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Subsurface CO_2 storage estimation in Bakken tight oil and Eagle Ford shale gas condensate reservoirs by retention mechanism

Venkat Pranesh

Petroleum and Environmental Technology Division, Coventry University, United Kingdom

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ABSTRACT

This paper describes the CO_2 geological sequestration process in unconventional reservoirs in northern and southern United States such as Bakken tight oil and Eagle Ford shale gas condensate reservoirs. The hysteresis modelling and retention mechanism was performed in this research and this is one of the efficient and proven method to store CO_2 in the subsurface. This can be achieved through CO_2 EOR process while injecting CO_2, the fluid will be trapped in the pore spaces between the impermeable rocks and oil can be recovered simultaneously. A total of four cases was taken for the analysis, such as the Bakken and Eagle Ford reservoirs with CO_2 huff-n-puff process and another two cases with CO_2 Flooding. Injection pressure, injection rate, injection time, number of cycles, carbon dioxide soaking time, fracture half-length, fracture conductivity, fracture spacing, porosity, permeability, and initial reservoir pressure as is taken as inputs and cumulative oil production, and oil recovery factor was taken as outputs. The reservoirs were modelled for 30 years of oil production and the factor year was taken as Decision Making Unit (DMU) and the models was calculated at each year. The retention was successfully calculated in all four models and percentage of retention above 90% was observed in all four cases and the injection pressure has the most dominating effect on the CO_2 geological sequestration. It was also revealed that the CO_2 huff-n-puff performance in Bakken reservoir is not that much more effective since the retention rate decreases during soaking period and flooding was found to be a suitable method in this formation. Even in Eagle Ford formation, the average performance of CO_2 flooding process is better than the huff-n-puff, but the latter process was quite effective in this shale gas condensate reservoir.

1. Introduction

The phenomenon of climate change was seen as unprecedented and a growing threat to humanity and world economy. It was globally accepted that, the increasing CO_2 emissions are responsible for climate change. At the starting of late 19th century the average global temperature was more than 1.5 °F [35]. The CO_2 emissions from petroleum industries are consistently being blamed for the formation of greenhouse gases in the atmosphere and as long as we burn fossil fuels the climate change continues to happen. The consequences of climate change due to greenhouse gas emissions will be more severe than we think. Climate scientist all over the world, warns that, the constant presence of CO_2 in the atmosphere will lead to extremely hot summers, cold winters, droughts, heavy rainfall and flooding, melting of ice caps and glaciers at the poles, thereby affecting the livelihood of people in a geographical area and the local economy. A four major greenhouse gas gases, which causing climate change are CO_2, CH_4, N_2O and Fluorinated gases, but this paper focuses only on the CO_2 emissions, mitigation, and utilization in an oil and gas industry. Fig. 1 shows the worldwide greenhouse gas emissions since 2010.It can be noted from Fig. 1 that, the CO_2 is found to be the highest global greenhouse gas emissions from 2010. This is completely due to the burning of fossil fuels and forestry process, but deforestation and other land usage account only for 11%, but the emission from fossil industries contributes to 65%, the magnitude of oil and gas CO_2 emissions is higher than the other sectors which is extremely in serious condition. The contribution of methane (CH_4) and nitrous oxide (N_2O) is 16% and 6% respectively. The CH_4 and N_2O emission is regarded to be slightly serious since its primary emissions are from agricultural activities, combustion, transportation, etc. It was observed that, a 2% of Fluorinated gases (F-gases) emissions were recorded since 2010. The F-gases includes, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6) emissions mainly from refrigeration and other industrial activities. Like water flooding the CO_2 flooding is an EOR process in which the captured carbon dioxide is transported to oil field through the pipeline and injected into the reservoir to extract oil and gas. Its process is schematically presented in the Fig. 2. The recovery depends upon several following factors. Injection pressure, time, mass, wellbore

E-mail address: venkat.pranesh@outlook.com.

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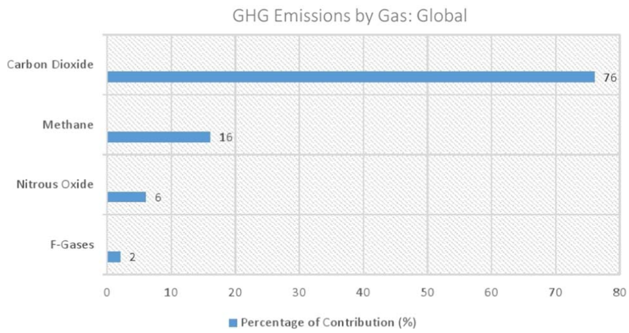

Fig. 1. Global greenhouse gas emissions since 2010 [14]

length and diameter, fracture properties, oil viscosity, mobility ratio, porosity, permeability, compressibility, reservoir pressure lithology etc. Both miscible and immiscible CO_2 flooding were successfully demonstrated in different oil and gas projects around the world. Mostly, many researchers analyzed the reservoir oil recovery rate by using miscible flooding, but some authors argue that, the performance of using immiscible CO_2 flooding is better than the miscible flooding [6]. Bikkina et al. [7], analyzed the dominance of permeability and wettability on the efficiency of miscible CO_2 flooding. Lab testing was conducted by the authors to estimate the influence of these two parameters on the performance of miscible carbon dioxide-EOR. The hydrophilic Berea core samples wettability changed to be oil-wet and n-hexadecane for dry core samples. Core flooding testing was performed for synthetic brine-n-hexadecane-CO_2 systems at 1400 psig back-pressure to reach MMP of CO_2 in n-hexadecane at the temperature of 24 °C. It was observed that, the wettability has severe dominance on CO_2-enhanced oil recovery. In oil water and oil wet samples under brine flooding it indicates that, 5 pore volumes of carbon dioxide recovered 100% and remaining oil in place is about 43%.Gao et al. [16], investigated the CO_2 immiscible flooding, gas breakthrough and performance in ultra-low permeability reservoirs at Yaoyingtai Oilfield, China. The authors have found that a gas breakthrough occurs during carbon dioxide with immiscible flooding and as a result, the well should be shutdown. In order to avoid this scenario the authors suggesting to use alternative water and gas injection as this can mitigate the gas breakthrough and enhance the sweep efficiency. Liu and Zhang [24], theoretically studied the carbon dioxide-methane flooding on enhanced oil recovery in low permeable rhythmic oil and gas reservoir. The authors have made an investigation and reviews on sweep efficiency, mobility ratio, and CO_2 breakthrough. They have concluded that, CO_2-CH_4 flooding is the best method for dissimilar hydrocarbon reservoirs which are rhythm and higher oil recovery can be obtained from a homogeneous reservoir.The CO_2 huff-n-puff process has been used in all types of reservoirs since in late 1980's. The schematic procedure of huff-n-puff process is shown in Fig. 3. It comprises of three steps such as carbon dioxide injection, soaking, and production. The first stage is injection, where CO_2 injected into the reservoir and the well will be shut-down for some time (very short period) for soaking this process is the second stage, and after soaking the well is opened for fluid recovery to the surface. The oil and gas recovery through huff-n-puff process is very effective in Eagle Ford gas condensate reservoir than CO_2 flooding due to decrease in oil saturation near wellbore, high drawdown pressure, and easily overcoming the problem of fluid transport [31]. The same impacts were also observed and reported in the Bakken tight oil reservoir [41].Ma et al. [25], studied the working system of huff-n-puff with CO_2 on enhanced light oil recovery in the tight formation reservoir. In this work core-flooding experiments were conducted by utilizing a composite with 973 mm length, 9.6% average porosity, and 2.3 mD average permeability. The primary factor effects, like injection rate (with maximum & minimum pressures), slug size, soaking time, and N_2 were examined. The results from experimentation pointed out that, recovery factor was sensitive to the higher injection pressure and in simultaneous cycles the N_2 injection can effectively enhance the performance cycle of CO_2. On the other side, there were also reports of lower oil recovery rate during continuous immiscible and miscible CO_2 huff-n-puff process [2,3]. But during the cycling injection process of carbon dioxide increases the rate of oil recovery and this process indicates that the CO_2 soaking period is significant in cumulative oil recovery and the oil recovery factor is independent of CO_2 injection time [1]. Torabi et al. [36], evaluated the miscible, near miscible, and immiscible CO_2 huff-n-puff process to enhance oil recovery in a system of single matrix-fracture. The authors have conducted both experimental and simulation processes to understand the impacts of minimum miscibility pressure (MMP) and injection pressures. Core analysis with saturated light oil and compositional simulator was employed to model the huff-n-puff CO_2 experiments. Sheng et al. [32], investigated the potential of gas powered huff-n-puff process to proliferate oil production in an unconventional condensate reservoir. The authors have simulated Eagle Ford gas condensate reservoir and analyzed the optimum huff-n-puff procedure for 600 days.

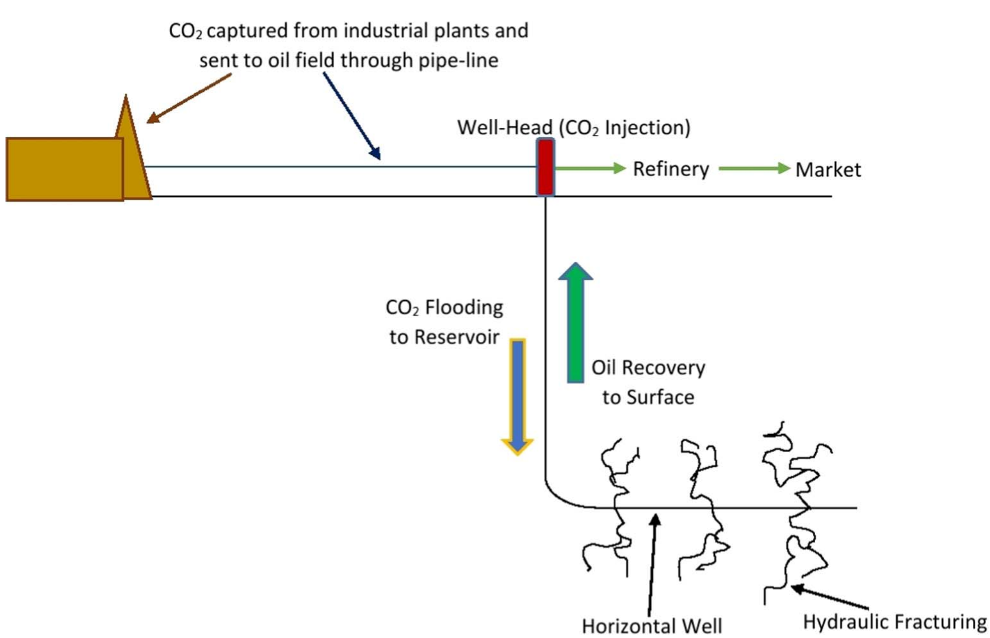

Fig. 2. Schematic diagram of CO_2 flooding.

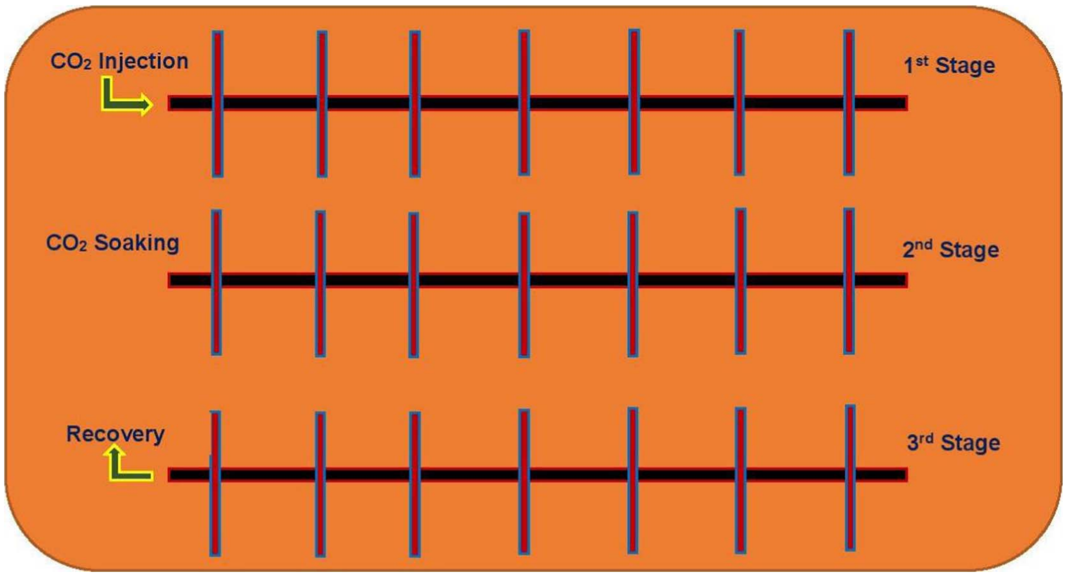

Fig. 3. Schematic diagram of CO_2 Huff-N-Puff process.

Other impacts such as gas composition, injection pressure, and initial water saturation were also investigated in this research. The simulation results, suggest that either huff or puff process time should be about 900 days and the maximum gas injection pressure must be above upper dew-point pressure, hence the liquid dropout can be vaporized again.

2. Unconventional reservoir

Unconventional reservoirs also known as shale are characterized by the fine grains in shale rocks and with respect to the depth of the reservoir. Unlike conventional methods, this method needs new methods for commercial and effective hydrocarbon production. This type of reservoir become a subject of great interest among all oil and gas companies throughout the world, they are showing interest and investing in unconventional oil and gas reservoir exploration and production. As this became the new source of energy exploitation and generating a good profitable business. This project specifically deals with Bakken tight oil and Eagle Ford gas condensate reservoirs. The following Fig. 4 shows the America's six major shale oil and gas geological formations.

2.1. Bakken shale oil reservoir

The Bakken geological formation is a type of rock unit from the time of Late Devonian to Early Mississippian age covering about 520,000 km^2 of the Williston Basin subsurface, underlying regions of North Dakota, Montana, Manitoba and Saskatchewan. It is a sequence of interbedded sandstone, siltstone, and black shale in these areas and it is also one of the major deposits of shale oil and gas in Canada and USA. The Bakken formation is mixed carbonate-clastic petroleum layers with low permeability and porosity and possess a complicated lithology, consisting of Upper, Middle and Lower Bakken Shales, Three Forks and Sanish shown in Fig. 5. The Middle Bakken and Three Forks are two main layers in the production of tight oil since they hold finest reservoir characteristics such oil saturation and porosity [18].Brandt et al. [9], examined the net energy of oil production from the Bakken reservoir by a model based on well-level engineering. The net energy return was computed for Bakken field and the energy needed for drilling and producing oil from this field is evaluated for over 7000 wells using production assessment models and open source drilling. The results were observed to a huge decline in net energy rate. The outcome is more sensitive to embodied energy and estimated ultimate recovery.Liang et al. [23], investigated the production ability of single well and its influencing factors in the Bakken shale oil reservoir, Williston Basin. Liang employed orthogonal experiment design, gray correlative method, and information amount theory in designing and optimizing of a horizontal well (with fracturing). The results reveal that the parameters fracture length, permeability should be considered as primary influencing factors. These parameters assist in the optimization of oil production from a single well in Bakken. Saidian and Prasad [30], studied the porosity and pore size distribution (PSD) of Bakken and Three Forks formations to estimate the reserves and production, and also for production planning. From the nuclear magnetic resonance logs the author has estimated the PSD properties in the subsurface of Bakken reservoir. Data were analyzed on scanning electron microscopy (SEM), mineralogy, and mass magnetic susceptibility (MMS). It was founded, surface relaxivity depends on distribution in natural rocks, paramagnetic mineral content, and magnetic susceptibility.

2.2. Eagle Ford gas condensate reservoir

The Eagle ford group is a formation of sedimentary rock in the age of late cretaceous underlying from the southern US states of New Mexico to Texas, comprising of fossiliferous marine shale with organic rich-matter and Fig. 6 shows the Eagle Ford formation's column of strat. The mineralogy of the Eagle Ford formation consists of calcite greater than 50%, moderate quantities of clays, kerogen, and quartz. This group encompasses a hydrocarbon fluids in wide spectrum ranging from low Gas-Oil-Ratio (GOR) black oils to volatile oils and lean, and rich condensates of gas [29]. It was estimated by US government agency Energy Information Administration (EIA) that, in this formation, there's 3.37 billion barrels of oil and 2.5 trillion cubic feet of gas.Al-Otaibi et al. [4], conducted critical reviews and analysis on the simulation and production forecast of oil wells in the Eagle Ford shale reservoir. They have evaluated the recovery rate of wells and its production life (in years). The author's consistently enumerates the plan and effect of drilling in this field. Also, they propose that hydraulic fracturing and horizontal wells play a major role in the determination of wells performance and oil production in the Eagle Ford unconventional reservoir. Hsu [17], analyzed the Eagle Ford geology characteristics, authors conducted core laboratory experiments, and the clay shale mechanical properties were analyzed.Triaxial compression and extension test was made to determine the shear strength of the shale. The lab results revealed that the shale has anisotropy strength. The Authors concluded that this important information can be used as the

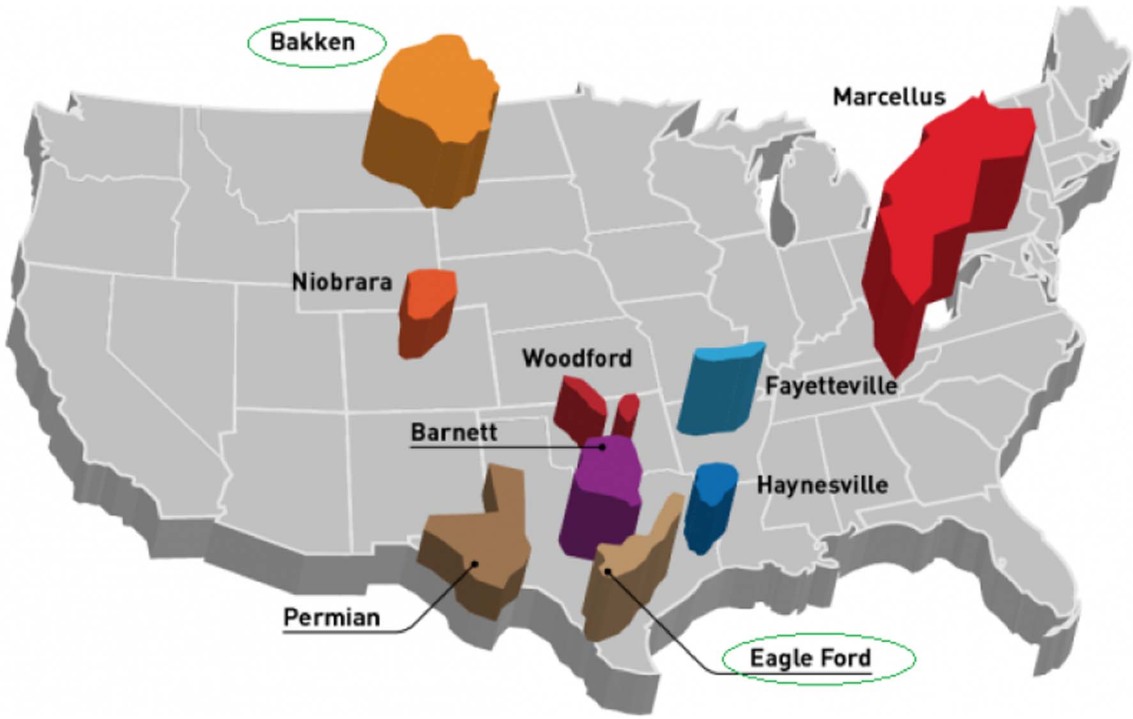

Fig. 4. Major shale plays in the United States [15] and the green eclipse indicates this paper focus of study. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

basis for drilling and reservoir simulation. Tunstall [37], forecasted the shale oil production from the Eagle Ford unconventional reservoir using the iterative Bass model. The preliminary production data from 2006 to 2010 was obtained for analysis. The forecast development was made through ordinary least square regression methods using a Bass Diffusion model which ultimately predicted the performance of this oil field. It was predicted from the modelling results that oil and condensate production in the Eagle Ford reservoir could have reached as high as 2.6 million barrels per day by 2020. Similarly, this technique was applied to other oil and gas fields in the US, fortunately they also showed good forecast for decision making.

2.3. Geological sequestration in Bakken and Eagle Ford reservoirs

An important method to accomplish a substantial reduction in carbon dioxide emissions is CO_2 geological sequestration. The major risk in this technology is the CO_2 leakage, due to the impact of buoyancy CO_2 migrates upwards [38]. The Permian Basin in the borders of Texas and New Mexico in US was the first site to test this process of CO_2 storage in large scale in 1972 [5] and its successful implementation needs knowledge of storage capacity of CO_2 in different geological formations [12]. The Fig. 7 depicts a schematically the geological sequestration in unconventional reservoirs such as Bakken and Eagle ford reservoirs.A huge mass of CO_2 is injected into the reservoir for enhancing the oil recovery, during flooding or huff-n-puff process some amount of carbon dioxide get trapped in the pore spaces between the

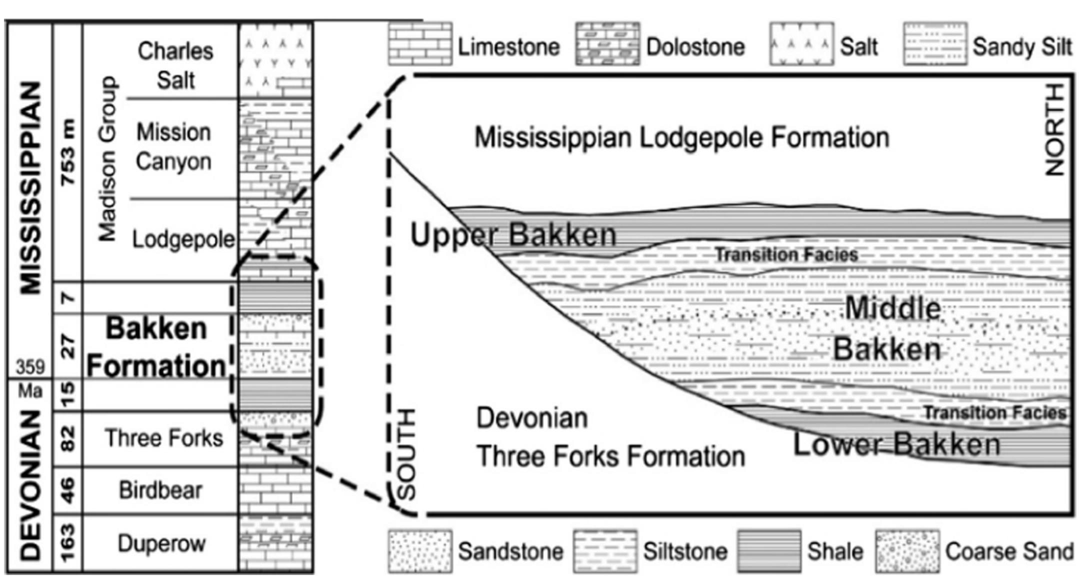

Fig. 5. Multiple oil-bearing layers of Bakken formation: A cross sectional view [41]

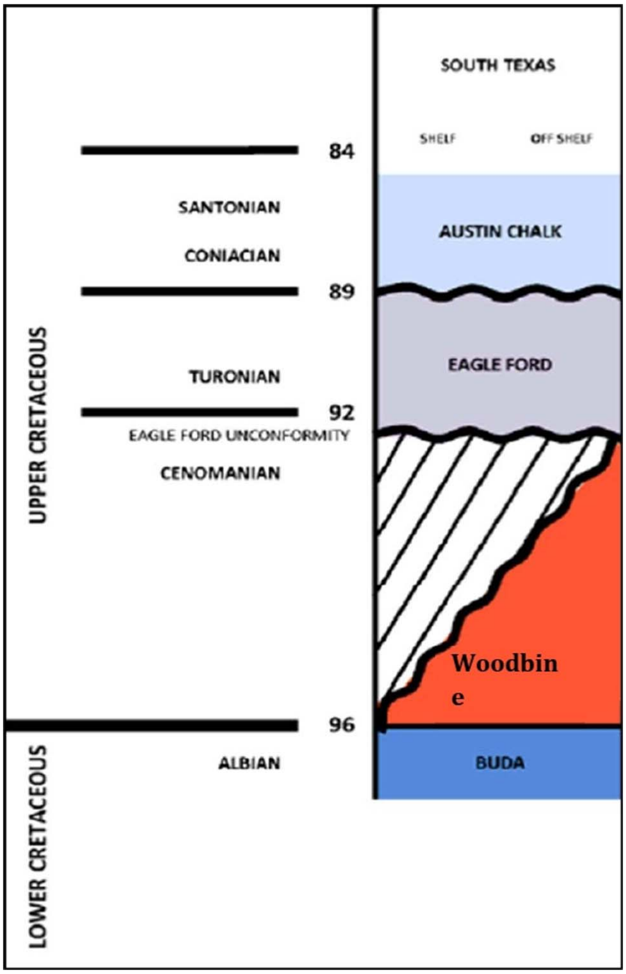

Fig. 6. Eagle Ford shale column of stratigraphy [10]

rock, thereby leading to a permanent storage of ultimate greenhouse gas CO_2. It has been reported on recent research that, the Bakken and Eagle Ford reservoirs have a great potential for carbon dioxide storage. Abedini and Torabi [2,3], experimentally demonstrated the cyclic CO_2 injection process on geological storage and enhanced oil recovery. In this research, the authors used Bakken oil field sample mixtures which are taken from different places from the same field. A study on phase behavior on the light crude oil-CO_2 and brine-CO_2 systems was performed. The Solubility of CO_2 in the brine samples and oil as well as oil swelling factor as a consequence of dissolution of carbon dioxide was experimentally measured. Experimental findings show that, the potential for CO_2 sequestration has improved at higher operating pressures. At a higher operating pressure the oil recovery factor was high and the optimum pressures for CO_2 oil recovery and storage was found at operating pressures near minimum miscibility pressure. Dai et al. [11], statistically quantified the uncertainties associated with carbon dioxide sequestration and enhanced oil recovery at the Farnsworth Unit of the Anadarko Basin, Texas, USA. A sequence of Geo-statistical based Monte-Carlo simulation of CO_2 injection was conducted and global sensitivity and statistical analysis were also executed. The highlight of results point out that the porosity, permeability, and reservoir thickness are the main parameters that influence the net CO_2 injection/storage and hydrocarbon recovery rates. Also, it reveals that with the increase of reservoir thickness injection pressure also rises. Olea [28], has reviewed the retention factors in enhanced oil recovery for four lithology like sandstone, dolomite, chert, and limestone. Olea discusses about the subsurface capture of CO_2; retention mechanisms, they involved stratigraphic trapping, planned CO_2 sequestration, chemical reaction with reservoir matrix to form other minerals, migration into aquifer leakage, and in fracture reservoirs an occurrence thief zone leakage. From the overall review, the author concluded that in literature many retention factor value is reported and there is a tendency for higher retention values for carbonate than siliciclastic reservoirs.Narinesingh and Alexander [27], studied the impacts of CO_2 injection pressure on geological sequestration along with enhanced oil recovery in condensate reservoir. The authors simulated a 2D static model using CMG Reservoir Modelling. The model dimensions are 8000 ft long, 150 ft wide, and 150 ft thick, three layers was used for vertical thickness. They encoded a series of CO_2 injection in psi such as 2500, 3000, 3500, 4000, 4500, and 5000 in the reservoir model. The ultimate result indicates that due to the effect of injection pressure a large amount of CO_2 is trapped in the reservoir in the supercritical phase. Li and Elsworth [22], studied the impacts of CO_2 enhanced shale recovery and sequestration geomechanics. A homogenous isotropic reservoir model was developed to analyze the geomechanical and fracture closure, and permeability effects of shale gas reservoir. CO_2 was used as EOR fluid and injection pressures were selected as 0 MPa, 4 MPa and 8 MPa to investigate the elevated methane production and storage optimization. The simulation results displayed that shale gas production enhanced by 2.3%, 14.3% and 28.5%. The capacity for sequestration was in the order of 10^4 m3 when supercritical CO2 for three injection pressure scenarios. It is

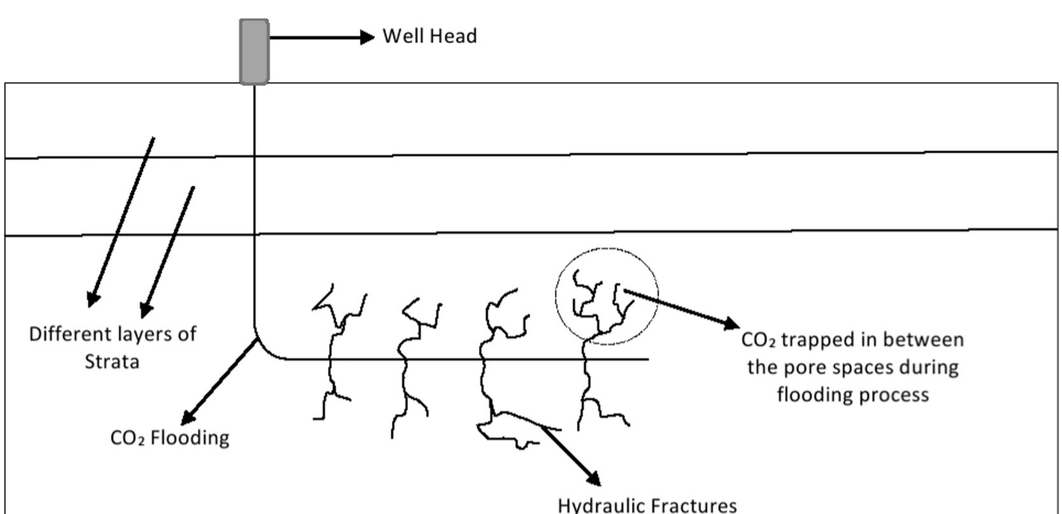

Fig. 7. Schematic view of geological sequestration in an unconventional reservoir.

obvious from their results that the quantity of carbon dioxide adsorbed is proportional to the injection pressure. Azzolina et al. [5], made statistical studies of historical operations on the storage of CO_2 associated with enhanced oil recovery. The authors examine a database of 31 existing CO_2 EOR projects that was organized for the valuation of oil reserves to interpret the oil recovery, retention factor and utilization of carbon dioxide for these oil reservoirs. Each data was extrapolated to 300% cumulative HCPV by fitting nonlinear functions. In the range of 31 sites the percentile values for 3 factors at 300% HCPV were taken as 10th, median 50th, and 90th. Their three factors, namely net CO_2 utilization, cumulative oil recovery, and retention. This model can also estimate the uncertainty in the calculated values as a function of HCPV.Most petroleum companies across the United States are targeting these two geological formations for the safe storage of CO_2 and on the other side the supercritical carbon dioxide injection will effectively enhance the oil production from these unconventional reservoirs [34]. This chapter analyses the trapping of carbon dioxide by hysteresis and percentage of retentions in Bakken tight oil and Eagle Ford gas condensate reservoirs with CO_2 flooding and huff-n-puff process.

3. Materials and methods

The methodology for this research consist of three steps as presented in Fig. 8. The first step is to define the research problem and formulating the objectives. The second step involves modelling the equations and hysteresis for carbon dioxide storage in complex geological formations. The third step comprises of calculating the retention factor by using the appropriate formula or equation and finally interpreting the results.The Bakken and Eagle Ford reservoir models were simulated using CMG-GEM reservoir software. The Bakken tight oil reservoir model was simulated with reservoir properties, gathering from Wei Yu et al. [40] and regarding modelling of Eagle Ford gas condensate reservoir the reservoir properties were obtained from Sheng [31]. All necessary reservoir data were obtained from these two literatures (this research project was executed with a help of secondary data). However, the simulation results aren't mentioned in this paper and only deals with the CO_2 retention for geological storage in the Bakken and Eagle Ford reservoirs.

3.1. Hysteresis modelling

Hysteresis Modelling was performed to calculate the percentage of CO_2 retention in the Bakken shale oil and Eagle Ford gas condensate reservoirs. The carbon dioxide retention percentage was calculated for 30 years and injection rate, and injection pressure values were taken for calculations. Calculations were conducted for four divisions which includes the following:

i. CO_2 huff-n-puff process in Bakken reservoir.
ii. CO_2 flooding in Bakken reservoir
iii. CO_2 huff-n-puff process in Eagle Ford gas condensate reservoir, and
iv. CO_2 flooding in Eagle Ford gas condensate reservoir.

The trapping of carbon dioxide by hysteresis were obtained from reservoir modelling.

3.2. Trapping of CO_2 by hysteresis

The trapping of carbon dioxide by hysteresis can be explained clearly, it is a process in which the CO_2 is retarded due the effect when the forces (mainly capillary pressure) acting on it are changed, it could be a change from the fluid viscosity or internal friction. Carbon dioxide trapping in between the pore spaces is the governing contributor to the hysteresis and there is an observation of little advective process due to capillary force hysteresis [13]. During CO_2 injection into the reservoir, this process breaks down the carbon dioxide in supercritical phase and that is stored in the fractured/pore spaces, which in turn trapped by hysteresis and it gets dissolved in the formation water [27]. In retention percentage calculation, it was assumed that, the amount of CO_2 remaining at subsurface is equal to the amount of CO_2 trapped by hysteresis.

This phenomenon can be attributed as follows

- The low permeability layer in which the CO_2 was injected in supercritical phase.
- Either high or low volume of CO_2 injection.
- CO_2 injection at high well injection pressure.
- Early shutdown of the well in huff-n-puff process due to soaking.
- Early shutdown of the well in flooding process due to well liquid loading.

3.3. Retention mechanisms

Carbon dioxide can be stored without recovering nor producing oil, but it is always impossible to produce oil without leaving some amount of carbon dioxide in the subsurface during CO_2-EOR process. A simple method to calculate the quantity of CO_2 remaining at subsurface is the retention factor. It is defined as "the proportion of injected CO_2 that, remains in the subsurface as a result of flooding" [28]. The formula for CO_2 retention factor is presented below:

$$Retention = 100 \times \frac{CO_2\ Remaining\ at\ Subsurface}{Cumulative\ CO_2\ Injected} \quad (1)$$

The subsurface temperature and pressure play a vital role in trapping CO_2. Oil produced from the subsurface after primary and secondary recovery, the concept of retention factor comes in the tertiary recovery (EOR). High retention percentages can be obtained in the miscible CO_2 flooding. Under this condition, the injection of carbon dioxide drives out the residual oil from the fractured/pore space through solution forming with oil. Thereby, reducing the viscosity and interfacial tension [19]. The major mechanism preventing the carbon dioxide to recover to the surface are dissolution in interstitial formation water and oil [28]. The mechanism reactions as follows:

$$V_R = V_w + V_o \quad (2)$$

$$V_w = B_{carbon\ dioxide} \cdot C_{carbon\ dioxide} - w \cdot S_w \cdot \eta \cdot TPV$$

$$V_o = B_{carbon\ dioxide} \cdot C_{carbon\ dioxide} - oil \cdot S_{ro} \cdot \eta \cdot TPV$$

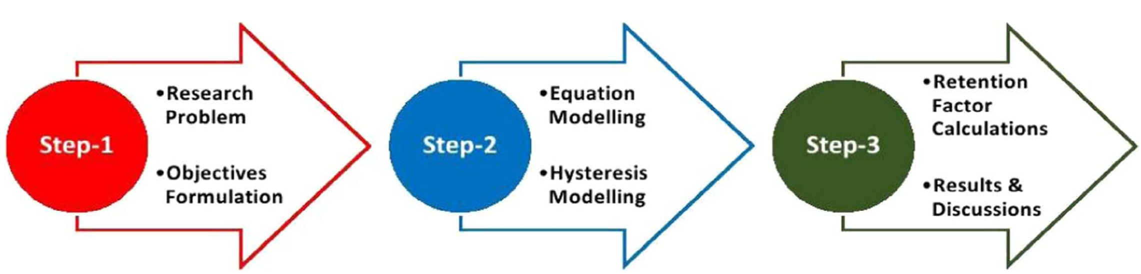

Fig. 8. Research methodology.

Where

V_o = Volume of CO_2 to remain in subsurface dissolved in trapped oil (in MMscf).
V_w = Volume of CO_2 to remain in subsurface dissolved in interstitial formation water (in MMscf).
$B_{carbon\ dioxide}$ = CO_2 Formation volume factor
$C_{carbon\ dioxide}$-*water* = Indicates the solubility of carbon dioxide in water
$C_{carbon\ dioxide}$-*oil* = Indicates the solubility of carbon dioxide in oil
S_w = Average water saturation
S_{ro} = Average residual oil saturation
η = Sweep efficiency
TPV = Total pore volume of reservoir (in MMcf)

There are also other sources to trap CO_2 in the subsurface which solely depends upon the reservoir geology and flooding properties such as injection pressure, mass, time, etc [8].

- Stratigraphic or Structural trapping.
- Chemical reactions within the reservoir rock matrix.
- Migration of CO_2 into the aquifer below.
- Leakage of CO_2 to thief zone.

Hence, the CO_2 retention in oil and gas reservoirs during the EOR process denotes a special case of CO_2 sequestration. In addition to oil production, an economic and statistical analysis of retention percentage in a particular reservoir need to be evaluated [26].

4. Results and discussions

The unconventional reservoir dimensions can expand to an area of a number of thousand meters and the depth can be up to several kilometers. The interaction of carbon dioxide with in situ hydrocarbons and other minerals usually takes place in microscopic level. However, the method of EOR can continuously be used for geological sequestration of CO_2 while injecting for oil and gas recovery. Its retention mechanism and factor can be computed and studied in depth and literature reviews for carbon dioxide storage through EOR are presented below:

4.1. Bakken reservoir

This section describes about the CO_2 retention percentage in Bakken shale oil reservoir for both CO_2 huff-n-puff and flooding scenarios.

4.1.1. CO_2 Huff-N-Puff case

We simulated a Bakken reservoir model by using CMG-GEM reservoir software. The reservoir model is 340 ft (length) × 1300 ft (width) × 40 ft (thickness). For the base case the fracture half-length is 340 ft, fracture conductivity is 1 md-ft, and the fracture spacing is 50 ft. The values for porosity, permeability and initial reservoir pressure are 0.04, 0.00005 md and 8000 psi. These values are fitted in the simulated reservoir model and the simulation was to determine to run for 30 years. The carbon dioxide trapped by hysteresis was obtained from simulation results and the retention percentage was calculated by using equation 1. In the numerator, it indicates the amount of CO_2 remaining at the subsurface, which is assumed equivalent to CO_2 trapped by hysteresis. Table 1 presents the results of geological sequestration of carbon dioxide during huff-n-puff process.

It can be seen from the table that, for about 30 years the CO_2 in the supercritical phase has been injected into the Bakken reservoir. It can be noted that, for the first year, no injection carbon dioxide was injected and from starting of second year a 50 MSCF/day of CO_2 with an injection pressure of 2000 psi was injected into the reservoir. It was reported in the second year that, 8 MSCF of carbon dioxide was trapped due to hysteresis. It can be observed that, the CO_2 injection rate and mass were maintained constant from year 2 to the year 10, but the trapping of CO_2 increases at each year. This is due to overwhelming injection of CO_2 and most of the fluid gets trapped in the soaking period. The well will be shut down for every 3 months and mostly the fluid trapping will take place in the first and the second stages of huff-n-puff process that is CO_2 injection and soaking. After the first decade, the injection rate increase to 100 MSCF/day with 4000 psi injection rate and from the beginning of the third decade, the injection rate and pressure increase up to four and two times higher than the second decade that is 5000 MSCF/day and 6000 psi. It is obvious that, large amount of CO_2 was getting trapped when the injection pressure and mass increases. Fig. 9 shows the CO2 retention percentage for huff-n-puff case with respect to year.

Table 1
CO_2 Sequestration results in Bakken reservoir for Huff-N-Puff scenario.

Year	Injection Pressure (psi)	Injection Rate (MSCF/day)	CO_2 Trapped By Hysteresis (MSCF)
1	0	0	0
2	2000	50	8
3	2000	50	13
4	2000	50	17
5	2000	50	22
6	2000	50	26
7	2000	50	30
8	2000	50	33
9	2000	50	37
10	2000	50	41
11	4000	100	48
12	4000	100	55
13	4000	100	62
14	4000	100	67
15	4000	100	70
16	4000	100	74
17	4000	100	77
18	4000	100	85
19	4000	100	89
20	4000	100	93
21	6000	500	148
22	6000	500	192
23	6000	500	245
24	6000	500	266
25	6000	500	298
26	6000	500	342
27	6000	500	357
28	6000	500	386
29	6000	500	415
30	6000	500	432

A graph was plotted between the year and retention percentage, it can be observed from the graph that, from second year to eleventh year the percentage of retention gradually increases due to upsurge in the CO_2 injection rate and pressure. In the 12th year the CO_2 retention starting to fall, this phenomenon may be due to the sudden change in the mass and pressure and it gradually rises till the end of the second decade. The same scenario was observed in the last ten years and the Fig. 10 illustrates the carbon dioxide gas retention with respect to injection pressure.

4.1.2. CO_2 flooding case

In terms of carbon dioxide storage both immiscible and miscible CO_2 flooding will contribute to the efficient geological sequestration. The same base case model is used for flooding process with different injection pressure and mass values, the simulation ran for 30 years. Table 2, presents the results for the sequestration of carbon dioxide in Bakken formation for flooding scenario. As usual for the first year there was no CO_2 injection and as a result, no gas was trapped by hysteresis. In this model, a high injection pressure modelling was proposed, in the second year the CO_2 gas was injected with a rate of 200 MSCF/day and 8000 psi injection pressure, which is regarded as high in the initial

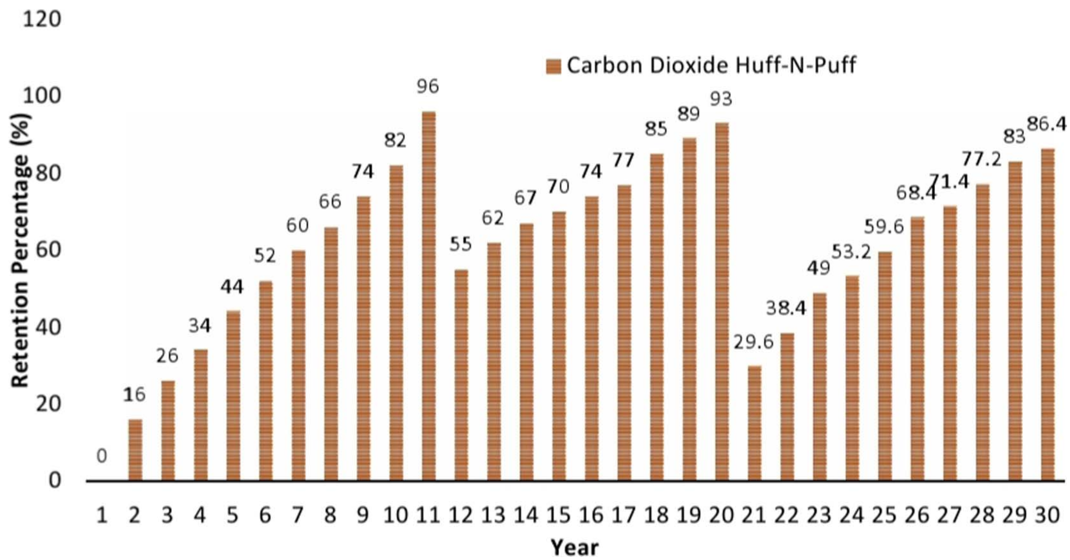

Fig. 9. Retention percentage with respect to year for CO_2 Huff-N-Puff process in Bakken reservoir.

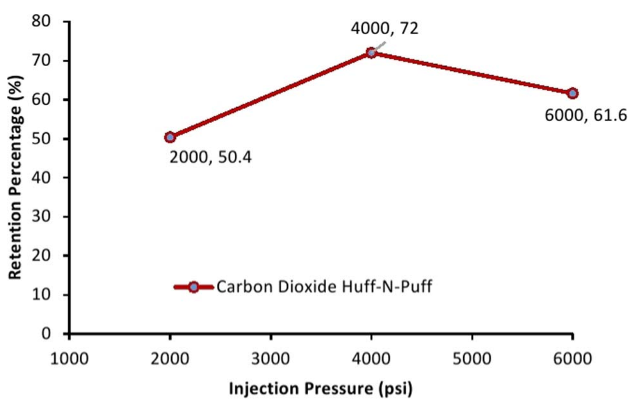

Fig. 10. Retention percentage with respect to injection pressure for CO_2 Huff-N-Puff process in Bakken reservoir.

Table 2
CO_2 sequestration results in Bakken reservoir for flooding scenario.

Year	Injection Pressure (psi)	Injection Rate (MSCF/day)	CO_2 Trapped By Hysteresis (MSCF)
1	0	0	0
2	8000	200	43
3	8000	200	52
4	8000	200	70
5	8000	200	93
6	8000	200	102
7	8000	200	112
8	8000	200	142
9	8000	200	160
10	8000	200	175
11	8000	200	246
12	12,000	600	266
13	12,000	600	295
14	12,000	600	312
15	12,000	600	327
16	12,000	600	349
17	12,000	600	356
18	12,000	600	382
19	12,000	600	424
20	12,000	600	453
21	15,000	800	500
22	15,000	800	540
23	15,000	800	563
24	15,000	800	592
25	15,000	800	604
26	15,000	800	613
27	15,000	800	640
28	15,000	800	670
29	15,000	800	695
30	15,000	800	729

stage. A 43 MSCF of CO_2 was trapped by hysteresis in this stage. The injection pressure and mass was kept constant till the 11th year and it increases to 600 MSCF/day, 800 MSCF/day, 12,000 psi, and 15,000 psi in the following decades. Already, this was discussed that, when the injection rate and pressure increases more carbon dioxide will be trapped in the reservoir and the geomechanical integrity play a significant role in the successful process of CO_2 geological sequestration [21]. The Fig. 11 shows the CO_2 retention percentage with respect to year for flooding scenario. It can be observed from this bar diagram that, the conditions for this flooding scenario was almost similar to the case of huff-n-puff process. The retention gradually rises at starting of first decade and decline at the end, and a breakthrough was observed in year 12 and attains peak in the year 20 and same conditions prevail for the last 10 years.

The above Fig. 12 shows the plotted graph between injection pressure (psi) and retention percentage. The curve is plotted with an average value of both these variables. It should be noted that, at 8000 psi injection pressure the retention of CO_2 was 59.7% and 58.5% in 12,000 psi, almost slightly slanted line was perceived from the graph. In 15,000 psi injection pressure it soared to 76.8%, CO_2 can be effectively stored during the flooding process with higher injection pressures, especially flowing through horizontal wells and fractures [40]. Since Bakken is a tight formation, the CO_2 retention due to huff-n-puff process will not be effective. Also, the subsurface stratigraphy and geology of the Bakken play a crucial role in trapping carbon dioxide through this process. During huff-n-process, there will be an injection and as well as formation pressure decrease during soaking time. Typically, soaking process is allowed for 3–5 months. During CO_2 injection into the reservoir the retention linearly rises and after that the well is closed for soaking to happen. During this time the carbon dioxide retention is in equilibrium and migrates from the pore chamber. After the soaking period the well is opened again, but still the CO_2 retention rate decreases gradually because the loss in reservoir pressure. Then it needs to escalate with high injection pressure and mass flow rate. Therefore, in the Bakken reservoir formation the CO_2 huff-n-puff is not a good method of injection and oil recovery as well. During CO_2 flooding process, there won't be any interruption in the reservoir pressure and also, yield high gas-oil miscibility and oil recovery rates. Consequently,

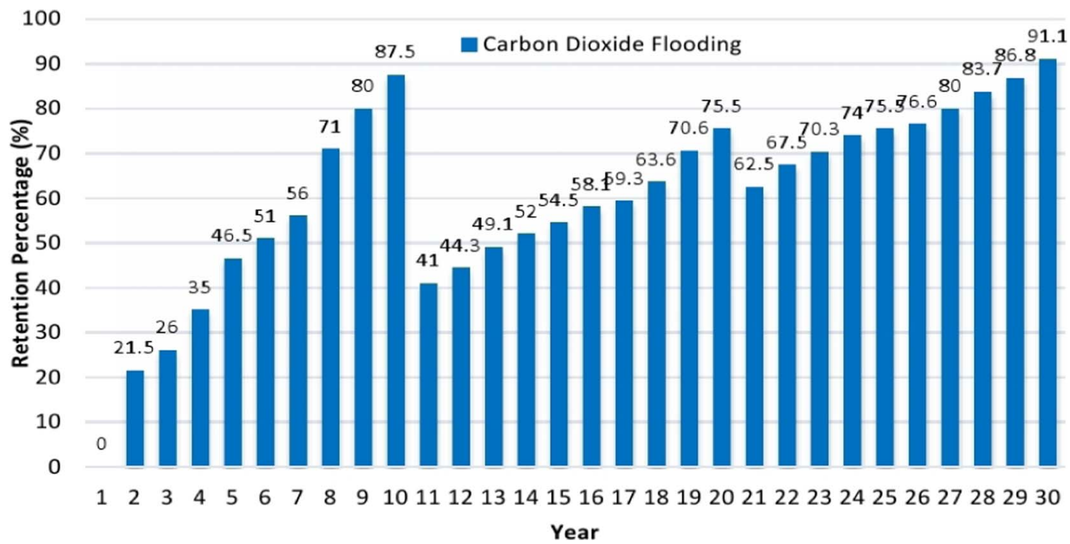

Fig. 11. Retention Percentage with Respect to Year for CO_2 Flooding in Bakken Reservoir.

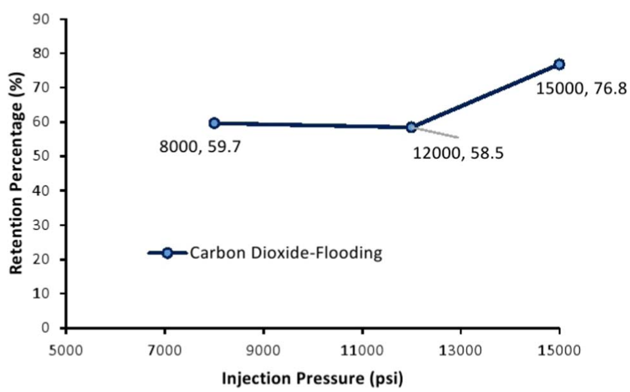

Fig. 12. Retention percentage with respect to injection pressure for CO_2 flooding in Bakken reservoir.

the carbon dioxide retention percentage also significantly rises. Some authors claim that CO_2 huff-n-puff technique is may not be suitable in tight formations. It should be noted that in the Huff-N-Puff case, highest CO_2 retention can be achieved only during the soaking phase (regardless of injection pressure). But, in the flooding case the highest retention rate can be obtained during rising injection pressures. It is difficult to indicate (that is the sweet spot) for pressure at which the retention is maximum. This can be explained by Figs. 9 and 11. It can be seen that a graph is plotted between year and retention percentage. As it can be observed that for every first ten years there is a rise in the carbon dioxide retention, but after that there is a sudden fall in retention rate and then soars till that decade's end and then the same process repeats. This is because, the well is shut-down for a long period of time. Even similar behavior was observed in the Eagle Ford formation, but here are huge fluctuations in the retention rate. From this it can be inferred that it is very difficult to plot nor indicate the place where CO_2 retention rate is maximum. It depends upon the period or phase, which we choose.

4.2. Eagle Ford reservoir

This section describes about the retention percentage of CO_2 in Eagle Ford gas condensate reservoir for both CO_2 huff-n-puff and flooding scenarios. The condensate reservoir offers a best storage site with an advantage of EOR through condensate and reservoir re-pressurization [33].

4.2.1. CO_2 Huff-N-Puff case

We developed and simulated a base case condensate reservoir model with Eagle Ford reservoir properties. The simulation was done in GMG-GEM reservoir simulation software and a total of 30 years was modelled to run. The carbon dioxide hysteresis trapping was obtained from the simulation results and it is presented in table 3. In the first year, no data was recorded and from year 2 to the year 5 the carbon dioxide was injected into the reservoir with an injection rate of 60 MSCF/day and 500 psi injection pressure. For this first 4 years a total of 83 MSCF of CO_2 was trapped by hysteresis. During the sixth year the injection rate and pressure get double that is 120 MSCF/day and 1000 psi, this value was kept constant until 15th year. The CO_2 injection

Table 3
CO_2 sequestration results Eagle Ford reservoir for Huff-N-Puff scenario.

Year	Injection Pressure (psi)	Injection Rate (MSCF/day)	CO_2 Trapped By Hysteresis (MSCF)
1	0	0	0
2	500	60	12
3	500	60	19
4	500	60	24
5	500	60	28
6	1000	120	33
7	1000	120	36
8	1000	120	40
9	1000	120	44
10	1000	120	45
11	1000	120	49
12	1000	120	53
13	1000	120	58
14	1000	120	67
15	1000	120	75
16	1500	295	93
17	1500	295	105
18	1500	295	116
19	1500	295	128
20	1500	295	146
21	1500	295	163
22	1500	295	188
23	1500	295	210
24	1500	295	233
25	1500	295	271
26	2500	530	334
27	2500	530	369
28	2500	530	392
29	2500	530	455
30	2500	530	486

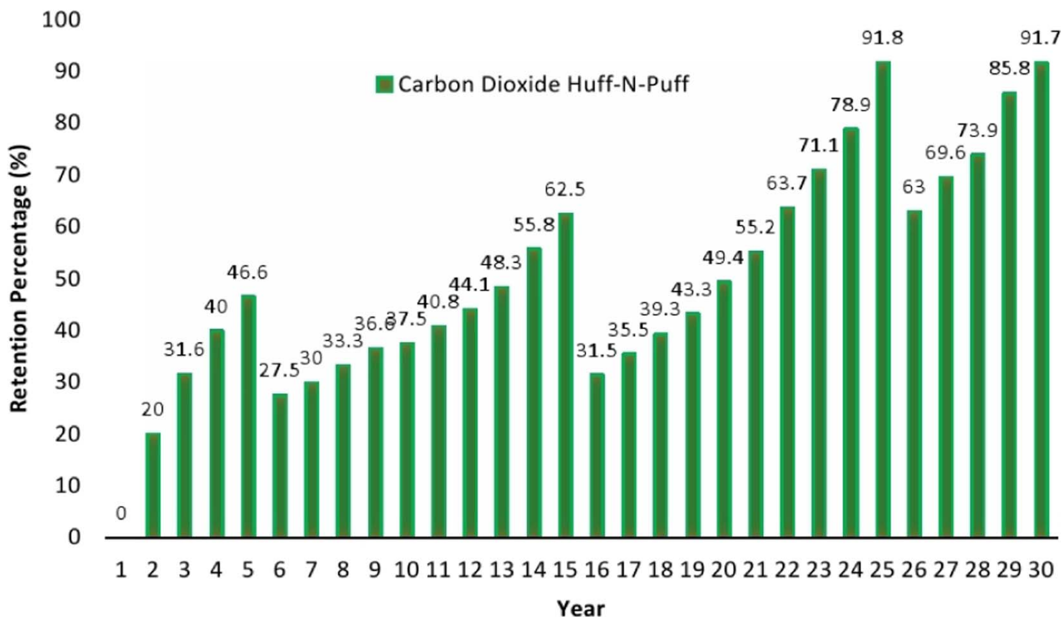

Fig. 13. Retention percentage with respect to year for CO_2 Huff-N-Puff process in Eagle Ford reservoir.

pressure and injection rate changes to 1500 psi and 295 MSCF/day and 2500 psi, and 530 MSCF/day in the last five years. It is a fact, when there is a change of injection pressure and mass from lower to higher values subsequently the large amount of CO_2 will be trapped in the reservoir by hysteresis [27].

The Fig. 13 indicates the carbon dioxide percentage of retention with respect to year for huff-n-puff process. It can be seen from the graph that, in CO_2 injection rate and pressure the retention percentage gradually rises and fall during the alternation in the input values. The highest retention percentage was achieved in the 25th year with 295 MSCF/day and 1500 psi and in 30th year with 530 MSCF/day and 2500 psi, its values are 91.8% and 91.7% just only a 0.1% difference. In the operation of CO_2 huff-n-puff in condensate reservoir, a gas with moderate injection pressure can be injected to acquire high retention values, typically more than 70% [20]. The Fig. 14 presents the percentage of retention with regards to injection pressure (psi) in the unconventional condensate reservoir. It can be noted from the graph that, at 500 psi at 34.5% was gotten and the line rapidly rises when the CO_2 injection pressure increase up to five times. 77.2% carbon dioxide retention was achieved during huff-n-puff process in condensate reservoir with 2500 psi injection pressure.

4.2.2. CO_2 flooding case

In this case, the reservoir model was tested with medium injection pressure and injection rate. Generally, in condensate reservoirs more

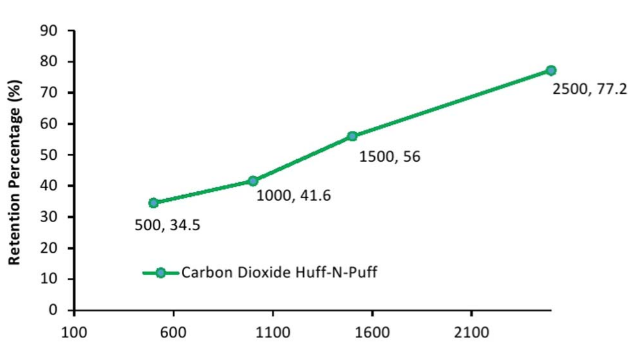

Fig. 14. Retention percentage with respect to injection pressure for CO_2 Huff-N-Puff process in Eagle Ford reservoir.

carbon dioxide can be trapped and more oil can be recovered simultaneously. The extreme higher injection typically above 5000 psi will lead to incremental increase in the condensate saturation in the gas and as a result there would be a liquid loading effect. Here the injection pressure was designed to 800, 120, 2600, and 3000 psi along with an injection rate of 80, 140, 300, and 580 MSCF/day. The highest retention percentage was acquired in the 15th year for about 94.2% indicated in Fig. 15. During this year, the flooding was operated with 140 MSCF/day and 1200 psi, 132 MSCF of carbon dioxide was trapped in the subsurface by hysteresis as shown in the Table 4.

The above Fig. 16 illustrates that the variation of CO_2 retention percentage with CO_2 injection pressure. A 44% carbon dioxide retention was obtained in 800 psi and it rises up to 74.7% in 1200 psi this is due to the effect of change in the fluid injection pressure. At 2600 psi, it (line) slight descent to 73% and in 3000 psi injection pressure it tumbles to 65.7% retention of carbon dioxide. In Fig. 14 (huff-n-puff) the retention performance increases and decreases in Fig. 16 (flooding). But, the average performance of flooding case is higher (64.35%) than the huff-n-puff case, which contributes about 52.33%. In the flooding case, initially high injection pressure is required to enhance the retention rate and then it start to decrease. Whereas, in huff-n-puff case, the highest retention rate can be achieved even with lesser injection pressure. Even though, both are unconventional formations, the subsurface geology and stratigraphy of the Eagle Ford formation is entirely different of the Bakken. Hence, huff-n-puff method may be suitable for this formation and can yield better results than flooding. It should be noted from Figs. 13 and 15 that the maximum CO_2 retention rates was observed in the third decade for huff-n-puff and second decade for flooding. Therefore, it can be inferred that both cases showed highest retention rates, but the time period was different. In this scenario also it is very difficult to indicate the sweet sport region.

In a condensate reservoir, when injection pressure increases the trapped gas saturation gets lower, thereby plummeting in the CO_2 retention and also this occurrence happens with decreasing rock compressibility [29]. Reservoir geomechanics has a potential effect on the storage of carbon dioxide in the subsurface. In both Bakken and Eagle Ford reservoirs the horizontal wells through hydraulic fractures has geomechanic effect for the adsorption of gas to fractures and pore spaces. The combination of hydraulic fracturing and horizontal wells technology has been used extensively to make networks of large fractures in shale reservoirs [39], due to CO_2 high adsorptive affinity it gets

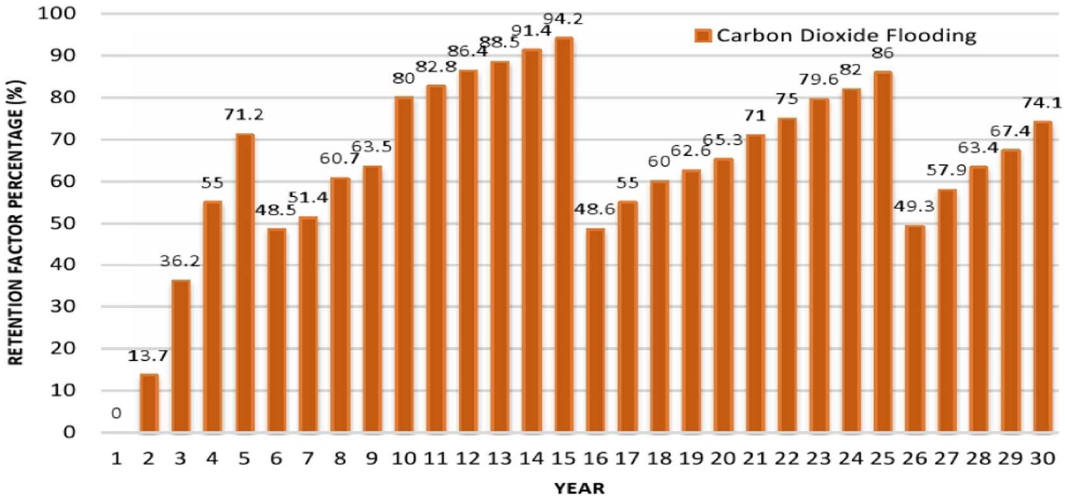

Fig. 15. Retention percentage with respect to year for CO_2 flooding in Eagle Ford reservoir.

Table 4
CO_2 sequestration results Eagle Ford Reservoir for flooding scenario.

Year	Injection Pressure (psi)	Injection Rate (MSCF/day)	CO_2 Trapped By Hysteresis (MSCF)
1	0	0	0
2	800	80	11
3	800	80	29
4	800	80	44
5	800	80	57
6	1200	140	68
7	1200	140	72
8	1200	140	85
9	1200	140	89
10	1200	140	112
11	1200	140	116
12	1200	140	121
13	1200	140	124
14	1200	140	128
15	1200	140	132
16	2600	300	146
17	2600	300	165
18	2600	300	180
19	2600	300	188
20	2600	300	196
21	2600	300	213
22	2600	300	225
23	2600	300	239
24	2600	300	246
25	2600	300	258
26	2600	580	286
27	3000	580	336
28	3000	580	368
29	3000	580	391
30	3000	580	430

into the rock matrix in the form of adsorbed gas. Under the condition of high temperature and pressure, the carbon dioxide was sequestrated in the subsurface in a supercritical state. It is evident that, the certain mass of CO_2 adsorbed is directly proportional to the injection pressure [22]. Henceforth, it should be noted that, the role of geomechanics is to cover the concepts and implications of rock mechanics and structural geology in the sequestration of CO_2. In the process of CO_2 storage in deep, unconventional formations the factor temperature cannot be ignored or assumed constant. In addition to geomechanical effect, the geothermal gradient has a potential impact to some extent. Therefore, carbon dioxide storage (practically or in reality) is consistently being performed under non-isothermal reservoir conditions.

On the whole, in remarkable conclusion, it can be said that, the CO_2 injection pressure and mass is the most dominating factor in CO_2

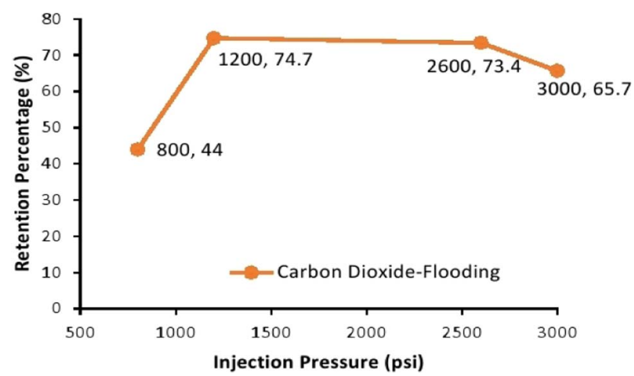

Fig. 16. Retention percentage with respect to injection pressure for CO_2 flooding in Eagle Ford reservoir.

sequestration in the Bakken and Eagle Ford reservoirs. Hence, it can be implicated that the retention mechanism and calculations were critically examined. The retention of carbon dioxide in the Bakken and Eagle ford formations has been analyzed and it was found that, the retention percentage gradually varies and drops with over a decade. From the analysis, it is clear that, CO_2 injection pressure, mass, and geomechanics are the dominating factor in the retention factor determination in addition to reservoir geology.

5. Conclusions

The retention percentage for geological sequestration was calculated using appropriate retention formula for the unconventional reservoirs during the CO_2 EOR huff-n-puff and flooding processes. Critical reviews were made of two types of carbon dioxide enhanced oil recovery process such as the huff-n-puff and flooding and with a help of hysteresis modelling, the CO_2 retention calculations for geological sequestration in the Bakken and Eagle Ford reservoirs during CO_2 huff-n-puff and flooding operations was successfully evaluated, in all four models a good carbon dioxide retention percentage was obtained, even percentage of retention > 90% was acquired in all four cases. It was observed and indicated in the retention mechanism that, the injection pressure is the dominating factor in the CO_2 geological sequestration in both unconventional reservoirs. Overall, it can be concluded that the Eagle Ford models using CO_2 EOR huff-n-puff and flooding methods are good. These models are better than the Bakken tight oil models and more improvements are required to be made in these models. Therefore, condensate reservoir under complicated geological formations can be a more suitable place for the efficient and safe storage of

CO_2. Therefore, statistical appraisal on enhanced oil recovery (flooding and huff-n-puff) with carbon dioxide provides a viable and plausible means for estimating the storage of CO_2 in Bakken shale oil and Eagle ford gas condensate reservoirs. Finally, this paper has emphasized and paved a new way to quantify the subsurface CO_2 storage.

Acknowledgement

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Appendix A. Supplementary data

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.fuel.2017.11.049.

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