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Which Type of Water Injection is Able to Give a Higher Oil Recovery Factor "Formation Water or Sea Water"?

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Abstract—**Produced water from carbonate reservoir can be reinjected into the formation to stimulate hydrocarbon production in aging wells. This is known as water injection or water flooding. This is the most economically friendly method of produced water disposal. In this paper, a laboratory approach to compare and evaluate the efficiency of formation and sea water injection for enhancing oil recovery at room condition in carbonate reservoirs. The main objective of this paper to achieve the maximum oil recovery for the limestone rock by using formation and sea water. This study was conducted using several samples of limestone rock saturated with oil by placing them in the reservoir conditions by placing them in a vacuum oven to ensure complete saturation of the samples with oil and then extracting the oil from them using liquid permeability where the samples are injected by formation and sea water. The oil recovery by formation water injection is range from 26.4 % to 47 %. The oil recovery by sea water injection is range from 0.00 % to 10 %. The oil recovery factor for formation water injection is higher than the oil recovery factor for sea water injection.**

Keywords— Oil Recovery, Formation Water, Sea Water, Porosity, Permeability, Limestone Rock

I. INTRODUCTION

A significant proportion of the world's oil reserves are found in carbonate reservoirs. Many of these are located in the Middle East, Libya, Russia, Kazakhstan, and North America. Many researchers have focused on the impact of injecting brine chemistry for more oil recovery from depleted oil reservoirs. Injection of sea water with a correct composition can act as an effective enhanced recovery method. Nengkoda et al, 2010 conducted by injecting hot sea water where composition is near to Indonesian sea water characteristics with different temperatures and rates. Their result find that the gas production rate increases with time until reach maximum, and then it begins to decrease. The combination of hot water and flue gas injection has a substantial potential for increasing the recovery from light-oil reservoirs, Fossum et al 1992. The sea water used in the capillary pressure test modified the wettability of the carbonate system, changing the wettability of the rock to a more water wet state. This was indicated by comparing the saturation change in the spontaneous imbibition phase of the test between simulated formation and sea waters, Webb et al 2005. The oil recovery increased by 30% after sea waterflooding when we used 5 wt% of Na4EDTA chelating agent diluted from initial concentration of 40 wt% using sea water. The recovery increase can be attributed to the change in the rock surface charge, rock dissolution, IFT reduction mechanisms, Attia and Mahmoud, 2015. The impact of seawater on oil recovery in sandstone is higher than carbonate. At higher temperature, the oil recovery is more moderate than low temperature. Likewise, as the aging time increase for both sandstone and carbonate rocks the oil recovery increase, Naser, et al, 2018. The Gaberoun Water Leak Injection has caused the increasing of oil recovery in sandstone and carbonate core. The impact of GWLI on oil recovery in sandstone core samples was higher than carbonate core samples, Naser, et al, 2019. Carbonate rocks, sandstone rocks obtained from a Libyan oil reservoir, high salinity water, sea water, low salinity water, and water contains different sulfate concentrations were employed in this study. The results of this research will shed more light on the mechanism of modified salinity flooding (MSFTM) and will help operating companies to better plan water flooding process, Zekri, et al, 2011. Re-injected produced water into sandstone reservoir at the initial stage is to maintain reservoir pressure, replace produced oil, and provide for the recovery of oil by water displacement, Madi 2018. The objective of this paper to achieve the maximum oil recovery for the limestone rock by using formation and sea water.

II. EXPERIMENTAL MATERIALS

- Core Samples: It is a chemical sedimentary rock composed of calcium carbonate and has a light color as shown in the figure 1.
- Oil Sample: Oil sample comes from Zelten oil field (now known as the Nasser field) is located at the foot of the Zelten Mountains, about 169 kilometres (105 mi) south of Brega in Concession 6. Zelten holds the title as the largest oil field in the Gulf of Sidra. The 229 wells in Zelten use a gas lifting system. The Zelten oil field is not associated with the town Zelten, which is located in the North-West of Libya.
- Formation Water: also, comes from Zelten Oil Field.
- Sea Water: sea water comes from Misurata Sea.

Fig. 1. Limestone Sample

III. EXPERIMENTAL EQUIPMENT

- Plugging Machine: Figure 2 shows plugging machine diamond tooled drill press is to drill Limestone samples. It comes with a floor standing drill press, a rotary union, a coolant feeding system, a coolant recovery pan with splash guard and a core clamping vise. The union permits to connect the coring bit to the drill press and feed coolant to the coring bit.
- Trimming Saw: Figure 3 shows the trimming saw to cut and edge sanding preset core sample lengths. The preset sample lengths can be adjusted at any time by rearranging machined spacers to the desired length between the blades.
- Manual Saturator: Figure 4 shows the manual saturator use to obtain remarkable saturation of cleaned and dry core samples by simple process. The measurement of porosity (connected pore space) by the liquid saturation method involves the gravimetric determination of pore volume by obtaining: the weight of the core sample clean and dry, the weight of the sample saturated with a liquid of known density, and the weight of the saturated sample submerged in the same liquid.
- Liquid Permeameter: Figure 5 shows the Liquid Perm is an instrument dedicated for routine core analysis. The pressure control regulator is used to adjust gas pressure up to 100 psi in a vessel initially filled water (brine). The gas pressure transfers water into the sample at constant pressure. The flow rate exiting the core sample is determined by measuring the time to fill a graduated flask. After reporting the sample diameter and length, the flow measured and the upstream pressure in a template XLS file, the liquid permeability is calculated from Darcy's law.

Fig. 2. Plugging Machine

Fig. 3. Trimming Saw

Fig. 4. Manual Saturator

Fig. 5. Liquid Permeameter

IV. **METHODOLOGY**

The case study approach has been chosen to investigate the efficiency of formation and sea water injection for enhancing oil recovery at room condition in carbonate reservoirs. The sampling procedure is described, followed by the means of data collection. Methods of data analysis and the limitations of the research are discussed. Finally, figure 6 shows the framework for this research is introduced and as follows:

- **Formation Water and Oil Analysis:**
  - a) Formation Water Density Measurement
  - b) Formation Water PH measurement
  - c) Formation Water Viscosity Measurement
  - d) Oil Density Measurement
  - e) Oil Specific Gravity Measurement
  - f) Oil API Gravity Measurement
  - g) Oil Viscosity Measurement
- **Core Preparation**
  - a) Core Cutting
  - b) Core Trimming
  - c) Core Cleaning
  - d) Core Drying
  - e) Core Water Saturation:

- Stage 1 Vacuum: The water used to saturate the core sample is filtered. Fill the jar with the water no more than half height to avoid damaging the vacuum pump. Start the vacuum pump for one hour as shown in the figure 7. If saturate water does not show important ebullition from the 1st minute of evacuation, check that the corks of the moisture trap and liquid tank are correctly inserted.

- Stage 2 Fill: Valve status remains unchanged. Stop the vacuum pump. Disconnect the vacuum pump hose from the tank to break the vacuum. The desaturated water is drawn into the evacuated vessel containing the core samples. The cores are allowed to saturate. Wait until water has been transferred to the cell as shown in the figure 8.

- Stage 3 Pressure: Switch the valve HV01 closed. Operate the hand pump to pressurize the liquid surrounding the sample to 2,000 psi. Pressure build-up requires that a few ml of saturating fluid is transferred. Thus, about 20 stokes are required to raise pressure as shown in the figure 9.

- Stage 4 Vent and Empty: Once the pressure has being applied during required time pressure from the tank and the samples. Extra water is suddenly expelled from pressure vessel to liquid tank. Once the pressure is back to atmospheric value, open by hand the vessel lid and remove the basket with cores.

- Step 5 Weighting Saturated Samples: Weight the cores saturated to determine the pore volume.

f) Core Analysis:

- Porosity Measurement:

The measurement of porosity by complete the core saturation methods involves the gravimetric determination of:

1. Pore volume by obtaining: the weight of the core sample clean and dry, the weight of the sample saturated with a water density, and the weight of the saturated sample submerged in the same water.
2. Bulk volume by obtaining the caliper measurements.

g) Liquid Permeability Measurement:

The framework for this step is introduced as follows:

1. Connect to main supply and power up the instrument at main switch on the rear panel as shown in the figure 10.
2. The pressure transducers require a “warm up” period of about one hour before use.
3. Switch the source valve on / off to off position. Ensure that regulators are fully turned anticlockwise initially.
4. Connect two regulated nitrogen supply to the appropriate ports on the rear of the instrument.
5. Load the core holder. Regulate confining pressure supply to desired value without exceeding 400 psi. Regulate core nitrogen supply without exceeding 100 psi.
6. Turn confining valve pressure / vent to pressure. Gas at desired pressure is now applied to the core holder sleeve. This pressure is now displayed on confining pressure gauge.
7. Ensure that regulators are fully turned anticlockwise initially.
8. Install a beaker the outlet of the core holder.

9. Switch source valve on / off to on. Slowly increase regulator to obtain desired liquid flow or test pressure.
10. Let the flow stabilize, then place the graduated flask at the outlet of the core and start the stopwatch. Stop the watch as soon as the water level reaches the graduation.

h) Core Oil Saturation:

Samples were saturated with crude oil by placing them in a container containing crude oil and then placing this container in the oven. It set the temperature to 70 ℃ as shown in the figure 10.

- **Core Flooding:**

Repeat the permeability measurement framework with formation and sea water injection. Figure 12 shows the beakers filled with oil production sample after sea water injection. Figure 13 shows the core sample after sea water injection.

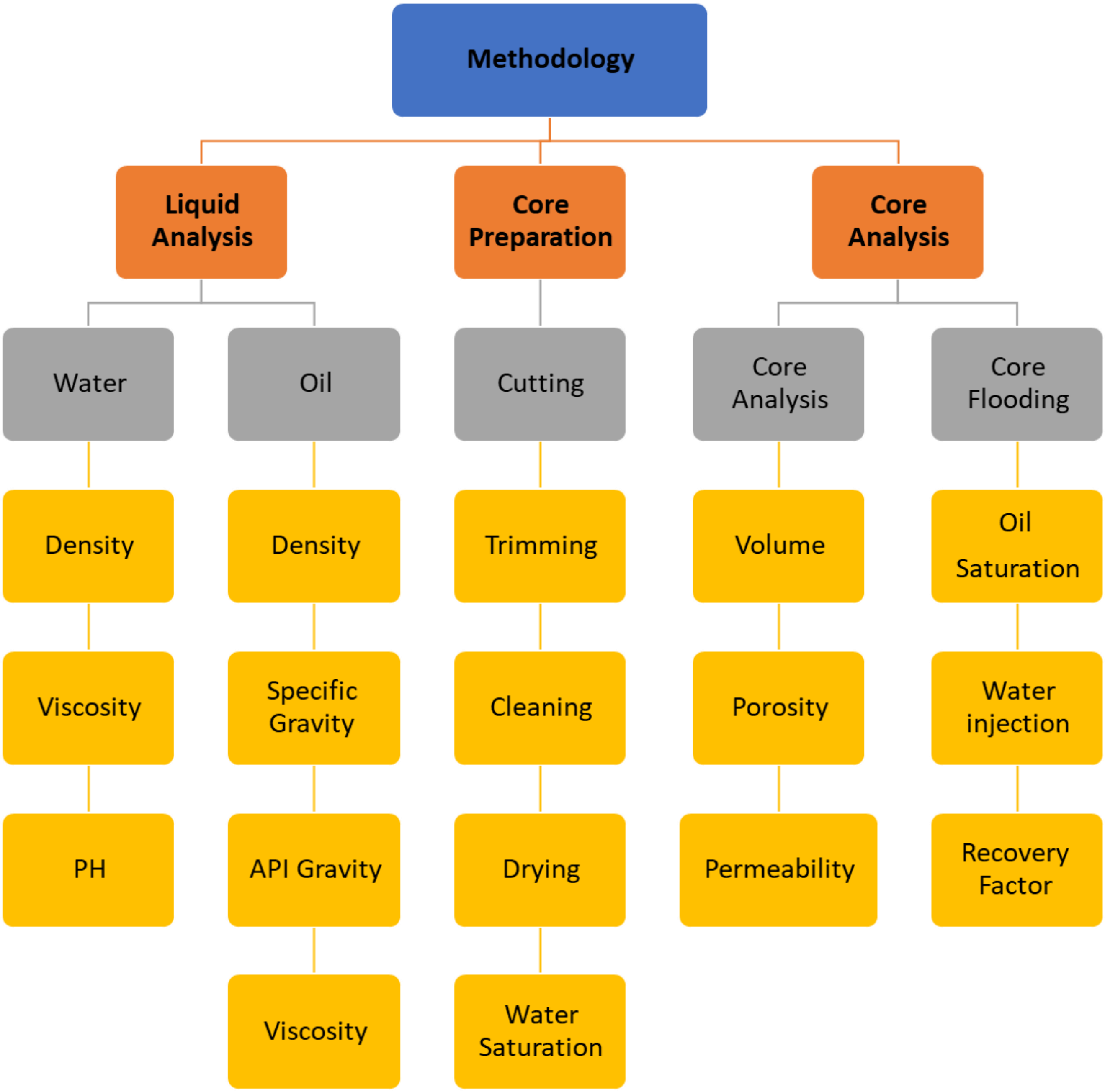

Fig. 6. Methodology

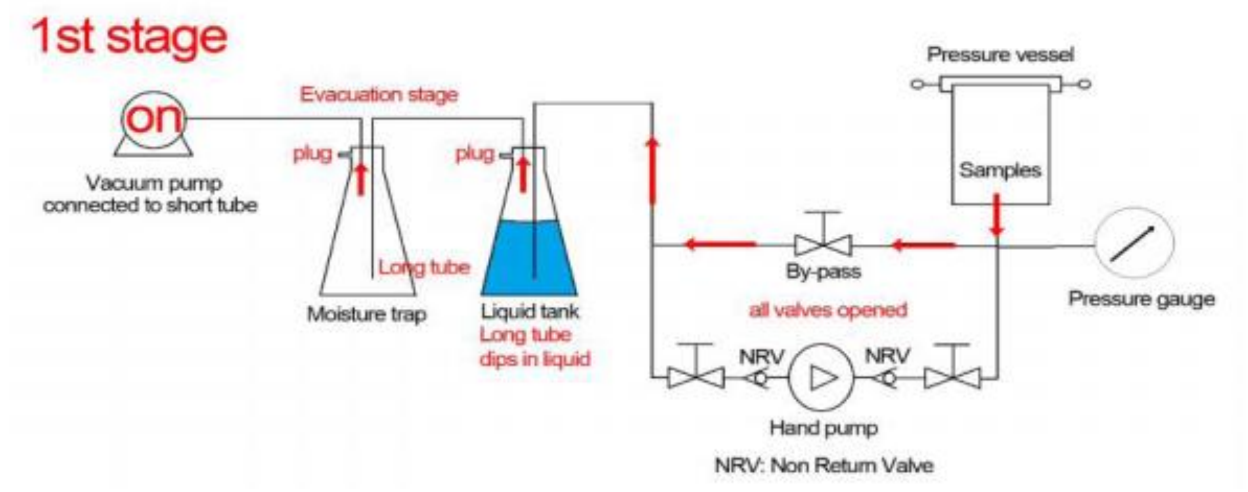

Fig. 7. Stage 1 Vacuum

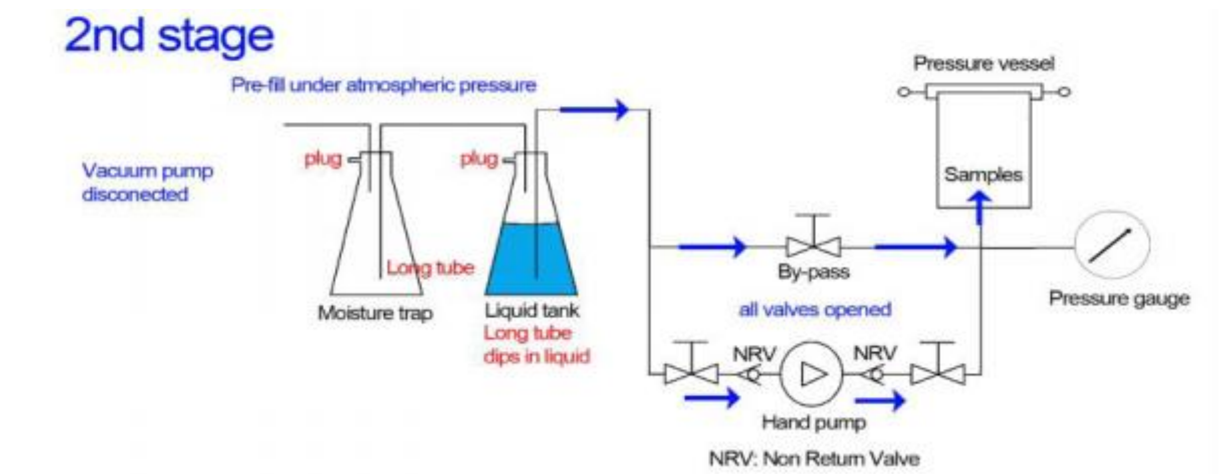

Fig. 8. Stage 2 Fill

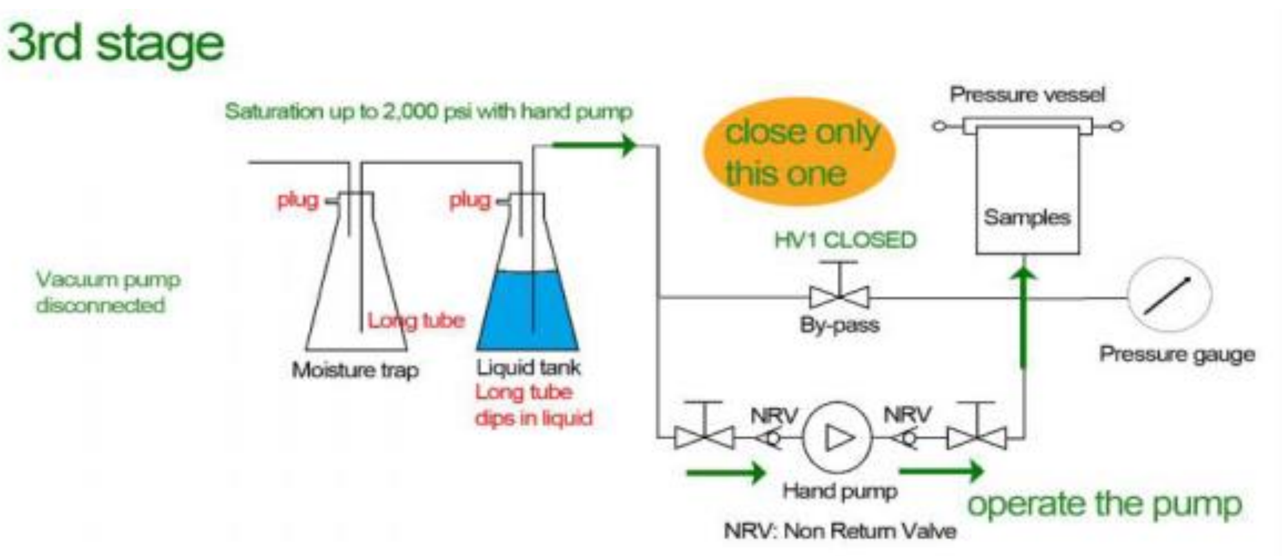

Fig. 9. Stage 3 Pressure

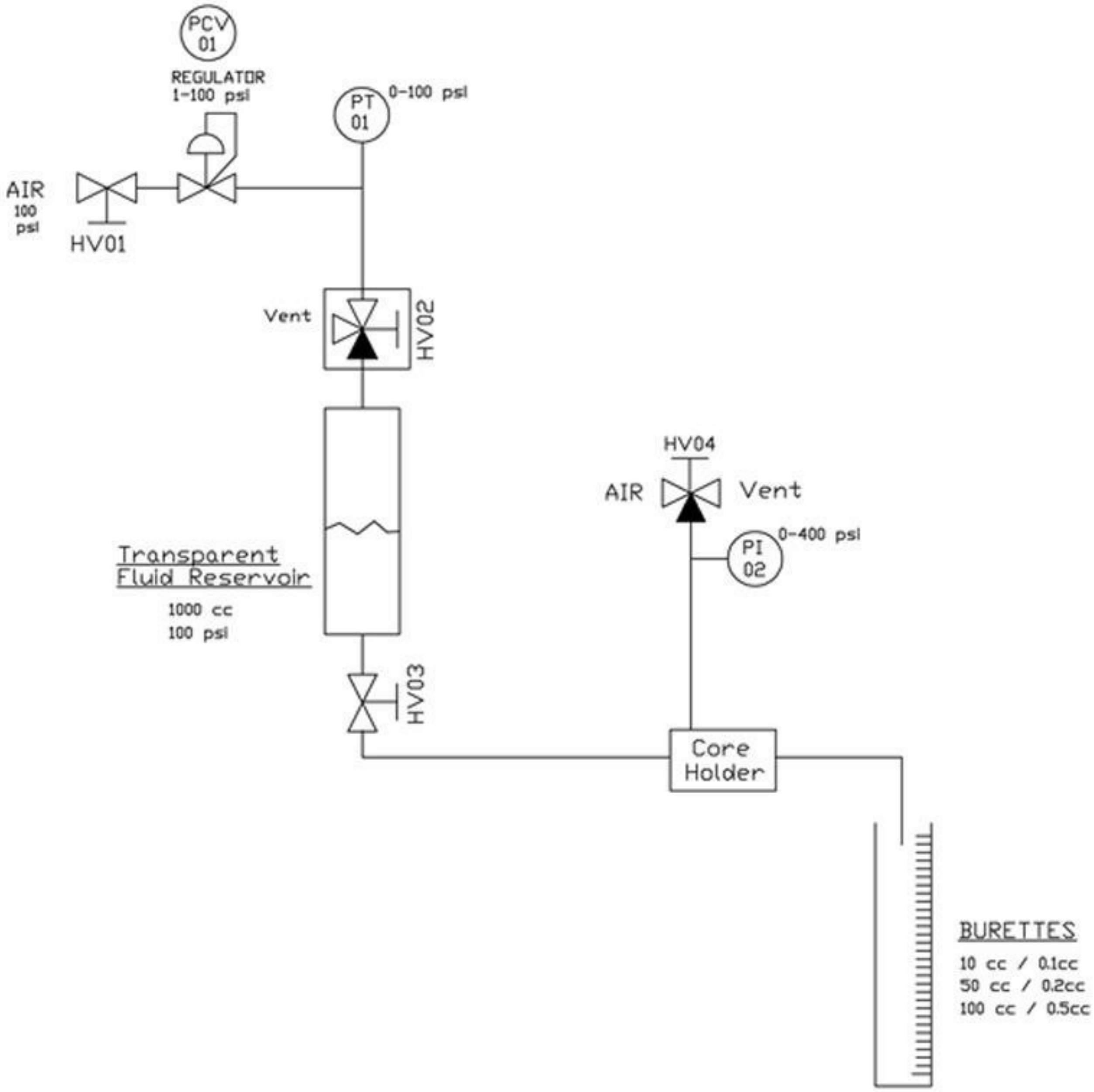

Fig. 10. Flow Diagram

Fig. 11. Saturated Sample with Crude Oil

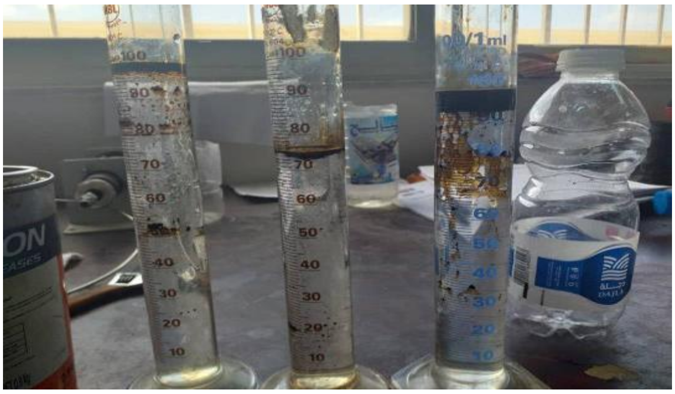

Fig. 12. Beakers Filled with Oil Production

Fig. 13. Core Sample After Sea Water Injection

V. EXPERIMENTAL RESULTS:

Water Analysis Result: Table 1 shows the density, viscosity, and pH results for formation water and sea water.

TABLE 1: WATER PROPERTIES RESULTS

Property	Density (g/cc)	Viscosity (cp)	pH
Formation Water	0.9938	0.8994	8.04
Sea Water	0.944	0.669	7.568

Oil Analysis Result: Table 2 shows the specific gravity, API gravity, API Degree, viscosity, and oil density result.

TABLE 2: OIL PROPERTIES RESULTS

Property	Specific gravity	API gravity	API Degree	Viscosity (cp)	Density (g/cc)
Crude oil	0.81	40.223°	Light oil	4.05	0.81

Core Analysis Result: Table 3 shows the length, diameter, bulk volume, pore volume, grain volume, and porosity. Figure 13 shows Porosity for each core sample.

TABLE 3: CORE PROPERTIES RESULTS

Sample name	Length (cm)	Diameter (cm)	Bulk volume (cc)	Dry weight (g)	After Saturation (g)	Pore volume (cc)	Grain volume (cc)	Porosity (%)
101	6.44	3.81	73.037	118.257	122.610	4.353	68.684	5.96
102	5.24	3.81	59.428	98.334	99.200	0.866	58.562	1.46
103	4.7	3.81	53.303	86.588	89.012	2.424	50.879	4.55
104	3.7	3.81	41.962	68.185	69.071	0.886	41.076	2.11
105	3.8	3.81	43.096	75.743	77.317	1.574	41.522	3.65
106	4.4	3.81	49.901	84.247	85.193	0.946	48.955	1.90
107	5.09	3.81	57.726	95.672	98.682	3.010	54.716	5.21
108	4.9	3.81	55.572	85.218	87.759	2.541	53.031	4.57
109	4.6	3.81	52.169	85.554	88.535	2.981	49.188	5.71
110	6	3.81	68.047	108.572	112.223	3.651	64.396	5.37
111	4.7	3.81	53.303	87.628	89.731	2.103	51.200	3.95
112	5.7	3.81	64.645	103.106	108.683	5.577	59.068	8.63
113	4.5	3.81	51.035	85.711	88.760	3.049	47986.000	5.97
114	5.5	3.81	62.376	100.929	102.945	2.016	60.360	3.23

Fig. 14. Porosity for Each Core Sample

Permeability Result: Table 4 and figure 14 shows the results of the liquid permeability apparatus for measuring the permeability of limestone core samples.

TABLE 4 PERMEABILITY RESULTS

Sample name	K (D)
101	6.818
102	4.66
103	6.867
104	5.079
105	5.420
106	3.662
107	5.120
108	6.705

109	6.705
110	6.887
111	5.680
112	6.026
113	6.138
114	4.498

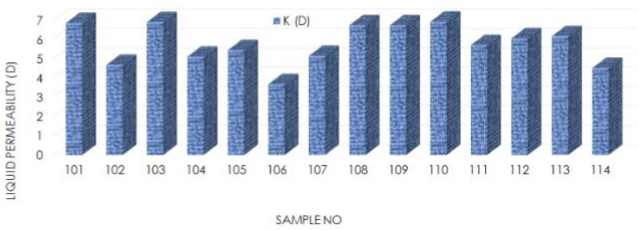

Fig. 15. Permeability for Each Core Sample

Recovery Factors from Formation Water Injection Results: Table 5 and figure 15 shows the results of the recovery factor for formation water injection.

TABLE 5 RECOVERY FACTOR RESULTS

Core number	Recovery Factor (sea water injection)	Recovery Factor (formation water injection)	Total Recovery Factor
101	0.999	47.969	48.968
102	5.162	41.292	46.454
103	5.048	30.29	35.338
104	1.671	40.096	41.767
105	0	41.62	41.62
106	1.577	31.532	33.109
107	1.272	50.87	52.142
108	5.551	44.411	49.962
109	10.565	26.412	36.977
110	2.085	41.695	43.78
111	1.279	46.058	47.337
112	1.04	49.902	50.942
113	0	44.028	44.028

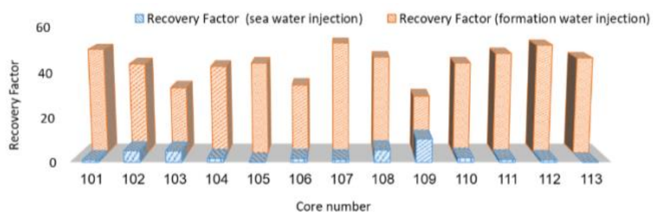

Fig. 16. Recovery Factor Results

V. CONCLUSION

We present a laboratory approach to evaluate the efficiency of formation and sea water injection for enhancing oil recovery at room condition in carbonate reservoirs. In this study, we concluded some conclusion as shown below:

1. The core sample are used in this study are limestone.
2. The formation water viscosity is 0.8994 cp, the viscosity of the sea water is 0.669 cp, and the viscosity of the oil is 4.05 cp.
3. The formation water density is 0.9938 g/cc, the density of the sea water is 0.994 g/cc, and the density of the oil is 0.810 g/cc.
4. The formation water potential of hydrogen is 7.568, the potential of hydrogen of the sea water is 8.040.
5. The core porosity is range from 3.3 % to 6.8 % with average porosity is 4.4 %.
6. The core permeability measurement is range from 3 Darcy to 6.8 Darcy with the average is 5.7 Darcy.
7. The aging time for oil saturation is for three weeks, with the original oil in place is range from 14.4 to 25.016 ml.
8. The oil recovery by formation water injection is range from 26.4 % to 47 %.
9. The oil recovery by sea water injection is range from 0.00 % to 10 %.
10. The oil recovery factor for formation water injection is higher than the oil recovery factor for sea water injection.

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