

Optimization of Field Development Scheduling and Water Injection Study for Keyi Oil Field, Sudan

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Abstract - In this paper, in order to improve the reservoir performance in Keyi oil field Sudan, the studies focused on modeling and simulation of actual performance and tested water injection as a future development. Reservoir simulation studies for Keyi oil field, Muglad Basin, Sudan used to know the best field development methods. Keyi oil field sandstone reservoirs is young reservoir started production at 15 September 2010. The OOIP in the area under study is 40.6 MMSTB. The objective of this simulation study is to determine the suitable method for long-term production. The simulation model was developed using three-phase, 3D and black oil options in ECLIPSE. The study of the optimum future performance was evaluated through several cases. The keys criteria; cumulative oil and water productions, water cut, and recovery, were used as qualitative indicator to determine the quality of the comparison matches and to see if the water injection method is economic risk. The simulation Results showed that the cumulative oil productions were 10.9 MMSTB with water injection, and 4.40 MMSTB with no water injection, thus the water injection is the suitable method to improve the reservoir performance in the area under study.

Key Words: Keyi oil field, Simulation model, Optimization, Water injection, Eclipse software.

1. INTRODUCTION

The main task of a reservoir engineer is to develop a scheme to produce oil and gas as much as possible within economic and physical limits. Optimization of oil and gas reservoir development requires integration of quantitative geological and geophysical analysis with appropriate flow models to assess alternative development and completion schemes and their relative economic values.

1.1 Objectives of the Study

The objectives of the current study are:

1. To predict future performance of a reservoir and find ways and means of optimizing the recovery of sum of the hydrocarbons under various operating conditions.
2. To accomplish reservoir pressure maintenance used water injection method.

1.2 Literature Review

The main goal of reservoir simulation is Reservoir simulation is the most powerful predictive tool available to the reservoir engineering, it involves far more geological and reservoir data than any other reservoir performance forecast tool [7]. The case study and the data that used in this paper is a Sudanese oil field data (Keyi oil field). Keyi oil field is a young sandstone reservoir, started production at 15 September 2010, was no subjected for study or publication before and the data collection very difficult.

The primary stage is the period in the oil recovery process when oil flows naturally to the wells due to natural energy such as initial pressure, gravity and water drive. As a result of production, the pressure declines and consequently oil production start to decrease. Hence, the secondary stage is utilized to prevent reduction of oil recovery. The most common method of secondary recovery is water flooding [1, 2]. 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 its performance is essential [3].

Water injection is one of the most popular methods for to accomplish reservoir pressure maintenance and/or dispose of brine water (or produced formation water), and/or as a water drive to displace oil from the injector wells to the producer wells [3]. Keyi oil field is an appropriate choice to apply the water injection process for two reasons. First, 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. Second, 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.

2. GEOLOGICAL DESCRIPTION OF RESERVOIR

The area selected for this study is Keyi Oilfield is lying on western escarpment of Fula Sub basin in Muglad Basin, block 6, Sudan. Keyi Oilfield has been structurally subdivided into three main structures which are Keyi North, Keyi Main and Keyi South. There are five producing formations from Keyi fields which are Ghazal, Zarga, Aradeiba, Bentiu and Abu Gabra. The detail STOIP (2P) of Keyi Oilfield is listed in the following Table (1) below:

Table -1: The detail STOIP (2P) of Keyi Oilfield

Formation	Ghazal+ Zarga	Aradeiba+ Bentiu	Abu Gabra	Total
STOIP (MMSTB)	40.626	14.45	34.97	90.046

Keyi Main is the biggest oil bearing block in Keyi Oilfield with major reservoirs of Gharzal and Zarga. Gharzal and Zarga reservoir of Keyi Main are the area selected for study, was put into production on 15 September 2010. They are characterized as medium buried depth (1500-1700 m), fine to very fine grain size sandstone, thin dispersed argillaceous lamination, lateral rapidly change of individual sand body. The reservoir can be divided into two productive members.

2.1 Ghazal formation: Ghazal formation consist of clay stones inter bedded with unconsolidated sandstone, very fine to fine grained, with traces of medium and coarse grained sandstone, Ghazal formation was deposited in fluvial and alluvial fans environment. Formation thickness range (170 - 426) m [6].

2.2 Zarga formation: Zarga formation consists of mudstone, clay stones silty in parts inter bedded with very fine to fine & medium grained sandstones & siltstone. It was deposited in a flood plain lacustrine environment with fluvial-deltaic channel sands. Its thickness range (120 - 160) m [6]. According to the stratigraphy and development of sand bodies, in Zarga, 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. See Figure 1 [6].

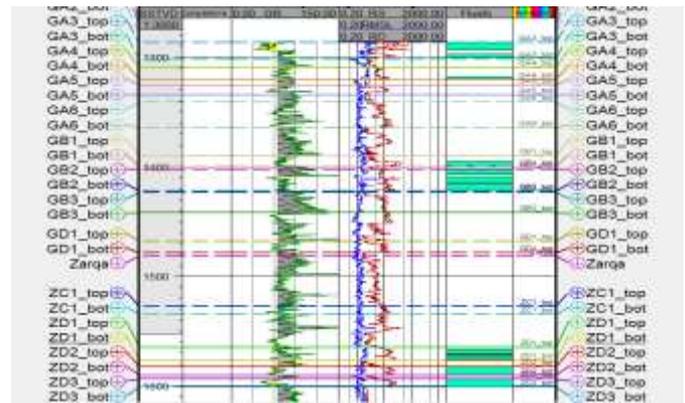


Fig - 1: Substrata Classification for Zarga, Ghazal Layers

3. Reservoir Physical Properties:

Oil reservoirs are medium porosity and medium-high permeability. GA5 has best physical properties with permeability 600-2300 mD and ZD3 is worst with permeability 60-700 mD. See table below (Table 2).

Table -2: The Thickness of Sandstone

Layer	GA4	GA5	GB	ZD1	ZD2	ZD3
Por(%)	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

3.1 Reservoir Production Features

The reservoir has a certain production capacity, the majority of wells contained no water at the early production stage and the output of oil wells declined rapidly after the operation.

- 1. Well data:** Additional well information required for the model such as the perforations, hole size, production and injection data, defined separately for the wells. The completion intervals in the model were checked to ensure that they did not make well connection in void grid blocks, or in no-flow zones.
- 2. Grid Section:** 3D reservoir model was constructed. The reservoir model consists of $37044 [X_{(i)} \times Y_{(j)} \times Z_{(k)} = 49 \times 63 \times 12]$. Size of X and Y direction: about 50 meters and the vertical direction: 4~64 m.
- 3. Validation of Reservoir Model:** The goal of a numerical-model study is the prediction of reservoir performance in more detail and with

more accuracy than is possible with simple techniques such as extrapolation. It is intuitively evident that for a model to behave like the reservoir it must be conceptually similar to the reservoir. Significant differences between the data

Defining the reservoir in the numerical model and the actual values of the parameters governing the reservoir performance will cause correspondingly significant errors in the simulation. The most useful way to test the model is to simulate the past performance of the reservoir and compare the simulation with actual historical performance. The key criteria used for comparing the reservoir past performance and detailed reservoir simulator results, were pressure, water cut, cumulative oil and liquid production, field oil and liquid production rate.

4. Reservoir Pressure: The pressure is the most important type of data used to monitor reservoir conditions, obtain reservoir descriptions, develop recovery schemes and forecast reservoir performances. The changes in the reservoir pressure due to alternation of the production conditions are characteristic of the reservoir properties themselves. Therefore, the reservoir properties can be inferred by matching the pressure response to a reservoir model [4, 5]. The inferred reservoir model can then be used for future reservoir management.

The actual well bottom hole pressure is calculated from the available historical data for dynamic fluid level and casing pressure using the equation:

$$\text{BHP} = \text{Casing Pressure} + \text{Depth of Liquid Column} \times \text{Average Gradient of Liquid}$$

Where:

BHP = Bottom Hole Pressure, psi

Depth of Liquid Column = (Mid Perforation - DFL), ft

DFL = Dynamic Fluid Level, ft

4. GUIDELINES AND STRATEGY OF SIMULATION MODEL

The production data from all the wells in Keyi oil field was collected from September 15, 2010 till December 30, 2011 (450 days) and entered as a history data for *BLACK OIL* simulator (ECLIPSE). Oil rate was used as a production control for all the wells in the period till 450 days. The values of oil rate, water rate, and gas rate were entered directly in historical production well data. Fixed liquid rate and minimum bottom hole pressure target were used to

predict the future performance for 20 years (7200 days).

The most useful -and usually the only available- way to test the validity of the model, is to simulate the past performance of the reservoir and to compare the simulation with actual, historical performance. Simulation was run to make the comparison between the simulator results and history data. Water-cut, production rate, cumulative oil production and cumulative water production match were used as qualitative indicator to determine the quality of the match. Adjustments are made in relative permeability data to get high quality match.

1. Reservoir 3D Model

Keyi oil field was proven productive in September 2010, production started from 6 intervals namely, GA4, GA5, GB, ZD1, ZD2, and ZD3 All of these layers distributed in the formations named, the Ghazal Formation and the Zarqa formation. Core analysis and well logging showed that the reservoir rock is characterized by both medium porosity and medium to high permeability. The average matrix permeability is on the order of 20 to 1200 md approximately, with average porosities ranging from 20 to 30 %.

Based on geological model, up-scaling was done based on more than dozen zones (GA4, GA5, GB, ZD1, ZD2, and ZD3) divided to 12 single layers. Based on that information the reservoir model for the Keyi area is developed using two-phase, 3D and black oil options in Eclipse. 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.

2. History Matching and validation of Reservoir Model

A comparison between the values of original oil in place that resulted from the geological model time, and simulation result is shown in table 3.

Table - 3: Keyi initial oil in place: geological model and simulator result

Layer	No	OOIP (MMSTB)	Match OOIP (MMSTB)	Error (%)	Relative Error (%)
GA4	1	5.969	5.95	0.02	0.30
GA5	3	1.672	1.67	0	0.12

GB	5	19.996	19.93	0.07	0.34
ZD1	7	11.467	11.71	-0.24	-2.09
ZD2	9	1.221	1.22	0	0.32
ZD3	11	0.251	0.25	0.00	-0.07
Total		40.58	40.73	-0.15	-0.09

3. The initial reservoir pressure and pressure trends:

The pressure decreased rapidly. See figure 2 below.

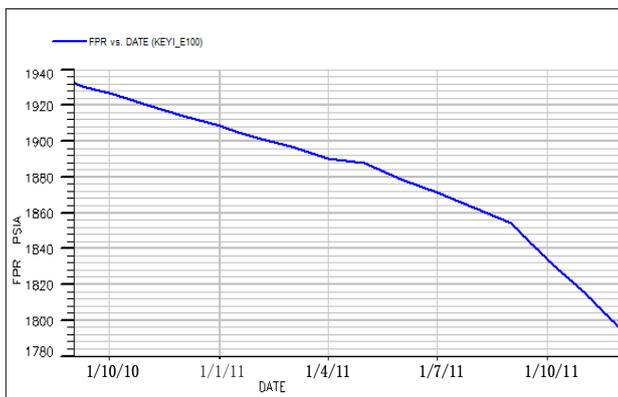


Fig - 2: Pressure Match Curve

4.1 History Matching of Field Production

Production data brings an important, yet indirect constraint to the spatial distribution of reservoir variables. Production data rarely suffice however to characterize heterogeneous reservoirs, a large amount of uncertainty still remains after history matching of geostatistical models.

Reservoir simulation is routinely employed in the prediction of reservoir performance under different depletion and operating scenarios. Usually, a single history matched model, conditioned to production data, is obtained. The model is then used to forecast future production profiles.

The production past performance was matched with simulated oil and liquid production rate, oil and liquid cumulative production and water cut. See figures (3 to 6).

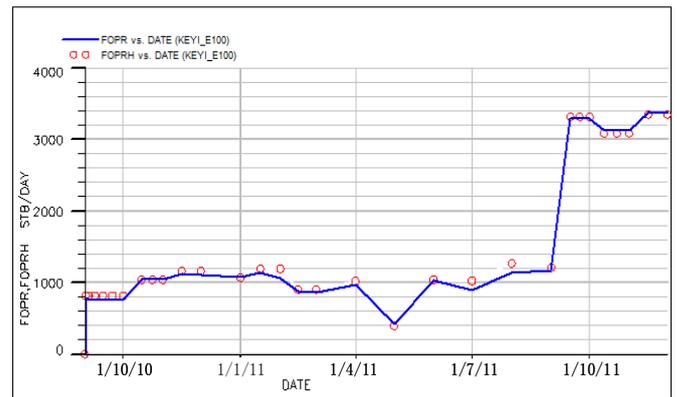


Fig - 3: Field Oil Production Rate vs. Time (History data and simulation result)

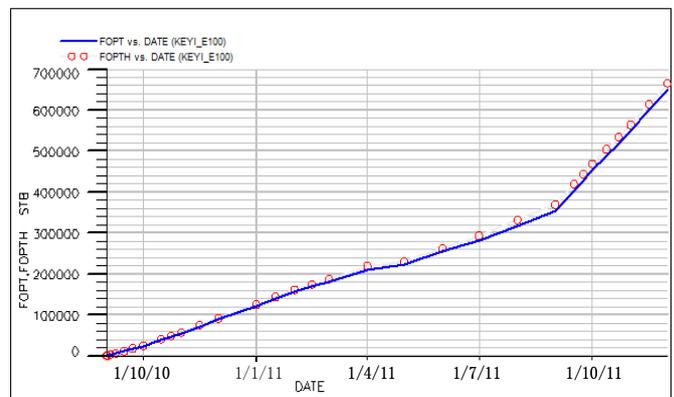


Fig - 4: Field Cumulative Oil Production vs. Time (History data and simulation result)

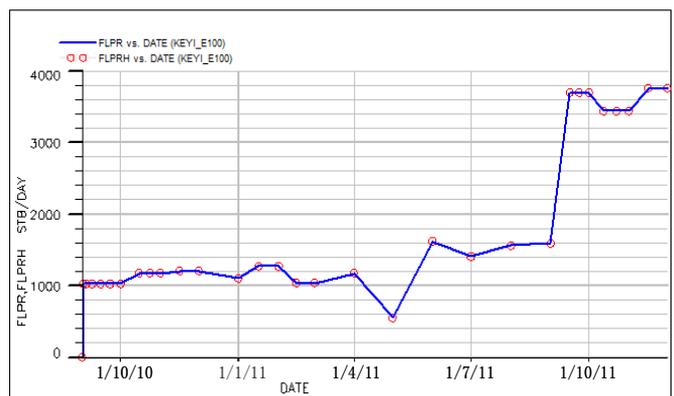


Fig - 5: Liquid Rate vs. Time (History data and simulation result)

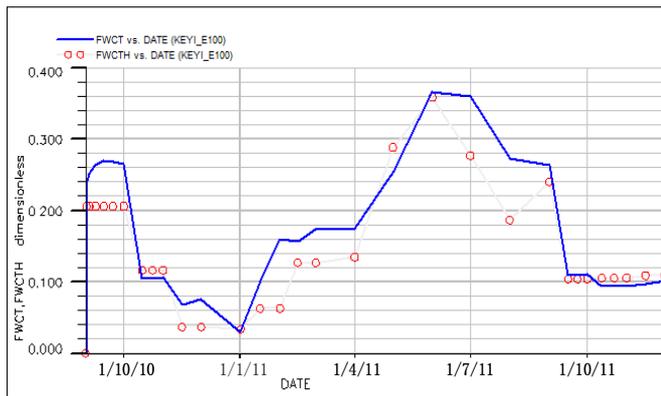


Fig - 6: Field water cut vs. time (History data and simulation result)

4.2 Prediction performance Guidelines and Constrains

The following guidelines and constrains were used in this study:

1. 20 years used as forecasting time for all the runs (from 450 to 7200 days).
2. Liquid rate used as production well control for all the production wells.
3. Well efficiency factor used as 0.99 for all the wells in the area and choose to be include in network calculations.
4. Minimum oil production rate 16 M³/d (100 bbl/d) was used as production well economic limits for all the production wells.
5. In well connection data transmissibility and skin factor set to be 0, well bore used as 0.203 m; for all the old and new wells.
6. Maximum allowable water cut used to be 98% for all the new wells planned to drill in the area.

Results of the Prediction performance

Simulation result shows that the cumulative oil production after 20 years is 4.4×10^6 STB with oil recovery amounts to 10.5%.

5. FEASIBILITY STUDY OF WATER INJECTION

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 required.

5.1 Case Preparation for Water Injection

Preparation principles:

1. Adjust injection-production well pattern on the basis of existing wells;
2. If 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.
3. With the consideration of the actual production situation, the implemented case should avoid the wells of normal production layers.

5.2 Water injection case design:

1. Base case:

1. Adopt periphery and internal water injection.
2. Work over & additional perforation for the existing 13 wells, close high water cut zones, perforate new formations.

2. Water injection case:

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.

5.3 The result of the Water injection

The simulation results show that the cumulative oil production of the water injection is 10.9×10^6 STB with oil recovery amounts to 26.4%.

5.4 Cases comparison between water injection and Prediction performance (base case):

For the base case and the water injection case, for 20-year forecast is done. See Table 4 below.

Table - 4: Comparison between Water Injection and Prediction performance (Base Case)

Case	Cum. Oil (MMSTB)	Rf (%)	Pressure @ 2031 (psi)	Water Cut @ 2031 (%)
Base Case	4.4	10.5	69.5	98.3
Injection Case	10.9	26.4	1739.6	96.4
Increment	6.5	15.9	1670.1	1.9

As can be seen from the table, the same 20 years' prediction, accumulated oil production by the water

injection case is 10.9 MMSTB, by no water injection case is 4.4 MMSTB, and the difference is more than 6.5 MMSTB. It shows that water injection case development indicators are much better than no water injection. See figure (7 - 9) comparison between the base case and the water injection case. Figure (10) showing the production profile (Water injection Case).

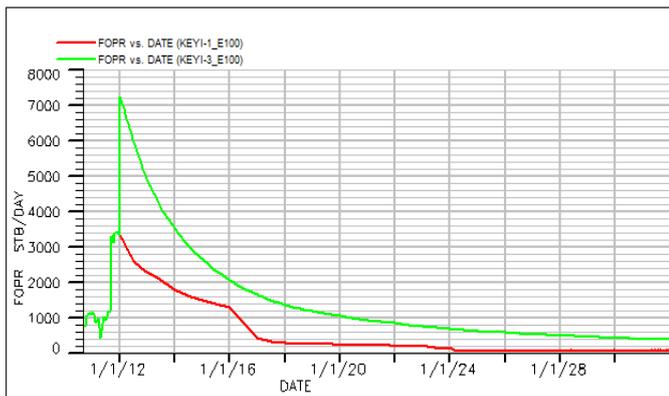


Fig - 7: Oil Rate Comparison between Water Injection & Base Case

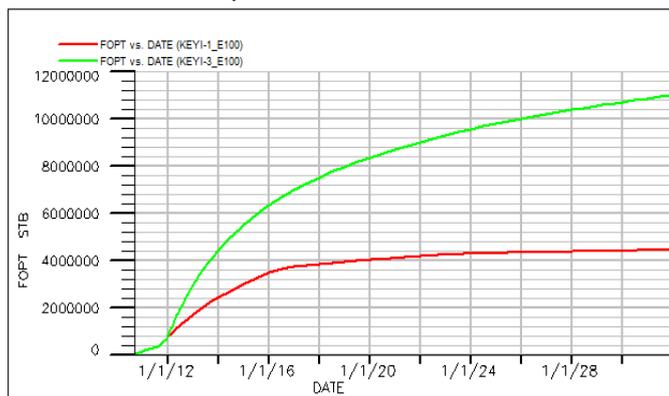


Fig - 8: Cum Oil Production Comparison between Water Injection & Base Case

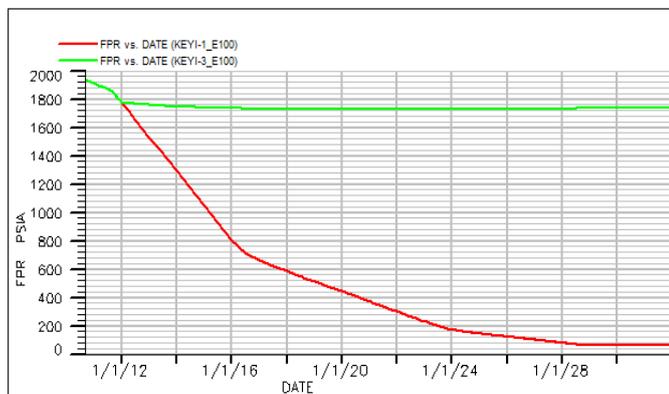


Fig - 9: field pressure Comparison between Water Injection & Base Case

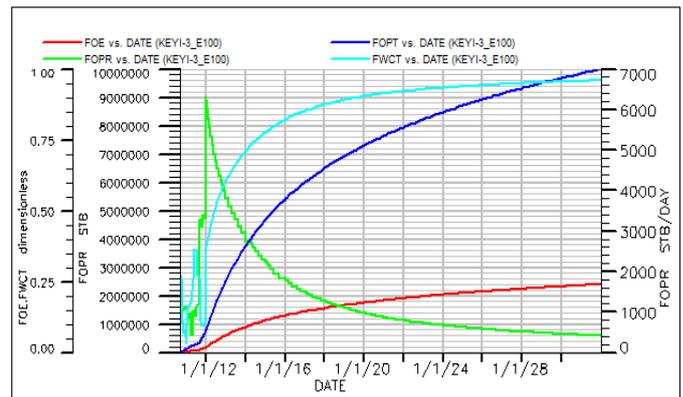


Fig - 10: Production Profile (Water Flooding Case)

6. Conclusions

1. The simulation result showed that the cumulative oil production after 450 days is 0.65×10^6 STB.
2. Simulation result shows that the cumulative oil production after 20 years is 4.4×10^6 STB with oil recovery amounts to 10.5%.
3. After 20 years later, the water injection case has a better accumulated oil production, 10.97 MMSTB, the pressure and water cut are respectively 1739.6 psi and 96.4%. The recovery factor is 26.38%.
4. Due to the simulation result water flooding is an economic and effective method to keep the formation pressure, and the optimum method to enhance recovery factor in Keyi oil field.

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