Issues in Simulation of Shale Gas Reservoirs

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A valid reservoir simulator is a key enabling technology for the characterization, development, and management of a producing reservoir. Furthermore it provides a platform to integrate geologic, geochemical, geophysical, and petrophysical parameters, and examine their effects on production. The ability to use simulation to investigate the sensitivity of production to reservoir parameters is particularly important for reservoirs such as shale gas reservoirs where traditional core measurements are difficult or impractical to perform. Simulation provides the means to both model gas production and produced water.

As shale gas reservoir rocks are studied in more detail, their pore geometry is recognized as being extremely complex. The shales contain hydrophobic pores in the organics, pores of indeterminate wettability in the non-organic part of the matrix, natural fractures most likely dominantly water wet, and stimulation produced fractures that possibly have fractional wettability. The organics also store methane as adsorbed gas and absorbed gas. This storage mechanism is a function of pressure and as gas is released from the organics both permeability and porosity may possibly increase. There is as yet no clear understanding on how these pore systems are connected and it is very possible that different reservoirs have different connectivities. A valid shale gas simulator needs to incorporate these effects in order to make meaningful interpretations from simulation predictions.

Additionally, in shale gas reservoirs such as the Barnett, wells that have been massively hydraulically fractured typically produce only a fraction of the stimulation fluid leading to the creation of water blocks that have been observed to negatively impact well productivities following re-fracture treatments. Consequently, the appropriate model physics built in to a reservoir simulator will enable the modeling of the deposition of the stimulation fluid and can potentially be a vital tool for designing completions that mitigate the severity of these effects.

Some of the approximations in standard commercial simulators may be inappropriate for porous media with very small pore sizes such as shale gas reservoir rocks. The most serious approximations are: 1) the assumption of instantaneous capillary equilibrium which is used in standard simulators to eliminate one of the fluid pressure variables, 2) that transport can be completely defined by viscous flow (Darcy's law), and 3) that relative permeability is not flow rate dependent. These assumptions result in simulators that: do not correctly predict the amount of produced water; do not properly handle the changes in gas transport rates with time, so probably cannot correctly model gas production; and do not correctly predict the deposition of stimulation water especially during re-stimulation.

Another challenge in modeling shale gas reservoirs is accounting for the relative contributions of pressure gradients and concentration gradients to gas transport in these nano-porous media. The relative importance of the two mechanisms depends on parameters such as pore size, pressure, and temperature. Sigal and Qin (2008) examine the relative importance of pressure driven viscous flow and concentration driven restricted diffusion. For shale reservoirs, the small pore size and lower pressures near the complex fracture systems require that diffusion mechanisms be included in the simulator. It is also well known that slippage effects can be important for gas transport in low permeability formations. The mean free path of the gas molecules controls the appearance of slippage effects. At pressures and temperatures typical of the Barnett or similar reservoirs the mean free path of methane is on the order of 0.1 nm so slippage is probably unimportant but the mean free path is inversely proportional to pressure; consequently, near the hydraulic fractures or in lower pressure reservoirs gas transport could quickly become non-Darcy, and motivates the inclusion of this effect in a shale gas reservoir simulator (Florence et al., 2007)

Additionally, in a typical simulator irreducible water and gas saturations are constants that enter only through the relative permeability curves. Because of the small pore size, capillary forces can dominate fluid transport in shale gas reservoirs. This standard approach does not capture the effects of flow controlled by capillary forces. This is seen in standard laboratory measurements of ordinary rocks where multi-phase flow is stopped when water is no longer being produced from the sample. The sample is then centrifuged and the water saturation is reduced due to capillary drainage. Consequently, flow rate dependent relative permeability curves need to be introduced to correctly model gas and water transport.

All the above deficiencies in standard simulators have been addressed in the literature and theories have been formulated to address them. They have not, however, been implemented in commercial simulators. This paper provides a comprehensive review of technology gaps in the current state of commercial simulators, published methodologies on improving their deficiencies and our proposals for approaching the issues.

We also present some preliminary results using an in-house reservoir simulator that was modified to implement a solution that does not force instantaneous capillary equilibrium and the effects of this phenomenon were studied. A simple example illustrates why instantaneous capillary equilibrium may be inappropriate and therefore justifies the need to develop simulators that do not make the above assumptions. The mathematical formulation used to implement a non-equilibrium capillarity model is developed and discussed.

Lastly, a set of simulation studies are discussed where saturation profiles for two-phase flow displacement are compared for capillary equilibrium and non-equilibrium conditions. We also investigate the effect of wettability by considering a 100% water-wet and a 100% oil-wet formation. The results indicate a dramatic impact on the saturation profiles produced by relaxing the capillary equilibrium requirement as shown in Figure 1.

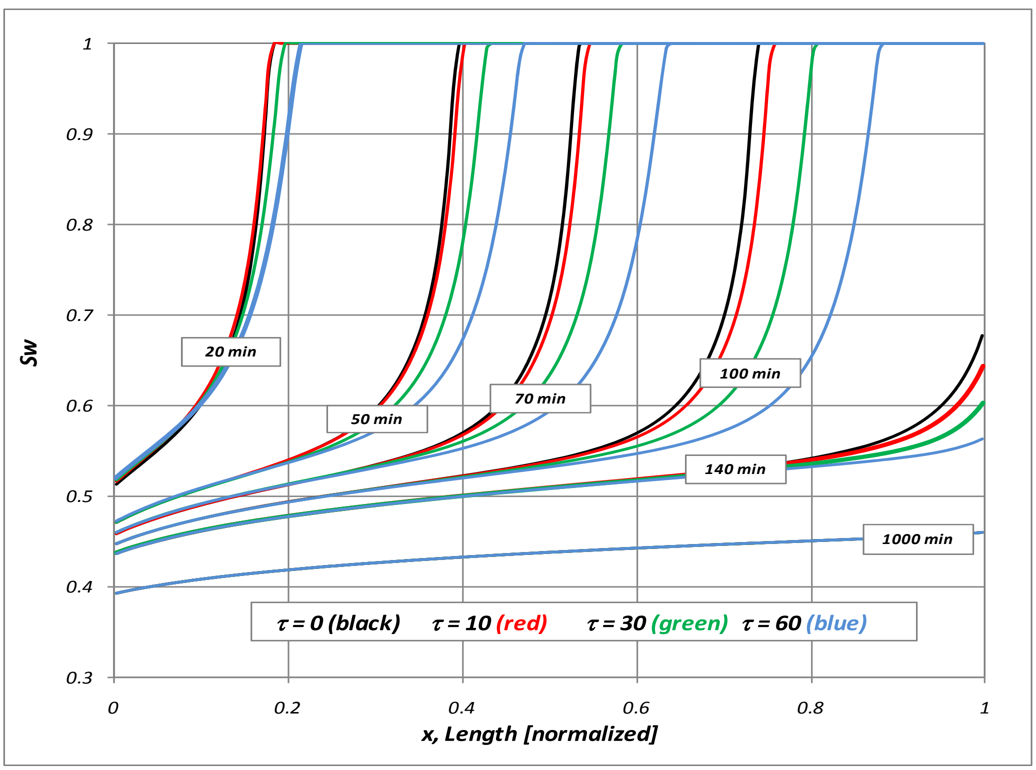

Figure 1 – Effect of relaxation time, τ, on saturation profiles simulating a 1-dimensional coreflood (drainage)