3D numerical simulation of clastic reservoir with bottom water drive using various ior techniques for maximizing recovery

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Abstract

In most reservoirs with oil rims, as the production begins, the gas–oil and oil–water fluid interfaces start deforming because of the imbalance between viscous and gravitational forces, leading to coning or cusping. This can be overcome using proper withdrawal rate, offset from water–oil contact and horizontal length. Further smart horizontal wells require optimization of nozzle size and compartment length also. To see the effect of these parameters on recovery, a three-dimensional geological model of a clastic reservoir from Upper Assam Basin has been used. This model was history matched for a period of 16 years on 46 wells. After successful validation of model on field scale and well level, performance prediction was carried out to see the effect of withdrawal rate, offset from water–oil contact, horizontal length, compartment length and nozzle size using vertical/horizontal and ICD completion. From the analysis, it is evident that application of advanced well completion, ICD, is suitable for such reservoir. Depending on the scenario, maximum cumulative oil production was obtained from ICD wells with 1.08 MMm³ compared to vertical well with cum oil production of 0.63 MMm³. Economic analysis has been carried out for the examined scenarios.

Keywords Field development · ICD · Undrained oil · Water injection · Recovery

List of symbols

ICD	Inflow control device
EOS	Equation of state
FDP	Field development plan
FWL	Free water level
GOR	Gas–oil ratio
HCPV	Hydrocarbon pore volume
SCAL	Special core analysis
THP	Tubing head pressure
TVDSS	True vertical depth below sea level
K	Permeability (mD)
Kh	Horizontal permeability (mD)
ko	Oil permeability (mD)
Kv	Vertical permeability (mD)
lab	Laboratory
MM	Million metric
NPV	Net present value

WOC	Water–oil contact
Pc	Capillary pressure

Greek symbols

q_w	Water density (lbm/ft ³)
q_o	Oil density (lbm/ft ³)
ϕ	Porosity (fraction)
σ	Surface tension
μ_o	Oil viscosity
θ	Contact angle (degrees)

Introduction

The study on remaining oil in high water cut oilfield is a fundamental for oilfield development and enhanced oil recovery, which is a worldwide highly comprehensive research problem and hot issue. Today, advanced technologies of horizontal drilling and application of advanced well completion such as ICD turn the development of unswept oil into a reality.

Extreme water production is one of the main reasons which contribute in decrease of productivity of wells. Rising water cut influences inflow performance and tubing performance curve negatively. Excessive water production

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enhances the expenditure of lifting of fluids to surface, treatment of water, and disposal. Production of water is also related to scale formation at different production system components (Al Hasani et al. 2008).

Determining good well locations and completions of production and injection wells are important to optimally develop and produce a reservoir (Forouzanfar and Reynolds 2013). Dosunmu and Osisanya (2015) show that horizontal well productivity is significantly affected by oil viscosity, horizontal permeability, and well diameter. Al Qahtani et al. (2015) showed a noble idea of taking full advantage of long horizontal well if it is produced from both ends, i.e. from heel and toe.

Oil recovery is increased by appropriate selection of ICD, which also stops flow of unwanted production of water and gas. Results obtained from fields and simulation studies show that production of oil, gas, and water is very much dependent on the type of ICD and number of ICD used (Mojaddam Zadeh et al. 2012).

Well placement in a bottom water drive reservoir poses several challenges. The real oil fields are complex environments due to heterogeneities, presence of geologic discontinuities (e.g., faults, fractures, and very high and low permeability zones), and geologic uncertainties. Moreover, coning tendency in vertical well leads to early water breakthrough, which can be avoided using horizontal well placement techniques with optimized length, rate and offset. Further smart horizontal wells are also being used extensively

for maximizing recovery. A proper methodology needs to be developed for avoiding early water breakthrough and increase water-free production.

Objective of the study is to carry out sensitivity study on offset, withdrawal rate, horizontal length, compartment length and nozzle sizes in three-dimensional numerical simulation model.

Methodology

In this work, methodology adopted for determination of optimum variants for vertical well, horizontal well and smart horizontal well is given below.

- Static modeling.
- History matching.
- Sensitivity analysis.
 - Vertical well (offset from woc, withdrawal rate).
 - Horizontal well (offset from woc, withdrawal rate, horizontal length).
 - Smart horizontal well (compartment length, nozzle size).
- Economics and recovery factor.

Fig. 1 Fault pattern of the reservoir

Static modeling

Pillar gridding process in petrel is used to make the static model. The original model was kept intact with minor modifications. A number of NE–SW trending normal faults of limited lateral continuity intersects the structure at the Barail Arenaceous level. Figure 1 shows the fault pattern of the reservoir.

Geological grid was made with cell size 75 m × 75 m using grid rotation of 40°. Once the grid was made, structure and properties were upscaled and the total number of cells in the model is now 1,035,960. The total number of

cells present in the geomodel prior to upscaling is 8,171,520 which were further upscaled to 100 × 100.

Five different rock types (RT) have been kept in the model (RT 1–5). RT 1 is the best rock type where as RT 5 is bad rock type in the study. Rock-type statistics expressed in terms of porosity, permeability and oil saturation is presented in Table 1. Porosity, permeability and reservoir thickness distribution of the geocellular model (GCM) have been shown in Figs. 2, 3 and 4, respectively.

History match

Observed data (oil, gas, water rates and pressure data) for 46 wells for duration of 16 years was computer generated with an industry standard simulator. Outcome of the history match on reservoir level is illustrated in Fig. 5. Well-wise flowing/static pressure data, gas–oil ratio and water cut were used as parameters for history matching. From Fig. 5, it is evident that GOR, pressure, water rate, oil rate have been matched reasonably well with the observed data by the industry standard simulator at field scale.

Table 1 Statistics for different rock type

Rock type	% fraction	So %	$\langle K \text{ (md)} \rangle$	$\langle \text{Phi \%} \rangle$
1	14.5	60.44	1157	22.25
2	28.5	51.64	502	20.73
3	33.1	37.66	220	18.29
4	8.1	7.11	180	15.44
5	15.8	1.35	157	10.96

Fig. 2 Porosity distribution

Fig. 3 Permeability distribution

Performance prediction

The oil flow rate, vertical and horizontal permeability, oil viscosity, oil formation volume factor, oil–water mobility ratio and the perforation interval length are the major factors which affect the breakthrough time of water and gas (Wagenhofer and Hatzignatiou 1996). Evaluation of some of these parameters has been carried out to see their effect on production behavior. Performance prediction of the simulation case has been carried out in three parts, which is listed below:

- vertical well (offset from WOC, withdrawal rate).
- Horizontal well (offset from WOC, withdrawal rate and horizontal well length).
- Smart horizontal well (compartment length, nozzle sizes).

Sensitivity study of vertical well—offset and withdrawal rate

The history-matched model was used to perform sensitivity studies on offset from WOC and withdrawal rate. All

variants are been mentioned in Table 2. From all combinations mentioned in Table 2, 15 cases were constructed, details of which is mentioned in Table 3.

All sensitivity studies in prediction mode were simulated using production rate control mode. Constraint on production at well scale was specified as per the capacity of surface handling equipments. Apart from above constraints, wells were subjected to some additional constraints which is shown in Table 4.

Sensitivity study of horizontal well—offset, withdrawal rate and horizontal length

The history-matched model was used to perform sensitivity studies on offset from WOC, horizontal well length and withdrawal rate. All variants are mentioned in Table 5. From these grouping 48 cases were prepared, details of which is given in Table 6.

All sensitivity studies in prediction mode were simulated using production rate control mode. Constraint on production at well scale was specified as per the capacity of surface handling equipments. Apart from above constraints

Fig. 4 Reservoir thickness distribution

wells were subjected to some additional constraints which is shown in Table 4.

Sensitivity study of inflow control device—compartment length and nozzle sizes

A horizontal well does not contribute equally throughout its length. Heel contribution of production is more than from toe because of frictional pressure drop along wellbore length, which leads to non-uniform influx throughout

the wellbore length. This effect also known as heel-toe effect which leads to reduced recovery of oil because of early water/gas breakthrough and uneven area swept area near producing well. To resolve this issue, inflow control device (ICD) has been widely used in producing wells for controlling and optimizing individual well or overall reservoir performance. The sole purpose of ICDs is to make equal inflow along the entire wellbore length despite location and permeability variation. Application of ICDs allows the entire horizontal length of the wellbore to add

Fig. 5 History match results

Table 2 Sensitivity parameters for vertical well

Rate (m ³ /day)	50	100	150		
Offset (perforation bottom) from WOC (m)	0	5	10	15	20

Perforation top was assumed 2 m below GOC for all cases

Table 3 Cases examined for vertical well

S. no.	Withdrawal rate (m ³ /day)	Offset from WOC (m)
1	50	0
2	50	5
3	50	10
4	50	15
5	50	20
6	100	0
7	100	5
8	100	10
9	100	15
10	100	20
11	150	0
12	150	5
13	150	10
14	150	15
15	150	20

to the total production and thereby optimize hydrocarbon recovery.

Careful choice of ICD increases the oil recovery and constrains unwanted production of water and gas. IT has been observed from actual field experience and outcome from the extensive simulation studies that the oil, water and gas production are extremely reliant on the type and arrangement of ICD (Mojaddam et al. 2012). A suite of optimized ICD modeling workflows and evaluation tools were developed to address these issues using a plug-in architecture in an industry-leading exploration and production platform (Schlumberger PETREL 2015) and reservoir simulator (Schlumberger 2015). Historically, the most common method for designing ICD completions has been to use steady-state or pseudo steady-state (i.e. static) analytical modeling using data at one or more points in time (Ellis et al. 2009).

ICD design has been done using equal length compartment and variable nozzle sizes in each ICD.

Equal length compartments with uniform nozzle sizes—sensitivity on packer length

A design with equally spaced compartments and uniform nozzles sizes is preferred if there is significant uncertainty in the reservoir characterization or risk in getting the

Table 4 Well level constraints for prediction runs

Constraints	Value
Maximum individual well production rate	Decided based on historical well production rate in the reservoir
Completion type	Single completion: bottom-to-top
Minimum well bottom-hole pressure	50–100 bars, depending upon the segment performance
Maximum water cut	95%
Minimum economic limit on oil rate	1 m ³ /day
Maximum GOR constraint	1500 m ³ /m ³

Table 5 Sensitivity parameters for horizontal well

Rate (m ³ /day)	200	250	300	
Offset (perforation bottom from WOC (m))	5	10	15	20
Horizontal length (m)	600	800	1000	1200

Perforation top was assumed 2 m below GOC for all cases

completion to TD. Different packer length (Table 7) has been selected for simulation runs using ICD well completion.

Equal length compartments with variable nozzle sizes—sensitivity on nozzle sizes

Equally, spaced compartments with variable nozzle sizes designs are the preferred option if the reservoir is homogeneous with significant heel-to-toe pressure decline along the wellbore.

High-rate horizontal wells often suffer from the so-called heel-toe effect. This is caused by the frictional pressure gradient along the well, which means that the heel has a significantly lower pressure than the toe and so produces more fluid. This can lead to premature breakthrough of water or gas. A total of 35 cases have been examined for this case, details of all the cases are given in Table 8.

Equal length compartments with variable nozzle sizes—uncertainty on nozzle sizes

After determining most sensitive parameter from previous section, uncertainty analysis is carried out on variable A, B E and F. Experimental design setup was done for the four variables using full factorial design which gives a total of 16 cases to be examined, additionally one central point has also

been added to make the no. of simulation runs 17. Details of all the cases are given in Table 9.

Results and discussion

Vertical well sensitivity results

Results of sensitivity of vertical well are plotted in Fig. 6. It can be observed that cumulative production increases with increasing assigned rate from 50 to 150 m³/day. Cumulative oil production increases with increase in offset from WOC. Incremental production is maximum by increasing the assigned rate from 50 to 100 m³/day.

In bottom water reservoirs with active aquifer, proper planning and completion of the well(s) in vertical direction will require the consideration of fractional well penetration to achieve optimum critical oil production rate and breakthrough time (Okon et al. 2018).

Cumulative oil production increases with increase in offset from WOC and production rate. There are inverse relationships between water cut at end of prediction and cumulative oil produced, as well as between water cut at end of prediction and offset from WOC (Kumar et al. 2017a, b).

Controlling parameters for economical and optimal production rate from vertical well in a bottom water drive reservoir are optimum perforation interval and systematic approach (Gamal et al. 2016).

Horizontal well sensitivity results

Sensitivity results of horizontal well are plotted in Fig. 7. It can be observed that cumulative oil production increases by assigning higher withdrawal rates (200,250,300 m³/day).

Table 6 List of cases for horizontal well

S. no.	Withdrawal rate (m ³ /day)	Offset from WOC (m)	Horizontal length (m)
1	200	5	600
2	200	5	800
3	200	5	1000
4	200	5	1200
5	250	5	600
6	250	5	800
7	250	5	1000
8	250	5	1200
9	300	5	600
10	300	5	800
11	300	5	1000
12	300	5	1200
13	200	10	600
14	200	10	800
15	200	10	1000
16	200	10	1200
17	250	10	600
18	250	10	800
19	250	10	1000
20	250	10	1200
21	300	10	600
22	300	10	800
23	300	10	1000
24	300	10	1200
25	200	15	600
26	200	15	800
27	200	15	1000
28	200	15	1200
29	250	15	600
30	250	15	800
31	250	15	1000
32	250	15	1200
33	300	15	600
34	300	15	800
35	300	15	1000
36	300	15	1200
37	200	20	600
38	200	20	800
39	200	20	1000
40	200	20	1200
41	250	20	600
42	250	20	800
43	250	20	1000
44	250	20	1200
45	300	20	600
46	300	20	800
47	300	20	1000
48	300	20	1200

Table 7 Compartment length as an input to ICD cases

Compartment length (m)
100
125
150
25
50
75

For maximum recovery, horizontal well length should vary between 600 and 800 m; additional increment in horizontal well length does not increase in oil production. Increasing horizontal well length from 600 to 1200 m does not increase the oil production cumulative linearly; maximum value is obtained for 800 m horizontal length in 36 cases out of 48 cases.

In bottom water reservoirs with active aquifer, placement of horizontal well should consider stand-off to drainage width as well as horizontal well length to drainage width to achieve optimum critical production rate and breakthrough time (Okan et al. 2018).

Offset from WOC, horizontal length, and withdrawal rate have an impact on cumulative oil production in case of horizontal well. Maximum impact on cumulative oil production is given by offset from WOC followed by withdrawal rate and last on horizontal well length (Kumar et al. 2017a, b).

ICD sensitivity results

Sensitivity on compartment length

To maximize cumulative oil production from ICD, it is pertinent to determine compartment length/number of nozzles and nozzle size in each ICD. Initially sensitivity on compartment length has been carried out and it is observed from Fig. 8 that, 150 m compartment length or seven nozzle ICD give maximum cumulative oil production.

Sensitivity on nozzle sizes

To determine nozzle size for each ICD for maximizing cumulative oil production, it is essential to determine which nozzle ICD is having maximum impact on recovery. A total of 39 cases have been run and results are plotted in form of a Tornado plot (Fig. 9) where variable which is most sensitive to recovery efficiency is on top and least sensitivity is on bottom.

Table 8 Details of all the cases examined for variable nozzle sizes

Case	Area of nozzle, 10^{-5} m^2							\$RUN
	\$G	\$F	\$E	\$D	\$C	\$B	\$A	
2548_800_300_150_1	2.00	2.00	2.00	2.00	2.00	2.00	0.50	1
2548_800_300_150_2	2.00	2.00	2.00	2.00	2.00	2.00	1.13	2
2548_800_300_150_3	2.00	2.00	2.00	2.00	2.00	2.00	1.75	3
2548_800_300_150_4	2.00	2.00	2.00	2.00	2.00	2.00	2.38	4
2548_800_300_150_5	2.00	2.00	2.00	2.00	2.00	2.00	3.00	5
2548_800_300_150_6	2.00	2.00	2.00	2.00	2.00	0.50	2.00	6
2548_800_300_150_7	2.00	2.00	2.00	2.00	2.00	1.13	2.00	7
2548_800_300_150_8	2.00	2.00	2.00	2.00	2.00	1.75	2.00	8
2548_800_300_150_9	2.00	2.00	2.00	2.00	2.00	2.38	2.00	9
2548_800_300_150_10	2.00	2.00	2.00	2.00	2.00	3.00	2.00	10
2548_800_300_150_11	2.00	2.00	2.00	2.00	0.50	2.00	2.00	11
2548_800_300_150_12	2.00	2.00	2.00	2.00	1.13	2.00	2.00	12
2548_800_300_150_13	2.00	2.00	2.00	2.00	1.75	2.00	2.00	13
2548_800_300_150_14	2.00	2.00	2.00	2.00	2.38	2.00	2.00	14
2548_800_300_150_15	2.00	2.00	2.00	2.00	3.00	2.00	2.00	15
2548_800_300_150_16	2.00	2.00	2.00	0.50	2.00	2.00	2.00	16
2548_800_300_150_17	2.00	2.00	2.00	1.13	2.00	2.00	2.00	17
2548_800_300_150_18	2.00	2.00	2.00	1.75	2.00	2.00	2.00	18
2548_800_300_150_19	2.00	2.00	2.00	2.38	2.00	2.00	2.00	19
2548_800_300_150_20	2.00	2.00	2.00	3.00	2.00	2.00	2.00	20
2548_800_300_150_21	2.00	2.00	0.50	2.00	2.00	2.00	2.00	21
2548_800_300_150_22	2.00	2.00	1.13	2.00	2.00	2.00	2.00	22
2548_800_300_150_23	2.00	2.00	1.75	2.00	2.00	2.00	2.00	23
2548_800_300_150_24	2.00	2.00	2.38	2.00	2.00	2.00	2.00	24
2548_800_300_150_25	2.00	2.00	3.00	2.00	2.00	2.00	2.00	25
2548_800_300_150_26	2.00	0.50	2.00	2.00	2.00	2.00	2.00	26
2548_800_300_150_27	2.00	1.13	2.00	2.00	2.00	2.00	2.00	27
2548_800_300_150_28	2.00	1.75	2.00	2.00	2.00	2.00	2.00	28
2548_800_300_150_29	2.00	2.38	2.00	2.00	2.00	2.00	2.00	29
2548_800_300_150_30	2.00	3.00	2.00	2.00	2.00	2.00	2.00	30
2548_800_300_150_31	0.50	2.00	2.00	2.00	2.00	2.00	2.00	31
2548_800_300_150_32	1.13	2.00	2.00	2.00	2.00	2.00	2.00	32
2548_800_300_150_33	1.75	2.00	2.00	2.00	2.00	2.00	2.00	33
2548_800_300_150_34	2.38	2.00	2.00	2.00	2.00	2.00	2.00	34
2548_800_300_150_35	3.00	2.00	2.00	2.00	2.00	2.00	2.00	35

A, B, C, D and E are nozzle sizes for ICD at compartment length of 150 m

Table 9 List of uncertain variables for cases examined

Case	Nozzle cross-sectional area, 10^{-5} m^2				\$LOOP
	\$F	\$E	\$B	\$A	
2548_800_300_150_36	1.750	1.750	1.750	1.750	1
2548_800_300_150_37	0.500	0.500	0.500	0.500	2
2548_800_300_150_38	0.500	0.500	0.500	3.000	3
2548_800_300_150_39	0.500	0.500	3.000	0.500	4
2548_800_300_150_40	0.500	0.500	3.000	3.000	5
2548_800_300_150_41	0.500	3.000	0.500	0.500	6
2548_800_300_150_42	0.500	3.000	0.500	3.000	7
2548_800_300_150_43	0.500	3.000	3.000	0.500	8
2548_800_300_150_44	0.500	3.000	3.000	3.000	9
2548_800_300_150_45	3.000	0.500	0.500	0.500	10
2548_800_300_150_46	3.000	0.500	0.500	3.000	11
2548_800_300_150_47	3.000	0.500	3.000	0.500	12
2548_800_300_150_48	3.000	0.500	3.000	3.000	13
2548_800_300_150_49	3.000	3.000	0.500	0.500	14
2548_800_300_150_50	3.000	3.000	0.500	3.000	15
2548_800_300_150_51	3.000	3.000	3.000	0.500	16
2548_800_300_150_52	3.000	3.000	3.000	3.000	17

Valve size for remaining ICD is $5\text{e} - 6 \text{ m}^2$

Fig. 6 Sensitivity results of vertical well

Equal length compartments with variable nozzle sizes—uncertainty on nozzle sizes

Nozzles B, F, E and A have maximum impact on recovery and hence a detailed uncertainty analysis has been run. A comparison of oil production cumulative is done in Fig. 10 for all the cases examined. Figure 11 compares the production profile of minimum (2548_800_300_150_50) and maximum recovery (2548_800_300_150_39) efficiency.

The number of ICDs, the number of nozzles in each ICD, and the size of nozzles are optimized to maximize the oil production for different reservoir condition. This optimal design, which consisted of five compartments in the horizontal section with 14 ICD joints, proved to be more effective in delaying water breakthrough and increasing recovery (Maalouf et al. 2017).

Economics and recovery factor

Economics and recovery efficiency for various cases has been compared in form of a table which is presented in Table 10. Table 11 lists all the assumptions in working out the economics.

Conclusions

Withdrawal rate and offset from WOC have an effect on oil production for vertical well. From sensitivity study on offset and withdrawal rate, it was observed that offset has more impact on cumulative oil production than withdrawal rate. Highest recovery of 0.63 MMm^3 cumulative oil is obtained using offset of 20 m and initial withdrawal rate of $150 \text{ m}^3/\text{day}$.

Horizontal well length, offset from WOC and withdrawal rate have an effect on oil production for horizontal well. Highest impact on oil production is given by offset from WOC; second big effect is given by withdrawal rate and

Fig. 7 Sensitivity results of horizontal well

Fig. 8 Sensitivity results of compartment length

Fig. 9 Tornado plot

Fig. 10 Comparison of oil production cumulative for different nozzle sizes

finally horizontal well length effects oil production. Highest recovery of 0.95 MMm^3 cumulative oil is obtained using optimal horizontal well length varying between 600 and 800 m offset of 20 m and initial withdrawal rate of $300 \text{ m}^3/\text{day}$. Above results when compared with producing well number 49, cumulative oil production of 0.152 MMm^3 is achieved during the entire production history with offset of 10 m, horizontal well length of 400 m and initial withdrawal rate at $200 \text{ m}^3/\text{day}$.

Compartment length and nozzle size have an effect on oil production for smart horizontal well (ICD). Maximum effect on oil production is given by nozzle size in each ICD followed by compartment length. Seven ICDs and compartment length of 150 m with variable nozzle sizes give maximum recovery with cumulative oil production of 1.08 MMm^3 .

Fig. 11 Production profile comparison of minimum and maximum recovery

Table 10 Results for various sensitivity cases

Cases	No. of wells	Cum oil (MMm ³)	NPV (crores)	Oil in place (MMm ³)	Recovery factor (%)
Vertical well	1	0.6348	323	1.56	40
Horizontal well	1	0.9316	495	2.17	43
Horizontal well + ICD	1	1.086	589	2.17	50

Table 11 Economic assumptions

Drilling cost-vertical well	Rs. 60,000/m
Drilling cost-horizontal well	Rs. 1,20,000/m
Sales price oil	\$50/bbl
Sale price gas	\$3/MMBTU
Operating costs for crude oil is Rs. 2275/m ³	
Operating costs for gas is Rs. 2025/1000 scum	
Tax calculated is 33.20% of [revenue—(drilling expenditure + wo expenditure + operating expenditure)]	

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