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Flexible Wellbore Model Coupled to Thermal Reservoir Simulator

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Abstract

In the past decade drilling techniques have become more sophisticated and allow more complex wellbore configurations. Consequently, simultaneous wellbore and reservoir simulation is important for many processes and necessary for some.

This paper describes a wellbore model (Flexible Wellbore) that is solved independently but is fully coupled with a thermal reservoir simulator. The wellbore can contain up to three tubing strings in an annular space, and each flowing stream may be an injector or a producer operated at various conditions. There are no restrictions on tubing lengths or how the wellbore intersects the reservoir grid. The flow regime is a function of liquid and gas velocities for each flowing stream and is used to calculate frictional pressure drop as well as axial and radial heat transfer. The model also handles transient wellbore behavior which may be significant for cyclic processes. Also discussed is fluid segregation which is relevant in slanted and undulating wellbore.

Introduction

In the past heavy oil producers focused on in-situ reservoir processes to improve economics then later realized that wellbore behavior also affects the economics. As a result, modeling of advanced wellbore effects has become a high priority. In the conventional Sink/Source approach the only variable that is evaluated is bottom-hole pressure (BHP). A well perforated in several layers links them together with a hydrostatic head based on an average fluid density. Over the years a number of improvements were added to the conventional Sink/Source approach, such as friction pressure drop and heatloss calculation. A homogenous cross-flow model was also incorporated as an alternative to the original zero flow. Back-flowing fluid is mixed and handled as a homogeneous fluid due to limited information. This approach is sufficient in many cases. However, it is not valid for modeling multilateral wells.

Several simulators[1,2,3] used various approaches to model the complex behavior. A very informative paper[4] describes all current wellbore models

Model Description

Flexible Wellbore (FW) models a collection of up to 3 tubing strings in an annular space that runs in any direction (vertical, horizontal, slanted, undulating) locally, with possible laterals. The tubing strings may have various lengths, may be fully or partially insulated and may have varying diameter along the length. The annulus may have casing, cement and varying diameter along the length. Radial heat flow is affected by wall thickness, insulation and cement.

Multiple tubing strings communicate with each other through the annulus. Normally each tubing string exchanges fluid with the annulus at the tubing toe only, but there is an option to do so at different sections along the tubing. Radial conductive heat transfer between tubing and annulus is along the full tubing length. Each flowing stream may be operated as an injector or a producer at various operating conditions.

Annulus and tubing string are divided into sections according to perforations specified in the data. Equations corresponding to all streams and sections of each FW are solved simultaneously; each FW equation set is solved separately from each other and independently from the reservoir. Spatially, all Flexible Wellbores are fully coupled to the reservoir through an annulus-reservoir flow term.

The following equations are solved for each section in each stream.

Fluid phase momentum and energy balance equations are used to calculate the friction pressure drop as well as the conductive radial heat flow.

$$-\frac{dP}{dL} = \rho_m V_m \frac{dV_m}{dL} + \rho_m \frac{dF}{dL} + g\rho_m \sin\theta \tag{1}$$

$$-\frac{dH_m}{dL} = V_m \frac{dV_m}{dL} + g \sin\theta - \frac{dQ}{dL} \tag{2}$$

A mechanistic model is employed to calculate the pressure drop. First a flow regime[5,6] is determined according to gas and liquid velocities and flow direction, then friction pressure drop and liquid hold-up[7] are evaluated. Radial heat transfer rate Q is a product of an overall heat transfer coefficient and a temperature difference between adjoining wellbore parts. The overall heat transfer coefficient is the inverse of heat resistance in series through:

a) tubing fluid
b) tubing wall
c) annular fluid
d) annular wall
e) reservoir block

Conductive resistance through the tubing/annulus wall depends on the wall thickness and metal conductivity, which are constant during the run. On the other hand, conductive resistance of fluids and reservoir block depend on the fluid composition, which can change during the simulation. Tubing/annulus fluid resistance also depends on fluid velocities (faster fluid movement results in higher heat transfer) since dimensionless Reynolds, Nusselt, etc. numbers are used in the calculations.

Mass of each chemical component as well as energy is conserved. This is necessary for modeling fluid segregation and transient behavior in the wellbore.

Component conservation equation for each section:

$$\sum \rho_p V_p m_{p,i} = B \frac{\partial}{\partial t}\left[\varphi_f \sum \rho_p S_p m_{p,i}\right] \tag{3}$$

Energy conservation equation for each section:

$$\sum \rho_p V_p H_p + \text{conductive heat}_{\,l,r} = B \frac{\partial}{\partial t}\left[\varphi_f \sum \rho_p S_p U_p + \varphi_w U_w\right] \tag{4}$$

The Flexible Wellbore model was implemented in STARS, the Computer Modelling Group's thermal and advanced processes reservoir simulator. In this paper "Sink/Source well model" refers to the sink/source type of well model as implemented in STARS.

Time coupling (as opposed to spatial coupling) is not fully implicit, that is, all the above equations are not solved simultaneously with the reservoir equations. Instead, the following is done during each Newton iteration of the coupled non-linear reservoir equations. First, the FW equations are solved assuming constant conditions in the surrounding reservoir region (perforated cells). This surrounding region is involved only in the annulus-reservoir flow terms. Each FW equation set is solved simultaneously and iteratively to a tight convergence tolerance using Newton's method. All the FW are processed separately in sequence. The FW solution consists of the conditions (pressure, temperature, phase saturations and compositions) in each section of each stream, including the annulus.

Secondly, the Newton iteration of the reservoir equations is done assuming constant conditions in the annulus of each FW when calculating the annulus-reservoir flow terms. The Flexible Wellbores are solved with the same timestep size as the reservoir equations. Therefore, a candidate for timestep size is estimated for each Flexible Wellbore as well as the reservoir, and the minimum size is chosen for the next time step. Consequently, a FW run may use smaller time steps than the corresponding non-FW run.

In the context of the iterative solution of non-linear reservoir equations, the FW model works like an analytical property or function since the result is deemed an exact solution of the FW equations. The FW solution lags the reservoir equation solution by an iteration, so the FW derivatives are not included in the iteration of reservoir equations. However, the annulus-reservoir flow term, with parameters alternating between constant and variable, works as an efficient interface between the FW and reservoir equations. This method compares favourably with the sink/source well model which actually is more implicit (well equation and BHP are solved simultaneously with reservoir equations).

Annulus-reservoir communication is along the full wellbore length. Whether the exchange is both fluid and heat depends on the data input. When a perforation is specified as closed then only conductive heat is transferred; when a perforation is open then fluid and its convective heat can flow.

During solution of the FW equations there is enough information about the wellbore conditions that cross flow, phase segregation and transient behavior can be handled correctly. In some processes or wellbore configurations these mechanisms are quite important to both the well and reservoir solution.

The Flexible Wellbore model is able to handle wellbore plugging by solids. This mechanism is important for the THAI (Toe-to-Heel-Air-Injection) process. Solid (coke in THAI) is created by reaction only, and as it deposits it reduces the hydraulic diameter and impedes the fluid flow.

Each stream in a Flexible Wellbore is operated or driven independently of the other streams. A stream's operating condition applies at a single reference location (entry for injector, exit for producer). For example, a producer's maximum-steam constraint is applied at the exit point, so steam that breaks through at the toe and condenses before reaching the heel does not trigger the constraint. In contrast, a Sink/Source well that applies the same constraint on a per-section basis will trigger the constraint immediately upon steam breakthrough at the toe. The Flexible Wellbore treatment is more correct physically.

Application

Flexible Wellbore should be used when the wellbore flow is more complex and significantly impacts the reservoir behavior. The following table compares capabilities of the Sink/Source well and Flexible Wellbore models:

	Sink/Source	Flex Well
Gravity	Explicit head	implicit
Fric-heatloss	optional	automatic
Cross flow W-R	optional (very simple)	automatic
Trajectory	optional	optional
Multilaterals	optional	optional
Transients	№	automatic
Fluid segregation	№	automatic
Tubing	№	max 3
Wellbore Heatloss and friction, wellhead to pay top	optional	optional
Orifice flow A-R	optional	optional
Orifice flow T-A	№	optional
Well plugging by solids	№	optional

W - wellbore　　A - annulus
R - reservoir　　T - tubing
№ - not possible　　optional – can be invoked with data

Table 1: Capabilities of Sink/Source and Flexible Wellbore models

The Flexible Wellbore model will be most useful for processes that need tubing(s), fluid segregation, correct cross-flow handling, well plugging and transient behavior. Most of these mechanisms are important in a Steam Assisted Gravity Drainage (SAGD) process, and so this process will be used as an example.

The SAGD process utilizes a wellbore pair, the top wellbore serving as an injector and the bottom wellbore as a producer. Those wellbores may be truly horizontal wells or they could undulate, and lately slanted wells have become more popular. In a reservoir with limited fluid mobility the first step is to establish communication between the wellbores. Generally steam is circulated (inject into tubing, produce from annulus) in each wellbore separately, so the near-wellbore region is heated initially by conduction only. As the oil warms up it becomes more mobile and eventually steam is able to flow into the reservoir.

Because the Sink/Source model cannot handle a linked tubing-annulus configuration, most simulations mimic this behavior by adding heat via a heater option along with steam injection. This approach has two significant issues:

a) Heater model parameters may be estimated based on conduction through the walls and some constant fluid composition and temperature, but the effect of stream velocities is neglected. On the other hand, the Flexible Wellbore handles heat transfer dynamically

b) Getting the appropriate steam amount into the reservoir.

Three examples are chosen to compare the Sink/Source well and Flexible Wellbore approaches:

Example #1: Simple homogeneous reservoir with a uniform grid and completely flat wells. It has to be noted that the Sink/Source well model used also an option for friction and heatloss calculation. The same operating constraints are specified for both well models during the drainage portion of the run. The Flexible Wellbore produced fluids only from the bottom annulus.

Example #2: Complex reservoir geology with some shale and the wellbore has a single shallow slope. The top injector's operating constraint is either maximum BHP or maximum steam rate. The producer operates either on maximum liquid rate, maximum steam rate or minimum BHP.

Example #3: Same as Example #2 except that the wellbore undulates, with some perforations in the shale zone.

Example #1:

Figures 1 and 2 show temperatures at the end of the circulation period for the S/S well and Flexible Wellbore, respectively. The S/S well injector together with the heaters supplies more heat than the Flexible Wellbore, resulting in higher temperatures after circulation in the region between the wells. However, there is almost no difference in the net injection and production rates (slopes in Figure 3). Most of the difference in accumulation is expected: the steam injected into FW top tubing 'injtb' is returned through FW top annulus 'injan' during the circulation period, whereas the single S/S injector delivers what it can directly.

This example is perfectly horizontal, so gravity and phase segregation do not play a role in the wellbore. The difference in temperature increase after circulation does not have a significant effect in the results because most of the benefit of heating occurs in the first 40°-60° of temperature increase, which is achieved by both cases.

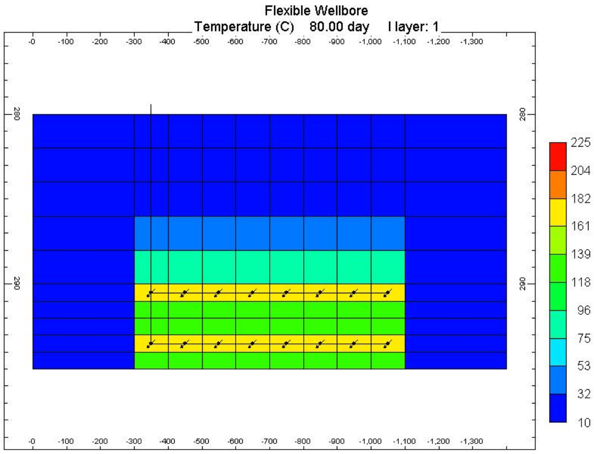

Figure 1: Temperature after circulation - Flexible Wellbore

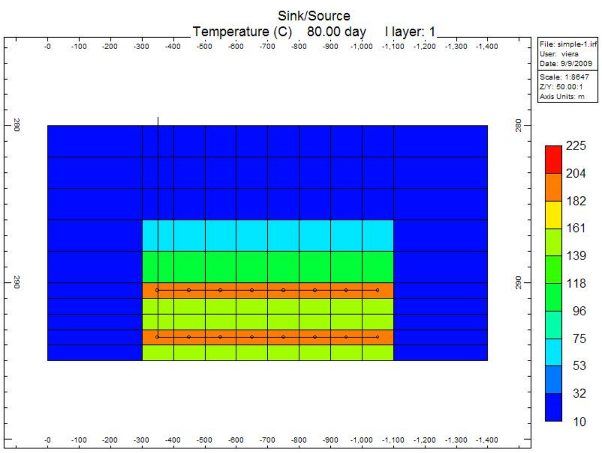

Figure 2: Temperature after circulation - Sink/Source well

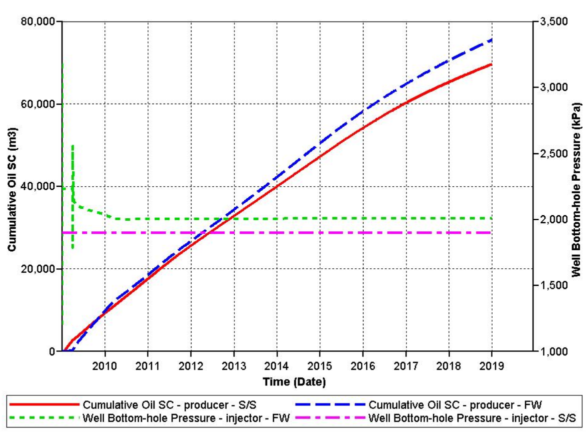

Figure 3: Comparison of cumulatives for S/S and FW models

Example #2:

Similar to the result of Example #1, the S/S model supplies more heat to the reservoir during the circulation period. However, heat as well as fluid moves differently in those two models as could be seen in Figures 4 to 9.

Pressure level (Fig. 5) is more uniform in the Sink/Source model because the same amount of heat is supplied via heaters to each section along the wellbore. On the other hand in the Flexible Wellbore model (Fig. 4), pressure is the highest around the toe of the wells and declines towards the heel. Injectivity is high around the bottom well due to higher permeabilities and water saturation.

Note that the white-filled cells in Fig. 4 have no pressure since they have no pore volume (shale). However, these cells do have a temperature (Fig. 6) since they account for heat storage and conduction.

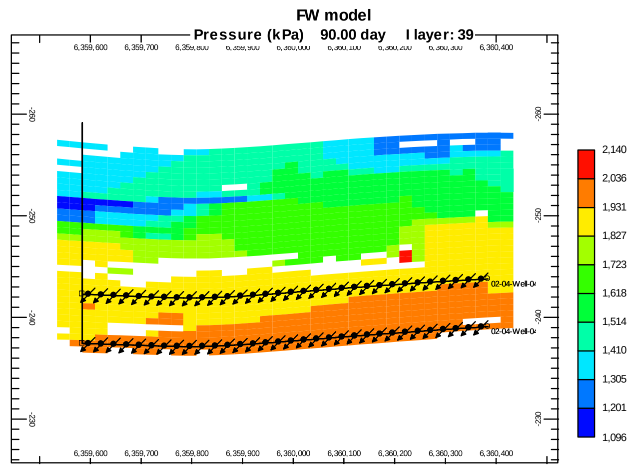

Figure 4: Pressure after circulation – FW model

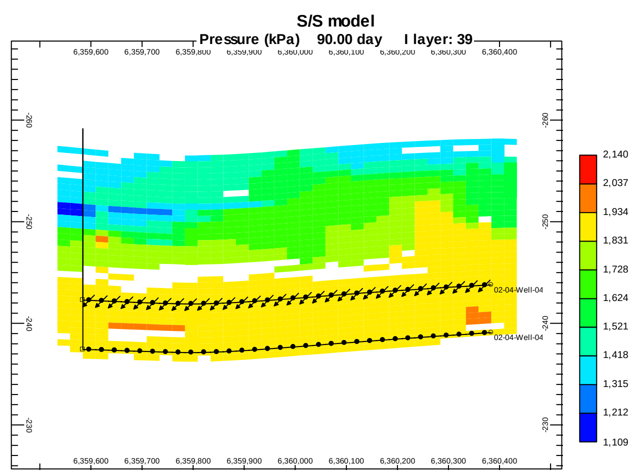

Figure 5: Pressure after circulation – S/S model

Temperature profiles seem to go the opposite direction. The Sink/Source well model (Fig. 6) has higher values around the toe and lower values towards the heel. This trend follows exactly the porosity profiles between those two wells. Heaters are the dominant factors in the Sink/Source model during the circulation period. For the same heat added, blocks near the toe have lower porosity, more rock, higher heat capacity and hence lower temperature. Lower porosity blocks also tend to have lower permeability and therefore less heat is supplied by convection.

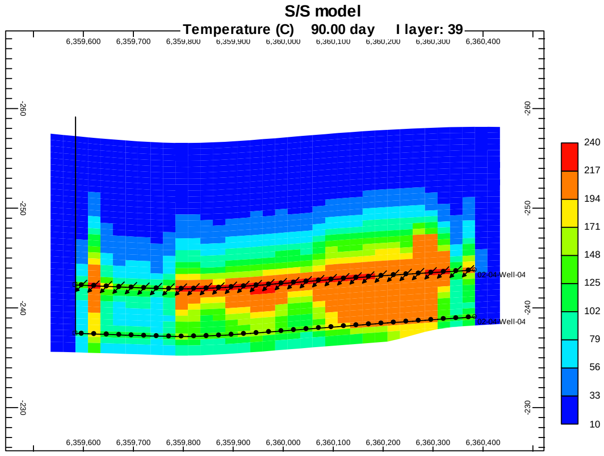

Figure 6: Temperature after circulation – S/S model

The Flexible Wellbore model (Fig. 7) shows a more uniform temperature distribution after the circulation period. In the Flexible Wellbore model the dominant factor during the circulation period is at first conductive heating then later convective heating dominates. This behavior can be seen in the bottom well. The temperature is higher around the toe where hotter fluid is discharged from the tubing and subsequently into the reservoir. Higher temperature is also seen around the heel. Annular fluid is hotter due to the higher conductive heat transfer from the tubing. The top well does not experience very much fluid flow because of very low permeabilities in the near well region. As a result, the temperature profile is more uniform.

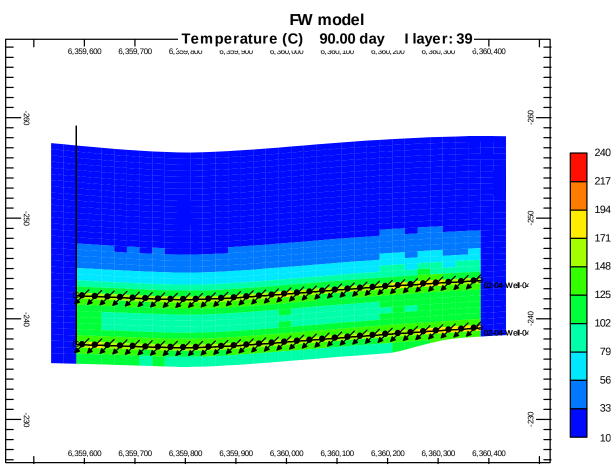

Figure 7: Temperature after circulation – FW model

The Flexible Wellbore did not encounter the porosity variation between the wells because at this time only the blocks where the well is located are heated. As more heat is supplied, the porosity effect eventually becomes apparent (Fig. 8).

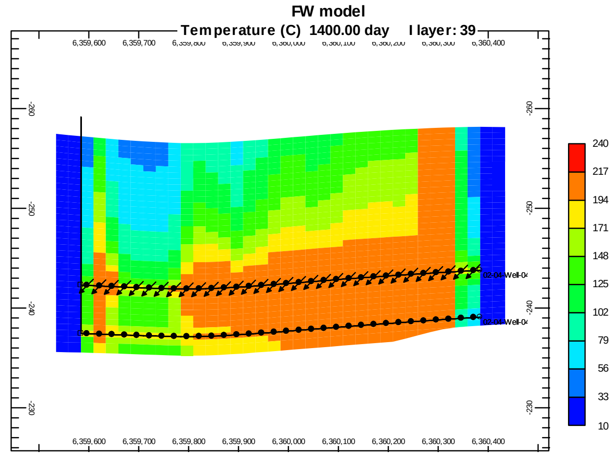

Figure 8: Temperature at 1400 days – FW model

The Sink/Source case used a conventional wellbore model without any special options such as friction pressure drop, heatloss and cross-flow calculations. On the other hand, the Flexible Wellbore model takes care of these mechanisms automatically. This different wellbore treatment might account for the temperature differences seen between Fig. 8 and 9.

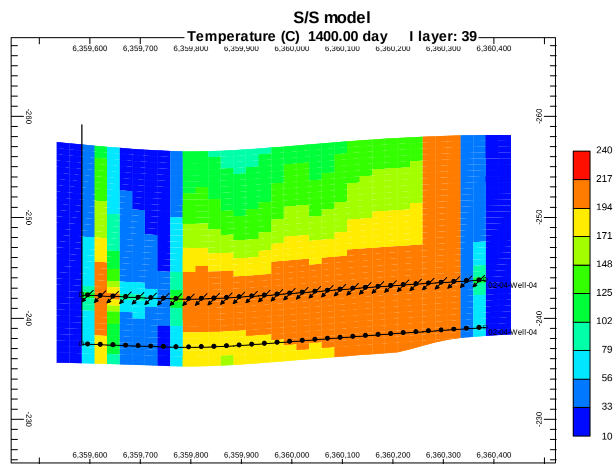

Figure 9: Temperature at 1400 days – S/S model

Figure 10 compares the cumulative oil production and injection bottom-hole pressure (BHP) between those two models. The injector operated mostly at constant rate and the producer at constant BHP. The producer's BHP was high enough not to trigger the steam rate constraint often. Around 6% more oil was produced with the Flexible Wellbore model.

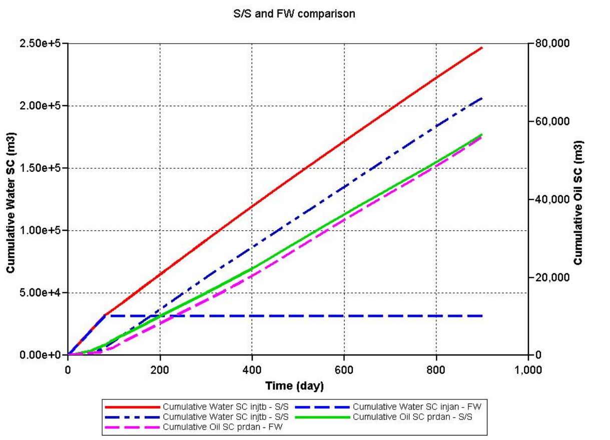

Figure 10: Well performance of FW and S/S models – Example #2

Example #3:

In this example, the reservoir and grid are the same as Example #2, but the top and bottom wellbores pass through shale (white-filled cells in Fig. 4) near the heel. After the circulation period, temperature behavior is very similar to Example #2. However, more differences between S/S and FW are seen at 1400 days (Fig. 11 and 12). First, the shale heats up faster with the Flexible Wellbore model (see blue area close to the S/S heel, Fig. 12) since the S/S case does not have conductive heat transfer to the shale. Second, the temperature variation between the top and bottom wellbore is quite different, due to fluid segregation and cross-flow (see green area near centre of FW wellbore, Fig. 11). The FW results respond to the wellbore fluid segregation. As in Example #2, the Sink/Source model did not use any optional features (Table 1).

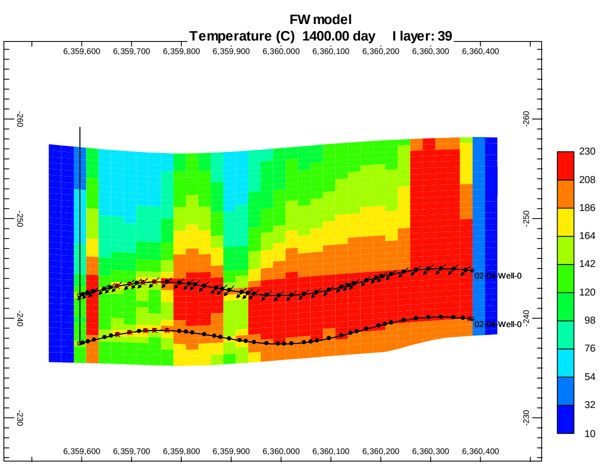

Figure 11: Temperature at 1400 days – FW model

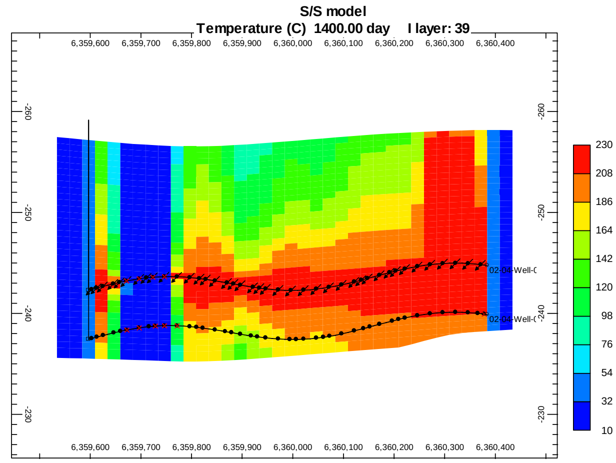

Figure 12: Temperature at 1400 days – S/S model

The Flexible Wellbore model produced 7% more oil after 10 years of production. Gas production difference is more pronounced especially after 2015 as can be seen on Figure 13.

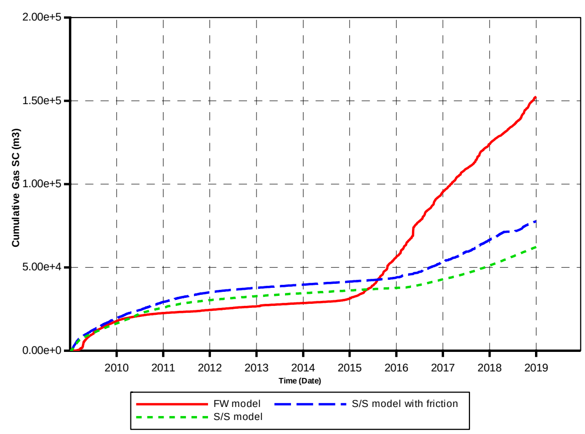

Figure 13: Gas production of FW and S/S models – Example #3

Numerical Behavior

It is difficult to compare the numerical performance of the Flexible Wellbore versus the Sink/Source well model, since the degree of complexity solved by each model depends on data. In Example #1 the two models solved roughly the same degree of complexity after the circulation period. The Sink/Source model needed 344 iterations to complete 900 days of production while the Flexible Wellbore model needed 418 (22% more) iterations. These are Newton iterations used to solve the non-linear reservoir equations.

It is different story for the more complex data which encountered cross-flow and phase segregation in the wellbore (undulating well). These mechanisms, not handled in the conventional Sink/Source well model, are numerically difficult because the wellbore cannot achieve a pseudo-steady state. The numerics become even more difficult when different perforations cross-flow at different times.

Examples #2 and #3 were run with the FW model, a conventional Sink/Source model (S/S) and an enhanced Sink/Source model (S/S-GFHL). The Flexible Wellbore (FW) accounted for all the reservoir-wellbore interaction mechanisms as well as wellbore behavior. The conventional Sink/Source model (S/S) neglected fluid segregation, friction and heat losses, and a cross-flowing section was treated as shut in. The enhanced Sink/Source model (S/S-GFHL) adds friction and heat losses for only the producer; cross-flow is still treated as shut-in.

Example #2: S/S-GFHL added two mechanisms to the conventional Sink/Source model but increased the CPU by 38%, an indication of the numerical difficulty associated with the extra physics. On the other hand, the Flexible Wellbore method accounted for all the extra physics but the CPU was decreased by 1.5%. Its numerical performance was influenced by the FW method imposing smaller time steps and hence requiring less implicitness (more blocks were treated as explicit).

Example #3: Wellbore undulation affected the numerical performance of the conventional Sink/Source (S/S) method only modestly (17% CPU time increase over Example #2) because no wellbore behavior was solved. The increased CPU time is due to the more complex wellbore-reservoir interaction. On the other hand, the addition of friction and heat-losses affected the results significantly. Example #3 experienced more severe cross-flow problems than Example #2. The undulating wellbore crosses different reservoir layers and therefore fluid with different composition entered the wellbore at each perforation. This added complexity had minimal effect on the S/S method (see above) but influenced the Flexible Wellbore and much more the S/S-GFHL method. CPU time for the FW model increased about 2 times and for the S/S-GFHL method about 4 times. The S/S-GFHL method had more troubles due to increased cross-flow oscillations and N-level treatment of head and friction. For this data the difference in oil production between the S/S and FW models is minimal. However, neglecting the wellbore behavior in the S/S model may show significantly larger differences in other data sets.

The Flexible Wellbore model was validated with numerous data and compared to the conventional S/S as well as to the S/S-GFHL model. The trend is similar to the above mentioned examples – more complex wellbore behavior and reservoir-wellbore interaction would increase the CPU time.

Conclusion

The Flexible Wellbore model solves multi-stream well equations while coupled to a thermal reservoir simulator. The well and reservoir models are fully coupled space-wise and strongly coupled time-wise. Coupling is through annulus-reservoir flow terms whose parameters alternate between constant and variable. This method helps isolate the reservoir iteration process from the wellbore model's numerical difficulties.

The wellbore can contain up to three tubing strings in an annular space, and each flowing stream may be an injector or a producer operated at various conditions. There are no restrictions on tubing lengths or how the wellbore intersects the reservoir grid. The flow regime is a function of liquid and gas velocities for each flowing stream and is used to calculate frictional pressure drop as well as axial and radial heat transfer. The model also handles transients, phase segregation and cross-flow.

Three example SAGD simulations with increasingly complex physical processes illustrate that FW can handle successfully a wide range of situations. For a simple horizontal case (Example #1) the FW solution is as efficient as the Sink/Source model but handles the circulation more correctly. When the wellbores undulate through shale strings (Example #3), severe phase segregation and cross-flow require the FW method.

Acknowledgement

The authors would like to thank Dr. Colin Card and Dr. Long Nghiem for their valuable advice.

NOMENCLATURE

B	=	section volume [m^3]
F	=	friction loss [m^2/s^2]
g	=	gravity constant [m/s^2]
H	=	molar enthalpy [J/gmol]
Hm	=	mixture enthalpy [J/g]
L	=	length [m]
P	=	pressure [Pa]
Q	=	heatloss [J/g]
S	=	phase fraction [m^3/ m^3]
t	=	time [s]
U	=	internal energy [J/gmol]
Uw	=	wall enthalpy [J/ m^3]
V	=	rate [m^3/s]
Vm	=	mixture velocity [m/s]
ρm	=	mixture mass density [g/m^3]
ρ	=	molar density [gmol/ m^3]
Subscripts		
p	=	phase
i	=	component
w	=	wall

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