



Tertiary matrix liberation of bypassed hydrocarbons in core sample pore throat restriction caused by fine particle's accumulation after water flooding

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Abstract

Hydrocarbon's reservoir management is important, so as to maximize its deliveries. An important reservoir managerial approach is pressure maintenance, of which water flooding is significant, because of its universal availability and avoid ability. Despite the numerous advantages of water flooding, its capability to mobilize, suspend, transport, and redeposit's fine sand particles near a producing wellbore is problematic. This problem often led to pressure losses, thereby causing production losses. To solve this problem, core sample with a dimension of 0.12 ft by 0.25 ft made from silicate sand grain of 215-micron aggregates were bonded with Portland cement, at a ratio of 75% to 25%, to represent a formation core. The core samples were oven dried to removes gaseous and other suspended particles. Then, respectively saturated with 1.08 cp brine and 58.02 cp crude oil. The samples were serially loaded into core holder for flooding. The result showed that, after water flooding of cores samples, A, B, C, and D under laboratory conditions, the residual oil saturations, S_{or1} , were respectively 39.94%, 39.61%, 32.49%, and 31.52%. These percentages showed that significant amounts of hydrocarbons were still trapped in the core samples after water flooding. Efforts to recover more of S_{or1} lead to the use of chemical flooding, a member of enhanced oil recovery. Bottles that were labeled samples A, B, C, and D contained different blends of mud acids with different concentrations. At the end of chemical flooding; the solution blend in bottle samples A, B, C, and D respectively recovered 41.462, 44.408, 35.242, and 39.499 from S_{or1} .

Keywords: Flooding, recoveries, mud acid, production losses, water flooding, particles mobilization.

Introduction

Fine particles scrapped from parent rocks during water flooding or water injection, mobilization, suspension, transportation, and redeposit ion of such particles in the reservoir is the major cause of reduced recovery factor, rf. Certain blends of acids have been found useful in neutralizing the effects of consolidated fine particles. Success stories of acidizing have been reported in Netherlands, Saudi Arabia, North America, South America and Far East as shown in Table-1. Acidizing is a tertiary oil recovery method. Despite the cheering news of recorded success stories, incorrect field procedures of acidizing project, is a major reason that could cause acidizing project failure¹. The USSR bloc is leading in acidizing project, with chemical injection, at associated daily hydrocarbon production of 50,000 barrels, with two distance runners up from Canadian oilfield of 17,200 barrels of oil per day, and 11,900 barrels of oil per day from United States of America, as shown in Table-1.

Tertiary oil recovery is majorly made up of chemical, thermal, and miscible injectants. All these methods involve injection of fluid into the reservoir, with various degrees of acceptability and applications around the world. Countries that have adopted and practice tertiary oil recovery methods are Canada, United States of America, European Countries, Venezuela, Russian (and members of defunct Union of Soviet Socialist Republic bloc).

The United State of America is leading, with 42%, the pack of all the countries that have adopted the use of enhanced oil recovery, followed by Canada and USSR with 10% each, as shown in Table-1. Algeria, Libya, and Indonesia are also in the league.

Secondary Oil Recovery: Water flooding: The infinite availability, low treatment cost and access to water make it the cheapest source of flooding. It has an average estimated operational cost of less than \$10 per barrel. And virtually, all the reservoirs in the world undergo water flooding at a certain stage of its live cycle. Fine particles mobilization, formation of emulsions, bubbles, and other complex bye products set limitations for water flooding. These limitations will promote poor sweep efficiency, leading to large volume of bypassed crude oil in the reservoir². Capillary forces are another force that could render oil immobile, even after being contacted by water³.

Monitoring, understanding, and mastering of changes that take place during water injection or flooding is crucial to the success of water flooding operations². This aspect is very crucial because chemical and physical properties of produced crude oil changes with time, as well as declining oil production rates. To recover some of the bypassed oil after water flooding, many techniques have been tried, first as a pilot study, then on a field application. All the enhanced oil recovery techniques revolve

around the following mechanisms for improvement; reduction of interfacial tension, increased displacing fluid viscosity, etc. Water flooding, with different salinities, is widely accepted because⁴. i. For reservoirs with existing water injection facilities, near zero capital expenditure and economical marginal operation cost, ii. In comparison with gas injection, water is easier and safer to inject, iii. High incremental oil recoveries, iv. Avoidance of reservoir souring, and reduction in the amount of scaling and corrosion.

Formation damage after secondary oil recovery: water flooding: Formation damage is an impairment of in situ reservoir conditions through an introduction of foreign materials or displacement of in situ materials. It is a combination of so many factors that impeded the flow of reservoir fluid. The extent of damages could determine through injectivity and productivity indexes, as well as oil production rate. Figure-1 displays the forms of possible damages⁵.

Waters from the sea, rivers, ocean passes through certain stages of purification treatments for conditioning before injection into the reservoir. Some of the desired treatment included solid particles removal, microbial removal and its growth preventions. The use of 30 g of salt per liter of water is a way of preparing low salinity brine for flooding purpose. The common problems associated with low salinity water flooding are; clay swelling, fine particles migration/deposition, detachment and straining. The fine particles in a reservoir are at mechanical equilibrium, the introduction and arrival of low salinity fluid weakens the electrostatic forces holding the grain together and

thereby set grain into a motion of disequilibrium, and into disaggregation. Disaggregated fine particles could carry as suspension, and re-deposited elsewhere. Accumulation of this deposit will lead to pore throat reduction, flow restrictions, and with time, it could lead to outright blockage of pore throat passages⁵.

To reduce undesirable consequences of fines migration, a number of mitigations techniques have been developed⁶, this includes the use of acid system to remove the fines deposited near wellbore region (matrix and fracture), gravel pack, sand control screening, hydraulic fracturing. The choice of whether to fracture or matrix acidize, depends on formation geology, production history, and well intervention objectives, shown in Figure-2.

Tertiary Oil Recovery: Chemical method: Tertiary oil recovery is majorly made up of chemical, thermal, and miscible injectants into the reservoir, with various degrees of acceptability and applications around the world. Popular chemical injected for enhancing oil recoveries are polymers (mostly done with water flooding, from 100 up to 1000 ppm concentrations), surfactants, alkalis, and acids. These four are the major approaches, under chemical flooding, although there are other additives. Microbial growth, salinity intolerance, and high cost are the major problems that limit the applicability of polymer injection. The principle behind chemical flooding is shown in Figure-3.

Table-1: An average daily worldwide Oil Production through EOR (000 barrels per day)³.

Country	Thermal	Miscible	Chemical	EOR Total	%
USA	454	191	11.9	656.9	42
Canada	8	127	17.2	152.2	10
Europe	14	3	—	17.0	1
Venezuela	108	11	—	119.0	7
Other S. American	2	NA	NA	17.0	1
USSR	20	90	50.0	160.0	10
Other (estimated)	171*	280**	1.5	452.5	29
Total	777	702	80.6	1574.6	100

*Mainly Durifield (Indonesia). **Mainly Hassi-Messaoud (Algeria) and Intisar (Libya).

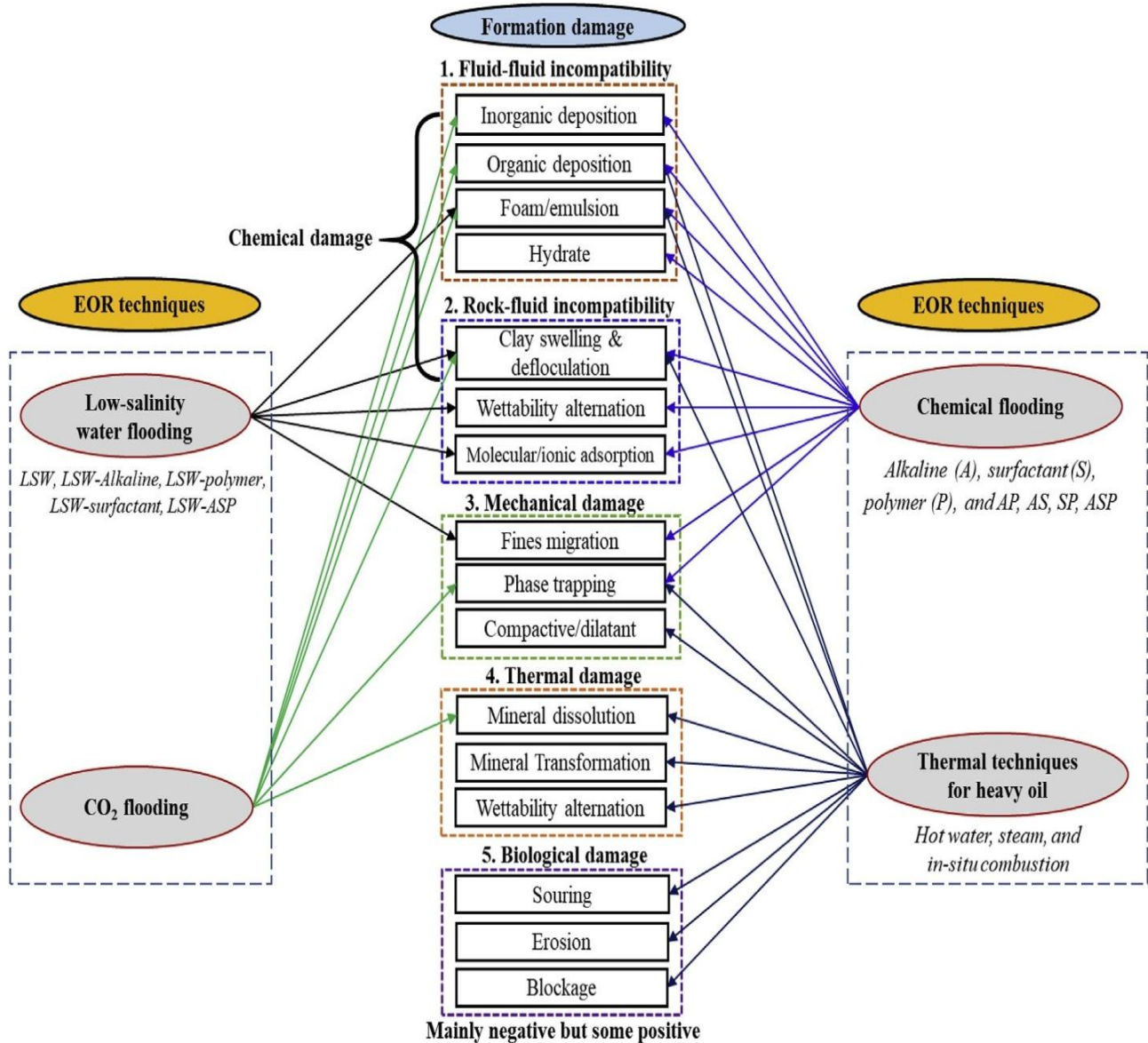


Figure-1: The potential formation damage mechanisms⁵.

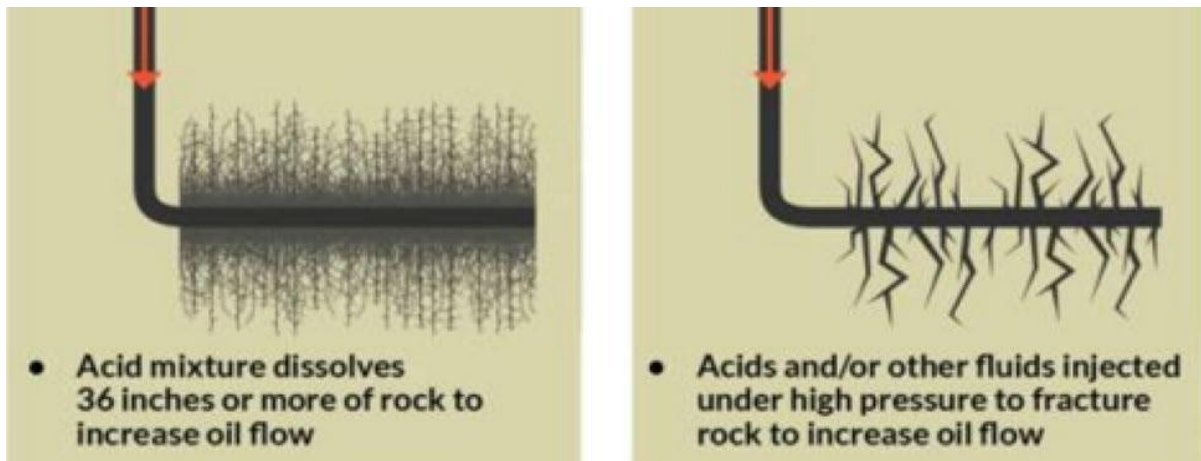


Figure-2: Difference between fracturing and matrix⁷.

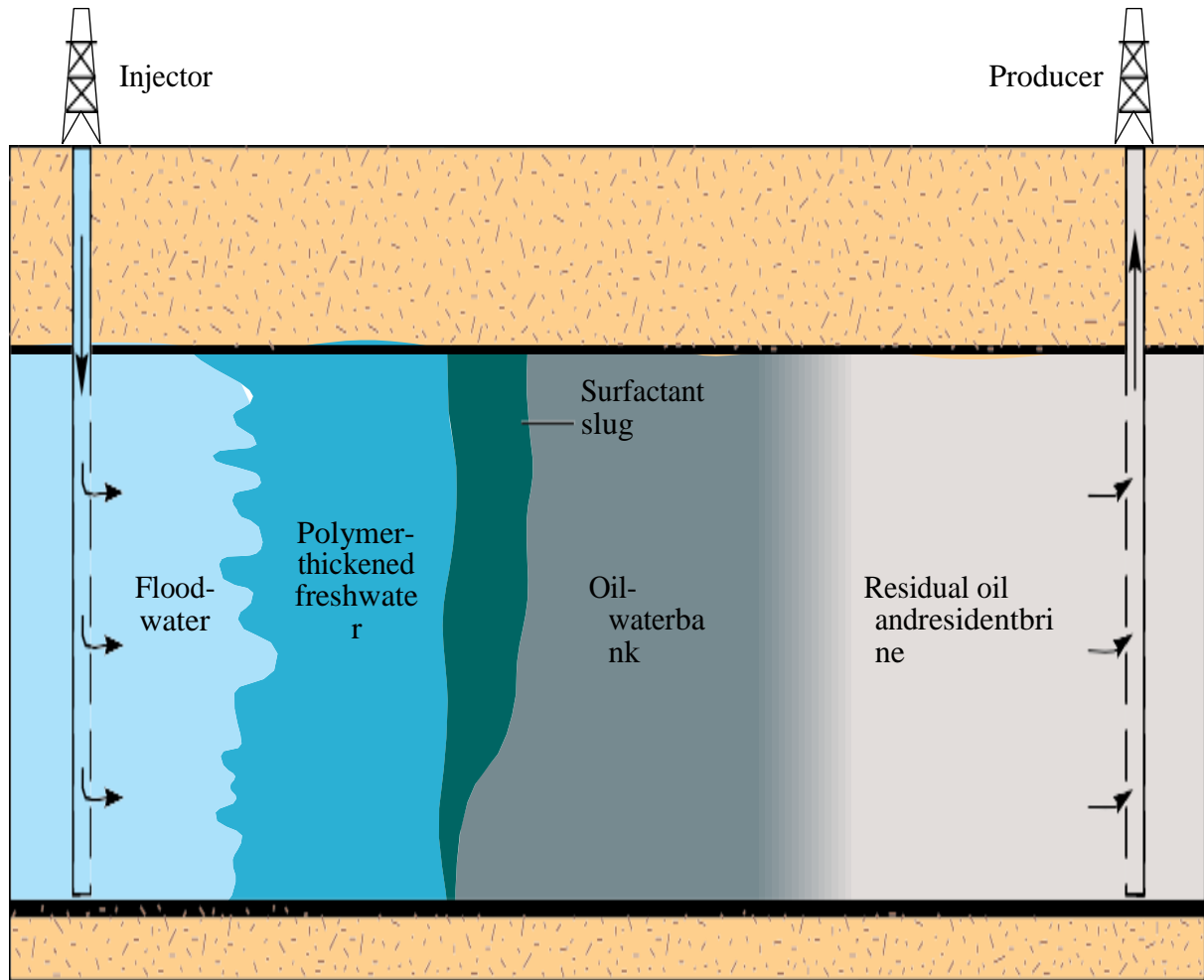


Figure-3: Chemical flooding process³.

The use of acids with low rates of reactions with fines and dissolvable particles, will penetrate deeper into the formation. HBF_4 , flouboric acid is a prominent member of acids that are effective with long low-rate span of reaction⁷. Reservoir complexities such as temperature, salinity, and fluid compositions determine the limitations of these acids. In view of the shortcoming of the mud acid at high temperatures, HBF_4 is foreseen as a better selection among other types of acid. It is expected to not only improve the porosity and permeability, but also eliminate the previously existing problems as it is less corrosive, stable and allowing deeper penetration due to slow hydrolysis rate⁷. Chemical oil recovery method is advisably employed after thermal and miscible floods. Surfactant's flooding is also known as detergent, micellar – polymer or microemulsion flooding. It reduces interfacial tensions between oil and water. Just like other process, surfactants flooding design is reservoir specifics. Alkali injections are done to react with organic compound in the crude oil and form surfactants on the reservoir sand.

Mineralogy of damaged/impaired core sample: Sandstone, also known as arenite, is a form of clastic sedimentary rock. It is

made up of predominantly silica, and many other silicate minerals, as shown in Table-2.

Table-2: Mineralogy of a typical Berea Sandstone^{10,11}.

Mineral	Concentration (wt%)	Chemical formulae
Quartz	75	SiO_2
Feldspar	5	$\text{K}_{0.5}\text{Na}_{0.5}\text{AlSi}_3\text{O}_8$
Dolomite	5	$\text{CaMg}(\text{CO}_3)_2$
Siderite	5	FeCO_3
Chlorite	5	$\text{Mg}_6\text{Si}_4\text{O}_{10}(\text{OH})_8$
Mica/illite	5	$\text{KAl}_3\text{Si}_3\text{O}_{10}(\text{OH})_2$

Zeolite may also be present in a sandstone, although it is rare⁸. The Table-3 is an illustration of minerals that could and could not dissolve in mud acid⁹.

Table-3: Solubility of sandstone minerals in mud acid⁹.

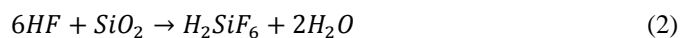
Minerals	Solubility	
	HCl	HCL–HF
Quartz	No	Very low
Feldspar	No	Low to moderate
Mica	No	Low to moderate
Kaolinite	No	High
Illite	No	High
Smectite	No	High
Chlorite	Low to moderate	High
Calcite	High	High, but CaF ₂ precipitation
Dolomite	High	High
Ankerite	High	High
Siderite	High	High

Reactions of mud acids with Quartz: Quartz, a form of silicate is the predominant component of sandstone formation, from Table-2. And it is soluble in hydrochloric acid, but soluble in a blend of hydrochloric and hydrofluoric acids. Silicon dioxide or silica or silicate materials are the most abundant component part on the earth surface. About 75% of the crust were made up of quartz. It reacts with mud acid as shown with chemical reaction equations, according to⁶;

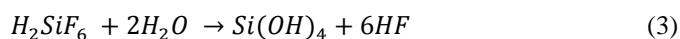


SiF₄ is a reactive gas particle that can lead to production of other complex compounds.

Addition of higher concentrations of hydrofluoric acid, HF, lead to the production toxic silicon species, H₂SiF₆.



H₂SiF₆ act as a catalyst for regeneration of HF, at low concentrations to precipitate silica.



The main reactant in the mud acid was HF, which is responsible for surface particles dissociation and HCl is responsible for particles dissolution.

Methodology

The materials, equipment, and procedures used in this study were as follow;

Core sample preparation: Core sample with 0.0762 m, 0.25 ft, length and a diameter of 0.038 m, 0.124671916 ft was produced. The core sample in figure shown as Figure-4, was produced from sandstone washed grains. The core samples were oven dried to remove trapped gaseous particles and liquid, at constant temperature of 80⁰C for 30 minutes. Cautions were taken to prevent cement bond break that might occur due to overheating.



Figure-4: Core samples produced from sandstone.

Major component of core flood equipment were vacuum pump, measurement system, core holder, Climatic Air Bath, Stainless Steel Accumulator, backpressure regulators/valves, Wet Rotary Gasometer, a computer system, and Separator. Figure-5 is a pictorial illustration of core flooding equipment pathway.

Core sample properties and acid solutions concentrations:

The silicate sample used in making core samples were predominantly of quartz origin. The quartz was made into a grain aggregate of 215-micron mesh sizes. Table-4 contained the concentrations of acid solutions used in the study.

Table-4: Core sample compositions, dimension and Chemical formulation.

Bottle	Core Sample		Solution Concentration (%)
	Composition	Dimension (ft ²)	
A	75% Quatz, 25% Cement	0.12*0.25	12%HCl, 3%HF
B	75% Quatz, 25% Cement	0.12*0.25	24%HCl, 6%HF
C	75% Quatz, 25% Cement	0.12*0.25	36%HCl, 9 %HF
D	75% Quatz, 25% Cement	0.12*0.25	48%HCl, 12%HF

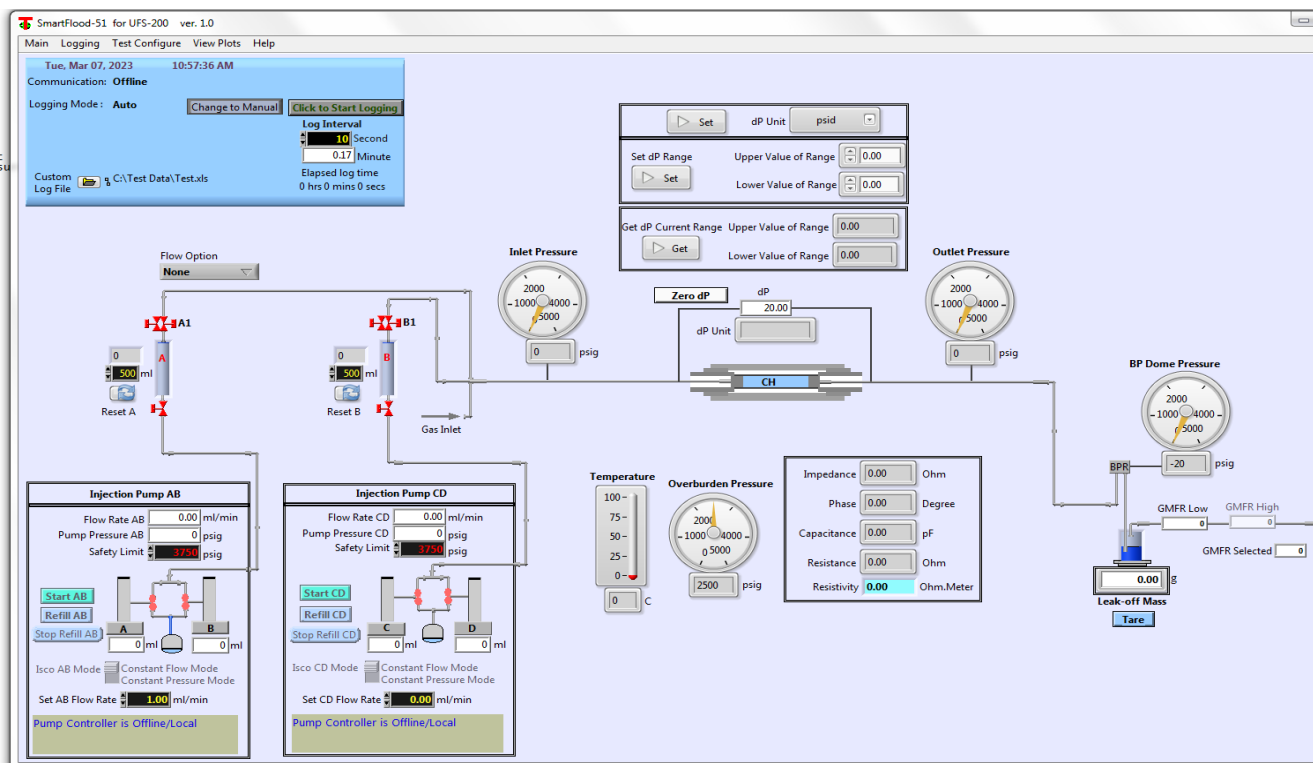


Figure-5: Schematic illustrations of digital software core flood control panel.

Experimental Procedures: Procedures for performing core flooding experiment were detailed below; i. The oven dried Core sample with dimension 0.0762m, 0.25ft, length and a diameter of 0.038m, 0.124671916 ft was placed in the core sleeve, the sleeve placed in a core holder, and all the interconnected flow lines connected. ii. The closed core holder was filled with brine, and then oil, through a syringe at confining pressure of 6.89 MPa. And injected fluid flow rate sets to 0.00006 m³/sec at 7.2 MPa pressure range, to overcome the confining pressure. The pressure differential across the core were measured with a transducer, with the inlet and outlet lines remaining open. Flow lines were not leaking under pressure differential. iii. A mixture of oil and injected water were collected in a graduated measuring cylinder, through to steady state condition, at constant injection rate of 60cm³/hr. The oil and water collected were separated under gravity. iv. At flood out, residual oil saturation was estimated with respect to volume recovered and volume injected. At this stage, chemical flooding started. v. Solutions of chemical purposely formulated for this stage commenced, and procedures i–iv, repeated. vi. A second stage residual oil saturation is calculated with material balance, through differential of injected and produced volumes. vii. Another round of water flooding was conducted, after flooding with acid solutions. viii. Pump was shut off, and all valves closed until zero fluid flow, ix. After the completion of the core flooding, all the fittings were disconnected and the core was taken out. All the fittings and the parts of the core holder were rinsed with the distilled water and the core samples were placed in an oven at 80°C for 24 hours to dry.

Results and Discussion

⁷investigated and reported results from 12% HCl and 3% HF on Jauf 778 core sample flooding, with an improved reported permeability ratio, of final to initial, to be 22.9 for matrix acidizing. Core mineralogy, grain sizes and sizes distribution in Jauf 778 were distinctly different from another depositional environment, like Nigeria. From the fluid flow equation, with a linear relationship of flow rates to permeability; the higher the permeability values, the higher the flow rate, as shown in the equation 4¹²;

$$q = \frac{KA\Delta P}{\mu L} \quad (4)$$

The results obtained by⁷ implied that matrix acid acidizing is promising, and could be use for further studies.

Table-5: Properties of brine and crude sample used.

Fluid	Viscosity (cp)	Density (g/cm ³)	API gravity (°)
Brine	1.08	1.0185	35.65
Crude oil	58.0204	0.9684	24.93

Table-5 contained representative reservoir fluid sample used to saturate the core sample. The brine, made up of salt and water, was used to saturate the core sample, followed by the crude oil. The properties of brine and crude oil, respectively, were 1.0185 g/cm³ and 0.9684g/cm³. The fluid sample were collected from an oilfield in Niger Delta.

From Table-6, the core sample made from 215-micron aggregates was gummed by Portland cement. There were four core samples, labeled A, B, C, and D, made from the same silicate species. The entire four samples had an aggregate of 0.25 effective porosity, with approximately equal pore volume of 0.7 cm³.

Table-6: Porosity values of the core sample.

Core Sample	Bulk volume, *10 ⁻³ (cm ³)	Pore volume *10 ⁻³ (cm ³)	Porosity (%)
A	2.8	0.7	25
B	2.8	0.7	25
C	2.8	0.7	25
D	2.8	0.7	25

Table-7 composed of fluid saturations after water flooding. The water flooding was conducted after fluid saturation with data contained in Table-5. The initial water saturation, mostly brine, ranges from 22.92% for core sample A, to 38.95% for core sample D. Respectively, the initial saturations range from 77.08% for sample A to 61.05% for sample D. There is an inverse relationship between water and oil saturations. That is, the higher the oil saturations, the lower the water saturation relative to fully saturated rock samples with the two immiscible fluids. After water flooding, the estimated residual oil saturations, S_{or}, range from 37.14% for sample A and 29.53% for sample D.

Table-8 is the breakdown of oil recoveries after flood out. The flood out stage is when only water, without oil, is been produced. At this point, a new residual oil saturation, S_{or1}, is reached, indicating the highest possible saturations after the expirations of water flooding. By comparing the initial saturation at S_{or} and the final saturations at S_{or1}, recovery efficiencies from core samples A, B, C, and were obtained to be, respectively, 51.816%, 51.7101%, 51.743%, and 51.629%.

Table-7: Water and oil saturations after water flooding.

Sample	S _{wi} (%)	S _{oi} (%)	S _{or} (%)
A	22.92	77.08	37.14
B	23.4	76.6	36.99
C	37.21	62.79	30.3
D	38.95	61.05	29.53

From Table-9, samples A, A; B, B; C, C; and D, D represented samples and the chemical acid solutions blends of different proportions. Acid blends of different concentrations were used to achieve matrix acidizing as represented in Figure-2. Also, at the expiration or spent out time of acid formulations, a new residual oil saturation, S_{or2}, were reached. Similarly, y comparing the initial saturation at S_{or1} and the final saturations at S_{or2}, recovery efficiencies from core samples A, B, C, and were obtained to be, respectively, 41.462%, 44.408%, 35.242%, and 39.499%.

Table-8: Recovery efficiency after flood out.

Sample	S _{wi} (%)	S _{oi} (%)	S _{or} (%)	S _{or1} (%)	Recovery efficiency (%)
A	22.92	77.08	37.14	39.94	51.816
B	23.4	76.6	36.99	39.61	51.7101
C	37.21	62.79	30.3	32.49	51.743
D	38.95	61.05	29.53	31.52	51.629

Table-9: Recovery efficiency after chemical flooding.

Sample	S _{wi} (%)	S _{or1} (%)	S _{or2} (%)	Recovery efficiency (%)
A, A	22.92	39.94	16.56	41.462
B, B	23.4	39.61	17.59	44.408
C, C	37.21	32.49	11.45	35.242
D, D	38.95	31.52	12.45	39.499

Conclusion

After water flooding of cores samples, A, B, C, and D under laboratory conditions, the residual oil saturations, S_{or1} , were respectively 39.94%, 39.61%, 32.49%, and 31.52%. These percentages showed that significant amounts of hydrocarbons were still trapped in the core samples after water flooding. Efforts to recover more of S_{or1} lead to the use of chemical flooding, a member of enhanced oil recovery. Bottles that were labeled samples A, B, C, and D contained different blends of mud acids with different concentrations. At the end of chemical flooding; the solution blend in bottle samples A, B, C, and D respectively recovered 41.462, 44.408, 35.242, and 39.499 from S_{or1} .

The overburden pressure in a reservoir is pretty much higher than confined pressure of the cores made in the laboratory. This pressure differential will certainly lead to spatial variations in recoveries efficiencies under secondary and tertiary methods. This should be investigated.

Data Availability: Data set and discussions of an experimental procedure conducted under an atmospheric temperature and pressure of 273.15°K and 14.7 psi, respectively, were presented in this manuscript as primary data. All other data, known as secondary data, from literatures were duly referred, cited within the manuscript and listed under the references section.

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