# WHY OIL COMPANIES MUST GRASP THE CORROSION ISSUE

Richard Pike

Corrosion may seem an unexciting subject, but international and state oil companies now need to place much higher priority on both the technology and management of its causes, monitoring its effects, controlling its various outcomes and undertaking remedial work. Extraordinarily for its potential consequences, it is one of the few phenomena where widely-used inspection techniques remain out of step with the reality of the chemical processes involved. Companies unwilling to address this will have both their reputation and value compromised.

During the last twenty years within the UK oil industry alone, there have been several major corrosion-related shutdowns of facilities and pipelines that have each cost hundreds of millions of pounds to rectify. Prudhoe Bay will shortly join a global list that has already grown significantly with major repair projects initiated in Russia, India and the Middle East, all driven by problems with corrosion.

How has this come about? Firstly, it is important to draw a distinction between internal and external corrosion. The former largely affects mature fields that are well past their primary production phase, where the initial expansion of fluids and gas below ground is sufficient to drive the flow of wells. Instead, in this later, secondary phase, large volumes of water (typically from the sea or a river) are injected into reservoirs to displace the oil, rather like a piston. With time, however, water migrates through the oil, so that wells eventually produce more than 90% water near the end of the field life.

Through water separation in surface facilities, often assisted by chemicals known as de-emulsifiers, the water content of the oil transported by pipeline for shipment at a port can be reduced to just a few percent. Internal corrosion of the steel pipe is driven by the presence of this remaining water, oxygen dissolved in it, and sometimes other substances such as carbon dioxide and hydrogen sulphide. The last of these can be generated by sulphate-reducing bacteria that are inadvertently introduced into the reservoirs during water injection. Many of the facilities most vulnerable to corrosion, in general, are well past their notional 25-year design life.

Corrosion is controlled routinely by both chemical and physical means. For example, oxygen is reduced during the water injection process, and biocides are also pumped into the reservoirs. A key step is the injection of corrosion inhibitor chemicals into the pipeline itself, and the use of emulsifiers to limit the separation of oil and water within the pipeline. Furthermore, to stop any settling of water at low points in the line, and also to clear sludge and wax, cylindrically-shaped mechanical ‘pigs’ with scrapers are sent down the pipeline (driven by the flow of oil), to be recovered with the collected debris at the downstream end.

Monitoring the effectiveness of these steps is through a variety of techniques. These include the use of small steel discs, or coupons, set into the pipeline so that they are exposed to liquids inside. These can be removed periodically for inspection and measurement without disrupting operations. Another method has a small strip of wire carrying an electric current inserted into the oil flow. As this corrodes over time, its electrical resistance increases.

For pipelines that are readily accessible to technicians, an ultrasonic probe placed on the outer surface will indicate the wall thickness of the pipe. Finally, by sampling the liquids and measuring the way the concentration of iron salts varies along the pipeline, the loss of metal from the inside surface can be estimated. Collectively, all these methods indicate how extensive corrosion might be, and corrective action can be taken to address this.

So how can this go wrong? Circumstances in Alaska are still under investigation, but worldwide a number of important themes have emerged in recent years. Firstly, there is usually such a cocktail of chemicals in the pipeline that it is not easy to predict the performance of the corrosion inhibitors or the optimal dosage, particularly where there is some separation of the oil and water within the pipeline itself. Secondly, pigging frequencies tend to be reduced if there is no obvious build-up of free water or debris, which may make the pipeline vulnerable in some highly localised areas where there is, unwittingly, some accumulation of these.

Thirdly, the traditional techniques for monitoring tend to measure average internal metal loss, whereas the mechanism of severe corrosion is pitting in particular vulnerable areas, with defects occurring apparently randomly, each no larger in area than a 1p piece. Consequently, there can be complete perforation of the pipe wall in just a few locations even though the average metal loss over one hundred miles of pipeline, say, may be relatively small.

This is analogous to a policeman measuring how much petrol motorists have used in the last twenty four hours, to check who has been speeding. Directionally, it may give some indication, but will provide no information on the time, location, or the maximum speed.

Fourthly, there can be inefficiencies in the way that information is gathered at the operating site, analysed and decisions made. Plant inspection is often seen as solely a service activity, and it takes a strong character to persuade the operations manager, who will have oil throughput targets to meet, to shut down facilities for more detailed physical examination. This is made all the more difficult because of the uncertainties in the conclusions that can be drawn from non-invasive, often circumstantial corrosion data.

Fifthly, changes in operating conditions and ownership of assets over time can lead to a gradual loss of ‘corporate memory’, that compounds the difficulties in predicting where corrosion might occur and the way in which it can be addressed.

Rarely do sites have their own corrosion specialists, and in the matrix organisation of oil companies effective relationships have to be forged with experts at headquarters. In practice, the success of this varies enormously, as does the way corrosion issues are elevated to senior management for key decisions.

The actual extent of corrosion can be determined by running intelligent pigs down the pipeline. These are comparable in size and shape to mechanical pigs, but have sensors to record the characteristics of every internal defect. Subsequently shutting down the pipeline, isolating and draining lengths of it by using valves, enables a physical inspection to be made. But all this is considered time-consuming and expensive, and is usually not undertaken until there is a leak, or when traditional methods indicate there really could be a serious corrosion problem.

History suggests that, at this stage, it is too late. The chemical processes involved are such that, by the time the first corrosion leak is observed, there will be already hundreds of other unseen defects, from minor to near perforation. The only course for a responsible operator is to shut down the pipeline and related facilities, thoroughly inspect internally, and carry out extensive remedial work.

Although recent attention has been focused on internal corrosion, the external surface of pipework is also vulnerable for different reasons. Oil and gas pipes above the ground that have been insulated to retain the heat of the transported hydrocarbons can also corrode dramatically. Rainwater entering gaps in the surrounding metallic cladding has been known to percolate through the glass fibre lagging, to corrode the steel pipe at a rate of 2mm a year. This has led to failure of a 10mm thick pipe wall within just five years.

Alternatively, unlagged pipes buried under the ground are subject to corrosion through small electric currents being set up in the soil. This can be reduced by a technique known as cathodic protection, where rings of metal (sacrificial anodes) are put at regular distances along the outside of the line, to corrode preferentially rather than the pipeline, itself.

But in Russia, for example, there is usually little protection like this, and leak detection, as a result of any of the different types of corrosion, is often based on waiting for the spring thaw, when pools of oil emerge at the surface. A recent fire in the Middle East, that devastated an entire gas-oil processing plant, was attributed to a leak from an underground pipeline. Cathodic protection had been installed, but had never been inspected or maintained. In the extreme, pipelines can be vulnerable to both internal and external corrosion simultaneously. Strict adherence to procedures based on industry best practice (at least) is essential, as is the development of staff who think creatively, and challenge the status quo, as problems and their patterns begin to emerge.

So often, after the event, companies reflect on how they should have run an intelligent pig earlier than they did, or opened up pipelines for direct internal visual inspection, or indeed stripped away external insulation, or dug up sections of buried lines, all to get a better understanding of what was actually happening at the time. This embodies the challenge of managing the risk of corrosion of pipelines and facilities where the steel surfaces are not accessible in normal operations.

There seems to be a strong case for critical pipelines having short stretches of similar pipework in parallel, so that without interrupting operations this type of larger-scale sampling examination can be undertaken. Returning to the motoring analogy, it is like having two lanes for one particular direction of flow in certain places, where you occasionally close down one for detailed examination.

With this background, there are five important questions company Board members should be asking their senior executives, and which investors and analysts, in turn, should be asking these Boards:

- What is your corrosion management process?
- What has been your experience of corrosion during the last twenty years, what were the outcomes, and how were lessons learned disseminated?
- How does information flow from readings taken on site by technicians, through to analysis and decision-making at senior management level?
- What is your ‘corrosion model’ for predicting where damage might occur, and how often and in what way is this challenged and verified?
- How does all this compare with international best practice?

Many on the receiving end of such questions will feel uncomfortable, because corrosion is not on their radar screens. This has to change. The future will need to address improved handling of data and problem-solving, new materials, corrosion-resistant surfaces and linings, and better understanding and inhibition of corrosion mechanisms throughout the oil supply chain. That will take good management……..and clever chemistry!

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