Summary
This paper describes a field study of a faulted, fractured, and multi-layered carbonate reservoir with 17 years of production and pressure history from 59 wells. The reservoir is supported by an extensive aquifer that has been sweeping the hydrocarbon from both the bottom and the edge. Early water breakthrough and rapidly increasing water cut has been a major problem in many of the wells. The major objective of this study is to understand fluid movement in this complex multi-layered reservoir system, to locate the hydrocarbon that is trapped or unswept, and to recover it in an optimum fashion. The field is currently producing at an average water cut of 84%. Three infill wells have been drilled on locations recommended by the simulation, and were found to be at their initial water saturation as predicted by the model.

Introduction
The Sabah field, located in the Southwest side of Sirte basin in Libya (Fig. 1), is operated by Zueitina Oil Company. The field was discovered in 1964 and brought on production in 1978. Oil rate reached the peak production of 41,000 STB/D in November 1982. The cumulative oil production as of 31 May 1997 reached 170.1 MMSTB. The reservoir contains highly undersaturated oil with an API gravity of 41.3. Submersible pumps were installed early in the life of the field and this precluded running production logs.

The productive horizon is the Beda ‘C’ formation, a vuggy carbonate of Palaeocene age capped by anhydrite. Initial reservoir pressure was 2241 psig, and at the inception of the study, it was around 1050 psig indicating significant pressure drop in spite of the extensive aquifer support. The past production performance was characterised by early water breakthrough, followed by rapid increase in water cut. It was believed that this was a sign of a poor sweep efficiency and possibly by-passed oil. The incentive of simulating reservoir fluid movement to locate the remaining oil and to define drainage area was there.

The previous simulation study in 1987 was inadequate to describe the reservoir, mainly due to uncertainties in the structure. An extensive geological, petrophysical, and reservoir characterisation study was conducted to construct the reservoir simulation model. Data sources included cores, wireline logs, repeat formation tester (RFT) and formation microscanner (FMS) logs, transient well tests, and PVT analyses. The study was completed in a parallel planning approach. Geological and petrophysical interpretations were modified during the course of study.

Geology
Structure. The field is situated in the Tagrifet trough of the Hercenian Unconformity. The structural closure is formed by an anticline, which is faulted by the NW-SE systems. The reservoir consists of three major blocks; Main, East and West Sabah, separated by the faults (Fig.2). Schematic section AB, as shown in Fig. 3, cuts the faults and has been chosen normal to the faults. It can be seen that there is an appreciable throw, which creates a trap. Where a permeable zone is faulted against impermeable rock, it is assumed that there is no fluid flow. As the faults die out on strike, there is potential for complex fluid movement across them. The overall effect of the fault systems is to impede but not arrest fluid movement in an easterly or westerly direction. This observation has been confirmed in the simulation.
Stratigraphy. The Beda ‘C’ reservoir is divided into five geological layers based on rock type, porosity/permeability variation and Sw characteristics; I-A, I-B, Tight, II-A and II-B (Fig.6). Layer I-A is fine-grained dolomite, which is frequently vuggy. The vugs are well connected in many cases, causing high permeability (over 1 Darcy in some cases). Layer I-B represents the fine-grained, less vuggy continuation of layer I-A. On logs it is identified by the higher water saturation and the porosity decreasing downwards. The Tight layer generally has a low permeability (less than 1 md). Its porosity frequently approaches to zero over a ten feet interval but can be as high as 15%. Layer II-A represents shallow marine grey limestone. In the upper most 30 feet there are vugs, however, these are not well interconnected. Layer II-B is fine-grained grey limestone with generally low permeability and may have isolated pockets of oil above the field oil/water contact, however these contribute little to reserves. The dolomite that makes up layers I-A, I-B and the Tight zone is of near constant thickness over the whole field (50-60 feet). The OOIP is estimated to be 482.4 MMSTB of which 347.8 MMSTB (72.1%) is accumulated in layer I-A.

Model

Rock and PVT Properties. Permeability distributions were obtained from log derived porosities (Fig.4). The permeability from transient well tests varies from 36 md to 1734 md, with an arithmetical average of 340 md. Comparison of the test-derived permeabilities with core permeabilities demonstrates little correlation. The basic core data comprise of 505 plugs and 181 full diameter data points. Only 7 core data points are above the average test permeability of 340 md. It is believed that this mismatch between core and test permeabilities is a result of another mechanism contributing to effective in-situ permeability, perhaps a network of natural fractures together with those induced by drilling. This would also explain the predominance of negative skin values, in spite of partial penetration, perforating only one shot in every 5 or 10 feet of net pay section. It is felt that the small scale acid wash performed on most of the wells was not sufficient to account for the size of the negative skin values. On the other hand, a network of fractures may explain the high skin values. This hypothesis is supported by loss of circulation during drilling, and high water cut almost immediately after completion in many wells. Having established a rationale for the permeability mismatch, global multipliers were applied to the permeabilities inferred from the porosity transformation to honour the transient well test permeabilities.

The hydrocarbon system was highly undersaturated oil, with an original reservoir pressure of 2241 psig, bubble point pressure of 427 psig, solution GOR of 205 SCF/STB, and oil API gravity of 41.3. The current reservoir pressure is 900-1000 psig in the central part and 1100-1200 psig at the flanks. Based on the special core analysis data, the residual oil saturation is 16-30% in the dolomite and 20-40% in the limestone intervals.

Model Grid. An irregular grid system was used in order to honour the complex faults mainly in SE-NW direction (Fig.5). The model layers were constructed by subdividing layer I-A into 3 layers, and layer II-A into 2 layers on the basis of porosity and saturation distinction in the layers. A total of 16,072 global grid cells were used in the model (49x41x8).

History Match

The history match of 17 years of production and workover history was achieved. The production schedule was entered in terms of monthly average gross rate for each well. Oil rate, water cut, and pressures (flowing, static, and RFT) were used as matching parameters. The field history match of oil rate and water cut is shown in Fig.7.

Modification of Structure Map. The history match was completed in two stages due to changes in structure map during course of the study. In the first stage, the history match was started with the existing structure map, which did not have the faults West and North of well B04 in the NW Sabah. In order to match individual well performances in that region, hypothetical permeability barriers (i.e faults) were located North and West of well B04. These modifications resulted in a region around B04 being protected from the aquifer encroachment and remaining unswept; subsequently, potential site for infill drilling. To confirm the existence and location of the faults in this area, a consulting company was hired to re-evaluate
the seismic data independently. In the course of their evaluation, the preliminary findings of the simulation study were not made known to them (i.e. a possible fault in the West and North of B04). Their study also detected faults around well B04 that agrees with the preliminary findings of the history match. Eventually, the new map with minor modification was used in the final history match.

Faults. The history match shows that faults in the Sabah field do not form a global seal. The West, Main, and East regions of the reservoir are in pressure communication.

Aquifer. The reservoir is supported by an extensive aquifer. Total aquifer volume connected to the reservoir is 311,000 MMSTB that is 645 times larger than the hydrocarbon volume. The edge aquifer is effective mainly from the NW and SE directions, and the bottom aquifer acts in the central main part of the field. For the duration of the history match period, the aquifer has been infinite acting, i.e. no boundary effect has been detected.

The Tight Layer. Aquifer strength together with permeability of the Tight layer dominated water cut performance of the wells. The Tight layer is very tight in the West and NW of the field; therefore, water cut increases gradually in these areas. In the SE of the Main Sabah, the Tight layer becomes more permeable (7 md maximum) and establishes communication between dolomite and limestone. Water cut of the wells located in this area increases relatively fast.

Fractures. The wells North of the Main field (G25, G26 and G41), wells to the South (G10, G11 and G12), and all the wells in the East Sabah were modelled with high vertical transmissibility. These wells started with high water cut when they were put on production. Without considering fractures and assigning high vertical transmissibilities, their initial water cut performances could not be matched. There is direct evidence of fracturing in some wells. G25 indicates fracturing on the caliper and porosity logs in the Tight zone. Wells G10 and G11 experienced loss of circulation during drilling to a degree that drilling had to be stopped.

It has been argued that the high water cut performance could be due to poor cement bond. The recent well G51 in the East Sabah was drilled only into layer I-A in the hope that this would reduce the water cut. Unfortunately this did not transpire and the well started with high water cut even though the Sw calculated from logs suggests that the area was unswept. This proves that high water cut can not be attributed to poor cement bond and is more likely due to fractures.

Prediction Cases

Infill Drilling. Three vertical infill wells appear economical for improving oil recovery and accelerating the production. Wells G51 and G53 were drilled in the East Sabah. Their saturation profile and production performances agree with the model results. In the East Sabah, most of the wells are producing above 90% water cut and the model indicates that the water comes mainly from below (the limestone section) through fractures, and some from SE through the edge aquifer. Water saturation map at the end of history match shows that the region NW of G33 is unswept by the aquifer, and therefore, it is at the connate water saturation. G51 and G53 were drilled NW of G33 in 1996. Well G51 is at the same elevation as G33 and G40, and G53 is structurally 15 ft lower than G33. Although the neighbouring wells G33 (500 meters away from G51) and G40 are currently producing at 96% and 92% water cut, respectively, G51 and G53 were at their connate water saturation. This confirms the simulation's findings that in East Sabah the water comes mainly from below through fractures. Wells G51 and G53 are compared to nearby wells in Fig.8-9. Their initial water cut performances are much better than initial performance of wells G33 and G40, which were put on production 13 years ago.

Well G52 was drilled in NW Sabah, on the flank of the reservoir. This was a high risk location because the nearby wells are structurally higher than this well and are either producing at more than 90% water cut or are watered out by the strong edge water from the North (Fig.10-11). For example, well G49, located East of G52, was wet when it was drilled in 1993. Well G36 located West of G52, was watered out by the edge
water from the North in 1988. Well G52 is structurally 61 ft lower than G49 and 35 ft lower than G36, however, G52 was found at connate water saturation when it was drilled in 1996. This area was protected by faults from water influx as predicted by the model. The well has been performing in a trend close to the prediction.

Workovers. Out of 43 producers currently on stream, 11 are producing from both the dolomite and the limestone intervals. The rest are producing only from the dolomite interval. The model shows that the limestone interval contributes only water in most of these 11 wells. In order to save reservoir energy and reduce water cut, the limestone intervals are recommended for cement squeeze.

Horizontal Wells. Two horizontal re-entry wells in the East Sabah (G53 and G33) are predicted to be economical and would improve ultimate recovery by 2.3 MMSTB. A Local Grid Refinement was constructed to optimise their location, orientation, and length. The optimum length was obtained to be 1650 ft for G53 and 1500 ft for G33. Their feasibility is being evaluated.

Water Injection. Several sensitivity runs were made on the feasibility of water injection in the Sabah field. The results show that converting 8 wells (shut-in or low producers) to water injection would accelerate the production and improve the productivity. Incremental reserves, in this case, would be 6.0 MMSTB.

Optimum field development strategy calls for mixture of workovers, 3 infill drillings, 2 horizontal wells, and water injection. The ultimate recovery, in this case, would be 223.8 MMSTB (46.4% of OOIP).

Conclusions
1. The study was completed in a parallel planning approach. During the course of the history match, new seismic interpretation was integrated to the simulation based on the preliminary results from the model.
2. A black-oil model has been successfully used to find the regions of trapped or unswept oil. Three infill wells have been drilled and their saturations and performance have been as predicted by the model.
3. Two horizontal re-entry wells in the East Sabah appear beneficial for improving the recovery and accelerating production.
4. Water injection seems feasible for increasing sweep efficiency and for pressure maintenance.
5. Optimum field development strategy formulated by the model may improve the ultimate recovery by 14.2 MMSTB.

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References
3. Carbonate Depositional Environment, AAPG Memoir, 1983

SI Metric Conversion Factors

- bbl x 1.589873 = m³
- ft x 3.048 = m
- ft³ x 2.831685 = m³
- in. x 2.54 = cm
- md x 9.869233 = μm²
- psi x 6.894757 = kPa
Fig. 1: Regional Location Map

Fig. 2: Structure Contour Map

Fig. 3: W-E Section

Fig. 4: Porosity-Permeability Transformation

Fig. 5: Areal Grid

Fig. 6: Type Log and Model Layering
Fig. 7: Total Field History Match

Fig. 8: Cross Section of East Sabah Wells

Fig. 9: Water Cut Performance of East Sabah Wells

Fig. 10: Cross Section of NW Sabah Wells

Fig. 11: Water Cut Performance of East Sabah Wells