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Modeling and Prediction of the Corrosion of Onshore Well Casings

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ABSTRACT

Casing corrosion is a phenomenon which is mostly overlooked during well design and construction. Many operators, in climates ranging from desert to arctic conditions, have experienced aggressive corrosion of the well conductors and casings. This paper describes some field examples for which the root cause of the attack has been established. The corrosion process has been modelled to provide a basis for ranking the condition of other wells in the field and prediction of the course of future corrosion attack. Corrosion mitigation steps for new wells are proposed (lessons learnt) and potential remediation steps for existing wells are suggested.

Key words: Production casing, surface casing, onshore wells, external corrosion.

INTRODUCTION

Well casings are usually selected of API[1] standard grade carbon steels and most will be cemented externally, in principal up to surface. Most operators give little further thought to the longer term performance of the casings over time, and, if they do, they probably consider that the cement provides an environment which is sufficiently protective to the steel. Indeed, normal class G cements have a naturally alkaline pH (about 12-13) at which steel is passive and will not corrode. Based on analysis of historic well data and a survey of industry's practice, it is apparent that in most cases little thought is

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given to the possible impact of corrosion of well casings on the long term integrity of the well. However, even a flawless primary cement job can be damaged by well operations or activities occurring after the cement has set. Changing stresses in the wellbore may cause microannuli, stress cracks, or both, often leading to Sustained Annulus Pressure (SAP). The presence of SAP is indicative of reservoir fluids within the annulus between the casings and, hence, potential access of corrosive fluids to the surfaces of casings bounding the annulus.

In recent years, well integrity studies carried out by Intetech Wells Ltd[(2)] have identified many examples where severe corrosion of casings has occurred, of sufficient extent to directly impact the integrity of the affected wells. Examples have been investigated of corrosion of surface casings and of production casings in climates ranging from hot desert to cold permafrost locations. In many cases the corrosion extended through the casing wall resulting in loss of annulus pressure integrity. In some cases the extent of steel thickness loss was sufficient to reduce the buckling resistance of the casing causing wellhead collapse by several inches. This resulted in fracture of the flowline in one case and loss of the well in other instances.

This paper describes some of the experiences, discusses some possible remediation steps and lessons learnt for well design and construction to avoid the problems.

MECHANISMS OF CORROSION OF BURIED STEEL

In order to get corrosion of the casing certain conditions have to exist. The most fundamental is that there has to be liquid water in contact with the casing surface. This allows aqueous corrosion attack to take place. If the cement sheath is intact and well-bonded to the casing surface then there is little chance for water to reach the steel surface. In these circumstances, the steel is well-protected by the alkaline pH and dry environment of the cement and will not corrode over long time periods. It is noteworthy that there are archaeological remains of iron arrow heads and lances which have been found in naturally cementitious conditions which are still intact after almost 2000 years, proving that iron will corrode at exceedingly low corrosion rate if the environment around it is naturally protective.[1]

Unfortunately, cement sheath quality is rarely so reliably perfect. In some cases well designs have not required cementing of the casing over critical geological intervals. More typically, cementing operations face significant losses in certain intervals so cementing has to be stopped without filling the annulus completely, or to the planned top of cement depth. Well operations, including thermal and pressure cycles, may also deteriorate the cement sheath quality with time. Under these circumstances ground water or subsurface aquifers may contact the casing. If the water has a composition which is aggressive to steel, including one or more constituents which can support a corrosive reaction, then corrosion of the casing may then take place.

The principal agent of corrosion in waters close to ground level tends to be oxygen. The oxygen supports the cathodic reaction needed to balance the anodic reaction of iron dissolution. Deeper in the ground other cathodic reagents can be found in aquifers or migrated reservoir fluids including dissolved acid gases like carbon dioxide or hydrogen sulphide.

The rate of reaction of steel exposed to ground waters is affected by many parameters, some of which can interact in complex ways. For example, the surface temperature of the casing is critical as this affects the corrosion rate. Taking the example of a water source which is exposed to the air, the rate of oxidation it will cause to steel approximately doubles for each 10°C rise in temperature, all other factors remaining equal.[2] However, the solubility of oxygen in water falls with increasing temperature so hotter water has a lower concentration of dissolved oxygen to drive the corrosion reaction: [3]

[(2)] Company name

- 10 °C - 10 ppm
- 20 °C – 8.2 ppm
- 30 °C - 6.8 ppm

The worst-case scenario would be cold water (with a relatively high oxygen content) in contact with a hot casing, a combination of conditions which was experienced in one of the case histories discussed below.

In the case of deeper water sources in contact with casing the temperature will often be higher which will generally just drive the corrosion faster. However, some corrosion products become more protective at higher temperature. For example, CO_2 corrosion tends to form an increasingly protective iron carbonate film with increasing temperature and so the corrosion rate may be *lower* deeper in a well where temperatures are higher.

The chloride content of the water phase is important. Brines are more conductive than pure water and so they more readily support the electrochemical corrosion process than chloride-free water. However the solubility of oxygen or carbon dioxide is lower in dense brines, so the concentration of the aggressive agent is reduced, so, like temperature, the chloride concentration has a complex impact on the corrosivity of the environment.

The final significant variable is the frequency with which the water is replenished with corrosive species, either because water is refreshed (at the surface) or water flows towards or through an annulus space because of pressure differentials. A typical cause of water replenishment can be the bleeding off of fluids from a pressurised annulus, typically one suffering from SAP. In many cases there can be actual benefit from not de-pressurising an annulus if the pressure is within the safe limits (below maximum allowable annulus surface pressure limit).

These varying factors:

- water contact with the casing surface
- temperature of the water
- temperature of the casing
- concentration of cathodic species in the water (particularly dissolved oxygen or carbon dioxide)
- concentration of chloride ions in the water
- ease of replenishment of the water

will all have an impact on the corrosion rate experienced by the casing.

CASE HISTORY – SURFACE CASING

Introduction

This case history concerns wells located in a permafrost region. From the well design the surface casing was intended to be cemented to surface through the permafrost layer. Permafrost at some well locations extends to a depth of approximately 1800 feet (549 m). The permafrost is unconsolidated sand, gravel, and ice which frequently results in wellbore enlargement during drilling and cement losses (together resulting in typically 250% "losses" across the permafrost). As a consequence there is shrinkage of cement from surface after completion of the job, exposing an estimated 2-100 feet (0.6 – 30 m) of surface casing at the surface.

The processes of hydration and cement structure formation in conventional Class G Portland cement at low temperatures are extremely slow, so an alternative cement formulation with accelerator additives is needed to speed up this process in permafrost conditions. The cement formulation used in this case history contained approximately 50% gypsum, 12-15% chloride salts and cement. This type of cement forms a very poor structure with high water content, high level of porosity and low strength. The freeze – thaw cycles cause further frost damage to the porous cement structure. Gypsum breaks down above about 150 °F (65.6 °C) so cement deterioration may occur in service. These processes all contribute to the likelihood of having a poor cement bond to the surface casing.

The annulus space between the conductor and the surface casing was open to atmosphere on many wells and would fill with aerated surface water from melting snow. The annular space was fairly continuously wetted, varying from wet mud or gravel to being water filled. Salts leached from the high chloride content cement into the water, creating a low resistance electrolyte fluid with high oxygen content, resulting in a corrosive environment. Elevated casing temperatures (~125 °F (52°C)), where present, accelerated the corrosion rates resulting in corrosion of the outer surface of the surface casing more than the cooler internal surface of the conductor pipe.

Where the surface casing was holed because of the corrosion, the production-to-surface annulus fluid (Freeze-protect) leaked into the well cellar, which is how many casing breaches were identified (whilst some were detected from inspection).

Loss of wall thickness of the surface casing also resulted in reduced strength with a risk of loss of support to the wellhead generating wellhead movement. In the extreme, casing wall loss can result in parting or buckling. Similar external conductor and casing corrosion experienced by other operators has resulted in well blow-outs and flowline rupture whilst these have not been documented in the public domain. The risk varies from well to well since, not only is there a variable amount of external corrosion, there is also the possibility of internal casing wear of unknown extent.

Failure Rate Evaluation

A total of 73 instances of failures of the surface casing were identified over the history of the field. Knowing the time to failure (dated from the date the well was completed to the first identified reference to failure in the well files) and the surface casing original wall thickness, the corrosion rate for each case was calculated.

Influence of Well Age and Service on Surface Casing Corrosion

Figure 1 shows the corrosion rates of the failed surface casings as a function of well completion date. The apparent gradual increase in corrosion rate with time is partly an artifact of the data (more recently constructed wells can only have higher corrosion rates as they have not been in the ground long enough to have a long life and hence lower corrosion rate). It may also reflect an improved awareness of the problem and hence earlier recognition and reporting of the problem as it arises. In the last 10 years (approximately) thinner walled casings have been used which fail sooner (at the same corrosion rate) and so the problem has become more acute as the impact on well life is arising in a shorter time frame.

The extreme value of the distribution of corrosion rates represented by the failed wells (1.4 mm/y) is quite high for oxygen corrosion in a fairly stagnant volume. Individual wells may have some specific feature which is causing some acceleration of corrosion rate. Possible causes could be:

- The circulation of annulus water is actually a more significant contribution to increased oxygen supply than initially might be expected (possibly related to WHT in these cases).
- The environment is more aggressive than seawater, possibly more acidic (i.e. other ions dissolved from the cement are lowering the pH relative to pH of seawater (approx. 8) or intermittently there has been some other chemical (acid) present.

- Internal casing wear (from drilling operations during well construction) has contributed to overall wall thickness loss rate

It can be seen that the corrosion rate of seawater injectors has a similar distribution to that of the producers, despite the fact that the typical surface casing temperature for seawater injectors was 65 ºF (18 °C) whereas producers and produced water injectors had a typical surface casing temperature of 125 - 130 ºF (52-54 °C). [Note that the produced or injected fluids are inside the tubing; the temperatures of the surface casing are quoted based upon wellhead temperature modelling from the tubing outwards].

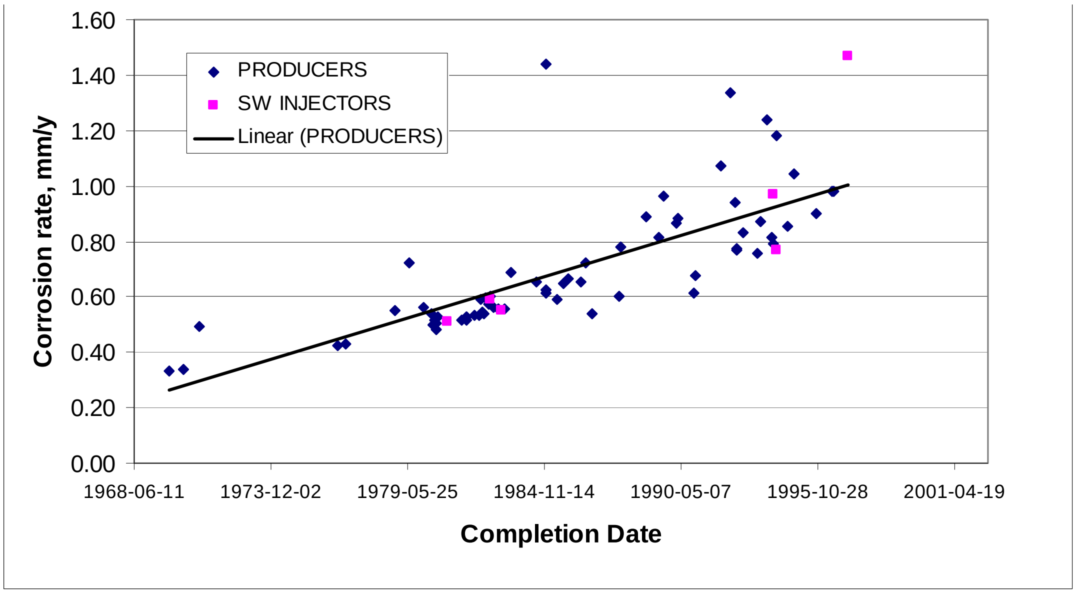


Figure 1: Distribution of Surface Casing corrosion rates experienced within 72 failures including 6 seawater injector wells.

The reason for this lack of correlation of corrosion rate with well service type and (by implication) surface casing temperature is thought to be because the casing temperature is actually quite variable over the time periods considered. Water injectors do not normally stay as injectors of just seawater for a long period and when injecting produced water they have a much higher surface casing temperature, comparable to the producers. Similarly, producer wellhead temperatures also vary significantly because of changes in production rate and shut-in periods. So producers are not necessarily hotter than the seawater injectors on average.

Temperature of the casing may therefore be a parameter which *does* affect corrosion rates, but without a data set of wells with fairly constant surface casing temperature, this variable cannot be isolated. It cannot therefore be usefully applied as a means to risk rank wells for investigation or repair.

Influence of Diameter on Surface Casing Corrosion

Consideration of the variation of corrosion rate with surface casing diameter (Figure 2) showed that the smaller diameter casing had a tendency to suffer a faster corrosion rate. Whilst the smaller diameter casing seems to have a higher corrosion rate, caution is needed with this interpretation because the selection of small casing diameters is a relatively new well design, so these casing failures are also more recent and therefore correspond with higher (apparent) casing corrosion rates (ref. Fig. 1). Nevertheless, there is some physical basis for the observed faster corrosion rate, as discussed below.

The smaller (10 ¾ inch (263 mm) diameter casing corresponds to newer wells. Slimmer well designs were introduced over time as the production rates decreased, hence requiring a smaller diameter tubing and correspondingly smaller casing. That trend continues today with a shift to 9 5/8 inch (244 mm) surface casing in many cases for the newer wells. The implication of this is that corrosion rate of the surface casing in newer wells will tend to be faster than in the older wells. Surface casing with small outside diameters are most at risk of surface casing leaks since not only is the corrosion rate higher but the wall thickness is also lower. The wall thickness of the 13 3/8 inch (340 mm) casing is 13 mm compared to 10.1 mm for the 10 ¾ inch (263 mm) and 9 5/8 inch (244 mm) casings. A smaller wall thickness obviously results in a shorter time to failure at a given corrosion rate.

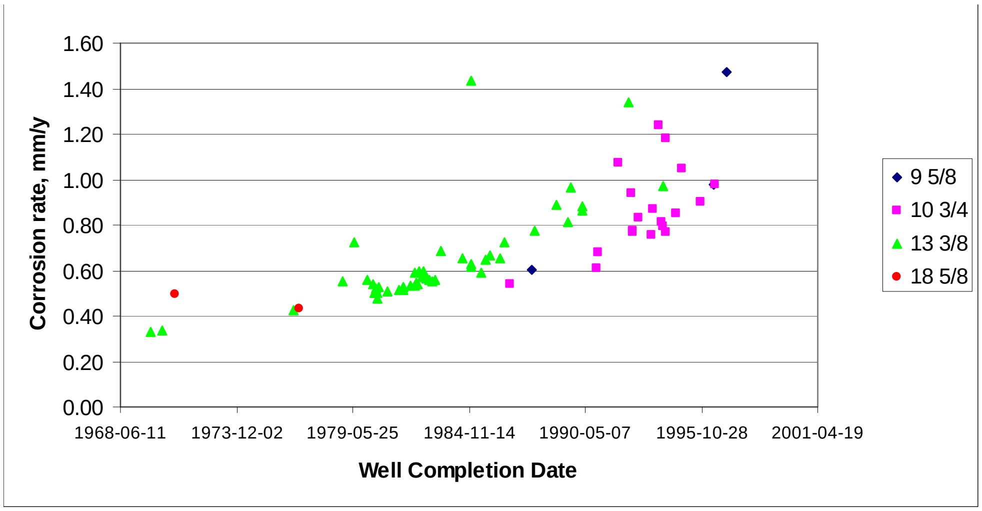


Figure 2: Distribution of Surface Casing corrosion rates experienced within 72 failures indicating the diameter of the surface casing

The reason for this variation in corrosion rate with casing diameter may be explained by consideration of the annular gap between the surface casing and the conductor. The conductor diameter was 20 inches (508 mm) for all wells, since this was the standard size selection, so the annular gap (which is filled with fluid) was greater for smaller size surface casing diameters.

The annulus cross sectional area was calculated between the conductor and surface casing to evaluate the theoretical cross sectional area available for oxygen diffusion into the fluid in the annulus.

The surface casing corrosion rates increase with the size of annulus cross sectional area (Figure 3). This indicates that the area for exchange of oxygen with the fluid in the annulus has a significant impact on the corrosion rates. This reinforces the fact that the primary driver for the corrosion rate is supply of the cathodic reactant (oxygen). Where the surface area of the fluid in contact with air is greater, corrosion rates are higher

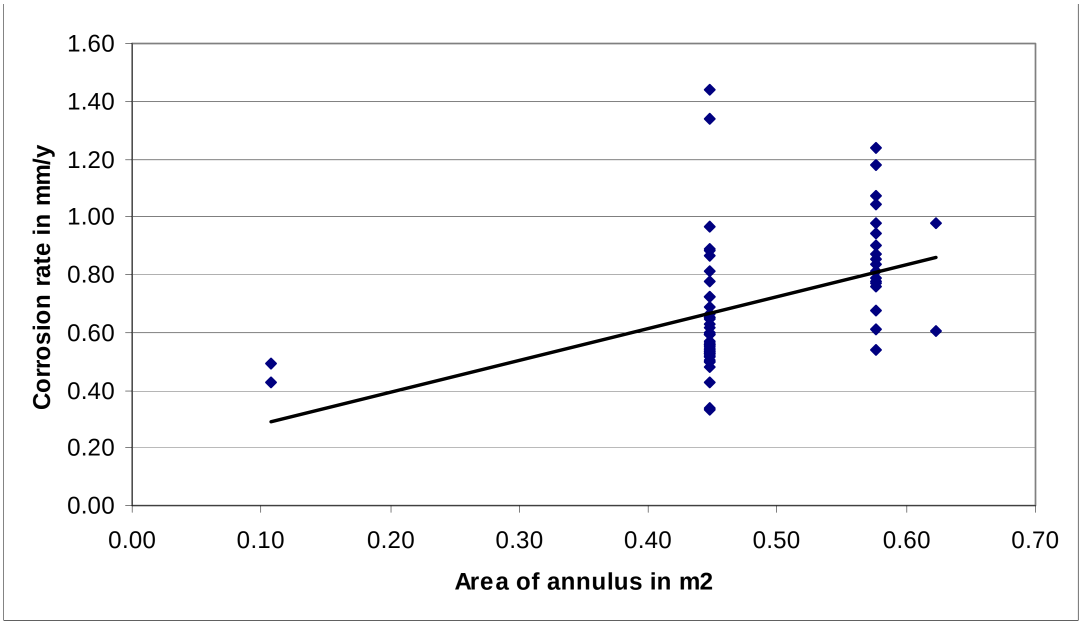


Figure 3: Surface Casing corrosion rate as a function of annulus cross sectional area.

The process of oxygen corrosion is mass transfer limited and hence any reduction in oxygen supply rate will be beneficial in reducing corrosion rates. Complete barriers (closed in wellheads) to oxygen entry would be most effective; polymeric barrier fluids injected into the annulus will reduce damage rates to some extent (depending upon quality of implementation) giving an unquantifiable but positive life extension.

Mitigation and Remediation

Mitigation in New Wells

The *mitigation* of this problem for *new wells* requires:

- a change of policy with respect to the cement slurry design for the surface casing, utilizing an improved cement grade which will be capable of filling the surface casing-conductor annulus fully to surface and achieving a good cement bond.
- improvements in cement slurry displacement methods, e.g. use of centralizers within the conductor section to reduce risk of channeling of cement around the off-center string.
- a re-evaluation of the policy of having an open annulus. A changed wellhead design which has an enclosed annulus would prevent snow melt ingress into the annulus and facilitate future diagnostic testing and communication testing across the surface casing.
- where the well design and ground conditions allow, casing cathodic protection can provide useful protection to the external surfaces of the conductor pipe and casings, where it is the outermost conductor/casing which is attacked. Conventional well cathodic protection was not a corrosion mitigation option for the case history described here where it was an *internal* inner casing surface which was corroding.

Remediation

Risk ranking of wells is possible based on the findings of this study. High risk wells will be the oldest wells with the smaller diameter surface casings and with the annulus open to atmosphere. Other operators may find a comparable risk-ranking based upon well age and casing weight helpful.

Annulus mechanical integrity pressure tests are needed to establish if the well still meets the design basis by safely containing pressure to at least the design maximum allowed annulus surface pressure value or to the previously monitored maximum annulus pressure. The tolerable test pressure value will be driven by formation strength criteria and by pipe triaxial collapse and triaxial burst criteria corrected to take corrosion and wear into consideration.

Casings passing the annulus pressure tests still have sufficient wall thickness to meet well design/operational requirements and they may be considered for treatment designed to prevent or significantly slow down further corrosion such as cement top-up or injection of a polymer sealant. This is intended to displace water from the annulus, thus removing the electrolyte supporting the corrosion process. Even if the removal of water is not perfectly achieved it is likely that this approach will stop or slow down the corrosion rate sufficiently to have a valuable mitigating effect by reducing the supply of the cathodic reagent.

Wells with a known casing leak or which show any signs during the pressure test that they fail the well design requirements need a more detailed diagnosis and repair technique. Following rigorous evaluation of the well condition, other operators have excavated wells, cutting back the conductor and removing any remnant cement. They have then welded half shells of new casing around the old followed by reinstallation of the conductor, re-cementing by squeezing and back-filling the excavation. This repair activity is quite costly but has been used extensively in similar permafrost conditions. The excavation depth is typically 3-5 feet (1- 1.6 m) in these cases. A comparable excavation and casing half shell replacement has also been carried out in certain Middle East fields where excavation has extended to as much as 34 feet (10 m). There are some risks (and considerable costs) associated with this approach, but it has been successfully carried out in several hundred cases. Key risks are related to welding onto damaged casings of variable wall thickness, relating also to internal wear, and the fact that normal grade steels require pre-heating, to avoid cold cracking after welding. In some cases repair operations had to be aborted due to loss of casing strength during the heating effect of the welding cycle.

A further draw-back of the excavation and casing welding repair is the likelihood that the casing condition may be quite bad deeper into the ground. In the Middle East example damage did extend below 1 joint in many cases (as demonstrated by a few deeper excavations), but safety considerations limited the repair to the first 34 feet (10 m). In the situation where the cement bond is poor, further corrosion may have taken place lower down the casing so even after casing repair by welding, the pressure integrity of the complete casing string may still be compromised. Whilst the “repaired” casing may still suffer from leaks and possible SAP, the wellhead may be stabilised sufficiently to prevent collapse.

An alternative approach, which might be possible in some cases, would be to carry out an annulus competency test to evaluate if the wellbore will support squeezing of specially tailored cement slurry into the annulus. If feasible, this is considered to be safer than excavation and welding of an external casing patch. Injecting cement into the annulus potentially reinstates the load-carrying capacity of the casing and provides a corrosion protective environment for the steel components for the remainder of the well life.

CASE HISTORY – PRODUCTION CASING

Introduction

Leakage of production casings at depths from around 2,500-7,000 feet (762 -2133 m), but mostly 4,000-6,000 feet (1219 -1829 m) was investigated for one operator. Failures resulted in breakthrough of the aggressive water aquifer at that depth into the production annulus, causing annulus pressure to be developed. Wells with gas lift valves installed in the tubing string exhibited a rapid increase in water cut and lower flowing tubing head temperatures as aquifer water flowed in through the annulus and into the tubing. As the failures arose in (partially) cemented production casings, none have been retrieved, so the cause of failure has to be inferred from the available failure rate data rather than from a failure analysis exercise.

Failure Rate Evaluation

The distribution of apparent production casing corrosion rates calculated from the actual failure data (i.e. production casing wall thickness divided by the years in service up to failure) is shown in Figure 4, identifying the gas lifted wells. [Gas lift is conventional, by injection into the production annulus].

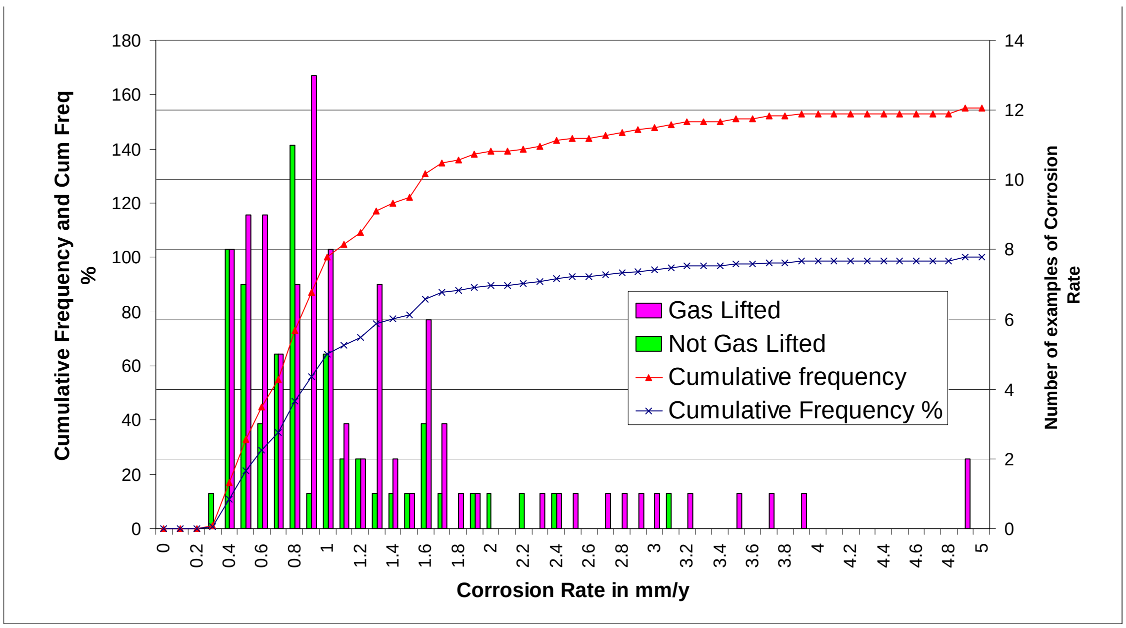


Figure 4: Histogram of apparent production casing corrosion rate identifying the gas lifted wells. The cumulative frequency is the sum of the total number of failures of all wells. The cumulative percentage shows, for example that approximately 80% of the failures arose at corrosion rates less than 1.5 mm/y.

The wells without gas lift tend to show a slightly lower corrosion rate, and the gas-lifted wells distribution is displaced to slightly higher corrosion rates. This has been attributed to earlier leak detection rather than a difference in failure mechanism. Overall, the corrosion rates show a log-normal distribution.

A potential cause of leak which has been proposed is leak through the buttress threads because of drying of the dope in wells which are gas-lifted. Alternatively, CO_2 in the gas lift gas, though dry (and therefore non-corrosive) at the wellhead conditions, may dissolve into the completion brine below the lowest gas lift mandrel and cause a localised *internal* corrosion of the production casing at that depth. If gas lift were an effective mechanism the frequency of production casing failures should be higher in gas lifted wells than others. In fact it is practically the same. Out of 1021 gas lifted wells, 99 had a production casing leak (9.6%) whereas from 419 naturally producing or injecting wells there are 49 with production casing leaks (11.7%). In other words, the tendency for leaks is not enhanced in gas lifted wells, but is spread approximately equally across the full population of well types.

Table 1 gives a breakdown of the numbers of production casing leaks detected in the different regions of the field. It illustrates the fact that the two regions of the field that were built up at a similar construction rate over the same time period have quite different frequency of failure: Region 1 having approximately 3 times as many leaks as Region 2. This reflects a difference in cementing policy; the Region 2 wells were intended to be cemented past the aggressive aquifer, whilst the Region 1 wells were not. Thus Region 1 wells have no protection of the casing through the aquifer, whereas Region 2 wells *should* be protected through the aquifer zone, where the cementing operation has been fully successful and offers an integral barrier to the casing. This points to the external corrosion from the aquifer being a much stronger influence on production casing than the impact of internal gas lift.

Table 1
Distribution of detected and documented production casing leaks in different regions of the field.

	Region 1	Region 2
Gas lift wells	70	20
Naturally producing wells and injectors	41	18
TOTAL	111	38
% of all production casing leak wells which are gas lifted	63.1%	52.6%
% of all wells (leak + nonleak) which are gas lifted	68.7%	71.6%

Overall, 58.7% of the wells with production casing leaks have gas lift starting at some date prior to observation of the production casing leak, i.e. 58.7% of the total well population in Figure 4 are gas lifted. However, considering just the 17 wells which indicate wall penetration rates greater than 2 mm/y, 11 commenced gas lift between 1 and 4 years prior to failure. This percentage (67% based on 11 gas lifted out of 17) is higher than the average for production casing failures. This suggests that whilst gas lifting is not the primary cause of the failure, it may contribute to its more rapid detection. Since production casing leaks are identified more readily in wells which are gas lifted, they are identified as having a higher corrosion rate. Thus the gas lifted well population (pink) in Figure 4 is skewed slightly to the higher corrosion rates relative to the non-gas lifted well population (green).

This suggests some variability in the accuracy of defining the "life" of the casing up to the leak date depending upon the service conditions. This may result in a wider spread of the corrosion rate results in wells which are not gas lifted (as the production casing leaks may go undetected for some months, or possibly years) and generally implies that *calculated* corrosion rates are *lower* than actual values because the moment of first failure is less easily detected.

Figure 5 shows the variation in apparent corrosion rate of the production casing as a function of well completion date. There is little variation of the corrosion rate over time, just a slight tendency (as noted in Figure 1) for corrosion rates to rise over time, probably because of better recognition and reporting of the problem and because of the increased use of gas lift over time.

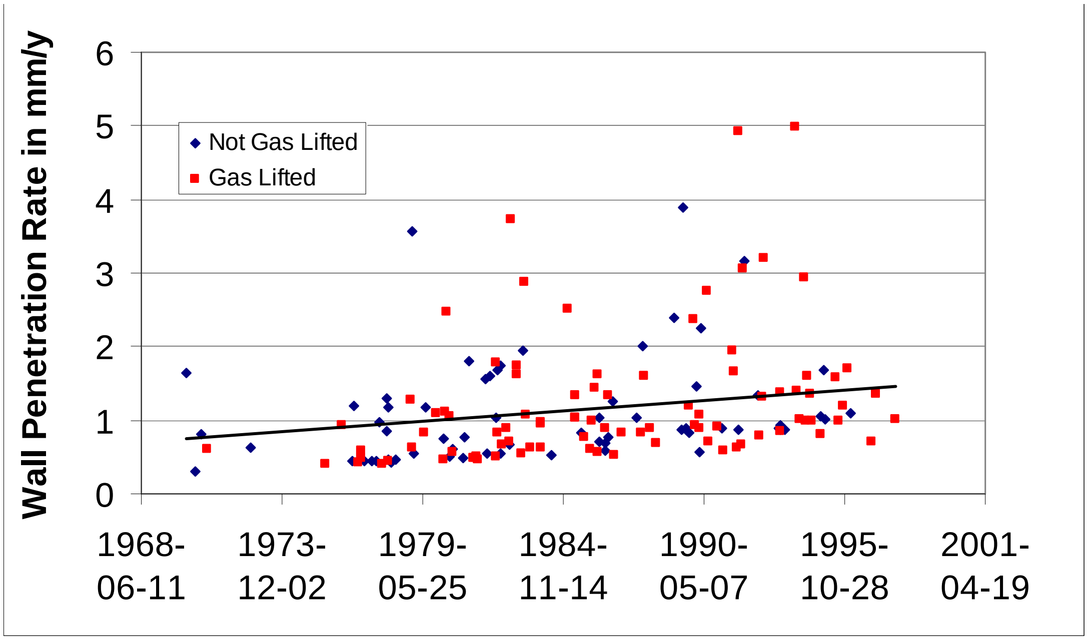


Figure 5: The production casing corrosion rate as a function of well completion date. Red symbols are wells with gas lift and blue symbols are naturally flowing producers and injectors.

Mechanism of Production Casing Corrosion

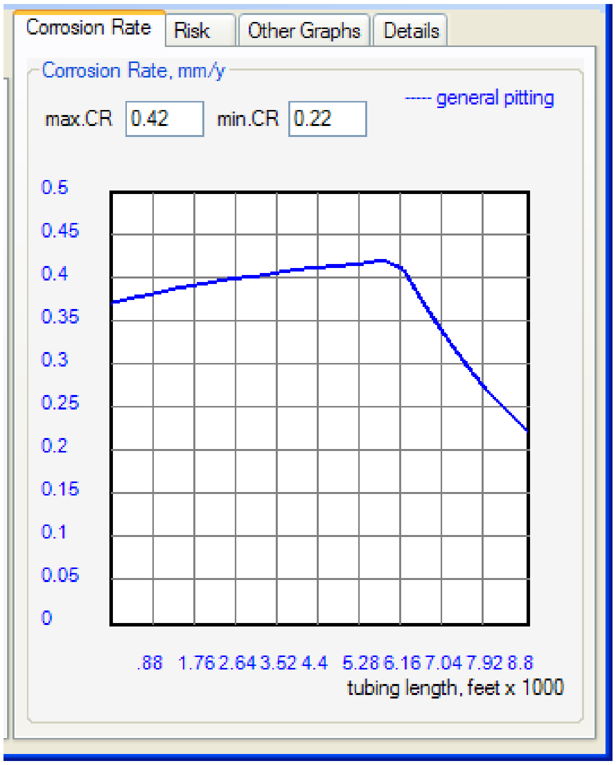
To understand any external corrosion process which may be taking place it is necessary to know the composition of the environment surrounding the production casing. Prior to the start of surface fluids disposal into the aquifer in the late '70's, the indigenous (uncontaminated) water was sampled in order to check the potential for scaling or other reactions which would indicate an incompatibility with the intended fluids for disposal.

These analyses from two exploratory wells indicate a dissolved CO_2 content in the indigenous aquifer water in the range 45-90 mg/l. This is equivalent to approximately 0.001-0.002 kmol/m3 CO_2. At the pressure and temperature conditions to be expected at the surface of the production casing this water could result in CO_2 corrosion of the steel. To get an indication of the rate of attack which is possible a corrosion model, the Electronic Corrosion Engineer(3), was used to evaluate the reaction rate controlled part of the CO_2 reaction (minimizing the effect of any liquid flow/mass transfer on the corrosion process).

In this illustrative case, the "effective" gas phase CO_2 required to produce 0.002 kmol/m3 dissolved CO_2 is 0.17 mol% CO_2. The corrosion rate profile down a typical 8800 feet (2682 m) of production casing (assuming it is in contact down the complete length with an aqueous environment of composition 0.002 kmol/m3 dissolved CO_2) indicates that there is a range of depth down to about 6,200 feet (1890 m) over which the corrosion rate might be around 0.4 mm/y (Figure 6). Below that depth the higher temperature results in the formation of iron carbonate scale and so the corrosion rate decreases as the protective

(3) Trade name

scale forms. This estimate is based on just the reaction of the CO_2 with the steel surface, ignoring any possible impact of fluid flow rates, as they are unknown.



Input data:
Wellhead temperature = 150 ºF (65°C)
Wellhead pressure = 1500psi (10.3 MPa)
Bottom hole temperature = 250 ºF (121 °C)
Bottom hole pressure = 3250 psi (22.4 MPa)
CO_2 = 0.17 mol%
HCO_3^- = 2000mg/l

Figure 6: Illustrative corrosion rate profile estimated for the *external* surface of the production casing.

Corrosion rates are strongly influenced by the flow conditions, the CO_2 corrosion rate calculation being a balance between a mass transfer contribution and a reaction rate contribution. Under normal circumstances of fluids flowing through tubing or piping, a reduction in flow velocity to zero indicates that the conditions are stagnant and there is a limited volume of corrosive species available to react with the steel surface. Corrosion rates therefore drop with time as the corrodant (dissolved CO_2) is used up.

In the context of the production casing the environment around the casing after drilling the well would be considered to be fairly stagnant. However, unlike the stagnant situation described above for a length of tubing or piping, the aquifer provides an infinite volume of corrodant. Corrosion rates would therefore be limited only by the rate of diffusion of dissolved CO_2 to the surface of the steel. CO_2 will diffuse down the concentration gradient caused by reaction of CO_2 with the steel as this removes CO_2 from the solution immediately surrounding the casing. Any movement of the aquifer related to thermal convection, or pressure induced flow would add to the supply of CO_2 to the casing.

In the context of pressure-induced flow, a possible matter of concern is the fact that the aquifer zone is used for fluid disposal. The aquifer in question is above, and independent of the production reservoir, so this disposed water is not being used for pressure maintenance in the reservoir. Volumes of produced fluids disposed into this zone have exceeded 400 Mm^3 over 30+ years.

Past studies have considered whether this disposal activity might be the direct root cause of the production casing failures either through its composition or by a process of fluid erosion. Detailed study of the proximity of disposal wells to known cases of production casing leaks has been checked by evaluating the offset distance at various depths. As an example, Figure 7 is extracted along one horizon to the closest of any disposal wells. This does not indicate a higher frequency of problems amongst wells close to disposal wells at this relevant depth. Conversely, there is no tendency for wells furthest from the disposal well locations to have a lower frequency of failure. Further depths have been checked, relevant to the observed depths of the casing leaks, and similar lack of correlation was noted.

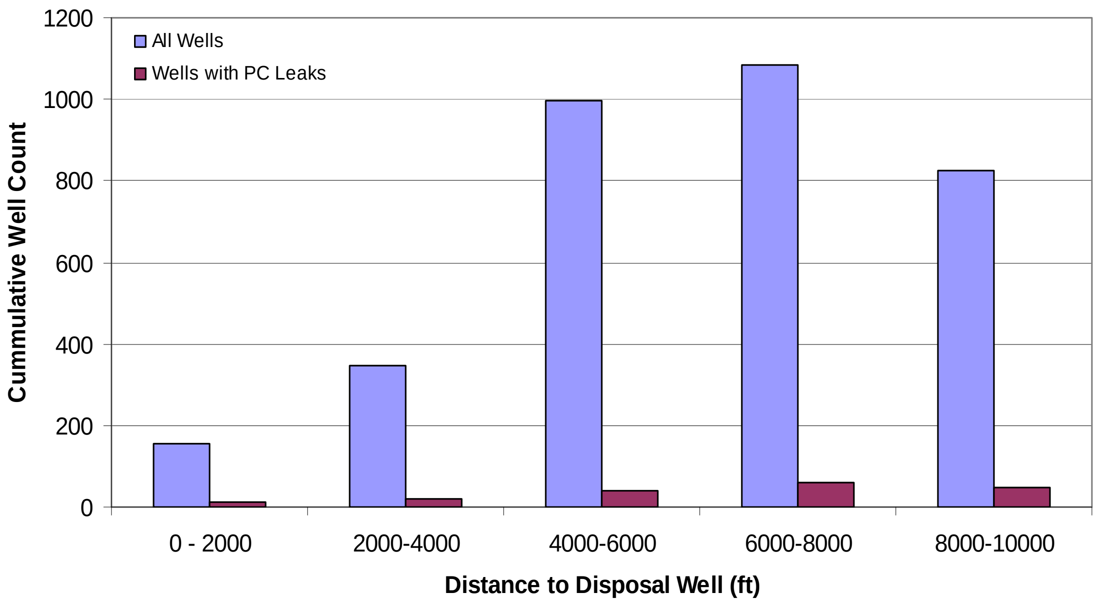


Figure 7: This is a count of all wells at the stated distances (extracted at the depth of leaks) from the disposal wells compared to the numbers of wells with identified production casing (PC) leaks.

A further geophysical investigation focused on the actual fabric of the reservoir with the aim of understanding whether faults in the structure could explain the protection of some wells and the problems experienced in others. The conclusion of this exercise suggests that there is no simple causation between production casing leaks and proximity to a disposal well. The produced water is not itself highly corrosive by the time it reached the disposal zone as the partial pressure of CO_2 is very low by the final gas separation step, but the sheer volume of injected fluid is considered to be a potential driver causing pressure induced flow of the aquifer and thus replenishing the corrosive species (CO_2) at the surface of the exposed casing strings. Any movement which brings dissolved CO_2 to the casing surface will allow the inevitable corrosion process to continue, but it is very difficult to define the flow path of the disposed fluids.

It is difficult to judge the extent to which the current disposal activity does cause pressure induced flow at any specific casing surface because there are many variables to consider. The first of which is the thickness of the permeable zone that may preferentially absorb disposed fluids. The volumes of fluids disposed at each well are different, but it is considered naïve to presume an equal spread of those injected volumes around the injection point. That is, the permeability of the disposal zone may be restricted in some parts to a thin reservoir (and hence disposed volumes will arguably travel further) or a thicker zone which will mean that the disposed fluids will not impact over such great distances from the injection point.

The complex interaction of multiple factors that may cause production casing leaks is most likely (in order of priority):

1) cement sealing performance 2) age of well 3) production casing thickness 4) CO_2 content in the indigenous aquifer. The 2nd order effects might include: 1) disposal well volumes and offset distances 2) reservoir fabric (faulting, fracturing, stratigraphy, petrophysical properties etc.) 3) injected fluid composition.

A critical conclusion from this environment evaluation is that it seems that the aquifer water is intrinsically corrosive. The theoretical estimate of the possible corrosion rate (@0.4 – 0.5 mm/y) is comparable with the modal corrosion rates estimated from the field failure data. Mechanisms exist which would both reduce that corrosion rate over time (decreasing diffusion rate of CO_2 to the surface as the diffusion gradient reduces with time) and increase it (influence of convection or pressure induced flow in the aquifer). Such impacts would account for the variation in exposed production casing corrosion rate experienced in the field in Region 1 (where the casing is uncemented through the aquifer). Region 2 has more variables which will impact the apparent corrosion rate such as the height of the cement and cement sheath sealing performance and its deterioration over time.

Mitigation and Remediation

Mitigation in New Wells

The *mitigation* of this problem is for all new wells to be sealed by cement sheath across the aggressive zone. The increase in cost of the additional cement is negligible compared to the cost of remediation of the problem in service. The cement program should be optimised to achieve the best bond possible, as the problem has also been experienced in some wells which had been fully cemented. In order to confirm that cementing techniques are achieving the required height it is recommended to run an Ultrasonic Casing Imager(4), or similar tool, and cement bond log.

In the case of Extended Reach Drilling (ERD) wells, such that cementing back to the aggressive zone is not considered feasible, the well design may need modifying to check if the inclusion of a heavier wall casing over the critical zone is possible. Given that the corrosion problem generally becomes apparent in older wells, a few millimetres of extra wall thickness on the casing may provide sufficient additional years to the overall well life to be acceptable. This option is considered to be less effective than cementing, as it only prolongs the time to failure rather than "solving" the problem.

No mitigation actions are available for currently completed wells. Over the life of the well the opportunity should be taken when the tubing is out of the well to log the production casing to check the wall thickness to identify any external loss in the depth of the aquifer. Identifying such damage may assist in building a better risk model to help to identify future workover requirements in advance and to model the whole well population risk level for longer term budget planning.

Remediation

Once a production casing leak is identified (from production annulus pressure behaviour and produced water characteristics) action should be initiated to evaluate and remedy the problem promptly in order

(4) Trade name

to prevent any additional damage. Various *remediation* methods have been attempted in the past with greater or lesser success. Options include rig workover, expandable casing repair, straddling the leak with packers, re-casing the well by scab liner or second liner, or sidetracking.

CONCLUSIONS

Sealing an annulus space against corrosive fluids migration is extremely difficult to achieve in some critical wellbore zones. Corrosion of well conductors, Surface Casings and Production Casings is found very widely around the world. Such damage may severely reduce the load carrying capacity of a well and may compromise the pressure-retaining capacity of casing barriers. Remediation of the problem is costly and difficult late in the well life. Lessons learned to prevent the occurrence of casing corrosion should be implemented at the stage of well design. Control of well construction, particularly the cementing operation integrity, is essential to avert the problem of well life time reduction.

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