The 1st International Conference of the Faculties of Sciences
19- 20 Dec 2021

PREDICTION OF CALCIUM CARBONATE AND CALCUIM SULFATE SCALE DEPOSITS IN MABRUK OIL FIELD, LIBYA

Asmaa D. Alnajar[1], R. T. Refai[2]
[1] Sabratha University, Faculty of Sciences, Department of Geology, Libya, asma_324@yahoo.com
[2] University of Tripoli, Geological Engineering Department, Libya, refai.taher@gmail.com

ABSTRACT

This Study focuses on predictions and probability of calcium carbonate and calcium sulfate scale formation. It has been conducted in the Sirt Basin on concession ‘‘NC -17’’ namely is Mabruke oil – field. Twenty-six chemically analysed water samples from different wells in this oil field were used in this study; these samples showed Total Dissolved Solids (TDS) ranges from 9075 to 85261 mg/L.

The chemical analysis of petroleum – associated waters from such wells was studied and interpreted. This was done in order to find out and predict $CaCO_3$ and $CaSO_4$ scales. This prediction was based on geochemical analytical calculations as well as applying Stiff and Davis method, this method is one of the easiest ways to calculate calcium carbonate and calcium sulfate scaling in brines, Where the saturation index is calculated and thus the prediction of scaling deposits. Accordingly, it was found that $CaCO_3$ scale was found to be likely in most water samples, Factors causing this type of scale are mainly pH, Pressure, HCO_3 and Ca concentrations. On the contrary $CaSO_4$ scale was found unlikely in most of the studied waters, with the fact that salinity, Ca^{+2} and SO_4^{-2} concentrations are the main factors causing such scale.

Keywords: TDS; Scale Formation; Brines; Solubility; Common Ion.

الملخص

تركز هذه الدراسة على التنبؤ واحتمالية تكوين رواسب تقشير كربونات الكالسيوم وكبريتات الكالسيوم. وقد أجريت هذه الدراسة في حوض سرت في امتياز "NC -17" في حقل المبروك النفطي. استخدم في هذه الدراسة التحليل الكيميائي لستة وعشرين عينة من آبار مختلفة في هذا الحقل. أظهرت هذه العينات أن إجمالي المواد الصلبة المذابة (TDS) يتراوح من 9075 إلى 85261 مجم / لتر.

تمت دراسة وتفسير التحليل الكيميائي للمياه المصاحبة للنفط لهذه الآبار. تم القيام بذلك للتنبؤ ومعرفة رواسب تقشير $CaCO_3$ و $CaSO_4$. اعتمد هذا التوقع على الحسابات التحليلية الجيوكيميائية بالإضافة إلى تطبيق طريقة Stiff and Davis، وهذه الطريقة هي واحدة من أسهل الطرق لحساب رواسب تقشير كربونات الكالسيوم وكبريتات الكالسيوم في المحاليل الملحية، حيث يتم حساب مؤشر التشبع وبالتالي التنبؤ برواسب التقشير. ووفقًا لذلك، وجد أن رواسب تقشير كربونات الكالسيوم $CaCO_3$ كانت مرجحة في معظم عينات المياه، والعوامل المسببة لهذا النوع من رواسب التقشير هي أساسًا تراكيز الأس الهيدروجيني والضغط و HCO_3 و Ca. على العكس من ذلك، وجد أن رواسب تقشير $CaSO_4$ غير مرجحة الحدوث في معظم المياه المدروسة، مع حقيقة أن الملوحة وتراكيز Ca^{+2} و SO_4^{-2} هي العوامل الرئيسية التي تسبب هذه الرواسب.

Author Correspondent: asma_324@yahoo.com

1. INTRODUCTION

The water associated with oil and gas pools is called oil – field waters (Leverson, 1967), these waters differ greatly from modern sea water, both in the amount of the dissolved salts and in the chemical composition of the salts, Water analysis is one of the most important aspects in oil – field water studies. When producing oil and gas there will most cases also be produced some water, which contains dissolved salts. These salts may precipitate and tend to deposit on surfaces. Deposition of inorganic minerals from brines is called scale, and its formation causes flow reduction or even blocking of pipes, valves and other equipment. Common types of scales during oil and gas production are $CaSO_4$, $SrSO_4$, $BaSO_4$ and $CaCO_3$ (Refai, 2011).

Flow reduction can lead to sever decrease in production rate, and may also lead to safety problem if scale forms. In the down hole safety valve. The economical impact for both prevention and removal of scale can be serious. In some cases, the scale may even be radioactive due to small amounts of radium, and must therefore be treated as radioactive waste.

Many types of scale as $CaCO_3$, $CaSO_4$, $BaSO_4$, and $SrSO_4$ are formed in Oil and gas reservoirs and production facilities in many Libyan oilfields. This is because the petroleum- associated waters in such fields contain considerable amounts of Ca, Ba, Sr. This also occurs where different waters are mixed. In particular, were reservoir waters and injected waters are mixed. These phenomena took place in Sirt basin oil and gas fields.
The work includes mineral scale prediction in oil fields by using chemical analysis of oil-field waters from many wells in field studied (Refai, 2008).

The continuing challenge posed by oil – field scale is most clearly reflected in the significant on going global research effort dedicated to developing newer and better technologies for its mitigation and control (McRae and Strachan, 2005).

Scale formation is one of the most serious oil – field problems that inflict water injection systems primarily when two incompatible waters are involved. Two waters are incompatible if they interact chemically and precipitate minerals when mixed (Merdhah and Yassin, 2008).

Scale removal in the oil and gas field is a difficult and complicated operation. Chemical dissolvers and mechanical removal are usually used together to remove the deposited scales. the design of the scale dissolver method should consider economic and technical aspects. It should be low-cost, non-damaging to the surface facilities, well tubed, equipped, and contain reservoir rock. In addition, it should have a high degree of thermal stability, be environmentally friendly and should not produce H_2S gas after scale dissolution (Gamal et al., 2020).

The study area includes Mabruk oil – field, the field is located in Concession 17, at the western side of Sirt Basin, which is approximately 170 km south of Gulf of Sirt (Figure 1) .

Structurally, the Mabruk oil – field occurs in the Sirt basin (Libya) in a longitudinal trough Figure (1). Generated by a family of faults oriented N150 to N170. This oil field is represented by three structures (North, West & Centre-East). The west structure can be separated into 3 sedimentological areas (North, Centre and South) (Noyau and Machhour, 2002).

Mabruk oil – field is producing from limestone, dolomatic limestone (carbonate) of Paleocene age.

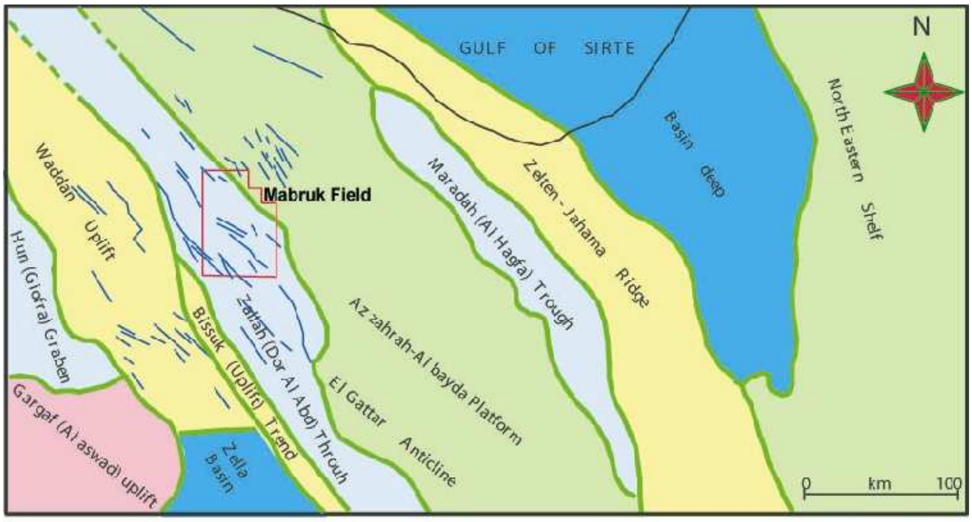

Fig.1. Paleogeographic setting of Sirt Basin Showing Location of Mabruk Oil Field (Noyau, and Machhour, 2002).

Geochemistry of oil –field waters: studied by (Collins 1975) and Dickey (1986). Oil – field waters in some oil – fields in westren Sirt Basin, Libya was geochemically studied by Refai, Shalgom and Abdalhafed (2003). Moreover, Calcite scale prediction at the near – well region: A radio tracer approach studied by (Stamatakis et al., 2013).

Ruwaih, et al., (2007) studied the groundwater chemistry in relation to aquifer mineralogy of the Eocene aquifer, Kuwait. Moreover, they studied the concentration of ions in groundwater depend on the rock mineralogy through which the water passes along the path flow.

Merdhah and Yassin (2009) studied solubility of common oil field scales of injection water and high – barium concentration and high salinity formation water. They found that at higher temperatures the deposition of $CaCO_3$, $CaSO_4$ and $SrSO_4$ scale increases and the deposition of $BaSO_4$ scale decreases since the solubilities of $CaCO_3$, $CaSO_4$ and $SrSO_4$ scales decreases and the solubility of $BaSO_4$ increases with increasing temperature.

Scale formation in oil reservoir during water injection at high – salinity formation water. Studied by (Merdhah and Yasin, 2007).

Mazumder (2020) demonstrated that the $CaSO_4$ crystals were found in three forms as hydrous, hemihydrates, and anhydride of gypsum; that is why its precipitation is complicated. The formation of gypsum usually is at low temperature. At the same time, the deposition of its anhydrite forms at high temperatures. As temperature increases, the solubility of scales is increased up to 40 C˚, and when T > 40 C˚, the solubility of $CaSO_4$ decrease.

Aims of this study Knowledge of Oil – field water classification, and mineral scale prediction from the chemical composition of oil field waters in Mabruk oil – field in Sirt Basin Libya, In other words, $CaCO_3$ and $CaSO_4$ scale prediction. To avoid corrosion of oil field equipment and to avoid mineral precipitation in reservoir rock pores. Precipitation of mineral scales leads to decreasing reservoir porosity and hence decreasing oil production. To prevent mineral scaling due to mixing incompatible waters. This is important during oil will development through water injection operations.

2. METHODOLOGY

The chemical analysis of twenty six oil – field water samples from Mabruk oil – field in Sirt Basin Libya were interpreted. This interpretation includes determination of total dissolved solids (TDS), ionic strength (I) as well as equivalent per million (epm).

In addition, some other parameters were taken into consideration this is for example saturation index, temperature, … etc, in order to find out $CaCO_3$ and $CaSO_4$ scale tendencies.

Total Dissolved Solids (TDS) is simply the total amount of matter dissolved in a given volume of water. It can be calculated by taking the sum of concentrations of all cations and anions (Patton, 1986).

expressed in units of mg per unit volume of water (mg/L), also referred to as parts per million (ppm).

3. RESULTS AND DISCUSSION

3.1 Total Dissolved Solids in the Studied Oil Field Waters

Field studied is Mabruk oil – field. Based on equation (1), The table below showing the chemical analysis of the oil field waters in mg/L, results of Total Dissolved Solids (TDS). pH and specific gravity be measured in the field.

$$TDS = \sum {}^{mg}\!/_{L} \text{ or ppm cations} + \sum {}^{mg}\!/_{L} \text{ or ppm anions} \qquad (1)$$

Table 1. Chemical analysis of the oil – field waters from Mabruk Oil Field NC-17, sirt basin Libya in mg/L.

Well No.:	Cations(mg/L)				Anions(mg/L)			TDS	pH	Sp.Gr.
	Na^+	k^+	Ca^{++}	Mg^{++}	Cl^-	$SO4^{--}$	$HCO3^-$	(mg / L)		
1	25750	160	3120	826	45590	2769	342	78557	6.78	1.06
2	22750	170	2400	875	39991	2617	281	69084	7.00	1.06
3	24500	210	1680	875	39991	4527	378	72161	7.19	1.06
4	21250	210	2400	729	35992	4300	390	65271	7.03	1.05
5	28250	235	2160	1118	47989	3802	159	83713	7.04	1.07
6	26000	210	2000	875	41991	5761	317	77154	6.78	1.06
7	26500	250	1920	1166	44790	4024	293	78943	6.79	1.06
8	24500	260	1760	875	39991	4836	281	72503	7.27	1.06
9	23500	260	1520	826	38191	4358	390	69045	7.13	1.06
10	19750	340	1600	826	33193	3642	317	59668	7.13	1.05
11	24500	250	1680	875	39991	4559	354	72209	6.96	1.06
12	20000	200	1120	972	33992	2304	317	58905	7.00	1.05
13	19750	190	1520	583	32393	69.13	3318	58201	7.24	1.05
14	29000	220	2080	1021	47989	4756	195	85261	7.17	1.07
15	18000	190	1200	875	29993	3362	268	53888	6.97	1.04
16	23750	200	1840	923	39991	3533	342	70579	6.56	1.06
17	17000	190	1280	729	27434	4329	354	51316	7.27	1.04
18	17750	160	1440	535	28394	4197	342	52818	7.39	1.04
19	20500	200	1600	729	33992	3629	232	60882	6.99	1.05
20	2900	123	130	73	3199	1967	683	9075	7.41	1.01
21	27750	230	2000	923	45790	4461	293	81447	6.61	1.07
22	23750	230	1920	1021	40391	3741	159	71212	6.99	1.06
23	7600	80	640	292	11797	2481	342	23232	6.45	1.02
24	20250	210	1680	1021	33992	4403	293	61849	6.32	1.05
25	16000	160	136	39	22595	3294	354	42578	6.26	1.03
26	14750	160	880	826	23995	3741	268	44620	6.41	1.04

3.2 $CaCO_3$ Scale Prediction in the Studied Oil Field Waters

In this study we used (Stiff & Davis method), this method will be applied to oil – field brines. This equation is as follows:

$$SI = pH - K - pCa - pAlk \qquad (2)$$

Where:
SI= Stability Index or Saturation Index.
(If SI is negative, the water is undersaturated with CaCO3 and scale formation is unlikely. If SI is positive, water is supersaturation with $CaCo_3$ and scale is likely to form), and if SI= 0 the water is in equilibrium with $CaCO_3$ and scale unlikely.
pH= is the actual pH of the water.
K= is a constant which is a function of salinity, composition and water temperature. Values of K were obtained from a graphical correlation with ionic strength (I) and the temperature of the water is given in figure (2).

$$pCa = \log \frac{1}{Moles\, Ca^{+2} / Liter} \qquad (3)$$

$$pAlk\, M = \log \frac{1}{Equivalents\, M\ Alkalinity / Liter} \qquad (4)$$

$$M\ Alkalinity = Total\ Alkalinity = CO_3^{-2} + HCO_3^{-} \qquad (5)$$

The next equation can be used to calculate the ionic strength (I):

$$I = \frac{1}{2} \sum_i C_i Z^2{}_i \qquad (6)$$

Where:
C: is the concentration of positive or negative ion in Molality, Z: is the valence of the ion.

Values of K as a function of ionic strength are given in figure (2), these curves are based on:

- Molar ionic strength (0-3.6).
- Temperature (0, 30 and 50°C).
- Pressure of 1 atmosphere.

All curves outside of this data range were extrapolated. pAlk and pCa obtained from chart conversion of mg/L Calcium and Alkalinity into pAlk and pCa, and can be calculated from Equations (3) and (4), A chart for the determination of pCa and pAlk given in figure (3).

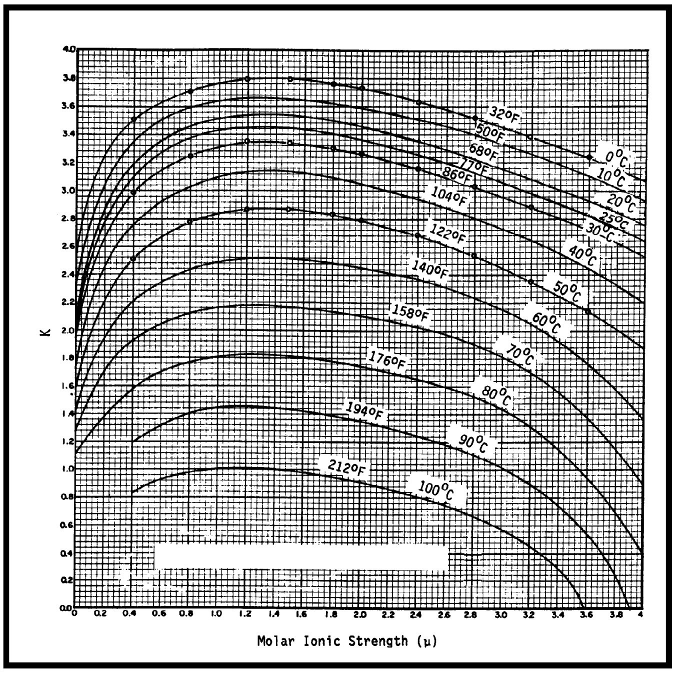

Fig.2. Values of Stiff and Davis K for $CaCO_3$ Scale calculation (Patton, 1986).

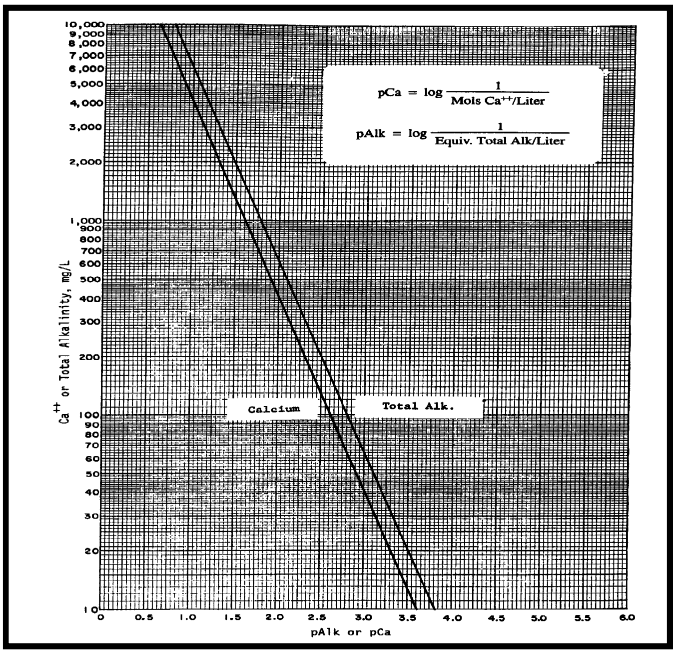

Fig.3. Conversion of mg/L Calcium and Alkalinity into pCa and pAlk (Patton, 1986).

Values of ionic strength (I) and the constant K are given in table (2).

Table 2. Calculated K values and ionic strength (I) of the oil – field waters from Mabruk Oil Field NC-17, Sirt Basin Libya

Well No.:	**Ca^{+2} (mg\l)**	**HCO_3^- (mg/l)**	**pH**	**I**	**T (C°)**	**K**
1	3120	342	6.78	1.58	57.00	2.68
2	2400	281	7.00	1.38	57.00	2.70
3	1680	378	7.19	1.43	57.00	2.69
4	2400	390	7.03	1.31	57.00	2.70
5	2160	159	7.04	1.68	57.00	2.68
6	2000	317	6.78	1.54	57.00	2.69
7	1920	293	6.79	1.58	57.00	2.68
8	1760	281	7.27	1.44	57.00	2.69
9	1520	390	7.13	1.36	57.00	2.71
10	1600	317	7.13	1.18	57.00	2.69
11	1680	354	6.96	1.43	57.00	2.69
12	1120	317	7.00	1.15	57.00	2.68
13	1520	3318	7.24	1.09	57.00	2.67
14	2080	195	7.17	1.71	57.00	2.67
15	1200	268	6.97	1.06	57.00	2.66
16	1840	342	6.56	1.40	57.00	2.69
17	1280	354	7.27	1.01	57.00	2.65
18	1440	342	7.39	1.04	57.00	2.67
19	1600	232	6.99	1.20	57.00	2.70
20	130	683	7.41	0.17	57.00	2.00
21	2000	293	6.61	1.62	57.00	2.69
22	1920	159	6.99	1.43	57.00	2.69
23	640	342	6.45	0.45	57.00	2.37
24	1680	293	6.32	1.24	57.00	2.70
25	136	354	6.26	0.78	57.00	2.60
26	880	268	6.41	0.88	57.00	2.66

The Results In Mabruk field showed in Table (3) and figure (4).that in oil – field waters would form $CaCO_3$ scaling. Because high concentrations of calcium, bicarbonate, and pressure drop one of the factors that led to the scale deposits may be. In addition to the high pH.

Table 3. $CaCO_3$ Scale prediction in the studied wells of Mabruk Field NC-17, Sirt Basin Libya

Well No.:	pCa^{+2}	pAlk	SI	Scaling Tendency
1	1.10	2.25	0.75	Likely
2	1.23	2.35	0.72	Likely
3	1.38	2.21	0.91	Likely
4	1.23	2.20	0.90	Likely
5	1.27	2.54	0.55	Likely
6	1.30	2.28	0.51	Likely
7	1.31	2.31	0.49	Likely
8	1.35	2.35	0.88	Likely
9	1.42	2.20	0.80	Likely
10	1.40	2.28	0.76	Likely
11	1.38	2.24	0.65	Likely
12	1.55	2.28	0.49	Likely
13	1.42	1.25	1.90	Likely
14	1.28	2.50	0.72	Likely
15	1.53	2.37	0.41	Likely
16	1.34	2.25	0.28	Likely
17	1.50	2.24	0.88	Likely
18	1.45	2.25	1.02	Likely
19	1.40	2.43	0.46	Likely
20	2.50	1.95	0.96	Likely
21	1.30	2.34	0.28	Likely
22	1.33	2.54	0.43	Likely
23	1.80	2.25	0.03	Likely
24	1.38	2.31	-0.07	Unlikely
25	2.48	2.24	-1.06	Unlikely
26	1.65	2.73	-0.63	Unlikely

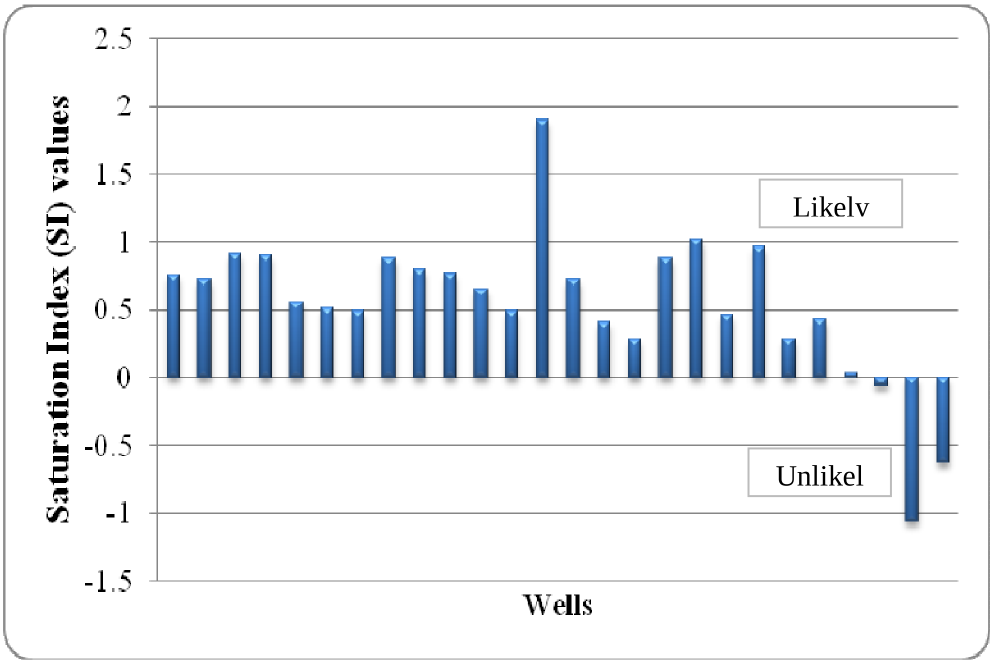

Fig.4. $CaCO_3$ Scale prediction in the studied wells of Mabruk Field NC-17, Sirt Basin Libya.

3.3 $CaSO_4$ Scale Prediction in the Studied Oil Field Waters

Solubility values of $CaSO_4$, $BaSO_4$ or $SrSO_4$, can be calculated using the following equations, providing values of conditional solubility product, Kc, are known for each compound:

$$S = 1000\left[\left(X^2 + 4K_C\right)^{0.5} - X\right] \qquad (7)$$

Where:
S is the calculated solubility of calcium sulphate (meq/l).
K_c is the Solubility product constant of $CaSO_4$.
X is the excess common ion concentration in Moles/liter. This is simply the difference between the calcium concentration and the sulphate concentration.
The following table present the parameters used to find saturation index:

Table 4. Parameters used to find saturation index of Mabruk Field NC-17, Sirt Basin Lib

Well No.:	Ca^{+2} (mol\l)	SO_4^{+2} (mol\l)	X	4Kc
1	0.083	0.031	0.052	9.40E-03
2	0.063	0.029	0.034	8.84E-03
3	0.044	0.050	0.006	8.96E-03
4	0.063	0.047	0.016	8.52E-03
5	0.058	0.042	0.015	9.84E-03
6	0.053	0.064	0.011	9.44E-03
7	0.051	0.045	0.006	9.36E-03
8	0.046	0.053	0.007	9.12E-03
9	0.040	0.048	0.008	8.84E-03
10	0.042	0.040	0.002	8.16E-03
11	0.044	0.050	0.006	8.96E-03
12	0.029	0.025	0.004	7.88E-03
13	0.040	0.001	0.039	7.60E-03
14	0.055	0.053	0.003	9.96E-03
15	0.031	0.036	0.005	7.48E-03
16	0.049	0.039	0.010	8.76E-03
17	0.033	0.047	0.014	7.12E-03
18	0.037	0.046	0.008	7.40E-03
19	0.042	0.040	0.002	8.08E-03
20	0.003	0.021	0.017	1.84E-03
21	0.053	0.049	0.004	9.74E-03
22	0.051	0.041	0.009	8.96E-03
23	0.016	0.026	0.010	3.88E-03
24	0.044	0.048	0.004	8.32E-03
25	0.004	0.035	0.032	5.88E-03
26	0.023	0.040	0.018	8.76E-03

The actual concentration of $CaSO_4$ in soluation is equal to the smaller of the Ca^{+2} or SO_4^{-2} concentrations (expressed in meq/l) in the water of interest, since the smaller concentration controls the amount of calcium sulphate which can be formed.

The data measured by Skilman, McDonald and Stiff has been widely used to estimate the solubility of gypsum in oil – field brines. They measured ion product constants in simulated oilfield brines over the following range:

- Temperature 50, 95, 122 and 176 ° F (10, 35, 50 and 80ºC).
- Ionic Strength: 0-6.0 moles\L.
- Pressure: 1 atmosphere.

The following procedure is recommended to assess the possibility of gypsum precipitation for a given brine:

- Calculate the molar ionic strength using Equation (6).
- Obtain the appropriate value of K_c for the temperature of interest from figures (5 & 6).
- Determine the excess common ion concentration, X, in moles/liter. This is simply the difference between the calcium concentration and the sulphate concentration.
- Calculate the solubility of gypsum in meq\l by solving Equation (7).
- Calculate the "actual concentration" of gypsum in the water, which is equal to the smaller of the Ca^{+2} or SO_4^{-2}concentrations expressed in meq\l.
- Compare the calculated solubility with the actual concentration to determine if precipitation of gypsum is likely. (Patton, 1986).

Thereupon, the resulted S value compared to the actual ion concentration of Ca^{+2}, SO_4^{-2} will indicate calcium sulphate scale formation as follows:

- If S is greater than smaller of the two ion concentration Ca^{+2}, SO_4^{-2}, the water is not saturated with calcium sulphate and scale formation is unlikely.
- If S is less than smaller of the two ion concentration Ca^{+2}, SO_4^{-2}, then calcium sulphate scale formation is likely.
- If S is equal to smaller of Ca^{+2}, SO_4^{-2} concentration, then the water is not saturated with calcium sulphate. Since the smaller controls the amount of calcium sulphate which can be formed.

The calculated calcium sulphate solubility must be expressed in (meq\l) (Patton, 1968).

Applying equation (7) Yields the results which are sown in Table (5) and figure (7).

$CaSO_4$ scaling is unlikely in most of the studied water samples. In western Sirt Basin, the most samples in Mabruk oil field would not form $CaSO_4$ scaling. Meanwhile, high TDS and an increase in the concentrations of calcium and/or sulfate are the main factors causing scaling.

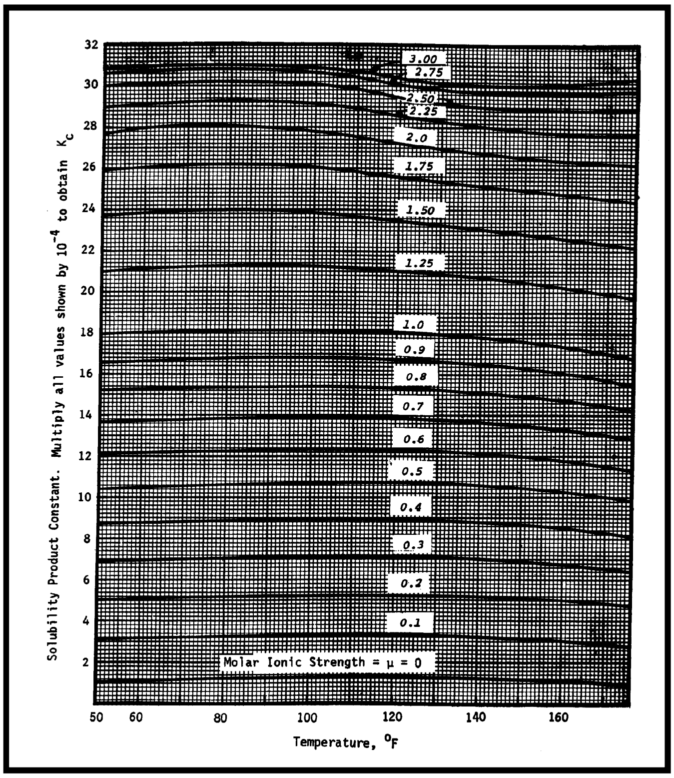

Fig.5. Calcium Sulfate (Gypsum) Conditional Solubility Product Constants (Patton, 1986).

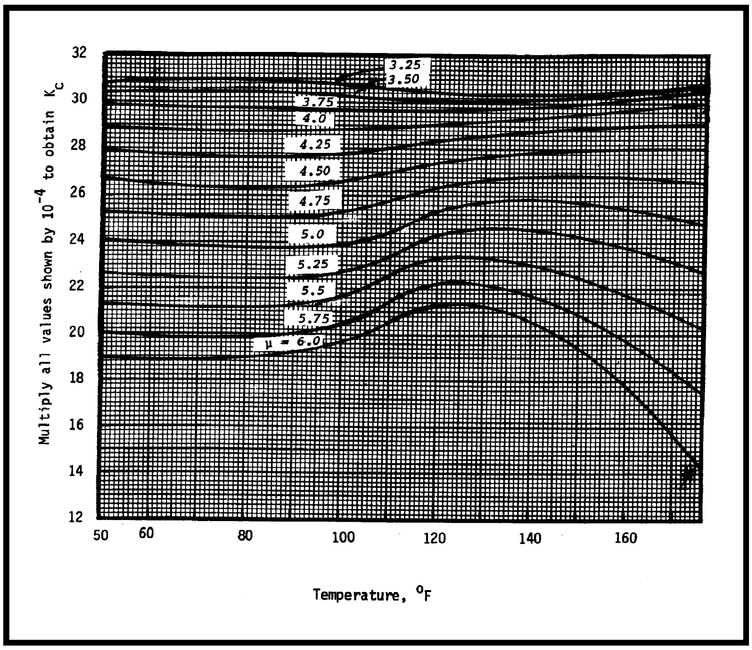

Fig.6. Calcium Sulfate (Gypsum) Conditional Solubility Product Constants (Patton, 1986).

Table 5. $CaSO_4$ Scale prediction in the studied wells of Mabrouk Field NC-17, Sirt Basin Libya.

Well No.:	Ca^{+2} (meq/l)	SO_4^{+2} (meq/l)	S (meq/l)	Concentration (meq/l)	Scaling Tendency
1	155.69	57.65	57.97	57.65	Unlikely
2	119.76	54.49	65.68	54.49	Unlikely
3	83.83	94.26	89.30	83.83	Unlikely
4	119.76	89.53	77.76	89.53	Likely
5	107.78	79.16	85.08	79.16	Unlikely
6	99.80	119.95	87.05	99.80	Likely
7	95.81	83.78	90.56	83.78	Unlikely
8	87.82	100.69	88.93	87.82	Unlikely
9	75.85	90.74	86.49	75.85	Unlikely
10	79.84	75.83	88.26	75.83	Unlikely
11	83.83	94.92	88.97	83.83	Unlikely
12	55.89	47.97	84.72	47.97	Unlikely
13	75.85	1.44	56.55	1.44	Unlikely
14	103.79	99.02	97.30	99.02	Likely
15	59.88	70.00	81.37	59.88	Unlikely
16	91.82	73.56	84.44	73.56	Unlikely
17	63.87	90.13	71.83	63.87	Unlikely
18	71.86	87.39	78.31	71.86	Unlikely
19	79.84	75.56	87.67	75.56	Unlikely
20	6.49	40.95	28.92	6.49	Unlikely
21	99.80	92.88	95.07	92.88	Unlikely
22	95.81	77.89	85.66	77.89	Unlikely
23	31.94	51.66	53.06	31.94	Unlikely
24	83.83	91.67	87.19	83.83	Unlikely
25	6.79	68.58	51.13	6.79	Unlikely
26	43.91	77.89	64.57	43.91	Unlikely

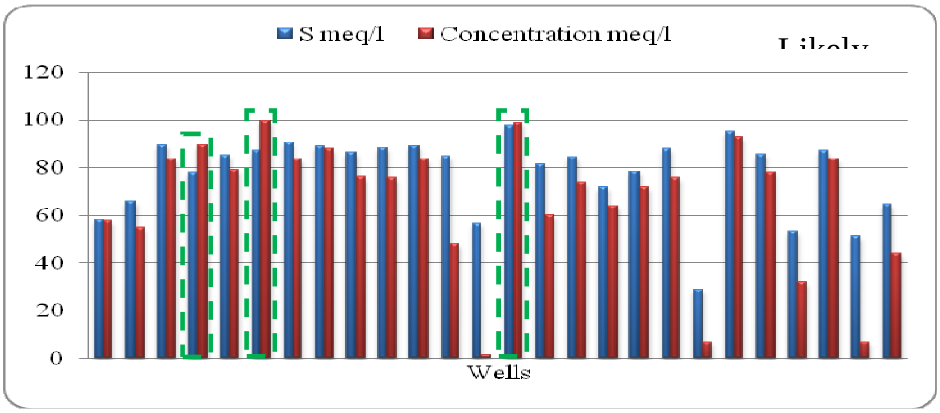

Fig.7. $CaSO_4$ Scale prediction in the studied wells of Mabrouk Field NC-17, Sirt Basin Libya.

4. CONCLUSION AND RECOMMENDATIONS

4.1 Conclusions

This study presents the results of calcium carbonate and calcium sulfate scale prediction. It has been conducted on Mabruk oil – field in the Sirt Basin in North Central Libya. From geological calculations and interpretations of the studied oil – field water samples the following conclusions are illustrated:

- Cations in oil – field waters are: Na^+, K^+, Ca^{2+}, and Mg^{2+}. Anions are: Cl^-, SO_4^{2-}, and HCO_3^-.
- Total Dissolved Solids (TDS) range from 9075 to 85261 mg/L.
- According to Gorrell's classification most of the studied samples are saline (25) samples, the rest of the sample is Brackish waters.
- $CaCO_3$ scaling is likely in most wells, with few wells in which it unlikely. Meanwhile, pressure, pH, Ca and HCO_3 concentration are the main factors causing such scaling. On the other hand, high TDS is the main factor causing no scaling.
- $CaSO_4$ scaling is unlikely in most of wells; with few samples in which it likely. Meanwhile, TDS and concentrations of calcium and/or sulfate are main factors causing such scaling.

4.2 Recommendations

- We recommend periodic chemical analysis of petroleum – associated waters in oil field wells to know their chemical changes with time. This benefits the prediction of water movement within a particular oil field.
- Using statistical and numerical methods to analyze results of the chemical analysis of the oil – field waters. This would be done by using modern techniques (Applying updated computer software's) used in such type of studies.
- Reinjection of compatible waters into reservoirs to avoid scaling effects during water flooding operations.
- Applying this type of studies on the rest of the oil fields in Libya. This would be done by coordination and formation of an advisory group from NOC, Libyan Petroleum Institute (LPI) and Libyan oil companies.

REFERENCES

Al Ruwaih, F. M., Hadi, K.M, and Shehata, M. (2007).Groundwater chemistry in relation to aquifer mineralogy of the Eocene aquifer: Kuwait. *Emirates Journal for Engineering research*,12 (2) .

Collins, A.G. (1975). Geochemistry of oil –field waters: Elsevier scientific Co.

Dicky, P.A. (1986). Petroleum Development geology: oklahomausa, usa, Tusa: penn well publishing company.

Gamal, H., Elkatatny, S., Alshehri, D., and Bahgat, M. (2020). A Novel Low – Temperture Non – Corrosive Sulfate/ Sulfide Scale Dissolver. *Sustainability*, 2455 (12), 2-14. doi: 10.3390/su 12062455.

Leverson, A. I. (1967). Geology of petroleum 2nd edition: W. H. Free man and company San Francisco. Second Edition. P 173,174.

Mazumder, M. A. (2020). A Review of Green Scale Inhibitor: Process, Types Mechanism and Properties. *Coatings*, 928 (10), 8-29. doi: 10.3390/coatings 10100928.

McRate, J.A., Strachan , C.J., and Thornton , A. (2005). Overview of scale treatment in oil field environments, from a technical viewpoint: *Petroleum Research Journal*, 17.

Merdhah, A. B, and Yassin, A. M. (2007). Scale Formation in Oil Reservoir During Water Injection at High – Salinity Formation Water: *Journal of Applied Sciences*, 7 (21).

Merdhah, A. B, and Yassin, A. M. (2008). Laboratory study and prediction of calcium sulphate at High – salinity formation water: *The Open Petroleum Engineering Journal*, 1.

Merdhah, A. B, and Yassin, A. M. (2009). Solubility Of Common Oil Field Scales Of Injection Water And High-Barium Concentration And High salinity formation Water: *Jurnal Teknologi Universiti Teknologi Malaysia*, 50 (1).

Noyau, A., and Machhour, L. (2002). Reservoir compartmentalization through geochemical and sedimentological investigations; example of the Mabruk oil field, sirt basin, Libya: the Fourth AAPG International Petroleum Conference and Exhibition, Cairo, Egypt.

Patton, C. C. (1986). Applied water technology. Oklahoma: Campbell petroleum series norman.

Refai, T., shallghoom , A., and Abdelhafeeth, L. (2003). Geochemical study of the oil field waters in same of the oil fields in western part of Sirt Basin, Libya: Libyan petroleum institute, unpublished study.

Refai, T.R. (2008). Topics in reservoir geology oil – field waters: Faculty of Engineering, unpublished course notes, Geological Engineering Department.

Refai, T.R. (2011). produced water management in Libyan oil fields: unpublished report Geological Engineering Department.

Stamatakis, E., Stubos, A., Bjornsted, T., and Muller, J. (2013). Calcite scale prediction at near – well region A radiotracer approach: EPJ Web of Conferences 50 (6), 03004:EDP Sciences. doi.org/10.1051/epjconf/20135003004.