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Archives of Applied Science Research, 2013, 5 (4):69-75  
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## Beneficial uses of the produced water from palogue oil field for injection to enhance oil recovery

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### ABSTRACT

*This study carried out in Palogue oilfield. One water samples collected from field processing facilities and one water sample collected from formation water in the same field. The water samples (formation and produced water) blend together. Nineteen blends of these waters for every field analyses for anions using UV Spectroscopy and cations using Inductive Coupled Plasma –optical E mission Plasma (ICP-OES).Scale deposition calculated for every blend and select the best blend to use for injection. Then the produced water sample analyses done for conductivity, total dissolve solids ond anions to calculate sodium adsorption ratio and to measure the suitability for irrigation of crops.*

**Key words:** Produced water, formation water, injection, enhances oil recovery

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### INTRODUCTION

Produced water is the largest volume waste stream in the exploration and production process. Over the economic life of a producing field, the volume of produced water can exceed by ten times the volume of hydrocarbons produced. During the latest stages of production, it is not uncommon to find that produced water can account for as much as 98% of the extracted fluids. With volume of this magnitude, the disposal of produced water becomes an important issue to both the operator and the environment. The optimum method for disposing of produced water is that protect the environment while imposing the least economic burden on the operator. Often, regulatory controls limit the options available to the operator. However, the methods dictated by regulatory controls may not be necessary or appropriate to protect the environment. (Produced water, Edited by J.P. and F.R.1992) In many land-based production operations, the produced water is either injected into a disposal well or the water is injected into a producing formation for enhanced oil recovery purposes via water flood or steam flood operations. Before being injected for either disposal or enhanced recovery, the produced water must undergo treatment to render the water suitable for use. The produce water can be treated and use for crop irrigation or can have safe disposal.

#### **Produced water injection for enhance oil recovery**

The injection water into oilfield reservoirs to maintain reservoir pressure and improve secondary recovery is a well established mature operation.

Scale formation in surface and subsurface oil and gas production equipment has been recognized to be a major operational problem. It has been also recognized as a major cause of formation damage either in injection or

producing wells. Scale contributes to equipment wear and corrosion and flow restriction, thus resulting in a decrease in oil and gas production.

There are other reasons why scale forms, and the amount and location of which are influenced by several factors, supersaturating is the most important reason behind mineral precipitation. A super saturated condition is the primary cause of scale formation and occurs when a solution contains dissolved materials which are at higher concentrations than their equilibrium concentration. The degree of super saturation also known as the scaling index is the driving force for the precipitation reaction and a high super saturation condition implies higher possibilities for salt precipitation. Scale can occur at downstream of any point in the production system, at which super saturation is generated. Super saturation can be generated in single water by changing the pressure and temperature conditions or by mixing two incompatible waters. Changes in temperature, pressure, pH, and CO<sub>2</sub>/H<sub>2</sub>S partial pressure could also contribute to scale formation (Mackay *J.E.*, 2003)

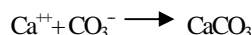
Common oil field scales:

The most common oilfield scales are sulfates such as calcium sulfate (anhydrite, gypsum), barium sulfate (barite), strontium sulfate (celestite) and calcium carbonate. Common scales have also been reported such as iron oxides, iron sulfides and iron carbonate. Lead and zinc sulfide scale has recently become a concern in a number of North Sea oil and gas fields (Collins and Jordan, 2001). Many case histories of oil well scaling by calcium carbonate, calcium sulfate, strontium sulfate, and barium sulfate have been reported (Mitchell *et al.* 1980; Lindlof and Stoffer, 1983; Vetter *et al.*, 1987; Shuler *et al.*, 1991)

There follows a brief description of each scale:

*Calcium carbonate deposits :*

Calcium carbonate or calcite scale is frequently encountered in oilfield operations. But the calcite has the greatest stability in oilfield circumstances, so it is the most common form of calcium carbonate encountered in oilfield production operation. Calcium carbonate crystals are large, but when the scale is found together with impurities in the form of finely divided crystals, then the scale appears uniform. Deposition of CaCO<sub>3</sub> scale results from precipitation of calcium carbonate as in the following equation:

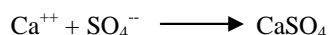


Calcium carbonate scale can also be formed by combination of calcium and bicarbonate ions, and this reaction is the major cause of calcium carbonate scale deposition in oilfield operations. This is because only a small percentage of the bicarbonate ions dissociated at the pH values found in most injection waters to form H<sup>+</sup> and CO<sub>3</sub><sup>2-</sup> (Moghadasi *et al.*, 2004b). In many oilfields, the deposition of calcium carbonate scale on surface and subsurface production equipment creates an operation problem. The formation water in which the carbonate-scale-forming components are initially dissolved becomes supersaturated with calcium carbonate because of the drop in pressure during production. The continuous flow of a supersaturated solution through the production equipment results in the growth of a dense layer of calcium-carbonate crystals (Bezemer and Bauer, 1969).

*Calcium sulphate deposits:*

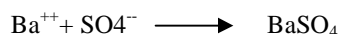
Calcium sulfate, or gypsum, is another solid frequently deposited by oilfield brines. Calcium sulfate usually precipitates directly on the metal surfaces of flow lines, boilers, heat exchanger tubes, etc., and consequently forms a scale rather than sludge. The crystals of calcium sulfate are smaller than those of calcium carbonate, so the scale is generally harder and denser than carbonate scales. Sulfate scales do not effervesce when treated with acid and cannot successfully be removed by acidizing at normal temperatures. Calcium sulfate scale is more difficult to remove than calcium carbonate scale.

The precipitation of calcium sulfate from water can be expressed as:



*Barium sulphate deposits*

One of the most insoluble substances formed from water and it is very difficult to remove once formed on equipment. It is formed by reaction between sulfate and barium ions as shown in equation below:



The solubility of barium sulfate in distilled water at 25 °C is 0.0023 g/liter. This is much less than solubility of 2.08 g/liter for calcium sulfate and 0.053 g/liter for calcium carbonate. Barium sulfate is so insoluble that quantitative analysis methods for both barium and sulfate are based upon the precipitation of barium sulfate. Barium is occasionally found in brines in some oilfields, because of the low solubility of barium sulfate, water containing barium contains only a few ppm, if any, dissolved sulfate. Oilfield waters containing 50 to 100 ppm barium are not common. Waters with more than 500 ppm sulfate would not contain appreciable amounts of dissolved barium.

#### *Strontium sulfate deposits:*

Another of alkaline earth metals, strontium, forms a sparingly soluble compound with sulfate. Strontium sulfate scale has not received the attention that gypsum or barite scale has, but in some areas, celestite may be a major problem. Solubility of strontium sulfate in water is 114 mg/l at 25 °C. This is less than calcium sulfate (2080 mg/l or 2630 mg/l expressed as  $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$ ) and more than barium sulfate (2.3 mg/l).

#### *Iron deposits :*

Deposits of iron compounds can be traced to two sources. One source is the water itself, which may contain dissolved iron. The second source is corrosion of iron or steel in the system, which results in formation of iron-containing corrosion products. Precipitated iron compounds from either of these sources may form scale on the surface of metal or remain in water as colloidal suspension. Water containing colloidal ferric oxide ( $\text{Fe}_2\text{O}_3$ ) has a reddish color and is usually called "red water". Water containing colloidal ferrous sulfide ( $\text{FeS}$ ) has a black color and is termed "black water".

#### *Silica deposits:*

Natural waters are occasionally found containing as much as 100 ppm silica. Silica may be present as colloidal, amorphous silica, and as the hypothetical monosilicic acid ( $\text{H}_4\text{SiO}_4$ ). For most uses, the silica content of the water is not an important consideration.

#### *Biological deposits:*

Algae, fungi, and bacteria are living organisms that may cause fouling in lines and equipment. Most algae require carbon dioxide and sunlight for their growth. They may be particularly active in cooling towers. Dislodged algae growths can cause serious obstructions in lines, on screens, or on the surface of formation rock. Plugging of injection wells by bacterial growth is not uncommon. However, oilfield waters usually do not contain the necessary nutrients to produce large bacterial growths. Biofouling problems in water handling systems are generally caused by a chemical change in the water or the addition of a bactericide that results in killing the organisms. The dead cells then accumulate on the formation face or in some location of restricted water flow.

## MATERIALS AND METHODS

Data collected for this study from different methods:

- Data from literature review.
- Data from Ministry of Petroleum (MOP)
- Data from Petro-Dar Operating Company (PDO)
- Data from Site survey for produced water samples.
- Data from Central Petroleum Laboratories (CPL).
- Data from Laboratory analysis.

#### *Laboratory analysis:-*

Laboratory analysis was done in Central Petroleum Laboratory (CPL) to measure the main parameter for formation, produced and injected waters. Two samples were collected from two locations includes formation water and produced water tank in Palogue field. The water samples were examined in accordance with the "Standard Methods for Examination of Water and Waste Water" 20 Edition.

pH test was done in central petroleum laboratory using JENWAY 3510 pH meter . A test for cations done by using Inductively Coupled Plasma-Optical Emission Spectrometry (ICP- OES) .Alkalinity is the acid neutralizing capacity of water. Usually expressed as "M" alkalinity (the methyl orange titration end point at a pH of 4.3) and "P"

alkalinity (the phenolphthalein titration end point at (pH 8.3). Several ions contribute to alkalinity. It is generally assumed to be due to bicarbonate, ( $\text{HCO}_3^-$ ), carbonate ( $\text{CO}_3^{2-}$ ), and hydroxyl ( $\text{OH}^-$ ) ions. The test carried out by using Automatic Titrate (Titrimo plus) using (2320 APHA Method). Chloride test (4500-Cl-APHA Method) using UV-4000 spectrophotometer. Sulphate test (HACH -Sulpha -Ver 4 Method) using UV- 4000 Spectrophotometer

The physical and chemical property of water sample from Palogue oilfield in table (1)

**Table (1) Produced and formation water analysis from Palogue oilfield**

Sample	CL mg/L	SO <sub>4</sub> mg/l	OH- mg/l	CO <sub>3</sub> mg/l	HCO <sub>3</sub> mg/l	pH	cond. ms/cm	TDS g/l	Salinity g/L	Ba ppm	Ca ppm	Mg ppm	Na ppm
Produced water	238.50	20.00	0.00	500.00	4045.00	8.14	7.59	4.07	3.30	0.91	7.38	3.22	3115.69
Formation water	230.50	22.00	0.00	700.00	4550.00	8.02	8.31	5.10	3.60	2.98	28.93	4.12	2977.34

The formation water and produced water blended in ratio for injection started from 5% produced water and 95% formation water then 10% produce water and 90 % formation water till blend 19 (95% produced water and 5% formation water) . Analysis was done for every blend to calculate concentration of cations and anions then calculate scale deposition for each blend.

**Table (2) Palogue blends of produced and formation water (1-19)**

Blend	Chloride mg/L	Sulfate mg/L	OH- mg/L	CO <sub>3</sub> mg/L	HCO <sub>3</sub> mg/L	Ba ppm	Ca ppm	Mg ppm	Na ppm	K ppm	Sr ppm	Ph
B 1 (5/95%)	242.6	29	0	500	4395	0.91	5.08	2.78	2134.67	110.65	0.34	8.08
B 2 (10/90%)	220.5	29	0	600	4245	1.03	6.56	2.99	2131.97	121.24	0.38	8.08
B 3 (15/85%)	236.1	27	0	700	4245	0.88	5.86	2.61	2225.03	111.07	0.31	8.08
B 4 (20/80%)	233.6	25	0	900	3945	0.95	6.83	2.75	2173.03	114.76	0.34	8.08
B 5 (25/72%)	244.6	26	0	700	4095	0.88	5.95	2.68	2173.28	111.61	0.32	8.08
B 6 (30/70%)	240.5	24	0	600	4295	0.94	7.02	2.61	2170.45	106.4	0.32	8.08
B 7 (35/65%)	236.9	22	0	700	4045	0.96	7.93	3	2139.9	120.99	0.36	8.08
B 8 (40/60%)	231.5	23	0	900	3695	0.86	6.94	2.69	2159.07	122.73	0.32	8.08
B 9 (45/55%)	230.9	21	0	700	3895	0.89	8.05	3.13	2072.22	129.84	0.34	8.08
B10 (50/50%)	213.0	21	0	1750	3845	<0.2	7.33	3.15	2839.07	145.27	2.03	8.08
B 11(55/45%)	20.33	22	0	1000	3795	<0.2	15.88	3.31	2088.08	184.58	4.0	8.08
B12 (60/40%)	20.93	20	0	1000	4095	<0.2	7.95	3.3	2224.8	160.48	4.88	8.08
B13 (65/35%)	21.5	18	0	700	3795	<0.2	10.15	3.02	1883	150.87	5.18	8.08
B14 (70/30%)	20.79	18	0	900	3545	<0.2	15.35	3.15	1931.7	158.59	5.15	8.08
B15 (75/25%)	20.83	16	0	700	3695	<0.2	9.13	3.17	1841.79	157.15	5.28	8.08
B16 (80/20%)	22.99	17	0	600	3795	<0.2	8.2	3.19	1899.94	152.95	5.13	8.08
B17 (85/15%)	21.0	16	0	500	3495	<0.2	11.15	3.3	1610.99	156.43	5.1	8.08
B18 (90/10%)	22.77	15	0	800	3445	<0.2	8.4	3.18	1833.96	147.11	5.0	8.08
B19 (95/5%)	21.03	15	0	400	3995	<0.2	12.1	3.08	1741.36	127.74	4.83	8.08

**RESULTS AND DISCUSSION**

**Scale Index calculations:**

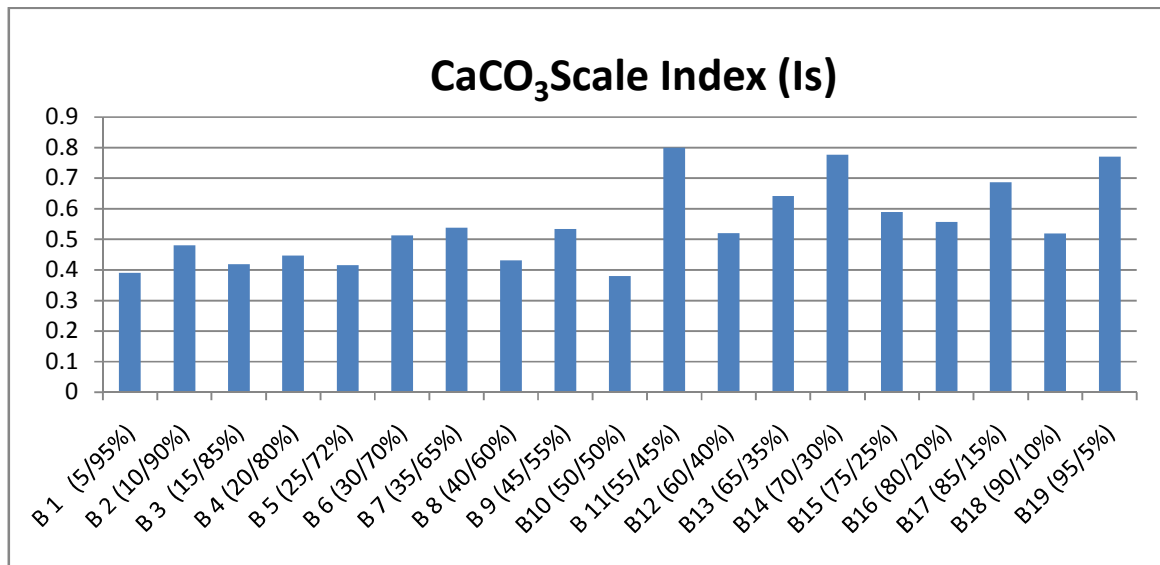
- If scale index calculation positive means scale likely and deposition starts to appear.
- If the saturation index is zero means the saturation point.
- If the saturation index negative means scale unlikely but corrosion start to take place.
- A positive value for the saturation index indicates that the water is oversaturated and will precipitate calcium carbonate; a negative value indicates that the water is corrosive, i.e., will dissolve calcium carbonate scale.

**Palogue oilfield**

**Table (3) CaCO<sub>3</sub> Scale index (Is) at temperature 68°F**

Blend	CaCO <sub>3</sub> Scale Index (Is)
<b>B 1 (5/95%)</b>	0.390
<b>B 2 (10/90%)</b>	0.481
<b>B 3 (15/85%)</b>	0.419
<b>B 4 (20/80%)</b>	0.447
<b>B 5 (25/72%)</b>	0.416
<b>B 6 (30/70%)</b>	0.513
<b>B 7 (35/65%)</b>	0.538
<b>B 8 (40/60%)</b>	0.431
<b>B 9 (45/55%)</b>	0.534
<b>B10 (50/50%)</b>	0.380
<b>B 11(55/45%)</b>	0.800
<b>B12 (60/40%)</b>	0.521
<b>B13 (65/35%)</b>	0.642
<b>B14 (70/30%)</b>	0.777
<b>B15 (75/25%)</b>	0.589
<b>B16 (80/20%)</b>	0.557
<b>B17 (85/15%)</b>	0.687
<b>B18 (90/10%)</b>	0.520
<b>B19 (95/5%)</b>	0.771

*B means Blend*



**Figure (1) Palogue oilfield CaCO<sub>3</sub> Scale index (Is) at temperature 68°F**

**From the above table (5):**

1) All blends Ca CO<sub>3</sub> scale index (Is) is above zero means scale deposition of Ca CO<sub>3</sub>. (Stiff, H. A. and Davis,)

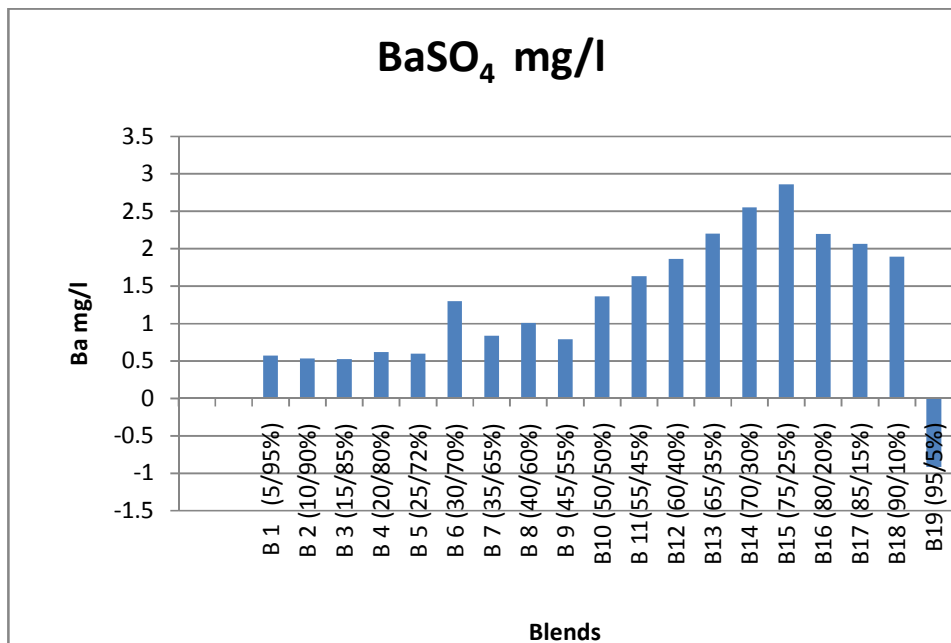
- 2)The best blend for mixing formation water with produce water is blend ten (10) with lower scale index 0.380 which contain a mixture of 50% produce water and 50% formation water.
- 3)This mixture means 50% of water injection is produced water and this decrease the water reach the environment and this is best way to manage the produced water for health environment and to enhance oil recovery which increase the production of the oil.
- 4) This water should be treated with scale inhibitor before injection and this mixture the less cost for scale deposition treatment.

**Palogue oilfield:**

**Table (4) Ca SO<sub>4</sub>, BaSO<sub>4</sub> and Sr SO<sub>4</sub> mg/l 68<sup>o</sup>F**

Blend	Ca SO <sub>4</sub> mg/l	BaSO <sub>4</sub> mg/l	SrSO <sub>4</sub> mg/l
<b>B 1 (5/95%)</b>	-2005	0.573	-202
<b>B 2 (10/90%)</b>	-2021	0.536	-206
<b>B 3 (15/85%)</b>	-1997	0.525	-202
<b>B 4 (20/80%)</b>	-2073	0.621	-219
<b>B 5 (25/72%)</b>	-2083	0.600	-221
<b>B 6 (30/70%)</b>	-2093	1.297	-220
<b>B 7 (35/65%)</b>	-2128	0.837	-232
<b>B 8 (40/60%)</b>	-2160	1.009	-239
<b>B 9 (45/55%)</b>	-2072	0.791	-220
<b>B10 (50/50%)</b>	-2082	1.366	-220
<b>B 11(55/45%)</b>	-2166	1.633	-243
<b>B12 (60/40%)</b>	-2208	1.865	-253
<b>B13 (65/35%)</b>	-2379	2.203	0.000
<b>B14 (70/30%)</b>	-1982	2.551	-264
<b>B15 (75/25%)</b>	-1959	2.859	0.000
<b>B16 (80/20%)</b>	-1917	2.197	-268
<b>B17 (85/15%)</b>	-1345	2.062	0.000
<b>B18 (90/10%)</b>	-1248	1.893	-302
<b>B19 (95/5%)</b>	-803	-0.917	-308

*B means Blend*



**Figure (3) Palogue oilfield water injection BaSO<sub>4</sub> mg/l 68<sup>o</sup>F**

From table (4)

- 1) No Ca SO<sub>4</sub> deposition in all blends, concentration is below zero.
- 2) BaSO<sub>4</sub> deposition in all blends but the deposition is less than CaCO<sub>3</sub>
- 3) No Sr SO<sub>4</sub> deposition in all blends.

### CONCLUSION

As a result of the study the conclusion listed on the following points:

The formation water and produced water mixing in Palogue field caused scale deposition.

The best blending ratio for Palogue oilfield blend ten (50% produced water and 50% formation water).d water and 45% formation water).

The above mentioned ratio less of scale deposited and high consumes of produced water that protecting the environment. The most common scale deposit is calcium carbonate.

The calcium sulphate deposit is not occurred (unlikely).Barium sulphate is likely but in small amount.

Strontium sulphate deposit is not occurred (unlikely)

The study area basement complex (Meta – Sediment) rich with Ca CO<sub>3</sub> rock found as crystalline marble at the surface (Rabak cement Query) and found also at subsurface as encountered at some drilled wells in block (7) and (3) (Central Petroleum Laboratories (CPL)) .This source supposes to introduce calcium carbonate in formation water beside the intruded volcanic sills inside sediment of Melut basin which related to the activity of African Rift zone. The accompanied solution with the volcanic rocks also adds sodium carbonate and chloride which is reported in many localize along the Rift zone like Magadi Lake at Kenya. (Baker, B.H. 1958. Geology of the Magahi area)

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