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Water Compatibility Study in Detecting Souring Potential: A Case Study

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Abstract

Reservoir souring most times occurs during secondary recovery, after water injection using seawater or produced water from a different reservoir. Water compatibility studies is thus necessary prior to injection to detect potential for souring and to implement preventive measures since souring poses challenges during production. This work stresses the importance of fluid compatibility studies before undertaking water injection projects. Two cases were considered; in the first case, water injection program was implemented using seawater without conducting fluid compatibility studies and serious souring problem was encountered later in the life of the reservoir. In the second case, fluid compatibility study was conducted where produced water from four sources were proposed to be used for water injection in two reservoirs. One reservoir (RW1) had high sulphate content of 20mg/l but did not have Sulfate Reducing Bacteria (SRB) probably because the reservoirtemperature was 103°C, well above the limit for the existence of most SRB. The second reservoir (RW2) with a temperature of 75°C had SRB concentration of 845cfu/ml and had a sulfate concentration of less than 0.01mg/l, indicating that souring will only occur if water containing sulfate is injected into it. The study shows that reservoir souring could occur in both reservoirs from external sources. It was concluded that three out of the four proposed produced water cannot be injected into RW1 without treatment since their water samples contain SRB. Reservoir souring and its associated problems were thus prevented from occurring in RW1 due to fluid compatibility studies.

Introduction

Secondary oil recovery stage involves water or gas injection into an oil reservoir, but water injection is more common because of its efficiency in oil displacement. The water mostly used for water injection schemes is either seawater or produced water from same or other reservoirs. Seawater is sometimes used because it is cheap and abundant, and proximity to oil producing sites is also an advantage. Re-injection of produced water into oil reservoirs for secondary recovery is an effective wayof utilizing and disposing produced water. However, there is need to conduct water compatibility tests on any kind of water intended to be used for injection schemes in order not to create problems such as scaling, corrosion and souring. In this work, two cases have been considered to stress the importance of conducting water compatibility studies before injection to prevent reservoirsouring. In the first case, water compatibility study was not conducted before a water injection program was carried out and it resulted in serious souring problems later in the life of the reservoir. In the second case, a water compatibility study was conducted prior to the injection scheme and a souring problem was identified and prevented.

Reservoir souring is the increase in hydrogen sulfide (H_2S) in produced reservoir fluids typically after secondary recovery by water injection. The presence of H_2S in a producing or injection wells can result in corrosion, loss of economic value of crude, health hazards and can undermine safety. Two main mechanisms of reservoir souring are biotic and abiotic, but biotic mechanism is more significant and results from the microbial activities of Sulfide Reducing Bacteria (SRB) which sometimes are introduced into reservoir formations through water injection schemes [1, 2]. SRB are organisms that reduce sulfates (SO_4^{2-}) to H_2S by oxidizing organic materials, and they are commonly found in anaerobic environments. One of the steps taken to control corrosion is to remove oxygen from injected water; this condition however provides conducive environments for the growth of anaerobic bacteria such as SRB [3]. Some chemicals used during petroleum Production such as antifoams, scale inhibitors and oxygen scavengers are dosed into injection water; these may add to the nutrient pool of nitrogen, carbon, and phosphorus available for SRB growth [3]. Most SRB strains thrive at temperatures below 85°C and can exist at varying pressures, but research has shown that a pressure of 15,000psi can be detrimental to their growth. They also require nitrogen and phosphorus in trace amounts to survive [4]. SRB strains require a concentration of less than 150,000mg/l of total dissolved solids (TDS) and a pH level of 6 - 8.6 to thrive [5, 6,].

Reservoir souring is a worldwide problem. A case study of an oil field in Japan is an example of how secondary oil recovery by water injection using seawater can introduce SRB and H_2S in a reservoir system that was previously devoid of the bacteria and H_2S [7]. H_2S concentrations as high as several thousand parts per million per volume (ppmv) have been reported. In the North Sea, H_2S concentration of 1.5tonnes per day with a maximum wellhead concentration of 1,000ppmv has been recorded while 40,000ppmv has been reported in Huntington Beach Field in California [8]. Reservoir souring has also been reported in the Bonga field of the Gulf of Guinea where reservoir temperatures are around 63°C and TDS iswell below the maximum limit of 15 to 20% [9]. Methods of militating against reservoir souring have been discussed [10, 11]. The Mechanisms of controlling reservoir souring using nitrate and biocide have been studied and simulated [12]. The chemical reactions and sulfur species associated with production and consumption of H_2S have been reported [13]. Hence, reservoir souring can be detected early prior to water flooding and can be prevented.

Materials and Methods

This study was conducted in the oil rich Niger Delta region of Southern Nigeria in West Africa. The fluid Samples were collected from oil reservoirs located in Rivers State (labelled as 9 in Figure 1). Figure 1 is the Map of Nigeria showing the Niger Delta States.

Figure 1: Map of Nigeria showing the Niger Delta Region

Two cases are considered in this work. In the first case, seawater was used for a water injection scheme in an oil reservoir without conducting any water compatibility study. After production for a while, produced water samples (A, B, C, - Q) were taken from several wells producing from the reservoir for analysis due to some encountered problems of which reservoir souring was suspected. The analysis conducted includes pH, TDS, and tests for sulfates and H_2S concentration. In the second case, it was proposed that produced water 1 (PW1), produced water 2 (PW2), produced water 3 (PW3) and produced water 4 (PW4) from four different reservoirs be used for water injection purposes in two reservoirs; reservoir water 1 (RW1) and reservoir water 2 (RW2). But water compatibility tests were first conducted before implementation and the tests carried out include pH, TDS, sulfate and SRB concentration.

Laboratory Analysis

Laboratory analyses were based on the American Society for Testing and Materials (ASTM), the American Public Health Association (APHA) and the Environmental Protection Agency (EPA) standards. Major equipment used for the work includes the Electrometers for pH and TDS and a UV-Visible Spectrophotometer (HACH DR 6000 Model) for Sulphate content determination. The amount of SRB was determined for the reservoir samples and produced water samples in the second case using the culture method.

Results and Discussions

In the first case, because of souring problems during production after the water injection scheme was implemented, laboratory tests were conducted on the produced water samples from the reservoir. The results of the pH values, TDS, H_2S and Sulfate concentrations are presented in Figures 2, 3, 4 and 5 respectively. The pH values of the samples range from 7.3 to 8.1 (Figure 2), TDS range from 16,000 to 27,000mg/l (Figure 3) while sulfate concentration range between 4 to 1200mg/l (Figure 4). These figures fall within the range where SRBs thrive. The concentration of H_2S ranged from 0.5 to 200ppm (Figure 5) showing that the seawater used for the injection scheme initiated H_2S production in the reservoir which gave rise to serious souring problem. It is observed that sample E had the highest values of TDS, H_2S and sulfate concentrations. Sample L had the same sulfate concentration as E but a lower value of H_2S.

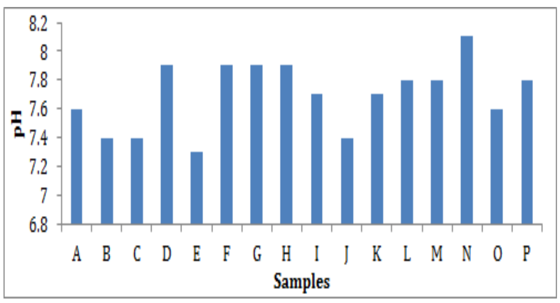

Figure 2: pH Values of Water Samples in Case 1

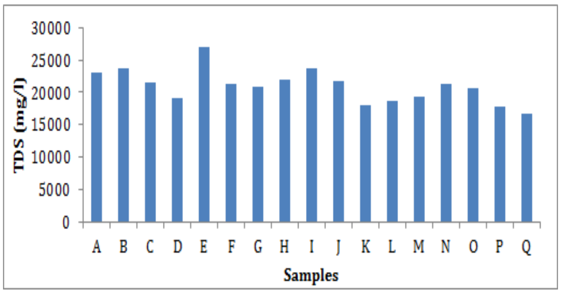

Figure 3: TDS of Water Samples in Case 1

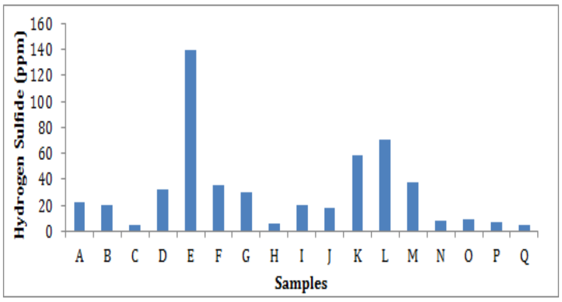

Figure 4: The H_2S Concentration in Water Samples of Case 1

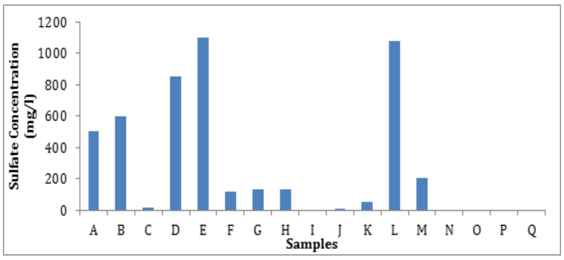

Figure 5: The Sulfate Concentration in Water Samples of Case 1

Souring can occur in a reservoir that was not initially sour by introduction of external fluids into the system. If a reservoir contains SRB but no sulfate, the souring potential will be low; similarly a reservoir with high sulfate content but without SRB will not become sour. Souring occurs when both SRB and sulfates are present because SRBs convert sulfates to H_2S. Hence it is observed that samples C, I, J, N, O, P and Q (in Figure 5) that had the least concentrations of sulphates also produced the least amount of H_2S (in Figure 4). Invariable, the seawater contained SRB but since these wells contained very low concentrations of sulphates, theamount of H_2S produced was insignificant compared to wells that had abundant sulphates. This stresses the need to conduct water compatibility studies before embarking on water injection programs to detect souring potentials. If water compatibility tests had been conducted in the first case in this study before implementing the water injection program, souring possibilities would have been detected and prevented from occurring. Treatment methods to prevent reservoir souring have been discussed [14].

The results of the second case where watercompatibility tests were conducted before water injection schemes were implemented are presented in Figures 6 to 8. The pH values and TDS are between 7.2 and 7.6 (Figure 6), and 14,000 to 21,000 mg/l (Figure 7) respectively. The sulfate content of all the samples is insignificant (less than 0.01mg/l) except RW2 which is 20mg/l, showing that RW2 could result in souring if injected water introduces SRB into the reservoir which will oxidize the sulfate to H_2S. Figure 8 shows that RW1 contains a significant amount of SRB (845cfu/ml), indicating that souring will occur if water containing sulfate is injected into it. RW2 and PW3 contain very insignificant amounts of SRB of less than 1cfu/ml.

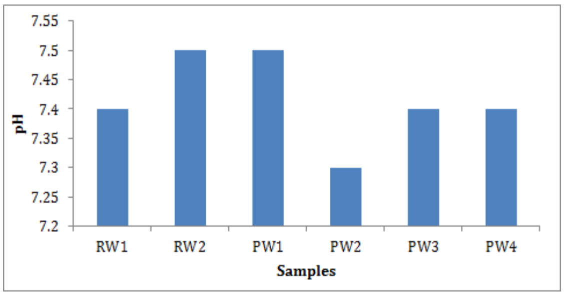

Figure 6: pH Values of Water Samples in Case 2

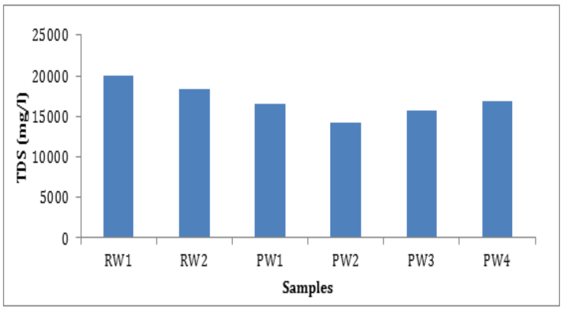

Figure 7: TDS of Water Samples in Case 2

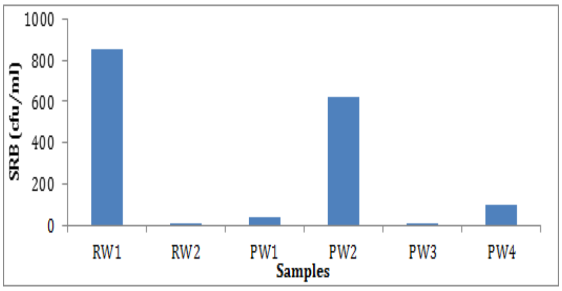

Figure 8: The SRB Concentration in Water Samples of Case 2

The presence and absence of SRB in RW1 and RW2 respectively could be due to the temperature levels; the temperature of RW1 is 76°C while the temperature of RW2 is 103°C. Most SRBs thrive within a temperaturerange of 5 to 80°C especially under anaerobic conditions. The presence of SRB in RW1 (845cfu/ml) does not pose the threat of hydrogen sulfide formation as the water hasno sulfate. Similarly, no souring will occur in RW2 with a sulfate concentration of 19.5mg/l but no SRB. Hence, water from PW1, PW2, PW3 and PW4 can be used in RW1 without causing souring problems because the sulfate content in them is less than 0.01mg/l. But water from PW1, PW2 and PW4 containing SRB cannot be injected into RW2 without treatment because introduced

SRB will convert the sulfate in the reservoir to H_2S, causing souring. Though the temperature of the RW2 is above the limit for the existence of SRB but continuous water injection could alter the temperature [15]. Only water from PW3 can be injected into RW2 without treatment and without the threat of souring potential. The recommendation made from this study was implemented and for years, there was no report of reservoir souring from producing wells in reservoirs RW1 and RW2 following water injection schemes.

Conclusions

The conclusions drawn from this study are as follows:

1. It is important to conduct fluid compatibility studies before commencing water injection schemes in oil reservoirs in order to reduce the risk of reservoir souring.
2. The temperature of reservoirs plays a significant role in determining the existence of SRB which thrive in temperatures less than 85°C.
3. Wells containing high concentrations of sulphate will most likely produce high concentrations of H_2S if water containing SRB is introduced into the same reservoir and vice versa.
4. Two water sources with high concentrations of sulphates and SRB must not be used together without treatment to avoid the occurrence of reservoir souring after water injection programs.

Recommendation

Water compatibility study is essential prior to water injection programs in petroleum reservoirs to detect potentials for reservoir souring so that measures can be taken to prevent its occurrence.

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Conflicts of interest

There are no conflicts to declare.