Development strategy of Thin-layered bottom-water reservoir

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Abstract. Improving the credibility of numerical simulation prediction is important for better development of marine sandstone heavy oil reservoirs with bottom water. Influencing factors are first evaluated, from modeling to selecting key parameters, such as grid size, relative permeability curve, capillary pressure, viscosity, permeability, etc. Moreover, field development experience shows that most of the oil is produced at high water-cut stage. Besides, due to the successful practice of massive liquid production, development feasibility of marine sandstone bottom-water reservoir is significantly improved. Therefore, based on sophisticated numerical simulation and massive liquid production, individual-well cumulative oil production in Oilfield FA-1 and FA-2 is increased by 74,000m3 and 51,200m3 respectively, accordingly contributing to increased 6.8% and 1% recovery efficiency. This practice may provide some guiding reference to other oilfield production.

Keywords: Marine Sandstone; Bottom-water Reservoir; Numerical Simulation; High water–cut Stage; Development Mode; Oil Recovery.

1. Introduction

Development of heavy oil reservoir with bottom water is a difficult problem [1]. Nowadays, horizontal well and other measures have been widely used to control water coning and increase oil recovery [2-6]. Numerical simulation is a good way to predict development effect, but Literatures [6-8] showed that simulation result is sensitive to several factors.

Although a series of measures, including controlling perforation thickness, producing at low drawdown pressure, injecting nitrogen foam, chemical water plugging, especially ICD for horizontal wells, had been taken to settle the bottom water coning problem, no one satisfactory effect has been detected in the target oilfields. Therefore, this problem is analyzed by numerical simulation, and the improving reliability method is also demonstrated by means of sensitivity analysis, including grid size, relative permeability, capillary pressure, viscosity and permeability. In addition, development strategy for thin-layer heavy oil reservoir with bottom water is proposed and demonstrated by field application.

Oilfield A is located in the Beibu Gulf of South China Sea, its pay zone, Formation J2, is one drape anticline trap derived from basal heave, all the faults in this formation are normal fault with small sizes. Average permeability is 12,000mD with weak heterogeneity, oil viscosity ranges from 52.35 to 83mPa s, average net pay is 7.9m, the thickness of water zone exceeds 50m. Oil development is very difficult with low oil recovery and strong uncertainty of performance prediction.

2. Improving incredibility of numerical simulation

The target of numerical simulation is recurrence of actual dynamic production of oil reservoirs, i.e. aiming at characterizing real physical processes of specific fluids by uniting motion equation, state equation and continuum equation, and considering specific geological conditions (structure, fault location, sandstone distribution, porosity, permeability, fluid saturation). Therefore, the incredibility of numerical simulation relies on whether geological modeling and distribution of porosity, permeability and saturation accord with geological understandings, as well as the rationality of relative permeability curve and fluid parameters.

Hence, our study started with sensitivity analysis of grid size, relative permeability, capillary pressure, viscosity and permeability to improve incredibility of numerical prediction of thin-layer heavy oil reservoir with bottom water.

2.1 Grid size

For bottom water reservoir, grid size will affect the form of bottom water coning ridge, and then affecting the forecast result. Four different grid sizes were selected to compare the effect of grid size on bottom water coning up. Water backbone expands with the increasing of horizontal grid step, resulting in distortion of its shape and larger cumulative oil production. When grid step falls less than 25m, cumulative oil production does not change much, but the reducing of grid step will increase the difficulty of running numerical model, so the optimized grid size was focused on 25m.

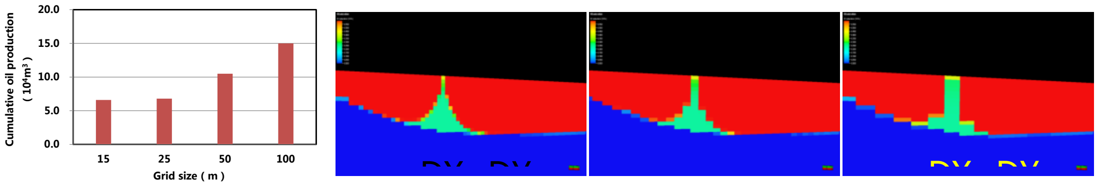

Fig.1 The influence of grid size on bottom water coning ridge and forecast result

2.2 Establishing geological model

Geological model with structural model and property model was built with the assistance of geological modeling software 'Petrel'. Structure model was established based on seism interpreted structure map and thickness map with 20 layers, horizontal grid size is 25m×25m, and optimized vertical grid step of oil layers is 0.5m, which leads to a very large total grid number. Hence, gradual changing grid size in oil-water transition zone and water zone was adopted to improve calculation rate, which has little effect on modeling of bottom water coning up. The final total grid number is 1248000.

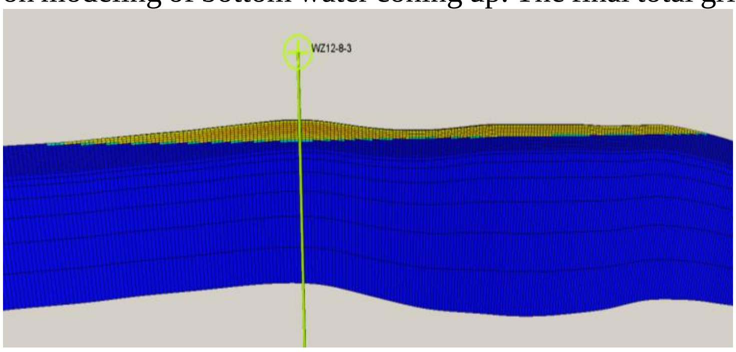

Fig.2 Geological model

Reservoir property model mainly indicates porosity model, permeability model and net to gross ratio model. Porosity model was built based on testing interpreted well spot data with Kriging interpolation, and then permeability model was fixed on by relationship between porosity and permeability. The matching error of original oil in place falls below 5%.

2.3 Relative permeability and capillary pressure

Normalization of relative permeability was conducted based on 5 core samples test data of two prospecting wells in our target area. Next, endpoint scaling was operated to ensure oil saturation of geological model accord with that in OOIP Table.

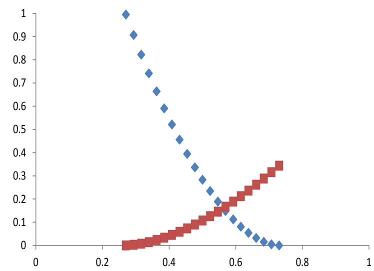

Fig.3 relative permeability curve

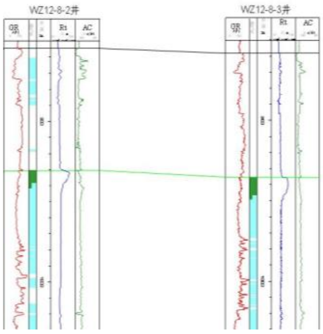

Fig.4 Well logging curves

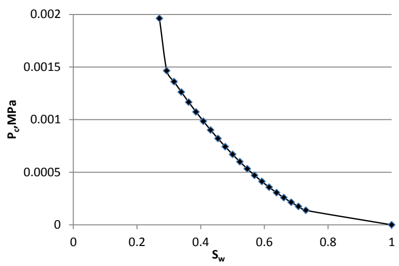

Fig.5 Capillary pressure curve

Capillary pressure curve was obtained by averaging core test data applying J function. Oil-water transition zone is clear in testing curve, approximately 2m, so Pcmax was computed as 0.019Bar.

3. Development strategy of marine sandstone bottom-water heavy oil reservoir

3.1 High water-cut stage is the main development period of thin-layer bottom-water heavy oil reservoir

The main focus of previous research was put on:Avoiding coning up of bottom water; Long length horizontal well first;Low rate production at smaller drawdown pressure,To prolong the water-free production period.

Horizontal well critical production rate was computed by CHAPERON equation:

$$q_o = \frac{4.888\times10^{-4} L k_o (h - z_w) 2(\Delta e_{wo}) F}{y_e B_o \mu_o} \tag{1}$$

Calculated critical production rate mostly falls below 10m3/d, corresponding critical production differential pressure are also very low. If effective horizontal length is 700m, then critical production rate will be 7m3/d, which cannot reach economical requirement. Reasonable production differential pressure should assure relatively larger oil recovery and oil production rate simultaneously. However, a large fraction of oil wells in marine sandstone reservoirs of west part of South China Sea have detected the appearance of sanding. So in practice, reasonable production differential pressure is often determined by critical sanding differential pressure

3.2 Lab experiment shows that the production potential of heavy oil reservoir at high water-cut period is still tempting

Lab water-driven oil test was conducted with different oil-water viscosity ratios between 0.33-16.5mPa s. Results demonstrated that a large fraction of oil is still able to be produced at high water-cut period. For example, oil displacement efficiency can still be increased by 10.8% during 90-98% water-cut period with oil-water viscosity ratio of 50, however, oil displacement efficiency will only be improved by 5.4% with oil-water viscosity ratio of 5.

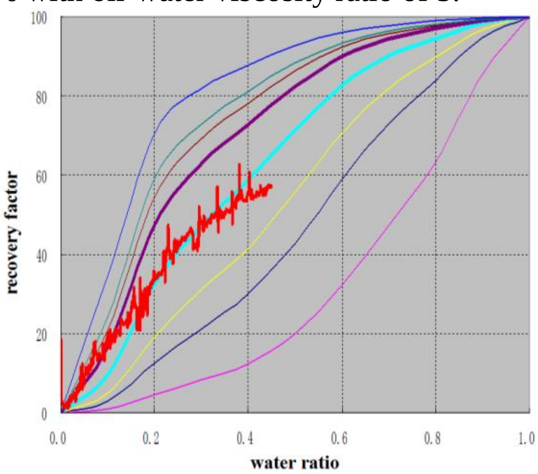

Fig.6 The relationship between water ratio and recovery factor

3.3 High water-cut period is the main development phase has been verified by field test

RE1 and RE2 are two fault nose structure controlled by fault, which are distributary channel microfacies and debouch bar microfacies deposition respectively. There is almost no interlayer found in these two high porosity and permeability reservoirs with bottom water. Reservoir and fluid parameters are listed in Table 1.

Table 1 Basic parameters of RE1 and RE2 in B Oilfield.

well	RE1	RE2
Porosity	28%	29%
Permeability	6,769mD	8,188mD
Net Pay	4.86m	9.52m
Oil Viscosity (RC)	52.6mPa s	46.8mPa s

Table 2 Production performance of B-Well #1 and B-Well #2

Items	B-Well #1	B-Well #2
Current liquid rate	2,244m3/d	1,203 m3/d
Current oil rate	96.1 m3/d	94.6 m3/d
Water cut	95.7%	92.1%
Cumulative oil production	16.33×104m3	9.38×104m3
Fraction of cumulative oil production when WCT reaches 90%	2.33×104m3	3.10×104m3

Taking Well #1 and Well #2 of B Oilfield as an example, water cut of Well #1 reached 73% after 1 month production, and then arrived at 89% after 6 month production. Production performance showed that scattered interlayer distribution has little block effect on bottom water, but water cut rises slowly during the high water-cut period, most of the oil is produced at this period. Its production performance is listed in Table 2.

From the actual production of Well #2, bottom water breaks relatively ealier, water cut rises quickly with rapid production decline. After 4 years of production, sidetracking was operated at 2009. Its production performance before sidetrack is shown in Table 2.

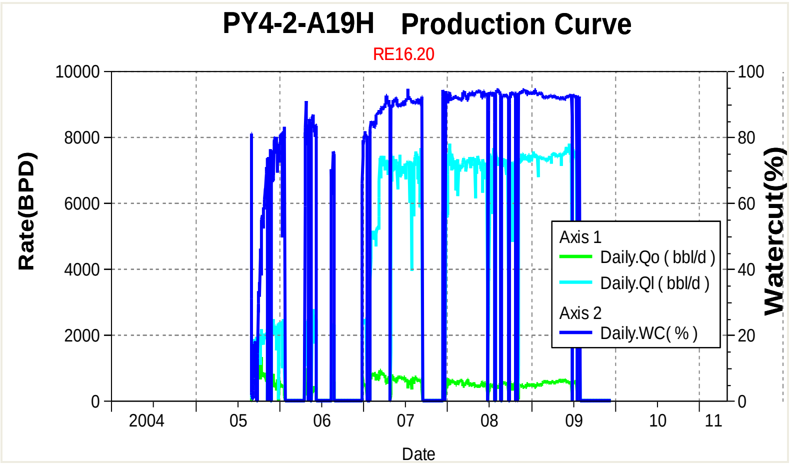

Fig.7 Production curve of PY4-2-A19H

4. Stimulation operation

4.1 ICD Water Control

ICD technology is to improve the level of oil water control in bottom water coning, so as to improve recovery efficiency. However, simulation results showed that water control effect of ICD is not obvious.

Sensitivity analysis reveals that wellbore friction will affect the coning form along the horizontal section. The influence of wellbore friction on coning form of bottom water is shown in Table 3. Since Formation Jiaowei has weak heterogeneity and is producing at low drawdown pressure, so wellbore friction along the horizontal section can be neglected, resulting in uniform coning up along the horizontal wellbore and failure of ICD.

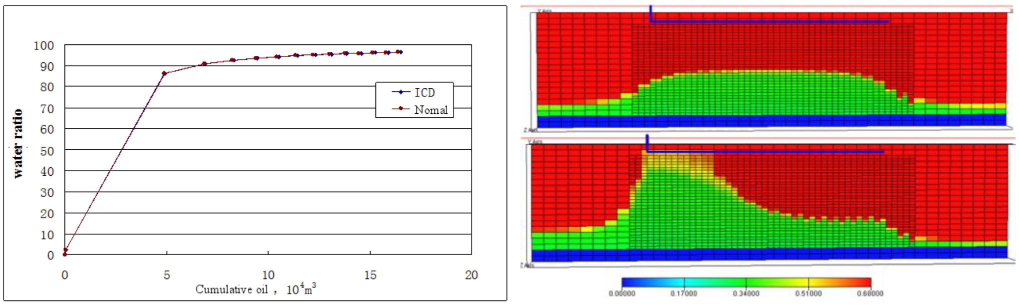

Fig.8 Comparison of production effect with and without ICD

Table 3 The influence of wellbore friction on coning form of bottom water

Considering Wellbore Friction	Coning Form
No	Uniform along the horizontal section
Yes	Relatively centralized near the heel

4.2 Production at High Liquid Rate

Two groups of schemes were put forward:

Group #1: initial liquid rate of 500m3/d, when water cut reaches 90%, liquid rate is brought up to 800, 1000, 1500, 2000m3/d; Group #2: initial liquid rate of 500m3/d, when water cut reaches 90%, oil rate target is set as 50m3/d with minimum oil rate and maximum liquid rate as 10m3/d and 2500m3/d respectively.

Simulation results showed that production allocation exerts a tremendous influence on cumulative oil production at the early stage, but cumulative oil eventually tends to converge. And showed that no matter whether oil production rate or liquid production rate is set, the larger liquid rate, the higher the final cumulative oil. Fraction of cumulative oil production after WCT reaches 90% exceeds 2/3.

4.3 Development Strategy

Production allocation at initial stage has little effect on ultimate oil recovery, so it has to be as low as possible, if economic condition allows, avoiding reloading a large-duty pump.

Higher liquid production rate is recommended at high water cut period.

Applicable Targets: high porosity and high permeability thin-layer heavy oil reservoir with bottom water.

5. Field Application

Fine numerical simulation technology and marine thin-layer heavy oil reservoir with bottom water development strategy was applied in C Oilfield, and better production performance was achieved.

5.1 Perfect History Matching of C Oilfield

C Oilfield is one simple anticline structure with weak fault influence. Average permeability is 600md, average porosity is 21%, reservoir effective thickness is 6.5m, oil viscosity is about 5.29mPa s. All wells have been shut down due to serious water channeling.

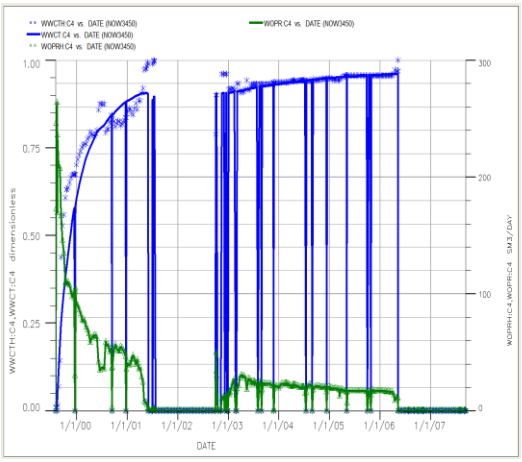

Fig.9 History Matching of C4

Good matching of water cut by single well in the original geological model cannot be obtained. By means of detailed reservoir description, sensitivity analysis, and local transmissibility ratio adjusting, perfect history matching of individual wells in C Oilfield has been achieved.

5.2 Stimulation Treatment of C Oilfield

Since remaining oil was left at the higher position of structure, and no well control area, stimulation treatment of higher liquid rate plus adjustment well was proposed. Specific operations and its contribution to oil recovery is listed in Table 4.

Table 4 Stimulation treatment and its contribution to oil recovery of C Oilfield

Treatments	Specific Steps	Increased Cumulative Oil	Contribution to EOR
Higher liquid rate		4.24×104m3	1.565%
Adjustment well	Shut down and sidetracking two watered-out producer, then increase liquid rate in large scale when WCT reaches 90%	14.46×104m3	5.335%

6. Conclusions

(1) The confidence level of detailed numerical simulation mainly relies on rationality of geological & numerical model, as well as reliability of sensitive parameters. Grid size has a great effect on forecast result for reservoirs with bottom water, thus sensitivity analysis is strongly recommended.

(2) Oil viscosity is depth-varying, and presents positive viscosity gradient. Viscosity near the mid-depth is more appropriate.

(3) For high porosity and high permeability heavy oil reservoirs with bottom water and weak heterogeneity, ICD water-control method will not obtain satisfactory effect due to low horizontal wellbore friction.

(4) Production allocation at initial stage has little effect on ultimate oil recovery, so it has to be as low as possible, if economical condition allows, to avoid reloading a large-duty pump. Higher liquid production rate is recommended at high water cut period.

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