Simulation of enhanced oil recovery with CO_2 injection

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Abstract

One of the goals of the Paris Agreement is to reduce the CO_2 emission to the atmosphere. This paper deals with CO_2-EOR, which is a good option for utilizing and storing CO_2. Four cases were simulated using the commercial software OLGA in combination with ROCX. To avoid the reproduction of CO_2 to the production well, two of the cases were run with autonomous inflow control valves and packers installed in the pipeline. These help to close off parts of the well when CO_2 and water breakthrough occur. The cases were run for 1500 days of production, and the accumulated oil production was in the range $1.1 \cdot 10^6$ to $1.3 \cdot 10^6$ m^3. The water production varied significantly for the different cases, and the water cut was reduced from 70% to 38% when inflow control valves were used. CO_2 injection increases the oil production but also the water production, and when combining CO_2-EOR and inflow control valves, the water cut was 56%. However, the accumulated oil production increased by 14% compared with a similar case without CO_2 injection. This underlines that CO_2-EOR is a good alternative for increasing the oil production, but it will also increase water production. Installation of autonomous inflow control valves in the production well are a good solution for reducing the water production and reproduction of CO_2.

Keywords: oil production, CO_2-EOR, OLGA/ROCX simulations, inflow control

1 Introduction

The oil production on the Norwegian Continental Shelf started in June 1971, and the oil laid the foundation for the economic growth in Norway. Some of the fields in the North Sea are now getting old, and new production technologies have to be considered to increase the oil recovery. Enhanced Oil Recovery (EOR) by injection of CO_2 is one of the tertiary oil recovery methods that can be used in mature fields.

The Paris Agreement was signed by 195 UNFCCC (United Nations Framework Convention on Climate Change) members by March 2019, and 185 states have committed to it. One of the three overall goals is to limit the global warming to less than 2˚C (Kallbekken and Jacobsen, 2018). In order to achieve the 2 degree target, 55 giga tonnes of CO_2 must be captured and stored by 2030 (United Nations Climate Change, 2015). Carbon capture and storage (CCS) is expensive due to energy intensive operation and high investment costs for the capture plants (Aabø, 2017). When using CO_2-EOR, the CO_2 will be utilized to get out more oil from the reservoirs and at the same time be stored. It will thus be profitable to capture and sell CO_2 to oil companies (International Energy Agency, 2019).

The objective of this study is a) to study how to increase the oil recovery from mature oil fields and b) to study how to avoid reproduction of high amounts CO_2 to the well. The paper deals with simulation of CO_2-EOR using the well simulation software OLGA in combination with the near well reservoir simulator ROCX. A homogeneous oil reservoir in the North Sea is simulated with and without injection of CO_2 to study the effect of CO_2-EOR on the oil recovery. To avoid reproduction of CO_2, the well is equipped with packers and autonomous inflow control valves (AICVs). The autonomous valves are capable of shutting off the parts of the well where breakthrough of CO_2 and water occurs.

2 Theory

Many of the oil reservoirs on the Norwegian Continental Shelf have a thin oil layer, and vertical wells will therefore have very little contact surface with the oil phase. If instead a horizontal well is drilled along the oil layer, this gives a much larger contact surface throughout the reservoir.

2.1 Horizontal wells and inflow control

The length of the horizontal wells are often in the range 1-3 km, and the pressure drop in the wells may be significant. Figure 1 shows a horizontal well indicating the inflow positions and the heel and toe locations. The reservoir pressure along the well is constant, whereas the pressure in the well decreases from the toe to the heel due to frictional pressure drop. This phenomenon is called the heel to toe effect, and results in increasing pressure difference between the reservoir and the production pipe from the toe towards the heel, and consequently the driving forces and the production rates are significantly higher in the heel compared to the toe (Birchenko et al., 2010).

To reduce the heel to toe effect and ensure production from all parts of the well, inflow control devices can be installed along the pipeline. In this study, autonomous inflow control valves (AICVs) are used. Figure 2 shows an AICV mounted in the base pipe with a sand screen. There are no restrictions on the number of zones in the production pipe. This means that the placement of AICVs can be done based on geological adaptations and

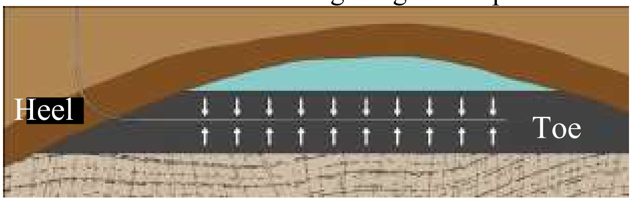

Figure 1. Horizontal well indicating the location of heel, toe and inflow zones.

the requirements of the field in question (Andersen, 2014). The valves are autonomous and do not require any external power or regulation connected to the surface. The valves can be installed in new and mature fields (Well Screen, 2017). The advantage of the AICVs is that they can autonomously close for low viscous fluids such as water and gas and stay open for high viscous fluids like oil. This means that when unwanted fluids reach the zones with high production rates, the AICVs make it possible to close off those zones. At the same time, the production will continue without any restrictions from the other zones. The principle of the AICVs is based on the difference in viscosity and density for different fluids (InflowControl, 2019; Aakre, 2017; Kais *et al.*, 2016). Figure 3 illustrates the AICV in open and closed position.

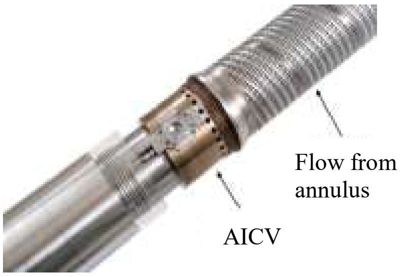

Figure 2: AICV mounted in the base pipe with sand screen.

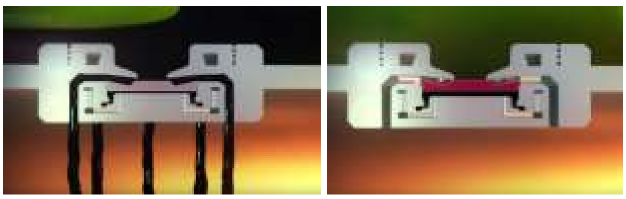

Figure 3. AICV in open (left) and closed (right) position (Aakre 2017).

2.2 CO_2-EOR

The AICV technology can be used for CO_2-EOR and storage. Previous studies have shown that AICV can be used to shut off carbonated water and supercritical CO_2. Installation of AICV for CO_2-EOR can have an efficiency of up to 99%. AICVs were tested for CO_2-EOR in a vertical pilot well in Canada in 2015. This was the first EOR installation that used autonomous inflow control in combination with CO_2 injection (Kais et al., 2016; Aakre *et al.*, 2018).

CO_2 injection has become more and more common in enhanced oil recovery, especially in North America where natural sources of CO_2 exist. Injected CO_2 will flow into the pores in the rock and expand, and thus more oil is forced to move out of the reservoir. CO_2 can also mix with the oil and reduce the oil viscosity. In addition to these oil production benefits related to CO_2, CO_2 storage in the reservoir after production has stopped is of great importance and can contribute to decrease the emission of CO_2 to the atmosphere significantly (Norwegian Petroleum, 2019; Rostron and Whittaker, 2011).

A big challenge related to CO_2-EOR is reproduction of CO_2 to the production well. Reproduction results in larger costs related to separation and reduced CO_2 storage. When installing AICVs on the pipeline, CO_2 as gas, supercritical fluid or as CO_2 dissolved in water, will be prevented from flowing into the production pipes and the injected CO_2 will be well distributed and remain in the reservoir. This leads to increased oil recovery and contribute to the environmental aspect by CO_2 storage (InflowControl, 2019).

3 Material and methods

In this study, Olga in combination with ROCX is used as the simulation tool.

3.1 Simulation set-up

OLGA is a software developed to simulate multiphase flow in pipelines, and covers modelling and simulation of wells, flowlines, pipelines and equipment from the well to the processing systems (Aakre 2017). ROCX is a three-dimensional near-well model coupled to the OLGA simulator to perform integrated wellbore-reservoir transient simulations. ROCX can simulate three-phase flow in porous media, and is developed to design reservoir models by defining properties of the reservoir including the fluid properties, and specifying the geometry of the reservoir. Parameters describing the reservoir properties are permeability, porosity, fluid viscosities and densities, relative permeability, pressure and temperatures, saturation of the different fluids and initial and boundary conditions. The mathematical models used in ROCX are described in detail in (Schlumberger, 2007). An overview of inputs needed for simulations using ROCX in combination with OLGA is presented in Figure 4. The overview is based on (Aakre, 2017).

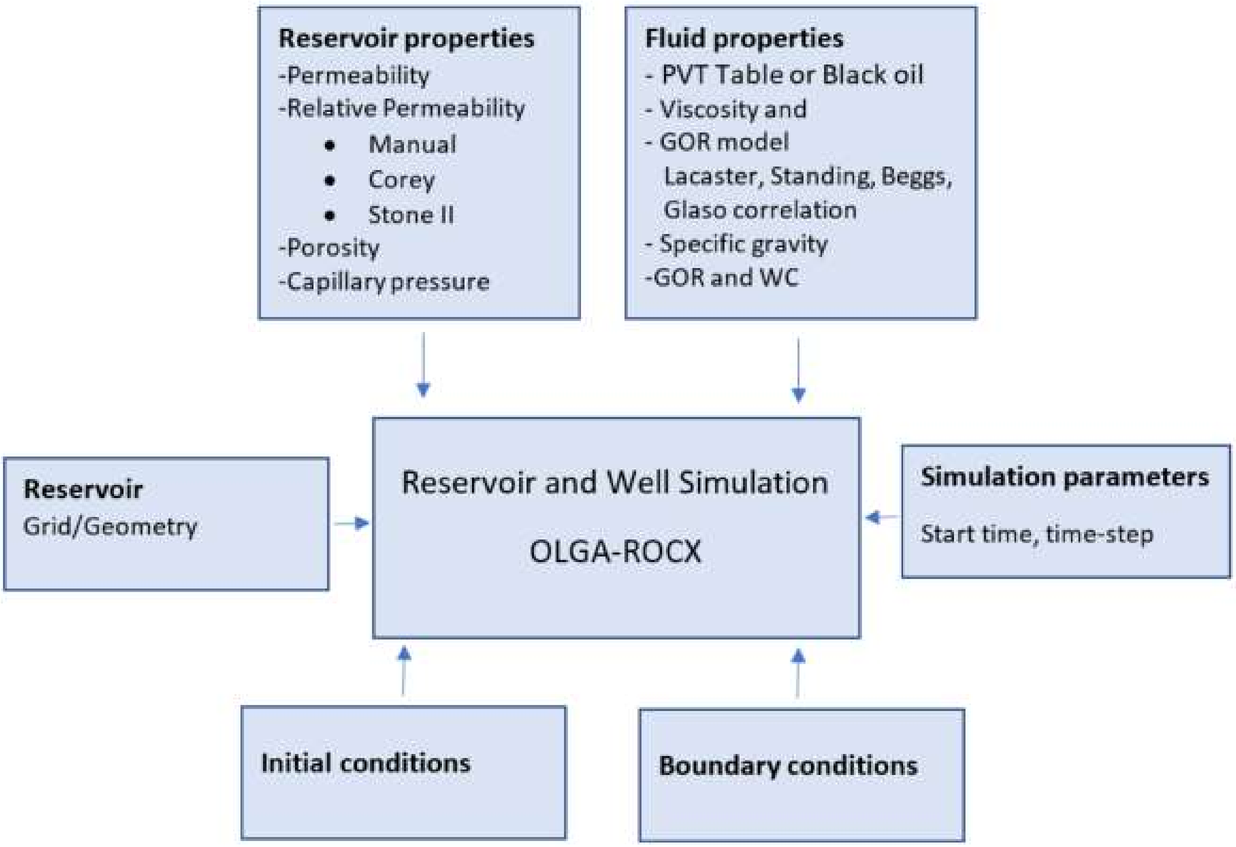

Figure 4. Overview of inputs needed for OLGA/ROCX simulations (Aakre, 2017).

Permeability is a measure for the capacity and capability for a porous rock to transfer fluids. Absolute permeability is a rock property, and describe the transfer of a fluid if the rock is 100% saturated with the actual fluid. The absolute permeability is defined by Darcy's law as:

$$\dot{Q} = \frac{k \cdot A}{\mu} \cdot \frac{dP}{dL} \tag{1}$$

where $\dot{Q}$ is the fluid volume flow, k is the permeability, μ is the viscosity of the flowing fluid, A is the cross section flow area and dP/dL is the pressure drop per unit length. Effective permeability is a measure for the transfer of fluid through a rock when there is more than one fluid present in the pores. The effective permeability is influenced by the wetting of the rock, meaning whether the rock is attracted to water or to oil. Relative permeability is the ratio of the effective permeability of the fluid and the absolute permeability, and is dependent on the saturation of the fluids in the rock.

The coupling between ROCX and OLGA accounts for the dynamic reservoir/wellbore interactions. OLGA is a one-dimensional transient dynamic multi-phase tool used to simulate flow in pipelines and connected equipment. The OLGA simulator is governed by the conservation of mass, momentum and energy equations for each phase (Thu, 2013; Schlumberger, 2007). The set-up in OLGA includes annulus, pipeline, packers and inflow control devices. Figure 5 illustrates the location of the annulus and the pipeline in the reservoir. Figure 6 shows the location of the packers between the rock and the production pipe.

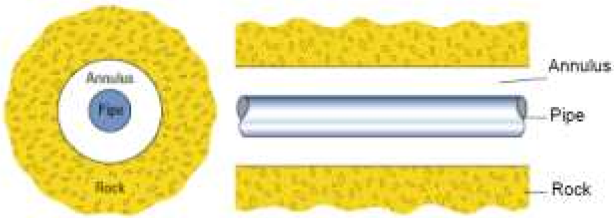

Figure 5: A sketch of the pipe and the annulus (Schlumberger, 2007).

To be able to simulate the flow from the reservoir via the annulus to the pipeline, the set-up shown in Figure 7 was used. The set-up involves two pipelines, the lower one to simulate the annulus and the pipe wall, and

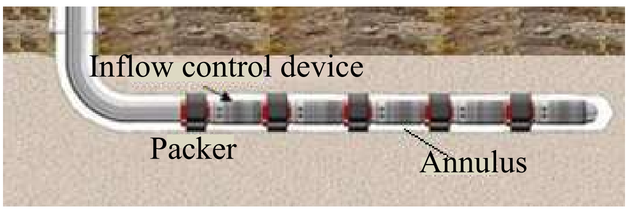

Figure 6. Horizontal well with inflow control devices and packers.

the upper one to simulate the flow and pressure drop in the well. The source (SOURCE 1) simulate the flow from the reservoir to the annulus, the valve (VALVE-1) illustrates an AICV, the leak (LEAK-1) simulate the flow through the AICV to the well, and the valve (PACKER-1) simulate a packer as a closed valve. Packers are used for zone insulation to avoid fluids to flow from one zone in the reservoir via annulus to another zone. This ensures that after breakthrough in one zone, AICV closes and this zone becomes insulated from the other zones. AICV is not an option in OLGA, and therefore it was necessary to build up valves with the same functionality as the AICVs. For that purpose, valves with transmitter and PID controller were used, and the closing and opening function was related to a water cut set point.

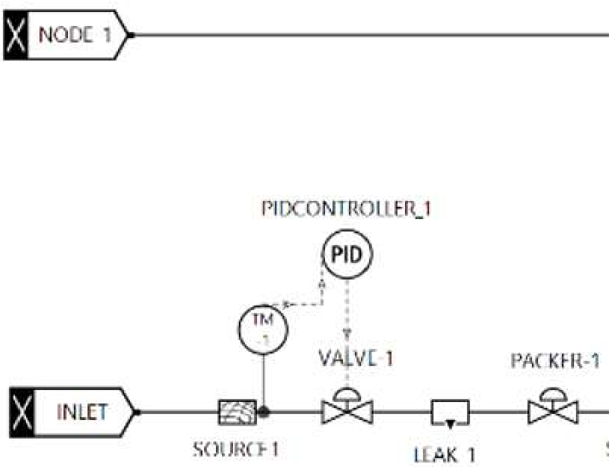

Figure 7. A well section including annulus, well, packers and AICV.

In this study, oil production with CO_2-EOR is compared to oil production without CO_2-EOR. The relative permeability curves for both the cases are plotted in Figure 8. As can be seen from the figure, the relative permeability curves change significantly when CO_2 is injected into a reservoir. Details about the influence of CO_2 injection on the oil properties are described in (Vesjolaja *et al.*, 2016; Badalge *et al.*, 2015). The Corey model is used to calculate the relative permeability for water, and Stoke II is used for the oil phase. The models are described by Schlumberger (Schlumberger, 2007).

The boundary conditions used for the simulations are pressure outlet set in OLGA, and the pressure and location of the water drive specified in ROCX. The location and the conditions for the sources (connection between reservoir and well) are also specified in ROCX. The initial conditions for reservoir saturation and reservoir pressure are specified in ROCX. A sketch of the initial reservoir with 100% oil saturation is presented in Figure 9. The arrow shows the location of the well.

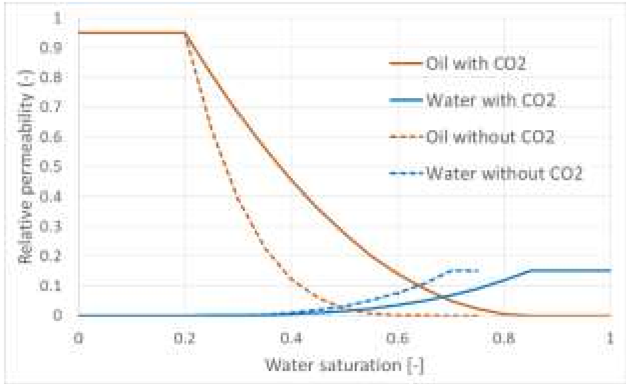

Figure 8. Relative permeability curves for oil and water.

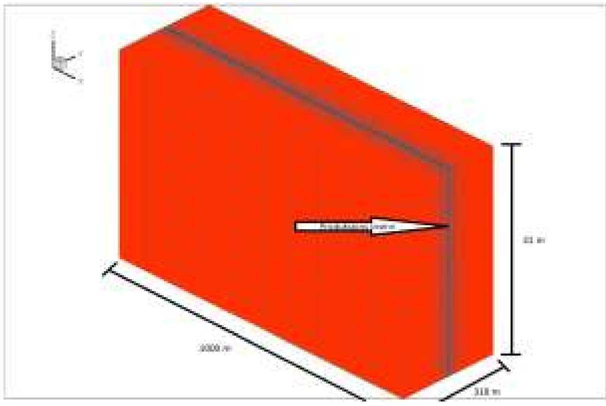

Figure 9. The initial oil reservoir (length 1000 m, width 318 m, height 31 m) as illustrated in Tecplot. The arrow shows the location of the well.

The set-up for the simulations is presented in Table 1. The blackoil model was selected in ROCX and it was assumed that the reservoir was initially saturated with oil. When using the black oil model, injection of CO_2 directly to the reservoir was not possible. In the simulations with CO_2-EOR, this was solved by assuming that CO_2 was already injected in the reservoir before the oil production started. The water in the simulations can therefore be considered as carbonated water. The Lasater model was used for the gas-oil ratio (GOR) calculations.

The well specifications was set in OLGA and are presented in Table 2. The outlet pressure from the well (spesified in the heel) is set to 166 bar. This means that the driving forces in the heel section is 10 bar, and lower in the toe. The cases are either run with passive inflow control devices (ICDs) or autonomous inflow control valves (AICVs). The ICD has a constant opening of diameter 0.028 m, whereas the AICVs has an initial opening of 0.028 m but the opening will decrease and go to about zero as the water production increases. The number of inflow control units in both cases is 10.

Table 1. Characteristics of the reservoir.

Reservoir	Homogeneous, sand stone
Oil viscosity	12 cP
Oil specific gravity	0.895
Porosity	0.33
Permeability	x- and y-directions: 8000 mD z-direction: 800 mD
Area	31.8 km^2
Thickness	31 m
Location of well	Grid 3 from the top in z-direction
Gas Oil Ratio	15 Sm^3/Sm^3
Reservoir pressure	176 bar
Reservoir temperature	76 °C

Table 2. Specification of the well.

Well length	1000 m
Number of sections	20
Diameter well	0.1 m
Pipe roughness	0.1 mm
Number of inflow devices	10
Valve diameter	0.028 m
Outlet pressure	166 bar
Initial frictional pressure drop	7 bar

4 Results and discussion

Table 3 gives an overview of the different cases that are simulated in this study. Case 1 is run without CO_2-EOR and without AICVs. Case 2 is run under the same conditions as Case 1, but with a choke mounted at the outlet of the production pipe. The choke is regulated by a PID which limits the total flow to maximum 1200 m^3/day. In Case 3, AICVs are installed on the pipe wall, and in Case 4 CO_2-EOR is used in addition to AICVs.

Table 3. Overview of the simulation cases.

Case	CO_2-EOR	AICV	Choke
Case1	No	No	Yes
Case2	No	No	No
Case3	No	Yes	No
Case4	Yes	Yes	No

Figure 10 shows a comparison of the accumulated production from Case 1 and Case 2. In Case 1, with no choking of the production rate, the carbonated water production is very high, close to $3 \cdot 10^6$ m^3 and 2.4 times the oil production. This involves that a large separation system is needed to handle the production flow. Most probably, the separation system on a platform in the North Sea is not design to handle these large amounts of liquids. It is therefore important to keep the total flow rate low to avoid overloading of the separation system and to reduce the costs related to separation. By choking (Case 2), the total flow can be adjusted to fit the capacity of the separators on the platform. When the total flow is adjusted to maximum 1200 m^3/day, the water break through is delayed, and the accumulated water production per 1500 days is reduced from $3 \cdot 10^6$ m^3 to about $1.8 \cdot 10^6$ m^3. The accumulated oil production is decreased from $1.25 \cdot 10^6$ m^3 to $1.13 \cdot 10^6$ m^3. This means that the accumulated water production has decreased with about 38% whereas the accumulated oil production has only decreased with about 10% during the 1500 days of production.

When using a choke, the flow from all the zones in the field will be reduced independent on whether they are producing oil or water. This results in less production from the toe where the oil saturation is still high. It is therefore important to utilize technology that can close off or choke the zones with high water production, and at the same time produce unhindered from the zones with high oil saturation. Suitable technology for this purpose is an autonomous inflow control valve.

In Figure 11, the accumulated production from Case 2 (choke) and Case 3 (AICVs) are compared. By using AICVs, the oil production after 1500 days is about the same as in Case 2 (choking of the total flow). However, the water production is further reduced to $1.11 \cdot 10^6$ m^3. The reason is that the AICVs choke or close a zone when it is producing more than 65% water. The closing frequency is illustrated in Figure 12. The closing of the AICVs starts in the heel and the AICVs close one by one towards the toe. After about 1000 days, all the AICVs are nearly closed, and the increase in accumulated oil and water production is low. Compared to Case 2, the oil production rate is about the same after 1000 days, but in Case 2, the water production rate is still high. The high water production in Case 2 after 1000 days, is because when choking the total flow, the production will mainly occur from the zones in the heel section which have the highest water cut the highest driving forces (difference between the reservoir pressure and the well pressure).

To increase the oil production, CO_2-EOR is used in Case 4. CO_2 changes the residual oil and also influence the oil viscosity. This is taken into account in the relative permeability curves. In Figure 13, the oil and water/CO_2 production from Case 3 and Case 4 are compared. Case 3 and Case 4 are both run with AICVs. When injecting CO_2, both the oil and the carbonated water production increase. However, due to the AICVs, the production rates are limited. CO_2-EOR results in an increase in oil production of 16.5% and an increase in water production of 44% relative to the similar case without CO_2.

Although the water production increased more than the oil production, the water cut is still well below 50%, and the water production is low compared to the other cases. Since the CO_2 is assumed to be dissolved in water in this study, a reduction in water production also indicates a significant reduction in the reproduction of CO_2 to the production well.

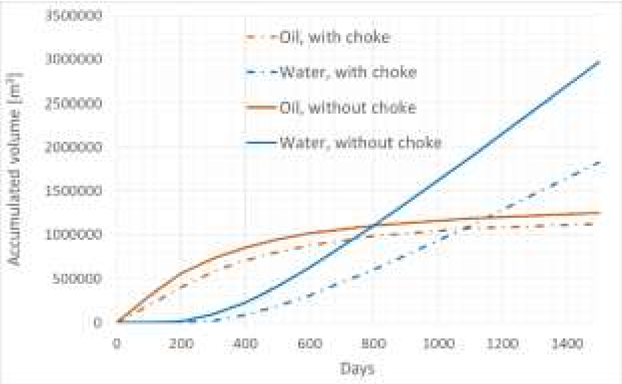

Figure 10. Comparison of oil and water production, Case 1 and Case 2.

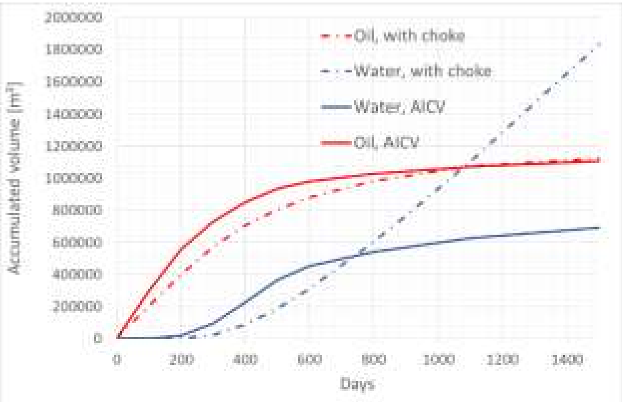

Figure 11. Comparison of oil and water production, Case 2 and Case 3.

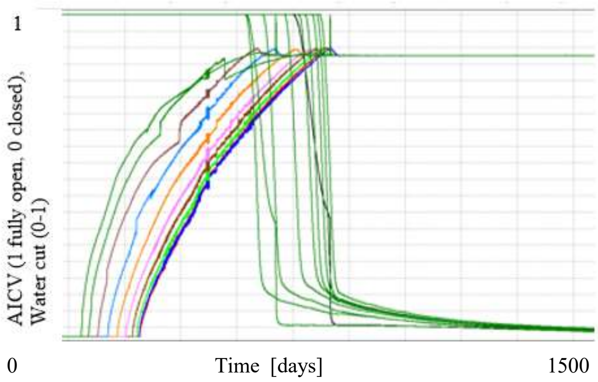

Figure 12. Closing order of the AICVs. Closes at WC 65%.

The results from the four simulated cases are summarized in Table 4. The water breakthrough occurs after about 120 days in Case 1, Case 3 and Case 4 and about 60 days later in Case 2. The reason for the later water breakthrough in the case with choking of the total flow, is that the total flow rate for this case is significantly lower than in the other cases in the early phase of the production. After the water breakthrough, the AICVs start to close, and the total flow rate for these cases will also decrease. Regarding Case 1, without any restrictions on the flow, the flow rate is increasing as the water cut increases. Initially (before water break-through) the total production rates from Case 1, Case 3 and Case 4 were equal due to equal diameter of ICDs and AICVs.

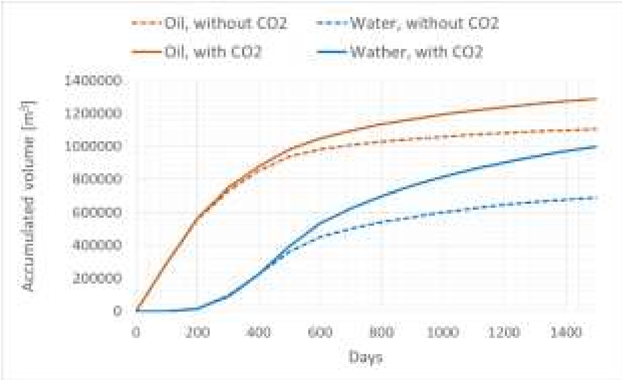

Figure 13. Comparison of oil and water production, Case 3 and Case 4.

Table 4. Summary of simulation results.

	Water break-through	Accumu-lated water [m^3]	Accumu-lated Oil [m^3]	% of oil produced
Case 1	176	$2.98\cdot10^6$	$1.25\cdot10^6$	29.6
Case 2	120	$1.83\cdot10^6$	$1.13\cdot10^6$	38.1
Case 3	118	$0.69\cdot10^6$	$1.11\cdot10^6$	61.5
Case 4	122	$1.0\cdot10^6$	$1.29\cdot10^6$	56.4

Based on the results, Case 1 is not a relevant case for oil recovery due to the very high water production. Case 1 is also not a realistic case, because the total production rates have to be controlled by a choke to avoid overloading to the downstream separation and processing systems. In future work all the cases should be run with a choke on the total flow in addition to the inflow control devices. The simulation results shows that CO_2-EOR increases the oil production significantly. In addition to CO_2 injection, the results shows that autonomous inflow control devices are necessary to avoid high water production and recirculation of CO_2 to the well.

5 Conclusions

The main objective of this study was to look at the effect of CO_2-EOR on increased oil production and in addition to find a method to avoid reproduction of CO_2 to the

production well. The properties of the oil reservoir are based on information from the Grane field in the North Sea. Four cases were run under different conditions. Simulations were performed using the OLGA and ROCX simulation tools. The production from a homogeneous reservoir was simulated for 1500 days.
CO_2-EOR is a good alternative for increasing the oil production from oil fields, but CO_2-EOR also leads to increased water production. When using autonomous valves the oil production was reduced by 11% and the water production was reduced by 77%. This is a significant reduction in the water production and thereby also reproduction of CO_2, which results in a more energy efficient and environmentally friendly oil production. The simulations also showed that it is crucial to install choke with PID regulator to control the total flow rate.

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