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Investigation of Oil Recovery Improving through Surfactant Flooding; Design Program Scenario

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Research Article

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Abstract

Chemical flooding is one of the major EOR techniques particularly for reservoirs where thermal methods are not applicable, that chemical flooding may be polymer flooding, alkaline flooding, surfactant flooding, or a combination of them. The application of designing a chemical flooding program is strongly affected by the current economics, reservoir oil type, and crude oil price. In this project, mechanisms of different chemical methods will be discussed, and design chemical flooding program by using a laboratory scale and programming method, this project is mainly about making a design of surfactant flooding program, that to make a good program, choosing the optimum surfactant concentration is very important, also economic study is very important in designing the program to know if the project is profitable or not to identify its efficiency, and choosing the better type of surfactant for the reservoir is very important to increase the hydrocarbon recovery, results of this project proved that the surfactant has goof effect on wettability of rock that it increases the rock wettability to water and that increase the hydrocarbon recovery.

Keywords: Surfactant flooding; Enhanced Oil Recovery; Economic profit

Introduction

Producing hydrocarbons conventionally from the reservoir passed by three stages, the first stage is producing hydrocarbon depending on natural forces that exist in the reservoir which is called the primary stage, these forces in oil reservoir maybe drive force occurred because of the existence of water aquifer, gas cap, or combination of these two fluids or the depletion occurs as a result of solution gas drive reservoir and before the pressure reaches the abandonment pressure that there is a low recovery by natural force then the company needs to go into the second stage which is a secondary recovery which depends on inject fluids that naturally exists in the reservoir to increase recovery factor than the third stage when the second stage reaches its limit which is enhanced oil recovery stage, also for the gas reservoir but in the gas, the reservoir may be by water aquifer or pressure depletion only [1] (Figure 1).

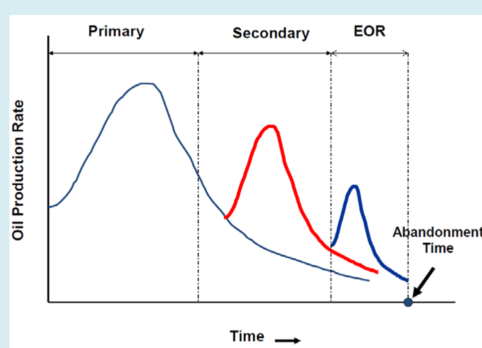

Figure 1: Oil reservoir recovery drive mechanism stages [2].

This design project mainly aims to design a program to enhance hydrocarbon recovery by chemicals, that enhanced hydrocarbon recovery is a very important process to increase hydrocarbon recovery by injecting a new fluid in the reservoir, this fluid may change rock properties like increasing porosity or permeability by making hydraulic fractures such as thermochemical fluids injection or changing rock wettability by using alkaline, or change fluid properties such as fluid viscosity, so design suitable enhanced hydrocarbon recovery is very important to increase recovery factor by knowing the needed demands for the reservoir and lowering the cost [3].

Literature Review

Enhanced Oil Recovery Methods EOR

EOR methods are methods that are used to increase the oil recovery in an economic way that is used to produce the remaining quantities of oil after using primary and secondary methods which represent 2/3 of the original quantity of oil in place [4]. The design of an enhanced oil recovery project is very important to increase the oil recovery factor to increase the profitability so, to measure EOR project profitability, the incremental oil amount must be determined which is the difference between the amount of oil produced by using EOR and without using it as which will be illustrated by Figure 2 [2].

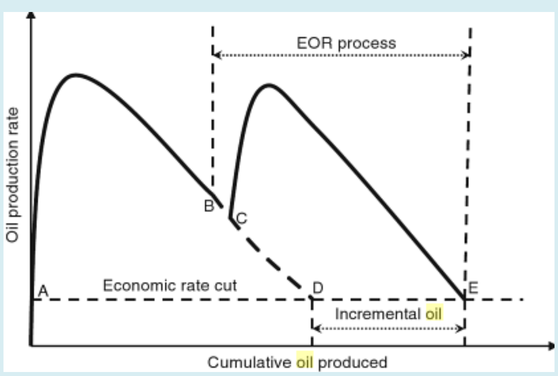

Figure 2: incremental oil amount [2].

EOR is an alternative method to increase oil recovery that is better than making new because it may be more expensive, but these methods must not be used in reservoir life early stage because the data lack so, overall economics and timing are important factors for design EOR project [5]. EOR is classified these are: thermal methods, microbial methods, miscible EOR methods, and chemical methods.

Thermal Method

This technique of EOR depends on the heat effect on crude oil which is when the temperature increases the oil viscosity decreases and oil becomes mobile, and surface tension of oil decreased, and the permeability of rock to oil increases [6]. The thermal method is used commonly in highly viscous oil fields that have more than one type of this technique, such as steam flooding, combustion, and steam injection by the cyclic method [7].

Microbial EOR Methods

This technique depends on the use of micro-organisms that form biosurfactants or produce CO_2 and damage the large molecules of hydrocarbon to increase the recovery of oil, that this method has many ways to perform it as mixing the hydrate of carbon with bacteria to inject it into the reservoir and it could form surfactant, polymer, etc to increase the recovery but this method is expensive so it does not be used `widely [8].

Miscible EOR Methods (CO_2 injection)

The miscible EOR method means injecting gas into the reservoir especially CO_2 or N_2, that increases the recovery of the hydrocarbon by dissolving it in swelling and reduce oil viscosity and surface tension with reservoir rock, that this method is an economical method because the injected gas will be produced and could be used again [9].

Chemical EOR Methods

Chemical enhanced oil recovery method is an efficient technique to increase the recovery of oil, because of this method efficiency and cost this method becomes popular from the year 1980 up till now, that this technique increases the oil recovery by increasing water injected to displace oil into reservoir efficiency d by lowering the interfacial tension to displace oil and extract it from small pores and control water mobility by increasing its viscosity then sweep efficiency that reduces the amount of water produced and increase the produced oil amount [10]. The chemicals that be used in this technique may be a surfactant, polymer, alkaline, any combination of two of them, or the combination of all of them. To obtain effective chemical flooding program reservoir properties such as permeability, and temperature must be studied [11].

Polymer flooding: This method depends on injecting polymer dissolved in water to increase water viscosity that increases the sweep efficiency by improving mobility which decreasing the fingering phenomenon that reduces the water production. Also, it affects the frictional flow that is the mobility ratio function [11]. El-hoshoudy, et al. [12-41] reported several publications about the use of polymer flooding in the enhanced oil recovery (EOR). The main polymer flooding function is controlling the water mobility by increasing its viscosity and decreasing the mobility to reach a better mobility ratio which is less than 1 to prevent the fingering phenomenon, and that permits the oil to be faster inflow [42]. Water with dissolved polymer affects fractional flow which is the fraction of flow rate of water to the rate of total flow which is mobility ratio function as when the mobility ratio reduces the flow rate of water decreases, as result of that the amount of produced oil increases while the decrease of residual oil as a result of increasing sweep efficiency as will be shown in Figure 3 & 4 [43].

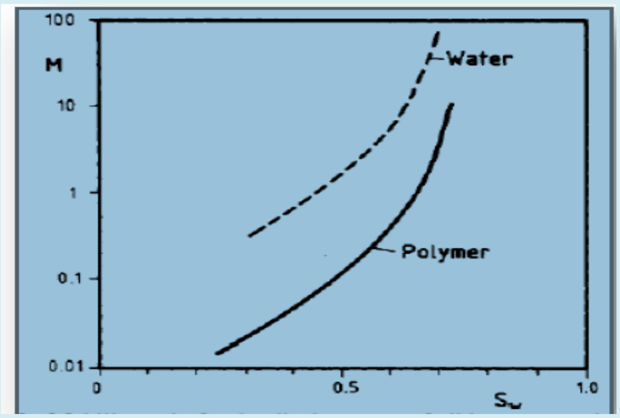

Figure 3: polymer flooding effect on mobility ratio.

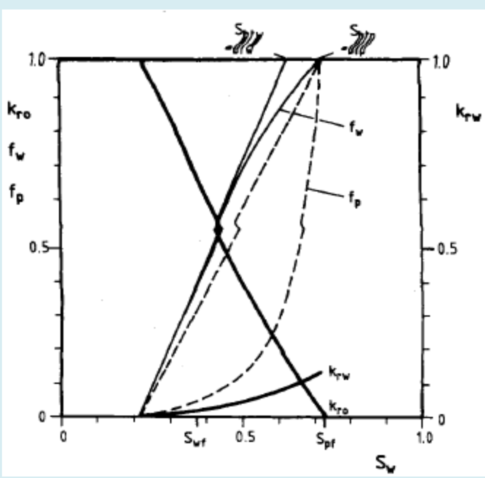

Figure 4: polymer flooding effect on the fractional flow [43].

Alkaline flooding: In 1917, a scientist called “Squires F“ discovered that when adding an alkaline chemical during the flooding of water, leads to an increase in the efficiency of oil displacement. Alkaline flooding is one of the Enhance oil recovery methods (EOR). the process includes injecting chemicals with a high PH number to the reservoir to increase the recovery of oil. This method has been discovered in the 20th century. The alkaline flooding process starts by injecting chemicals with high ph numbers like NaOH or Na_2CO_3 to the reservoir while the operation of water or polymer flooding. This chemical can make a reaction with different types of oil to make surfactants. Surfactants are used to reduce the interfacial tension between water and oil and this results in increased recovery of oil [44].

Alkaline flooding is most used in sandstone reservoirs but, it does not be used in the carbonate reservoir because the carbonate heterogeneity is very high and because of cautions which makes the problem of scaling when reacting with alkaline.

Mechanisms of Alkaline flooding

- Emulsification and entrapment
- Emulsification and entrainment
- Wettability reversal
- Oil phase swelling to reduce interfacial tension

Emulsification and entrainment: In 1942, “Subkow” observed this mechanism and take a patent for the production of oil. in 1966 which suggests a mechanism for cracking tar sands and after this injection of alkaline chemicals. When adding an alkaline chemical to a reservoir. This chemical will react with crude oil which contains naphthenic acids and this reaction from surfactants (Emulsifier). Emulsification results from the small IFT between oil and water. this makes a reaction and forms emulsions [45].

Emulsification and entrapment: This mechanism is observed in 1974 which indicates that the pore throat will be plugged by emulsions. This will make high permeability and helping in controlling mobility between fluids and increases volumetric sweep efficiency, and the PH values with variation in alkaline concentration In figure 1. From this chart, the strongest alkaline is Sodium hydroxide (NaOH) and the weakest alkaline is Sodium carbonate (Na_2CO_3) (Table 1) [44].

Sodium hydroxide	NaOH
Sodium carbonate	Na_2CO_3
Sodium metasilicate	Na_2SiO_3
Ammonia	NH_3
Sodium orthosilicate	$NaSiO_4$

Table 1: The most common used alkaline.

Surfactant

Surfactant is a chemical that is used in chemical systems that contains surface actives agents, which are polymeric molecules that can lower the IFT between the liquid and the oil in the reservoir. The most used structural form of surfactant is one that has nonpolar parts, hydrocarbon tail, and polar ionic parts, as shown in Figure 5 [46].

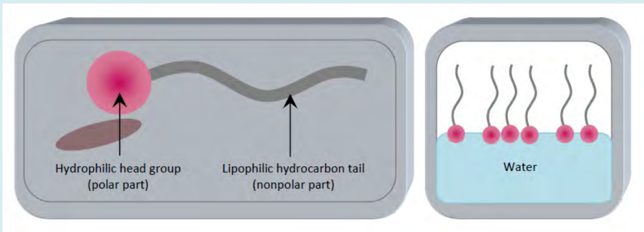

Figure 5: surfactant structural form.

In this figure surfactant component and movement in the water. 'Surfactants are also referred to as amphiphile molecules because they contain a nonpolar 'tail' and a polar 'head'-group within the same molecule'. Due to the balance that surfactant has between its components of the hydrophilic and hydrophobic part which give the surfactant, it's the active agent. In EOR our topic the surfactant flooding the hydrophobic tail interacts with residual oil and the other part of the hydrophilic head interacts with the water as shown also in the last figure. Typically contribute to a highly significant reduction in interfacial forces between (water and oil) and (oil and rock).

The classification of surfactant: This material can be classified on its ionic base of each group as follows (Table 2)

Anionic	
Sodium dodecyl sulfate (SDS)	$CH_3(CH_2)_{11}SO_4^-Na^+$
Sodium dodecyl benzene sulfonate	$CH_3(CH_2)_{11}C_6H_4SO_3^-Na^+$
Cationic	
Cetyltrimethylammonium bromide (CTAB)	$CH_3(CH_2)_{15}N(CH_3)_3^+Br^-$
Dodecylamine hydrochloride	$CH_3(CH_2)_{11}NH_3^+Cl^-$
Non-ionic	
Polyethylene oxides	$CH_3(CH_2)_7(O.CH_2CH_2)_8OH$

Table 2: the classification of surfactants [47].

The Anionic type of surfactant is negatively charged and is commonly for industrial usage like detergents. The Cationic type is the one that has a positively charged head and this type of surfactant dissociate in water to form amphiphilic cations and anions. The nonionic surfactant is the type that has no charge and mainly is used in EOR as a co-surfactant to enhance the surfactant process. The most commonly used surfactant in EOR can be sulfonated hydrocarbons like alcohol prepopulate sulfate. That is used to achieve the maximum surfactant flooding for any oil reservoir to enhance the oil recovery after the end of natural recovery and the end of secondary recovery the EOR which surfactant flooding one of its branches. The idea for using surfactant flooding in EOR is based on the ability of surfactant to lower the surface energy which was described by the Gibbs adsorption isotherm equation:

$$\Gamma_1 = \frac{1}{2RT}\left(\frac{\partial \gamma}{\partial \ln c_1}\right) \quad (1)$$

Surfactant flooding: This method is about the use of surfactant in EOR in the oil reservoir to ensure to have the maximum production efficiency, surfactant flooding is the injection of one or multi liquid chemicals with surfactant. This injection is effective will control the phase behavior in the oil reservoir. So, it will have the ability to mobilize the trapped crude oil by changing its IFT (Figure 6).

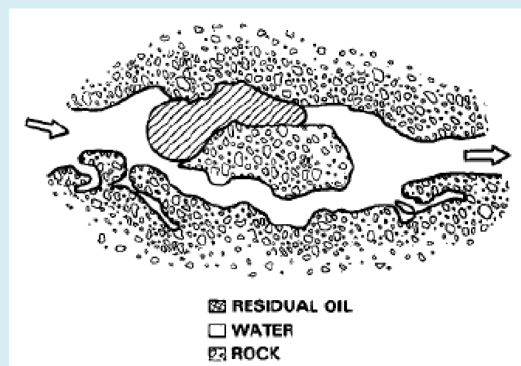

Figure 6: surfactant effect on IFT [48].

For this principle of flooding where residual oil is to be trapped in the reservoir the movement of that oil through the narrow pores will need a very low oil/water IFT and that what surfactant flooding is used for as EOR in the oil reservoir. There can be a great potential in using a chemical process with surfactant flooding since there are the ability to design a process of oil production and an overall displacement efficiency of oil nowadays thus the reservoir under the operation of water flooding has a production rate of 50-70% of its original oil in place, in this case, it is more than useful to have surfactant flooding process to increase the production rate and thus increase the economic productivity [48].

Methodology

- Identify the chemical type that is used in the program is in this project is a surfactant
- Make experimental work to know the flow rate of each surfactant used
- Make design by using MATLAB to study the efficiency of each surfactant used
- Make a comparative study between each surfactant

by knowing their efficiency and cost to know which surfactant gives better economic results.

The used surfactants including Dodecylbenzene sulfonic: This acid that is called dodecyl benzene sulfonic is considered as one of the acid classes that is called Benzenesulfonic that the position of the hydrogen is at 2 of the ring of the phenyl and this molecule of the hydrogen taking the group of the dodecyl place. And this acid that is called dodecyl benzene sulfonic is used in the operations of making detergents, this is used as an anionic surfactant. The structural formula of this acid that is called dodecyl benzene sulfonic is (Figure 7):

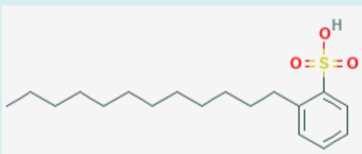

Figure 7: structure of dodecylbenzene sulfonic surfactant.

Cetyl trimethyl ammonium bromide: Salt surfactant is considered as a cationic surfactant, the other names of this surfactant are cetrimonium bromide, trimethyl ammonium bromide, Hexadecyl trimethyl ammonium bromide, suitable for the EOR process in carbonate rock of the reservoir [49].

Experimental work

This part of the project will show the steps of work that was made in the BUE laboratory that made into steps

1. Choose five cores then measure the size of used cores
2. Measure the mass of dry cores then saturate it with water to be fully saturated then measures the mass of the core after saturation
3. Inject water into cores by flooding device to know the flow rate and measure the difference in pressure
4. Initiate cores by flooding oil into cores to make the reservoir
5. Inject brine solution into each core then measure pressure and calculate the flow rate of oil and water with a concentration of 3.5 gm of NaCl to 100 ml of water
6. Then make a surfactant solution by concentration 10000 ppm and 20000 ppm of each surfactant used and 10000ppm of the mixture of two surfactants.
7. Inject the surfactant solution by flooding the device to cores and calculate the flow rate of oil and water

Choose Five Cores then Measure the Size of Used Cores

In this stage choose 5 suitable cores to use in flooding by each surfactant with different concentrations and use Vernier caliper to measure each core length and diameter. Then calculate the bulk volume of each core by using cylinder volume equation $V=\pi r^2 h$

Measure the Mass of Dry Cores then Saturates it with Water to be Fully Saturated then Measures The Mass of the Core After Saturation

Use the digital mass balance to measure the mass of dry core the saturate the cores with water to be fully saturated with water then measure the core weight after the saturation. The difference between saturated core mass and dry core mass = the pore volume of the core, the divide pore volume to bulk volume to calculate the porosity of each core.

Inject Water into Cores

Using flooding device to inject water into each core to calculate the flow rate when the core is fully saturated by only water by calculating the produced volume of water at a specified time and calculate the change in pressure delta p to calculate the absolute permeability by using Darcy equation q=1.127kA Delta p/μL (Figure 8).

Figure 8: Flooding device.

Initiate Cores by Flooding Oil into Cores to Make Reservoir

Initiate cores to form the reservoir, which occurs by using a flooding device to inject oil into cores and calculate the volume of water produced until there is no amount of water could be produced then calculate the connate water volume by minus the amount of water produced from pore volume (volume of water when the core is fully saturated with water), then calculate connate water saturation S_{wc} which equals to connate water volume divided by pore volume and calculate initial oil saturation S_{oi} which equals to $1-S_{wc.}$

Inject Brine Solution into Each Core

Inject brine solution by specified injected volume which equals to 0.5 PV, 1pv, 1.5pb, 2pv, then measure the volume of water and oil produced to reach the injected volume of brine solution, the needed time to reach the above volumes, and delta P to calculate flow rate= volume (V)/ time (T) then effective permeability of rock to water and oil then relative permeability and saturation of oil and water in the core. The saturation of oil is calculated by minus the volume produced at each value of injection from initial oil volume then divide the result by pore volume, then calculate the saturation of water which equals oil saturation.

Make Surfactant Solution by Different Concentration Each Surfactant used and Mixed between The two Surfactants

Make a solution of surfactant in water by each surfactant used by the first 10000ppm of dodecylbenzene sulphonic, crystal tram side ammonium bromide, or a mixture between them in water, then second 20000 ppm of dodecylbenzene sulphonic or Cetyl tramoside ammonium bromide.

Inject The Surfactant Solution into Cores

Inject surfactant solution by specified injected volume which equals to 0.5 PV, 1pv, 1.5pb, 2pv, then measure the volume of water and oil produced to reach the injected volume of brine solution, the needed time to reach the above volumes, and delta P to calculate flow rate= volume (V)/ time (T) then effective permeability of rock to water and oil then relative permeability and saturation of oil and water in the core. The saturation of oil is calculated by minus the volume produced at each value of injection from initial oil volume then divide the result by pore volume, then calculate the saturation of water which equals oil saturation.

Make Design by Using MATLAB to Study the Efficiency of Each Surfactant Used

Using the MATLAB program to make a study by using data to show the cumulative production by using surfactant according to graphs to know the efficiency of the design project.

Make A Comparative Study between Each Surfactant by Knowing their Efficiency and Cost to Know Which Surfactant Gives better Economic Results

In this part of the project calculate the cost of used surfactant and compare it and the profit of cumulative oil produced to make an economic study and know if the project is efficient or not.

Core Data

Core number	1	2	3	4	5
Diameter D (cm)	3.6	3.7	3.65	3.65	3.65
Height h (cm)	4.6	3.52	3.5	3.7	5.37
BV (cm^3)	46.84114286	37.86263	36.63688	38.73041	56.21143
dry core mass (gm)	67.686	59.053	59.632	59.755	93.145
saturated core with water mass (gm)	90.465	76.816	76.099	76.484	115.967
Pore volume PV (CC)	22.779	17.763	16.467	16.729	22.822
Porosity	0.48630325	0.469143	0.449465	0.431934	0.406003
Delta P	5	0.5	2.5	5	12
The volume of water produced	30	30	25	40	5
Time	30.48	30	23	30	60
q =v/t	0.984251969	1	1.086957	1.333333	0.083333
oil intiation volume cm^3	14	10	9	9	14
connate water volume	8.779	7.763	7.467	7.729	8.822
connate water saturation	38.53988323	43.7032	45.34524	46.20121	38.65568
viscosity of water cp	1	1	1	1	1
to calculate absolute permeability					

q in bbl/day	0.531496063	0.54	0.586957	0.72	0.045
water viscosity	1	1	1	1	1
core length in ft	1.5091864	1.154856	1.148294	1.213911	1.761811
core diameter in ft	1.1811024	1.213911	1.197507	1.197507	1.197507
core area in ft^2	1.096073691	1.157812	1.126732	1.126732	1.126732
Delta p in psia	5	0.5	2.5	5	12
Absolute permeability in md	129.8701257	955.8491	212.312	137.6591	5.202909

Table 3: the physical properties of the five cores data.

Flooding Data

For core 1

Used surfactant: Cetyl trimethyl ammonium bromide
Concentration: 20000 ppm
Brine solution flooding:

Brine Solution Core 1	**Injected P.V**	**V Oil Cc**	**Vw Cc**	**Pore Volume**	**Vo in the Reservoir**	**Vw in the Reservoir**
	before flooding			22.779	14	8.779
Concentration	11.3895	5	6.3895	22.779	9	13.779
35000 ppm	22.779	2.5	20.279	22.779	6.5	16.279
	34.1685	1.5	32.6685	22.779	5	17.779
	45.558	1	44.558	22.779	4	18.779
	56.9475	0.5	56.4475	22.779	3.5	19.279
Delta P	time sec	qo in bbl/day	qw in bbl/day	core length ft	core area ft^2	oil viscosity
12.5	24.34	0.110929	0.141756	1.509186	1.096073691	3
12.5	58.06	0.023252	0.188609	1.509186	1.096073691	3
12.5	77.86	0.010403	0.226573	1.509186	1.096073691	3
12.5	86.47	0.006245	0.278262	1.509186	1.096073691	3
12.5	115.31	0.002342	0.264345	1.509186	1.096073691	3
water viscosity	Ko	Kw	K			
1	32.52622	13.85509	129.8701			
1	6.817846	18.43455	129.8701			
1	3.05043	22.14511	129.8701			
1	1.831128	27.19714	129.8701			
1	0.686574	25.83692	129.8701			
Kro	Krw	So	Sw	RF	cumulative oil produced	
		0.614601	0.385399			
0.250452	0.106684	0.395101	0.604899	0.357143	5	
0.052497	0.141946	0.285351	0.714649	0.178571	7.5	
0.023488	0.170517	0.2195	0.7805	0.107143	9	
0.0141	0.209418	0.1756	0.8244	0.071429	10	
0.005287	0.198944	0.15365	0.84635	0.035714	10.5	

Table 4: Core 1 brine flooding data.

Surfactant 1 Liquid	Injected P.V	V Oil Cc	V Of Surfactant Cc	Pore Volume
	before flooding			22.779
Concentration	11.3895	1.5	9.8895	22.779
20000 ppm	22.779	1	21.779	22.779
	34.1685	0.5	33.6685	22.779
	45.558	0	45.558	22.779
vo in the reservoir	vw in the reservoir	Delta P	time sec	qo in bbl/day
3.5	19.279			
2	20.779	10	15.5	0.052258065
1	21.779	10	22.82	0.023663453
0.5	22.279	10	36.17	0.00746475
0.5	22.279	10	49.22	0
qw in bbl/day	core length ft	core area ft^2	oil viscosity	surfactant viscosity
0.344537	1.509186	1.096074	3	1.53
0.515366	1.509186	1.096074	3	1.53
0.502654	1.509186	1.096074	3	1.53
0.499824	1.509186	1.096074	3	1.53
Ko	Kws	K	Kro	Krws
19.15375	64.40314	129.8701	0.147484	0.495904
8.673185	96.33558	129.8701	0.066784	0.741784
2.735998	93.95928	129.8701	0.021067	0.723486
0	93.43024	129.8701	0	0.719413
So	Sws			
0.15365	0.84635	RF		cumulative oil produced
0.0878	0.9122			
0.0439	0.9561	0.107143		12
0.02195	0.97805	0.071429		13
0.02195	0.97805	0.035714		13.5
		0		13.5

Table 5: Surfactant flooding data Table 6: surfactant flooding data.

For core 2

Used surfactant: Dodecylbenzene sulfonic

Concentration: 10000 ppm

Brine solution flooding:

BRINE SOLUTION CORE 1	INJECTED P.V	V OIL CC	VW CC	PORE VOLUME
	before flooding			22.779
Concentration	11.3895	5	6.3895	22.779
35000 ppm	22.779	2.5	20.279	22.779
	34.1685	1.5	32.6685	22.779
	45.558	1	44.558	22.779
	56.9475	0.5	56.4475	22.779

vo in the reservoir	vw in the reservoir	Delta P	time sec	qo in bbl/day
14	8.779			
9	13.779	12.5	24.34	0.110928513
6.5	16.279	12.5	58.06	0.023251808
5	17.779	12.5	77.86	0.010403288
4	18.779	12.5	86.47	0.00624494
3.5	19.279	12.5	115.31	0.002341514
qw in bbl/day	core length ft	core area ft^2	oil viscosity	water viscosity
0.141756	1.509186	1.096074	3	1
0.188609	1.509186	1.096074	3	1
0.226573	1.509186	1.096074	3	1
0.278262	1.509186	1.096074	3	1
0.264345	1.509186	1.096074	3	1
Ko	Kw	K	Kro	Krw
32.52622	13.85509	129.8701	0.250452	0.106684
6.817846	18.43455	129.8701	0.052497	0.141946
3.05043	22.14511	129.8701	0.023488	0.170517
1.831128	27.19714	129.8701	0.0141	0.209418
0.686574	25.83692	129.8701	0.005287	0.198944
So	Sw	RF	cumulative oil produced	
0.614601	0.385399			
0.395101	0.604899	0.178571	2.5	
0.285351	0.714649	0.107143	4	
0.2195	0.7805	0.035714	4.5	
0.1756	0.8244	0.035714	5	
0.15365	0.84635	0.035714	5.5	

Table 6: core 2brine flooding data.

Surfactant flooding:

Surfactant 1 Powder	Injected P.V	V Oil Cc	V Of Surfactant Cc	Pore Volume
	before flooding			22.779
Concentration	11.3895	1.5	9.8895	22.779
20000 ppm	22.779	1	21.779	22.779
	34.1685	0.5	33.6685	22.779
	45.558	0	45.558	22.779
vo in the reservoir	vw in the reservoir	Delta P	time sec	qo in bbl/day
3.5	19.279			
2	20.779	10	15.5	0.052258065
1	21.779	10	22.82	0.023663453

0.5	22.279	10	36.17	0.00746475
0.5	22.279	10	49.22	0
qw in bbl/day	core length ft	core area ft^2	oil viscosity	surfactant viscosity
0.344537	1.509186	1.096074	3	1.53
0.515366	1.509186	1.096074	3	1.53
0.502654	1.509186	1.096074	3	1.53
0.499824	1.509186	1.096074	3	1.53
Ko	Kws	K	Kro	Krws
19.15375	64.40314	129.8701	0.147484	0.495904
8.673185	96.33558	129.8701	0.066784	0.741784
2.735998	93.95928	129.8701	0.021067	0.723486
0	93.43024	129.8701	0	0.719413

So	Sws	RF	cumulative oil produced
0.15365	0.84635		
0.0878	0.9122	0.142857	7.5
0.0439	0.9561	0.107143	9
0.02195	0.97805	0.035714	9.5
0.02195	0.97805	0	9.5

Table 7: core 2 surfactant flooding data.

For core 3
Used surfactant: Cetyl trimethyl ammonium bromide

Concentration: 10000 ppm
Brine solution flooding:

Brine Water Core 3	Injected P.V	V Oil Cc	Vw Cc	Pore Volume
	before flooding			16.467
Concentration	8.2335	2	6.2335	16.467
35000 ppm	16.467	1.5	14.967	16.467
	24.7005	0.5	24.2005	16.467
	32.934	0.5	32.434	16.467
	41.1675	0.5	40.6675	16.467
vo in reservoir	vw in reservoir	Delta P	time sec	qo bbl/day
9	7.467			
7	9.467	2.5	27.57	0.03917301
5.5	10.967	2.5	87.27	0.00928154
5	11.467	2.5	125	0.00216
4.5	11.967	2.5	105	0.00257143
4	12.467	2.5	101	0.00267327
qw bbl/ day	core length ft	core area ft^2	oil viscosity	water viscosity
0.122092	1.148294	1.126732	3	1
0.092611	1.148294	1.126732	3	1
0.104546	1.148294	1.126732	3	1
0.166803	1.148294	1.126732	3	1
0.21743	1.148294	1.126732	3	1
Ko	Kw	K	Kro	Krw
42.50861	44.16291	129.8701	0.327316	0.340054
10.07187	33.49903	129.8701	0.077553	0.257943
2.343925	37.8161	129.8701	0.018048	0.291184
2.790387	60.3356	129.8701	0.021486	0.464584
2.900897	78.64816	129.8701	0.022337	0.605591
So	Sw	RF	cumulative oil produced	
0.546548	0.453452			
0.425093	0.574907	0.142857	2	
0.334001	0.665999	0.107143	3.5	
0.303638	0.696362	0.035714	4	
0.273274	0.726726	0.035714	4.5	
0.24291	0.75709	0.035714	5	

Table 8: core 3 brine flooding data.

Surfactant flooding:

Surfactant 1 Powder	Injected P.V	V Oil Cc	V Of Surfactant Cc	Pore Volume
	before flooding			16.467

Concentration	8.2335	1.5	6.7335	16.467
10000 ppm	16.467	0.5	15.967	16.467
	24.7005	0.5	24.2005	16.467
	32.934	0.5	32.434	16.467
	41.1675	0	41.1675	16.467
vo in reservoir	vw in reservoir	Delta P	time sec	qo bbl/day
4	12.467			
2.5	13.967	10	48.21	0.01680149
2	14.467	10	37.33	0.00723279
1.5	14.967	10	39	0.00983965
1	15.467	10	39.332	0.01111111
1	15.467	10	33	0
qws bbl/day	core length ft	core area ft^2	oil viscosity	surfactant viscosity
0.075422	1.148294	1.126732	3	2
0.230972	1.148294	1.126732	3	2
0.476249	1.148294	1.126732	3	2
0.720756	1.148294	1.126732	3	2
0.741015	1.148294	1.126732	3	2
Ko	Kws	K	Kro	Krws
4.558037	15.20936	129.8701	0.035097	0.105033
1.962166	46.57712	129.8701	0.015109	0.321654
2.669375	96.03898	129.8701	0.01446	0.4666
3.014307	145.3455	129.8701	0.014343	0.62
0	149.431	129.8701	0	0.938132

So	Sw	RF	cumulative oil produced
0.24291	0.75709		
0.151819	0.848181	0.107143	6.5
0.121455	0.878545	0.035714	7
0.091091	0.908909	0.035714	7.5
0.060728	0.939272	0.035714	8
0.060728	0.939272	0	8

Table 9: surfactant flooding data.

For core 4
Used surfactant: Dodecylbenzene sulfonic:Concentration: 20000 ppm
Brine solution flooding:

Brine Solution Core 4	**Injected P.V**	**V Oil Cc**	**Vw Cc**	**Pore Volume**
	before flooding			16.729
Concentration	8.3645	2.5	5.8645	16.729
35000 ppm	16.729	1.5	15.229	16.729

	25.0935	1	24.0935	16.729
	33.458	1	32.458	16.729
	41.8225	0.5	41.3225	16.729
vo in reservoir	vw in reservoir	Delta P	Time	qo in bbl/day
9	7.729			
6.5	10.229	12.5	13.76	0.098110465
5	11.729	12.5	27.4	0.029562044
4	12.729	12.5	40.5	0.013333333
3	13.729	12.5	56.3	0.009591474
2.5	14.229	12.5	79.4	0.003400504
qw in bbl/day	core length ft	core area ft^2	oil viscosity	water viscosity
0.230148	1.213911	1.126732	3	1
0.300134	1.213911	1.126732	3	1
0.321247	1.213911	1.126732	3	1
0.31132	1.213911	1.126732	3	1
0.281035	1.213911	1.126732	3	1
Ko	Kw	K	Kro	Krw
22.50966	17.60105	137.6591	0.163517	0.12786
6.782473	22.9534	137.6591	0.04927	0.166741
3.059091	24.56807	137.6591	0.022222	0.17847
2.200589	23.80891	137.6591	0.015986	0.172956
0.780184	21.49276	137.6591	0.005668	0.15613
So	Sw	RF		cumulative oil produced
0.537988	0.462012			
0.388547	0.611453	0.178571		2.5
0.298882	0.701118	0.107143		4
0.239106	0.760894	0.071429		5
0.179329	0.820671	0.071429		6
0.149441	0.850559	0.035714		6.5

Table 10: core 4 brine flooding data.

Surfactant flooding:

Surfactant 2	Injected P.V	V Oil Cc	V of Surfactant Cc	Pore Volume
	before flooding			16.729
Concentration	8.3645	1.5	6.8645	16.729
20000 ppm	16.729	0.5	16.229	16.729
	25.0935	0.25	24.8435	16.729
	33.458	0	33.458	16.729
vo in reservoir	vw in reservoir	Delta P	Time	qo in bbl/day

2.5	14.229			
1	15.729	5	12	0.0675
0.5	16.229	5	22	0.012272727
0.25	16.479	5	28	0.004821429
0.25	16.479	5	41.96	0
qw in bbl/day	core length ft	core area ft^2	oil viscosity	surfactant viscosity
0.308903	1.213911	1.126732	3	1.43
0.398348	1.213911	1.126732	3	1.43
0.479125	1.213911	1.126732	3	1.43
0.430584	1.213911	1.126732	3	1.43
Ko	Kws	K	Kro	Krws
38.71662	84.45587	137.6591	0.28125	0.613515
7.039385	108.9109	137.6591	0.051136	0.791164
2.765473	130.9957	137.6591	0.020089	0.951595
0	117.7245	137.6591	0	0.855188
So	Sws	RF	cumulative oil produced	
0.149441	0.850559			
0.059776	0.940224	0.107143	8	
0.029888	0.970112	0.035714	8.5	
0.014944	0.985056	0.017857	8.75	
0.014944	0.985056	0	8.75	

Table 11: core 4 surfactant flooding data.

Core 5

The mixture of two surfactants.

Concentration= 10000ppm

Brine solution flooding:

Brine Solution Core 5	Injected P.V	V Oil Produced Cc	Vw Produced Cc	Pore Volume
	before flooding	0	0	22.822
Concentration	11.411	3	8.411	22.822
35000 ppm	22.822	2	20.822	22.822
	34.233	1.5	32.733	22.822
	45.644	0	45.644	22.822
v of water in the reservoir	vo in the reservoir	Delta P	time	qo in bbl/day
8.822	14			
11.822	11	40	76.49	0.021179239
13.822	9	40	119.5	0.009037657
15.322	7.5	40	132.96	0.006092058
15.322	7.5	40	227	0
qw in bbl/day	core length ft	core area ft^2	oil viscosity	water viscosity
			3	1

0.059379527	1.76181108	1.126731616	3	1
0.094091046	1.76181108	1.126731616	3	1
0.132940884	1.76181108	1.126731616	3	1
0.108580441	1.76181108	1.126731616	3	1
Ko	Kw	K	Kro	Krw
		5.202909	0	0
2.20387296	2.059641721	5.202909	0.423585	0.39586351
0.94044208	3.2636475	5.202909	0.180753	0.62727364
0.63392841	4.611195259	5.202909	0.121841	0.88627256
0	3.766227482	5.202909	0	0.7238696
So	Sw	RF		cumulative oil produced
0.613443	0.386557			
0.481991	0.518009	0.214286		3
0.394356	0.605644	0.142857		5
0.32863	0.67137	0.107143		6.5
0.32863	0.67137	0		6.5

Table 12: core 5 brine flooding data.

Surfactant flooding:

A Mix Between Surfactant 2 And 3	Injected Pv	V Oil Produced Cc	V Of Surfactant Produced Cc	Pore Volume
	before flooding	0	0	22.822
Concentration	11.411	1.7	9.711	22.822
10000 ppm	22.822	3	19.822	22.822
	34.233	2.5	31.733	22.822
vw in the reservoir	vo in the reservoir	Delta P	time	qo in bbl/day
15.322	7.5			
17.022	5.8	45	150	0.00612
20.022	2.8	45	280	0.005785714
22.522	0.3	45	430	0.003139535
qw in bbl/day	core length ft	core area ft^2	oil viscosity	surfactant viscosity
			3	2
0.0349596	1.76181108	1.126731616	3	2
0.038228143	1.76181108	1.126731616	3	2
0.039850744	1.76181108	1.126731616	3	2
Ko	Kws	K	kro	Krws
		5.202909	0.34	0
0.56607647	2.155752393	5.202909	0.1088	0.414336

0.53515633	2.357304158	5.202909	0.102857	0.45307429
0.29039491	2.457360414	5.202909	0.055814	0.47230512
So	Sws	RF		cumulative oil produced
0.32863	0.67137			
0.254141	0.745859	0.214286		8.2
0.122689	0.877311	0.178571		11.2
0.013145	0.986855	0		13.7

Table 13: Surfactant flooding data.

As shown from previous figures surfactant flooding could increase the productivity index, that it reduces residual oil saturation.

Results and Analysis

For core 1

Brine flooding:

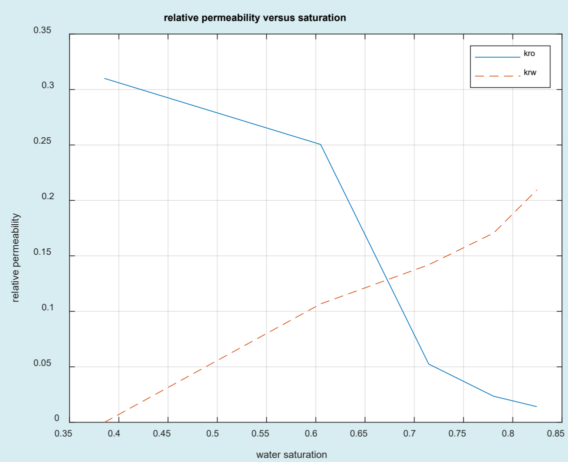

Figure 9: Relative permeability of water and oil curves for core 1.

Figure 9 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.674 SW which refers that the rock is strongly water wet.

Figure 10 shows the cumulative oil produced by primary and secondary recovery methods by using brine solution injection.

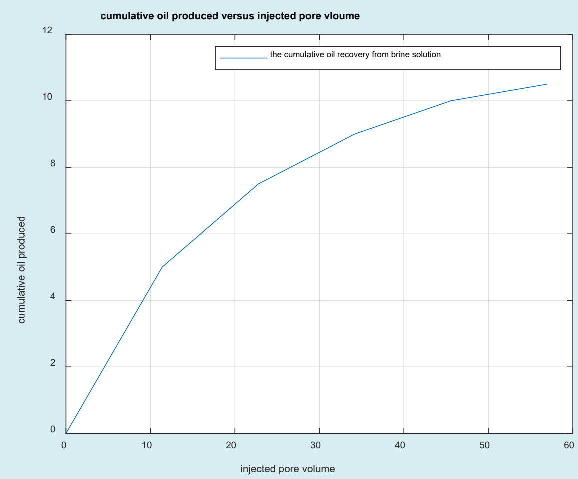

Figure 10: cumulative oil produced by secondary and tertiary recovery.

Surfactant flooding:

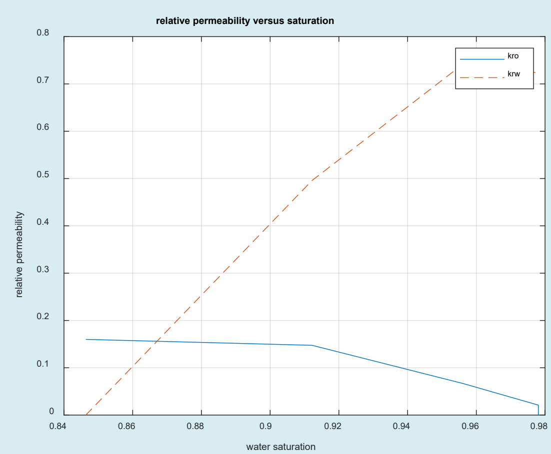

Figure 11: Relative permeability saturation curves of oil and surfactant for core 2.

Figure 11 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.862 SW which refers that the rock is strongly water-wet more than when using water flooding and that means the productivity index increased because rock wettability to oil decreased.

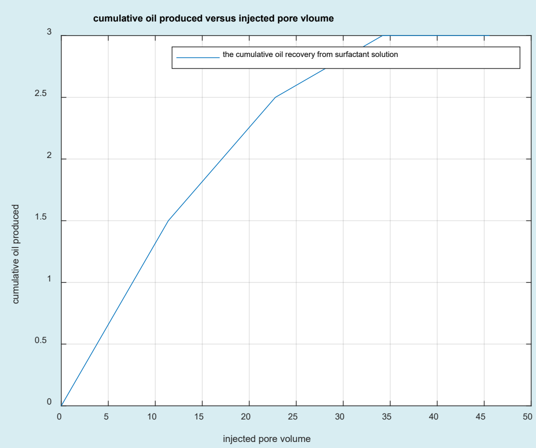

Figure 12: Cumulative oil produced from tertiary recovery.

Figure 12 shows the cumulative oil produced by primary and secondary recovery methods by using surfactant solution injection to core 1 (cumulative production from tertiary recovery).

Core 2:

Brine flooding:

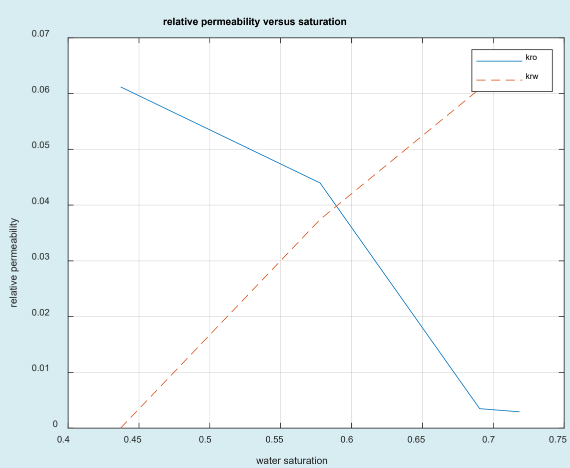

Figure 13: kr saturation curves of water and oil for core 2.

Figure 13 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.58 SW which refers that the rock is not so strong water wet.

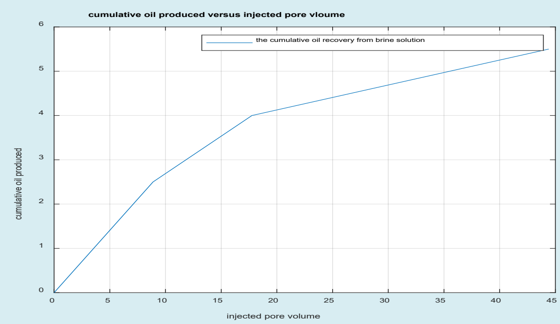

Figure 14: cumulative oil produced from primary and secondary recovery.

Figure 14 shows the cumulative oil produced by primary and secondary recovery methods by using brine solution injection for core 2.

Surfactant flooding:

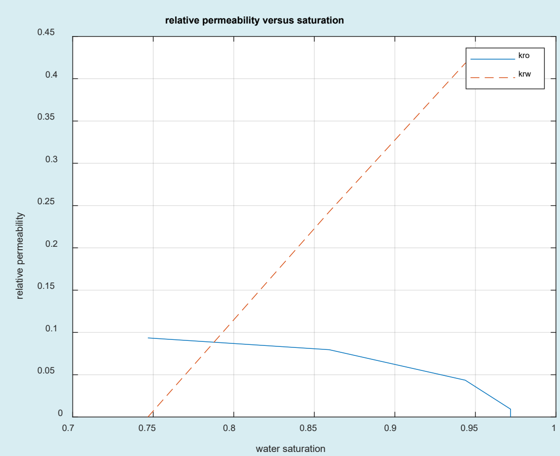

Figure 15: kr saturation curve of oil and surfactant for core 2.

Figure 15 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.788 SW which refers that the rock is strongly water-wet more than when using water flooding and that means the productivity index increased because rock wettability to oil decreased.

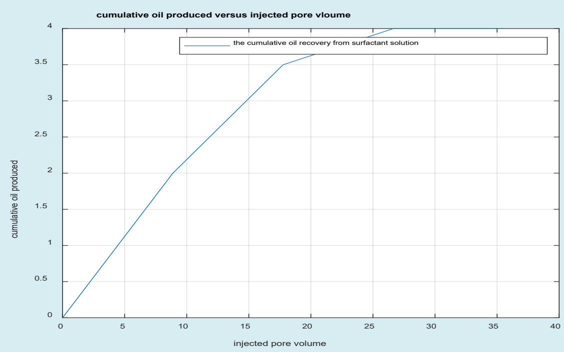

Figure 16: Cumulative oil produced by tertiary recovery.

Figure 16 shows the cumulative oil produced by primary and secondary recovery methods by using surfactant solution injection to core 2 (cumulative production from tertiary recovery).

Core 3:
Brine flooding:

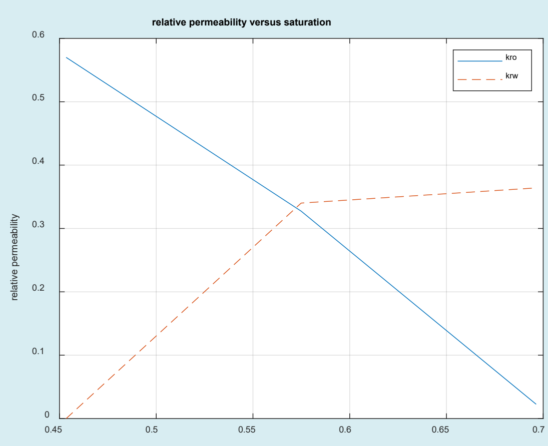

Figure 17: core 3 kr sw curves of water and oil.

Figure 17 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.5748 SW which refers that the rock is not so strong water wet.

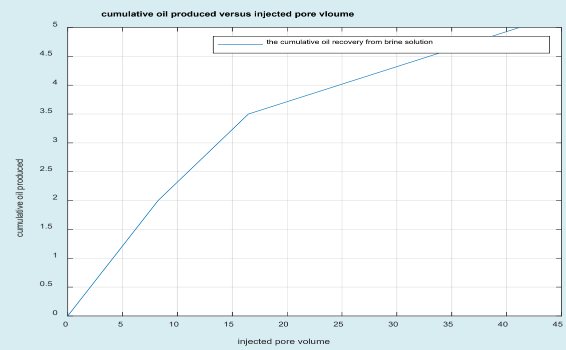

Figure 18: Cumulative oil produced by primary and secondary recovery.

Figure 18 shows the cumulative oil produced by primary and secondary recovery methods by using brine solution injection for core 3.

For Surfactant flooding:

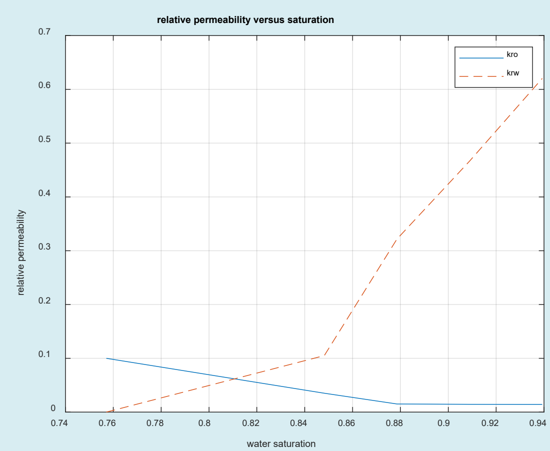

Figure 19: Core 3 krs and kro sw curves.

Figure 19 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.81 SW which refers that the rock is strongly water-wet more than when using water flooding and that means the productivity index increased because rock wettability to oil decreased.

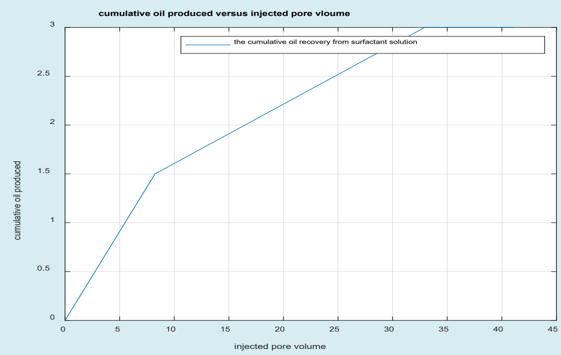

Figure 20: cumulative oil produced by tertiary recovery.

Figure 20 shows the cumulative oil produced by primary and secondary recovery methods by using surfactant solution injection to core 3(cumulative production from tertiary recovery).

Core 4:

Brine solution:

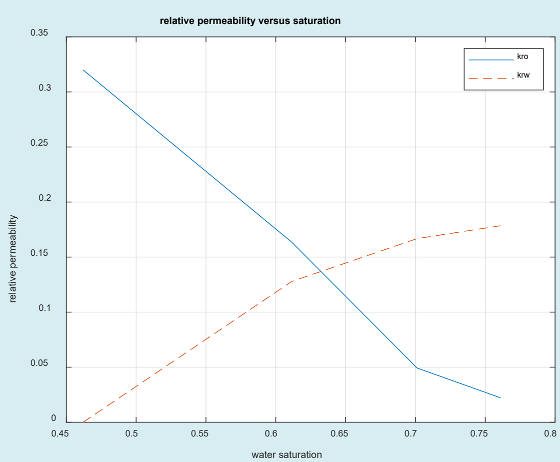

Figure 21: Krw and kro sw curves for core 4.

Figure 21 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.674 SW which refers that the rock is strongly water wet.

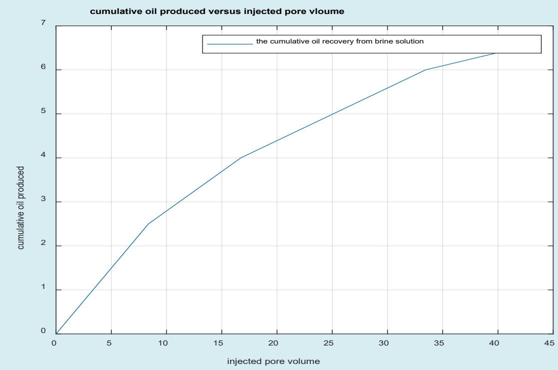

Figure 22: Primary and secondary cumulative recovery.

Figure 22 shows the cumulative oil produced by primary and secondary recovery methods by using brine solution injection for core 4.

Surfactant flooding:

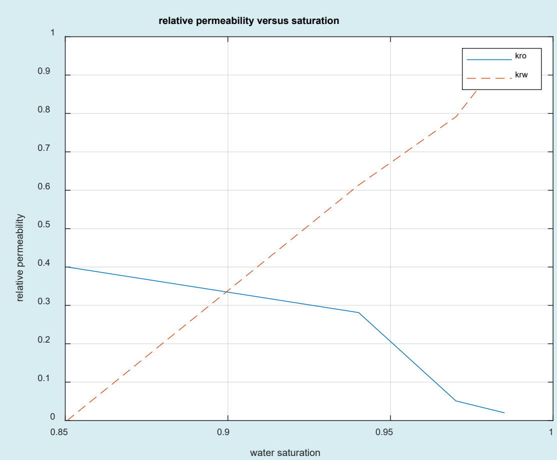

Figure 23: Krs Kro sw curves core 4.

Figure 23 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.9 SW which refers that the rock is strongly water-wet more than when using water flooding and that means the productivity index increased because rock wettability to oil decreased.

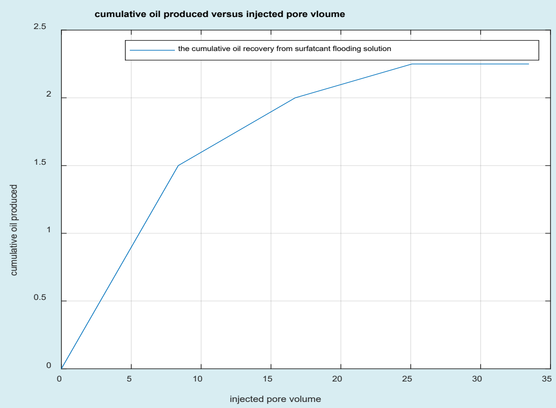

Figure 24: Tertiary cumulative recovery.

Figure 24 shows the cumulative oil produced by primary and secondary recovery methods by using surfactant solution injection to core 4(cumulative production from tertiary recovery).

Core 5:
Brine flooding:

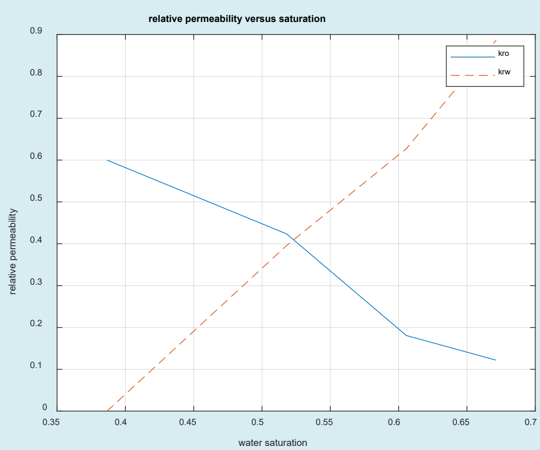

Figure 25: kro and krw vs sw curves for core 5.

Figure 25 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.524 SW which refers that the rock is not so strong water wet.

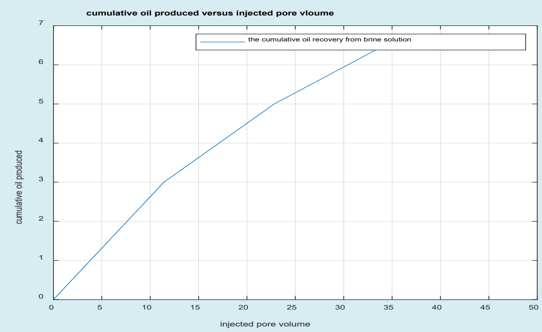

Figure 26: Primary and secondary cumulative oil produced.

Figure 26 shows the cumulative oil produced by primary and secondary recovery methods by using brine solution injection for core 5.

Surfactant flooding:

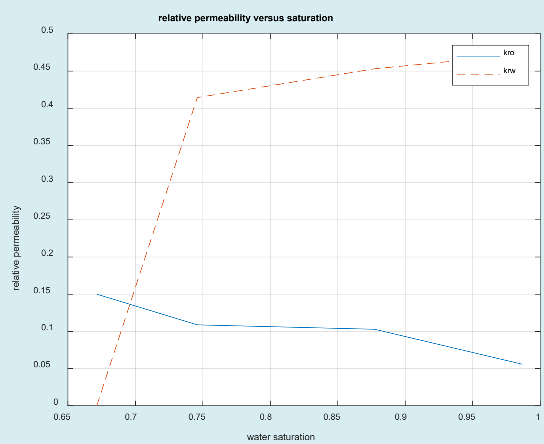

Figure 27: krs Kro saturation curves core 5.

Figure 27 shows the oil and water relative permeability versus the saturation of water, which showed that increasing the injected PV of water will increase the relative permeability of water and decrease the relative permeability of oil according to brine solution flooding to the first core, also, the water saturation increases. This is due to the high-water mobility, while there is an intersection between the two curves at 0.68 SW which refers that the rock is strongly water-wet more than when using water flooding and that means the productivity index increased because rock wettability to oil decreased.

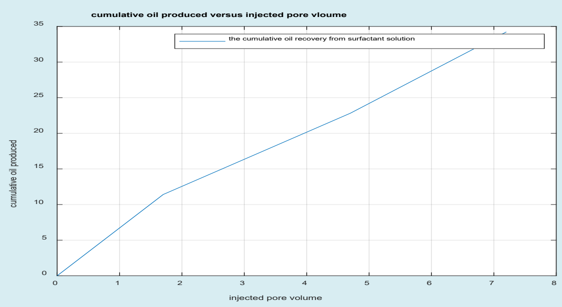

Figure 28: Tertiary cumulative oil amount produced.

Figure 28 shows the cumulative oil produced by primary and secondary recovery methods by using surfactant solution injection to core 5(cumulative production from tertiary recovery).

Analysis of Results

As shown from the relative permeability curves of the 5 cores used, the 5 reservoirs are water wet that the surfactant also increases the wettability of rock to water that increases the oil recovery also as shown from cumulative oil produced curves that mean that the design is efficient I increasing oil recovery but it must be comparative economic study to know which surfactant is more profitable.

Comparative Economic Study for used Surfactant

Core	Used surfactant	Concentration ppm	Cost Eur	Cumulative oil produced bbl	Profit Eur=amount bbl*cost of bbl (36.26)	Net cash flow=profit-cost
1	Cetyl trimethyl ammonium bromide	20000	22.5	0.01725	0.625485	-21.8745
2	Dodecyl benzene sulfonic	10000	0.6	0.023	0.83398	0.2398
3	Cytel trimethyl ammonium bromide	10000	11.25	0.017225	0.625485	-10.624515
4	Dodecyl benzene sulfonic	20000	1.2	0.0129375	0.469	-0.731
5	A mixture of two surfactants	10000	5.9	0.0414	1.5569	-4.3431

Table 14: An economic study.

Analysis of Economic Study

For surfactant cetyl trimethyl ammonium bromide: the cost is high that the company will lose money if use this surfactant in reserve 1 and 3 that the concentration has no effect on oil produced. For surfactant dodecyl benzene sulfonic: in reservoir 2 and 4, the lower concentration will be profitable than the higher concentration. For a mixture of the 2 surfactants: the mixture gives higher cumulative oil production but using this mixture in reservoir 5 is leading to losing money because the reservoir has a very low permeability value.

Conclusion

There are many techniques of EOR to increase oil recovery after primary and/or secondary methods to maximize profit. Although, many challenges should be considered before the beginning of any project to check its technical and economic viability. The surfactant flooding program is very useful in increasing oil recovery because the surfactant could increase the wettability of rock to water and that decreases the interfacial tension but in the design program the economic study must be done to know of the project is profitable or not. To design a surfactant flooding program identifying the suitable type of surfactant that may be anionic, cationic, non-anionic, or amphoteric with a suitable concentration and knowing the reservoir rock and fluid properties is very important to make a good design program. The experimental work at this project is very important to know the rock properties and know the cumulative oil produced to calculate the profit from the increased amount of oil by surfactant flooding, by making 5 cores as a reservoir and calculate the volume of oil produced after injection. Using a computer programming application (MATLAB) is very important to know the results of surfactants' effect on rock wettability from relative permeability versus saturation curves, also to know the increase of oil recovery after injecting surfactant. Making economic study is very important to measure the success of the project that may be the specified surfactant may give a high amount of produced hydrocarbon but because of its cost, the project may take money higher than the profit.

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