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Simulation Techniques used for Modeling Horizontal Wells andThe Role of Grid Refinement

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---***ABSTRACT***---
There have beensignificant technologies improvements since the oil industry first began drilling horizontal wells. However, the greatest obstacle is identifying suitable technology that can be used successfully in a specific reservoir. Selecting the best technology is a complicated process that requires simulation techniques combined with dynamic performance. Dynamic performance is modeled using numerical techniques, which can become an arduous task. This leads to an increase in well productivity or injectivity which surpasses the capabilities of vertical wells. This paper reviews studies that have used a number of different simulation techniques to accurately model horizontal wells. These techniques have been used to model different aspects of the recovery process, including completion, simulation, production, and enhanced oil recovery. These techniques can be used to solve complex problems with minimum costs in money and time.
KEYWORDS: *-Local grid refinement;Applied simulation techniques for horizontal wells*

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I. INTRODUCTION

Horizontal wellsmaximize the contact area with the reservoir, thereby increasing productivity. For this reason, fields can be developed more cheaply with a few horizontal wells than they can be with a greater number of vertical wells. However, the drilling of horizontal wells must be carefully planned, including by optimizing drilling, completion, stimulation, and production. Numerical models are typically used to simulate the effects of such plans, including secondary and tertiary recoveries. These models can be used to stabilize the inflow to the horizontal section, to minimize the loss of frictional pressure between the heel and the toe, to delay gas capping, and to reduce water coning. Numerical models are also used to evaluate critical aspects of horizontal wells prior to construction to identify potential problems. Numerous studies have examined the use of numerical models for this purpose, including the numerical modeling of seismic, drilling, completion, production, and oil recovery. These studies have shown that numerical modeling can be used to detect and minimize or avoid many problems in the early stages of the planning of the horizontal wells, including problems limit production. This paper reviews a number of these studies.

II. APPLIEDSIMULATIONTECHNIQUESFOR HORIZONTAL WELLS

Faulttransmissibility has a major impact on the flow pattern and pressure profile of a reservoir. To investigate fault transmissibility, Edris et al. (2008) used automated history matching to compare the results of their simulation to newly obtained data. The results of this process revealed a good match between their model's results and the data earlier rather than later. Ding et al. (2005) used a simulation to describe the flow of fluids inside fractures and the connections between a matrix and the fractures surrounding a well. To improve the ability of reservoir simulators to accurately predict the productivity of fractured wells, a near-well fracture-upscaling model was built based on the geological DFN model.

Stimulation has also been used in stimulation operations. In low-permeability reservoirs, hydraulic fracturing is used to create channels through which fluid can flow towards the wellbore. Byung et al. (2009) studied the effects of the number of fractures, fracture geometry, and the distance between fractures on productivity in draining a reservoir. Numerical modeling can be used to design multiple hydraulic fractures in a single open-hole well. In addition, transient analysis can be used to evaluate the results of simulation. Numerical modeling can also be used to understand the communication between a reservoir and an induced fracture open as long as possible. Rhein et al. (2009) evaluated the effectiveness of proppant in maximizing fracture conductivity by using a geo-mechanical model to evaluate fractures in a channel in the presence of proppant. Hegre et al. (1996) used the effective wellbore radius theory to model a horizontal well that was intersected by both transverse longitudinal fractures. The results suggested that horizontal wells with transverse fractures can successful if high fracture conductivities can be maintained.

Pressuretransient analysis is an important tool for describing essential reservoir parameters, including permeability and skin damage. Jackson et al. (2003) combined numerical modeling and gradient-based history matching in analyzing field data and experimental results, and the model they developed can be used to analyze formation tester of pressure transient tests.

Gravel packing, in which gravel is placed around a screen to create a permeable filter, is used to remove sand from produced fluids, to stabilize the production rate, and to prolong the life of a well. Samyak et al. (2008) used a 3-D simulation to design gravel from the surface to a designated location, and it detailed the concentration of gravel at every step. By using the model, the sensitivity concentration of gravel packs may be arranged to build reliable model.

Friction along a horizontal well causes the pressure to drop at the heel. For this reason, production should be optimized to maintain uniformity and to prevent water coning and gas capping. Thornton et al. (2010) used a numerical model to evaluate the effect of an inflow control device on wellbore performance. In addition, the flow from a reservoir can be tracked and controlled. Al-Khelaiwi and Davies (2007) proposed using inflow control devices to prevent coning at the heel of a horizontal well. They used a numerical model to evaluate the importance of using an inflow control device in well completion, and their simulation can generate the production profile along a wellbore, helping to predict any water coning or gas capping. Alhuthali et al. (2007) used numerical modeling to determine the best waterflooding reservoir organization by rate control and the results revealed that inflow control valves can be used to control the rate of flow through a horizontal well and to delay water breakthrough, thereby increasing the oil recovered from a heterogeneous reservoir. Islam et al. (1990) developed a comprehensive mathematical model to study the effects of drops in wellbore pressure on the performance of a horizontal well. Kossack et al. (1987) used numerical modeling to compare the performance levels of vertical and horizontal wells, finding that horizontal wells perform better than do vertical wells in producing from thin reservoirs.

Meszaros et al. (1990) found that for high viscous oil reservoirs, injecting gas into the top of the reservoirs may improve recovery. However, gravity stabilization is required to prevent early gas capping. In the absence of a natural dip, a horizontal well can be placed at the top of the formation. The dimension models demonstrated that while it is difficult to stabilize the gas front, it can be done by controlling the injection and production rates.

Bottom water drive (Aquifer) is a strong source of energy and supports reservoir pressure. However, early water breakthrough can occur when a uniform production profile is not maintained. (Elkaddifi et al 2004) studied the ability of polymer to in reduce water mobility and thereby increase oil production. A commercial simulator__ Computer Modeling Group (CMG)__ was used to conduct a sensitivity analysis of several parameters, including the viscosities of oil and water, the permeability ratio, and the polymer concentration. The simulator aided in determining the injection point and the injection rate and demonstrated that stopping the bottom water zone can minimize the cross flow between layers, thereby increasing the oil recovery. (Zagal and Murphy 1991) built a numerical model to study the performance of horizontal wells in water-drive reservoirs and found that horizontal wells ultimately yield better recoveries than do vertical wells. In addition, infill can be used to increase the recovery from horizontal wells. Zhang et al. (2010) used lab experiments, core samples and PVT propertiesto develop a black-oil simulator that could model flooding with brine and polymer. They took a variety of parameters into account in building their model, including pore volume, polymer shear thinning, and polymer adsorption. Hamadouche and Tiab (2007) used numerical modeling to assess the effectiveness studied the effectiveness of using horizontal wells to waterflood highly heterogeneous reservoirs. They included the parameters that affect the sweep efficiency of the ultimate recovery from horizontal injection wells: wellbore location, perforation length and location, anisotropy, and injection rate. Dakhilia et al. (1995) used a compositional chemical flooding simulator to investigate surfactant-polymer flooding. Their simulator could realistically model in three dimensions the behavior of heterogeneous reservoirs.

The drive mechanism used with a reservoir has a major impact on oil recovery. In many reservoirs, production rates decline quickly, limiting recovery and rendering wells uneconomical. plays the main role in oil recovery. Secondary drive mechanism can be used to overcome this issue and improve oil recovery, however, and numerical modeling is a powerful and flexible tool for evaluating different options before implementing them in the field. Taheri and Sajjadian (2006) evaluated different techniques for improving oil recovery from offshore reservoirs with low porosities and permeability levels. They used the Black-Oil simulator to model different scenarios and to identify the best scenario for horizontal and injector wells. Their goal was to increase the reservoir pressure using different methods to inject water and gas separately or simultaneously. They compared the recoveries obtained by using water-alternating-gas injection (WAG), by using simultaneous water-alternating-gas injection (SWAG), by injecting gas into the top and water into bottom of the reservoir, and by injecting water into top and gas into bottom of the reservoir. They obtained the best result using the WAG method. Beraldo et al. (1994) investigated the impact of reservoir heterogeneity on the water coning performance by using sequential stochastic simulation, which was used to analyze core and log data. In addition, history matching was used to compare the production data. Ridha, (2003) used a 3-D finite-difference reservoir simulator to compare three injection techniques: WAG, SWAG, and injecting water into the top of a reservoir and gas into the bottom of the reservoir. Ridha found that the third method yielded the highest recovery.

One way to control gas capping is to use a PID feedback controller to optimize the settings of an inflow control device. Leemhuis et al. (2008) used a numerical model to simulate this process, and their results were more accurate than those of simulation experiments.

Most of the reservoirs loses pressure after producing a large amount of fluid, and the remaining oil is produced either by secondary recovery methods or by enhanced oil recovery methods. However, fluid characteristics (like oil viscosity) sometimes requires that enhanced oil recovery be applied at the begging of reservoir life. Brooks et al. (2010) used a reservoir-simulation model to determine which of three alternatives __ high pressure steam injection, polymer flooding, and in-situ combustion___was best for reservoirs with medium-heavy oil, high permeability levels, and strong bottom aquifers. The main difficulty in producing from such reservoirs is high water cuts due to rapid water breakthrough. Ahmed (2011) built a 3-D compositional simulator that combine various scenarios of horizontal and vertical wells as injectors and producers to identify the best option for using miscible gas injection to improve the sweep efficiency of (and thus the oil recovery from horizontal wells. The results revealed that oil recovery was highest when the horizontal well was used as an injector. Ammer et al. (1991) investigated the effect of the carbon dioxide miscible displacement on the performance of horizontal injection wells, using a simulation model to prove that horizontal injection wells can increase oil recovery to a much greater degree than can vertical injection wells. Olsen et al. (1993) used a simulation model to determine the effects of water and gas injection on ultimate recovery and production performance.

Steam injection is used to increase the relative permeability of oil by reducing its viscosity. Ying and Wang (1990) used data from laboratory experiments to feed a simulation model and then used history matching to compare the results to field-production data. Their results revealed that steam flooding was successful when used with horizontal wells. Huang and Hight (1986) examined the possibility of using horizontal wells in steam-flood patterns. The results suggested that horizontal wells could increase recovery by delaying steam breakthrough.Kroemer et al. (1997) developed models to simulate the use of multi-laterals in hydraulic fracturing. Their purpose was to develop realistic principles for modeling the productivity of fractured well. They compared the results of their models with those of analytical models and found that the best way is to use Compositional Simulation Model. Gökta and Ertekin (1999) developed a 3-D model to simulate local grid refinement. To quantify the flow into the wellbore, the residual equation was used to model the flow performance levels of the horizontal wells. Fine and coarse grids were used together, and the flow equations were explained at the same time. While the model did not require the calculation of an equivalent well-block radius, the comparison indicated good conformity. In fact, the model produced perfect results. Kilic and Ertekin (1999) developed two different models for simulating flow regimes and flow geometries around sealing and non-sealing flow barriers. The first model was a three-phase black-oil simulator, and the second model was a single-phase 3-D simulator for compressible and slightly compressible transport formulations. In both models, local grid refinement technique was used to perfectly describe the flow regimes and flow geometries. The model was also able to afford a best representative of faulted reservoir model with less CPU time. The model was found to be reliable for analyzing the transient pressures of wells with non-sealing faults placed close together.

III. LOCAL GRID REFINEMENT

Localgrid refinement is a process that increase the number of grid cells at a particular position. The extra grid cells are often needed to increase the accuracy of the model at locations where important operations are likely occur. For instance, a simulation model for enhanced oil recovery containing multi-component and multi-phase fluid flow must have a high resolution to be reliable. For this reason, that part of the model must have an increased number of grid blocks to yield accurate results. Suicmez et al. evaluated the capacity of dynamic local grid refinement to simulate multiple contact miscible gas injection. They used three different simulation techniques were used. The first one was a 1-Dimension model with employed a variable number of grid blocks to determine the impact of numerical dispersion. The second model was a 2-Dimension model that employed a grid-sensitivity analysis in which grid blocks were refined both in the vertical and horizontal directions. The third model was a 3-Dimension model that introduced vertical heterogeneities. Nacula et al. (1990) studied static local grid refinement using a Cartesian grid. The result revealed that local refinement can be performed only for areas of a reservoir for which a high resolution is necessary. In addition, the results of local grid refinement can be compared to those of a complete fine grid. Al-Towailib and Liu (1991) used local grid refinement to model important reservoirs dimensions. They found that using grid refinement decreased the time required for the model to run and enabled it to simulate flow behavior more reliably. In addition, local grid refinement was found to limit variation in how reservoirs are characterized. Heinemann et al. (1983) employed dynamic local refinement in simulations of reservoirs, finding that the models that featured dynamic local refinement described pressure and saturation more accurately. Gourley and Ertekin (1997) evaluated the effectiveness of static local refinement in modeling reservoirs with impermeable flow barriers. Comparing the production of oil, water and gas in both cases, refined grid and fine grid showed good agreement. Wasserman (1987) used static local grid refinement in three-dimensional reservoir model. The results were excellent, especially compared to those of non-refined grid models. Sabry et al. (1995) studied the effect of local grid refinement in modeling pressure drops in and sweep efficiencies of horizontal well. When the results of the model were compared with actual field data, the model was shown to be perfect. Kocberber (1993) used natural grid refinement in modeling the conductivities of fractures surrounding horizontal injection wells for the purpose of evaluating the efficiency of water flooding. The model was found to be accurate. ViKas and Ertekin (1996) developed a black-oil simulator that applied grid refinement in different scenarios featuring horizontal wells: “sealed reservoir,” “bottom-water drive,” and “edge-water drive.” The refined grid included both static and dynamic local grid refinement processes.

IV. CONCLUSION

Simulation isimportant to the assessment of projects and the development of oil field, and computer models enable the simulation of reservoir behavior and the optimization of production processes. Different techniques have been developed to improve our understanding of reservoir characteristics and to manage production behavior. These techniques can be used to avoid many production problems and to delay many others. For this reason, these techniques are valuable in formulating long-term plans.

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