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Review of CO_2 injection techniques for enhanced shale gas recovery: Prospect and challenges

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ABSTRACT

CO_2 injection is a promising technique that not only enhances shale gas recovery but also achieves geological storage of CO_2. This paper reviewed the performance of CO_2 injection techniques based on simulations and field test studies. We observed that CO_2 injection can be practical and successful in a hydraulically fractured shale. The techniques can lead up to 26% more methane production after primary recovery, and sequester more than 60% of the injected CO_2 for continuous CO_2 injection, while for huff-n-puff higher amount of CO_2 is reproduced. Reservoir pressure gradient, competitive adsorption, flow dynamics, and shale properties were found as essential factors controlling CH_4 recovery and CO_2 storage. Despite the flow dynamics of gases being important for predicting gas production and storage, most simulations described it based on models suitable for well connected fractures and homogenous shale. Moreover, these models are incapable of analyzing fluid flow in stimulated fractures. Future studies on CO_2 injection should address the issue of higher CO_2 reproduction during the huff-n-puff, the effects of moisture content, induced effects on shale matrix properties by CO_2 injection, the kinetics of CO_2–CH_4 competitive adsorption, flow dynamics of multicomponent gas, and consider the complex pore system of a heterogeneous shale.

1. Introduction

Energy demand in the globe has dramatically increased in recent years and is expected to increase further due to high population growth, technological advancement, and a high standard of living (Lozano-Maya, 2016; Wang et al., 2017). The growing number of people and the world economic expansion, are expected to drive the global energy demand by 25% by the year 2040 (ExxonMobil Outlook for Energy, 2017). According to BP Energy Outlook (2018), the world energy demand is expected to grow at a rate of 1.3% per annum from 2016 to 2040. With this fact, the world has been in constant pursuit of other energy resources which could effectively meet the current and future energy demand concerns. ExxonMobil's global view (ExxonMobil Outlook for Energy, 2017) suggests that by 2040 nearly 60% of the global energy supply will come from oil and natural gas, while nuclear energy and renewables will contribute about 25% of the world's energy mix.

The increase of natural gas demand and scarcity of its supply from conventional resources has increased the significance of natural gas supply from shale (Wang et al., 2016a, 2016b; Yang et al., 2015a,b). According to the International Energy Agency (International Energy Agency, 2017), the world's natural gas consumption is expected to rise by 45% by 2040, whereas 30–50% of its supply is projected to come from shale gas (EIA, 2016). Due to its huge reserve discoveries, and being friendly to the environment, natural gas supply from shale gas is considered as a potential source to supply the world energy demand.

The technically recoverable resource of shale gas is estimated to be 214.55 trillion cubic meters (tcm) from 46 countries in the world (EIA, 2015). The top ten leading countries with the highest technical recoverable resources of shale gas are presented in Fig. 1, whereas, 57.6% of this recoverable resources are possessed by China (31.6 tcm), Argentina (22.7 tcm), Algeria (20 tcm) and the USA, Canada, and Mexico together possess 49.3 tcm (EIA, 2015). The USA, China, Canada, and Argentina, are the countries at present producing shale gas at a commercial scale. Algeria and Mexico are expected to start production in 2020 and 2030 respectively (EIA, 2015). By 2040, shale gas production in these six countries is projected to contribute about 70% of the total global shale gas production (EIA, 2016).

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Shale is a fine grained sedimentary rock with ultra-low permeability of a few hundred nano-darcies to a few milli-darcies (EIA, 2013), and low porosity of 6–10% (Jiang et al., 2016). For successful exploration and development of shale gas, currently shale gas production is done through horizontal drilling and hydraulic fracturing technology (Wu et al., 2019). Shale gas recovery factor through horizontal drilling and hydraulic fracturing ranges between 5% and 60% depending on the reservoir conditions, geological complexity, shale matrix properties, and the shale gas development technique (Table 1). However, rapid decline of production rate which can reach up to 50%–90% per year (United Nations, 2018), negative environmental impacts, high water consumption, higher development cost, deeper burial depth of shale deposits (greater than 3500 m), and limitations set by certain geological conditions (Dong et al., 2016b, 2016a; Le, 2018; Xin-Gang and Ya-Hui, 2015), prompt the search for alternative technologies.

Shale development cost is a function of deposits burial depth (Table 2). However, other factors like well configuration and complexity, well design, formation type, and location also may affect its determination. As the burial depth increases, so does the cost of development (Ahmed and Rezaei-Gomari, 2018). Furthermore, water consumption required for fracturing operations is a challenge for countries with a shortage of water resources. On average 2–4 million gallons of water are required for fracturing in the construction of one well (Middleton et al., 2015; Zhang et al., 2017). It is reported that 15–80% of fracturing liquid flows back to the surface after fracturing. It may end up polluting land and water resources if not handled properly because fracturing fluids are composed of toxic chemicals (Xin-Gang and Ya-Hui, 2015).

Hydraulic fracturing is also associated with the potential risk of landslides, earthquakes and surface collapse due to fractures formed in shale reservoirs susceptible to breaking the original balance of shale formation (Ma et al., 2017). During fracturing activities, micro-earthquakes commonly happen, associated with the propagation of the fracture. However, the United Nations (2018) reports that the seismicity triggered by hydraulic fracturing is normally of low intensity. On the other hand, the Geological conditions of countries outside North America are relatively complex. For example, Chinese and Europeans shale gas formations are hard to fracture with the current technologies due to high clay content, and their structures have numerous faults (Dong et al., 2016b, 2016a; Le, 2018; Xin-Gang and Ya-Hui, 2015). Moreover, most of their shale deposits are buried deeper than 3500 m, tectonically more complex, and more pressurized (Le, 2018). These challenges and limitations of horizontal drilling and hydraulic fracturing technology suggest the necessity of recovering shale gas through CO_2 injection techniques (continuous CO_2 injection and CO_2 huff-n-puff) as reviewed in this study.

Shale gas recovery through CO_2 injection is a dynamic displacement process, which is governed by the pressure gradient and competitive adsorption between CO_2 and CH_4 (Huo et al., 2017; Klewiah et al., 2020). When CO_2 is injected in shale, some of its molecules start accessing unoccupied adsorption sites while some compete to replace CH_4 from adsorption sites. Since 20–85% of gas in shale is stored in the adsorbed phase (Curtis, 2002), the adsorption process more specifically competitive adsorption between CO_2 and CH_4 is an important mechanism for facilitating gas production and storage during CO_2 injection in shale. CO_2 injection pressure, flow rate, and temperature are suggested in different researches to provide the primary force for displacing CH_4

Table 1
Shale gas recovery in the US.

Shale description	Shale location	Average gas recovery factor	References
Shale basins in the US	Shale basins in the US	5–20%	Rokosh et al. (2009), Sandrea (2012)
Poor reservoir condition	/	10	EIA (2013)
Good reservoir condition	/	30	EIA (2013)
Good natural fracture permeability	Antrim and Haynesville	30–60%	Rokosh et al. (2009
Medium clay content, moderate geologic complexity, and average reservoir pressure	Marcellus	20–35	Godec et al. (2013)

Table 2
Average drilling cost with formation depth (Mistré et al., 2018; Saussay, 2018; EIA, 2013; EIA, 2015).

Country	Average depth (m)	Average drilling cost (million USD/well)
USA	1097–4114	2.8–8.5
Canada	1676–3962	8.1–13.
Mexico	1066–3505	20–25
China	1700–5500	10.4–11.7
Poland	1828–4876	5–21
UK	1219–3962	17
Argentina	1524–4419	10–20

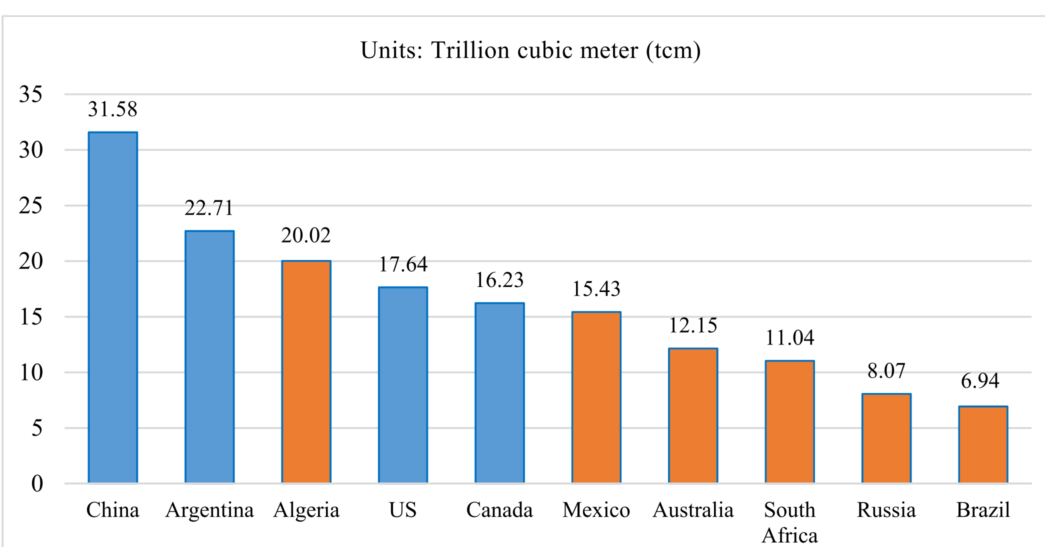


Fig. 1. Countries with technically recoverable shale gas resources (EIA, 2013).

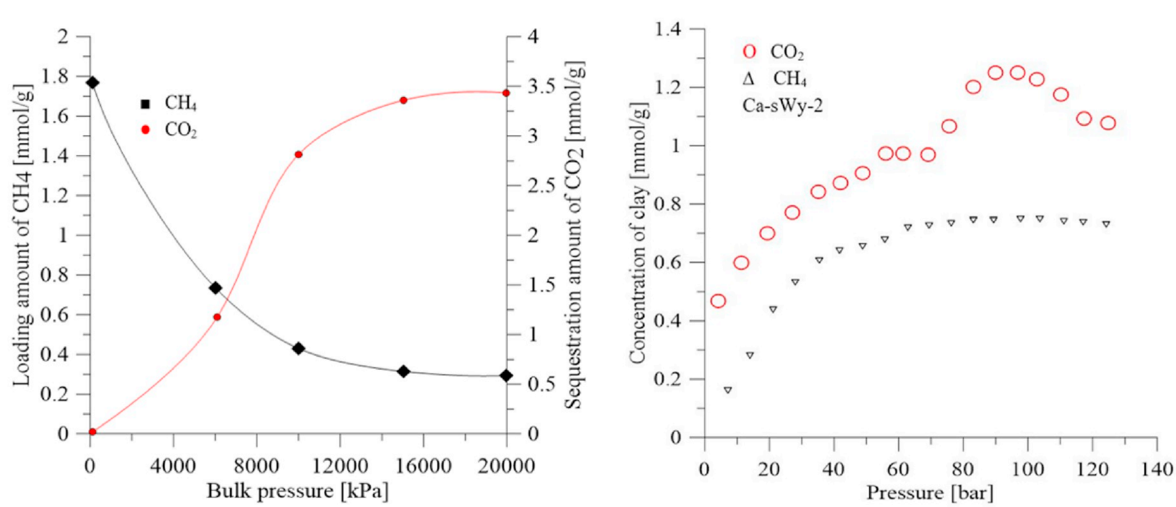
Table 3
The factors that enhance shale gas recovery through competitive adsorption mechanism of CO_2 and CH_4 in shale.

Forces	Effects	Affected gas	References
Van der Waal forces	The bonding strength of both polar and non-polar gas molecules.	CO_2, CH_4	(Merey and Sinayuc, 2016; Sui and Yao, 2016) (Middleton et al., 2015)
Electrostatics forces	The bonding strength of both polar.	CO_2	(Lu et al., 2015; Schaef et al., 2014)
Oxygen-containing functional groups	Provide attraction forces to charged ions.	CO_2	(Gensterblum et al., 2014; Liu et al., 2018; Luo et al., 2015)
Positively charged ions on inorganic minerals	Provide attraction forces to charged ions.	CO_2	(Gasparik et al., 2014; Hong et al., 2016; Ross and Marc Bustin, 2009; Schaef et al., 2014; Yang et al., 2015a,b)
Micropore size and volume, total organic carbon contents, and the interaction energy	Influence the competitive adsorption.	CO_2, CH_4	Huo et al. (2017)
Molecular structure and size, quadruple moment, and diffusion rate	Competitively enable CO_2 to enter into any adsorption site to enhance CH_4 desorption.	CO_2, CH_4	(Duan et al., 2016; Gu et al., 2017; Merey and Sinayuc, 2016; Sui and Yao, 2016)
CO_2 injection condition (Pressure, temperature, flow rate)	Re-pressurizes the reservoir and affects other parameters essential for CH_4 displacement.	CO_2, CH_4	(Chong and Myshakin, 2018; Du et al., 2016; Eliebid et al., 2018; Ho et al., 2018; Huo et al., 2017; Kazemi and Takbiri-borujeni, 2016; Wu et al., 2015; Xiaoqi et al., 2016; Yang et al., 2015a,b)

from shale (Kazemi and Takbiri-borujeni, 2016; Mamora and Seo, 2002; Wu et al., 2015). As it is demonstrated in Fig. 2(i), CO_2 is preferentially adsorbed over CH_4, and the increase of reservoir pressure due to CO_2 injection enhances both CH_4 displacement and CO_2 sequestration (Sun et al., 2017; Wu et al., 2015; Kazemi and Takbiri-borujeni, 2016). However, as more reservoir pressure rises leads to less energy loss in the shale gas reservoir resulting in less CH_4 recovery and less CO_2 sequestration (Wu et al., 2019). Shale formation ability to adsorb more CO_2 than CH_4 is reported in several studies (Fig. 2(ii)), and it is approximated that CO_2 adsorption is 2–10 times greater than CH_4 at different shale reservoir conditions (Nuttall et al., 2005a,b; Weniger et al., 2010; Kang et al., 2011; Heller and Zoback, 2014; Luo et al., 2015). On the other hand, the increase of shale reservoir temperature intensifies the thermal motion degree of gas molecules, increases desorption speed of gas, and opens more adsorption sites in organic matter, and in turn enhances gas recovery (Xiaoqi et al., 2016; Zhang et al., 2018a,b; Eliebid et al., 2017). The small CO_2 injection flow rate leads to longer residence time for gas mixture within porous media, resulting in more mixing of CO_2–CH_4 gas molecules that enhances CH_4 recovery (Du et al., 2016; Mamora and Seo, 2002). On the contrary, a high CO_2 injection flow rate negatively affects the CO_2–CH_4 competitive adsorption, and so does to both CH_4 recovery and CO_2 storage (Du et al., 2016).

The competitive adsorption process is facilitated by total organic content (TOC), kerogen type and maturity, affinity, pore structure, oxygen-containing functional groups, inorganic minerals, moisture content, molecular structures of CO_2 and methane (Heller and Zoback, 2014; Huang et al., 2018; Jiang et al., 2014; Ortiz Cancino et al., 2017). The presence of moisture, in particular, can significantly affect shale gas recovery due to its tendency of blocking gas enterable pores and occupies the adsorption sites for gas, which can affect both gas mobility and adsorption in shale (Huang et al., 2018; Klewiah et al., 2020; Zou et al., 2018). However, according to Huang et al. (2018), the presence of moisture content in shale at certain condition have the potential of enhancing CH_4 displacement. Other factors contributing to shale gas recovery during CO_2 injection through competitive adsorption mechanism are summarized in Table 3.

The present study reviewed enhanced shale gas recovery by CO_2 injection (CO_2-ESGR) techniques (the continuous CO_2 injection and the CO_2 huff-n-puff methods) to identify their challenges and limitations. Identified challenges and limitations are expected to foster more research on the feasibility of CO_2-ESGR techniques and their commercial applications. Since few implementations have been done, discussion of



i) CH_4 displacement and CO_2 sequestration at different CO_2 injection pressure in montmorillonite slit-nanopores at 323 K (Sun et al., 2017).

ii) Sorption capacities for CO_2 and CH_4 on calcium montmorillonite (Ca-SWy-2) at 50°C and 90 bar (Schaef et al., 2014).

Fig. 2. The effect of pressure changes on preferential adsorption of CO_2 over CH_4 in shale.

this manuscript mostly based on numerical simulation studies with only two inclusion of field test case studies. This paper is organized as follows: Firstly, we discussed shale gas recovery through CO_2 injection techniques, focusing specifically on continuous CO_2 injection, and CO_2 huff-n-puff. Secondly, we discussed the prospect and challenges of CO_2 injection techniques, followed by conclusions.

2. Shale gas recovery through CO_2 injection techniques

Shale gas is normally stored as free gas in fractures and large pores, absorbed gas in liquid phase, and adsorbed gas on organic and inorganic surfaces (Zhang et al., 2012). Adsorbed gas in shale accounts 20–85% of the total gas in place (Curtis, 2002), and is stored in nanopores due to their large specific surface areas and strong adsorption potential (Huang et al., 2018; Wu et al., 2015). The CO_2 injection techniques are considered as alternative methods for recovering shale gas and sequester permanently CO_2 into the geological trap. Various attempts have been made to study their feasibilities (Guiltinan et al., 2017; Hong et al., 2016; Huo et al., 2017; Lutynski and González González, 2016; Ortiz Cancino et al., 2017; Pan et al., 2018; Rezaee et al., 2017; Wang et al., 2018,b). However, up to date, it holds low economic feasibility for commercialized production. Their commercial applications have remained a challenge due to the complex nature of shale gas reservoirs (Godec et al., 2013; Jiang and Younis, 2016; Liu et al., 2018; Santiago and Kantzas, 2018; Wan and Mu, 2018; Wang et al., 2018,b; Xu et al., 2017). In this context, continuous CO_2 injection and CO_2 huff-n-puff are presented and discussed as CO_2-injection techniques. Due to scarcity of information on field-scale implementation, most discussed literatures are simulations based, with only two cases on field tests by Nutt et al. (2005) and Louk et al. (2017) discussed under CO_2 huff-n-puff section.

After CO_2 been injected in shale reservoirs, CO_2 molecules start competing for adsorption sites with CH_4 molecules and result in CH_4 displacement and CO_2 storage in shale formation (Fathi and Akkutlu, 2014; Du et al., 2016). The flow dynamics of both CO_2 and CH_4 in shale are dominated by desorption in the matrix, diffusion in the pores, and Darcy flow in fractures (Fig. 3). Gas production in shale starts with free gas in fractures flowing out first, then gas in the matrix pores transfers into natural fractures. This is followed by adsorbed gas desorbing from shale surface when pressure falls below adsorption pressure, and thereafter dissolved gas in organic matter diffuses due to pressure drop (Wu et al., 2019). Therefore, it could be inferred that the competitive adsorption and pressure drop in the shale reservoir remain to be the primary mechanisms for enhancing both shale gas recovery and CO_2 storage. CO_2 has unique characteristics such as low viscosity, easy diffusibility, high density and solubility of liquid, and zero surface tension, which facilitate shale gas exploitation (Jiang et al., 2016; Wang et al., 2012). As it permeates through the rock and dissolves in water and hydrocarbons, it results in various physical and chemical changes on

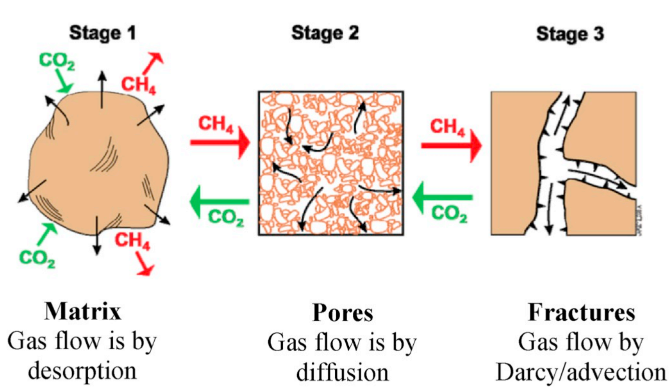


Fig. 3. Schematic diagram of the flow dynamics of CO_2 and CH_4 in shale gas, after CO_2 injection (Godec et al., 2014).

shale reservoirs properties (Ao et al., 2017; Wang et al., 2012; Wang et al., 2019). CO_2 interaction with shale matrix may transform micropores into mesopores or macropores through the dissolution process and may induce swelling which transforms macropores into mesopores or micropores when it is adsorbed (Yin et al., 2016).

2.1. Continuous CO_2 injection technique

Multiple wells are involved in the continuous CO_2 injection process, consisting of injection well(s) and production well(s). CO_2 is charged into a shale reservoir at the injection well(s) to increase reservoir pressure, and gas is produced at the production well(s) (Sheng, 2017). During the process, CO_2 permeates the shale reservoir based on the pressure gradient, at the same time displacing CH_4 gas through competitive adsorption and pressurizing effect (Kim et al., 2017). Factors like reservoir pressure gradient, CO_2 injection (pressure and flow rate), well spacing, shale matrix properties, and engineering design (such as fracture conductivity), facilitate continuous CO_2 injection process (Liu et al., 2013; Sun et al., 2013).

Schepers et al. (2009) applied a dual-porosity, single permeability model, to study the impacts of continuous CO_2 injection on CH_4 recovery and CO_2 storage of a Devonian gas shale play. The dual-porosity model assumes (see other assumptions in Table 4) a fractured reservoir is composed of fractures and matrix, whereas fractures provide the main flow pathways and matrix act as a receiver for gas flowing in the fractures (Warren and Root, 1963). Authors simulated production for an additional 20 years after the primary recovery (no CO_2 injection) which operated for 9 years, at average initial reservoir pressure of 307.65 kPa, production pressure of 206.8 kPa, reservoir temperature of 303.15 K, and well spacing of 146.6 and 196.6 m CH_4 recovery increased three times more (7.3–26%) than primary recovery, and 60–100% of the injected CO_2 was sequestered. This was related to the preferential adsorption of CO_2 over CH_4, pressure gradient, and the shale thickness. The primary production process depends on pressure gradient (depressurization) whereas gas flows from shale to wellbore through advection and desorption mechanism (Berawala and Andersen, 2019). Among other parameters, the thickness of the shale reservoir was identified as an important parameter that contributes to total gas in place and increment of gas recovery. However, despite promising findings the dual-porosity-single permeability model used suffers many limitations such as lack of precise evaluation on the transfer of functions (flow) between the matrix and the fractures. This is because it only considers the fracture system as the only pathways through which gas can reach the wellbore (Reeves and Pekot, 2001; Karimi-Fard et al., 2003; Nie et al., 2012). Also, it overestimates the fluid transport rate (compared to the flow in the actual wellbores) as adsorbed CH_4 diffuses from the matrix into the fractures directly after desorption (Reeves and Pekot, 2001; Xu et al., 2017). Furthermore, Fick's first law employed to model gas flow does not well model the flow dynamics behavior of multi-component gas (Fathi and Akkutlu, 2014).

Sun et al. (2013) investigated the effects of continuous CO_2 injection in shale to CH_4 recovery and CO_2 sequestration efficiencies through a dual-porosity model that incorporated multiple transport mechanisms. In a five-spot well pattern with a spacing of 200 m, CO_2 was injected at 6 and 7 MPa in the shale reservoir that had an initial pressure of 5.38 MPa and a temperature of 303.15 K. At the production pressure of 0.1 MPa, CH_4 recovery efficiency was 7–14%, while CO_2 sequestration was 74–80%. The pressure gradient in the reservoir and the preferential adsorption of CO_2 (due to strong affinity with shale surface) over CH_4 were key mechanisms that enhanced CO_2 storage and CH_4 displacement. Analysis of this simulation model focused on un-stimulated shale and revealed that the increase of CO_2 injection is an influential factor to increase natural gas production. Sun et al. (2013) and Schepers et al. (2009) cases both applied dual porosity model but Schepers et al. (2009) recovered more gases, which would be suggested as caused by the consideration of stimulated fractures. However, the dual-porosity model

Table 4
The assumptions used to develop different models as presented in this section.

Model used	Assumptions	References
Dual-porosity, single permeability model	- Fractures systems are directly connected with the wellbore, - The diameter of each block is small compared to the dimension of the reservoir, - Fluid pressure is uniform at the surface of each matrix block, - The matrix porosity and permeability are constant over each block.	(Schepers et al., 2009; Warren and Root, 1963)
Dual-porosity model	- The reservoir has well-connected fractures and lower-permeable matrix, - Gas is stored in fractures as free phase and in the matrix as both free and adsorbed phase, - Gas reservoirs are isothermal with gas adsorption (estimated by Langmuir equation), - Gas transportation occurs only in fractures to the wellbore.	Sun et al. (2013)
Dual porosity, dual permeability model	- Fracture and matrix systems are pathways connected with the wellbore, - There is inter-porosity flow between matrix and fracture. - Gas production to the wellbore is restricted fractures.	(Liu et al., 2013; Eshkalak et al., 2014; Li and Elsworth, 2019; Nie et al., 2012)
Triple porosity, dual permeability model	- There are two parallel hydro-dynamic systems (fracture and matrix) in the reservoir, - Desorption and diffusion occurs within the matrix, - Permeability is isotropic in all direction, - Maximum CO_2 storage is calculated by assuming all CH_4 in place stored as a free phase.	(Sawyer et al., 1990; Godec et al., 2013)
Multi-continuum multi-component model	- Gas stored in natural and primary fractures as free phase, and in the matrix as both free and adsorbed phase, - Gas flow to the wellbore only through primary fractures, - The pressure profile fully penetrates the formation in the vertical direction.	Jiang et al. (2014)
Extended Langmuir model	- The adsorption/desorption rates are directly proportional to unoccupied and occupied sorption sites respectively, - Each adsorption site accommodates only one adsorbate molecule, - Adsorption reaches dynamic equilibrium when the adsorption rate is equal to the desorption rate.	(Bacon et al., 2015; Weniger et al., 2010)
Multi-continuum quadruple porosity binary component gas model	- The dissolution of dissolved gas in organic matters obeys Henry's law, - The dissolved gas transport in organics is driven by pressure difference Knudsen diffusion and surface diffusion, - The adsorption/desorption of each component follows Langmuir isotherm adsorption law, - All hydraulic fractures fully penetrate the formation.	Wu et al. (2019)

is further described as incapable of evaluating the geometric arrangements of the fracture network especially in the presence of a fracture system with high heterogeneity (Jiang et al., 2014; Mohagheghian et al., 2019).

Liu et al. (2013) used a dual porosity, dual permeability model to simulate the feasibility of CO_2 storage and enhancing shale gas recovery in the New Albany shale by adopting a continuous CO_2 injection process. This model considers fracture and matrix systems as pathways connected with the wellbore, and it also considers the inter-porosity flow between matrix and fracture. At Reservoir pressure of 8.549 MPa and production pressure of 1.379 MPa, simulations for 30 years of production indicated CH_4 recovery efficiency less effective in comparison with no CO_2 injection process, and 95% of injected CO_2 was sequestered. The poor fracture networks between the wells probably caused most injected CO_2 not making to the well production zone and affected the gas recovering performance of the process. The dual-porosity model is only successful when utilized to simulate well-connected fractures (Mohagheghian et al., 2019). Poor results of this simulation especially in predicting gas production could also be associated with their model development technique which adopted tools originally developed to replicate fluid behavior in conventional reservoirs, which probably cannot accurately analyze gas behaviors in shale.

Similarly, the simulation performed by Eshkalak et al. (2014) also applied a dual porosity/dual permeability model that incorporated a Local grid refinement (LGR) to improve simulation in the region around hydraulic fractures. This model holds the same assumptions as suggested by Liu et al. (2013), but in addition, it also assumed a two-phase fluid flow of water and gas. At a production period of 30 years, reservoir pressure of 34.473 MPa and temperature of 355.22 K, producer bottom-hole pressure of 6.894 MPa, the continuous CO_2 injection process was found more efficient when conducted after re-fracturing production. Similarly as suggested by Schepers et al. (2009), Eshkalak et al. (2014) reveal that permeability improvement due to shale formation fracturing treatment and re-pressurization of shale formation by CO_2 injection play a major role in more CH_4 desorption from shale. In addition, consideration of the Local grid refinement (LGR) to improve the analysis of fluid flow dynamics around hydraulic fractures. Furthermore, Li and Elsworth (2019) evaluated the continuous CO_2 injection in shale in a five-spot pattern one injection well through a dual porosity, dual permeability model of multicomponent gas flow. CO_2 injection was done at 4 MPa and 8 MPa overpressure of the initial reservoir pressure of 30 MPa. An average of 20% increment of shale gas recovery was achieved after primary production for over 30 years caused by preferential adsorption of CO_2 over CH_4 and reservoir pressurization by CO_2 injection. Their process performance compares well with Sun et al. (2013) case which also used the same well space pattern. Though parameters evaluated may be different the use of multiple-spot well pattern seems to enhance the effects of reservoir pressurization by CO_2 injection and CO_2–CH_4 competitive adsorption as compared to dual-porosity-dual-permeability model as reported in Liu et al. (2013) and Eshkalak et al. (2014).

Moreover, a triple porosity, dual permeability model was constructed to simulate CO_2 injection in a hydraulic fractured Marcellus shale by Godec et al. (2013). Triple porosity, dual permeability model considers fractures and two kinds of matrix pores with different permeabilities (Xu et al., 2017). Gas storage is assumed to be in the micro-pore matrix system, molecular adsorption within the micro-pore matrix system, and the natural fractures within the shale. During the

CO_2 injection for 10 years in a reservoir with an initial pressure of 22.636 MPa, 1.0 kPa wellbore (producer) pressure, and optimal well spacing of 60–75 m, the prediction showed an increment of 7% CH_4 recovery after primary recovery. Apart from various parameters affecting gas production and storage, this simulation found the distance between injection and production as an important factor for continuous CO_2 injection. For a short well spacing, a sufficient quantity of gas recovery and storage would be achieved. For larger well spacing, a lower amount of CO_2 could be injected in shale because of little depleted pores volume available to accept injected CO_2, affecting both gas recovery and storage.

On the other hand, Jiang et al. (2014) developed a multi-continuum multi-component model (assumption included in Table 4) to investigate the effects of CO_2 injection in shale to enhance CH_4 recovery and CO_2 storage in shale gas reservoirs. The model incorporated multiple interacting continua (MINC) method to simulate fluid migration between matrix and natural fractures, and embedded discrete fracture model (EDFM) to describe flow in hydraulic fractures. After primary recovery (conducted without CO_2 injection), CO_2 was injected for 30 years in a reservoir with an initial pressure of 12 MPa, temperature (423 K), and producer (4 MPa). An increment of CH_4 recovery and CO_2 sequestration caused by re-pressurization of the reservoir and by CH_4 preferential displacement by CO_2 was observed. It was observed that gas adsorption/desorption and fractures (both natural and stimulated) have a significant impact on well productivity, and the decrease of reservoir pressure facilitated more release of gas. Comparing this model and dual porosity-dual permeability model, analysis of fluid flow dynamics in hydraulic fractures as also reported by Eshkalak et al. (2014) and Wu et al. (2019) improves efficiently shale gas recovery and storage performance.

On the other hand, Wu et al. (2019) developed a multi-continuum quadruple porosity binary component gas model to investigate CO_2 sequestration and enhanced shale gas recovery (see assumptions in Table 4). The model incorporated multiple transport mechanisms and used multiple interacting continua (MINC) method to simulate the matrix-fracture transfer flow. Embedded discrete fracture model (EDFM) was also included to simulate gas flow in hydraulic fractures and the transfer flow between hydraulic fracture and natural fractures. CO_2 was injected at 8.6 MPa in a reservoir with an initial pressure of 12 MPa and a temperature of 353 K, and 3.6 MPa wellbore pressure at the producer, and enhanced both CH_4 recovery and CO_2 storage. This simulation suggests that the reservoir re-pressurization (promotes the gas flow-ability), CO_2–CH_4 competitive adsorption and CO_2 injection could enhance more gas production because. Wu et al. (2019) and Jiang et al. (2014) approaches are relatively the same, the only additional work by Wu et al. (2019) was the consideration of dissolution of CO_2 and CH_4 in shale and analysis of fluid flow in the stimulated reservoir volume around fractured well. Both these studies proved the significance of fracturing the shale formation for successful gas production and storage as also reported by Schepers et al. (2009) and Eshkalak et al. (2014). Wu et al. (2019) further found that higher CO_2 injection pressure and longer injection time, gas adsorption, lower production pressure, and dissolution have a significant contribution to both CH_4 production and CO_2 storage.

A numerical simulation model by Bacon et al. (2015) analyzed the effects of continuous CO_2 injection in shale on both CH_4 recovery and CO_2 storage. At initial formation pressure of 9 MPa and a temperature of 320.5 K, CO_2 injection was done at 10.95 MPa continuously for 30 years in one of the two connected horizontal hydraulic fractured wells. CH_4 recovery improved by 10% more of the no CO_2 injection condition and 88% of the injected CO_2 was sequestered, this was due to reservoir permeability enhancement by hydraulic fracturing treatment, preferential desorption of CH_4 by CO_2, and reservoir re-pressurization. Despite efficient performance from this model the importance of flow dynamics of gases to gas production and storage in shale is not clearly described. As in other discussed models, the extended Langmuir isotherm model was used in this simulation to analyze the competitive adsorption of gases despite its limitations. The Langmuir model assumes isotherm equilibrium condition and does not sufficiently demonstrate the adsorption behavior of gases at high pressure ranges (Lan et al., 2019). Moreover, the Langmuir model is not capable of cannot modeling the possibility of multilayer adsorption occurrence in nano-scale pores (Shadi et al., 2018).

The discussed models have tried their best to analyze different parameters, which is a promising stage for CO_2-ESGR implementation. Through our discussion, we observed that successful CO_2–ESGR in the extremely low permeability of shale can be practical and efficient when conducted in a hydraulically fractured shale. The flow mechanism of gases from the matrix to natural fracture to the stimulated fractures and finally to the wellbore has a complex behavior due to the coexistence of many phenomena. Therefore distinguishing the flow characteristics of multicomponent gas present in shale reservoirs is necessary for precise gas recovery estimation. The discussion in dual porosity-dual permeability and multi-continuum models has shown that considering fluid flow dynamics in hydraulic fractures efficiently improves gas production and storage in shale.

Despite the comprehensive analysis provided by the discussed simulation models, various effects induced during the process were not simulated. Among them is the effect of moisture content which affects gas adsorption and mobility. Moisture content coexists with hydrocarbons in shale and is also introduced during hydraulic fracturing. Some scholars have pointed out that water molecules in shale tend to block gas enterable pores (Huang et al., 2018; Klewiah et al., 2020; Zou et al., 2018). Other effects are heat transfer effect (caused by changes of reservoir temperature) and effect on shale matrix properties due to CO_2 injection, all can have a high impact on gas recovery and storage as reported in several studies (Yin et al., 2016; Jiang et al., 2016; Wu et al., 2017; Sanguinito et al., 2018). Furthermore, despite the Langmuir model being limited to estimate gas adsorption/desorption only in low pressure conditions and its inability in high pressure (typical condition for moderate and deep shale formation) conditions, still, it has been the choice in simulations due to its simplicity. Additional observations on continuous CO_2 injection discussion are:

1. The average increment of CH_4 recovery after the primary recovery is between 7 and 26%, whereas more than 60% of the injected CO_2 is sequestered.
2. CO_2 injection pressure and injection time, production pressure, adsorption/desorption, fractures (both natural and stimulated), competitive adsorption, pressure gradient, shale thickness, and flow dynamics of gases are among the important parameters for gas productivity and storage in shale reservoirs.
3. The well spacing and well patterns are very influential factors for gas production and storage in continuous CO_2 injection, however, multiple well patterns have received less attention.
4. The contribution of the three modes of gas storage in shale (free, adsorbed, and dissolved) to both recovered CH_4 and sequestered CO_2 is not clearly described.

2.2. CO_2-huff-n-puff technique

The Huff and puff process can be defined as a cyclic CO_2 injection executed using only one well which serves both as an injection well and production well (Sheng, 2017). It involves three main stages which are: 1) Converting a horizontal well to a CO_2 injector for a period of time, 2) shut-in the well for a period of time to allow soaking of the CO_2 gas, and 3) opening again the well to resume gas production (Eshkalak et al., 2014). During the huff-n-puff process, gas injection is intended to keep pressure in reservoirs higher than the dew point to prevent condensate formation and re-vaporize formed condensate to the gas phase (Meng and Sheng, 2016a, 2016b). The formed gas condensate near the wellbore reduces relative permeability and decreases well production.

The process of CO_2 huff-n-puff process is facilitated by: 1) CO_2 injection pressure, which provides the primary force needed for displacing CH_4 from shale reservoirs (Kazemi and Takbiri-borujeni, 2016; Mamora and Seo, 2002; Wu et al., 2015); 2) CO_2 injection rate, which determines the rate of change of cumulative amount of injected CO_2 in shale with respect to injection time (Xu et al., 2017); 3) CO_2 injection time, this is used to estimate the CO_2 injection time versus the amount (concentration) of CO_2 injected in shale reservoirs (Jiang and Younis, 2016); 4) Soaking time, this allows injected CO_2 molecules to permeate into shale matrix through convection and diffusion to activate and displace CH_4 molecules (Fathi and Akkutlu, 2014; Jiang and Younis, 2016; Meng and Sheng, 2016a); 5) Number of injection cycles, these are meant to evaluate the impact of CO_2 injection time and soaking time to pressure changes of the reservoir and gas production, and normally are done sequence wise, where every cycle is completed by CO_2 injection, soaking, and production before another injection cycle starts (Louk et al., 2017; Meng et al., 2017; Pranesh, 2018); and fracture properties such as fracture half length, conductivity, and spacing, all together improve wide spread and permeability of injected CO_2 in a hydraulic fractured shale reservoir (Pranesh, 2018; Zhang et al., 2018a,b).

2.2.1. Study of CO_2-huff-n-puff technique based on the numerical simulation method

Several numerical simulation studies have been utilized to investigate the CO_2 huff and puff process. Schepers et al. (2009) applied a dual-porosity, single permeability model in the COMET3 simulator to investigate the performance of CO_2 huff-n-puff in comparison with no CO_2 injection scenario in a Devonian gas shale play. At reservoir temperature of 303.15 K, and pressure which was drawn down to 1.724 MPa, CO_2 was injected for 5 days, soaked for 1 month, and secondary production conducted for 3 months. Results showed an increment of 6% of CH_4 was recovered (influenced by reservoir depressurization) after primary recovery, while CO_2 sequestration was less efficient due to being quickly reproduced. The model incorporated Langmuir isotherm law and Fick's law of diffusion to model gas desorption and gas flow respectively, and it was found that thickness of the shale reservoir was a key function contributing to total gas in place and increment of recovered gas. Apart from the limitations of dual-porosity-single permeability model and Fick's first law as discussed above (Reeves and Pekot, 2001; Karimi-Fard et al., 2003; Nie et al., 2012; Fathi and Akkutlu, 2014; Xu et al., 2017), higher CO_2 reproduction is major concern for the huff-n-puff process, also reported by other scholars (Eshkalak et al., 2014; Kim et al., 2017; Xu et al., 2017). This shows comprehensive studies are required especially on the effects of CO_2 injection and soaking time on shale matrix properties and competitive adsorption of gases. Furthermore, the Langmuir isotherm employed to model gas adsorption is limited to low and moderate pressure conditions, and it does not predict adsorption behavior of gases at high pressure ranges (Lan et al., 2019). Also, Langmuir isotherm is incapable of modeling the possibility of multilayer adsorption occurrence in nano-scale pores (Shadi et al., 2018).

Eshkalak et al. (2014) compared CO_2 huff-n-puff and re-fracturing treatments gas production efficiencies through numerical simulation performed that incorporated a local grid refinement to model nonlinear pressure drop and a dual porosity dual permeability model. The initial reservoir pressure was 34.47 MPa, and CO_2 was injected for 5 years, left for 5 years to soak, and 15 years of production after soaking time. Results revealed re-fracturing treatment outperformed CO_2 huff-n-puff treatment due to high permeability improvement of the shale formation. It was concluded that CO_2 huff-n-puff is not a viable choice for CO_2-ESGR because of its low gas production and higher reproduction of injected CO_2 (96% of injected CO_2 was reproduced). The higher reproduction of injected CO_2 in the huff-n-puff process is a concern to be addressed (as suggested above) in future studies. Another point to note in this article is the soaking time applied was too long and it would lead to loss of some operation time, making the process uneconomical.

Jiang and Younis (2016) developed a comprehensive simulation to study the complex transport processes and phase behavior of gas condensate in shale. The simulation incorporated a three-phase multi-component flow model that assumes no mass transfer exists between hydrocarbons and water phases, gas stores in fractures as free phase and in the matrix as both free and adsorbed phase. It also incorporated a discrete fracture and matrix (DFM) model to handle the complex fracture geometries of hydraulic fracture, and local grid refinement (LGR) to capture the transient flow regime. The simulations for CO_2 huff-n-puff considered no soaking time, and the cyclic injection time varies as (60/80/100/140 days), and results obtained were compared with the depletion mode. Considering the effects of capillary pressure, reservoir pressure (23 MPa), temperature (480 K) and porosity, results showed that shorter CO_2 injection time leads to higher gas recovery. This could be related to the effectiveness of injected CO_2 amount and reservoir depressurization effect. The desorption process, capillary pressure, and molecular diffusion were found to have a significant effect on gas recovery. Comparing Jiang and Younis (2016) simulation with that of Schepers et al. (2009) which also adopted shorter CO_2 injection cycle, despite models applied are different, the incorporation of LGR and DFM by Jiang and Younis (2016) could be counted to improve the flow dynamics analysis of gases in shale which enhanced CH_4 recovery. However, the assumption that reservoir fluid flows only from hydraulic fractures to wellbore overlooked the other possibility of fluid flow from natural fractures and matrix direct to the wellbore as suggested in other models (Karimi-Fard et al., 2003; Nie et al., 2012).

Fathi and Akkutlu (2014) used multi-continuum modeling incorporating the triple porosity-single permeability model to investigate the impact of CO_2 injection in shale on CH_4 recovery and CO_2 storage. Among many assumptions (listed in Table 5), the model considered the existence of discrete matrix blocks in the reservoir and gas release from matrices being controlled by the transfer function as a numerical valve. The reservoir initial pressure was maintained at 32.129 MPa, and simulation was performed for 45 years, including 10 years of primary production, 5 years of CO_2 injection, followed by 30 years of the final production. Results showed an increase of 85% CH_4 production (after primary production), and 90% of injected CO_2 was sequestered, suggested to be contributed by positive counter-diffusion and competitive of the CO_2 molecules. Surface diffusion of adsorbed gases was observed to be an important transport mechanism during the gas recovery process due to its influence on CH_4 displacement and the competitive adsorption effects. However, the higher recovery and storage achieved could be associated with the assumptions of considering the rocky properties as homogeneous and isotropic, whereas real shale formation is heterogeneous.

Likewise, Xu et al. (2017) studied CO_2 huff-n-puff injection into shale through the triple porosity dual permeability model that considers the effects of gas adsorption/desorption, the competitive adsorption, and binary gas diffusion. The simulations considered 2000 days for CO_2 injection, 2000 days for soaking, and 4000 days for gas production after soaking, in 20 stages hydraulic fractured reservoir which was set at an initial pressure of 26.2 MPa, 3.45 and 6.9 MPa production pressures. The results revealed significant shale gas recovery (due to a strong competitive of CO_2 over CH_4) in comparison with no CO_2 injection scenario. CO_2 sequestration was about 1.5%, which could be associated with a longer production period during depressurization. Their simulation performed a comprehensive analysis of the flow dynamics of multicomponent gas from the matrix to natural fractures to stimulated fractures. It was further observed that apart from competitive adsorption and pressure drop, gas production could increase as the total organic carbon content increases. Xu et al. (2017) and Eshkalak et al. (2014) report high reproduction of CO_2, and both studies applied longer soaking time. Furthermore, Xu et al. (2017) may be compared with Fathi and Akkutlu (2014) which also employed longer CO_2 injection cycles and adopted triple porosity but obtained different results, particularly on CO_2 sequestration. This suggests that the impact of CO_2 injection in

Table 5
The assumptions on different models discussed in this section.

Model used	Assumptions	Scholars applied the model
Multi-continuum model	- Discrete matrix blocks exist in the reservoir, - Gas release from matrices is controlled by the transfer function as a numerical valve, - The net rate of gas mass interchange between the fractures and the pores, - Gas transport involves a matrix with triple porosity continua.	Fathi and Akkutlu (2014)
A dual porosity, dual permeability model	- Fracture and matrix systems are pathways connected with the wellbore, - There is inter-porosity flow between matrix and fracture	(Eshkalak et al., 2014; Nie et al., 2012)
The three-phase multicomponent flow model	- No mass transfer exists between hydrocarbons and water phases, - Gas stores in fractures as free phase and in the matrix as both free and adsorbed phase, - Molecular diffusion takes place only in the gas phase, and the flow in the liquid phase is facilitated by a pressure gradient, - Organic-inorganic dual continuum system is harmonized, - Pores in the inorganic matrix are larger than 10 nm.	Jiang and Younis (2016)
Triple porosity dual permeability model	- Organic kerogen is assumed as porosity I, inorganic pores and natural fractures as porosity II, and hydraulic fractures as porosity III, - Other assumptions used to develop dual permeability may hold.	(Nie et al., 2012; Xu et al., 2017)
A model accounts all mechanisms contributing to gas production	- Captures the effects of all involved mechanisms in shale gas flow, - Included the effect of sorption and pore radius change, - The continuity of a component assumes constant porosity in the matrix, - Permeability was assumed constant - One dimensional model.	(Mohagheghian et al., 2019; Rezaveisi et al., 2014)
New multicomponent isotherm	- Porosity and pore radius are homogeneous within the matrix, - The shale matrix initially contains CH_4 component only, in free and adsorbed phase, - CO_2 injected in the shale stores in both free and adsorbed phase, - The composition of free and adsorbed components is the same, - Other phases like water and oil are not present in the shale.	Berawala and Andersen (2019)

relation to soaking time on gas recovery and adsorption is still not clear.

Mohagheghian et al. (2019) developed a model (see Table 5 for assumptions) that incorporated multi-components flow mechanisms, competitive adsorption of multicomponent, pore size variation and real gas effect, to assess the effects of CO_2 injection on CH_4 recovery and CO_2 storage in partially depleted shale reservoirs. In the reservoir with an initial pressure of 34.47 MPa and temperature of 348 K, CO_2 was injected for 30 days (after primary depletion of 120 days), left to soak for 10 days, and secondary production ran for 60 days. Results showed an increment of 26% recovery of CH_4 gas and 90% of injected CO_2 caused by reservoir re-pressurization and preferential adsorption of CO_2 over CH_4 in shale. Findings from Mohagheghian et al. (2019) compare well with that of Jiang and Younis (2016), both cases applied short soaking time, however, approaches to analyze flow dynamics of gases were different. On the contrary, Schepers et al. (2009) observed high reproduction of CO_2 despite utilizing short soaking time, most probably was influenced by limitations of the models used. In addition, Mohagheghian et al. (2019) model did not take into account the coupling mechanisms of gas transport, this may affect capturing the actual effect of the multiple transport mechanisms of the fluid flow dynamics.

Berawala and Andersen (2019) developed a new multicomponent isotherm model that mainly assumed that different molecules can occupy a surface, but not necessarily take the same space (see Table 5 for other assumptions). The developed model was then applied to study the feasibility and effectiveness of CO_2 injection in the tight shale formation under injection-production settings representing lab and field implementation. Simulations at the lab scale considered initial reservoir pressure (250 bar) and production pressure (50 bar). CO_2 injection was done for 0.05 days, followed by gas production at different well pressure (250, 350, 450, 550 bar). At field scale simulation mode, Marcellus shale formation with initial reservoir pressure of 350 bar and temperature of 323.15 K was considered. First well pressure was set to 150 bar to produce for 300 days, then well pressure was raised to 550 bar during which CO_2 was injected for 300 days, and this cycle was repeated. Comparing with the no CO_2 injection scenario, the effectiveness of CO_2 injection to enhance gas recovery was found to depend on: specific surface area, reservoir re-pressurization, diffusion coefficient, time, gas concentration in the mixture, and competitive adsorption between CO_2 and CH_4 in the shale. These parameters are relatively the same as discussed in other models which have shown diverse impacts on gas production and storage performance. Despite comprehensive analysis on the multicomponent adsorption kinetics, their simulations assumed flow of gases takes place in one direction, which according to other scholars (Fathi and Akkutlu, 2014; Wu et al., 2019) can hardly describe the fluid flow in a shale formation with complex pore system due to the nonlinear effect produced by diffusive mass fluxes.

On the other hand, Kim et al. (2017) compared both continuous CO_2 injection and CO_2 huff-n-puff techniques with respect to no CO_2 injection process through numerical simulation method considering the multi-component adsorption, dissolution, and molecular diffusion. The simulations were done based on the Barnett shale reservoir which had an initial reservoir pressure of 14.75 MPa and a temperature of 314.11 K, and it operated continually for 30 years on two wells without CO_2 injection. During continuous CO_2 injection, both wells operated for 5 years first, then CO_2 was injected in one well for 5 years at a rate of 100 Msf (million standard cubic feet)/day, and the other well continued producing. After 5 years of production, the injector was shut-in, and the producer continued for an additional 20 years of production. For the huff-n-puff model, CO_2 was injected in both wells at a rate of 250 Msf/day for 1 month after 5 years of production, left to soak for 1 month, and then secondary production continued for 4 months. This cycle was repeated for 6 years. Results showed continuous CO_2 injection performed better (24%) than CO_2 huff-n-puff (6%), and more than 75% of the injected CO_2 in huff-n-puff was reproduced, while for continuous CO_2 injection, only 1% was reproduced.

The difference in performance for the two models could be associated with the coverage area CO_2 spread in the shale reservoir. In CO_2 huff-n-puff, only a small area confined near the production well is affected by CO_2 injection, while for continuous CO_2 injection the area between the injector and producer is affected, which relatively is bigger than that for huff-n-puff. Since during the CO_2 huff-n-puff, the same wells (injector and producer) initially used for continuous CO_2 injection were turned into injectors, connectivity of fracture network existed between the wells. There is a possibility that during the soaking time, injected CO_2 in each well permeated in the reservoir fracture network (between the wells), and caused reservoir pressure to attain an equilibrium state since the same amount was injected in each well. This probably affected the adsorption/desorption process of the gases, and in turn, affected CH_4 recovery and CO_2 storage efficiencies. Nevertheless, observed high CO_2 reproduction as reported in other studies is still a major concern for CO_2 huff-n-puff process. Kim et al. (2017), Schepers et al. (2009), Mohagheghian et al. (2019) and Jiang and Younis (2016), all adopted shorter soaking time, but Kim et al. (2017) and Schepers et al. (2009) observed high CO_2 reproduction as observed by Xu et al. (2017) and Eshkalak et al. (2014) studies which applied longer soaking time.

The CO_2 huff-n-puff discussions reveal a concern for the high reproduction of CO_2 injected in shale during the process. The comparisons made above show that there is no unified understanding among scholars concerning the effects induced by CO_2 injection in relation to soaking time on shale reservoir properties to gas production and storage. Consideration of fluid flow dynamics in stimulated fractures facilitated a good estimation of both gas production and storage, however, flow dynamics of multicomponent gas is not sufficiently addressed. As discussed in continuous CO_2 injection, Langmuir isotherm model is also employed by huff-n-puff studies, though is not capable of modeling gas adsorption at higher pressure condition (Shadi et al., 2018; Lan et al., 2019). The complex pore system of shale (shale heterogeneity), effects of moisture content and effects of shale matrix properties induced by CO_2 injection are not considered in the current simulation models though they are important in the prediction of shale gas adsorption/desorption. In addition, more observation for CO_2 huff-n-puff are summarized below:

1. The average increment of CH_4 recovery after primary production is about 6–26%, whereas a range of 1.5–90% of the injected CO_2 in shale successfully got sequestered.
2. Studies did not distinguish the contribution of gas storage modes in shale (free, adsorbed, and dissolved) to both recovered CH_4 and sequestered CO_2.

More information is provided in Table 5 to the assumptions used to develop various models discussed in this section.

2.2.2. *Study of CO_2-huff-n-puff technique through field case tests*

Despite several studies reporting promising findings to enhance shale gas recovery by CO_2 injection in shale formations, rare field tests are reported. This study managed to obtain only two reports on field tests from Nutt et al. (2005) and Louk et al. (2017). Nutt et al. (2005) report a small field scale project that intended to inject 300–500 tons of CO_2 in the Devonian Ohio shale in eastern Kentucky. This project, however, was not successful due to a packer failure that forced the termination of the project. On the other hand, Louk et al. (2017) conducted a field small scale test on the CO_2 huff-n-puff process in Morgan County, Tennessee in a hydraulically fractured well of Chattanooga shale reservoir. Successfully, 510 tons of CO_2 were injected in the shale reservoir that had an estimated initial pressure of 6.86 MPa, a temperature of 289.67 K for 12 days. After a soaking period of 4 months, secondary production was performed at a production pressure of 1.792 MPa. Results showed an increase in gas production by 8 times after CO_2 injection, and 59% of injected CO_2 was sequestered within 17 months though it continued decreasing as the production time increased. As observed in the simulation studies, the increase of CO_2 injection pressure in the field test also enhanced gas recovery and storage. Another comparative result with simulation studies was a higher CO_2 reproduction during the puff period.

3. Prospect and challenges of CO_2 injection techniques

Most studies on CO_2 injection techniques focus on evaluating the CH_4 recovering and CO_2 sequestration potential of the shale reservoirs. However, the feasibility of these techniques in the field-scale trial is quite complicated due to the complex pore structures in shale and the ultralow permeability. Though extensive researches have been done to investigate CO_2 injection based on simulations method, comprehensive models that can effectively analyze all mechanisms involved in CO_2-ESGR are lacking due to complicated and demanding computational works. This study identified some issues that are important for the prospect of CO_2 injection techniques as summarized below.

1. Future research should consider the effects of shale reservoir heterogeneity nature on the dynamic processes involved during gas production especially the kinetic competitive adsorption between CO_2 and CH_4 and flow dynamics of multicomponent gas. Since shale formations are composed of different pore sizes, their distribution and interconnectivity are important in the analysis of both competitive adsorption and flow dynamics of gases in shale.
2. Several studies have shown concern about the high amount of CO_2 injected during the huff-n-puff process being reproduced together with gas. We suggest further study should be conducted to investigate the effects of CO_2 injection amount, soaking time, and production time on the CO_2–CH_4 competitive adsorption mechanism and shale matrix properties.
3. Most models used to analyze the flow dynamics of gases are suitable for well connected fractures, assume shale formation as homogenous, and cannot model fluid flow in stimulated fractures. Future simulation models should also consider this since fluid flow dynamics is an important factor for predicting gas production and storage in shale.
4. Current simulations studies on CO_2 injection fail to predict the potential effects on CO_2 injection on shale matrix properties, and its impact on gas production and CO_2 storage. It is reported in several experimental studies that when CO_2 interacts with shale formation causes changes on shale properties like pore specific surface area, pore-volume, porosity, mineral composition, permeability, etc. (Jiang et al., 2016; Ao et al., 2017; Luo et al., 2018; Sanguinito et al., 2018; Ao et al., 2017, 2017; Rezaee et al., 2017; Wu et al., 2017; Yin et al., 2016). However, a lack of unified understanding among scholars on these changes suggests the necessity for future simulations studies to consider this aspect.
5. Moisture content is another aspect lacking in the current simulation studies on gas recovery and storage through CO_2 injection. Moisture content in shale competes with both CO_2 and CH_4 for adsorption sites and also can block pore throats and networks, hence affecting gas adsorption and mobility (Huang et al., 2018; Klewiah et al., 2020; Zou et al., 2018). Thus, it is recommended in the future simulation models.
6. Current studies have neglected to evaluate the changes in reservoir temperature induced by CO_2 injection, hence we recommend the consideration of heat transfer effects of the flow dynamics of gases.
7. The limitations in existing laboratory facilities (especially to replicate real shale reservoir conditions) hinders experimental based approaches to evaluate CO_2 injection techniques, suggesting field tests as an option for future studies.
8. Future studies should be able to predict the contribution of gases stored as free phase, adsorbed phase, and dissolved phase to both recovered CH_4 and sequestered CO_2.

4. Conclusions

This review has described the CO_2 injection techniques (continuous CO_2 injection, and CO_2 huff-n-puff) in shale gas reservoirs with the main purpose of defining their potential and limitations for enhancing shale gas recovery. Due to limited information on field test studies, only two field test cases were reviewed and the remaining studies were from numerical simulation methods, which incorporated various mathematical models. The CO_2 injection techniques may produce an increment of up to 26% methane recovery after primary gas production and sequester more than 60% of the injected CO_2 for continuous CO_2 injection. For CO_2 huff-n-puff many studies report a higher amount of CO_2 injected in shale being produced back during the puff period. We noted that shale gas recovery and CO_2 storage during CO_2 injection depend on pressure drop, competitive adsorption, flow dynamics of gases, well design, and shale reservoir properties. It was further observed that simulation models that considered fluid flow dynamics in the stimulated fractures showed significant performances for gas production and storage. This shows that understanding the natural and stimulated fracture system is key to enhancing gas production and storage through CO_2 injection.

On the other hand, the field study test showed a higher gas recovery and storage efficiency as CO_2 injection pressure increased which compared well with the simulations for huff-n-puff. As production time increased field test showed a decrease in CO_2 reproduction while CH_4 recovery increased, the same scenario reported in simulations. Despite the limitations of the Langmuir isotherm in higher pressure conditions, it was incorporated by the simulation models to predict gas adsorption/desorption. Other key points to note in this study may include:

1. Due to extremely low permeability of shale formation, successful CO_2–ESGR can be practical and efficient when conducted in a hydraulically fractured shale.
2. Analysis of the effect induced by CO_2 injection on shale matrix properties, the effect of moisture content, and shale heterogeneity to gas production and storage, are lacking in the current simulation models.
3. The contribution of the multicomponent gas is not clearly described in the gas flow mechanism in the simulations.
4. The contribution of the three modes of gas storage in shale (free, adsorbed, and dissolved) to both recovered CH_4 and sequestered CO_2 has received less attention in the current models.

Declaration of competing interest

We declare no conflict of interest.

CRediT authorship contribution statement

Raphael Iddphonce: Data curation, Investigation, Writing - original draft, Writing - review & editing. **Jinjie Wang:** Conceptualization, Funding acquisition, Validation, Supervision, Writing - review & editing. **Lin Zhao:** Writing - review & editing.

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Nomenclature

P	Pressure
T	Temperature
tcm	Trillion cubic meter
TOC	Total Organic Carbon
ε_A	Interaction energy
Msf	Million standard cubic feet)/day

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