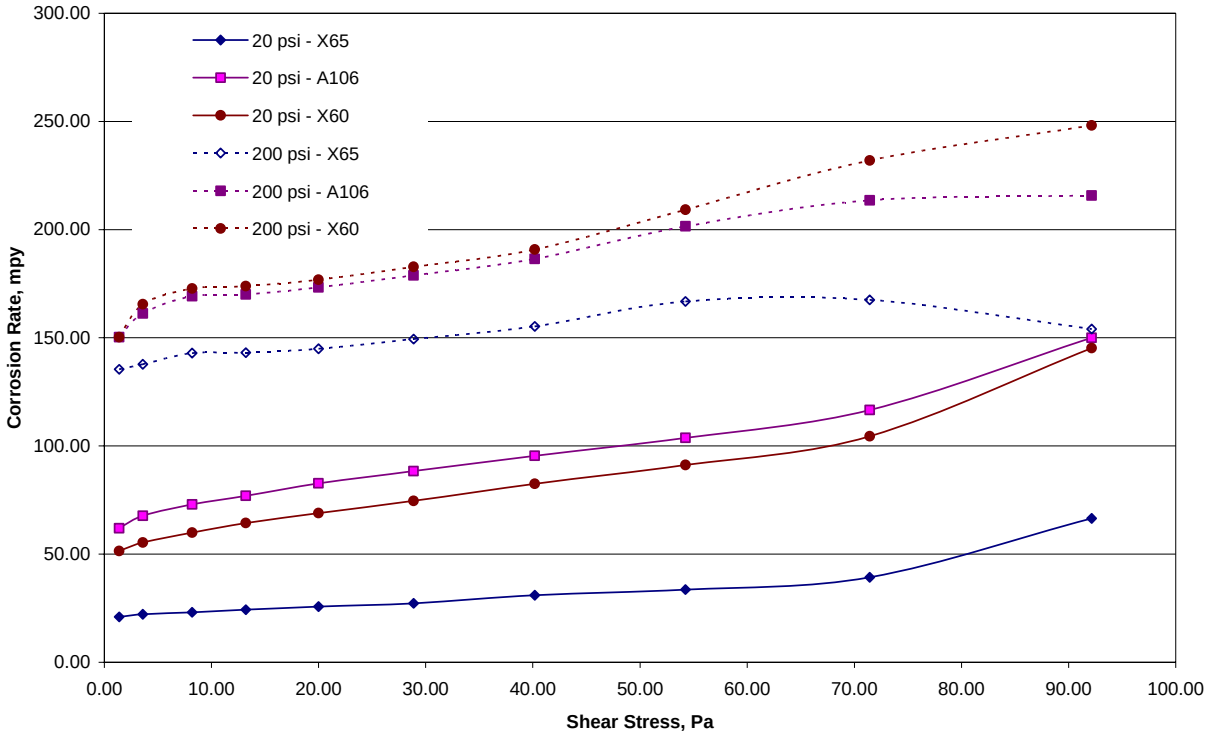

Figure 9: Corrosion Rate as a function of wall shear stress in multiphase oil/gas systems [35]

These factors need to assessed accurately and accounted for in the assessment of corrosion susceptibility for oil and gas multiphase flowing systems. The Predict software system incorporates all these relevant components in predicting corrosion rates for multiphase pipelines.

PROGRAM INTERFACE & FUNCTIONALITY

The software system provides comprehensive functionality to assist in performing effective ICDA and protect against costly pipeline failures. The easy-to-use graphical interface integrates the effects of a complex set of environmental parameters based on extensive literature, data, lab testing and field experience to map potential corrosion hot spots and provide a birds eye view of the health of a pipeline system.

The program interface is shown in Figure 10. While this program uses a complex computational model for determining the corrosion rate, the ease-of-use in applying the system to obtain meaningful answers is transparent. The first step in generating a consultation is to specify the Production data, which is done by clicking on the Production Data button on the main screen, and as shown in Figure 11. The production data in terms of Gas Production, Total Water Content (higher numbers are used to simulate a water carry over), H_2S mol% and CO_2 mol%. The next step is to provide ionic data for water that is carried over. This helps in computing the ionic strength and also encompasses effects of bicarbonates on pH and Chlorides etc. on corrosion rates. The input data screen for water analysis is shown in Figure 12. Clicking on the Pipeline Analysis buttons displays the Pipeline Profile Inputs Screen, Figure 13, which performs comprehensive flow modeling for the pipeline system to generate the corrosion distribution profile, water holdup and critical angle values. The import functionality enables the user to import Pipe Geometry into the program. Files of type .CSV (Comma Separated Values)

and .XLS (Microsoft®-Excel[2] Files) can be imported. Data can be stored in the import file as Distance and Elevation (i.e. the absolute distance starting from point 0 and absolute elevation of each point) or as Length and Angle (Lengths of individual segments and their angle to the horizontal).

The results screen shown in Figure 14, displays the overall graphical view of the piping system. Using the arrow keys to select the segment, detailed parameters about the segment can be viewed. The segment selector moves along the pipeline marking the current segment selected. The color of the selector and the angle changes to red to mark the segments with angles greater than the critical angle and hence susceptible to internal corrosion.

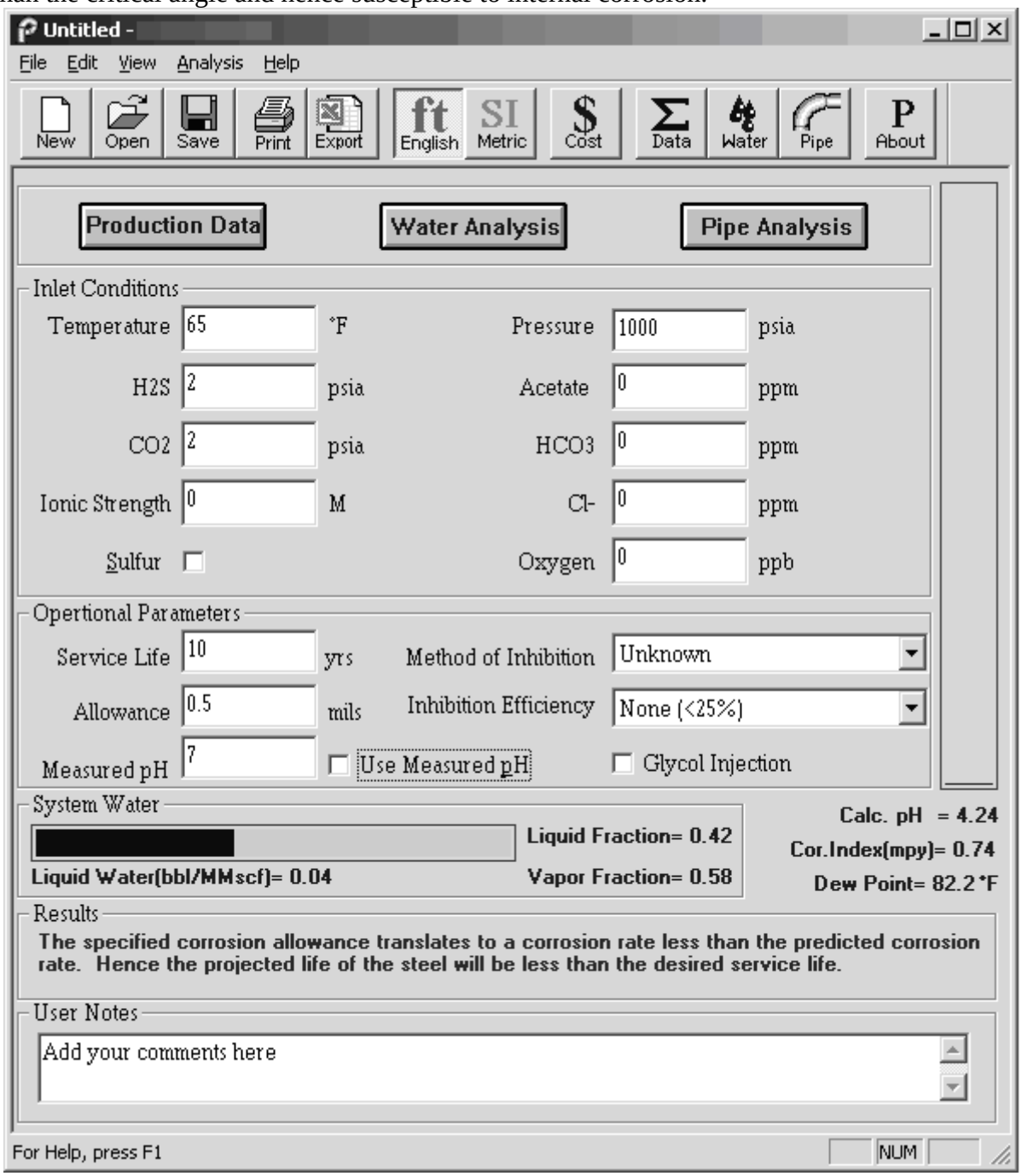

Figure 10: Program Startup Screen

[2] Registered trademark – Microsoft Corporation

The system's enhanced calculation rules for predicting the water content of natural gas and dew point calculations enable accurate predictions for water condensation and thus corrosion rates. A view of this corrosion profile provides immediate information about problem spots in the pipe system where there is a high possibility of water accumulation and potentially damaging corrosion rates.

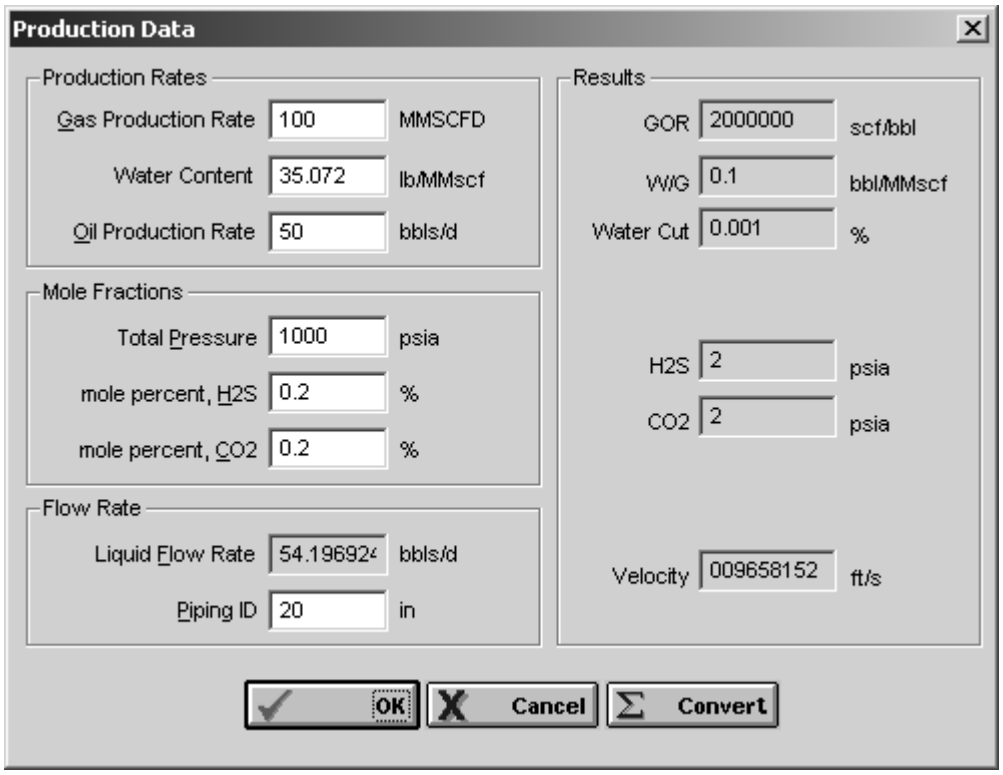

Figure 11: Production Data Screen

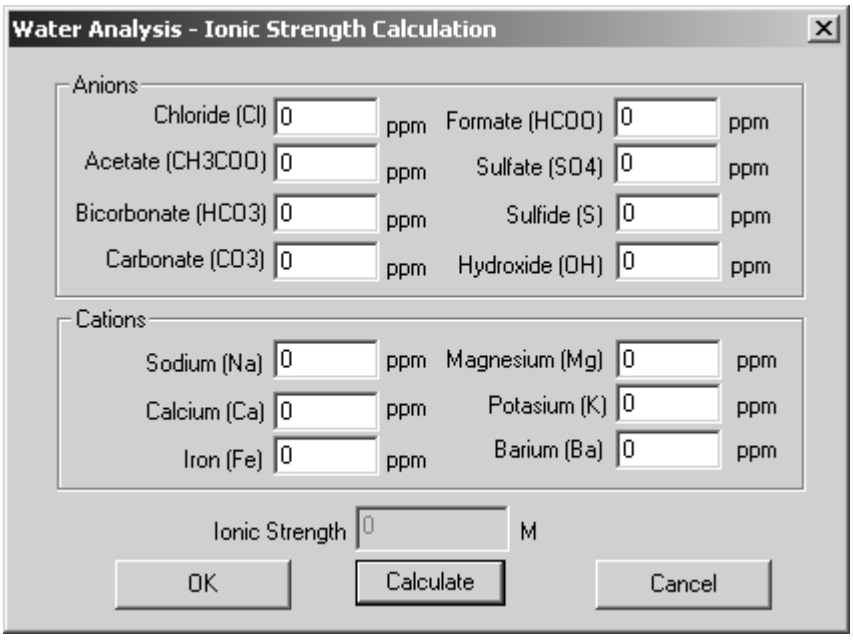

Figure 12: Water Analysis Screen

This corrosion prediction model seamlessly integrates the effects of system thermodynamics and phase equilibrium, ionic electro-chemistry, fluid dynamics and metallurgy to form a comprehensive corrosion prediction tool. The knowledge of quantifiable potential corrosion damage at the identified critical spots in a pipeline provides the user with valuable information in making maintenance decisions and reducing inspection costs in line with efficiently implementing ICDA.

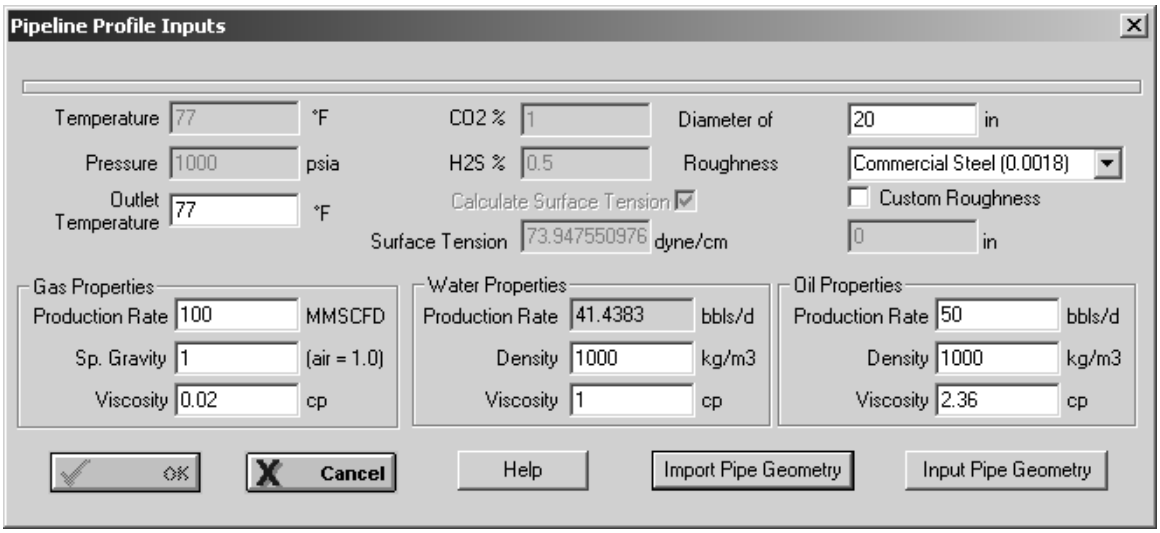

Figure 13: Pipeline Profile Inputs Screen

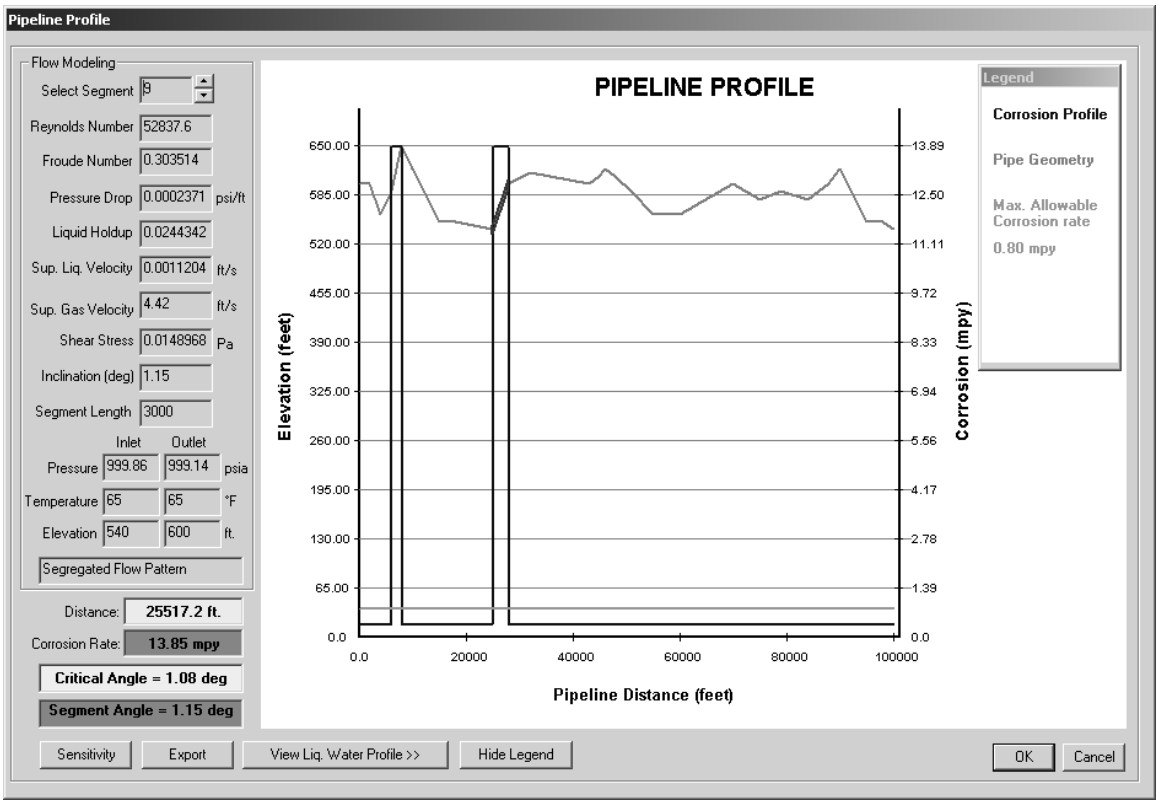

Figure 14: Pipeline Profile Results Screen

CASE STUDY

The case study presented here is a part of the ICDA analysis for a major pipeline in the United States. Historical and operational data analysis and GPS Data for line profiling and mapping were handled by an inspection partner company. Flow modeling and line profiling was undertaken to assess potential for water hold up and corrosion in the line and to quantify corrosivity in segments operating above the critical inclination angle with an available aqueous electro-chemical environment. Two of the cases have been presented here:

Based on the transmission data provided, this Case 1 was set up for 8 MMSCFD (0.227 Mm^3/day) of gas transmission at 83.7 psia (577.1KPa), 60 ºF (15.6 ºC) to assess the effect of any liquid carryover in the pipeline, which had been noted to have occurred in the past. Pipeline I.D. of 11.8 inches (299.7 mm) and a worst case CO_2 concentration of 1.68 mole percent was used. The total pipeline was mapped to generate an Elevation vs. Distance profile which was imported into the software as an MS-Excel file. This section of the pipeline ran a total of 286125 feet (87.2 km) and the analysis of a stretch of 8925 feet (2.7 km), has been presented here in Case 1. As shown in Figure 15 the line is free of any critical segments and the corresponding computed critical angle determined to be 2.06 degrees.

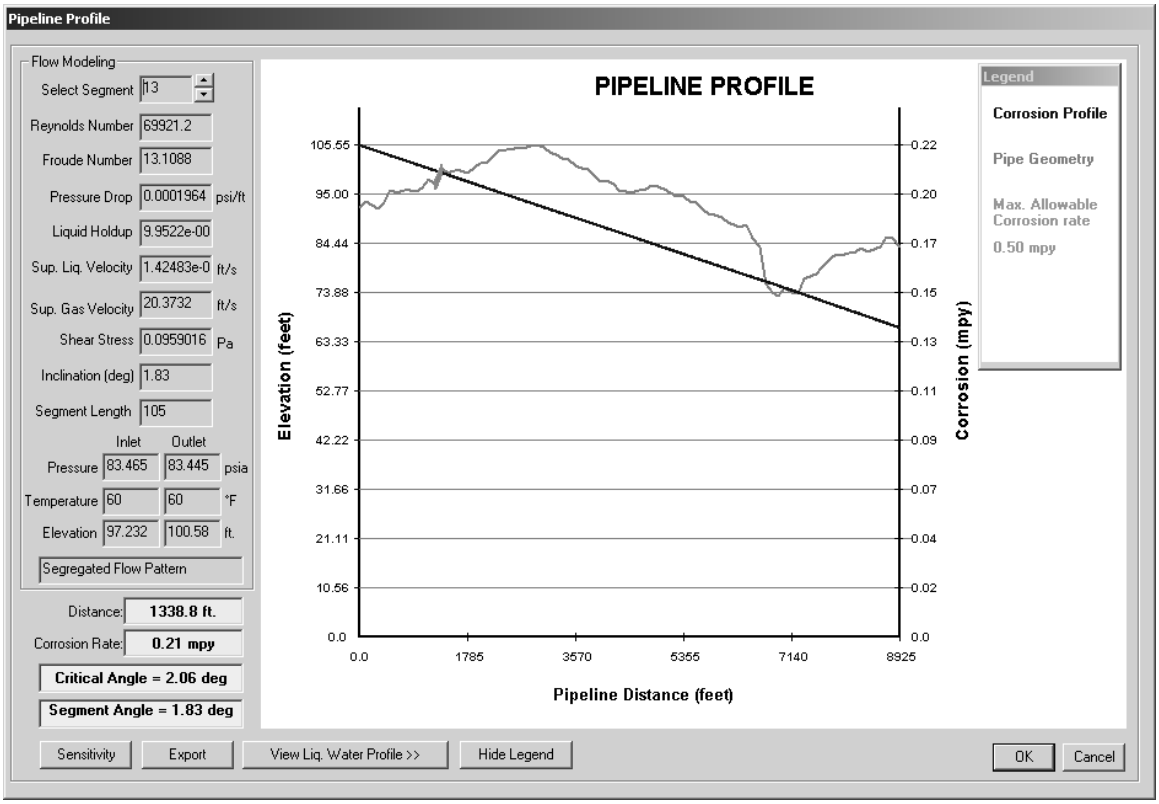

Figure 15: Pipeline Profile Results Screen for Case 1

Case 2 was set up for a section of the pipeline further downstream with 13.95 MMSCFD (0.395 Mm^3/day) of gas transmission at 155.5 psia (1072.1KPa) and 60 ºF (15.5 ºC). The elevation data for this section was also similarly imported into the program, the analysis of a stretch of 16485 feet (5.03 km), has been presented here in Case 2. Case 2 data are shown in Figure 16. Critical angle computed under these operating conditions was found to be in the range of 3.26 degrees and 3 critical segments with greater inclinations were identified. The line characterization under conditions of liquid carryover points to a worst case corrosion rate of up to 18.5 mpy (0.47mm/y).

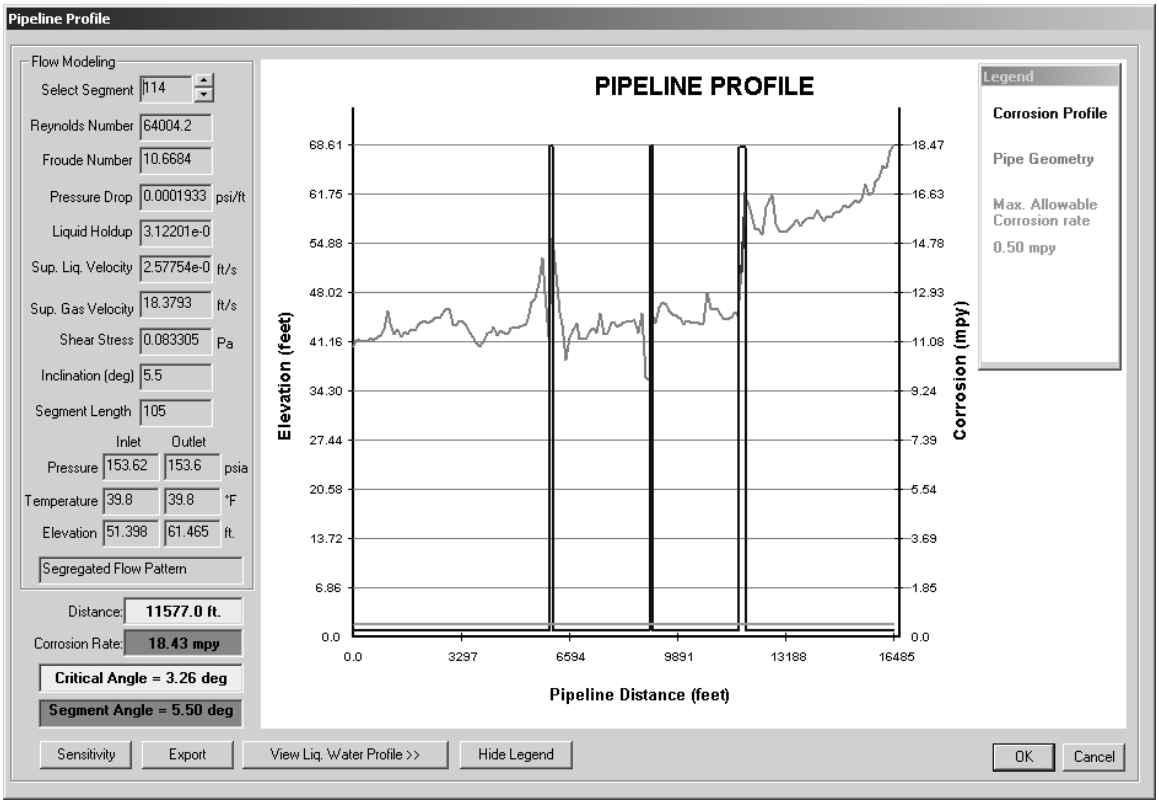

Figure 16: Pipeline Profile Results Screen for Case 2

Conclusions

A new approach to implement ICDA has been developed through the application of state-of-the-art corrosion prediction, flow modeling and ICDA methodologies, integrated into a easy-to-use software package. Technical fundamentals relating to corrosion assessment prediction have been provided, alongside a description of system interface and application case studies. The ability to assess water retention in a pipeline segment, when augmented by accurate and rigorous corrosion / flow modeling, provides a compelling basis to characterize pipelines, quantify corrosion behavior therein and minimize potential for corrosion damage and costly pipeline failures.

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