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Review article

A review of the current progress of CO_2 injection EOR and carbon storage in shale oil reservoirs

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ABSTRACT

CO_2 injection is a promising method to rejuvenate the shale oil reservoirs after the primary production. In this work, we comprehensively reviewed the CO_2 injection enhanced oil recovery (EOR) and carbon storage related literature in shales over the past decade. The aspects reviewed include description of major shale reservoirs producing oil and the necessity to perform EOR, selection of injection scheme, models applied to simulate gas injection, oil recovery mechanisms for different types of gas, molecular diffusion and its laboratory measurement, nanopore effect, adsorption effect on carbon storage and transport, laboratory work of gas injection in shale cores, pilot tests, and economic evaluation. Advanced models in recent years applied to simulate these processes were introduced in details, such as the traditional dual continuum model, the embedded discrete fracture model (EDFM). Heterogeneity effect and upscaling algorithm on the shale oil recovery performance were discussed. Molecular diffusion, as an important flow and oil recovery mechanism, was described regarding its definition, empirical correlation and laboratory measurement with consideration of the porous media effect which is crucial for accurate modeling result. Recovery mechanisms by carbon dioxide, methane and nitrogen were compared at the molecule and pore levels. Pros and cons of different types of gas were evaluated as well. Pore confinement caused by the extremely tiny pores in the organic matter, along with the capillary and adsorption effects were discussed, and approaches to take them into account of the model were addressed. Core-scale gas injection experiments on shales from various institutions were described, and the results were compared. Outcomes of recent pilot tests in the Eagle Ford, and the Bakken formations were summarized, and finally, economic considerations were provided for the feasibility of gas injection in shale oil reservoirs.

1. Introduction

The fraction of import of net crude oil and petroleum-related production in the U.S. decreases during the recent years, which is contributed mostly to the development of tight oil reservoirs [1]. With projections to 2040 in the reference case, tight oil will be dominating over the non-tight oil. Table 1 shows several major arising plays in the U.S. that are extensively tight oil. The Bakken play is comprised of three parts: lower, middle and upper Bakken [2]. The upper and lower Bakken are classified as the world-class source rock, and the middle Bakken is the primary production zone. The Bakken play is relatively thin lying in the central and deep part of the Williston Basin that it includes both conventional and unconventional parts. It covers across states of Montana, North Dakota in the northern central America and provinces of Saskatchewan and Manitoba in south-central Canada. The originally oil in place (OOIP) is estimated between 300 Bbbl [3] and 900 Bbbl [4] and the technical recoverable reserve is estimated to be between 4.5 Bbbl and 20 Bbbl [5]. Kerogen type is mainly Type II [6]. The kerogen type is defined based on the ratio between the hydrogen index and oxygen index. The higher the ratio, the higher quality the kerogen is, meaning that it is more oil prone. Type I is oil-prone, type II is oil and gas prone, type III is gas prone, and type IV is neither oil or gas prone [6]. In 1996, the first Albin wells were successfully completed in the Middle Bakken. In 2000, the Elm Coulee was discovered, and the

Abbreviations: AD-GPRS, automated differentiation based general purpose research simulator; CCS, carbon capture and storage; CT, computed tomography; DFIT, diagnostic fracture injection test; DFT, density function theory; DK, double-porosity; DP, double-permeability; EDFM, embedded discrete fracture model; EERC, Energy & Environmental Research Center; EOR, enhance oil recovery; GOR, gas oil ratio; LGR, local grid refinement; MINC, multiple interacting continua model; MMP, minimum miscible pressure; MRI, magnetic resonance imaging; NMR, Nuclear Magnetic Resonance; NPV, net present value; OOIP, originally oil in place; PNL, pulse-neutron log; PSD, pore size distribution; SRV, stimulated reservoir volume; TOC, total organic carbon; TRR, technically recoverable resources; USI, ultrasonic imager; VLE, vapor-liquid equilibrium; WAG, water alternating gas

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Nomenclatures

C_0	initial investment
C_t	period cash inflow
D	diffusion coefficient
D_{eff}	effective diffusion coefficient
F	formation resistivity factor
FCO_2STR	amount of CO_2 stored subsurface
FICIT	purchasing and injection amount of CO_2
f^L	fugacity in the liquid phase
FOPT	produced amount of oil
f^V	fugacity in the vapor phase
FWPT	amount of produced water
J	molar flux
k	Lattice Boltzmann constant
k_a	apparent permeability
k_{50}	median in the permeability distribution spectrum
$k_{84.1}$	median added with one standard deviation
K_a	partition coefficient
l	distance
m	cementation factor
M	molecular weight
n_c	number of components
P_c	critical pressure
P_c	capillary pressure
P_{cp}	critical pressure with the pore confinement
P^L	liquid pressure
P^V	vapor pressure
R	period discount rate
r_p	pore size
S	saturation
T	temperature
t	time step
T_c	critical temperature
T_c	cumulative time
T_{cp}	critical temperature with the pore confinement
V_A	absolute adsorption
V_{bi}	partial molar volume at the boiling pressure
V_c	critical volume
V_{dp}	Dykstra–Parsons variation coefficient
V_G	Gibbs
X	fraction
x	faction in the liquid phase
y	fraction in the gas phase
z	fraction globally
Z_c	compressibility factor at critical state
ΔP_c	critical pressure shift
ΔT_c	critical temperature shift
ε	characteristic energy
ρ	density
ρ_a	density of the adsorption phase
ρ_g	density of the free gas
ρ^L	liquid density
ρ^V	vapor destiny
σ	Leonard-Jones potential parameter
σ_F	interfacial tension
τ	tortuosity
ϕ	porosity
ϕ_{void}	porosity consisting only of the void volume
ϕ_a	apparent porosity
ϕ_{app}	porosity in the adsorptive gas flowing equation
χ^i	parachor coefficient
Ω	collision integral
μ	viscosity

Table 1
Information of major shale oil plays in the US [5,11].

Play	Bakken	Eagle Ford	Niobrara	Utica	Wolfcamp
Area, mi^2	200,000	1000	14,000	170,000	98,000
Depth, ft	8500–10,000	4000–12,000	6000–8,000	2000–14,000	5500–11,000
Porosity, %	8–12	4–10	3	6–12	2–10
Pressure Gradient, psi/ft	0.50–0.60	0.50–0.75	0.42–0.60	0.6	0.55–0.70
Total organic carbon (TOC), %	9+	4–8	7–12	0.3–2.5	2–6
Thermal Maturity, R_0, %	0.6–1.0	0.7–1.8	0.5–1.4+ (Uneven cooking)	0.6	0.8
Thickness, ft	8–14	300–475	150–300	70–750	1500–2600
Cond Ratio, B/MMcf IP rate, MMcfd	200–1800	250–1500	400–500	4,5–17 MMcfd 200–1500 Bcpd	1050
EUR/Well, MBbl	700	600	250–450	3.6–5.4 Bcf	650–750
Avg Lateral, ft	8700–10,000	6000–7000	4050–5100	500–900	4550–6700
Well Spacing, Acres	160	40–80	160 (D/S 40)	160	80
TRR, Bbbl	4.5 (20)	7–10	1.5	3.0 (5.5)	30 (Ind. est.)
Well Cost, $MM	8.5–9.0+	6.0–9.0	3.5–5.5	6.0–8.0	7.0–8.0
First Production	2008 (Middle Bakken)	2006	2006	2011	2011

first horizontal well was drilled in the Middle Bakken. In 2006, the Parshall Field was discovered [7]. The first successful liquid production from the Bakken occurred in 2008. Until the end of 2014, producing wells in the Bakken tight oil has reached 7630 [5].

The Eagle Ford play lies in south Texas that it covers more than 20 counties across Mexico. The OOIP in the Eagle Ford is between the P90 5.3 Bbbl and P10 28.7 Bbbl [8]. Oil production from the Eagle Ford play, along with Austin Chalk contribute primarily in the region of onshore Gulf coast. Kerogen type is mainly Type II, the lithology in the Eagle Ford consists of about 15% silica, 70% carbonate, and 15% clay. The formation rock is relatively brittle for fracturing purpose. The Eagle Ford has significant storage of dry gas, wet gas, and oil resources that it has been one of most active plays in the US, till the end of 2014, producing wells have reached 5650 [5].

The Niobrara (and Codel) shale lies in the Wattenberg Field located in the northeast of Denver, Colorado, where both conventional and unconventional reservoirs exist. Niobrara B and C chalk and the Codel sandstone have been oil production zones for decades [9]. Drilling and multi-stage fracturing began in 2006–2007. Niobrara shale is located at about 7000 ft depth with the thickness ranging from 150 ft to 300 ft. The complex geological condition of the Niobrara shale makes it challenging to develop sweet spots and perform hydraulic fracturing. Until the middle of 2013, the number of well completion reached 874 [5].

The Utica shale is located in the northern part of US across several states. It has producing windows of dry gas, wet gas, and oil. It has a wide range of depth varying from 2000 ft to 14000 ft and a wide range of thickness varying from 70 ft to 750 ft. The technically recoverable resources (TRR) is estimated to be 3.0 [5].