International Journal of Sciences: Basic and Applied Research (IJSBAR)

ISSN 2307-4531
(Print & Online)

http://gssrr.org/index.php?journal=JournalOfBasicAndApplied

Reservoir Simulation Model Using Water Injection and Water Alternating Gas Injection Techniques in KEYI Oilfield, Moglud Basin, Sudan

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Abstract

Simulation is only way to describe quantitatively the flow of multiple phases in a heterogeneous reservoir. Construction of reservoir simulation model requires a lot of data such as the types of rock and fluid properties. Enhancing the recovery of an oil reservoir is one of the major roles of any oil company. This is achieved by development of the oilfields by employing different techniques such as infill drilling, water injection, gas injection, water alternate gas (WAG) injection and even thermal methods. Reservoir simulation studies using water injection and water alternate gas injection for KEYI oil field, Muglad Basin, Sudan. The purpose of this simulation study is to determine the suitable method for increase and enhanced oil recovery. The simulation model was developed using two-phase, 3D and black oil options in ECLIPSE soft ware. Finally, the simulation result showed that water alternating gas technique is the best method to improve oil recovery from KEYI oil field, Muglad Basin, Sudan.

Keyword: Water injection; Water alternating gas injection; Eclipse software; KEYI oil field; Reservoir Simulation.

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1. Introduction

1.1 Background

Enhancing the recovery of an oil reservoir is one of the major roles of any oil company. This is achieved by development of the oilfields by employing different techniques such as infill drilling, water injection, gas injection, water alternate gas (WAG) injection and even thermal methods. Hydrocarbon is produced from the subsurface through primary, secondary and tertiary (enhanced recovery, EOR) methods. Primary recovery refers to the recovery of the oil by relying solely on the natural energy of the reservoir [1]. Secondary recovery are recovery techniques used to augment the natural energy of the reservoir by artificially injecting fluid (gas or water) into the reservoir to force the oil to flow into the wellbore and to the surface [8]. The main objective of a secondary recovery program is to sweep the oil towards the production wells for increased productivity. Secondary recovery is also used to restore and maintain reservoir pressure, which normally declines during the primary recovery phase. Due to its capital intensive nature, secondary recovery should only be employed when primary recovery is no longer economically viable to recover the oil [7]. Water and gas injection are the secondary recovery methods. Water injection is the most common method of secondary recovery. In this process, water is injected into the reservoir to maintain the pressure and also to sweep the residual oil. In order to select the most economical scenario of water injection, a tool to forecast performance is essential [3]. Gas injection is the act of injecting gas into an oil reservoir for the purpose of effectively sweeping the reservoir for residual oil as well as maintenance of pressure. Substantial quantities of oil normally remain in the reservoir after primary and secondary recovery. A significant portion of this residual oil can be economically recovered through Water –Alternating-Gas injection [4]. Water alternating gas injection (WAG) also referred to as combined water and gas injection (CGW) is an enhanced oil recovery (EOR) method where water and gas injection are carried out alternately in a reservoir for a period of time in order to provide both microscopic and macroscopic sweep efficiencies and reduce gas override effect. The alternate injection of gas and water slugs increases mobility control and stabilizes the displacement front [9]. Displacement of oil by gas has better microscopic efficiency than by water and displacing oil by water has better macroscopic sweep efficiency than by gas. So WAG injection improves oil recovery by taking advantage of the increased microscopic displacement of gas injection with the improved macroscopic sweep efficiency of water flooding. Compositional exchanges between the oil and gas during WAG process can also lead to additional recovery [9]. This project comes from some form present a new method for recovering residual oil, which can be successfully applied in oil field located in Muglad basin in Sudan known as the "KEYI Oil Field." This oil field divided into Ghazal and Zarqa layers, which divided according to the stratigraphy and development of sand bodies, in Zarqa, Ghazal layers, more than dozen individual sand bodies are classified detailed, but there are 6 main oil-bearing sand layers respectively, GA4, GA5, GB1, ZD1, ZD2, ZD3. The research of water injection and WAG is to do for these substrata. The secondary technique and tertiary recovery technique of oil, which studies in the area under study, were known as water injection and water alternating gas (WAG) injection techniques. Water Alternate Gas (WAG) injection technique of oil combines the advantages of the water flooding and gas injection methods to control the gas mobility and optimize the residual oil production.

2. Material and Methods

The main scope of the present work is to make a simulation study into the KEYI oil field in order to optimize the oil recovery. Use water injection (WI) and water alternating gas (WAG) injection techniques. In order to accomplish the aim of this study, reservoir simulation ECLIPSE software was used. Import the geological model file in ECLIPSE and review all the grid blocks and make the beginning of data evaluation. Prepare all the data and put it in format to be run by eclipse software. Interpretation consists of the following stages:

1. Run the simulation to get the original oil in place and compare it with the result from the geological model.
2. Review the simulation results to compare -well rate vs. time, water cut vs. time, cumulative production vs. time for all the wells and for the field- with actual data. Also match the pressure history (BHP) and see if it's similar to actual field running program.
3. Run the simulation several times and correct the parameters that can be change (aquifers data, relative permeability and capillary pressure functions) till the result of simulation and actual data become similar to each other. (In other words; force the simulation to give the past performance). At this time the result of simulation will accept and the model will be valid for develop works and future characteristics corrections.
4. Forecast the future performance by adding a new future time (20 years or more)
5. Plan some prediction cases (as example: to test the future well productivity; more than one well oil rate, injection rate will be select and compare between the cases to see the suitable one).
6. Add a new well and review the result to see if it is economic or not.
7. Plan some cases to test:

   1. Water injection

   2. Water – Alternating –Gas injection (WAG)

8. Comparison between cases.

2.1 Guidelines and Strategy of Simulation Model

The production data from all the wells in KEYI oil field was collected from September 2010 till December 2011 (456 days) and entered as a history data for *BLACK OIL* simulator (ECLIPSE). There are 13 production wells in the area under study. History match was done by input liquid rate to match other indicators pressure, water cut and oil production. Oil rate was used as a production control for all the wells in the period till 456 days. The values of oil rate, water rate, and gas rate were entered directly in historical production well data. 5350 ft is used as a datum depth for all the wells in well specification data. Fixed liquid rate and minimum bottom Hole pressure target were used to predict the future performance for 20 years (7791 days).

2.2 Reservoir 3D Model

KEYI oil field started production from 6 intervals namely, GA4, GA5, GB, ZD1, ZD2, and ZD3. All of these layers distributed in the formations named, the Ghazal Formation, and Zarqa formation. Core analysis and well logging showed that the reservoir rock is characterized by both medium to high porosity and medium to high permeability. Based on that information the reservoir model for the KEYI area is developed using three-phase, 3D and black oil options in Eclipse software. The grid dimension is (49x63) with (3087) grid blocks in the horizontal direction and (12) grid blocks in the vertical direction. A total number of (37044) grid blocks were used to simulate the area. Table 1 shows the regions average grid parameters.

Table 1: Regions average grid parameter

Reservoir properties	Reservoir Regions					
	1	2	3	4	5	6
Name	GA	GB	GD	GH	ZA	ZC
Layers	1-2	3-4	5-6	7-8	9-10	11-12
Formation Pressure (psia)	2534.3	2569.9	2682.3	2800.9	2867.3	3072.8
Depth(ft)	4697.3	4779.3	5038.3	5311.6	5464.8	5938.3
Thick(m)	9	22	34	24	16	6
Net Pay(m)	3.9	4.0	11.8	11.9	5.2	11.8
OWC(ft)	4697.1	4779.3	5016.3	5311.6	5464.8	5973.8
Average Porosity (%)	25.7	24.3	20.8	21.3	19.9	20.9
Average K (Kx = Ky)(md)	1224.3	912.7	531.4	527.8	1544.1	1060.2
S.Gravity API	29.2	18.6	29.5-35.6	33.5-38	31.2	31.6
So %	77.0	75.0	67.0	68.0	65.0	67.0
Bo bbl/stb	1.04	1.04	1.04	1.05	1.05	1.05

2.3 KEYI oil field overview

KEYI area is located in Block 6 close to the North flank of Muglad basin flank area, 600 km to the west of Khartoum. It is situated to the North West of the Fula oil field. The southern East part of 3D area of KEYI field is 32.5 km far from Baleela camp. There are three main oil pools namely are KEYI North, KEYI Main, KEYI South the total area 126 km. All these oil fields are distributed within the area covered by 126 sq km 3D seismic survey. It is a part of trend of Cretaceous sedimentary basin of apparent rift origin related to the global phenomenon of plate tectonics. Wells and seismic data from the Sudan basin confirmed thick continental facies of cretaceous and younger age. The original oil in place (OOIP) was 40.6 MMSTB; the cumulative oil production was 0.65 MMSTB KEYI Oilfield structure is a fault nose; the internal structure is simple with no obvious faults. Structure relief is less than 100 m.

2.4 Reservoir Features

2.4.1 Distribution of Sandstone

Development of sand bodies in each substratum is contiguous, large difference between the thicknesses of sandstone, the largest one is GB with 18-50m, the thinnest is ZD3, and the thickness is only 4-8m. See Table 2.

Table 2: The Thickness of Sandstone

Layer	**GA4**	**GA5**	**GB**	**ZD1**	**ZD2**	**ZD3**
Cross (m)	6-12	8-14	18-50	9-39	10-22	4-8

2.4.2 Reservoir Physical Properties

The logging data in the studying area showed that the porosity changed less and is between 20-30% among substrata, the permeability changed much and is between 20-1200 mD. Oil reservoirs are medium porosity and medium-high permeability. GA5 has best physical properties with permeability 600-1200 mD and ZD3 is worst with permeability 60-120 MD. See Table 3.

Table 3: Statistics for physical of different substrata

Layer	**GA4**	**GA5**	**GB**	**ZD1**	**ZD2**	**ZD3**
Porosity (%)	24-28	24-28	28-32	14-28	10-30	1-28
K(MD)	20-1200	600-2300	400-1500	100-800	100-900	60-700

KEYI oilfield belongs to layered structural reservoir, different layers have different oil and water contacts Table 4 , the reservoir has edge water energy, calculated the volume multiples of water bodies for each substratum by the geological mode provided, the edge water energy is relatively weak. See Figures 1 and 2.

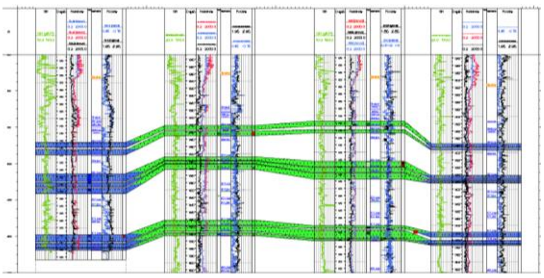

Figure 1: KEYI -17, -4.-7,-1 Reservoir Cross-section

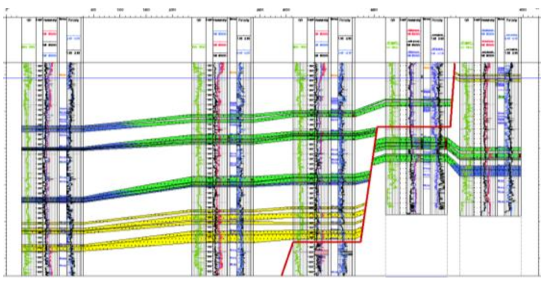

Figure 2: KEYI -2, -3, -4, -S-2, -S-4 Reservoir Cross-sections

Table 4: Calculated Data for Edge Water Energy of Each Substratum

Zones	Sand Volume （MMSTB）	Pore Volume （MMSTB）	OOIP （MMSTB）	Water Body Volume Times
GA4	1.4	13.0	6.0	2.2
GA5	0.5	4.7	1.7	2.8
GB	6.2	54.7	20.0	2.7
ZD1	2.7	24.4	11.5	2.1
ZD2	0.5	4.3	1.2	3.5
ZD3	0.1	1.3	0.3	5.0
Total	11.4	102.5	40.6	2.5

According to analysis and test results, KEYI oilfield belongs to normal temperature and pressure, that is the normal temperature and pressure system.

2.4.5 Characteristics of Reservoir Fluids

In reservoir studies, from material balance calculations to simulation, fluid properties are always required to estimate the reserve volumes, surface volumes, and the transport parameters that interact with the flow. The variations of PVT properties during depletion phase are also needed to evaluate the reservoir performance and to design surface and subsurface facilities [2]. Ideally, PVT properties are experimentally measured in laboratory. When such direct measurements are not available, PVT correlations from literature are often used see Tables 5 and 6.

Table 5: PVT Data

Well	P_r (psia)	Visc@Pr	R_s scf/stb	T_r (F°)	P_b (psia)	Visc@P_b	API	B_o@P_b
Keyi-3	2162	25.6	11.93	152.6	127.5	17.8	23	1.1045

Table 6: The other fluid data

ρ_w	C_w	C_o	C_r	B_w
lb/ft^3	1/psi	1/psi	1/psi	rb/stb
62.4	4.63×10^{-6}	4.10238×10^{-7}	5.6×10^{-4}	1

1. Oil: Oil within the area is of medium gravity, low shrinkage and waxy. Oil gravity varies from 23.9 to 36.2 API˚. Oil viscosity varies from 17.8cp to 25.6cp. The oils contain little gas and consequently the bubble point pressure and the formation volume factor are low.

2. Water: KEYI oil field is such a reservoir that characterized by the formation water, which is quite fresh; its salinity is about 300 – 3000 ppm. The type of formation water is NaCl and $NaHCO_3$.

3. Gas: The reservoir is under saturated; dissolved gas is very low therefore this few amount is ignored and only two phases were used. 0.04994238 Ib/ft^3 used as dissolved gas density for simulator calculations.

PVT data used in simulation model study are summarized in Table 7.

Table 1: Reservoir Fluid Properties

Property	**Values**
Oil formation volume factor at reservoir pressure	1.051
Oil formation volume factor at bubble point	1.1045
Stock tank oil density , Ib/ft^3	52.7516
Oil viscosity at reservoir pressure, cp	25.6
Oil viscosity at bubble point, cp	17.8
Gas density, Ib/ft^3	0.04994
Density of stock tank water, Ib/ft^3	62.4279
Water formation volume factor,	1.03
Water viscosity, cp	0.34
Water compressibility, /psi	4.63×10^{-6}

3. Results

3.1 Initial Oil Saturation

The total reserves provided by the geological model is 40.6MMSTB, mainly distributes in GB substratum, which contains 20.0 MMSTB, and is 49.3.0% of total reserves, followed by ZD1, 11.5 MMSTB, 28.2% of total reserves, the least is ZD3, only 0.3MMSTB, accounting for 0.6% of total reserves. See Table 8 .Based on initialization data and after run of the simulation; 3D oil saturation maps of the virgin GA4, GA5, GB, ZD1, ZD2, and ZD3 have been shown in Figures 3~ Figure 8. Figure 9 shows the residual oil saturation distribution in whole KEYI oil field.

Table 8: Reserve Data for Each Substratum

layer	OOIP	Percent of OOIP (%)
GA4	6.0	14.7
GA5	1.7	4.1
GB	20.0	49.3
ZD1	11.5	28.2
ZD2	1.2	3.0
ZD3	0.3	0.6
Total	40.6	100.0

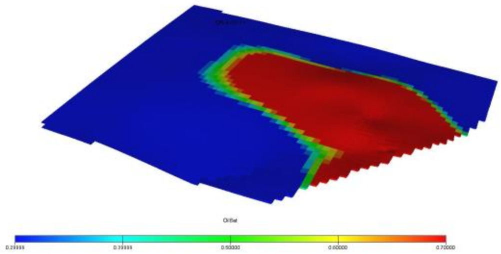

Figure 3: Top virgin GA4 oil saturation

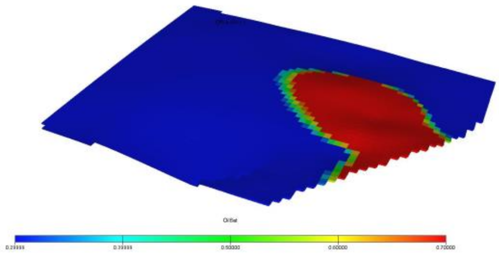

Figure 4: Top Virgin GA5 oil saturation

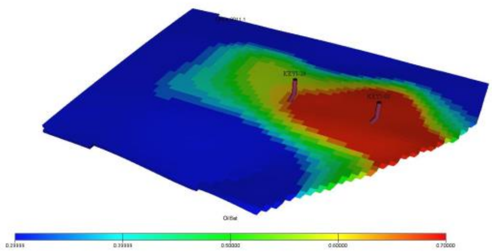

Figure 5: Top virgin GB oil saturation

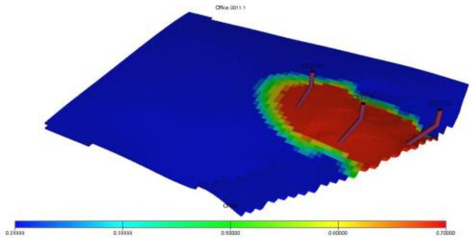

Figure 6: Top virgin ZD1 oil saturation

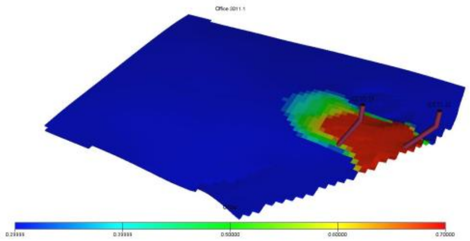

Figure 7: Top virgin ZD2 oil saturation

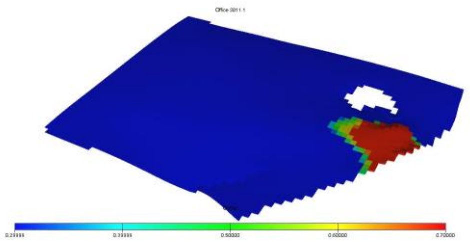

Figure 8: Top virgin ZD3 oil saturation

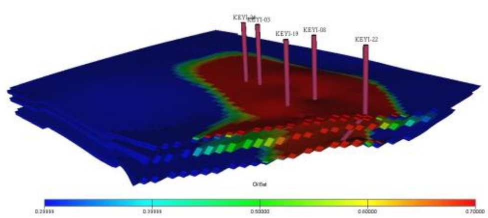

Figure 9: Original Oil in KEYI oilfield

3.2 History Matching and validation of Reservoir Model

One common use of reservoir simulation for field problems is the history matching. This process estimates reservoir data by finding simulating data that gives reservoir performance similar to field performance data. This is sometimes called *inverse problem*. In other words, engineer starts with the answer (field performance data) and tries to find the problem (the reservoir description). The field performance data are usually production/injection rates and well buildup pressure. If a simple model is to be used to predict reservoir future performance, it must be validated against more detailed reservoir simulators. In the case of KEYI oilfield sandstone reservoir models, this was done with the aim to demonstrate an adequate match in terms of water cut development and overall field recovery. In general, the data that are matched are pressure, water cut, production rate, and cumulative production. In this study due to the absence of most of these data, the key criteria used for comparing the reservoir past performance and detailed reservoir simulator results were: a comparison between the initial oil in place value from the geological model software and simulation results, pressure and production data. The first consideration is matching the reservoir size or the original oil in place. This often is determined with a simulator but uses the principles of material balance. Reservoir in this study is a young reservoir, so care was taken to make sure that simulator values are consistent with whatever data are available, to get good estimation of original oil in place. In this step the original oil in place from geological model results compared with that from simulator. A comparison between the values of original oil in place that resulted from the geological model time, and simulation result is shown in Table 9.

Table 9: KEYI oilfield initial oil in place (geological model and simulator result)

Layer	**NO**	**Initial oil in place, geological software result 10^6 STB**	**Initial oil in place, simulator result 10^6 STB**	**Relatively error (%)**
GA4	1	5.960	5.95	0.30
GA5	3	1.672	1.67	0.12
GB	5	19.996	19.93	0.34
ZD1	7	11.467	11.71	-2.09
ZD2	9	1.221	1.22	0.32
ZD3	11	0.251	0.25	-0.07
The total		40.58	40.73	-0.09

The history match of the region mainly includes: reservoir oil output, water cut and other indicators. First, match the trend of the field oil production and water cut; second, to match on the individual well production state. Among them the composite water cut is one of the major indicators of reflecting the movement laws of oil and water within the reservoir, composite water cut match is one of the key indicators in numerical simulation history match process. Reservoir history match results are shown in Figure (10 ~ 14).

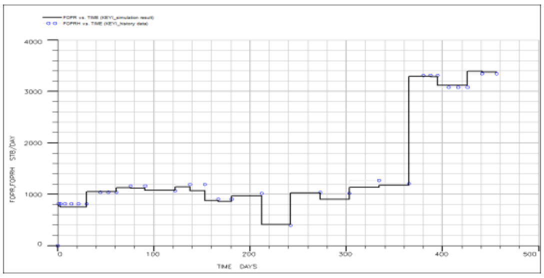

Figure 10: Field Oil Production Rate vs. Time (History data and simulation result)

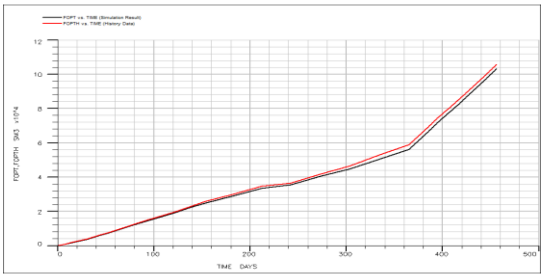

Figure 11: Field Cumulative Oil Production vs. Time (History data and simulation result)

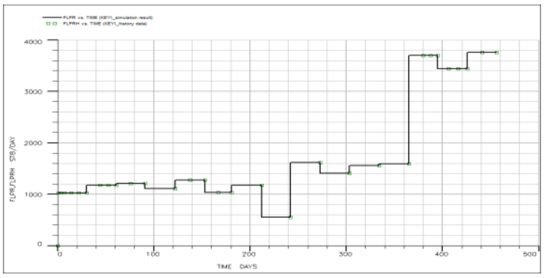

Figure 12: Liquid Rate vs. Time (History data and simulation result)

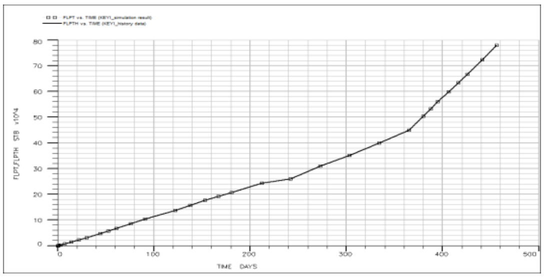

Figure 13: Field Cumulative Liquid Production (History data and simulation result)

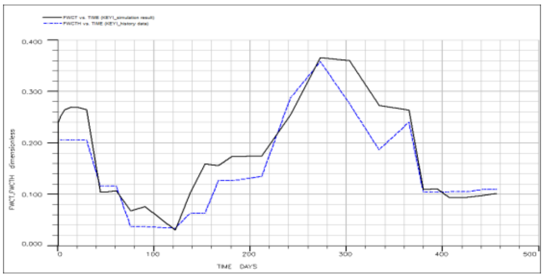

Figure 14: Field water cut vs. time (History data and simulation result)

3.3 Forecasting Future Performance – Optimization of Production

The main objective of a simulation project is to forecast performance [5]. Numerical simulation is an effective method to forecast the performance of a sandstone reservoir. Most reservoir simulation studies require that forecasts of future performance be made under different operating conditions or with two or more equally probable reservoir conditions. The general guidelines and physical constrains imposed on model forecasting need to be carefully selected, because they can have a significant impact on calculated results. Guidelines in this study related to the general policies and strategies that are to be followed in determining overall operation of the field and model. For example, guidelines can govern well target producing rates and minimum operating pressures. Constrains deal mainly with physical and external limits of the system such as maximum and minimum fluid handling capacities and allowable operating pressures. The following guidelines and constrains were used in this section:

- 20 years used as forecasting time for all the runs (from 456 to 7791 days).
- Liquid rate used as production well control for all the production wells.
- The best location for the production pump subjected to be 200 m above the mid perforation, therefore; the minimum bottom hole pressure target for all production wells used to be 300 psia which calculated from:
- The fluid injection type is water.
- Well efficiency factor used as 0.99 for all the wells in the area and choose to be include in network calculations.
- In well connection data transmissibility and skin factor set to be 0, well bore used as 0.124; for all the old and new wells.
- Maximum allowable water cut used to be 98% for all the new wells planned to drill in the area.
- Production using existing well spacing.
- Total producers: 13=13 existing wells.
- Aquifer: by geologic model.
- Production using 260-500m well spacing;
- Using averaged water-oil relative permeability curve.
- Production interval: current perforated zones
- Driving mechanism: Natural energy.

The simulation was run after adding 20 years, the results showed that: The cumulative oil production after these 20 years was 4.4×10^6 STB with oil recovery amounts to 10.5 %. Figure 15 through Figure 19 show field production summary of base case.

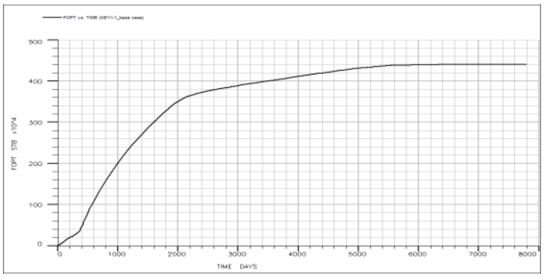

Figure 15: Field oil production rate

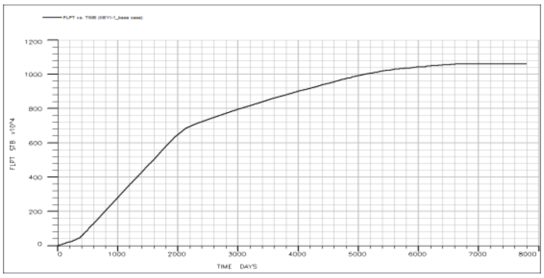

Figure 16: Field Cumulative Liquid production

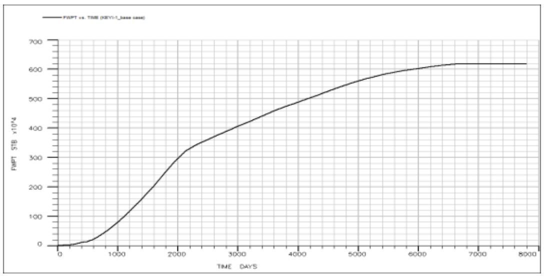

Figure 17: Field water production

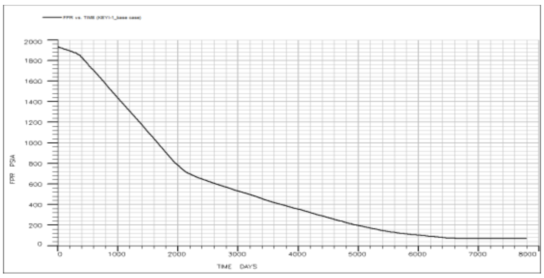

Figure 18: Field Pressure rate

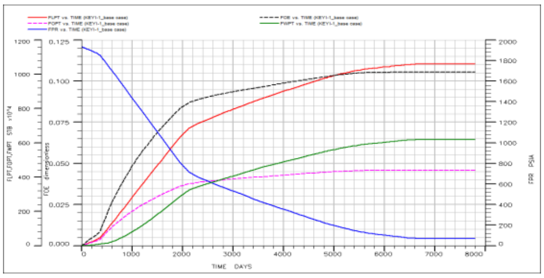

Figure 19: Field production summary

3.4 Feasibility Study of Water Injection and Water Alternate Gas Injection Techniques

The practice of water injection expanded rapidly after 1921. The circle-food method was replaced by a line-food, in which two rows of producing wells were staggered on both sides of an equally spaced row or line of water intake wells. By 1928, the line flood was replaced by a new method termed the "five-spot" because of the resemblance of the pattern to the five spots on dice [11].

3.4.1 Feasibility Study of Water Injection Technique

After the oil wells were put into production, due to the edge water energy was weak and there was no water injected to provide energy, the pressure decreased rapidly. Although there was no pressure monitoring data, the low production rate and the low fluid level show that it is weakness of nature aquifer in KEYI reservoirs. Water in wells at edge of the reservoir rises fast, affecting oil production, at the initial stage there was water when the wells near the edge put into production, water cut soon rose and output declined, affecting the individual well capacity. Due to weakness of edge water, formation pressure declined quickly after putting into production. To achieve the effect of high and stable yield in the block, water injection will be study in this part of study.

3.4.1.1 Water Injection Cases Design

Water injection or water flooding is the injection of water into an oil reservoir so that oil is displaced to production well. In other words, water is injected in order to sweep the remaining oil towards the producers [6]. Adjust injection-production well pattern on the basis of 13 existing wells; new wells need to be drilled according to the needs of the well pattern, deploy new wells by referring to the current well spacing, around 260m.With the consideration of the actual production situation, the implemented case should avoid the wells of normal production layers. Work over & additional perforation for the existing 13 wells, close high water cut zones, perforate new formations. Figure 20 shows the base map of the existing 13 wells.

A. Water Injection Case 1:

1. Base on the Base case, 3 producers convert to injectors, Keyi-4, -19, -11. Because well Keyi-4 and Keyi-19 have higher water cut and lower oil rate. Well Keyi-11 turn to injector for the pattern of injection and production.

2. Drilling one producer, Keyi-33, between Keyi-4 and Keyi-25, one injector, Keyi-34, between Keyi-11 and

Keyi-20, 5 injectors in the edge of the structure, Keyi-28, Keyi -29, Keyi -30, Keyi -31, Keyi -32. See Figure 21.

3. Water injection rate is 12360 STB/DAY.

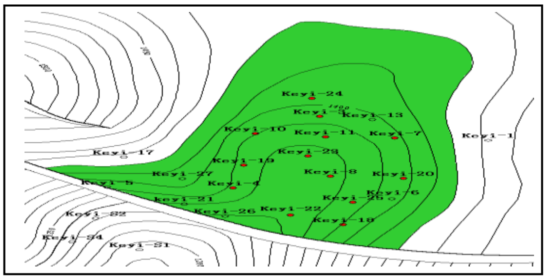

Figure 20: The Map for base case (13 production wells)

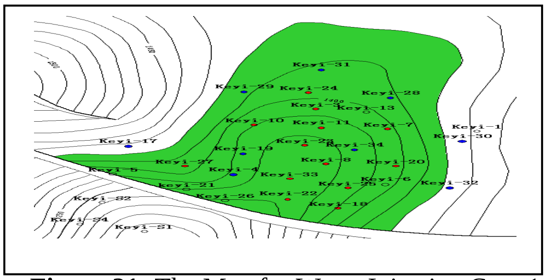

Figure 21: The Map for Water Injection Case 1

After ran simulation model of KEYI oilfield using water injection case 1, result showed that 10.16×10^6 STB with recovery about 24.4 % can be produce after the end of the twenty years and after adding new injector wells at 7791 days. The cumulative oil production will be increase than that in the base case which was about 4.4×10^6 STB; 10.5 % as recovery. Figures 22 through Figure 26 showed KEYI field cumulative oil and liquid, field oil production rate , field water cut, field water injection rate, field cumulative water injection, and field oil recovery. Figure 27 and

Table 10 are show field oil production summary.

Table 10: Comparison between the base case and water injection (case 1)

cases	Cumulative oil (MM STB)	Recovery (%)	Pressure (PSIA)	Water cut (%)
Base case	4.4	10.5	69.79	98.3
Case1(WI)	10.16	24.4	3605.30	97.7
Increment	5.76	13.9	3535.79	0.6

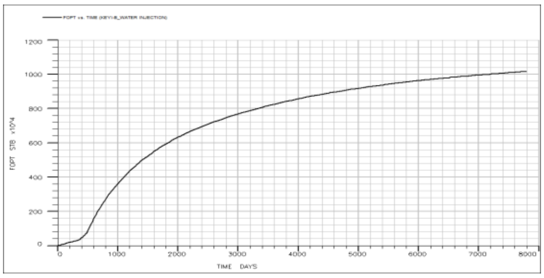

Figure 22: Field cumulative oil production vs. Time

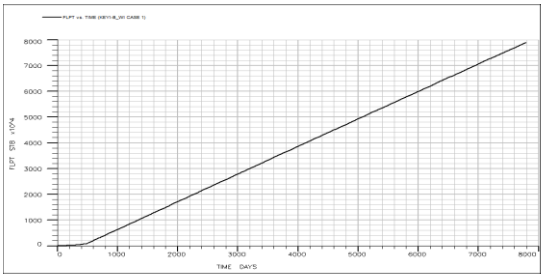

Figure 23: Field cumulative liquid production vs. Time

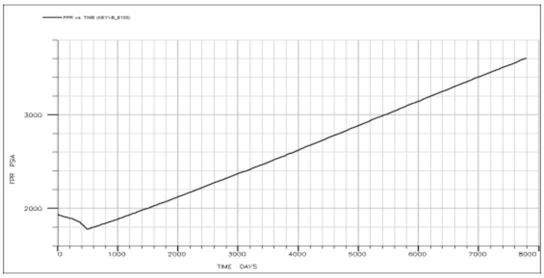

Figure 24: Field Pressure Rate vs. Time

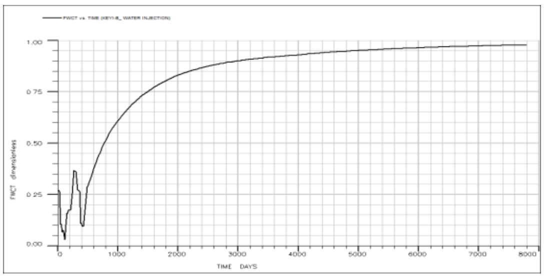

Figure 25: Field water cut vs. Time

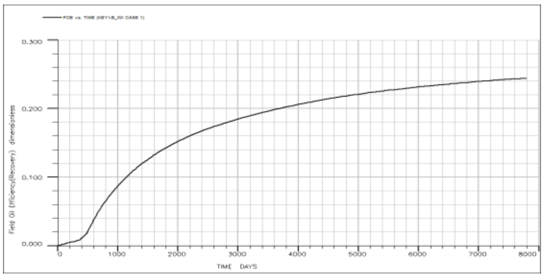

Figure 26: Field Oil Recovery vs. Time

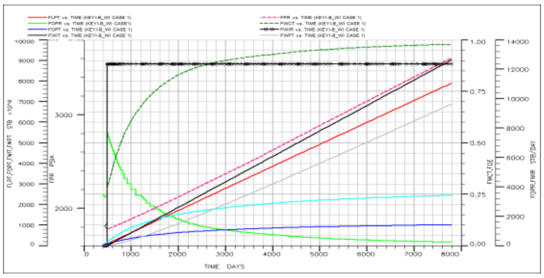

Figure 27: Field oil Production Summary (WI case one) vs. Time

3.4.1.2 Water Injection Case 2

1. In this case used the existing injector wells in case 1 (KEYI – 04, -17, -19, -30, -28, -29, -31, -32, and -34) with changed the injection rate of them at 01/Jan/ 2012 as in Table 11.

2. at 01 Jan 2015 changed the injection well rate of the following wells: KEYI – 31, -32, -30, -28, and -29). See Table 11.

3. Field water injection was 8120 STB/DAY till 1545 days, and then changed to 6920 STB/DAY till 7791 days.

After ran simulation model of KEYI oilfield using water injection case 2, result showed that 10.77×10^6 STB; with recovery about 25.9 % can be produce after the end of the 7791 days and after changing the wells injection rate. So the cumulative oil production will be increase than that in the case 1 which is about 10.16×10^6 STB; 24.4 % as recovery. Figures 28 through Figure 32 show the KEYI field cumulative oil and liquid, field oil production rate , field water cut, field water injection rate, field cumulative water injection, and field oil recovery.

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Table 11: Water injection rate of injector wells

		Liquid rate		
		Case 1	**Case 2** **01/ Jan/2012**	**Case 2** **01/Jan/2015**
NO	**INJ WELLS**			
1	KEYI - 04	1440	900	-
2	KEYI - 17	1560	1040	-
3	KEYI – 19	840	560	-
4	KEYI – 30	1560	1040	740
5	KEYI – 28	1440	900	700
6	KEYI – 29	1560	1040	740
7	KEYI – 31	1560	1040	840
8	KEYI – 32	1560	1040	840
9	KEYI - 34	840	560	-

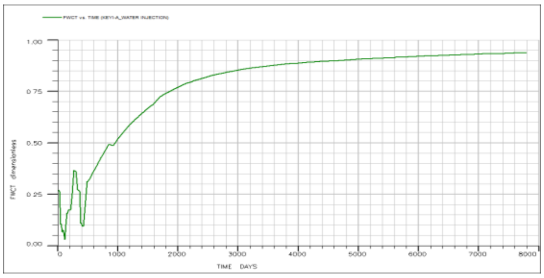

Figure 28: Field Water Cut vs. Time

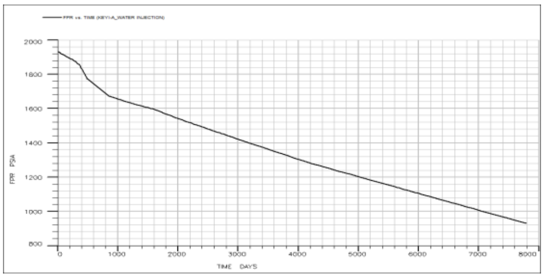

Figure 29: Field Pressure Rate vs. Time

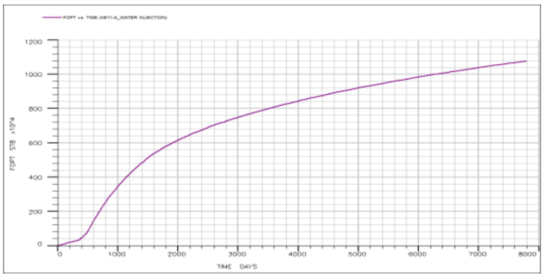

Figure 30: Field Cumulative Oil Production vs. Time

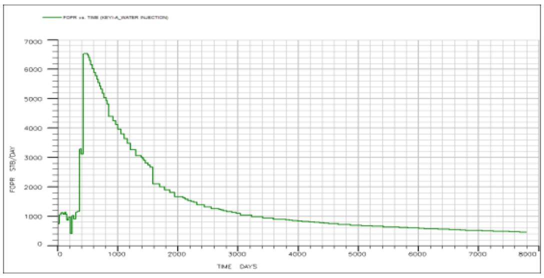

Figure 31: Field Oil Production Rate vs. Time

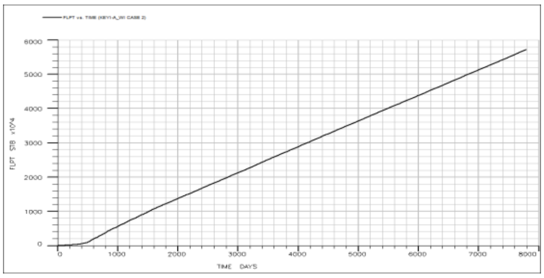

Figure 32: Field Cumulative Liquid Production vs. Time

The overall results for base case and water injection cases in term of oil recovery efficiency (FOE), Oil Production Total (FOPT), Field Pressure (FPR), and Field Water Cut (FWCT) had been compared in Table 12 and Figure 33 through Figure 35 which concluded that water injection case 2 was the best choice for the model, because had the greatest recovery factor, after compared with base case and water injection case 1.

Table 12: Comparison between the base case and water injection (case 1 and case 2)

cases	Cumulative oil (MM STB)	Recovery (%)	Pressure (PSIA)	Water cut (%)
Base case	4.4	10.5	69.79	98.3
Case1(WI)	10.16	24.4	3605.30	97.7
Case 2 (WI)	10.77	25.9	930.28	0.938

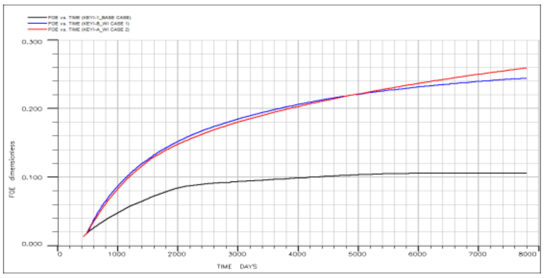

Figure 33: Comparison of Field Oil Efficiency (base case and Water Injection cases) vs. Time

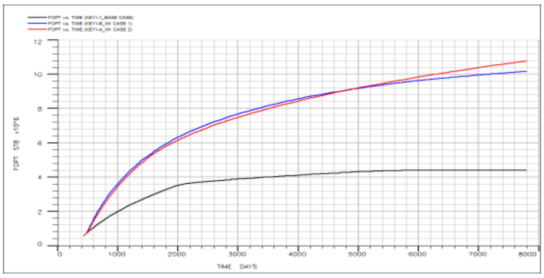

Figure 34: Comparison of Field Oil Production total (base case and Water Injection cases) vs. Time

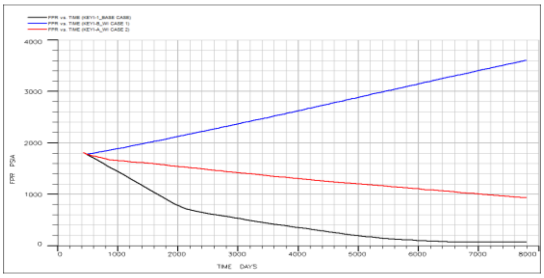

Figure 35: Comparison of Field Pressure Rate (base case and Water Injection cases) vs. Time

3.5 Feasibility Study of Water Alternating Gas Injection (WAG) Technique

3.5.1 Introduction

Water alternating gas injection (WAG) is one of the most popular methods or enhanced oil recovery. Injected gas can occupy parts of the pore space being occupied by oil, and can reduce the viscosity of the remaining oil to make it more mobile. Water is injected subsequently to displace the remaining oil and gas. Repetition of the WAG process can further improve the recovery of the remaining oil in the reservoir [10].

3.5.2 Water Alternating Gas Injection (WAG) Technique Design (WAG)

Optimal value of WAG ratio in the KEYI oil field, the following values was suggested initially:

❖ In this case use the existing producer and injector wells in the base case

❖ In the eclipse simulator, these iterations will be performed injecting at 6 months cycle time interval. Table 13 shows water and gas injection for WAG technique.

Table 13: Water and Gas injection Rate for WAG technique

Cases	Water injection rate (STB/DAY)	Gas injection rate (STB/DAY)
Case 1(keyi-3)	10300	10300
Case 2(keyi-3B)	17088	17088
Case 3(keyi-4)	11600	11600

After ran the simulation model of three cases depend on the base case the results showed that:

- In case 1of Water Alternating Gas injection (WAG) the cumulative oil production was 10.97×10^6 STB field oil production rate was 369.06 STB/DAY, and the field pressure was 1739.6 PSIA.
- In case 2 of Water Alternating Gas injection (WAG) the cumulative oil production was 11.13×10^6 STB oil production rate was 291.57 STB/DAY, and the field pressure was 3179.1 PSIA.
- In case 3 of Water Alternating Gas injection (WAG) the cumulative oil production was 11.57×10^6 STB oil production rate was 291.57 STB/DAY is, and the field pressure was 2049.9 PSIA.
- See Table 14 and Figure 36 through 38 showed the comparison between three cases of the Water Alternating Gas injection method.

Table 14: Comparison between three Water Alternating Gas injections (WAG)

Cases	FOPT (MMSTB)	FOPR (STB/DAY	FPR (PSIA)
Case1	10.67	369.06	1739.6
Case2	11.13	291.57	3179.1
Case 3	11.57	3689.95	2049.9

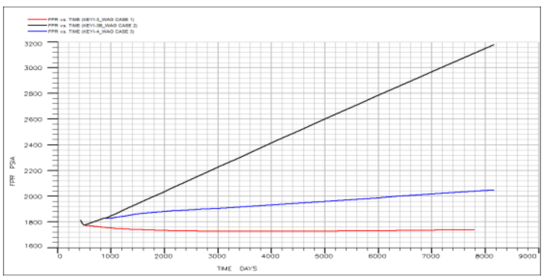

Figure 36: Comparison of Field Pressure Rate (WAG 3 cases) vs. Time

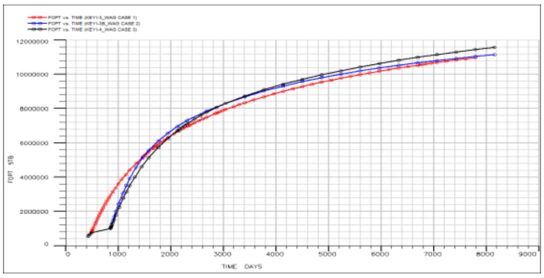

Figure 37: Comparison of Field Cumulative oil production (WAG 3 cases) vs. Time

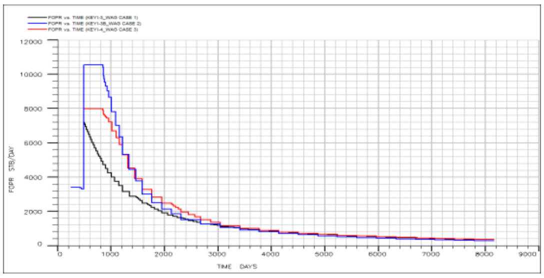

Figure 38: Comparison of Field Production oil Rate (WAG 3 cases) vs. Time

From the previous figures and table we can concluded that Water Alternating Gas injection case 3 was the best model, because had the greatest recovery factor, after compared with case1 and case 2.

4. Discussion

Based on reservoir characteristics and pre – geological model of KEYI oilfield, coarsening the grid by 49x63 on the plane, 12 by vertical obtained 3087, as known the simulation model was developed using three – phase, 3D and black oil options in ECLIPSE software. The total reserve provided by the geological model was 40.6 MMSTB which distributed in GA4, GB5, GB, ZD1, ZD2, and ZD3 as can be seen from Table 9 the overall reserve mach had a high precision, the overall relative error was 0.09, the maximum relative error of substrata was 0.15. 3D model of KEYI oilfield was done after imported the geological model in to eclipse software used 13 existing production wells and other related parameters, compared between OOIP from geological model and that from simulation. The process which estimates reservoir data by finding simulating data that gives reservoir performance similar to field performance data is called history matching. Figure 10 through Figure 14 showed the compared between the history data and simulation results over all fit results were better and met the requirements. The cumulative oil production in the area under study after 456 days was 0.65 MMSTR. After added 20 years used as forecasting time and ran the simulation, the results showed that, the cumulative oil production was increased to 4.4 MMSTB with oil recovery amount to 10.5 %. Figure 15 through Figure 19 showed field production summary of base case. After forecasted the future performance the water injection and water alternating gas injection were tested in the area under study in order to increase oil recovery. After applied some cases of water injection, simulation result were compared in Table 12 and Figure 33 through 35. Finally tested water alternating gas injection technique used three cases. After ran the simulation models, deepened on the base case,. Table 14 and Figure 36 and figure 37 showed the comparison between the cases of the WAG injection.

5. Conclusions

This project studies the reservoir simulation model of KEYI oilfield using water injection and water alternating gas injection techniques. Geological model, regions average grid parameters, the thickness of sandstone, statistics for physical of different substrata, PVT data, and reservoir fluid properties were used for built the simulation model. The water injection technique was studied by applied two cases. The results showed that the cumulative oil production and recovery factor for two cases were 10.16 MMSTB with recovery about 24,4%, and 10.77 MMSTB with 25.9%, respectively. Water alternating gas injection technique was studied by applied three cases with different water and gas injection rate. The results showed that the cumulative oil production and recovery factors for three cases were 10.67 MMSTB with 25.6%, 11.13 MMSTB with 26.7%, and 27.8 %, respectively. The overall results showed that, water alternating gas injection technique is the best method to increase cumulative oil recovery to 26.7 % in the KEYI oilfield, water injection is the second technique can applied in the area under study with 25.9% of cumulative oil recovery.

6. Recommendations

- KEYI oil field needs more studies to increase the oil recovery for example: gas injection, and SWAG (selective water alternating gas) injection.
- KEYI oil field needs some experimental studies of water and gas injection technique.
- KEYI oil field needs the economic evaluation.

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