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Numerical investigation of fluid-loss mechanisms during hydraulic fracturing flow-back operations in tight reservoirs

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ABSTRACT

Multi-stage hydraulic fracturing is widely applied in tight reservoir exploitation. Production is enhanced significantly if hydraulic fractures can connect to sweet spots with enhanced permeability due to the presence of micro- (and induced) fractures. However, less than 50% of fracturing fluids are typically recovered. This study models the mechanisms of water loss and retention in fracture–matrix system and investigates their associated time scales under different reservoir conditions. Numerical simulation results are analyzed to identify circumstances under which these phenomena might be beneficial or detrimental to subsequent production.

A series of mechanistic simulation models consisting of both hydraulic fractures and stochastically-distributed secondary fractures are constructed to simulate imbibition, fluid re-distribution, and flow-back during shut-in and cleanup. Water imbibition into the matrix would help to displace hydrocarbons into nearby micro- and hydraulic fractures, and this process could lead to an increase in initial rate. Although other mechanisms including water loss in desiccated matrix and water trapping in induced secondary fractures were proposed in literature, detailed understanding of these water-trapping mechanisms is still lacking. Fluid-loss and retention mechanisms in matrix and induced fractures are systematically investigated. Impacts of secondary fracture distributions and properties, matrix permeability, multiphase flow functions, initial saturation, water injection rate and shut-in duration on fluid retention and the associated time scales are assessed.

This work presents a quantitative study of the controlling factors of water retention. It investigates the roles of multi-scale fractures in flow-back behavior and ensuing recovery performance. The results highlight the crucial interplay between shut-in duration and properties of connected fractures in the short- and long-term production performances. The results would have considerable impacts on understanding and improving current industry practice on fracturing design and assessment of stimulated reservoir volume.

1. Introduction

Multi-hydraulically fractured horizontal wells are widely adopted to obtain economic production of tight oil. This stimulation technique would accelerate production and increase reserves significantly if hydraulic fractures can connect to the sweet spots with enhanced permeability due to the presence of secondary fractures (Zou, 2012; Pitman et al., 2001). In some instances, hydraulic fracturing may reactivate secondary fractures that are closed under initial in-situ stress conditions or induce additional ones near the wellbore.

Thousands of cubic meters of fracturing fluid are injected into the formation during hydraulic fracturing operation (McClure, 2014). In tight oil reservoir, slick water is typically used as fracturing fluid (Mayerhofer and Meehan, 1998; Reinicke et al., 2010). During the injection phase, water may leak off into the matrix, resulting in a fracturing fluid efficiency (fracturing fluid volume in fracture over total injected volume) to be less than 100% (Economides and Nolte, 2000). After injection, the well is shut-in for a period, and the fluid pressure immediately after injection is the Initial Shut-in Pressure (ISIP) (McClure and Zoback, 2013). According to the micro-frac investigations in western Canadian tight oil reservoirs, including Viking Sandstone and Cardium Sandstone, the value of ISIP is typically higher than the initial reservoir pressure by 15–55 MPa (Woodland and Bell, 1989). During the shut-in/soaking period, fracturing fluid leaks off into the formation involving complex interplay between the capillary and viscous forces (Economides and Nolte, 2000). The fracturing fluid

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Nomenclature

A_M	contact area between fracture and matrix, m^2
a_F	fracture aperture, m
a_{NF}	secondary-fracture aperture, m
a_{HF}	hydraulic-fracture aperture, m
SRV	stimulated reservoir volume
B_o	formation volume factor of oil, m^2/m^2
B_w	formation volume factor of water, m^2/m^2
P	probability
P_b	bubble point pressure, Pa
P_{cM}	capillary pressure in matrix, Pa
P_{cF}	capillary pressure in fracture, Pa
P_i	initial reservoir pressure, Pa
P_{wf}	minimum wellbore flowing pressure, Pa
C_t	total compressibility, Pa^{-1}
J	Leverett j function
k_M	matrix permeability, m^2
k_{NF}	secondary-fracture permeability, m^2
k_{HF}	hydraulic-fracture permeability, m^2
n	index of refined grid
N	total number of refined grids
N_{Ca}	capillary number
N_F	total number of secondary fracture in the domain
S_{wM}	matrix water saturation
S_{wNF}	secondary-fracture water saturation
S_{wHF}	hydraulic-fracture water saturation
S_{wirr}	irreducible water saturation
P_{32}	fracture intensity
P_j	pressure of phase j, Pa
P_F	water pressure in fracture, Pa
P_M	water pressure in matrix, Pa
P_{Fi}	initial water pressure in fracture, Pa
P_c	capillary pressure, Pa
u_j	flow rate of phase j, m/s
q_{oi}	initial oil flow rate, m^3/day
q_{inj}	water injection rate during injection period, m^3/day
Q_o	cumulative oil production, m^3
Q_w	cumulative water production, m^3
v	flow rate m/s
V_{PF}	pore volume in fracture, m^3
t_{inj}	water injection duration, hr
T	transmissibility
w	distance from a particular refined grid outer boundary to the parent grid center, m
w_e	half width of the parent grid, m

Greek symbols

∇	gradient, m^{-1}
μ'	viscosity, Pa•s
μ	mean of probability distribution
σ	standard deviation of probability distribution
σ'	interfacial tension between water and oil, N/m
ϕ_M	matrix porosity
ϕ_{NF}	secondary-fracture porosity
ϕ_{HF}	hydraulic-fracture porosity
λ_{rj}	relative mobility of phase j

begins to flow back as the well resumes production (McClure, 2014). However, less than 50% of fracturing fluids are typically recovered (McClure, 2014; Cheng, 2012; Wattenbarger and Alkouh, 2013).

Three fluid-loss mechanisms have been reported in the literature (Pagels et al., 2012; Wattenbarger and Alkouh, 2013). Water imbibition from fracture system into rock matrix is facilitated by the high matrix capillary pressure in tight rocks. Water and oil redistribute in the fracture–matrix system during this counter-current imbibition process. (Pagels et al., 2012; Bahrami, 2012; Holditch, 1979). Besides matrix imbibition, water can be retained in the secondary fractures (Pagels et al., 2012; Fan et al., 2010). Finally, secondary fractures, which are filled with fracturing fluid and perpendicular to maximum in-situ stress, might close and lose contact with the main hydraulic fracture systems as fluid pressure depletes (Pagels et al., 2012; McClure 2014).

Experimental, analytical and numerical simulation studies of imbibition and flow-back process in fractured media have been published. Brownscombe and Dyes (1952) performed a series of countercurrent spontaneous imbibition experiments and concluded that large fracture system would provide a conductive system enhancing the imbibition process. Makhanov et al. (2014) demonstrated that the spontaneous imbibition rate in tight rocks would depend on factors including clay content, properties of secondary fractures, shut-in duration, and matrix mineralogy.

(Semi)-analytical models, which are essentially simplified solutions to the detailed governing equations, have been employed extensively in the areas of pressure transient (PTA) and rate transient (RTA) analysis. Recent works have extended their formulations to analyze early-time flow-back production data for fracture characterization (Clarkson and Williams-Kovacs, 2013; Alkouh et al., 2014; Williams-Kovacs and Clarkson, 2013; Ezulike and Dehghanpour, 2014; Adefidipe et al., 2014). However, these techniques have limited application in understanding water retention and imbibition mechanisms for a number of reasons: (1) assumptions associated with these models involve homogeneous fracture properties and sequential depletion from matrix to secondary fractures and from secondary fractures to hydraulic fracture in a fully-connected fracture network, failing to capture the impacts of realistic fracture networks on water loss and multiphase production during flow-back (Alahmadi, 2010); (2) certain studies presume that the water is immobile within the secondary fracture network (Williams-Kovacs and Clarkson, 2013); and (3) capability to incorporate multiphase flow functions (relative permeability and capillary pressure) in matrix and fracture systems is limited. For example, Abbasi et al. (2014) assumed single-phase flow, although two-phase flow might exist even during early flow-back. Ezulike et al. (2013) proposed a two-phase dual-porosity model with single-phase oil flow in matrix and negligible saturation and capillary pressure gradient in fracture, assuming that the initial hydrocarbon volume in fracture prior to flow-back was known. It is clear that none of these models are suitable for studying fluid-loss mechanisms in complex fractured media because two-phase flow and fluid distribution during shut-in and flow-back are not taken into account explicitly.

On the contrary, the complex physics of fluid flow in fractured porous media can be captured by numerical simulation. Three approaches have been developed for numerically simulating fluid flow in fractured media. In the *single-porosity* approach, matrix and fractures systems are explicitly represented in the computational domain. High permeability and porosity values are assigned to fracture cells. Flow in fracture–fracture, matrix–fracture, matrix–matrix connections are simulated in detail (Karimi-Fard et al., 2004; Aziz and Settari, 1979; Qasem et al., 2008; Rubin, 2010). The