Asian Journal of Geological Research

2(3): 239-251, 2019; Article no.AJOGER.53683

Enhanced Oil Recovery Using CO_2 Flooding: Norne Field E-Segment Case Study

M. M. Iliya[1*], N. U. Okereke[2] and H. O. Usman[1]

[1]Department of Geology and Mining, Nasarawa State University, Keffi, Nigeria.
[2]Department of Petroleum Engineering, Federal University of Technology, Owerri, Nigeria.

Authors' contributions

This work was carried out in collaboration among all authors. Author MMI designed the study, performed the statistical analysis, wrote the protocol and wrote the first draft of the manuscript. Author NUO managed the analyses of the study. Author HOU managed the literature searches. All authors read and approved the final manuscript.

Article Information

Editor(s):
(1) Dr. Mohamed M. El Nady, Department of Exploration, Egyptian Petroleum Research Institute, Nasr City, Cairo, Egypt.
(2) Dr. Jyh-Woei Lin, Department of Electrical Engineering, Southern Taiwan University of Science and Technology, Tainan City, Taiwan.
(3) Dr. Adewumi, Adeniyi JohnPaul, Lecturer II, Department of Geological Sciences, Achievers University, Owo, Nigeria.
Reviewers:
(1) Isac Inácio Tsamba, Eduardo Mondlane University, Mozambique.
(2) Fábio Henrique Portella Corrêa de Oliveira, Universidade Federal Rural de Pernambuco, Brazil.
(3) Peter Stallinga, University of The Algarve, Portugal.
Complete Peer review History: http://www.sdiarticle4.com/review-history/53683

Original Research Article

Received 01 December 2019
Accepted 05 February 2020
Published 14 February 2020

ABSTRACT

Background: The Norne field is located 80 km north of the Heidrun field in the Norwegian Sea discovered in December 1991.

Aim: The feasibility of using CO_2 flooding as a method of enhanced oil recovery in a segment of the Norne field was analysed.

Methods: A numerical simulation using a black oil simulator approach was taken. For this study, a synthetic reservoir model, with fluid and rock properties from Norne field E-Segment was used to test the effect of CO_2 flooding on recovery factor.

Results: The key findings are as follows: (1) The oil recovery of the base case after 7 years of water flooding was 40% (2) The recovery factor obtained after 15 years of continuous CO_2 injection was 32%.

Conclusion: This study indicates that there is a feasibility of carrying out CO_2-EOR in the Norne field based on initial CO_2-EOR screening and simulation.

**Corresponding author: Email: minermamidak@gmail.com;*

Keywords: Simulation; CO_2 flooding; Enhanced Oil Recovery (EOR); recovery factor.

1. INTRODUCTION

Owing to the growing energy demands globally, especially in the BRICS (Brazil, Russia, India, China and South Africa) nations, there is a need to increase the production from oil fields and also explore marginal fields. It is in this vein that tertiary methods of enhanced oil recovery are implemented. One of such methods is CO_2 Enhanced oil recovery (EOR) which combines the advantage of the additional recovery of oil and reduction of levels of emission of Green House Gases (GHGs) in the atmosphere [1,2]. According to a publication by ENI (2013), the current recovery rates from oilfields worldwide is 30-35% of which it ranges from an average of 10% from extra heavy oils to 50% average of most advanced fields in the North Sea. With declining production rates in the North Sea, there is a need to explore methods or techniques to increase the recovery and so the need for enhanced oil recovery. A study by Hart energy, 2012 indicates that the North Sea oil and gas production has declined at an annual average growth rate (AAGR) of 7.7% between 2006 and 2011, from 2,599 MMboe to 1,772 MMboe. In another global data forecast, the survey stated that production rates will drop from 1,702MMboe in 2012 to 1,447 MMboe in 2050 representing a decrease in production rates leading to a negative AAGR of 2%. Similarly, according to EELR Report, for the European countries the three key issues are that are the driving forces to implementing CO_2 EOR include;

- Reduction in the oil production rate from the North Sea Continental Shelf (NSCS).
- Growth in dependence upon energy imports.
- An increasing drive to reducing CO_2-emissions on account of climate change.

Increasing energy needs and depleting resources have generated interest in the area of enhanced oil recovery. Many EOR methods are currently in use and CO_2 is of great interest as it reduces the emission of greenhouse gases greatly and allows companies to earn carbon credits.

1.1 Study Area - Norne Field

The Norne field is the largest discovery on the Norwegian continental shelf in more than a decade with recoverable oil reserves of 450 Million bbl [3]. Natural gas has also been exported from Norne since 2001. er 1997. It consists of two separate oil components, the Norne main structure (C, D and E segment) and the Northeast segment (G segment). 98 percent% of oil in place is situated at the Norne main structure [4]. The field is located 80km north of the Heidrun field in the Norwegian Sea discovered in December 1991. Fig. 1 shows the location of the field. Development drilling began in August 1996 and subsequently, production began in November of the same year. The Norne oilfield has a water depth in the area of between 370 – 390 metres [5]. It has an estimated recoverable reserve of 90.8 million sm^3 of oil, 12.0 billion sm^3 gas and 1.6 million tonne NGL [6].

1.2 Geology

This field lies within the licence blocks 6608/10 and 6608/11 [7] which is on a horst block approximately 9 km×3 km [8]. The field is located at the Revfallet fault Complex. The Nordland area which houses the Norne field has been exposed to two episodes of rifting which occurred during two different periods; in the Permian and Late Jurassic to Early Cretaceous. During the period of the first rifting a wide range of area was affected by faulting. Normal faults trending in NNE-SSW directions were common from this period. According to Verlo and Hertland [8], during the second rifting period, four phases occurred ranging from late Bathonian to early Albian. The tectonic activity was limited between the two rifting periods although during the mid and late Triassic some faulting occurred. Subsidence and transgression dominated this period. Unconformities occurred in the Tilje, Tofte formations and within Ile formation possibly due to the tectonic activity [9]. Most of the structural development affecting the Norne reservoir took place during the first rifting period causing the reservoir to be buried deeper allowing the formation of oil and gas and subsequently leading to accumulation within the reservoir.

Steffensen and Karstad [5] in their study reported that the Norne field reservoir is divided into four different formations: Ile, Garn, Tofte and Tilje (see Fig. 2). The reservoir rocks are made up of lower to middle Jurassic sandstones [8]. The reservoir rocks are buried at a depth of between 2500-2700 metres and have been affected by diagenesis. Porosity ranges from 20-30 per cent while permeability varies from 20 to 2500 MD [10].

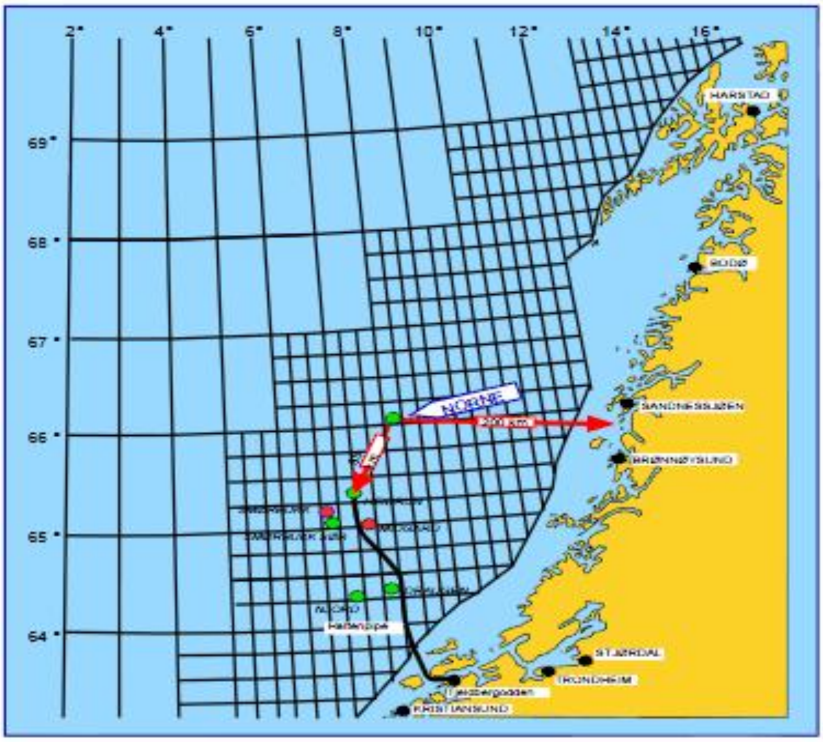

Fig. 1. Location of the Norne field in the Norwegian continental shelf

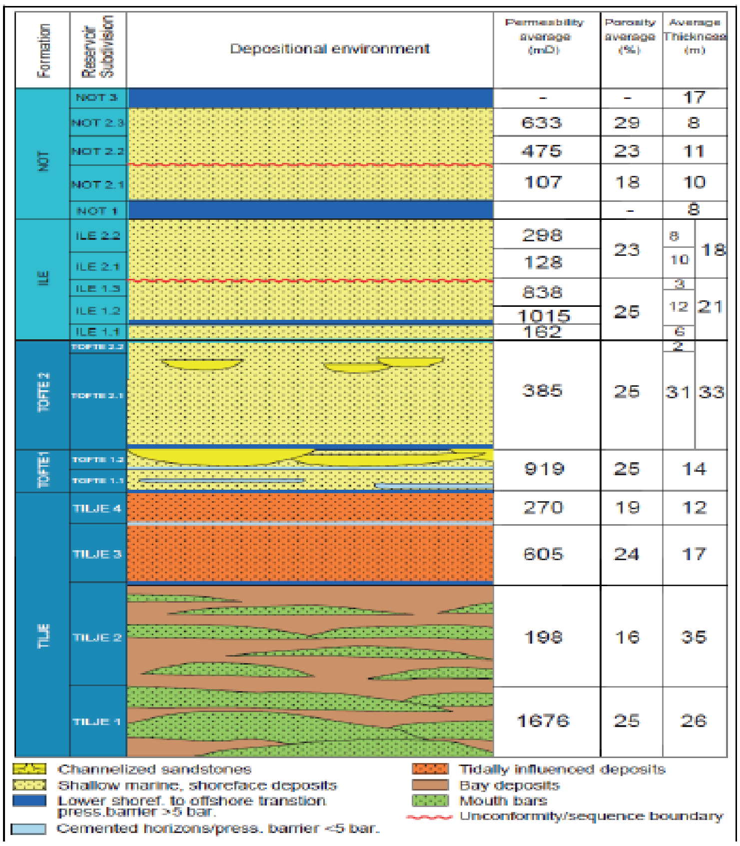

Fig. 2. A cross-section of the Norne field reservoir adapted from (Alabay, 2012)

The Spekk formation is believed to be the source rock. The caprock which seals the reservoir and keeps the oil and gas in place is the Melke Formation. The Not Formation behaves as a sealing layer, preventing communication between the Garn and Ile Formations. The reservoir thickness within the Norne varies as a result of erosion. The reservoir thickness, from Top Åre to Top Garn Formations, is in the range of 260 m in the southern parts to 120 m in the northern parts [7]. Fig. 2 shows the geological zonation of the Norne reservoir. Presently, the reservoir–zonation has been altered. In the present zonation, the Ile and Tofte zones have been subdivided and the Tilje formation made further simple.

2. METHODOLOGY

2.1 Simulation

Oil recovery behaviour of the Norne field was examined using a simple synthetic but realistic 3D model of the Norne field which had a single producer and 4 injectors with available reservoir and field properties from the Norne field (Table 1). Continuous CO_2 injection for 15 years was tested and summarised as follows;

Table 1. Summary of reservoir and field properties

Field input data	Units	Norne main Structure
Oil Viscosity	Pas	6×10^{-4}
Reservoir Temperature	°C	98.3
Reservoir Pressure	Bar	273.2
Depth	m	2456
Gas/Oil Ratio	Sm^3	111
Oil Formation Factor	Rm^3/Sm^3	1.3185
Bubble Point	Bar	251
Oil Gravity	API	42

For this scenario, it was simulated using the same injection rate and bottom hole pressure for the first 5, 10 and 15 years. Changes in the effect of CO_2 injection in the synthetic model have been observed through changes in oil saturation and gas saturations. The saturation maps below show that there has been a measurable decrease in oil saturation during the 15 years of continuous CO_2 injection. The results for the oil production, recovery factor and reservoir pressure were obtained using the OFFICE option in ECLIPSE by loading the vectors from the summary section of the simulation run.

3. RESULTS AND DISCUSSION

3.1 Base Case Result

3.1.1 Reservoir pressure

Fig. 3, gives a plot of reservoir pressure against production time. The reservoir pressure at the beginning of production in 1998 was about 270 bars. In the curve, there was a sudden decline in pressure to about 235 bar after about 500 days (the year 1999) of production. Donaldson et al. [11] stated that at the early stage of a reservoir, the natural drive of the reservoir moves the oil to the production well but with time there is a decline in the pressure leading to a reduction in the production rate which accounts for the abrupt pressure decrease. There is a linear relationship in pressure decline and cumulative production rates, provided the reservoir is highly permeable and has a constant volume, therefore it was expected that the production rates will be affected as proposed by Donaldson et al. [11]. However, Hales [12] stated that due to the influx of water during pressure decline most reservoirs do not have a constant volume. But it will be noticed that the production rate was not affected which could be due to the influx of water into the reservoir as proposed by Hales [12]. The field pressure is still in the undersaturated region since the pressure is above the bubble point pressure which is 251 bars. There was a slow pressure decline in 2002, The steady increase in the reservoir pressure can be attributed to the use of water flooding in the field as well as a gas injection in some wells [13]. This trend shows a correlation between water flooding and pressure maintenance, with more water flooded into the reservoir the pressure was maintained but it is noticed in the plots of field oil recovery that there was no improvement in the recovery factor indicating that a tertiary method of oil recovery was needed.

3.1.2 Water in place and water cut

The water cut is one of the important data used for the estimation of the productivity of a reservoir. Though this may vary from one reservoir to the other in terms of value. In the North Sea, average water cuts in the range of 30-45% are acceptable, while in the US water cuts of between 90-95% is acceptable. From Figs. 4-8, there was a very low water cut at the beginning of production in 1997 but after about 1000 days of production, the water cut increased significantly which was at its peak in 2004 with a water production of 5×10^{8} sm^3/day.

The high-water cut may be attributed to premature water breakthrough as water injected enters through the fractures reducing the sweep efficiency. There is uniformity in the trend of increase in water injection in the field and the increase in the water cut. The water cut (30%) was at its peak after 1800 days of production but slowly declined thereafter with an increase in the amount of water being injected into the reservoir (Fig. 4). As of 2004; there was a steady increase in the water cut with a decline in the water production rate. The high-water cut may be attributed to the heterogeneity of the reservoir which causes a non-uniform sweeping of hydrocarbons which may be the reason for the low recovery in the field. Fig. 5 and Fig. 6 show the injection rates and water production rates for the two active injectors in the segment. From the plots, it is noticed that most of the water was injected in the well F-3H was at a higher rate compared to Well F-1H which could have been the reason for higher water production from the well between the year 2000-2003. Fig. 4 shows instability in the water cut, the water cut shows some fluctuations with the water cut being the highest in 2004. The blue spikes show the water cut while the yellow shows the water production rate.

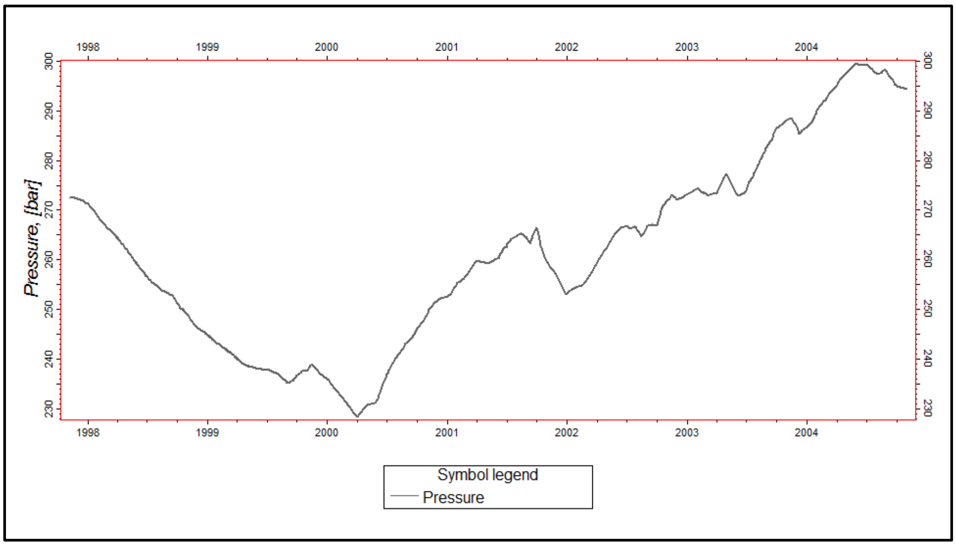

Fig. 3. Graphical representation of field pressure from 1997 to 2004

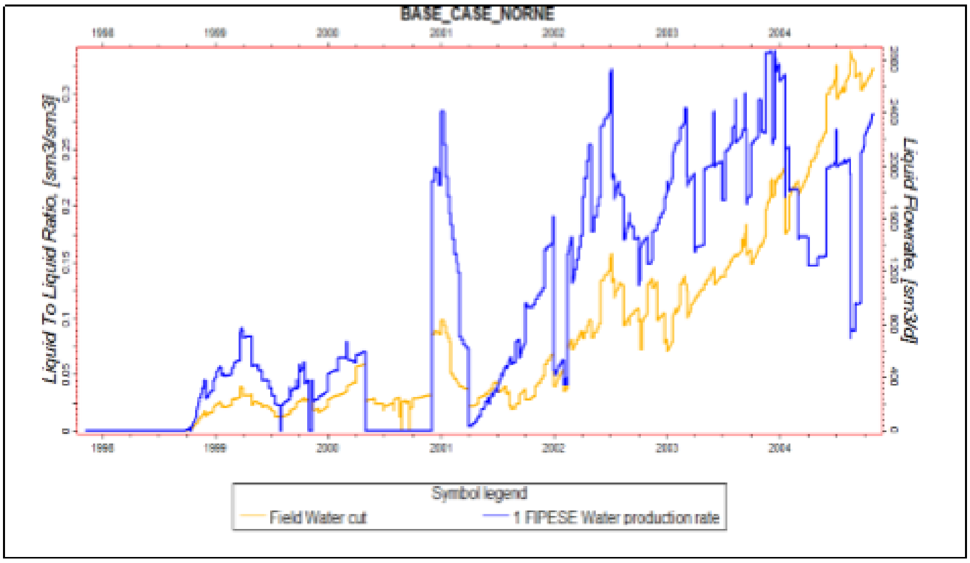

Fig. 4. Graphical representation of field water production profile and field water cut

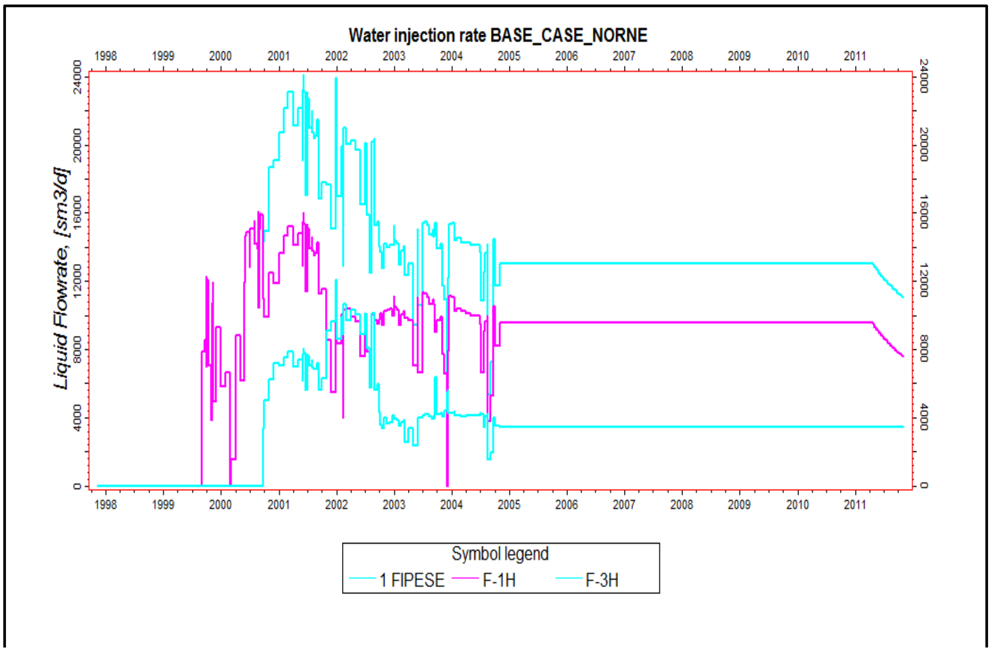

Fig. 5. Water injection rate for wells F-1H and F-3H

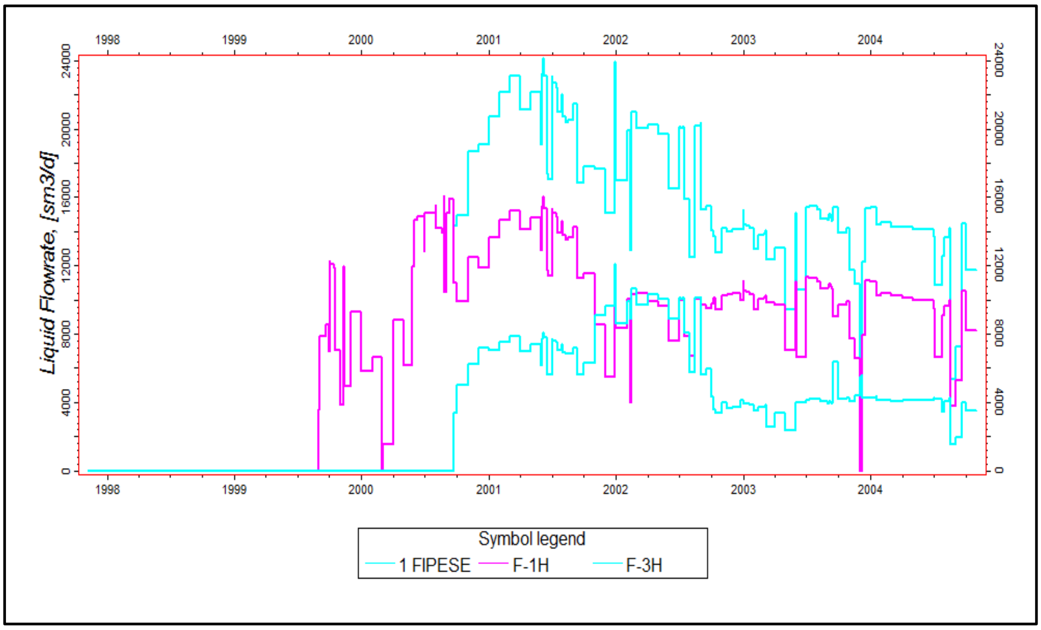

Fig. 6. Water production rates for Well F-1H and F-3H

3.1.3 Production rates

From the results of the simulation in Fig. 7, Oil production rate peaked in 2001 at 9000 Sm^3/day while there was an abrupt decline in 2004 to 1800 Sm3/day. The gas production rate was at its peak in 2000 at 2×10^6 m^3/day with a decrease to 5×10^5 m^3/day in 2004. The high gas production rates in the year 2000 could be attributed to the short period of gas injection into the Garn formation which was subsequently stopped due to the pressure build-up in the Garn formation leading to the abrupt increase in the pressure profile in 2000 as mentioned by Alkasim et al. [13,14]. This was as a result of lack of connection between garn and Ile formation as reported by Àwan et al. [15]. Both high oil and water productions are initially recorded as well as their cumulative. From the simulation of oil production rates, it was noticed that the gas production had a similar trend with observed data (Fig. 7) but the first peak of production is observed in the field upon initiation of water injection after 300 days of production. The gradual decrease in production rates for both gas and oil in the field although there has been being a steady increase in the field oil recovery rates from 0-40% for about 3000 days of production (Fig. 7) which is lower than the average recovery rates in the North Sea as reported by [16]. The recovery rate can be increased using a tertiary oil recovery technique since following water injection and a subsequent short period of gas injection there was a steady decrease in the gas and oil production rates from Fig. 3. From Fig. 8, it is noticed that most of the oil production was from well E-3AH between 2001- 2005. The peak of production for the well was in 2001 but after that period the production rates were similar with well E-2H.

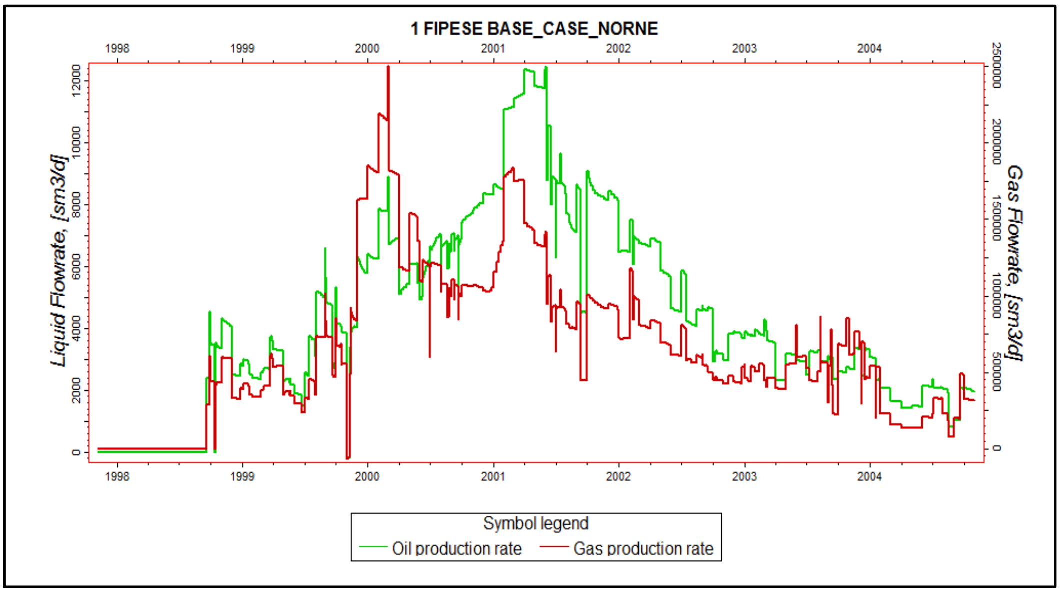

Fig. 7. Field gas production rate and oil production rate

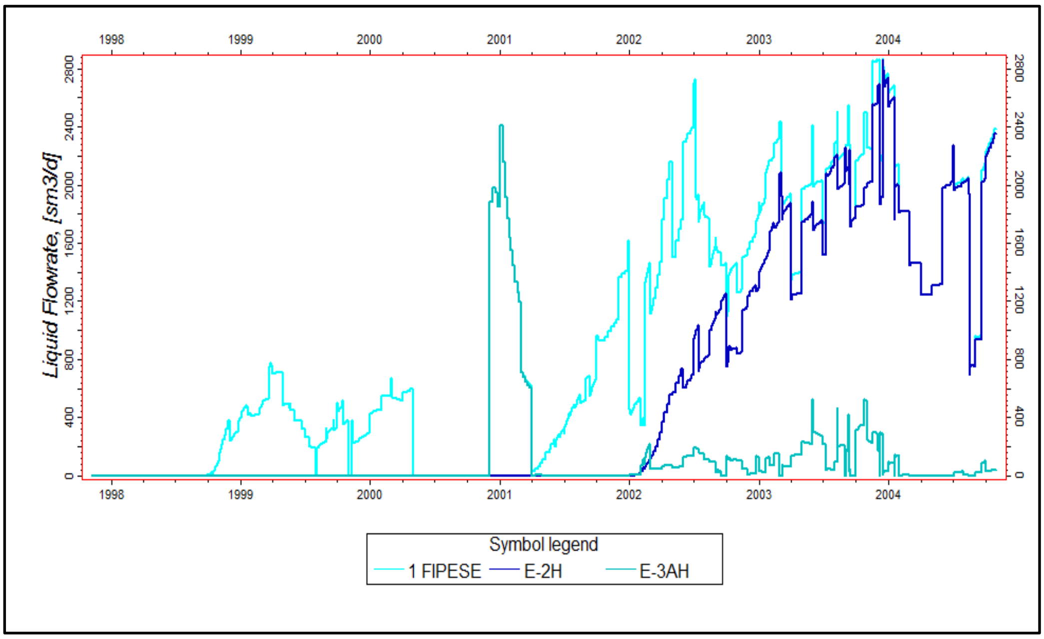

Fig. 8. Oil production from Well E-2H and E-3AH

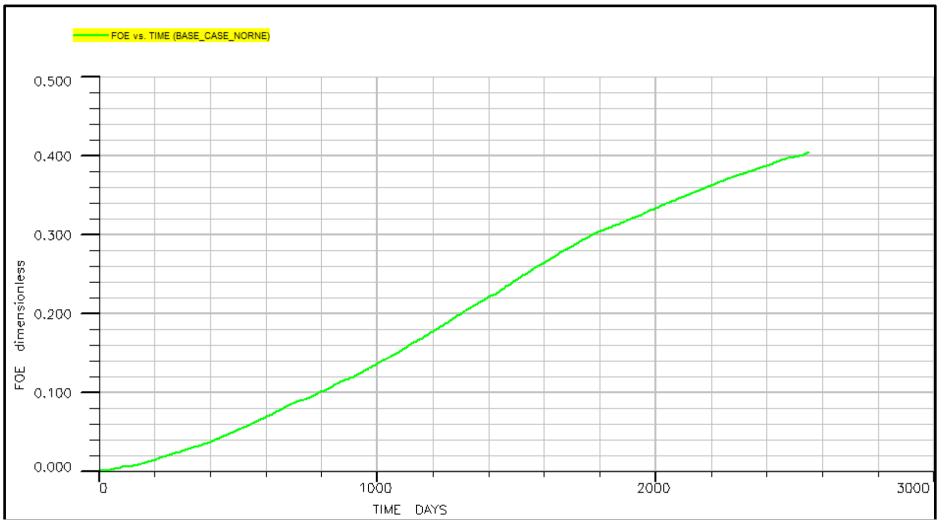

Fig. 9. Field recovery rate for 1997-2006

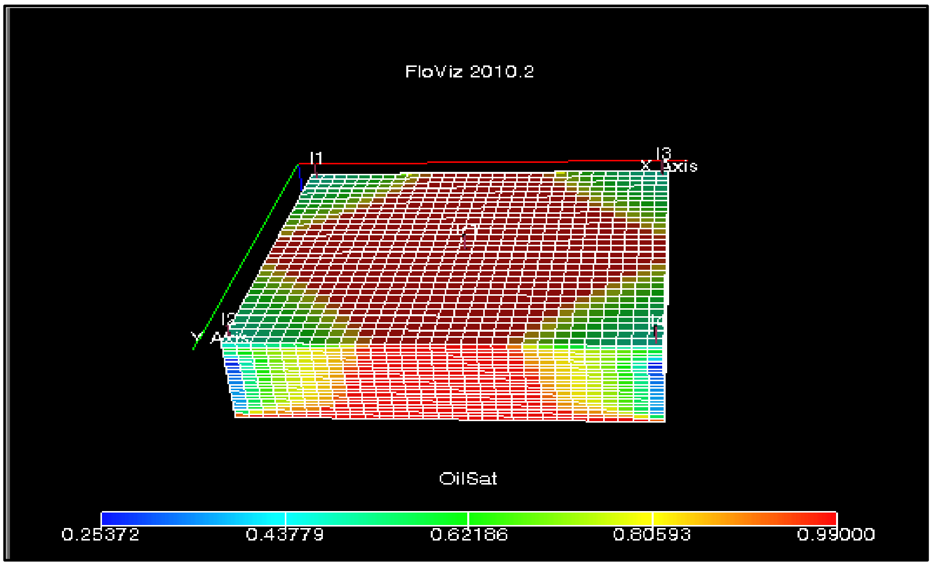

Fig. 10. Oil saturation a year of CO_2 injection into a heterogeneous reservoir (Warm colours represent high oil saturation while the cold colours represent low oil saturation)

3.2 Results of Simulation Using the Synthetic Model

In this section, the CO_2 injection and production responses for different injection periods are discussed separately. The names designated for the injector and producer wells are I1, I2, I3, I4 and P1. Fig. 10 shows the initial oil saturation of the reservoir after a year of CO_2 injection. The recovery factor, field oil production and reservoir pressure were constant at the beginning of the simulation period in 2008. The reservoir remained oil-saturated from Fig. 10. during the first year of injection, the oil saturation in most regions of the reservoir was 0.99 approximately unity indicating it was oil saturated.

Fig. 11 summarises the performance of 5years of continuous CO_2 injection. For this simulation, the production well operates at a fixed bottom hole pressure of 300bars. Injection rates of CO_2 are 20000 m^3/day. The miscibility of CO_2 in the liquid phase is important due to its effects on oil recovery. All the injectors are assigned with an equal amount of CO_2 during the simulation period. The recovery from the continuous injection with CO_2 is shown in two different ways: field total oil production and field oil efficiency. The results show that the recovery is about

15.5% for the first 1600 days with a cumulative oil production of 4×10^6 Sm^3. The field pressure has been altered by CO_2 injection in the first5 years. There is a gradual increase in the field pressure from 270 bars to about 299 bars. Fig. 12 shows a slight variation in the oil saturation, with the saturation changing from 0.99 in most of the reservoir during the first year to 0.546 indicating that there is a considerable difference in the oil saturation after the 1600 days of continuous CO_2 injection, the oil bank has moved towards the producer well. The oil recovery and total production profiles (Fig. 11) indicate that there is a significant amount of oil recovered during the first 1600 days of injection. There is a depletion of the oil bank as the saturation of gas increases in the reservoir with the migration of the gas upwards due to buoyancy forces.

Summary of 10 years of continuous CO_2 injection is shown in Fig. 13, it is important to note the increase in pressure; the pressure has increased to above 300bars. The results of the oil recovery and oil production show a slight variation with an increase of 20% and 6×10^6 Sm^3 respectively. The increase in reservoir pressure effects on the recovery factor where more oil production is achieved with the reservoir pressure being maintained. Hategan and Hawkes [17] in their research concluded that reservoir pressure was one of the parameters that effects on the production. Thus, accounting for the decrease in oil saturation, due to increase in oil produced during the 10 years of continuous CO_2 injection as seen in Fig. 14. In Fig. 14, the oil saturation has reduced significantly to 0.1 as opposed to the initial oil saturation of 0.99 during the first year.

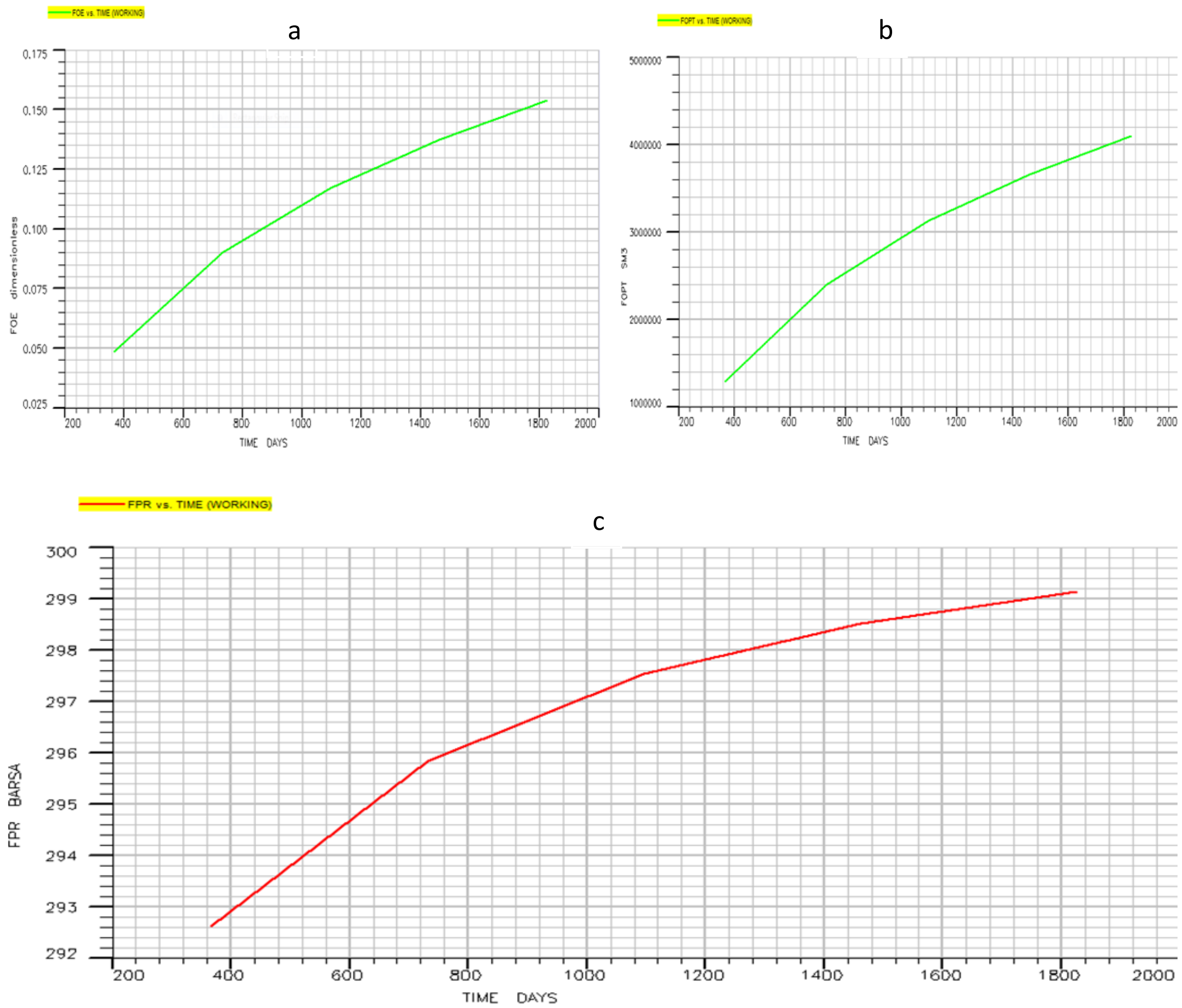

Fig. 11. (a) Plot of field oil recovery against time (b) field oil production against time (c) field pressure against time after 5 years of continuous CO_2 injection

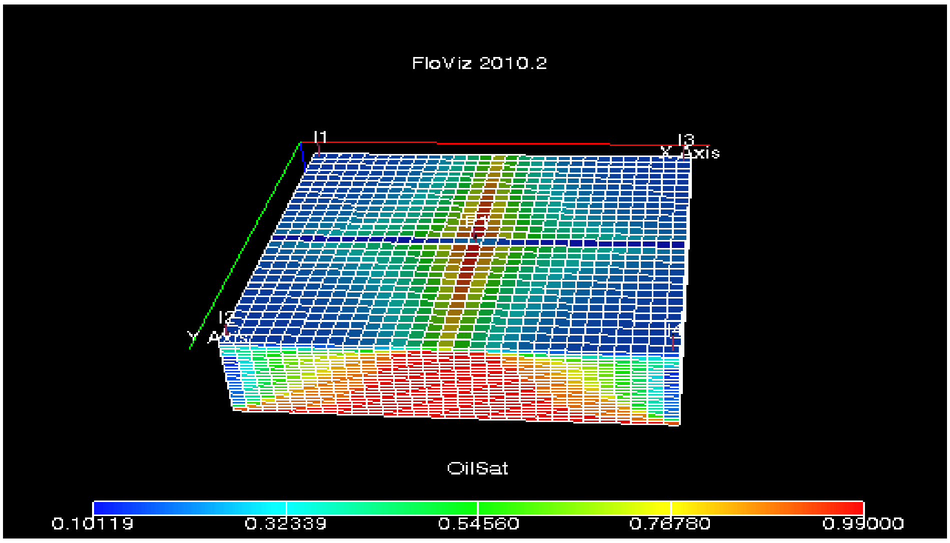

Fig. 12. Oil saturation 5 years of CO_2 injection

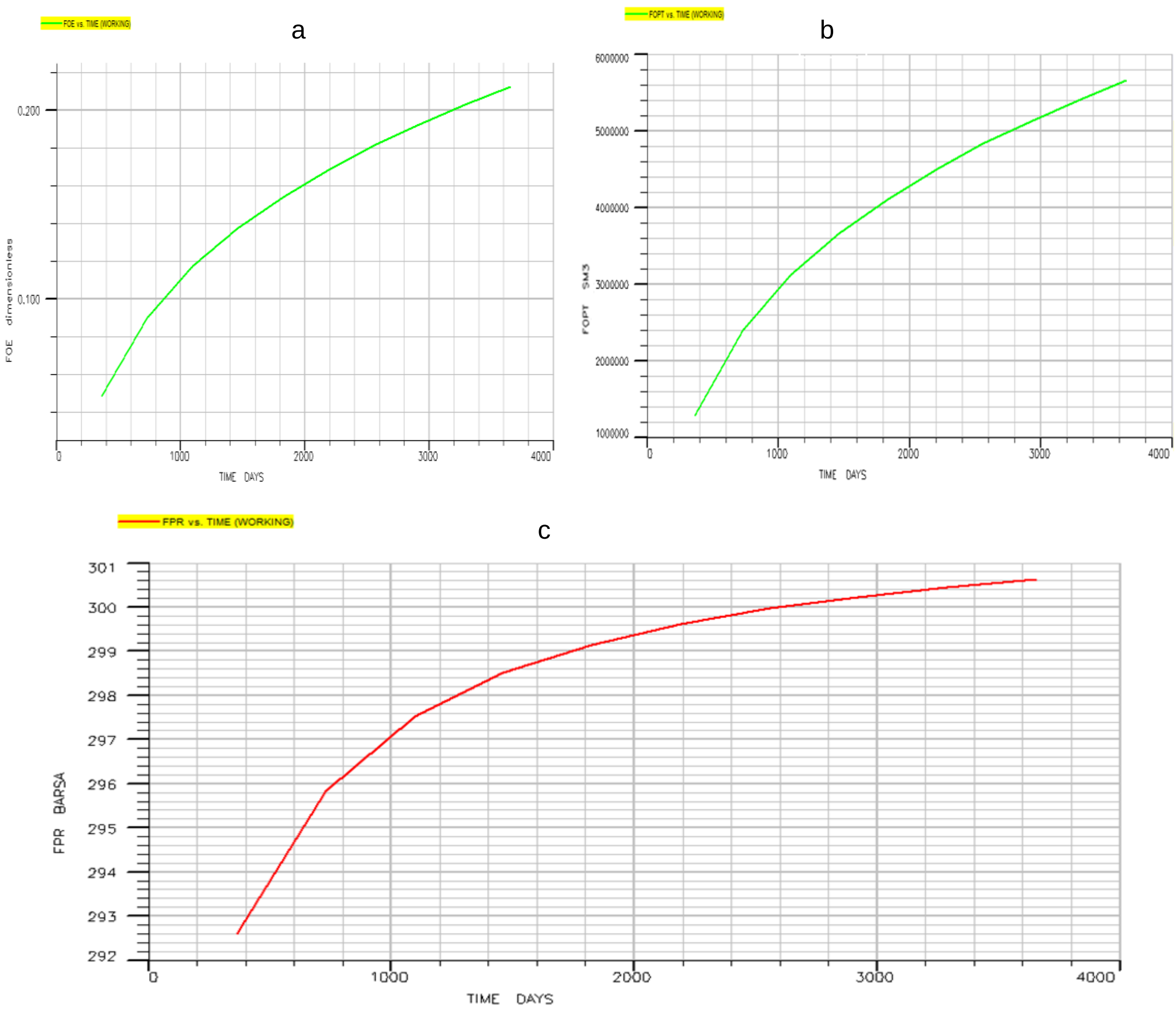

Fig. 13. (a) Plot of field oil recovery against time (b) field oil production against time (c) field pressure against time after 10 years of continuous CO_2 injection

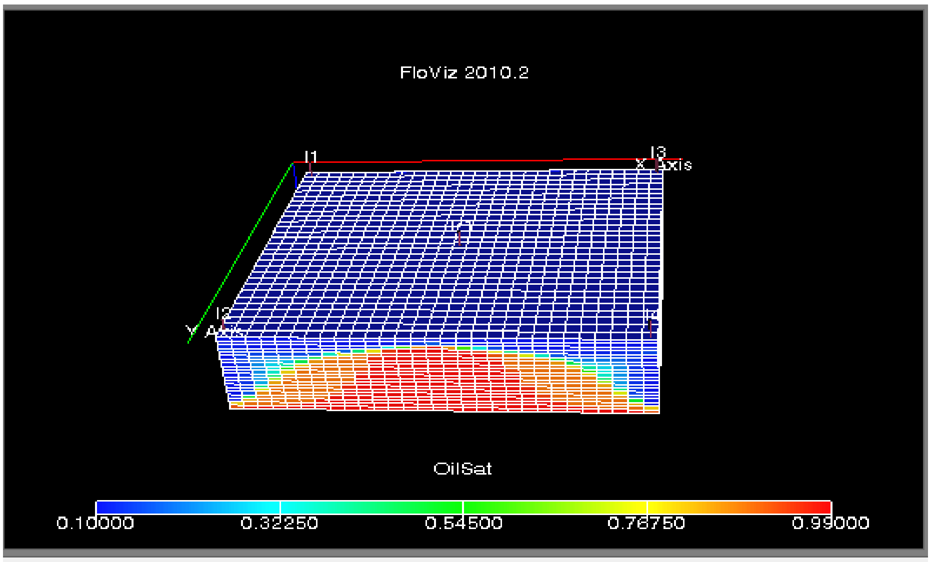

Fig. 14. Changes in oil saturation after 10 years of CO_2 injection

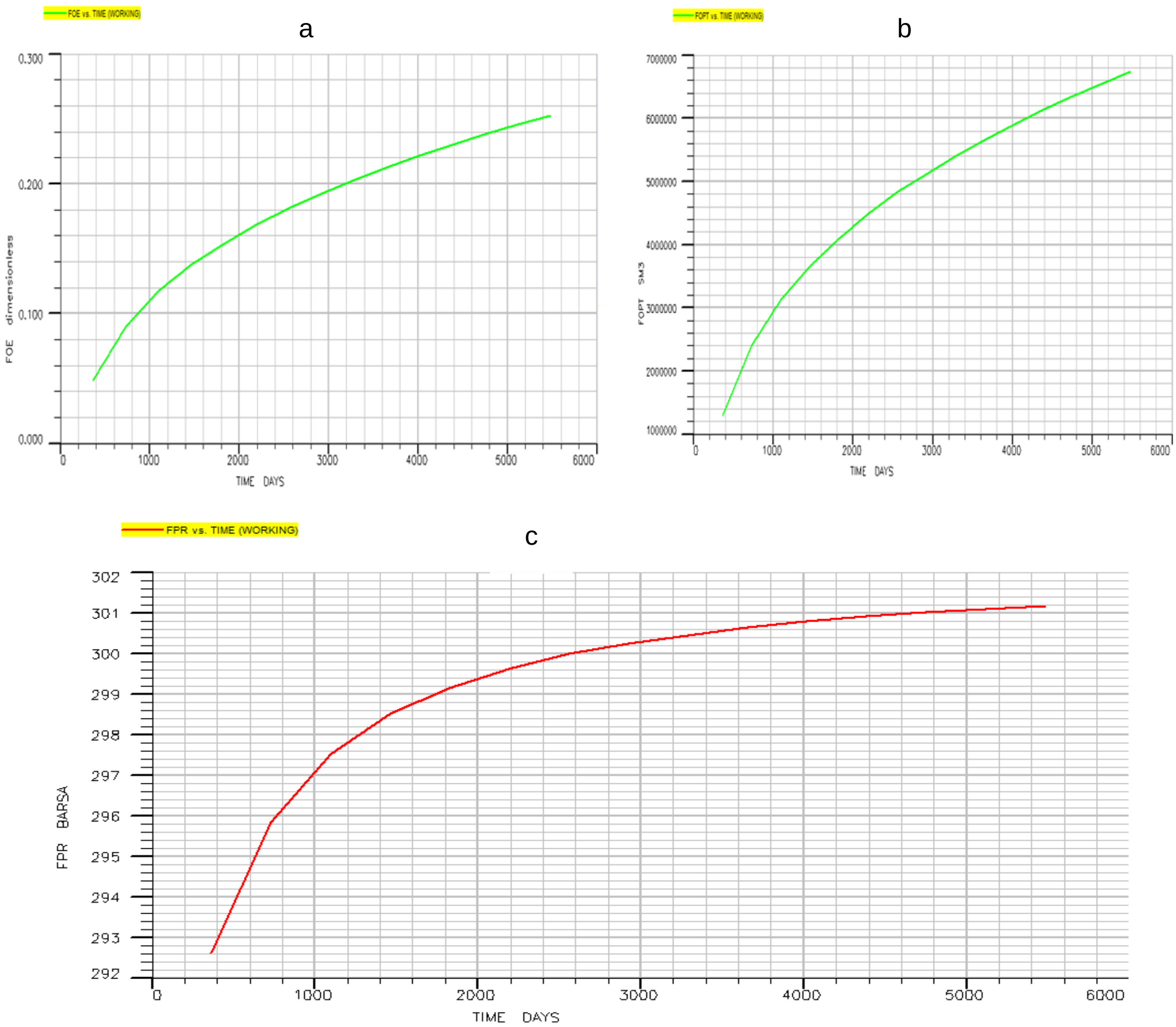

Fig. 15. (a) Plot of field oil recovery against time (b) field oil production against time (c) field pressure against time after 15 years of continuous CO_2 injection

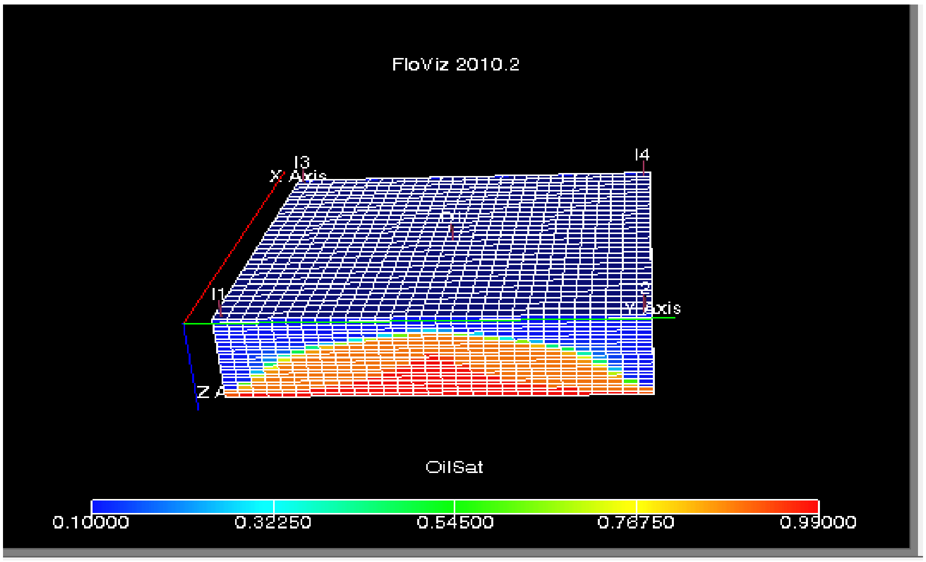

Fig. 16. Oil saturation after 15 years of CO_2 injection

Fig. 16 shows a variation in the oil saturation with continuous CO_2 injection over 15 years in the synthetic model. Since the beginning of CO_2 injection, there has been an increase in the oil production and recovery factor but it was noticed that the considerable additional recovery during the last five years of continuous CO_2 compared with the first five years of injecting CO_2 as recovery factor and total oil production after 15 years is 25% and 6.9×10^6 sm^3 respectively (Fig. 15). From the foregoing, it is evident that most of the oil was recovered during the first 5 years of CO_2 injection.

Comparison of the final oil recovery as a function of time shows a maximum additional recovery of 32%. Holt et al. [18] in their work obtained a recovery factor from continuous CO_2-EOR from 8.5 to 9.5% for a conceptual model of some representative North Sea fields. Similarly, Akervoll and Bergmo [19] in their studies of some representative North Sea and Norwegian reservoirs ended up with an average recovery factor of 9 to 10.1%. [20], came up with a recovery of 12-13.2% in their work. The recovery results obtained based on the conceptual model in this study is slightly higher than those obtained by these authors in their simulation.

4. CONCLUSION

A simple but realistic synthetic model which has the same reservoir and field properties with the Norne field E-Segment was used to simulate the possibility of carrying CO_2 enhanced recovery. The simulation led to the following discoveries:

I. The field recovery factor was about 40% after 7 years of water flooding and a short period of gas injection and therefore there is a dire need to increase the recovery factor of the field.
II. CO_2 flooding was one of the Enhanced oil recovery methods that can be used to increase recovery in the field based on the reservoir characteristics such as temperature, depth and API but the choice of this particular method was based on its dual benefits.
III. From preliminary results, the feasibility of carrying out CO_2 EOR on the field based on initial EOR screening proposed by different authors and simulation studies was validated. Most of the oil in the field was recovered during the first 5 years of CO_2 injection indicating that a large percentage of the oil will be recovered during the first few years of CO_2 flooding.
IV. The recovery with continuous CO_2 injection was approximately 32% after the 15 years using the synthetic model.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

REFERENCES

1. Picha MS. Enhanced oil recovery by hot CO_2 flooding. In SPE middle east oil and gas show and conference. Society of Petroleum Engineers; 2007.

2. Masoud M. Comparing carbon dioxide injection in enhanced oil recovery with other methods. Austin Chemical Engineering. 2015;2(2):11.
3. Adlam J. The Norne field development overview. In Offshore Technology Conference. Offshore Technology Conference; 1995.
4. Rwechungura RW, Suwartadi E, Dadashpour M, Kleppe J, Foss BA. The Norne field case-a unique comparative case study. In SPE Intelligent Energy Conference and Exhibition. Society of Petroleum Engineers; 2010.
5. Steffensen I, Karstad PI. Norne field development: Fast track from discovery to production in the Norne field. JPT. 1996; 48:296-299.
6. EIA. [Online]; 2012. Available:http://www.eia.gov/countries/cab.cfm?fips=NO [12 October 2013]
7. STATOIL; 2012. [Online] Available:http://www.statoil.com/en/ouroperations/explorationprod/ncs/norne/pages/default.aspx [10 October 2013]
8. Verlo SB, Hertland M. Development of a field case with real Production and 4D data from the Norne Field as a benchmark case for future reservoir simulation models testing: Master's Thesis, NTNU, Norway; 2008
9. Osdal B, Alsos T. Seismic modelling of eclipse simulations and comparison with real 4D data at the Norne field'. 64th Annual International Conference and Exhibition, EAGE, Extended Abstracts. 2002;A–29.
10. Rwechungura R, Suwartadi M, Dadashpour E, Kleppe J, Foss B. The norne field case-A unique comparative case study. 2010;SPE 127538.
11. Donaldson EC, Chilingarian GV, Yen TF. Enhanced oil recovery, 1, fundamentals and analyses. Developments in petroleum science 17A. 1st Edition; 1985.
12. Hales HB. Pressure decline analysis for prediction of gas reservoir volumes. SPE-9471-PA. 1981;33(11).
13. Alkasim F., Tevik S, Jacobsen K, Tang Y, Jalali Y. Remotely controlled in-situ gas lift on the norne subsea field. SPE Annual Technical Conference and Exhibition. 2002;SPE 77660:1-3
14. Atabay S, Ole MD, Jon MF, Anna RF. Developing a toolbox for evaluating of water injection performance on the norne field. SPE Europe/EAGE Annual Conference. 2012;SPE 154046-MS.
15. STATOIL. Annual Reservoir Development Plan Norne Field; 2006.
16. Awan AR, Teigland R, Kleppe J. A survey of North Sea enhanced-oil recovery projects initiated during the years 1975 to 2005. SPE Res. Eval. & Eng. SPE-99546-PA. 2008;11(3): 497-512.
17. Hategan F, Hawkes RV. The importance of initial reservoir pressure for tight gas completions and long-term production forecasting. Journal of Canadian Petroleum Technology; 2006.
18. Holt T, Jensen JI, Linderberg E. Underground storage of CO_2 in aquifers and oil reservoirs. Energy Conversion and Management. 1995;36:535-538.
19. Akervoll I, Bergmo EP. CO_2 EOR from representative North Sea Oil Reservoirs. SPE international conference on CO_2 Capture, storage and utilization held in New Orleans, Louisiana, USA; 2010.
20. Vuillaume J, Akervoll Bergmo P. CO_2 injection efficiency, synthesis of conceptual chalk model: Incremental oil recovery and CO_2 storage potential. 2011;SPE 143531.

Peer-review history:
The peer review history for this paper can be accessed here:
http://www.sdiarticle4.com/review-history/53683