Reservoir Management Strategies for Development of Water Injection Planning Project

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Abstract

Planning development strategies of oil reservoirs is a very important stage in the reservoir management. Nevertheless, predicting reservoir performance has a large degree of uncertainty. Reservoir simulation studies are usually performed to quantify this uncertainty. Thus, the reservoir simulation has become an important tool for the development and management of petroleum reservoirs. The process consists of the construction and operation of a numerical model, which represents the actual reservoir, to analyze and predict the reservoir fluid behavior.

One of the reservoir management strategies is the process of injecting water into the aquifer to maintain the reservoir energy and enhance the oil recovery. This study aims to present development planning strategies to support managers in the decision making process of water injection for oil fields under given operational and economic restrictions. The sensitivity of the voidage replacement ratio (VRR) was studied to obtain the best water injection planning strategy to maximize oil production recovery and therefrom profitability. Various planning development strategies were implemented utilizing different VRR values ranging from 0.65 to 2. The results show that the best planning development strategy increases the oil recovery factor from 31.74% (base case) to 32.08% at VRR of 0.75.

Keywords
Reservoir management, reservoir simulation, reservoir modeling, water injection, voidage replacement ratio (VRR)

1. Introduction
Before 1970, reservoir engineering was considered the most important technical item in the management of reservoirs and most people considered reservoir management synonymous with reservoir engineering (Essley, 1965). After 1970, some people explained the value of synergism between engineering and geology and emphasized the detailed reservoir description, utilizing geological, geophysical and reservoir simulation concepts to provide a more accurate reservoir description to be used in engineering calculations (Craig et al., 1977, Harris and Hewitt, 1977).

The success of reservoir management is greatly influenced by the reservoir production performance under the current and future operating conditions. The accuracy and reliability of the results are affected by the quality of the reservoir simulation model used to make reservoir performance analysis. A reservoir simulation model can simulate many scenarios for the reservoir under different development strategies and thus provides a powerful tool to optimize the reservoir operation. The process of developing a sound reservoir model plays a very important role in reservoir management. However, production optimization is performed using the reservoir models to simulate, predict and optimize the production performance to maximize asset value.

One of the primary duties of reservoir management is to optimize recovery from a reservoir. There are numerous avenues to pursue. When the original reservoir energy is exhausted in an oil reservoir, energy often can be added to the reservoir. One way in which energy is added to the reservoir is by injecting water in specifically determined locations to supplement the natural energy that is indigenous to the reservoir. This, in return, improves the oil-production characteristics of the field before the economically productive limits are reached. Its popularity is accounted for by the general availability of water, the relative ease with which water is injected and the ability with which water spreads through an oil-bearing formation and water's efficiency in displacing oil.

In earlier practices, water injection was done in the later phase of the reservoir life, but now it is often carried out in an earlier phase to avoid the creation of voidage in the secondary gas cap. Using water injection in earlier phases helps in improving production, because once the secondary gas cap is formed the injected water initially tends to compress the free gas cap and later on pushes the oil; therefore, the amount of required water injected is much greater. The water injection is generally carried out when the solution gas drive is present or the water drive is weak. Thus, to reduce the costs, the water injection should be carried out when the reservoir pressure is greater than the bubble point pressure. Furthermore, the key factors that drives water injection development and increasing use are; (a) water is inexpensive, (b) it is generally readily available in large quantities from nearby streams, oceans, produced water, or wells drilled into shallower or deeper subsurface aquifers, (c) water injection effectively made production wells that were near the water-injection wells flow or be pumped at higher rates because of the increased reservoir pressure.

Nystad (1985), Damsleth et al. (1992), Beckner and Song (1995) utilized simulation and developed methods for the optimization of problems related to the development and management of petroleum reservoirs. Asheim (1987) used the reservoir simulation to calculate the objective function (NPV) and implicit differentiation to calculate the gradients of the objective function with respect to the optimization variables (well production rates). The production and injection rates, in one producer and two injectors, were optimized to maximize NPV. He achieved 4.5% improvement on NPV comparing to a heuristic case. van Essen et al. (2009) used a bigger synthetic reservoir model for water injection optimization using multiple geological scenarios. The model was 3D, two phase (oil & water) reservoir with 18,553 active grid blocks, consisting of seven geological layers. The model was used in some other studies (Jansen et al., 2009; Van Essen, 2011) for further investigation of closed-loop reservoir management and production optimization approaches. Asadollahi and Naedal (2009) used a history matched model for Brugge field to investigate the effect of different formulations on the optimization problem. They found the production and water injection rates to be more efficient optimization variables than the well bottom-hole pressures for the Brugge field case.

The objective of this work is to present a methodology to support managers in the decision making process for water injection planning optimization for the given oilfield under operational and economic restrictions. Different scenarios of water injection techniques were verified by changing control data for injection wells, and altering the value of voidage replacement ratio (VRR). The voidage replacement refers to replacing the volume of oil, gas, and water produced from the reservoir by injected fluids. VRR is the ratio of reservoir barrels of injected fluid to reservoir barrels of produced fluid. The VRR analysis aids in identifying parts of a field where more or less water must be injected in order to reach or maintain VRR targets. Mathematically VRR can be expressed as follows

$$\mathrm{VRR} = \frac{\text{water injection rate} + \text{water aquifer rate}}{\text{liquid production rate}} \tag{1}$$

Some researchers attempted to achieve the optimal VRR for polymer flooding. Among them were Delgado (2012), Delgado et al (2013), San Blas and Vittoratos (2014), and Brice et al. (2014). Others reported that the success of waterflood projects depends on optimal VRR management. Vittoratos (2013) noted that the current paradigm of VRR = 1.0 for the duration of the waterflood is optimal. In 2014, Vittoratos and Zhu developed a methodology for the quantification of the relative importance of the mechanisms activated by VRR < 1. The authors noted that the absolute value of the VRR < 1 depends primarily on the oil quality and its associated properties, whereas the optimal time evaluation of the VRR depends on the well spacing and reservoir heterogeneity. Awotunde and Sibaweihi (2012) combined NPV and VRR in multi-objective for solving the well placement optimization problem.

2. Case Study

2.1 Field description

The field covers a productive area of 25,500 acres. It was discovered in October 1959 and started producing oil in October 1964 from three wells at a total oil rate of around 1000 bpd. The development plan began in 1968, by which forty nine wells were drilled and put on production. As of March 1970, the average reservoir pressure declined from its initial value of 2490 psi to 2141 psi due to limited water aquifer support. Therefore, pressure maintenance by water injection was started in 1970 to stop the reservoir pressure decline. As by the end of December 2010, a total of 179 oil producers were on line, the total daily average oil rate from these wells was 98,000 bpd, and the cumulative oil production was 2,400 MMbbl, which represents 66.75% from the booked oil reserves. The reservoir rocks are formed from reef limestone. Its lithology composition is very complex, consisting of a faunal assemblage representing tidal flat-lagoon to reef margin depositional environments. The reservoir bounded on the west by a major fault, whereas the south, east and north is surrounded by the lithology changes from porous limestone beds to tight marly limestone and/or shale beds. The basic reservoir data are summarized in Table 1.

Table 1. Reservoir data summary as for Dec. 2010

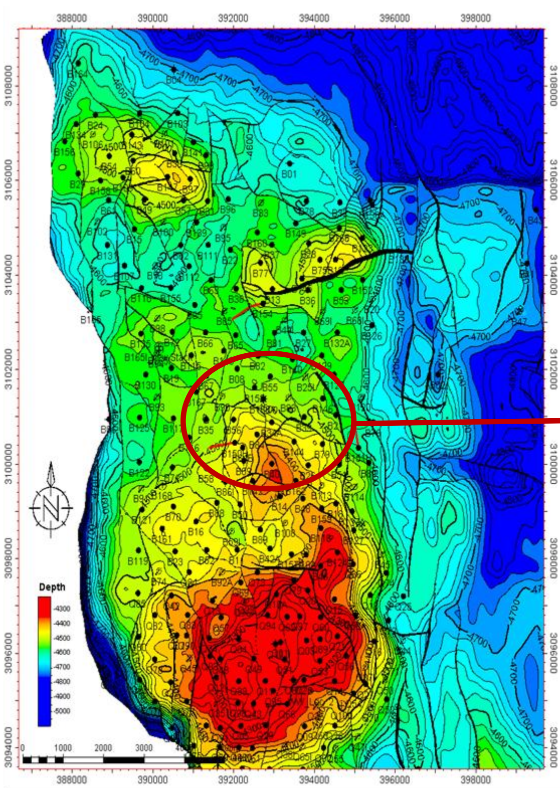
Reservoir description	Unit		Source
lithology		Limestone	
Depth	Ft	4980	
Total wells drilled to date	#	266	
Productive acreage	acres	25,457	
Average well spacing	acres/well	104	
Initial bottom-hole pressure	Psig	2490	
Current bottom-hole pressure	Psig	2310	
Reservoir temperature	ºF	158	
Rock properties			
Average porosity	%	22	Logs
Average permeability	Md	32	Core
Average water saturation	%	32	Logs
Rock compressibility	1/psi	3.4´10^{-6}	Estimated
Fluid properties			
Bubble-point pressure	Psig	1372	PVT
Diff. solution GOR	scf/stb	392	PVT
Flash solution GOR	scf/stb	330	PVT
Initial oil FVF	rb/stb	1.265	PVT
Initial oil viscosity	Cp	1.13	PVT
water viscosity	Cp	0.5	PVT
Oil compressibility	1/psi	9.6´10^{-7}	PVT
Water compressibility	1/psi	93.4´10^{-8}	PVT
Oil API gravity	API	35.6	PVT
Oil initial in place & reserves			
Oil initial in place	MMstb	9630	
Reservoir mechanism	weak water drive + water injection		
Oil recovery factor	%	37	
Recoverable oil reserves	MMstb	3595	
Remaining oil reserves	MMstb	1245	

2.2 Reservoir Simulation Model

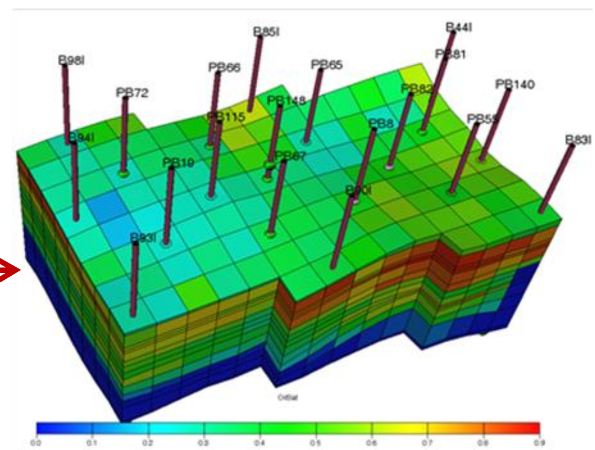
A black oil simulation model for a sector of a giant carbonate reservoir, the sector model is located in the north of the oilfield (Fig. 1a). It contains twelve oil producing wells and seven injection wells. The reservoir simulation grid is coarse model; it was built by Eclipse software after up-scaling the fine geological grid with 38×72×19 grids. Fig. (1b) shows sector model simulation grid. Different scenario of water injection was studied to obtain the optimum scenario improving the oil recovery of the sector model.

2.3 History Matching (Validate simulation model)

Once a reservoir simulation model had been constructed, the validity of the model was examined by using it to simulate the performance of the field under past operating conditions. This is usually done by specifying historical controlling rates, such as field liquid production rate versus time, and then making a comparison of the non-specified performance such as oil production rate, water production rate, and water cut with measured data. If there are significant differences between the calculated performance and the known performance of the well/reservoir system, adjustments to the reservoir simulation model are made to reduce this difference. This process is called history matching and illustrated in Figs 2, 3, 4 and 5. Dotted line represents the history production data and the solid line represents the simulation data. However, in this study, the sector model was run through the production history of 42 years (1964 – 2006). Numerous of simulation runs were made to match the field performance. A good match was achieved by changing the injecting wells productivity index. The overall field performance and quality of the history matching on the wells were at an acceptable level.



(a) Reservoir Structure Map



(b) Sector Model

Fig. 1. Reservoir structure map and sector model used in the simulator

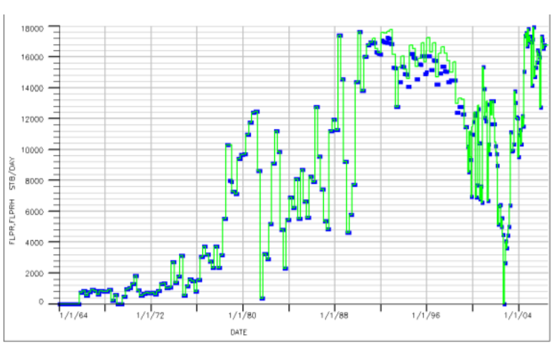


Fig. 2. History matching plot; Liquid Production rate

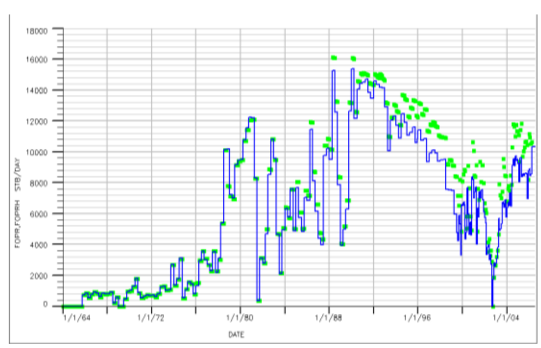


Fig. 3. History matching plot; oil production rate

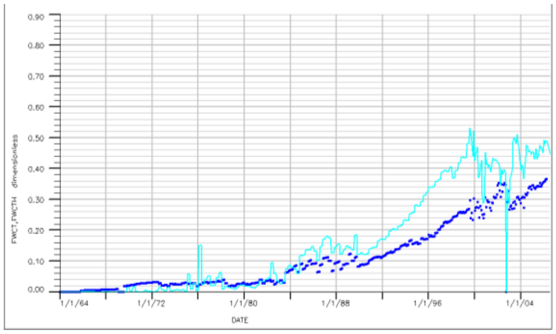


Fig. 4. History matching plot; water cut

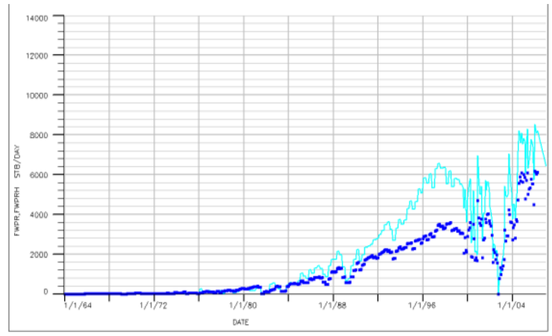
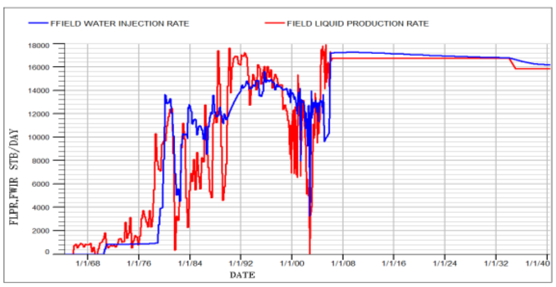
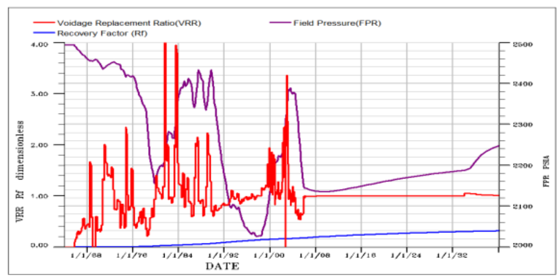


Fig. 5. History matching plot; water production rate

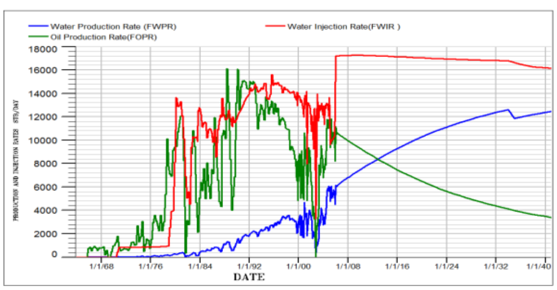
The main constrain factors made during the production runs were; (a) the production wells were set at liquid rate control mode based on the latest production data, while the control of injection rate was dependent on the VRR value, and (b) economic constrains were based on economic rate of 50 STB/D and WC greater than 95%.



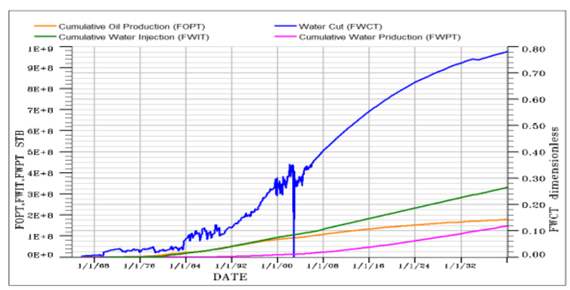
a) Q_L (red) & W_i rates (blue) vs. t



b) VRR (red), RF (blue) & p_{res} (dark blue) vs. t



c) Q_o (green), Q_w (blue) & W_i (red) rates vs. t



d) N_p (orange), W_p (purple), WC (blue) & W_i (green) vs. t

Fig. 6. Base case of the oilfield with 34 years forecasted (2006-2040)

Calculation of Voidage Replacement Ratio (VRR)

Generally, the purpose of varying VRR value was to study the sensitivity in order to optimize the best water injection planning strategy to maintain the reservoir pressure, maximize oil production recovery and therefrom profitability. However, in the base case, the assumed VRR value was taken as field volume injection rate / field volume production rate neglecting the impact of aquifer and contribution it may have on production. Based on equation 1, different scenarios are made with different VRR values of 0.65, 0.7, 0.8, 1.0, 1.5, 1.7 and 2. The existing wells (twelve production wells and seven injection wells) were set at liquid rate control mode based on the latest production data, throughout the 42 years history time and prediction period of 34 years (2006 – 2040). The injection rate ranged from 16200 to 17100 STB/D, and VRR was assumed unity. Fig. 6 represents the base case of the oilfield with forecasting 34 years ahead (2006 – 2040). Table 2 exemplifies the simulation results of the bas case.

The main constrain factors made during the production runs were; (a) the production wells are set at liquid rate control mode based on the latest production data, while the control of injection rate was dependent on the VRR value, (b) economic constrains were based on economic rate of 50 STB/D and WC greater than 95%, and (c) the new wells were set at liquid rate control.

Table 2. Simulation results of the base case of the oilfield with 34 years forecasted (2006-2040)

Recovery factor, *RF*	31.74%
Reservoir average pressure	2247 psi
Cumulative oil production, N_p	178.907 MMSTB
Water cut, *WC*	78 %
Cumulative water injection , W_i	330 MMSTB
Cumulative water production , W_p	147.75 MMSTB

4. Results and Discussions

The results show the current paradigm of VRR = 1.0 is not optimal. Besides, the simulation runs show that at VRR equals to 0.65 the reservoir pressure (1348 psi) declined below the bubble point (p_b = 1400 psi), which led to the rejection of this scenario. From the other side, at VRR of 2 the sector provides the same performance of 1.5. That is due to the sensitivity of the model sector to VRR values greater than 1.5. On the other hand, the model sector provides a higher *RF* (32.8%) at VRR of 0.75. The model's predicted performance at different values of VRR in 2040 is summarized in Table 4. The best scenario was noted at VRR of 0.75, which provides the best reservoir performance. The RF improved from 31.74% (base case) to 32.08%; that is an increase by 0.34%. The cumulative oil production (N_p) increased from 178.907 MMSTB to 180.81 MMSTB; that is an increase by 1.903 MMSTB. Fig. 7 clarifies the reservoir performance of the 0.75 VRR scenario, and Fig. 8 explains the difference between the two scenarios. The simulation results are summarized in Table 3, and the relationship between the RF and VRR values is presented in Fig. 9.

Table 3. Impact of varying VRR value on recovery factor and reservoir pressure

VRR	0.65	0.75	0.8	1.0	1.5	1.7	2.0
RF, %	32.05	32.08	32.00	31.59	30.9	30.9	30.9
p_{res}, psi	1348	1511	1677	2395	3650	3650	3650

Table 4. Impact of Varying VRR value on reservoir Performance

Production performance	VRR values			
	0.75	0.8	1	1.5
RF, %	32.08	32	31.59	30.9
p_{res} , psi	1511.26	1677	2395	3650
N_p, MMSTB	180.81	180	178.04	174.36
WC, %	76.32	77	78.38	80.33
W_i , MMSTB	286.95	300.84	345.45	413.18
W_p , MMSTB	144.172	147.032	150.9	154.29

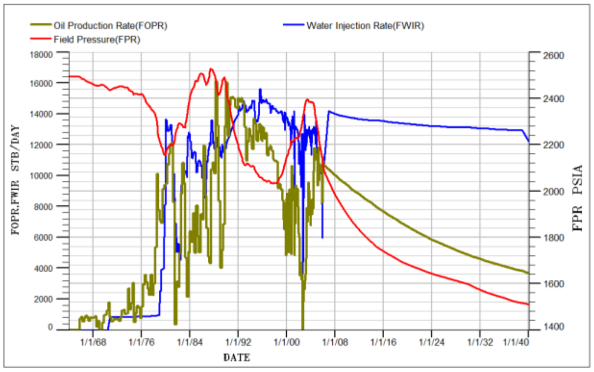


Fig 7. The reservoir performance of the 0.75 VRR scenario. Q_o (green), W_i (blue), and p_{res} (red)

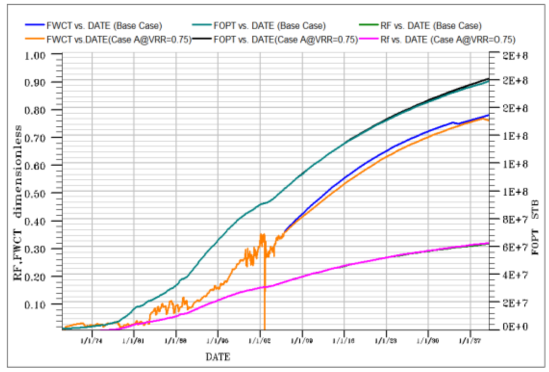


Fig. 8. The difference between the two scenarios. Base case WC (blue), base case Np (green), base case RF (dark green), 0.75 *VRR* scenario WC (orange), 0.75 *VRR* scenario Np (black), 0.75 *VRR* scenario RF (purple)

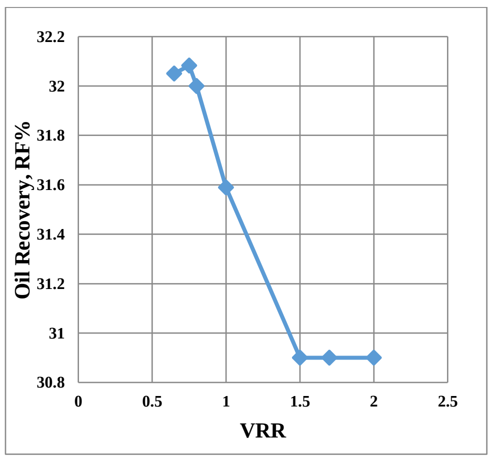


Fig. 9. Impact of varying VRR value on recovery factor

Conclusions

Based on the simulation results and the sensitivity analysis of the VRR performed, the following conclusions could be noted:

- A black oil simulation model for a sector of a giant carbonate reservoir was constructed. The sector model contains twelve oil producing wells and seven injection wells. The model was up-scaled the fine geological grid with 38×72×19 grids.
- The sensitivity analysis of VRR values ranged from 0.65 to 2 was implemented by different scenarios to obtain the best planning strategy of water injection to maximize RF and therefrom profitability. The results show the current paradigm of VRR = 1.0 is not optimal. Besides, at VRR of 0.65 the reservoir pressure (1348 psi) declined below the bubble point (p_b = 1400 psi), which led to the rejection of this scenario. From the other side, at VRR of 2 the sector provides the same performance of 1.5. That is due to the sensitivity of the model sector to VRR values greater than 1.5.
- The model delivers a best RF of 32.08% at a VRR value equals to 0.75 resulting in an increase in N_p by 1.903 MMSTB.

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Biography

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