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Controls on Porosity and Permeability of the Lower Cretaceous Nubian Formation Reservoir, Abu Attiffel Oil Field, Eastern Sirt Basin, Libya.

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ضوابط المسامية والنفاذية بخزان تكوين النوبة التابع للعصر الكريتاسي السفلي بحقل أبو الطفل النفطي، شرق حوض سرت، ليبيا

ميلاد رحومة

يشكل تكوين الحجر النوبي التابع للعصر الكريتاسي السفلي قاعدة التتابع الطبقي بحقل أبو الطفل النفطي وتعلوه، وبسطح عدم التوافق، صخوراً فتاتية تتمثل في العضو الثامن من مجموعة الركب تنتمي إلى الجزء العلوي من العصر الطباشيري.

يمثل تكوين الحجر النوبي، والذي لم يكن بالإمكان الوصول إلى الجزء السفلي منه، رواسب أنهار ذات نظام صرف متشعب ومتعرج. وتم من خلال الدراسة البتروغرافية تحديد عدة عوامل تتحكم في توزيع المسامية والنفاذية، حيث لوحظ أن أعلى نسبة للمسامية تتواجد في رواسب الأنهار المتعرجة وفي رواسب الحواجز الجانبية منها، وبالمقابل فإن رواسب ضفاف الأنهار لها مسامية ونفاذية منخفضتين.

تمثلت العوامل الثانوية بنتائج عمليات النشأة المتأخرة خاصة المواد اللاحمة (السيليكا والدولوميت والطين) وذوبان المكونات غير الثابتة (الفلدسبار والرواسب الأرضية)، كما أدى ترسب السيليكا والدولوميت الحديدي والكاولينايت إلى إنخفاض المسامية والنفاذية بالجزء العلوي من الخزان النفطي، أما نمو المرو وتكوين الكلورايت فقد أديا إلى إنخفاض المسامية والنفاذية بالجزء السفلي من الخزان النفطي. ونتيجة إلى زيادة دفن هذه الرواسب بالأعماق فقد أدى ذوبان الفلدسبار والمواد اللاحمة المكانية والرواسب الأرضية إلى إنتاج مسامية ثانوية وزيادة في النفاذية.

Abstract: *The Lower Cretaceous Nubian Formation forms the basal part of the sedimentary sequence in Abu Attiffel oil field. It is unconformably overlain by Upper Cretaceous clastic rocks (Member VIII of Rakb Group.) and the lower boundary is not reached. The Nubian Formation represents fluvial deposits of braided and meandering river systems.*

On the basis of detailed petrographic analyses several controls on porosity and permeability are designated to explain the present characteristics of the Nubian reservoir in Abu Attiffel oil field.

Primary controls, represented by the variation in the primary sedimentary texture of the facies, show a clear regular relationship to porosity and permeability values distribution. The highest porosity and permeability are present in the braided river and point bar deposits and, in contrast, the overbank deposits have lower porosity and permeability.

Secondary controls are represented by the product of the diagenetic processes particularly cements (silica, dolomite and clays) and dissolution of unstable constituents (feldspar and

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matrix). The porosity and permeability in the upper part of the reservoir (braided river deposits) are mostly reduced by precipitation of silica, ferroan dolomite, and formation of kaolinite, whereas in the lower part of the reservoir (meandering river deposits) they are mostly reduced by quartz overgrowth, and formation of authigenic chlorite which can have a remarkably important effect in reducing the permeability. With further burial significant dissolution of feldspar, some authigenic cements (kaolinite), and matrix generate secondary porosity and enhance the permeability.

INTRODUCTION

The Abu Attiffel oil field is located on the Hameimat Trough, eastern Sirt Basin (Fig. 1) where the Nubian Formation and its equivalent strata have yielded major hydrocarbon production in addition to the Sarir and Messlah fields (Abdulgader, 1996). The stratigraphic sequence and lithofacies analysis of the area have been generally described (Hea, 1971).

The Nubian Formation forms the basal units of the Abu Attiffel oil field sedimentary sequence which is subdivided into three members (Fig. 2). The Upper and Lower members of the Nubian Sandstones represent braided and meandering river systems, whereas the middle member Nubian Shale represents shallow lake or lacustrine flood plain deposits. This formation is unconformably overlain by Upper Cretaceous clastic rocks (Member VIII of Rakb Group.) and the lower boundary is not reached. However, in a nearby well (Y1-80), the Nubian Formation overlies the basement rocks of igneous and metamorphic origins.

This study investigates the controls on porosity and permeability of the Nubian Formation. In order to achieve this objective one hundred and twelve thin sections were made from conventional cores recovered from A61-100 and A67-100 AGIP wells. Petrographic analyses revealed the existence of several diagenetic events which may explain the present characteristics of the reservoir.

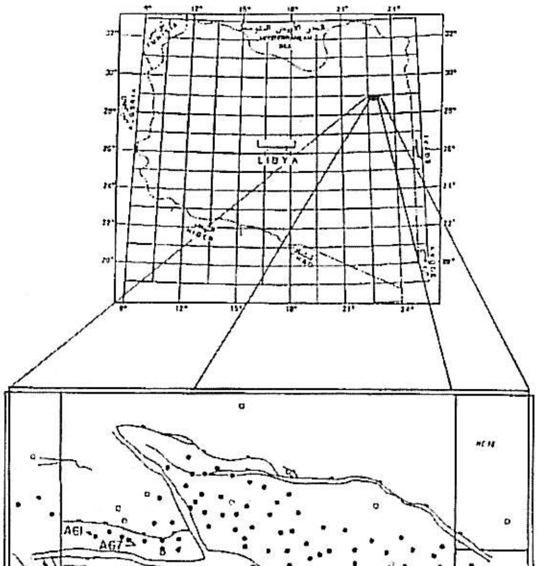

Fig. 1. Location map of the studied wells.

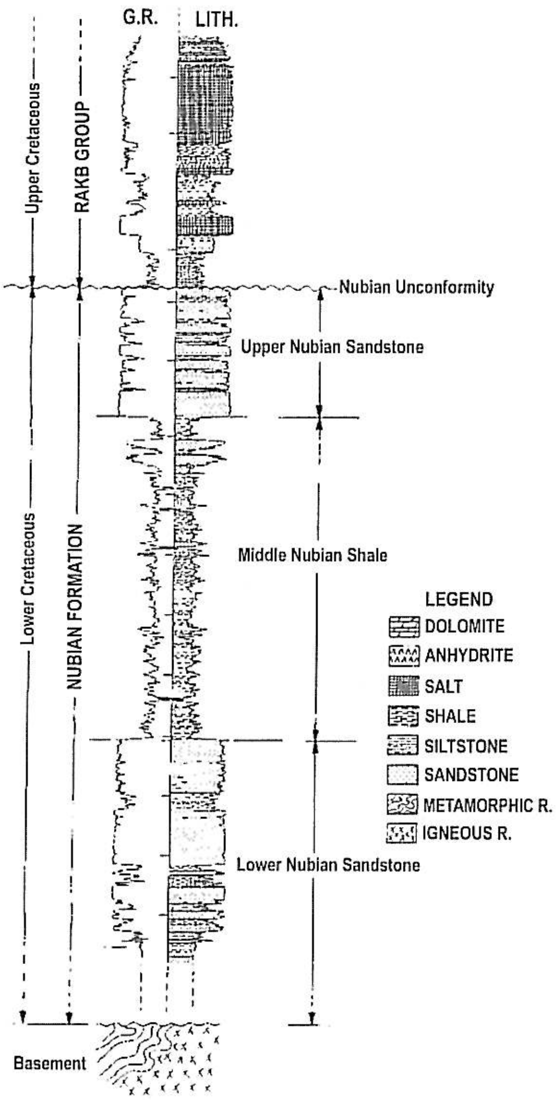

Fig. 2. Generalized composite section of Nubian Formation, compiled from final well logs of the wells A61-100, A64-100 and Y1-80.

Geological Settings

The Sirt Basin is tectonically a northwest-southeast elongated basin or embayment in which the major structural features trend northwest-southeast. Several trending faults in the basin probably reflect the original basement block-faulting and subsequent movement along these faults (Goudarzi, 1980).

Early Cretaceous rifting in the Sarir and Al Hameimat zone in the south of the Sirt Basin, therefore, formed E-W and ESE-WNW trending basin. The trend of these rifts was largely controlled by the craton margin-parallel basement faults of the north African megashear zone, which were in turn strongly influenced by Hercynian structural trends (Anketell, 1996).

Controls on porosity and permeability

The study of selected rock samples of the A61-100 and A67-100 wells suggest that the primary depositional facies were considered the predominant control on porosity and permeability distribution (Ben Rahuma, 1997). The relationship of porosity and permeability, however, appears to have been affected by diagenetic processes, namely, formation of authigenic cements and clays, and porosity enhancement by dissolution of unstable minerals and microfracturing.

Primary Controls

On the basis of primary sedimentary texture variations, the facies types show a clear linear relationship to porosity and permeability distribution. The highest porosity and permeability values are present in the braided river and point bar deposits. This phenomenon is due to the fact that these sandstones are coarse grained, with typical moderate to good sorting characteristics and low detrital clay content.

In contrast, the overbank deposits have low porosity and permeability values owing to their poor sorting and moderate to high detrital mud content (Fig. 3a).

Secondary Controls

Further controls to primary sedimentary texture (grain size, sorting and matrix content) seem to have affected porosity and permeability development. These are represented by several diagenetic features, observed in thin sections which have played a significant role in modifying the original porosity and permeability. The most important of these features are compaction, cementation and dissolution.

Several signs of compaction in the formation were observed, and appear to have reduced the porosity. Many thin sections display the effect of pressure solution on sand grains in contact, where grains initially with point contacts changed to concave-convex, or sutured contacts and sometimes stylolitic (Fig. 3b and 5a). Permeability has also been reduced by pore throat narrowing and squeezing of clay and labile grains.

Authigenic cementation: The most common authigenic cements in these sandstones are silica overgrowths and carbonates, with less important ones such as anhydrite, barite and pyrite. The net effect of all these mineral cements has diminished or nearly completely destroyed the primary intergranular porosity.

Authigenic quartz: Abundant authigenic cement throughout the formation shows a clear inverse relationship to the detrital mud content and is strongly controlled by the sorting of the sediments. Quartz overgrowth is the most common type of porosity destroyer in sandstones, particularly in braided river and point bar deposits (Fig. 3c and d). There is, however, sufficient porosity remaining even at deep burial depth, but the permeability decreases dramatically, owing to plugging of pore throats by silica cement (Fig. 3d).

Carbonate cement: It is the second common type of cement mostly found in the braided river deposits. It occurs as typically rhomb-shaped crystals which caused reduction of the intergranular and dissolution porosities (Fig. 3e and f).

Authigenic anhydrite, barite, and pyrite: They occur as scattered traces of cement in the studied section causing negligible diminishing of porosity.

Authigenic clays: Authigenic clay minerals show a wide distribution in the studied sandstones. Kaolinite and chlorite occur as late pore filling minerals (Fig. 4b and c), and chlorite is found also as pore lining (Fig. 4a). The presence of these authigenic clays have destroyed part of the effective porosity and drastically reduced permeability. Initial examination of the petrographic data suggests that no clear trend exists

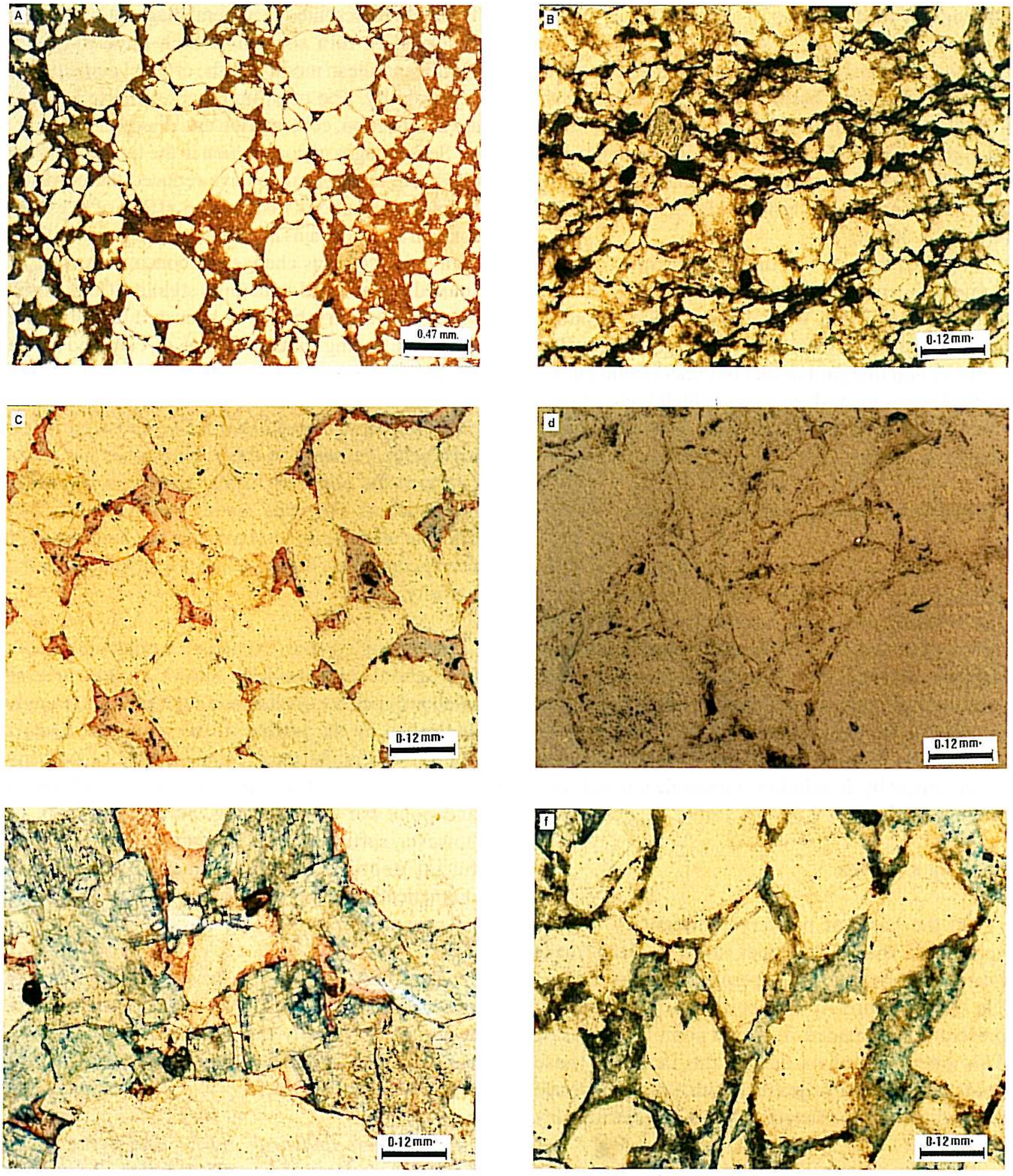

Fig. 3. A) An immature and poorly sorted texture, containing very high amount of matrix, has often inherited precipitation of authigenic cement, A67-100 well, 1472ft. B) Solution seems (low amplitude stylolites). This is formed during compaction of relatively uncemented material until relatively late in its diagenitic history, A67-100 well, 13976ft. C) A authigenic quartz cement (note euhedral crystal faces), in which a significant amount of pore space has been filled, A67-100 well, 13971ft. D) Advanced stage of silica cementation completely obliterating intergranular porosity, A67-100 well, 14052ft. E) Authigenic cementation, ferroan dolomite associated with anhydrite. In this case the dolomite is well recognizable by its rhombic outline, and sharply defined zonation. Ferroan dolomite is stained blue by Alizarin Red, and anhydrite remains unaffected (arrows), A67-100 well, 13944ft. F) Complex cementation. Quartz overgrowth formed as the first generations of cement were followed by ferroan dolomite. The ferroan dolomite marginally replaced the overgowth and both filled the porosity, A67-100 well, 13949ft. All of these figures are taken in plain light.

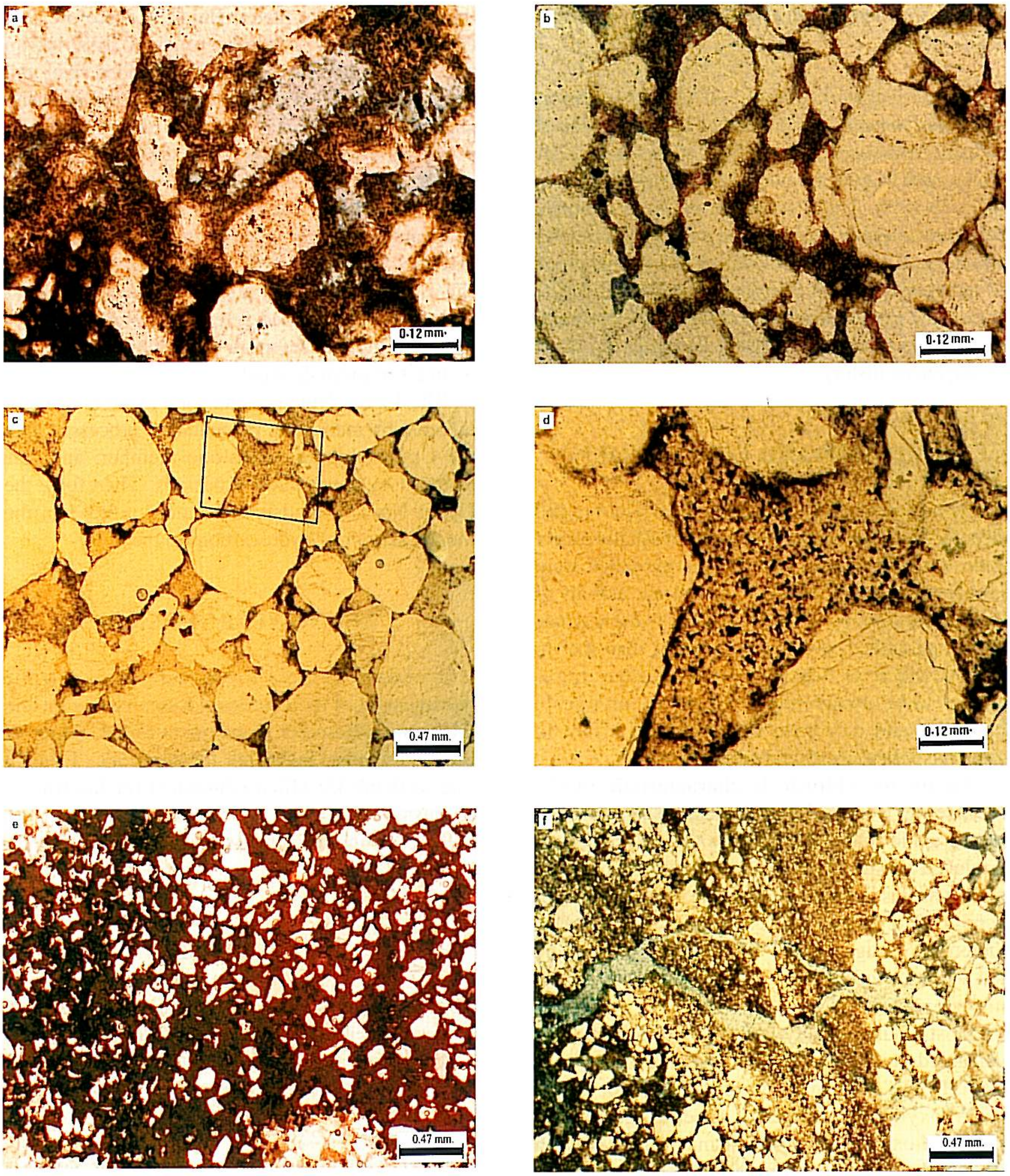

Fig. 4. A) Authigenic chlorite (as fibrous crystals), here seen pore filling and pore lining, clearly has destroyed the porosity and reduce the permeability, A61-100 well, 13902ft. B) Authigenic chlorite (here as plate like crystals), seen as pore filling, clearly destroyed the porosity, A67-100 well, 13982ft. C) Authigenic kaolinite cementation, here seen as pore filling completely is obliterating the porosity, A67-100 well, 13958ft. D) Enlarged view of the outlined area in the previous figure, showing more detailed crystal morphology of the kaolinite. This view showing micro-porosity of the kaolinite that has been completely filled by bitumen. E) Authigenic pyrite cementation, completely filling the intergranular porosity and replaced the matrix and detrital grains, A61-100 well, 14729ft. F) Ferroan dolomite filling fracture. This fracture may have formed at a relatively late during burial and has been completely healed by growth of dolomite cement, A67-100 well, 13944ft. All of these figures are taken in plain light, except of the figure E taken in reflected light.

between the distribution of authigenic clay minerals and porosity.

Porosity Enhancement: At effective burial secondary porosity was created by the dissolution of unstable constituent, particularly those of feldspar grains, rock fragments, matrix and authigenic cement (Fig. 5b to f). The dissolution of these unstable constituents highly enhanced the porosity, which later was reduced again by precipitation of a second phase of authigenic cement (ferroan dolomite, anhydrite, barite, and pyrite) and clays (chlorite and kaolinite) which were produced relatively during a later stage of diagenetic history.

DISCUSSION AND CONCLUSIONS

Authigenic kaolinite is characteristic of the braided river facies. The braided river deposits usually reflect depositional processes of high energy which were probably directly affected by the tectonic activity of the area during deposition. This allows feldspar grains to be aggregated in a higher amount than that in meandering river deposits. These feldspar grains appear to be completely alterated to authigenic kaolinite and can have a remarkable effect in reducing both porosity and permeability.

Authigenic chlorite is characteristic of the meandering river facies. It is clearly seen from the petrographic study of this facies that the chlorite is produced mostly from the alteration of the detrital mud, which is more abundant in the meandering river deposits. The distribution of authigenic clay minerals, therefore, is suggested to have been controlled by the variation of primary sedimentary texture and mineral content.

Most of the porosity is suggested to have been generated during burial by effects of carbonic acid. Burial and thermal maturation can cause decarboxylation of organic material, generating carbon dioxide (CO_2), which may combine with subsurface water to form carbonic acid (H_2CO_3), hence lowering the pH of the pore fluids and increasing the potential of the dissolution (Brown *et al*, 1989). The dissolution processes are directly related to the ability of formation fluid to move through the formation. Therefore, the dissolution processes are directly controlled by the primary sedimentary texture and burial rate through time. The overbank facies of meandering river deposits, characterized by high detrital mud content, prevents the movement of formation fluid and, therefore, less early diagenetic cementation and dissolution processes effect is expected. The braided river and point bar deposits containing little detrital mud and showing better sorting, render the dissolution processes more effective to enhance the porosity.

The cement and matrix dissolution porosities were mostly found in braided river deposits and were less abundant in point bar deposits, whereas intergranular and micro porosities were found more commonly in the overbank of meandering river deposits. Therefore, the braided river and point bar facies represent the best reservoir properties and form the main reservoir in the field.

The Lower Nubian Sandstone member is more affected by authigenic cementation processes than the Upper Nubian Sandstone member, and less affected by dissolution processes. Therefore, the Upper Nubian Sandstone member represents the main reservoir of hydrocarbons in the field.

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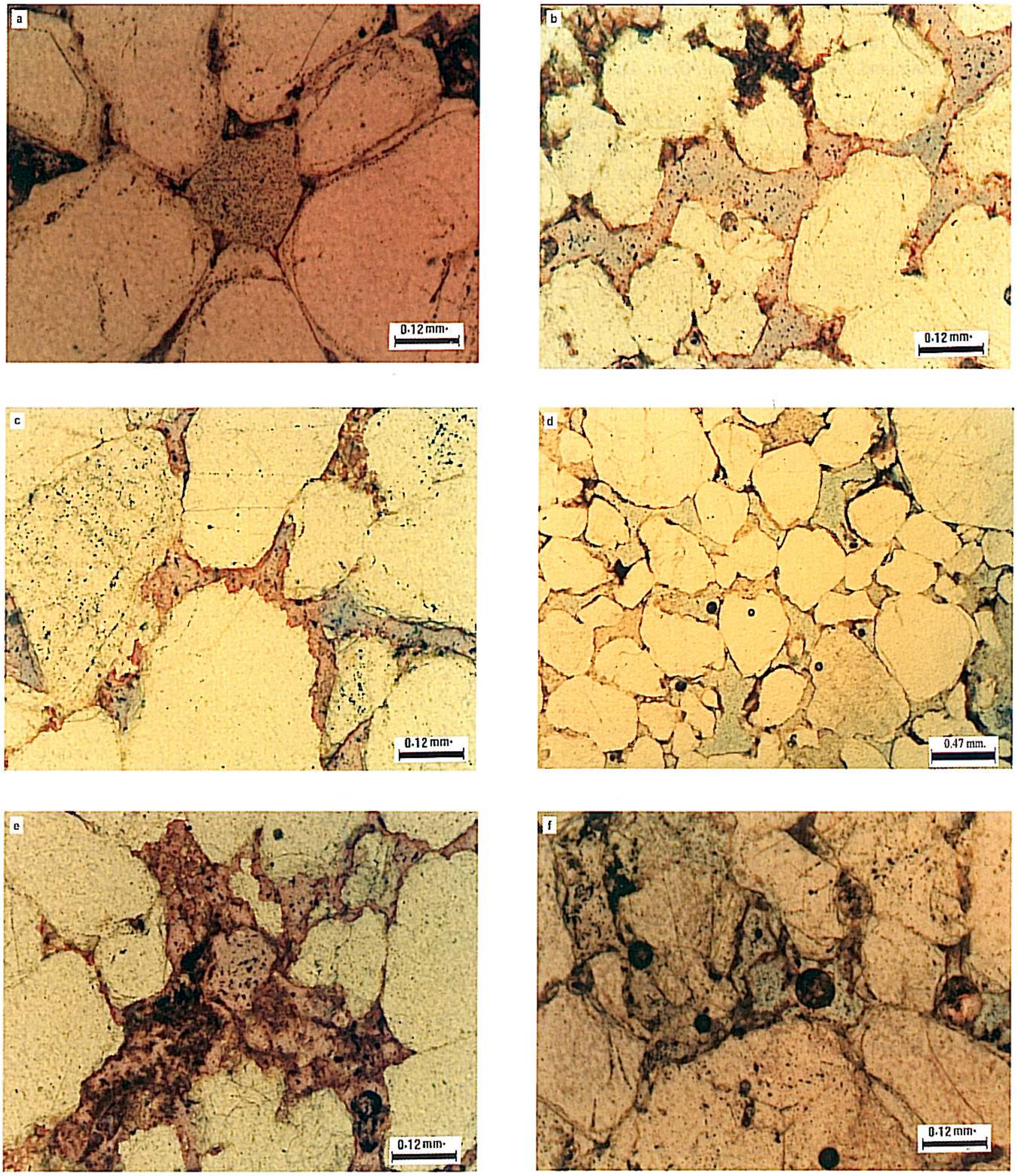

Fig. 5. A) Intergranular porosity confined by quartz overgrowth and physical grain compaction, A61-100 well, 13946ft. B) Chanalized porosity. This porosity have resulted from subsequent dissolution of matrix and authigenic cementing material has left interconnected pore spaces (appear mauve to blue coloured), A67-100 well, 14078ft. C) Partial dissolution of detrital quartz grain and quartz overgrowth has yielded leaching (secondary) porosity. This porosity has occurred as result of corrosion of the quartz grains during relatively late stage of the diagenitic history and has led to enhancement of the porosity and permeability, A67-100 well, 13967ft. D) This view show primary porosity completely destroyed by cementation of quartz overgrowth and authigenic kaolinite. From the other hand secondary porosity (marked by blue), were generated by dissolution. This secondary porosity are lined by head oil which it may have prevent re-cementation, A67-100 well, 13958ft. E) Selective leaching of unstable grains has generated secondary porosity. The remnant authigenic clay indicates original grain morphology, A67-100 well, 14048ft. F) The same phenomenon as in previous view, A61-100 well, 13891ft. All of these figures are taken in plain light.

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