Enhanced oil recovery using CO_2 injection and inflow control devices

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Abstract
CO_2 capture is an important aid to achieve the goals of reduced emissions. Today the market for captured CO_2 is limited. Injection of CO_2 in oil reservoirs is one way of utilizing the captured CO_2 and provide permanent storage of the CO_2. By injecting CO_2, the mobility of oil is increased, and the amount of residual oil is reduced. This is called enhanced oil recovery. The goal of this study is to show the effects of CO_2 injection combined with autonomous inflow control valves on oil production. Simulations are carried out using the software OLGA in combination with ROCX. The input data to the simulations are based on information obtained from a literature study. To show the effect of the autonomous inflow control valves and CO_2 injection, the simulations were compared with simulations performed without autonomous inflow control valves and CO_2 injection. The results from the simulations show that CO_2 injection contributes to increase the mobility of both oil and water which leads to an increase in both oil and water/CO_2 production. Autonomous inflow control valves reduce the amount of water produced by choking the production in areas with water breakthrough. The combination of CO_2 injection and autonomous inflow control valves results in a higher oil-water ratio and a considerably lower water production.

1. Introduction

Due to global warming, countries around the world have signed a climate agreement which obliges the countries to reduce the emission of climate gases, among them CO_2. CO_2 can be captured from power plants, and the captured CO_2 can further be injected into oil reservoirs or aquifers to reduce the CO_2 emission to the atmosphere. Injection of CO_2 into oil reservoirs increases the oil recovery and at the same time, the CO_2 can be permanently stored. CO_2 capture in combination with CO_2 enhanced oil recovery (CO_2-EOR) and CO_2 storage is called Carbon Capture, Utilization and Storage (CCUS), and is a promising way to reduce the CO_2 emission to the atmosphere. CO_2-EOR is used in US and Canada, but mainly by using CO_2 from natural deposits. So far, CO_2-EOR is not utilized on the Norwegian shelf. However, a mapping including 46 oil fields has been carried out on the Norwegian shelf, and it is indicated that the potential for increased oil recovery using EOR methods, including CO_2-EOR, is 700 MSm^3 [1]. The Norwegian Petroleum Directorate has also mapped the potential of CO_2 storage on the Norwegian shelf and has concluded that the storage potential is more than 80 billion tonnes of CO_2 [2]. This corresponds to today's Norwegian CO_2 emissions for 1600 years.

When CO_2 is injected into a reservoir, the CO_2 is physically mixed with the oil and the properties of oil are changed. CO_2 reduces the oil viscosity and in addition it has a swelling effect which increases the oil volume in the reservoir pores [3, 4, 5]. The effect of CO_2 injection is most significant for heavy oils. The solubility of CO_2 in oil increases with decreasing temperatures, and the effect of CO_2 injection is therefore highest in reservoirs with moderate temperatures. Injection of CO_2 can contribute to decrease the oil viscosity up to 25% [6]. A combination of the effect of reduced oil viscosity and the swelling contributes to increase the mobility of oil in the reservoir, and thereby decrease the residual oil significantly [7]. Laboratory tests with CO_2 injection in core samples from the Oseberg field, have shown that the residual oil saturation can be reduced to 0.1 [8]. Fig. 1 gives a schematic of the transition zone of CO_2 between the injection and the production well. Supercritical CO_2 is injected into the oil reservoir at high pressure. Hydrocarbons from the reservoir oil vaporize into the CO_2 and a part of the injected CO_2 dissolves into the oil. The two phases become completely miscible without any interface effects and contribute to develop a transition zone that is miscible with oil in the front and with CO_2 in the back [9].

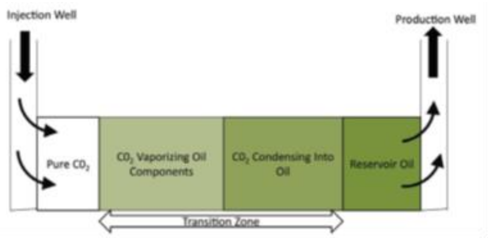

Figure 1: The schematic of the CO_2 transition zone between the injection and production well [9].

One of the main problems related to CO_2-EOR is a direct breakthrough of CO_2 or CO_2 solved in water into the production well. The breakthrough can be due to fractures and zones with high permeability in the reservoir, or due to frictional pressure drop in long horizontal wells. Fig. 2 shows a scenario where CO_2 is injected into a reservoir and flows together with water directly to the production well without being distributed in the reservoir and mixed with the oil. To avoid this type of breakthrough, different types of inflow control devices can be installed in the production well. Inflow control devices have the option to equalize the production rates along a horizontal well as shown in Fig. 3. This will solve or reduce the early breakthrough problem of CO_2 into the production well, and thereby make the CO_2-EOR process more energy effective.

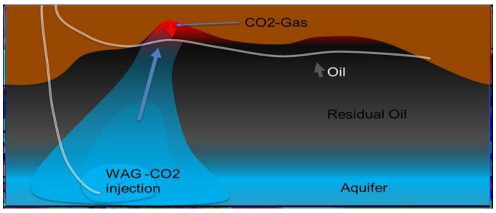

Figure 2: Short circuiting of CO_2 between the injector and the production well.

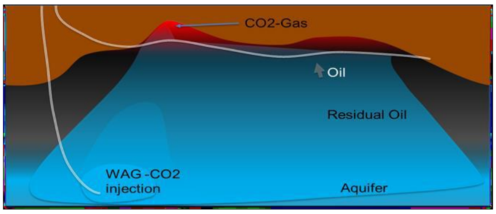

Figure 3: Improved distribution of CO_2 in the reservoir by using inflow control devices.

Different types of inflow control devices are developed to delay or avoid early breakthrough of unwanted fluids like water and gas/CO_2 into the production wells. The inflow control devices can be divided into two main categories, passive inflow control devices (ICDs) and autonomous inflow control devices (AICD). In this study, an orifice ICD and an autonomous inflow control valve (AICV) are used to delay or avoid direct breakthrough of CO_2 and water to the production well. The description and functionality of ICD and AICV are presented in the literature [10, 11, 12, 13]. ICDs are commonly used in oil fields all over the world to delay water and gas breakthrough. AICVs have so far mainly been installed in Canada, USA, and the Middle East, and have also been tested in a CO_2 EOR well in Canada [14, 15]. There is a lack of production data available regarding CO_2-EOR and inflow control devices. Aakre *et al.* [15] simulated the effect of AICV in a vertical CO_2-EOR well in Canada and compared the results with real well data. Hansen and Moldestad [16] simulated oil production in a field with CO_2-EOR and horizontal wells completed with ICDs and AICVs. Water/CO_2 breakthrough usually occurs first in zones with high drawdown or with higher permeability than other zones along the production well. To avoid water/CO_2 to reach the other zones via annulus, zone isolation is used by installing packers between the different sections. Fig. 4 shows a schematic of the production line including packers, sand screen and ICDs/AICVs.

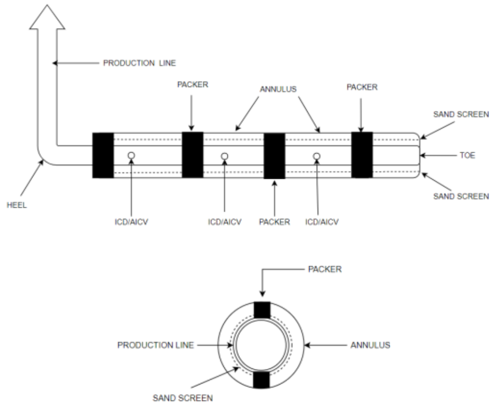

Figure 4: Production line with packers, sand screen and ICDs/AICVs.

2. Methodology

2.1. Simulation tools

The simulations have been performed using the simulation tool OLGA in combination with ROCX. OLGA is a software developed to simulate multiphase fluid flow in networks of wells, flowlines, pipelines and process equipment. ROCX is a near-well reservoir simulator and can be combined with OLGA. Due to the coupling between OLGA and ROCX the dynamic interactions between the wellbore and the reservoir are considered [17]. Fig. 5 shows an overview of inputs needed for the simulations of oil, gas, and water production from a reservoir.

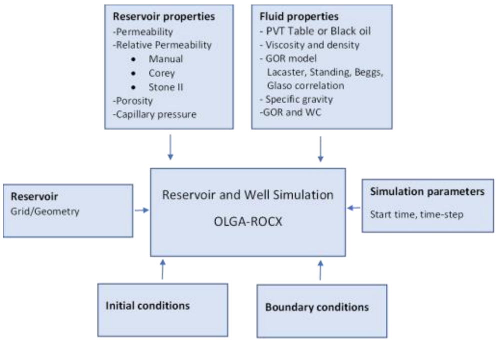

Figure 5: Overview of input to combined OLGA and ROCX simulations.

2.1.1. ROCX

ROCX calculates the fluid flow in a porous medium based on the conservation equations for water, oil and gas. Reservoir properties such as porosity, fluid saturation, permeability, relative permeability, capillary pressure, temperature, and pressure are implemented in ROCX. The required fluid properties are viscosity, density, bubble point and gas/oil ratio. Initial and boundary conditions are set for the reservoir and the sources coupled to OLGA. ROCX receives information from OLGA regarding pressure and pressure drop in the well and through the inflow control devices. Based on the reservoir and fluid information and the information given in OLGA, the production rates into the wellbore are calculated for each phase [17].

The simulations have been performed in two different types of reservoirs: a homogeneous reservoir and a heterogeneous reservoir. The size of the reservoir is 1000 m in x-direction (length), 100 m in y-direction (width) and 20 m in z-direction (height). The reservoir is divided into 2100 cells, 10 in the x-direction, 21 in the y-direction and 10 in the z-direction. The size of the cells is constant in the x- and z-direction, 100 m and 2 m respectively. In the y-direction the cell sizes are reduced from 10 to 1 m towards the well. The horizontal well is located along the x-axis 2 m from the top of the reservoir and in the middle (cell 11) in the y-direction. The porosity of the reservoirs was set to a constant value of 0.3. The viscosity of oil was 2 cP for the case without CO_2 injection and was reduced to 1.5 in the cases with CO_2 injection to simulate the effect of CO_2 on viscosity. The reservoir pressure and temperature were 130 bar and 100°C for all the simulations. Simulations were carried out in a homogeneous and a heterogeneous reservoir. The permeability in the homogeneous reservoir was 1000 mD in the x-and y-direction and 100 mD in the z-direction. In the heterogeneous reservoir, a zone with permeability 10000 mD in x- and y-direction and 1000 mD in z-direction was defined in the heel section of the reservoir. Fig. 6 shows the permeability distribution in the heterogeneous reservoir.

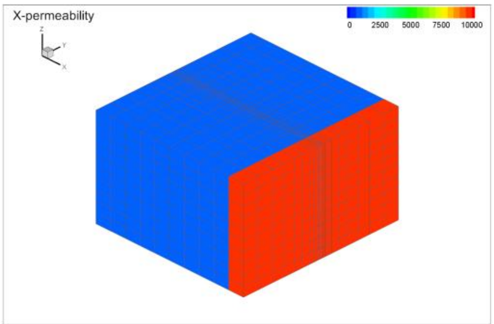

Figure 6: Permeability zones in heterogeneous reservoir.

Tab. 1 shows the input data to ROCX for the basecase and the case with CO_2 injection.

Table 1: Input data to Rocx.

Input data	**Basecase**	**CO_2-EOR**
Reservoir pressure	130 bar	130 bar
Reservoir temperature	100°C	100°C
Pressure, heel (boundary)	120 bar	120 bar
Porosity	0.3	0.3
Oil viscosity	2 cP	1.5 cP

The relative permeability curves for the basecase and the case with CO_2-EOR are presented in Fig. 7. The input data for calculation of the relative permeability curves are presented in Tab. 2. The relative permeability curves are calculated based on the Corey equation for the water and the Stone II correlation for the oil. The relative permeability curves when CO_2 is injected in the reservoir are modified based on information presented in the introduction.

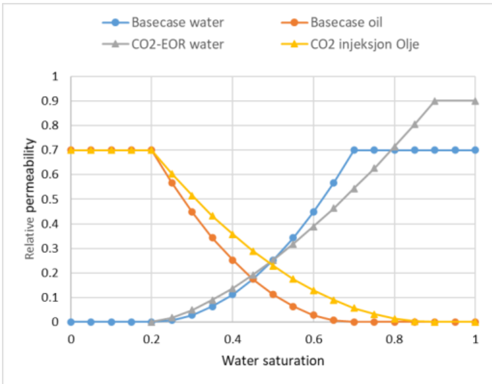

Figure 7: Relative permeability curves for basecase and CO_2-EOR case.

Table 2: Input data for relative permeability curves.

Input data	**Basecase**	**CO_2-EOR**
S_{wc}	0.2	0.2
S_{or}	0.3	0.1
K_{rwoc}	0.7	0.9
K_{rowc}	0.7	0.7
n_w	2	1.5
n_{ow}	2	2

S_{wc} is the irreducible water saturation, S_{or} is the residual oil saturation, K_{rwoc} is the end point relative permeability for water at maximum water saturation, K_{rowc} is the endpoint relative permeability for oil in water at irreducible water saturation, n_w is the Correy exponent, and n_{ow} is a fitting parameter for oil [18].

2.1.2. OLGA

OLGA is a transient dynamic multi-phase simulator used to predict flow in pipelines and connected equipment. The OLGA simulator is governed by conservation of mass, momentum, and energy [19, 20].

The simulations are carried out using ICD and AICV completion. Fig. 8 shows one section of the well set-up with ICD completion. To be able to include the effect of zone isolation, the set-up includes two pipelines. The upper one is the production pipe, and the lower one is illustrating the annulus and the transition of fluids from the annulus via the ICD to the production pipe. The source represents the fluid flow from the reservoir, and the leak represents the fluid flow to the well. The packer is represented by a closed valve. The total set-up includes 10 sections all including Packer, Source, ICD and Leak. Packers are used to isolate the production zones from each other, and thereby avoid fluids to flow from one zone to another through annulus.

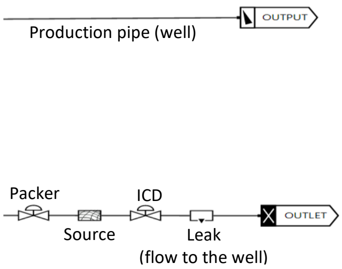

Figure 8: Set up for ICD in OLGA.

Fig. 9 shows two sections of the OLGA-setup for a well with AICV completion. The installations Source, Packer and Leak are defined in the same way as for the ICD case. The AICV is presented by a control valve with transmitter and PID controller. Tab. 3 shows the input data to OLGA. The PID controller starts to close the valve when the water cut (WC) is 75%. The AICV closes gradually from 100% to 1% opening.

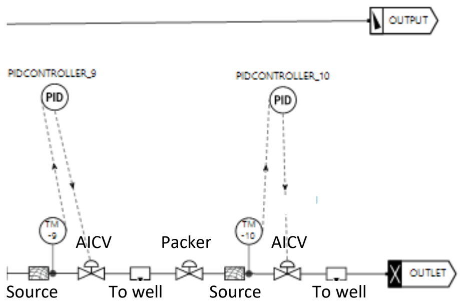

Figure 9: Set-up for AICV in OLGA.

Table 3: Input data to OLGA.

Parameters	
ICD/AICV diameter	0.02 m
Leak diameter	0.035 m
Annulus diameter	0.15 m
Set point AICV (WC)	0.75
Discharge coefficient ICD/AICV	0.84
Length production well	992 m
AICV opening (closed position)	1%
Number of ICDs/AICVs	10

3. Results

Simulations are performed for a homogeneous reservoir with and without CO_2 EOR. In addition, simulations of a heterogeneous reservoir with CO_2 EOR are carried out. These simulations are performed using wells with ICD and AICV completion. The CO_2 is assumed solved in water, and when water is mentioned it also includes CO_2.

3.1. Homogeneous reservoir

Two cases were simulated for the homogeneous reservoir, one basecase and one case with CO_2 EOR. In both cases, the production well is completed with ICDs. Fig. 10 shows the water cut versus time for the two cases.

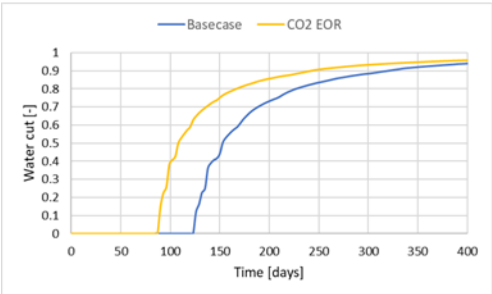

Figure 10: Water cut versus time for Base-case and CO_2-EOR case

The water breakthrough occurs after 90 days for the CO_2-EOR case and after 126 days for the basecase. The associated oil production versus time is presented in Fig. 11.

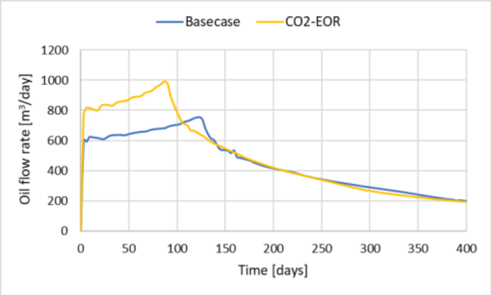

Figure 11: Comparison of oil flow rates for basecase and CO_2-EOR case

Initially, the oil production is significantly higher when using CO_2-EOR compared to the basecase. However, after water breakthrough, the oil production decreases, and after about 111 days the oil production for the CO_2-EOR case is lower than the oil production rate in the basecase. After 150 days, the oil production is about equal for the two cases. As can be seen from Fig. 10, the water cut increases when CO_2 is injected into the reservoir. Tab. 4 gives an overview of the production data for the basecase and the CO_2-EOR case.

Table 4: Production data

	Basecase	CO_2-EOR
Accumulated oil	190000 m^3	210000 m^3
Accumulated water	430000 m^3	702000 m^3
Water breakthrough	126 days	90 days
WC (400 days)	94%	96%
ΔP toe-heel (400 days)	4 bar	4.6 bar

The accumulated oil production increased by 10% and the water production increased by 63% when CO_2 was injected into the reservoir. The increase in oil production is because CO_2 reduces the oil viscosity, and the oil becomes more mobile as shown in Fig. 11. When the oil mobility increases, the water will follow the oil and move faster. The viscosity of water is lower than the oil viscosity and therefore the water production exceeds the oil production after water/CO_2 breakthrough. In addition, the changes in the relative permeability curves influence significantly on the mobility of the fluids. This is observed by the earlier water breakthrough for the CO_2 case. Due to frictional pressure loss in the production pipe, the pressure in the toe section is higher than in the heel section, and therefore, the first water breakthrough occurs in the heel of the production pipe. When the results from the basecase and CO_2-EOR case are compared, it is shown that the pressure difference (toe-heel) after 400 days of production is 0.6 bar higher when CO_2-injection is used. This is due to the higher total flow rate, which creates higher friction in the production pipe.

3.2. Heterogeneous reservoir

Two different cases were simulated for the heterogeneous reservoir, one case with CO_2-EOR and ICD completion, and one case with CO_2-EOR and AICV completion. The heterogeneous reservoir has a high-permeability zone in the heel section. These simulation cases were performed to determine whether AICVs can reduce the water production compared to the ICDs.

3.2.1. Well with ICD completion

Fig. 12 shows the volume of accumulated oil and water versus time. The water breakthrough occurs after 12 days, and the first breakthrough is located in the heel section. Fig. 13 shows the water cut versus time for the heel, middle and toe sections of the well. After about 100 days, water breakthrough is observed in all the zones and the water production increases rapidly compared to the oil. After 400 days, the accumulated oil production is 212000 m^3 and the overall water cut is 81%. The water cut in the heel section exceeds 90% after 150 days and is close to 100% at day 400.

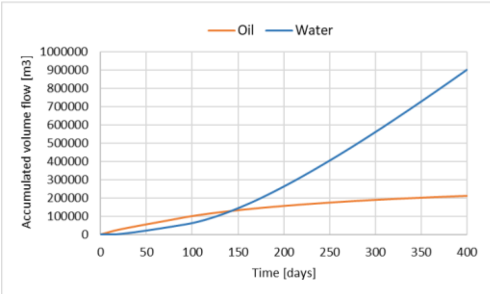

Figure 12: Accumulated oil and water for the ICD case.

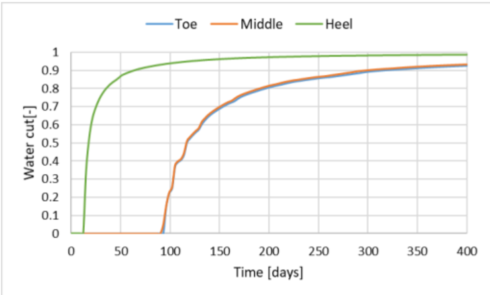

Figure 13: Water cut versus time for the ICD case.

Fig. 14 represents the oil and water flow rates as a function of time. After water breakthrough has occurred in all the zones, the total flow rate increases significantly. Fig. 15 shows the pressure along the well at different times. The pressure in the toe section (location 0) increases significantly with time due to increased total volume flow and thereby increased frictional pressure drop in the well.

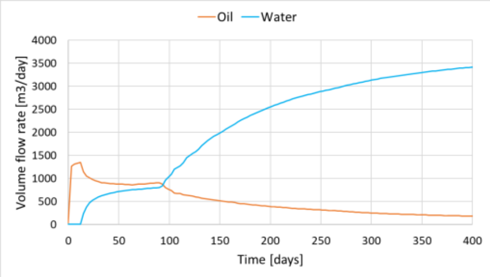

Figure 14: Volume flow rate for oil and water for the ICD case.

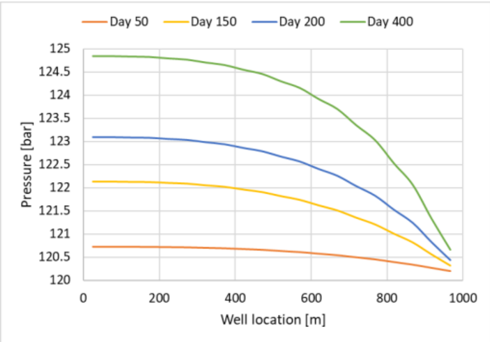

Figure 15: Pressure versus well position for the ICD case.

3.2.2. Well with AICV completion

Fig. 16 shows the accumulated oil and water production versus time for the AICV case. The water/CO_2 breakthrough is observed in the heel section after 12 days of production. This is the same as for the ICD case. After 400 days, the oil production is 164000 m^3 and the water production is about the same. The water cut curves for the toe, middle and heel sections are presented in Fig. 17. The AICVs start to close when the water cut reaches 75% in the current zone. After about 170 days, all the AICVs are partly closed, and the production capacity is reduced to about 1%. The flow rates versus time for oil and water/CO_2 are presented in Fig. 18. The flow rates for both oil and water/CO_2 vary with time due to the breakthrough of water/CO_2 in the different zones followed by the choking of the AICVs.

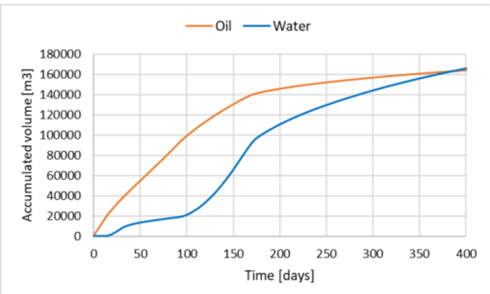

Figure 16: Accumulated oil and water for the AICV case.

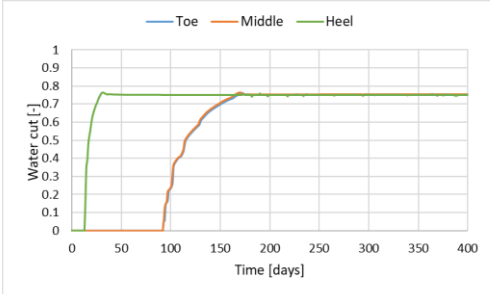

Figure 17: Water cut versus time for the AICV case.

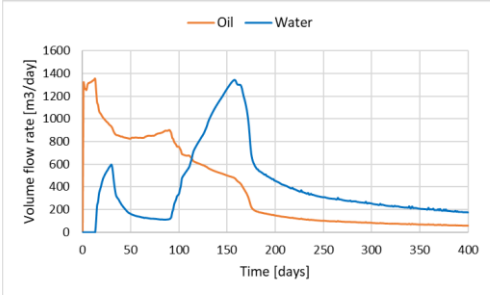

Figure 18: Volume flow rate for oil and water for the AICV case.

Fig. 19 presents the pressure profile in the AICV completed well at different times. The well pressure in the heel is set constant to 120 bar, and the decreasing pressure from the toe to the heel is due to the frictional pressure drop in the production pipe. The pressure in the toe section decreases from 122 bar at day 150 to close to 120 bar at day 400. The reduction in the pressure is due to the decreasing production rates after the choking of the AICVs. The low pressure drop at day 50 is due to the water/CO_2 breakthrough in the high permeability zone and the following choking of this zone.

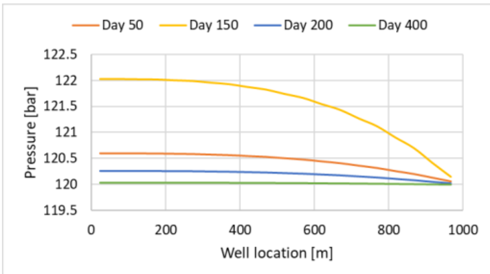

Figure 19: Pressure versus well position for the AICV case.

4. Summary and Discussions

Simulations were performed in a homogeneous reservoir to study the effect of CO_2 EOR on oil production. It was observed that CO_2 EOR increases the oil production rate until breakthrough of water/CO_2 occurs. The total oil production increased by 10% after 400 days of production, but since CO_2 influences the mobility of both oil and water, the water/CO_2 production increased by with 63%. The water cut at day 400 increased from 96% to 98% when CO_2 was injected. The average water cut based on 400 days of production is 69% and 77% for the basecase and the CO_2 EOR case, respectively. This indicates that CO_2-EOR has the potential to decrease the residual oil in the reservoir and increase the total oil production. However, a significant amount of water will be produced together with the oil. The oil and water/CO_2 production depends very much on the relative permeability. In this study, it was not possible to find exact information about relative permeability for the simulated type of reservoir. The next step was to study the effect of using AICVs compared to ICDs in a heterogeneous reservoir with CO_2 EOR. Fig. 20 shows the comparison between water production from a well with AICV completion and a well with ICD completion. The AICV well is reducing the water production by 82% compared to the ICD well.

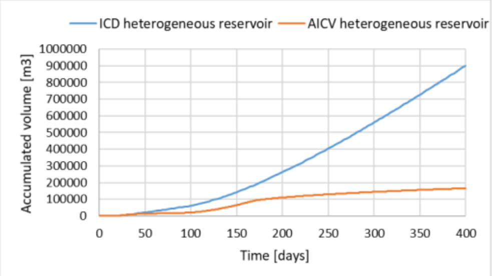

Figure 20: Comparison of accumulated water for AICV and ICD in the heterogeneous reservoir.

The simulated oil flow rates versus time for the two cases are presented in Fig. 21. The ICD well is producing more oil than the AICV well after breakthrough of water/CO_2 has occurred in all the zones. The reason why more oil is produced in the case of ICD is that no quantity restrictions have been set, which is unrealistic. In the case with ICD completion, the accumulated oil/water ratio is significantly lower than in the case with AICV completion. The normal scenario is to use a choke valve to control the total production rate and avoid overloading the top-side separation processes. A choking of the total flow will result in an even lower oil/water ratio for the ICD case because the main production will occur from the high permeability zone, and after breakthrough, the water/CO_2 production will increase significantly with time.

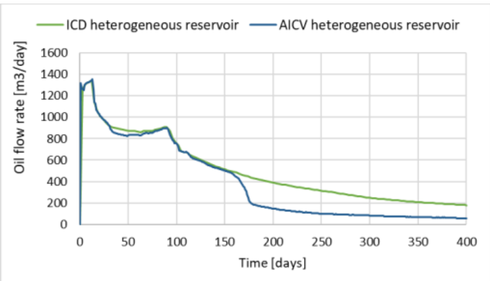

Figure 21: Comparison of oil flow rate for AICV and ICD in the heterogeneous reservoir.

Tab. 5 summarizes the production results from the heterogeneous reservoir.

Table 5: Production data for ICD and AICV completed wells in heterogeneous reservoir with CO2-EOR

	ICD	AICV
Accumulated oil	212000 m^3	164000 m^3
Accumulated water	902000 m^3	166000 m^3
Water breakthrough	15 days	15 days
Water cut (day 400)	98%	75%
Total oil/water ratio	0.230	0.988

Future simulations will be performed with choking of the total flow for both the ICD case and the AICV case to obtain more realistic and comparable results for the two cases. The set point for a choke valve will be chosen based on the capacity of the top-side process equipment.

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