IPA99-E-067

PROCEEDINGS INDONESIAN PETROLEUM ASSOCTIATION
Twenty Seventh Annual Convention & Exhibition, October 1999

HORIZONTAL DRAINS IN DEEP, TIGHT GAS RESERVOIRS: TAMBORA FIELD'S EXPERIENCE AND OUTLOOK

Frederic Febvre*
Didier Caie*
Sugimin Harsono*
Januar Wirawan*

ABSTRACT

Tambora is a gas field located in the Mahakam Delta in East Kalimantan and operated by TOTAL Indonésie.

A part of the gas-in-place is situated between 3800 and 4200 m below sea level (mss), in deep multi-layered, fluvio-deltaic sands, with relatively poor reservoir properties.

The initial policy was to produce these reservoirs by comingling with shallower and better quality sands, through multi-packer well completions. The result to date is that these tight sands have been largely under-produced.

Following advances in drilling technology, the re-development of these reservoirs has become possible by means of horizontal drains.

This paper presents a new drilling strategy with the first horizontal well, which was drilled in 1997 to a record-depth of 3900 mss, with a conventional drilling rig. Successful production performances are presented with the reservoir simulation studies that guided the well design. This paper also summarises the specific problems faced and techniques used when drilling this well. Historical data, test results and both numerical and analytical interpretations are presented.

A brief section summarises why horizontal drains are a better development option than hydraulic fracture jobs for Tambora deep sands.

The paper concludes by a discussion of future plans focusing on multi-drain side-tracks, drilled through the completion string of existing wells with a coiled tubing unit.

INTRODUCTION

The Tambora Field is located in the delta of the Mahakam in East Kalimantan on the Island of Borneo. TOTAL Indonésie discovered the field in 1973, with production commencing in 1984 of the shallow oil reservoirs. Due to oil production decline and an increase in LNG demand, the field was converted to gas production in 1990.

The gas is produced from multi-layered, fluvio-deltaic sands, lying between 2500 and 4200 mss. The porosity of these reservoirs decreases with depth from 33% to 8%, and the permeability from 5000 to 0.6 mD. A part of the IGIP lies below 3800 mss in relatively poor quality reservoirs, of the so-called zone G.

The initial policy was to produce shallower and better quality sands by comingling, through multi-packer well completions. The tight G-zone sands would then be brought on production after the upper horizons were depleted or water-flooded. However, the low productivity of these zones has meant that these tight sands have so far been under-produced.

Various techniques have been reviewed to improve recovery from these reservoirs, both through new and old completions. Horizontal drilling has emerged as the most promising technique. The first horizontal well to be drilled in TOTAL Indonésie was designed specifically for the production of the G-zone reservoirs of the Tambora Field.

* Total Indonesie

TAMBORA G ZONES LIMITED PRODUCTIVITY

The gas from the G-zone of Tambora is the deepest in the field. The initial gas in place (IGIP) of this zone is over several hundred Bcf of which 10%, has been produced so far, compared to more than 40% for the shallower reservoirs. These thin, channel sand reservoirs are 0.5 to 30m thick with inter-layer water bearing sands, shales and coals.

The main difficulty in producing this G-zone is the tightness of the formation. The permeability is around 1 mD and the porosity is as low as 8%. With these kind of characteristics, the productivity is very poor and many of the DST's performed on this zone in the early 1980's without stimulation, resulted in no-flows.

The existing comingle completions are not favorable to reservoirs with a low Productivity Index (PI), when completed with upper zones with a PI several times better (Figure 1). However dedicated vertical completions could not be economically justified for such poor zones.

The existing development with vertical well completion in several zones of contrasting reservoir charateristics, means that the G-zones would remain under-produced. This means that in order to maintain the existing plateau, the field would require early gas compression facilities, while the ultimate recovery of the G-zones would remain poor.

PRODUCTIVITY ENHANCEMENT ALTERNATIVES

Two possible solutions to enhance the productivity from the G-zones were considered: firstly, hydraulic fracturing and then dedicated horizontal drains.

Hydraulic fracturing was briefly studied, but the fracturing gradient was estimated from nearby field data, to be around 0.3psi/m, equivalent to a frac. Pressure of over 12,000 psi at reservoir depth. The existing casings were not designed for such high requirements and most of them had already been weakened by earlier FIT perforations. For such thin zones with nearby water sands, there was also the potential risk associated with the non control of the fracture height. Additionally the existing surface facilities could not support this type of heavy work-over without major upgrading. Operational data available from a nearby field, also showed that success was not guaranteed.

Horizontal drilling appeared to be more attractive, either through dedicated completion, or side-track of existing dead wells. The productivity enhancement for the selected G-zone was thought to be around 4 for a drain of an optimum length of 700m. A parametric reservoir simulation supported this estimation.

For the first horizontal well target, a large reservoir was selected for its low productivity, namely: G53C-T12. The key parameters of G53C-T12 are summarised in Table 1 and Figure 2.

The only well producing from this reservoir at that time (TM-34) was close to its minimum possible well head flowing pressure (1015 psi).

DEEP DEPLETED SANDS HORIZONTAL DRILLING

A feasibility study highlighted many risks attached to such a deep horizontal well:

- It was a Company first and, despite similar experiences in other affiliates, it was not known whether the local conventional drilling rig could achieve such high technological requirements. In particular TDS, drawork, and mud-pumps were a concern and much time was spent on the preparation of this equipment.

- The targeted reservoir was known to be depleted. Equivalent density (Deq.) was estimated from a nearby pressure survey to be 0.78 g/cc. This would require a light oil based mud system to minimise formation damage.

- The Bottom Hole Assembly selection was critical (mud motors, bits, steering). Hole cleaning was a particular concern at these depths, with the low Deq. mud.

- Due to the lack of historical references, all the predictions of the torque and drag could only be taken cautiously. Although the recommended drain length was 700m, nothing guaranteed that it could be drilled.

- Pilot hole and well to well correlation would be critical for the steering of the well. However these would not be sufficient for such a thin reservoir with large well spacing. Therefore advanced gas logging was designed to help steer the well in the reservoir in real time.

- Hole stability of the horizontal section was also a concern, although a study indicated that a perforated liner was not required, hence the well was designed with an open-hole completion.

Drilling Performance:

- The well was drilled and completed in 68 days; the profile is summarised in Figure 3. Drilling included an 8"½ pilot hole down to the base reservoir for geological correlation. The hole was then plugged back and side tracked to reach 90° inclination in the reservoir. However the motor drive shaft and the bit were lost in the hole whilst pulling out. Fishing was unsuccessful and a technical side track of the well was required.

- A 7" liner was run and cemented to cover the shale above the reservoir. The horizontal section was drilled in 6" diameter and left in open hole. Target Depth (TD) was reached at 4460m Total Measured Depth (TMD), or 3855m True Vertical Depth (TVD). Total departure was 804m. The drain was washed with solvent before displacement with diesel to run the completion.

- Due to low ROP, both in sliding mode and rotary mode, in addition to difficulties to maintain the proper inclination, the decision was made to stop drilling after 403m of horizontal drilling. This was within the range of optimum drain length designed from reservoir simulation (between 400 and 700m).

- In summary, the main problems encountered during the drilling phase were:

- Low ROP in phase 12"1/4, 8"1/2 and 6", that can be explained by the hard formation, and steering difficulties (hang up, WOB transmission, tool face control).

- Directional equipment failures including 1 motor broken during the 8"1/2 phase, requiring a technical side-track, and 4 MWD failures. During 6"phase, the 4"3/4 PDM runs were drastically reduced to 40 circulating hours maximum.

- Critical directional problems during the 6"horizontal drain: the high trend to build and veer to the left was very difficult to brake, even with a long section of "low side" sliding.

Gas logging:

During the drilling of the pilot hole in the 8 ½", the gas logger was calibrated using the following gas data: TG (Total Gas), C1, C2, C3, and ratios C1/C2, C1/C3, C2/C3. In this reservoir TG of more than 3200ppm and C1 more than 3000ppm (MW: 1.17gr/cc) were recorded. The classical ratio Wh (hydrocarbon wetness), Bh (balance), did not give any significant results. The most reliable ratios were C1/C3, C2/C3 and the following parameters were used for geological monitoring of the drain: C1/C3 (cut off > 30), C2/C3 (cut off > 4).

Variation of the TG was in the range of 500 to 15000ppm (MW: 1.0 g/cc). The ratio C2/C3 was above 4 as long as we remained in the targeted reservoir section and variation of C1/C3 ratio ranged between 8-100 (Figure 5). No formation change could be detected from cuttings (composition remained almost the same: 80-90% sandstone and 10-20% shale). The gas shows were erratic, being dependent on drilling parameters and also reservoir properties (Vsh, porosity).

Since the hole drilled was designed to follow a slight dip of the formation and the reservoir was assumed to be well known and thick enough, it was expected to stay confined to the targeted reservoir section only.

In conclusion, the detailed correlation between existing wells was very important to decide the horizontal profile during the well design, and also to monitor progress during the drilling operations. Gas ratio by itself was a great help to fine tune, but could not have been substituted for good well planning.

Synergy between geology-reservoir and drilling departments:

The rig was primarily used for conventional drilling and hence was new to this kind of high tech work. However, good "on site" communication between the drilling operator, directional drillers, geologists and service companies ensured the success of this horizontal well. Steering the well from gas logging analysis and well to well correlation was not a straight forward technique. It required continuous feed-back from all involved parties in order to ensure the drain was placed at its optimum location within the reservoir at all times.

COMPLETION / START UP

Due to the low reservoir pressure (Deq. 0.78), the well was slowly started up with a snubbing unit, pumping gas down to displace the diesel-based completion fluid. The initial rate was 12 MMscfd at 123 bars WHFP.

However during the clean up phase, a mix of brine, sand and drilling mud slugged to the surface and eventually clogged the macaroni in the packer assembly restrictions at 3833 mBRT. After several days of pulling, a fish was left in the hole hence the well could no longer be produced. It was not clear whether the hole had collapsed or if the drilling mud had caused the macaroni to be stuck.

Due to the very promising initial rate, it was decided to go back to the well with the drilling rig to fish out and replace the completion with a $4^{1/2}$" slotted liner in the horizontal drain.

The rig work-over was straight forward, and the horizontal open hole was found in perfect condition. Hence it was concluded that the cement and mud mixed with completion fluid, got the macaroni stuck.

Well Performance:

Again the well was slowly started up with a snubbing unit pumping gas down to displace the diesel-based completion fluid. At the end of the clean up, the well flowed up to 20 MMscfd at 126 bars WHFP, with no condensate and little water (Figure 4).

TM-38 was put on production on a medium choke at 10MMscfd to minimise the draw-down on the formation and save its potential. This has enabled reliable monitoring of the first few months of production, based on the WHFP readings.

After 4 months, a multi-rate PBU (Pressure Build-Uptest) was run to confirm the well's PI, skin and reservoir pressure. The analytical model gave a very good match on the derivative pressure (Figure 6), and it confirmed that the PI was over 5 times better than that of the corresponding vertical well. But, the comparison between the clean-up rates and the multi-rate PBU showed that the well potential declined each time the well was shut-in (Figure 5). It was concluded that due to the drain profile slightly up-dip from the heel, formation water and completion fluid might be accumulating downhole at the drain's lowest points. Hence the decision to produce the well on a higher choke to ensure good water carry over to the surface.

SIMULATION

The simulation study was performed in two steps. Firstly, a general parametric study was carried out to optimise the lateral drain length, placement and diameter as functions of reservoir thickness, porosity and permeability, to cover our range of reservoirs.

Secondly, a simulation was undertaken of the specific reservoir selected for the first horizontal well in Tambora.

Parametric Study:

Three generic and vertically stacked reservoir channels with typical G-zone parameters were built and run for a total of 39 cases with a range for each key parameter. In this study the studied parameters were horizontal drain length, permeability, K_v/K_h ratio and initial reservoir depletion. Comparisons were run for a horizontal well, a vertical well with 0 skin factor (representing an existing completion if it was stimulated) and a vertical well with +10 skin factor (representing one of the least damaged existing completions).

The simulation showed that horizontal wells would perform better and, were therefore required in order to produce the Tambora G-zone more efficiently. In terms of average gas rate in the first year of production, they would outperform vertical wells by a factor of 2.8 for a 400-m drain length. They also would increase the ultimate recovery by at least 12%.
This initial study provided key information on the best drain length to be drilled, and ultimate recovery as a function of varying reservoir characteristics, such as permeability, thickness, IGIP (Figure 7).

TM-38 Study:

After the early results of TM-38, a reservoir simulation model was built in order to have a reliable forecasting tool for this well's performance, and a base for future horizontal wells design. It was also built to compare the interpretation of TM-38 PBU with the numerical and analytical models.

The initial gas in-place of reservoir G53C-T12 was between 73 Bscf and 32 Bscf, depending on the South-North connection of the sand bodies and depth of the Gas Water Contact (GWC). Because the contact had not been crossed in that reservoir, it was based on questionable RFT data. The GWC was assumed to be 15 m below the lowest proven gas of TM-12 (4012 mSS) on the Western side, and at 3866 mSS on the Eastern side (determined from pressure gradient), since the fluid status in well TM-33 on the Eastern flank remains unclear. The apparent discrepancy between GWC depths was explained by an active aquifer on the East flank.

The South-North reservoir connectivity between the two sand bodies was also in doubt.

Methodology: A model representing reservoir G53C-T12 was built using existing geological maps with wells TM-34 and TM-38 as the producers. This model was based on dry gas properties. Water and condensate production were ignored because the ratios of their cumulative production to the cumulative gas production under reservoir conditions were only 2% and less than 0.5%, respectively.

The model's dimension was 36 x 82 x 3 (8856 cells). The global grid size was 100 x 100 m and the grids around TM-38 were then refined to 50 x 50 m and 25 x 25 m to obtain a better resolution around the horizontal drain, which is 400 m in length (Figure 8).

The history match was achieved in two steps. First the match of the reservoir pressures was obtained from static gradient surveys, MDT's and back pressure tests by tuning the gas water contact depth (geologically unidentified) to adjust the size of the reservoir (Figure 9). Secondly the match of the productivity of TM-38 utilised PBU, bottom hole flowing pressures and separator readings.

By modifying the permeability of the LGR area and also adjusting the skin factor of TM-38 to +15 to balance the permeability modification, a very good match to the shape of the bottom hole pressure profiles was attained (Figure 10). The bottom hole pressure of the model was 400 psi higher than the actual. However, as the model only produced gas, while TM-38 actually produced small amounts of water and condensate, the liquid build-up around the wellbore could increase the pressure loss from the formation to the borehole and induce more wellbore friction than in the model.

Despite this shift, the model was considered to have attained a good match. The modified permeability distribution of the reservoir G53C-T12 indicated that the good permeability zone of the channel at the top of the structure was wider than initially interpreted.

As a confirmation, the 400 psi-shift simulated bottom hole pressures were output, re-interpreted using an analytical model and the results were compared to the interpretation results of the actual back pressure test. A part from the transient period that cannot be reproduced by a reservoir simulator, the comparable parameters are listed in Table 2 below.

Results:

- The history match was satisfactorily obtained. The initial gas in-place of reservoir G53C-T12 was confirmed at around 50 Bscf. This indicated that the gas water contact on the eastern flank was lower than interpreted previously. It therefore confirmed the lack of aquifer support.
- The TM-38 match indicated that the good permeability zone at the top of the structure was probably wider than initially interpreted.
- The model can be used as a reliable base for TM-38 forecast. The ultimate recovery of reservoir G53C-T12 through TM-38 will exceed 90% (47 Bscf) after 25 years of production. It will already reach 80% after 8 years, while the ultimate recovery with a conventional well would only be 62% after 15 years of production.

CONCLUSION

TM-38 has been a successful deep horizontal drilling project. It has shown that with good well planning and strong reservoir support, such innovative projects could be achieved. As a result of this technology, the recovery from the deep tight sands of Tambora will be dramatically improved and additional reservoirs will be developed. Building on this first experience, new horizontal wells will be drilled in similar targets in Tambora.

In order to make the best of existing completions, Total Indonesie is planning a horizontal sidetracks campaign. In a further step to minimise costs, the emerging Coiled Tubing (CT) drilling technology will be applied for these wells.

The CT re-entry technique is mid way between well servicing and drilling. Total experience in using CT for well cleaning or light work-over will be combined with experience in directional and horizontal conventional drilling. CT re-entry will provide a cheap smart way to enhance field productivity, thanks to:

- rigless operation
- through tubing re-entry (no need to pull the existing completion)
- several re-entries (depending on the original well design, the number of re-entries is not limited)
- flexibility (adaptation to particular well designs)

Based on the results of TM-38 and simulation work, the first candidate has been designed with a 200m dual lateral drain. It should have an initial potential of 12MMscfd and will be drilled at the end of 1999.
This should be the first multi-lateral sidetracks by coil tubing drilling in Indonesia.

AKNOWLEDGEMENTS

We thank the management of Total Indonesie, Inpex and Pertamina, for their support and permission to present this paper.

TABLE 1

G53C-T12 KEY PARAMETERS

Average Reservoir Depth	3850 m
Porosity	11 %
Maximum Thickness	23 m
Water Saturation	29 %
IGIP	50 Bscf
Cumulative Gas Produced	12.5 Bscf
Reservoir Map Based on	10 wells
Existing Producers	1
Average Well Rate (1997)	4 MMscfd

TABLE 2

COMPARISON OF BACK PRESSURE TEST INTERPRETATION RESULTS

Parameters	Actual Test	Simulated Test
Reservoir Pressure (psia)	3393	3424
Hor. Permeability (mD)	9.1	8.5
K_v/K_h (fraction)	0.01	0.05
Skin factor	0.5	0.8

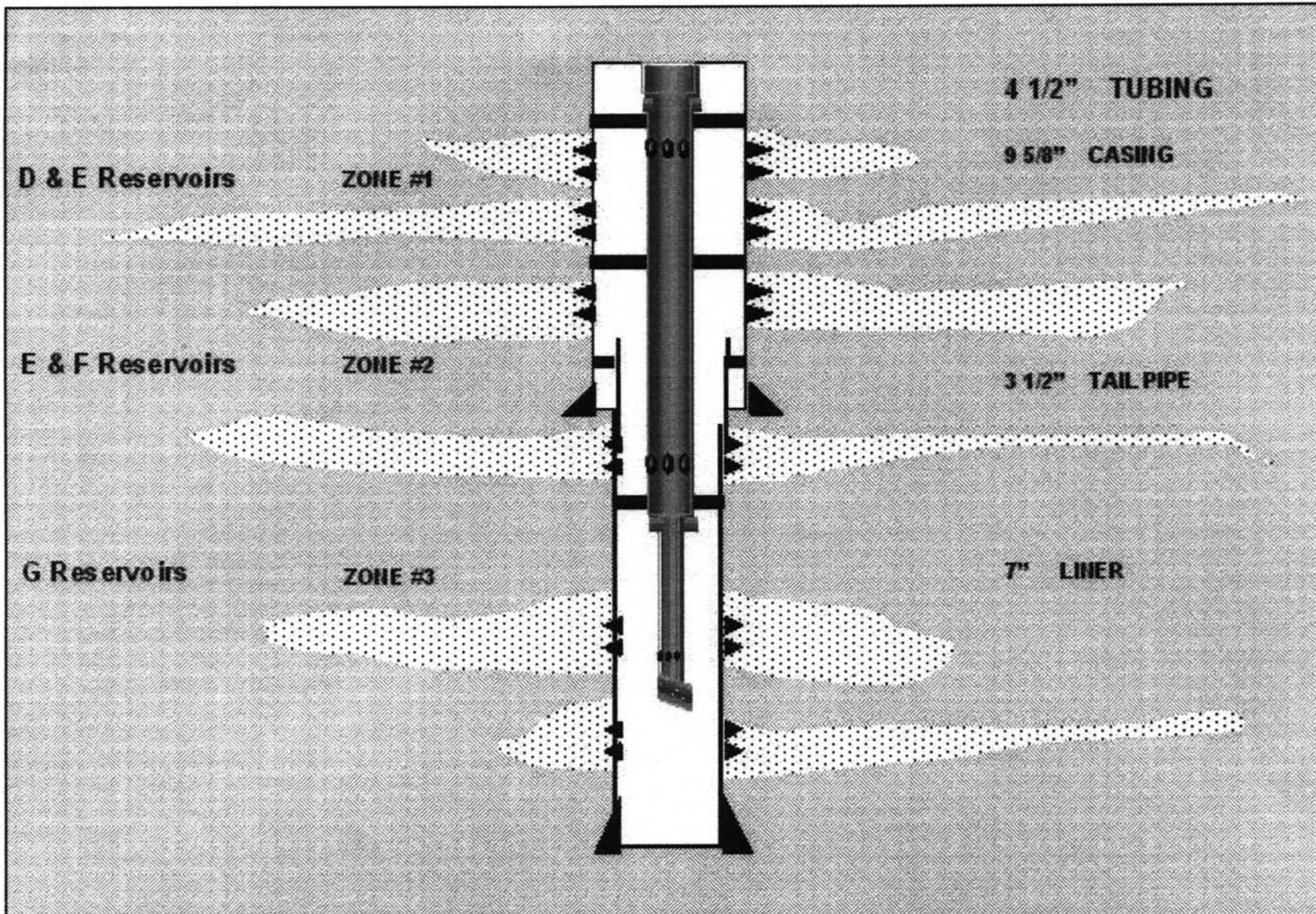

FIGURE 1 - Tambora Gas Well - Typical Commingle Completion

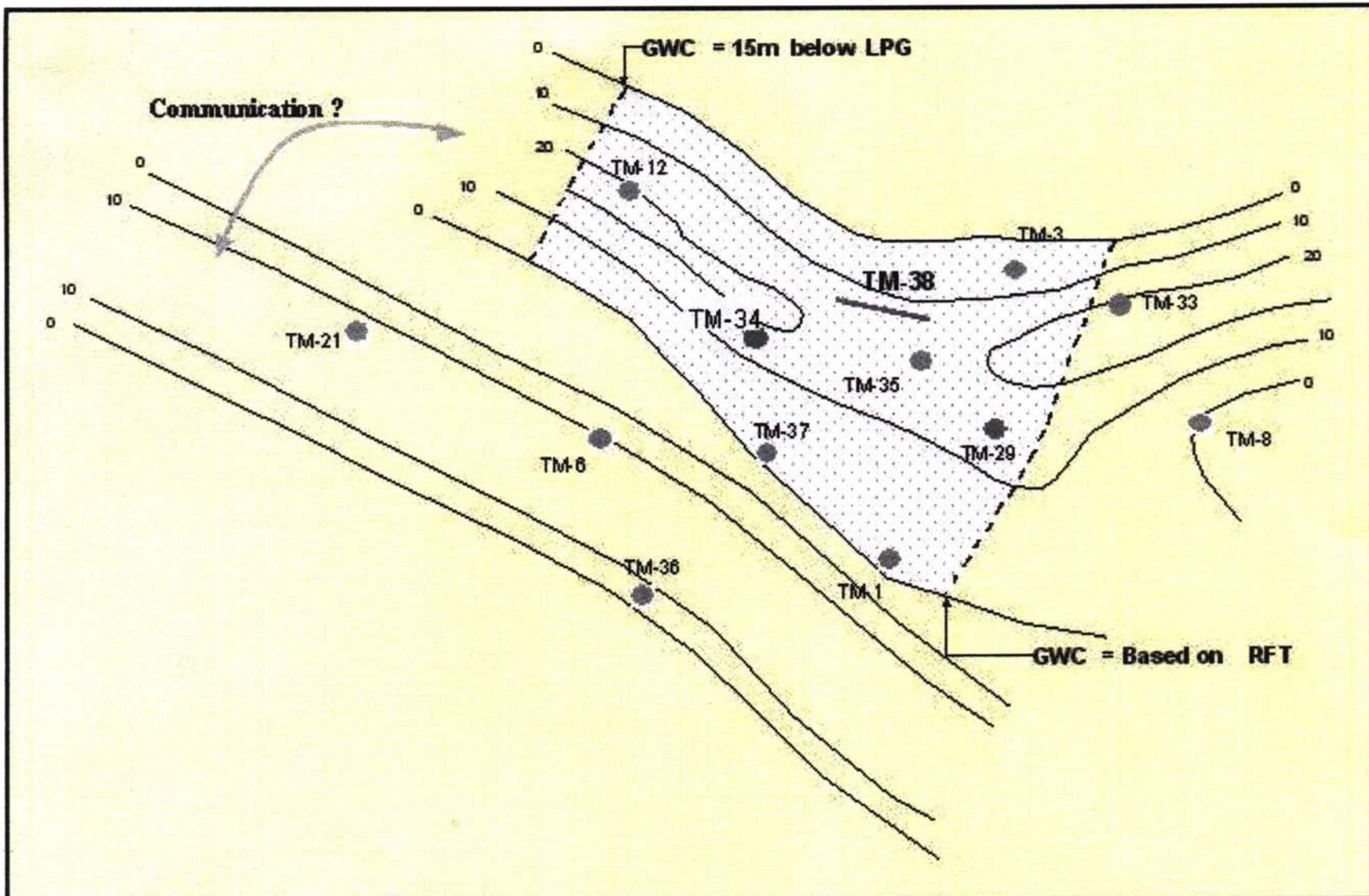

FIGURE 2 - Reseroir G53C-T12 Thickness Map (Meters)

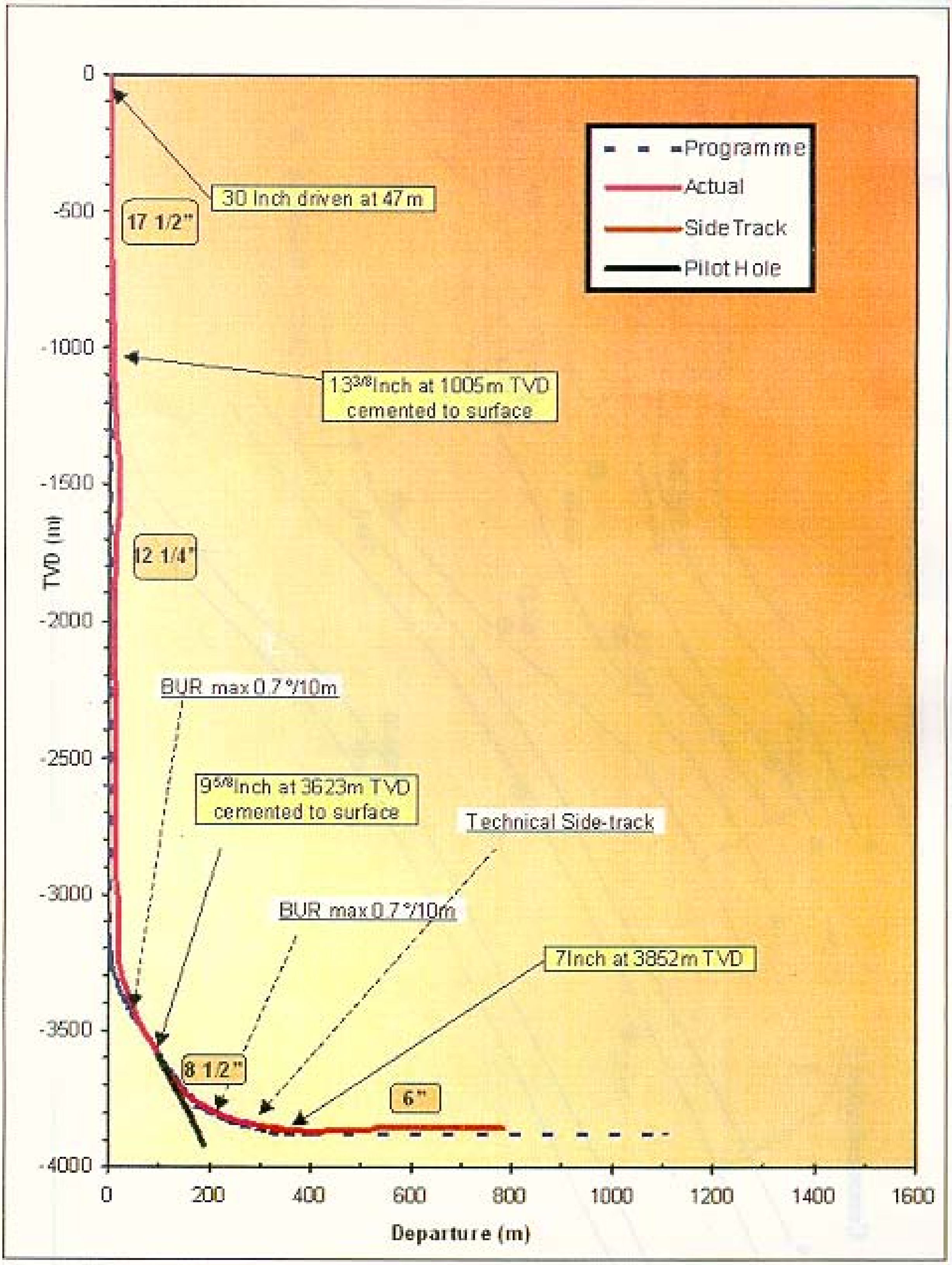

FIGURE 3 - TM-38 Planned and Actual Drilling Well Profile

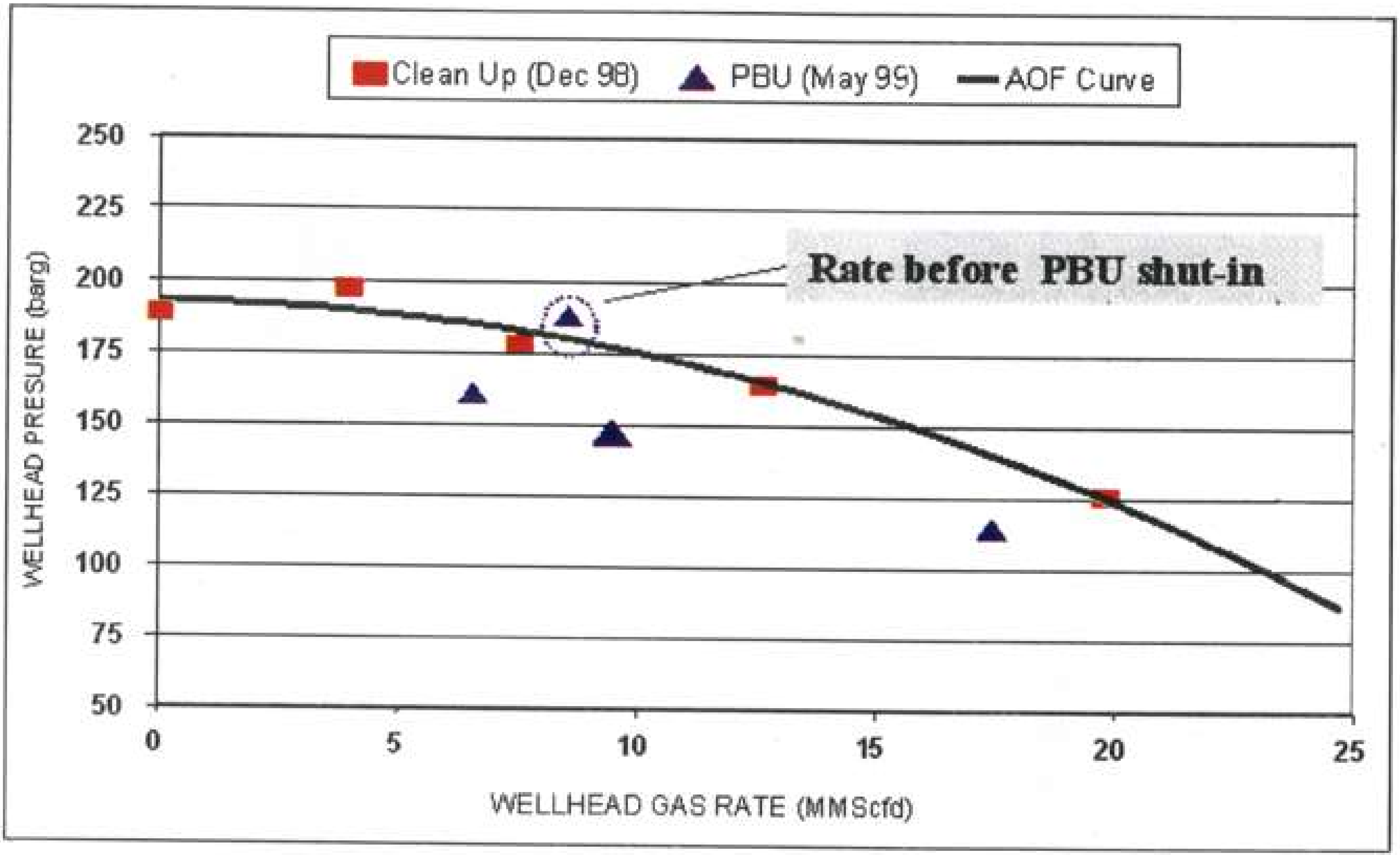

FIGURE 4 - TM-38 Open Flow Tests: Clean UP vs PBU

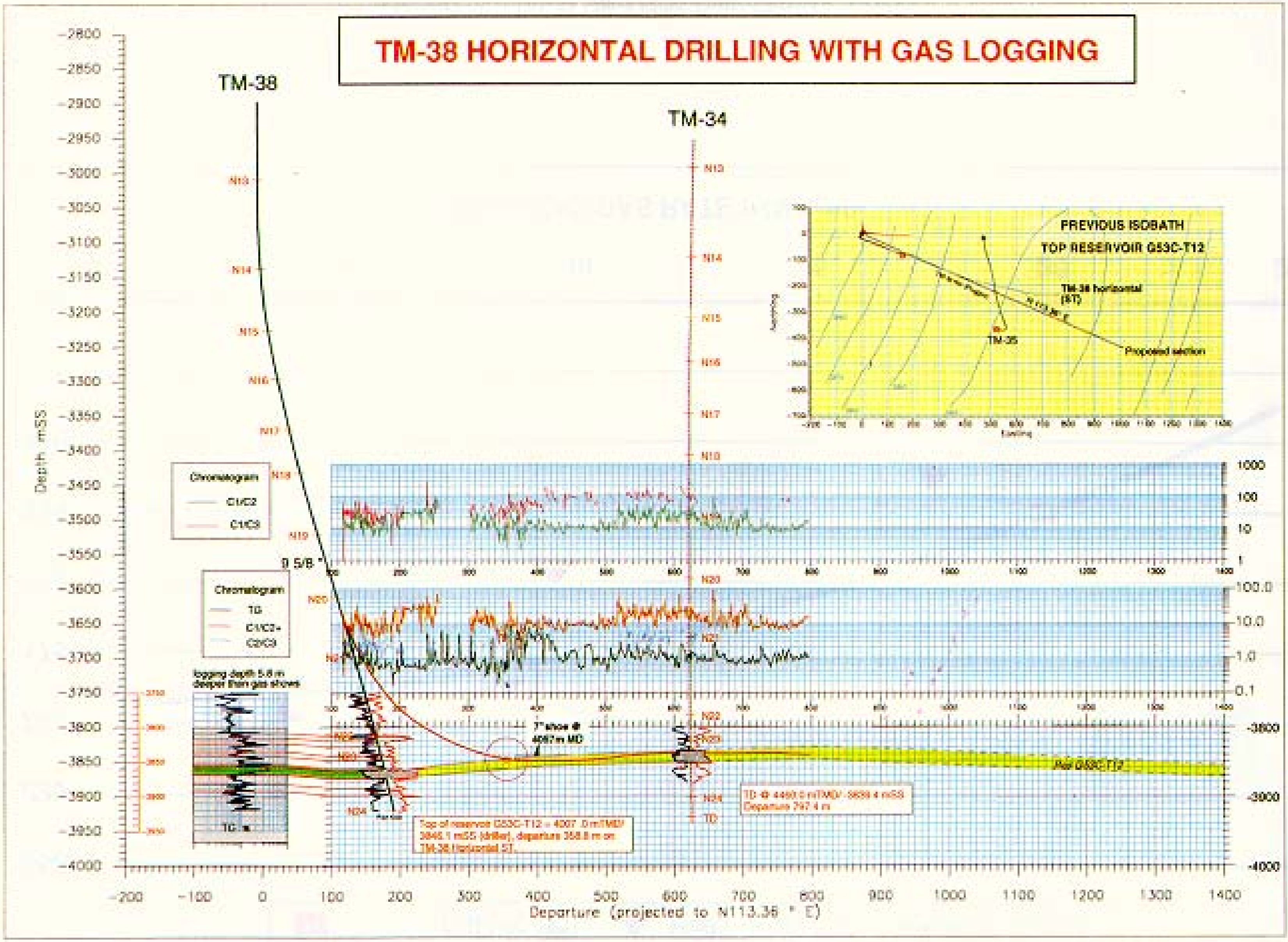

FIGURE 5 - TM-38 Horizontal Drilling: Gas Logging Calibration and Monitoring

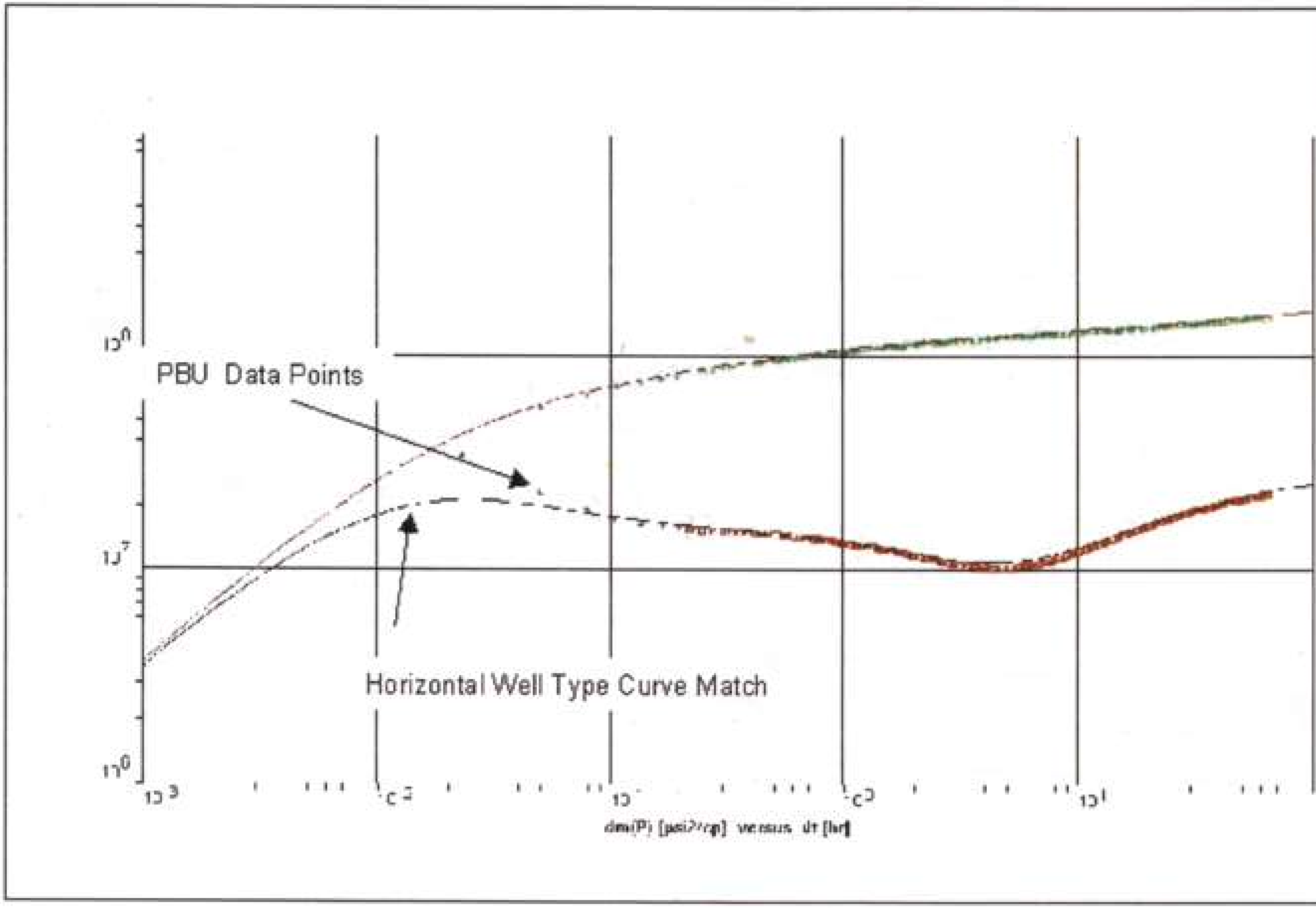

FIGURE 6 - TM-38 PBU Analysis: Log-log Plot of Pressure Derivative Match

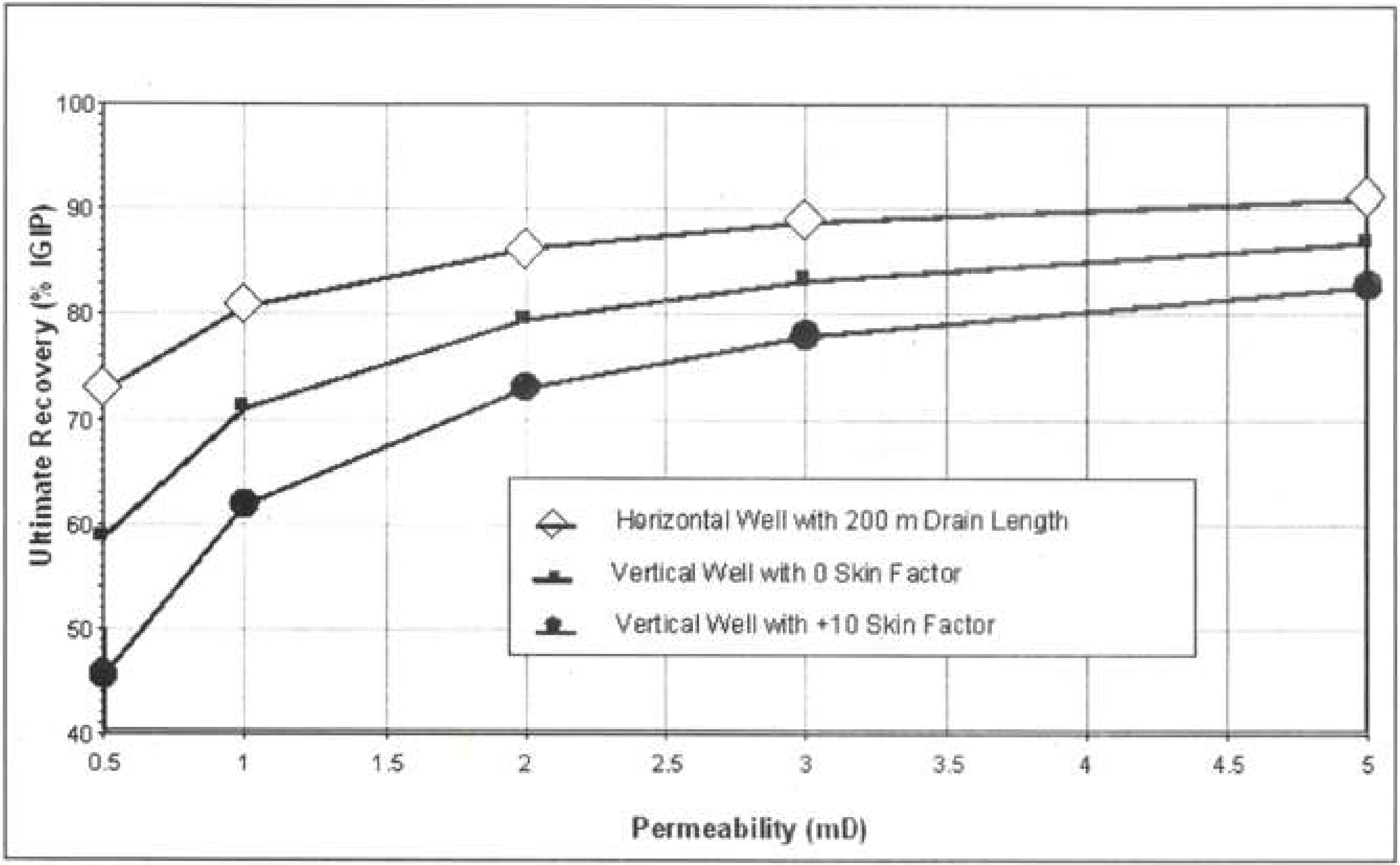

FIGURE 7 - Parametric Study: Ultimate Recovery vs Permeability

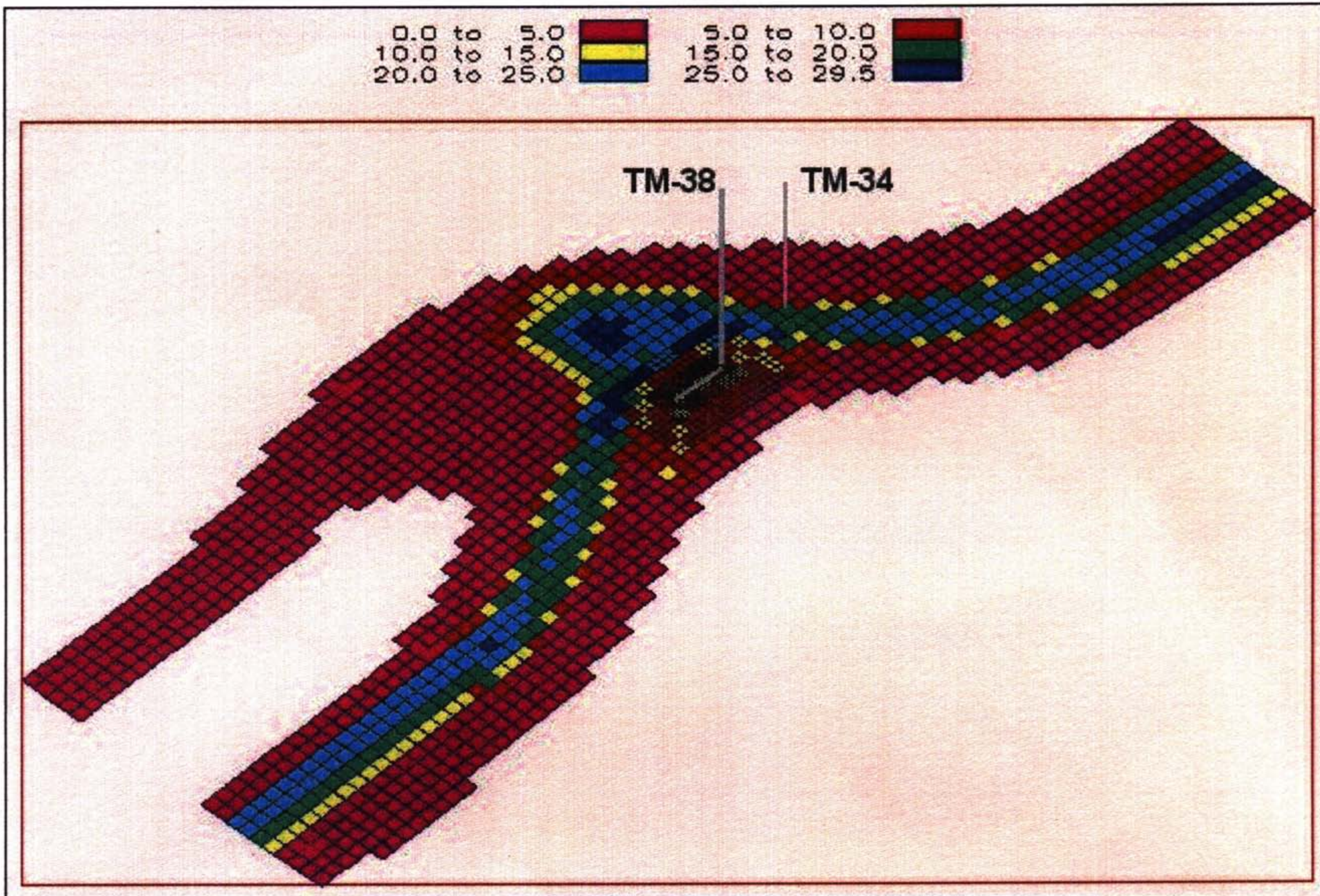

FIGURE 8 - Simulation Model Permeability Map of Reservoir G53C-T12 After Modification Around Tm-38 (units in MD)

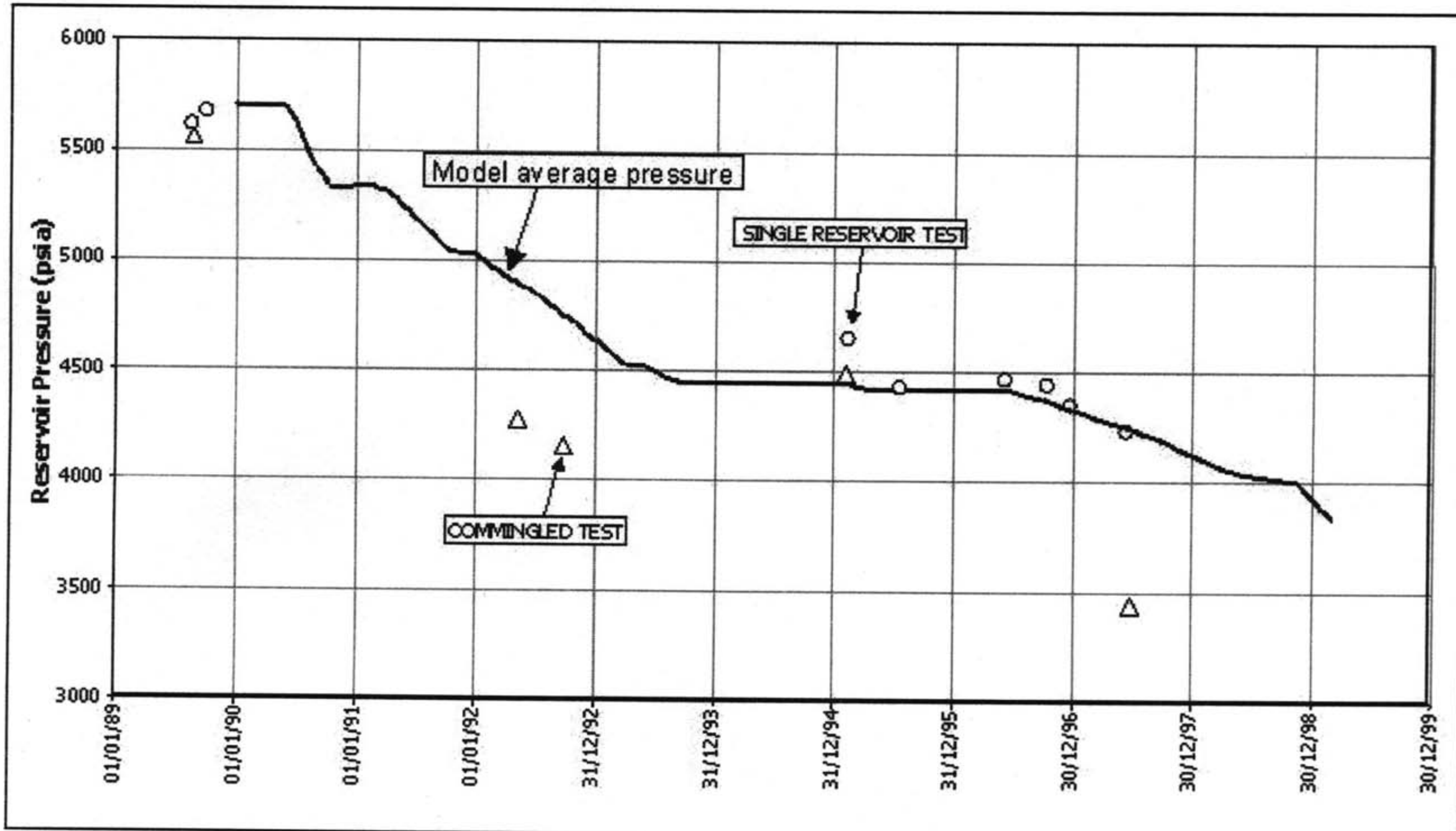

FIGURE 9 - Average Simulation Reservoir Pressure of G53C-T12 Afater History Match.

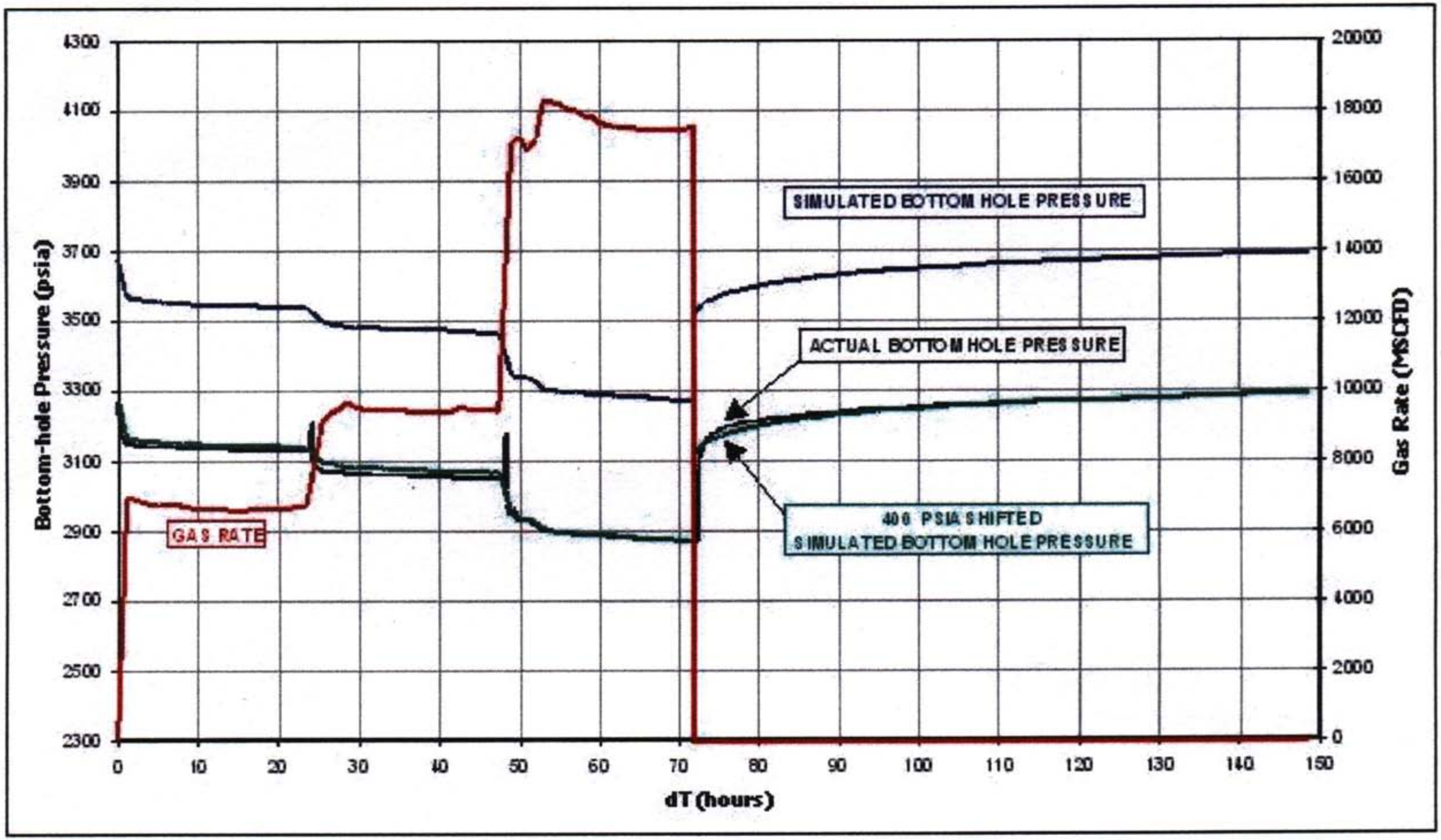

FIGURE 10 - TM-38 Pressure Build up Test: Simulated and Measured Pressure Comparison