Detecting Scaling Potential in Oilfield Waters

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Abstract

Production of formation water during petroleum exploitation is sometimes inevitable, necessitating disposal strategies. Produced formation water can be re-injected back into the reservoir either for enhanced oil recovery schemes or for the purpose of disposal. In any case, there is a need to prevent scale formation because it leads to permeability impairment. In this work, formation water compatibility tests were conducted to detect scaling potentials using the Langelier Saturation Index (LSI). Six water samples were used; four produced water samples intended for use in water injection schemes and two water samples obtained from reservoirs needing water injection programs. The water composition of scale-forming elements such as barium, strontium and calcium were determined for all the samples. Other determined parameters included pH values, total dissolved solids (TDS) and LSI. The LSI for different ratios of produced and reservoir water mixtures were determined. Laboratory results indicated that all the water samples contained scale-forming elements and compounds, and they all had to scale potential at ambient temperature but especially at higher temperatures. The produced formation waters were incompatible with the reservoir waters in terms of their scale-forming tendency. To prevent scale formation, especially at higher temperatures, it was recommended that scale inhibitors be used with the least scale-forming produced water. It was also recommended that produced formation waters be subjected to fluid compatibility studies before use in water injection schemes to prevent scale formation.

Keywords: *Scale, Langelier, Formation water, Concentration, Temperature*

1. Introduction

Most hydrocarbon reservoirs have underlying aquifers called bottom water or adjacent water sources called edge water. Production of oil and gas results in pressure drop in reservoirs such that surrounding waters are admitted into reservoir systems. This water interacts with reservoir rock and fluids as well as mixes with the formation water that is trapped in the system. As oil and gas are produced over time, this water continues to increase and advance into reservoir systems such that when it gets to producing wells, it is produced along with oil and gas. This water is called produced water or oilfield water which is environmentally unfriendly because it contains elevated levels of dissolved ions, salts, hydrocarbons, heavy metals and other trace elements. Its environmental impact has been reported since the mid-1800s when the first oil and gas wells were drilled and operated. The most common concerns include degradation of soil, ground water, surface water and ecosystems [1]. Thus, oilfield water

disposal poses a big challenge to the petroleum industry especially because the volume involved most times is huge and spans over a long period of time.

Produced water is usually managed in several ways which include production avoidance but this is difficult to achieve especially when reservoirs are under a strong water drive mechanism. Some countries permit that oilfield waters be treated and discharged into water bodies which is not a good practice. Few countries require that produced water be re-injected into the same reservoir formation from which it is produced which is a good practice. In any case, oilfield waters must be disposed of and an effective disposal strategy is its use for water injection schemes in oil reservoirs that require artificial water injection. Instead of using seawater for water injection purposes, produced water can serve as a good alternative. It has been used often times for pressure maintenance and for water injection schemes during the secondary oil recovery stage. Studies on the proper handling of produced water are increasing due to more stringent regulations, and this includes reuse for industrial and agricultural purposes which must be treated to meet approved water quality standards. In this work, however, the focus is on detecting scaling potential in oilfield waters intended to be used for water injection schemes. This is very important because scaling can impede rock permeability if it is incompatible with reservoir in-situ formation water which invariably reduces production [2]. Scale formation in oil pipelines undermines flow assurance by reducing pipe diameter; fluid volume and flow rate, hence frequent pipeline cleaning exercises are conducted. But if scaling potentials are detected early, scale inhibitors will be used to minimize scale formation and its associated problems.

For produced water to be used for re-injection purposes, water compatibility studies must be conducted just as it is done in using seawater. This is key because using incompatible water in a reservoir formation can create serious problems since the composition of produced water varies from one location and reservoir to another. Variation in oilfield waters depends on the geological formation, environment and existing conditions. Before any water injection scheme is implemented in an oil reservoir, a water compatibility study should be conducted to avoid scaling, corrosion and souring issues [3, 4]. These problems gradually destroy production assets; increase the cost of production and can reduce the value of produced oil.

Problems caused by scale formation in oilfield facilities especially during water injection schemes have necessitated studies on its causes, prediction and prevention measures. Mineral scaling potential has been studied and predicated using the OLI ScaleChem software package [5]. Types of oilfield scales, the kinetics of reaction, mechanism and causes of deposition have been studied [6, 7]. Scale deposition and prediction of sulphates in reservoirs and proposed photon scattering as a method of scale detection in multiphase oil, water and gas pipelines have also been studied and reported [8, 9]. Scale formation in oil pipelines can be prevented by the use of appropriate scale inhibitors.

Oilfield scales are inorganic crystalline deposits that form as a result of the precipitation of solids from brine present in reservoirs or production flow systems. Factors that affect oilfield scale formation include pH, pressure, temperature, evaporation and ionic composition of brine. The increasing temperature may decrease or increase the solubility of precipitates depending on the type of system. If the dissolution process is exothermic, solubility will decrease with increasing temperature, but if endothermic, solubility will increase with increasing temperature [10]. It has been reported that the scaling tendency of calcium carbonate and strontium sulphate increases with an increase in temperature [11, 12].

Produced formation water contains various organic and inorganic matters which include dissolved solids, suspended solids, oil, heavy metals and radioactive elements in varying proportions. These compositions can react with the water compositions from other sources to create favorable conditions for the precipitation of various compounds which leads to water incompatibility. Calcium (Ca^{2+}), Strontium (Sr^{2+}), Sulfate (SO_4^{2-}) and Barium (Ba^{2+}) constitute common elements and compounds that exist in formation waters leading to scale formation in oil pipelines. Calcium carbonate ($CaCO_3$), also called calcite is a common type of scale found in oil pipelines and it is affected by the presence of various ions present in formation water. Incompatible waters that give rise to scaling may contain high

concentrations of SO_4^{2-} and low concentrations of Ca^{2+}, Ba^{2+}, Sr^{2+}, or low concentrations of SO_4^{2-} and high concentrations of Ca^{2+}, Ba^{2+}, Sr^{2+} leading to precipitation of $CaSO_4$, $BaSO_4$ and $SrSO_4$ [13, 14]. The chemical equation shown below illustrates how the white precipitate scale of barium sulphate can be formed just like other sulphates form.

$$Ba^{2+} + SO_4^{2-} \Longrightarrow BaSO_4 \text{ (white precipitate scale)}$$
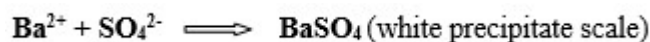
2. Method of Study

The presence of some elements and compounds gives rise to scale formation, therefore the first step in detecting scaling potential in oilfield waters is to find out if these elements and compounds exist in oilfield waters. Tests for the presence and concentration of magnesium, calcium, carbonate, sulphate barium and strontium were conducted on all the water samples. In this work, four samples of produced water were obtained from four different reservoirs (PW1, PW2, PW3 and PW4) and they were intended to be used for water injection schemes in two oil reservoirs (RW1 and RW2) in the Niger Delta. The ionic composition, total dissolved solids (TDS), pH values and Langelier Saturation Index (LSI) were determined for the six water samples. Thereafter, the LSI for several ratios of water mixtures of reservoir water and produced water samples (RW1/PW1, RW1/PW2, RW1/PW3, RW1/PW4, RW2/PW1, RW2/PW2, RW2/PW3 and RW2/PW4) were determined. The mixture ratios that were tested were 0/100, 20/80, 40/60, 60/40, 80/20 and 100/0 of reservoir waters or produced waters.

2.1 Laboratory Work

Laboratory analyses were conducted based on the American Society for Testing and Materials (ASTM), American Public Health Association (APHA) and Environmental Protection Agency (EPA) standards. Some pieces of equipment used include electrometers for pH, conductivity, TDS and salinity, while ultraviolet (UV) Visible Spectrophotometer (HACH DR 6000 Model) was used for sulphate content determination. The digital scale equipment for titration was used to determine the carbonates and bicarbonates contents while Microwave Plasma-Atomic Emission Spectrometer (ICP model MP-AES, Agilent, USA) was used to determine the presence and concentration of metals in the water samples.

2.2 Determination of Fluid Scaling Tendency

The saturation level (SL) of water in terms of dissolved minerals is a good indicator of scaling potential. Water is said to be under-saturated when the SL value is less than one, which means that it can dissolve more solids. When water is at equilibrium, SL will be one. When water is supersaturated, SL value is greater than one and can result in precipitation. As the saturation level increases beyond one, the driving force for precipitation increases. Hence, high precipitation levels of minerals in water increase the scaling tendency.

The most widely used indicator for water scaling potential is the Langelier Saturation Index (LSI) which has been extensively discussed in other publications [11, 15, 16]. This index indicates the driving force for scale formation and growth in terms of pH as the master variable. Factors that can affect the LSI include temperature, water quality and evaporation, and the index is applicable to low ionic strength water solutions that are near the neutral pH value of water. It is ideal for conditions under ambient temperature and for $CaCO_3$, but has been extended for use under higher temperatures and on other scales forming elements and compounds [17]. LSI is interpreted as the pH change required to bring water to equilibrium, it shows how saturated the water is especially with $CaCO_3$ and it is expressed as:

$$LSI \ = \ pH - pHs \tag{1}$$

Where pH is the pH of the water sample and pHs is the value when all forms of alkalinity are adjusted to the point where it is just saturated in calcium carbonate. This equation expresses the effect of total alkalinity, pH, dissolved solids, calcium and temperature in relation to the solubility of $CaCO_3$ for water with pH values of 6.5 to 9.5 [16]. There are three possible cases of LSI and they are:

1. Under a saturated state which does not have scaling potential: LSI is negative and less than zero.
2. Supersaturated state which has scaling potential: LSI is positive and greater than zero.
3. Saturated state which is borderline to scaling potential: LSI is zero.

3. Results and Discussion

Laboratory results obtained from the various tests conducted in this work are presented in Figures 1 to 14. Elements and compounds present in the formation water samples that can result in forming scales are presented in Figures 1 and 2. The presence of calcium and carbonate in all the water samples means that using LSI to determine scaling tendency is proper because LSI was originally derived for scales that form from the precipitation of $CaCO_3$ in water.
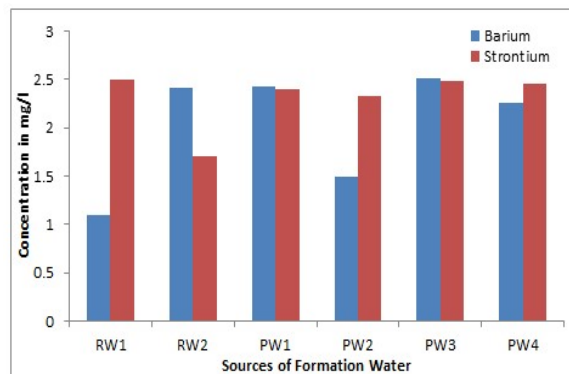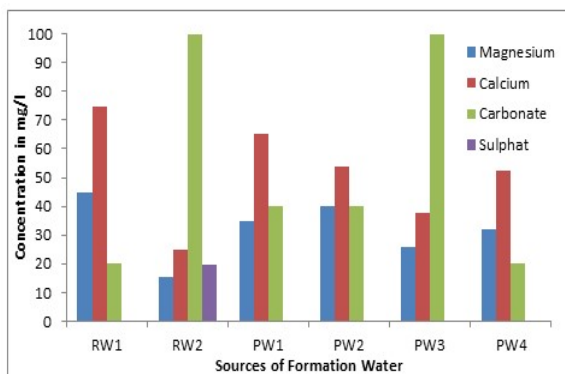

Figure 1: Some Elements in the Formation Waters   Figure 2: Other Elements in the Formation Waters

In Figure 1, it is evident that RW2 contains a small amount of sulphate (19.50mg/l) and some quantity of calcium, meaning that scaling from calcium sulphate can occur even without water injection from an external source. In fact, only RW2 has sulphate amongst all the water samples tested. There are other scaling-forming elements and compounds in all other water samples too because they all contain calcium and carbonate which can form $CaCO_3$ under favorable conditions. Figure 2 shows that all the water samples contain barium and strontium, thus all the water samples have scale-forming substances. This means that a mixture of RW2 with all the samples from the produced water can result in scaling, forming $BaSO_4$ and $SrSO_4$.

Presented in Figures 3 and 4 are the total dissolved solids (TDS) and lead content respectively in the water samples. The concentration of the TDS is above 14000mg/l in all the water samples but note that the TDS concentration of PW2 is the lowest compared to values from other water samples which might be a result of lower concentrations of scaling elements and compounds as shown in Figures 1 and 2. Figure 4 shows that the lead concentration is above 0.13mg/l in all the water samples. This amount

of lead in each water sample is above the compliance limit for inland effluent discharge in Nigeria which is 0.05mg/l [18]. Hence, re-injecting the produced waters into hydrocarbon reservoirs is a more effective means of disposal than treatment and discharge into water bodies which are not environmentally friendly. In as much as this option of produced water disposal is ideal, the produced and reservoir water compatibility study is crucial in order to detect and prevent scale formation and the problems associated with it.
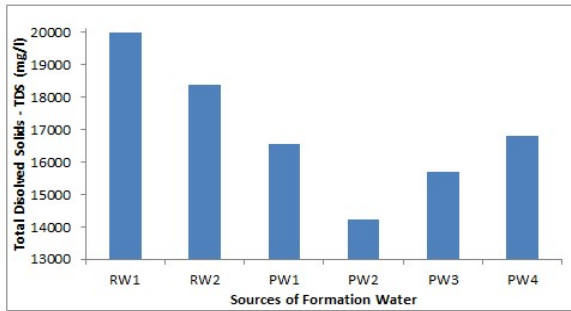
Figure 3: TDS in the Water Samples
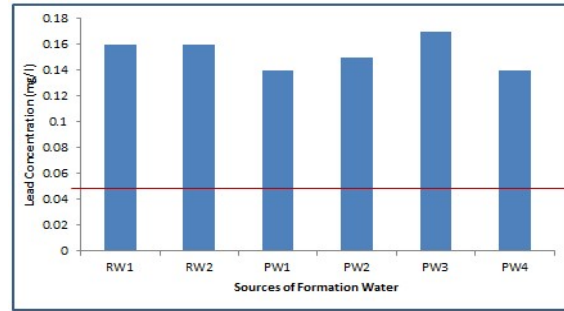
Figure 4: Lead Content in the Water Samples

Figures 5 and 6 are the plots of the pH values and LSI at different temperatures for all the water samples respectively. The pH values of all the formation water samples range between 7.3 and 7.6, tending toward alkalinity and are quite close to the neutral pH value of 7 for water. This renders LSI suitable for determining scaling potential in the water samples under consideration because LSI works best within a pH value range of 6.5 to 9.5 and especially close to a water neutral pH value of 7. Note that PW2 has the lowest pH value.

Figure 6 shows that the LSI of all the water samples have scaling potential because their LSI values are all above zero. It is observed that the LSI of all the water samples increase as temperature increases, implying that they are all exothermic processes that decrease solubility (thereby increasing precipitation) as temperature increases. It is also observed that PW2 has the lowest LSI at all temperatures compared to results from other water samples, indicating that it has the lowest scaling potential among the six formation water samples.
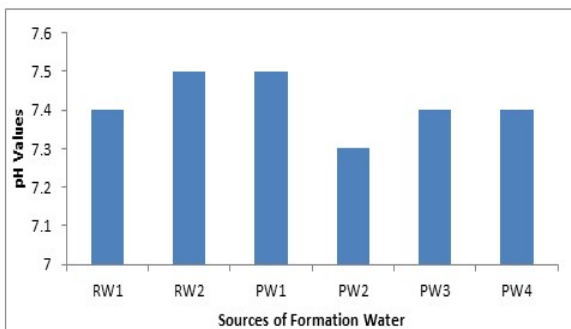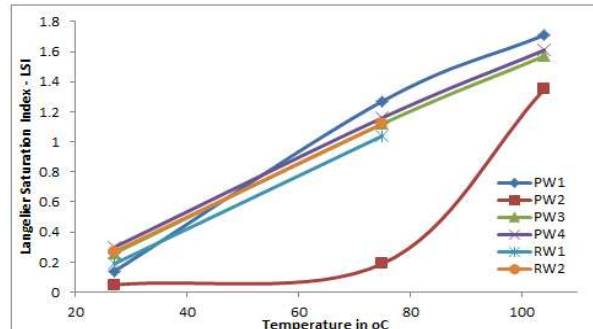

Figure 5: pH values of the Formation Waters

Figure 6: LSI of the Formation Waters

Figures 7 to 14 show the LSI of the in-situ reservoir waters and produced water mixtures at different ratios and at 27°C and 104°C. Take note that R1 and R2 are the same as RW1 and RW2 respectively, and P1, P2, P3 and P4 are the same as PW1, PW2, PW3 and PW4 respectively in Figures 7 to 14. Figures 7 to 10 are the cases of RW1 and PW1 to PW4 mixtures while Figures 11 to 14 are the cases of RW2 and PW1 to PW4 mixtures under different ratios.

The LSI of all the water mixtures is above zero, indicating that all the water mixtures have scaling potential. For RW1, the best option would be using 100% water from PW2 because that is the option with the lowest LSI, and as such has the lowest scale-forming tendency. There are two possible options for RW2; either using 100% PW2, or 40% reservoir water mixture with 60% produced water from PW3 (40/60).
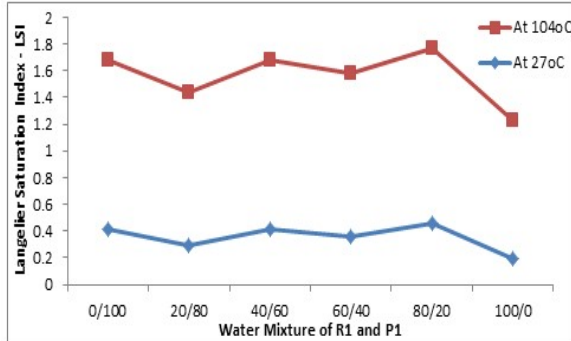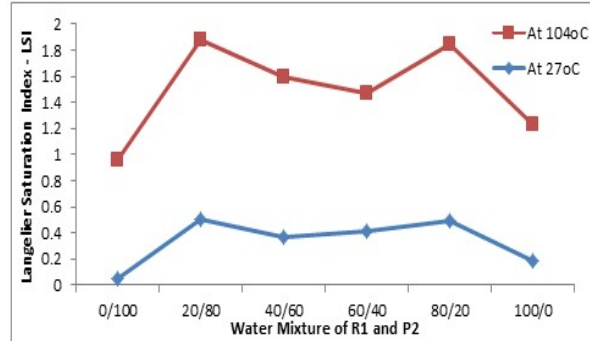

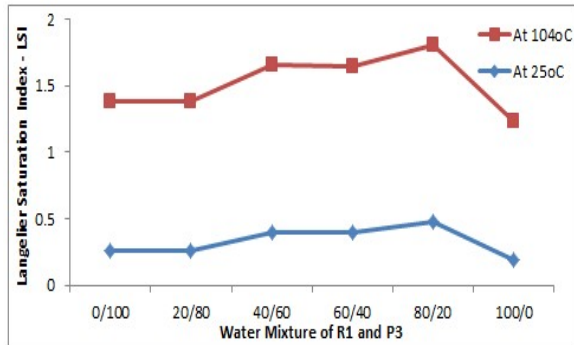Figure 7: LSI of Water Mixtures – RW1/PW1

Figure 8: LSI of Water Mixtures – RW1/PW2

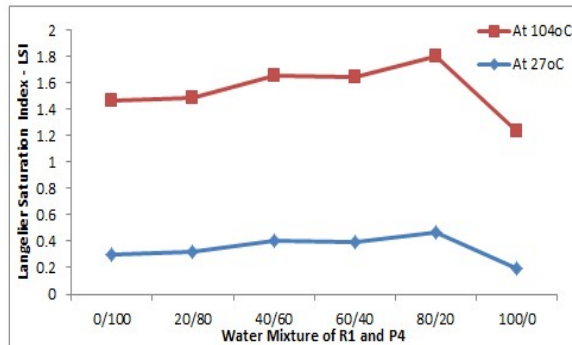Figure 9: LSI of Water Mixtures – RW1/PW3
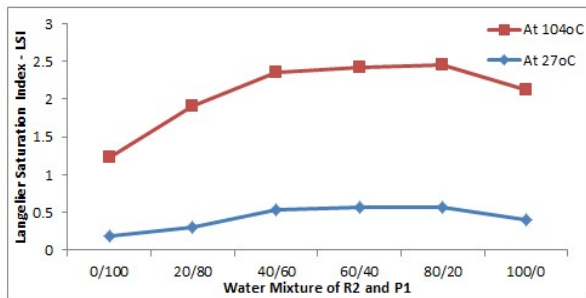

Figure 10: LSI of Water Mixtures – RW1/PW4

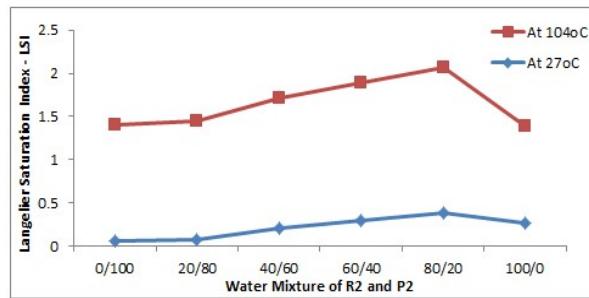Figure 11: LSI of Water Mixtures – RW2/PW1
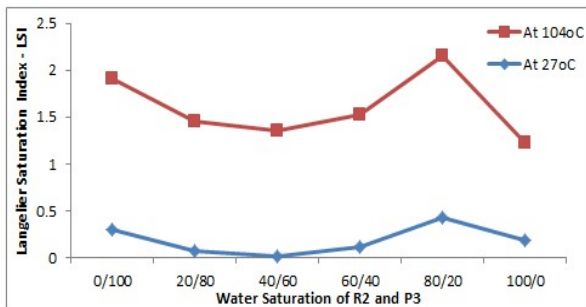

Figure 12: LSI of Water Mixtures – RW2/PW2
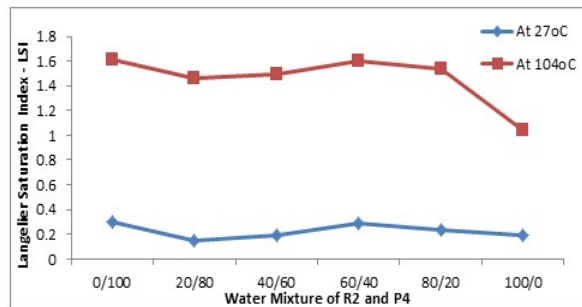

Figure 13: LSI of Water Mixtures – RW2/PW3

Figure 14: LSI of Water Mixtures – RW2/PW4

The presented results have shown that all the produced and in situ water samples have scaling potential, especially at higher temperatures. In order to avoid scaling problems if these produced waters must be used for water injection, scale inhibitors should be used because hydrocarbon reservoirs exist at higher temperatures, not ambient temperatures. However, results have also shown that PW2 is the most suitable water for use in water flooding projects among the four produced water samples. This is because PW2 has the least tendency for scale formation but it can only be safely used with an appropriate scale inhibitor. This work has emphasized the need to conduct water compatibility tests in order to prevent scale formation when produced water is intended to be used for water injection programs in reservoirs.

4. Conclusions

All the produced water intended to be used for the water injection scheme and the in-situ reservoir waters studied contained scale-forming elements and compounds. LSI was used to detect scale forming potential in all the produced oilfield waters and reservoir waters which had values above zero. It was observed that the LSI of all the water samples increased with an increase in temperature, indicating exothermic processes that promote precipitation. The LSI of the reservoir and produced water mixtures at all levels also had values above zero indicating scaling potentials. Oilfield water compatibility tests therefore should be conducted when produced water is intended to be used for water injection schemes in reservoirs to prevent scale formation.

5. Recommendation

When water compatibility tests show that scaling tendency exists in oilfield waters intended to be used for water injection schemes, scale inhibitors should be used to prevent scale formation.

Acknowledgements

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