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Improving the Recovery of Hydrocarbons in a Well in the Gullfaks Field by Injecting Sequestrated CO_2

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Abstract

The Gullfaks field was discovered in 1978 in the Tampen area of the North Sea and it is one of the largest Norwegian oil fields located in Block 34/10 along the western flank of the Viking Graben in the northern North Sea. The Gullfaks field came on stream in 1986 and reached a peak of production in 2001. After some years, a decrease in production was noticed due to the decrease in pressure in the well. The goal of this paper is to improve the production of a well located in Gullfaks field by injecting CO_2 through coiled tubing. The use of the CO_2 injection method is due to the fact that it is a greenhouse gas, and its production in the atmosphere contributes to global warming. It is important to reduce its emission into the atmosphere and to boost the production of oil in the well. The CO_2 is injected through the coil tubing to lighten the hydrostatic column and allow the fluid to move from the tubing to the surface. The completion and PVT data are processed in Pipesim and Prosper softwares. By integrating a number of calculations by using the nodal analysis methods and gas injection methods, the results obtained show that the well is not producing and by injecting sequestrated CO_2 at the flow rate of 1.482 MMScft/d with an injection pressure of 2500 psig, the oil flow rate provided by the coiled tubing gas injection is 900 Stb/d. The profitability of the project is achieved over a period of 20 years with a net present value (NPV) of $11948858.5 and a return on investment after 5 years 2 weeks.

Keywords: Gullfaks field, coiled tubing, injecting sequestrated CO_2, Pipsim software, Prosper software, economic analysis.

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1- Introduction

The Gullfaks field is one of Norway's largest oil fields located in block 34/10 along the western flank of the Viking Graben in the northern North Sea [1-3]. It is a structural complex with reservoirs in several strata, fragmented by numerous faults [4-6]. It was discovered in 1978 in the Tampen region of the North Sea; it was put into production in 1986 and reached peak production in 2001 [7-9]. However, the improvement of the production forecasts of an oil field constitutes one of the concerns of the production engineer within the oil companies. It is also one of the lines of action envisaged by oil companies [10-12]. As soon as the Gullfaks field began production in 1986, a drop in production was noticed due to the depletion of the reservoir. After primary and secondary recovery carried out, it was observed that the reservoir still contained a considerable amount of hydrocarbons that could be exploited [5-7]. This made it possible to use assisted recovery techniques.

Among assisted recovery techniques: Heat injection accounts for 39%, gas injection accounts for (60%), and chemical injection accounts for (1%) [14-16]. Although these techniques make it possible to recover hydrocarbons efficiently and profitably, they are very expensive and the scarcity of products to be injected into the wells must be taken into account. Some work in the literature has used a new approach based on enhanced hydrocarbon recovery by injection of sequestrated CO2 to boost production while reducing CO_2 emission into the atmosphere [17-24]. The recovery of hydrocarbons from CO_2 sequestration is a modern technique still very little used in the oil industry. This technique of enhanced hydrocarbon recovery is in the news since it demonstrates that it is possible to capture a good part of the CO_2 generated by oil exploitation and reinjection it into the well in order to reduce the carbon footprint carbon from these operations. In November 2022 during the COP (Conference of the Parties) 27 in Sharm El Scheik in Egypt, there was a lot of talk about climate change and the harmful effect of the exploitation of fossil fuels on the climate. This study proposes to

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improve the recovery of hydrocarbons in a well of the Gullfacks field using the injection of CO_2 sequestrated in the atmosphere. To achieve this, several objectives have been set: Perform a nodal analysis to predict the performance of the well, justify the choice of the method, design gas injection by coil tubing in order to see the maximum depth of CO_2 injection and the flow injected and to make an economic analysis to predict the performance of the project. This paper consists of three sections. The first section covers the introduction. The second section describes the data, tools, methods used and results obtained. The third section is the conclusion.

2- Materials, Methods and Results

Completion data appears in Table 1.

Table 1. Completion Data

	Measure depth	OD (in)	ID (in)	Grade
Conductor	500ft	30	28	B
Surface	4000ft	22	20	X52
Intermediate	8000ft	13.625	12.375	L80
Production	9000ft	7	6.094	C95
Tubing	8000ft	4.5	3.5	D95

The PVT data in Table 2 are used for the nodal analysis which makes it possible to determine the differentiability of the reservoir, to materialize the flow model of the reservoir and the head losses in the well.

Table 2. PVT Data

Settings	Values
Reservoir pressure	2500psi
Reservoir temperature	150°F
Water-cut	50%
Reservoir permeability	80 mD
Drainage radius	800ft
Skin	2
Reservoir height	300ft
Volume factor	1.3
Oil viscosity	1.2 cp
Total compressibility	0.00009 psi^{-1}
Production decline rate	0.08 yr^{-1}
Oil density	35° API
Gas oil ratio	500 Scft/STB
Gas density	0.65

The nodal analysis method, the coiled tubing gas injection method, the economic analysis method, Pipesim software and Prosper software are used to obtain the results in this paper from the data in Table 1 and Table 2.

The design of the well in the initial state is presented in Fig. 1.

Fig. 1 indicates that the hole layer connection is at 8500 ft which allows communication between the reservoir and the bottom of the well. The nodal analysis of the well in the initial state is shown in Fig. 2.

Fig. 2 reveals that the IPR (Inflow performance relationship) in red and the VLP (Vertical flow performance) in blue do not intersect, which means that the well is not producing and not eruptive. To make the well eruptive, the gas injection method by coiled tubing is used because there is the presence of coiled tubing and separation gas in the site. This method is flexible at low maintenance cost and is used to produce acceptable oil flow usable for deep wells at high temperature with a vertical or horizontal profile. Fig. 3 presents the design of CO_2 injection by coiled tubing.

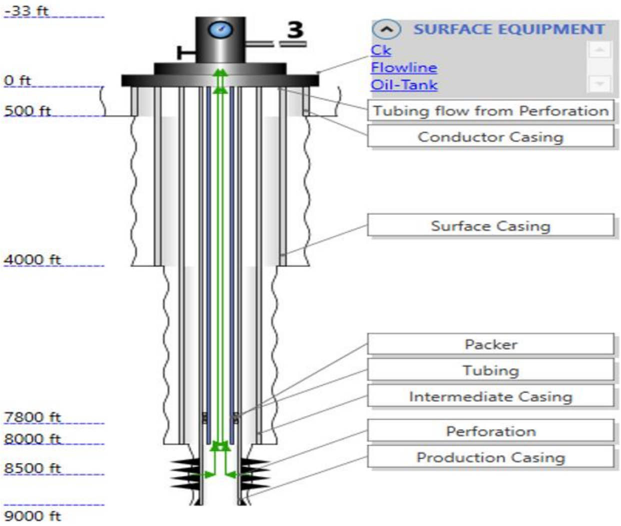

Fig. 1. Design of the Well in the Initial State

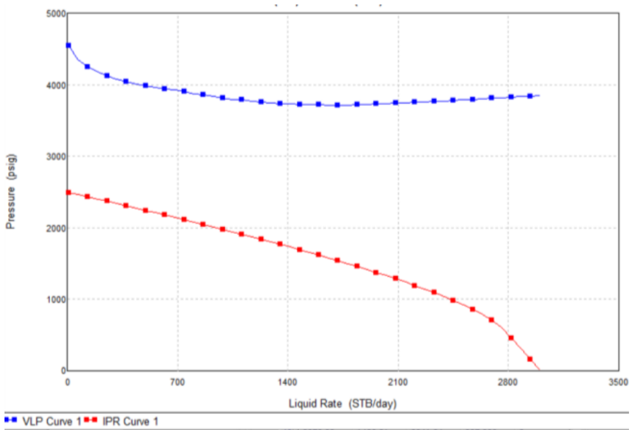

Fig. 2. Initial State Well Performance Curve

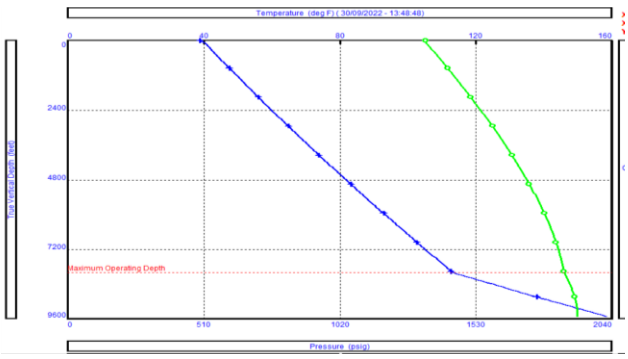

Fig. 3. Pressure and Temperature Gradient Curve

Fig. 3 shows the maximum depth of gas injection which is 7999.9 ft at this level we observe a drop in pressure at the bottom of the well due to the gas which lightens the hydrostatic column of Table 3.

The oil flow and the water flow rate are the same in Table 3 because the water cut is 50%. After injecting CO_2

into the well, it is necessary to do a second nodal analysis to see the new performance of the well as shown in Fig. 4.

Table 3. Results of the CO_2 Injection Design by Coiled Tubing

Parameters	Values
Liquid flowrate	916.9 STB/d
Gas flowrate at CO_2 injection	1.482 MMscft/d
CO_2 injection pressure	2500 psig
Oil flowrate	458.45 STB/d
Water flowrate	458.45 STB/d

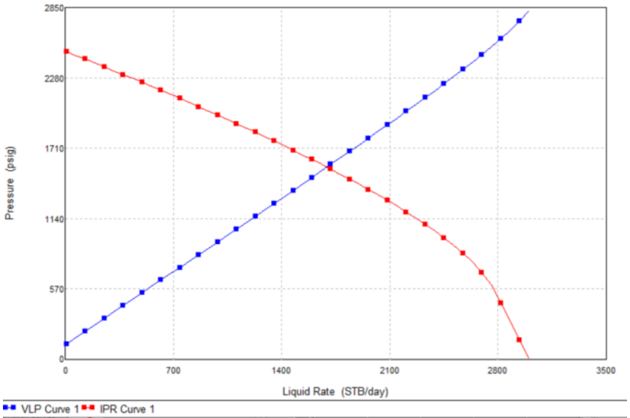

Fig. 4. Well Performance Curve after CO_2 Injection

According to Fig. 4, the curves of IPR and VLP meet which shows that the well-produced thanks to the injection of CO_2 which decreased bottom pressure to below reservoir pressure (as shown Table 4). This meeting point is called the operating point, which is the net flow produced by the well.

Table 4. Results of the Nodal Analysis of the Well after CO_2 Injection

Parameters	Values
Liquid flowrate	1800 stb/d
Oil flowrate	900 stb/d
Water flowrate	900 stb/d
Reservoir pressure	2500 psi

The oil flow and the water flow rate are the same in Table 4 because the water cut is 50%. The operator's objective is to produce at a rate greater than or equal to 200 stb/d because below this rate, the well is no longer economically profitable. The exponential model predicted the decline in production over time as shown in Fig. 5.

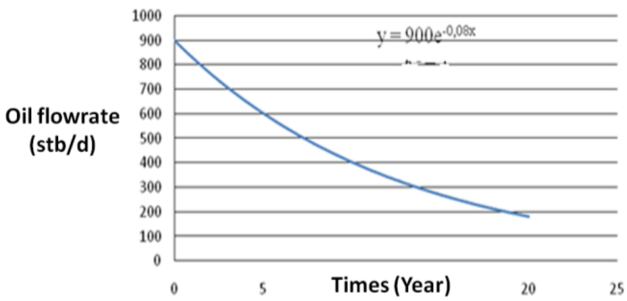

Fig. 5. Production Decline Curve

From Fig. 5, the flowrate produced at year 19 is less than 200 stb/d. So, the economic balance sheet is made in 20 years. Expenses consist mainly of capex and opex according to Table 5.

Table 5. Capex and Opex Expenditure

Parameters	Values
Purchase of the compressor	$15000
Purchase of coiled tubing	$80,000
Water treatment cost	$20000
Cost to produce a barrel of oil	$17050242.9
Total tax	83812045.1$
Total energy cost	$182,500
Maintenance cost	25000$

In Table 5, the purchase of the compressor and the coiled tubing are approximate values. The cost of water treatment is estimated based on the price of water treatment used by oil company Perenco. We used the number of barrels produced per day, multiplied by 15$ which is the price we spend to produce a barrel of oil and multiplied by 365 days to have the cost we spend to produce a barrel of oil/year. The cost of energy/day is estimated at 20 to 35$/day so to have the total cost in energy we made 20$ *365*20 since we produce in 20 years. The maintenance costs are estimated based on the maintenance costs of oil companies as Haliburton and Schlumberger. We first calculate the cash flow=cross revenue – expense and then the net cash flow = cash flow – tax. Expenses during the 20 years of production are estimated to be worth $17,300,742.9. Revenues are essentially based on hydrocarbon sales, with a barrel price estimated at $87. During this 20-year period, revenues are estimated at $296,674,226. The NPV is estimated to be $11948858.4. The project is profitable because NPV is positive. The return on investment is 5 years 2 weeks.

3- Conclusion

This paper focuses on improving the recovery of hydrocarbons in a well in the Gullfaks field by injecting CO_2 sequestrated by the coiled tubing. The nodal analysis of the well at the initial state showed that the well is non-eruptive. After injecting CO_2 into the well at a rate of 1.482 MMscft/d with a pressure of 2500 Psi, the oil flowrate obtained is 900 stb/d. The economic analysis gives a gross profit of $11948858.4 after 5 years and two weeks. However, as one produces the viscosity of the fluid increases in the reservoir and the capillary force increases. which can be due to the fact that, the wettability tends to load pushing the oil to become residual. In this case the oil no longer comes near the well while this method of injection into the well becomes inappropriate so the solution is to inject carbon dioxide rather in the oil zone to reduce the viscosity of the oil and allow it to be swept. In order to make carbon dioxide injection recovery even more efficient and profitable, the following recommendations will be perfect: Use nitrogen in case of corrosion caused by CO_2, reduce the carbon footprint of the industry by storing more CO_2, redo the sensitivity analysis if there is a change in a parameter and have a stable energy source.

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