

On the Sweet Corrosion of Oil and Gas Wells

Yxuan Peng¹, Zhen Guo²

^{1,2}China University of Geosciences, 29 Xueyuan Rd, WuDaoKou, Haidian Qu, Beijing Shi, China
(²zhen.guo49@gmail.com)

Abstract- Sweet corrosion (CO₂) is one of the main concerns threatening the metallic infrastructures of oil industry. Downhole equipment of oil and gas wells are suffering more dramatically from CO₂ corrosion due to high temperature and high pressure (HTHP) exists in such conditions. In compare to the surface facilitates, corrosion of downhole equipment is more costly since the repair and/or replacement of the damaged parts requires total shutdown of the producing well. Indeed, the accessibility of downhole equipment is not as readily as surface equipment. Therefore, corrosion control program of oil and gas wells is very important for oil operators. This paper provides an overlook to the corrosion of oil wells and the important factors that govern corrosion in sweet environments.

Keywords- Sweet Corrosion, Oil well, HPHT, Downhole

I. INTRODUCTION

Corrosion is a real challenge for the metallic infrastructure of oilfields [1]–[4]. Carbon dioxide (CO₂) and hydrogen sulfide (H₂S) are two key players behind corrosion attacks in oil and gas production and transmission tubular [5]. Carbon dioxide (CO₂) corrosion is widely known as “sweet corrosion” while hydrogen sulfide (H₂S) corrosion is referred to “sour corrosion” [6], [7]. Downhole corrosion of oil and gas wells has taken considerable attention due to the high pressure & temperature, multiphase flow, complicated water chemistry, and high CO₂ and H₂S concentration in the produced streams that can cause corrosion failure of production tubing. Conditions in wells are often much harsher than those in the transportation lines [8]. The presence of oil can have a dramatic effect on the corrosion behavior of the system bases on the wettability characteristic of the crude oil. In addition, some surfactant present in crude oil can offer levels of corrosion inhibition if they reach the metal surface [2], [9]. In compare to surface facilities, prediction and mitigation of corrosion in downhole condition is a challenge for oil producers due to contribution of many important parameters in corrosion processes.

II. BASICS OF CO₂ CORROSION (SWEET CORROSION)

CO₂ corrosion occurs in an aqueous environment. The aqueous phase plays the electrolyte role in the electrochemical reactions involved in corrosion processes. The metal exposed to such corrosive medium, in this case, mild carbon steel (iron), dissolves by the anodic reaction, and hydrogen gas

produced at steel surface as a result of hydrogen evolution (cathodic) reactions. Chemical and electrochemical reactions are contributing in corrosion phenomena. Important homogeneous chemical reactions taking place in the bulk solution in CO₂ environments are the followings:

Dissolution of carbon dioxide in water phase



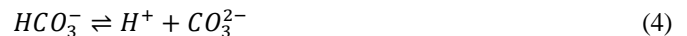
Carbon dioxide hydration; formation of carbonic acid



Carbonic acid dissociation



Bicarbonate anion dissociation

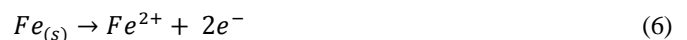


Water dissociation



The main heterogeneous electrochemical (anodic and cathodic) reactions taking place at the steel surface are:

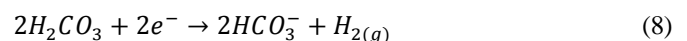
Anodic reaction; oxidation of iron



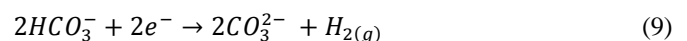
Cathodic hydrogen evolution; reduction of free hydrogen ions



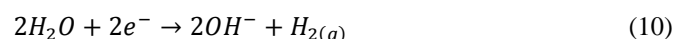
Cathodic hydrogen evolution; reduction of carbonic acid



Cathodic hydrogen evolution; reduction of bicarbonate ions



Cathodic hydrogen evolution; reduction of water



III. INFLUENTIAL PARAMETERS GOVERNING SWEET CORROSION IN OIL AND GAS WELLS

Pressure and temperature are important factors in the corrosion processes. Temperature is one of the main input parameters for corrosion prediction models including the de Waard-Milliams corrosion model [10]. Without a protective

corrosion product layer, high temperatures generally lead to higher corrosion rates, while low temperatures lead to lower corrosion rates. Iron carbonate (FeCO_3) is the main corrosion product layers in CO_2 environments [11]. Total pressure has little direct effect on the corrosion process but is directly affecting the partial pressures of CO_2 which, influence the corrosion rates. Pressure also affects the gas density and gas velocity. In high pressures and temperatures, both gas and liquid phases show non-ideal behaviors.

The volumetric flow rates of the produced stream including gas, oil and water are important parameters for calculating the velocity of each phase. Moreover, water velocity significantly influences the corrosion mechanism via mass transfer phenomena [5]. Moreover, erosion-corrosion accelerated in higher fluid velocities especially in presence of sand in the system. In high liquid velocities, possible removal of corrosion product exposes the bare steel surface to the corrosive medium and thus increases the chance of metal loss [12]. Corrosion rate is dramatically driving by the type of flow regime in well column [13], [14]. Flow can transition between several flow regimes during its travel from the down hole hole to the wellhead [17]. Generally, flow regime is strongly influenced by volumetric flow rate [15].

The composition of the gas stream has a significant effect on the corrosion, as it directly influences water composition. To predict the magnitude of corrosion, at least, the concentration of acidic gases (CO_2) should be measured in the gas phase. However, a more accurate characterization is possible if a thorough composition of gas phase is known.

The water chemistry of the brine co-produced along with the hydrocarbon is an important parameter for corrosion scenarios. The composition of the produced water influences the interaction between aqueous species and ionic strength of the solution. Brine contains different type of ions depending on well conditions. Table 1 shows a typical ion concentration seen in some oil wells in western Pennsylvania [16]. Ion type and concentration vary greatly from well to well even on the same oil reservoir.

TABLE I. A TYPICAL ION TYPE AND CONCENTRATION OBSERVED IN OILFIELD BRINE

Sample name	Mg^{2+}	Ca^{2+}	Na^+	Cl^-
	(mg/L)	(mg/L)	(mg/L)	(mg/L)
1	2,000	16,000	56,700	122,000
2	2,500	18,000	58,300	123,000
3	2,520	19,000	58,500	123,000
4	2,410	17,100	52,100	111,000

It is reported that high concentrations of salts can lead to localized corrosion while it decreases general corrosion rate [17]. Brines in oilfield can have up to 200,000 ppm of chlorides, therefore, this ion needs to be taken into account for corrosion modeling [8], [16]. Chloride does not participate in electrochemical reactions involved in corrosion. However, it can destruct protective corrosion products on the steel surface

and increase the mass transfer of corrosive species from bulk liquid phase towards the steel surface. Calcium is another ubiquitous ion present in oilfield brine, as shown in Table 1. Like chloride, calcium does not directly interfere the electrochemical reactions involved in corrosion. However, in presence of carbonate (CO_3^{2-}) and/or bicarbonate (HCO_3^-) ions, calcium carbonate can precipitate as solid phase if exceeding the solubility limits of CaCO_3 (s). Precipitation of this scale (CaCO_3) can influence the mass transfer of corrosive species. The scaling tendency of a brine can be calculated if the ions concentration is known in the operational condition of the well [18], [19]. The acidity of the brine is often specified in terms of alkalinity, as a precise *in-situ* pH measurement is almost impossible in down hole condition. Total alkalinity is the amount of acid requires neutralizing the produced water (brine) phase from the well. Alkalinity is typically measured in laboratory by means of titration method. The pH endpoint can vary depending on the procedure and the type of indicator employed, but typically it is between pH 4.6 and pH 6.5 [20]. This quantifies the acid-reducing power of the produced water, and is generally reported as bicarbonate equivalent (HCO_3^-). Total alkalinity is an important parameter in pH calculations. Organic acids may be present in oilfield brine. They can significantly impact the corrosion rate even at low concentrations [21].

The inner diameter of production tubing is used to convert the volumetric flow rates to velocities. The length of the tubing should be considered for temperature and pressure profiles prediction along the well column. The chemical and material properties of the tubing play a significant role in corrosion processes. Some researchers showed that different heat treatments (normalized, quenched, and tempered), metallurgy, and microstructures of carbon steel have an impact on the localized corrosion of carbon steels [22].

IV. CONCLUSIONS

In high pressure and temperature of oil and gas wells, production tubing is more susceptible to corrosion attacks. Material properties and the size of tubing influences the corrosion behavior of the tubing. Furthermore, Operational parameters including gas, oil, and water flow rate, flow regime, water chemistry of the brine, the composition of the gas phase, and pressure and temperature gradient along the well column have a significant impact on the corrosion mechanisms in down hole condition.

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