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Full Length Article

The use of numerical simulation to investigate the enhanced Eagle Ford shale gas condensate well recovery using cyclic CO_2 injection method with nano-pore effect

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A R T I C L E I N F O

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A B S T R A C T

The huge reserves of Eagle Ford shale gas condensate reservoirs have drawn great attention. The well productivity analysis indicates that the leading Eagle Ford is in reservoir decline stage. Condensate banking effect induces severer adverse effect on ultra-low permeability reservoirs and shale gas production than conventional reservoirs. The objective of this paper is to investigate the effect of CO_2 huff-n-puff injection on mitigating condensate accumulation surrounding the induced fractures. The nano-pore confinement effect on condensate and gas production performance is considered. The nano-meter scale of shale condensate plays exhibit different phase behavior than conventional condensate reservoirs. The influence of nano-pore confinement on liquid phase behavior in shales is similar to adding CO_2 in admixture with reservoir fluids, which acts to suppress the phase envelope. The interaction of CO_2 injection with reservoir oil at molecular scale was discussed. Two scenarios including a lean gas condensate and rich gas condensate were compared in order to study the CO_2 huff-n-puff performance with different reservoir fluids. The simulation results indicated that CO_2 is more favorable in improving the rich condensate recovery. Removal of condensate accumulation in rich condensate Eagle Ford shale reservoirs by CO_2 huff-n-puff injection results in substantial recovery increment in comparison with the pressure depletion scheme. This paper focuses on studying the influences of nano-pore walls on CO_2 injection phase behavior in shale gas-condensate reservoirs.

1. Introduction

The fluids flow in gas condensate reservoirs is very complex. The condensate occurs when the reservoir pressure reduces to a point below the dew-point pressure. Well deliverability of horizontal wells is impacted by the condensate accumulation near the hydraulic fracture regions which decreases the gas permeability. Condensate only becomes mobile when its saturation approaches the required minimum condensate saturation (called critical saturation). The pressure response in the fractures drops more sharply than the shale matrix. In hydraulically fractured shale gas condensate reservoirs, the condensate firstly occurs in the hydraulic fractures. However, the mass transfer between the matrix and the fracture is reversible. The small volume of condensate in the fracture is free to enter into the shale matrix by imbibition effect because the fracture volume is negligible compared with shale matrix. The condensate in the large matrix blocks is also free to flow into the fracture system driven by pressure and diffusion process [5,24]. Numerical studies showed that diffusion plays a dominant role in controlling fluid flow in kerogen, but the diffusion effect is negligible compared with advective flux for cases in which the shale matrix permeability is larger than 10-nd [32]. The core flooding of Marcellus gas condensate experiment showed that condensate dropout is not the only reason for fluid composition change during the production process. Another reason is attributed to preferential adsorption of the heavy components on the surface of shales and preferable desorption of methane as pressure reduced [1]. Recycling of dry gas for pressure maintenance to remove condensate banking has been implemented in numerous studies. A review of the literature suggested that gas cycling and carbon dioxide injection can be used to increase reservoir pressure and mitigate the condensation formation [38].

Comprehensive experimental results by using mercury injection capillary pressure tests, NMR interpretation and SEM methods showed that the median pore throat diameter of Eagle Ford shale rock samples ranges from 10 to 35 nm [21]. The confined phase behavior of hydrocarbons in nano-pores was reported in the literature, which exhibit large deviation from their bulk measurements [11,30,37,50,54]. The alternation of fluid critical and transport properties due to pore proximity effect in nano-pores contributes to enhanced shale gas-condensate

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Nomenclature

P_{cb}	critical pressure of bulk fluid, atm
P_{cp}	critical pressure of confined fluid, atm
r_p	Pore throat radius, nm
T_{cb}	critical temperature of bulk fluid, K
T_{cp}	critical temperature of confined fluid, K
ΔP_c^*	Relative critical pressure shift, dimensionless
ΔT_c^*	Relative critical temperature shift, dimensionless
σ_{LJ}	Lennard-Jones size parameter, nm
f_i^L	the component fugacity in the liquid phase
f_i^V	the component fugacity in the vapor phase
P^l, P^V	the liquid phase pressure and vapor phase pressure
T	temperature, K
r	pore radius, nm
θ	wettability angle
σ	interfacial tension
γ_i	the component's Parachor
x_i	the component's molar fraction in the liquid phase
y_i	the component's molar fraction in the vapor phase
ρ^L, ρ^V	liquid and vapor density respectively

production [11]. Li and Mezzatesta [22] reported that the pore confinement has insignificant effect on the shale gas condensate recovery factors. Altman et al. [2] showed that the nano-pore wall proximity effects in shale gas condensate reservoirs affect the phase behaviors which lead to an increase of liquid dropout in the matrix, but its effect on well productivity is not pronounced. Their simulation results indicated that the contribution of Knudsen flow to oil recovery is up to 30%. However, there are disagreements on whether the pore confinement has significant effect on shale condensate recovery. The effect of capillary pressure on hydrocarbon production is significant when the reservoir pressure falls below the bubble point [12]. The pore size distribution also has considerable influence on pore confinement. When most of the reservoir pores fall in a macro-pore domain, the pore confinement effect on hydrocarbon production can be negligible. Sanaei [37] used the simulation approach to study the Eagle Ford condensate shale. The condensate saturation and liquid dropout was reduced near the fractures by considering the confinement effects. He claimed that the condensate recovery could be underestimated without considering the nano-pore suppression effect. History matching of the Bakken field gas production data showed that including the pore confinement effect is more consistent with real data [29]. However, the process of history match involves in a lot of uncertainties by itself, it is difficult to justify which factor is playing a role. Panja and Deo [33] used the Monte Carlo simulation of shale condensate production, which indicated that reservoir permeability, fracture spacing and initial reservoir pressure are the most influential factors that control condensate production from shales.

The biggest concern of gas injection in shale oil reservoirs is gas breakthrough early. However, using foams and gels can mitigate gas breakthrough in fractured system of shale oil reservoirs [14–16]. In previous studies, great efforts have been made to improve the mobility control of gas injection [8,17,45]. Considering the ultra-low permeability of shale formations, generation of strong foams or gels may not be suitable because of operational constraint, the CO_2 huff-n-puff injection is becoming more prevalent [20,36,55]. There are some recent research work on the feasibility of CO_2 huff-n-puff as an enhanced shale gas condensate recovery option [18,26,39,41,42]. Experimental studies [26] of methane huff-n-puff injection in shale gas condensate reservoir core samples showed 25% of condensate recovery was achieved, which is higher than gas flooding method (19%). Meng and Sheng [27] suggested that the gas huff-n-puff injection implement at a late production period when the well production rate drops to a low level. A shorter injection period could lead to a higher recovery performance [18]. Desorption mechanism was found to have significant impact on

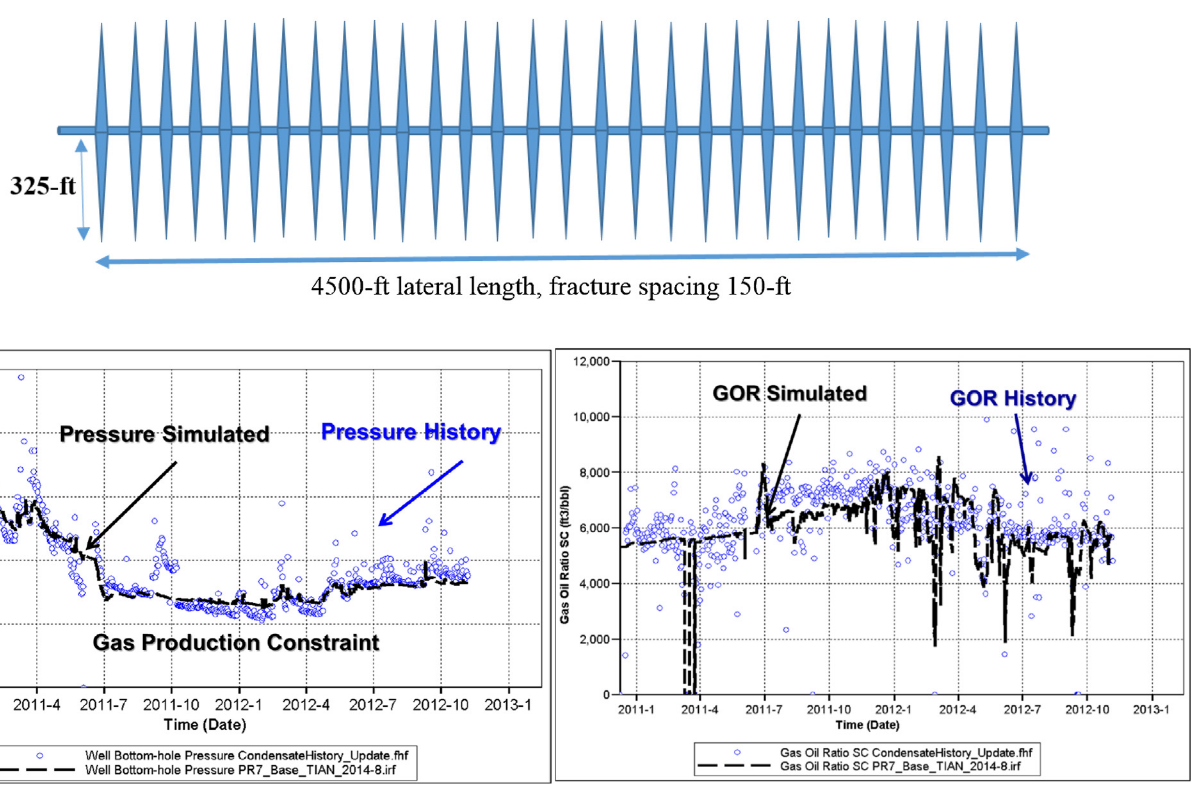

Fig. 1. History match of the Eagle Ford gas condensate well production data by Tian [49].