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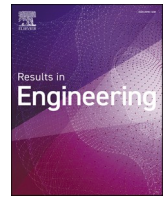Covenant University
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Investigating the effect of salt concentration on oil recovery during guar gum polymer flooding: A simulation study

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ARTICLE INFO

ABSTRACT

Reservoirs producing heavy crude oil (gravities <20) pose serious production challenges due to oil's highly viscous nature. The risks of optimizing oil production from these reserves to meet energy demands are more feasible than the financial requirements of venturing into newer fields. Water injection options in such reservoirs substantially affect the oil produced but are limited, especially when the reservoir fluid is more viscous than the injected water. Thermal options for heavy oil reservoirs are often discouraged due to loss of energy and the lighter portion of the hydrocarbon fluids, hence less expensive and environmentally friendlier options such as polymer flooding are encouraged. This study considers polymer injection options and the effects of salt concentrations as it affects heavy oil recovery us. Firstly, 6 wt %'s of Guar Gum (GG) (0.1, 0.2, 0.3, 0.4, 0.5, and 1.0) are diluted in 300 ml of water and the rheological properties estimated from these concentrations are used to build 6 different reservoir models (with an oil density of 20lb/ft3) in conjunction with polymer/salt keywords, rock and fluid properties using the Eclipse black oil model. Two salt concentrations are considered individually for each polymer concentration and a base case of natural production is considered. An oil recovery of 5.90 % (primary production), 30.78 % (water injection), 48.53 %, 48.74 %, 48.78 %, 49.18 %, 49.34 %, and 55.49 % are recorded under polymer flooding. An oil recovery of 55.04 % and 54.60 % is recorded at 5 % wt. and 10 % wt. Salt concentrations during 1 % wt. Polymer flooding. Increasing GG concentration will evidently increase oil recovery due to a higher viscosity index while increasing salt concentrations will reduce oil recoveries.

1. Introduction

A major factor that affects oil production in oil reservoirs is the density of crude oil. Heavier crude oils (API<20) will not flow easily from the reservoir to the wellbore and surface due to their high viscous nature [1]. For such reservoirs, gas injection is not advised as this leads to viscous fingering due to the high mobility nature of the injected gas thus bypassing a substantial amount of oil reserves, while water injection is feasibly of more advantage (in terms of oil recovered) over gas injection, high water cuts can be experienced resulting in water handling issues at the surface [2]. To optimize oil production from heavy oil reservoirs, the first step is a screening and ranking criterion on enhanced options of recovery [3]. have studied these optional developments and concluded that the thermal options even though deliver substantial oil recovery up to 30 %, challenges such as loss of heat, loss of lighter

hydrocarbon contents, effect on environment and facilities (downhole and surface) and costs are the major pitfalls. Chemical options like the microbial injection will reduce the heavy oil viscosity and alter wettability thus improving the oil displacement efficiencies [4] and are environmentally friendly and cheap to deploy but the waiting time required for the microorganisms to reproduce to perform its functions leads to a loss in production time [5,6].

Most of the enhanced recovery options for heavy oil reservoirs have water as their base or carrier fluids. Polymer flooding options provide a wider range of advantages such as eco-friendly, and relatively cheaper compared to other chemical enhanced recovery options [7]. Polymers, when added to the injection fluids increase their viscosity thus presenting a linear flooding pattern that leads to a higher oil recovery [8]. The advent of bio-polymer extracts from solanum tuberosum, plantain and yam peels have been studied experimentally and extensively as

Fig. 1. Electronic Weighing balance.

Fig. 2. Viscometer.
*Source: Petroleum Engineering Laboratory, Covenant University. (2023)

Table 1
Model description.

Variable	Value
Model type	Black oil
Simulation start date	November 4, 2021
Cell Dimension (X, Y, Z)	10, 10, 1
Geometry option	Cartesian
Grid option	Block centered
Unit	Field
Grid section	
Porosity	0.2
X and Y permeability	1500 md
Tops	4000 ft
Cell sizes in X, Y and Z direction	75 ft, 75 ft, 30 ft.
PVT section	
[b]Oil,[b]Water, and [a]Gas densities	20, 64, and 0.044 (lb/ft^3)
[a]Reference pressure	4000 psia
Reservoir Temperature	80 °C
[a] Rock/Water compressibility	4E-6/psi/3E-6/psi
[a]Water formation volume factor	1 rb/stb
[b]Water viscosity	0.6 cp

[a] Values obtained from the Eclipse Manual.
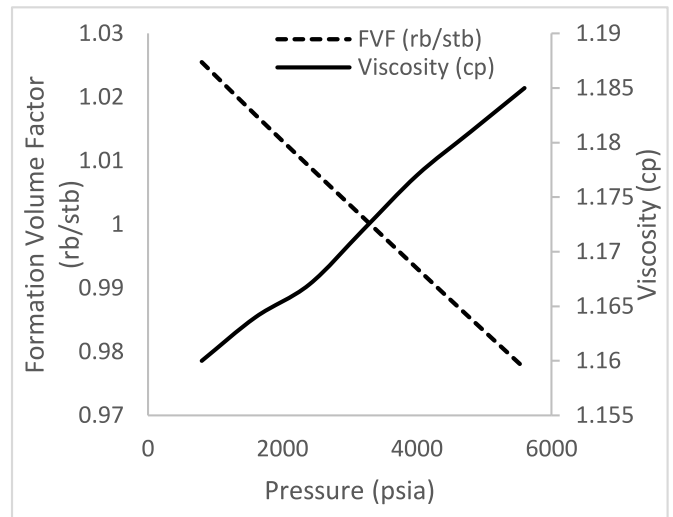[b] values measured in the laboratory.

Fig. 3. Dead Oil property.

Table 2
Viscosity/Share rate Reading for GG.

Viscosity (cp) at 30 °C						
Shear rate	1.0 wt%	0.5 wt %	0.4 wgt %	0.3 wgt %	0.2 wgt %	0.1 wt %
1021.4	53.35	25	16.75	10.65	6.85	4.95
510.69	93.2	40	24.7	17.7	10.3	6.7
340.46	126.75	50	30.15	23.25	13.2	8.7
170.23	207.3	70	43.5	35.7	22.2	14.7
102.14	300	120	61	42.5	29.5	19.5
51.07	507	200	101	61	48	35
10.21	1510	500	415	270	205	155

ecofriendly and cheaper chemicals that can be utilized during enhanced oil recovery [9]. Guar gum GG is an uncharged polysaccharide that serves the purpose of suspension, emulsifying, gelling and stabilizing agent in textile, food, petrochemical, mining, and paper for various applications. GG is easily dissolved in water unlike other gums that needs a prolonged exposure to hot water to dissolve to achieve the same viscosity strength [10]. Due to its ability to increase viscosity (a reduction in mobility) of the injecting fluid, its application has extended to enhancing oil recoveries in medium to heavy oil reservoirs with a smooth flood front without viscous fingering. Extensive experimental polymer flooding options have been carried out by Ref. [11] and the results recorded have shown an average substantial increase in oil recovery of 11 %.

There are factors that affect the performance of polymer during its use as an enhanced form of oil recovery. Such factors include temperature, injection rate, adsorption and reservoir or injection fluid salinity. During polymer flooding there are high possibilities of polymer adsorption on rock surfaces, this might be of an advantage in reservoirs with high oil rock wettability indexes as the polymer will alter the wettability [12,13] but conversely, the injecting fluids would have lost its higher viscosity potencies. The advent of temperature resistant polymers and nano coated polymers has helped to reduce the challenges arising from high temperature and polymer adsorption. Nanoparticles and nanocomposites have been studied has functional substances that helps to reduce the rate of polymer adsorption on rock surfaces by

Table 3
Viscosity/% wt. reading for GG.

	1.0 % wt.	0.5 % wt.	0.4 % wt.	0.3 % wt.	0.2 % wt.	0.1 % wt.
Viscosity	53.35	17.85	16.75	10.65	6.85	4.95
	93.2	28.4	24.7	17.7	10.3	6.7
	126.75	36.45	30.15	23.25	13.2	8.7
	207.3	57.3	43.5	35.7	22.2	14.7
	300	78	61	42.5	29.5	19.5
	507	117	101	61	48	35
	1510	410	415	270	205	155

Table 4
Polymer viscosity function and salt concentration.

Polymer	PLYVISC		PLYMAX	
	Polymer Concentration, Cp (lb/stb)	Fm	Polymer Concentration, Cp (lb/stb)	Salt Concentration, Cp (lb/stb)
A	0.01	180	0.01	0
B	0.1	220	0.1	0
C	0.004	150	0.004	0
D	0.005	170	0.005	0
E	0.05	200	0.05	0
F	0.15	245	0.15	0

Table 5
Polymer viscosity function with salt.

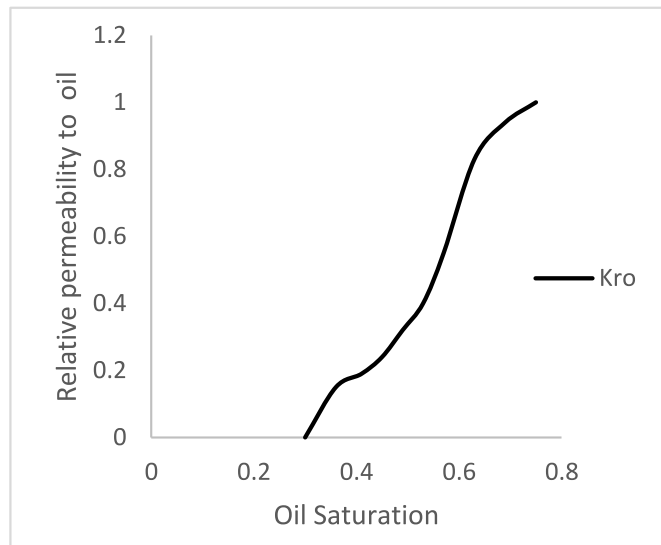| PLYVISCS @ 5 % salt		PLYVISCS @ 10 % salt	
Polymer Concentration, Cp (lb/stb)	Fm	Polymer Concentration, Cp (lb/stb)	Fm
0	1	0	1
	1		1
7	20	7	15
	2		1

Fig. 4. Oil saturation.

attaching itself to rock surfaces instead of the polymers, thus the polymer retains its full potency and functionality [14,15]. Salt concentrations have shown to be a major factor since the inherent reservoir fluids might have higher salinity thus the higher the salt concentrations, the lower the oil recoveries during polymer flooding [16]. At higher temperatures, polymers like GG disintegrate due to the weakening of the internal bonds leading to a reduction in viscosity [17,18]. High saline nature of the reservoir or the injecting fluids can also adversley polymers

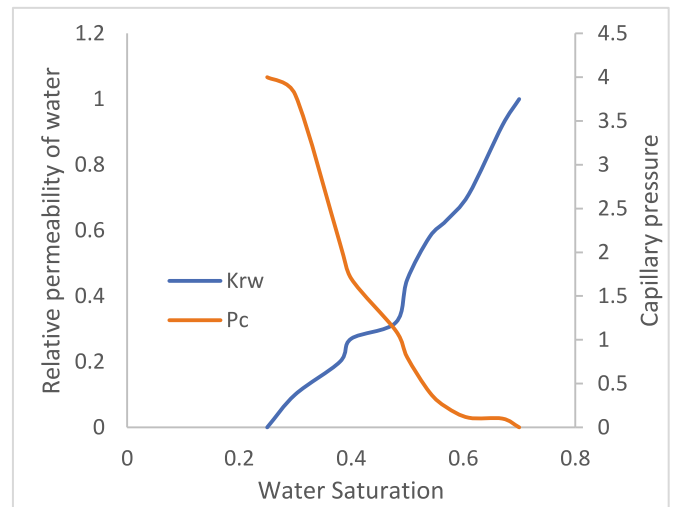**Fig. 5.** Water saturation.

Table 6
polymer rock property.

Dead pore spaces	0.16
Residual resistant factor	1.5
Mass rock density	1000 lb/b
Adsorption index	1
Maximum polymer adsorption value	0.005

Table 7
Polymer adsorption index (@ 5 % salt).

Polymer	PLC (lb/stb)	Psc(lb/lb)
A	0.01	0.009
B	0.1	0.009
C	0.04	0.009
D	0.005	0.009
E	0.05	0.009
F	0.15	0.009

Table 8
Polymer adsorption index (@ 10 % salt).

PLC (lb/stb)	Psc(lb/lb)
0	0.005
20	0.01
70	0.15

Table 9
Fluids in place.

Reservoir	Oil (stb)	Water (stb)
A	2,641,332.3	854,031.93

and they disintegrate the bonds after prolonged exposure or contact [17]. The Polymer chain stretched in distilled water due to the force of repulsion between the negative charges in the salt chain, thereby leading to a reduction in the polymer viscosity [19,20]. Experimental methods on the use of salt resistant polymers (SRP) have somewhat proven to be of advantage as the reservoir fluids salt content will have a lower effect in degrading the viscosity ratio of the polymer. The issues with SRP's are their compatibility in highly heterogeneous reservoirs with very low permeabilities and issues arising from their preparation and mixture with produced water, [21].

Bio-degradable polymers such as Xanthan gum (XG) and Arabic gum (AG) have lower viscosity values at higher gram percentages (when
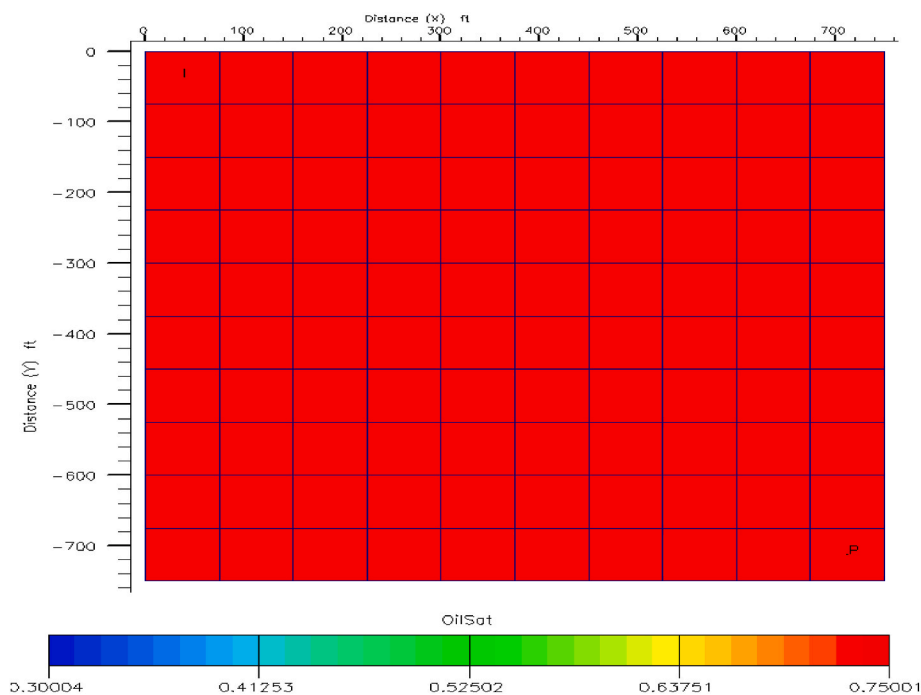
Fig. 6. Initial oil saturation.

Table 10
Well specification.

Well name	I location	J location	Group	Phase	Datum depth (ft.)
P	1	1	producer	oil	3000
I	10	10	injector	water	3000

Table 11
Well completion specification.

Well name	I location	J location	K upper	K lower	Well bore ID (ft.)	Well direction
P	1	1	1	1	1	Z
I	10	10	1	1	1	Z

diluted with water) when compared with Guar gum (GG). The presences of salt concentrations will break bond chains and further reduce viscosities in reservoirs where reservoirs where XG and AG will be deployed and this will ultimately result in lower oil recoveries, higher water cuts and loss of capital in deploying these schemes. GG on the other hand produces a higher viscosity content at low concentrations, its bonds are less weakened by present of salt, enhanced injectivity at higher pressures, and have lower affinities to be absorbed on rock surfaces [22]. Experimental studies on polymer flooding and the effects of salt concentrations have been conducted at pore scale levels with challenging issues arising from conducting experiments of multiple salt and polymer concentrations, costs, duration of the experiment and inaccurate measurements of oil recovery. Also, most studies have only considered the salt content of the injection fluid neglecting that of the reservoir and this might be impossible experimentally unless a salty oil is used or diluted with a known salt. Reservoir simulation tools such as eclipse, Mbal, CMG have been developed to perform functions such as estimating oil recoveries from different case scenarios and sensitivity analysis. Laboratory core flooding experiments usually precede field implementation of chemical enhanced oil recovery options such as polymer flooding. The experimental procedures recorded in literature are time consuming, expensive and results might be inaccurate due to

human and equipment errors during measurements and calibrations. Also, it is somewhat hard to maintain the properties of the core and fluid samples prior to the experimentation. Reservoir simulation can be a useful tool in justifying to a higher degree of certainty the results from core flooding experiments. Due to these issues a simple reservoir model can be developed to substitute experimental methods using any of these tools from available average PVT and solution data from representative reservoirs and viscosity readings from polymer/salt concentrations measured from the laboratory can be imputed using required keywords to configure such reservoir models to polymer models. The aim of this study is to investigate the effect of salt concentrations during polymer flooding. To do this, rheological properties of 6 different GG concentrations were conducted with and without presence of salt concentrations. These data are subsequently used incorporated in the Eclipse software in conjunction with representative, Grid, correlations, and equations (Equations (1)–(7)) that are used to develop the PVT and Saturation data. Options for varying other parameters such as injection rates, trajectory, oil viscosity, polymer, and salt concentrations can be easily considered as options that affect oil recoveries during polymer (with/without salt concentration) injection. 6 polymer models are developed and 12 models for case study of with/without salt concentrations. A total of 20 models are developed (counting for natural recovery and water flooding).

2. Methodology

In this study, the effect of salt concentration (NaOH) is estimated on oil recovery during Guar gum (GG) injection. Six weights of GG are measured using an Analytical laboratory weighing balance (Fig. 1) and each is dissolved in 300 mLs of water. The resulting solutions viscosities are measured using a rotary viscometer (Fig. 2). The dataset presented is used to create a simple reservoir model using the Eclipse software and the incorporation of keywords representing polymer and salt function [23]. have used similar procedures to develop complex reservoir models for alternative EOR schemes that can be deployed for heavy oil reservoirs. The preliminary model design data is shown in Table 1.

The Eclipse black oil simulator is equipped with certain variables/ functions that can be utilized to accommodate polymer properties
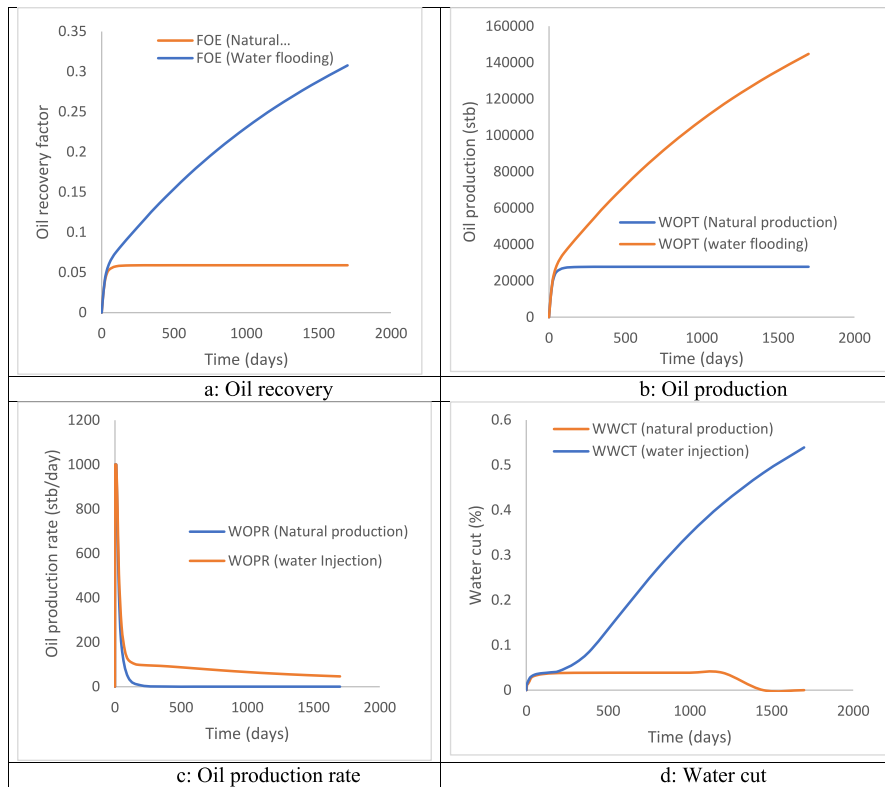
Fig. 7. 1a: Oil recovery
1b: Oil production
1c: Oil production rate
1d: Water cut.

(viscosity) and behavior (absorption) in the reservoir system. Since the model is described without a gas cap or solution gas phase, the keyword PVDO is used to describe the oil property without gas. The keyword shows the relationship between the pressure, formation volume factor and the oil viscosity (Fig. 3). Fig. 3 describes the relationship between the pressure and the fluid formation volume factor (FVF) and its viscosity. As the pressure declines, there is no substantial change in viscosity and the FVF an indication of little or no presence of gas in oil solution. The flow of the polymer concentrations through the model is assumed to have no influence on the flow of oil, therefore, standard black oil equations are therefore used to denote the oil phase in the model. Equation (1) describes the modified standard water equation, while equations (2) and (3) show the flow of polymer and brine within each grid block. The bulk pore volume for versions of the Eclipse software from 2008 onwards is described by equation (4).

$$\frac{d}{dt}\left(\frac{VS_w}{B_T B_W}\right) = \sum \left[\frac{Tk_{rw}}{B_w \mu_w effR_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w \qquad [1]$$

$$\frac{d}{dt}\left(\frac{V^* S_w C_p}{B_T B_W}\right) + \frac{d}{dt}\left(V\rho_r C_p{}^a\frac{1-\varphi}{\varphi}\right) = \sum \left[\frac{Tk_{rw}}{B_w \mu_w effR_k}\left(\delta P_w\right.\right.$$
$$\left.\left. - \rho_w g D_z\right]C_p + Q_w C_p \right. \qquad [2]$$

$$\frac{d}{dt}\left(\frac{VS_w C_n}{B_T B_W}\right) = \sum \left[\frac{Tk_{rw}}{B_w \mu_w effR_k}\left(\delta P_w - \rho_w g D_z\right)\right] + Q_w C_n \qquad [3]$$

$$V^* = V\left(1 - \frac{S_{dpw}}{S_w}\right) \qquad [4]$$

An OFITE 800 viscometer model is used to measure viscosity (at room temperature) at different dial readings using equation (7). 6 polymer concentrations are prepared by measuring 5 different weight

percentages of polymer and dissolving each in deionized water. Table 2 shows that the viscosities of the fluid samples reduce with an increase in share rate while Table 3 describes a linear relationship between the viscosity and % wt., thus as the weights increases the solution viscosity increases. Tables 4 and 5 describe the final viscosity function of polymer concentrations without salt and at the specified salt concentrations respectively.

The keywords PLYMAX is used to indicate the initial polymer/salt concentration in solution while the PLYVISC and PLYVISCS are used to represent the viscosity function of each polymer concentrations without salt and in the presence of salt. The oil (SOF2) and water (SWFN) saturation end points with their respective relative permeabilities are expressed in equations (5) and (6) and resulting plots in Figs. 4 and 5 respectively. The figures show that the ratio of decline of oil and water saturations is proportional to their relative permeabilities. The keywords PLYROCK (Table 6) is used to indicate the polymer rock properties while PLYADS (Tables 7 and 8 for salt at 5 % and 10 % respectively) represents the adsorption of polymer on rock surfaces. The adsorption causes a reduction in residual resistant factor for rock due adsorption of polymer on the rock surfaces.

$$K_{rw}(S_w) = K_{rw,or}\left(\frac{S_w - S_{cw}}{1 - S_{cw} - S_{or}}\right)^{nw} \qquad [5]$$

$$K_{ro}(S_w) = K_{rw,cw}\left(\frac{1 - S_w - S_{or}}{1 - S_{cw} - S_{or}}\right)^{nw} \qquad [6]$$

$$\eta = KF\frac{\theta}{RPM} \qquad [7]$$

At the initialization section, EQUIL keyword is used to initialize a datum depth of 3000 ft, water oil contact of 7000 ft, an initial PRESSURE and SWAT (water Saturation) of 4000 psia and 0.2 respectively for each
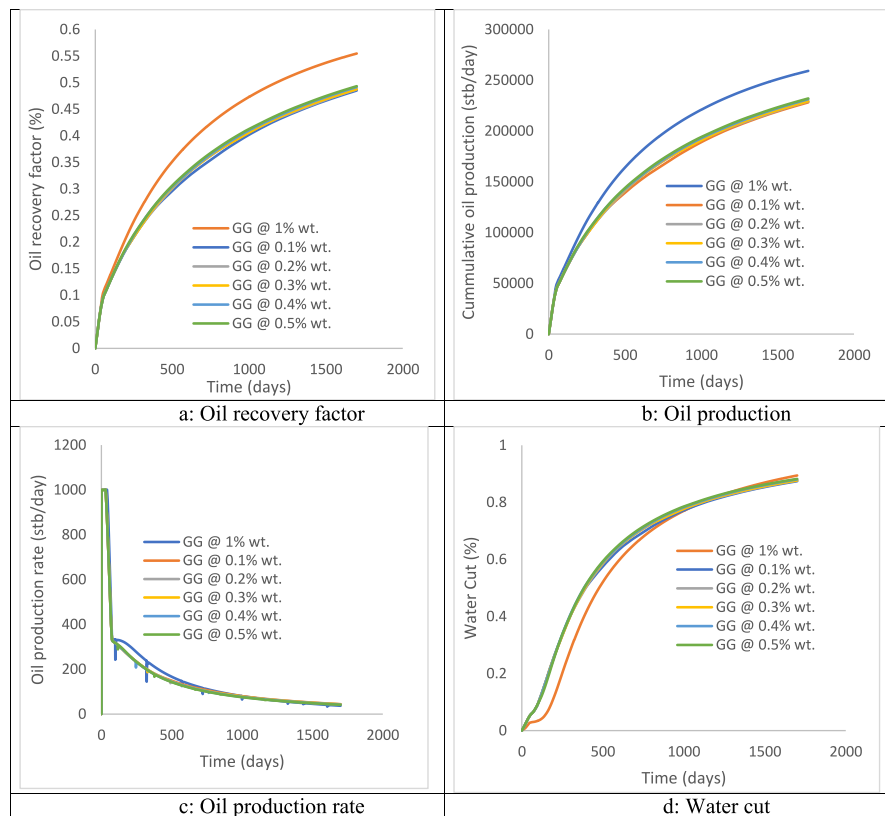
Fig. 8. 2a: Oil recovery factor
2b: Oil production
2c: Oil production rate
2d: Water cut.

cell. The model is initialized to obtain the fluids in place described in Table 9 and initial oil saturation Fig. 6 vertical wells (producer and injector) are constructed into the 2000 ft. Pay zone at 1000 stb/day respectively. Fig. 6 is the initial oil saturation of the model (i.e. the oil saturation before production began) in the first layer. Since production/injection is yet to commence, the oil saturation is expected to be high (around 75 %). This high saturation is indicated as red in the color band. When the production and injections commence, it is expected that the oil saturation will reduce to a point along the color band (i.e. from 0.75 to 0.30).

Two wells (Producer and Injector) are specified at the schedule section using the keyword WELSPEC (Table 10). The wells are connected to the reservoir using the keyword COMPDAT (Table 11). Keywords WCONPROD and WCONINJ are indicated for a production rate of 200 stb/day and water injection rate of 150 stb/day. The final polymer concentration attached to the injector well is imputed by the keyword WPOLYMER.

A base case of natural production is considered followed by water injection then (0.1, 0.2, 0.3, 0.4, 0.5, and 1.0) % wt. of GG. Each % wt. of GG is then subjected to 5 % wt. and 10 % wt. Salt (NaOH) concentration. A total of 20 reservoir models are designed to carry out this research and the oil recoveries, oil production, and water cuts for each case study is compared.

3. Results and discussions

Case 1. Natural Production and Water Injection

This case scenario describes both the natural production from the well using the reservoir energy and water injection process. The injector well has been initiated but has been shut in during the natural injection while the injector well is initiated with water injection options at 200 stb/day. Fig. 7.1a shows the oil recovery at 5.90 % and 30.78 % during natural and water flooding production scenarios this gives an incremental oil recovery of 24.88 %. at a cumulative oil production of 28 Mstb and 145 Mstb respectively (Fig. 7.1b).

The oil production rates recorded in Fig. 7.1c show a substantial increase/rise in oil production rate of about 102 stb/day during water injection over natural production. This increase also accounts for the substantial oil recovered during water flooding. As expected, the water cut during water injection will be higher (Fig. 7.1d) reaching a high level of 54 % indicating that most of the injected water has been produced.

Case 2. Polymer injection

Substantial increase in oil recoveries is observed over water injection during this case scenarios. An estimate of 55.49 % and 48.53 % is recorded during polymer flooding (1 % wt. and 0.1 % wt.) Fig. 8.2a. This resulted in an incremental oil recovery of 24.71 % and 17.75 % over water flooding. The trend in decline of the production rates (Fig. 8.2c) follows that of Fig. 7.1c at 100 days, but at a higher rate of 339 stb/day. This substantial increase in rates is also observed in the cumulative oil production recorded in Fig. 8.2b. Volumes of the injected water and those produced due to increase in oil produced will evidently increase the water cuts to an average 88 %.

Case 3. Salt Concentration at 5 %

A reduction in oil recoveries is estimated during each polymer concentration injection at 5 % wt. At 1 % wt. and 0.1 % wt., an oil recovery factor of 55.05 % and 48.11 % is recorded (Fig. 9.3a). This estimate shows a reduction in oil recoveries of 0.44 % and 0.41 % when compared with case 2. Fig. 9.3b describes the profiles of the cumulative oil produced (in comparison with case 2) dropped from 259272 stb to
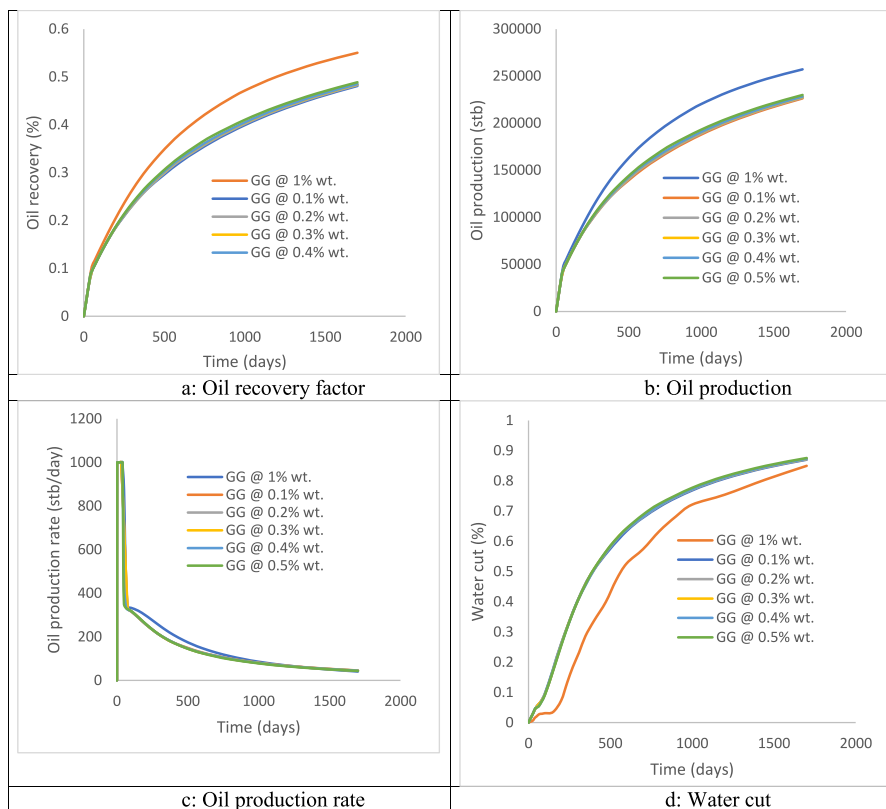
Fig. 9. 3a: Oil recovery factor
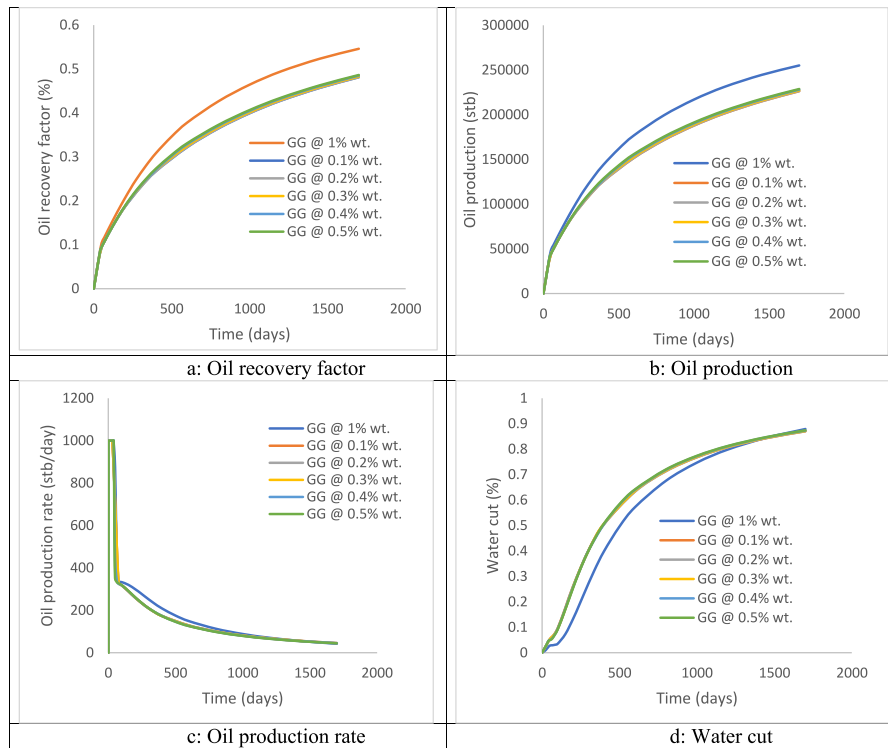3b: Oil production
3c: Oil production rate
3d: Water cut.

Fig. 10. 4aOil recovery factor
4b: Oil production
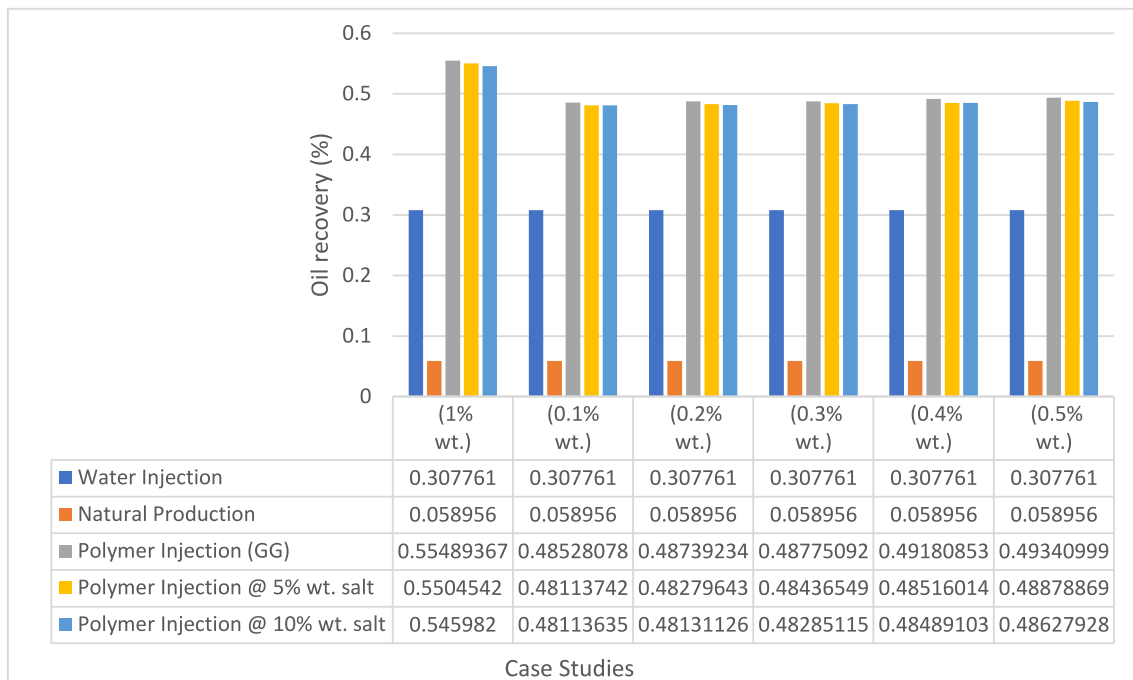4c: Oil production rate
4d: Water cut.

Fig. 11. Summary of oil recovery.

257174 stb (for 1 % wt.) and 228306 stb to 226345 stb (for 0.1 % wt.). An indication of this reduction is highlighted in Fig. 9.3c as the average oil production rates dropped from 1000 stb/day to 334 stb/day (at 65 days) before a gradual decline to 44 stb/day at 1700 days. Average water cuts of 87 % is recorded during this case scenario (Fig. 9.3d).

Case 4. Salt Concentration at 10 %

A further reduction in oil recoveries and oil produced is noticed during each polymer injections during this case study. At 1 % wt. and 0.1 % wt. respectively, an oil recovery of 54.60 % and 48.11 % is recorded (Fig. 10.4a). This estimate shows a reduction in oil recoveries
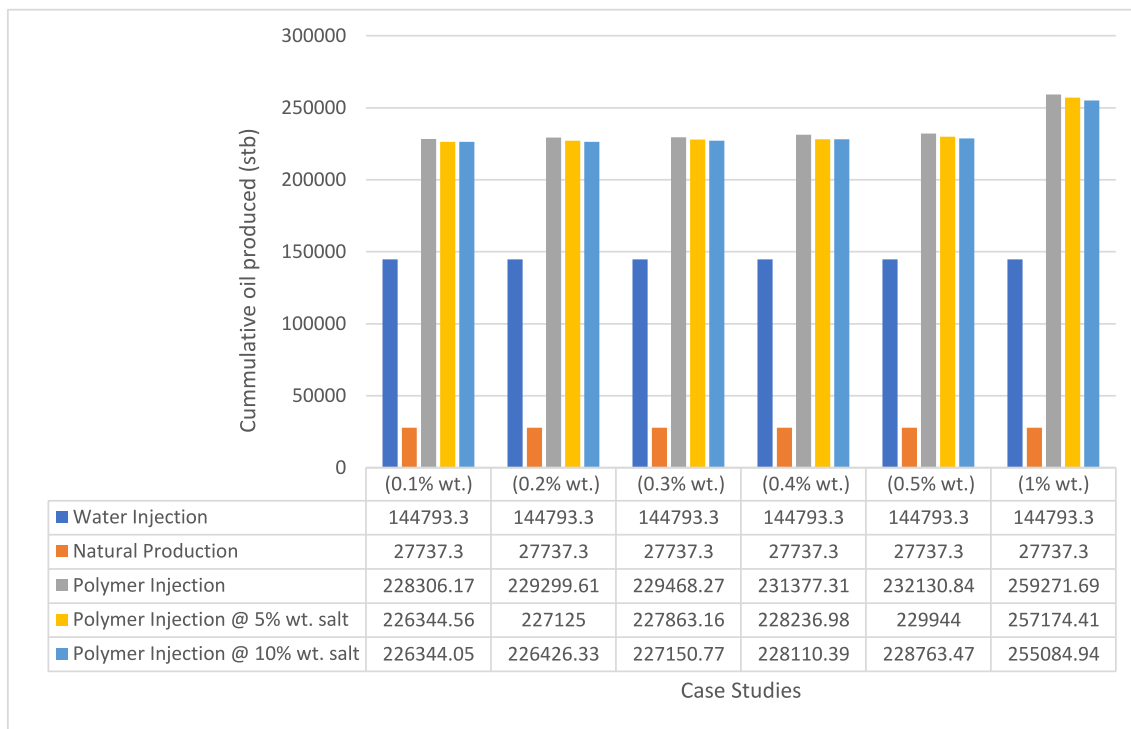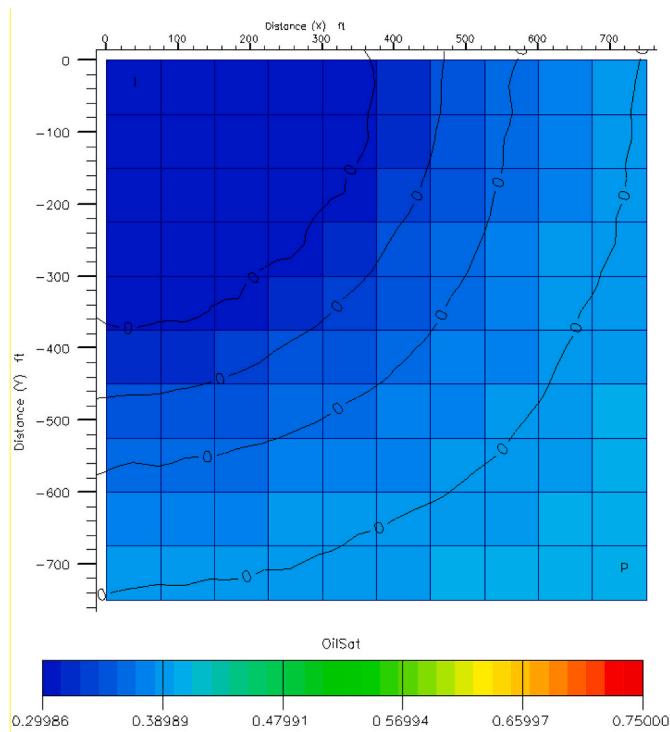
Fig. 12. Summary of Cumulative oil production.

	(0.1% wt.)	(0.2% wt.)	(0.3% wt.)	(0.4% wt.)	(0.5% wt.)	(1% wt.)
■ Water Injection	144793.3	144793.3	144793.3	144793.3	144793.3	144793.3
■ Natural Production	27737.3	27737.3	27737.3	27737.3	27737.3	27737.3
■ Polymer Injection	228306.17	229299.61	229468.27	231377.31	232130.84	259271.69
■ Polymer Injection @ 5% wt. salt	226344.56	227125	227863.16	228236.98	229944	257174.41
■ Polymer Injection @ 10% wt. salt	226344.05	226426.33	227150.77	228110.39	228763.47	255084.94

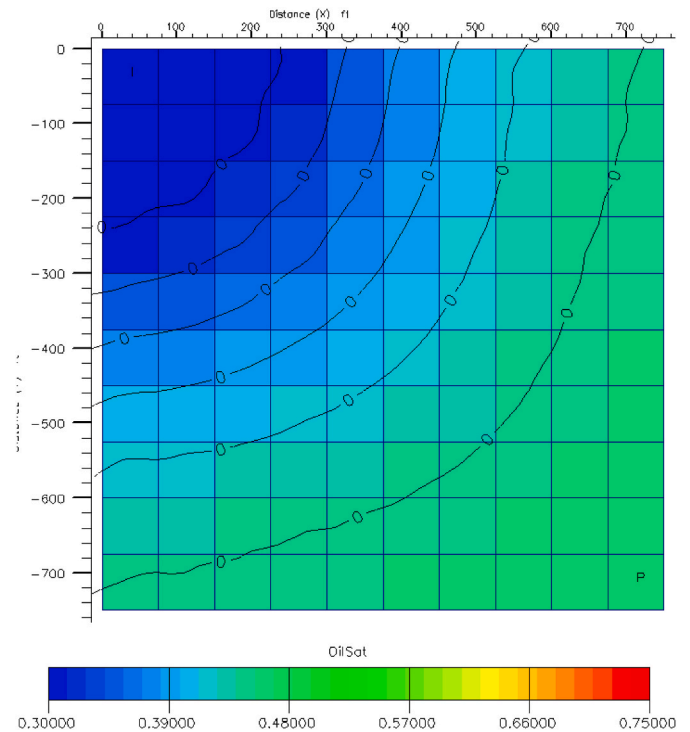**Fig. 13.** Final oil Saturation at Polymer 1 % wt.

Fig. 14. Final oil Saturation at Polymer 0.1 % wt.

of 0.45 % and 0.0001 % (for case 3) and 0.89 % and 0.41 % (for case 2) at 1 % wt. and 0.1 % wt. respectively. The cumulative oil produced at these concentrations is 255 Mstb and 226 Mstb (Fig. 10.4b) which signifies a little reduction in in oil produced of (4187 stb and 1962 stb) for case 2 and (2090 stb and 0.51 stb) for case 3. The oil production rates, and water cuts recorded are similar to those in case 3 as production rates

dropped from 1000 stb/day to an average of 331 stb/day after 60 days and water cuts of 88 % (Fig. 10.4c and d).

Figs. 11 and 12 is describes is a summary of the recovery factors and cumulative oil produced from the case studies. figures (11 and 12) briefly show the increment in oil (recovery & produced) at respective polymer concentrations over water flooding and natural production. The oil production profiles for water injection and natural production
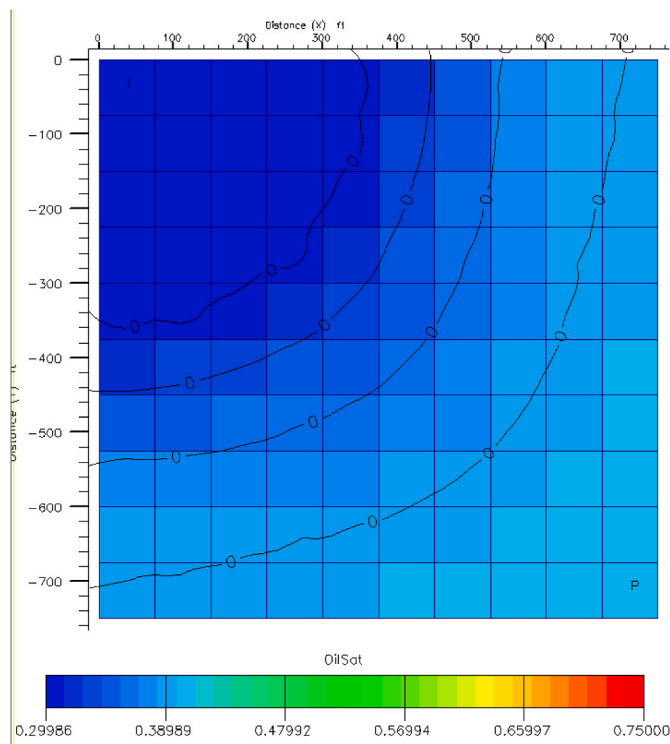
Fig. 15. Final oil Saturation at Polymer 1 % wt. and salt at 5 % wt.

are kept constant for comparative purposes. Figs. 13 and 14 show the final oil saturation profiles after polymer flooding at 1 % wt. and 0.1 % wt. In comparison with Fig. 6 (red notation for high oil saturation), substantial oil has been pushed from the injector well to the producer well (a shift in high oil saturation (red band) to low oil saturation (low band, either blue or green) due to the effectiveness of the polymer. Fig. 14 shows a substantial volume of oil saturation still left behind because of the lower viscosity nature of the injecting fluid. Due to the lower nature of the injecting fluid, a substantial amount of oil is left untapped thus leading to a substantial amount of oil saturation (green region towards the producer well). The injector well in the first cell on the top left has pushed a significant amount of oil to the producer well in the first cell in the bottom corner. Oil saturation has reduced from 0.75 % to around 0.31 % and 0.35 % for Figs. 13 and 14 respectively. Figs. 15

and 16 show the final oil saturation at 5 % wt. and 10 % wt. Salt during polymer 1 % wt. injection. The effect of increasing salt concentration is shown judging by the lower number of lighter blue boxes corresponding to the oil saturation band, in Fig. 15, compared to Fig. 16. Figs. 15 and 16 show higher volumes of oil around the producer well still left behind compared to those accumulated around the injector well.

4. Conclusion and recommendation

This study has shown that Guar gum injection %wt. (0.1, 0.2, 0.3, 0.4, 0.5, and 1.0) resulted in an incremental oil recovery of about (17.8 %, 17.96, 18 %, 18.40 %, 18.56 %, and 24.71 %) respectively over water injection. As the GG concentrations increases, oil recoveries also increased minimally. Due to this, it is advised that the economics of increasing the polymer concentrations (especially GG) be weighed against the oil to be recovered. The presence of salt concentrations (at 5 % wt. and 10 % wt.) in the polymer mixture or reservoir fluids reduces the overall oil recovery at each guar gum concentration, and this reduction in oil recoveries is more pronounced as the salt concentration increases. The results have shown that the effect of salt concentrations on oil recovery reduces from the injector to the producer well. This is evident in the substantial amount of accumulated oil left in place around the producer well. It is also recommended that options for low salinity water flooding [24,25] or freshwater flooding be initiated in reservoirs with high saline contents before polymer flooding. Salt resistant polymers can be deployed as a cost effective EOR choice as they maintain a higher viscosity retention rate and increase oil recovery, [26]. It is also recommended that economic implications on the increased water cuts during polymer flooding should be considered if it justifies the increment in oil recovered.

Ethical statement

The experimental procedures do not involve any experimentations on humans or animals.

CRediT authorship contribution statement

Oluwasanmi Olabode: Writing – original draft, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Babalola Oni:** Investigation, Formal analysis, Data curation, Conceptualization. **Humphrey Dike:** Resources, Project administration, Methodology. **Oluwatimilehin Akinsanya:** Writing – review & editing, Writing – original draft, Validation. **Johnson Ajidahun:** Visualization,
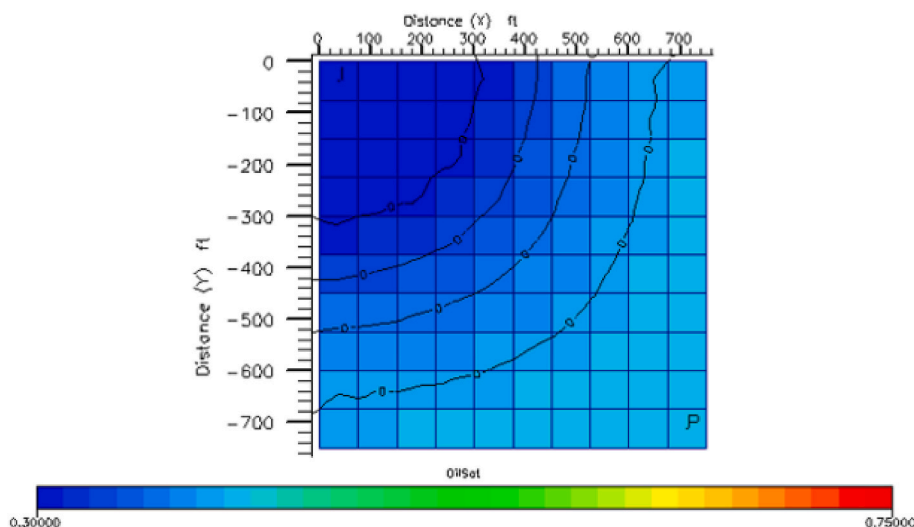

Fig. 16. Final oil Saturation at Polymer 1 % wt. and salt at 10 % wt.

Validation, Supervision. **Deborah Olaniyan:** Project administration, Supervision, Validation, Writing – review & editing.

Declaration of competing interest

The authors declare that there are no conflicting interests as regards the development of this article.

Data availability

Data will be made available on request.

Nomenclature

S_{dpv}	*denotes the dead pore space within each grid cell*
$C_p{}^a$	*denotes the polymer adsorption concentration,*
ρ_r	*denotes the mass density of the rock formation*
φ	*denotes the porosity*
ρ_w	*denotes the water density,*
Σ	*denotes the sum over neigbouring cells*
R_k	*denotes the relative permeability reduction factor for the aqueous phase due to polymer retention,*
C_p, C_n	*denotes the polymer and salt concentrations respectively in the aqueous phase*
μ_{aeff}	*denotes the effective viscosity of the water $(a = w)$, polymer $(a = p)$ and salt $(a = s)$.*
D_z	*is the cell center depth,*
B_r *and* B_w	*are the rock and water formation volumes,*
T	*is the transmissibility,*
K_{rw}	*is te water relative permeability,*
S_w	*is the water saturation,*
V	*is the block pore volume,*
Q_w	*is the water production rate,*
P_w	*is water pressure,*
G	*is gravity,*
η	*is viscosity in centipoise,*
θ	*is the viscomter dial reading,*
F	*is the spring factor,*
K	*is the machine cnstant of the rotor,*
PVT	*is the pressure, volume and temperature properties of the reservoir fluids,*
$PVDO$	*is the dead oil property,*
$PVTW$	*is the water property,*
$SOF2$	*is the oil saturation function,*
$SWFN$	*is the water saturation function,*
$wt. =$	*weight,*
$\%wt. =$	*Percentage weight,*
$\frac{lb}{ft^3} =$	*pounds per foot cube,*

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