LIFE OF FIELD CORROSION OF A FLOWLINE SYSTEM

Abstract

This corrosion study was carried out in conjunction with a large engineering company as part of a FEED for a deepwater development. A method was employed to aid communication between the Flow Assurance and Corrosion disciplines. This interdisciplinary approach removed the need to identify an arbitrary corrosion design case.

The System

The system was a 20 km deepwater flowline system gathering production from four drill centres *en route* to the processing facility. The fluids in question presented a number of flow assurance issues, including wax and hydrate formation. Consequently, insulated flowlines were selected to keep fluid temperatures above the wax appearance temperature and gave a sufficient cooldown time on shut down.

Although the provision of insulation solved these two major flow assurance issues, it exacerbated another. The significant carbon dioxide content of some of the production fluids meant that carbonic acid corrosion problems could arise under the prevailing conditions. The analysis was complicated by widely varying conditions (including pressure, temperature and composition) throughout the flowline system and through field life. Thus a comprehensive analysis was required to take account of variations in both time and location.

Thermal Hydraulics

Compositional Life of Field calculations were already performed for this system in order to assess the other Flow Assurance issues. These results are shown in Figures 1 to 3 as plots of temperature, pressure and carbon dioxide mole fraction in the gas phase.

Figure 1 Life of Field Temperatures

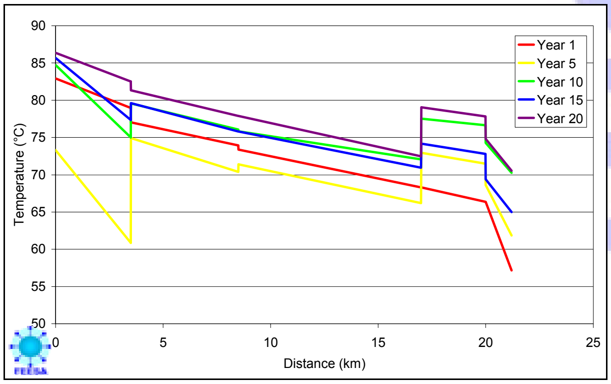


Figure 2 Life of Field Pressures

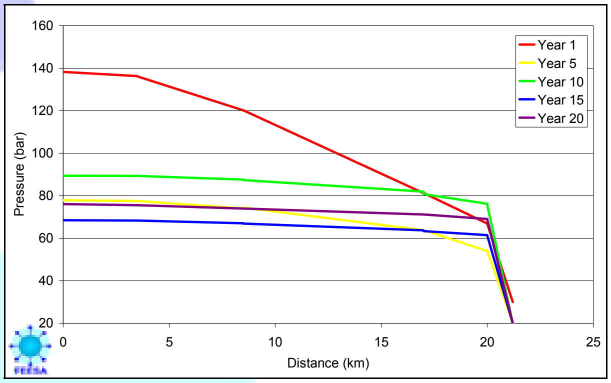
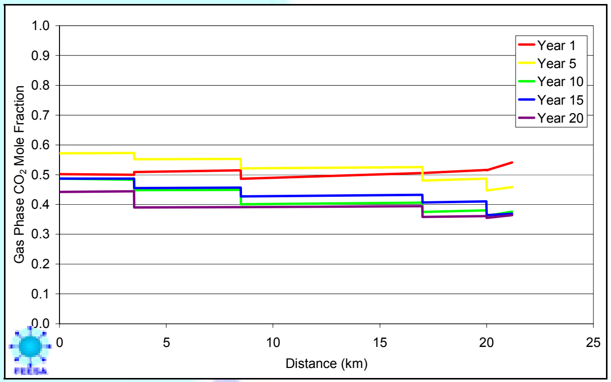


Figure 3 Life of Field CO_2 Gas Mole Fraction



The discontinuous profile is due to the different flowing well head temperatures and compositions of the wells at each of the production manifolds.

Carbon dioxide mole fraction in the gas phase is important as most carbonic acid corrosion methods are correlated in terms of carbon dioxide partial pressure in the gas phase (the product of the mole fraction and the pressure). It is a common mistake to use the combined fluid carbon dioxide mole fraction to calculate this number (i.e. gas plus liquids). This mistake can lead to a significant under-prediction in the corrosion rate calculation since the volatility of carbon dioxide means that its concentration in the gas phase is usually higher than the combined fluid.

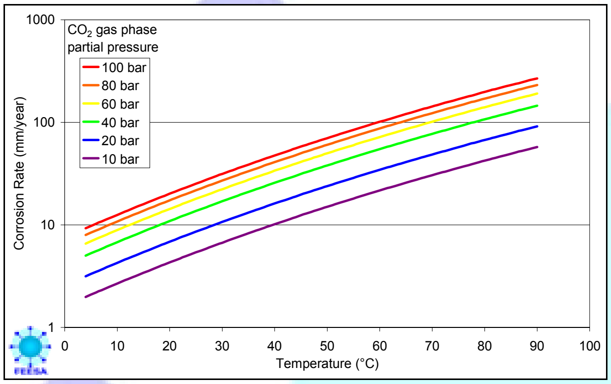
Perhaps the most well-known carbonic acid corrosion correlation is that proposed by de Waard and Milliams in 1975, which has the following form:

$$\log_{10}\left(v_{cor}\right) = 5.8 - \frac{1710}{T} + 0.67\log_{10}\left(ppCO_2\right) \qquad (1)$$

Where v_{cor} is the corrosion rate in mm/year, T is the temperature in Kelvin and $ppCO_2$ is the partial pressure of CO_2 in the gas phase. Most studies (including the study which motivated this case study) use more complex correlations, often based on the original de Waard and Milliams method.

A plot of the de Waard and Milliams equation over the range of conditions is shown in Figure 4.

Figure 4 De Waard and Milliams Equation



As can be seen in Figure 4, the corrosion rate is a strong function of temperature and pressure. However, it should be noted that these predictions are for illustrative purposes and that at higher temperatures experimental observations show that the corrosion rate begins to reduce due to the inhibiting effect of iron carbonate scale on the metal surface.

From Figure 1, it is clear that the flowline temperature varies widely both along the flowline length and in time. Figure 3 shows that no one section has consistently the highest carbon dioxide gas mole fraction. This poses the problem of how in such complicated systems does one identify a design case without recourse to excessive conservatism?

With the software tools now available, the answer is to simulate the entire system through field life calculating instantaneous corrosion rates through the system and integrate to determine the location with the worst cumulative metal loss. This approach provides a rational basis for then defining the corrosion allowance and the chemical management strategy.

For this case study, the predicted instantaneous corrosion rates were excessive and it was therefore decided that continuous corrosion inhibitor injection was required. In Figure 5, the effective corrosion rates (assuming a certain corrosion inhibitor effectiveness and availability) are plotted at various points along the flowline throughout the design life of the system. Integrating these values produces the plot in Figure 6, the amount of pipe wall loss after year 1, 5, 10, 15 and 20 along the length of the flowline.

As can be seen in Figure 5, the corrosion rate for the worst corrosion spot (0 km) varies from 0.21 to 0.42 mm/year. Thus the traditional approach of choosing the 'worst case' pressure and temperature could lead to an excessively conservative corrosion rate estimate, and hence an unnecessarily large corrosion allowance. Moreover, the method described here also offers the possibility of varying the corrosion allowance throughout the system thus reducing the require capital investment.

Figure 5 Life of Field Corrosion Rates

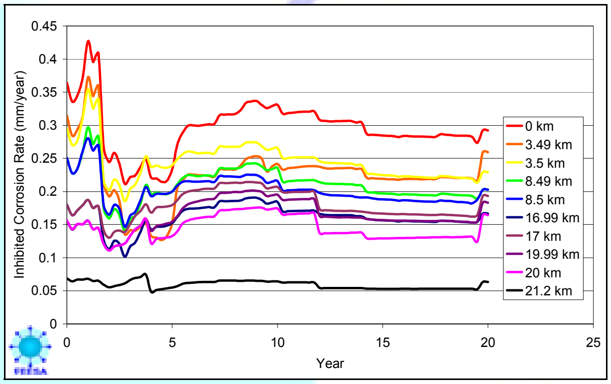
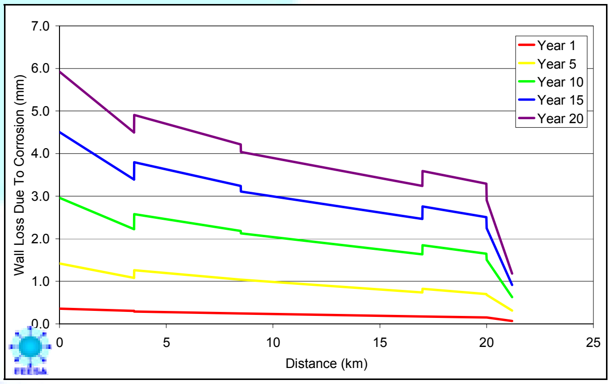


Figure 6 Life of Field Corrosion



Conclusion

The corrosion problem in such systems amounts to a trade-off between the material selection cost, the cost of flowline corrosion allowance and the lifecycle costs of corrosion inhibitor systems. Careful consideration of this optimisation can yield significant improvements to the project economics.

The proposed Life of Field integrated approach to corrosion calculations, removes the need to select an artificial design case based on somewhat arbitrary worst case conditions. This improves the accuracy of the result, removes unnecessary conservatism and allows a single design margin to be added at the conclusion of the calculations.