Engineering Failure Analysis 47 (2015) 178–198

Contents lists available at ScienceDirect

Engineering Failure Analysis

journal homepage: www.elsevier.com/locate/engfailanal

Premature failure of tubing used in sweet Extra Arab Light grade crude oil production well

Said S. Al-Jaroudi [a,*], Anwar Ul-Hamid [b], Mohammed A. Al-Moumen [a]

[a] Northern Area Oil Operation, Technical Support Department, Saudi Aramco, Saudi Arabia
[b] Center of Research Excellence in Corrosion, Research Institute, King Fahd University of Petroleum and Minerals, Dhahran 31261, Saudi Arabia

A R T I C L E I N F O

Article history:
Received 13 June 2014
Received in revised form 5 October 2014
Accepted 9 October 2014
Available online 20 October 2014

Keywords:
Wet sweet Extra Arab Light
Oil production well
API 5CT grade J-55 carbon steel
Sweet CO_2 corrosion
Mesa attack

A B S T R A C T

A 30 feet long and 3.5 in. diameter joints tubing used in wet sweet Extra Arab Light grade crude oil production well failed after 3 years of service. The bottom-hole temperature and pressure were, 82 °C and 170 atm, respectively. The tubing had a nominal wall thickness of 6.45 mm and was located at starting depth of 1465 m. The average production rate and water cut of the oil well during the last 3 years of operation were 8761 BPD (barrel per day) and 7.72%, respectively. Failure occurred due to corrosion resulting in leaks of three out of 5 consecutive joints of the tubing. On the other hand, rest of the 120 joints did not show any leaks. All failures occurred close to the joints. Various sections of the failed joints were metallurgically evaluated using scanning electron microscopy coupled with energy dispersive X-ray spectroscopy. The corrosion product was identified using photometric and potentiometric analysis combined with X-ray diffraction. Gas and water samples obtained from the production well were also analyzed. The material of the production tubing was identified as API 5CT grade J-55 carbon steel. Visual inspection revealed plastic deformation of tubing alloy at localized regions and internal corrosion as well as localized pitting at failed locations. Evidence of external corrosion was not found. Predominant mode of failure was sweet CO_2 corrosion in the form of mesa attack combined with chloride corrosion. Operating conditions of low pH, high pressure and high temperature along with presence of organic acid is thought to be responsible for the observed mesa attack. Replacement with a super 3–13% Cr production tubing and application of cathodic protection were suggested as a permanent solution to the corrosion problem whereas a number of short-term measures were also recommended.

1. Introduction

The problem of sweet oil well corrosion in the presence of CO_2 has major technological and economic implications. Carbon steel is widely used as tubing or pipeline steel in the oil and gas industry, and is usually heavily corroded due to exposure to CO_2 [1]. Carbon steel tubing is preferred over other materials due to its extensive availability, low cost, and ease of fabrication. However, carbon steel has low resistance to carbon dioxide corrosion. The CO_2 corrosion can induce premature failure in tubing or pipeline steel with accompanying economic loss. Corrosion can appear in three principal forms i.e., pitting [2], mesa attack [3] or flow induced localized corrosion [4]. Dry CO_2 gas is not corrosive at temperatures generally

* Corresponding author. Tel.: +966 3 378 4818; fax: +966 3 378 4620.
E-mail address: said.jaroudi@aramco.com (S.S. Al-Jaroudi).

http://dx.doi.org/10.1016/j.engfailanal.2014.10.006
1350-6307/

encountered within oil and gas production systems, but causes grave damage when dissolved in an aqueous phase such as brine formation water. CO_2 is extremely soluble in water and brines but its solubility in hydrocarbons is 3 times higher. Dissolved carbon dioxide in the produced brines is very corrosive to carbon and low alloy steel tubulars and to the process equipment used in the oil industry [5]. Moreover, around 60% of oilfield failures are related to CO_2 corrosion. These failures occur mainly due to inadequate knowledge, lack of predictive capability and poor resistance of carbon and low alloy steels to this type of corrosive attack [5]. Corrosion control costs in oil industry are significant and are primarily related to materials replacement and corrosion control programs.

There has been great interest in understanding the mechanism of CO_2 corrosion and surface film formation, as they determine the resulting corrosion rate. There are some known general characteristics but the mechanism is far from clearly understood and it is difficult to predict corrosion behavior due to a large number of inter-related variables. CO_2 corrosion is affected by a number of factors including environmental, metallurgical and hydrodynamic conditions. For instance, the corrosivity of the environment is a function of numerous factors such as water chemistry [6–19], gas/fluid velocity [6,10,20–24], CO_2 content [8,11–16,20] and temperature [6,7,9,12–16,20,25,26] in addition to carbon and low alloy steels microstructure [6,10,21,23,29–40] and their chemical composition [5,15,27–29,39,41–45].

Production oil well tubing under investigation failed after 3 years of service. Out of five tubing joints, three developed pinholes. The joints were located above the top packer and were used to transport wet sweet Arab Extra Light grade crude oil. Physical specifications and operational parameters of the production tubing are listed in Table 1. Corrosion control programs, such as cathodic protection, coating or corrosion inhibitors were not used for these production tubing joints. This paper states the production well history, identifies the cause of tubing joint failure and provides recommendations to prevent similar failures in the future along with a mitigation strategy.

2. Background

The production well under investigation was drilled and completed as a horizontal cased hole oil (wet) producer. The total depth of the well is 12,800 ft with 2 km horizontal open hole and 4.5 ft tubing. The end of the tubing depth is 6097 ft and the packer was installed at 6064.16 ft, where the horizontally drilled maximum drift angle is 92.0 deg. at 5743 ft. The produced well had been kept shut for a year before the first production was started.

After 4.5 years in service, a pinhole leak was observed on the spool line between the wing valve and the choke valve. The well was isolated which resulted in a loss of 3500 barrels of oil per day (MBOD). Also, after another 14 months of operation, high pressure was observed in tubing casing annulus during routine annuli survey. Diagnostic annuli was conducted on the well under shut-in condition, to determine whether the annuli pressure was due to diesel (corrosion inhibited) thermal expansion or communication between tubing and tubing–casing annulus (TCA). Survey data indicated that the pressure in the annuli was due to downhole communication, which required the use of a workover rig.

Workover on the production well commenced 5 years into service. The objective of this workover was to eliminate the communication from tubing to tubing casing annulus and improve well productivity by extending the motherbore and adding two laterals. During the work period, tubing was pulled out and pinhole leaks were found in the second tubing joint above the packer, which was responsible for downhole communication between tubing and the TCA. Within a 2-month period, the well was worked over and recompleted as a maximum reservoir contact (MRC) well, by adding two laterals with a total reservoir contact of 10.1 km. Smart completion and permanent downhole gauge system were installed and successfully tested for full functionality while the workover rig was still on location.

In addition to the above, the production well TCA problem was noticed for the second time during routine annuli surveys. A high tubing casing annulus pressure of 1020 psig was encountered in the annuli survey conducted 3 years later. At the

Table 1
Characteristic and operation condition of the tubing joint under investigation.

Parameter	Design	Operation
Tube material	J-55 C.S.	
Tubing length	33′	
Outer diameter (OD)	3.5″	
Inner diameter (IO)	2.992″	
Thickness	0.254″	
Operating temperature		76–82 °C
Operating pressure		48–68 atm
Production rate[a]		8761 Barrels per day
Calculated flow rate[a]		3.55 m/s
Fluid density		814.8 kg/m^3
Fluid viscosity		3.7×10^{-4} kg/s m
Gas oil ratio, GOR[a]		1458 SCF/bbl
Water cut[a]		7.71%
CO_2 concentration in the gas stream		1.95 mol%

[a] The values given represent operation parameter averages during a 3-year period.