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Finite service life evaluation method of production casing for sour-gas wells

Zhang Zhi [a,*], Li Jing [a], Zheng Yushan [a], Zhang Cheng [b], Zhang Qingsheng [b], Zeng Dezhi [a], Zhong Xiankang [a]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan, 610500, PR China
[b] Puguang Branch Company of Zhongyuan Oilfield, Sinopec, Dazhou, Sichuan, 636156, PR China

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ABSTRACT

The material selection and design for oil and gas wells containing hydrogen sulfide and carbon dioxide is very difficult due to the uncertainties such as the changeable production capacity, partial pressure of corrosive medium (like CO_2 and H_2S). For oil and gas wells, there is a high production rate in the initial stage while the production rate is very low in the rest of stage. Meanwhile, some wells may have water outflow in the very early period but they even become flooded in the following process. According to relevant standards, Nickel-based alloys must be used in these conditions. However, using Nickel-based alloys could greatly increase construction cost. In this paper, we propose an evaluation method for those types of wells based on a finite life design theory, which utilizes a high pressure high temperature (HPHT) flow corrosion test. Furthermore, phase state and transformation kinetics are introduced into the evaluation. The simulation covers the formation of water corrosion in three periods, which include the condensate water gas production period, the water-carrying gas production period and the water accumulation period. Corroded casing strength was derived according to API Specification 5CT, and the residual strength including residual tensile strength, residual internal pressure, and the residual collapsing strength of the casing. Finally, residual strength data was used for the finite life theory based on the resistance safety method, and compared with the Offshore Drilling Manual, the finite service life can be predicted.

1. Introduction

Many oil and gas wells contain large amounts of hydrogen sulfide and carbon dioxide (Zhang et al., 2017; Zhi and Han, 2017). As a result, corrosion should be considered in the selection of production casing materials. Eliyan et al. (Eliyan and Alfantazi, 2014) analyzed the effect of corrosion product film on corrosion rate through the microscopic structure. Li et al. (Quanan et al., 2004) compared the thickness and grain size of CO_2 corrosion production film under different temperatures and established the relationship between temperature and the production film. For the operating conditions on corrosion, Sellaturay (Sellaturay et al., 2014) analyzed temperature, the effect of flow-rates, bicarbonate content, organic acid content, H_2S and CO_2 partial pressure on corrosion rate.

The structure of tubular is complicated, and the corrosion mechanism is affected by a series of comprehensive factors. Barik et al. (2005) and Postlethwaite et al. (Postlethwaite and Nesic, 1993) introduced numerical methods to study solid-liquid two-phase flow induced corrosion near the wall. Through scanning electron microscopy, X-ray diffraction and the analysis of polarization curves, Q.Y. Liu et al. (2014) studied immersion tests combined with electrochemical measurements. Amani (Amani and Hjeij, 2015) found that the proper choice of materials, protective coatings, chemical inhibitors, and other corrosion control methods can reduce the rate of corrosion in drilling and production operations.

Beside these researches, Zhang Zhi et al. (2012) investigated the corrosion of samples in the environment without H_2S by using the weight loss method and electrochemical method. They found that the corrosion rate of samples increases significantly after hydrogen charging. Both the corrosion product film and the hydrogen permeation can affect the corrosion rate. In addition, the formation of corrosion product film provided protection to the substrate. However, cracks in the product film accelerated local corrosion. LQ Chen et al. (2010) studied the corrosion rate of casing material in condensate gas field with different water content and rotational rate. After the test, they found that the corrosion rate of the samples increased with the rise of water content. Zhou et al. (2009) studied the multiphase corrosion behavior with CO_2 in gathering and transportation pipelines with water content 5%, 30%, 60%, 90% and

* Corresponding author.
E-mail address: zhangzhi@swpu.edu.cn (Z. Zhi).

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100%. They pointed out that with the rise of water content, the wettability of oil is decreased, and the corrosion rate is increased.

To sum up, many scholars have done a lot of researches on the factors that influence corrosion rate. However, the service life of casing tubular is infrequently considered. Besides, for oil and gas well containing H_2S and CO_2, the water content is changeable during different operating stages. In this paper, finite life design theory was put forward based on three water production phase.

2. Finite service life design theory

In the process of material selection for production casing of oil and gas wells with H_2S and CO_2, the safety and cost have to be significantly considered. For exploratory wells, there are some uncertainties, such as production capacity, H_2S content and distribution. In some wells, the production rate is high in the early period while the production rate decreases rapidly in the later period. Based on current standards, nickel-based alloy is the preferred material for production casing. However, when it comes to low production wells, the well-drilling cost is prohibitive. Therefore, the finite service life design theory and method are proposed for the type of wells mentioned above. The basic idea of the finite life design theory is the concept of applicable design, which can be seen in Fig. 1.

The applicable design means that:

(1) A stress reduction design method has been adopted to ensure wells can safely produce for 5–8 years. For example, in Sichuan province of China (Zhi et al., 2012), the high H_2S wells and H_2S containing gas condensation wells have been built many years ago. These wells generally have been producing gas for at least 10 years (some for 30 years), and the materials of the production casing are low-grade carbon steel. Although some casings have damaged during production period, there were no serious safety problems or environment hazards.
(2) For some kind of casing in the environment containing H_2S, CO_2 and Cl^-, electrochemical corrosion might allow to some extent as long as no hydrogen stress cracking appears. Then T95 or P110 should be selected as production casing, using well completion optimization technology, such as increasing wall thickness to satisfy the corrosion allowance.
(3) The research of corrosion test with different water content should be further completed. Carbon steel or carbon steel with inhibitors or undercoat should be selected as anti-corrosion plan for production casing. For instance, Corrosion resistant steel or bimetal composite pipe technology should be adopted in the well sections where serious multiphase flow corrosion occurs.
(4) An accident or risk response plan should be established to safely control wells or abandon wells in case of emergency.

In most corrosion researches, high temperature and pressure reactors are static or rotating flowing. However, they can't simulate the flow state and transformation kinetics during the corrosion evaluation. In the process of stirring reaction, the corrosion product film is hard to adhere to the metal surface because of the fluid turbulence effect. Furthermore, the tested corrosion rate is higher than real corrosion rate, Therefore, in this situation, it increases the difficulty in material selection (Thaker and Banerjee, 2016). In order to solve the problem, a high pressure high temperature (HPHT) flow corrosion test instrument was adopted in this paper. In the corrosion evaluation, different stages of corrosion were analyzed, so that the evaluation results are more applicable to downhole conditions. The corrosion stage includes corrosion in condensate water gas production period, corrosion in water-carrying gas production period and corrosion in water accumulation period.

3. Corrosion environment for HTHP sour gas wells

The main factors that affecting the corrosion rate contains

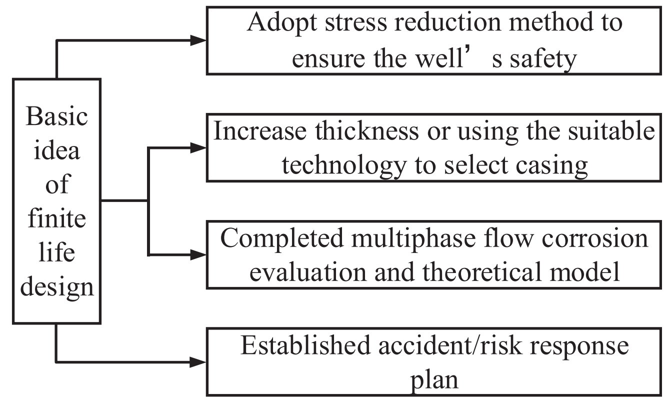

Fig. 1. Basic idea of the finite life design.

temperature, pressure, medium pressure, velocity. In the production stage, the temperature and pressure are relatively stable, while the water content will change with the production period. Therefore, this paper mainly studies the influence of water content on corrosion rate in different production stages.

3.1. Condensate water increment design for different production periods

In the development of gas fields, water is often found in the ground separator. Sometimes, fluid deposits are also found in the wellbore. The produced water might be condensate water or formation water. If categorization is based on produced water, the gas production period can be classified into three periods: the condensate water gas production period, the water-carrying gas production period and the water accumulation gas production period. The underground phase state should be analyzed first in order to judge the type of produced water. If all produced water is in a gaseous state in the underground, it is either condensate water or formation water. At formation temperature and formation pressure, natural gas usually contains saturation vapor. The saturation vapor content depends on gas temperature, pressure, composition, and other conditions. Hydrogen sulfide and carbon dioxide can be dissolved in condensate water, because of the lack of inorganic salts, pH value is very low. When the condensate water is absorbed on tubular wall, local corrosion will appear. In the case of formation water, it is necessary to judge whether there is accumulated liquid in the wellbore. If there is no accumulated liquid, formation water increment can be determined based on the produced water in the separator at the wellhead. If there is accumulated fluid, liquid-carrying gas model is used to calculate the formation water carried by the wellbore to determine the formation water increment.

In spite of the fact that is formation water corrosion or accumulated water corrosion, the creation of formation water itself cannot be avoided. In this case, the appropriate number of Cl^- and Br^- add in the formation water. In general, corrosion during water accumulation gas production is the most severe corrosive condition. Thus, an on-site gas production system is used to control and extend the period of the condensate water gas production. When water output is inevitable, reducing the diameter of the tubing can increase the flow rate for the purpose of increasing water-carrying capacity and prolong the period of water-carrying gas production. Three periods of water content during the production are calculated as follow:

(a) Condensate water content calculation for high-sulfur gas well.

The calculation model for the saturation water content of high-sulfur gas is (Wang, 1994):

$$W_{H_2O} = \frac{804\left(1 - S - y_{H_2S} - y_{CO_2}\right)}{P - P_{SW}\left(1 - S - y_{H_2S} - y_{CO_2}\right)} \tag{1}$$