

Unusual Corrosion of Well Tubulars and Casings in Sour Gas Lift Well Annuli – Causes and Mitigations

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ABSTRACT

Gas lift, utilizing the injection of high-pressure gas via well production annuli and into the production bore through mandrels or valves, is a common artificial lift method in oil wells. Unexpected corrosion located in the annuli below the gas-lift valve was observed on several well completions and led to an investigation of its causes and deployment of alternative mitigation measures. The aggressiveness of the corrosion seen is not in line with industry experiences and prompted a need to better understand contributory factors. Unlike the often traditionally held belief that corrosion should be limited to the interface of the injected gas and packer fluid column; corrosion was seen to extend far beyond this area deep into the wells.

Investigations consisted of reviewing historical packer fluid treatments and well operating conditions, literature surveys, and metallurgical and scale analysis of the retrieved production tubing. In addition, microbiological analysis was undertaken to establish if a microbial influence was present. To substantiate findings a review of the Company's gas lifted well stock and reported corrosion cases was undertaken.

This paper will describe that CO₂ + H₂S corrosion was identified as the main degradation mechanism and that the presence of glycol in the packer fluids exerted a crucial detrimental factor. A microbial influence could not be ruled out.

Chemical treatment test methods developed to establish the longevity of protection to be expected, and initial results from them, are described.

Key words: H₂S + CO₂ corrosion, gas lift, well annuli, glycol

INTRODUCTION

Injection of hydrocarbon gas is a common practice to enhance production rates from multiphase wells in the Oil and Gas industry. The gas used is normally dehydrated by a combination of compression and chemical treatments to reach a given dew point specification. The dry non-corrosive gas is injected to the production annulus and enters the production bore via a gas lift valve (GLV) located on the production tubing above the production packer.

The presence of this dry gas in the annulus does not present a corrosion threat to carbon steel well tubing or casing however a corrosion risk at the interface of the injected gas and static fluids residing in the annulus is often postulated. The general experience is that corrosion issues in such circumstances are rare. (Ref 1).

Several cases of severe tubing and casing corrosion were experienced in a large Middle East oilfield prompting the need to understand contributing factors and establishment of suitable mitigation measures.

Internal corrosion of the tubing is not discussed.

WELL DESIGN AND OPERATING CONDITIONS

Well Design

The basic well design, equipment and location of the injected gas and annulus fluids are shown in Figure 1.

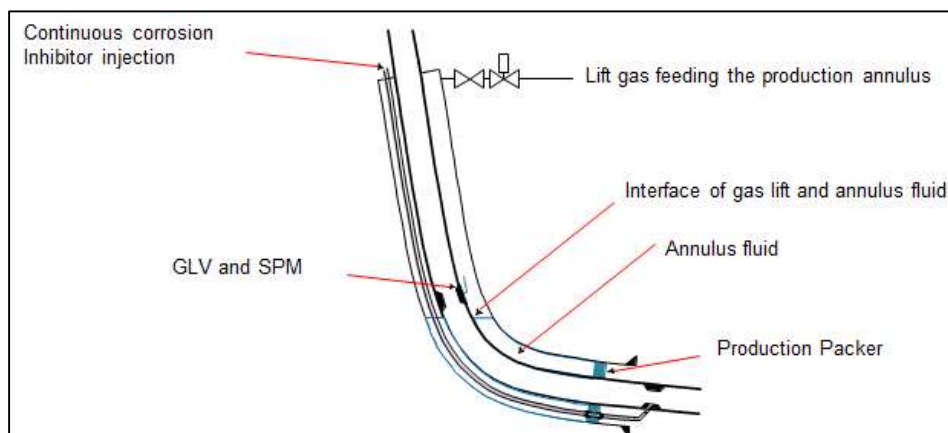


Figure 1: Basic well design

Other key design details are summarized as:

- Production tubing above the production packer and entire production casing are API 5CT L80 (low alloy steel) and protected from internal corrosion by injection of corrosion inhibitor injected below the production packer depth.
- Production tubing below production packer is API 5CT L80-13Cr.
- Wells are of a long horizontal design of several kilometers with annulus fluid columns ranging between 100 and 1000 meters.

Operating Conditions

Whilst operating conditions differ from well to well depending upon the location across the field and the reservoir from which they produce, the ranges of conditions seen are shown in Table 1.

Table 1
Operating conditions

	Unit	Value / range
Bottom hole pressure	bar	~120
Bottom hole temperature	°C	57-60
Flowing well head pressure	bar	<10
Flowing well head temperature	°C	45-50
Temperature at SPM	°C	50-55
Gas lift injection pressure	bar	121
Production fluids CO ₂	mole %	2 to 3
Production fluids H ₂ S	mole %	Up to 1.5
Gas lift CO ₂	mole %	2.8 to 6.0
Gas lift H ₂ S	mole %	0.4 to 0.7

During operation production may be stopped on a varying frequency depending upon operational and production needs. During such periods the gas lift valve (GLV) (a dart type check valve housed in a side pocket mandrel (SPM)) located on the production tubing should prevent flow of production fluids from entering the annulus. Experience shows that these devices may not fully seal or that the sequence of well and gas lift injection may be such that production fluids enter the annulus.

The current field has a history of significant microbial activity in the production fluids following long term injection of seawater to the reservoirs. On this basis, production fluid with microbial activity entering the annuli is considered possible.

Beneath the SPM an interface between the injected lift gas and 'static' annulus fluid column exists where some turbulence would be expected. Beneath this interface flow would be expected to be very little, in fact likely closer to 'stagnant'. Thus, the area could be considered a large 'dead-leg' as frequently seen in process facilities. The dried gas stream contacting the fluid packer implies some mass transfer phenomena, driven by momentum transfer and concentration gradients.

- From the gas to the fluid: mass transfer of acid gases
- From the fluid to the gas: mass transfer of H₂O

The diffusion of acidic species can be described in two stages:

- High mass diffusion rate, in the convection zone, at the shallower annulus fluid area
- Lower mass diffusion rate in the conduction zone, at the deeper annulus fluid area

Thus, from a corrosion perspective, the fluid area immediately beneath the SPM would generally be expected to have a higher corrosiveness due to easier saturation with acid gases and reduced consumption of the gases over the shorter distance. In some cases, production continued for an extended period following detection of a hole in the tubing via an annulus pressure increase.

Annulus Fluids

Upon completion of the wells a fluid (often termed 'packer fluid') is left in the annulus. Upon commencing gas lift injection, the fluid is displaced just below the lowest injection point (GLV). Over time it is expected that the fluid would evaporate due to the continued contact with dry gas displacing the fluid column a further 100-200ft.

The well annuli in question originally had a water-based fluid present consisting of low chloride (<500mg/l) water and biocide. Latterly these water-based fluids were 'topped-up' or displaced by a glycol-based fluid containing biocide and corrosion inhibitor. Laboratory testing of the chemical cocktail at the time did demonstrate effectiveness in reducing acid gas ($H_2S + CO_2$) corrosion. The biocide was a quaternary type while the inhibitor was amine based. The use of glycol was considered necessary to promote the dispersion of the fluid into the existing fluid column.

The glycol-based fluids make up was typically:

- 75-79% triethylene glycol
- 1-5% biocide
- 20% corrosion inhibitor

At the time of deploying these top-ups it was envisaged that the treatments would be repeated on a 5-yearly basis, although the basis for such frequency wasn't established.

EXPECTED CORROSION BEHAVIOURS

External corrosion of the tubing and internal corrosion of the casing could be expected in the case of sufficient corrosivity of the annulus fluids.

The area often considered at risk from corrosion in such cases is the interface of the injected (dry) gas and static annulus fluid. Whilst recognized in industry (Ref 1) as a threat to tubing and casing if constructed from carbon steel, experience has shown that corrosion rarely leads to a loss of integrity of either. The lack of severe corrosion instances at this interface can be attributed to a lack of flow, slow diffusion of acid gases from the gas to the fluid and the creation of stable protective scales. Corrosion in the underlying stagnant fluid column extending from the interface down to the production packer has also not been reported widely.

CORROSION EXPERIENCED

In recent years several cases of corrosion resulting in leakage of production tubing and wall loss of the production casings have been experienced. A number of such cases were investigated, and findings reported on herein. Table 2 details the cases investigated and includes the date of completion, glycol-based treatment deployment and tubing leak detection. Tubing leaks were detected by monitoring of gas lift injection rates and annulus pressure monitoring.

Table 2
Tubing leak cases investigated

Well	Initial packer fluids	Date completed	Glycol based treatment	Tubing hole
AB-05	NaCl brine + completion fluid recipe (ref Table 2)	Jan-2009	Jul-2010	Nov-2015
BD-15	Drillwater + completion fluid recipe (ref Table 2)	Nov-2008	June-2010	Sep-2015
CD-33	Drillwater + completion fluid recipe (ref Table 2)	Feb-2011	Jan-2013	Mar-2014
DA-22	Drillwater + completion fluid recipe (ref Table 2)	Aug-2009	Aug-2010	Jul-2015
DA-30	Seawater + completion fluid recipe (ref Table 2)	Oct-2002	Mar-2007	Jul-2011
BA-08	Seawater + completion fluid recipe (ref Table 2)	Nov-2001	Sept-2007	Jul-2015
BA-16	Seawater + completion fluid recipe (ref Table 2)	June-2000	2005	Jun-2016
BA-20	Seawater + completion fluid recipe (ref Table 2)	Initial completion Sept-98, w/over Aug -2003	2005	May- 2012

All tubing was of a size 4-1/2" diameter x 12.6 pounds per foot (ppf) meaning a wall thickness of 6.88mm. Service life is deemed to be the period from completion to detection of leak (hole).

These result in the following corrosion rates:

- 0.4mm / year for the longest service life well and 2.3mm/yr for the shortest service well if corrosion.
- If corrosion was predominately in the 'glycol-based fluid' period, rates of 0.8mm / yr to 8.0mm/yr were present.
- Following deployment of glycol-based fluids tubing were seen to fail within 14 months to 9 years and in average after 5-7 years.

Such corrosion rates were not expected, and at their upper end exceed what would be expected in the operating conditions given in Table 1 without some aggravating factor(s). (Ref 2).

Retrieved tubing inspections

Detailed visual inspection of retrieved tubing from wells where leaks were reported was undertaken and, in some cases, the associated production casing was subjected to caliper surveys to ascertain their condition.

Figure 2 gives an example of the outcome of such assessments. The pictorial approach was developed to show correlation between the location of holes on the tubing and degradation of the casing. Each sphere represents a 40ft length of tubing thus corrosion is seen to extend 8000 feet into the annulus fluid column. Each red sphere represents a hole, e.g., the red sphere at joint 200 being a hole deep in the annulus.