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The Mabruk History or How to Develop a Challenging Field

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تاريخ حقل المبروك أو كيف يتم تطوير تحديات الحقل

دانيل سوزيومايr و بينوت لادوت

يتكون حقل المبروك الواسع من أربعة تراكمات للنفط بغربي حوض سرت الرسوبي وتوجد أفضل خصائص المكمن بحقل المبروك، غرب، حيث أنه الحقل الوحيد قيد التطوير حالياً.

تتكون صخور المكمن بالحقل من رواسب جيرية على عمق حوالي 3500 قدم، ترجع إلى عصر الباليوسين. وقد سلطت الدراسات الجيولوجية الضوء على الإختلافات الحادة بين سحنات مفصولة ومعقدة نتج عنها التعرف على العديد من الصخور وأكثر من عشرة أسطح تماس بين الماء والزيت. ونظراً لضآلة سمك المكمن (45 قدم) والنفاذية فإن قابلية الإنتقال منخفضة، كما أن أداء الآبار العمودية بصفة عامة ضعيف جداً.

توالت عدة شركات مشغلة لهذا الحقل منذ نهاية الخمسينات ولكن البداية الفعلية كانت عام 1995 ف مع شركة CPTL كمشغل. وشمل البرنامج التطويري لهذا الحقل مرحلة النموذج التجريبي والتي استغرقت مدة سنتين قبل الإنتهاء من برنامج النضوب. وتم حتى فترة إنعقاد هذا المؤتمر (1999) إستخراج حوالي 16 مليون برميل، ويصل المعدل الحالي للإنتاج حوالي 15000 برميل يومياً يتم إستخراجها من 35 بئر إنتاجية. كما يتم المحافظة على ضغط المكمن بحقن الماء عن طريق 23 بئر. وللتعامل مع الإنتاجية الضعيفة وعدم التجانس العالي تم إستعمال تقنيات حفر متطورة متعددة الصرف والضخ (Esp, PcP).

بدأت محاكاة المكمن للتنبأ بالمناطق ذات المردود المتدني، ويستعمل تنعيم المحاكاة الشبكي لتمثيل المعالم الجيولوجية بطريقة تؤثر تأثير على أداء المكمن.

Abstract: *The Great Mabruk field is made up of four oil accumulations located in the Sirt Basin. West Mabruk, where the best reservoir characteristics were encountered, is the only one currently developed.*

The reservoir, located at a depth of 3500 feet, is made up of carbonates of Palaeocene age. The geological studies highlight steep variations of facies together with a complex compartmentalization, resulting in the definition of numerous rock types and more than ten oil water contact (OWC). Owing to the small thickness (45') and owing to permeability, the transmissibility is low and the performance of vertical wells is generally very poor.

Since the late fifties several companies have followed one another as operator but the real start-up of the field took place in 1995 with CPTL as operator. The development included a two-year ‹‹pilot›› phase prior to finalizing the depletion scheme. To date almost 16 million stb have been recovered and the current rate is around 15000 bopd from 35 producers. Reservoir pressure is maintained by 23 water injectors.

Sophisticated techniques concerning drilling (multi-drains) and pumping (PCP, ESP) were pioneered to cope with the low productivity and

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the high heterogeneity. Reservoir simulation was initiated to predict the areas to be poorly swept. Fine simulation grids are used to represent geological features in a way that captures their impact on reservoir performance.

BRIEF REVIEW OF THE HISTORY

The Great Mabruk field is made up of four oil accumulations located in the Sirt Basin (Libya), namely North Mabruk (discovery well #1), Central Mabruk (discovery well #2), East Mabruk (discovery well #3) and West Mabruk (discovery well #6). Figures 1 and 2 show the location of the field and of the different panels.

It is noteworthy that West Mabruk, which was the last to be discovered, is the only one currently developed. This suggests that the characteristics encountered in the other three were really discouraging. Effectively several companies have followed one another as operator since the late fifties.

Between 1959 and 1961, Exxon drilled 26 wells and implemented a five spot water injection pilot in the NE part of West Mabruk. Following corrosion problems and early water breakthrough (250 m spacing), they gave up rapidly.

Sirt Oil resumed the development in 1982, shot a 3D seismic, drilled four wells and abandoned. Since the beginning, the original oil in place (OOIP) estimate decreased from 1 Gstb (including 0.6 Gstb in West Mabruk) to half of this value.

However TOTALFINA, SAGA and the National Libyan Oil Corporation (NOC) were not put off by the challenge. The subsidiary CPTL was created and the real start-up of the field took place in 1995 with CPTL as operator. The development included a two-year ‹‹pilot›› phase prior to finalizing the depletion scheme.

To date around 16 million stb have been recovered from West Mabruk. The current rate is 15000 bopd from 35 producers. Pressure maintenance is ensured by 23 water injectors. A large part of the wells (all the recent ones) are horizontal or multi rains. With some additional wells, the recovery is expected to reach 125 million stb for a water cut of 90%, 29% OOIP. Moreover, it is planned now to shoot a 3D seismic in the East and Central Mabruk accumulations with the objective of launching the development of these panels.

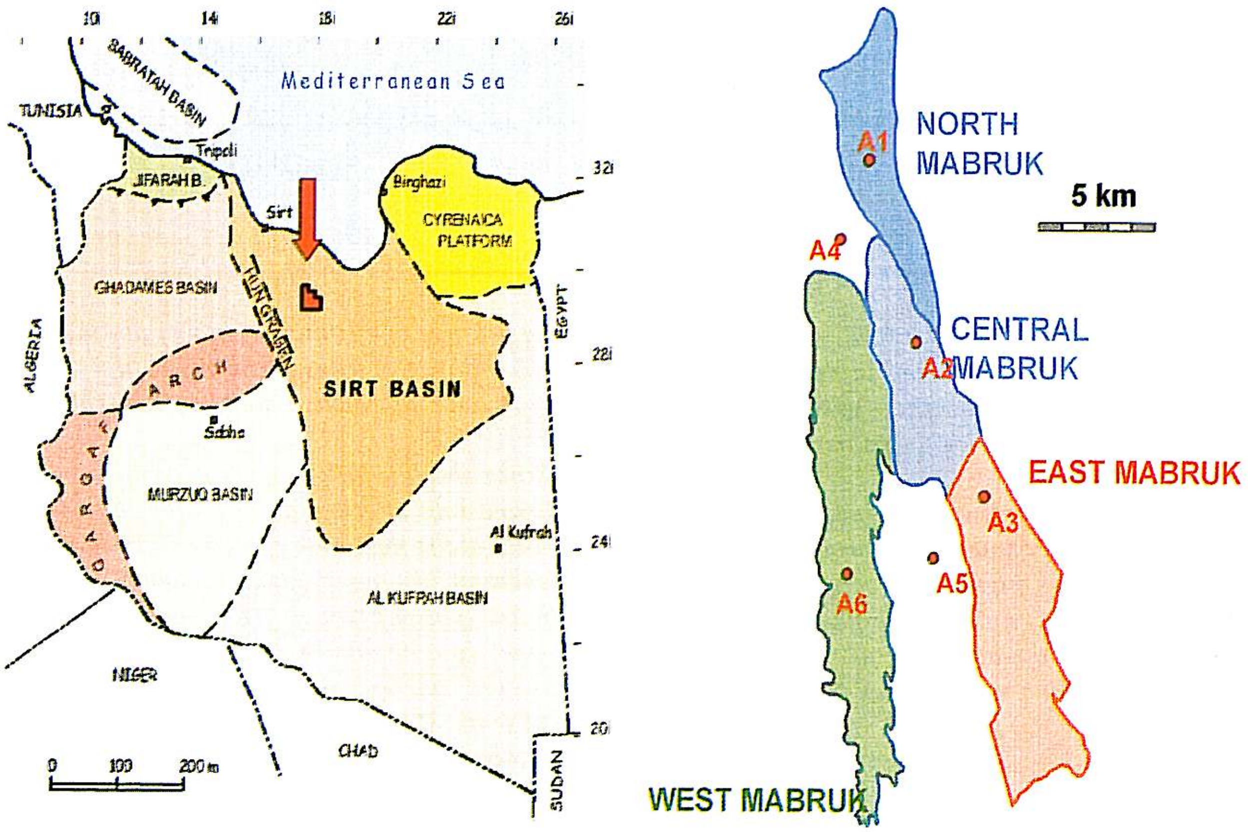

Fig. 1. Location map.

The purpose of this paper is to describe the problems posed by these fields and how the determination of three companies got over them.

GEOLOGICAL BACKGROUND

The reservoir is located at a depth of 3500' (3000 feet ss, 900 mss). It is made of carbonates pertaining to the so-called upper Mabruk member of the Heira Formation, of Palaeocene age, which overlies the Dahra Formation (Upper Cretaceous).

The structure is an elongated NS anticline truncated by numerous NW/SE faults (Fig. 2). The dip is low (around 3° on the flanks). The hydrocaron column does not exceed 500 feet (150m) and the oil accumulation extends over a surface of roughly 15 km x 3 km.

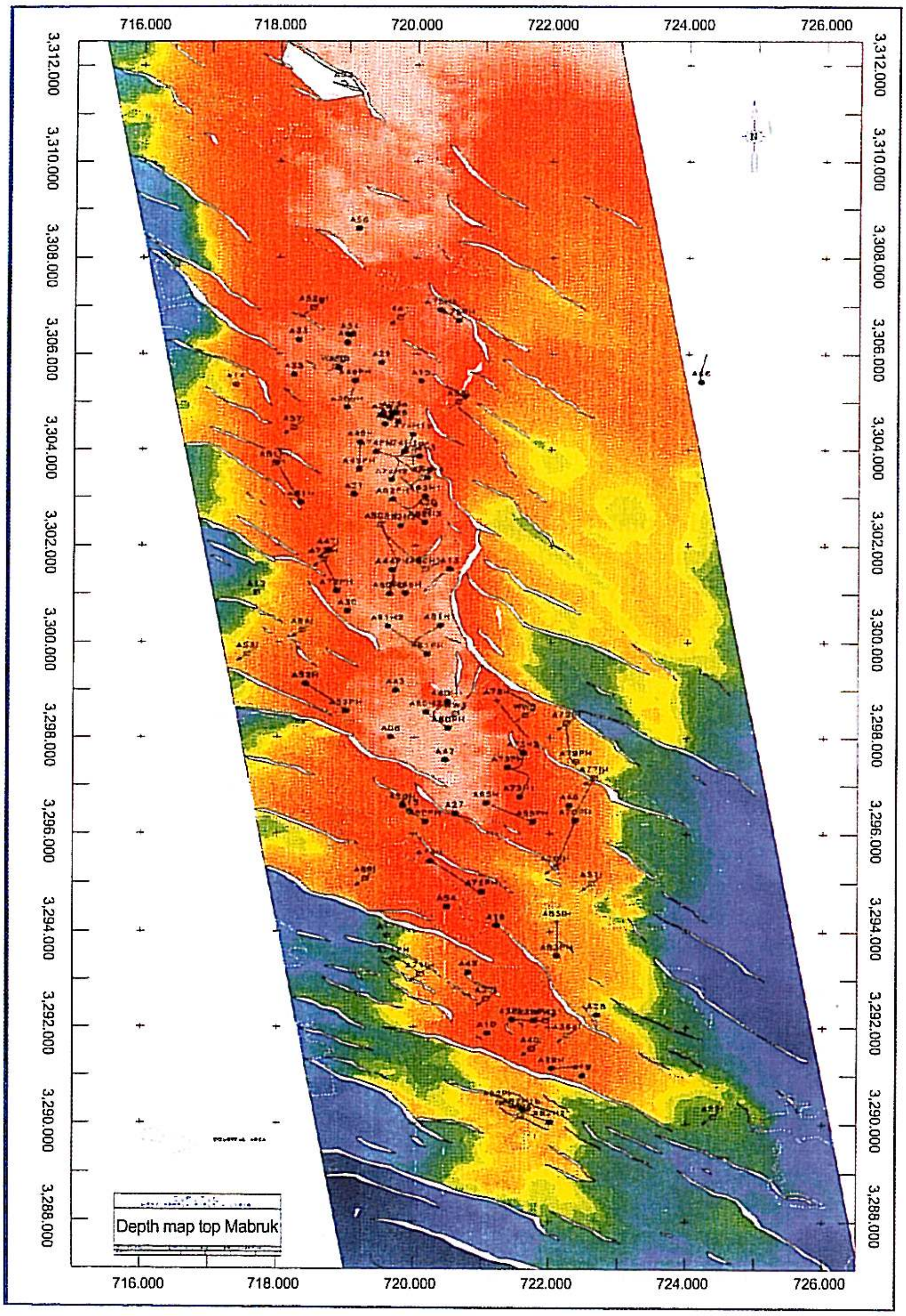

Fig. 2. Structural map at top Upper Mabruk.

The interpretation of the 3D seismic, shot in 1982, proved very difficult and some parts of the structure (crest and eastern flank) have remained "blind" for years,. It is only the use of recent tools (correlation maps) that allowed an interpretation everywhere (interpretation supported by the drilling of new wells in the "blind zones").

However, significant uncertainties concerning the structure and the fault pattern are still remaining today. Among other things, it is not possible to assess definitely the number of isolated panels from the current seismic data.

The gross thickness of the reservoir averages 90 feet (27 m), distributed in three layers: from top to bottom, A2, B and C (Fig. 3). The C layer exhibits much poorer properties (very low N/G) than A2 and B, which both contain most of the oil in place. The average net thickness is 45 feet (14 m).

The facies changes from the north (micritic skeletal limestone) to the south (dolomitic limestone). In fact, the Mabruk reservoir is characterized by its heterogeneity resulting in sharp facies changes.

Porosity, which varies between 16% and 30%, averages 23% over the field. It decreases from the crest to the flanks.

There is no clear relationship between porosity and permeability. Estimated from test data, permeability is generally low: median around 20 mD. However it can be enhanced locally owing to fissuring. The permeability thickness varies among the tested wells between 0.1 D.foot and 15 D.feet, the median being 1 D.foot.

PVT AND OOIP

Oil samples were taken in two wells, located at both ends of the field, north and south. In both cases, the oil is largely undersaturated with a dissolved GOR of only 5 v/v. Bubble point is 130 psi for an initial pressure of 1180 psig at 2530 feet ss (81 bars at 771 mss). However, the oil seems lighter in the south (39.4°API) than in the north (34.7°API). This has an impact on the viscosity, which is higher (3cp) in the north than in the south (2cp). The reservoir temperature is 135°F (57°C). The initial oil FVF is 1.05 v/v and the compressibility 9.1 10^{-6} psi^{-1}. The formation water has a rather high salt content (TDS=63 g/l). Its viscosity is 0.5 cp.

As explained above, the compartmentalization of the field is complex. A consequence is that no less than eleven different OWC were recognized. The OOIP of West Mabruk has been estimated at 430 million stb. The HCPV being 875 million stb this corresponds to an average connate water, saturation of 48%. The mobile oil is 276 million stb this OOIP is almost equally distributed between layer A2 (221 million stb 51%) and layer B (195, million stb, 45%). There are only 17 million stb (4%) in layer C.

DEVELOPMENT PLAN

Recap on Reservoir Characteristics: A brief review of what was described above shows that almost all the characteristics are unfavorable to a development:

- The transmissibility through the reservoir (kh/ı) is low, due to the poor permeability, the small thickness and the (relatively) high viscosity of the oil.
- The natural energy of the system is low. The compressibility is small and (almost no dissolved gas) there is no active aquifer.
- In case of water drive, the mobility ratio is higher than one.
- The reservoir is highly heterogeneous and, moreover, unpredictable. In some areas it is fractured.
- The structure is divided in many compartments.

Solutions Contemplated for West Mabruk: To cope with the difficulties described above, the following solutions were found. It is noteworthy that some of these solutions were pioneered in Libya.

- Owing to the lack of natural energy (low compressibility, no aquifer influx), the recovery process involves the implementation of a water flood. The low transmissibility implies reducing the distance between producers and injectors (to maximize the rate that can flow through the reservoir). Therefore, peripheral injection was complemented by pattern injection.
- To get decent rates per well, horizontal drains were drilled for both producers and injectors. Owing to the presence of local barriers between layers and to cater for the heterogeneous nature of the reservoir (i.e. to increase the chance to encounter a zone with good facies), some wells count several drains (up to four).
- The reservoir pressure and the well PI being low, it is important to lower the BHFP in the producers as much as possible (while keeping above the bubble point of 130 psi). Owing to the shape of

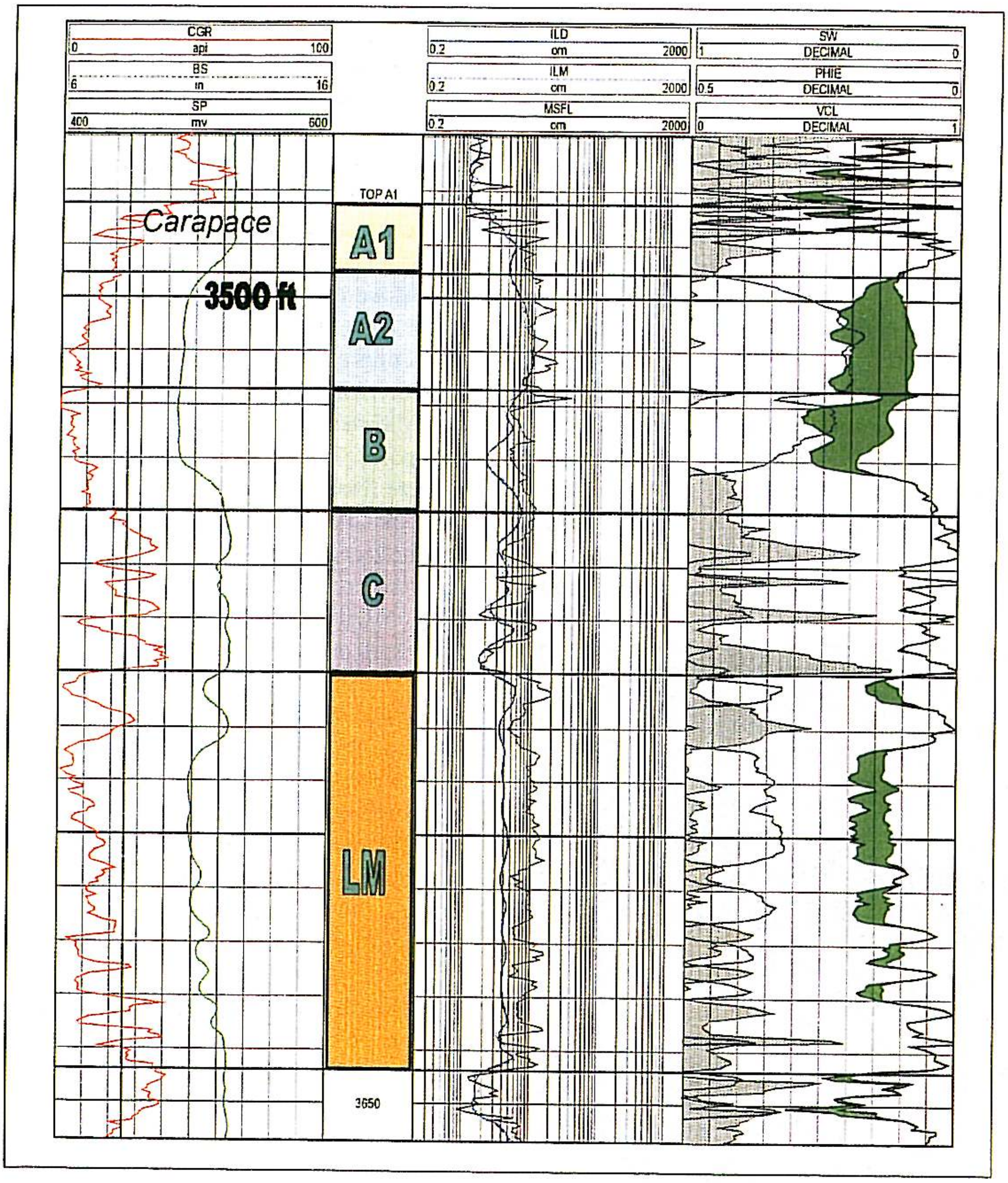

Fig. 3. Reservoir layering.

the well, it is not possible to achieve this objective while using beam pumps in horizontal wells. The use of PCP (Progressive Cavity Pumps) and ESP (Electrical Submersible Pump) allowed a significant reduction of the BHFP and an increase of the production rates.

The reservoir heterogeneity, the field compartmentalization and the low transmissibility imply planning for a large number of wells, which has a significant impact on the CAPEX and also the OPEX. Therefore it was deemed necessary to have a tool allowing the simulation of a development plan to optimise this number.

A reservoir simulator was built. It was based on the reinterpretation of the old 3D seismic (elimination of the "blind zones"). A sedimentological study was carried out to predict the facies distribution. A comprehensive SCAL work was also performed.

The reservoir model was validated through the match of the production history (pressure and water cut development by well). It was then used for the predictions and the optimization of the development plan: number, location of the wells and distribution between producers and injectors to accelerate the recovery while improving the sweep.

THE RESERVOIR MODEL

Grid and Compartmentalization: The grid of the reservoir model comprises a total of 30360 blocks (110x92x3), of which 13255 are active. it is oriented along with the main faults direction (Fig. 4). Corner point geometry was used to capture the impact of the throw of the faults on the communication within or between layers. There are three layers, corresponding to the geological units A2, B and C. The size of most cells is 160m x 160m (525 feet squared).

The field compartmentalization was reviewed with the aim of simplifying. In other barriers words, barriers were kept only when justified by pressure and/or contacts considerations. Various data concerning the OWC can be obtained from the wells: FWL (Free Water Levels, encountered in only two wells), LPO (Lowest Proven Oil) and HPW (Highest Proven Water).

Fig. 4. Model grid.

Previously the western and eastern flanks of each panel were generally assumed to be isolated owing to differences in contacts. However pressure ,data following the field start up suggest sometimes a clear communication between both flanks. The following explanation is proposed to reconcile contacts with pressure data. It is based on the assumptions that:

- the western flanks are truncated by NW/SE barriers and the reservoir properties are vanishing westwards so that they do not communicate with the eastern flanks;
- oil migration comes from the east.

When oil fills the structure up, water is expelled from the west to the east until the WOC reaches the spill point. Thereafter, water remains trapped in the western flank and if oil continues to accumulate, the WOC will be, deeper on the eastern flank. Following this theory, it is possible to have a single panel with different contacts on both flanks provided that the, contact on the western flank correspond to the depth of the spill point.

The simplification of the compartmentalization resulted in the diminution of the number of isolated panels to five.

The oil /water contacts are identical in the three layers A2, B and C. However, they are different on both flanks of the structure. Moreover, because of the truncation of the western flanks, there may be several contacts per panel on this side. The final number of different contacts is eleven.

Petrophysics: The porosity and net/gross maps are derived from log data. There is about one control point per square kilometer.

To determine the permeability variation throughout the field it was decided to rely just on the test data. Permeability thickness could be measured in around 30 wells. This corresponds to an average distance of 1200 m between data points. Then, a mapping software was used to build a kh map.

However, this map had to be significantly altered to match the pressure history. Permeability anisotropy, with a mere 30% improvement along the SE/NW direction, proved helpful in the match of pressures and water cuts. This anisotropy can be related to the presence of natural fissures parallel to the main faults. On the whole, permeability had to be increased by about 60%. This increase can also be partly explained by a relative permeability effect: most of the tested wells are in the transition zone and what is measured is the effective permeability rather than the absolute permeability. The main features of the final kh map are the presence of two ‹‹good›› zones at both ends of the field and a worsening towards the eastern flank. The average (absolute) permeability among the tested wells turns out to be around 60 md, which yields an average permeability thickness of 2.6 D.ft in the whole field.

A comprehensive sedimentological study was performed to describe the various facies and their distribution throughout the oil accumulation. Several lithofacies were defined. Taking into account the effects of diagenesis they became ten rock types pertaining to five categories. In every part of the field there are at least five different rock types present. On the other hand some exist only in certain areas (the south for the dolomites).

However, the difficulty in deriving reliable relationships between porosity and permeability suggests that the actual number of rock types could be largely more than ten. Then, as the number of rock types increases, another difficulty arises with the number of available plugs per rock type, which is too small to derive reliable averages.

Several solutions were tested with the model and the one which produces the best history match consists in inputting a single set of curves for capillary pressure and for relative permeabilities. Theses curves are based on a Swi of 35%. Plotted on a Swi vs ö graph together with the SCAL measurements, this value corresponds approximately to the average field porosity of 23%.

Regarding the shape of the capillary pressure curve, the analytical expression of Brooks Corey was used with a pore size distribution index(ë) of 2 and threshold pressure of 1 psi. The resulting distribution of water saturation vs depth compares reasonably well with the values derived from the logs.

As far as rel perms are concerned, the SCAL experiments, carried out on preserved cores show a mixed or oil wettability together with a fair displacement efficiency. Analytic expressions (Corey) were used, which fit the experimental points. The single set of curves is based on Swi of 35% and Sorw of 21.5%, which yields a displacement efficiency of 67%. The corey exponents are No=3 (typical of intermediate wet behaviour) and Nw=2 (typical of oil-wet behaviour).

PVT: In West Mabruk two types of oil were identified: a 34.7° API in the north and a lighter one in the south (39.4°). The main difference concerns the viscosity, which is higher (3cp) in the north than in the south (2cp). Both types of oil are displayed in the present model.

History Match: The history available for the match extends over four years since the production startup in February 1995. The data to match are the pressures and the water cut development in all the producers.

The largest effort was devoted to the match of the RFT measurements which are considered to be the most reliable among the acquired data. A fair to good match was obtained in most of the cases. Regarding RFT, it is worth mentioning that no significant pressure differential between layers was ever observed in any well, which supports the assumption of effective vertical communication.

PBU/PFO data were available for a large number of wells. The match obtained with these data does not appear as good, which can be explained by the uncertainty concerning the determination of the average pressure in the well drainage areas.

Finally, BHFP, measured through sonologs, were available for all the producers and could be matched by tuning the well productivities. However, in a few cases, we had to assume a sharp decrease of the PI with time, which can be attributed either to a local "double porosity/double permeability" behaviour[1], or to decrease in permeability close to the wellbore, due to the closure of micro fissures caused by the pressure drawdown.

A fair to good match of the water cut development was also achieved in each producer. However, at the end of May 1998, only 28% of the producers had a significant water cut for a field recovery of just above 3% OOIP.

The parameter that influences most the match is the absolute permeability. Inputting locally a SE/NW anisotropy (+30%), justified by the presence of fissures in the same azimuth, proved helpful. Figure 5 illustrates the water cut match obtained for the field.

Prediction Runs: Once validated by the history match, the reservoir simulator was used to:

- optimize the number of producers and injectors;
- define the trajectories of the multi-drains to improve the sweep efficiency;
- locate the injectors to bring an effective pressure support;
- evaluate the impact of the water injection capacity on the production profile;
- assess the reserves and determine the production profiles.

Figure 6 shows saturation maps drawn out by the model at two different times.

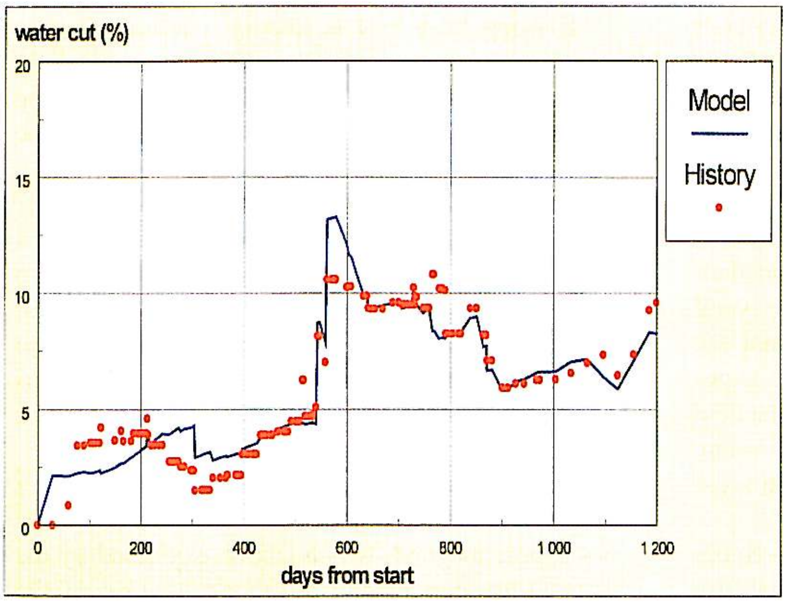

Fig. 5. Water cut match.

WELL ARCHITECTURE AND DRILLING TECHNIQUES

With the introduction of the horizontal wells in Mabruk field in 1995, TOTAL petroleum engineers faced a new challenge: conciliate the complex technology involved in the horizontal drilling and the drastic budget limitations.

TOTAL drillers, geologists and reservoir engineers worked together to select the technical options the most adapted to Mabruk requirements, helped by the worldwide experience gained by TOTAL in horizontal drilling through its subsidiaries. The different technologies

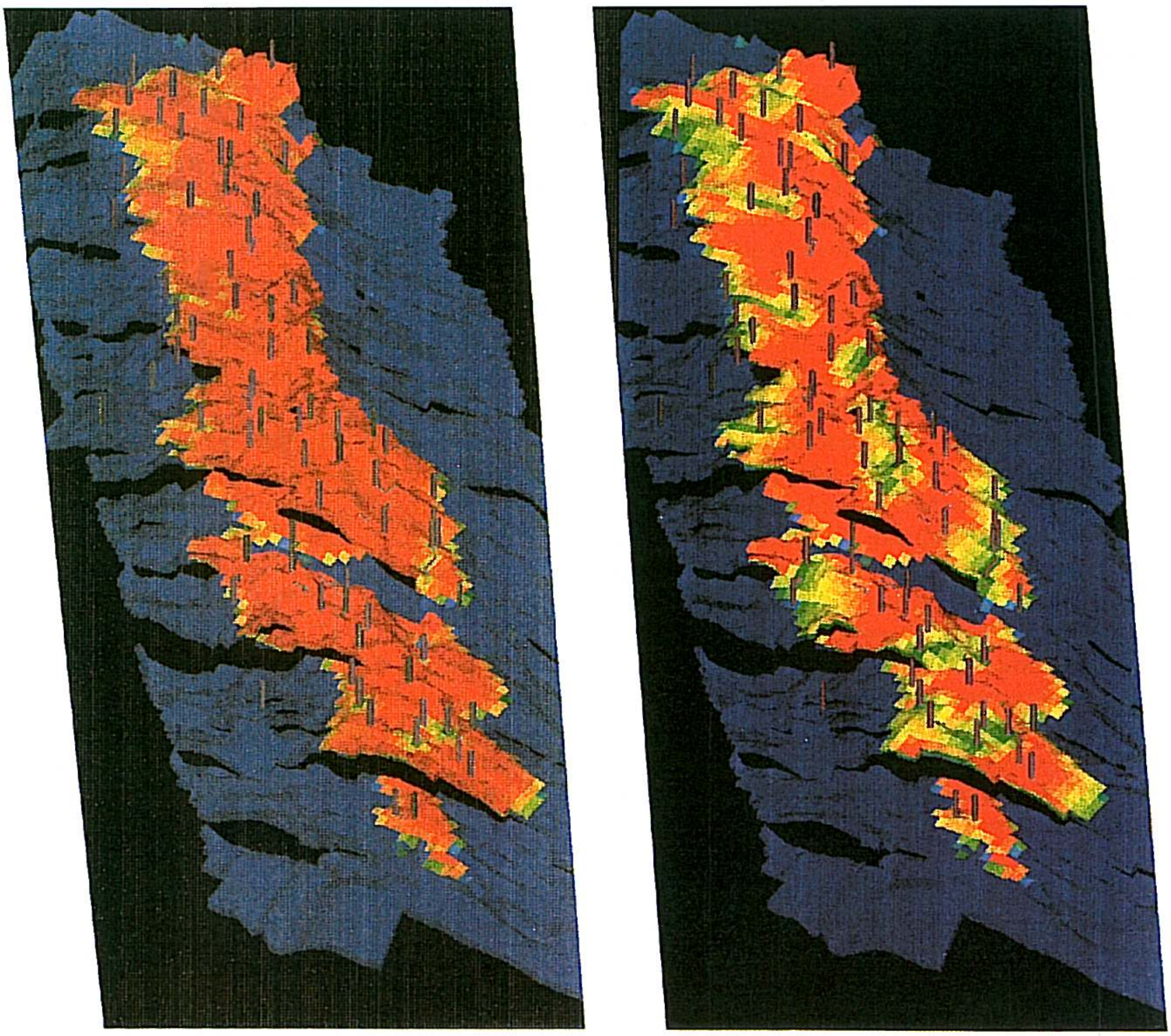

Fig. 6. Saturation maps.

provided by the Services Companies, as Survey tool MWD, geological steering, directional drilling, drilling bits... were integrated into a homogeneous package to result in a viable and cost-effective project. Thirty horizontal wells were drilled by CPTL in West Mabruk field between 1995 and 1999, including twenty-one, oil producers and nine water injectors. Today, a horizontal well costs around 20% higher than a vertical well when the Productivity Index is multiplied by about two.

The multi-drain technology was introduced in Mabruk field at the end of 1996 to be used as:

1. Delineation tool. The additional drain, drilled first, could be drilled in area where the seismic interpretation was doubtful. If the zone was not interesting, the drain would be plugged back and the main drain would be drilled as planned.
2. Enhance oil recovery tool. Additional drains should increase the reserve, increase the drainage efficiency and the well PI and reduce the CAPEX by reducing the well concentration in the field.

Multi-drains in Mabruk field are planar, i.e. all the drains are drilled at the same plane in the same reservoir. They are completed open-hole with commingle production assisted by artificial lift ("level 1" of multi-lateral technology).

The well architecture, given in figure 7, derives from the horizontal well design:

- The 12¼" section is drilled vertical. The 95/8" surface casing is set below the loss zone of AMUR
- A 8½" pilot hole can be drilled to Mabruk reservoir. The hole is then plugged and sidetracked. The KOP is around 50 feet below the 9⅝" casing shoe.
- The 8½" build up is drilled in medium radius (9°/100 feet) to reach the tight top layer of the reservoir (CARAPACE) at around 70°. inclination where the 7" production casing is set.
- The drain hole diameter is 6". The first drain is drilled as a standard horizontal well and any additional drain starts from an open hole side track.

With the benefit of C.P.T.L. experience in horizontal drilling, the open-hole multi-drain technology (including open-hole side track, re-entry...) was rapidly mastered. Nine multi-drain wells were drilled in Mabruk field with two up to four drains (see Fig. 8 A74H first quadrilateral well drilled in Libya) for a cost increase of 5% to 10% by branch. Conversely, the multi-lateral technology increased the well production by 50 to 100%, and reduced well concentration in the field by increasing the drainage area.

ARTIFICIAL LIFT OPTIMIZATION

An aggressive program of artificial lift is being also implemented to optimize the horizontal well production, otherwise limited with the beam pump located in the vertical section far above the reservoir. Submersible Electrical Pump (ESP) and, for the first time in Libya, Progressive Cavity Pump (PCP), were run in high deviated sections close to the pay zone, increasing typically a well production by up to 50% (Fig. 9).

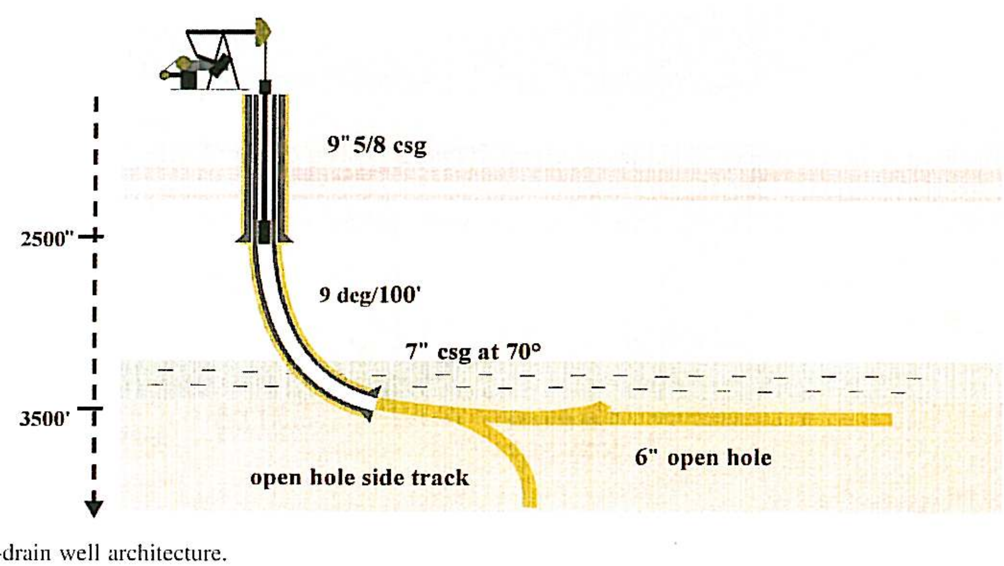

Fig. 7. Multi-drain well architecture.

* The early time data are governed by the capacity of high permeability medium (e.g. fracture network) connected to the well and the late time data by the transmissibility between this medium and a lower permeability/high capacity medium (e.g. matrix)

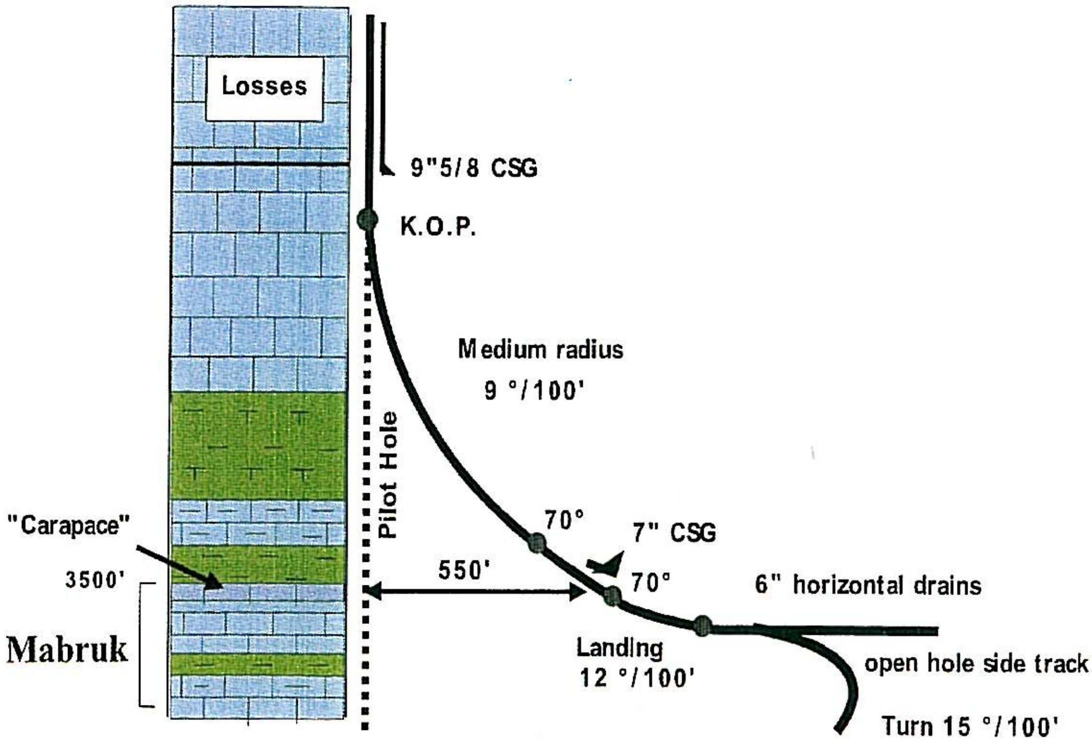

Fig. 8. A74H quadri-lateral well.

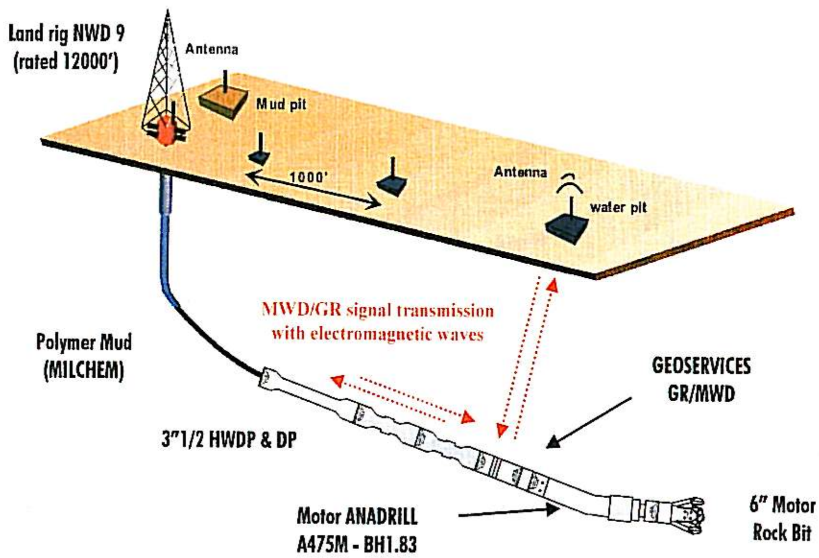

Fig. 9. Artificial lift optimization.