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Use of Smart Controls in Intelligent Well Completion to Optimize Oil & Gas Recovery

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Authors' contributions

This work was carried out in collaboration between both authors. Author AA designed the study, performed the statistical analysis, wrote the protocol and wrote the first draft of the manuscript. Author KB managed the analyses of the study. All authors read and approved the final manuscript.

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ABSTRACT

For the past few years, the oil and gas industry has faced several economic, geographic and technical challenges largely due to decline in crude oil prices and market volatility.

In the quest to address some of these challenges to accelerate production and subsequently maximize ultimate recovery, operators are limited to remote hydraulic and electro-hydraulic monitoring and control of safety valves providing the means of obtaining downhole production data which demands periodic well intervention-based techniques with risk of loss of associated tools. This has highlighted the need for companies to adopt new technology to take advantage of low crude oil price environment, optimizing recovery without interventions and with minimal production interruption.

One of the recent improvements in production technologies which can remedy these problems having unique capabilities to do so is the Intelligent Well Completion (IWC) technology. In this paper the utilization of IWC to optimize oil recovery was evaluated. The use of a reservoir simulator, the Schlumberger ECLIPSE-100 simulator, was employed to model an intelligent well. Case study simulations were performed for an active bottom-water drive. Modeling of the Intelligent Well Inflow Control Devices (ICDs) and downhole sensors for the multilaterals was achieved using the Multi-Segment Well model.

Optimal IWC technology combination for maximum hydrocarbon recovery and minimal water

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production was determined using the reactive control strategy (RCS) which indicated a drastic reduction of about 52.1% in water production with a slight drop of 1.5% in field oil efficiency (FOE). The simulation results obtained clearly showed that the utilization of intelligent well-ICDs in Production wells can significantly increase the cumulative oil production and reduce water production.

Keywords: Intelligent well completion; oil recovery; optimization; inflow control devices.

ABBREVIATIONS

AICD - Autonomous Inflow Control Device
FOE - Field Oil Efficiency
FOPT - Field Oil Production Total
FWCT - Field Water Cut
FWPT - Field Water Production Total
ICD - Inflow Control Device
ICV - Interval Control Valve
IWC - Intelligent Well Completion
RCS - Reactive Control Strategy
SGOR - Segment Gas Oil Ratio
STB - Stock Tank Barrel
SWCT - Segment Water Cut
WOR - Water Oil Ratio

1. INTRODUCTION

Intelligent Well Completion (IWC) technology broadly refers to any sort of downhole monitoring and/or remote control system which is capable of collecting, transmitting and analyzing reservoir, wellbore production and completion data, while providing the capability for remote action control of the well, reservoir and production process [1]. It does not refer generally to any capability for automated self-controlled system put in place, but relies on manual interface to initiate instructions to the well [1].

Advancement in computer assisted operations in hydrocarbon exploration and production technologies have led to upgrades in well architecture complexity [2], having intelligent wells as the most advanced method of well completion available. The major benefits being the upsurge in maximum hydrocarbon recovery, increase in the well performance and productive life, and thus optimizing production [3]. Also the main driver for this technology being the emergence of horizontal and multi-lateral wells around the world due to having the ability to control flow from many laterals or zones utilizing down-hole control devices and valves.

The declining production from the first generation of offshore wells in the early 1990's spurred up the drive in finding better alternative methods capable of performing downhole monitoring, control and optimization [4]. This resulted in the emergence of two basic schools of thought. One group supported the hydraulics-based systems (mostly the Mechanical sliding sleeves), while the other group favored all electric systems and was further divided into sides in favor of and opposed to the use of a more improved fiber optics downhole system [5]. Based on the possible outcome of the debate from these schools of thoughts, the system which is widely recognized as the first true smart well installation was done by a small firm of innovative engineers working in the UK North Sea (Developments in Troll field in the North Sea by Norske Hydro in 1992 [6], and then Saga's Snorre Field in the North Sea, 1997 [4]).

Inflow Control Devices (ICDs) or Inflow Control Valves (ICVs) are surface controlled chokes mounted on screen joints used to restrict and regulate production from the reservoir into the flow conduit [7]. Applications of these devices include, but not limited to regulation of flow at each predetermined zone by creating a pressure difference between the annulus and the production string, shutting off gas or water production zones, shutting-in a well or layer for pressure build-up operations [8], reduction of frictional pressure losses along the completion (Heel-Toe effect), provide uniform sweep efficiency across the sand-face, minimize pressure drop through ICD housing to improve flowing bottom-hole pressure and equalizing productivity [9]. Despite these varying range of ICD applicability, their overall efficacy depends largely on the reservoir properties (permeability, porosity, saturations, and reservoir pressure profile), and the wellbore properties (Inflow Performance Relation (IPR), Vertical lift performance (VLP) and well Productivity Index (PI)) [10]. It is quite important to have a good understanding of the reservoir geology so as to decide the optimal placement of these ICDs or ICVs. They should be placed in zones that show signs of early water or gas breakthrough [9], as they show high success rates when installed in high permeability layers, although variations would occur due particularly to the scenario being investigated. ICDs are usually designed in various types depending on its operability. They could be controlled or automated by an operator, or having its parts hydraulically, electrically or hydro-electrically (hybrid unit) operated, and vary from open to close and/or may operate in multiple incremental steps [11]. In spite of their variations, ICDs are purpose built, and operate within set end in view. For instance an ICD which is installed for shutting off excess gas production may not serve to optimal capacity when used to choke water production [12].

The technology that finally spurred the industry towards intelligent well development is the proliferation of offshore multilateral wells. Due to the need for optimum efficiency and increase in productivity, extended-reach and multilateral wells are widely used to achieve extensive reservoir contacts (reservoir-to-well exposure). These complex well configurations basically provide numerous advantages, some of which are; optimizing sweep efficiency, increasing the available drainage area, delaying water or gas breakthrough and thus improving well productivity. Increase in reservoir contact enable operators to achieve similar production rates as conventional wells utilizing less drawdown pressure [13]. With complex and highly heterogeneous reservoir systems, such complex well configurations are usually accompanied by a lot of uncertainties and risks if not properly designed and managed [14]. In some reservoirs having extended reach wells, a major issue like the heel-toe effect often leads to an early end of the productive life of the well, with a large portion of the reserve left unrecovered. The heel-toe effect is a situation in which significantly higher drawdown pressures occurs at the heel than at the toe of a horizontal well, which leads to unequal inflow along the well path [13]. As a result of higher drawdown in the heel, water or gas breakthrough is accelerated in this region which leads to an early end of the productive life of the well.

A different behavior is observed in the pressure drops for the horizontal or highly deviated well configurations and the vertical well configurations which are pressure drops due to gravity, acceleration, and friction [15]. Acceleration and frictional pressure drops for the vertical wells can be ignored but for a horizontal section having pressures which has fallen below the initial bubble point pressure, these two components become very crucial (the effect being comparable with well drawdown). Although horizontal wells have a higher production yield than vertical wells, they don't tend to access all the recovery layers [16]. Consequently to access and achieve maximum recovery, it is important to have a controlled flow of fluid from the reservoir. ICDs can be installed to balance the pressure differential across the completion and thus abate issues associated with variances in reservoir parameters that can lead to early water breakthrough and low recovery as it helps with the ability to isolate, test, monitor, and control each lateral of the wellbore [17], invariably optimizing recovery. To evaluate these benefits derivable using the IWC technology, a case study simulation is performed for an active bottom water drive reservoir. This was done by performing flow simulations to predict and compare the performance of the oil reservoir under conventional multilateral wells without Intelligent Completion Devices (Non-ICD Multilaterals), and that with ICDs (ICD Multilaterals). Also the effect of vertical location of varied lateral well on intelligent completion system equipped in dual-opposing multilateral wells was assessed using the Reactive Control Strategy. This strategy was duly applied to control water production from relatively high-permeability layers prior to water breakthrough.

2. METHODOLOGY

2.1 Simulation

The simulation was carried out in two parts. First, different downhole completion configurations were considered, then next was to evaluate the effect of intelligent completion whereby the conventional base case scenario and the alternative IWC scenario had their ultimate recoveries for all runs compared.

2.1.1 The simulation model

The conceptual model used is described on a regular Cartesian grid represented in 40 x 20 x 10 fine scale grid cells (40 cells in the X direction, 20 cells in the Y direction and 10 cells in the Z direction totaling 8000 grid cells) with global dimensions of approximately 400 ft x 400 ft x 50 ft in the X, Y and Z direction respectively. The reservoir has a net thickness of 250 ft. The gas oil contact and the oil water contact is at 9200 ft and 9450ft respectively, having datum depth at 9200 ft (depth at which early pressure measurement was made) with pressure of 4600 psia. The reservoir employs an active bottom-water drive system and has a porosity range from 0.16 to 0.29, a permeability range from 50 to 400 mD., with an average net-to-gross of 0.68.

2.2 Base Case Scenario Model

A base case simulation model refers to the initial conditions of the field before applying any unconventional technology and/or Intelligent Well Completion technology. The simulation model provides a baseline with which to measure the verging improvement observed when intelligent well control is adopted. The control modes for all wells were set under the SCHEDULE section of the data file having the following constraints:

- All reservoir simulations are performed based on 10 years of production time.
- Minimum bottom-hole pressure (BHP) of 1500psi.
- Maximum liquid production rate is varied within the range of 8,000-12,000 STB/D initially before the optimized production rate is chosen to represent the production rate for the rest of the simulation cases under other constraints.
- Maximum allowable water cut of 60% for initial cases.

For the horizontal well base cases on X-grid blocks with initial length of 2000ft drilled and completed in the target zone of 250ft of the reservoir model, the optimization of location (various depths) and liquid production rate was carried out. The various depths for the horizontal producers placed on 5th, 6th, and 7th vertical grid blocks (layers 5, 6, and 7) indicated depth nodes of 9225 ft, 9275 ft and 9325ft respectively. The I-coordinate was positioned on grid blocks 21 to 30 on X-axis, and J-coordinate was positioned on grid block 8 on Y-axis.

For the Multilateral well configuration, first is the dual-opposing laterals (Well WPML1) at depth node of 9275ft having both laterals branching off on same layer (6th layer from the 6th vertical grid block), then next is the Multilateral well configuration (Well WPML2) having dual-opposing laterals on the 6th and 7th layers at depth nodes of 9275ft and 9325ft respectively. The effective length of the lateral sections being 8000ft (20 grid blocks) for each well, as the I-coordinate was positioned on grid blocks 12 to 30 on X-axis, and J-coordinate was positioned on grid block 8 on Y-axis. All the wells had wellbore diameter of 0.292 ft (3.5in), with the assumption of no presence of skin nearby, and wells penetrate the full thickness of the block through its center perpendicularly to two of its faces.

2.3 The Intelligent Well Model

The conceptual model enables the separate phases to flow with different velocity in the reservoir. This puts to use Inflow Control Devices (ICDs) and downhole sensors for downhole monitoring and control of each production layer using the Multi-Segment Well Model. This will aid ECLIPSE 100 to simulate the downhole flow control devices more accurately. To include a series of these devices in a multi-segment well, the devices should be represented by segments branching off the tubing.

First the dimensions for multi-segments is introduced in the RUNSPEC section using the keyword WSEGDIMS, before defining the multi-segment well structure using WELSEGS in the SCHEDULE section, then lastly properly assign segments to represent the ICD-segments with keywords WSEGAICD (signifying Autonomous ICD) still in the SCHEDULE section. The keyword WSEGITER (SCHEDULE section) was used in the model which helps solve large multi-segment iteration of the time step, and gives the well a greater chance of converging its solution [18]. A detailed method for achieving all of these is highlighted below;

- Create the main branch describing the tubing (WELSEGS keyword)
- Create the annulus branch which branches off from the main branch (WELSEGS keyword).
- Create the ICD segments which also branches off from the main branch (WELSEGS/WSEGAICD).
- Link each ICD segment with the corresponding annulus segment (WSEGLINK).
- Then linking each annulus segment with the correct reservoir connection (COMPSEGS).

Keywords WSEGAICD and WSEGMULT are also used to include the Autonomous ICD and that for multiplier for segment frictional pressure-drop respectively, both across the segmented tubing.

The target here is production optimization by way of accelerating and maximizing oil

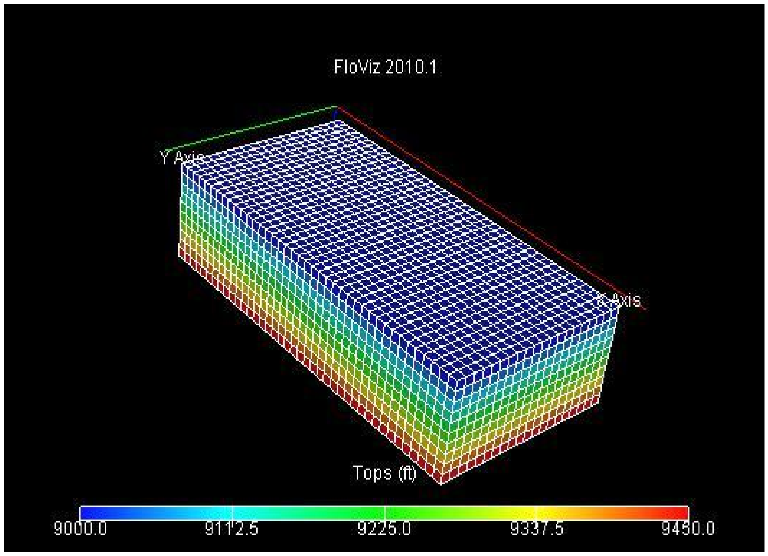

Fig. 1. ECLIPSE-100 Floviz image of the base-case reservoir model

production, while water production is minimized. Downhole control was simulated by installing the Inflow Control Devices (ICD) and downhole sensors around the tubing with the above method, applying the keywords to initiate commands where necessary. Fluid flow control is achieved by the device where it imposes an additional pressure drop between the sand-face and the tubing (modeled as a constriction with a specified cross-sectional area). The pressure drop across the device (Autonomous ICD; AICD in this case) varies with the density and viscosity of the reservoir fluid flowing through the AICD according to the following equations [18]:

$$\delta P = \left(\frac{\rho^2{}_{mix}}{\rho_{cal}}\right) * \left(\frac{\mu_{cal}}{\mu_{mix}}\right)^y * a_{AICD} * q^x \quad \text{Eqn1}$$

Where;

a_{AICD} = strength of the AICD
x = volume flow rate exponent
y = viscosity function exponent
$\rho^2{}_{mix}$= density of the fluid mixture in the segment at local conditions
ρ_{cal} = density of the fluid used to calibrate the ICD
μ_{mix} = viscosity of the fluid mixture in the segment at local conditions
μ_{cal} = viscosity of the fluid used to calibrate the ICD
q = volume flow rate of fluid mixture through the ICD at local conditions, which is equal to the volume flow rate through the ICD segment multiplied by a scaling factor that depends on the length of the device.

The density of the fluid mixture at local segment conditions is given by:

$$\rho_{mix} = \alpha o * \rho o + \alpha w * \rho w + \alpha g * \rho g \quad \text{Eqn 2}$$

Where;

αo, αw, αg = volume fraction of the free oil, water, gas phases at local conditions
ρo, ρw, ρg = density of the oil, water, gas phases at local conditions

The viscosity of the fluid mixture at local segment conditions is given by:

$$\mu_{mix} = \alpha o * \mu o + \alpha w * \mu w + \alpha g * \mu g \quad \text{Eqn 3}$$

Where;

αo, αw, αg = volume fraction of the free oil, water and gas phases at local conditions
μo, μw, μg = viscosity of the oil, water and gas phases at local conditions.

Keyword COMPSEGS was used to define the location of the device mounted on the tubing. The ICD segments were given the same depth as their 'parent' tubing segments, so that there will be no hydrostatic head across them, with the pressure loss across the ICD segment then reported as the friction pressure loss, having the acceleration pressure loss is set to zero [18]. Applying the keyword WSEGMULT as defined above (multipliers for segment frictional pressure drop) specify the scaling factor by which the frictional pressure drop calculated across a segment is multiplied in a multi-segment well [18]. The scaling factor is then applied to model the operation of an adjustable flow control device with the purpose of cutting-off production from completions with high water cuts.

For the dual-opposing wells equipped with ICDs, having I and J-coordinates same as wells with laterals on 6^{th} layer (depth node of 9275 ft), the watercut value is inputted to be the maximum allowable watercut set in the well connection economic limit. At the commencement of each new timestep the well is tested again and the segment-watercut (SWCT) will be closed or reopened once the set limit is exceeded or has dropped down respectively. As a segment can only represent a single device at any one time, all segments chosen in the selected range are treated as ICD segment in parallel. A simulation workflow is shown in Fig. 2. below [19].

3. RESULTS AND DISCUSSION

3.1 Horizontal Wells

For rate optimization, simulations were carried out for varying oil flow rates to achieve maximum productivity. The generated results from the simulations are highlighted below;

At a quick glance on the Table 1 below, it is observed that as more oil is being produced, more amount of water is produced at the same time. This is especially true for reservoirs that are supported by strong water aquifer. Analyzing the results generated above, the fields oil production volume having the highest value of 23,641,620 STB was achieved at a production rate of 10,000 STB/D (differing slightly from that achieved at 12,000STB/D); the field's total production being at the optimal value right from the production onset.

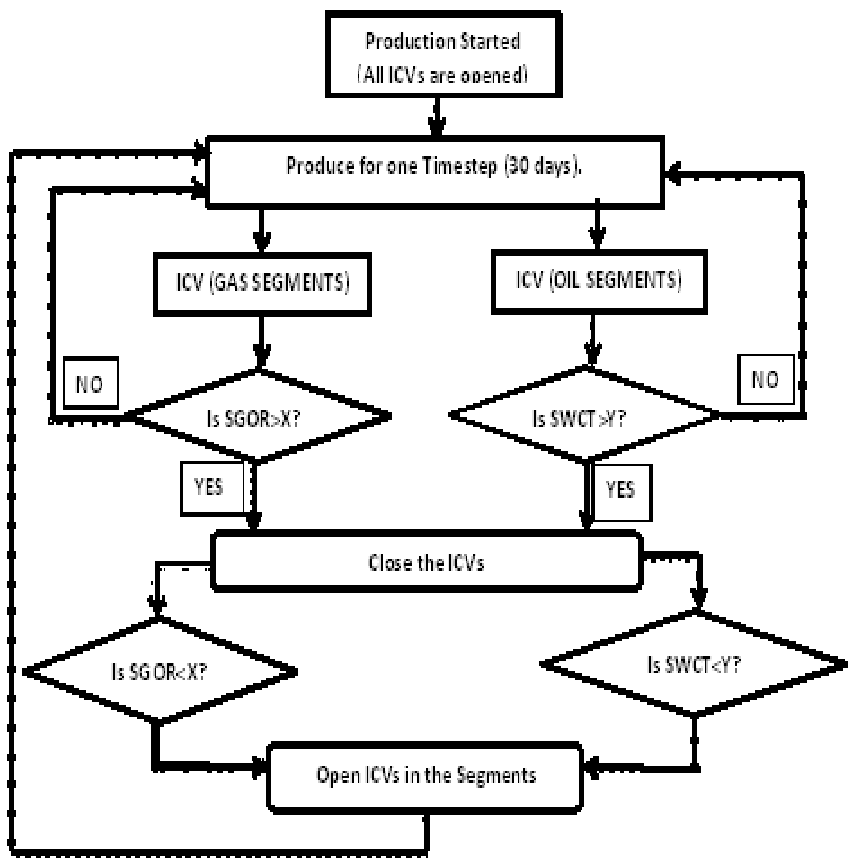

Fig 2. Schematic of a typical flowchart to execute the program

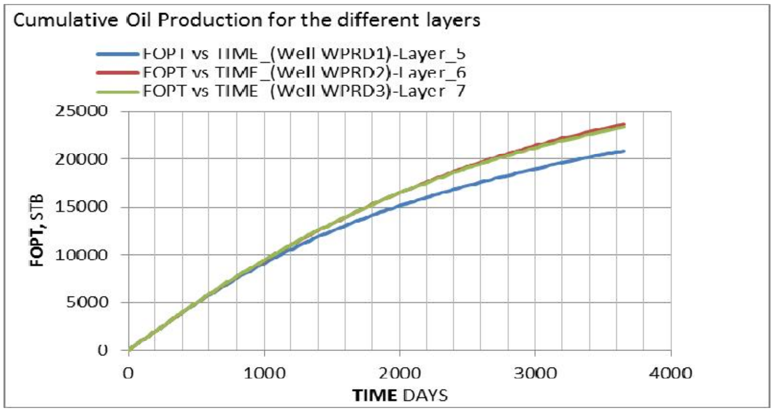

Fig. 3. Comparison of simulated cumulative oil produced from horizontal wells located at various layers. (Varied depths)

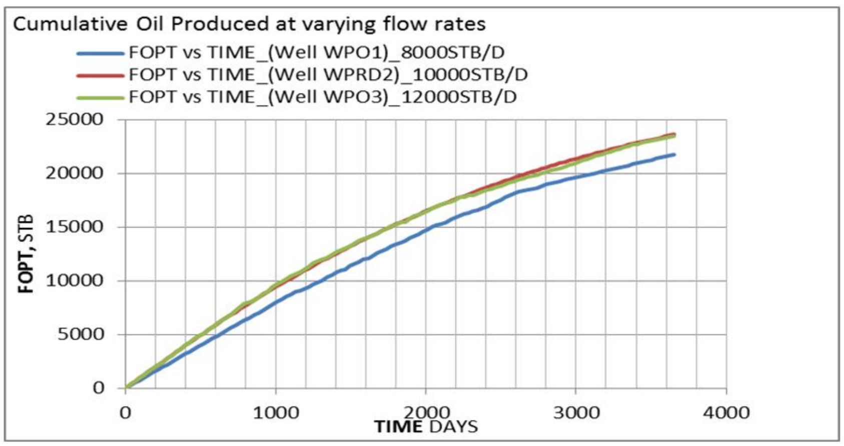

Fig. 4. Comparison of simulated field oil production totals from horizontal wells at varying flow rates

Also observed was the field water production total (FWPT) obtained at 12,000 STB/D which is significantly higher than keeping the rate at 10,000 STB/D, indicating an 11% increase in comparable water produced (a difference of 2,009,930 STB) giving a 50.80% water cut as against 48.57%. Therefore the liquid rate of 10,000STB/D was maintained as the optimum liquid production rate since it's evident in a higher FOE of 37.56% being achieved, and is thus used for the other following simulation cases.

3.2 Multilateral Wells (Schematics for Varying Depths Locations (Eclipse-100 FloViz))

One primary objective of multilateral wells is to increases overall hydrocarbon production. They are proven to be more effective than single horizontal wells due to the fact that branches in the multilateral well accesses multiple reservoirs/layers from a single surface location and drains the fluid in a more distributional way.

As seen in Table 2, there's a significant increase in field oil production total of 27,575,210 STB gotten when simulated for layer 6^{th} – 6^{th} grid block indicating a 3.90% increase as against FOPT for laterals completed in layers 6^{th} – 7^{th} grid block. Also total water produced from dual laterals on layer 6 (6^{th} -6^{th} grid block) showed a 5% drop in comparable volume of water produced from laterals on layers 6 and 7. This indicates the well completion having lateral on 7^{th} layer was majorly affected by the water cresting phenomenon and thus the expected high water cut of 65.74% was noticed.

With these adjustments to optimize production and increase the ultimate recovery, a gradual and continuous cumulation in the water produced has been observed along each optimized simulation step. The optimized step for dual-opposed completion which had an enormous increase in the field oil production volume gave rise to an increment of 61.88% for water cut which invariably has exceeded the 60% set limit for this simulation work. This highlights the need for water management to optimize the production process. Thus the concept of Intelligent Well Completion technology is utilized to mitigate the production of water, and in effect reduce the field water cut to an acceptable or a bearable level.

Table 1. Output data from wells at different liquid production rates

Liquid production rates (STB/D)	FOPT (MSTB)	FWPT (MSTB)	FWCT (fraction)	FOE (fraction)
8,000	21,770.51	17,063.77	0.4642	0.34592
10,000	23,641.62	18,166.52	0.4857	0.37565
12,000	23,528.94	20,176.45	0.5084	0.37386

**Note: 1 MSTB = 1,000 STB*

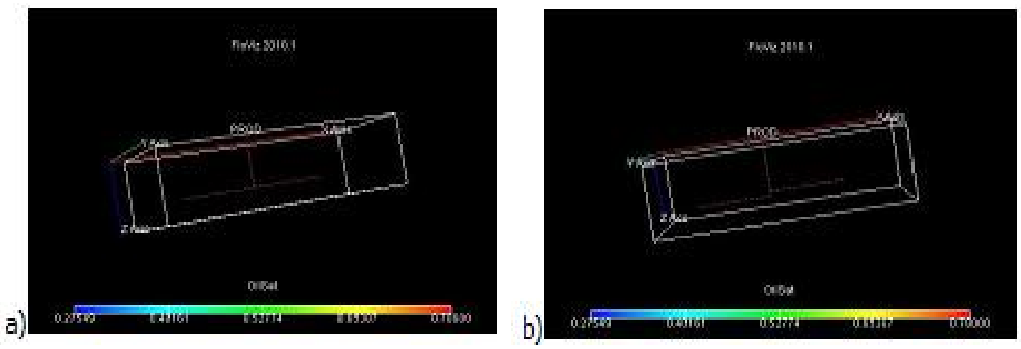

Fig. 5. (a)Dual-opposing lateral well at same layer (6th layer from the 6th vertical grid block). Depth node at 9275ft. (b)Dual-opposing lateral well at different layers (6th and 7th layers from the 6th and 7th vertical grid block). Depth node at 9275ft and 9325ft respectively

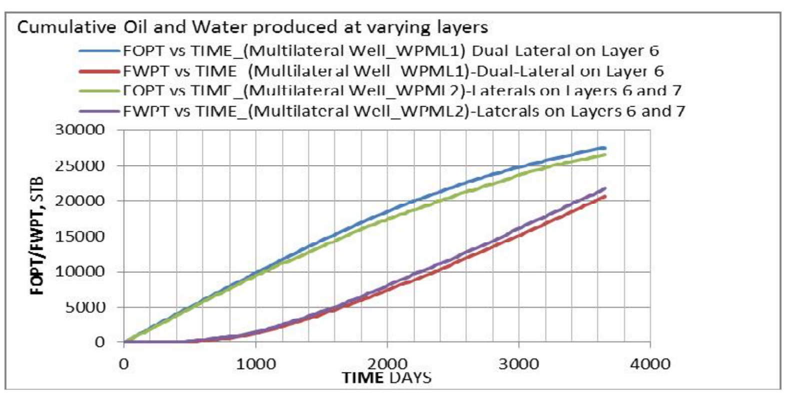

Fig. 6. Comparison of simulated field oil & water production Totals from multilateral wells for optimal lateral-positioning. (Dual-lateral on Layer 6 vs. Laterals on layer 6 & 7)

Table 2. Output data from wells at different lateral positions (different vertical grid blocks)

Lateral Positions	FOPT (MSTB)	FWPT (MSTB)	FWCT (fraction)	FOE (fraction)
Layers: 6th -6th grid block (well WPML1)	27,575.21	20,698.79	0.6188	0.43815
Layers: 6th -7th grid block (well WPML2)	26,546.81	21,797.48	0.6574	0.42181

3.3 Intelligent Well Performance

As stated earlier, intelligent modifications employ downhole monitoring and control of each production layer with the aim of optimizing oil production, while achieving minimal water production. Due to the limitations on this research work which hinged more on lack of on-hands direct field application and real life field reliability data to test results viability in real-time conditions, water cut was detected by modeling for production from layers in high risk zones and regulating flow manually, by placing the ICDs on the well segments through the lateral branch-offs. The generated results from the production simulations are highlighted below.

As can be observed from the production results in Table 3, field oil production total for ICD configuration dropped slightly to 26,630,600 STB with a difference of 900 MSTB indicating a 3.4% drop in cumulative oil produced as against 27,575,210 STB for that without ICD control which was more evident during the late-life of the well. A noticeable drop in oil production rates was observed from the well's mid-life at the sixth year due to a restrictive pressure drop flow across the ICD. As the fluid forces their way through, the friction on the surface of the channels is raised thus increasing the backpressure at that point and in effect slowing down fluid entry.

Also observed in the early stage of the wells life was no noticeable difference in cumulative oil produced, and therefore signifying only a comparable slight drop of 1.5% in FOE.

The total field water produced, which stood at 9,909,399 STB in this case showed a remarkable decrease as compared to 20,698,790 STB gotten for the Non-ICD well, indicating a drastic reduction of about 52.1% in water production. Figure shows the cumulative oil and water production, and highlights the reduction in water production achieved by applying downhole layer control. As observed in the early life of the well, the reservoir fluid varying in density and viscosity was constantly regulated via the ICD orifices in well segments showing early signs of water breakthrough. These problematic segments having high permeabilities were slowed down, preventing water from being produced and subsequently allowing for oil flow from the less permeable zones thereby exerting control over the full completion length. This invariably helped mitigate the heel-toe effect observed along the horizontal completion. Also, the additional pressure drop imposed between the sand-face and the tubing helped stabilize the inflow profile along the well culminating to a water cut of 28.69% as against 61.88% which indicates a 33.19% water cut reduction.

3.4 Sensitivity Analysis

As uncertainties in a reservoir caused by changes in fluid and reservoir properties are highly unavoidable, sensitivity analysis was then ran to prove the effectiveness of the reservoir model to a varied condition of the reservoir. The intelligent well performance was analyzed by varying reservoir permeability. This was achieved by increasing anisotropic ratio (Kv/Kh) to 0.2 and to 0.3 i.e. from the permeability Table 4 below, vertical permeability across layers was doubled and tripled.

The generated results from the production simulations are highlighted below.

From the Figures, and the production results in Table 5 as shown below, a difference in field oil efficiencies as well as field water cut was observed when permeability anisotropy was modeled (between the vertical and horizontal direction) across the layers. Such behavior in permeability distribution significantly affects the reservoir mechanism during depletion. Analyzing the results generated, varying permeability distribution across layers for non-ICD wells having anisotropy ratio (Kv/Kh) of 0.1 gave an FOE of 43.8% when compared with FOE of 40.9% of that for Kv/Kh of 0.2 and FOE of 40.2% gotten for Kv/Kh of 0.3, indicating a recovery efficiency decrease of about 2.9% as permeability anisotropy increased from 0.1 to 0.2 and decreased further to 0.64% as it progressed to 0.3. Also water cut stood at 65.5% for Kv/Kh of 0.3 and 63.8% for Kv/Kh of 0.2 as against 61.9% for Kv/Kh of 0.1. This is as a result of uneven advance of the displacing water which is normally faster in zones of high permeability. This signifies an increase in bottom water intrusion which in this case the model sensitivity was then duly applied.

As observed below, the ICD configuration for Kv/Kh of 0.1 gave FWCT of 28.7% and dropped slightly to 27.6% and to 26.5% when permeability was increased to 0.2 and then to 0.3 respectively (indicating a 1.1% and 1.2% decrease in FWCT respectively). This can be attributed to the ability of the ICD (WSEGAICD model used) being more potent in control within multilaterals in high permeability layers evident in the slight drop in water cut. On comparison of FWCT between non-ICD well and ICD well both at Kv/Kh of 0.2 having 63.8% and 27.6%, and at Kv/Kh of 0.3 having 65.5% and 26.5%, there's a significant difference indicating a 36.2% and 39% drop respectively in water cut on adaptation of the ICDs. As early water cresting occurred at the laterals, the ICD delayed the breakthrough by restricting the low viscosity fluid while favoring the high viscosity fluids. This enabled the advancing waterfront to be more uniform thus giving the optimal inflow performance along the well such that ultimate recovery would take place if the waterfront enters the tubing over the entire length at the depletion stage.

3.4.1 Sensitivity approach validation

This was carried out with a simulated field diagnostic plot using the field water and oil production rates versus time on a log-log plot. This plot was used to identify the water production mechanism trend for the producing well either experiencing water coning, near wellbore channeling, high permeability or layer breakthrough [20]. The generated results from the production rate simulations are highlighted below.

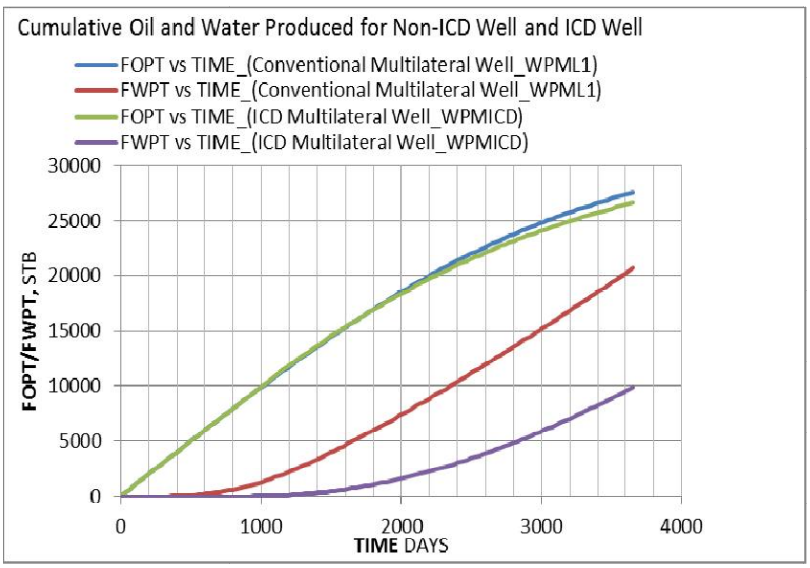

Fig. 7. Comparison of simulated field oil and water production totals from conventional multilateral well and ICD-multilateral well. (well WPML1 vs. well WPMICD)

Table 3. Output data from Non-ICD an ICD multilateral wells

Well Configuration	FOPT (MSTB)	FWPT(MSTB)	FWCT(fraction)	FOE(fraction)
Non-ICD Config.(wellWPML1)	27,575.21	20,698.79	0.6188	0.43815
ICD Config. (well WPMICD)	26,630.60	9,909.39	0.2869	0.42314

Table 4. Permeability sequence

Layer	Kh (mD.)	Kv (mD.)	Varied Kv (mD.) {Kv/Kh of 0.2}	Varied Kv (mD.) {Kv/Kh of 0.3}
1-2	50	5	10	15
3-3	80	8	16	24
4-4	120	12	24	36
5-5	180	18	36	54
6-6	240	24	48	72
7-8	300	30	60	90
9-9	360	36	72	108
10-10	400	40	80	120

Table 5. Output data from sensitivity analysis for varied permeability

	Kv/Kh ratio of 0.1		**Kv/Kh ratio of 0.2**		**Kv/Kh ratio of 0.3**	
Well Configuration	FWCT	FOE	FWCT	FOE	FWCT	FOE
Non-ICD Config.	0.618764	0.438149	0.637720	0.409025	0.654867	0.402627
ICD Config.	0.286911	0.423140	0.276452	0.406466	0.264718	0.398472

**Note: Values expressed in fractions*

In general, a gradual increase in water indicates a build-up of a water cone (WOR vs. time) [20], so the target here would basically be to reduce the WOR value so as to control water breakthrough. For the non-ICD well WPML1 on the plot (blue Marker), it can be noticed that the water production showed a gradual increase in the first 100 days evident in the early life of the well. This increased quickly within the later years, showing more of channeling due to high permeability layers (indication of a steady increase), which resulted in high water–oil ratios and would consequently lead to earlier economic limits. On application of IWC technology, from the plot it can be inferred that the ICD well WPMICD (red Marker) shows a remarkable drop in field water production rate. As noted earlier, zones with high permeability experiences a high pressure drop across the ICD and consequently gives a higher annular pressure which results in reduced drawdown and flow-rates at those places. The opposite effect is true for low permeability areas. As a result, the rate of water advance (which is normally faster in high permeability layers) was duly controlled. This all necessitated the application of permeability variance for the model used in this research on the field under study since its flow geometry being an active bottom-water drive has a significant vertical flow.

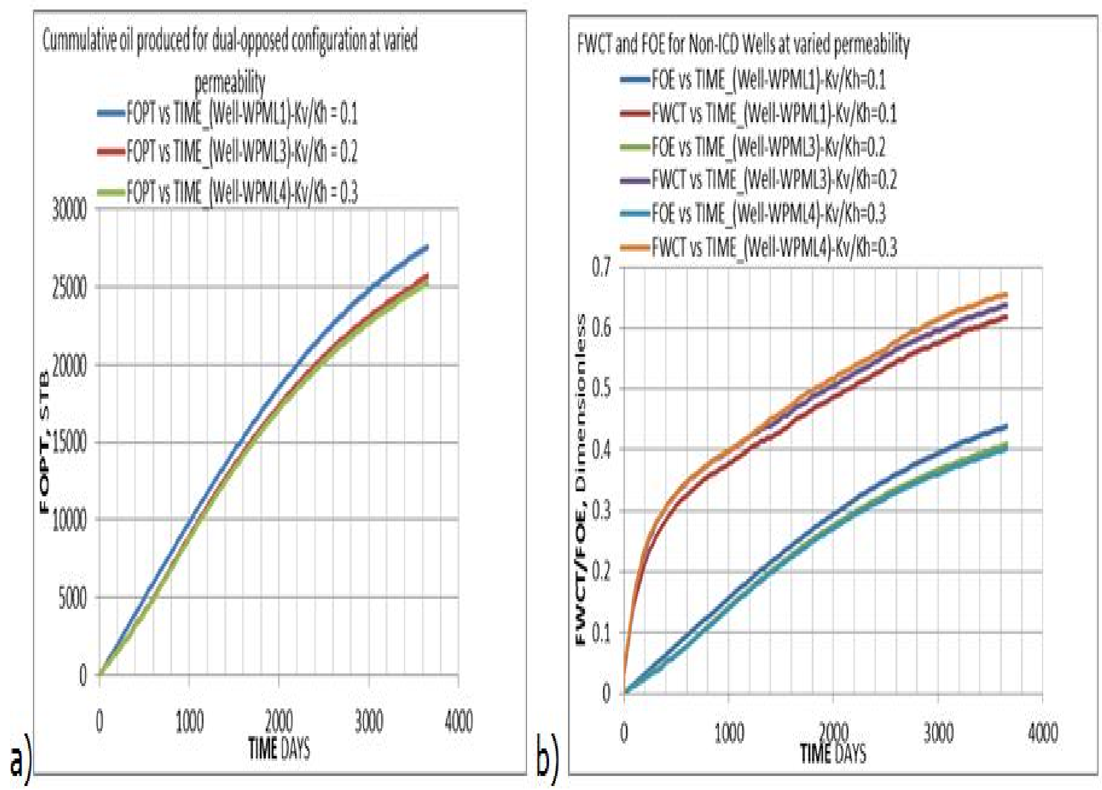

Fig. 8. (a) Sensitivity analysis plot of cumulative oil at varied permeability for non-ICD wells. (b) Sensitivity analysis plot of Water cut and Oil efficiency at varied permeability for non-ICD wells

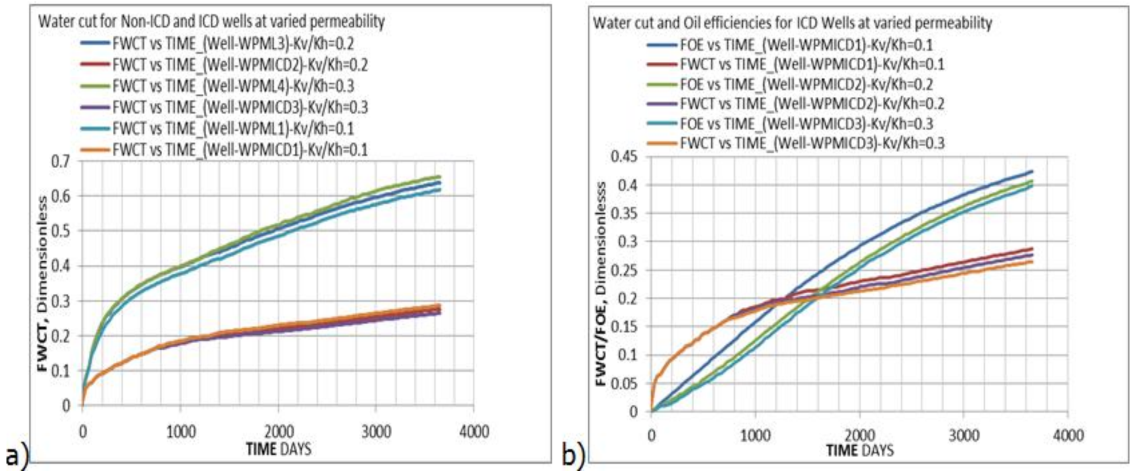

Fig. 9. (a) Sensitivity analysis plot of Water cut only at varied permeability for non-ICD (WPML1, 3 & 4) and ICD wells (WPMICD1, 2 & 3). (b) Sensitivity analysis plot of Water cut and Oil efficiency at varied permeability for ICD wells

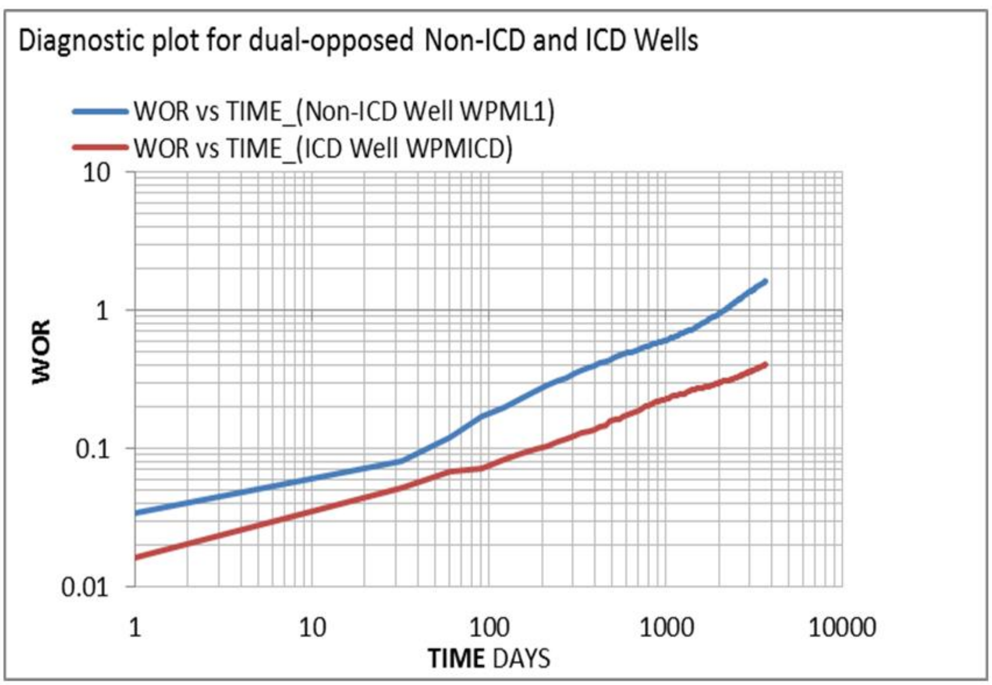

Fig. 10. Diagnostic plot of WOR vs. time (for water production mechanism trend)

4. CONCLUSION

From our work, it can be drawn that;

- The completions with ICDs controlled and balanced inflow from the laterals, as it was applied to minimize variable productivity effect or heel-toe effect within the lateral. This had a greater economic return than conventional completion as evident in the field oil production totals and field oil efficiencies obtained.
- A significant reduction of 52.1% in total field water production was observed on application of ICDs as water production was controlled. This gave field water cut reduction from 61.88% down to 28.69%

thus saving cost and reducing impact on the environment as produced water is often corrosive.
- Sensitivity analysis on the ICD well performance was carried out by varying reservoir permeability (the ratio of vertical permeability to horizontal permeability was varied in this case) which plays a major role in its effectiveness. It was observed that as the ratio becomes higher than most common value of 0.1, early vertical breakthrough of water occurs as bottom-water coning phenomenon is evident towards the completion interval.
- The simulation results concludes that deploying ICDs optimizes production, reduces field water cut, improves well performance and prolonged the well life by mitigating water breakthrough as compared to cases where ICDs were not installed.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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