1. Introduction

BEB operates six steam drive projects in Northwest Germany with a total of 18 steam injectors and 140 producers in two oilfields (25° API, 120-140 mPas). The first project, Georgsdorf SD1, was started in 1975 and until mid 1996 about 0.75 pore volumes (PV) of steam have been injected. Earlier analyses showed that the oil steam ratios peaked at an injection volume of 0.35 PV and were slowly decreasing afterwards. However, there was no experience on when to end steam injection and how to proceed in the most efficient way. Since the few accessible case histories were not directly applicable, simulation models were used to analyse some key issues, listed below, which are critical to the future economics of all steam drive projects.

1. What is the most economic steam slug size?
2. What is the optimum post steam pressure maintenance / water injection concept?
3. Are there specific reservoir parameters which predominantly control the areal sweep efficiency?

The analysis was carried out in a two step approach. First a mechanistic, homogeneous model reflecting average reservoir parameters of the Georgsdorf field was set up to run sensitivities as a basis for economic evaluations and to define the optimum post steam strategy. This strategy was then applied to a real field model of the 1975 steam drive project. Recently the initial mechanistic model was extended to analyse reservoir parameter variations in a more detailed way.

2. Georgsdorf SD1 Project History

The project area is 1.5 km long and 500 m wide. It is separated to the north and south by sealing faults, by an aquifer to the west and by an increasing shale content to the east. Steam was injected successively into three different groups of two injection wells, and there are 20 production wells. The structure map of the project area, Figure 1, shows the locations of injection- and production wells. The main project/reservoir parameters are as follows.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil in place (OIIP)</td>
<td>5.75 Mio. m³</td>
</tr>
<tr>
<td>Recovery at project start</td>
<td>8.03 %</td>
</tr>
<tr>
<td>Current recovery</td>
<td>31.5 %</td>
</tr>
<tr>
<td>Total steam injected</td>
<td>5 Mio. m³</td>
</tr>
<tr>
<td>Incremental oil production</td>
<td>1.07 Mio. m³</td>
</tr>
<tr>
<td>Cumulative OSR</td>
<td>0.268</td>
</tr>
<tr>
<td>Cumulative IOSR</td>
<td>0.211</td>
</tr>
<tr>
<td>Steam Temp. (Well Head)</td>
<td>320 °C</td>
</tr>
<tr>
<td>Steam Quality (Well Head)</td>
<td>98 %</td>
</tr>
<tr>
<td>Injection WHP</td>
<td>90 - 110 bar</td>
</tr>
<tr>
<td>Depth</td>
<td>620 - 820 m</td>
</tr>
<tr>
<td>Thickness</td>
<td>38 m</td>
</tr>
<tr>
<td>Average dip angle</td>
<td>14 °</td>
</tr>
<tr>
<td>Pore Volume</td>
<td>6.66 Mio. m³</td>
</tr>
<tr>
<td>Permeability</td>
<td>1,000 mD</td>
</tr>
<tr>
<td>Init. Res. temperature</td>
<td>40.5 °C</td>
</tr>
<tr>
<td>Oil density (RC)</td>
<td>0.865 g/cm³</td>
</tr>
<tr>
<td>Oil viscosity (RC)</td>
<td>135 mPa·s</td>
</tr>
</tbody>
</table>

Figure 2 gives an overview of the history of the injection/production performance. Oil rates tripled after only one year of steam injection, but an unexpected negative effect of the steam process was the generation of up to 20,000 ppm of H₂S in the associated gas production, which required a costly recompletion of production wells and surface facilities.
3. Mechanistic Model
In an actual field application of the steam drive process, many complex physical, reservoir, and operational features make the interpretation of results, both in full field simulations and in the field, difficult. Thus, the objective of this mechanistic model study was to design a simplified pattern steam flood that could be easily run and applied for software testing and sensitivity analyses.

- Model Description
An Eclipse simulation model was set up with 2000 (20x20x5) gridblocks. The grid blocks in the steam drive area were 50 by 50 meters in the xy plane. In the x-direction 3 rows of elongated (100 and 200 m) grid blocks were used to join the steam drive area to the aquifer. The simulated reservoir was represented by one homogeneous sandstone layer of twenty meters thickness. The dipping layer was given a horizontal permeability of 1000 mD, a vertical permeability of 100 mD, and a porosity of 26%. In the simulation the layer was subdivided into five equal sub-layers to enable the modeling of a vertical distribution of steam and temperature. All of the injection and production wells of the regular five-spot pattern were completed in all five layers.

The simulations were run so that the pressure during continuous steam injection would be kept at the same level. Thus, the liquid injection and production rates were at balance. The steam injection rate was 480 m$^3$/day (CWE) with a bottom hole quality of 0.85. During the post steam water injection phase, water was injected at the same rate.

In addition to minimum BHP and rate control, the up-dip producers were also controlled by a temperature cut back routine that reduces the well's maximum allowable liquid production rate as a function of the bottom hole temperature. This rate cut back (or increase as the temperature declines) was designed to keep the well head temperature below 100 °C, which is for technical reasons the maximum allowable temperature.

The current E500 software does not allow for the presence of a hydrocarbon gas phase. In the real world, however, there will be a gas saturation after the pressure drops below the bubble point or after the oil heats up. The increased system compressibility that results from this free or critical gas saturation is emulated by an increased rock compressibility, about 50 times higher than usual. The rock compressibility was set to $25.0 \times 10^{-4} \text{ bar}^{-1}$.

The rock heat capacity was 2400 kJ/m$^3$/K and the rock thermal conductivity was 150 kJ/mole/day/K. The most important fluid property to be specified in a thermal model is the oil viscosity as a function of temperature. The viscosity drops from 135 mPa·s at initial reservoir temperature of 40 °C to 15 mPa·s at 100 °C and 1.5 mPa·s at 250 °C.

- Scenarios
At constant injection rates steam slugs of 0.1 to 2.5 times the total PV of the defined steam drive area were simulated by different injection periods. At the end of each period, four different post steam operating scenarios were simulated to determine the optimum steam slug size and post steam process combination.

The post steam operations were as follows:
Case A: Shut-in the steam injector and let the aquifer support continued operation.
Case B: Ramp down the steam injection rate over 3 years (75%, 50%, and 25%) and then (in post steam year 4) inject cold water into the steam injector.
Case C: Shut-in the steam injection and inject cold water just up-dip from the up-dip producers.
Case D: Shut-in the steam injection and inject cold water a long distance up-dip from the up-dip producers.

Ten years of post steam operations were simulated. At that point the cumulative oil produced and volume of steam injected are the key results.

- Results
Economic calculations were made with the model predictions to determine the profit (or loss) for each scenario. To compare the cases, the incremental profit was calculated from the incremental oil production (steam flood + post steam oil production minus primary/secondary oil production).
The optimum steam slug size is directly related to the cost of steam. At low cost steam (below 10 DM/ton) the maximum profit is achieved with a steam slug size of 1.5 pore volumes. At higher volumes, steam is being cycled through the reservoir. When the steam costs rise above 12.5 DM/ton, steam flooding becomes uneconomic. The absolute steam costs quoted above are dependent on the model assumptions and the oil price scenario used and not generally applicable.

The best post steam operation for most volumes of steam injected is Case B, the replacement of steam by water injection into the steam zone. Sensitivities showed that this also holds for different oil price scenarios.

4. Field Model Georgsdorf SD1
As opposed to the homogeneous mechanistic model, the real SD1 reservoir is characterized by many heterogeneities. These include permeability variations, especially in the vertical direction, porosity changes and faults which act as transmissibility barriers. Actual well locations (no regular patterns) and the asymmetrical reservoir geometry, furthermore, distinguish the real project from the simplified pattern model. To include the individual features of the SD1 project an appropriate field model was set up.

The optimum post steam strategy from the mechanistic model, i.e. to inject water into the steam zone, was confirmed by the field model. An economic evaluation based on the future oil production rates from continued steam injection (in excess of the current 0.75 PV) and from water injection showed that immediate conversion to water injection into the steam zone is the better strategy. This means the results from the field model did not support the recommendation from the mechanistic model to inject more than 0.75 pore volumes of steam.

The 'Zero Case' (stop steam injection, pressure support only from the aquifer), and the water injection case produce about the same decreasing oil rate during the first year of post steam operations. In the latter case some good producers in the central project area suffer from increasing watercuts, while in the 'Zero Case' there is a significant pressure drop. In the longer term however, the incremental production increases dramatically in the water injection case due to the positive effects from the pressure support and the areal distribution of heat energy extending to the down-dip wells. Figure 3 compares the future oil production rates from the 'Zero Case' and the recommended water injection into the steam zone during the ten years of post steam operations. The actual field performance after one year of water injection confirms the model predictions.

The first simulation results also indicated that pressure maintenance could be improved by high water injection rates to achieve an early condensation of the relatively large steam zone. Since pressure measurements in the field did not support the existence of such a large steam zone, the energy balance was analysed. A software bug was found that prevented the calculation of heat losses to the overburden. Although, with the corrected software, about 40% of the total energy injected is lost to the over-/underburden at the end of the steam injection phase, the resulting incremental production dropped by only 25%. The recommended concept, therefore, is still the most economic alternative.

The energy balance, Figure 4, shows that at the end of the thermal phase the total heat losses amount to 50% of the total energy injected. After ten years of post thermal operations 25% of the energy is still preserved in the reservoir-rock and fluids. About 85% of the energy losses are resulting from conduction to the over- and underburden, 15% are contained in the produced fluids, when the maximum well head temperature is limited to 100 °C. This is consistent with earlier analytical calculations.

5. Further Optimisation Potential (current status of investigations)
In addition to the optimisation of post steam operations, the potential to improve the profitability of active steam flood projects is currently being investigated. This includes production acceleration projects like slanted or horizontal (re-entry) infill drilling or relocation of steam injection wells. The other important way to improve the profitability is to save costs. This could for ex-
ample be achieved by partial replacement of steam in an early project phase by parallel injection of water. The objective is to provide the pressure support by cheap water and to save steam costs by limiting the steam to the heat energy still required for viscosity reduction.

A key requirement for the planning of such projects is to gain maximum quality information on the areal and vertical sweep efficiency. The fluid movement in a dipping steam drive reservoir is mainly affected by the permeability and its variations, by gravity forces, by the applied drawdowns and the temperature distribution which itself depends on the other parameters.

As a first step for further planning, the initial mechanistic model was upgraded (nine-spot pattern) and various sensitivity analyses were carried out:

1. A high permeable layer near the top of the reservoir improves the temperature distribution, and recovery increases by 5%. A stochastic areal permeability variation within the layers has only a minor influence on the recovery.
2. In a dipping reservoir, gravity rather than pressure drawdown is dominating the distribution of steam, steam condensate and temperature.
3. The reduced thermal influence in the areas between the production wells, as expected from appropriate field data, was not confirmed. Neither grid refinements nor a change of the grid orientation did affect the rather uniform temperature distribution.
4. Grid orientation effects must be taken into account when the arrival time of the steam front is predicted, but they have no influence on the long term recovery.
5. A re-saturation of the steam vapour zone in the two top layers, where the residual oil saturation drops below 5%, cannot be avoided by post steam water injection into the former steam injector or the updip steam zone. The resulting losses of producible oil are, however, compensated by the improved drainage of the lower layers during the post steam phase.

Result no. 3 is in contradiction to actual field data. A field model is therefore being set up to analyse the potential for infill drilling.

To check the validity of all results, the sensitivities will be rerun as soon as a new E500 version, incorporating a hydrocarbon gas phase, becomes available. This new software feature will also be used to investigate the partial replacement of steam by water.

6. Conclusions
The results of a simplified mechanistic model must be used with caution because the particular reservoir, fluid, or operational characteristics may result in different optimum strategies. The proposed post steam operation based on the first mechanistic model was confirmed by the field model. The best steam slug size, however, was not. Each individual situation, therefore, must be simulated to determine the best steam drive case.

As opposed to the results of the sensitivity study, actual temperature data from recompleted wells and new side-tracks in existing steam floods indicate a significant potential for further infill drilling. The location of infill wells, especially in combination with relocated steam injectors, will therefore be analysed with appropriate field models.

7. Acknowledgement
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8. References
STEAM DRIVE PROJECT GEORGSDORF SD 1

1 Steam Injectors 1975 - 1981
2 Steam Injectors 1981 - 1985
3 Steam Injectors 1985 - 1996
4 Post Steam Water Injectors since 1996

Figure 1

Figure 2
Incremental Oil Production from Active Post Steam Water Injection

Net Oil [m³ / month]

0 2,000 4,000 6,000
0 2 4 6 8 10
Years after Start of Post Steam Operations

Water Injection Into Steam Zone
Zero Case: Only Aquifer Support

Figure 3

Heat Energy Balance

Heat Energy [%]

Cumulative Energy Injected
Heat Loss to Over-/Underburden
Energy in the Reservoir
Heat Energy Produced

Figure 4