Modeling Advanced Wells in Reservoir Simulation

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The use of advanced wells to improve the economics of production is now common practice. The term "advanced" is used to cover horizontal, multilateral, and smart wells (those containing sensors, flow-control, and other devices such as downhole separators). A single advanced well can contact a larger region of the formation and may contact several isolated oil-bearing regions. Control devices enable progressive reduction of production from high water-cut or high gas/oil ratio (GOR) regions. However, advanced wells are considerably more expensive to drill and complete, and their use must be justified by a corresponding increase in economic recovery. Reservoir simulation plays an important role in this decision. But to provide meaningful results, the simulation model must be able to predict well performance accurately over the lifetime of the reservoir. For smart wells, the model also must be able to predict effects of the control devices. Therefore, it is important that the well model be able to calculate, with a reasonable degree of accuracy, the pressure and fluid-flow rates at all locations in the well (including any lateral branches) and the pressure drop across control devices. For this degree of functionality, a suitably advanced form of well model must be used.

Conventional Well Models

In reservoir simulation, the basic purpose of a well model is to supply source and sink terms to the reservoir model. For a production well completed in a single cell of the reservoir simulation grid, the corresponding sink term is represented by an inflow-performance relationship.[1,2] This relationship describes the inflow rate of each fluid as proportional to the drawdown (the difference between the pressure in the grid cell and the pressure in the wellbore), the fluid mobility (relative permeability divided by viscosity), and a term known as the "well index" or "connection transmissibility factor" that accounts for pressure losses within the grid cell resulting from radial inflow into the well.[3]

For a well completed in two or more reservoir grid cells, a similar inflow-performance relationship is applied in each completed cell. Typically, wellbore pressures at each grid-cell completion are related by a simple estimate of the hydrostatic-pressure difference in the wellbore. It can be calculated from the average density of the fluid mixture in the wellbore or, more accurately, from the local density of the fluid mixture in each section of the wellbore between adjacent grid-cell completions. Usually, the calculation neglects other contributions to the wellbore pressure gradient (such as friction), but in general it is adequate for vertical or deviated wells because the hydrostatic gradient is the dominant component of the overall wellbore pressure gradient. Some degree of approximation still exists in the hydrostatic gradient; slippage between the wellbore fluids is neglected and the hydrostatic gradient reflects the homogeneous density of the fluid mixture in the wellbore, which assumes that all the fluids flow with the same velocity. A different approach is required to model the pressure drop from formation level to the tubing head. For this length scale, slippage effects can be very important, and friction also may have a significant effect. A common approach is to perform the pressure-drop calculation for a combination of pressures, flow rates, and water/gas fractions, then store the results in a multidimensional wellbore hydraulics table. This table must be computed for each well before the simulation is performed. However, with this approach, the simulator can simply interpolate the table each time it needs to know the pressure difference between the tubing head and bottom hole, which is considerably faster than calculating the pressure each time.

Typically, for this simple well model, a single variable corresponding to the well's bottomhole pressure (BHP) represents the state of the well. At a given set of reservoir conditions, the BHP value is obtained from a relation that depends on the well's operating target. For a well controlled to operate at a given oil-rate target, the sum of the oil inflow rates from each completed grid cell must equal the target oil rate. It was recognized at an early stage that there were advantages in solving the well equation for the BHP simultaneously with the equations describing fluid flow in the reservoir grid. This strongly coupled approach was developed initially for a single-well simulator,[4] in which it is necessary to solve all variables simultaneously (implicitly) to achieve a stable solution in the small radial grid cells near the well. However, the strongly coupled approach was soon adopted in full-field simulators that were able to handle many wells completed in multiple grid cells and operating under a comprehensive range of control modes.[5,6]

When a well is completed in two or more poorly communicating regions of the formation with significantly differing pressures, crossflow may occur. Fluid flows into the well from the high-pressure regions, and some flows back out into the low-pressure regions, even though the well as a whole is producing. Crossflow may happen similarly in injection wells. To model crossflow, the simulator must be able to compute both the reinjection rate and the composition of the injected fluid mixture. The injected fluid composition should reflect that of the fluid mixture in the wellbore, which would depend on the inflow into the producing completions and (for injection wells) the rate of injection from the surface. One approach to modeling crossflow is to introduce additional variables to describe the fluid contents of the wellbore. A three-variable well model was developed for a black-oil simulator,[7] in which the two

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additional variables correspond to the flowing fractions of water and gas within the wellbore. All three variables are treated as strongly coupled main variables and are solved simultaneously with the reservoir grid. The concept can be extended to compositional simulation by including $N_c - 1$ variables (where N_c is the number of components) to define the composition of the wellbore fluid.[8] Alternatively, some models use the wellbore-fluid composition from the previous iteration of the well solution.[9]

With the additional variables describing the contents of the wellbore, it is possible to determine the composition of the fluid mixture that flows from the well into the formation when crossflow occurs. The limitation with this approach is that the additional variables describe the average contents of the wellbore, and the model behaves as though all the fluids flowing into the wellbore are completely mixed in the well. Therefore, the composition of the reinjected fluid in the simulation model will be independent of the injecting-perforation locations in the well. For most simulations involving conventional wells, this limitation should not be a serious problem. But if the well produces from multiple zones with differing mixtures of mobile fluids and experiences crossflow, describing the composition of the injected fluid according to the average wellbore contents could lead to inaccuracies.

The disadvantages of the conventional well model make it unsuitable for simulating advanced wells. A different type of well model has been developed that is more suited to the task. However, a well model must fulfill certain requirements to simulate advanced wells more accurately.

Requirements for Modeling Advanced Wells

First, it is important to provide a more accurate calculation of the wellbore pressure gradient. The pressure gradient should be determined from the local fluid-mixture properties rather than the average contents of the well. Slip (when the fluids flow with different velocities) may have an important effect on the mixture density, so a fluid-flow model that predicts slip is advantageous. The pressure gradient should also include friction, an important contribution in long horizontal wells or branches. Ideally, the acceleration component of the pressure drop should be included. This component may be significant in regions of the wellbore where the fluid velocity increases because of the inflow of additional fluid, such as along the perforated lengths of the well or at branch junctions. A pressure gradient is needed to accelerate the fluid in these regions.

To determine how the pressure varies with position in the well, the composition of the fluid mixture at each location in the well must be determined. In a multilateral well, for example, each branch could be producing a completely different mix of fluids. Knowledge of the local fluid-mixture properties is useful for other purposes also. Local flowing conditions could be used to trigger an adjustment in a control device setting (e.g., to close a valve if the water fraction is too great). The local fluid-flow rates or holdup fractions also could be compared with the readings from a downhole sensor. If crossflow exists in the well, the composition of the mixture flowing from the wellbore into the formation is represented more accurately by the local wellbore-mixture properties adjacent to the injecting perforations.

An additional requirement of an advanced-well model is to provide an adequate representation of the wellpath. In conventional-well models, the simulator's knowledge of the wellpath could be limited to knowing the grid cells in which the well is completed. In an advanced-well model, it must be possible to define the wellpath independently from the reservoir grid (i.e., include sections of unperforated tubing that extend outside the reservoir grid in the well representation). The wellpath representation must be able to handle multilateral wells, including cases in which branches join outside the reservoir grid.

For advanced wells containing flow-control devices, the well model should be able to include individual device models, such as control valves, chokes, and pumps. For smart wells, in which control device settings can change in reaction to changes in flowing conditions, logic must be provided to enable the device settings to be changed manually during the simulation, and ideally to enable the simulator to change the settings automatically according to a defined procedure.

Finally, the complete well model with all its main variables should be solved implicitly and be strongly coupled to the reservoir equations. These requirements are necessary to achieve stability over the time steps that the simulator chooses for the reservoir model, which could be several days or weeks, and which typically are much longer than the time scale for changes in flow conditions to propagate throughout the well.

Multisegment Approach to Well Modeling

A more effective well model for advanced-well simulation can be constructed by subdividing the wellbore into segments, each having its own set of strongly coupled main variables. An alternative name for this approach is the gridded wellbore, which reflects that the wellbore fluid conditions are solved in their own finite-difference grid analogously to the conditions in the reservoir. The technique was used by Stone *et al.*[10] in a steamflood simulator and proposed by Nolen[11] and Masters and Mott[8] as a means of modeling crossflow more accurately. An implementation in a commercial black-oil simulator and its application to model two types of advanced wells were described more recently in 1998.[12] One of the wells was a dual-lateral, with the two branches joined at a depth substantially above the formation. The study demonstrated how the well was liable to crossflow, taking fluid from the higher-pressure region and injecting it through the other branch into the lower-pressure region. Placing a choke in the high-pressure branch prevented the crossflow and improved overall production. The other well had a single horizontal bore, and the study compared the benefits of applying two types of flow-control devices.

The segments form a 1D grid in the wellbore. **Figs. 1, 2, and 3** show how multilateral wells may be represented by a network of such segments forming a tree structure. Segments that represent perforated lengths of the well have connections to the reservoir that are represented by an inflow performance relationship in an analogous way to conventional wells. Other segments represent unperforated lengths of tubing, while additional segments configured to represent the pressure-loss characteristics of the device can model flow-control devices. The black-oil implementation described in Ref. 12 has four main variables per segment. These variables represent total flow rate, fractional flow rates of water and gas, and pressure. Four equations must be solved in each segment. The first three are mater-

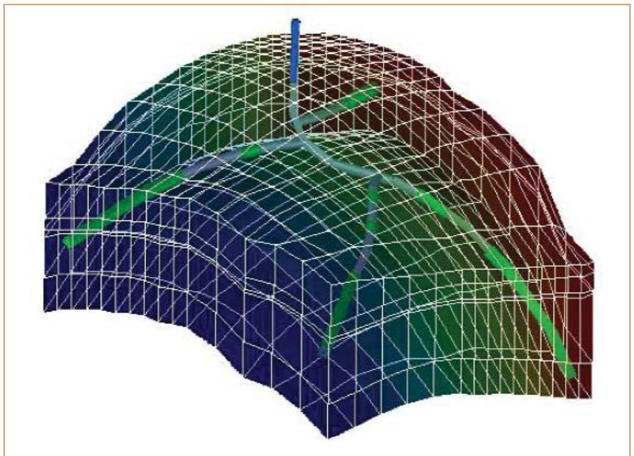

Fig. 1—A 3D schematic of a multilateral well in a structured grid. The perforated lengths of tubing are marked in green.

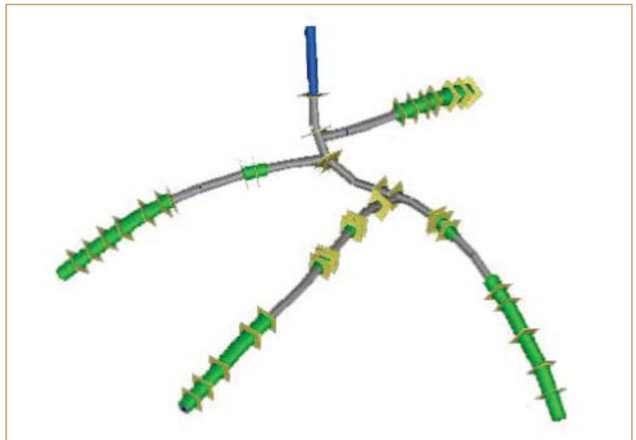

Fig. 2—The well in Fig. 1 is divided into segments, as indicated by the yellow squares.

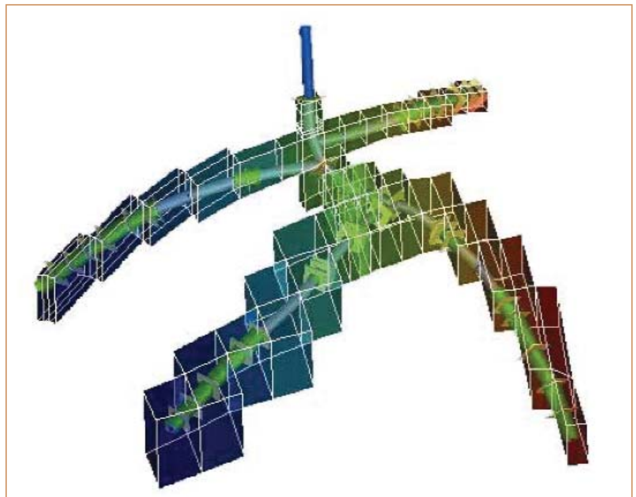

Fig. 3—The multisegment well in Fig. 2 showing the grid cells intersected by the wellbore.

ial-conservation equations for the oil, water, and gas phases, while the fourth equation relates pressure drop to local flowing conditions. In the topmost segment, there is no pressure-drop equation; in its place is an equation related to the well's mode of control. These equations are solved implicitly and simultaneously with the reservoir grid. A preliminary step to solve the well equations on their own, before each iteration of the coupled system, accelerates convergence of the coupled well/reservoir system.

The similarity between a multilateral well and a gathering-tree-structured network has prompted an alternative approach to modeling advanced wells in a reservoir simulator. This approach extends a surface-network model down into the formation to include the well itself.[13] Normally, a surface-network model would be used to model the pressure and flow downstream of the well through a pipeline network. The two approaches are largely equivalent; a network node and its outlet branch correspond to a segment. Equally, a multisegment well model could be extended outside the reservoir to represent a surface pipeline network.

The multisegment well model was implemented in a compositional reservoir simulator that models thermal processes.[14] Instead of four main variables per segment, this implementation has N_c+3 variables per segment, where N_c is the number of components (including water). The variables represent the molar densities of each component (the number of moles per unit volume), the total flow rate through the segment, the pressure, and the energy. Correspondingly, there are N_c+3 equations per segment. These equations are a mass-conservation equation for each component, a volume-balance equation (the sum of the volumes occupied by each component equals the volume of the segment), an equation relating the pressure drop to the flowing conditions, and an energy-conservation equation. The energy variable and associated conservation equation are needed only for thermal simulations. The energy equation includes the transport of energy with the fluid, conduction of heat through the pipe wall, storage of heat in the pipe wall, and thermal effects (e.g., expansion and vaporization) within the fluid. A heat-transfer coefficient is used to account for the energy transfer by conduction and radiation between the pipe wall and the formation. If the well tubing is surrounded by an annulus through which fluid also flows, the model can account for the heat conducted between the annulus and the fluid in the tubing through the tubing wall.

Multiphase Flow Modeling

It is important to have an accurate calculation of the wellbore pressure gradient. This calculation should include the friction pressure losses as well as the hydrostatic pressure gradient, which should also account for slip between the phases. An established method of estimating the pressure gradient is to use an empirical 1D correlation, such as those of Beggs and Brill[15] for horizontal or inclined flow and Hagedorn and Brown[16] for vertical flow. Several correlations of this type are described in Ref. 17. A typical procedure is to use the local volumetric flow rates of liquid and gas to establish the flow regime that would occur at these rates by use of a flow-pattern map appropriate to the correlation. For each flow regime (e.g., bubble, slug, annular, or stratified), a specific relation exists for the liquid and gas holdup fractions and the friction pressure drop. Note that in the absence of slip, when each phase flows with the same velocity, the liquid and gas holdup fractions would have the same ratio as their local volumetric flow rates. This approach is relatively simple to implement and compute. However, the accuracy of this approach is limited, especially when a correlation is used outside the range of flowing conditions covered by the experiments used to derive it. Furthermore, the correlations can produce severe discontinuities in the pressure gradient at flow-regime transitions.

It was recognized that to obtain greater accuracy, it would be necessary to model the physical mechanisms of the flow in more detail. This approach is used by a class of methods known as mechanistic models.[18,19] To determine the pressure gradient for a given flow of liquid and gas, an initial guess is made for the flow regime. A model specific to this flow regime is then solved that uses a momentum balance equation for each phase and assumes momentum is transferred between them according to the geometry of the flow pattern. If the system has no stable solution, another flow pattern is assumed and the process is repeated until a stable solution is found. Although this approach involves modeling more of the physics of the flow regime, empirical correlations are used at a deeper level (e.g., for friction at the pipe wall and friction between the phases). The empirical correlations can be tuned to match the results to experimental observations. In general, mechanistic models are significantly more accurate than the 1D correlations, but they require substantially more computing time to produce an answer.

With a wide choice of methods for calculating multiphase pressure drops, the nature of the problem imposes some limitations on the methods that may be regarded as best suited for advanced-well simulation models. The ideal method should be simple enough for rapid computation. The pressure-drop calculation could be performed many times in each well segment during the solution of a single time step. The 1D correlations are computed relatively quickly, whereas solving a mechanistic model would be time consuming if the simulation contained many well segments. The ideal method should provide continuous results over the complete range of flowing conditions. Discontinuities cause problems in implicit numerical methods and could stop the system of equations from converging. Both 1D correlations and mechanistic models exhibit serious discontinuities across flow-regime boundaries, but techniques can be applied to smooth the transitions. The ideal method should have a form that can be differentiated with respect to the solution variables that define the flow conditions. An implicit numerical method requires computation of the derivatives of the pressure loss with respect to the segment-solution variables. Again, this requirement favors the more simple correlations. However, the more accurate mechanistic models should not be dismissed. An alternative approach, which preserves the accuracy of the mechanistic model while offering a rapid method of calculation, is to use a mechanistic model to calculate tables that provide the pressure drop as a function of flow rate, pressure, and water and gas fractions. These tables are the same types as the wellbore hydraulics tables commonly used to translate between BHP and wellhead pressure in a simulator. The pressure drop across a segment, and its associated derivatives, can be obtained very rapidly by interpolating the table. The pressure loss obtained from the table may be scaled according to the length of each segment. However, separate tables would be needed for different tubing diameters, and also for different inclinations. Also, this approach is not well suited for handling the changing compositions of oil and gas in a compositional simulator.

Some of the 1D correlations use a drift-flux model to represent two-phase flow. First proposed by Zuber and Findlay,[20] it describes the slip between the phases as the sum of two mechanisms. One mechanism results from the nonuniform profiles of velocity and phase distribution over the pipe cross section. Even if the two phases are moving with the same local velocity at any point in the cross section, their average velocities will be different when integrated over the area. The other mechanism represents a local velocity difference (drift velocity) that reflects the tendency of the lighter phase to rise through the mixture because of buoyancy. Drift-flux models have been used successfully in several correlations for vertical, deviated, and horizontal flow.[21–24] Hasan and Kabir[24] also proposed a formula by which the drift velocity can be scaled according to the inclination of the pipe. The contribution of the two slip mechanisms can be described by simple expressions that are continuous over a wide range of flowing conditions, which makes drift-flux models particularly suited for use with advanced-well models in reservoir simulation.[12] In addition, the formulation can model countercurrent flow, in which the heavy and light phases flow in opposite directions. One application is to model the process of phase separation in the wellbore when the well is shut in during a buildup test, which influences the wellbore storage response. Countercurrent flow may also occur in a flowing well at low flow rates. Simulation studies have shown that imposing a no-slip flow model in these circumstances can lead to instabilities, while a drift-flux model gives a better representation of the physical process and, consequently, produces a more stable solution.

It must be noted that these flow models are intended for modeling two-phase flow, with either gas/liquid or liquid/liquid mixtures. There are no models for three-phase flow (oil, water, and gas) that are applicable across the full range of flowing conditions, and, in general, the flow patterns are very complicated. In the absence of a viable model for three-phase flow, an alternative approach is to apply a two-stage technique by use of the available two-phase models.[12] First, the oil and water are combined into a single liquid phase with suitably averaged properties, and the slip between the gas phase and this liquid phase is determined. Then, the slip between the oil and water in the combined liquid phase is determined in a similar way. This approach ignores any effect that the presence of a third phase may have on a two-phase flow model. Therefore, this method should not be expected to be free of inaccuracies. The oil and water in the combined liquid phase may form an emulsion having a much larger viscosity, and sudden changes in the frictional pressure drop may occur when the identity of the continuous phase in the liquid changes. These changes in the pressure gradient are virtually impossible to predict and must be calibrated with experimental data. Much more work is required on three-phase flow modeling, but it is doubtful as to whether a flow model that approaches the accuracy of the models for two-phase flow can be expected.

Representing Flow-Control Devices

Flow-control devices can be included in a multisegment well model by configuring a segment's pressure-drop relation to represent the characteristics of the device. In general, control devices operate by forcing the flow through a small diameter orifice, which results in an increased pressure drop across the device. Under subcritical (subsonic) flow conditions, the flow rate through the device will depend on both the upstream and downstream pressures.

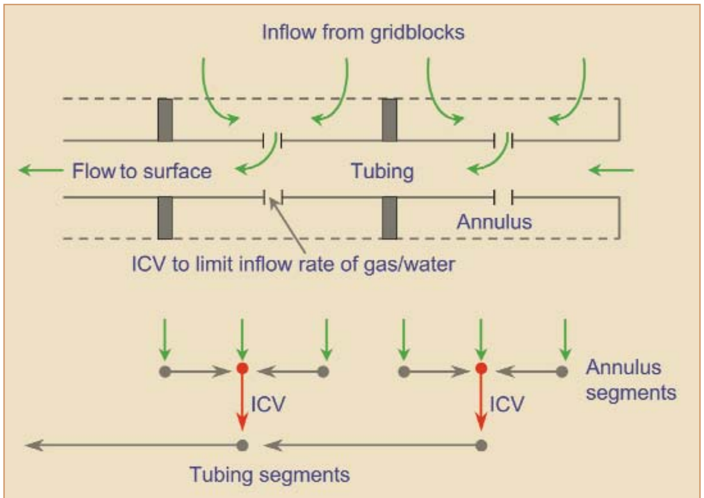

Fig. 4—Remote completion control in a horizontal well and the corresponding network of well segments.

High-velocity flows where free gas is present may become critical (sonic), especially in two-phase mixtures in which the speed of sound is substantially lower than in either phase on its own, and under these conditions, the flow rate will be independent of the downstream pressure.

For single-phase subcritical flow through an orifice, a simple correlation relates the pressure drop to fluid density and velocity.[17] Methods dealing with multiphase flow in both subcritical and critical states are available. For multiphase flow in general, empirical correlations can be highly inaccurate when used outside the range of conditions for which they were developed. Methods based on the physics of flow, such as those of Sachdeva[25] and Perkins,[26] are more successful. However, these methods involve complex calculations, and it is computationally more efficient to use them to prepare precalculated pressure loss tables rather than implementing them directly in the simulator. By configuring a segment to have its pressure drop interpolated from a predefined table, it is possible to model any type of flow-control device once the pressure-drop characteristics of the device are expressed in the form of a wellbore hydraulics table.

It is not always necessary to use a physical model of the control device in the simulation. When performing simulation studies to investigate suitable operating strategies for a smart well, the following questions may be asked. "What will be the effect on the well's production profile if lengths of completion are choked off that produce at a water cut greater than 0.7?" Or, "Should the oil/water/gas flow through a segment be limited to less than a certain rate?" To answer these types of questions, it is better to build a pseudodevice into the model that provides a steeply increasing pressure drop at water cuts that exceed the limiting value, or that determines the upstream pressure necessary to limit a phase flow rate to the desired maximum value. Such pseudodevices model a particular control strategy rather than a physical device. The pressure drop calculated by the simulator across a pseudodevice segment can be used to determine the settings or characteristics of the corresponding physical device that would be best for the purpose.

As an example of how the multisegment approach can be used to provide a detailed model of a control device in a smart well, consider one of the case studies from Ref. 12. This case investigates the use of remote completion control in a horizontal well. The horizontal section of the well has an inner tubing and an outer annulus. The annulus is divided into separate sections, from which the flow can be controlled independently from the surface. The reservoir fluid enters the annulus from the formation, then flows through the section's inflow control valve (ICV) into the tubing. Thus, adjusting the section's ICV can control the rate of production from each section. By monitoring the water and gas fractions entering from each section with downhole sensors and adjusting the ICVs, it is possible to reduce the flow from individual sections progressively as their water cut or GOR increases. **Fig. 4** shows how the well configuration may be represented in the simulation model by a network of segments. The segments representing the annulus accept inflow from the formation. The flow from each section of the annulus converges into a segment that represents the ICV, through which it enters the tubing. Each ICV segment may be configured either as a pseudodevice (to model a particular control strategy) or a physical device (to determine the flows through the device at a particular setting).

Downhole Separation

A sufficiently flexible advanced-well model should be able to accommodate downhole devices in addition to chokes and valves. An example is the downhole separation of oil and water. Water is separated from the production stream at formation level, then injected back into the formation through the same well. This type of system can reduce the costs of surface facilities for handling water and the provision of injection wells. Also, the pumping power needed to lift an oil/water mixture to the surface is reduced. Bowers *et al.*[27] described a system that uses hydrocyclone separators and electrical submersible pumps. A pump can be at the inlet to the separator (a push-through system) or, as shown in **Fig. 5,** at the water outlet (a pull-through system). A second pump may be at the oil outlet to boost the flow to the surface. In principle, two pumps are necessary to control independently the total flow rate and the flow split (the fraction of the inflow that exits through the oil outlet). Increasing the flow split will reduce oil carryover in the water outlet, but the fraction of water produced to the surface will increase. Conversely, decreasing the flow split will reduce the water content in the oil outlet stream, at the expense of progressively increasing the amount of oil in the water outlet stream. The optimum flow split will depend on whether the primary objective is to reinject clean water or to remove as much water as possible from the production stream to the surface.

The ability to simulate this type of system would be very useful when performing assessment studies to see whether benefits justify installation costs. By use of a multisegment model for the well, it is possible to configure a segment to represent a separator by applying a scaling function to the water fraction at the water outlet so that it exceeds the water fraction in the segment. Additional segments having pressure boosts that depend on the flow rate could represent the pumps. In principle, a table or simple analytic model could represent the pressure/flow relationship. The flow split will depend on the hydraulics of the complete system, but it could be adjusted by altering the pressure dif-

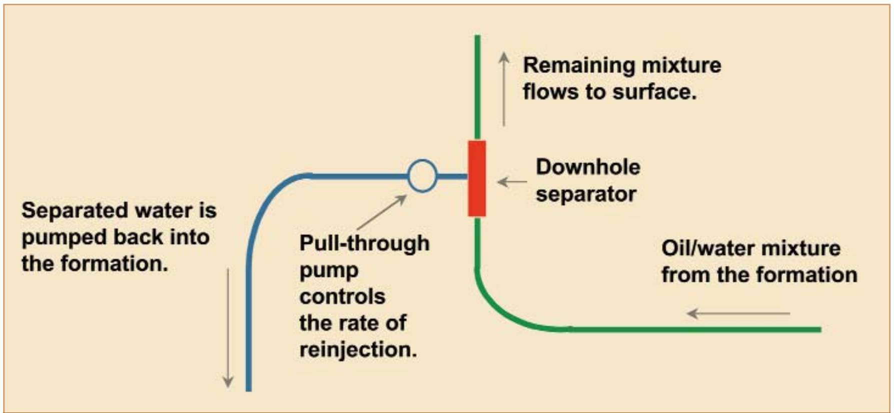

Fig. 5—Possible well configuration for downhole separation.

ferentials across the pump. Additional control logic could be built into the model, for example, to reduce the pressure boost in the pull-through pump at the water outlet if the oil content of the stream is too high. If the pump characteristics are represented in the model by a table, water-quality control could be achieved by defining the pressure boost as a function of both flow rate and water fraction, decreasing the pressure boost if the water fraction drops below a particular value.

Another method considered for downhole separation is gravity separation in the wellbore.[28] This method could be viable for gas/liquid separation, but the rate of oil/water separation would be substantially slower. However, it is possible to model the natural separation of phases within the wellbore by dividing it into several segments and applying a drift-flux slip model.

Future Directions

Several areas of advanced-well modeling would benefit from further R&D. As noted, there is still room for improvement in multiphase-flow modeling, including three-phase flow, in which there is a need both for more experimental data and for the development of suitable flow correlations. Correlations are being developed to account for the effect that fluid influx through the perforations has on the wellbore frictional-pressure gradient. The fluid inflow acts to increase the friction in laminar flow and to decrease it in turbulent flow. The effect may be significant in long horizontal wells having extensive perforated lengths. Empirical correlations based on single-phase flow experiments are available,[29,30] and work is continuing, for example, to include the effect of perforation density.

An area not covered in this article concerns the reservoir grid surrounding the well. Generally, advanced wells have more complex trajectories than conventional wells and may intersect blocks in a structured grid nonorthogonally. Simulation models would benefit from the use of more advanced gridding techniques to improve the representation of the pressure distribution around the well. Research programs continue in this area, including the use of flexible unstructured grids and modular grids where local grids constructed around the wellbore are embedded in the global reservoir grid. For examples, see Refs. 31-33. Wells completed in unstructured grid cells require a different approach for calculating their well index, because Peaceman's formula[3] applies only to rectangular cells in a regular Cartesian grid. A simple formula may be used to obtain the well index in a flexible Voronoi grid, provided the well is not too close to a reservoir boundary or to other wells.[34] (Similar conditions apply to the validity of Peaceman's formula in a Cartesian grid.) If these conditions are not satisfied, a more exact value may be obtained by comparing the results with a fine-grid numerical solution or a known analytical solution. Recent advances in analytical modeling of advanced wells now incorporate the effects of reservoir heterogeneity,[35] and, in principle, these methods could be used to compute values for the well index. However, an accurate calculation of the well index for advanced wells is by no means trivial to compute, and this area is still the subject of ongoing research.

Application of downhole monitoring devices that measure pressure, flow rates, and water/gas fractions provides data that can be used for both matching and control purposes. Techniques for tuning certain parameters in the reservoir model (e.g., permeability, pore volume, and aquifer strength) to match historical well production rates are established.[36] Also, it is possible to tune parameters relating to pressure losses in the well tubing and a surface pipeline network.[37] Because of the similarities of a surface pipeline network and a multilateral well, in principle, similar tuning techniques could be applied in the advanced-well model to match the observations at downhole monitors. These advances could counteract much of the uncertainty in multiphase-flow modeling.

Another area for development is the dynamic calculation of optimal settings for the control devices in a smart well. Currently, the automatic device controls built into simulation models generally are heuristic, in that they react to changes in the local flowing conditions according to a defined procedure (e.g., increasing the pressure loss as the water cut increases or if the water flow rate increases above a preset limit). In principle, it should be possible to apply more rigorous optimization techniques to maximize the production, not just on an individual well basis but for the field as a whole.

The following four components are required for a complete simulation system.

• A simulation model of the reservoir.

• An advanced-well model, with appropriate models for the control devices. If necessary, the model could extend into, or be coupled to, a surface-pipeline network model.

• Code to interpret data from monitoring devices and for adjusting parameters in the reservoir and well models to match the simulator's calculations of those data.

• Code to calculate optimal settings of control devices dynamically to maximize production.

If this combined system could be taken out of the office and into the field, then coupled to a real-time control system, the way would be paved for a truly intelligent field. JPT

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