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Possible Application Of Enhanced Oil Recovery Technology In Low Permeability Carbonate Reservoir

Abdulrazag Zekri, Phd, Hamdi Ben Zekri, PE, Mamdouhgannam, Ph.D., Essa Georges Lwisa, M.Sc. PE, Gamal Al-Austa, Ph.D.,
UAE University
Corresponding Author : Abdulrazag Zekri, Phd

ABSTRACT: *For low permeability reservoirs (permeability in range of 0.1 to 1 mD), innovative exploration/ exploitation strategy is required for optimal hydrocarbon recovery. A number of reservoirs or layers discovered has very low permeability. These reservoirs or layers are ignored by local and regional oil companies due to many discoveries of easy oil, i.e. reservoirs with high permeability's. This project discusses about a low permeability reservoir of AB Field, which has a substantial reserve base and potential for exploration/exploitation. The primary recovery methods are expected not to produce the desired results. A number of enhanced oil recovery options are tested through core flooding experiments including sea water flooding, low salinity flooding, surfactant flooding, nitrogen flooding, and carbon dioxide injection. Phase behavior studies, contact angle, and interfacial tension experiments were performed. Laboratory core flooding results indicated that Carbon dioxide flooding is the optimal flooding scheme for the candidate reservoir as shown in Fig. 1. Oil price of carbon dioxide sensitivity analysis indicated that a $ 35/ bbl is the critical value for the implementation of carbon dioxide flooding for the selected low permeability oil reservoir. Based on the results of our experimental work the following conclusions are reached:*

Optimum surfactant concentration for our reservoir is 0.3 weight % and Sea water with salinity of 50,000 ppm is the optimum salinity for the selected surfactant.

Sea water shows a higher displacement efficiency than formation water.Carbon dioxide flooding can significantly enhance oil recovery from low permeability formations.Super critical nitrogen gas flooding can lead to higher displacement efficiency than sea water but ultimately recovers less oil than carbon dioxide flooding.Low salinity flooding can be effective in improving the displacement efficiency of low permeability limestone oil reservoir, but requires a good understanding of the complex interactions between rock, brine, and oil.

Surfactant flooding recovers oil through interfacial tension reduction.

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I. INTRODUCTION

After more than a century of petroleum exploitation, thousands of oil and gas fields are approaching the ends of their economically productive lives. The life of an oil well usually undergoes three distinct phases where various techniques are employed to maintain crude oil production at maximum levels which are primary, secondary and tertiary, or enhanced oil recovery. These techniques are mainly aimed to serve a common purpose which is reducing the residual oil saturation which results in enhancement of the displacement efficiency and improvement of the ultimate oil recovery. Primary oil recovery refers to the process of extracting oil either via the natural rise of hydrocarbons to the surface of the earth or via pump jacks and other artificial lift devices. Since this technique only targets the oil, which is either susceptible to its release or accessible to the pump jack, this is very limited in its extraction potential. In fact, only around 5% - 15% of the well's potential are recovered from the primary method. Secondary recovery employs water and dry gas injection, which will displace the oil, force it to move from its resting place and bring it to the surface. Water is most commonly used due to its availability and low economic value; through water flooding process it is pumped to maintain the required pressure of reservoir. Water flooding is effective in all reservoirs, and typically recoveries are 25 to 45% after primary recovery. EOR techniques are applied at thethird phase of production after both primary and secondary recovery has been exhausted[1,2,3,4,5,6,7,8,9]. Rather than simply trying to force the oil out of the ground, as did the previous two methods, enhanced oil recovery seeks to alter its properties to make it more conducive to extraction. Low permeability oil reservoirs needs an innovative technique to recover its reserves as primary recovery methods do not produce the discovered reserves. The Canadian society[5] of unconventional resource's classified oil reservoirs as unconventional and conventional reservoirs as shown in **Fig. 1.** Low permeability oil reservoirs are reservoirs having on the average a permeability in range of 0.1 to 1 mD, as shown in **Fig. 1.**

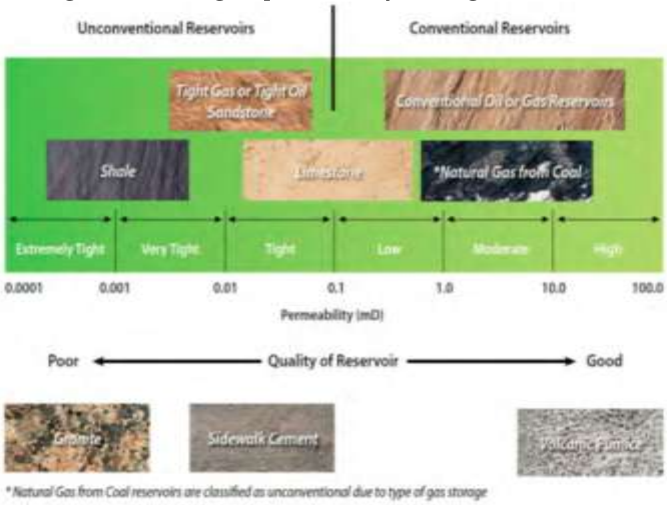

Figure 1. Oil reservoir characteristics, Canadian Society of Unconventional Resources.

The possible application of the following EOR techniques in a selected low permeability carbonate oil reservoir: surfactant, low salinity, CO2, Nitrogen, and sea water flooding were investigated. The displacement efficiency of various scenarios for the selected process are evaluated and the optimum system for a selected local field is carbon dioxide flooding. The overall project plan of work is shown in **Fig. 2**.

Figure 2. Project overall plan of work.

.Apparatus and Material

Core Flooding Apparatus

The schematic diagram of the core flooding apparatus is shown in **Fig. 3**.A Nitrogen cylinder is connected to an oil tank. The core holder and all of the tunings were covered with a heating tape to insure a high temperature injection. Pressure and temperature were recorded throughout the experiment.

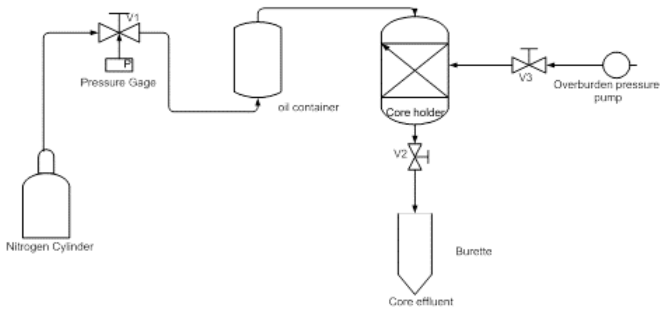

Figure 3. Core flooding apparatus.

Rocks and Fluids

Twenty core samples from ARAB C and Thamma V were selected and tested. Porosity and permeability were determined using the industry procedure. Permeability of the cores ranged from 0.082 to 116 MD, see **Table 1**. Actual crude oil samples obtained from the candidate oil reservoir and actual formation brine collected from the field separator with salinity of 127,000 ppm were employed in this study.

Experimental Procedure

The spinning drop apparatus was used to study the interfacial tension between the selected oil field cured and surfactant solutions of 0.05, 0.1, 0.3, and 0.7 weight %. A non-ionic surfactant obtained from Schlumberger Company was employed in this project. Spinning Drop Interfacial Tensiometer Model TX500KBIKS was employed in this study, see **Fig. 4**. The spinning drop apparatus includes a capillary tube, into which an aqueous bacteria solution is injected, followed by a small drop of oil. The oil and nutrient-rich brine bacteria solution are mixed together in a cylindrical tube and shaken well. The mixed fluids are then kept for 48 hours to reach equilibrium before using them in IFT measurements.

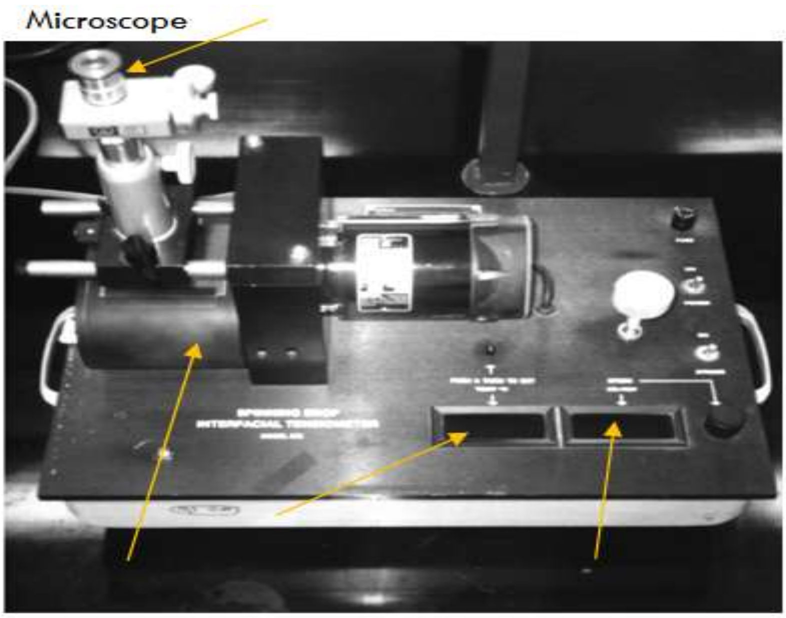

Figure 4. Interfacial tension apparatus.

The limestone cores were dried at 80□ C for 72 hours. Each core was evacuated for 12 hours and saturated with 7% (by weight) brine solution. During this step, we measured the volume of water required to completely saturate the core in order to determine its pore volume and porosity. The core was then flooded at a high rate with the crude until no further brine was produced. The residual brine saturation was calculated from the recovered effluent brine volumes.

The cores were initially fully saturated with water, a requirement for the measurement of the absolute permeability's of the samples, the cores are then flooded with oil to residual water saturation, and the water produced signifies the volume within the core that was replaced by oil, i.e. original oil in place OOIP for the samples.

II. RESULTS AND DISCUSSION

Interfacial Tension& Phase Behavior Measurements

To select the optimum surfactant concentration four interfacial tension measurements were conducted between the selected oil field cured and surfactant solutions of 0.05, 0.1, 0.3, and 0.7 weight %. A non-ionic surfactant obtained from Schlumberger Company was employed in this project.

Table 2. Porosity and Permeability of the tested cores.

Sample N°	Sample Name	Dia (mm)	Length (mm)	Bulk Vol (cc) L*A	Bulk Vol (cc) GV + PV	Weight (g)	Pref (psi)	Pexp (psi)	Grain Vol. (cc)	Pore Vol. (cc)	Porosity (%)	Kg (mD)	Grain density (g/cc)
n	82_arab_c	37.77	49.37	55.32	55.32	144.27	100.00	79.37	51.90	3.43	6.19	0.082	2.780
2	83_arab_c	37.83	51.10	57.44	57.44	159.83	100.03	81.95	57.12	0.32	0.56	0.000	2.798
3	84_arab_c	37.82	50.32	56.53	56.53	152.52	101.41	81.11	55.22	1.31	2.31	2.139	2.762
4	85_arab_c	37.73	50.70	56.69	56.69	131.22	105.77	78.23	48.68	8.01	14.13	2.656	2.696
5	86_arab_c	37.67	51.69	57.61	57.61	126.37	100.04	72.58	46.99	10.62	18.44	12.240	2.689
6	87_arab_D	37.59	50.09	55.59	55.59	145.13	100.09	76.40	51.38	4.21	7.58	4.114	2.825
7	88_arab_D	37.67	51.93	57.88	57.88	142.51	98.92	74.82	50.61	7.27	12.56	12.149	2.816
8	89_arab_D	37.69	50.72	56.59	56.59	142.51	107.65	81.07	50.23	6.36	11.24	116.396	2.837
9	92_arab_D	37.63	51.37	57.13	57.13	138.11	100.08	75.86	50.79	6.34	11.10	9.946	2.719
10	93_arab_D	37.42	50.70	55.76	55.76	139.79	100.04	75.98	50.95	4.81	8.62	1.364	2.744
11	181_Tammama V	37.77	52.00	58.25	58.25	121.48	100.06	70.95	44.96	13.30	22.82	121.208	2.702
12	183_Tammama V	38.97	50.56	60.31	60.31	132.25	100.03	74.73	49.56	10.75	17.83	1.918	2.669
13	185_Tammama V	38.00	51.00	57.84	57.84	154.08	127.05	104.95	57.78	0.06	0.11	0.135	2.667
14	187_Tammama V	37.83	51.89	58.32	58.32	148.81	100.06	79.91	55.10	3.22	5.52	0.291	2.701
15	189_Tammama V	37.81	52.50	58.94	58.94	130.96	100.03	71.75	48.70	10.24	17.37	1.771	2.689
16	190_Tammama V	38.23	47.90	54.99	54.99	118.78	100.05	72.52	44.21	10.79	19.61	8.542	2.687
17	191_Tammama V	37.82	52.84	59.36	59.36	130.92	100.00	73.96	48.68	10.68	18.00	0.985	2.690
18	193_Tammama V	37.80	51.44	57.73	57.73	123.63	100.03	69.68	46.05	11.68	20.24	30.551	2.685
19	194_Tammama V	38.17	52.03	59.53	59.53	127.95	82.12	59.91	47.50	12.04	20.22	9.684	2.694
20	195_Tammama V	37.74	51.55	57.66	57.66	128.20	100.25	73.20	47.57	10.09	17.50	5.505	2.695

The results of the IFT are presented in Table 2 and the optimum concentration of surfactant is 0.3 weight % as shown in **Fig. 5**.

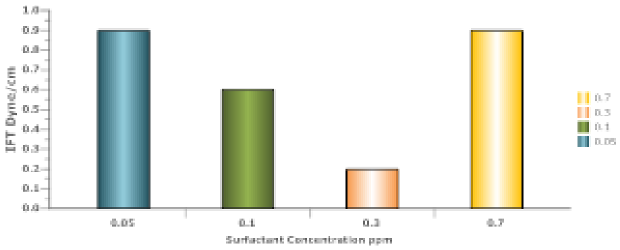

Figure 5. IFT measurements of surfactant

Equal volumes of the following waters, formation brine water (127000ppm), sea water (50000ppm), and low salinity water (5000ppm) were added to equal volumes of oil, 100ml of the oil and 100ml of the water. Surfactants of concentration 0.3 were add to the waters. The mixture were kept for approximately 48 hours and photos were taking as function of time. The results of the study indicated that sea water is the optimum system where a maximum emulsion phase was observed as shown in **Fig. 6**.

Figure 6. Phase behavior study results.

Core Flooding Experiments

This sectioncovers the experimental analysis conducted for the selection of the optimum EOR/IOR methodology based on the experimental results attained. The optimization of one of the strategies “surfactant flooding” through IFT tests as well as a phase behavior test was conducted, yielding an optimum surfactant concentration of 0.3% and proving sea water to be the optimum medium for the surfactant flooding.

The methodologies covers tertiary experimental work that includes low salinity flooding, surfactant flooding, CO_2 Flooding, and Nitrogen Flooding. Out of the twenty core samples four low permeability samples were selected, shown in **Table 3**.The samples have approximately similar porosities and permeability since each of the methodologies werepreformed onseparate samples to limit the effect of heterogeneity on process performance.

Table 3. Selected Core Samples.

Well id: SB-0567 Brine SG (gm/cc): 1.103

Samlpe id	Dry wt (gm)	Sat. wt. (gm)	Length (cm)	Diameter (cm)	Pore vol. air (cc)	Pore vol. water (cc)	Bulk vol. (cc)	Grain vol. air (cc)	Grain vol. water (cc)	Garin den. (gm/cc)	Porosity air (%)	Porosity water (%)	Permeability Liquid (md)
1	171.84	184.98	6.510	3.820	12.01	11.91	74.64	62.63	62.73	2.74	16.1	16.0	0.35
2	171.84	186.06	6.844	3.800	13.99	12.89	77.65	63.66	64.76	2.70	18.0	16.6	0.30
3	173.84	189.46	6.934	3.812	14.70	14.16	79.17	64.47	65.01	2.70	18.6	17.9	0.39
4	174.98	192.89	7.100	3.824	16.78	16.23	81.58	64.80	65.34	2.70	20.6	19.9	0.50
5	170.78	192.10	7.240	3.800	19.36	19.32	82.14	62.78	62.82	2.72	23.6	23.5	2.23

The comparison of the alternatives are based on tertiary recovery mode where the incremental production of each of the alternatives marks the main criteria for calculating the displacement efficiency and the optimal recovery system. The secondary recovery stage means that the cores were flooded with sea water with a salinity of 50,000 ppm until reaching a water cut equal to 100% implying reaching residual oil saturation, the flood then switched accordingly to the alternative chosen. **Fig. 7** shows the results of the secondary recovery stage.

To evaluate the performance of sea water flooding in this reservoir one core flooding run was conducted at elevated temperature and pressure of 90 ℃ and pressure of 3000psia respectively. Samples were prepared at irreducible water saturation i.e. we started the flood at secondary mood with high salinity water first until oil recovery stopped than the flood switched to sea water. Results indicated that sea water can recover residual oil that remained after formation brine flooding.

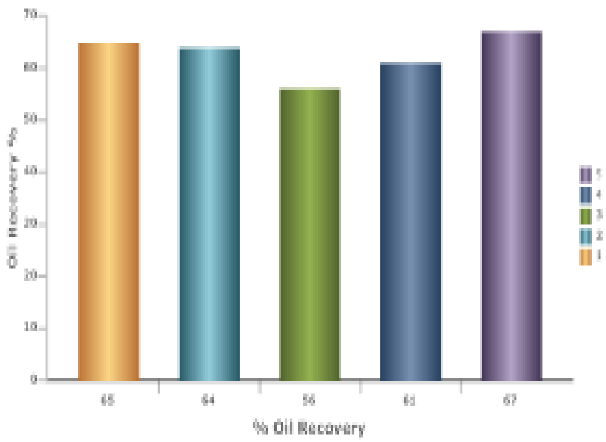

Figure 7. Secondary recovery from sea water injection.

The core was initially flooded by formation water which resulted in the recovery of 68.6% of the oil within the core sample, following that the formation water was replaced by sea water and the flooding process continued recovering an extra 4% of theremaining oilin place. **Fig.8** presents displacement efficiency versus formation brine followed by sea water. Sea water recovery is around 4% of OIP and 11% of remaining oil in place after water flooding.

Figure 8. Sea water and formation brine displacement efficiency.

Low salinity flooding

Low salinity flooding was performed with sea water diluted to 5000 ppm salinity. This test was performed employing core sample 2 with liquid permeability of 0.3 mD. The core was flooded initially with sea water to residual oil saturation then the flood was switched to low salinity flooding at reservoir condition of high temperature and high pressure conditions.Low salinity flooding resulted in displacement efficiency of approximately 7.14%. This increase in displacement efficiency can be attributed to the change in wettability towards a water wet system, this can be reflected through end point relative permeability calculations.The end point water permeability to low salinity water is 0.10 mD compared to 0.45 mD for sea water. The reduction of water permeability a good indication to wettability alteration of the system to water wet system and that contributed to the improvement in the displacement efficiency.

Surfactant flooding

Core sample 3 with liquid permeability of 0.39 mD employed in this task. The core was flooded with sea water to residual oil saturation then flood switched to surfactant flooding. The surfactants optimum concentration of 0.3 wt %. The optimum surfactant concentration was determined in the preliminary phase. The surfactant flooding was conducted at reservoir condition of high temperature and pressure conditions.Surfactant flooding resulted in an improvement in the displacement efficiency of a 0.96% recovery. The improvement in the displacement is due to reduction of interfacial tension of the system as IFT drop from 5 dyne/cm for sea water to 0.1 dyne/cm for the optimum surfactant concentration. End point water permeability measurements for sea water and surfactant flooding indicates that wettability alteration could be another force that contributes to the improvement in the displacement efficiency of surfactant flooding. The end point water permeability to surfactant flooding is 0.011 mD compared to 0.45 mD for sea water

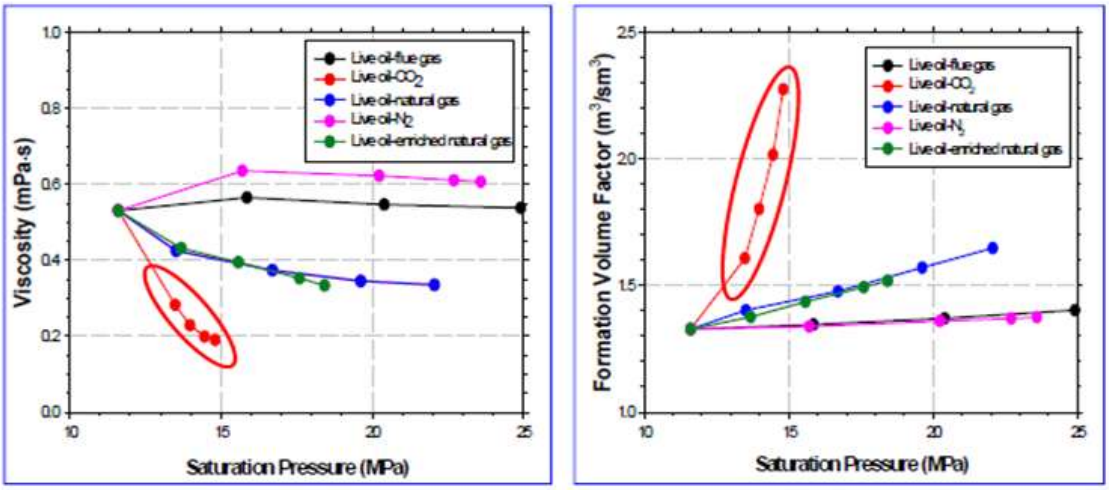

Figure 9. Viscosity and formation volume factor vs saturation pressure (Nakutnyy, 2015).

Nitrogen flooding

The N2 flooding was conducted on core samples 4 with liquid permeability of 0.5 mD. The core was flooded with sea water to residual oil saturation then flooding was switched to nitrogen flooding at tertiary mode. The experiment was run at high temperature and high pressure conditions.The core flooding runs were conducted at a temperature of 90 ˚C and a pressure of 1300 psi. N2 flooding resulted in an improvement of the displacement efficiency of 6%. Nitrogen was injected as a supercritical fluid pressure with a density of 5.0594 Ib/cubic ft and viscosity of 0.022 cp. The improvement of the displacement efficiency of nitrogen over sea water flooding is due to oil swelling and viscosity reduction as shown in Figure 9.

Enhanced oil recovery optimization

The experimental analysis ranked the chosen alternatives based on their tertiary recovery, the results ranked the alternatives as follows:

1) CO2 Flooding
2) Low Salinity Flooding
3) Immiscible Nitrogen Flooding
4) Surfactant Flooding

Figure 10 presents a comparison between different flooding alternatives i.e. surfactant flooding, lowsalinity flooding,

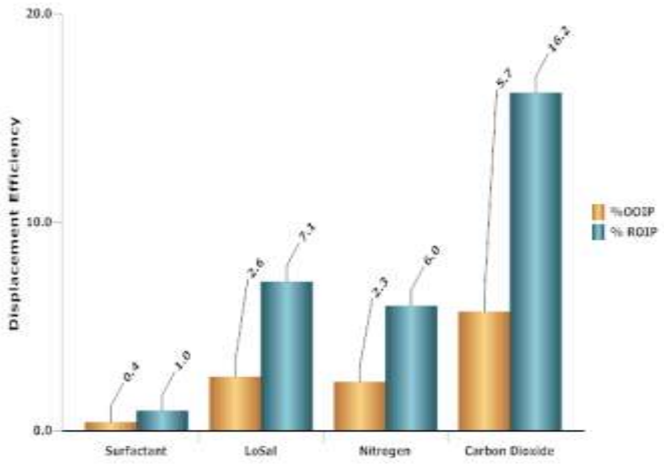

Figure 5.5 Displacement efficiency of selected *alternatives.*

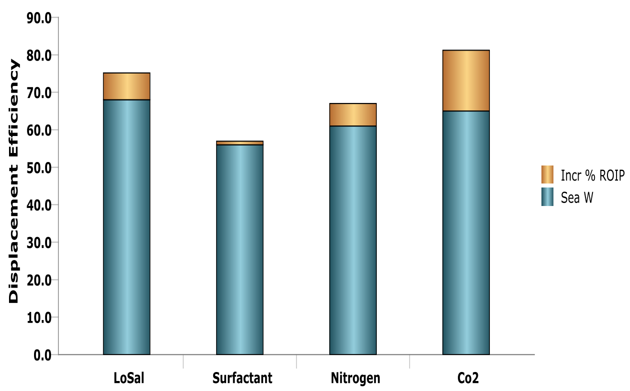

Figure 5.6 Displacement efficiency sea water & different alternatives

carbon dioxide flooding, nitrogen flooding in a tertiary mode. All cores having similar of very low permeability on the average of 0.35 md. All cores were flooded initially with sea water to residual oil saturation then followed by different alternatives. Tertiary carbon dioxide and low salinity flooding produced displacement efficiencies16.22% and 7.14% respectively. Figure 11 presents the displacement efficiencies of sea water and different enhanced oil recovery alternatives. Results clearly indicated that supercritical carbon dioxide flooding is the most technically suitable technique for carbonate tight oil reservoirs followed by low salinity flooding (5000 ppm dilution of sea water).

III. CONCLUSIONS

Design process for the evaluation of a new enhanced oil recovery of low permeability oil reservoir is presented in this project. Results indicated that carbon dioxide flooding is the optimum system and low salinity showed great improvement in the displacement efficiency compared to sea water injection. Surfactant flooding exhibited poor improvement in the sweep efficiency compared to other alternatives

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