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Review article

Advances in improved/enhanced oil recovery technologies for tight and shale reservoirs

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ABSTRACT

This paper presents a comprehensive review of the technical progress as well as updated knowledge and understandings of IOR/EOR technologies for tight oil reservoirs. Critical and in-depth assessment of various IOR/EOR methods is made upon the best practice and lessons learned, mainly, in the North America. In the past few years, many traditional and new IOR/EOR methods have been tested in laboratory and piloted in field to investigate their potential in improving oil recovery from unconventional plays, including water injection, miscible and immiscible gas injection, water-alternating-gas injection, chemical flooding, and nanotechnology. Feasibility concerns and technical challenges, such as low injectivity, formation damage, and low sweep efficiency arising from extremely low permeability and high heterogeneity in fractured tight oil reservoirs, are raised for directly adopting traditional IOR/EOR methods. IOR/EOR mechanisms in tight oil reservoirs mainly involve gas and oil flows in nanometer pores, gas dissolution and diffusion through low permeability matrix, oil swelling, wettability alteration, IFT reduction, and fracture-matrix interaction, thus thorough understanding of flow and transport mechanisms in multi-scale pores and fractures is indispensable for developing effective IOR/EOR technologies. To optimize the selection of specific gas species or chemical formulas, it is necessary to conduct preliminary assessment of practicability and viability with both experimental studies and numerical simulations for operation upscaling and production prediction before field implementation.

1. Introduction

During the past two decades, the oil and gas industry in North America has successfully evolved into the era of commercially developing unconventional oil and gas plays. As of 2015, about three quarters of the natural gas production and half of the total petroleum liquids produced in the United States were contributed by shale and tight reservoirs [26]. These numbers are predicted to keep increasing in the next few decades. Meanwhile, great success in North America enables unconventional resources to gain more and more attention in other countries, e.g., China and Argentina. Nonetheless, different from conventional oil and gas resources, unconventional resources mostly reside in low permeability rocks, where the pores are tiny and poorly connected, making it difficult for oil and gas to mobilize or flow through the rock to the well.

Shale and tight reservoirs are not newly found reserves, instead they were discovered several decades ago, but most of them were not economically recoverable until recently. In fact, in some sweet spot areas, production has been put on line not long after the discovery. For example, along some anticlines in Williston Basin, vertical wells started producing in the 1950s. Nonetheless, due to relatively low productivity, exploitation was not much expanded. In the past two decades, Williston Basin soon became one of the most commercially recoverable plays by primarily benefiting from the fast evolving technologies, i.e. horizontal drilling and hydraulic fracturing.

After hydraulic fracturing, horizontal wells drilled in unconventional reservoirs can achieve very high initial production rates of hundreds of or even thousands of barrels per day. But these wells also suffer a rapid decline in production rate during first two to three years. Based on the statistics of oil production data of wells drilled in the Permian Basin from 2007 to April 2015 [27], most of the wells drastically declined to 20% of the initial peak production rate. Fast decline in production rate engenders the well to meet the marginal cost earlier and thus forces wells to be abandoned earlier. This not only jeopardizes the return of millions of dollars invested but also leaves a huge amount of oil and gas resources in rock matrices underground.

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Nomenclature

Acronyms

AS/V	apparent surface to volume ratio
bbl/d	barrels per day
cP	centipoise
CT	computer tomography
EIA	Energy Information Administration of the United States
EOR	enhanced oil recovery
EGR	enhanced gas recovery
EUR	estimated ultimate recovery
FE-SEM	field emission scanning election microscope
F&D	finding and development
gpt	gallons per thousand gallons of fluid
IFT	interfacial tension
IOR	improved oil recovery
$LSCO_2WAG$	low-salinity-alternating-CO_2 flooding
LTG	low tension gas flooding
Mbbl	thousand of barrels
MINC	multiple interacting continua
MMbbl	million of barrels
MMP	minimum miscibility pressure
Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
mD	milli-Darcy
NDIC	North Dakota Industrial Commission
NGL	natural gas liquid
NOB	net overburden
nD	nano-Darcy
OOIP	original oil in place
STB	stock tank barrel
PN	polysilicon nanoparticles
PV	pore volume
RF	recovery factor
ROIP	remaining oil in place
SAG	surfactant alternating gas
SAGD	steam-assisted gravity drainage
SEM	scanning electron microscope
SRV	stimulated reservoir volume
USGS	United States Geological Survey
μD	micro-Darcy
VLE	vapor-liquid equilibrium
WAG	water-alternating-gas

It is known that oil and gas recovery factors (RFs) are strongly related to reservoir permeability and porosity. For conventional oil reservoirs, the RFs can generally reach 30–40% after water flooding; while for gas reservoirs, the RFs could be as high as 90%. Tella et al. [157] estimated that for tight oil reservoirs with a median porosity of 20% and permeability of μD to mD, the oil RFs could be 5–15%; and for tight gas reservoirs, RFs could be between 30% and 50%. Shale formations generally have porosity values less than 15% and permeability less than 1 mD, so their RFs would be even smaller. For oil, the RFs could be 1–10%; while shale gas RFs could vary from 5 to 30%. In comparison with conventional reservoirs, large percentage of oil and gas resources could be left in place after depletion. In view of the huge amount of the residual hydrocarbon resources and heavy investment in drilling and fracturing, it is certainly worth investigating and developing practical IOR/EOR methods in order to revitalize the unconventional plays currently under primary recovery sooner or later. With appropriate IOR/EOR technologies, relatively large incremental oil/gas production and delayed abandonments could be achieved at low cost.

2. Conventional IOR and EOR methods

Conventional IOR and EOR methods refer to the approaches that have been well developed to improve or enhance oil recovery from conventional oil reservoirs, including secondary and tertiary recovery methods. Generally, after secondary water or gas flooding (i.e. restricted IOR methods), RFs of conventional reservoirs can be elevated from about 20% to about 35–45%. Tertiary oil recovery or EOR methods refer to utilization of physics, chemistry, biotechnology to economically recover hydrocarbons from mature fields, including conformance control, chemical flooding, CO_2 EOR, and most current techniques adopting nanoparticles. In general, oil recovery from conventional fields can be further improved by 5–20% with tertiary EOR methods.

2.1. Water flooding

After primary recovery, water is usually injected to supplement reservoir energy and to displace remaining oil [148]. The sweep and displacement efficiencies of water flooding have been well investigated. Sweep efficiency is strongly dependent on the mobility ratio

$$M_R = \frac{\lambda_d}{\lambda_i} = \frac{K_{rd}\mu_i}{\mu_d K_{ri}} \tag{1}$$

where K_{rd} and μ_d denote the relative permeability and viscosity of the displacing fluid, while K_{ri} and μ_i denote those of the displaced fluid, respectively. Theoretically, the lower the mobility ratio is, the higher the sweep efficiency will be.

Displacement efficiency is found directly correlated to capillary number,

$$Ca = \frac{v\mu}{\sigma} \tag{2}$$

where v is the interstitial velocity, μ is the fluid dynamic viscosity, and σ is the interfacial tension (IFT). Oil recovery increases with increasing Ca. It is suggested that for oil to be mobilized, Ca should be higher than 10^{-5}. Assume that the flow velocity is 10^{-6} m/s, water viscosity is 10^{-3} Pa/s, and IFT is 25 mN/m, then Ca is 4×10^{-8}, in this case, the oil in pores are almost immobile. If a surfactant solution, e.g. petroleum sulfonates, which can reduce the IFT to 10^{-2}, is injected, then Ca could be reduced to 10^{-4}, then approximately half of the oil could be recovered [158].

At macroscale, since injected water is heavier and less viscous than reservoir oil in general, water flooding suffers from gravitational differentiation and fingering problems, resulting in early breakthrough. The heterogeneity and natural fractures of the reservoirs may further reduce the sweep efficiency by allowing water to channel through the highly permeable portion of the reservoir and forming water dominant pathways.

2.2. Gas injection

As a major EOR approach in the United States, gas injection commonly uses CO_2, N_2, or natural gas to displace oil under either immiscible or miscible condition. Compared to water flooding, gas injection could have higher displacement efficiency and can be applied to a wider range of reservoirs, especially, low permeability and heavy oil reservoirs. The main oil recovery mechanisms of immiscible gas injection are reservoir pressure supplement to drive oil towards the production wells and gas dissolution into the oil phase to make it lighter and less viscous. For a miscible process, besides the above mechanisms, IFT between injected gas and oil is dramatically reduced or even eliminated, which would significantly increase microscopic

displacement efficiency.

Immiscible gas injection requires *in situ* oil to be greater than 40 °API, below which immiscible gas injection cannot make the oil mobile enough and miscible gas injection should be adopted. Since two distinct phases exist in immiscible flooding, fingering and channeling, similar to water flooding, could occur. Madathil et al. [102] reported a successful application of immiscible natural gas injection in an offshore reservoir in Abu Dhabi. They concluded that updip injection into oil formations with low injection rate gives higher sweep efficiency.

Miscible gas injection requires the downhole pressure to be higher than the minimum miscibility pressure (MMP), which can be determined experimentally by slim tube test or rising bubble test [176,28]. Except for extremely high-pressure reservoirs, injected gas cannot achieve miscibility at the first contact with the reservoir fluids. Instead, the injected gas gradually extracts lighter components from the oil phase during the flow process and finally becomes miscible with the oil after multiple contacts. In a multiple contacts process, considerable oil may still be trapped since a two-phase zone exists between the injection well and the miscible zone.

As to the selection of injection gas, comparison of the MMP, sweep efficiency, cost and required density of *in situ* oil for the three major gases, are listed in Table 1 [148,156].

Natural gas injection can achieve miscibility under relatively low pressure, because of its compatibility with the *in situ* hydrocarbons. One effective natural gas injection technique is recycling produced gas to maintain the reservoir pressure. Before injection, heavy components (C_{3+}) and water are removed from the produced gas at surface.

CO_2 flooding is a proven and promising EOR technique for tertiary oil recovery. During the past three decades, the number of active CO_2 flooding projects in the United States has increased by more than 300% [104]. CO_2 flooding has brought many water-flooded reservoirs back to life by increasing the RFs by up to 30%, as summarized by Rao [121]. For immiscible CO_2 flooding, CO_2 usually turns into supercritical phase under the high-pressure and high-temperature downhole condition. The density of supercritical CO_2 is usually lower than that of the *in situ* hydrocarbons, therefore supercritical CO_2 may override oil. Meanwhile, since the viscosity of supercritical CO_2 is much smaller than that of oil, viscous fingering and channeling are likely to occur in immiscible CO_2 flooding. Miscible CO_2 flooding can be used to recover crude oil with an API gravity higher than 25. If CO_2 source is available, miscible CO_2 flooding will be much more cost-effective than natural gas flooding. After CO_2 dissolution, the oil viscosity gets reduced and the oil volume significantly expands, enabling residual oil more mobile. The sweep efficiency of CO_2 flooding highly depends on the purity of the injected CO_2 [186]. Therefore, a purification of source CO_2 is necessary.

Although pore scale capillary forces can be eliminated by miscibility, miscible flooding still cannot achieve perfect sweep efficiency. Reservoir heterogeneity at macroscale may induce figuring and channeling such that less viscous miscible phase may form preferable flow pathways in high permeability zones. Moortgat et al. [111] developed three-phase compositional models to study the impact of heterogeneity on miscible gas flooding, and found that even for a slightly heterogeneous reservoir, obvious figuring can occur. Once the miscible phase channels through a high permeability zone, certain amount of *in situ* fluids will be left behind.

To control the mobility of injected gas, additives or thickeners that can increase the viscosity as well as the density of CO_2 should be adopted, including polymeric thickeners and small molecule thickeners. The most notable polymeric thickeners are fluoroacrylate-styrene copolymer and silicone oil-toluene solutions. Fluoroacrylate-styrene copolymer, in dilute concentrations of ~1 wt%, is able to improve CO_2 viscosity up to ~10-fold in light of flow through Berea sandstone at reservoir conditions [179,178]. Small molecule CO_2 thickeners, on the other hand, form viscosity-enhancing macromolecular structures to make CO_2 more viscous. A few small molecule CO_2 thickeners have also been screened, including a tri(semifluorinated alkyl)tin fluoride [65], fluorinated urea and bisurea compounds, and fluorinated and twin-tailed surfactant with a divalent metal cation [29]. All these fluorinated compounds can increase CO_2 viscosity by 50–500% at a concentration of ~2–10 wt%. So far, there are no field application of CO_2 thickeners reported because of the great expense. Effective and affordable CO_2 thickeners are still in great needs. Besides, foams and gels can also be used as CO_2 mobility controllers, current advancement of which have been summarized by Enick et al. [30].

2.3. Water-alternating-gas injection

Another effective option for mobility control of injected gas is the water-alternating-gas (WAG) injection, in which gas is firstly injected and then followed by water injection. This alternative sequence can be repeated several times. The injected gas slugs form a miscible zone with the oil bank at the front, while water slugs modify the injection profile of gas and prevent it from fingering and channeling. WAG injection has become a proven technique to improve the sweep efficiency of gas flooding [9,95]. Han and Gu [51] experimentally optimized the slug sizes and ratios of CO_2 WAG injection on Bakken tight cores.

Low salinity water has also been used in WAG, as is called low-salinity-alternating-CO_2 flooding ($LSCO_2WAG$). Dang et al. [24] and Teklu et al. [154] conducted numerical simulation and experimental study respectively to prove the feasibility and capability of $LSCO_2WAG$. Essentially, $LSCO_2WAG$ combines the advantages of LS water flooding and WAG. The LS water increases the microscopic efficiency, while WAG improves the macroscopic efficiency.

2.4. Thermal recovery

Thermal EOR intentionally introduces heat into a subsurface deposit to recover hydrocarbons, primarily from heavy oil reservoirs [119]. Cyclic steam stimulation or steam huff-n-puff (RF = 10–40% OOIP), steam flooding (50–60% OOIP), hot water flooding, steam assisted gravity drainage (SAGD) and *in situ* combustion (70–80% OOIP) have been investigated and implemented in the past few decades [159]. Viscosity reduction, thermal expansion, and imbibition are major EOR mechanisms associated with accessory solution gas drive and gravity drainage [123]. Thermal EOR methods dominated the EOR projects implemented worldwide for heavy oil development by a share of 47.7% from 1959 to 2010 and 67% of the enhanced oil production in 2010 [74].

Cyclic steam stimulation or steam huff-n-puff injects steam periodically to heat the reservoir around the wellbore. Steam flooding, in a manner similar to water flooding, continuously injects steam to push the oil towards the producer. SAGD utilizes two parallel horizontal wells in a vertical plane with the upper well as the injector and the lower well as the producer. As a more gentle and continuous process, SAGD yields higher recovery and requires less water and energy. To further reduce the energy requirement, two variations of SAGD were developed, i.e. vapor extraction (VAPEX) and steam and gas push (SAGP) [13]. In VAPEX, a mixture of a non-condensable gas, e.g., methane, and a volatile liquid solvent, e.g., propane/butane mixture, is injected. Then the solvent dissolves into the oil, reduces its viscosity and enables production without gas coning. SAGP improves the thermal efficiency of SAGD by adding non-condensable gas into the steam, an addition of 0.5 mol% can lower steam consumption by ~30%. Another

Table 1
Comparison of gases used for miscible gas injection.

Gases	MMP	Sweep efficiency	Cost	*In situ* oil
co_2	Lowest	Highest	Medium	> 25 °API
Natural gas	Medium	Medium	Highest	> 30 °API
N_2	Highest	Lowest	Lowest	> 40 °API

thermal method, *in situ* combustion injects air into the reservoir with the intent of oxidizing a small fraction of the hydrocarbon in place to generate heat and gas to reduce oil viscosity and increase drive energy [119]. The *in situ* combustion approach comes with high risks but also with great opportunities of enhancing heavy oil recovery. However, it is often too complex to model.

2.5. Chemical flooding

Chemical flooding uses chemicals to either improve the sweep efficiency or the displacement efficiency of displacing fluids. Commonly used chemicals consist of alkali, surfactant, polymer, gels, emulsion as well as their combinations, such as alkali-polymer, surfactant-polymer, alkali-surfactant-polymer, etc. In practice, slugs of different formulas and sizes are usually injected sequentially into the reservoir to optimize the chemical performance. There are lots of publications on chemical EOR methods (e.g. [55,133,134] and their mechanisms have been clearly illustrated, thus in this review they are not discussed.

In addition to the chemical EOR methods mentioned above, there are many other forms of techniques applying physicochemical theories to enhance oil recovery, including foam flooding [54,76], surfactant alternating gas flooding [89], polymer [32,170,92,93], coated polymer [132], inorganic nanoparticle flooding [3], gel particles for conformance control [2,8], etc. Low salinity water flooding was also found with great IOR potential in laboratory experiments [150,151], which was further confirmed in Alaska North Slope field tests by BP [107,131]. Though many mechanisms have been proposed to interpret the low salinity effect, no consensus has been reached upon the role of brine in oil/brine/rock interactions [67].

To keep pace with the increasing oil consumption in the coming decades, life of mature oilfields needs to be extended. Therefore, in addition to the currently available IOR/EOR methods, new technological breakthroughs are in demands to supply the world with affordable oil and gas resources, while minimizing adverse environmental concerns.

3. Fluid storage, flow and recovery mechanisms in unconventional reservoirs

Fluid flow in fractured tight oil reservoirs is complicated by the highly heterogeneous and hierarchical rock structures, ranging from organic nanopores, inorganic nanopores, micro-fractures, to big hydraulic fractures. The corresponding fluid flow and storage mechanisms originated from these characteristics are low permeability, confinement of phase envelope, osmosis, geomechanical rock deformation, and high-velocity non-Darcy flow in hydraulic fractures. Given these diverse and interdisciplinary features, many efforts have been devoted to including them into flow modeling and simulation for unconventional reservoirs.

3.1. Nanopores and organic matter

Many analytical techniques (e.g., FE-SEM, mercury intrusion capillary pressure, and nuclear magnetic resonance) show abundant nanopores connected to sparse micrometer pores in unconventional reservoirs. Nelson [114] summarized the measurements of the width of pores and pore-throats in different siliciclastic rocks, along with the size of hydrocarbon molecules and the diameter of solid particles, ranging from sub-millimeter to the nanometer scale. For most shales, the pore throat diameter falls in the range of 0.01–0.1 μm, which is almost the same as the asphaltene molecule, 50 times larger than light oil molecule, and 100 times larger than methane molecule. Sandstone pores are typically 3 or 4 orders of magnitude larger than shale, which is why unconventional plays need stimulation treatments for economic production.

Loucks et al. [99] classified the shale pores into three major types: intrapores inside organic matter, interpores between particles and crystals, and intrapores inside crystals. The intrapores inside organic matter are secondary pores created during thermal maturation, when the organic matter is decomposed and converted into hydrocarbon. They are observed to be bubble-like from FE-SEM images, varying from nearly spherical to irregularly polygonal. Interpores develop during the sedimentation process and significantly diminish after burial and compaction. Their presence and proportion vary considerably in different shales. In Barnett shale, intrapores inside organic matter are predominant [98]. In upper Eagle Ford, inorganic pores are major ones, while the organic pores are crucial for fluid flow in the lower Eagle Ford [137].

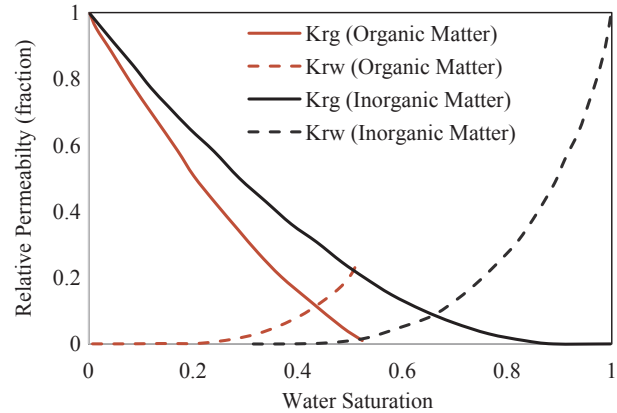

Fig. 1. Water and gas relative permeability in organic and inorganic porous media [180].

Fluid flow and storage in organic pores are very different from inorganic pores. First, organic pores are typically one or two orders of magnitude smaller than inorganic pores, and thus the permeability is lower. Second, organic pores are strongly oil-wet while inorganic pores are generally water-wet, whereby the non-wetting and wetting phase distributions in pores are established. Macroscale multiphase flow behaviors, e.g., relative permeability curves, are therefore different (Fig. 1).

3.2. Low permeability

Shale formation is characterized by extremely low permeability from sub-nD to μD, varying for different shales, even under the same porosity, stress, and pore pressure. As summarized by Wang and Reed [169], permeability of deeply buried organic-lean mud rocks can be less than tens of nD, and that of organic-rich gas shales ranges from sub-nD to tens of mD. In laboratory, permeability is measured by using either core plugs or crushed samples.

In reservoir simulation, shale matrix permeability k_m and tortuosity τ_m can be estimated with pore throat diameter d, matrix porosity ϕ_m, and cementation exponent e,

$$k_m = \frac{d^2}{32}\frac{\phi_m}{\tau_m} \tag{3}$$

$$\tau_m = \phi_m^{1-e} \tag{4}$$

The effective permeability of fractured shale reservoir $k_{f,eff}$ can be estimated using,

$$k_{f,eff} = k_m + k_f\phi_f \tag{5}$$

where ϕ_f is the fracture porosity, and fracture permeability k_f can be approximated as parallel plates with a specific width.

We can assume core permeability as matrix permeability, which can be compared with the effective reservoir permeability from transient flow well tests to quantify the stimulation effectiveness.

3.3. Confined phase change and osmosis

Nanopores lead to significant interfacial curvature between confined vapor and liquid phases. Zarragoicoechea and Kuz [185] pointed out that phase behaviors of fluids in confined pores are different from the bulk phase, in that phase envelope and critical points are functions of the ratio of the molecular size to the pore size.

The effect of surface curvature on phase behavior would affect equilibrium compositions and pressures. Experiments showed that the nanometer pores significantly suppress the vaporization of hydrocarbons [171]. That is, the bubble-point pressure is a function of pore radius. Firincioglu et al. [33] studied the nanopore confinement effect on phase behavior by including capillary pressure and surface forces in the vapor–liquid equilibrium (VLE) calculation. The surface forces may contain structural, electrostatic and adsorptive forces; for practicality only van der Waals forces were included with capillary pressure in the VLE calculation. It is found that the contribution of the surface forces to phase behavior increases as pore size decreases; however, it is about 1–9 magnitudes smaller than that from capillary pressure. Thus, including the capillary pressure in VLE calculation is sufficient to represent the nanopore confinement effect. Wang et al. [173] studied phase behaviors of typical light oil and condensate in nanopores with capillary pressure effect and showed that residual liquid in pores with radii of 10 nm or less would probably always be trapped. Meanwhile, the fluid properties, such as density and viscosity, are also affected, which further complicates the fluid flow behaviors. Thus, it is necessary to improve the conventional VLE calculation for capturing the effect of capillarity on phase behaviors for accurately modeling tight oil reservoirs.

In addition, because of the small pore size, shale can act as a semi-permeable membrane, restricting the passage of solutes. In shale and tight reservoir systems containing crude oil, minerals, and brine, solutes can be water molecules [31] and light hydrocarbon molecules [193]. Mostly recently, selective hydrocarbon transport through nanopores have been studied to illustrate the fluid properties and distributions as reservoir pressure depletes [191].

3.4. Fracture systems

Fractures are ubiquitous in unconventional plays and their presence is a critical factor in defining the economic prospect. To match production rates and ultimate recoveries of unconventional reservoirs, permeability values input in simulators are usually required to be 2–4 orders of magnitude greater than the matrix permeability [166]. Fractures in unconventional reservoirs occur from micro-fractures, small and intermediate fractures, to big hydraulic fractures. These branched fractures of different scales significantly increase contact areas between fractures and matrices, consequently impacting the overall flow and transport processes.

Fracture spacing, orientation, size, and filling are the key factors that govern the gas production from shale plays. To quantify these parameters, a multi-disciplinary and fully-integrated approach utilizing diverse datasets from cores, well logging, and seismic analyses is necessary. Natural fractures observed from the cores and the field are often narrow (aperture < 0.05 mm) and bounded by beddings (height < 2 ft) [38]. Typically, most small fractures are sealed with calcite or bitumen strips (Fig. 2). Only the large ones above a specific threshold are open and contribute naturally to reservoir storage and flow capacity. Whether the sealed fractures can be reactivated during hydraulic fracturing depends on the degree of cementation. Natural fractures are not oriented randomly but are present in en echelon arrays, as determined by the *in situ* stress, mechanical stratigraphy, and local fault geometry. Understanding of natural fracture orientations is significant for optimizing hydraulic fracturing treatments and maximizing gas production from unconventional reservoirs.

Hence, handling flow through fractured media is critical in shale and tight reservoir simulation. Published studies have paid a lot of attention to modeling fractures in shale gas formations (e.g. [20,21,90,177]. However, most of them use commercial reservoir simulators developed for conventional fractured reservoir simulation, which have very limited capabilities for modeling unconventional reservoirs with multi-scale fractures. Therefore, more efforts on model developments, from new conceptual models to in-depth modeling studies of laboratory experiments to field scale applications, are needed.

For low matrix permeability or large matrix block size, traditional double-porosity model may not be applicable, due to that it might take years to reach the pseudo-steady state. The multiple interacting continua (MINC) concept [120], as shown in Fig. 3, is capable of describing gradients of pressures, temperatures, or concentrations within multi-dimensional nested meshes. In comparison with the double-porosity or dual-permeability model, MINC does not rely on the pseudo-steady state assumption to calculate fracture-matrix flow and is able to simulate fully transient fracture-matrix interaction by subdividing matrix blocks into nested-cell grids. Thus, it should generally be applicable for handling fracture-matrix flow in fractured tight reservoirs. However, the MINC approach may not be applicable to systems in which fractures are too sparse to be approximated as a continuum.

As Fig. 4 shows, in our hybrid-fracture model, both hydraulic fractures and stimulated reservoir volume (SRV) are evaluated from the microseismic cloud. A primary hydraulic fracture system and an associated stimulated volume are set in each hydraulic fracture stage. Specifically, we first define a primary fracture based on the orientation and region of the microseismic cloud. The hydraulic fractures are modeled by discrete fracture method. By assuming the SRV near the hydraulic fractures containing natural fractures, we apply MINC in it. Single porosity is applied in the region outside the SRV. As pressure gradients change substantially within short distances of hydraulic fractures, local grids are further refined to improve simulation accuracy.

3.5. Geomechanical effect

In unconventional shale and tight reservoirs, initial pore pressure is usually very high and the decrease is substantial during the production, therefore rock compaction or geomechanics can have a significant impact on both fracture and matrix permeability.

Wang and Reed [169] showed that permeability in the Marcellus Shale is strongly dependent on pressure and could decrease by an order

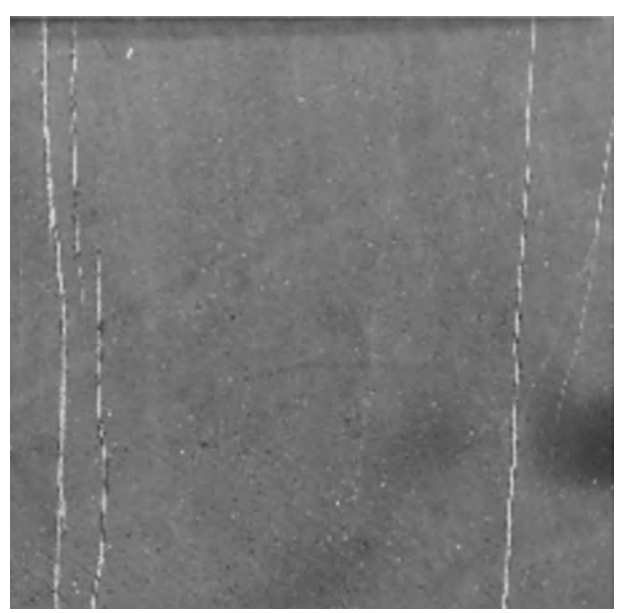

Fig. 2. Natural fractures sealed with white calcite in shale, 10 cm by 10 cm.

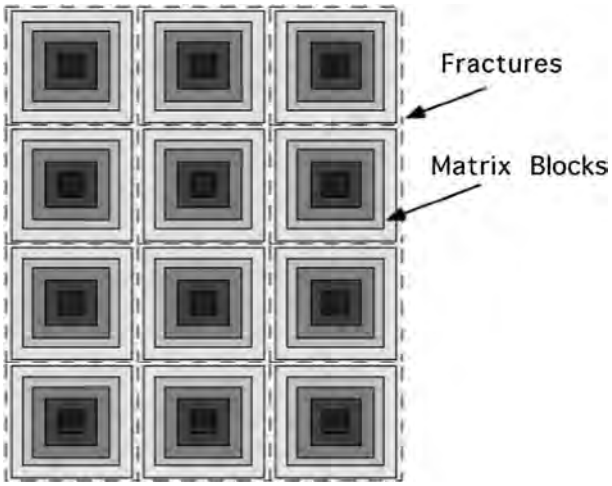

Fig. 3. Sketch of MINC grids [120].

of magnitude with a reasonable increase in effective stress, which is significantly higher than consolidated sandstone or carbonate. Holditch [59] measured air permeability of Travis Peak cores from two wells in East Texas at surface and *in situ* conditions to illustrate the effect of net overburden pressure on air permeability. For cores of high permeability (10–100 mD), the overburden pressure effect is relatively slight. However, as the core permeability decreases, the overburden pressure effect increases substantially. For cores with unstressed permeability of about 0.01 mD, overburden pressure decreased the permeability to 0.001 mD. Low permeability rocks are more stress-sensitive because of the smaller pore throats compared to the high permeability rocks [59].

The impact of stress change on fracture permeability in shale and tight formations is expected much more significant because of the 2-D nature of fracture geometry, which cannot support stress loading in the normal direction of fracture plates. If the fracture planes are aligned, unpropped fractures will show very low permeability at high closure stresses. However, if the fracture planes are displaced or the fracture is partially propped, fracture conductivity would be retained. Chu et al. [19] constructed compaction tables relating permeability reduction factor to effective stress change for Bakken tight oil reservoir based on laboratory measurements and history matches, as shown in Fig. 5.

Other tight oil reservoirs also show a strong stress-dependent rock property. For example, simulation study for the Eagle Ford tight oil reservoir concludes that the transmissibility could decrease by an order of magnitude due to degradation of the fracture permeability. Besides, porosity, rock volume, capillary pressure and phase envelope are also affected by rock compaction and deformation. In addition, there are some laboratory experiments showing that relative permeability could also be influenced by the overburden stress [82]. Therefore, it is necessary to couple fluid flow and geomechanics in order to model rock compaction effect on production performance for tight oil reservoirs.

Several correlations have been used for calculating porosity as a function of effective stress and permeability as a function of porosity [127,115]. For example, Rutqvist et al. [127] used the porosity function obtained from laboratory experiments with sedimentary rocks

$$\phi = \phi_r + (\phi_0 - \phi_r)e^{-a\sigma'} \tag{6}$$

where ϕ_0 is the porosity under no stress, ϕ_r is the porosity under high effective stress, and a is a parameter. The corresponding permeability in terms of porosity is

$$k = k_0 e^{c(\phi/\phi_0 - 1)} \tag{7}$$

where c is a parameter.

4. Laboratory study and modeling of unconventional IOR/EOR approaches

More and more efforts are being devoted to develop EOR technologies for unconventional reservoirs. The IOR/EOR technologies in this section, based on our review of current laboratory researches, include immiscible/miscible CO_2 injection, CH_4 and N_2 gas injection, and chemical flooding. Modeling and simulation are important tools to evaluate the practicability of an EOR project and potential oil recovery before any implementation. Gas and water flooding, WAG, gas huff-n-puff, and CO_2 immiscible/miscible flooding are topics that are being investigated by modeling and simulation. Critical operating parameters of these EOR processes are injection time, soaking period, huff-n-puff frequency, and fracture-matrix characteristics. Introduction of these contents aims to open a window for potential EOR technologies in unconventional reservoirs and to provide valuable information of physics and chemistry behind these complex EOR processes.

4.1. Immiscible/miscible CO_2 injection

By 2012, CO_2 miscible flooding produced 308,564 bbl/d, which accounts for 41% of the total US EOR daily production and is more than any other EOR methods. CO_2 immiscible flooding added another 43,675 bbl/d. Moreover, CO_2 has been successfully applied in heavy oil or fractured reservoirs. CO_2 injection, therefore, has been considered for tight oil reservoirs [163].

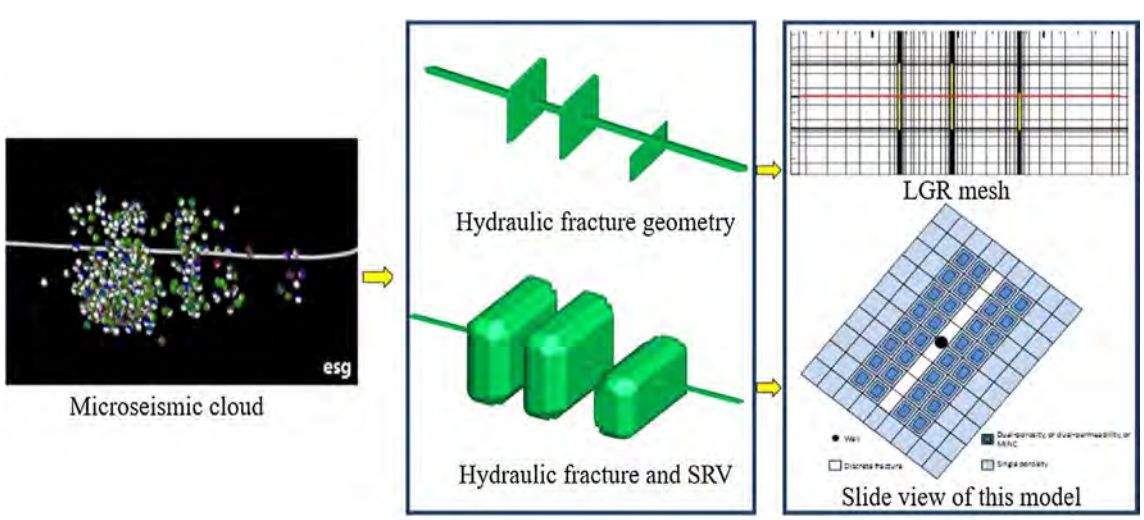

Fig. 4. Hybrid-fracture model building methodology from microseismic cloud.

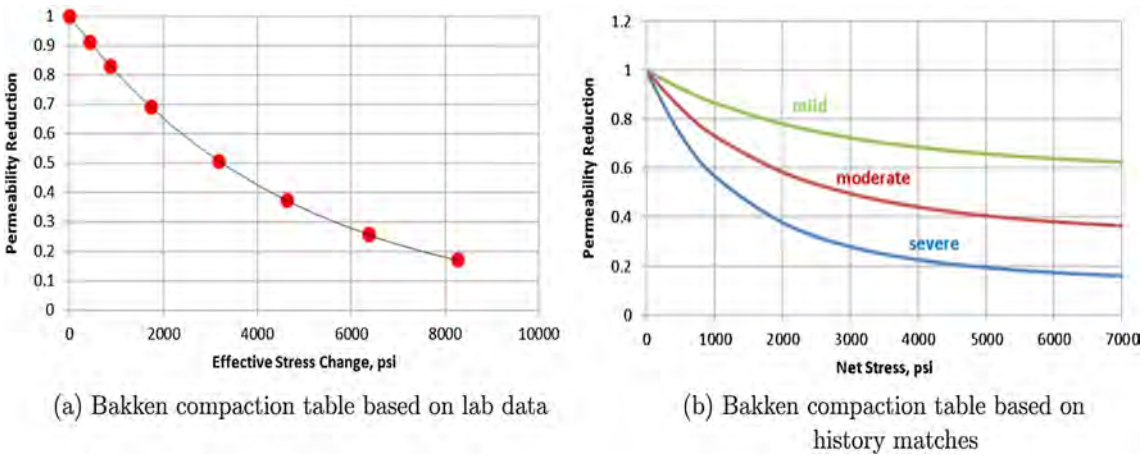

Fig. 5. Bakken formation compaction correlations [19].

The mechanisms of CO_2 EOR in conventional reservoirs include: (a) swelling oil, where the CO_2 dissolution can expand oil phase volume by 10–60%, (b) reducing oil viscosity, (c) favorably changing of oil and water phase density to reduce gravity segregation, (d) alternating rock wettability towards water-wet, and (e) reducing IFT between hydrocarbon-enriched CO_2 and CO_2-saturated oil [61,143,85,141,42,181].

However, the mechanisms of CO_2 EOR in tight oil reservoirs cannot be considered the same as those in conventional reservoirs, due to different petrophysical properties, reservoir fluid thermodynamics, and mass transport mechanisms. CO_2 might dominantly flow through fractures and not significantly into matrix. Kovscek et al. [77] thought that as the reservoir pressure depletes and solution gas evolves from oil, significant gas saturation could be generated in the rock matrix. In such cases, continuous gas pathways would form, accelerating gas delivery from fracture into matrix. Diffusion has also been noted as an important mechanism that impacts the oil recovery process during gas transport. Hawthorne et al. [52] proposed a five-stage conceptual model to explain CO_2 EOR in Bakken formations: (1) CO_2 is injected into the fractures, (2) CO_2 saturates fractures and contacts rock matrix, (3) CO_2 penetrates the matrix under pressure gradient, swells and expels oil out of pores, (4) oil of reduced viscosity drains into the fractures, and (5) as the CO_2 pressure gradient drops, oil transport is dominated by concentration gradient across the matrix and the fractures.

4.1.1. CO_2 huff-n-puff experiments

Many laboratory experiments investigated the potential of CO_2 EOR in tight oil reservoirs. Using a Hassler core holder, Tovar et al. [163] modeled the fractured shale reservoir by surrounding the nano-Darcy shale cores with glass beads, which ensured that high-pressure CO_2 was always in contact with the matrix. Two Berea sandstone plugs were mounted at both ends as filters to prevent production of glass beads. A CT scanner was used to monitor density changes of the system at ~6-h intervals.

At 150 °F, two experiments were conducted at 3000 psi and 1600 psi, respectively, to vary the density of injected CO_2, which is denser than the main crude oil constituents at 3000 psi but much lighter than them at 1600 psi [163]. The experimental procedure simulated the CO_2 huff-n-puff process by injecting CO_2 for soaking and producing crude oil periodically. Results showed that the oil RFs could range from 18 to 51% for the 3000 psi case and 19–55% for the 1600 psi case. Compared with the dark color crude oil produced in the field, the oil recovered from the core is much lighter in color with lower viscosity, suggesting hydrocarbon vaporization as a main recovery mechanism. Also, CT scan verified that CO_2 is able to penetrate the shale cores.

Sun et al. [145] performed simulations to validate the experiments of Tovar et al. [163] and to investigate the effect of rock and fluid properties on oil recovery by rebuilding the core assembly into a Cartesian grid. Simulation results from 2D core slice model showed that RFs are not sensitive to the permeability of either matrix or fracture. Better RF is obtained when fracture and matrix porosity is higher, and diffusion coefficient is larger. A 3D homogeneous core scale model was used to simulate the first experiment of Tovar et al. [163], reaffirming the significant role that diffusion plays. However, their field scale huff-n-puff modeling showed that convection instead of diffusion is considered as the dominating mechanism.

4.1.2. Diffusive flow and convective flow

Kovscek et al. [77] conducted immiscible and near miscible CO_2 injection experiments on siliceous shale cores to quantify the EOR potential using X-ray CT imaging to interpret the *in situ* gas and oil distribution. These cores have a permeability range of 0.02–1.3 mD and a medium porosity of 30–35%. CO_2 was injected into the cores in both countercurrent and concurrent modes to assess the diffusive and convective transfer mechanisms, respectively. It turned out that countercurrent CO_2 injection at near miscible state achieved slightly greater recovery. Gas saturation maps indicated that continuous gas pathways formed along the core heterogeneities, allowing CO_2 to permeate the core and contact the oil phase.

Kovscek's group further extended the CO_2 injection experiments to miscible conditions [165]. The countercurrent mode achieved an oil recovery of 54% and the subsequent cocurrent mode gave an additional 39%, leading to a total oil recovery of 93% OOIP. Despite the low permeability and heterogeneity, both diffusive and convective transfer mechanisms were demonstrated significant in the experiments. Nonetheless, to achieve sufficient CO_2 penetration and miscibility, tight and heterogeneous rocks as well as uneven oil and gas distributions are still very challenging factors for optimizing the injection process.

4.1.3. Hydrocarbon mobilization mechanisms

Hawthorne et al. [52] conducted experiments to discuss the processes that control the transport of oil from rock matrices into the CO_2 filled fractures. Core samples were obtained from Middle, Upper and Lower Bakken reservoir. Permeability of reservoir rocks in Middle Bakken ranges from 0.002 to 0.04 mD [80], and those of Upper and Lower Bakken reservoirs are orders of magnitude lower. Cores of different geometries were cut from the bulk samples for tests. Crude oil was obtained from a close location and its estimated MMP ranges from 2800 to 3000 psi. All CO_2 exposures were performed at reservoir temperature of 110 °C in an extractor with 5000 psi CO_2 supplied by a syringe pump. CO_2 was freely surrounding the rock samples to model the fracture flow dominance. Produced hydrocarbons collected at the outlet were analyzed and calibrated to the Bakken crude oil.

Two different procedures were implemented on the samples. In the first procedure, the sample was pressurized to 5000 psi for 50 min,

followed by a 10-min dynamic sweep with CO_2 to collect the mobilized hydrocarbons. This 1-h sequence was repeated for 7 h then followed by longer static exposures with 10-min collections of mobilized hydrocarbons at 24, 48, 72 and 96 h. In the second procedure, shorter exposures were performed under dynamic conditions. CO_2 was continuously flowed during the first 7 h of extraction, but then was kept static from 7-24 h, followed by a 1-h dynamic collection of the produced hydrocarbons [52]. The results showed that CO_2 exposure recovered 60% of the hydrocarbons from tight samples of Lower and Upper Bakken formation. The thinner square and small cores accelerated the recovery process and resulted in higher RFs. From the perspective of specific steps of CO_2 EOR in fractured shale reservoirs, the results provide some interpretations: 1) the absence of an especially fast recovery in the first few minutes indicates that initial oil swelling is not a significant recovery mechanism, 2) the preference to produce lower molecular weight hydrocarbons shows that hydrocarbon mobilization into CO_2 is a dominant recovery process, 3) the more surface area per rock mass CO_2 accesses, the faster hydrocarbons will be recovered, 4) the pores in the source shales must have sufficient connectivity to be accessed by CO_2, even if very slowly.

4.2. CH_4 and N_2 injection

The injected gas could be hydrocarbon gas, CO_2, N_2, or a mixture of gases. Selection of the optimum gas source depends on reservoir conditions, gas availability, and economic assessment. Gas can be injected into the subsurface media continuously or cyclically, known as flooding or huff-n-puff processes. The huff-n-puff EOR method avoids gas viscous fingering in the high viscosity reservoir and increases both the sweep efficiency and the oil displacement efficiency at the same time. In recent years, gas huff-n-puff has been used to increase oil recovery in shale oil reservoirs. Numerous experiments have been conducted using different gases, such as N_2 and CO_2 to recover oil from shale cores [87]. The benefits of N_2 include its low cost, simple production process, and non-corrosive property [182]. It is challenging to use CO_2 in certain circumstances because of high cost, corrosion, transportation, etc. Compared with CO_2, CH_4 and N_2 are more readily available in the oilfield.

The mechanisms involved in cyclic gas injection vary and are complex, but generally include oil swelling and viscosity reduction, increase of relative permeability, wettability change, re-pressurization, diffusion, and decrease of interfacial tension [40].

4.2.1. CH_4 huff-n-puff experiments

Li and Sheng [87] explored the effect of core size on the cumulative oil RFs from CH_4 huff-n-puff experiments on shale core plugs from the Wolfcamp formation in Apache's Lin field. The cores that were drilled parallel to the sedimentary layers were divided into two groups. One group contained six 2″ long cores with different diameters of 1″, 1.5″, 2″, 3″, 3.5″ and 4″, respectively. The other contained four cores with the same diameter of 1.5″, but varied lengths of 1″, 2″, 2.75″, and 3.5″. The main experimental flows consist of crude oil saturation and cyclic CH_4 injection. The core plugs were first placed and vacuumed in a container, into which crude oil was pushed by syringe pump for saturation at 4000 psi. Before and after saturation, cores were weighed for RF calculation. In the injection process, CH_4 was injected into the container to reach 2000 psi and then it was shut in for 24-h soaking. Finally, the core containers were depressurized using a backpressure regulator to control the production rate. All experiments were conducted at 95 °F.

It is found that the cores with a larger apparent surface-to-volume ratio (AS/V) yielded a higher RF under the same operation conditions. That is, smaller diameter has relatively higher pressure gradient ($\Delta p/\Delta r$) which helps gas penetrate matrix, resulting in a higher RF. Therefore, multi-stage fracturing with shorter fracture space will result in higher AS/V in the reservoir, which is helpful for huff-n-puff EOR from liquid-rich reservoirs. In the other group of experiments using cores of the same diameter but different lengths, the AS/V of all cores is the same. Eight cycles of CH_4 huff-n-puff indicated that lengths only have a small impact on the oil recovery, reaching that the same AV/S gives similar oil recovery. In addition, incremental RFs exhibit a consistently decreasing trend with cycle numbers, of which the first five cycles are generally above 5%. It is inferred that as gas approaches the core center, convection and dispersion effects become smaller while resistance increases with distance, decreasing oil transport and hence the RFs [87].

4.2.2. N_2 huff-n-puff experiments

N_2 was used to explore the EOR potential and critical parameters of huff-n-puff method on three shale cores from Barnett, Marcos, and Eagle Ford [39]. The cores were prepared in the same dimensions with diameter of 1.5″ and length of 2″. Mineral oil Soltrol 130 was used to saturate the cores under 2000 psig for 48 h. Experimental procedures are similar to those in Li and Sheng [87] and were carried out at 95 °C.

Results indicated that oil recovery was improved drastically when the soaking pressure increased from 1000 psig to 3000 psig, which is near-miscible. For example, RFs on Barnett core increased from 6.5% to 14.91%. Extending the shut in period yielded higher recovery, e.g. at 3000 psig, RFs from Marcos shale increased from 13.50% to 19.59% for 1-day and 3-day shut in periods. In addition, increasing huff-n-puff cycles improved oil recovery for three shales but the efficiencies were different. For instance, after 6 cycles at near miscible pressure of 3500 psig, the recovery from Eagle Ford shale reached 70.20%, and the Marcos and Barnett shales gave 53.23% and 30.99%, respectively [39]. Clearly, N_2 huff-n-puff EOR from shale oil reservoirs are promising and should be optimized upon operating pressure, shut in time, and the number of cycles for a specific reservoir.

4.2.3. N_2 flooding experiments

Yu and Sheng [182] performed two groups of flooding tests on Eagle Ford outcrop cores to investigate the effects of flooding pressure and time on RFs. The representative core porosity is 5.21% and permeability is 70 nD, and the dead shale oil has a density of 0.815 g/cc and a viscosity of 8.5 cP at 71 °F and atmospheric pressure. They concluded that longer flooding time and higher injection pressure achieved higher RFs but problems of decreasing incremental RFs and gas breakthrough still existed. During the gas flooding process, a gas flow meter was installed to monitor the mass flow rate and the flooding process was visualized by a CT scanner.

The results indicated that N_2 was able to recover more than 20% oil after 5-day flooding at 1000 psi. Oil produced fast in the beginning and then gradually dropped until zero. About 50% of total oil production in 5 days was recovered in the first day. Gas broke through after 8 h flooding and the flow rate became stable in one day. Gas dominant channels formed inside the cores weakened the gas drive in longer operation. As injection pressure increased, gas broke through earlier and higher recovery efficiency was achieved, as can be attributed to extended contact areas under higher pressure gradient [182]. Although high injection pressure is proven favorable, reservoir conditions and economics are constraints needed to be considered.

4.3. Chemical flooding

A few factors that restrict application of conventional chemical EOR techniques to unconventional reservoirs are low permeability, reservoir pressure, temperature, heterogeneity, water coning, and gas source availability. Regarding tight carbonates and sandstones of 2–35 mD, removal of polymers from chemical flooding is necessary because of the pore plugging and shear degradation [146]. Wettability alteration of reservoir rocks is an effective approach to enhance oil recovery through modifying capillary forces, as can be achieved by using surfactants [7]. Surfactant adsorption on interfaces alters pore surface wettability and

reduce interfacial tension, facilitating water invasion into pores to expel oil [46]. During hydraulic fracturing, surfactants are added to fracturing fluids to facilitate the flow back process by mitigating water blockage.

4.3.1. Low tension gas flooding experiments

Low tension gas (LTG) flooding is a technique that intends to simultaneously improve displacement efficiency using surfactant solution and augment sweep efficiency using gas in a co-injection process. Szlendak et al. [146] designed a chemical formulation and performed LTG flooding on Texas Cream limestone cores to evaluate the overall EOR effectiveness in tight reservoirs. Oil recovery, fractional flow, salinity, mixing, sectional pressure drop, microemulsion and surfactant production were used to evaluate LTG flooding. Specifically, Szlendak et al. [146] tested four relatively uniform cores (T1, 3–5) with a permeability range of 10.8–14.2 mD and one core (T2) of 2.6 mD containing a low permeability streak. Aqueous solutions were injected by a pump, while gas rate was controlled by a Brooks mass flow regulator with regulated upstream and downstream pressures. Pressure along the core was monitored at the dimensionless length of X_D = 0, 0.25, 0.75, 1. At 45 °C, the cores were first saturated with brine, and then were brought to irreducible brine saturation by injecting crude oi. Then oil was displaced by brine, after which 0.3 pore volume (PV) of chemical slug was co-injected with N_2 at 50% fraction. Drive slug followed until 0% oil cut or total fluid injection reached 3.5 PVs. LTG flood #1 (LTG_T1) is a base case contrasted with tests 2 through 5 to establish permeability tolerance (LTG_T2), relative contributions from surfactant flooding (no gas) (Surf_T3) and gas flooding (no surfactant) (Gas_T4), and effect of high initial oil saturation on LTG flooding (LTG_T5).

Tertiary recovery of 91% of remaining oil in place (ROIP) was achieved by LTG_T1 flooding with remaining oil saturation of 0.03. The oil produced as microemulsion accounts for 30% of total recovered oil. Sectional pressure gradient along the core increased as residual oil was mobilized to form oil bank, and decreased when the oil bank progressed out of the section. Pressure gradient during LTG flooding was reduced but displacement was maintained stable. Application of LTG to tighter rock (LTG_T2) produced comparable results. Tertiary oil recovery is lower at 75% ROIP, but similar high oil cuts resulting from a large oil bank were observed. Comparison of oil recovery from surfactant injection (Surf_T3) and gas co-injection (Gas_T4) with LTG_T1 showed that recovery of LTG was roughly equal to the sum of surfactant and gas recovery until the total injection of 0.75 PV, beyond which, LTG_T1 continued to increase whereas Surf_T3 and Gas_T4 leveled out. As is obvious, the mobility control of injected gas was enabled and stable displacement was achieved in LTG flooding. Szlendak et al. [146] hypothesized that the existence of a weak-foam region provided desirable flow-resistance for light oil displacement in tight rocks. The lamellae generation in this region is primarily a result of snap-off and leave behind rather than division, and they remain static due to the high pore-throat capillary constriction [146].

Szlendak et al. [147] further continued to evaluate the influence of other parameters by performing 1) co-injection at varied gas fractions of 0%, 30%, 50%, and 85%, and 2) surfactant-alternating-gas (SAG) injection at varied gas/liquid ratios on cores with similar characteristics. The objective of co-injection flooding is to assess the EOR performance under the circumstance of different gas fractional flow, in which injected gas tends to migrate upward due to gravitational segregation, leading to a higher gas fractional flow in the upper reservoir. As an alternative to co-injection, SAG flooding is performed to evaluate the effect of *in situ* mixing zones on LTG fluid rheology and flooding effectiveness using two different solutions. In SAG approach A, chemical composition, quantity, and injection order were identical to co-injection approach; in SAG approach B, three SAG strategies using drive solution at different liquid-to-gas ratios of 0.05 PV_L:0.15 PV_G, 0.1 PV_L:0.1 PV_G, and 0.15 PV_L:0.05 PV_G were carried out.

Results showed that tertiary recovery ranged from 27% to 92% of ROIP. Generally, high gas fraction led to higher RFs while low gas fraction resulted in lower RFs. However, this positive correlation was weakened slightly at very high gas fractional flow, with the highest RF achieved at the gas fraction of 50%. Comparison of SAG approach A to co-injection indicated that SAG accelerated oil production with higher oil cut. Normalized pressure gradient of SAG was similar to co-injection, suggesting that similar mechanisms controls mobility and facilitates oil displacement. The SAG approach B consisting of two injection cycles of different liquid-to-gas ratios demonstrated that peak mobility reduction that is higher than co-injection can be achieved repeatedly with well-developed gas-liquid mixing and progression in the flooding process [147].

4.3.2. Wettability alteration and spontaneous imbibition

Surfactant effectiveness in changing wettability have been extensively studied in conventional reservoirs and wettability can be measured by different methods quantitatively or qualitatively [7]. However, in tight oil reservoirs of low porosity and ultralow permeability, many of the wettability measurements are not practical except contact angle and nuclear magnetic resonance. Alvarez et al. [7] used captive bubble method to measure contact angle and used pendant drop and spinning drop methods to measure IFT. The effects of wettability and IFT alteration on spontaneous imbibition in tight oil reservoirs were evaluated. Alvarez and Schechter [5] supplemented their experiments by performing spontaneous imbibition experiments to investigate and compare the capability of anionic and nonionic surfactants in imbibing into ultralow permeability tight oil reservoir cores. Alvarez and Schechter [6] also included complex nanofluids into spontaneous imbibition experiments for recovery evaluation.

The tight oil reservoir cores that Alvarez et al. [7] used are preserved side-wall cores from depths of 6000 to 9000 ft, with the porosity of 3 to 5%. Dead crude oil came from the same well. Four different surfactants, two nonionic and two anionic, were tested at concentrations of 0.2, 1 and 2 gpt. The major experimental procedures are: 1) a preserved core is fractured and wrapped in Teflon; 2) overburden pressure is applied via a Hassler core holder; 3) fracturing fluid is injected at 600 psi until it comes out of the outlet; 4) CT scans are taken at different time intervals; 5) more fluid is injected at 600 psi to retrieve more oil. The results exhibited that almost all surfactant concentrations of 1 and 2 gpt can alter shale wettability from intermediate-wet towards water-wet, except a nonionic surfactant. Anionic surfactants achieved smaller contact angles than nonionic surfactants. IFT measurements at reservoir temperature also showed that anionic surfactant is more effective in reducing IFT than nonionic surfactants. The core flooding also verified that the anionic surfactants are superior in recovering oil [7].

In the spontaneous imbibition experiments, Alvarez and Schechter [5] prepared fracturing fluid solutions by adding different surfactants at 2 gpt. Saturated cores obtained from a well in the Permian Basin, with the porosity range of 6–7% and permeability of 0.2–1 μD, were submerged into fracturing fluids for imbibition at reservoir temperature. Results showed that anionic surfactant performed better by recovering 16.6% OOIP at 10 days, compared to 9.0% OOIP by nonionic surfactant. The higher recovery is attributed to a more efficient change in wettability and reduction in IFT.

The introduction of complex nanofluids lowered the contact angle, reduced the IFT, and increased the magnitude of zeta potential. According to spontaneous imbibition tests on Bakken cores, complex nanofluids gained comparable oil RFs as anionic and nonionic-cationic surfactants, which are all better than water [6].

4.3.3. Surfactant additives in fracturing fluids

Liang et al. [94] studied fracturing fluid loss, flowback, and oil production on Texas Cream limestone cores using a Hassler core holder to discuss the mechanism of permeability reduction after fluid loss. The core samples have an average permeability of 8 mD and porosity of 26%, and pentane was used as the model oil. They explored different

IFT reductions with three surfactants, including methanol that can reduce the IFT by a factor of 2, a surfactant (A) that can reduce the IFT by one order of magnitude, and a surfactant (B) that can reduce the IFT to $\sim 10^{-2}$ mN/m and form microemulsions. One of the core faces is considered as the fracture, through which fluid loss and flowback as well as oil production occurred by switching the injection directions.

During the experiments, pressure drop across the core was reduced by lowering IFT. When surfactant B was used to reduce IFT, enhancement of hydrocarbon permeability was observed, attributing to the reduction of trapped water in the invasion zone. However, surfactant A decreased the hydrocarbon permeability even it reduced IFT. The possible explanation is that surfactant B formed microemulsion whereas A formed macroemulsion, which is longer lasting and more viscous [94]. Therefore, besides IFT, other factors like emulsion formation should be considered in selecting surfactants for fracturing fluid to mitigate formation damage.

4.4. Modeling and simulation of IOR/EOR processes

Efforts have been devoted to model different IOR/EOR processes for tight oil reservoirs. Simulations incorporating reservoir fluids and geological models with specific IOR/EOR design and operating parameters can provide meaningful guidelines for field applications. Unconventional reservoirs are characterized by low permeability, complex fracture networks, high capillary pressure, and also complicated geomechanical and fluid flow mechanisms. Using a compositional simulator, some researchers have investigated IOR/EOR processes of gas huff-n-puff and flooding, and WAG injections. Operating parameters in these procedures, such as hydraulic fracturing spacing and length, injection initiation time, soaking period, cyclic number and length, matrix permeability and reservoir heterogeneity have been examined and discussed.

4.4.1. Physical mechanisms incorporated in the simulators

Based on the generalized Fick's law, Hoteit [63] proposed a diffusion flux model to simulate gas-oil mass transfer by taking the component interactions and the diffusion coefficients into consideration. This model balances the total flux and is advantageous to models based on the classical Fick's law. In addition, mass transfer across phases was considered as an important mechanism occurring in fractured rock matrix, when under-saturated oil in the matrix contacts gas in fractures. To tackle this problem, chemical potential rather than concentration gradient was used as the driving force for gas-oil transfer. Meanwhile, across the gas-oil interface continuous component fluxes and thermodynamic equilibrium were assumed by using transfer coefficients that were calculated from diffusion coefficients. In one of their simulated cases, diffusion is shown to significantly improve the recovery of condensate by gas injection into fractured reservoirs [64].

Jiang and Younis [68] developed a compositional simulator for modeling gas condensate shale reservoirs with complex fracture networks. Multicomponent apparent permeability, sorption, molecular diffusion and the effect of capillarity on VLE were incorporated in the simulator. Not only the combined effect of capillarity and multicomponent transport mechanisms on production from shale reservoir was investigated, but preliminary simulation of CO_2 huff-n-puff for EOR was carried out as well. They concluded that the incorporated mechanisms are very important factors influencing the oil and gas storage and transport in shale reservoirs and also CO_2 huff-n-puff is potentially applicable for shale oil EOR. Several operating parameters such as cycle number and injection length were discussed and shorter cyclic interval and shorter huff time (injection length) were preferable.

4.4.2. CO_2 huff-n-puff EOR

Yu et al. [183] simulated the CO_2 huff-n-puff process and pointed out that the main mechanisms for gas EOR in naturally fractured reservoirs include viscous force, gravity drainage, and molecular diffusion. They also believed that low permeability weakens the contribution from viscous forces leaving gravity drainage and molecular diffusion to dominate the EOR process. Effect of molecular diffusion on the CO_2 injection effectiveness was discussed along with the sensitivity analysis of number of cycles, fracture half-length, and reservoir permeability and heterogeneity on the production. By combining multiple hydraulic fractures with local grid refinement and setting the reservoir matrix permeability as 10 μD and fracture conductivity as 50 mD-ft, CO_2 huff-n-puff was simulated for the Bakken formation. Results indicated that diffusion helps CO_2 penetrate into matrix and recover more oil. Provided other parameters constant, an increased number of CO_2 huff-n-puff cycles could generate an incremental recovery of 2.43% after a 30-year period. Moreover, low matrix permeability, long fractures, and high heterogeneity are favorable for CO_2 huff-n-puff.

Based on the models of Yu et al. [183], Zuloaga-Molero et al. [194] used an embedded discrete fracture model that is more computationally efficient to explicitly model complex fracture networks. It is suggested that the fracture networks might be adverse to CO_2 flooding due to early breakthrough and hence poor sweep efficiency, and CO_2 huff-n-puff operation could avoid this issue. Simulations indicated that huff-n-puff performance is sensitive to different fracture geometries. When fractures became shorter and closer to each other, reduction in incremental recovery was observed due to the decrease of CO_2 contacted area resulting from fracture interference. Furthermore, simulation was extended to two horizontal wells with identical fractures, the geometrical complexity of which was varied. After 3-year primary production, one well was converted for injection. Results showed that, unlike huff-n-puff, CO_2 flooding efficiency is not necessarily negatively affected by fracture complexity.

Using UT-COMP to simulate multiple cycles of CO_2 huff-n-puff in middle Bakken formation, Chen et al. [16] concluded that CO_2 huff-n-puff has relatively limited EOR effect as compared to primary recovery since the fast declining peak rate cannot compensate the loss in the injection and soaking periods. Also, it does not help improve the recovery by extending soaking durations, and reservoir heterogeneity worsens the production decline in CO_2 huff-n-puff, leading to reduced RFs. Sanchez Rivera et al. [124] further investigated parameters for operation optimization in fractured Bakken shale formation, including production pressure, number of cycles, primary production time, injection and soaking time. The computational domain contains the half-length of a hydraulic fracture and the locally refined matrix around the fracture. Single porosity model was applied for the matrix with natural fractures set to connect the hydraulic fractures. It demonstrated that too early huff-n-puff operations were unfavorable for recovery. The incremental oil recovery can be positively correlated to injection volume. Also, shorter soaking periods are preferred over longer periods, which gave no diffusion benefits. In presence of natural fracture networks, CO_2 can migrate deeper into the formation and contact more hydrocarbons, enhancing oil recovery. The incremental recovery progressively decreased with increasing number of cycles, so it needs to be optimized. In addition, considering the cost of pure CO_2, re-injection of produced gas was simulated, demonstrating better recovery and economics than pure CO_2 injection.

4.4.3. Gas and water flooding

Different gas species have been evaluated for gas flooding in shale oil reservoirs by simulation. Simulation results showed that significant oil could be recovered regardless of the type of gas injected [56]. Specifically, miscible hydrocarbon gas injection performed as well as miscible CO_2 injection. Moreover, the economics of hydrocarbon gas were proven favorable for the immiscible case and much better for the miscible case.

Zhu et al. [192] investigated a new gas flooding scheme for shale oil recovery using CO_2, where gas was injected into one fracture and produced from an adjacent one. The effects of injection pressure, permeability heterogeneity, mechanical dispersion, fracture spacing and

gas composition on oil recovery were discussed. Similar to other studies, the cubic drainage volume between two stages of hydraulic fractures was extracted as the computation domain and the fractures were modeled by keeping the same conductivity but larger width to achieve numerical stability. Simulation results showed that, after 500 days of primary production, injection at 7000 psi for 5000 days was capable of increasing oil recovery by 15% and 11% for reservoir models with matrix permeability of 10 μD and 1 μD, respectively. Increasing injection pressure generated significant improvement of recovery for low permeability matrices. In this flooding scheme, reducing fracture spacing improved oil production proportionally before gas breakthrough, nonetheless shorter spacing also brought about faster production decline after breakthrough and lower EUR. Injection of recycled hydrocarbon gas was also investigated and yielded higher recovery than CO_2, due to the higher injectivity.

Ghaderi et al. [41] simulated EOR from three parallel horizontal wells with multistage staggered fractures where the center well was used as an injector to investigate the efficiency of CO_2 flooding and WAG in tight oil reservoirs. Effects of CO_2 slug size, WAG ratio, and cycle length on oil recovery were discussed. After primary recovery and subsequent water, about 70% of the OOIP remained trapped in the inter-fracture volume. For CO_2 flooding, gas quickly broke through to the producers due to high mobility, after which reservoir pressure rapidly dropped below MMP, losing the benefit of miscible flooding. Instead, WAG injection can develop efficient miscible flooding by maintaining the pressure above or close to MMP and significantly improve oil recovery. For example, a WAG ratio of 2.0 gave an incremental oil recovery of 21.7%. On the other aspect, decreasing the cycle length helped maintain reservoir pressure better and thus improved the sweep efficiency. It is suggested that the WAG ratio and the cycle length should be optimized upon simultaneous achievements of pressure maintenance and CO_2/oil miscible contact for field application design.

5. Current IOR/EOR pilot tests in unconventional reservoirs

In the past decade, many methods have been proposed for IOR/EOR from low permeability reservoirs, of which some have been applied in pilot tests. Simulation studies often tend to be optimistic about sweep efficiency. Hence, the incremental recovery rates are much higher than actual production increase from pilot tests [136,167]. Laboratory studies also showed that significant recovery increase could be achieved by exposing oil-saturated cores to CO_2 or hydrocarbon gas [80,40].

Besides the ultralow permeability that makes injected fluids very difficult to enter the matrix, hydraulic fracture networks further exacerbate the breakthrough issue. Low permeability also gives rise to a dilemma for injection wells, where on the one hand the injectivity of a well in tight formations could be challenging; on the other hand, fracturing a horizontal well as an injector seems to be commercially impracticable. Last but not least, injection control over a long horizontal lateral requires additional well monitoring (e.g. distributed temperature sensing and distributed acoustic sensing) and advanced completion tools for zonal isolation. All these factors contribute to the status of lacking efficient IOR/EOR technologies for unconventional reservoirs.

5.1. Bakken and Eagle Ford tight oil reservoirs

In most of the unconventional reservoirs, the average RFs are significantly lower than conventional reservoirs. There have been tremendous amounts of theoretical studies conducted to improve the recovery from unconventional reservoirs. But, very few of them have been applied to fields, especially for shale and tight oil reservoirs. Currently, the Bakken formation has drawn most of the attention on field IOR/EOR pilot tests due to its overwhelming success. Eagle Ford also has some pilot tests going on. Although Permian Basin has many more EOR projects than other plays, the majority of them are implemented in the formations characterized as conventional. For other unconventional plays, there is little information on existing IOR/EOR pilot projects.

5.1.1. Bakken shale

Deposited from the Late Devonian to Early Mississippian age, Bakken formation occupies about 200,000 square miles under the Williston Basin across the United States and Canada. Bakken formation is comprised of three layers: an upper shale layer, middle dolomite/sandstone member and a lower shale layer. The middle member is about 2 miles deep. The lower shale are organic-rich marine deposits, characterized as source rocks and seals for other formations below, such as the Three Forks (dolomite) and Sanish (sandstone) formations. In an oil and gas assessment conducted by USGS [164], the estimated technically recoverable oil reserve in Bakken formation is 3.65 Bbbl. Bakken was the largest continuous oil formation in the lower 48 states of the US until the recently new assessment on the Permian Basin came out. The oil production from Bakken region increased from 0.2 million barrels per day in 2009, to the peak of more than 1.2 million barrels per day in 2014 and continued to the middle of 2015.

Production in Bakken is still on primary recovery, whose RFs are typically less than 10%. Thus, more and more attention has been focused on the need for EOR methods. In the last decade, a number of water and gas injection pilot tests have been carried out in Bakken. Among these pilot tests, five were implemented in the North Dakota portion of Bakken [113], two were performed in Montana portion of Bakken [105], and the rest were conducted in Saskatchewan, Canada, as summarized in Table 2. Four tests focused on injecting water while the rest injected gas. The earlier pilot tests, including two CO_2 and two water injection projects, were mainly designed as injectivity tests with huff-n-puff operations to demonstrate the possibility of fluid injection in extremely low permeability formations. The later five tests consist of three water and two natural gas flooding operations.

5.1.2. Eagle Ford shale

The Eagle Ford shale in South Texas deposited during the

Table 2
Summary of EOR pilot tests.

No	Operator	Formation	State	Year	Well #	Fluid	Type
1	EOG	Bakken	ND, US	2008	16713	CO_2	Huff-n-puff
2	–	Bakken	MT, US	2009	–	CO_2	Huff-n-puff
3	EOG	Bakken	ND, US	2012	17170	Water	Huff-n-puff
4	EOG	Bakken	ND, US	2012–2013	16986	Water	Flooding
5	EOG	Bakken	ND, US	2014	16986	Natural gas	Flooding
6	Whiting	Bakken	ND, US	2014	24779	CO_2	Huff-n-puff vertical well
7	–	Bakken	MT, US	2014	–	Water	Flooding
8	Lightstream Resources	Bakken	SK, CA	2011	–	Natural gas	Flooding
9	Crescent Point Energy	Bakken	SK, CA	2006–2011	> 30 wells	Water	Flooding
10	EOG	Eagle Ford	TX, US	2013–2015	> 15 wells	Natural gas	Flooding

Cenomanian and Turonian ages of the Late Cretaceous, predominantly consisting of organic matter-rich marine shales and marls with interbedded thin limestone layers. The oil and gas pay zone varies between 4000 and 14,000 feet, averaging about 475 feet below the Austin Chalk. According to an assessment conducted by EIA [25], the proved reserves in Eagle Ford are 3.37 billion bbl. By the end of 2013, oil production had skyrocketed to over 1 MMbbl/d. Analysts expected that $30 billion would be spent on developing Eagle Ford in 2015, which certainly shrank under the low oil price situation. The only reported EOR pilot project is listed in Table 2.

5.2. Water injection

It is challenging to conduct water flooding in unconventional oil reservoirs, due to associated low injectivity, poor sweep efficiency with fracture networks, as well as clay swelling issues. To improve oil recovery of unconventional reservoirs, various water injection strategies, such as huff-n-puff and flooding, have been tested in fields.

5.2.1. Water huff-n-puff

The mechanisms of water huff-n-puff tests differ from cyclic steam injections. Since cold water is injected, additional oil recovery can only be achieved after the formation rock imbibes injected water, during which oil can be displaced out of matrix pores. This requires the rock to be water-wet. Although there have been significant amounts of researches using surfactants to alter the rock wettability, none of the pilots appeared to use any surfactants.

The pilot test #3 in Table 2 operated by EOG was performed using produced water as injection fluid in the Bakken formation at a location close to the pilot test #1. The well was fractured in August 2008 with sand and gel, and was on regular primary production until April 2012. The wellbore diagram indicated seven packers [140]. The actual first huff-n-puff test started on April 22, 2012. According to NDIC, around 1200 barrels of produced water were injected per day without any problems. The first injection cycle lasted just over a month with injected water volume of 10,380 bbl in April 2012, and 28,797 bbl in May 2012. Then this well was shut in for over 2 weeks to let injected water soak into the formation. The well was put back on production for about 3 to 4 months. On October 12, 2012, for the second cycle of produced water injection, EOG requested injection through artificial lift at low pressure. After the second cycle, the well was shut in again for about 2 weeks and then allowed to produce. Water injectivity through this well didn't appear to be an issue.

There was no significant change on oil production rate after injection of produced water for either cycle. Significant increments on produced water were observed after both shut in periods. In late 2013, this well was shut in due to fracturing jobs on an offset well, which were 1000 to 3000 feet away. Increase in oil and water production in late 2013 and early 2014 was likely attributed to the "frac-hit" or "well bashing" effect, where hydraulic fracturing at a nearby well causes a response in an offset well [79]. This effect can have either positive or negative influence on the fluid production of an offset well.

5.2.2. Water flooding

The pilot test # 4 in Table 2 is one of the earliest pilots with the goal to increase recovery at an offset well implemented in North Dakota. The operator (EOG) injected produced water into a horizontal well. There were offset wells to the east and west of the injector approximately 2300 feet away. In addition, there were offset wells located north and south of the horizontal injector that were about 900 and 1200 feet away from the heel and toe of the injector, respectively.

Water injection started on April 16th 2012, and in the following 8 months produced water was continuously injected at ~1350 bbl/d. The bottomhole pressure increased to around 6000 psi. Water breakthrough happened in less than a month in both of the east and west offset wells with significant increases in water production. A small decrease in oil production was observed, probably due to the high volume of water choking off some of the oil. The wells to the north and south did not show any noticeable change in oil or water production.

The injection stopped around the end of 2012 and the beginning of 2013 for about six months due to high water cut at the two offset wells in the east and west. Then the water injection started again for another 8 months with a much lower injection rate of about 380 bbl/d. The bottomhole pressure was maintained around 5500 psi, and the offset wells did not show noticeable increase in water production. The second injection demonstrated that water injection can help maintain pressure without rapidly breaking through to the offset producers. However, there is still no increase in oil production. During these two water injection periods, totally 438,969 barrels of water were injected, while only about 65,000 barrels of additional water were produced. After water injection ended, the injector was produced intermittently (about 1/3 of the time) for 4 more months.

The pilot test # 7 in Table 2 is a water flooding project in Montana. One injection well and several offset wells were monitored for pressure and flow rates. The water injection rate for the first three months was around 1700 bbl/d. Then the rate was reduced to slightly under 1000 bbl/d for the last five months of the project. The high water injection rate again demonstrated that in a fractured low permeability formation, the injectivity usually will not be an issue. Similar to pilot test # 3, the results of this water flooding project are also obscured by frac-hits from nearby wells being hydraulically fractured at the same time. Increments in oil and water rates were observed for most of the surrounding offset wells after the water injection started. However, according to Hoffman and Evans [57], most of these responses could be attributed to frac-hits.

The closest offset well, about 880 feet away from the injection well, was clearly impacted by the water injection. Since the oil rate of this well did not show an obvious increase during the injection, while water production reached over 150 bbl/d after water breakthrough comparing to about 10 bbl/d before injection, which happened about one week after the water injection started. During the last month of water injection, an injection profile log determined that half of the injection went in the two fracture stages closest to the heel of the well while the rest of the water was spread out over the other nine stages. Attempts to bypass these two stages during injection were unsuccessful. The injection well was then shut in ever since. In early 2015, the oil rate of the offset well after shut in for a couple months increased to around 60 bbl/d that had not been seen since 2013. There were no nearby wells being fractured during this time, so it is possible to attribute this enhancement to the water flooding.

The pilot test # 9 in Table 2 consists of 8 water flooding projects conducted by Crescent Point Energy in the Bakken formation in Saskatchewan, Canada from 2006 to 2011.

The first pilot of test # 9 injected water into one horizontal well to support four offset horizontal wells. Water injection started in the last quarter of 2006, with production response identified in the third quarter of 2008. Daily oil rates increased from 50 to 100 bbl/d before injection to 550 bbl/d across the four producers, and cumulative production reached about 500 Mbbl. Production response was also identified on wells outside of the defined well group.

The second pilot of test # 9 has 5 horizontal wells: three injectors and two producers in between. Water injection started in the last quarter of 2009, and production response was identified in the first quarter of 2010. Production data in November 2010 showed that this pilot was producing at 125 bbl/d and declining at a much slower rate.

The third pilot of test # 9 is the largest, which comprises five horizontal injectors and six horizontal producers in an interlaced pattern. Water injection started in the third quarter of 2010, and a stable oil rate showed up two months later, which might be attributed to water injection. By the time of the report from Wood and Milne [175], the pilot was still under evaluation.

According to a recent report by Mancini [103], Crescent Point Energy has dramatically expanded its water flooding program, increasing

water injectors from 30 in 2011 to 285 in early 2016. Field pilot evaluation showed that water flooding in hydraulically fractured horizontal wells in Bakken formation greatly reduced the overall decline rates, from 35% in 2011 to around 28%. In 2016, the company planned 120 more wells for water injection. The corporate presentation by Crescent Point Energy in August 2016 mentioned that water flooding in its Viewfield Bakken region can increase EURs by up to 3 times (Table 3).

5.3. CO_2 IOR/EOR

Among current IOR/EOR methods, CO_2 injection has been proven as a commercially successful technique in low permeability oil reservoirs. North America has the largest number of CO_2 IOR/EOR projects in the world and this is largely attributed to the favorable geology and availability of CO_2 gas sources [60,112,42]. CO_2 injection projects have gained huge success in both conventional and unconventional reservoirs [81].

Oil production from CO_2 EOR in the US has been steadily increasing over the past few years. It was projected that oil production from CO_2 EOR projects is likely to be doubled to 638,000 bbl/d by 2020 [75]. CO_2 IOR/EOR could be a promising technology to significantly unlock the production potential of unconventional oil as well as to provide a long-term solution to greenhouse gas emission reduction. CO_2 injection can be generally categorized into miscible and immiscible processes. In the US, miscible CO_2 EOR dominated over immiscible. CO_2 EOR process can also be classified as continuous injection, cyclic injection (huff-n-puff), and WAG injection based on the injection scheme. WAG is the most frequently applied EOR process in conventional oil reservoirs [142,10,48,126,42,4].

Mobilizing residual oil by gas injection can reach the optimum when miscibility is achieved. Typically, the MMP of CO_2 with a certain reservoir oil is lower compared with hydrocarbon gas or N_2 gas [143,60,155,86]. Hence, CO_2 injection is preferred to other gases in terms of miscibility. CO_2 injection also offers environmental advantage by sequestering the greenhouse gas in reservoirs.

Due to the inherent corrosive nature of CO_2, to reduce and mitigate technical uncertainties and environmental risks, CO_2 injection operations especially in existing wells require special considerations such as wellbore integrity [36,49,62]. Firstly, CO_2 is a corrosive agent to metallic components in the presence of water. Secondly, CO_2 is a major contributor to explosive decompression damage to elastomeric parts in forms of blisters, splitting, and cracks. Thus all the equipment (tubing, pump, and storage tank) must have enough corrosion-resistance under the designed CO_2 condition (concentration, temperature, and pressure). To mitigate the damage risks in case of unexpected rapid depressurization of CO_2-rich gas, all elastomeric parts selected should be resistant to explosive decompression [47]. Additionally, there should be equipment on wellhead to capture and recycle the produced CO_2.

Another challenge associated with CO_2 injection is the possible formation damage caused by precipitation [168]. CO_2 would mix and interact with the reservoir oil to change the reservoir fluid properties, which may further lead to the precipitation of the heavy oil components, primarily asphaltenes [15]. How this would affect the CO_2-based EOR in a tight oil reservoir under reservoir conditions is not well understood. Asphaltene precipitation and accumulation on the oil and CO_2 interface would also increase MMP of the system, negatively affecting the economics of the injection process [71].

5.3.1. CO_2 huff-n-puff

CO_2 huff-n-puff or cyclic CO_2 injection, is a single-well operation developed for rapidly producing oil. Similar to the conventional cyclic steam injection process in heavy oil recovery, CO_2 is first injected into a producer (hours to days), then the well is shut in (days to weeks) for soaking, finally the well is reopened for fluids to be produced (weeks to months). Since this technique is applicable through a single well operation and a producer could easily be converted to a huff-n-puff well, it requires low initial investment [50,161,1]. CO_2 huff-n-puff has gained many successes in conventional light oil reservoirs [138,109] as well as in several heavy oil cases [72,34]. Its application to unconventional reservoirs has been investigated by a few researchers recently [139,52,153,40,101]. In addition, several field pilot tests have also been implemented, and some of which substantially increased oil production [57].

The EOR mechanisms of CO_2 huff-n-puff include: 1) viscosity reduction, 2) oil swelling and saturation increase, 3) solution gas drive by CO_2 and natural gas, and 4) hydrocarbon extraction by CO_2. The most important operating parameters in CO_2 huff-n-puff are injection rate and time, number of cycles, soaking time, and pressure. CO_2 huff-n-puff efficiency decreases with the number of cycles [139,183,101]. For conventional reservoirs, successful projects have reservoir properties within the following ranges: 1) API oil gravity of 10–40°, 2) porosity ranging from 10 to 35%, 3) depth from 1000 to 13,000 ft, 4) zone thickness from 5 to 225 ft, and 5) permeability ranging from 10 to 2500 mD [109].

Due to the tight nature of unconventional reservoirs, some researchers argued that the desired permeability range could be relaxed by injecting CO_2 through high permeability hydraulic fracture and natural fracture networks, which connect with the ultralow permeability matrices [163,101,23]. Interestingly, there are simulation studies based on Bakken formation suggesting reservoir heterogeneity especially with low permeability zones near a well might help to keep CO_2 at a high pressure near the well, resulting in higher recovery [110,183].

Generally, miscible process is preferred over immiscible process [84]. Experimental and modeling studies [160,139] for Permian and Bakken Basin also illustrated that a higher injection pressure would lead to improved oil recovery for the first several cycles, but it is difficult for the recovery to be further significantly improved by increasing the injection pressure that is already far above the MMP.

A longer soaking time usually brings about a higher RF, as CO_2 could fully mix with the oil phase by seeping through rock matrices under pressure driven flow as well as molecular diffusion. But there should be a critical value when soaking reaches equilibrium. Compared with conventional reservoirs, it might take longer to observe the oil production increase in unconventional reservoirs after soaking due to the tight matrix [52,40,153,88].

The pilot test #1 in Table 2 in Bakken was designed to evaluate the feasibility of injecting CO_2 into the sub-mD rock. The injection well #16713 was fractured in April 2008 with gel and sand proppant using six packers [140]. The CO_2 injection started on September 15th, 2008, lasting for 29 days with an average injection rate of about 1000 thousand of standard cubic feet (Mscf)/d. After 11 days of injection, CO_2 broke through in an offset well (#16768) which is about 1 mile away from the injection well. According to the production data of the well #16713 and nearby offset wells, there was little increment in oil production after CO_2 huff-n-puff. Offset well #16768 showed some additional gas production from the test. No published post-injection results from this pilot is available, especially after March 2010.

The pilot test #2 in Table 2 was also designed to test CO_2 injectivity and was conducted in the Bakken formation in Montana. CO_2 was

Table 3
Examples of Bakken recoveries and economics per section [22].

Pilots	OOIP (MMbbls)	Estimated RFs	Incremental EURs (Mbbls)	Cumulative F & D cost per bbl
4-Well spacing	6.1	10%	615	$13
8-Well spacing	6.1	19%	553	$13
Water flooding	6.1	> 30–40%	> 615–1291	< $7–$9

injected at rates from 1500 to 2000 Mscf/d for 45 days at 2000 to 3000 psi. There was a very small production increase after CO_2 injection. However, the increment could also be attributed to the fractures being recharged by seepage from the matrix during soaking.

The injection pressures of pilot test #1 and #2 were both kept well below the formation fracturing pressure, demonstrating the practical CO_2 injectivity at the planned rate of 1–2 MMscf/d [57]. However, based on the production data, it is difficult to conclude that injecting CO_2 in a huff-n-puff manner could enhance oil production.

The pilot test #6 in Table 2 was a CO_2 huff-n-puff operation conducted in a vertical well (#24779), which ran through a ~60 feet thick middle Bakken pay zone. The well was initially drilled as a stratigraphic test well and had no production. CO_2 injection started on February 11th, 2014. However, breakthrough was observed at an offset well about 900 feet away in less than 24 h, thus the well was shut down shortly after.

5.3.2. CO_2 flooding

CO_2 flooding is an IOR/EOR process that CO_2 is continuously injected to displace the oil toward production wells. The produced CO_2 is separated from the hydrocarbon stream and re-injected into injection wells. Depending on the reservoir condition and oil composition, CO_2 might be miscible with oil at first contact or multiple contacts. However, when CO_2 injection pressure cannot be maintained above MMP or the reservoir oil composition is not favorable, injected CO_2 would remain immiscible with the oil. The CO_2 impurity can either raise or lower the MMP, for instance, lean gases such as nitrogen and methane raise the MMP, while ethane, propane, or hydrogen sulfide tend to lower the pressure requirement. When miscibility cannot be reached, incremental recovery can still be achieved as the main mechanisms are almost the same. CO_2 would mainly provide drive energy as the solution gas does in solution gas drive [60], but in a less favorable mode than miscible flooding. Consequently, the incremental recovery would be less than the miscible flooding. Miscible process is mostly applied to light and medium oil reservoirs while the immiscible process may be used for heavy oil recovery [11,181].

5.4. Hydrocarbon gas injection

Though re-injection of produced hydrocarbon gas into reservoirs seems to reduce sales potential, as a matter of fact, it could not only increase oil recovery but also limit environmental impacts by reducing water consumption for flooding and avoiding gas flaring and venting. Additionally, this provides the opportunity to produce and sell the natural gas later when it is more profitable [58]. Also by using hydrocarbon gas, existing facilities do not need costly modification to tackle the corrosion and recapture issues of CO_2. Moreover, hydrocarbon gas is non-damaging to the formation. If another new EOR technique becomes more technically or economically viable, the project can be easily changed over [130].

Hydrocarbon gas injection projects can also fall into two categories: miscible and immiscible injection [75]. Based on injection mode, it can be classified as cyclic injection, continuous gas flooding, and WAG flooding [135]. Currently, hydrocarbon gas injection projects in the US are implemented in high permeability light oil reservoirs and miscible injection is preferred over immiscible injection in project numbers of 12 to 2 [75]. Therefore, simulations, experiments and well pilot tests are still required to optimize operating parameters and screen unconventional reservoirs in order to achieve commercial scale success.

Hydrocarbon gas injection projects can be implemented when and where there is a readily available gas supply. Based on gas composition, hydrocarbon gas source can be classified as dry gas (lean gas) and wet gas (rich gas). Dry gas often comes from another gas reservoir, while associated gas or gas cap gas are often rich gas. Dry gas is primarily methane with little condensable hydrocarbons, while wet gas contains significant heavier hydrocarbons such as C_3, C_4 and other liquid hydrocarbons in addition to methane (< 85%). The vaporizing effect of dry gas could help increase the natural gas liquids (NGL) content in the produced gas, bringing about additional commercial benefits. Compared with CO_2 supply, hydrocarbon gas might be more accessible if associated gas could be efficiently used instead of being flared or vented. For example, everyday approximately 250 MMscf gas produced from Bakken and 100 MMscf gas from Eagle Ford were either flared or vented in 2015, due to insufficient gas transportation capacity [125]. Hence, re-injecting the produced gas into the formation seems to be a win-win strategy, which not only increases oil recovery but also mitigates environmental concerns related to greenhouse gas emission and flaring.

The primary mechanisms of immiscible hydrocarbon gas injection in conventional reservoirs are: (1) maintenance of reservoir pressure, (2) displacement of oil by gas, (3) vaporization of the intermediate components, (4) oil swelling, and (5) gravity drainage. For miscible process, injected gas could also dramatically reduce IFT between injected gas and oil, which will significantly increase microscopic displacement efficiency [83,84]. However, for unconventional reservoirs, some researchers argued that mechanisms of gas injection might be very different. Most injected gas will move rapidly through fractures, so gas cannot effectively seep into the tight matrix to achieve viscosity reduction or oil swelling. Therefore, the dominant mechanism in gas injection might be just pressure maintenance [52,136]. But there are other studies implying that the MMP of gases (e.g. CO_2, hydrocarbon gas and N_2) with unconventional reservoir oil could be theoretically several hundred psi lower than in conventional reservoirs because of the nanopore confinement [155,172,117].

5.4.1. Hydrocarbon gas huff-n-puff

Hydrocarbon gas huff-n-puff is considered to be a cost-effective candidate for improving the recovery of unconventional reservoirs, especially liquid-rich ones. Huff-n-puff could avoid early gas breakthrough which happens during gas flooding in fractured reservoirs and achieve higher sweep efficiency [133,135]. And huff-n-puff may also reactivate small fractures, which help improve the recovery. Lastly, gas huff-n-puff requires lower injection pressure than flooding. For example, a middle Bakken reservoir has relatively low porosity (~8–10%) and permeability (~0.05 mD), leading to very high injection pressure for continuous gas injection and very long for the displacing front to reach a producer [128].

Albeit theoretical studies showed that hydrocarbon puff-n-huff can be economical, pilot tests are still required to acquire preliminary data, experience, and screening criteria to identify potential candidates for field applications. Till now, no such field tests have been reported in unconventional reservoirs. This might be the result of operators' preference of CO_2 huff-n-puff or hydrocarbon gas flooding over hydrocarbon gas huff-n-puff. Moreover, current oil downturn might also suspend related field tests [96,87,108].

5.4.2. Hydrocarbon gas flooding

Hydrocarbon gas flooding is a very similar process with CO_2 flooding. For immiscible flooding, hydrocarbon gas mainly supplements the energy in the reservoir as well as reducing the oil phase viscosity. For miscible flooding, there are three kinds of multiple contact miscibility processes: (1) vaporizing gas drive (lean gas), (2) condensing gas drive (rich gas), and (3) vaporizing/condensing gas drive. All of them significantly reduce IFT at miscibility, thus leading to high microscopic displacement efficiency. To evaluate the recovery potential and the economic value of hydrocarbon gas flooding in unconventional reservoirs, Hoffman et al. [58] used a compositional simulator to model the produced gas flooding in a dual-porosity horizontal well geometry and found that the process is very positive even including the cost of gas compressor installation and fuel gas consumption.

The pilot test # 5 in Table 2 utilized the same injection well as pilot test # 4. In June 2014, EOG requested this well to be converted into a

gas injector. Enriched natural gas containing approximately 55% methane, 10% nitrogen and 35% C_{2+} fractions, which was sourced from surrounding production wells, was injected. Injection lasted for 55 days in the middle of 2014 with an average rate of about 1600 Mscf/d and the surface injection pressure around 3500 psig.

All four offset wells showed increases in production immediately after the gas injection. However, the interpretation was complicated by the fact that wells further to the west were being hydraulically fractured during the gas injection. The increases at two of the wells (south and west) could be explained by frac-hits. But it is more complex for the other two wells. After one week of injection, an increase of about 160 Mscf/d in gas production was observed at the east offset well, which was about 10% of the injection rate. The well was subsequently shut in until one month after the gas injection was over. When the well was turned back on, the gas rates were still high. In addition, the oil rates peaked up for a short time and then returned to a normal decline.

This pilot indicates that rich gas, which is more readily available in the field, can be used as an injection fluid. Furthermore, using natural gas will prevent flaring, which has long been an issue in some parts of Bakken.

The pilot test # 8 in Table 2 is a tertiary dry gas flooding project conducted in the Bakken formation of southeast Saskatchewan, Canada (Table 4).

According to Schmidt and Sekar [130], the injection well has a 1 mile horizontal section, which supports 9 perpendicular horizontal wells as producers. This created a toe-heel injection pattern with nine offset producers drilled in a north-south orientation. The pilot project was designed to inject dry, sale-quality natural gas into a horizontal well, which offers an equal distance to the nearest hydraulic fracture in all offset producers. The injected dry gas came from the sales line of Lightstream Resources and was transported through pipeline to the pilot well. The gas was then compressed at site and injected at rates between 350 and 1000 Mscf/d, yielding a voidage replacement ratio of 0.7–1.1.

In December 2011, the injection started at 300 Mscf/d with a pipeline pressure of 500 psi. With a newly installed compressor, gas injection rate was raised up to 1000 Mscf/d at 1000 psi in March 2012. Gas broke through immediately in two offset wells, causing a significant drop in oil production from March to July 2012 with the lowest daily oil rate of 53 bbl/d. Following workovers, consistent production was restored in all nine production wells and oil rates steadily climbed up to 295 bbl/d. In addition, gas injection rate averaged around 500 Mscf/d at the injection pressure of 1000 psi and interpreted bottomhole flowing pressures increased significantly.

Toe-heel gas injection offers an equal distance from the injector to the nearest hydraulic fractures in all offset producers, which helps improve the sweep efficiency. Bottomhole injection pressures were kept well below the fracture pressure to prevent unwanted gas leak-off. Moreover, daily production data, and fiber optics real-time survey with distributed temperature sensing and distributed acoustic sensing data were acquired for flow profiles along the horizontal wellbores of producers. Once a gas breakthrough has been confirmed, strategies are put in place to mitigate the problem. For example, when gas breaks through at the toe-end, toe portions of the producing horizontal well can be plugged off to alleviate the gas cycling at the problematic port. All these measures can work effectively to identify the preferential flow channels in fracture stages so they can be shut off to optimize sweep efficiency [35].

In one of the best responding producers, gas production increased by about four times over the baseline. NGL production from this well increased from 2.2 bbl/d to 5.6 bbl/d, due to the vaporizing effect of dry gas cycling. Oil production at the same well increased by approximately 10% during the same period. The operator claimed that this pilot project achieved significantly positive production responses during December 2011 to 2014, increasing from initially 130 bbl/d to the peak rate of 295 bbl/d. The average decline rate of wells decreased from 20% prior to gas injection to approximately 15%. They also projected that production rates would stabilize in the future given the pressure being added to the reservoir through continuous voidage replacement.

According to EOG, the pilot test #10 in Table 2 consisted of four successful pilot projects in Eagle Ford shale. Produced gas was injected into 15 horizontal wells. These pilot projects demonstrated consistent well responses with significant oil production increase at relatively low cost. Through gas injection, the estimated recovery can be boosted to 1.3–1.7 times of the primary recovery at a finding cost of $6/bbl or less. In addition, the capital investment and operating cost are low since the process makes use of readily available produced gas in the field. However, due to lack of publicly available information, there is no further production data for analysis. Another gas EOR project encompassing 32 production wells was planned for operation in 2016.

Though hydrocarbon gas flooding was not favored compared with huff-n-puff from experimental studies or modeling [135], its pilot tests indicated promising results. Compared with CO_2, hydrocarbon gas flooding utilizes existing infrastructure without the risk of corrosions and poses no damage to the formations. If CO_2 supply is not available, hydrocarbon gas injection could be a decent alternative. From pilot tests, especially the one in the Canadian Bakken formation, with well designed and implemented conformance control, high sweep efficiency can be ensured for commercially successful oil rate improvement.

5.5. WAG

Water-alternating-gas flooding is an operation combining the advantages of both water flooding and gas flooding by alternatively injecting water and gas slugs.

5.5.1. CO_2 WAG

In water-alternating-CO_2 (CO_2 WAG), intermittent slugs of water and CO_2 are injected to improve the sweep efficiency and to minimize the required amount of CO_2. WAG is the most frequently applied CO_2 EOR technique for fields which have gone through water flooding [142,10,48,126,42,4]. When CO_2 is injected into a water-flooded reservoir, it tends to go into the high permeability zones where there is also previous injected water. Subsequent water injected after the first CO_2 cycle is hence partially diverted to low permeability zones owing to decreasing water relative permeability in high permeability zones. CO_2 flow in the high permeability zones could also be inhibited by the existed water. All these phenomena improve the sweep efficiency. Also, water flooding can reduce reservoir temperature to bring down the MMP of the subsequent CO_2 flooding. Typical incremental oil recovery by CO_2 WAG flooding ranges from 5 to 25% [60,42].

In either continuous CO_2 injection or WAG, CO_2 sweeps through the formation, forming a leading miscible bank, in which the CO_2 completely dissolves into oil, swells the oil, and eliminates the IFT, allowing oil to be driven more easily toward the production wells. The produced fluid containing oil, formation water and gas is separated into three

Table 4
Reservoir properties of pilot area in Saskatchewan, Canada.

Reservoir properties	Values
Pilot area (acres)	1280
Net pay (ft)	23–26
Porosity (%)	9–10
Permeability (mD)	0.01–0.1
Water saturation (%)	55–59
Original reservoir pressure (psi)	2320
Original formation volume factor (Reservoir Barrel/STB)	1.328
Bubble point pressure (psi)	990
Oil viscosity (cP)	2–3
Stock tank oil gravity, °API	42
OOIP, thousand STB (Pilot Area)	8000

phases. Gas, primarily CO_2, is combined with imported CO_2 and re-injected alternatively with the separated water, creating continuous WAG circulation through the formation and, thereby, sustaining CO_2 EOR. When oil production rate falls below the economic limit, the field is abandoned. Finally, partial or all CO_2 used for EOR remains in the formation and is permanently sequestered away from the atmosphere.

Due to the ultralow permeability of tight matrix, water might predominantly stay and channel through the fracture networks during WAG. Continuous CO_2 flooding might have better performance in production compared with WAG for unconventional reservoirs, but its economics should be further investigated [30]. The major problems with WAG injection operations are corrosion, mainly of injection facilities but also of production equipment after gas breakthrough, as well as scale formation and asphaltene/paraffin precipitation.

5.5.2. Hydrocarbon gas WAG

Water-alternating-hydrocarbon gas is now widely applied to improve oil recovery from matured fields by re-injecting produced gas into water injection wells [78]. Water injection after gas helps to control the high gas mobility and stabilizes the displacement front. Besides the mechanisms from gas flooding, the lower IFT of the gas-oil system compared to the water–oil system enables gas to displace oil from the small pores that are difficult for water to enter. The injection of water in the presence of gas leads to partial gas trapping which can cause mobilization of the oil at low saturation and reduce residual oil saturation [162].

An earlier review reported that 24 of 59 WAG projects worldwide used hydrocarbon gas and 28 of 59 used CO_2 [18]. Successful WAG injections resulted in an increased oil recovery of 5–10% OOIP; CO_2 WAG achieved an average incremental RF of 10%, while hydrocarbon gas and N_2 obtained 8%. The higher recovery by CO_2 might be attributed to that most CO_2 WAG projects are miscible, while a large portion of hydrocarbon gas and N_2 WAG tests are immiscible.

CO_2 induced corrosion, asphaltene precipitation and scale formation are still very challenging for CO_2 WAG in field tests. Most importantly, CO_2 is not always available in field. On the contrary, hydrocarbon gas can be separated from the production stream on site, hence all offshore WAG projects today use hydrocarbon gas. For unconventional reservoirs, hydrocarbon gas WAG could become feasible, but its EOR mechanisms in unconventional reservoirs have not been studied thoroughly and there are still many uncertainties. To date, there are hardly any reports of successful hydrocarbon gas WAG in unconventional reservoirs [96,57].

5.6. Nanotechnology

Unconventional reservoirs are characterized by nanometer pores. Pore throat diameters are generally greater than 2 μm in conventional reservoirs, about 0.03–2 μm in tight sandstones, and from 5 to 100 nm in shales [114]. Hence the application of nanotechnology to unconventional reservoirs becomes intuitive. Two attractive characteristics of nanoparticles for assisting IOR/EOR processes are their size range (1–100 nm) and manipulative behavior. Nanoparticles have large tunable specific surface areas that are of high surface energy; also they are able to flow through typical unconventional reservoir pores with little risk of blockage [37]. Besides, Brownian motion enables nanoparticles to suspend in solutions, providing strong driving force for diffusion. So it could easily move into small pores of tight formations to displace oil.

5.6.1. Nanoparticles/Nanofluids in water flooding

Nanoparticle suspensions or nanofluids tend to occupy the rock surface and remove the attached oil droplets by exerting a structural disjoining pressure, which is related to fluid spreading due to the surface energy imbalance among mineral, oil, and aqueous phases [174,17].

Recently, laboratory experiments have confirmed several mechanisms in using nanoparticle suspensions for EOR. Nanoparticles can significantly lower the contact angle of aqueous phase on the rock surface and reduce the IFT between the aqueous phase and oil, thus forming a wedge film to separate attached oil from the rock surface, as have been verified by micromodel and sandstone core floods [43,53]. Experimental measurements showed that a polymeric nanofluid achieved a much smaller contact angle of ~25° as compared to brine with ~65° on glass substrates immersed in oil at room temperature; IFT between nanofluid and oil was only ~8.8 mN/m in contrast to the reference brine and oil IFT of 43 mN/m [189]. Favorable wettability alteration towards water-wet was also confirmed by spontaneous imbibition tests on strongly oil-wet carbonate reservoirs by using ZrO_2-based nanofluids [70]. Onyekonwu and Ogolo [116] studied the performance of hydrophilic, hydrophobic, and neutrally wet polysilicon nanoparticles in EOR. Flooding experiments on water-wet Niger Delta cores indicated that neutrally wet and hydrophobic polysilicon nanoparticles yielded higher oil recovery through reducing IFT and changing the rock wetness. Li et al. [91] investigated the potential of hydrophilic silica nanoparticle (~7 nm) suspension for EOR and found that silica nanoparticles in synthetic brine can reduce the IFT and make the rock surface more water-wet. An incremental oil recovery of about 4–5% was obtained as compared to brine in 300–400 mD Berea sandstone cores. Luo et al. [100] prepared a nanofluid with 0.01 wt% graphene based amphiphilic nanosheets which could spontaneously approach the oil/brine (4 wt% NaCl and 1 wt% $CaCl_2$) interface to reduce the IFT and achieved incremental RFs of up to 15.2% on synthetic sandstone cores.

Synergistic effect was also observed between nanoparticles and surfactants in EOR. By reducing the IFT and stabilizing the surfactant adsorption on sand surface, addition of nanoparticles greatly improved the oil recovery in displacement experiments [144]. In addition, it is found that low concentrations of specially fabricated nanoparticles are capable of modifying the fluid properties, such as reducing the viscosity and yield stress of heavy oil [184,149].

For successful usage of nanoparticles, factors such as concentration, salinity, and particle size need to be screened. High concentration and large particle size might cause formation damage. It has been confirmed by TEM images and core flooding that the retention of nanoparticles in cores plug impaired porosity and permeability [69]. High concentration tends to block pore throats and does not produce additional oil in low permeability reservoirs [53]. Also, silica nanoparticles dispersions are often unstable and might agglomerate in high salinity brine [187].

Laboratory studies of nanoparticle-based fluids demonstrated great EOR potential and there are also a few successful field cases on asphaltene, paraffin and scale remediation [106], For unconventional reservoirs, applications of nanofuids are very rare and pilot tests are needed to verify their feasibility.

5.6.2. Nanoparticles in CO_2 flooding

Foams have been used for mobility control in CO_2 injection to improve CO_2 performance for low to medium permeability reservoirs, nanoparticles can be used as an additive to stabilize foam as well as reduce surfactant loss due to adsorption [30]. Zhang et al. [188] modified a CO_2 WAG process by adding nanoparticles and found that 0.05 wt% of nanofluids gave the best performance in core flooding. By accounting for permeability reduction, simulations were conducted for this nanofluid-alternating-gas process with main mechanisms of wettability alteration and IFT reduction in a tight oil reservoir of 0.85 mD, predicting a RF that is 11% higher than a regular WAG. Also, nanoparticles could mainly stay around an injection well in high permeability channels, as indicated by simulated concentration maps.

6. Summary and recommendations

During the past decade, unconventional reservoirs of extremely low porosity and permeability became the game-changing resource

contributing to the oil and gas production in the US. Nonetheless, most wells of the unconventional reservoirs suffer from dramatic decline in production rates in a short period, leading to limited return on heavy investment in horizontal drilling and hydraulic fracturing as well as low RFs. Therefore, the necessity to improve/enhance oil recovery has never been greater, posing great challenge to developing effective technologies for improving conventional oil recovery.

6.1. Summary of current IOR/EOR technologies for unconventional reservoirs

The goal of IOR/EOR approaches applied in conventional reservoirs is to displace oil into production wells, whereas fluid injection in unconventional reservoirs would travel only through highly permeable channels, such as fracture networks, rather than displace the oil from the low permeability matrices where the majority of oil resides. Mass transfer driven by the concentration gradient between the injected fluid and oil would become as important as pressure gradient driven flow. Due to high injectivity and high mobility of gas, hydrocarbon and non-hydrocarbon gases, such as CH_4 and CO_2, have become the first choice for EOR pilot tests and field implementation in unconventional reservoirs. Though most of the pilot tests were unsuccessful due to the lack of experience and other constraints, a few pilots confirmed increased production under effective well operation. For fractured wells, it is learnt that gas or even water can be effectively injected, but the key is to improve microscopic sweep efficiency of rock matrices with effective conformance control. Response time for IOR in unconventional reservoirs is long, which could be several months, depending on the specific conditions. Many studies have favored the application of gas huff-n-puff with CO_2 or hydrocarbon gas, but this method still needs confirmation from more pilot tests for a particular field. In addition, nanotechnology seems promising for EOR in unconventional reservoirs due to the nanosize of nanoparticles and its effectiveness in promoting microscopic displacement, but its mechanisms are still not well understood with few applications. For IOR and EOR methods to work for unconventional reservoirs, well-understood geology and a well-designed strategy are also required.

Laboratory studies reveal physical and chemical mechanisms that dominate the IOR/EOR processes, promoting the development and application of feasible IOR/EOR technologies for unconventional reservoirs. Currently, researchers focus on building physical models and carrying out experiments to investigate the following topics: 1) CO_2 injection under miscible and immiscible states for flooding or huff-n-puff; 2) injection of CH_4 and N_2 at miscible and immiscible states for flooding or huff-n-puff; 3) chemical flooding including gas/surfactant co-injection, wettability alteration, and spontaneous imbibition on reservoir rock. In laboratory, the recovery efficiency of these IOR/EOR methods are generally promising, but with great variations ranging from about 10% to as high as 90% of OOIP. Current EOR methods are mainly conventional or extended conventional EOR techniques. In view of the characteristics of unconventional reservoirs, EOR mechanisms under study are focused on: 1) gas and oil transport in small pores, 2) mass diffusion from fracture to low permeability matrix, 3) gas swelling and mixing with oil, 4) wettability alteration and IFT reduction using surfactants, and 5) surfactant imbibition, transport, and mobility control. Although the majority of the experiments indicate EOR potentials, the challenging question is whether decent or economically viable recovery efficiency can be achieved in the field where geology is much more complicated and engineering control is much more difficult. On the other hand, numerical simulation is capable of investigating large scale or field applications of promising EOR techniques in complex fractured reservoirs under different scenarios and optimizing controllable parameters for higher recovery, such as denser fractures, shorter soaking time, and more cycles of injection for CO_2 huff-n-puff process. Physical mechanisms of molecular diffusion, capillary pressure, adsorption, and non-Darcy flow have been considered and incorporated to improve the accuracy of simulations. However, more efforts are needed to integrate complex physics occurring in tight oil reservoirs into unconventional reservoir simulators, such as multiphase flow and multicomponent phase changes in nanopores and coupled geomechanics. In addition, field data are limited for validation of models or modeling results.

Unconventional reservoirs, such as Bakken, Eagle Ford, and Niobrara, are predominantly undergoing primary recovery, in which production decline rates are fast and recovery efficiency is very low. These pose the need for adapting conventional IOR/EOR technologies and developing new IOR/EOR methodologies for unconventional reservoirs. Over the past decade, there have been a number of field IOR/EOR pilot tests carried out in shale and tight oil reservoirs, attempting to improve the oil recovery using fractured wells. Most of these pilot tests were focusing on water and gas flooding operations. Although gas or even water can be effectively injected, but the macroscopic sweep efficiency of many tests is very low, due to early breakthrough in days and weeks. Contrarily, response times of many wells are several months, because of the low permeability. Gas injection, especially hydrocarbon gas injection, seems to be more favorable in unconventional reservoirs compared with water injection. The early huff-n-puff tests demonstrated the feasibility of injecting gas or water into low permeability reservoirs, accumulating valuable experience and showing promising potentials. However, these field pilot tests give very limited knowledge on how to optimize well pattern and operating parameters for field scale applications.

6.2. Recommendations for future development

Not only currently available IOR/EOR methods need to be improved for application in unconventional oil reservoirs, but also new breakthroughs in science and technology are required to more effectively produce oil and gas from these unconventional resources, while minimizing the adverse environmental concerns. Herein, we make recommendations for future development of effective IOR/EOR approaches for unconventional reservoirs.

6.2.1. Improve sweep efficiency

Because of low permeability and high heterogeneity with fracture networks in unconventional reservoirs, conventional water or gas flooding cannot displace much of the remaining oil as achieved in conventional reservoirs. The combination of WAG flooding and channeling gas control technique has a great potential to overcome these challenges. WAG flooding can improve sweep efficiency of gas injection by utilizing water to control the gas mobility and the flooding front. Meanwhile, in the gas channeling control technique, the reaction product of injected ethylene diamine and CO_2 can block off high permeability regions and divert the injected gas into low permeability regions [190].

6.2.2. Combine oil/gas production with CO_2 storage

Depleted oil and gas reservoirs, saline aquifers, unmineable coal seams, basalts, and shale reservoirs are all possible candidates for CO_2 geological storage. As a simultaneous opportunity for carbon sequestration, EOR and enhanced gas recovery (EGR) from unconventional reservoirs using CO_2 are receiving increasing interests, in view of the economic benefits and the existing infrastructure that can be leveraged [152]. Broadly distributed shale reservoirs have huge pore volume in place that can be used for massive CO_2 storage. Shales are good porous media for CO_2 storage with approximately 5–10 kg/t of formation rocks or 1 million tons/km^2 in adsorption capacity [12,73,45,44], suggesting a substantial opportunity for CO_2 storage in shale reservoirs. This becomes even more attractive as significant CH_4 can be released with relatively modest energy consumption [129,14]. In EGR, the affinity of shales for CO_2 to CH_4 by mass basis is 14:1 [97]. One kg of CH_4 generates about 55 MJ [118], while to store 1 kg of CO_2 consumes only

1 MJ [66], suggesting that 55 MJ is obtained while only about 14 MJ is spent for compression. Even separation of CO_2 in carbon capture and storage projects would consume more energy, there will still be a net energy gain. CO_2 storage in shale reservoirs provides an economically preferable option as compared to saline aquifers, so long as a CO_2 supply is close to the shale reservoirs to take advantage of field infrastructure [122].

6.2.3. CO_2 thickening

There has been considerable progress in laboratory studies for directly thickening of CO_2, including developing both polymeric and small molecule thickeners. But neither of them are economically viable for field pilot tests currently. Therefore, effective and affordable thickeners that can dissolve into CO_2 at reservoir conditions and increase the CO_2 viscosity to a level comparable to oil need to be continuously quested.

6.2.4. Nanotechnology

Water flooding with nanoparticles is reported to have a huge potential in improving displacement efficiency for low permeability reservoirs. The use of nanotechnology in the oilfields, especially, for EOR purposes could be enhanced if the physical mechanisms between nanoparticles, fluids and rock surfaces are well understood. Nanotechnology is helpful in EOR by providing us a new look and understanding of the reservoirs and how fluids flow through very small pore spaces as well as serving as new ways to monitor and enhance the reservoir performance.

6.2.5. Combined usage of surfactants

Water flooding with surfactants is a traditional EOR method for conventional reservoirs, because surfactants are able to chemically shift the rock wettability from oil- and intermediate-wet to water-wet. Surfactants can be injected with alkalis, polymers, and gases to combine the benefits of different EOR approaches. For unconventional reservoirs, however, the direct injection of water with surfactants may not be suitable, because of the low injectivity of rock matrix. An alternative approach is to add surfactants in fracturing fluids during fracturing. Field recorded data indicates that only 5–50% of the injected fracturing fluid can be recovered as flowback while a large portion remains in the subsurface. Since most of the hydrocarbons in unconventional reservoirs are produced from the SRV, which is equivalent to the volume filled with remaining fracturing fluids, the remaining fluid with surfactants could potentially lower the IFT and thus facilitates oil flow in the SRV.

6.2.6. Numerical simulation

In addition to these laboratory and field experiments, numerical simulation is also a powerful tool to perform EOR study. Numerical simulation is helpful in the evaluation of EOR schemes by providing preliminary results, which can demonstrate promising techniques and engineering operations to enhance oil from complex fractured reservoirs. Note that although the experimental results indicate the potential of oil recovery, the challenging question is that whether these recovery efficiencies can be achieved in field conditions where geology is much more complicated and engineering control is much more difficult to exercise.

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