MECHANISM OF SCALE FORMATION BY WATER IN OIL FIELDS

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Abstract - This paper presents the mechanism of scale formation by water in oil fields and suggests an accurate model capable of predicting scaling phenomena in oilfields operations due to mixing of incompatible waters or change in thermodynamics, kinetics and hydrodynamic condition of systems. A new and reliable scale prediction model which can predict scaling tendency of common oilfield water deposits in water disposal wells, waterflooding systems and in surface equipment and facilities is developed and present. The development of the model is based on experimental data and empirical correlation, which perfectly match oil fields conditions. Furthermore the simultaneous deposition of oilfield scales and competition of various ions to form scale which is common phenomena in oil fields are reflected in the development of the model allowing the effect of each scale on the others to be taken into account. The new model has been applied to investigate the potential scale precipitation in oilfields, either in onshore or offshore fields where water injection is being performed for desalting units' water disposal purpose or as a method of secondary recovery or reservoir pressure maintenance.

I. INTRODUCTION

Amongst the production issues in oil and gas industry is the scale deposition resulting from the waterflooding process and chemical treatment operations which are applied to maintain sustainable hydrocarbon production at oil, gas or gas condensate fields. Hydrocarbons coming out of a reservoir consist of millions of different components (N_2, CO_2, H_2S) or gaseous form. In addition fresh water is usually associated to hydrocarbons coming out of reservoir, bringing within itself to the surface various dissolved compounds. The resulting composition of producing fluid may count up to large number of different components and substances. These fluids will experience drop in pressure or a change in temperature, and some compounds may become more stable at solid state and will start to precipitate (Time, 2011). The pre cipitation of these solids occurs as a result of changes in the ionic composition, pH, pressure and temperature of the brine. When water flooding method is applied for enhance oil recovery, then the problem of scale deposits may occur right from water injection facilities to the producing well, and generally scale deposits can occur during and after injection operation in the injector wellbore, near the injection well bottom hole, in the reservoir between the injector and producer, at the skin of producer well, in the producer wellbore, oil well casing, oil pipelines and other production facilities. The composition of scale deposits samples is made up of or ganic, inorganic and crystal water (Jiecheng et al., 2011). A scale deposit may occur as single mineral phases, but more commonly it is a combination of different elements, which can occur when a solution becomes saturated, mostly due to changes in temperature during injection operations, changes in pH values or if two dif ferent chemicals that will precipitate are brought together. There are several mineral ions usually dissolved at produced water; these include calcium, barium, strontium, cations and carbonates , sulfate anions. The effect of scale can be dramatic and immediate with a fall in the production capacity to zero in a few hours and the treatment cost can be massive (Al Salami and Monem, 2010). Scale deposi tion in the formation pores restricts the flow of fluid through the formation of a thick layer in the wellbore tubular which reduces the diameter of the production tubing and chokes the production from the reservoir (Fig. 1). This can lead to a drastic increase in pressure drop and thus a decrease in the well productivity.

Scale precipitation can also cause formation damage in the reservoir, flow loss or blockage on flow lines and equipment, en ergy leak, accelerate corrosion, and severe accidents, which can influence the safety of production and the economic benefit of petroleum industry (ElSaid et al. 2009). This paper reviews and assesses some of the management and mitigation strategies of oilfield mineral scale deposits in onshore and ultradeepwater wells, and chemical stimulation techniques applicable in oil in dustry to

improve well productivity. Also discussed are thermo dynamics and kinetics models of scale prediction.
Common oilfield scale deposits can be classified into “pH in
dependent” and “pH sensitive” scales. The scaling tendency of sulfates (calcium sulfate, barite and celestite) and halite scales are not a strong function of brine pH. The carbonates (calcite, dolomite and siderite) and sulfide scales are acid soluble and their scaling tendencies are strongly influenced by the brine pH. For pH sen sitive scales, the scale prediction is more complicated since issues that control the brine pH also affect their scaling tendencies. The most common oilfield scales are listed in Table 1 (Kelland, 2009; Bin Merdah, 2008). These scales are sulfates such as calcium sul fate (anhydrite, gypsum), barium sulfate (barite), and strontium sulfate (celestite) and calcium carbonate. Other less common scales have also been reported such as iron oxides, iron sulfides and iron carbonate and calcium naphthenate scale from acidic crudes (Rousseau et al., 2001). The heavy or slightly biodegraded crudes are "highTAN crudes", i.e. contains significant amounts of carboxylic (mainly naphthenic) acids (Rousseau et al., 2001). Naphthenic acids are mixtures of alkylsubstituted acyclic and cyclic structures with the general chemical formula $C_2H_{2m+z}O_2$. Literature survey shows that certain crude oils produced from both onshore and offshore fields in a range of places, including Azerbaijan, Angola, Congo, Cameroon and Nigeria, the North Sea. Naphthenate formation in these fields hinders oil production, resulting to unplanned plant shutdown, loss of pro duction and offspecification export oil quality control problems. Therefore, it is important to understand the chemistry of these crude oils and their formation waters, as well as the changes in the physical parameters that occur during oil production to enable oil companies address this type of flow assurance problem; and possibly design new improved production facilities to mitigate the naphthenate/carboxylate soap problems.

During production and processing of highTAN crude oils, the amphiphilic naphthenic acids may also accumulate at interfaces and stabilize waterinoil emulsions (Ese and Kilpatrick 2004; Poggesi et al., 2002, Rousseau et al., 2001, Dyer et al., 2003), causing enhanced separation problems. Pressure drop during fluid transportation from the reservoir to the topside leads to release of carbon dioxide from the solution during production. Scale formation can occur through homogeneous and hetero geneous nucleation mechanisms. Homogeneous nucleation occurs in the absence of a foreign substance and is not a likely mechanism because in nature it is not likely that environments are free from foreign substances. Thus, homogeneously formed scale particles do not necessarily deposit or grow onto a surface and hence, could flow through the system without causing too many depositional issues. Heterogeneous nucleation occurs in the presence of a for eign substance to trigger nucleation. The foreign substance can be scale nuclei or corrosion products, welds/stress points on metal surface, corrosion sites on metal surface, scratches on metal sur faces, or small particles of suspended solids. Therefore, hetero geneously formed scale particles build up on solid surfaces causing problems such as pressure increases and restriction of fluid flow in the formation, pipelines, surface facilities and can potentially prevent production equipment such as downhole subsea safety valves or the heat exchangers/motors on pumps from operating as expected.

Mathematical models can be used to describe some scaling processes. Advanced equations developed by some authors (Ber thoud, 1912; Bowen and Epstein, 1978; Ruckenstein and Prieve, 1973) have been used to describe scaling precipitation rates. Simplified approach uses diffusionreaction model.
Autoscaling happens when a reservoir fluid experiences changes in temperature and pressure as it is produced, and when such changes take the fluid composition beyond the solubility limit for a mineral, thereby leading to scale precipitation. Sulfate and carbonate scales can precipitate as a result of pressure changes within the wellbore or at any restriction downhole. Sodium chloride (halite) also forms in a similar way from highly saline brines undergoing large temperature drops. Decrease in pressure and/or increase in temperature of a brine, leads to a reduction in the solubility of the salt, which most commonly

resulting to precipitation of carbonate scales, such a $CaCO_3$. In carbonate scale deposits, temperature effects often work against pressure effects. For example, the pressure drop at the point of entry into the wellbore can lead to matrix scale. As the flow progresses up the tubing to surface temperatures and well head pressure, the resulting temperature drop may override the pressure effect, reducing scale formation in the tubing. On the other hand, subsequent release of pressure from the wellhead to surface can lead to massive deposit of scale in surface equipment and tubing.

Mechanical removal has been used in the past for removing scales (Amjad and Zuhl, 2008). Use of mechanical method (drilling or reaming) is quite easy to understand and has been used to re move different kinds of scale depositions. However, it is not without several limitations and therefore should only be considered as the last option (Fleming, 2010; ShoWei et al. 2011). It is very expensive, a drilling rig has to be moved in and, particularly in deep well, with a lot of complications associated with the drilling process. Also the method is not very effective for restimulating a well because it does not remove the scale deposits from the formation i.e from outside the wellbore, thus ignoring all the formation damage. An impermeable skin may also remain inside the wellbore caused by the drilling cuttings squeezed into the perforation holes or production slots in the tubing or liner; and this can cause the productivity to drop to zero. Therefore chemical procedures of re moving scale are preferred over mechanical methods (Vetter, 1976).
World oilfields are under threat of scale formations in production facilities. When scale deposits are held onto the production equipment surface, it reduces its diameter and subsequently grows continuously until it blocks the tubing as well as the surface equipment. This leads to production stoppage, and results in losses to the production company. Therefore, scale formation should be given a priority treatment because of its threat to flow assurance. A good management strategy must be put in place to prevent it from building up or having further occurrence. Just as it has been acknowledged over the years that scale prevention is better than waiting until it forms and then taking remedial action. Many different technologies that could potentially be deployed by the oil- field operators to reduce the risk of scale formation, control scale formation and to remove it if formed within downhole and topside oil/gas facilities are critically reviewed. With the significant advancement and improvements in chemistry and fluid finish for effective scale inhibitions, oilfield scale can be removed from in- side the tubular without risk to the steel tubing.

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