

Prediction of offshore viscous oil field performance using reservoir simulation

E. F. Balbinski¹, D. J. Element¹, S. G. Goodyear¹ and A. J. Jayasekera²

¹AEA Technology plc, Winfrith Technology Centre, Dorchester, Dorset DT2 8ZE, UK

²Department of Trade and Industry, 1 Victoria Street, London SW1H 0ET, UK

ABSTRACT: Development plans for UKCS viscous oil reservoirs use production profiles predicted by full-field simulation models. The use of horizontal wells, possibly combined with other IOR techniques, and the unusually high vertical permeability of many of the fields, lead to a range of issues that need to be carefully considered when building simulation models.

The strengths and weaknesses of different gridding systems, and the level of areal and vertical grid refinement that is needed, are discussed and illustrated with a range of examples including: interpretation of Extended Well Test results and integration with full-field modelling; sensitivity to relative permeability assumptions; prediction of gas movement from primary gas caps; and the comparison of different IOR techniques.

Where horizontal wells are drilled to reduce gas coning, undulations in the well trajectory can cause local coning of free gas, giving significantly earlier breakthrough times compared to strictly horizontal wells. A good correlation is found between effective stand-off and breakthrough time. Where localized gas production occurs, scoping calculations suggest that inflow of oil from further down the wellbore may be significantly reduced by multi-phase friction effects and gravity potential terms not modelled in conventional simulators.

KEYWORDS: *simulation, enhanced oil recovery, viscous oil recovery, reservoir performance*

INTRODUCTION

Early production from UKCS oil fields has been of light oil. However, a significant number of 'heavy' oil fields have also been discovered, which, in the context of this paper, is taken to refer to reservoirs with *in-situ* viscosities greater than 5 cp. The majority of UKCS heavy oil occurs in relatively shallow reservoirs, comprising high porosity unconsolidated sands with excellent horizontal permeability (typical average values of 3000 to 10 000 mD) and very high vertical permeability ($k_v:k_h$ in the range 0.2 to 1.0). The oil columns are usually at least partially underlain by water and some also have primary gas caps. Jayasekera & Goodyear (2000) have reviewed the status of UKCS viscous oil fields and provide a fuller list of references.

This combination of reservoir parameters and the demanding offshore environment of the UKCS, presents a special set of reservoir engineering challenges, because of the difficulties in achieving and maintaining sufficiently high production rates to justify development. Predictions of production profiles are usually based on full-field simulation models. However, the use of horizontal wells, possibly combined with other IOR techniques, and the unusually high vertical permeability of many of the fields, lead to a range of issues that need to be carefully considered when building simulation models and integrating laboratory data. This paper gives an overview of experience in

modelling UKCS viscous oil fields (Element & Goodyear 1999), highlighting key issues that need to be addressed.

OVERVIEW OF FULL-FIELD MODEL CONSTRUCTION ISSUES

Viscous oil fields typical of the UKCS can show a very wide range of waterflood displacement mechanisms. The unusually high vertical permeability of many of the fields means that waterflood displacements will often be gravity dominated. Where the displacement is gravity dominated, water will slump to the base of the reservoir, leaving high oil saturations at the top of the formation between wells. However, in the zones swept by water, relatively low effective residual oil saturations may be achieved under the action of gravity drainage. Where the displacement is viscous dominated, uneven sweep will occur with channelling of water through any higher permeability layers, with relatively high effective residual oil saturations in the swept zones.

The viscous oil means that water or gas flooding will have unfavourable mobility ratios, for example a field with a 100 cp oil will have a waterflood endpoint mobility ratio of approximately 40. However, because the displacements are immiscible the effective mobility contrast is always much less severe than is suggested by the endpoint values. In viscous-dominated displacements the poor displacement efficiency means that a relatively high oil saturation is left immediately behind the shock front so that the total mobility of the fluids is significantly reduced. In one dimension the shock front mobility ratio

Presented at the 10th EAGE European Symposium on IOR, Brighton 1999.

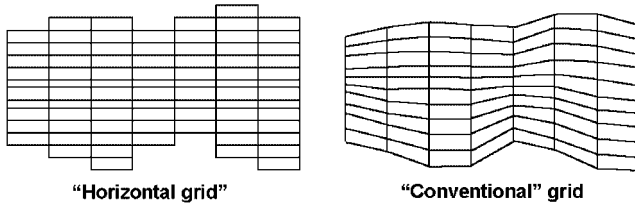


Fig. 1. Grid frameworks for simulation models.

M_s can be related to the breakthrough water fractional flow $f_w(S_w^{BT})$ and the shock front and endpoint oil mobility, λ_o , according to:

$$M_s = \frac{\lambda_o(S_w^{BT})}{\lambda_o(S_{wi})} \frac{1}{1 - f_w(S_w^{BT})}. \quad (1)$$

Since the oil mobility decreases with increasing water saturation, equation (1) allows an upper bound to be established for M_s :

$$M_s < \frac{1}{1 - f_w(S_w^{BT})}. \quad (2)$$

For the example being discussed, with typical fractional flow curves, equation (2) shows it is difficult to construct scenarios where the shock front mobility ratio is greater than 4. This means that any effects from viscous fingering are unlikely to make a significant impact on predicted recoveries and so very fine grids are not needed. The effect of channeling through any higher permeability zones may be important and this can be modelled with conventional numbers of grid blocks.

Gridding requirements

Two basic grid frameworks (Fig. 1), are typically used for modelling viscous oil fields:

- 'horizontal grids' with uniform layer thickness in the horizontal plane, and the reservoir top and bottom surfaces defined with inactive blocks or truncated blocks;
- 'conventional grids' following the reservoir layering and boundary surfaces.

The strengths and weaknesses of the 'horizontal gridding' system are complementary to the strengths and weaknesses of 'conventional grids'. Horizontal grids have the advantage of allowing the original OWC and GOC (if a gas cap is present) to be represented exactly, and where the displacement is gravity dominated to follow the rise of the horizontal fluid contacts. However, the disadvantages are that permeability contrasts and shales cannot be easily represented in the model and where water is drawn up-dip as a tongue at the base of the reservoir, or gas over-ride occurs, it may not be possible to include sufficient vertical resolution.

The optimum grid block size, and relative refinement areally and vertically, is best assessed by a pre-study, prior to construction of the full-field model. This should explore the validity of the gridding over the possible range of uncertain reservoir parameters, such as vertical permeability. These issues are illustrated with examples in the following four sections. However, at this stage it is worth summarizing the key points.

In the more viscous fields, which require large numbers of relatively closely spaced horizontal wells, it may be difficult to achieve acceptable numbers of blocks between neighbouring

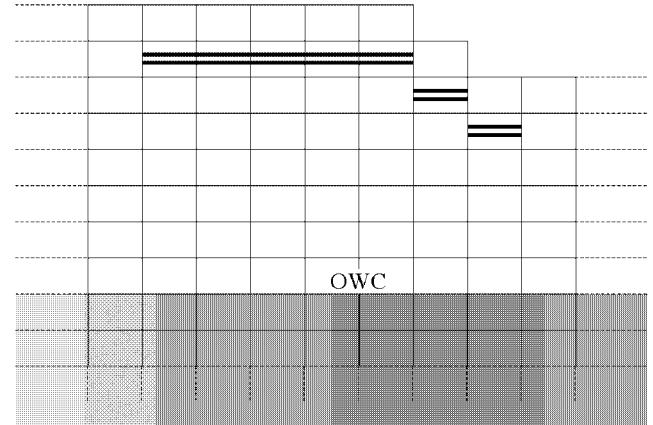


Fig. 2. Cross-section of full-field grid showing EWT well trajectory.

wells to allow coning to be represented. As a general rule, at least one row of blocks should be used between rows containing adjacent wells. If the blocks containing wells have a reduced width, this may allow sufficient representation of coning phenomena for the purposes of full-field modelling. Where the displacement is more viscous dominated, more blocks between the wells will be needed.

The level of vertical refinement needs to be considered relative to the principal displacement mechanisms. Where the flood is gravity dominated, sufficient blocks are needed to represent the movement of the fluid contacts. Where the flood is less gravity dominated, even modest variations in permeability in a vertical sense may need to be represented, since the displacement has an unfavourable mobility ratio.

INTERPRETATION OF EXTENDED WELL TESTS

Extended Well Tests (EWTs) may be performed to gather additional dynamic data prior to a final development decision, for example, with the intention of validating coning behaviour. In these circumstances, a greater level of grid refinement may be required to interpret the test, compared to that needed to make fullfield predictions. For example, the water breakthrough time, and point of breakthrough along the well, may be strongly influenced by the actual trajectory of the well and local inflow performance, which need to be represented explicitly in the model. These points are illustrated with a generic model, in which a 10^6 STB EWT is performed on an oil column with variable thickness (from 80 to 120 ft) which is entirely underlain by bottom water. The oil and water viscosity at reservoir conditions are taken as 100 cp and 0.8 cp respectively. The porosity is 0.35, the horizontal and vertical permeabilities are 4000 and 2000 mD respectively. Figure 2 shows the oil column and horizontal well trajectory (3500 ft length), as represented by a 'horizontal grid' model with typical full-field areal (250×500 ft) and vertical (20 ft) block dimensions. The producer has been drilled to follow the top of the reservoir, to delay water breakthrough.

Simulation using the full-field model grid showed water breakthrough right at the end of the production period of 10^6 STB (Fig. 3). The model was refined around the well (by a factor of 3 in the vertical direction, a factor of up to 7 in the y direction perpendicular to the well trajectory, and a factor of 6 in the x direction along the well). Water breakthrough was brought forward to between 0.61 and 0.69×10^6 STB, depending on whether the well was positioned in the centre or bottom block of the set of three vertically refined blocks corresponding to each coarse block.

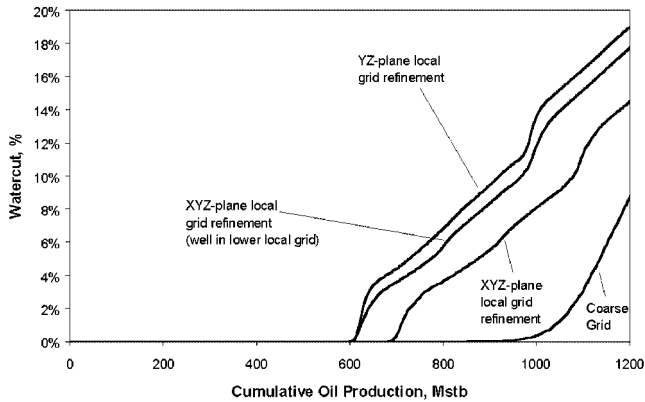


Fig. 3. Effect of grid refinement on prediction of EWT performance.

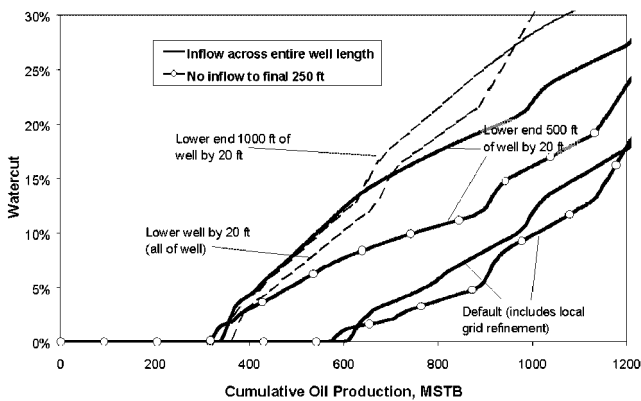


Fig. 4. Effect of well path on prediction of EWT performance.

Uncertainty in the actual well trajectory arising from depth measurement errors is a potentially important factor in history matching EWT performance. Taking as the base case, the well trajectory in the lower set of refined blocks, sensitivities to lowering the well trajectory by 20 ft, over the entire well length, the 1000 ft nearest the toe, and the 500 ft nearest the toe, have been run. These show a significant reduction in the water breakthrough time to $0.32\text{--}0.345 \times 10^6$ STB (Fig. 4), for all the cases considered, since the water breakthrough first occurs at the toe of the well. In practice, inflow into the well may not be uniform, due to local variations in well PI. Cases were also run in which the last 250 ft at the toe were assumed not to contribute to flow (requiring the local refinement in the x -direction introduced earlier). Over the timescale of the test, this made a significant difference to the rise in the water cut.

This section has shown the importance of adequate grid refinement and proper representation of the well trajectory and inflow. For a **fixed reservoir** description these can give rise to a significant variation in reservoir performance during the well test, although in this case they make little impact on cumulative recovery. For the coarse model, the refined model, and the refined model with the well profile lowered over the last 1000 ft, the recovery at a 90% water cut is 0.446 , 0.471 and 0.438×10^6 STB, respectively. This recovery is achieved at very similar times, 2006, 2000 and 1902 days, respectively. Given that part of the rationale of an EWT is to determine dynamic reservoir parameters, it is important to reduce the uncertainty in the well trajectory and inflow to a minimum, to give the best

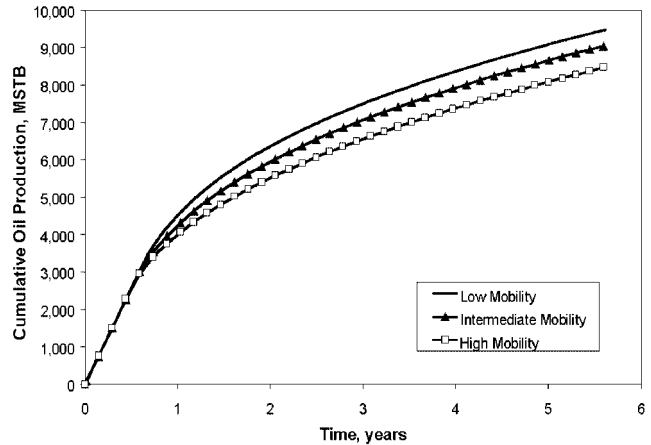


Fig. 5. Impact of uncertainty in total mobility on recovery.

chance of being able to tie down the reservoir parameters unambiguously.

SENSITIVITY TO RELATIVE PERMEABILITY ASSUMPTIONS

Given the adverse endpoint mobility ratio for a waterflood, it is likely that relative permeability will influence the predicted reserves more than in light oil reservoirs. Variations in relative permeability affect the fractional flow curve and the total mobility. It is well known that the shape of the fractional flow curve will affect the recovery at water breakthrough and the scope for further oil production as more water is cycled through the reservoir. However, it is less clear what influence uncertainty in the total mobility function will have on recovery. These data may be difficult to measure, given the very low pressure drops that can be encountered in SCAL studies at reservoir rates. To assess this sensitivity, two complementary sets of relative permeabilities have been constructed based on the oil–water curves used to date. In these sets the fractional flow curve is preserved, but the total mobility after the shock front is either increased (by a factor of 1.7) or decreased (again by a factor of 1.7), any changes in recovery can then be related directly to changes in the total mobility curve.

Recovery has been calculated for a 160 ft oil column in a 2D cross-section model perpendicular to the well path. In a refined model (10 ft horizontal grid blocks local to the well), this shows a variation of 10^6 STB on the recovery at 2000 days, purely from the difference in mobility (Fig. 5). The total mobility also impacts the accuracy of different gridding systems. Comparisons have been made between a coarse grid (250 ft), the refined grid and a coarse grid with a single refinement containing the well (referred to as the intermediate grid with the 250 ft block split into 100 ft, 50 ft and 100 ft blocks horizontally). These comparisons have used the intermediate mobility relative permeabilities. Generally, the coarse grid overestimates recovery and underestimates water breakthrough time. The intermediate grid gives better predictions of water breakthrough, but depending on the time and total mobility model used, either underpredicts or overpredicts recovery. This is illustrated in Figure 6, which shows the cumulative recovery as a function of time for the base case relative permeabilities on the different grids. The water breakthrough times for the coarse, intermediate and refined grids are 230, 188 and 201 days respectively.

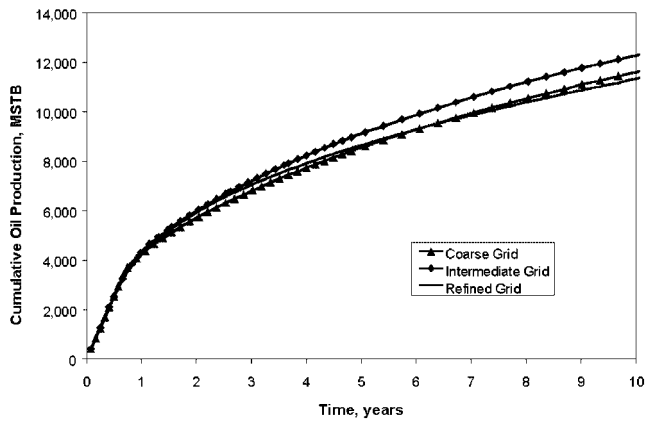


Fig. 6. Effect of grid refinement on prediction of full-field performance.

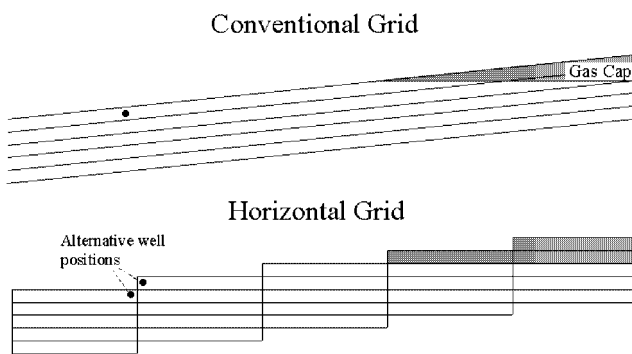


Fig. 7. Grid frameworks for modelling gas cap movement.

PREDICTION OF GAS MOVEMENT FROM PRIMARY GAS CAPS

Where gas is pulled from a gas cap across the top of the reservoir to producing wells, the very high contrast between the gas and oil endpoint mobility can mean that very thin blocks are needed at the top of the reservoir to predict gas breakthrough times. A useful rule of thumb based on experience is that the ratio of the thickness of the top layer of blocks to the total formation thickness should be roughly equal to the endpoint mobility ratio for gas and oil, recognizing that at the top of the reservoir the oil saturation will approach its residual value under the action of gravity drainage and the high gas throughput. Alternatively, a pseudo-relative permeability approach could be adopted, for example applying linear relative permeabilities just to the top layer of a coarser model and using the rock curves elsewhere.

The impact of gridding on predictions of gas breakthrough is illustrated in the following example, where oil is produced under primary depletion from a horizontal well located 2000 ft from a gas cap. Simulation models are constructed with a horizontal grid size of 200 ft, using both 'horizontal grids' and 'conventional grids' with a basic vertical resolution of 20 ft (Fig. 7). In the 'horizontal grid', the well can either be assigned to the block immediately to the left or right of the true position. In the 'conventional grid' the effect of vertical refinement could be explored in a series of models in which the top layer was progressively refined by a factor of 2, to give top layer thicknesses of 10, 5, 2.5, 1.25, 0.625, 0.3125 ft, respectively. The producing GOR from the models is shown in Figure 8. The

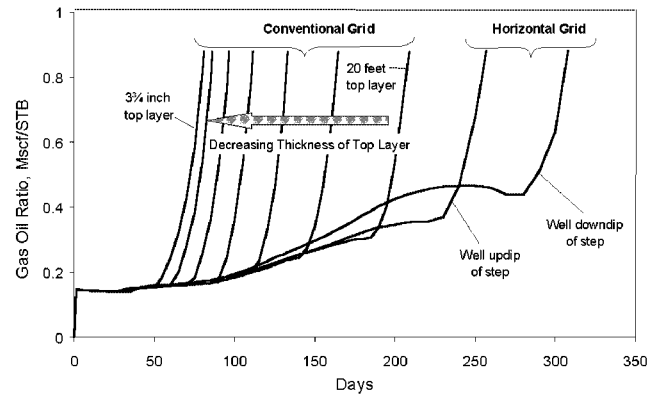


Fig. 8. Impact of gridding on prediction of gas breakthrough.

general slow rise in GOR corresponds to free gas generated by production below the bubble point, with the sharp rise corresponding to the arrival of free gas from the primary gas cap. The basic coarse grid models give free gas breakthrough at 185 days for the 'conventional grid' and 240 and 290 days for the 'horizontal grid', depending on the assignment of the well block. The 'conventional grid' allows vertical refinement to capture the actual movement of the gas tongue, with a resolution of 0.3125 ft being required to achieve satisfactory convergence to the correct solution, with breakthrough at 50 days. This shows the need for adequate gridding, which can only be practically achieved with the 'conventional grid'. The 'horizontal grid' predicts gas breakthrough up to a factor of 6 later than reality, which could critically affect decisions about the timing of water injection to control gas production early in field life.

COMPARISON OF RECOVERY TECHNIQUES

Where simulation models are being used to compare the benefits of different recovery techniques, particular care is required to ensure that results reflect genuine differences between recovery performance rather than different responses to the selected grid. An example of this issue is given by a comparison of cold water and hot water flooding (Woods *et al.* 1995) in a horizontal injector producer pair with a spacing of 750 ft, using different grid resolutions. At one extreme a grid was used that was representative of a full-field model areal grid, with only one row of blocks (650 ft width) between the rows of blocks (each of 50 ft width) containing the wells. This was compared with the results from models with the central 650 ft row of blocks divided into 3, 5 and 7 rows of blocks. In each of these cases ten vertical blocks were used. In addition, a base case refined grid with 20×20 blocks was used. Recovery efficiencies were calculated at 10 years, together with the incremental recovery for the hot water injection (Table 1). This shows that very large errors can be made on coarse grids for the hot water flooding (overestimating the incremental recovery by up to a factor of 4.5), even though the cold water flooding is predicted satisfactorily irrespective of the grid size used in these cases. This result is primarily due to numerical dispersion spreading the injected heat throughout the reservoir in the coarse models, and reducing the oil viscosity (which is very sensitive to modest changes in temperature compared to the difference between the original reservoir and injected water temperature).

Table 1. Effect of grid refinement on cold and hot water flooding

Case	Number of blocks between well blocks				
	1	3	5	7	20 × 20
Cumulative production at 10 years (× 10 ⁶ STB)					
Cold water	10.75	10.44	10.41	10.41	10.30
Hot water 200°F	13.85	11.67	11.31	11.21	11.21
Hot water 400°F	17.79	13.67	12.04	11.61	11.77
Incremental production (% cold water)					
Hot water 200°F	28.9	11.8	8.6	7.7	8.8
Hot water 400°F	65.5	31.0	15.6	11.6	14.2

Table 2. Comparison of gas breakthrough times for flat and undulating wells

Undulation amplitude (ft)	Stand-off (mean ft)	Flat (years)	Undulating (years)	Change (years)	Change (%)
5	79	3.48	3.14	0.34	10
10	79	3.48	2.69	0.79	23
20	79	3.48	1.86	1.63	47
10	54	1.14	0.71	0.43	38
10	39	0.40	0.18	0.22	55

IMPACT OF WELL UNDULATIONS ON GAS BREAKTHROUGH

A number of moderately viscous (5 to 10 cp) UKCS oil reservoirs have gas caps. Oil production is generally by horizontal wells with a stand-off designed to delay production of free gas. Experience with these fields has raised a number of generic issues concerning well performance and modelling. For example, the ability to control production of free gas has varied considerably between reservoirs with similar characteristics. One specific issue is the effect of undulations in the trajectory of the horizontal well. Large vertical variations may occur, up to about 60 ft peak to trough, though typical variations are less than 30 ft. These undulations should be compared with mean stand-offs between the well mid-points and initial GOCs, which are typically more than about 50 ft.

To investigate the effect of well undulations, three-dimensional, fine gridded, half-well models were constructed for a flat well and an undulating well (Balbinski *et al.* 1998). For the base models, the producing horizontal well was 2000 ft long with an initial stand-off of 79 ft from the gas cap. The undulating well was given two peaks and two troughs along its length, all with an amplitude of 10 feet. The grid was 50 × 13 areally, with 50 ft wide cells along the length of the well. In the dimension perpendicular to the well, cell sizes increased from about a foot to 1000 ft on the outer boundary. The areal extent was 2500 ft by about 1900 ft. The grid was refined vertically with a 1 ft cell thickness near the well, increasing to a maximum of 50 ft in the oil leg and 80 ft in the gas cap. In reality, pressure support would be given by water or gas injection, however, to focus on the gas coning issues no water leg was included in the model and both the oil leg and the gas cap were given artificially large volumes.

At the base rate of 10 000 BOPD, free gas was produced by the flat well after about 3.5 years of oil production, initially from a completion about 1/5 of the well length away from the heel, but very quickly spreading along most of the length of the well. In the undulating well, gas breakthrough occurs after about 2.7 years, initially from the peak closest to the heel, and then remaining local to the peaks of the well for some time. The gas:oil ratio increases over seven times more rapidly for the

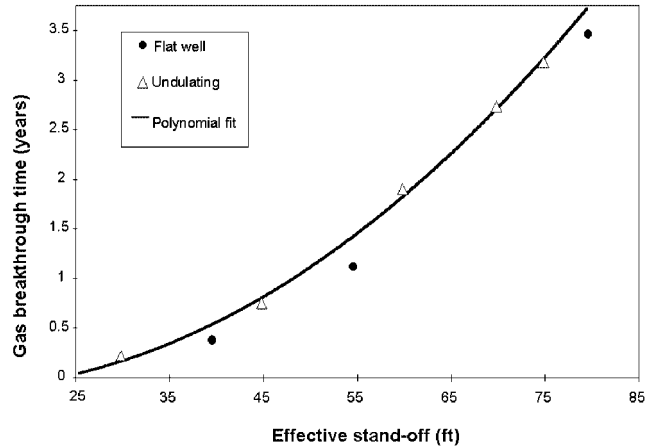


Fig. 9. Relationship between gas breakthrough time and effective stand-off for undulating wells.

flat well after gas breakthrough than for the undulating well in the base case. This is because much more of the completed length is producing gas in the flat well case than for the undulating well case where the gas remains localized.

Additional cases were run examining sensitivities to undulation amplitude and mean stand-off (Table 2). The effective stand-off (distance from GOC to nearest completion) has a significant effect on the breakthrough time. In the worst case gas breakthrough occurs more than 1.6 years earlier for the undulating well.

The gas breakthrough time is very sensitive to the stand-off, even for the flat well. Although the absolute difference in breakthrough times decreases with stand-off, the percentage difference increases, indicating a strong non-linear dependence. Using the effective stand-off concept, the gas breakthrough times for the flat and undulating wells show a good correlation (Fig. 9).

Additional simulations were run with effective oil production rates of 5000 and 15 000 BOPD. The gas breakthrough time is sensitive to the oil production rate. For example, reducing the rate by half from the base case increases the breakthrough time by about a factor of four. Choosing an appropriate rate is therefore a critical operating factor. However, the percentage differences in breakthrough times for the flat and undulating wells are fairly insensitive to the production rate.

Friction effects due to fluid flow in the wellbore can be very sensitive to diameter and so a case was run reducing the wellbore diameter from 6 to 4.5 inches. For the base case, the difference in the gas breakthrough times between flat and undulating wells was reduced by 34 days, but the percentage difference in breakthrough time was only reduced from 23 to 21%. The sensitivity to wellbore diameter is therefore relatively less important than the other sensitivities considered.

IMPACT OF LOCAL INFLOW OF GAS ON WELL PERFORMANCE

Local gas production might inhibit liquid production from further back along the well. One mechanism for this to occur is that gas flowing into the wellbore forms a multi-phase mixture with the oil and water present, with increased friction giving rise to greater drawdown on the well between the heel and the point of gas breakthrough. Another mechanism is gas arriving at a local high in the wellbore being retarded by the

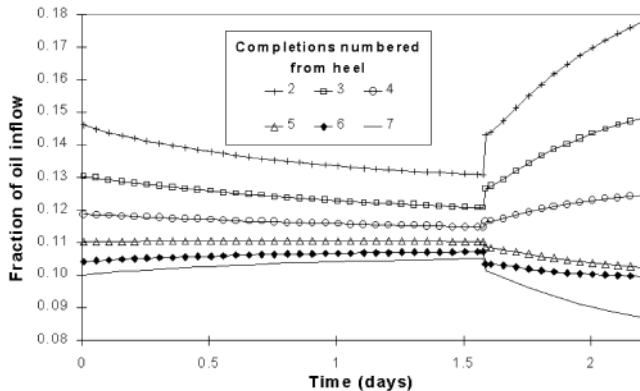


Fig. 10. Effect of gas production on oil inflow per completion in undulating well.

adverse gravitational potential for flowing down to the well heel.

A conventional black-oil reservoir simulator, allowing well cross-flow and using the Beggs and Brill correlation to evaluate the friction pressure drop, has been used for scoping calculations to investigate these mechanisms. However, because local hold-up of fluid along the wellbore is not modelled, transient phenomena may not be fully represented.

Multi-phase mechanism

As a preliminary, multi-phase flow information was output from the undulating well model described earlier just after gas breakthrough. A significant degree of liquid hold-up was predicted. The liquid fraction falls to less than 80% at the local high where gas production first occurs, but increases to about 90% at the outflow end. The mixture velocity falls monotonically from about 0.6 m s^{-1} at the outflow end to about 0.4 m s^{-1} at the first local high and only about 0.02 m s^{-1} at the toe of the well. The flow regime is generally turbulent, except near the toe of the well, for example, the Reynolds number where free gas is produced is about 10^4 . In terms of the flow regimes defined by Beggs and Brill, the flow changes from 'Intermittent' near the heel to 'Transitional' further down the well. Flow velocities are too high for 'Segregated' flow to occur where the free gas is produced.

A range of cases were run using a simplified well model with a single undulation, exploring the effect of the position of the GOC relative to the well. In the first case, the initial GOC was set 5 ft above the highest well completion. The well was produced at an initial rate of 7000 BOPD, which was maintained for about 1.6 days until free gas production started. The run was continued for about 8 days, although after 2.2 days, the well was limited by the bottom-hole pressure constraint. A maximum free gas production rate of about 5×10^6 SCF per day and GOR of about $1800 \text{ SCF STB}^{-1}$ were attained. There is some reduction in oil production from the far half of the wellbore due to gas production in the middle. This is shown by a plot of completion oil inflow against time for several completions (Fig. 10). Completion two is at the heel and six at the highest point. Before gas breakthrough there is roughly equal share, but afterwards, completions nearer the outlet increase their share, while completion seven, which is just beyond the well high point, drops from 11% to about 9%, a change of almost 20%. After free gas is produced velocities at completions between the local high and the outlet increase as might be expected. However, there is a similar percentage

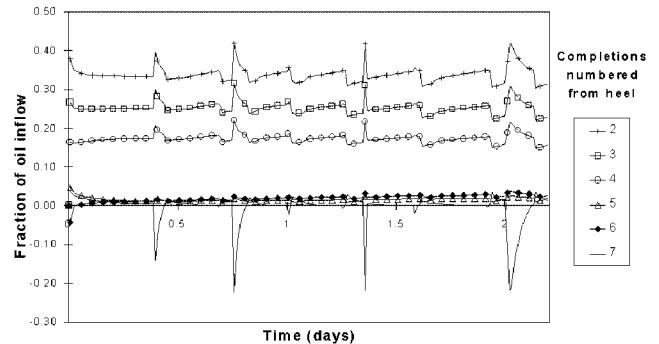


Fig. 11. Effect of gas production on oil inflow per completion in undulating well (extreme case).

reduction in fluid velocities for completions beyond the high point as for oil inflow.

In a more extreme case, the GOC was initialized to the high point of the well, so that free gas was produced immediately. A maximum free gas production rate of about 6×10^6 SCF per day with a maximum GOR of about $4200 \text{ SCF STB}^{-1}$ was obtained. Oil recovery was dominated by the three completions nearest the outflow from the start (Fig. 11), the contribution from completions further down the well being small. At several times crossflow occurs in completion 7, just beyond the point of free gas production, that is oil is flowing out of the completion (Fig. 11). The solution is flipping between oil flow along the wellbore and oil flowing out of the completions. The steady-state solution method is probably breaking down here, as apparent transient effects are occurring. These results do, however, suggest that localized gas production could significantly reduce oil production from further along the well.

Adverse gravitational potential

Two scoping calculations have been performed to assess the effect of an adverse gravitational potential. In the first the effect of an adverse gravitational potential arising from an undulation in the wellbore has been estimated by comparing the component of the gravitational potential gradient along the wellbore with the fluid pressure gradient along the wellbore. In order for flow to occur along the wellbore, the magnitude of the fluid pressure gradient must be greater than the hydrostatic part of the potential gradient:

$$\frac{\partial p}{\partial x} > (\rho_o - \rho_g)g \frac{dz_c}{dx}, \quad (3)$$

where densities are at wellbore conditions. For the case of the simplified model described in the previous section, the right-hand side of equation (3) evaluates to about $5.7 \times 10^{-3} \text{ psi ft}^{-1}$. Just after gas breakthrough occurs, the fluid pressure gradient is $3.2 \times 10^{-3} \text{ psi ft}^{-1}$ at the heel of the well, reducing to $1.0 \times 10^{-3} \text{ psi ft}^{-1}$ at the minimum well depth. The gravitational gradient exceeds the fluid pressure gradient and it might therefore be expected that retardation of fluid flow would occur due to the adverse gravitational effect of an undulation of this size. Note that the maximum hydrostatic gradient is about 4 times less in this model than in the base undulating well model simulated previously, so this is a more conservative example.

Another way of testing this possibility is to simulate the movement of a gas bubble at a local high in a near-horizontal

wellbore. This was done by modelling the wellbore with a very high permeability, though no multi-phase effects could be included. Transmissibility barriers were used to channel any movement of the gas bubble down the well. The oil production rate was gradually increased from zero. Initially there was no movement of the gas bubble, so all the oil production came from the half of the well nearest the outflow end. However, as the production rate increased, the gas moved gradually down towards the outflow end. As the oil rate increased from 1000 to 2000 BOPD, the gas bubble moved very quickly towards the heel and was produced. This suggests that some retardation effect may occur from this mechanism, providing the well undulates sufficiently rapidly and flow rates are not too high.

CONCLUSIONS

The combination of reservoir parameters and the requirement for large numbers of horizontal wells to be modelled in high viscosity heavy oil fields, makes it difficult to construct simulation models that can be used for full-field predictions and the interpretation of EWTs. A series of generic examples illustrates the issues that need to be addressed when constructing simulation grids. In many cases a pre-study is required to ensure that the final grid selection is fit for purpose. For immiscible gas and water displacements the effective mobility ratio across the shock front is never as unfavourable as the endpoint mobility ratio, and useful reservoir performance predictions can usually be made without having to use extremely fine grids to capture viscous fingering effects.

Simulation models have also been shown to be sensitive to uncertainties in the total mobility function – a sensitivity which is quite separate to the effect which the fractional flow curve has on recovery.

Undulations in the wellbore trajectory can have a significant effect on gas breakthrough times. Time to gas breakthrough correlates well with effective stand-off (the vertical distance of the GOC to the nearest completion).

There are two likely mechanisms which scoping calculations suggest might affect oil production in wells with local highs. One is multi-phase friction effects causing reduced oil flow where gas production is occurring. Another is the adverse gravitational potential gradient due to a local high.

Scoping simulations have demonstrated the possibility of reduced oil production further down the well from localized free gas production. For one case considered oil production fell by about 20% further down the wellbore from the point of free gas production. In a more extreme case oil production was dominated by completions closest to the outlet and oil flowed out of the well beyond where free gas production occurred.

This work was performed as part of the UK Department of Trade and Industry's Hydrocarbons Additional Recovery Programme (HARP) studies at AEA Technology. The DTI's permission to publish is gratefully acknowledged. We thank Terry Fishlock of AEA Technology for his helpful review comments on the paper and remember the late Vanessa Potts for performing the simulations comparing cold and hot water recovery.

REFERENCES

- Balbinski, E.F., Goodyear, S.G. & Townsley, P.H. 1998. The effect of undulations in horizontal well trajectories in viscous oil reservoirs with gascaps. Paper presented at the IEA Collaborative Project on Enhanced Oil Recovery, 19th International Workshop, Carmel, California, 5–7 October.
- Element, D.J. & Goodyear, S.G. 1999. Modelling issues for interpretation of viscous oil production performance. Paper presented at the IEA Collaborative Project on Enhanced Oil Recovery, 20th International Workshop, Paris, France, 22–24 September.
- Jayasekera, A.J. & Goodyear, S.G. 2000. The development of heavy oil fields in the United Kingdom continental shelf: past present and future. *SPE Reservoir Evaluation & Engineering*, **3**, 371–379.
- Woods, C.L., Goodyear, S.G., Jones, P.I.R. & Reynolds, C.B. 1995. The impact of injection water temperature on recovery from viscous oil reservoirs. Paper presented at the 8th European Symposium on IOR, Vienna, 15–17 May.