ASPECTS OF DISCRETIZED WELLBORE MODELLING COUPLED TO COMPOSITIONAL/THERMAL SIMULATION

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Abstract

The practical advantages and limitations of discretized wellbore modelling when coupled to full field compositional and/or thermal simulations are presented in detail. The implementation of an efficient, strongly coupled discretized wellbore model is first discussed, with emphasis on wellbore hydraulic options and run-time-saving features such as pseudo-steady state initialization. The impact of these various aspects are shown on typical isothermal and thermal compositional field scale processes. The traditional sink/source modelling approach to fully coupled wells is used as a reference case in these comparisons where applicable. By doing so, this paper presents guidelines for the simulation engineer on the use and possible misuse of discretized wellbore model.

Introduction

In the past decade the use of horizontal wells increased rapidly due to improved drilling techniques as well as more efficient application to reservoirs where production from vertical wells was not economical. Reservoirs with vertical fractures, gas caps and/or bottom aquifers or heavy oil and tar sands reservoirs were the major contenders. New processes were used to deplete these reservoirs and numerical simulation became a tool in understanding these processes. Initially horizontal wells were modelled by the traditional sink/source approach. In this method only the hydrostatic pressure distribution along the well is known. Compositional, energy and frictional pressure drop effects are neglected. In the course of history matching the performance of these reservoirs, it was realized that wellbore flow characteristics may impact on reservoir behaviour in terms of different breakthrough time, uneven communication between wellbore and a reservoir, etc. Therefore, several approaches were tried by different authors[1,2] to include hydraulics in the modelling of wellbore flow. In this work the approach of Collins et. al[3] was extended and implemented in a thermal/compositional simulator.

Implementation of Strongly Coupled Well Model

CMG's simulator STARS is an advanced simulator that can handle a wide range of processes such as steam drive, steam cycling, combustion, polymer, foam and emulsion flow, etc. In STARS two well models are available. The first one is a standard sink/source approach. The second one, Discretized Wellbore model (DW) is more sophisticated and attempts to overcome some deficiencies of the first model. It also considers fluid and heat flow in the wellbore. The focus of this paper is on the second model, however, a brief description of a sink/source model is also furnished for completeness.

Sink/Source Model

In a sink/source (SS) model, flow from/to a reservoir is represented by a single term in reservoir flow equations. Steady state flow is assumed to be in the wellbore, i.e., there is no wellbore storativity. Only one equation per completion (layer) is solved with a bottom hole pressure as a primary variable. It means that only the pressure distribution due to gravity is known in the wellbore, but not the composition nor the temperatures distribution. This poses numerical difficulties when some layers in a well are producing and some injecting. Heat conduction between a wellbore and a reservoir is also neglected. Fluid flow from/to a reservoir is calculated from Equation (1)

$$q_j = \mathrm{WI}\,\lambda\left(p_w - p_{ij}\right) \quad j = w,o,g \qquad (1)$$

WI is a well index that describes the geometry of a specified wellbore. It may be calculated according to Peaceman[4] and takes into account the reservoir heterogeneity. λ represents fluid mobility and has a different meaning for an injector or a producer. When fluid is injected, λ would be the total mobility of a grid block. When fluid is produced, λ would be the mobility of each phase produced from a grid block.

Discretized Wellbore Model

A DW model may be used for wells in the horizontal or vertical direction as well as for undulating or deviated wells. Wells may also be regular or with circulating fluid (tubing and annulus).

A wellbore in the DW model is discretized in the same fashion as a reservoir, that is, each wellbore section is treated as a grid block and the completion to the reservoir is handled as an interblock connection. The fluid flow equation for each component as well as the energy equation are solved in each grid block the same way as equations describing flow in the reservoir. Grid fluid as well as rock-fluid properties must be assigned to the wellbore. Some of these properties are read in as data and some are calculated internally (e.g., porosity, permeability). Wellbore porosity is set to one, initial permeability is calculated from the Hagen-Poiseuille equation for laminar flow in a pipe as $r_w^2/8$. To calculate annulus permeability in a circulating well, an incompressible, laminar fluid flow in a steady state in an annular region is considered. Bird et. al[5] evaluated the average velocity for annular flow as

$$\bar{v} = \frac{\Delta\phi}{L\mu}\frac{r_a^2}{8}\left(\frac{1-R^4}{1-R^2} - \frac{1-R^2}{\ln 1/R}\right) \qquad (2)$$

with $R = \frac{r_w}{r_a}$

From equation (2) annulus permeability may be determined as

$$k_a = \frac{1}{8}\left(r_a^2 + r_w^2 - \frac{r_a^2 - r_w^2}{\ln r_a / r_w} \right) \quad \text{(3)}$$

When flow becomes turbulent (Re > 2,100), permeabilities are updated in such a way that the wellbore hydraulics are captured and flow equations still have the form of Darcy's law[3]. Permeabilities together with other grid dimensions are used to calculate transmissibilities for convective mass and heat flow. Transmissibility between a horizontal wellbore (or annulus) and a grid block containing a well is calculated according to Peaceman[4].

$$T_{wb} = \frac{2\pi d_i \sqrt{k_k k_j}}{\ln r_e / r} \quad \text{(4)}$$

r_e is an effective drainage radius and is evaluated as

$$r_e = \frac{\left[d_j^2 \sqrt{k_k / k_j} + d_k^2 \sqrt{k_j / k_k} \right]^{1/2}}{\left(k_k / k_j\right)^{1/4} + \left(k_j / k_k\right)^{1/4}} \quad \text{(5)}$$

Transmissibility between a tubing and an annulus in a circulating well is determined from a cylindrical flow pattern as

$$T_{ta} = \frac{2\pi d_i k_a}{\ln r_e / r_w} \quad \text{(6)}$$

where $r_e = r_w \exp\left(\frac{r_a^2}{r_a^2 - r_w^2} - 0.5 \right)$

Because well permeability in a perpendicular direction to the flow is not known, it must be chosen in such a way that there is a very small pressure drop between tubing and annulus at the toe of the well, but it should be low enough not to cause numerical problems.

Transmissibility for conductive heat transfer is calculated according to Equation (4) or (6) by setting permeabilities to one. Only heat conduction is considered between tubing and annulus along a circulating well except at the toe, where fluid is discharged from a tubing to an annulus.

Generally, rock-fluid interaction in the wellbore is described by straight line relative permeability curves without capillary pressure. Specification of initial conditions in the wellbore will determine whether transient behaviour will be simulated or wellbore conditions are immediately in pseudo-steady state. An option to initialize the wellbore automatically to the pseudo-steady state is available.

Wellbore Hydraulics

Some processes, such as Steam-assisted Gravity Drainage (SAGD), applied to heavy oil or tar sands reservoirs may be strongly affected by wellbore hydraulics when the driving force in a reservoir has a magnitude similar to frictional forces in a wellbore. Therefore, one of the major functions of a DW model is to describe reasonably well the frictional pressure drop in a wellbore. Frictional pressure loss is considered in both laminar and turbulent flow regimes. In laminar flow, friction factor f = 64/Re is directly built into permeability calculation. In a turbulent flow regime, frictional pressure drop is determined according to Dukler et al.[6]

$$\frac{\partial p}{\partial i} = \frac{2 v_t^2 f_{tp} \beta}{D_h \rho_m} \quad \text{(7)}$$

The two phase (liquid-gas) friction factor f_{tp} is a product of a single phase friction factor and a correlation coefficient that depends on a liquid volume fraction. The single phase (homogeneous) friction factor is calculated from Colebrook's equation[7].

$$\frac{1}{\sqrt{f}} = 4 \log \frac{1}{2\varepsilon} + 3.48 - 4 \log \left(1 + \frac{9.35}{2\varepsilon \, \mathrm{Re} \sqrt{f}} \right) \quad \text{(8)}$$

β is a dimensionless coefficient that depends on liquid holdup. Liquid holdup (void fraction) represents a slip between gas and liquid phase. Its magnitude depends on the flow regime, i.e., the amount of each phase present as well as phase velocities. Liquid holdup Rg is predicted from Bankoff's correlation as

$$\frac{1}{Y} = 1 - \frac{\rho_l}{\rho_g}\left(1 - \frac{K}{Rg} \right) \quad \text{(9)}$$

The correlation parameter K is a function of Reynolds number, Froude number and a flowing liquid volume fraction. It may attain values from 0.185 to one.

Absolute permeabilities in the wellbore are updated each time step to consider the friction losses. To be able to obtain an expression equivalent to Darcy's velocity, permeability in turbulent flow is calculated as:

$$k = \mu_m \left[\frac{D_h}{2\rho_m f} \frac{1}{\Delta\phi / \Delta x} \right]^{1/2} \quad \text{(10)}$$

Contrary to laminar flow, where permeability depends only on the wellbore diameter, in turbulent flow permeability becomes also a function of fluid properties and friction factor. Gas phase mobility is altered to account for the difference in liquid and gas phase velocity, i.e., gas relative permeability is augmented by the ratio of gas saturation and void fraction Rg. This operation relates the liquid holdup calculated from pipe flow equations to saturation needed in flow equations in porous media.

$$kr_g^{n+1} = \alpha^{n+1} Sg^{n+1} \quad \text{(11)}$$

where

$$\alpha^{n+1} = \alpha^n \frac{Sg}{Rg}, \ \alpha^0 = 1 \ \text{and n = time step number}$$

Wellbore hydraulics may be used in wells with co-current upward or horizontal flow due to the chosen correlations, particularly for the liquid holdup evaluation.

Wellbore Initialization to Pseudo-steady State Conditions

Initial conditions in a wellbore will determine the short term behaviour of a reservoir in the vicinity of a well. When a wellbore is initialized to conditions such that transient effects are simulated in the wellbore, the large changes of pressure, saturation, temperature and composition will require small time steps with an increase in the total number of iterations. The effect of wellbore transients on numerical performance is larger in heavy oils or bitumen reservoirs than in conventional oil reservoirs due to very low oil mobility. It also seems to be more pronounced in injectors than producers. Simulation of the transient behaviour does not affect long term physical results for most of the processes used in EOR simulation. However, transients may be important in cyclic processes where the cycle duration is the same order of magnitude as the transient period. The transient period is generally longer for injectors. It will increase when low mobility fluid is injected or when low mobility fluid is originally in the wellbore. Simulation of wellbore transients is necessary in well test analysis.

Upon request, STARS will do automatic pseudo-steady state initialization in the discretized wellbore at the beginning of simulation and at each time when operating conditions are changed. When wellbore transients occur due to well communication, they can not be eliminated. Operating conditions such as pressure, rate, composition, etc., are taken into consideration during pseudo-steady state initialization. When constant bottom hole pressure is specified as an operating condition, this value is assigned as a wellbore pressure. When constant rate is specified as an operating condition then the grid block fluid mobility together with grid block pressure, geometry and the rate are used in calculation of wellbore pressure. Global composition of fluid is estimated either from specified injection composition or from a fluid flowing out of a grid block. Temperature is set to a grid block value for a producer or to a value specified in input data for an injector. The fluid is then flashed to obtain phase compositions. Special care must be taken in initializing circulating wells. Everytime, the downstream part of the circulating well, whether it is tubing or annulus, must be initialized to the same conditions as the upstream part of the well to avoid numerical problems. Total segregation of fluids is assumed in vertical wells. Pseudo-steady state initialization is very useful for cyclic processes (if the transients are not important) or in simulation where well operating conditions (composition, pressure and temperature) change often.

Results

Description of Test Problems

Three examples with different processes were chosen to show the effects of wellbore hydraulics on reservoir depletion. Additional effects such as reservoir heterogeneities, fluid segregation and pseudo-steady state initialization in the wellbore are also discussed.

Example no. 1 has two pairs of horizontal wells each 1 km long. Two bottom wells are completed in a high water saturation zone, which allows higher injectivity and faster well communication. Steam is cycled in each well for 260 days and later a SAGD process is applied. The reservoir contains bitumen. This test problem was chosen to study the influence of other wells on frictional pressure loss during well communication. Pressure drop in one of the bottom wells will be shown. It is 10 cm in diameter and 238.5 m3/day CWE of steam is injected or the same amount of liquid is produced. It is also a good candidate to demonstrate the effects of wellbore hydraulics when different processes are used in the same reservoir.

Example no. 2 describes a field in the Troll West Oil Province located offshore Norway[9]. It contains a thin layer of light oil that is sandwiched between an aquifer and a gas cap. 5,000 m^3/day of liquid is produced from a horizontal well 500 m long and 17 cm in diameter. The well is placed 3 m above the water-oil contact. The effects of wellbore hydraulics and heterogeneities on the gas cap movement are shown with this example.

Example no. 3 illustrates a steam-foam drive process in a massive multizone reservoir[10]. It represents a pilot conducted in Midway Sunset field in California. Steam is injected for five years into a reservoir through a vertical well that is perforated in the bottom two layers only. Later, surfactant is injected for another five years. Reservoir fluids are produced through a vertical producer that is perforated throughout the reservoir. The reservoir is 550 ft. thick and contains shales in the top part. Because of these parameters, it is a good example for gravity segregation, wellbore backflow as well as the effect of heterogeneities. Although this example has vertical wells, it shows the extreme situation for horizontal wells drilled from a surface. As mentioned earlier, wellbore hydraulics are not used with vertical wells due to disparity of the used correlation and a counter-current flow encountered in these wells.

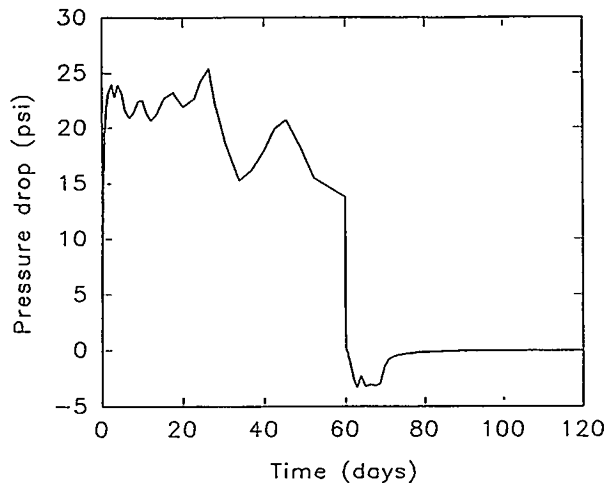

FIGURE 1: Frictional pressure drop.

Wellbore Hydraulics

Frictional pressure drop in a wellbore depends on parameters specified in Equation (7) such as relative roughness, flow rate, pipe diameter and fluid properties. In addition, pressure drop in a specified wellbore will be affected by neighbouring wells when they start communicating. Pressure drop values in a specified wellbore will change each time a neighboring well switches an operating constraint. The effect of perforations on wellbore flow is not considered in this paper. For homogeneous flow in a single well, pressure drop may be easily predicted from Equation (7) using single phase parameters. However, for communicating wells the pressure drop estimation is not so straight forward. Figure 1 shows the pressure drop in a 1 km long well (example No. 1). The calculated pressure drop of about 23 psi before well communication (up to 30 days) corresponds roughly to literature values for pressure drop in steam pipes[11]. Pressure drop along a wellbore depends not only on the wellbore hydraulics but also on the operating conditions of adjacent wells when they communicate. This could be seen by the erratic behaviour between 20 to 45 days which is caused by constraints switching in neighbouring wells. Two phase fluid (oil/water + steam) flows in the well for the first 10 days of the production cycle. Later, colder less mobile oil will be produced.

Wellbore Initialization

Wellbore initialization to a pseudo-steady state is very important from a numerical and CPU timesaving point of view. CPU savings for an injector depend on the mobility of an injected fluid as well as the initial mobility of a reservoir and a wellbore fluid. The most savings will be for water or steam injection into a heavy oil or bitumen reservoir or a high viscosity fluid injection such as polymer. The duration of a transient period is also controlled by reservoir heterogeneities. Even though the transient state may last only for several days, which is a negligible time in a field simulation, the CPU time needed to achieve the pseudo-steady state may be 70% to 80% of total CPU time; sometimes in a complex process it may cause non-convergence.

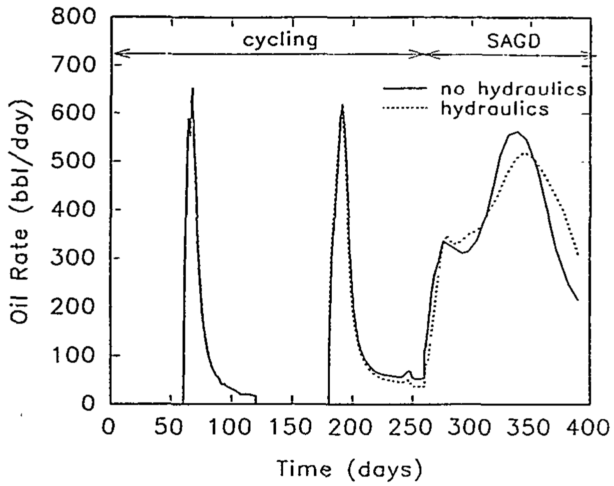

FIGURE 2: Effect of wellbore hydraulics.

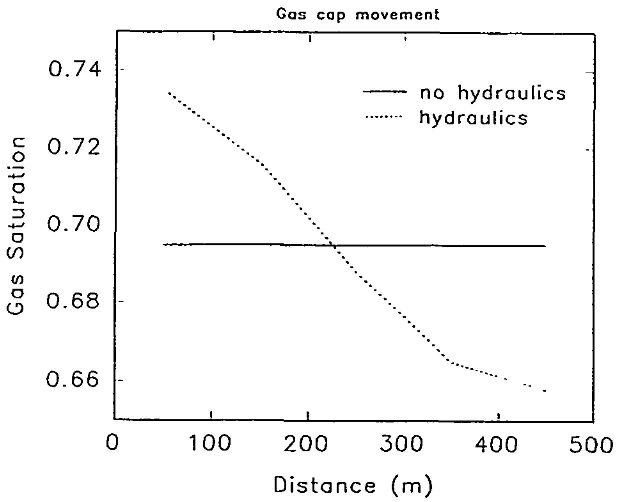

FIGURE 3: Effect of wellbore hydraulics.

The transient behaviour in example No. 1 (steam injection into a bitumen reservoir) lasts for about half a day but total CPU time is 1.6 times higher than for pseudo-steady state initialization. In example no. 3 the transients last for about five days even though the oil is less viscous and CPU time is 2.24 times higher. In this case reservoir heterogeneity and steam segregation in the wellbore dominate the initial behaviour. When the transients are simulated only in a producer and an injector is initialized to a pseudo-steady state the difference in CPU time is minimal (10% increase). The same behaviour was observed in the other two examples which means that an initialization of producers may not be very critical.

Comparison of Sink/Source and Discretized Wellbore Model

The question may arise, when is the SS model sufficient and when should one use the discretized wellbore model? The answer is not so simple and straightforward but the following points may be used as guidelines in the decision making process. An SS model may be adequate:

1. For reservoirs with reasonable injectivity where the effect of heat conduction between a wellbore and a reservoir is negligible. Injectivity is very low in heavy oil or tar sand reservoirs without bottom water and therefore oil may be initially mobilized only by heat conduction which is not possible with an SS model.
2. For processes with small flow rate or big pipe diameters where frictional pressure drop is almost nonexistent.
3. For short horizontal wells with a possibility of homogeneous fluid along a wellbore.
4. For homogeneous reservoirs where wellbore-reservoir communication is uniform.
5. For vertical wells where fluid segregation is minimal.
6. For reservoirs which have much higher pressure drawdown than the expected frictional pressure drop.

For any other case the discretized wellbore model should be used. However, one has to be aware of possible numerical difficulties due to drastic PVT behaviour and increased non-linearities. A wellbore does not contain rock to buffer the effect of temperature and when pressure and temperature conditions are close to saturated values every small change in them will cause phases to appear or disappear. In a reservoir, rock will absorb the marginal fluctuation in energy and therefore transition between phases is smoother.

As mentioned earlier, the DW model has two major roles. First, it considers wellbore hydraulics and secondly it improves modelling of certain phenomena that are not captured in the SS model. In the following section, the effects of wellbore hydraulics, fluid segregation and backflow are discussed. The influence of reservoir heterogeneities is also examined.

Effect of Wellbore Hydraulics

The significance of wellbore pressure drop on reservoir performance depends on the specific EOR process as well as the scale, i.e., lab or field. Generally, when the pressure drop between an injector and a producer is the same order of magnitude or less than the wellbore pressure drop, then the hydraulics will play a significant role. It means, that for example, gravity drainage processes will be affected more than steam drive processes. In laboratory experiments using a SAGD process even wellbore pressure drops of less than 1 kPa may be important.

Figure 2 shows oil rate for a bottom left well from an example No. 1 for an SS and DW model. The effect of pressure drop in the wellbore is minimal during the first 260 days when the well operated in cyclic mode, although the frictional pressure loss is about 20 psi (590 psi in the reservoir). Later, when a SAGD process was applied, pressure drop in the reservoir stabilized to about 5 psi and differences in the produced oil were observed.

Wellbore hydraulics is also important in reservoirs with coning problems. Figure 3 shows the gas saturation in reservoir grid blocks along a well after one year of production for example No 2. In an SS model the gas cap moves uniformly towards the wellbore (solid curve). Due to frictional pressure loss (around 15 kPa in this example) more gas is drawn at the heel of the well which results in a non-uniform gas cap movement and an earlier gas breakthrough time (around 10 days).

The effect of frictional pressure drop in example No. 3 is not considered due to unsuitability of the used correlation for countercurrent flow.

Backflow in the Wellbore

Backflow (production of fluid through some perforation and injection through another in the same well) may occur in long wells when the pressure drop along the wellbore is much smaller (higher for a producer) than the pressure drop in corresponding reservoir grid blocks. This situation happens when a well is perforated in regions with different permeability and/or fluid mobility. Because of this, vertical or inclined wells experience backflow more often than horizontal wells. Horizontal wells must be highly undulated for backflow to occur. To be able to treat backflow properly, it is necessary to know the fluid composition in the wellbore. In a standard SS model this information is not available and hence numerical problems will be encountered when an incorrect composition is used. A standard SS model will converge to unphysical values in situations with a severe backflow problem. Various enhancements have been proposed to improve the physical and numerical results[12]. In the STARS SS model, the backflowing layers are automatically shut-in and reopened again when backflow stops. In a DW model, pressure, temperature and composition in the well are evaluated at each iteration and therefore

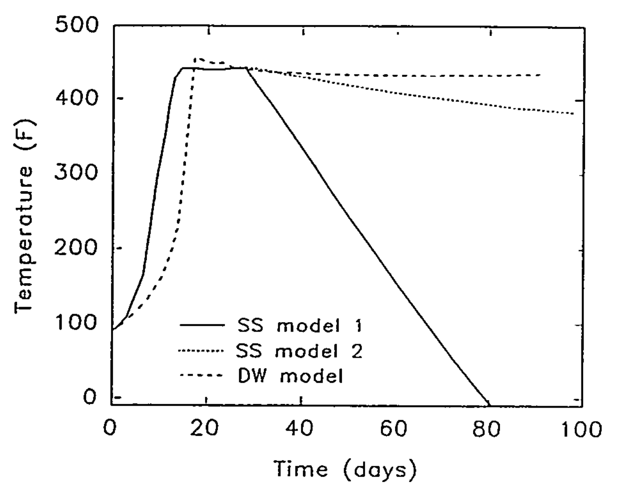

FIGURE 4: Backflow in a bottom injector layer.

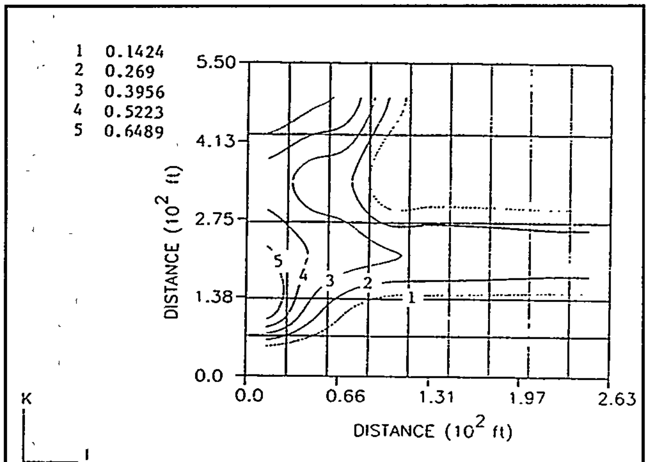

FIGURE 5: Effect of fluid segregation—DW model Gas Saturation after steam injection.

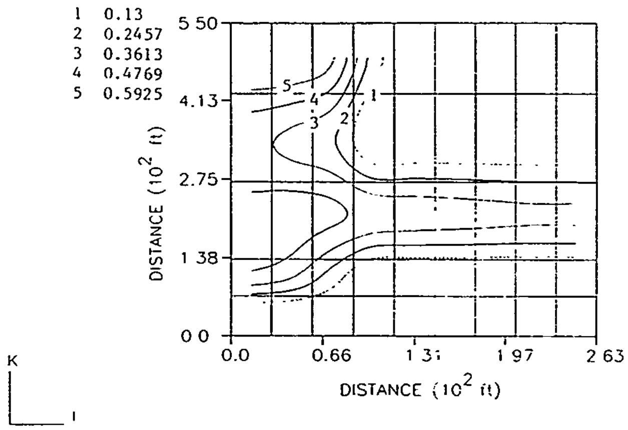

FIGURE 6: Effect of fluid segregation—SS model Gas saturation after steam injection

the backflow situation could be treated correctly.

Figure 4 shows temperature in a bottom layer of a 42 m long vertical injector perforated in a layered reservoir (example no. 3). After 30 days of injection the bottom layer starts producing and temperature falls below initial reservoir temperature when an SS model is used (curve 1). When a backflowing layer is shut in, temperature will still decrease but the value is not unphysical (curve 2). On the other hand, temperature decreases very little during the backflow and then stabilizes when a DW model is used (curve 3). The duration of the backflow period also varies. In a DW model it lasts for about 20 days, while in an SS model the backflowing layer remains shut in for the entire steam injection time. The pressure distribution changes when surfactant is being injected and the shut in layer opens.

Effect of Fluid Segregation in a Wellbore

One of the assumptions in an SS model is homogeneous fluid flow along a well and therefore gravity does not have any effect on composition. In reality, the fluid in a well will segregate due to gravity especially in long vertical wells. This phenomenon is correctly captured by a DW model. Segregation in a wellbore has two consequences:

1. A change in gravity head due to different phase densities; the pressure drop between a wellbore and a reservoir will be different, resulting in a variation in the amount of injected or produced fluids.
2. Selective injection through specific layers when components soluble only in one phase are used (e.g., water soluble surfactant will enter the reservoir mostly in the bottom layers where water saturation is high and pure steam will be injected at the top).

Example no. 3 is used to illustrate these effects. During a steam injection period several phenomena occur as could be seen on gas saturation profiles in Figures 5 and 6:

a) Due to the above mentioned backflow in the SS model, the specified steam rate is injected only to layer 4 (bottom layer is shut in) and therefore temperature is lower in the bottom layer. In a DW model the rate is split between both layers. Hot water at saturation temperature is injected into a bottom layer and 100% steam into a layer above (layer 4). Therefore, steam breaks through about 110 days earlier with the SS model than with the DW model.
b) Steam front at the reservoir top moves faster with the DW model due to additional heat conduction through the uncompleted top three layers.

After five years of steam injection, steam and surfactant are being injected for another five years. Water soluble surfactant will enter the reservoir through both layers of the SS model but only through the bottom layer of the DW model. In both cases, relatively high oil saturation prohibits foam creation. Surfactant flows upwards to layer 3 which has oil saturation less than the threshold values for foam creation and therefore it foams there. Later, oil saturation in layers 4 and 5 will reduce below the critical value and foam will also be formed there. The flow path is affected by surfactant concentration in layers 4 and 5 as well as the fluid segregation in a producer. Figures 7 and 8 show foam distribution after 10 years. The foam moves more diagonally towards a producer with the DW model. With the SS model, it moves like a sphere. Saturation distribution looks very different contrary to steam only injection. There is a tendency to sweep the reservoir top better with the DW model. The surfactant break through time, which is an observable characteristic in the field, is delayed for about 600 days due to fluid segregation with the DW model as could be seen in Figure 9.

Fluid segregation may be also observed in highly undulating wells or horizontal wells drilled from surface. In the latter case, only heavier fluids may enter the reservoir through the horizontal part of the well. This may cause less energy to be injected into the reservoir in processes with steam injection.

Effect of Reservoir Heterogeneities

Reservoir heterogeneity may enhance or diminish the effects of wellbore hydraulics. It should be taken into consideration when horizontal wells are drilled because the reservoir behaviour is different when a well is drilled from a more permeable region as opposed to a less permeable region.

When reservoir heterogeneity is parallel to a well direction it will either delay or accelerate fluid flow into a wellbore but will not alter the uniform movement. The shape of a fluid front flow-

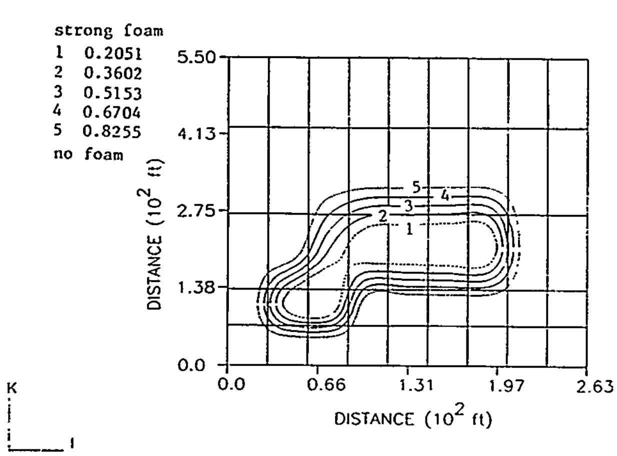

FIGURE 7: Effect of fluid segregation—DW model. Foam distribution after 10 years of steam and surfactant injection.

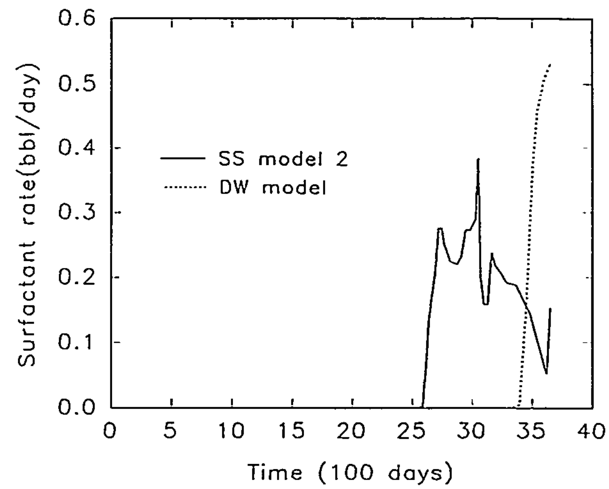

FIGURE 9: Effect of fluid segregation.

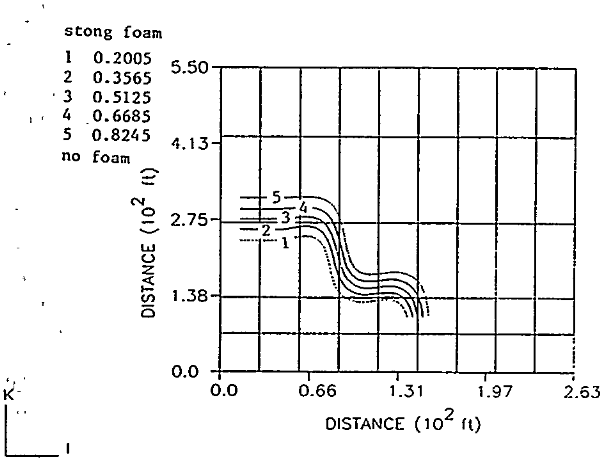

FIGURE 8: Effect of fluid segregation—SS model 2. Foam distribution after 10 years of steam and surfactant injection.

ing into a wellbore will depend mostly on pressure drop in a wellbore as could be seen in Figure 3. However, when a reservoir has discontinuous shale barriers which are shorter than a well length then the fluid front will be also affected by them.

When reservoir heterogeneity is perpendicular to a well direction, it introduces instability to the uniform front movement in a reservoir, e.g., uneven steam chamber growth in a SAGD process, shift in break through time, etc. These instabilities may be enhanced or reduced by other forces such as gravity for vertical or deviated wells or friction in horizontal wells. First, we will compare results of example no. 3 with and without shale barriers in the top two reservoir layers. Due to gravity effects, the steam override and fluid distribution in the reservoir is different. In the heterogeneous case, steam breaks through a different layer and reaches it faster than in the homogeneous case. This difference occurs because steam in the former scenario travels a shorter upward vertical distance. The cumulative oil production during steam injection is the same in both cases as could be seen in Figure 10. However, it changes dramatically during the surfactant injection period due to dissimilar fluid distribution and foam formation tendency. In the homogeneous case, areas with sufficient surfactant concentration have also fairly high oil saturation and therefore foam can not be created and sweep efficiency improved.

In reservoirs with horizontal wells, where gravity forces are negligible in comparison with frictional pressure drop along a wellbore, results will also depend on the drilling strategy. When a well is drilled from surface in the region of low permeability, gas breakthrough as well as fluid distribution will be different than drilling it in the high permeability region. Figure 11 shows a gas cap front movement in a modified example no. 2 (permeability varies along a well k1 = 2.1D, k2 = 6.4D, k3 = 3.3D, k4 = 8D, k5 = 13.7D). Without a pressure drop in the wellbore (curve 1 – SS model) gas front movement is affected only by the heterogeneities and is independent of drilling strategy. When frictional pressure drop is considered, the non-uniformity of the gas front is increased when the well is drilled from a low permeability region

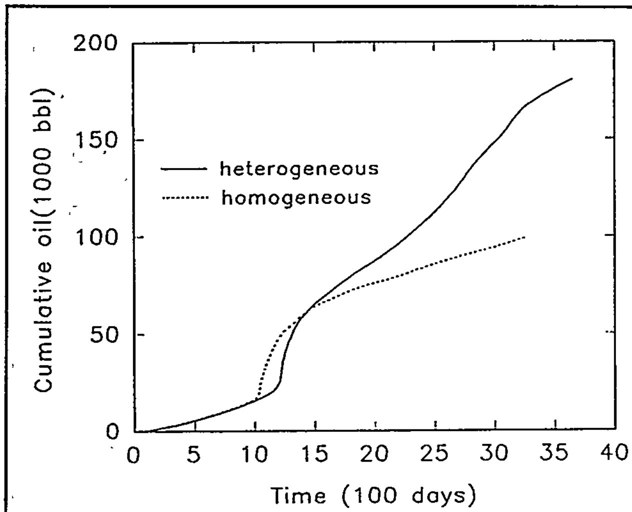

FIGURE 10: Effect of reservoir heterogeneity.

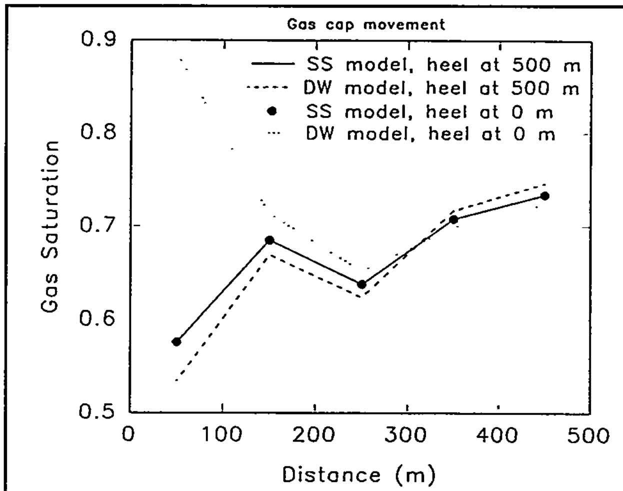

FIGURE 11: Effect of drilling strategy in heterogeneous reservoirs.

(curve 3 – DW model). When a well is drilled from a high permeability region (curve 2 – DW model), frictional pressure drop will decrease (8 kPa vs. 18 kPa) due to easier drawdown at the heel of the well. Gas saturation profile is similar to an SS model. The effect of heterogeneities on oil production was minimal in this example. However, if an EOR process would be applied after the primary production, differences would be apparent due to different fluid distribution in the reservoir.

Conclusions

1. Frictional pressure loss can not be correctly predicted from an analytical solution when wells communicate or two phase flow with varying properties is present.
2. Wellbore initialization to a pseudo-steady-state is important for injectors.
3. Frictional pressure drop in the wellbore is significant in a process when forces (viscous, gravitational, etc.), in a reservoir are smaller or the same order of magnitude as friction in a wellbore.
4. Fluid segregation in a wellbore will alter fluid distribution in a reservoir. This phenomenon should be considered when processes with a phase preferential component dissolution are used.
5. Attention should be paid to the drilling strategy in heterogeneous reservoirs.

NOMENCLATURE

D_h	= hydraulic diameter (m)
d_i	= gridblock size in i direction (m)
f	= friction factor
k	= permeability (m^2)
kr	= relative permeability
L	= wellbore length (m)
p	= pressure (kPa)
p_w	= wellbore pressure (kPa)
q	= flow rate (m^3/day)
r_a	= annulus radius (m)
Re	= Reynold's number
Rg	= void fraction
r_w	= wellbore radius (m)
Sg	= gas saturation
v_t	= total mass velocity per unit area (kg/m^2 day)
Y	= flowing liquid volume fraction
β	= dimensionless coefficient
ε	= relative roughness
$\Delta\Phi$	= potential difference (kPa)
λ	= mobility (1/kPa day)
μ	= viscosity (kPa day)
ρ	= density (kg/m^3)

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