Rejuvenation of a mature oil field: Underground Gas Storage and Enhanced Oil Recovery, Schönkirchen Tief Field, Austria

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Abstract

The Schoenkirchen Tief reservoir is located in the Vienna Basin. The reservoir contained 19 mn m³ oil originally in place. The current recovery factor after 46 years of production is 59 %. The field was produced by water injection. The wells, located at the crest of the high relief structure are exhibiting a high water cut.

2006-2008, a comprehensive study was performed to optimise the future development of the field. The study showed that this field can be used for high performance Underground Gas Storage. Due to gas/oil gravity drainage, oil will be mobilised and can be produced resulting in enhanced oil recovery.

The field development of this fractured dolomite reservoir can be optimised by using vertical dewatering wells. Completing the vertical wells far down in the structure results in minimising gas coning and fast build up of the working volume of gas. To reduce water handling costs, these water wells will produce the water out of the reservoir into a highly permeable aquifer located above the reservoir. This means, no water will be produced to surface.

The drainage of oil in the matrix of this dual-porosity dual-permeability reservoir model is lagging behind the downward movement of the gas/oil contact in the fractures in this high relief reservoir. Once the oil rim reached the original oil/water contact in the matrix, horizontal wells can be drilled to produce additional oil.

Processes which had to be considered in this field development are the fracture-matrix interaction, hysteresis and fluctuations of the oil rim in the fractures during the gas cycles.

Introduction

In 2006, about 60 % of the gas which was consumed in the European Union was imported. 25 % of the gas was imported from Russia, 16.7 % from Norway and 10.5 % from Algeria. Due to declining production from The Netherlands and the United
The percentage of gas imports into the European Union is forecasted to increase to more than 70% in 2030.

One of the main gas import pipelines in which gas is transported from Russia to the European Union is crossing Austria. This pipeline is passing the Vienna Basin, a pull-apart basin in which Austria’s largest oil and gas fields are located.

The request for more Underground Gas Storage (UGS) capacity and the shortfall in gas supply from Russia in winter 2006 and 2009 triggered the investigation of conversion of oil or gas fields in the Vienna Basin into UGS.

The Schönkirchen Tief field which is located about 20 km northeast of Vienna in the Vienna Basin was identified as a suitable candidate field for high performance UGS. The field consists of dolomites showing dual permeability behaviour. It exhibits high permeabilities, has a large enough size and is at the end of the oil production life time.

In 2006-2007, an integrated study has been performed to determine the suitability of using this field for UGS. Initially, the field contained oil and was water flooded from the bottom upwards for the last 46 years. The current reservoir pressure is about 40 bar lower than the initial reservoir pressure. The questions which should be answered by the study were: How much gas can be injected until the initial pressure is reached? Is there a risk that the gas/oil contact in the fracture system is pushed lower than the spill point of the field during the gas injection phase? How much additional gas can be injected by producing water from the reservoir? What ratio of working volume to cushion gas can be achieved? How much oil reserves are lost if the field is converted into UGS or does gas injection lead to enhanced oil recovery (EOR)?

To address these questions, a detailed geological study and laboratory experiments have been performed. A static and dynamic numerical model were created, history matched and used for prediction of the UGS behaviour and EOR. These simulations were complemented by simulations using a fine grid to investigate reservoir processes in more detail.

The geological study included various data sources such as outcrop analysis, core analysis, Formation Micro Image (FMI) and log data analysis, geomechanical analysis. A brief overview of the geological setting and parameters derived from this study is given in the following section. Also, production data were used for constraining the geological model (pressure data, gas/oil ratio and permeabilities). The overall production history of the field is given in the “production history” section. This section is followed by showing the history match which was achieved in close co-operation of the various disciplines. After a satisfactory history match including uncertainties was achieved, injection of gas for UGS and EOR was simulated (“Transforming Schönkirchen Tief into UGS” section).
Geological setting/reservoir parameter

The Schönkirchen Hauptdolomit belongs to the Northern Calcareous Alps (NCA). The NCA were buried in the pull apart basin located east of Vienna (Vienna Basin) by more than 2000 m of sediments.

A plan view of the field is shown in Fig. 1. This map shows the structure of the field with three build-ups. These three build-ups (around ST031, ST008 and ST004) were formed in a shallow-marine environment as reefs. The highest build-up is located in the north (close to well ST031), the deepest (close to well ST004) in the south.

Fig. 1 Plan view of the top structure of the Schönkirchen Tief Field.

The field is dynamically connected to a field initially containing gas in the west (Schönkirchen Tief Gas) and to an oil bearing reservoir in the northeast (Prottes Tief). The northern edge of the Schönkirchen Tief Field is marked by a fault.

The Schönkirchen Tief Field consists of three subunits (Fig. 2):
- Bockfliess Formation
- Weathered Zone
- Triassic Hauptdolomit

![Schematic cross-section of the Schönkirchen Tief Field.](image)

The Triassic Hauptdolomit experienced early diagenetic dolomitisation. This dolomitisation did not result in generation of additional pore volume but in a brittle rock. This rock was heavily fractured through six phases of deformation. In cores, permeabilities of several tens of mDarcy were measured. Field data such as well inflow measurements and pressure build-up tests indicate permeabilities of more than 500 md up to 7000 mD. The total porosity of the Hauptdolomit is about 5%.

The Weathered Zone is a heterogeneous layer consisting of different rock types: A) Deeply weathered in-situ rocks or relict mountains B) Thallus/debris material and C) fine grained plane sediments.

The maximum thickness of the Weathered Zone is 110 m. Measured permeabilities of the cores from the Weathered Zone were several tens of mDarcy. In the Weathered Zone, some areas showed high productivities indicating good permeabilities. However, other areas are less permeable. This indicates filling of fractures by material from the overburden. The porosity of the Weathered Zone is about 8%.
The Bockfliess Formation is a shale-dominated sequence containing laterally limited sands that can be hydrocarbon filled. Some of these sands are in dynamic communication with the Hauptdolomit reservoir. The permeability of these sands ranges from 40mD–400 mD and the porosity is 8.5 % on average.

To capture the flow in a system consisting of high permeable fractures and lower permeable matrix, a dual permeability simulation model was used. For the block size, log interpretation and an outcrop study showed that on average, blocks of 3 m by 3 m with a height of 9 m can be assumed.

Dependent on the reservoir unit, a full or partial dual permeability approach was introduced. For the whole Hauptdolomit Unit, a dual permeability approach was used since it consists of a fracture system and a matrix. The flow in the Weathered Zone was simulated by using a dual permeability approach in some areas and single permeability in others. The Bockfliess Flow Unit, consisting mainly of sands, was represented by a single permeability approach.

To simulate the gravity drainage and imbibition correctly, two different shape factors were used, the Kazemi shape factor for imbibition and

\[ \sigma_{gd} = \frac{2}{l_z^2} \]

for drainage, using the vertical dimension of the matrix block \( l_z \).

The original oil in place was 19 MSm³. Initially, there was a gas cap present containing 155 MSm³ of gas in place. The original oil/water contact was situated at 2740 meter subsea (mSS), the initial gas/water contact at 2550 mSS and the top structure at 2470 mSS. The initial oil viscosity was 1.3 cP and the initial pressure 292 bar at the initial oil/water contact.
Table 1 summarises the geological data and Table 2 the fluid parameters.

**Table 1 Average reservoir parameters of the different units.**

<table>
<thead>
<tr>
<th></th>
<th>Triassic Hauptdolomite</th>
<th>Weathered Zone</th>
<th>Bockfliess Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture permeability in md</td>
<td>750</td>
<td>550</td>
<td>-</td>
</tr>
<tr>
<td>Matrix permeability in md</td>
<td>50</td>
<td>90</td>
<td>400</td>
</tr>
<tr>
<td>Fracture porosity in %</td>
<td>1.2</td>
<td>1.7</td>
<td>-</td>
</tr>
<tr>
<td>Matrix porosity in %</td>
<td>3.7</td>
<td>6.2</td>
<td>8.5</td>
</tr>
<tr>
<td>Maximum reservoir thickness in m</td>
<td>70</td>
<td>50</td>
<td>20</td>
</tr>
</tbody>
</table>

**Table 2 Summary of fluid properties.**

<p>| | |</p>
<table>
<thead>
<tr>
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<tbody>
<tr>
<td>Oil viscosity at initial reservoir pressure in cP</td>
<td>1.3</td>
</tr>
<tr>
<td>Initial Reservoir Pressure at initial oil/water contact in bar</td>
<td>292</td>
</tr>
<tr>
<td>Bubblepoint Pressure</td>
<td>278</td>
</tr>
<tr>
<td>Initial gas oil ratio in m³/m³</td>
<td>90</td>
</tr>
<tr>
<td>Oil formation volume factor in m³/m³</td>
<td>1.27</td>
</tr>
</tbody>
</table>
Production History

Production from Schönkirchen Tief commenced in 1962. Peak oil production was reached in 1965 with 2500 m³/d (Fig. 3). From then onwards, oil production declined, with a second peak in 1970. The current oil recovery factor is 59%.

The pressure in the field declined until 1970 to about 235 bar. In 1971, a bottom water injection scheme was implemented. The pressure increased to about 245 bar and only slightly decreased afterwards (Fig. 4).
The wells were completed successively upwards after watering out. Currently, the wells are completed close to the current gas/oil contact in the uppermost part of the field.

**History matching**

To achieve a history match, first, the pressure of the Schönkirchen Tief structure including the three fields Schönkirchen Tief, Prottes Tief and Schönkirchen Tief Gas was matched. Next, the movement of the gas/oil and oil/water contact in Schönkirchen Tief of the gas/water contact in Schönkirchen Tief Gas simulated was compared with field data. Then, the water/cut and GOR of individual wells were matched. After a satisfactory history match was achieved, the main uncertain parameters were modified and the dynamic model was again history matched using the modified parameters.

The Schönkirchen Tief Field is dynamically connected to the Prottes Tief oil field and Schönkirchen Tief Gas field. Only very limited aquifer influx is present in the structure containing the three fields. A good pressure match could be obtained in the initial face when no water was injected. Hence, the volumes of movable fluids could be determined accurately. A pressure match is shown in Fig. 5.
Fig. 5 Pressure match of the well Schönkirchen Tief 13. Owing to the very good permeability, only small differences in the pressures of the individual wells exist.

In this study, the wells were constrained on liquid rates rather than oil rates. The reason is that the wells are producing in the late time of the field with high water cuts. A well producing at 95% water cut leads to a large difference in liquid production for a small error in oil production if oil production is used to constrain the well.

The water cut match is given in Fig. 6. It should be noted that the production strategy in this high relief reservoir was to perforate the wells about 30 m above the initial oil/water contact. After the water reached these perforations, the wells were perforated further up. Therefore, the wells are producing for a long period of time only oil. After water breakthrough, the water cut sharply increases. In the 1990s, some wells showed this sharp increase in water cut. In the simulation, the water/oil contact is rising slightly faster than in the field, this results in a higher water cut during that period of time than in the production history. At the end of production, however, the oil rates and water cuts are matched very well. The overall difference in cumulative oil production is less than 4%.
Fig. 6 Historical (dark blue) and simulated (light blue) water cut from Schönkirchen Tief.

The gas production is mainly determined by the gas/oil contact in the fractures of the fractured reservoir. Due to coning effects and small differences in volumes and permeabilities of the fractures, this parameter is difficult to match. Fig. 7 shows the cumulative gas production match of Schönkirchen Tief.
Fig. 7 Historical (red) and simulated (green) cumulative gas production in Schönkirchen tief.

The field was produced by water injection for the last 37 years. When changing the reservoir management strategy from bottom water injection to crestal gas injection, uncertainties concerning the gas injection and liquid withdrawal rate have to be considered.

To capture the major uncertainties, uncertain parameters such as residual oil saturation, shape factor, matrix- and fracture permeability were modified and a history match was performed using the changed parameters.

The Schönkirchen Tief reservoir has been produced slowly in the past. Hence, the imbibition of the water from the fractures into the matrix could keep pace with the upward movement of the water/oil contact in the fractures. Increasing or decreasing the fracture permeability by a factor of two resulted in very similar history matches. The difference between fracture and matrix permeability is large in all cases. Due to the low production rates, only limited coning in the fracture system was observed.
The shape factor also does not change the history match owing to the slow way of producing Schönkirchen Tief. This leaves enough time for the exchange even for a lower shape factor. Matrix permeability has some influence on the history match, for some wells, the history match is improved for others it is worse.

The main impact on history matching have the volumes of movable oil which are present in the various depths of the reservoir. An example for a variation in parameters and the resulting history match is shown in Fig. 8. To achieve a history match for changing the residual oil saturation by 5 % of Oil Originally In Place (OOIP), the pore volume has to be decreased accordingly. Hence, the movable oil remains the same, resulting in a good history match.

Fig. 8 Sensitivity of the history match to residual oil saturation. To achieve a history match, the movable oil has to be modified to result in the same amount of movable oil.

Due to the availability of limited amounts and poor quality of core, SCAL data are not reliable in this field. Residual oil saturations against water of about 25 % and of 15 % against gas were used for the base case.
Transforming Schönkirchen Tief Gas into UGS

Hydrocarbon fields are good candidates for conversion into UGS. It has been proven over geological times that the overburden of the reservoir is sealing for hydrocarbons, the permeabilities and volumes are known from production history.

Converting gas or gas condensate fields has been done frequently (Damm 1997, Zakirov et al. 1998, Gerov & Shteryo 2002). Oil reservoirs have not been converted into gas storage as frequently. Conventionally, oil reservoirs are produced by making use of a natural aquifer or water injection. Converting such a reservoir into UGS leads to very different production mechanisms. Hence, the uncertainty is larger. Examples for conversion of an oil reservoir into UGS are described by Burke 1960 and Coffin & Lebas 2008.

Until now, the Schönkirchen Tief reservoir was produced by injection of water below the initial water/oil contact and producing from upper parts of the field. In the meantime, the wells are perforated close to the crest of the reservoir. The reservoir pressure is about 240 bar, almost 50 bar below initial pressure.

Due to the high permeabilities, large volumes in place and large reservoir thickness, the field has been identified as a good candidate for UGS. Three different phases can be envisaged while transforming the field into UGS:

1. Injection of gas up to the initial pressure
2. Injection of additional amounts of gas with continuous dewatering
3. Production of incremental oil

The three phases are described in more detail in the subsequent paragraphs.

Injection of gas up to the initial pressure

The current reservoir pressure is about 40 bars below the initial reservoir pressure. In the first phase, gas can be injected until the initial reservoir pressure is reached to avoid the risk of fracturing the caprock.
To increase the amount of gas which can be injected, water can be withdrawn from the reservoir. Fig. 9 shows the maximum amount of gas which can be injected with and without water production. Without water production, gas can be injected until the initial pressure is reached. If water is produced at the same time, more space can be occupied by the injected gas, resulting in higher gas storage volumes than without water production.

![Fig. 9 Gas injection for the first phase with and without dewatering.](image)

To be able to withdraw water at high rates, vertical wells with a large perforation interval are used. These wells are perforated far below the original oil/water contact to avoid production of gas once the reservoir is filled with gas up to the original oil/water contact. Fig. 10 illustrates the concept of water production from the Schönkirchen Tief reservoir and water injection into an overlying sandstone.
After the first phase, a period of two years is foreseen to monitor the movement of the gas/oil contacts in the fracture system and the pressure response of the reservoir.

The next phase is characterised by additional dewatering and gas injection as described in more detail in the following section.

**Injection of additional gas with continuous dewatering**

To be able to inject more gas and hence increase the working volume of the UGS, additional water has to be withdrawn from the structure. Fig. 11 shows the first cycle of the gas injection, the two monitoring cycles and increasing gas injection after a second period of water withdrawal for the second phase.
Fig. 11 First phase of gas injection, monitoring phase and second phase with water withdrawal for the conversion of the reservoir into UGS.

In the second phase of the UGS, the gas will move down in the fractures until it almost reaches the original oil/water contact. In the gas production part of the storage cycles, the gas/water contact in the fractures will move upwards. To optimise gas injection and withdrawal, the wells will be placed high in the structure.

Gas injection at the top of the reservoir and production of liquids below the initial oil/water contact results in gas/oil gravity drainage in the matrix of this fractured reservoir. This process can be used to produce incremental oil as shown in the section below.

Production of incremental oil

Updip gas injection into a high relief oil field has been shown to be one of the most efficient methods to recover oil after waterflooding. Field experience has shown that more than 15 % incremental oil can be recovered from a waterflooded
reservoir by updip gas injection (e.g. Johnston 1968, Carlson 1988, Shahsavari & Dabbous 1991, Langenberg et al. 1995, Gunawan & Caie 1999). In these field cases, significant increase in oil production by gravity drainage has been achieved, although by waterflooding already more than 55 % of the oil has been recovered. These field test results are supported by laboratory studies (e.g. Kantzas et al. 1988, Blunt et al. 1994, Oren & Pinczewski 1995, Ren et al. 2003). For high relief fractured carbonates, updip gas injection to increase oil recovery has been used successfully in Oman and Iran (O'Neil 1988, Novinpour et al. 1994, Saidi 1996, Eikmans 1999, Sadooni 2008).

Initially, the injected gas will mainly move into the fracture system of the fractured Schönkirchen Tief reservoir. The matrix blocks are surrounded by gas and gravity drainage will occur. From history matching, logs and field observations, no vertical transmissibility barriers are expected. Therefore, the gas/oil gravity drainage process is expected to be efficient.

Due to continuous dewatering in the second phase, even during the periods of withdrawal of gas, gravity drainage will continue. Gravity drainage results in very low residual oil saturations due to film flow of oil at the edges of the pores downwards. Fig. 12 shows the oil saturation in the matrix before gas injection and after several cycles of gas injection. It shows that an oil rim is formed in the lower part of the reservoir.

Fig. 12a Fluid saturations at the beginning of gas injection in the matrix (oil: green, blue: water, red: gas). Close to the crest of the reservoir, a limited amount of movable oil is present. Note the high water saturations below the gas cap in the water flooded area of the field. The initial oil/water contact is shown by the arrow.
Fig. 12b Oil saturations after several cycles of gas injection. An extended oil rim has been created. This oil rim thickens with time due to continuous gas/oil gravity drainage.

This oil rim can be produced by using horizontal wells which are drilled close to the original oil water contact. Dependent on the permeability of the matrix – which is an uncertain parameter in this field – up to 5 % of incremental oil in place compared to water flooding can be recovered by using such wells at this stage. For a discussion of the effect of a moving gas/oil contact and uncertainties, please refer to de Kok & Clemens 2008.

**Summary and Conclusions**

The Schönkirchen Tief reservoir, having a high relief, very good permeabilities and size can be converted into an Underground Gas Storage field.

In the first phase, gas can be injected until the initial reservoir pressure is reached. To be able to inject more gas, liquids have to be withdrawn from the field. Withdrawal of liquids can be achieved most cost efficiently by using vertical wells. These wells will be perforated far below the initial oil/water contact and with a long perforation interval to be able to produce at low drawdowns. The reason for perforating these wells far below the initial oil/water contact is that in the second phase of the Underground Gas Storage project, gas will reach the initial oil/water contact in the fractures. It is planned to inject the withdrawn water into a sandstone above the reservoir to minimise water handling costs.

In a second phase, water production will be increased to be able to increase the working volume of the Underground Gas Storage field. This will result in gas/oil gravity drainage in the matrix of this fractured reservoir. After several cycles, an oil rim will be generated in the matrix. This oil rim moves downwards and grows in
thickness. Oil from this oilrim can be recovered in the third stage of the development by using horizontal wells.

Acknowledgments

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