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Shale gas reservoir treatment by a CO_2-based technology

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ABSTRACT

The booming development and production of shale gas largely depends on extensive application of water-based hydraulic fracturing treatments and primary pressure depletion. Issues associated with this procedure include fast production rate drop, low recovery factor, high water consumption, and formation damage. It is necessary to develop new reservoir fracturing and enhanced gas recovery (EGR) technologies to reduce water usage and resource degradation, guarantee the environmental sustainability of unconventional resource developments, and boost individual well production. Building on gas storage and transport mechanisms in shales, this study investigated the feasibility of a new CO_2-based reservoir treatment technology. CO_2 has a higher adsorptivity than CH_4, enabling it to liberate adsorbed natural gas in place. Therefore, gas production will be boosted by injecting CO_2 to replace CH_4. This novel reservoir treatment process will also open a large market for the beneficial utilization of CO_2. In this paper, the authors discuss the theoretical principles and feasibility of using CO_2 in both the stimulation stage and the secondary gas recovery stage. Following that, the authors outline a case study performed to simulate applying the CO_2-EGR process in the Barnett, Eagle Ford, and Marcellus shale plays. The marginal revenue per thousand standard cubic feet (MSCF) of increased CH_4 production was calculated. The profitability was found to be largely determined by the prices of natural gas and available CO_2. A cost breakdown analysis indicated that the CO_2 procurement expense was the main component in the total cost. The proposed CO_2-EGR process was mostly like to be successful in the Barnett shale.

1. Introduction

Gas production from shales in the United States has continuously increased and has become one of the major domestic sources of energy. The boom of shale resource development and production largely depends on water-based hydraulic fracturing (fracking) (Wang et al., 2015). The driving mechanism is primary depletion of reservoir pressure (Sheng, 2009). The typical gas production rate from a single well usually drops rapidly in the first 1–2 years. The fast production rate drop significantly impacts the economics of individual wells and the overall development. During the fracking process, a large volume of water is mixed with proppants and other chemicals and injected into the reservoir at high pressures to create fractures in the rock face. A typical hydraulic facture operation requires three to five million gallons of water per well (Arthur et al., 2012). As natural gas is one of the cleanest and most abundant energy sources, more shale gas reservoirs are expected to be developed in the next decades (Economides and Wood, 2009; Esfahani et al., 2015). In addition, there are increasing concerns about water usage and environmental footprints in unconventional field development (Ziemkiewicz et al., 2013). The water-based fracking process is also associated with some issues in formation damage, water-phase trapping, and flowback difficulty. During the development of shale gas plays, clays swell when they encounter fracking water, further reducing the available matrix permeability and preventing release of gas and oil in the matrix. Fracking fluids can get trapped in the liquid phase in rock pores next to the fractures due to the very low permeability in tight gas and shale formations. Because of the relatively high viscosity of the fracking fluid, control of proppants during the flowback procedure is also an issue from the views of economics and safety. Therefore, it is necessary to seek an alternative reservoir treatment process to reduce water usage as well as to improve production.

In this paper, we discuss the feasibility of a carbon dioxide (CO_2)-based reservoir treatment technology for gas shales. The

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proposed technology is waterless and reservoir friendly. It aims at improving reservoir performance by inducing fractures, liberating adsorbed methane, avoiding clay swelling, and boosting single well production. In the treatment, CO_2 is used as the fracking fluid to stimulate the reservoir. During the secondary recovery stage, CO_2 is injected into the reservoir as a displacing fluid to liberate adsorbed methane (CH_4) and increase the CH_4 production rate. This is based on the principle that CO_2 has a much higher sorption affinity to kerogen than CH_4. Herein the process is termed as CO_2-enhanced gas recovery (CO_2-EGR). In the following sections, the authors first review the gas storage and transport mechanism in the shale reservoir, and then discuss the obstacles in shale gas production. Following that, the principles and advantages of the CO_2-fracking and CO_2-EGR processes will be introduced. Finally, the authors outline a case study modeling the application of CO_2-EGR to the Barnett shale, Eagle Ford shale, and Marcellus shale plays to evaluate the cost components and potential profitability of the process.

2. Gas storage mechanisms and production obstacles

There are four major media in productive gas shales: organic matter, nonorganic matrix, natural fractures, and hydraulic fractures. It is observed that, in shale, the finely-dispersed kerogen material is imbedded within an inorganic material (Ambrose et al., 2010), and the organic matter is the main constituent of total pore volume associated with *in situ* generation and storage of gas (Kang et al., 2010). Gas is stored in shale in four basic forms: adsorbed gas on organic matter, free gas in pores and fractures, solution gas in liquid hydrocarbons, and solution gas in formation water (Lancaster and Hill, 1993; Boyer et al., 2005; Mengal, 2010). Free gas is natural gas that is trapped in the pore spaces of the shale; additionally, adsorption is the pressure-dependent attraction of gas molecules to the surface of a solid, resulting in a dense phase of gas at the surface. In the reservoir, the sorbed gas is in equilibrium with the free-phase gas (Lewis et al., 2004).

The fractured reservoir usually is depicted using the classic dual porosity model. The matrix is assumed to provide the storage capacity, and the fractures function as the main transport pathways for production. In the matrix, gas is transported by Fickian diffusion, while in the fractures with high permeability, gas is transported according to Darcy's law (Cui et al., 2009). The organic matter pores, which range in size from 5 to 1000 nm, can adsorb gases as well as store free gases. The porosity of the organic matter can be five times higher than that of the nonorganic matrix (Wang et al., 2009). Also, due to pore wall effects, density of the gas in the adsorbed phase is about two times higher than that of the bulk gas (Ambrose et al., 2010). By storing gas in a dense, liquid-like adsorbed phase, the overall storage capacity of the rock is enhanced compared to storing gas in the free phase alone (Kurniawan et al., 2006; Heller and Zoback, 2014). The amount of adsorbed gas is a function of kerogen type and content, pore structure, pore pressure, and temperature (Chalmers and Bustin, 2008; Ross and Bustin, 2009; Ambrose et al., 2010). Previous studies have concluded that total organic carbon (TOC) is the primary factor controlling the adsorptive capacity of the rock (Schettler et al., 1991; Lu et al., 1995; Heller and Zoback, 2014). Depending on the reservoir properties and conditions, adsorption may account for as much as 20%–85% of the gas in place in shales (Lancaster and Hill, 1993; Lewis et al., 2004; Pan and Connell, 2015). However, the majority of this adsorbed gas may not be recovered as the sorption isotherms only indicate an obvious steepness at lower pressures (Freeman et al., 2013).

The total gas in place, G_{st} (scf/ton), can be expressed as (Ambrose et al., 2010):

$$G_{st} = G_f + G_a + G_{so} + G_{sw} \tag{1}$$

where G_f (scf/ton) is the gas content in the free phase, G_a (scf/ton) is the gas content in the adsorbed phase, G_{so} (scf/ton) is the solution gas in liquid hydrocarbons, and G_{sw} (scf/ton) is the solution gas in formation water.

The free gas can be estimated using:

$$G_f = 32.0638 \frac{\phi(1 - S_W - S_O)}{\rho_b B_g} \tag{2}$$

where ϕ is the porosity, ρ_b (g/cm^3) is the bulk density, S_W is the water saturation, S_O is the oil saturation, and B_g is the gas formation volume factor.

The amount of sorbed gas can be quantified by the Langmuir isotherms (Langmuir, 1916). This theory assumes that the gas is adsorbed as a monolayer on the rock surface. It describes the relationship between the adsorption of pure gas molecules on a coal or shale surface and gas pressure at a constant temperature.

$$G_a = V_L \frac{P}{P + P_L} \tag{3}$$

where V_L (scf/ton) is the Langmuir volume, P_L (psi) is the Langmuir pressure, and P (psi) is the reservoir pressure.

Solution gas is generally not significant in published volumetric calculations of gas in place. Adsorbed gas, on the other hand, might contribute significantly to the total gas volume of most shale gas plays (Euzen, 2011; Holmes et al., 2011). Using the Barnett shale as an example, laboratory tests indicated that adsorbed gas content ranges from 105 to 125 scf/ton at a reservoir pressure of 3800 psi, and the sorbed gas may account for as much as 50% of the total gas in place (Montgomery et al., 2005). Fig. 1 displays gas content of Barnett shale core samples. Total gas in place and the adsorbed gas isotherms are indicated in the diagram.

Shale gas production involves three main processes: depletion of free gas in fractures, depletion of free gas in matrix pores, and desorption of sorbed gas (Gault and Stotts, 2007). In the initial stage, the produced gas is dominated by free gas from the fracture network. Because of the limited amount of free gas in factures, the production curve usually declines drastically over the first 1–2 years (Fig. 2). Following that, free gas in the matrix and desorption of desorbed gas dominate the production. Numerical simulations suggest that desorption of gas maintains reservoir pressure for a longer period of time (Shabro et al., 2011).

The drastic drop of the gas production curve and the flat tail can

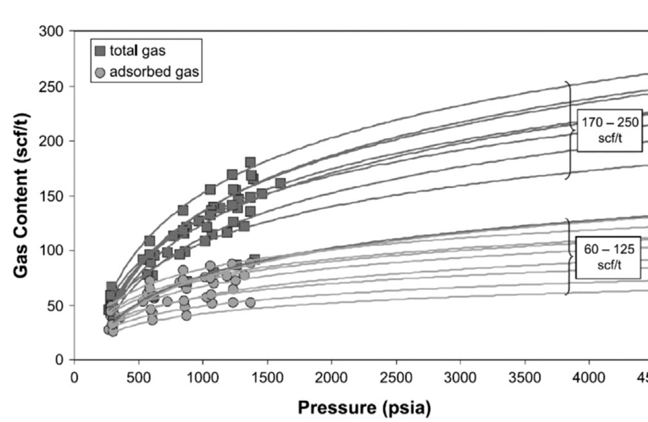

Fig. 1. Total gas and adsorbed gas content in the Barnett Shale (Montgomery et al., 2005).

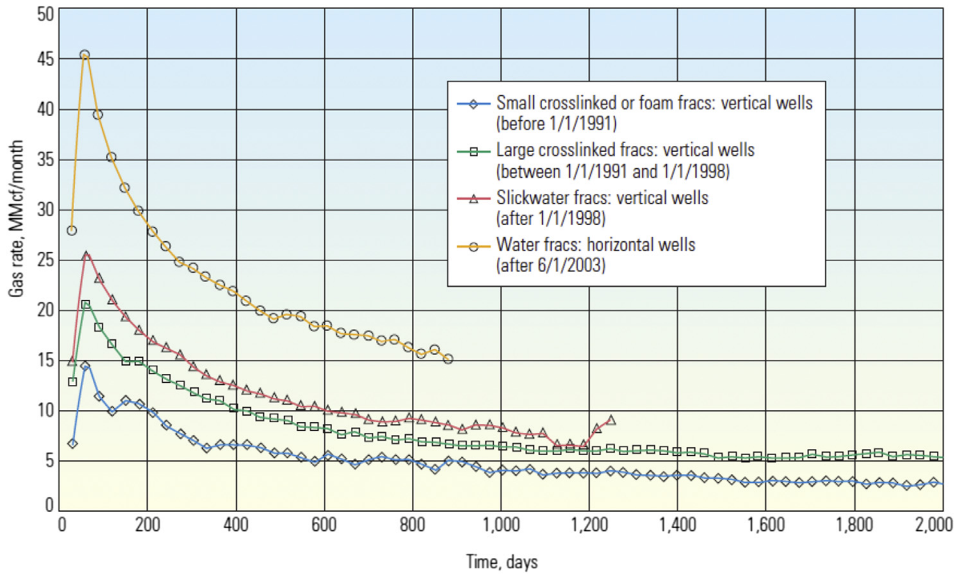

Fig. 2. Typical gas decline curves of Barnett Shale (Boyer et al., 2005).

be explained using the Langmuir isotherm of gas content vs. pressure. The adsorbed gas content is a function of pressure, and physical adsorption can be reversed by reducing the pressure of the adsorbed gas (White et al., 2005). In the example of Barnett shale shown in Fig. 1, it is clear from the isotherm curves that a significant drop will only occur if the pressure is below 1500 psi. This means that the adsorbed gas will not be released until the reservoir pressure is reduced to that level. However, in a typical reservoir/production pressure range (>2000 psi), the gas content is not so sensitive to the pressure, and it is almost impossible to reduce the reservoir pressure to a level below 1500 psi. Therefore, the amount of adsorbed gas that can be released through pressure drop in production is limited. After the first 1–2 years of high production, which is mainly contributed by free gas in fractures, the production curve usually drops to a stable but low rate (Fig. 2). Desorption and diffusion are responsible for the characteristics of the flat production tails. As the production curve of a single well declines in the short term, the developer must continue investing and developing new wells in large scale to sustain the cash flow of the project. This, in turn, results in a larger environmental footprint and economic burden.

Table 1 lists the percentages of adsorbed gas and free gas in total gas in place for several gas shales in the U.S (Hill and Nelson, 2000; Jarvie et al., 2005; Patterson, 2009). In general, mature thermogenic shales have a higher free gas fraction. By contrast, biogenic shales, such as the Antrim shale, are predominantly saturated by adsorbed gas with a smaller amount of free gas (Boyer et al., 2005). As discussed, currently most of the produced gas from shales is contributed by the free-phase gas; thus, the hard-to-recover sorbed gas portion presents a big potential to improve the production and economics of a single well.

Table 1
Free gas and adsorbed gas fractions in some representative shale plays in the U.S.

Play	Source	Free gas fraction	Adsorbed gas fraction
Barnett	Thermogenic	~50%–65%	~35%–50%
Marcellus	Thermogenic	~50%	~50%
Fayetteville	Thermogenic	~40%	~60%
Woodford	Thermogenic	~54%	~46%
Lewis	Thermogenic	~40%	~60%
Ohio	Thermogenic	~50%	~50%
New Albany	Mixed	~50%	~50%
Antrim	Biogenic	~30%	~70%

3. CO_2-based treatment technology

To resolve the aforementioned challenges associated with shale gas production, the authors propose a novel CO_2-based treatment technology for shale gas reservoirs. During the stimulation procedure, CO_2 is used as a fracking fluid. In the enhanced recovery procedure, CO_2 is used as a displacing fluid. In this proposed technology, supercritical CO_2 is mixed with proppants and injected into the shale reservoir to frack the reservoir. As the pressure of CO_2-based fracking fluid overcomes the tensile strength of the rock, fractures are generated. Proppants carried by the fluids will hold the fracture open. In the EGR stage, since the organic surface of shale has a higher affinity for CO_2 than CH_4, CO_2 will replace CH_4 adsorbed on the surface, liberating CH_4 and improving gas recovery.

The CO_2-based treatment will improve economics and production from several aspects, including reducing water consumption, inducing artificial fractures, leaving reservoirs damage-free, improving fracking fluid clean-up, and maintaining gas production rate. CO_2-based nonconventional fracturing fluid has been applied or discussed by several researchers (Harris et al., 1984; Gupta, 2009; Mazza, 1997). Liquid CO_2 as fracturing fluid is already commercially used in many tight gas applications in Canada and the U.S. (Gandossi, 2013), but supercritical CO_2 use is at the concept stage. Studies have analyzed its potential use for fracturing shale formations, with positive conclusions (Ishida et al., 2012; Wang et al., 2012). Supercritical CO_2 exhibits a unique blend of high density and low viscosity. The liquid-like density allows supercritical CO_2 to be as capable of creating fractures and carrying proppants as water-based fluids. Low viscosity means the fluid has greater mobility, higher penetration rate, fast clean-up, and good recovery during flowback of the fracturing fluid. Under favorable reservoir conditions, injected liquid CO_2 may vaporize, leaving liquid-free proppants in the reservoir. In water-based fracking processes, clays swell when mixing with water, shrinking available channels in the pores for fluid flow. However, CO_2 does not cause this type of damage and is consequently considered to be "reservoir-friendly".

As mentioned in the previous section, there is a large amount of adsorbed gas in shales which is hard to release by pressure drop. It is known that shale has a preference to adsorb CO_2 over CH_4 (Krooss et al., 2009; Liu and Wilcox, 2012). Adsorption and desorption of CO_2 to and from coals and shales was also found to proceed more rapidly than that of CH_4. CO_2 and CH_4 adsorption on shale rocks have been measured by some researchers (Nuttall et al., 2005; Kang et al., 2010; Heller and Zoback, 2014). The selectivity of CO_2 over methane varies from 2 to higher than 5 at various temperatures and pressures (Vermylen, 2011). This selectivity provides the justification for the approach involving the use of CO_2 to liberate adsorbed CH_4. Therefore, injection of a high-affinity gas like CO_2 might be a potential way to sweep the reservoir and enhance CH_4 recovery (Li and Elsworth, 2014).

In addition, CO_2 capture and storage has been proposed as a major effort to reduce anthropogenic CO_2 emissions and mitigate global climate change. Favored storage options are saline aquifers, depleted gas and oil reservoirs, or unminable coal seams (Freund and Ormerod, 1997; Holloway, 1997; Hitchon et al., 1999; Hattenbach et al., 1998; Bachu, 2000; IPCC, 2005). Shale has a higher storage capacity for CO_2 than CH_4. Due to the large surface areas of pores, organic-rich shale may provide a huge potential for CO_2 storage through the adsorption trapping mechanism (Lawrence et al., 2006; Busch et al., 2008; Kang et al., 2010). Moreover, the organic matter functions as a molecular sieve which allows CO_2, with its linear molecular geometry, to accumulate in smaller pores where other gases like CH_4 cannot access (Kang et al., 2010). Therefore, the CO_2-EGR process can also utilize the significant adsorption potential of gas in shales, making shales viable media for CO_2 sequestration.

There are two major challenges associated with this proposed technology: the availability of CO_2 sources, and the ability of fracking fluid to carry proppants. These challenges will require additional research. Due to the large surface area and high CO_2 adsorption capability in shales, large quantities of CO_2 would be consumed during the treatment process. This provides an opportunity in beneficial utilization of CO_2. Currently, industry has prioritized CO_2 utilization over CO_2 sequestration. However, the demand for CO_2 in the market comprises only a small portion of the annual emissions from industry sources. If this technology is applied successfully, a new, potentially large, CO_2 market will be unlocked.

Because of the low viscosity of the CO_2-based fluid, its ability to carry the proppants may be constrained. This issue can be resolved by using a properly structured CO_2/water two-phase fluid with a high internal phase ratio. Laboratory experiments and field tests in Anakarko Basin indicated that a foam comprising 70% CO_2 could maintain typical properties of good proppant transport and low fluid loss (Harris et al., 1984). If two-phase foam is not employed, new proppants which are lightweight and strong must be developed for effective long-term use.

4. Application potential

4.1. Modeling approach

To assess the application potential of the proposed technology, a case study was performed to simulate the CO_2-EGR process. The authors selected three representative shale gas plays in the U.S. to model: the Barnett shale, the Eagle Ford shale, and the Marcellus shale. A common analogy to the CO_2-EGR process is CO_2-enhanced coalbed methane (CO_2-ECBM) recovery. Experience and lessons from the CO_2-ECBM technology can be applied to the proposed CO_2-EGR process. Both the shale gas and coalbed methane (CBM) reservoirs are continuous gas accumulations. Pilot tests of CO_2-ECBM have been carried out in many places, and a large amount of data has been published characterizing coals from various coal basins worldwide for their gas sorption capacity (Gray, 1987; Busch and Gesterblum, 2011; Cai et al., 2013; Liu et al., 2014). In primary CBM recovery, the seam is first dewatered to low pressure and then allowed to naturally depressurize with time. CH_4 present in the coal diffuses from an area of higher pressure within the coal to an area of low pressure at the bore holes. During ECBM recovery, CO_2 injection increases the production of CH_4 by reducing the partial pressure of CH_4 in coal and displacing of CH_4 from sorption sites. The sorbed CO_2–CH_4 front is expected to grow elliptically out from the injection wells due to coal anisotropy (White et al., 2005).

However, one should note that there are several important differences between coal and shale in terms of gas storage and transport (Hartman et al., 2008; Jenkins and Boyer, 2008): a) coals contain more than 50% by weight (wt%) organic matter, whereas shales contain less than 50 wt% organic matter; b) nearly all coalbed gas is sorbed gas, whereas shale gas is a combination of sorbed gas and free gas; c) shale-gas reservoirs typically are thicker (>100 ft) with lower sorbed gas content than coalbed, and contain a much larger volume of free gas in the pore space; and d) shale gas reservoirs usually have much lower permeabilities than the coalbed, with values in the nano-to microdarcy range.

In the case studies models, several assumptions were made as follows:

- The reservoir had been fractured using the CO_2-based stimulation process described previously;
- Primary recovery of the shale gas was driven by natural depressurization and CO_2-EGR was applied after the steep drop stage in primary recovery;
- The CO_2 injection wells and natural gas production wells were arrayed next to each other, and the injection wells were converted from production wells;
- When CO_2 injection was started, the reservoir is adsorbed by CO_2 and CH_4;
- The reservoir pressure was maintained at an approximately constant level during CO_2 injection;
- Gas adsorption in the rock followed the Langmuir monolayer adsorption theory;
- The increased production of CH_4 by CO_2 injection was equal to the desorbed CH_4 from the surface of the rock;
- The project was terminated when CO_2 broke through in the production well, which was set as 10 years based on experience in CO_2 –ECBM operations (White et al., 2005).

When CO_2 is injected into the reservoir and present in free phase, it will compete with CH_4 for adsorption sites; thus, the adsorption and desorption of the gases are not independent from one another. The adsorption characteristics of the rock are described by the binary isotherms, which are generated by laboratory testing. Many previous studies have provided the binary or ternary isotherms of coals for the purpose of examining the feasibility of CO_2-ECBM (Rupper et al., 1972; Arri et al., 1992; Hall et al., 1994; Clarkson and Bustin, 2000; Harpalani et al., 2006). However, currently there is little literature providing the binary isotherms of shale rocks. In such cases, the extended Langmuir isotherms were used for representing the adsorption isotherm data of mixures of gases. The binary sorption was estimated using pure gas isotherms (Myers and Prausnitz, 1965; Ruthven, 1984; Yang, 1987; Arri et al., 1992). The extended Langmuir isotherm is expressed as:

$$G_{a,i} = \frac{V_{L,i}\frac{P_i}{P_{L,i}}}{1 + \sum_j \frac{P_j}{P_{L,j}}} \tag{4}$$

where $G_{a,i}$ (scf/ton) is the gas content of gas component i, $V_{L,i}$ (scf/ton) is the Langmuir volume of gas component i, $P_{L,i}$ (psi) is the Langmuir pressure of gas i, and P_i (psi) is the partial pressure of gas component i:

$$P_i = Py_i \tag{5}$$

where P (psi) is the pore pressure and y_i is the volume fraction of gas i in the free phase.

With the extended Langmuir isotherm, the gas content of each component can be directly calculated from its partial pressure. Only the Langmuir constants from pure gas sorption are required. The selectivity ratio, α, is defined as (Arri et al., 1992):

$$\alpha = \frac{\left(\frac{V_{L,i}}{P_{L,i}}\right)}{\left(\frac{V_{L,j}}{P_{L,j}}\right)} \tag{6}$$

The amount of CH_4 liberated through CO_2 injection, ΔG_{CH_4} (scf/ton), is calculated by:

$$\Delta G_{CH_4} = G_{CH_{4,0}} - G_{a,CH_4} \tag{7}$$

where $\Delta G_{CH_{4,0}}$ (scf/ton) is the CH_4 gas content before CO_2 injection and G_{a,CH_4} (scf/ton) is the CH_4 gas content at any point after CO_2 injection.

The increased amount of CO_2 (ΔG_{CO_2}, scf/ton) in the reservoir is equal to the injected amount of CO_2 (G_{CO_2}, scf/ton):

$$\Delta G_{CO_2} = G_{CO_2} \tag{8}$$

Here the ratio of production (R_{prd}) is defined as a parameter to represent how many volumes of CO_2 must be injected to liberate one unit volume of CH_4:

$$R_{prd} = \frac{\Delta G_{CO_2}}{\Delta G_{CH_4}} \tag{9}$$

The single phase CO_2 injection rate (q_{CO_2}, MSCF/D) of a horizontal well can be estimated using the Economides et al. (1993) model:

$$q_{CO_2} = \frac{k_H h\left(p_{wf}^2 - p_e^2\right)}{1424\mu ZT\left[\ln\left(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right) + \frac{I_{ani}h}{L}\left(\ln\frac{I_{ani}h}{r_w(I_{ani}+1)}\right)\right]} \tag{10}$$

where r_w (ft) is the well radius, h (ft) is the pay zone thickness, T (°R) is the reservoir temperature, K_H (mD) is the horizontal permeability in the fractures, L (ft) is the length of the horizontal section, I_{ani} is the permeability anisotropy, μ (cp) is the viscosity, Z is the gas compressibility, and a(ft) is the semimajor axis of the drainage ellipsoid formed by a horizontal well of length L, calculated by Equation (11):

$$a = \frac{L}{2}\left\{0.5 + \left[0.25 + \left(\frac{r_{eH}}{L/2}\right)^4\right]^{0.5}\right\}^{0.5} \tag{11}$$

where r_{eH} (ft) is the hydraulic drainage radius.

In this study, the cost associated with the CO_2-EGR process was broken into capital cost and operation cost. Since the CO_2 injection wells were converted from the original natural gas production wells, drilling and completion cost was not included in the EGR cost estimation. The capital cost items include:

- CO_2 compressor capital cost, C_{comp} ($)
- CO_2 well abandonment cost, C_{aband,CO_2} ($)
- CH_4 well abandonment cost, C_{aband,CH_4} ($)

The operating cost items are:

- Fixed operation cost of CO_2 well, $C_{F.O.CO_2}$ ($/month)
- Variable operation cost of CO_2 well, $C_{V.O.CO_2}$ ($/MSCF)
- Fixed operation cost of CH_4 well, $C_{F.O.CH_4}$ ($/month)
- Variable operation cost of CH_4 well, $C_{V.O.CH_4}$ ($/MSCF)
- Electricity cost of CO_2 compressor, C_{elec} ($/month)
- CO_2 purchase expense, $Expex_{CO2}$ ($/month)

The annualized capital cost CO_2 compressor (A_{comp}, $/year) is calculated by Mian (2011):

$$A_{comp} = C_{comp}\left[\frac{i_e(1+i_e)^t}{(1+i_e)^t - 1}\right] \tag{12}$$

where i_e is the annual interest rate and t (year) is the project life.

The annualized abandonment cost of the wells (A_{aband}, $/year) is calculated by Mian (2011):

$$A_{aband} = C_{aband}\left[\frac{i_e(1+i_e)^t}{(1+i_e)^t - 1}\right] \tag{13}$$

The net revenue of the CO_2-EGR process was the sale income of CH_4 less the associated costs listed above. The calculation flow diagram is displayed in Fig. 3. Assumptions relating to the CO_2 compressor and well arrangement are listed in Table 2.

Using the methods and equations described in the last section, the authors estimated the potential applicability of the CO_2-EGR process in the Barnett, Eagle Ford, and Marcellus shale plays. The revenue from each increased production volume of CH_4 ($/MSCF) was calculated as a function of three factors:

- Injection pressure was set as 1.2, 1.5, and 1.8 times of the reservoir pressure;
- CO_2 price from $15/ton to $45/ton;
- Natural gas price from $3.00/MMBTU to $8.00/MMBTU.

The authors also calculated the percentage of each cost component in the total cost, including the cost of the CO_2 compressor, costs associated with the CO_2 injection well, costs associated with the CH_4 production well, and costs associated with CO_2 procurement. The cost and revenue were expressed in 2014 U.S. dollars.

4.2. Barnett shale

The input parameters for the model of Barnett shale are listed in Table 3. Fig. 4 displays the Langmuir parameters of the Barnett shale rocks measured by Heller and Zoback (2014).

Using Equation (9), the production ratio, R_{prd}, was calculated as 2.04; that is, to increase the CH_4 production by 1 SCF from the Barnett shale, 2.04 SCF of CO_2 needs to be injected into the reservoir. Fig. 5 shows the revenue per increased MSCF of CH_4 through CO_2 injection to the Barnett shale, at a fixed natural gas price of $5.50/MMBTU. The revenue is expressed as a function of CO_2 price and injection pressure. It is obvious that the CO_2 price had a more significant impact than the injection pressure. If the CO_2 price is higher than $40/ton, the project is not profitable.

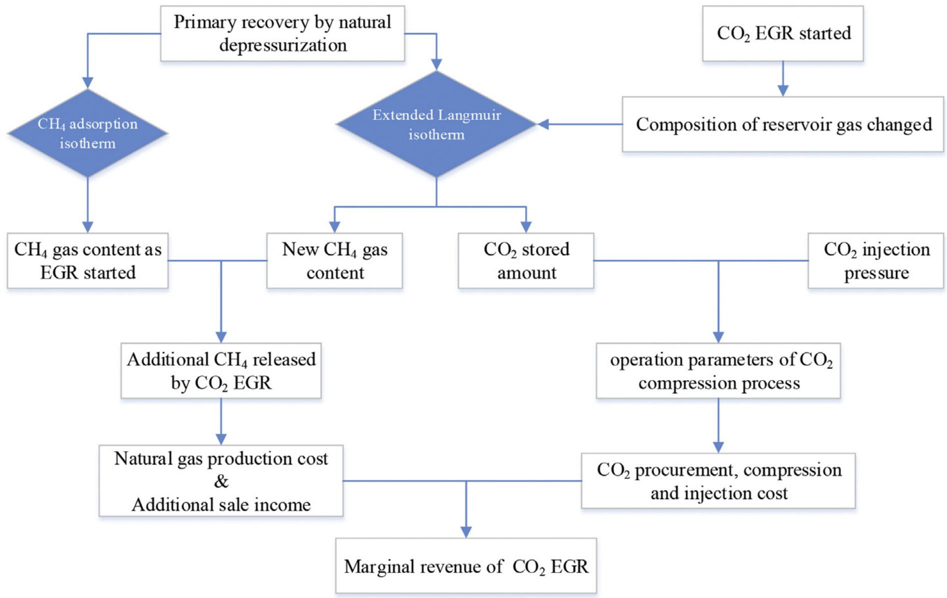

Fig. 3. Calculation flow diagram.

Table 2
Assumptions of CO_2 compressor and well arrangement.

Length of horizontal section, L	5000	ft
Well spacing, W	3200	ft
Hydraulic drainage radius, r_{eH}	1746.5	ft
Well radius, r_w	0.5	ft
EGR project life, t	15	Years
Isentropic efficiency of CO_2 compressor, η	85	
Abandonment cost of horizontal well, C_{aband,CH_4}, C_{aband,CH_4}.	500,000	$
Fixed operation cost of horizontal well, $C_{F.O.}$	2000	$/month
Variable operation cost of horizontal well, $C_{V.O.}$	0.1	$/MSCF
Electricity price, $R_{elec.}$	0.06	$/kWh
Annual interest rate, i_e	10	%

Table 3
Inputs for the case study of Barnett shale.

Reservoir depth, D	7000	ft
Pay zone thickness, h	300	ft
Original reservoir pressure, P_0	3800	psi
Reservoir temperature, T	640	°R
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3400	psi

Fig. 6 shows the revenue per increased MSCF of CH_4 produced as a function of natural gas price and injection pressure, at a fixed CO_2 price of $30/ton. Similarly, the natural gas price was the determining factor compared to the injection pressure. The CO_2-EGR process becomes profitable when the natural gas price is over $4.00/MMBTU.

Table 4 lists the percentage of each cost component. As mentioned above, CO_2 price was the determining factor in profitability, and the CO_2 purchase cost comprised the largest share in the total cost, ranging from 63% to 87%.

4.3. Eagle Ford shale

The input parameters for the Eagle Ford shale model are listed in Table 5. Fig. 7 depicts the Langmuir constants of the Eagle Ford shale rocks measured by Heller and Zoback (2014). Compared to the Barnett shale, the Eagle Ford shale has a lower storage capacity for both CO_2 and CH_4.

The production ratio, R_{prd}, was calculated as 2.88; that is, to increase the CH_4 production by 1 MSCF from the Eagle Ford reservoir, 2.88 MSCF of CO_2 must be injected. This production ratio is higher than that calculated for the Barnett shale. Fig. 8 is the

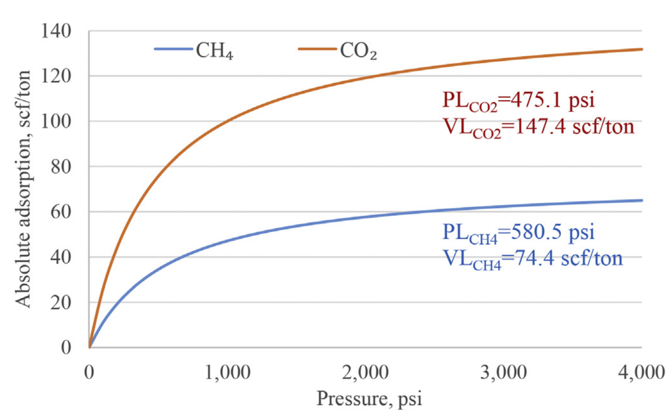

Fig. 4. CO_2 and CH_4 adsorption isotherms on Barnett samples (after Heller and Zoback, 2014).

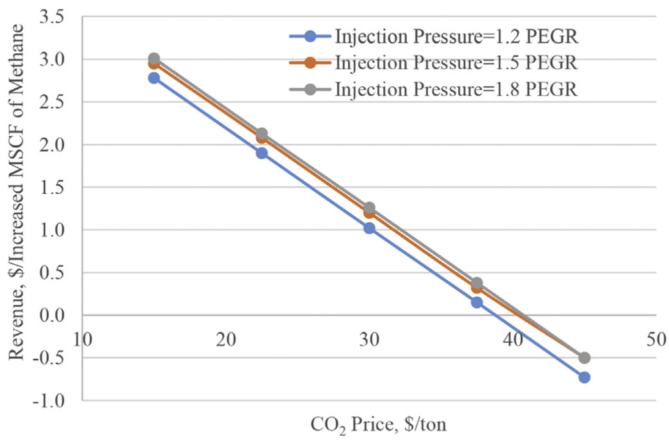

Fig. 5. Revenue sensitivity as a function of injection pressure and CO_2 price (CH_4 price = $5.50 MMBTU), Barnett shale.

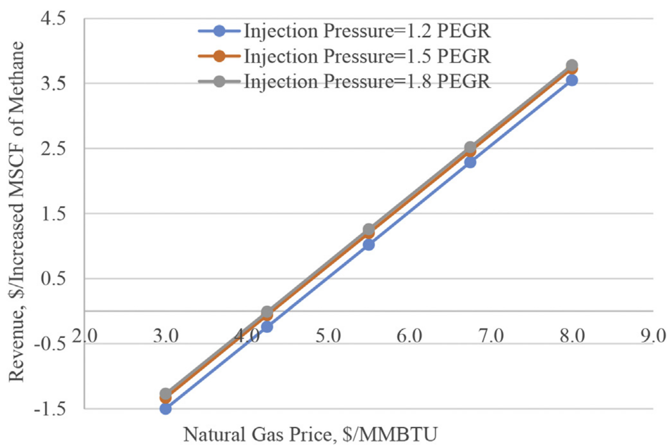

Fig. 6. Revenue sensitivity as a function of injection pressure and CH_4 price (CO_2 price = $30/ton), Barnett shale.

revenue per increased MSCF of CH_4 production at a fixed natural gas price of $5.50/MMBTU. The revenue was estimated as a function of CO_2 price and injection pressure (Fig. 8). Similar to the case of Barnett shale, the CO_2 price was the major factor in determining the profitability. If the CO_2 price is higher than $30/ton, the project is not profitable. Fig. 9 shows the revenue per increased MSCF of CH_4

Table 5
Input for the case study of Eagle Ford shale.

Reservoir depth, *D*	9000	ft
Pay zone thickness, *h*	200	ft
Original reservoir pressure, P_0	6400	psi
Reservoir temperature, *T*	715	°R
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3000	psi

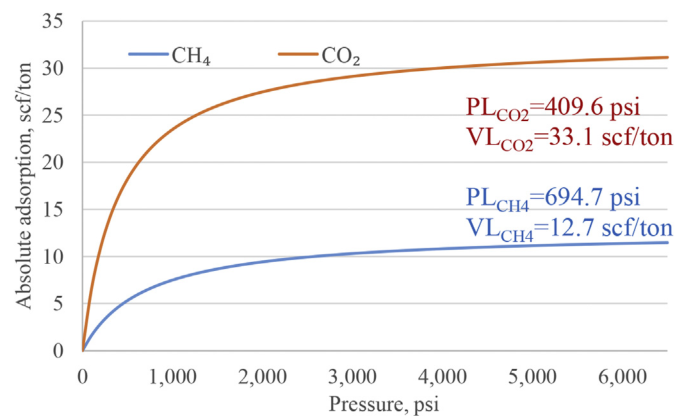

Fig. 7. CO_2 and CH_4 adsorption isotherms on Eagle Ford samples (after Heller and Zoback, 2014).

as a function of natural gas price and injection pressure, at a fixed CO_2 price of $30/ton. The CO_2-EGR process became profitable when the natural gas price is over $6.00/MMBTU.

Table 6 lists the percentage of each cost component. CO_2 price was again the determining factor in profitability, and CO_2 purchase cost comprised the largest portion in the total cost, ranging from 65% to 88%.

4.4. Marcellus shale

The input parameters for the Marcellus shale model are listed in Table 7. Fig. 10 shows the Langmuir parameters of the Marcellus shale rocks measured by Heller and Zoback (2014).

Using Equation (9), the production ratio of the Marcellus shale, R_{prd}, was 2.46. This is lower than that of the Eagle Ford shale but higher than that of the Barnett shale. Fig. 11 shows the revenue

Table 4
Fractions of each cost component in CO_2-EGR, Barnett shale case.

Injection Pressure Ratio	CO_2 price	Production cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	$/ton	$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	2.78	7%	20%	9%	63%
1.5	15.0	2.61	7%	16%	9%	67%
1.8	15.0	2.55	7%	15%	10%	69%
1.2	22.5	3.66	5%	16%	7%	72%
1.5	22.5	3.48	5%	12%	7%	76%
1.8	22.5	3.43	5%	11%	7%	77%
1.2	30.0	4.54	4%	13%	6%	77%
1.5	30.0	4.36	4%	10%	6%	80%
1.8	30.0	4.30	4%	9%	6%	82%
1.2	37.5	5.42	4%	10%	5%	81%
1.5	37.5	5.24	4%	8%	5%	84%
1.8	37.5	5.18	3%	7%	5%	85%
1.2	45.0	6.29	3%	9%	4%	84%
1.5	45.0	6.12	3%	7%	4%	86%
1.8	45.0	6.06	3%	6%	4%	87%

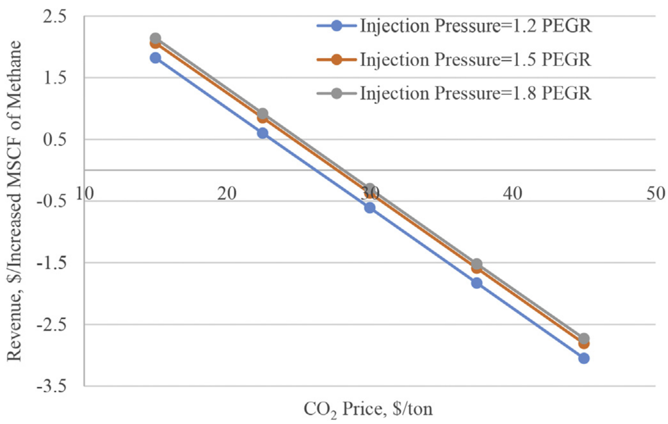

Fig. 8. Revenue sensitivity as a function of injection pressure and CO_2 price (CH_4 price = $5.50 MMBTU), Eagle Ford shale.

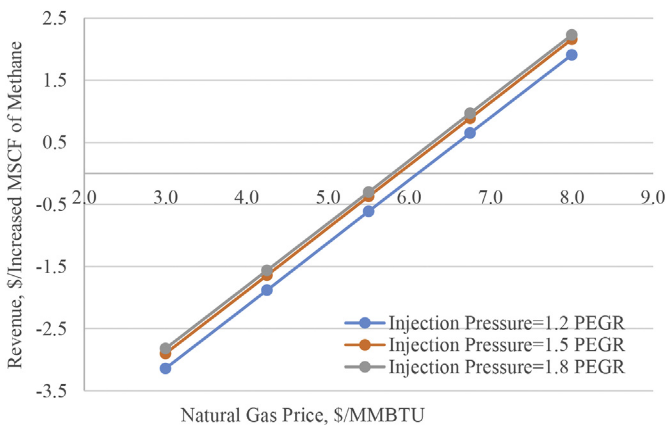

Fig. 9. Revenue sensitivity as a function of injection pressure and CH_4 price (CO_2 price = $30/ton), Eagle Ford shale.

per increased MSCF of CH_4 through CO_2 injection at a fixed natural gas price of $5.50/MMBTU. The revenue was expressed as a function of CO_2 price and injection pressure. Similar to the cases of the Barnett and Eagle Ford shales, the CO_2 price was the major factor in determining the profitability. When the CO_2 price was higher than approximately $33/ton, the project was not profitable.

Table 7
Input for the case study of Marcellus shale.

Reservoir depth, D	5000	ft
Pay zone thickness, h	100	ft
Original reservoir pressure, P_0	4000	psi
Reservoir temperature, T	565	°R
Horizontal permeability in fracture, K_H	0.25	mD
Permeability anisotropy, I_{ani}	71	
Primary recovery year, $t_{primary}$	5	years
Reservoir external pressure during EGS, P_{EGR}	3500	psi

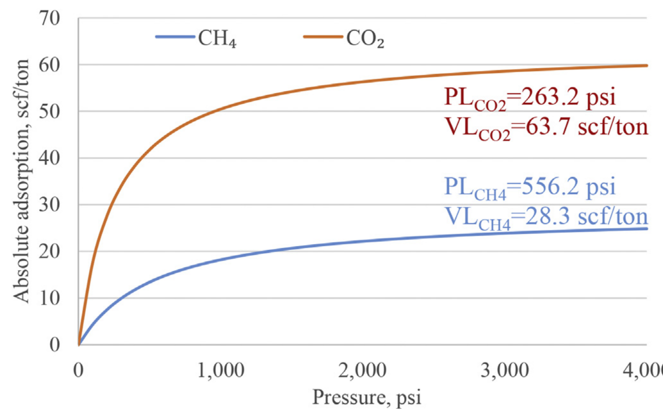

Fig. 10. CO_2 and CH_4 adsorption isotherms on Marcellus samples (after Heller and Zoback, 2014).

Fig. 12 shows the revenue per increased MSCF of CH_4 as a function of natural gas price and injection pressure, at a fixed CO_2 price of $30/ton. The CO_2-EGR process became profitable when the natural gas price is over approximately $5.00/MMBTU. Table 8 lists the percentage of each cost component. As mentioned above, the CO_2 price is the determining factor in profitability, and CO_2 purchase cost comprised the largest portion of the total cost, ranging from 63% to 87%.

4.5. Discussion of case study results

From the calculation results above, it can be concluded that CO_2 procurement was the biggest share of the total cost in CO_2-EGR process for all the three shale plays. The sum of the well abandonment cost, well operation cost, and CO_2 compression cost was less than the CO_2 purchase expense. The CO_2 and CH_4 prices had the

Table 6
Fractions of each cost component in CO_2-EGR, Eagle Ford shale case.

Injection Pressure Ratio	CO_2 price	Prod. cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	$/ton	$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	3.74	6%	21%	8%	65%
1.5	15.0	3.50	5%	16%	8%	70%
1.8	15.0	3.42	5%	15%	9%	71%
1.2	22.5	4.96	4%	16%	6%	74%
1.5	22.5	4.71	4%	12%	6%	78%
1.8	22.5	4.64	4%	11%	6%	79%
1.2	30.0	6.17	3%	13%	5%	79%
1.5	30.0	5.93	3%	10%	5%	82%
1.8	30.0	5.86	3%	9%	5%	83%
1.2	37.5	7.39	3%	11%	4%	82%
1.5	37.5	7.15	3%	8%	4%	85%
1.8	37.5	7.08	3%	7%	4%	86%
1.2	45.0	8.61	2%	9%	4%	85%
1.5	45.0	8.37	2%	7%	4%	87%
1.8	45.0	8.29	2%	6%	4%	88%

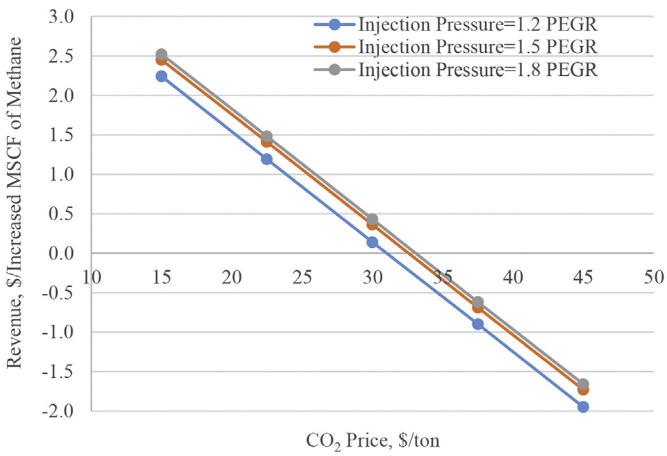

Fig. 11. Revenue sensitivity as a function of injection pressure and CO_2 price (CH_4 price = \$5.50 MMBTU), Marcellus shale.

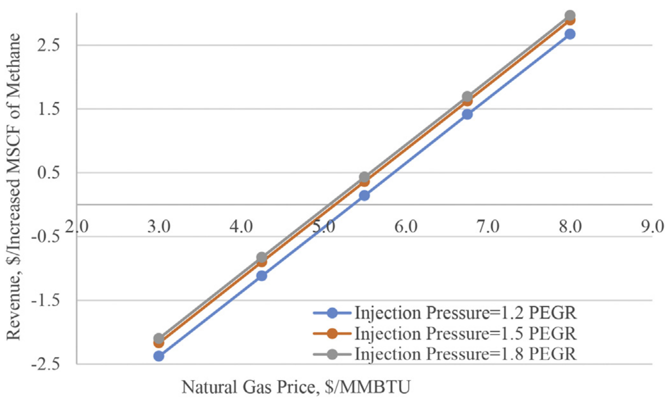

Fig. 12. Revenue sensitivity as a function of injection pressure and CH_4 price (CO_2 price = \$30/ton), Marcellus case.

greatest influence on the profitability of the project. The injection pressure in all cases had a smaller impact on the net revenue. Hence, there are two market factors that would play a significant role in applying the proposed EGR process: the prices of natural gas and CO_2. Recent natural gas wellhead prices in the U.S. are lower than \$4/MMBTU (U.S. Energy Information Administration, 2015), which is not high enough to support the EGR process according to the simulated results. The typical cost of capturing CO_2 from flue gas using conventional capture technologies, such as amine scrubbing, is in the \$40–100/ton CO_2 range (Figueroa et al., 2008). The capture cost can be less than \$40 per ton from some industrial sources, such as natural gas processing plants, hydrogen plants, ammonia plants, and refineries (U.S. Energy Information Administration, 2011). Considering additional transport costs, the CO_2 price would be higher than the acceptable range according to the case study. In summary, the current market environment might not be favorable for the CO_2-EGR process. Reducing CO_2 price and rebounding natural gas prices will definitely advance the feasibility of CO_2-EGR.

Among these three shale plays in the case study, the proposed CO_2-EGR process was mostly like to be successful in the Barnett shale, mainly because the Barnett shale had the lowest R_{prd} (2.04), which means less CO_2 was required to increase one unit volume of natural gas production in the EGR process. Therefore, the R_{prd} value can be used as one of the criteria in assessing the feasibility of CO_2-EGR. A lower R_{prd} value indicates favorable conditions in terms of economics, but will also limit the CO_2 storage capacity of the reservoir.

5. Conclusion

More shale gas is expected to be developed to meet the ever-increasing worldwide energy consumption. To substantiate shale gas production in a more efficient and environmentally-friendly way, novel reservoir stimulation and enhanced gas recovery methods are needed. In this paper:

- The authors have reviewed the storage and transport fundamentals of shale gas, discussed the causes of fast drop production rate in shale gas production, and proposed a CO_2-based reservoir treatment technology for gas shales.
- Using CO_2-based fracking fluid will bring advantages including reduced water consumption, averted reservoir damage, and expedited fracking fluid flow-back.
- Through CO_2 injection during the EGR process, natural gas production will be boosted by the displaced sorbed gas, resulting in benefits of improved single well production and economics, reduced large-scale well drilling, and more limited environmental footprints.
- Results of the case study indicate that CO_2 procurement was the biggest cost for the EGR process, higher than the sum of other cost components.

Table 8
Fractions of each cost component in CO_2-EGR, Marcellus shale case.

Injection Pressure Ratio	CO_2 price	Prod. cost of CH_4	CH_4 well	CO_2 well	CO_2 compressor	CO_2 purchase
	\$/ton	\$/increased MSCF CH_4	Share %	Share %	Share %	Share %
1.2	15.0	3.33	7%	21%	10%	63%
1.5	15.0	3.11	7%	17%	10%	67%
1.8	15.0	3.04	6%	15%	10%	69%
1.2	22.5	4.37	5%	16%	7%	72%
1.5	22.5	4.15	5%	12%	7%	76%
1.8	22.5	4.08	5%	11%	7%	77%
1.2	30.0	5.42	4%	13%	6%	77%
1.5	30.0	5.20	4%	10%	6%	80%
1.8	30.0	5.13	4%	9%	6%	82%
1.2	37.5	6.46	3%	11%	5%	81%
1.5	37.5	6.25	3%	8%	5%	84%
1.8	37.5	6.18	3%	7%	5%	85%
1.2	45.0	7.51	3%	9%	4%	84%
1.5	45.0	7.29	3%	7%	4%	86%
1.8	45.0	7.22	3%	6%	4%	87%

- Prices of CO_2 and CH_4 were the key factors in determining the profitability of the EGR process.
- The proposed CO_2-EGR process was mostly like to be successful in the Barnett shale since it has the lowest R_{prd} (2.04).

To push the proposed technology to be applicable in practice, more research activities and a favorable market atmosphere are necessary. Some scientific and engineering questions need to be further investigated, including adsorption characteristics of multiple gases in shales, properly constructed CO_2-based fracking fluid development, and multiphase transport phenomenon studies in shale matrices and fractures. A higher natural gas market price will be a driving force, and a stable decrease of CO_2 price through developing more advanced capture and transport technologies is also of significance.

Acknowledgments

The authors are grateful for the support from the Institute for Energy Studies at the University of North Dakota.

Nomenclature

Symbols

A	annualized capital cost ($/year)
a	large half-axis of the drainage ellipsoid (ft)
Bg	gas formation volume factor
C	cost ($)
D	reservoir depth (ft)
G	gas content (scf/ton)
h	pay zone thickness (ft)
I_{ani}	permeability anisotropy
i_e	annual interest rate
k	permeability (mD)
L	length of well horizontal section (ft)
P	pressure (psi)
P_L	Langmuir pressure (psi)
q	gas flow rate (MSCF/D)
R_{prd}	production ratio of CO_2/CH_4
r_{eH}	hydraulic drainage radius (ft)
r_w	well radius (ft)
$R_{elec.}$	electricity price ($/kWh)
S	saturation
T	temperature (°R)
t	project life (year)
V_L	Langmuir volume (scf/ton)
W	well spacing (ft)
$wt\%$	weight percentage
y	gas volume fraction
Z	gas compressibility
α	selectivity ratio
ΔG	change of gas content (scf/ton)
ρ_b	bulk density (g/cm^3)
ϕ	porosity
η	efficiency
μ	viscosity (cp)

Subscripts

a	adsorbed phase
Aband.	well abandonment
Comp.	CO_2 compressor
f	free phase
F.O.	fixed operation cost
H	horizontal
i	gas component
j	gas component
O	oil
so	solution gas in oil
st	gas in total
sw	solution gas in water
V.O.	variable operation cost
W	water
0	original

Abbreviations

CBM	coalbed methane
ECBM	enhanced coalbed methane
EGR	enhanced gas recovery
PEGR	reservoir pressure during enhanced gas recovery
TOC	total organic carbon

Units

cp	centipoise
ft	feet
kW	kilowatt
mD	millidarcy
MMBTU	million British Thermal Unit
MSCF	thousand standard cubic feet
MSCF/d	thousand standard cubic feet per day
nm	nanometer
psi	pounds per square inch
°R	degree Rankine
scf	standard cubic feet
ton	short ton
$	2014 U.S. Dollar

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