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01

MINIMIZATION OF UNWANTED WATER PRODUCTION IN HETEROGENEOUS RESERVOIRS USING INTELLIGENT WELL TECHNOLOGY

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Abstract: *In this paper, the use of intelligent well completion (IWC) to minimize water production is evaluated in heterogeneous reservoirs having many wells (producers and injectors). To model the intelligent well, the reservoir simulator, Schlumberger ECLIPSE-100 Simulator is used. A case study simulation is applied on a modified Eclipse benchmark model, which served as a base case. The use of IWC technology combination resulted to a minimal water production (a drastic reduction of about 41 percent in water production) and an optimal oil recovery by accelerating the production time and improving the net present value (NPV) of the field's production. This clearly shows the benefits of adopting IWC technology in solving water production problems in heterogeneous reservoir.*

Key word: Water Control, Unwanted Water, Heterogeneous Reservoirs, Intelligent Well Completion

Introduction

The oil and gas industry have gone through several challenges (economic, geographic and technical) mainly due to a fall in oil prices and market volatilities. Water production is one of the main problems encountered during oil production, it not only reduces hydrocarbon recovery (reduce revenue) but it is equally very costly managing the water produced (increases CAPEX/OPEX) especially in offshore locations due to the limited space and the many regulations governing the deposit of water in the sea [1]. Thus, over time, techniques are being developed to minimize (restrict or exclude) the production of this water from the different production wells. Intelligent Well Completion (IWC) technology is one of the recent production technologies that can solve this problem. It is a technique that combines permanent downhole sensors with downhole control valves that are operated from the surface, allowing operators to actively regulate production as it is being monitored, evaluated, and actively managed. The downhole devices aimed at minimizing water production have over the years evolved from passive control i.e. Inflow control devices (ICD), to active control i.e. interval control valves (ICV), to newly developed Autonomous Inflow Control Devices (AICD) and Autonomous Interval Control Valves (AICV)[2]. Oil is a major global energy source and its exploration and production are of extreme importance. The average amount of water produced now by oil companies from their depleting reservoirs is 3 barrels for every barrel of oil[1]. More than $40 billion is spent annually on undesired water management [3]. Innovative water control technology can bring about a significant cost reduction and ameliorate oil production. Many studies have proposed optimization models at various stages of the production process. Contrary to these studies, intelligent well technology follows a thorough strategy of optimizing every step of the manufacturing process rather than focusing on a single step. Intelligent well technology has been used to optimize both production and injection operations. Rodrigues et *al.,*[4] presented a work on intelligent completion and horizontal wells to increase production and reduce free-gas and water in the mature fields. Experimental research has been done to show how water alternating gas (WAG) operations in smart wells can be improved [5]. Gao et *al* presented a review of smart wells and their applications. [6]. The dynamic optimization of waterflood in a numerical reservoir utilizing smart wells was investigated by Brouwer et *al.,*[7]using the optimum control theory. Through control injection wells in heterogeneous and fractured reservoirs, Mazo et *al*. conducted a water management analysis. Musaga et *al.*, [8] in his thesis titled a technology perspective and optimized workflow to intelligent well applications, his work focused on demonstrating the potential benefits of adopting smart well technology in optimizing oil production. Afuekwe et *al.,*[9] used smart controls in IWC to optimize oil and gas recovery. Shaibu et *al.,*[10] in 2017 published on an intelligent well approach to controlling water coning problems in horizontal production well. Where it carried out a study to control water-coning problems in a homogenous reservoir with a single well.

In this paper, the objectives are to optimize the model proposed by Shaibu et *al.,* considering a heterogeneous reservoir having several wells (producers and injectors). In the configuration (heterogeneous reservoirs) which is a more realistic model, we suspect that IWC will be more effective to reduce water production. On the other hand, we think that IWC might not be applicable on all the wells in this reservoir. The aim of this paper is to minimize the production of water from a reservoir model by choosing an optimal IWC combination for drilling and completion of this field. Quantify it by numerical reservoir simulation predictions. The simulation package to be used will be Schlumberger ECLIPSE 100 Simulator. Based on this predicted results, economic analysis would be carried out to determine the feasibility of the IWC. An economic viability of IWC is done by comparing increased investment cost (CAPEX and OPEX) to increase in revenue which is as a result of the higher hydrocarbon recovery, reduced water production and savings in rig time.

Material and Methods

There is no fit-for-purpose configuration of IWC technology. Its design and modelling area dynamic process that needs proper analysis before its implementation. We need to ascertain that the properties of the field under study are suitable for the application of IWC. This analysis begins (ranges) from an analytical approach to a complex reservoir simulation model. The reservoir parameters such as heterogeneity (porosity and permeability), recovery mechanism, recovery efficiency, fluid type, pressure variations, total reserves, are taken into consideration. Equally well geometry, well type, artificial recovery mechanism, operating environment (offshore or onshore) are some of the parameters taken into consideration for IWCs applicability on a field. In this work, using the Eclipse 100 simulator four scenarios were simulated i.e., the base case which served as the baseline on which we can evaluate the benefits of adopting IWC, the traditional method, and the two intelligent methods (layer on/off and Feedback on/off).

Reservoir Model

Here an overview of some fundamental equations and numerical methods that are implemented in the reservoir simulation are shown. A multiphase black oil model is employed to better understand the fluid flow behavior in the porous reservoir media. The equations presented here are derived from the textbook by Ertekinet *al*.,[11].

Mathematical Formulations of Fluid Flow Equation

Darcy's law for multiphase flow as seen in the Eq. (1) below can be substituted into the mass conservation Eqs. (2.a) to (2.c) below to obtain the fluid flow equations in Eqs. (3.a) through (3.c).

Darcy's Multiphase Flow Equation:

$$\overrightarrow{u_l} = -\beta_c \frac{kk_{rl}}{\mu_l}\left(\vec{\nabla} p_l - \gamma_l \vec{\nabla} Z\right), \tag{1}$$

where l is the phase or component (oil, water or gas), K_{rl} is the relative permeability to phase L, dimensionless, $\mu_l$is the viscosity of phase l, cp, P_l is the pressure of phase l, psia, γ_l is the gravity of phase l, psi/ft, β_c is the transmissibility conversion factor, $\overrightarrow{u_l}$ is the phase superficial velocity and Z elevation referred to datum, ft.

Mass Conservation Equation for Oil, Water and Gas:

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_o}{B_o}\right) + \nabla.\left(\frac{1}{B_o}\overline{u_o}\right) = q_o, \tag{2a}$$

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_w}{B_w}\right) + \nabla.\left(\frac{1}{B_w}\overline{u_w}\right) = q_w, \tag{2a}$$

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_g}{B_g} + \frac{R_{so}S_o}{B_o}\right) + \nabla.\left(\frac{1}{B_g}\overline{u_g} + \frac{R_{so}}{B_o}\overline{u_o}\right) = q_g, \tag{2c}$$

where $\emptyset$ is the porosity, S_o, S_g, S_w are the saturations of oil, gas and water respectively,B_o,B_g,$B_w$are the formation volume factors of oil, gas, and water respectively,$\overrightarrow{u_o}$ is the oil-phase superficial velocity vector, $\overrightarrow{u_g}$ is the gas-phase superficial velocity vector,$\overrightarrow{u_w}$ is the water-phase superficial velocity vector,R_{so} is the solution GOR, q_o, q_g, q_w are the production rates at reservoir conditions of oil, gas and water respectively. Equations (2.a) to (2.c) are respectively the mass conservation equation for oil, water and gas components for three-dimensional (3D) (rectangular) flow of multiphase black-oil system. The various terms in these equations have the units of volume at standard conditions per unit time. By substituting Darcy's law of multiphase flow Eq. (1) into Eqs. (2.a), to (2.c) the following set of equations are obtained;

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_o}{B_o}\right) - \nabla.\left(\frac{1}{B_o}\beta_c \frac{kk_{ro}}{\mu_o}\left(\vec{\nabla}p_o - \gamma_o \vec{\nabla}Z\right)\right) = q_o, \quad (3a)$$

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_w}{B_w}\right) - \nabla.\left(\frac{1}{B_o}\beta_c \frac{kk_{rw}}{\mu_w}\left(\vec{\nabla}p_w - \gamma_w \vec{\nabla}Z\right)\right) = q_w, \quad (3a)$$

$$\emptyset \frac{\partial}{\partial t}\left(\frac{S_g}{B_g} + \frac{R_{so}S_o}{B_o}\right) - \nabla.\left(\frac{1}{B_g}\beta_c \frac{kk_{rg}}{\mu_g}\left(\vec{\nabla}p_g - \gamma_g \vec{\nabla}Z\right) - \frac{R_{so}}{B_o}\beta_c \frac{kk_{ro}}{\mu_o}\left(\vec{\nabla}p_o - \gamma_o \vec{\nabla}Z\right)\right) = q_g, \quad (3c)$$

where k is the permeability,k_{ro} , k_{rw}, k_{rg} are the relative permeability's of oil, water and gas respectively, γ_o, γ_w, γ_g are the gravities of oil, water and gas respectively, p_o,p_w, $p_g$are the pressures of oil, water and gas respectively. Eqs. (3.a), to (3.c) are the flow equations for the oil, water and gas components respectively. Which are equally the general forms of multiphase flow equations. These equations can be simplified depending on the prevailing reservoir conditions, to reduce the complexity of the equation set. The Black oil model is known as the three-phase oil/water/gas flow model. While oil and water are immiscible, gas may exist as free or solution gas. The reservoir is assumed to be at constant temperature, and the fluids are assumed to be in thermodynamic equilibrium throughout the reservoir. The flow equations for this black oil model are expressed as seen in Eqs. (3.a), to (3.c). Additional relationships needed to complete the flow description are:

$$S_O + S_w + S_g = 1\,, \quad (4a)$$

$$P_{cow} = P_o - P_w = f(s_w), \quad (4a)$$

$$P_{cgo} = P_g - P_o = f(s_g), \quad (4c)$$

where $P_{cow}$is the oil/water capillary pressure, psi, P_{cgo} is the gas/oil capillary pressure, psi, f (S_w) is the water saturation function, f (S_g) is the gas saturation function. Eqs. (3.a), to (3.c) and Eqs. (4.a), to (4.c) contains 6 unknowns' parameters: $P_o,\ P_w,\ P_g,\ S_o, S_w\ and\ S_g$. The eqs. (3.a), to (3.c) may be used to eliminate three unknowns in the Eqs. (2.a) to (2.c). The black-oil model formulation in terms of $P_o, S_w\ and\ P_g$ can be obtained by the aid of Eqs. (4.a) to (4.c). Then we can solve explicitly for the remaining unknowns, $S_o, P_w, and\ P_g$, by substitution of the principal unknown into Eqs. (4.a) to (4.c). Eclipse 100 simulator uses these multiphase blackoil fluid flow equations by applying finite difference techniques for numerical computations on the reservoir models.

Reservoir Properties

In this paper, an Eclipse benchmark model is used for simulating the case study. This model is selected from a set of other benchmark reservoir models like UNISIM-I-D, SPE 10, Brugge, Norne and PUNQ because its reservoir properties were best suited for this study. The heterogeneous properties of this reservoir model make it a good fit for simulating intelligent wells. The table 1 gives us a detailed description of the reservoir.

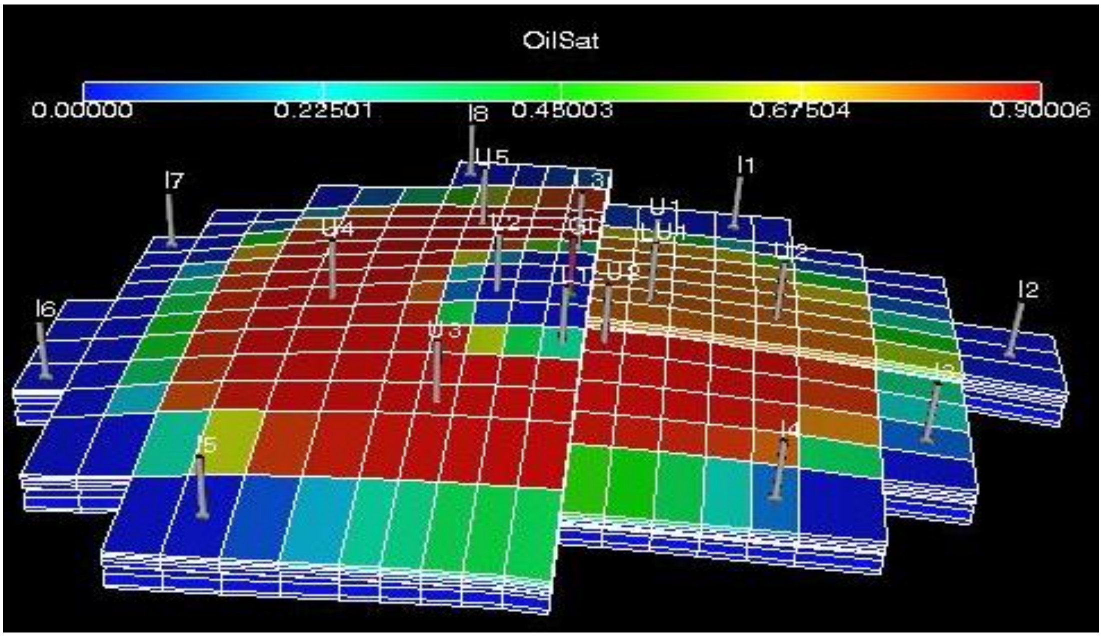
This is a Cartesian grid model with a total of 2400 grid cells, its geological structure contains 2 sealing faults, which divide the reservoir up into 3 distinct fluids in place regions. The reservoir model has a dimension of857.06 x 797.99 x 52.17 (feet) and a scale grid of 20 x 15 x 8 (NI x NJ x NZ). This reservoir has average reservoir permeability in the X, Y, Z directions of 572.89md, 572.89md and 28.644md respectively. The reservoir is segmented into 3 regions with a water oil contact (WOC) of 7500feet in region 1, 7550 feet in region 2 and 7600feetin region 3. The saturation range of the reservoir clearly shows its heterogeneity. This saturation ranges from 0.0 to 0.9 as seen in Fig. 1. Thus, highlighting the heterogeneity of the chosen reservoir model. The field is made up of 10 production wells and 9 injector wells i.e., 8 water injectors and 1 gas injector. A maximum liquid rate of 20000 stb/day was used to operate the production wells, while the injection wells provide pressure support for oil displacement and are operated under a 2000 psia bottom hole pressure (BHP). The well has produced for a period of 10 year.

Table 01: Reservoir Description

Field property	Value
Global Dimensions Model length (DX) Model width (DY) Model height (DZ) Grid cells (*NI* x *NJ* x *NZ*) Total number of grid cells	 857.06 797.99 52.17 20 x 15 x 8 2400
Average Porosity	0.217 (0 to 0.3)
Average Net to Gross NTG	1
Average PERMX (md)	572.89 (4.2 to 2783.6)
Average PERMY (md)	572.89 (4.2 to 2783.6)
Average PERMZ (md)	28.644 (0.21 to 139.18)
Average Initial Reservoir pressure (psia)	3955.6
Initial Field Oil in Place (STB)	563335059
Average Initial Water Saturation	0.59023
Average Initial Oil Saturation	0.39478
Water oil contact – WOC (feet)	Region 1 = 7500, Region 2 = 7550, Region = 7600

The reservoir properties in Table 1 above permit us to conceive the 3D model of the reservoir as presented in Fig. 1.

Figure 01: Oil saturation profile with the different wells.



Methodology / Test cases

After the modifications carried out on the model, four simulation cases were run by adjusting the data input file of the Eclipse benchmark model. A baseline case is run where the production wells are operated for 10 years with no water production control method. A traditional / conventional method used in limiting water production is carried out. Finally, then carried out intelligent well modification to show the different strategies of water control by this method. Three decision drivers where set for this paper which are water production, economic oil production rates (good NPV) and time saving on the rig.

Base Case Scenario

The baseline eclipse models were running at its initial condition before applying any intelligent control. This model gives us the baseline on which we can evaluate the benefits of adopting IWC. In this model, the maximum liquid rate was set at 25000 stb/day and the BHP at 2000 psia. These modifications were done under the schedule section of each model.

Traditional Water Control

This method has as objective to control water breakthrough without the application of an intelligent well technology. This case study is carried out under the same conditions as the base case models, but for the fact that the producers were set to a maximum water cut of 70 percent. The well is shut-in and assumed uneconomical when the water cut threshold is reached for a given producer, Similar to the baseline case, this method provides a reference for which we can measure the benefits of using intelligent well completion technology.

Intelligent Well Control

This method employs downhole monitoring and control of each production layer. The objective here is to accelerate and maximize oil production, while minimizing the production of water. The simulation of Downhole control was done by introducing inflow control devices (ICD) as discussed previously around the tubing. The objective of this device is to obtain flow control by imposing an additional pressure drop between the sand face and the tubing. This device diverts fluid inflowing from the formation through a sand screen and then into a spiral before it enters the tubing. The pressure drops across the device is calibrated to account for the varying density and viscosity of reservoir fluid flowing through the device (Autonomous ICD in this case). Based on the following Eq. (5):

$$\delta P = \left(\frac{\rho_{mix}^2}{\rho_{cal}}\right) \times \left(\frac{\mu_{cal}}{\mu_{mix}}\right)^y \times a_{AICD} \times q^x, \tag{5}$$

where$a_{AICD}$is the strength of the AICD, x is the volume flow rate exponent, y is the viscosity function exponent, ρ_{mix}^2 is the density of the fluid mixture in the segment at local condition, ρ_{cal} is the density of the fluid used to calibrate the ICD, μ_{mix} is the viscosity of the fluid mixture in the segment at local conditions, μ_{cal} is the viscosity of the fluid used to calibrate the ICD, q is the volume flow rate of the mixture through the ICD at local conditions.The density of the fluid mixture at local segment conditions is given by:

$$\rho_{min} = \alpha o * \rho o + \alpha w * \rho w + \alpha g * \rho g, \tag{6}$$

where αo, αw, αg are the volume fractions of the free oil, water, gas phases at local conditions andρo, ρw, ρg are the densities of the oil, water, gas phases at local conditions. The viscosity of the mixture at local segment conditions is given by:

$$\mu_{mix} = \alpha o * \mu o + \alpha w * \mu w + \alpha g * \mu g, \tag{7}$$

where μo, $\mu w, \mu g$ are viscosity of the oil, water and gas phases at local conditions respectively. The first intelligent completion method used was the ON-OFF control, where by the model was simulated by monitoring in a constant manner all the producing layers with respect to a set upper limit water cut threshold. This water cut threshold limit was set at 50 percent and production constraints were imposed such that once this limit for a producing layer is attained or exceeds the threshold, the layer concerned is completely shut. These modifications were done using the CECON keyword of the schedule section. The CECON keyword permits the monitoring of production at each grid block with a connection to the wellbore against a set proxy [12]. When this proxy model measure is violated, the required action is applied. The action taken is either by completely shutting off the connection or setting it to an auto mode. The feedback ON-OFF control mode was the second intelligent method employed for this work. In this mode, we continuously monitored the overall well water cut during production with respect to a given upper limit water cut threshold. This water cut threshold was set at 30 percent and we placed some limits on the production such that when this well water cut threshold is violated, the most offending producing layer in the well is completely shut. The WECON keyword was used for this intelligent well modification. This keyword checks the whole well production against the set proxy model condition [12]. When this proxy model is violated on the well, the downhole producing layer connection is checked by the simulator and the desired action is applied on the most problematic layer connection. The actions that could possibly be taken include completely shutting off the connection or setting it to auto mode, where the connection is continuously monitored every time step against the set threshold condition.

Economic Evaluation

The main objectives of hydrocarbon exploitation entails « maximum recovery », which has to be carried out « safely » and «profitably». Therefore, satisfying one of these conditions is not a sufficient condition for the implementation of the technology. In this reservoir model, a modified NPV model was used to evaluate the economic value of adopting intelligent well technology. So, in the conventional formula in Eq. (8), a fixed discount rate of 10 percent was used.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o, \tag{8}$$

where C_t = cash flow = Revenue – (CAPEX+ OPEX+ ROYALTY+ TAX).Revenue = oil price ($/bbl) x total oil (bbl) – water disposal/treatment cost x total water. Taxable income = Revenue – (OPEX + ROYALTY).Tax = Tax rate x Taxable income. C_o = CAPEX, r = discount rate, and t = number of time period (t =1 to T).

The conventional method of NPV analysis fails to incorporate some key intrinsic values provided by intelligent well completion, which among many others include accelerated production. To achieve this, in the conventional equation above a new term value of time saving (VTS) is included:

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o + VTS. \tag{9}$$

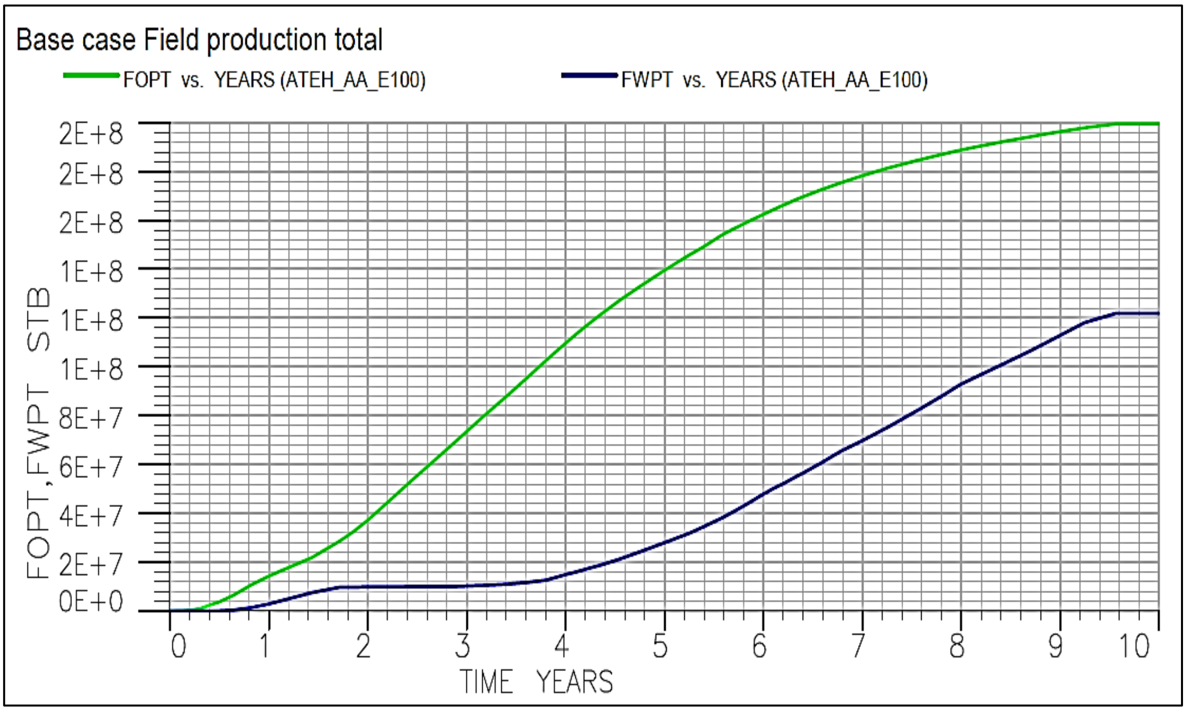
The VTS is the sum total of all operating expenses and other expenses that are saved through the implementation of IWC, which will otherwise be sustained as cost if the field was produced using conventional methods. We have daily operations costs or lifting costs which include fixed cost like labor and transportation costs. For easy analysis, we only included the operating expenses in the VTS term even though more complex analysis could be done. Table 2 presents the field economic value.

Table 02: Field Economic Values

PARAMETERS	UNIT PER WELL	TOTAL
Cost of well ($)	10,000,000	100,000,000
Completion cost	2,000,000	20,000,000
Total CAPEX	12,000,000	120,000,000
Cost of IWC	0.3 x Cost of completion	6,000,000
Cost of downhole sensors	3,000,000	30,000,000
Total cost of IWC	15,600,000	156,000,000
Fixed OPEX	20,000,000 per annum	200,000,000
OIL Price ($/bbl)	40 (September 2020)	
Royalty (percent)	10	
Discount rate (percent)	10	
TAX RATE (percent)	20	

Results

Figure 02: Base Case Field Production Totals



The main objective of this paper was to build an intelligent well model that will optimally reduce water production in a heterogeneous reservoir while simultaneously maximizing oil production. This paper's focus is on oil production, implying that gas production output data will not be included. The results we obtained from the modifications carried out on the base case scenario field model to increase its « smartness », the traditional water control method and the intelligent simulation models are presented here. The three principal drivers used to quantify the benefits of adopting IWC, which are water production, economic production rates (NPV), and time saving (accelerated production).

Base Case Scenario

A summary of the output results obtained by running the base case at initial conditions before any intelligent control modification was applied, is presented in Table 3.

Table 03: Field production output base case scenario.

FOPT (MSTB)	FWPT (MSTB)	FRF	FWCT
199558.1	121932.0	35.4 percent	72 percent

Therefore, the objective here is to produce less water, more oil and make higher economic benefits. Figure 2 presents the base case total field production rate of oil (green) and water (blue). In Figure 2, the graph shows that at year 5.6, we attain the water breakthrough point wherein we begin to produce more water than oil. This points us to the need of applying a water control method to retard or restrict this water from being produced.

Traditional Control Method

This control method helps to manage water breakthrough with no application of an intelligent technology. The same constraints used in the base case model were applied here, but for the fact that the producing wells were placed at a maximum water cut of 70 percent. The well is shut-in and considered uneconomical when this water cut threshold is attain for a given producer. This method gives us a reference against which to measure the benefits of adopting intelligent well technology. The result of the simulation, which shows the comparison between the base case scenario and the traditional water control case, are presented in Figure 3.

Figure 03:(a) Field Production Total – Base Case Versus Traditional Water Control and (b) Field Water Cut Comparison – Base Case Versus Traditional Water Control

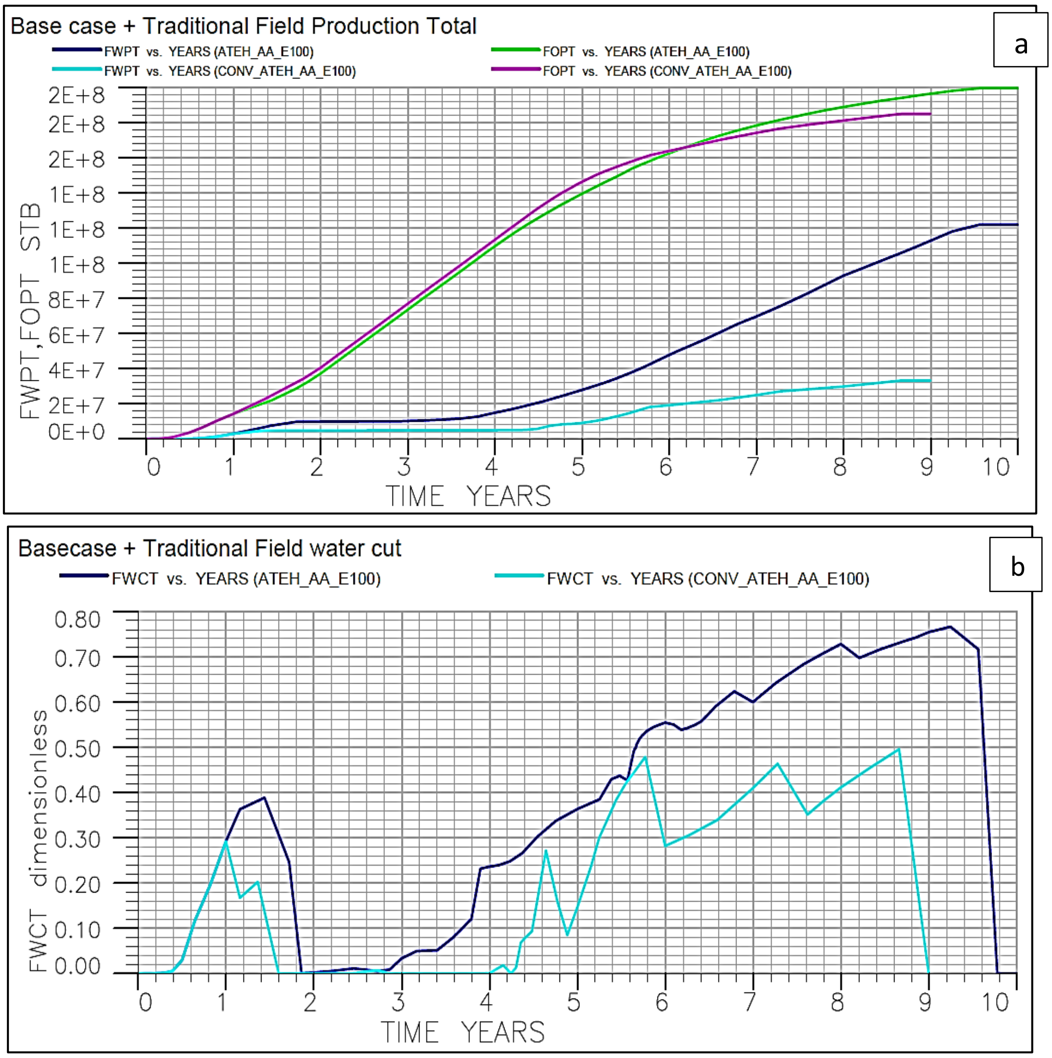


Figure 3 (a)reveals that there is a slight reduction in the production rates beginning from year 5 of the traditional water control case. Equally, the rate of water produced is greatly reduced when compared with the base case scenario. This shows an optimization of the production process when water control is applied. Finally, Figure 3 (b) shows a reduction in the field water cut from 72 percent in the base case scenario to 51 percent in the traditional water control case.

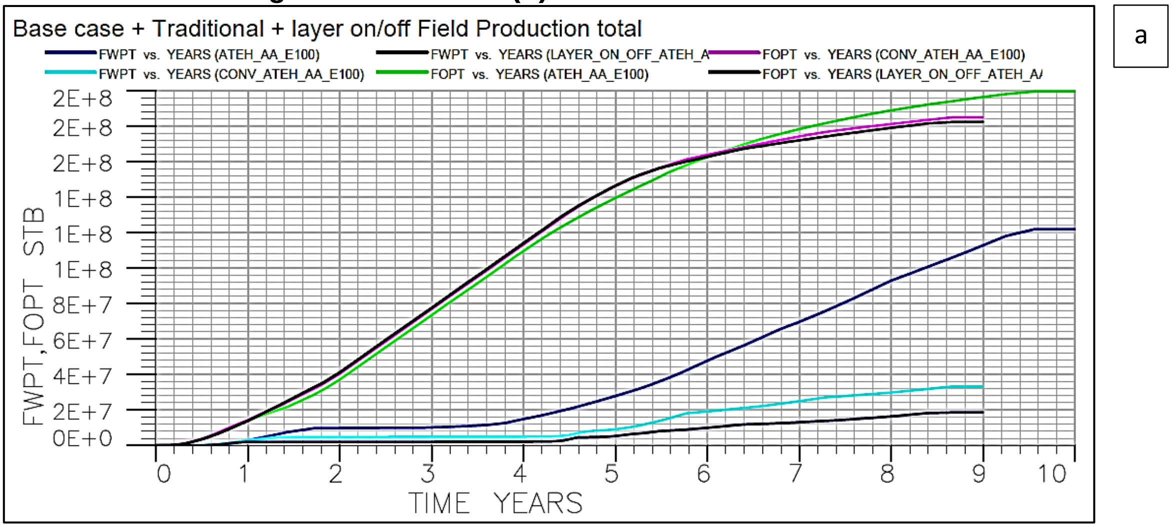
Intelligent Well Control

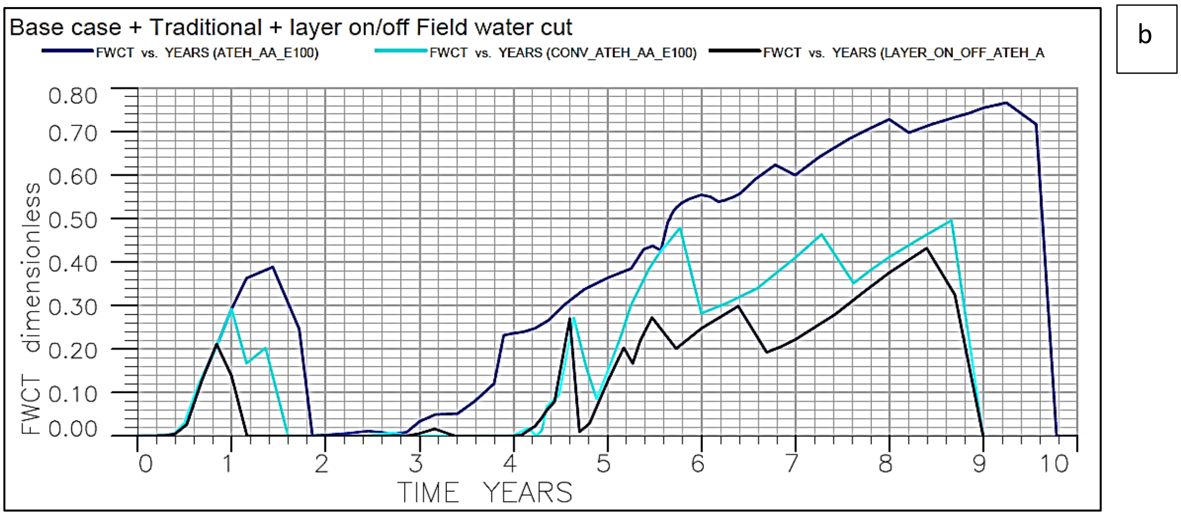
We simulated two methods of intelligent well control, which are; Layer ON-OFF control and the feedback ON – OFF control. These intelligent well control modes employ downhole monitoring and control of each production layer. Their goal is to maximize oil production while decreasing water production.

Layer ON – OFF Control

The simulation was done by continuously checking all the producing layers against a predetermined upper limit water cut threshold. In order to ensure that if a producing layer's water cut reaches the threshold, that layer is entirely shut, the water cut threshold was set at 50 percent and some production limits were also imposed. Figure 4 shows a comparison between the base case scenarios, the traditional water management case and the ON – OFF Layer control case.

Figure 4:(a) Field Total Production – Base Case, Traditional Water Control, and ON-OFF Intelligent Control and (b) field Water Cut for Three Cases



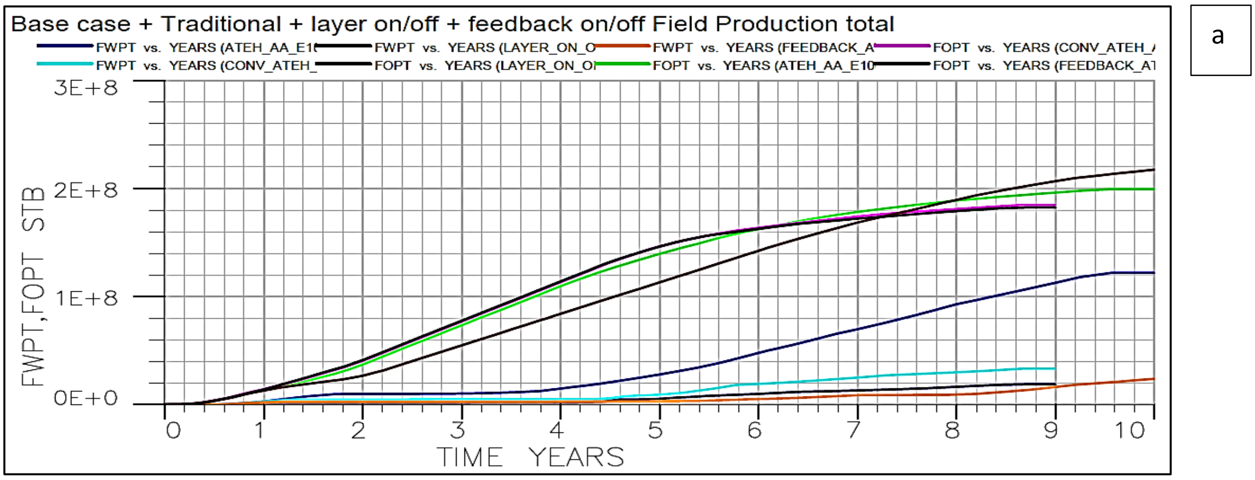


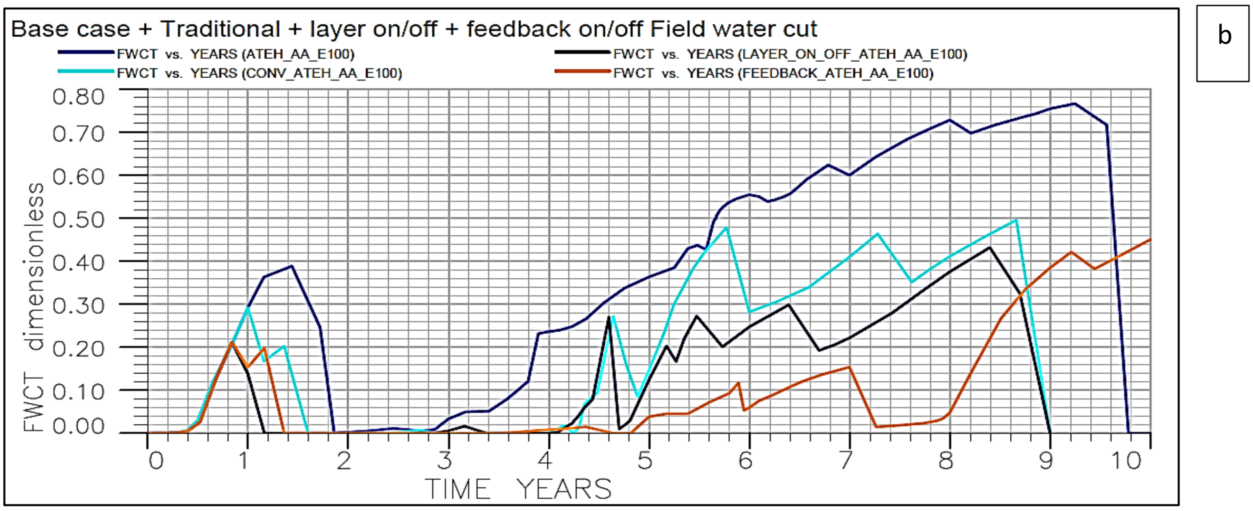
In the oil production rate, we notice a significant decrease in the oil production rate from year five. However, we have a significant reduction of the rate of water production when compared to the base case scenario and the traditional water control case. These points out the optimization of the production process when water management is applied using intelligent well controls. Figure 4 (a) gives us the total production of oil, and water production. Showing us how a minimum or a reduction in water production is obtained by using downhole layer control. Finally, Figure 4 (b) shows a reduction in the field water cut from 72 percent in the base case scenario to 31 percent in the ON – OFF layer control case.

Feedback ON – OFF Control

The whole well water cut was continuously monitored throughout production against a predetermined upper limit water cut threshold in this control mode, which is a minor modification of the Layer ON – OFF control mode. This well's water cut threshold was set at 50 percent and some production restrictions were imposed so that when it is crossed, the well's most problematic layer is completely closed. The feedback operating mode simulates a straightforward ON/OFF ICV by altering the control approach somewhat, similar to the ON-OFF control strategy. Figure 5 shows the field production totals and field water cut of the four simulated cases.

Figure 5:(a) Field Production Total – All Cases And (B) Field Water Cut – All Case





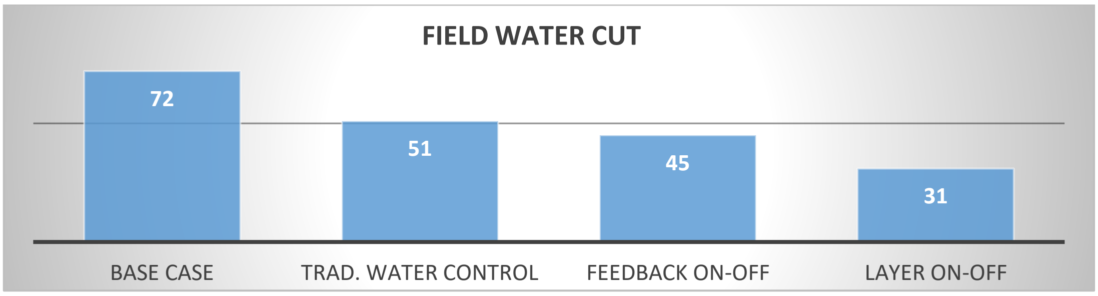
It is noticed in Fig. 5 (a) for the two intelligent cases, that the water production levels are greatly lower and do not attend the breakthrough point as seen in the base case and the traditional water control method. The rate of production in these intelligent cases reduces due to a drop in the reservoirs pressure. This highlight show little water is produced by the two intelligent modification situations, with the ON- OFF Layer case being the most successful. As can be observed in Fig. 5 (b), the field water cut went from 72 percent in the base case scenario, to 51 percent in the traditional water control case, to 45 percent in the feedback ON-OFF case and to 31 percent in the ON-OFF layer control case. Giving us a 41 percent, reduction in the field's water cut. Similar results were obtained in some real-life fields. In Ecuador, the water cut decreased by 34 percent, in the UAE we had a 47 percent decrease in the water cut after the installation of an intelligent well system [13]. Equally, so can see an increase in oil production. These results clearly highlight the benefits of using intelligent well control in minimizing field water production. Table 4 presents the summary of the field data obtained in the 4 cases.

Table 04: Summary of Field Data

Simulation case	Base case	Traditional control	Feedback on/off	Layer on/off
FOPT (MSTB)	199558.1	184882.8	217310.1	184956.9
FWPT (MSTB)	121932.0	33201.5	24084.9	15930.5
FWCT	72 percent	51 percent	45 percent	31 percent
FRF	34.5 percent	32.82 percent	38.58 percent	32.83 percent

From Table 4, it can be seen that the two intelligent cases produce a better oil production total and a minimal water production compared to the base case and traditional control methods. The field water cut comparison for all cases is depicted in Fig. 6.

Figure 6: Field Water Cut Comparison for All Cases



It can be seen from Fig. 6 how the two intelligent cases have reduced water cut from it is initial value of 72 percent to 45 percent in the feedback ON-OFF case and 31 percent in the layer ON-OFF case.

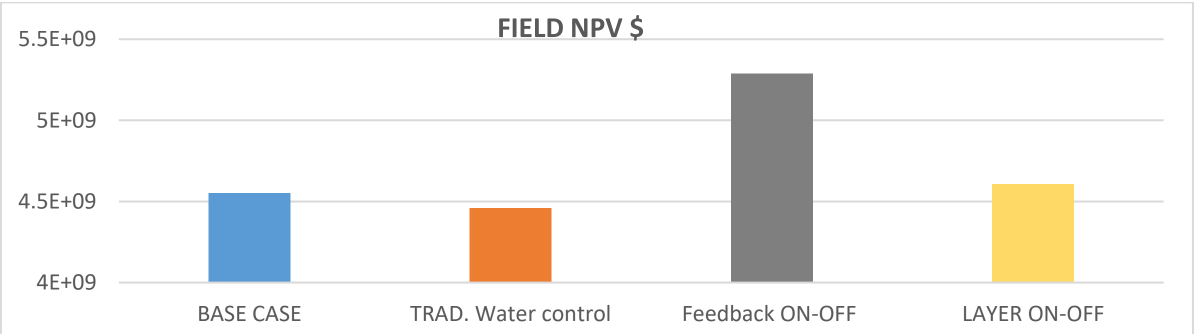
Economic analysis

Table 5 presents the findings of the economic analysis and Fig. 7 displays the NPV comparison for all scenarios.

Table 05: Results of Economic Analysis

Simulation case	Base case	Traditional case	Feedback on/off	Layer on/off
NPV (millions $)	4550.307	4459.7	5288.3	4606.3

Figure 07: NPV Comparison for All Case



As seen in the Table 5 and in Fig. 7, the two intelligent modifications, i.e., the layer on-off and the feedback on-off are the most profitable cases. It should be highlighted that the only direct cash flows included in this NPV analysis were the total oil and water produced, CAPEX for both the base case and the intelligent modifications, operating expenses (OPEX), and other direct cash flows. The statistics above, however, ignore the advantages of intelligent wells, such as risk reduction, labor cost savings, downtime, and other unanticipated costs.

Conclusion

The main aim of this paper was to build an intelligent well model that will optimally reduce water production in a heterogeneous reservoir while simultaneously maximizing oil production. The results successfully demonstrated the benefits of using intelligent downhole control devices in this work. The decision drivers set for this paper were attained. The field water cut was greatly reduced from 72 percent in the base case scenario to 31 percent in the layer ON-OFF intelligent well case, giving us a 41 percent reduction in the water cut. Equally, oil production was economic in both intelligent well cases as we can see on the net present value forecast. This net present value forecast can be greater than this, given that some variable factors like saving in labor cost and unforeseen risk associated with extended production were not involved in its calculation. It is very important to note that the decision drivers could be different for operators, given that the nature of the field equally differs. Therefore, it is critical that the decision drivers should be well analyzed and defined at the beginning of the field study.

Data Availability

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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