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Estimating the Amount of CO_2 Required and the Subsequent Increase in Oil Production for CO_2 Flooding

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Abstract: ***This paper presents an application of CO2 Miscible flooding technique on an Oil field, and how the process is justified based on improved oil recovery and economic profitability. The project was carried out by the use of EORgui screening software to assess the suitability of the oil filed. The most important screening parameters used are cumulative production and minimum miscibility pressure. Water injection at a constant rate of 195 bbl/day into a 40-acre, 5-spot pattern results in an oil recovery of 1.125 Hydrocarbon pore volumes of oil (420667.56 Mbbl) Mbbls) corresponding to 16.67% incremental oil recovery over a 20-year period at a 443.5Mscf/d CO2 Injection rate. The potential demand of CO2 needed for this project was found to be 3199.85MMScf. The cumulative net operating income saw a tremendous increase over the project's lifespan resulting in positive cumulative cash flows before and after taxes depicting the economic feasibility of the project. A sensitivity analysis conducted shows that the efficiency of Miscible CO2-EOR varied under varying reservoir conditions hence may not be suitable for certain reservoir conditions. Cumulative oil production decreases with increasing Dysktra Parson's coefficient of heterogeneity and increasing oil viscosity. For reservoir pressures below the MMP (1200psia), immiscible flooding occurs and vice versa. For reservoir pressures well above the MMP it was found out that best production occurs for the highest reservoir pressure; 2000psi***.

Keywords: Enhanced Oil Recovery (EOR), Miscible CO_2 flooding, Minimum Miscibility Pressure (MMP), EOR Screening

1. Introduction

The introduction of new technology aimed at improving oil recovery from wells to meet global energy needs and to meet the economic demands of the population has necessitated Enhanced Oil Recovery as a means to meet growing global crude oil demand. During the early stages of production, oil naturally flows to the surface due to existing reservoir pressure and the drive mechanisms at the primary phase. As reservoir pressure drops, water is injected to boost the pressure to displace oil in the secondary phase. Lastly oil is recovered in the tertiary phase by means of CO_2 injection, natural gas miscible injection, steam recovery or chemical flooding.

CO_2 EOR applications have proven very useful in the fight against global warming as it is a favorite technique for reducing CO_2 emissions into the atmosphere. The technique doesn't only lower costs for CO_2 sequestration by means of higher incremental oil recoveries but prevents additional cost of separating waste products from recovered hydrocarbons since it does not yield any.

2. Problem Statement

Natural reservoir drive mechanisms are responsible for the production of oil in the initial stages. As production time increases the pressure begins to drop and the production per day decreases. Secondary recovery techniques are applied to recover additional oil. Even after secondary recovery, significant oil droplets are trapped in the pores of the reservoir rock or as films around rock grains due to high capillary forces and interfacial tension between the oil and the rock. This phenomenon decreases production drastically, making the final production stage of the field less profitable. An efficient Enhanced Oil Recovery process aims at mobilizing these dispersed oil droplets to form an oil bank that can move towards the production wells.

2.1 Study Objectives

The objective of this work is to show how CO_2 injection can be used to increase oil recovery in a reservoir and also assess the economic viability of the processes. These objectives will be achieved by;

- Screening the reservoir to establish CO_2 EOR as the best recovery technique.
- Estimating the incremental oil recovery and the amount of CO_2 required
- Determining the economic viability of the process

3. Literature Review

3.1 Enhanced Oil Recovery with CO_2

Miscible CO2 flooding increases oil production in the final phase of a reservoir's life by maintaining favorable mobility characteristics for oil and CO2 towards improvement of volumetric sweep efficiency. Residual oil remains as isolated droplets trapped in the pores of the reservoir rock or as films around rock grains after secondary recovery. When CO2 is injected into the reservoir, the development of favorable complex phase changes increases oil fluidity by (i) breaking interfacial tension between oil and the reservoir rock; reducing the capillary forces and (ii) expanding the volume of the oil (oil swelling) and subsequently reducing its viscosity.

The role of CO2 in immiscible flooding is similar to that of water in secondary oil recovery processes, i.e. to raise and maintain reservoir pressure. (Tzimas E. et al., 2005, p.28) In immiscible CO2 flooding, the oil rather becomes saturated with CO2 forming an oil CO2 mixture with less viscosity in which lighter hydrocarbons are extracted into the CO2 phase, mobilizing a portion of the residual oil. In extra heavy oil reservoirs, CO2 and the oil form two distinct fluid phases, maintaining a separation interface all along the process. The oil recovery can reach 18% of OOIP. It is reported that the addition of CO2 in poor quality heavy oil may reduce its viscosity by a factor of 10 (ECL Technology, CO2 Injection for Heavy Oil Reservoirs, 2001).

3.2 Case Study

Ren et al., 2004 conducted a study for a North Sea Field (Fulmar) to demonstrate a CO_2 -EOR and storage scenario. Four cases of CO_2 injection were simulated with various combinations of pressure and injector locations at the top and bottom of the oil formation. The best scenario simulated is to inject CO_2 at the top of the reservoir and at a relatively low pressure near MMP, where gravity stabilization prevails for this relatively thick reservoir. The incremental oil recovery was 10.7% OOIP after 20-year gas injection, while 6.5% OOIP can be achieved after 10 years of injection. At the end of 20 years CO_2 injection, 55% of CO_2 injected was stored in the reservoir excluding gas reinjection. The produced gas with high CO_2 content needed to be recycled or reinjected into another reservoir.

3.3 The X Field

The X field comprises of a sandstone formation with reservoir depth of 5,000 ft. The X reservoir is filled by under saturated oil and solution gas with initial GOR of 600 scf/stb. The current reservoir pressure and temperature are 2000 psig and 105 °F respectively. The reservoir fluid can be categorized as light oil with the API gravity of 32^0. The X field have been producing for 4 years with waterflooding started in the second year of production. The cumulative production of oil is 53,612.38 MSTB or 39% recovery factor. Oil production rate of X field has been declining drastically in the 4^{th} year of production and hence the reason for an Enhanced Oil Recovery is been considered as an option for increasing oil recovery.

4. Methodology

4.1 The Screening Method

EORgui screening tool is used to assess both technical performance and economic feasibility of the oil field. EORgui tool quickly screens and ranks appropriate EOR methods for the oil field per the summary of its reservoir and fluid properties. It prepares the input files required for the technical analysis portions of the publically available Fortran applications. The Graphical User Interface (GUI) runs the Fortran applications and imports the results back into the application. The results of the run were exported into Microsoft Excel and also plotted in high output quality charts for interpretation.

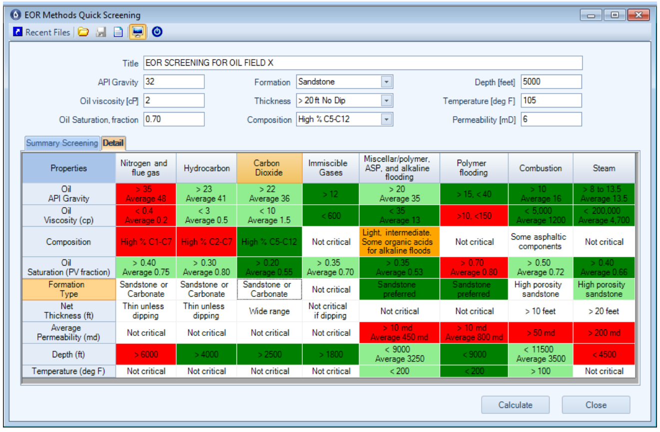

Figure 1.0: EOR screening criteria for X Field

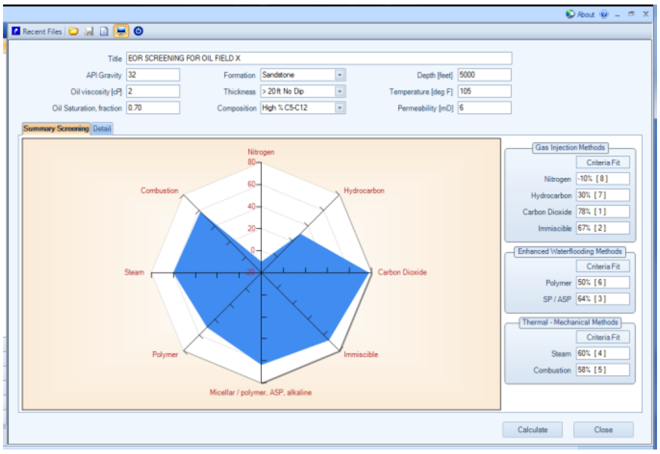

Figure 2.0: EOR screening results for oil filed X. CO_2 gas injection saw a criteria fit of 78% with relative ranking of 1 representing the most suitable EOR method

4.2 Simulation of the CO2 Miscible Flooding Prediction Model

The EORgui CO_2 predictive model is a three dimensional (layered, five spot) two phase (aqueous and oleic) three component (Oil, water and CO_2) model. After all the input data have been entered, the model was executed by selecting "Calculate" from the bottom menu. The software computes oil and CO_2 breakthrough and recovery from fractional theory modified for the effects of viscous fingering, areal sweep, vertical heterogeneity and gravity segregation. The software uses default parameters if an input is left blank. Some of the results from running the program include total CO_2 injected, total oil produced, CO_2 produced, and water produced. Oil produced is then used as a basis in production profile to justify economic feasibility.

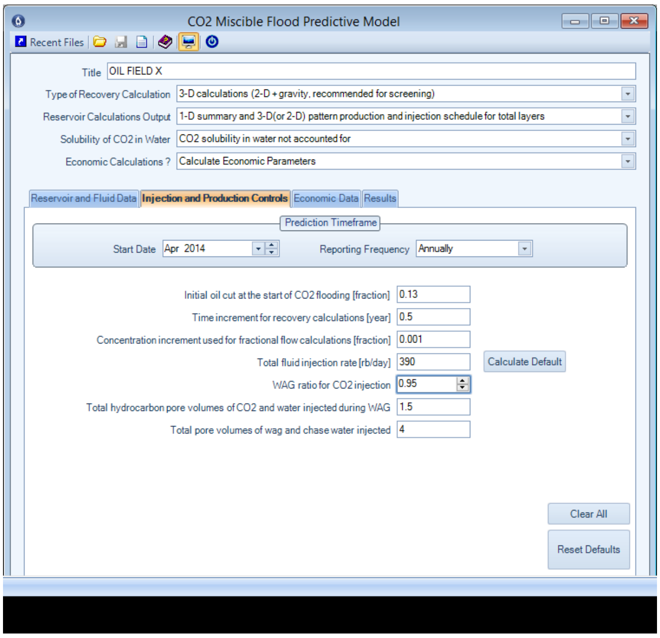

Figure 3.0: Miscible CO2 flood injection and production control parameters

4.3 Economic Analysis

The X-oilfield study case is subjected to analysis to determine the economic performance of the project. Methodology for economic assessment was carried out using mid-year discounting factors and cash flow modelling for 20 years. 10% discount rate was used. Some basic assumptions made to model the economic feasibility of CO2 flooding of the X field are as follows;

Input	Low	Most Likely	High
Oil Price Input, $/BBL	70	85	110
Gas Price Input$/MCF	3.3	4.17	5
CO_2 Price Input$/MCF	0.9	1.13	1.35
Annual Fixed Opex M$/Year	28	35	42
Variable Opex $/BBL	0.397	0.456	0.56
CO_2 Treating/Recycling cost $/MCF	0.232	0.29	0.346

5. Results and Discussions

In the 20 years' lifetime of the project, peak incremental oil production rate occurs in 2026 corresponding to 80,539 BPD and gradually decreases to 69730 BPD at the end of injection period as shown in figure 4.0. The cumulative amount of incremental oil recovery is found to be 420667.56 Mbbl representing 16.67 % oil recovery from original oil in place (OIIP). This requires a total of 3,199MMscf of CO2. Consequently, oil production saw a tremendous increase to a peak of 29,396Mbbl in 13 years and gradually declined to 25451.59 at the end of the 20 years as shown in figure 5.0. Not only oil was produced at producer well but also water and CO2 were produced. Figure 6.0 shows the production profiles of water, oil and CO2.

Figure 4.0: Incremental oil production rate over the 20 year Period

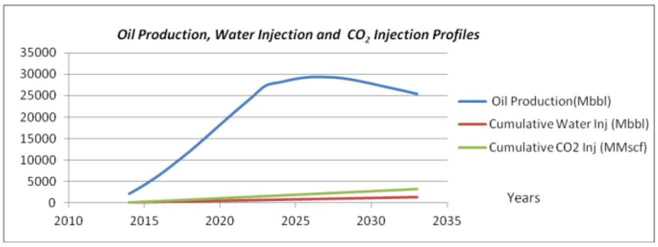

Figure 5.0: Incremental annual oil production profile over the 20-year period

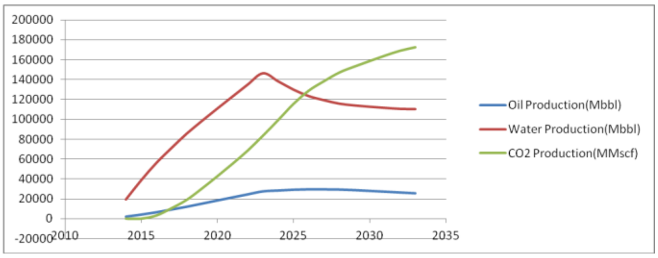

Figure 6.0: Oil, Water and CO2 production profiles

The economic model estimated the Total Project Expense (PV) required on taking on this project to be about 4384.2 MM$. Other prominent economic indicators are as follows;

Net Present Value: $311976.49

Total Loan Principal Repayment (PV): 0MM$

Based on economic indicators as described above, the X-field miscible CO2 flooding project is economically feasible. Figure 9.0 shows a tremendous increase in the cumulative net operating income generated in the life time of the project. Figure 8.0 shows a positive cash flow from the third year of the project which means capital returns has occurred.

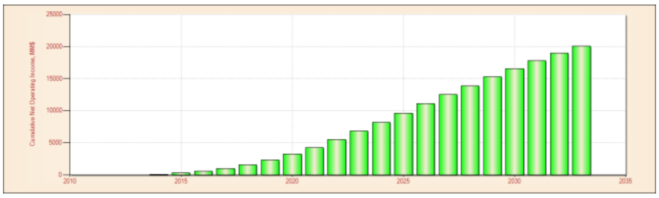

Figure 7.0: Shows a tremendous increase in the net operating income generated by the project

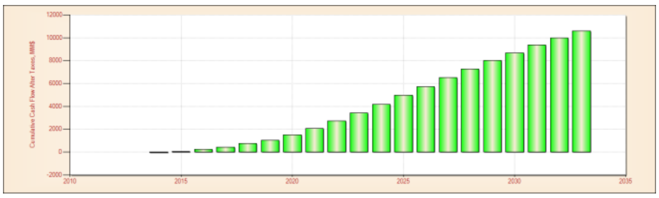

Figure 8.0: Showing a positive cumulative cash flow after taxes indicating capital returns

6. Sensitivity Analysis

The performance of the Miscible CO2 flood was analyzed under various reservoir conditions. The analysis was conducted under the following parameters; Dykstra Parson's Coefficient, Reservoir Pressure and Oil Viscosity.

6.1 Dykstra Parson's Coefficient

A sensitivity analysis was performed in order to show the effect of Dykstra Parson's coefficient of reservoir heterogeneity on cumulative oil production using profile results. The CO2 flood test was run with four different values for Dykstra Parson's coefficient (0.5, 0.6, 0.7 and 0.8), and cumulative production vs. time was plotted in Figure 9.0. Results show that oil production decreases with increasing Dykstra Parson's coefficient

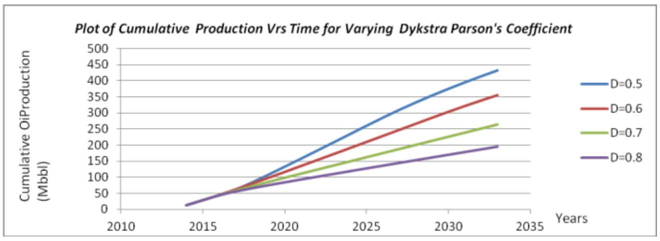

Figure 9.0: Sensitivity to Dykstra Parson's coefficient

6.2 Reservoir Pressure

A sensitivity analysis was performed to analyze the effects of reservoir pressure on oil produced under the 40-acre, 5-spot pattern case. The model was run using average reservoir pressures of 500, 1000, 1500, 2000 psi. Immiscible floods occur at 500 and 1000 since they are less than the MMP, while the remaining two runs are miscible. The plot of cumulative production vs. time in figure 10.0 shows that the highest production occurs at an average reservoir pressure of 2000 psi.

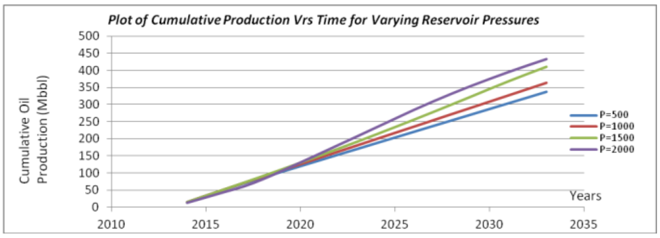

Figure 10.0: Sensitivity to Reservoir Pressure

6.3 Oil Viscosity

A sensitivity analysis on the effects of oil viscosity on oil production was performed using the CO_2 flood test. The model was run with values of 2, 1, 10 and 50cp. Figure 11.0 shows that, increasing viscosity results in low oil production

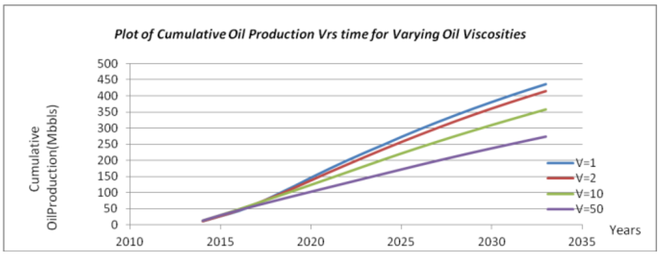

Figure 11.0: Sensitivity to oil viscosity

7. Conclusion

Oil recovery was efficiently improved using miscible CO_2 flooding resulting in a recovery factor of 16.67%. The incremental oil recovery amounts to 420667.56 Mbbl of oil which requires a total of 3,199MMScf of CO_2. The incremental oil recovery resulted in a subsequent increase in the cumulative cash flow of the project justifying its economic feasibility. From the derived results from this study, it can be concluded that the miscible CO_2 flooding project is a very good and economically viable one for that matter. The sensitivity analysis was carried out to determine critical parameters on which oil production would be dependent. Results of the sensitivity analysis predicts that a steady decline in production beyond the 20-year period could result and be attributed to increasing heterogeneity or increasing oil viscosity since the reservoir could undergo significant formation changes over the years. This in a way predicts what profit margin and earnings to be expected as the project progresses.

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