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Matching Production rates from the Saih Rawl and Barik gas-condensate fields using state-of-the-art Single Well Reservoir Simulation models.

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Abstract

This paper describes how the initial 6 months of production data from the Barik and Saih Rawl gas condensate fields was matched in state of the art single-well-simulation models. A total of 10 wells were matched and very good agreement between the simulated and actual data was obtained. Detailed results are presented for 3 of the 10 wells. The results from reservoir simulation also agreed favourably with results from analytical well test analysis. The production wells in the two fields described have been stimulated with either single or multiple, propped hydraulic fractures.

Introduction

The Barik and Saih Rawl gas condensate fields situated in the central part of the Sultanate of Oman are being developed to supply gas for the Oman LNG project as well as for domestic power consumption. The reservoirs in these fields lie at depths of 4 – 5 km with hydrostatic initial reservoir pressures. Both fields tie into a central processing plant (CPP) which exports the condensate into the existing oil export line while the gas is evacuated down two different routes. Firstly, gas for the LNG plant, situated in the coastal town of Sur, is transported via a 340 km 48" pipeline, and secondly, gas for domestic usage is transported down a 100 km 28" pipeline tying into the existing gas infrastructure. Both the CPP and the LNG plant have two trains capable of processing a total of 40 million Sm³/day of gas. (1400 million ft³/day)

The fields were discovered in 1989 and a total of eight exploration/appraisal wells were drilled. Development drilling started in 1997 and at 1.1.2000 a total of 35 development wells

had been drilled. Production began mid 1999 and a total of 80-100 wells are expected during field life. Both fields are produced under depletion drive.

Reservoir Description

The Saih Rawl field consists of two reservoirs, the Barik Sandstone and the Miqrat sandstone while the Barik field only contains the Barik sandstone. Currently only the Barik sandstones in the two fields have been developed. As a result this paper details the results obtained from production wells drilled in the Barik sandstone only. Top structure maps of the two fields are supplied in **Figures 1 & 2**.

The Barik sandstone is a thick layercake sequence of sand and sand-shale mixtures (known as heteroliths). Most of the heteroliths can be correlated on an interfield scale (50 to 100km) and are 2 to 5m thick. These sand-shale sequence results in a series of self contained flow units that have a low average permeability of 1 to 5 md. Some thin higher permeable zones (50 md) exist towards the bottom of the reservoirs.

Saih Rawl is the larger of the two fields and is expected to contribute approximately 70% of the LNG sales. The top of the Barik Sst. is at a depth of 4300m with a typical reservoir thickness of 200m. The reservoir is divided into 8 main flow units above the free water level. (**Fig.3**) The initial reservoir pressure is 513 bar, and the temperature is 137 degC. The dewpoint pressure is 424 bar and the initial condensate gas ratio (CGR) is approximately 450 Sm³/million Sm³.

The Barik field is smaller in size and is expected to contribute approximately 30% of LNG sales. The reservoir is divided in 6 separate flow units and is typically 100m thick. Top reservoir is at 4100m and the initial reservoir pressure is 479 bar. The temperature is 129 degC. The dew-point pressure is again 424 bar and the initial CGR is approximately 900 Sm³/million Sm³.

In terms of PVT characteristics the fields see moderate to high condensate drop-out from CVD experiments. The maximum liquid drop-out for the SR and BK fields are 9% and 25% respectively.

The low permeability has lead to an intense and successful stimulation program. In SR, 3 to 4 fractures are placed while only 1 to 2 fractures are placed in the BK field wells.

Method of Matching

The ten wells presented in this paper have all had welltests with down hole gauges installed. None of them have had down hole shut in tools installed due to the risk of proppant backflow leading to stuck tools. Even with large wellbore storage effects, fracture signatures are clearly seen on the log-log (derivative) plots from analytical well test matching. In addition, some of the wells were specifically tested with the flowing BHP staying above the dewpoint. This was to ensure single-phase flow and therefore a good estimate of reservoir KH without any relative permeability effects hampering analysis. Having analysed the well tests with the analytical well test package from PAN system, (both single and two phase analysis depending on whether the flowing BHP fell below dew-point) the results were transferred to single well simulation models and served as the starting point for matching 6 months of production data. The single well models built have the following characteristics:

- Quarter models with logarithmic spaced cartesian coordinates
- Fractures modeled explicitly with gridblocks being only a few millimeter wide
- Models run in both equation of state and volatile-oil mode
- Capillary number dependant relative permeability applied at each time step for each gridblock.
- In general 8 to 15 geological layers were modeled
- Non Darcy and multi-phase flow modeled in both reservoir and fracture.

The simulation models were run in both equation of state and volatile oil mode with very similar results. As a result the voloil mode was used most frequently to decrease simulator run times. Relative permeability data from SCAL measurements for varying capillary numbers was included in the models and at each time step the simulator assigned the relevant relative permeability curve to each and every grid block. In general, for the SR field the capillary numbers in the fractured wells rarely increased to values large enough for the relative permeability to rise above the base line. Not even very close to the wellbore would this happen. For the Barik field however, strong viscous stripping is observed with the relative permeability significantly above the base line rel. perm curve obtained from SCAL measurements. This viscous stripping results in a 3 fold increase in relative permeability in BK as compared to SR.

The history matching consisted of inputting the gas production history and matching on the FTHP. Relative permeability curves from SCAL verified by welltest results from specifically designed above and below dew-point tests were subsequently fixed in all simulations. Parameters varied to obtain a match include reservoir KH and fracture dimensions, more specifically the dimensionless fracture conductivity, F_{cd} .

$$F_{cd} = \frac{K_f * w}{K_m * X_f}$$

To verify the PVT model, condensate production was compared to production data once a match on THP was obtained. Both PVT models predict condensate production rates to within 15% of the actual measured condensate volumes.

Results

The results obtained are presented in **table 1**. In this table the results from analytical well test analysis is compared with the results from matched simulation models. As can be seen, very encouraging results were obtained where the results from 6 months of initial production data matched in the single well simulation models matches closely to the results from analytical well test data.

The amount of data that can be obtained from well test analysis depends essentially on the duration of the flowing and build up period coupled with understanding how long wellbore storage will mask reservoir response. As a result of not using down-hole shutin, no fracture signature is seen on the derivative plots from early fractured wells. As the fracture treatments got larger, however, the fracture characteristic clearly shows up. Below is shown how the well test results have changed with improvements in fracture placements, both in terms of tonnage of proppant, fracture dimensions and size of proppant.

The early fractures with fracture half-lengths (X_f) of approximately 20m did not show up on the derivative plots as they are completely masked by wellbore storage. Large skins are also apparent from the separation of the two lines. Gradually, as larger and better fractures were placed into the formations its signature becomes apparent on the derivative plot and the separation between the two lines is smaller indicating less skin. The largest fractures placed have a X_f of approximately 100m.

Today well tests are being carried out as indicated below where not only the fracture signature is seen but where also the radial flow portion of a test is reached. Three distinct signatures are clearly seen in **Figure 5** which depicts the derivative ("log-log") plot of Well J from well test analysis. Wellbore storage is followed by late time fracture flow which is finally followed by radial flow.

Tests have been carried out with the FBHP both being above and below the dew point to be able to match on reservoir KH as well as relative permeability.

Having matched the well tests using analytical techniques, the results were used as the starting point for matching the first 6 months of production data. Matching this data was crucial, as it is necessary to understand the decline rate to ensure enough wells are drilled to meet the contractual sales agreement. As is evident from **Table 1**, very good matches were obtained in all 10 wells matched. The difference between the results from the analytical well test analysis and reservoir simulation history matching are generally within $\pm 10\%$. Well C&D have had additional perforations added after well testing resulting in somewhat different KH results. This is also seen in

Table 1 where the KH from simulation (post additional perforations) is higher than the KH obtained from well test analysis (pre additional perforations).

Below, 3 example matches are shown which show the degree of match obtained. Two graphs for each well are shown. The first figure shows the match on THP, comparing the actual measured FTHP with the history matched FTHP. The second figure shows the well production history and GOR. The 3 wells presented are wells B, C and J which correspond to the same wells presented in **Figure 4 and 5**. (Well E has little production history and has therefore not been included)

Well B, SR-Field

Well B is a SR producer which had an initial maximum rate of 2.2 million Sm³/day at 105 bar FTHP. It is located in the southern crest of the SR field. Three, out of 4 attempted, fractures were placed in the formation. A total of 65 tonnes of proppant was placed.

No fracture characteristic is seen on the log-log plot during pressure transient analysis indicating a fairly small effective fracture length. This is to be expected with the small amounts of proppant placed in this first development well in SR.

As can be seen in **Table 1**, the match in the reservoir simulator confirms the KH derived from well test analysis. The difference in matched fracture lengths as well as Fcd can be attributed to fracture cleanup. Also, the fact that no fracture characteristic is seen in the well test analysis increases matching uncertainty and large variations in Fcd are possible when assuming small fracture lengths in analytical well test packages. It is not possible, in the SWM, to obtain a match with the frac length obtained from well test analysis. With such a small Xf no match is possible in the early fracture dominated flow and a large increase over and above the well test KH is needed to match late time production data. Subsequent tests on this well are recommended to verify whether the well has indeed experienced fracture clean-up. As seen in **Figure 6**, with the larger Xf (45m) a very good match on FTHP is obtained both during early time, which is mainly controlled by fracture characteristics and late time, where the reservoir KH is mainly dominating the production level.

The GOR in **Figure 7** is relatively constant over the production period although it does drop off for short periods of time immediately after opening up wells. This is often seen in gas condensate wells and is due to the well offloading the near wellbore liquids before further gas condensate fluids enter the well. The GOR also temporarily decreases slightly as the drawdown applied decreases towards the end of the production history. The GOR is only expected to rise significantly when the well no longer has any above dew point fluids within its drainage radius.

Well C, SR-Field

The reservoir KH and fracture dimensions for this well are specified in **table 1**.

Well C is a SR production well with an initial maximum rate of 2.6 million Sm³/day at 105 bar FTHP. It is located in the southern crest of the SR field. 4 fractures were placed in the formation. A total of 200 tonnes of proppant was placed.

Figure 9 shows the 6 months production history and the corresponding GOR. For this production level a match on FTHP was obtained which is shown in **figure 8**. As for the previous well, a good match is obtained for the production data both in early and late time. Having two distinct periods where different factors dominate flow behaviour greatly increases the level of confidence that can be placed on the results from the matching process. It is not possible, for instance, to obtain matches by swapping KH for Xf. This will not result in a match as the two flow periods (early and late) are dominated by different factors. Having the simulation results also match results from analytical well test analysis instills a high level of uniqueness in the complex matches.

The relatively large fracture half length is as expected due to the large amounts of proppant placed. This also compares well with the log-log diagnostic plot from well test analysis that indicates a large fracture half-length.

The GOR in **Figure 9** is relatively constant at the initial value which is as expected. Only when the well is no longer connected to any above dew point reservoir is the GOR expected to rise.

Well J, BK-Field

The reservoir and fracture dimensions for this well are specified in **table 1**.

Well J is a BK production well with an initial maximum rate of 2.3 million Sm³/day at 105 bar and is located on the crest of the Barik field. Two fractures were placed with the total proppant placed amounting to 144 Tonnes.

As can be seen from **Figure 10**, a very good match is obtained on FTHP with the simulated FTHP very closely mimicking the actual measured FTHP. The match in the reservoir simulator confirms exactly the KH and fracture dimensions obtained from well test analysis. A good match is obtained both during early and late time.

The GOR in **Figure 11** is gradually increasing over the time period matched which may indicate little or no above dew point reservoir fluids left within the wells' drainage radius. This is mainly due to a nearby well having been on pre-production since 1994.

Conclusions

From the above the following can be concluded:

- The single well simulation models are able to closely match well production behaviour
- Very good agreement is obtained between results from analytical well test analysis and reservoir simulation
- 2 phase analytical well test analysis yields high quality results

- As a result of this tight integration between field, analytical and simulated data, a high degree of confidence exists on forward predictions from the simulation models.

Acknowledgements

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MT = 1.0 E+3 kg

Symbols and Abbreviations

| | | |
|-------|---|---|
| SR | = | Saih Rawl field |
| BK | = | Barik field |
| BSst. | = | Barik Sandstone |
| LNG | = | Liquefied Natural Gas |
| CPP | = | Central processing plant |
| CGR | = | Condensate Gas Ratio |
| GOR | = | Gas Oil (Condensate) Ratio |
| CVD | = | Constant Volume Depletion |
| SCAL | = | Special Core Analysis |
| Fcd | = | Dimensionless Fracture Conductivity |
| Kf | = | Fracture permeability |
| Km | = | Matrix permeability |
| W | = | Fracture width |
| Xf | = | Fracture half length |
| FBU | = | Flowing Build Up survey |
| FDP | = | Field Development Plan |
| KH | = | permeability x thickness product (mD.m) |
| THP | = | Tubing head Pressure |
| FTHP | = | Flowing Tubing head pressure |
| PVT | = | Pressure, Volume, Temperature experiments |
| FWL | = | Free water level |
| LNG | = | Liquefied Natural Gas |

SI metric Conversion Factors

| | | | | |
|-----|-----------------|-------|-----|-----------------|
| Bar | = | 1.0 | E+5 | Pa |
| Ft | = | 3.048 | E-1 | m |
| In | = | 2.54 | E-2 | m |
| °F: | (°F - 32)/1.8 = | | | °C |
| lbm | = | 4.535 | E-1 | kg |
| gal | = | 3.785 | E-3 | m ³ |
| psi | = | 6.895 | E+3 | Pa |
| mD | = | 9.869 | E-1 | μm ² |

| Well Test Analysis Results | | | | Single Well Simulation Model Results - Matching production data | | |
|----------------------------|----------------|--------------------------------|-------|---|--------------------------------|-----|
| Well Name | KH (md m) | Avg. Frac $\frac{1}{2}$ length | Fcd | KH (md m) | Avg. Frac $\frac{1}{2}$ length | Fcd |
| A | 40 – 84 | <i>Not seen</i> | - | 78 | 25 | > 5 |
| B | 204 | 20 | 0.5 | 224 | 45 | 4 |
| C | 156 | 80 | 0.9 | 169 | 80 | 1 |
| D | 45 – 64 | 100 | 2 – 4 | 98 | 100 | 3 |
| E | 250 – 270 | 100 | 1 – 3 | 220 | 100 | 1 |
| F | 60 | 15 | > 5 | 60 | 15 | > 5 |
| G | 140 – 154 | 17 | > 5 | 150 | 15 | > 5 |
| H | 112 – 126 | 60 – 75 | 5 – 7 | 157 | 60 | 5 |
| I | 240 | 35 | > 5 | 201 | 60 | 2 |
| J | 330 | 60 | 0.5 | 330 | 60 | 0.5 |

Table 1: Well test analysis and Single well simulation model results

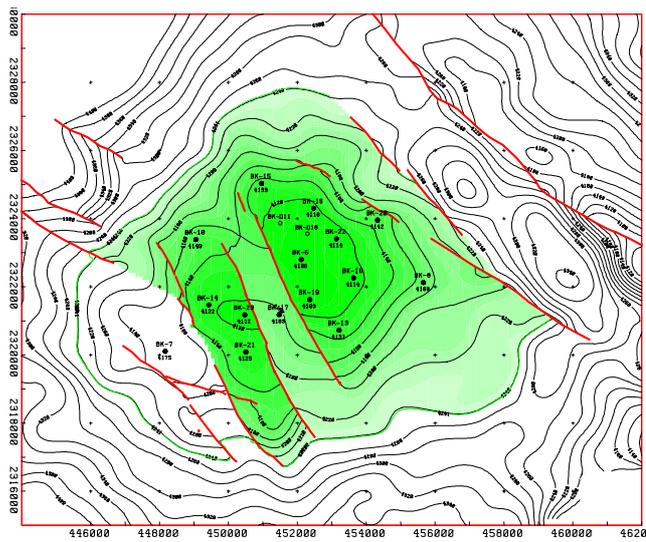


Figure 1. Barik field Barik Sst. top structure map

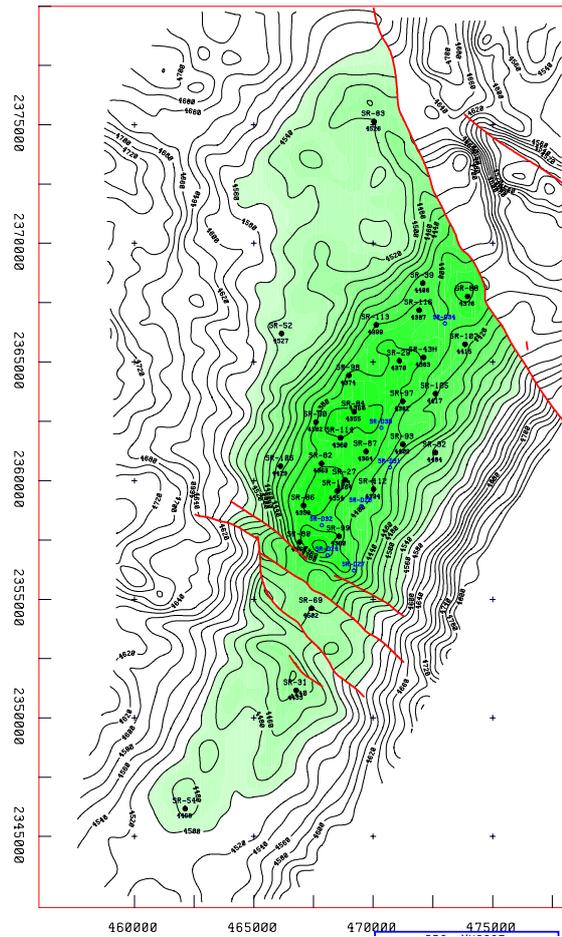


Figure 2. Saih Rawl field Barik Sst. top structure map

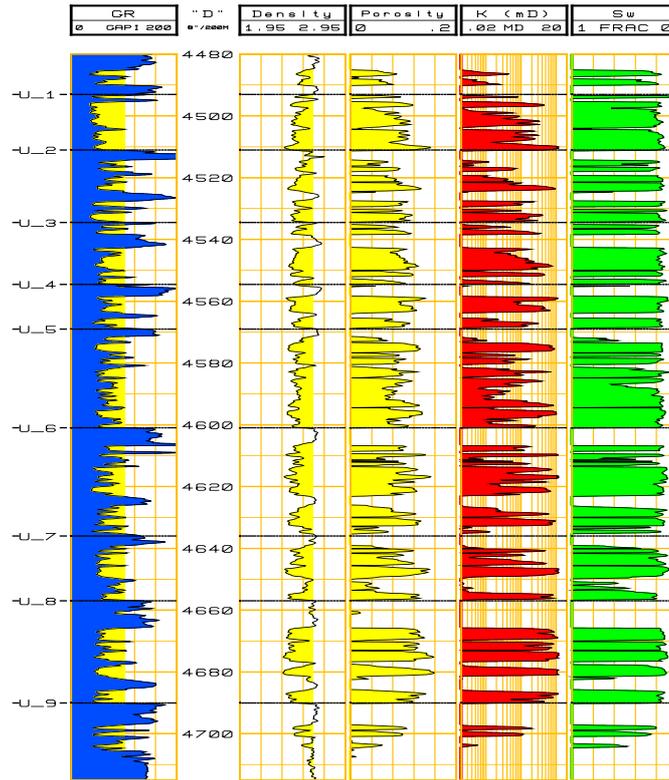


Figure 3 ; Type log of Saih Rawl well (Barik Sst Formation). Heteroliths are characterised by high GR, density over (shaded) cut-off. Main heterolith layers are in general very continuous over the area of the field. Depth, D, in meters abhdf, FWL at 4712 m abhdf. Geological sub-units indicated in the left hand column.

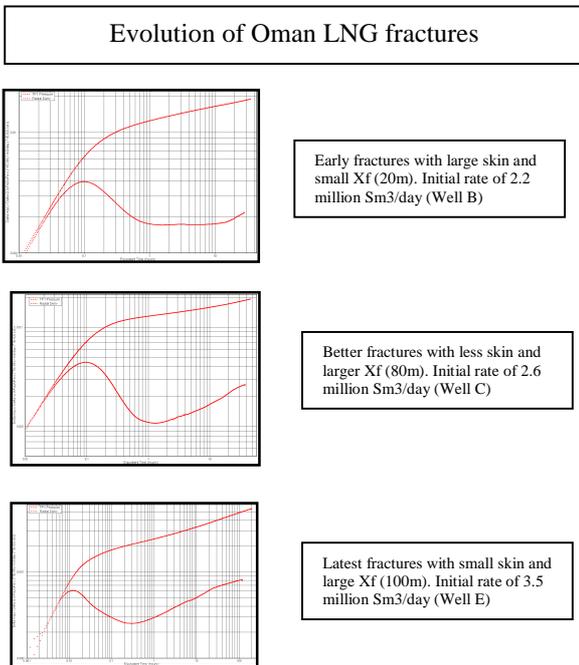


Figure 4 – Evolution of well test signatures from well test analysis

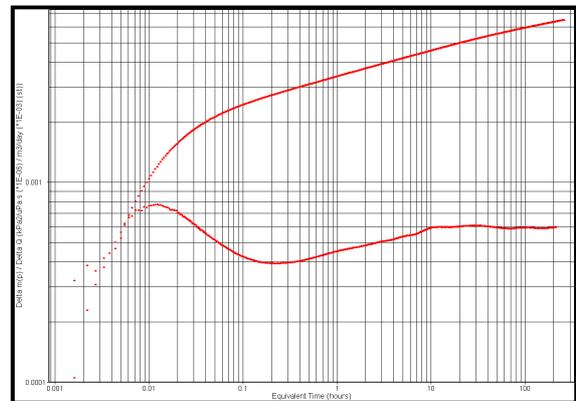


Fig 5 – Well J, well test signature

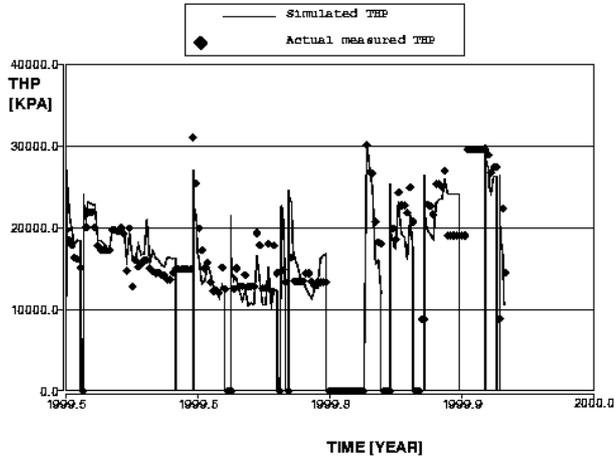


Figure 6 – Well B, Simulated and actual FTHP

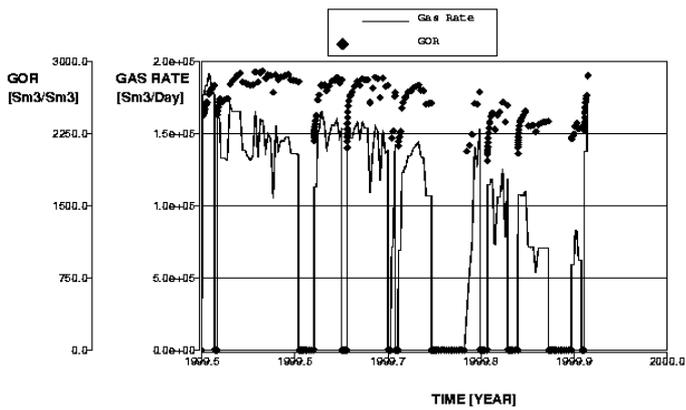


Figure 7 – Well B, Gas production rate and GOR

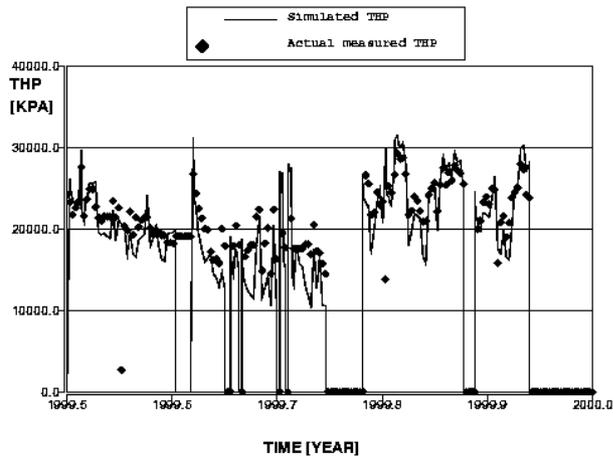


Figure 8 – Well C, Simulated and actual FTHP

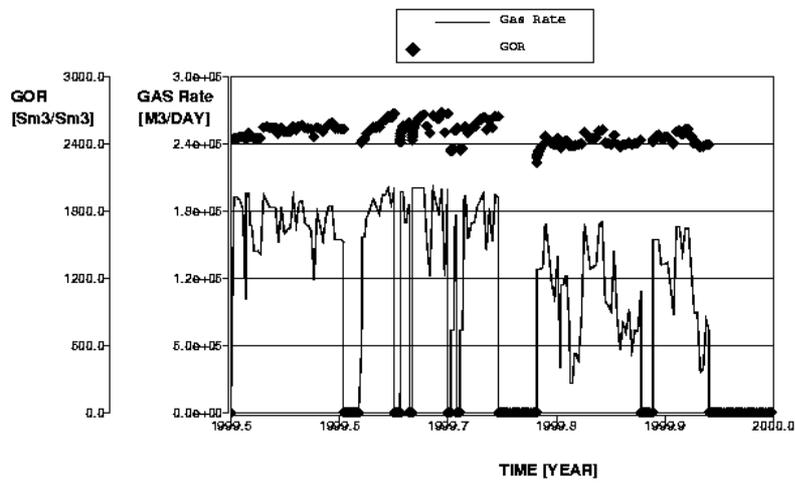


Figure 9 - Well C, Gas production and GOR

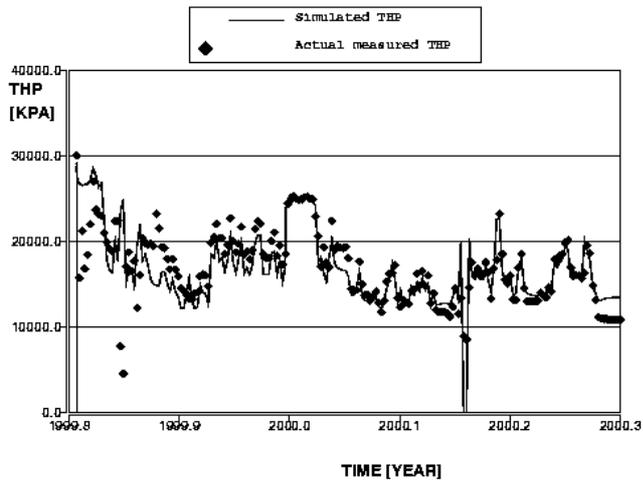


Figure 10 – Well J, Simulated and actual FTHP

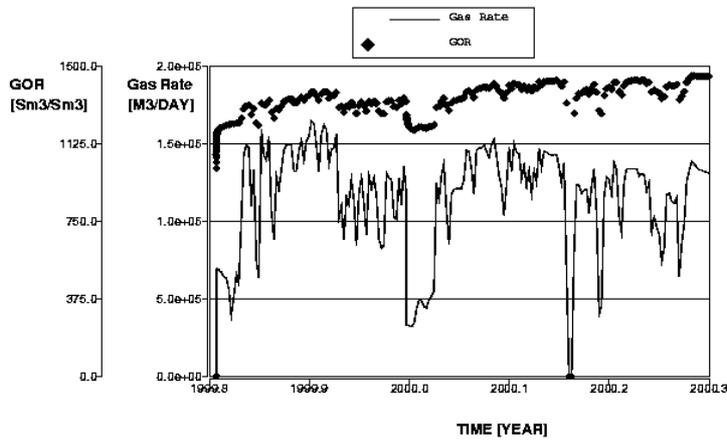


Figure 11 – Well J, Gas production and GOR