Enhanced Gas Recovery with Multiphase Pump Equipment at the Sour Gas Field Rütenbrock, Germany

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1. INTRODUCTION

Due to the challenges in finding new reserves and the current high prices of hydrocarbons, the oil and gas industry has made efforts to increase the rate of recovery in mature fields. Sweeping the greatest possible quantity of the hydrocarbons in place in the reservoir is a key objective in order to improve the recovery factor. The use of enhanced oil/gas recovery (EOR/EGR) techniques can boost recovery rates. Also, Multiphase Pumping Technology is an evolving EOR/EGR option for many fields worldwide in different production schemes.

First time the Multiphase Pump Technology (MPT) project investigated an optimized recovery effect on an existing sour gas reservoir with 40 years of production history. The test site Rütenbrock is located in the NW part of Germany and operated by Wintershall.

The reservoir represents a fractured Dolomite formation of the Permian Zechstein (Main Dolomite Ca2) with a thickness of about 30 meters. A detailed static geological model has been designed considering geophysical as well as petrophysical data, interactively being improved by dynamic reservoir data. The final dual porosity simulation model contains 332,280 cells in total and 201,619 active cells. The Multiphase Pump was installed on one well for 2 years during tail-end production as a means for reducing wellhead pressure and consequently accelerating and increasing production.

2. OBJECTIVES & METHODOLOGY

Within the joint projects ("Verbundprojekt"): MPA-Project and the German-Russian cooperation – MPT Fundamental Research on Multiphase Technology in Offshore and Onshore Production this scientific study investigated the Rütenbrock Main Dolomite (Ca2) reservoir performance during multiphase pump operations applying industry standard numerical reservoir simulation.

The process steps in building the geological model includes: setting up a structural model (including fault model, defining stratigraphy and layering process), and subsequently building a property model (including upscaling of logs to cell grid and filling cells with reservoir parameters such as porosity).

For reservoir simulation the methodology consisted of the process stages of initialization, history matching and predictions. Two software packages were utilized, Petrel & Eclipse from Schlumberger and PROSPER, PVTp & MBAL from Petroleum Experts Ltd. The integration of multiphase pump functionality was only achieved by setting the reduced flowing wellhead pressures in Eclipse prediction simulation scenarios.

Data Resources and Preparation

The available geological data sets were collected from the operator and included well data such as well heads, well paths/deviations, well tops, geological profiles, well logs, core measurements/ descriptions as well as structure and thickness maps concluded by production data.

For the description of the Main Dolomite (Ca2) rock/fluid properties and production history, the collected dynamic data include historical gas & water flow rates, static/flowing bottom hole and tubing head pressure measurements, gas & water compositions, some pressure build-up tests and well completion data (depths and tubing/casing details, deviation surveys). All the available geological and dynamic data were filtered, screened and validated.

3. GEOLOGICAL MODEL

A static geological model was built as a basis for subsequent reservoir simulation. The geological 3D-Model is a simplified representation of more or less complex natural bodies based on available data.

Geological Setting

The deposition of the reservoir rock took place during the Zechstein 2 cycle (Stassfurt-Carbonate, Ca2) in the southern Permian Basin. This large intracratonic Basin extended with a length of 2500 km from UK in the west to Poland in the east (Fig. 3.1) and with a width of 600 km from Denmark in the north to Germany and Netherlands in the south. During the basin subsidence in late Permian times the Zechstein marine transgression had rapidly taken place from the north. Deposition within the basin was controlled by sea-level fluctuations and resulted in up to 2000 m thick siliciclastic-calcareous-evaporitic cycles.

The Stassfurt-Carbonate is developed in the study area in slope facies with transition to basin facies to the north (Fig. 3.1). It is approximately 30 meters thick and consists of fine-grained grainstones, packstones and mudstones.

The field Rütenbrock consists of five compartments, which are separated by faults with an offset of up to several hundred meters (Fig. 3.2). The well Rütenbrock Z10a (RB_Z10a), where the multiphase pump has been installed, is located at the top of the structure of the main compartment.

Building the Structural Model

Building the structural model is a stepwise process. In this study the geological modeling was interactively improved by simulation results. All relevant data were imported to Petrel and the stratigraphic sequence was constructed. Surfaces of the top and bottom of the reservoir were created and subsequently a fault model was built and the geometry of the cell grid was defined. Several realisations with different numbers of layers showed that with a vertical resolution of 60 layers for the approximately 30 m reservoir interval measured porosity values were upscaled to the model with almost no averaging loss during the upscaling process. Less number of layers seemed to level out the measured values.

With the evaluated vertical resolution of 60 layers to preserve log resolution the length and width of each cell was evaluated to be 150x150m, resulting in 332,280 grid cells in total.

Building the Property Model

The sonic measurements available at nearly all wells were compared and validated with available core measurements, shale corrected and then used for porosity calculation. The resulting porosity logs were upscaled to the model. Evaluation of core measurements indicated the existence of a dual porosity system with an unknown proportion of fracture porosity throughout the field. According to Nelson[9] (2001), fracture porosity is principally less than 2%; in most reservoirs less than 1%, with a general value of less than 0.5%. For the Main Dolomite (Ca2) reservoir a fracture porosity of 0.5% was assumed.

For the distribution of matrix porosities stochastic (Fig. 3.3) and deterministic modeling methods have been compared leading to the conclusion that the heterogeneity of the carbonate reservoir is presented better by the stochastic methods. A trend towards lower porosity values northeastwards due to increasing fine sized mudstones described at the well profiles was additionally incorporated in the matrix model.

The uncertainties of the fraction of fracture porosity, the distribution of the matrix porosity over the field and different water saturations being tested led to more than 400 realisations of porosity models which were screened and evaluated together with the reservoir simulation.

The final static model was handed over for the purpose of numerical reservoir simulation including structural model and porosity maps.

4. RESERVOIR PORE FLUIDS

As further objective of investigation, 2 data bases on the variety of typical reservoir rock characteristics and fluids properties worldwide were established in order to get familiarized with the physical and chemical processes in the interaction of reservoir behavior and hydrocarbon production measures.

5. RESERVOIR SIMULATION

To perform the numerical reservoir simulation, a dynamic model was constructed on the basis of the 3D geological model of Rütenbrock integrating the reservoir rock, fluids, flow functions and production history data.

Rütenbrock Field: Production History

The operator Wintershall has discovered the Rütenbrock gas field in 1959/1960 and developed the field in the following years. Production from the Main Dolomite (Ca2) reservoir started in 1971 and continued from some wells to date. Due to the existence of sealing faults, the Main Dolomite (Ca2) reservoir is comprised of five compartments shown in Figure 5.1. Twelve wells were drilled on the structure and 10 wells have produced from the Main Dolomite (Ca2) reservoir. Only 4 wells including RB_Z10a have produced from the main compartment. The field cumulative gas production history (Fig. 5.2) shows that after 25 years the field was approaching with steep decline of production rates the tail-end production phase. The multiphase pump has been tested on well RB_Z10a from 01/2004 to 03/2006. After the pump phase RB_Z10a was produced intermittently at consistently decreasing rates up to date.

Reservoir and Fluid Properties

Porosity and permeability were obtained from wireline logs and core data respectively. There was no information on the detailed porosity and permeability distribution at Main Dolomite (Ca2) reservoir. The existence of a dual porosity/dual permeability system (matrix and fracture porosity) on the Main Dolomite (Ca2) reservoir was confirmed by the evaluation of core data (Figure 5.3). Two basic trends can be identified; a trend of high permeability & low porosity assigned to the fractures and the other trend of low permeability & high porosity allocated to the matrix. The evaluation of core data in the Main Dolomite (Ca2) reservoir proved that only for the matrix a porosity/ permeability correlation could be derived and used in the simulation. The fracture permeability has been treated as history match parameter.

The volume percentage of gas composition at Main Dolomite (Ca2) reservoir consists of 81.6% methane, 0.39% ethane, 14% N_2, 3.8% CO_2 and 0.0041% H_2S. Different PVT data were assigned to each of the compartments of the field due to the dissimilarity in the volume percentage of main gas composition components (Methane, N_2, and CO_2). Based on the low number of measurements there is an uncertainty on the salinity of the reservoir water.

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Relative Permeability & Capillary Pressure Functions
Since no data about the relative permeability and capillary functions were available, it was necessary to use published data and apply the existing correlations to create the essential tables of flow functions. Relative permeability and capillary functions were considered as uncertainty parameters. Capillary pressure curves were obtained from previous studies[10]. Relative permeability functions were calculated for matrix and fractures using the Corey correlation incorporated in Eclipse simulator.

Free Water Level (FWL) Evaluation
No indication from the history data stated the depth of the gas-water contact. The FWL was obtained through the calculation of the gas and water pressure gradients versus depth using different water salinities. The intersection of the gradients gives the free water level at depth of 3722 m in the main compartment (Fig.5.4). The gas-water contact depth was treated as a history matching parameter.

Dynamic Simulation
The reservoir model comprises a total of 201,619 active cells. The grid cells were assigned with porosity and permeability values. The permeability along the X direction was assumed to be equal to the permeability in Y direction stating an isotropic permeability in the horizontal direction. Vertical permeability is one/10th of the horizontal permeability. All essential data for instance the faults, PVT, SCAL, VFP and production history data were introduced to the model.

Model Initialization
The initialization process consists of the reservoir model validation through the calculation of the original fluid in place volumes. The model initialization allows establishing the initial fluid saturation and the pressure distribution within the reservoir. The model was initialized using initial pressures versus reference depth (437 bara & - 3400 mNN at main compartment) and equilibration data specifications for the initial water saturation. Different methods of matrix initial water saturation distribution have been investigated as average values, by grouping or in normalized form. The average matrix initial water saturation distribution was selected with regard to its suitability in the corresponding simulation history match results. The process of initialization is the most important step for the screening of the constructed porosity models. The essential selection criterion for the model was to verify the calculated initial mobile gas in place 1.9 x 10^9 m^3 (Vn) of the main compartment from the material balance P/Z plot (Fig. 5.5). From the created realisations of porosity models seven models have been selected and tested in Eclipse. The final realisation model was chosen because of the appropriateness of the history match simulation results.

History Matching
The history match process is iterative and validates the hydrocarbon volume present in the reservoir. The history match involved matching simulated production volumes, static bottom-hole pressures and cumulative reservoir production. The history match was focused on the main compartment (Fig. 5.6). The uncertainties in this model were fracture permeability, GWC depth, relative permeability/capillary pressure functions and the presence of flow barriers or tight zones. Concerning the communication between the reservoir compartments, it is obvious that applying sealing faults between the compartments ensure the better match. The build-up pressure test reports were integrated in the simulation model for the verification of the history match. Well tests were used as calibration to adjust the reservoir parameters by comparing pressure response from the model simulation with actual well test pressure response (Fig.5.7).

Finally an optimized history match was achieved and the key solution was a combination of the accurate adjusting of the above mentioned uncertainties. Figure 5.8 shows the pressure and gas rate history match of well RB_Z10a.

In order to match the flowing wellhead pressure of RB_Z10a and to create the most precise VFP vertical flow performance tables, it was essential to test various flow correlations (PROSPER software) to model the well flow up to the surface. The best match of wellhead flowing pressure to the measured was accomplished using the correlation PETEX 4.

Production Forecast
The production forecast of the (best case) history match was carried out for the period from January 2004 to March 2006 with and without the multiphase pump deployment at well RB_Z10a. Table 1 specifies the input data of the history match case. Two prediction scenarios, conventional compression and multiphase pump were compared with actual history production data. Average gas rates of 22,000 m^3/day for the multiphase pump scenario and 20,000 m^3/day for the conventional compression scenario have been assumed. The lowest limit wellhead pressure of the conventional compression scenario was set to 13 bar, in the multiphase pump scenario to 2 bar.

Forecast Simulation Results
The positive impact of the multiphase pump is confirmed by numerical simulations. The forecast simulation for the production period 01/2004 to 03/2006 integrating the multiphase pump resulted in a cumulative gas volume of 17.2 million m^3, representing an increase of 4.2% compared to the actual produced total gas of 16.5 million m^3 for the same production period. In contrast, the forecast simulation for the conventional compression resulted in a cumulative gas volume of 3.3 million m^3 with only one fifth (-80%) of the actual gas production (Table 2).

Multiphase Pump Efficiency
The analysis of daily production reports from 2004 to 2006 shows an average increase of 15 m^3/hr by multiphase pump compared to the conventional compression rate (Fig. 5.9). Based on the actual operation hours from 01/2002 to 03/2007 the well efficiency of RB_Z10a was calculated 98% for the utilization of the multiphase pump between 01/2004 and 03/2006 compared to 88% during the conventional compression phase between 01/2002 and 12/2003 before the deployment of the MPT test facility, excluding shut-in periods, and 55% by including the shut-in periods (Fig. 5.10).

6. CONCLUSIONS & OUTLOOK

The investigated reservoir performance of the Rütenbrock Main Dolomite (Ca2) reservoir during multiphase pump operations revealed the following:

1. The structural model was successfully constructed and confirmed by the reservoir simulation.

2. The limitation on petrophysical data led to a large number of model realizations that were screened and interactively advanced in order to provide the basis for a successful simulation.

3. The prediction simulation results of the period 01/2004 - 03/2006 demonstrate that the continuous application of the multiphase pump had a positive impact on the gas recovery of well RB_Z10a.

4. Based on the actual production data analysis, well RB_Z10a turned out to be more efficient by the deployment of the multiphase pump between 01/2004 and 03/2006

Further simulation runs are ongoing in order to optimize the model and apply same in an integrated full field production model.

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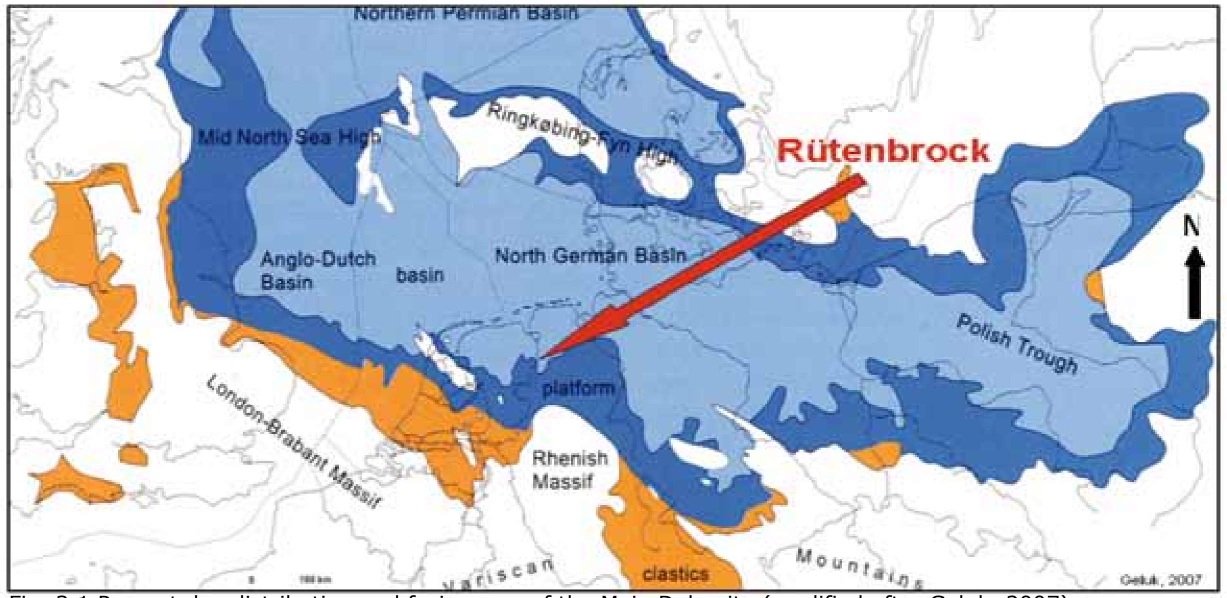

Fig. 3.1 Present day distribution and facies map of the Main Dolomite (modified after Geluk, 2007)

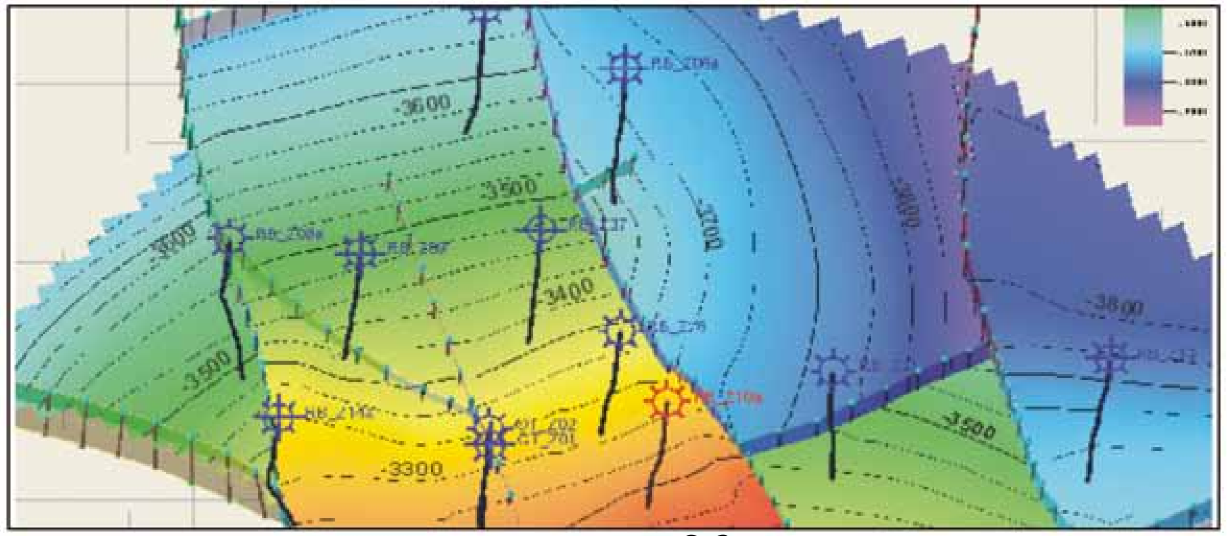

Fig. 3.2 Perspective view of the structure map Main Dolomite (Ca2) at Rütenbrock gas field.

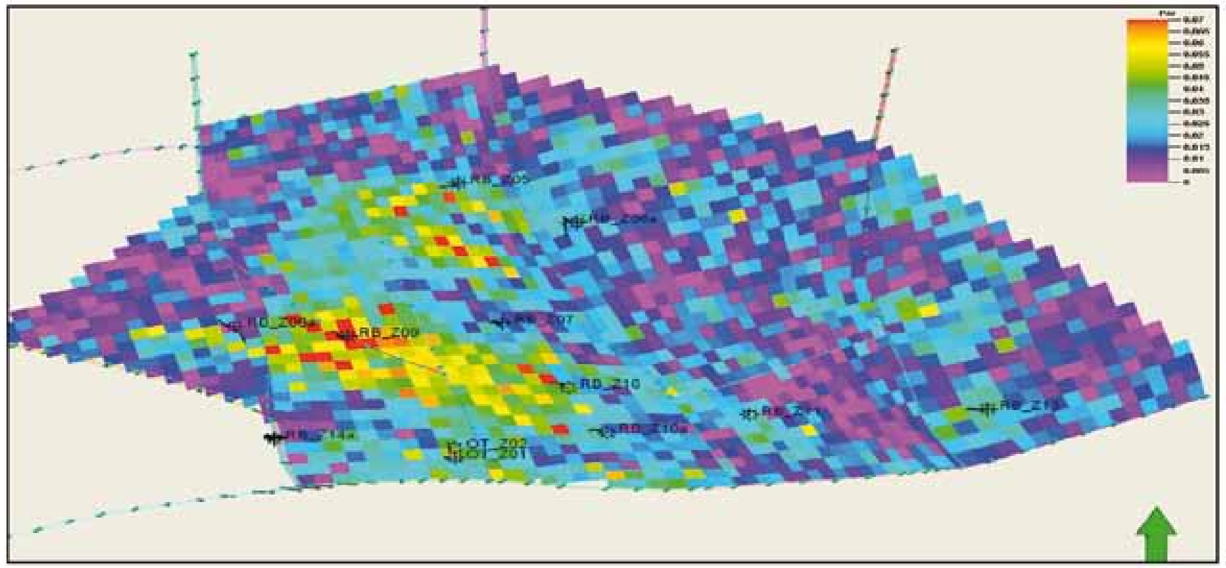

Fig. 3.3 Example of stochastic porosity distribution in the Main Dolomite (Ca2) at Rütenbrock gas field

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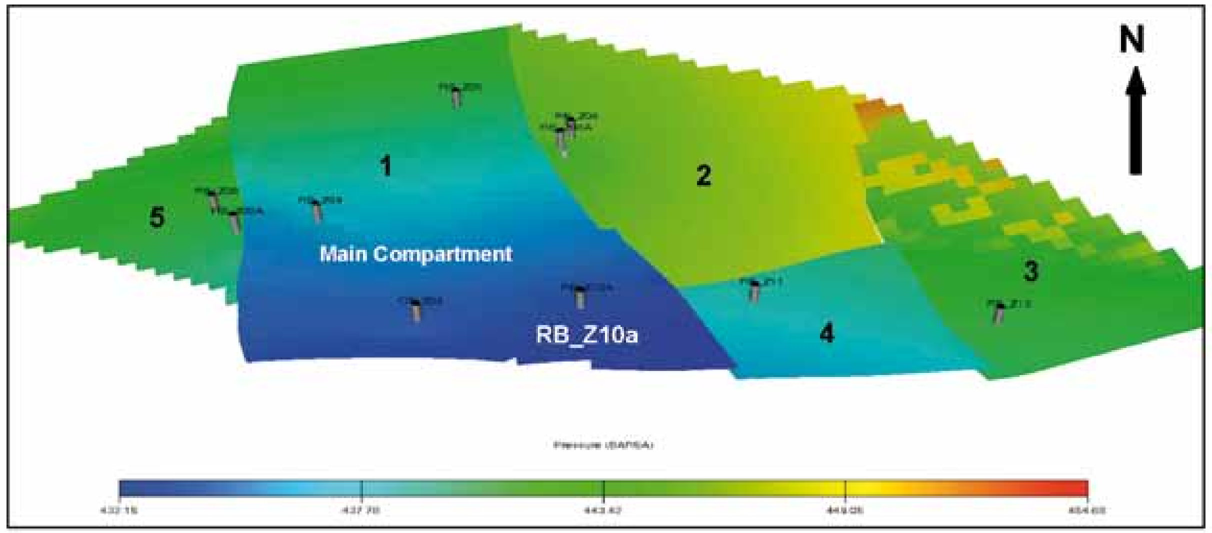

Fig. 5.1 Perspective view of the Main Dolomite (Ca2) reservoir structure, well locations and reservoir pressure distribution

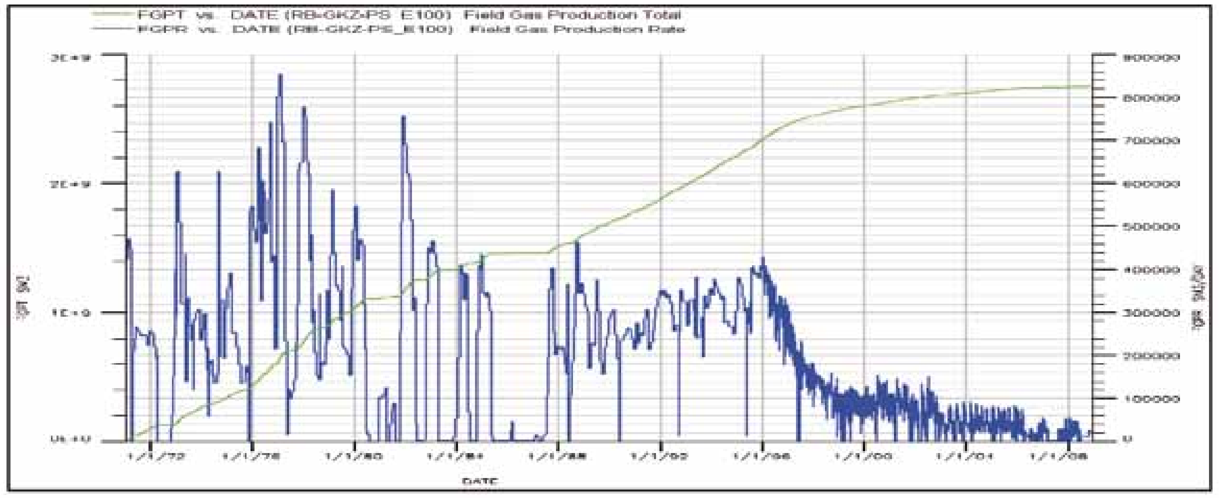

Fig. 5.2 Rütenbrock Main Dolomite (Ca2) cumulative and gas production rate

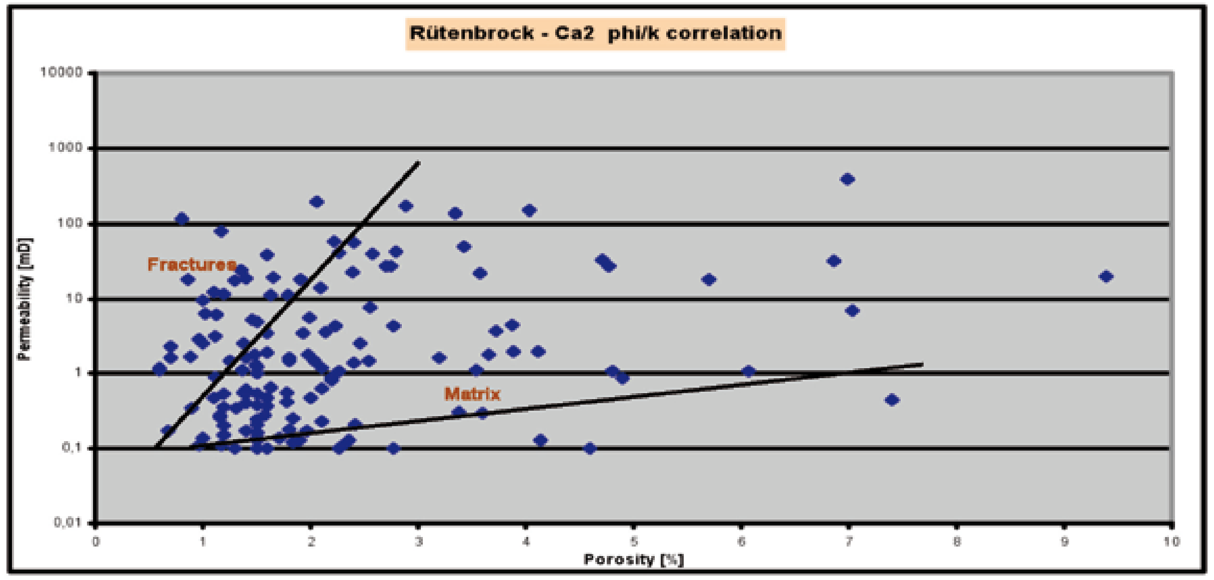

Fig. 5.3 Main Dolomite (Ca2) reservoir fractures & matrix core data

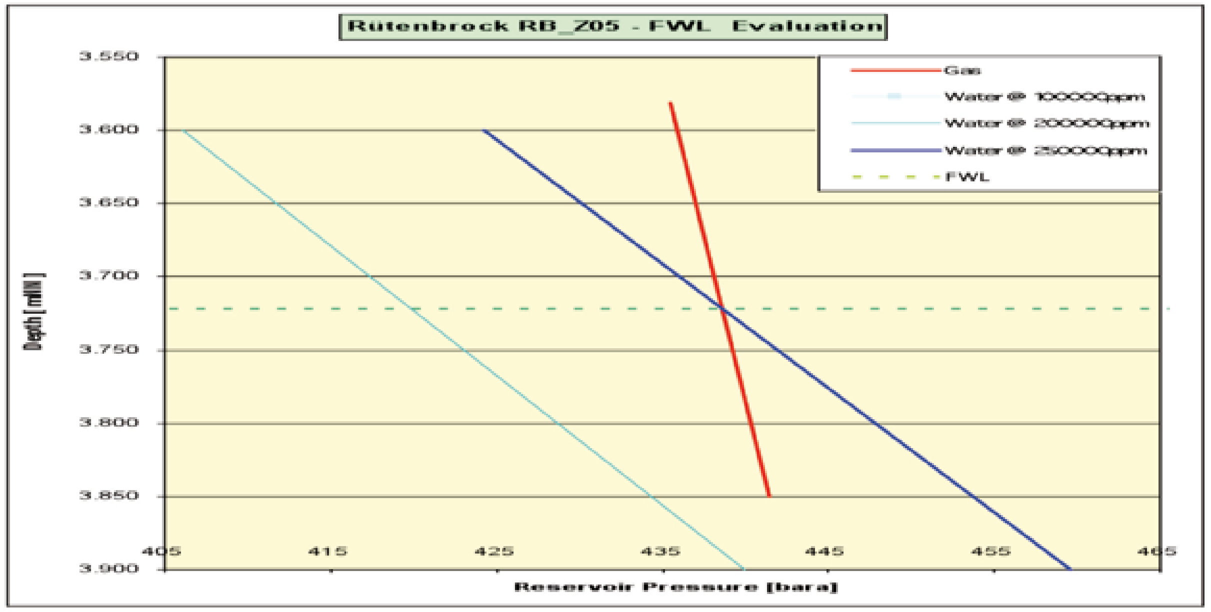

Fig.5.4 Free water Level (FWL) in the main compartment

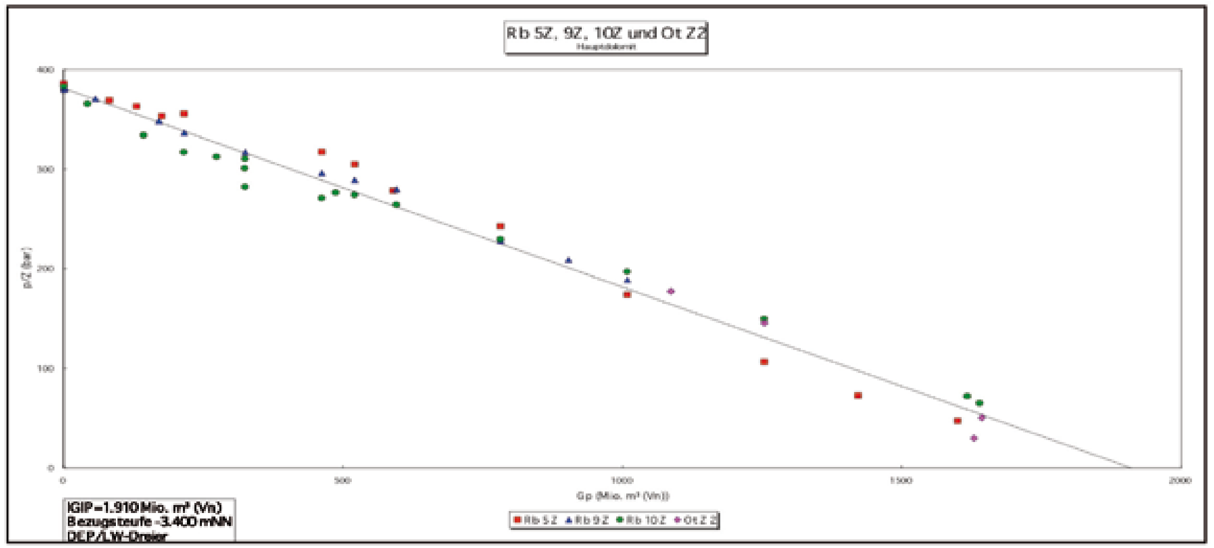

Fig. 5.5 GIIP calculation - P/Z vs. Gas production from the main compartment

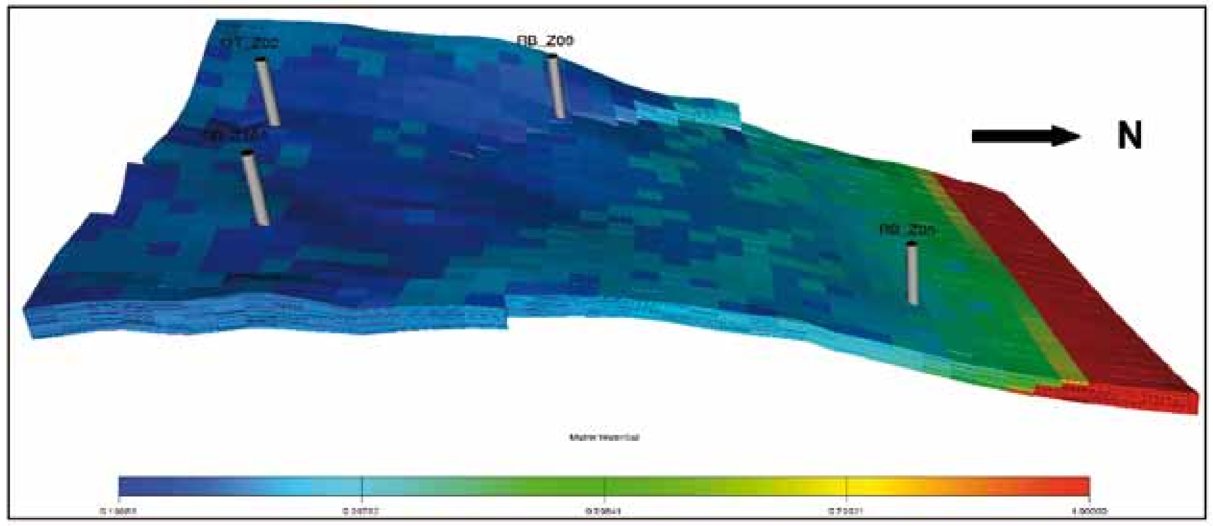

Fig. 5.6 View of the main compartment structure, gas producers' location and matrix water saturation distribution

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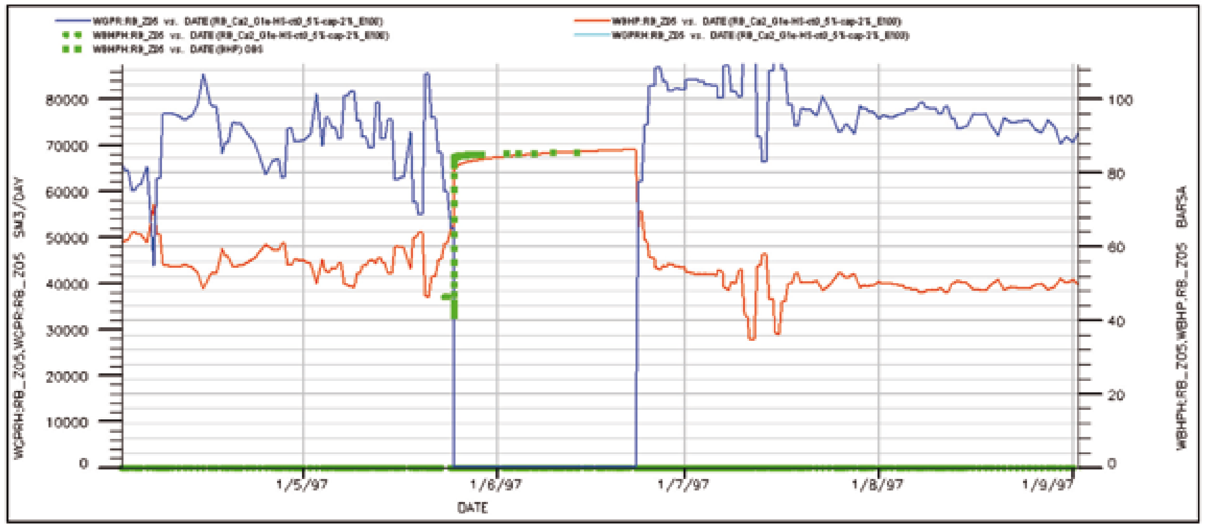

Fig. 5.7 Integration of the pressure build-up test of RB_Z05 in the simulation

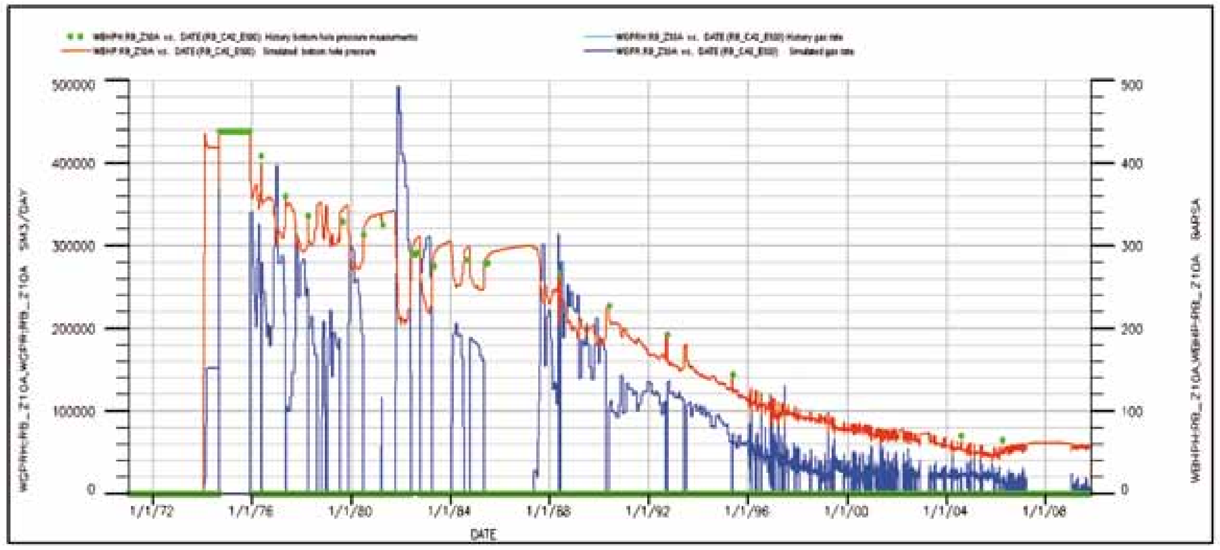

Fig. 5.8 Base case history match at well RB_Z10a history bottom hole pressure & gas-rate vs. simulation

Table 1 Base case data

Simulation case	Base case
Matrix „*cut-off*", [%]	0.5
Matrix-Permeability Correlation	$K = 0.0184 * e^{0.538*\phi}$
Fracture Porosity, [%]	0.5
Fracture Permeability, XYZ [mD]	7
Average matrix initial water saturation, [%]	48
Fracture initial water saturation, [%]	2
FWL Depth, [m]	3722

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Table 2 Comparison of RB_Z10a actual/ forecast production for the period **01/2004 - 03/2006**

Simulation/Actual Production	Gas rate [m³/day]	THP (reduction limit) [bar]	Cum. Gas Mio m³ (01/2004 - 03/2006)	Difference [%]
Actual Production (CC + MPP)	(average) 22000	17 - 2	16.5	-
Forecast CC	20000	13	3.3	- 80%
Forecast MPP	22000	2	17.2	+ 4.2%

*) CC = Conventional Compression; MPP = Multiphase pump; THP = flowing wellhead pressure

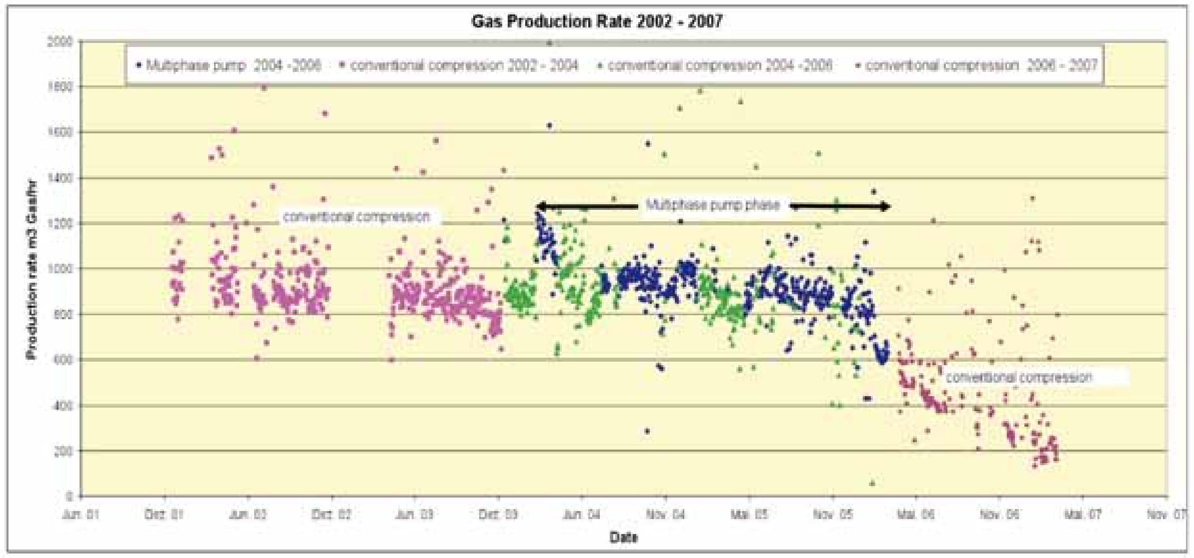

Fig. 5.9 Well RB_Z10a production rate from 2002 to 2007

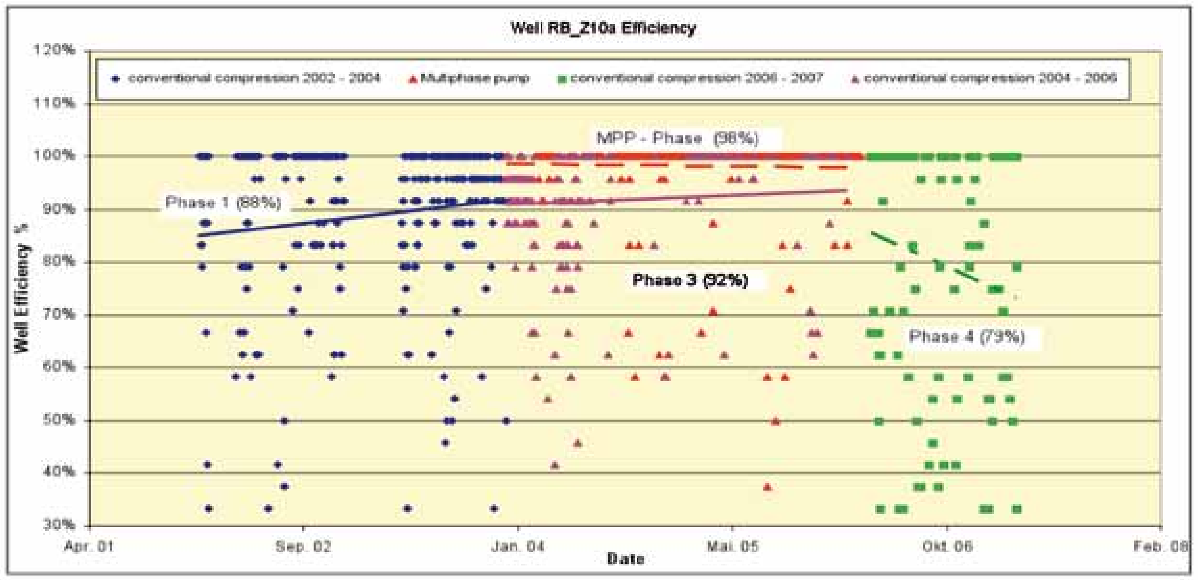

Fig. 5.10 Well efficiency of well RB_Z10a during the production period 2002 - 2007