Petroleum System Modelling in Ghadāmis Basin of NW Libya

K. Ameed R. Ghori[1] and Rajab A. Mohammed[2]

ABSTRACT

Oil and gas distribution, geochemical data, present-day temperatures and petroleum system modelling of geological sections based on wells drilled below 3000 m in the Libyan deep central part of Ghadāmis Basin indicate at least two viable petroleum systems within the Lower Silurian and Middle–Upper Devonian.

Oil and gas have been produced from reservoirs of the Ordovician Memouniat Formation, Silurian Tanezzuft and Acacus formations and within the Devonian Tadrart, Ouan Kasa, Aouinet Ouenine, and Tahara formations. Oil and gas have also been produced from the Triassic Ras Hamia and Jurassic Abreghs formations.

The Silurian Tanezzuft and Devonian Aouinet Ouenine formations contain the best source rocks of the basin and are the major source for hydrocarbons produced from the Silurian, Devonian and possibly younger reservoirs. TOC analysis of over 330 samples from six wells indicate that the thickest and organically richest source beds are within the basal 60–140 m of the Tanezzuft Formation and upper 60–120 m of the Aouinet Ouenine Formation. In the Tanezzuft Formation average organic richness is 4% TOC and ranges up to 10% TOC, whereas the Aouinet Ouenine source beds have an average organic richness of 2.5% TOC and reach a maximum of 4% TOC. Rock-Eval pyrolysis of 103 samples and visual kerogen analysis of 18 samples indicates that the organic facies predominantly contains type II kerogen.

Over 235 temperature measurements in 44 wells indicate that the average geothermal gradient is 3.1°C/100 m and most of the prospective reservoirs are within the oil preservation temperature limits of less than 150°C.

Hydrocarbon generation modelling indicates that the maturation of the Tanezzuft source beds range from early generation to mainly gas phase of the hydrocarbon-generative window, whereas the Aouinet Ouenine source beds range from immature to early oil generation phase of the oil window. In the deeper western and southwestern parts of the basin, the peak hydrocarbon generation within the Tanezzuft source beds to charge traps was first reached during the Carboniferous-Permian, which was followed by the second phase of oil generation during the Tertiary. Within the source beds of the Aouinet Ouenine Formation, the maximum rate of oil generation was also reached during the Tertiary whereas in the shallower eastern and northeastern parts of the basin source beds of the Aouinet Ouenine Formation are immature and the peak oil generation within the Tanezzuft source beds was reached during the Tertiary.

INTRODUCTION

The Palaeozoic Ghadāmis Basin is the second most important oil and gas producing basin of Libya after the Upper Cretaceous-Tertiary Sirt Basin. The basin is more oil-prone than gas and its several oil and gas bearing formations range from the Ordovician Terminal Sandstone of Memouniat Formation to the sandstone of Jurassic Abreghs Formation. The proven and possible source rock ranges from the Ordovician shales of the Melez Chograne Formation to the shales of the Lower Carboniferous M'rar Formation (Ghori, 1982, 1989). These source rocks are usually in close juxtaposition with reservoirs and many petroleum systems were inferred from the structural relationship between oil and gas accumulations and nearby source rocks:

- Ordovician sourced system: reservoirs of the Memouniat Formation are in the best juxtaposition to accumulate petroleum sourced from the shales of the Melez Chograne Formation.
- Silurian sourced system: reservoirs of the Silurian Acacus Formation and the Devonian Tadrart and Ouan Kasa formations are in the best juxtaposition to accumulate petroleum sourced from the shales of the Tanezzuft Formation. The Tanezzuft shales and the Acacus and Tadrart sandstones are considered to be

[1] Geological Survey of Western Australia, 100 Plain Street, East Perth, Western Australia 6004.

[2] Exploration Division, Arabian Gulf Oil Company, P.O. Box 263, Binghāzī, Libya, GSPLAJ.

the major source and reservoir rocks of the basin, respectively.

- Devonian sourced system: reservoirs of the Aouinet Ouenine and Tahara formations are in the best juxtaposition to accumulate petroleum sourced from shales of the Aouinet Ouenine Formation.
- Carboniferous sourced system: reservoirs of the M'rar Formation are in the best juxtaposition to accumulate petroleum sourced from shales of the formation. The M'rar Formation has hydrocarbon source potential but M'rar reservoirs are unproductive.

The aims of this study were firstly, to identify and characterize the source-rock intervals from the first-hand geochemical analyses carried out by the Geochemical Laboratory of the Arabian Gulf Oil Company (AGOCO). Secondly, to develop one-dimensional geologically plausible maturity models of key wells by combing measured maturity values and present-day formation temperatures with burial, erosional, and thermal information. Thirdly, the maturity models were used to develop a two-dimensional model of the geological cross-section to reconstruct the process of hydrocarbon generation as a function of the type and amount of kerogen as inferred from the geochemical data. Finally, to estimate the charge timing of petroleum systems from recognized source rock within the study area.

PETROLEUM GEOLOGY

The Ghadāmis is a large intracratonic basin of the Saharan platform spread over parts of western Libya (Al Ḥamādah al Ḥamrā' area), eastern Algeria and southern Tunisia. Within Libya, the sedimentary basin fill is over 5 km, and is wider and deeper towards the west with most of its Palaeozoic formations exposed in the south at Al Qarqaf Arch (Fig. 1). The depositional history of the basin was interrupted by several unconformities including intra-Ordovician, Late Silurian (Caledonian), Carboniferous-Permian (Hercynian), and Cretaceous (Austrian). The Hercynian unconformity separates the two major phases of basin evolution, the thick Palaeozoic deposit of the intracratonic phase from the overlying thinner deposits of the Mesozoic sag phase; generalised time-

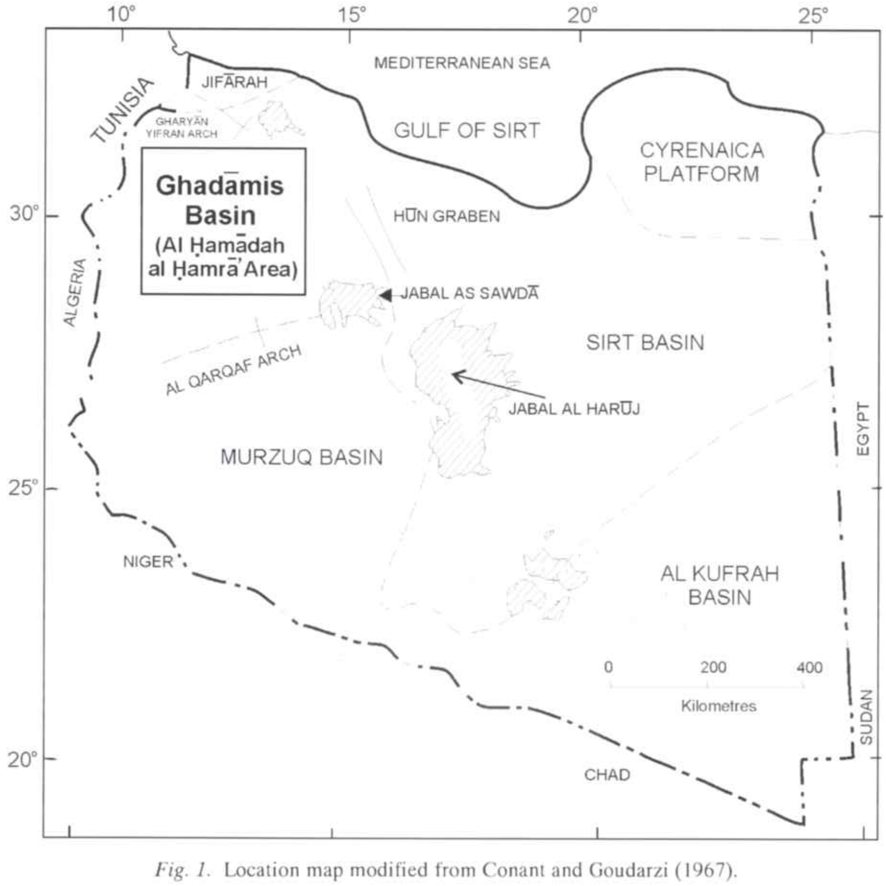

Fig. 1. Location map modified from Conant and Goudarzi (1967).

stratigraphy, proven and potential source and reservoir rocks are summarised in Fig. 2.

The petroleum geology with an emphasis on the time-stratigraphy of the Ghadāmis Basin is given below from the viewpoint of the present study on petroleum system modelling. The geological and stratigraphic information is from various unpublished reports and published papers including Conant and Goudarzi (1967), Bellini and Massa (1980), Goudarzi (1980), Hammuda (1980), Klemme and Ulmishek (1991), Makhous *et al.* (1997), Boote *et al.* (1998), Crossley and McDougall (1998), Echikh (1998), Logan and Duddy (1998), and Macgregor (1998).

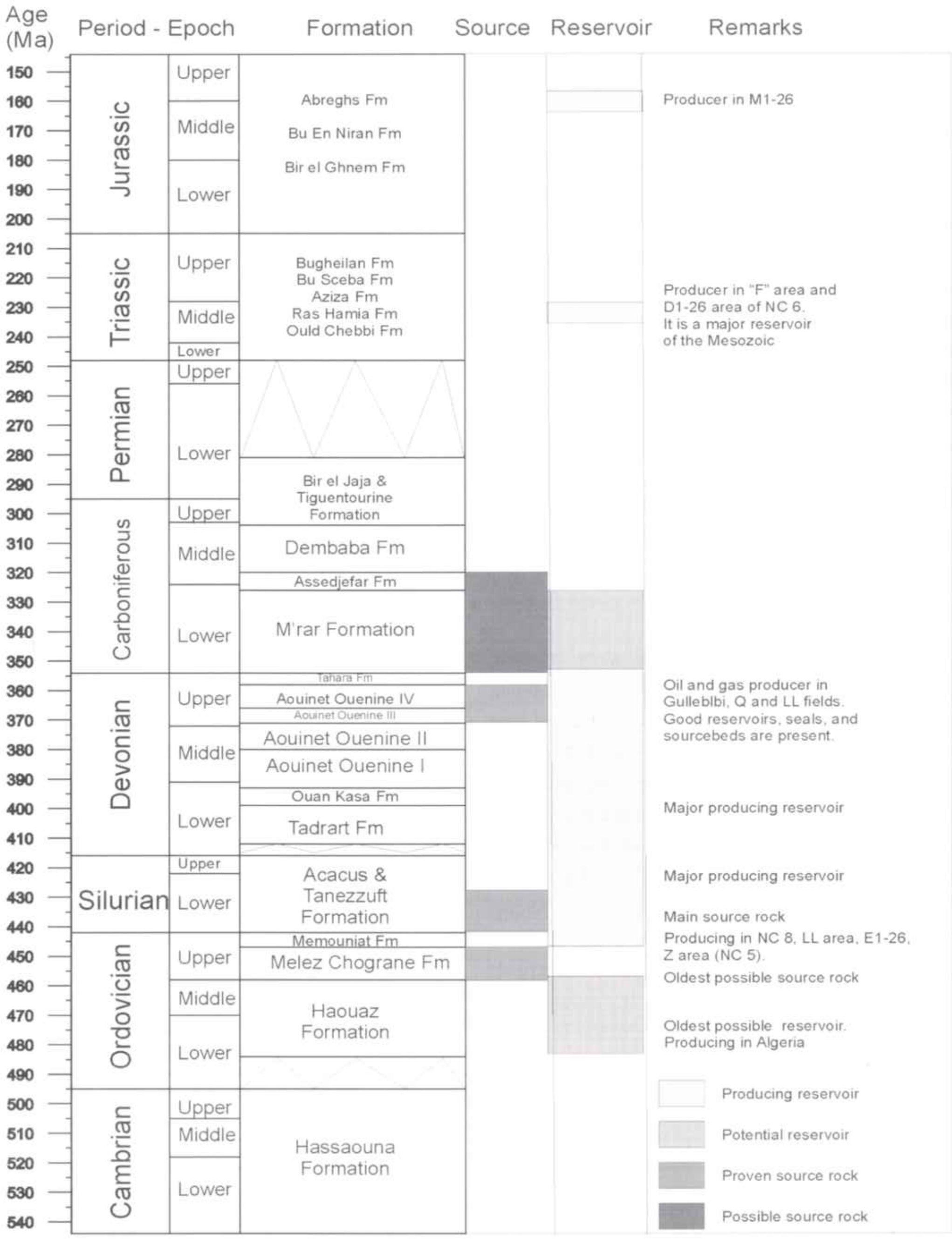

Fig. 2. Generalised time-stratigraphy of the Ghadāmis Basin, proven and potential source and reservoir rocks, based on Haq and Eysinga's (1998) timescale.

Cambrian-Ordovician

Deposition began in the Cambrian with predominantly fluvial to high-energy conditions, which deposited the coarse sandy facies of the Cambrian Hassaouna Formation. This was followed by deposition of the Lower Ordovician shallow marine sandstones and maximum flooding shale facies of the Tremadocian Achebyat Formation, which were overlain by the regressive facies of marine to deltaic sandstone and shales of the Arenigian–Llandeilian Haouaz Formation. After a short intra-Ordovician break, deposition recommenced and the widespread marine transgressive shaly facies of the Caradocian Melez Chograne Formation was deposited. Towards the end of the Ordovician glacial cycle the sandy facies of the Ashgillian Memouniat and Bir Tlacsin formations were deposited.

Only a few wells have penetrated this succession and most of them were completed within the top part of the Memouniat Formation. The Memouniat sandstone is the major producing reservoir of the succession in several oil fields. Although the shales of the Melez Chograne Formation are considered the oldest possible source rock of the basin, according to the geochemical database available for this study this remains to be proved by geochemical analysis.

Silurian

Post-glacial flooding resulted in a wide marine transgression and during the Llandoverian the thick basal radioactive shaly facies of the Tanezzuft Formation was deposited across the basin, followed by deposition of pro-delta and delta sandy facies of the upper Tanezzuft and Acacus formations. Within the Silurian succession, the change from the upper sandy facies of the Acacus Formation to the lower shaly facies of the Tanezzuft Formation is gradual and progressive showing progradation from north to south over the Ordovician.

Although the organic-rich shales of the Tanezzuft Formation form the most important source rocks of the entire basin the Acacus Formation is the main regional reservoir of the Silurian, while the Lower Acacus is a prolific producer from many oil fields and a few gas fields in the central and NW parts of the basin.

Devonian

The Silurian succession was terminated by the Caledonian unconformity and deposition of the transgressive-dominated coarse sandy facies of the Siegenian–Emsian Tadrart and Ouan Kasa formations recommenced. After a short break a widespread marine transgression deposited the shaly facies of the Eifelian Emgayet Shale. This was followed by deposition of the regressive, fluvial-dominated deltaic facies of the Givetian Aouinet Ouenine I Formation. This cycle is overlain by the extensive transgressive marine shales and limestone facies of the Frasnian Aouinet Ouenine II Formation, which in turn is overlain by the regressive cycle of the silty shale and carbonate facies of the Famennian Aouinet Ouenine III and IV formations. Towards the end of the Devonian the clastic sandy facies of the Famennian Tahara Formation was deposited.

The Tadrart and Ouan Kasa formations contain the major producing reservoirs of the basin, with the best reservoirs within the Tadrart Formation. The other reservoirs of the Devonian succession include the sands of the Aouinet Ouenine and Tahara formations. The reservoir quality of the Aouinet Ouenine and Tahara formations is poor compared to the Tadrart and Ouan Kasa formations. The organic-rich shales in the upper part of the Aouinet Ouenine Formation are the best source rocks of the Devonian succession and are comparable with the source rock quality of the Silurian Tanezzuft Formation.

Carboniferous

During the Early Carboniferous, deposition began with fluvial- to wave-dominated thick clastic facies of the Tournaisian–Visean M'rar Formation and was followed by widespread transgression and deposition of fluvio-deltaic to marine shales and limestone facies (Assedjefar Formation). This clastic-dominated facies was followed by deposition of shallow-marine carbonates and evaporite-dominated facies of the Namurian–Westphalian Dembaba Formation and the clastic-dominated facies of the Stephanian–Asselian Tiguentourine Formation towards the close of the Carboniferous. The Palaeozoic depositional cycles were terminated by the Hercynian unconformity, which had a significant effect on the Palaeozoic petroleum systems of the basin. This succession is considered to contain potential source and reservoir rocks but this has yet to be proved.

Mesozoic-Cenozoic

After the Hercynian orogeny, the sag phase of basin evolution began with the deposition of Triassic fluvial sand and shale that grade upwards into finer clastic, carbonate and evaporite, and which were deposited during the

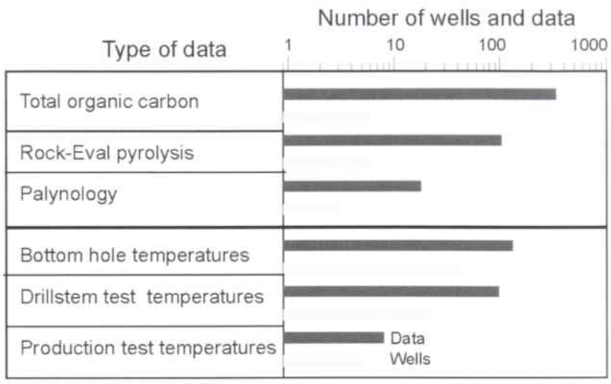

Fig. 3. Geochemical and temperature data utilised in this study.

subsequent Mesozoic-Cenozoic subsidence. Within the Mesozoic succession the major producing reservoir is the sandstone of the Triassic Ras Hamia Formation, followed by the minor producing Jurassic reservoir of the Abreghs Formation.

PETROLEUM GEOCHEMISTRY

Database

The present-day temperature data available for this evaluation include 132 wireline-logging temperatures from 44 wells, 97 drill stem test temperatures from 22 wells, and 8 production test temperatures from 5 wells. The geochemical data include 337 total organic carbon content and 103 Rock-Eval pyrolysis analyses on samples from six wells, while palynological data include 18 visual kerogen analyses on samples from three wells (Fig. 3). The geochemical and palynological analytical work was carried out by the Geological Laboratory of the Arabian Gulf Oil Company in Binghāzī (Ghori, 1989).

Source-rock potential

A plot of TOC versus Rock-Eval S_1+S_2 of 67 samples analysed from the Silurian indicates the presence of organic-rich shale intervals within the Tanezzuft Formation (Fig. 4), and 34 samples from the Devonian indicate the presence of organic-rich shale intervals within the Aouinet Ouenine Formation (Fig. 5).

Silurian source rocks are recognised within the lower part of the Tanezzuft Formation and their petroleum generating potential is classified as fair to very good, while Devonian source rocks are recognised in the upper part of the Aouinet Ouenine Formation and their petroleum generating potential is classified

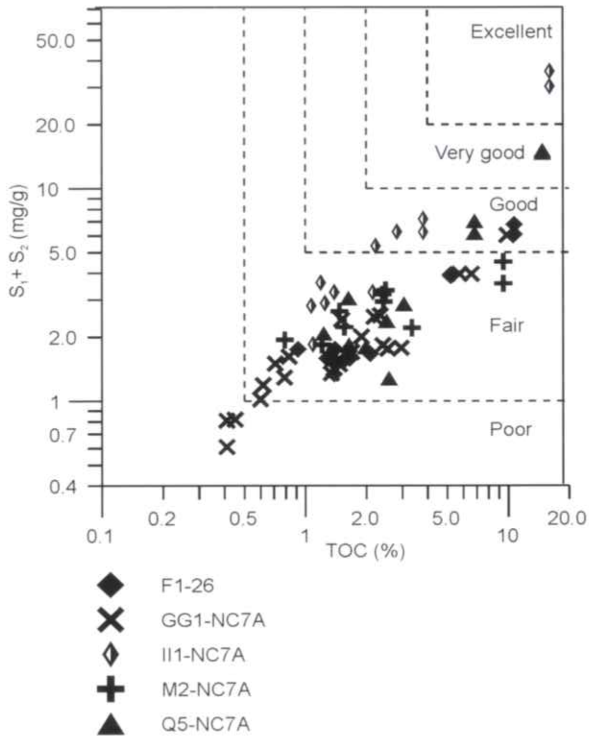

Fig. 4. Petroleum-generating potential as a function of organic richness (TOC%) versus potential yield (S_1 + S_2 mg/g), for samples from the Silurian.

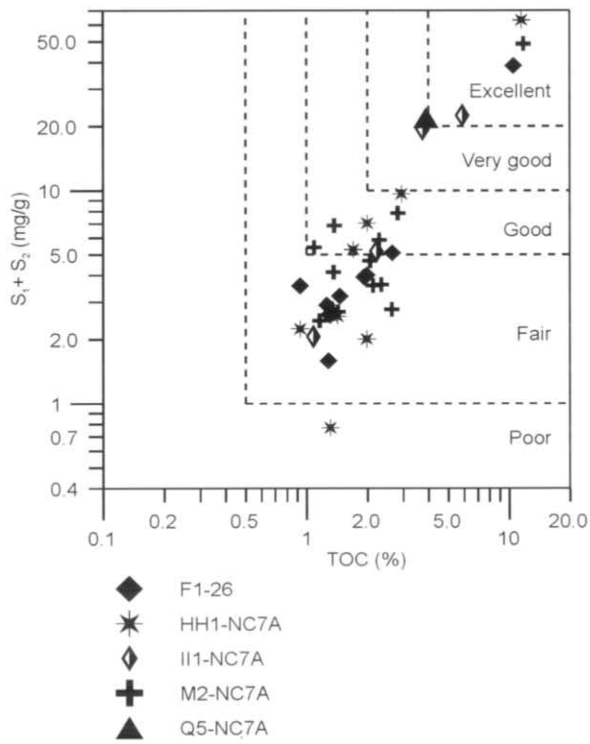

Fig. 5. Petroleum-generating potential as a function of organic richness (TOC%) versus potential yield (S_1 + S_2 mg/g), for samples from the Devonian.

as fair to excellent. Within the analyzed wells the following six are used to illustrate the organic richness and generating potential of the Silurian and Devonian rocks: F1-26, GG1-NC7A, HH1-NC7A, II1-NC7A, M2-NC7A, and Q5-NC7A (Figs 6-11).

Source-rock type

Rock-Eval pyrolysis and visual kerogen analysis were used to determine the type of kerogen in the samples.

A plot of HI versus T_{max} characterizes the kerogen within the Silurian Tanezzuft Formation as oil- and gas-generating type II and III (Fig. 12) and within the Devonian Aouinet Ouenine Formation as oil- and gas-generating type II (Fig. 13). At present, the Tanezzuft source rocks are at a higher level of thermal maturity and so their quality of kerogen is poor compared to the quality of kerogen within the Aouinet Ouenine source rocks because these are not as mature as the Tanezzuft source rocks.

Source-rock maturity

Rock-Eval pyrolysis and palynology have provided information on the level of thermal maturation for the Silurian and Devonian source rocks.

The Rock-Eval T_{max} and PI values for samples with source potential are plotted versus depth in Fig. 14. Both parameters indicate that the maturity of samples ranges from immature to over-mature with most of the samples within the oil-generative window. These parameters indicate that the older and deeper Tanezzuft Formation is at the higher level of thermal maturation compared to the younger and shallower Aouinet Ouenine Formation. These maturities were also reflected by visual kerogen analysis not shown here.

Present-day temperature

The present-day subsurface temperatures were estimated from bottom-hole temperatures (BHTs) recorded during wireline logging in 44 wells, drill stem test (DST) temperatures in 22 wells and production test (PT) temperatures in 5 wells (Fig. 3). Of these, the most reliable temperatures are from PT followed by DST temperatures (Hermanrud *et al.*, 1990, 1991). BHTs are regarded as the least reliable. Although most measured temperatures are lower than true formation temperatures and require some upward correction (Oxburgh and Andrews-Speed, 1981), PT and DST temperatures are generally used without correction.

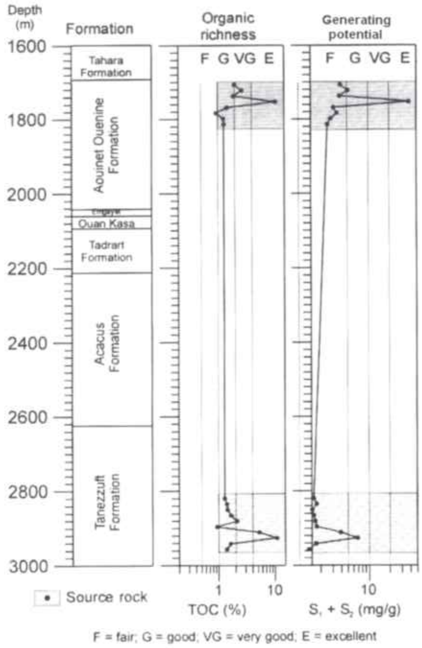

Fig. 6. Organic richness and generating potential of rocks in F1-26.

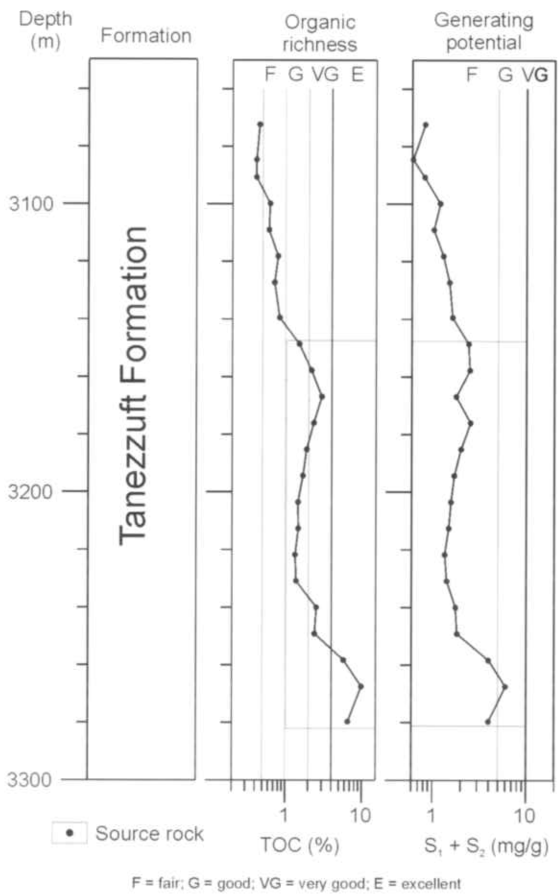

Fig. 7. Organic richness and generating potential of the Tanezzuft Formation in GG1-NC7A.

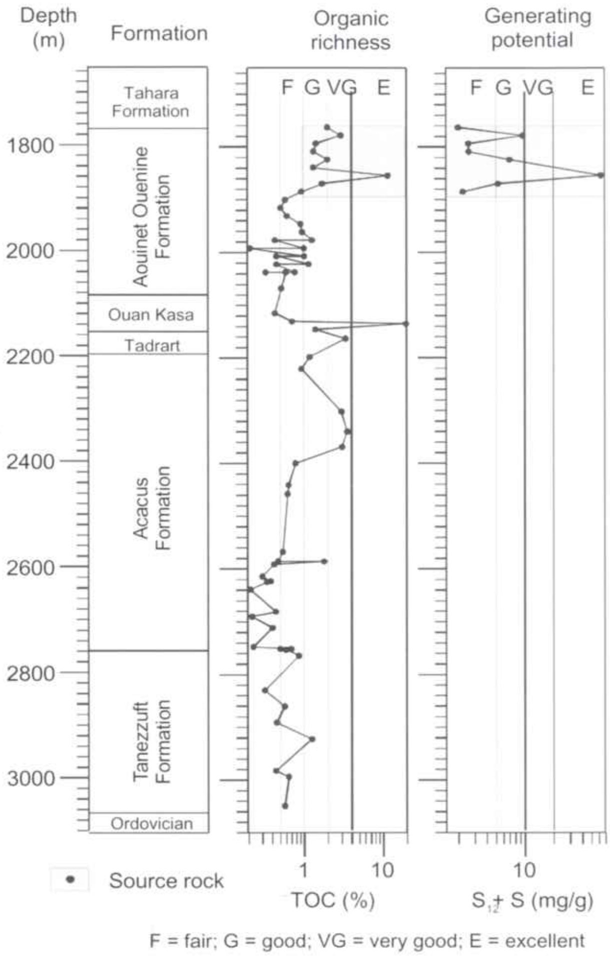

Fig. 8. Organic richness and generating potential of rocks in HH1-NC7A.

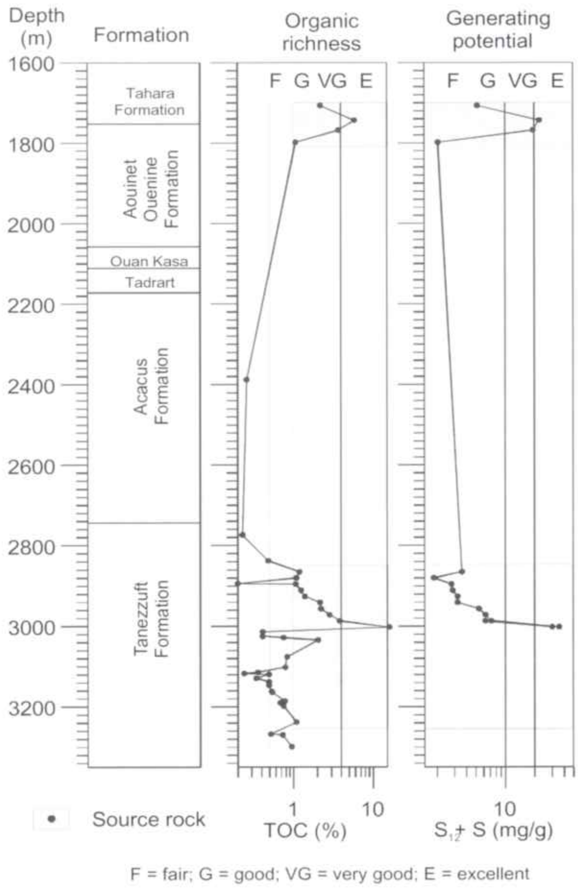

Fig. 9. Organic richness and generating potential of rocks in II1-NC7A.

Measured BHT is usually 10 to 15% lower than the actual formation temperature due to the short time interval between mud circulation and logging for the formation to attain thermal equilibrium and usually requires upward correction (Beck and Balling, 1988; Hermanrud *et al.*, 1990, 1991). In this study BHTs are corrected by using "Kehle's Correction Curve" developed by the Geothermal Survey of North America (Kehle, 1971, 1972), which provides rough compensation for different times-since-circulation and is suitable for the type of temperature data available. The average geothermal gradient within the study area is 3.1°C/100 m based on temperature data available from BHT, DST and PT using 26°C as the surface temperature (Fig. 15).

The average geothermal gradient from 8 measured PT temperatures is 3.1°C and from 86 DST temperatures is 2.8°C, whereas from 116 recorded and estimated BHTs they are 2.6°C and 3.1°C, respectively. This indicates that the average geothermal gradient of the study area is at least 3.1°C/100 m, and the measured DST and BHT temperatures are approximately 10% and 16% lower than the minimum equilibrium formation temperatures, respectively.

PETROLEUM SYSTEM MODELLING

Source-rock thermal maturation and hydrocarbon generation histories of 18 wells were simulated to calculate the timing of petroleum generation and migration in the study area, utilising petroleum systems modelling software of Platte River Associates. The modelling was performed in three steps: (i) one-dimensional modelling of a single well location, utilising version 7.06 of BasinMod 1-D; (ii) one-dimensional modelling of multi-well locations, in version 7.06 of BasinView and; (iii) two-dimensional modelling of a cross-section using version 4.17 of BasinMod 2-D.

In the first step, one-dimensional burial histories were reconstructed from the stratigraphic sections and their lithologies as encountered in wells. The thermal histories

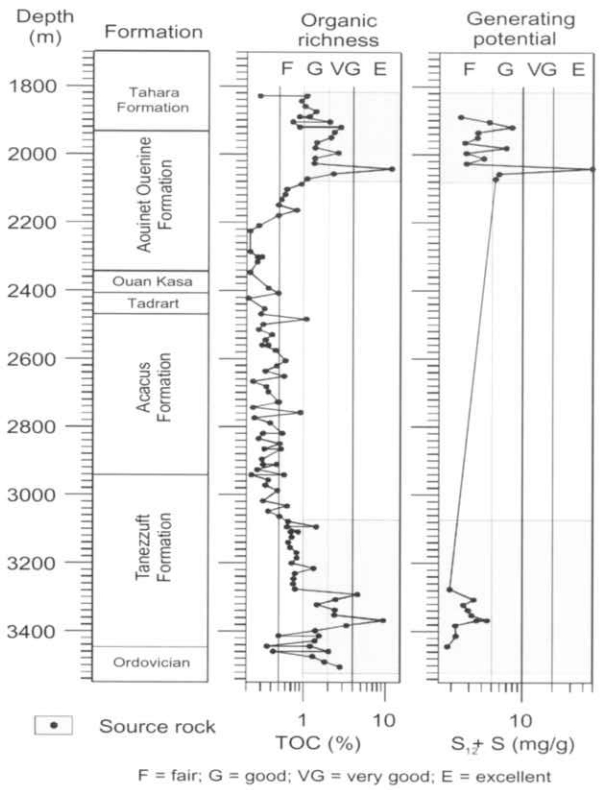

Fig. 10. Organic richness and generating potential of rocks in M2-NC7A.

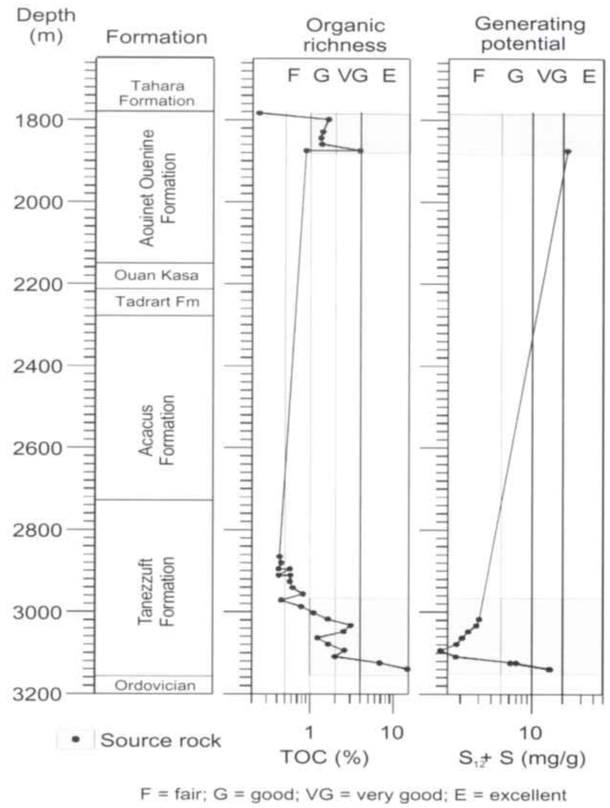

Fig. 11. Organic richness and generating potential of rocks in Q5-NC7A.

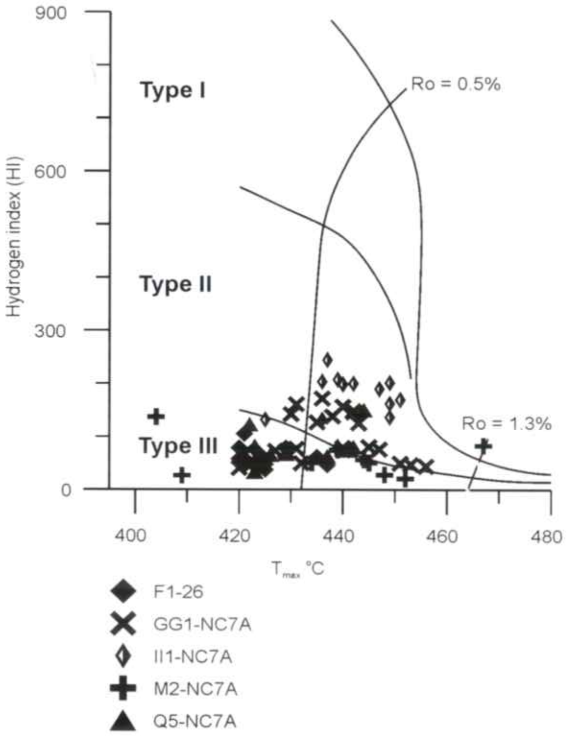

Fig. 12. Type of kerogen as a function of the Rock-Eval parameters, T_{max} versus hydrogen index for samples from the Silurian.

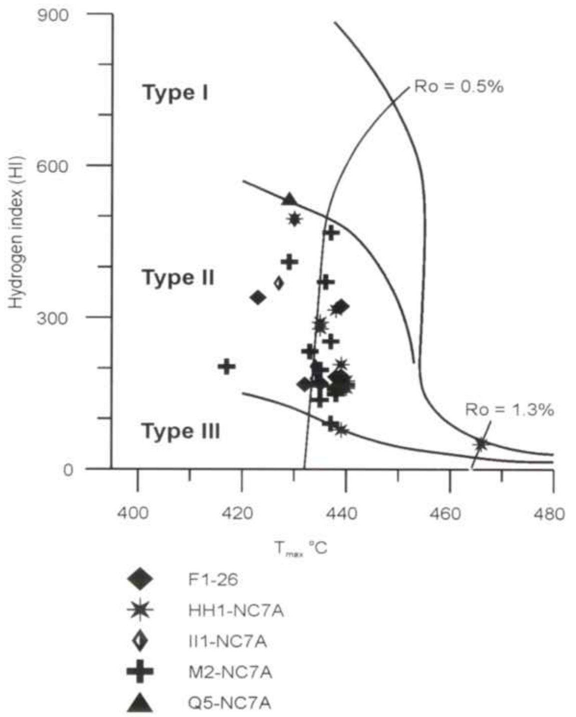

Fig. 13. Type of kerogen as a function of the Rock-Eval parameters, T_{max} versus hydrogen index for samples from the Devonian.

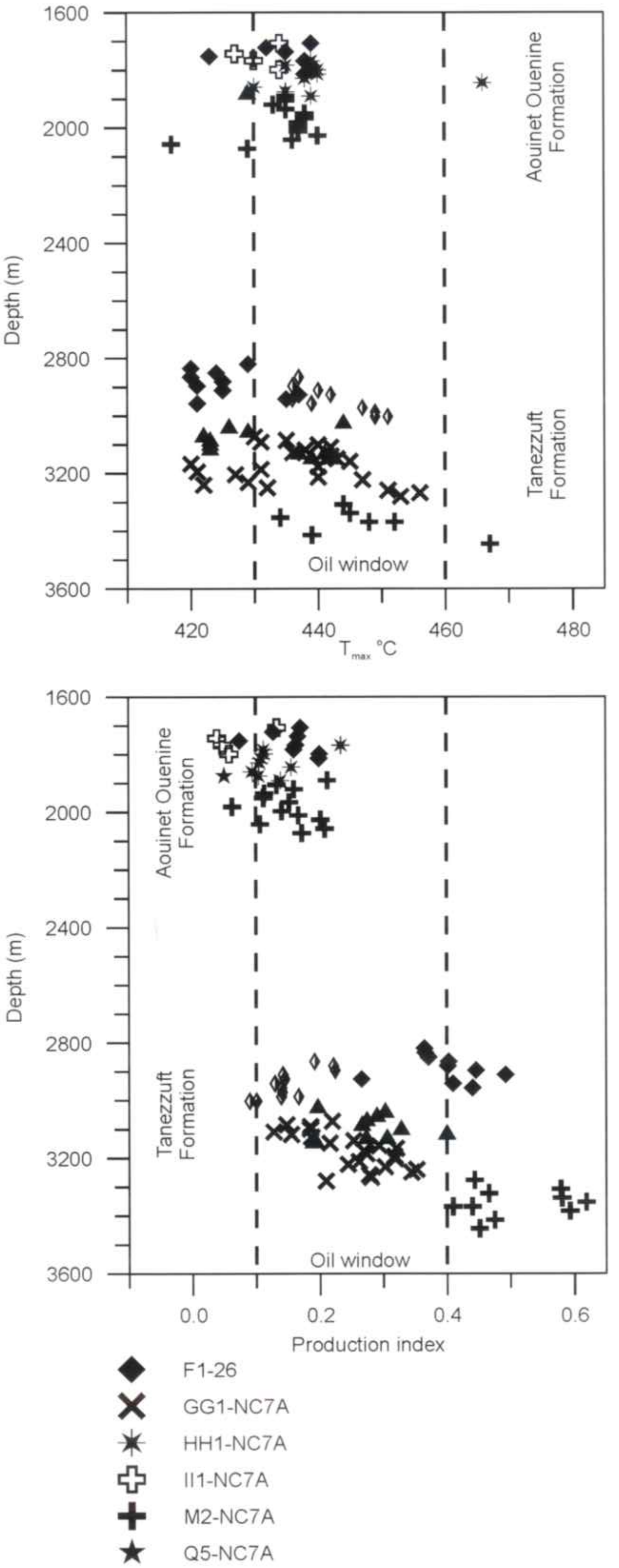

Fig. 14. Maturity as a function of the Rock-Eval parameters: a) T_{max} versus depth; b) production index versus depth, for samples from the Silurian and Devonian.

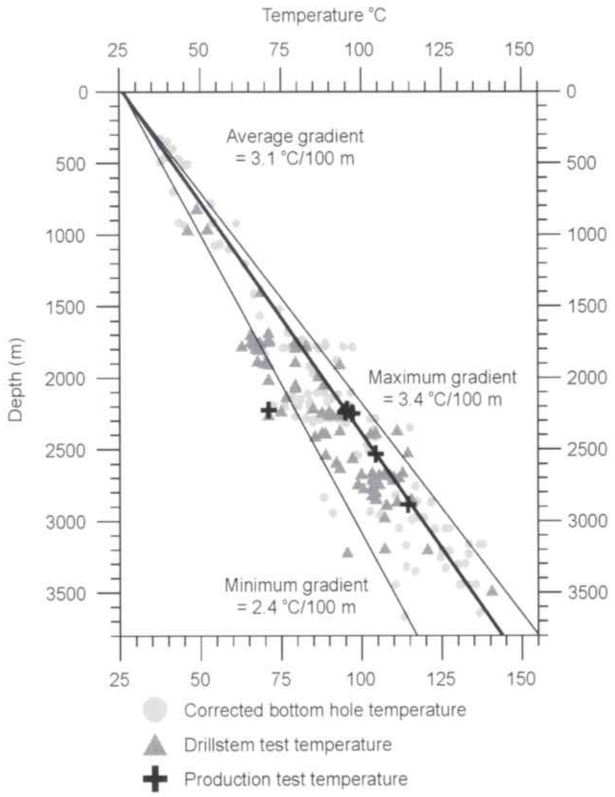

Fig. 15. Present-day subsurface temperatures versus depth.

were reconstructed using estimated erosional histories and adjusting thermal conductivities and transient heat flow to constrain maturity models versus measured data. Corrected BHTs and T_{max} were used to constrain present-day and palaeotemperatures. The depth of the oil window is used as an equivalent for the burial depths required for the conversion of 10% to 90% of the available kerogen to petroleum. On the basis of the geochemical and palynological data, Silurian and Devonian source rocks are assumed to be initially type II kerogen. The following vitrinite reflectance values are adopted to define maturation stages: immature zone, less than 0.5% Ro; early mature, 0.5% to 0.7% Ro; mid-mature, 0.7% to 1.0% Ro; late mature, 1.0% to 1.3% Ro and, mainly gas generation, over 1.3% Ro. Predicted maturity and oil windows are based on Lawrence Livermore National Laboratory (LLNL) vitrinite and kerogen kinetics, respectively.

Maturity calibration and burial histories of only Q5-NC7A and M2-NC7A are shown here in Fig. 16. The modelling suggests that at Q5-NC7A in the northeast, the Aouinet Ouenine Formation is immature and the Tanezzuft Formation is at the main phase of the oil generative-window (Fig. 16a). At M2-NC7A in the southwest, the Aouinet Ouenine Formation is at the early to main phase

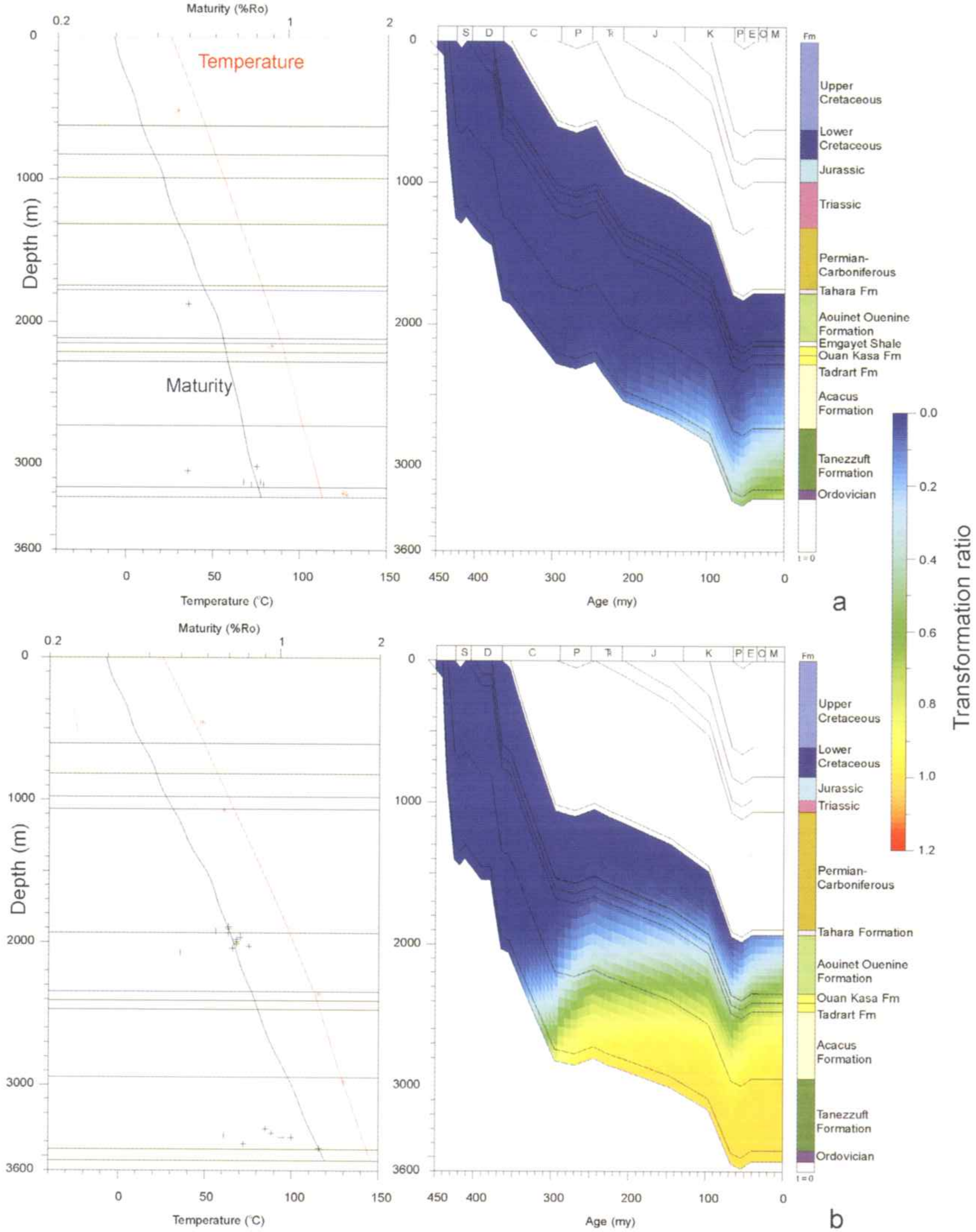

Fig. 16. Calibration of calculated versus measured maturity and temperature, and burial and thermal history of two key wells: a) Q5-NC7A; b) M2-NC7A.

of the oil-generative window and the Tanezzuft Formation is mainly at the gas-generative phase.

In the second step, one-dimensional models developed in the first step were used to develop a multi-well model of 18 wells. The purpose of this was to estimate geographic variation in the present-day maturation levels at the surface of the Tanezzuft and Aouinet Ouenine formations which contain the major source beds of the basin. The modelling suggests that the maturity of the Aouinet Ouenine Formation is at the immature to early mature phase of the oil-generative window and that its maturity progressively increases from the northeast to the southwest (Fig. 17a). The maturity of the Tanezzuft Formation ranges from the early mature to over-mature phase of the oil-generative window and its maturity also progressively increases from NE to SW (Fig. 17b).

In the final step, two-dimensional modelling of a composite cross-section from C1-26 in the southwest to AA1-NC7A in the northeast was carried out. The locations of the wells are shown in Fig. 17. The aim was to estimate and illustrate the maturation levels across the region and to determine the timing of hydrocarbon generation. Firstly, the model was optimized against measured present-day temperatures and maturity and then the maturation levels were calculated using lateral variation in present-day and palaeotemperatures. This was followed by the kinetic modelling of petroleum generation as a function of geothermal history, and type and amount of kerogen to determine the depth and timing of hydrocarbon generation, using a 4% and 2.5% type II kerogen for the Tanezzuft and Aouinet Ouenine formations, respectively.

Figure 18 illustrates the present-day maturity across the basin from C1-26 in the southwest to AA1-NC7A in the northeast. The maturity is based on transformation ratios calculated in ten wells, using the following scale of kerogen transformation to petroleum: immature (<10%); early generation (10-25%); main phase (25-65%); and mainly gas generation (> 90%). In the southwest, the Silurian rocks are over-mature and the Devonian rocks are within the oil window whereas in the northeast, the Silurian rocks are within the oil window and the Devonian rocks are immature.

Figure 19 illustrates timing as a function of the hydrocarbon-generation rate for the Tanezzuft and Aouinet Ouenine source beds at M2-NC7A and Q5-NC7A, where they have attained different levels of thermal maturity as well as the amount of hydrocarbons generated. In M2-NC7A, oil generation in the Tanezzuft source beds in the basal parts the formation peaked during the Carboniferous-Permian and in the Aouinet Ouenine source beds in the upper parts of the formation peaked during the Tertiary, whereas in Q5-NC7A, oil generation within the Tanezzuft source beds peaked during the Tertiary and the Aouinet Ouenine source beds were immature.

The modelling clearly demonstrates the differences in timing and levels of hydrocarbon generation attained in the Tanezzuft and Aouinet Ouenine formations at various geographic locations. The hydrocarbon-generative history of the area was affected by its burial and erosional histories as a result of Caledonian, Hercynian, Mesozoic, and Tertiary tectonic events during evolution of the basin. For modelling it was considered that in the study area the major erosion occurred during the Hercynian tectonic phase. The Tanezzuft Formation was deeply buried in the western parts of the study area where it reached optimum maturity for hydrocarbon generation during the pre-Hercynian evolution of the basin, and consequently a significant quantity of its generative potential might have been exhausted during the Carboniferous-Permian. Continued post-Hercynian burial during the Mesozoic-Tertiary sag phase of the basin's evolution was responsible for the second phase of oil generation from the Tanezzuft Formation and the first phase of oil generation from the Aouinet Ouenine source beds. In the E and NE parts of the study area where source rocks were not buried deeply enough during the pre-Hercynian phase of basin evolution, the first phase of oil generation from the Tanezzuft source beds occurred during the Tertiary, and the source beds of the Aouinet Ouenine Formation are immature.

PETROLEUM SYSTEMS

Geochemical data were not available to enable the oils to be differentiated into discrete families and to correlate them with recognised source rocks of the study area, as defined by Magoon and Dow (1994). However, recognised source rocks and the regional stratigraphic distribution of source, reservoir and seal rocks indicate the presence of two petroleum systems charged by the source rocks of the Lower Silurian Tanezzuft and Upper Devonian Aouinet Ouenine formations. Although the shales within the Ordovician Melez Chograne and Carboniferous M'rar formations have some limited source potential, the Llandoverian Tanezzuft and Frasnian Aouinet Ouenine formations have the best source rock characteristics within the analysed wells of the Ghadāmis Basin. Both source rocks were deposited over a wide area of the basin during regional flooding events and their present distribution is a result of gentle Hercynian deformation, uplift and erosion.

Figure 20 summarises the timing of peak oil generation

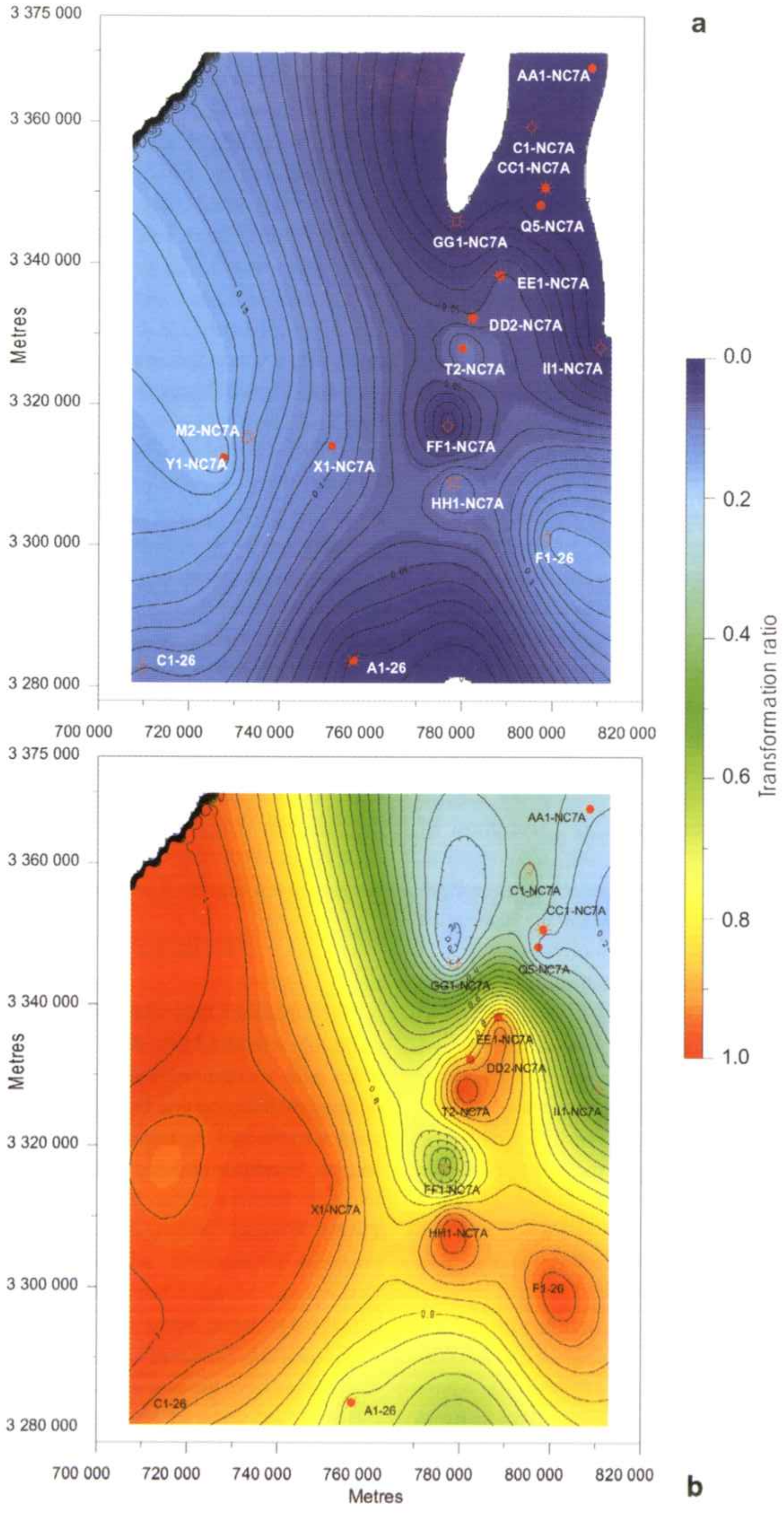

Fig. 17. Maturity at the surface of the two key stratigraphic horizons: a) Aouinet Ouenine Formation; b) Tanezzuft Formation.

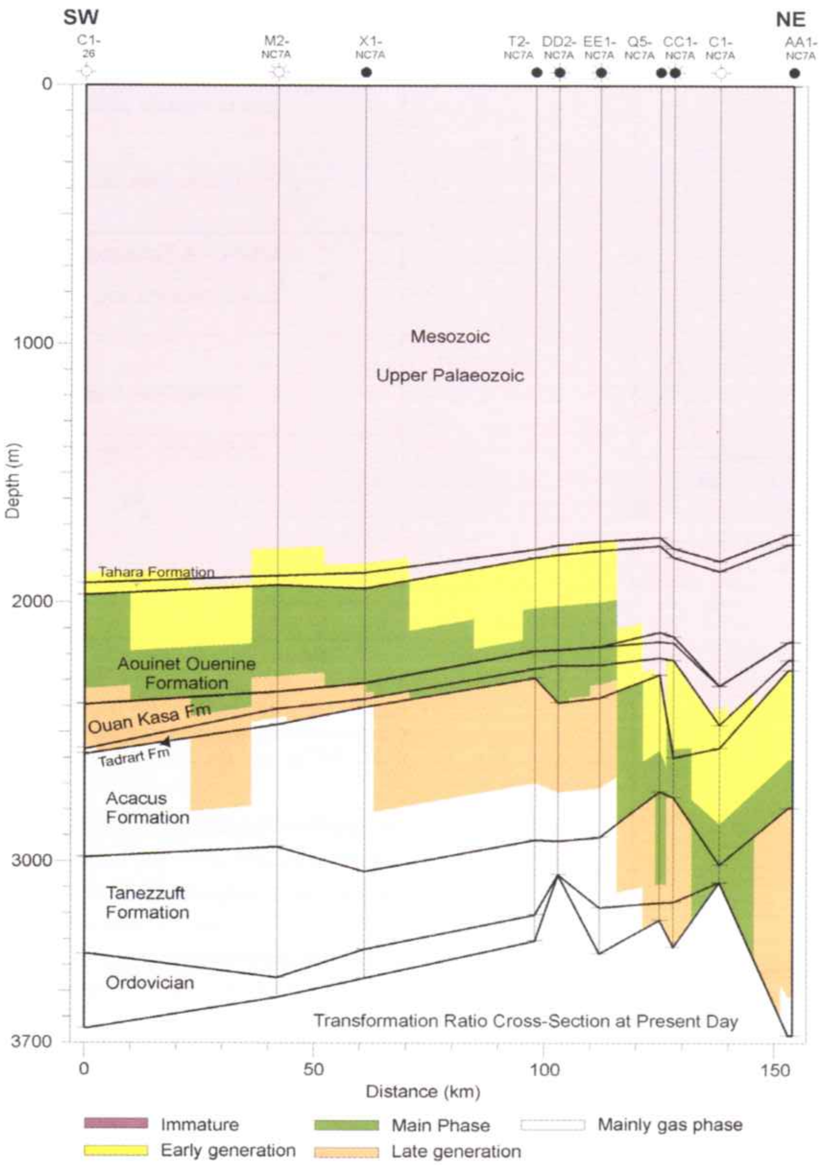

Fig. 18. Maturity across the study area, from C1-26 in the southwest to AA1-NC7A in the northeast. The maturity is based on two-dimensional modelling, and well locations are shown in Fig. 17.

at the top and bottom surfaces of the Aouinet Ouenine and Tanezzuft formations in two key wells, M2-NC7A and Q5-NC7A. The modelling indicates that in the deeper SW parts of the basin at M2-NC7A, the source beds within the basal Tanezzuft Formation were at peak oil generation during the Carboniferous-Permian, whereas the source beds within the top part of the Aouinet Ouenine Formation had not reached peak oil generation. In the shallower parts of the basin at Q5-NC7A, the source beds within the basal Tanezzuft Formation were at peak oil generation during the Tertiary, whereas source beds within the top part of the Aouinet Ouenine Formation had not reached maturity.

CONCLUSIONS

Total organic carbon content, Rock-Eval pyrolysis, palynology, present-day temperatures, and petroleum system modelling indicate two effective petroleum systems, charged by the Lower Silurian Tanezzuft Formation and the Upper Devonian Aouinet Ouenine Formation.

TOC analysis of over 330 samples from six wells indicates that the thickest and organically richest source beds are within the basal 60–140 m of the Tanezzuft Formation and the upper 60–120 m of the Aouinet Ouenine Formation. In the Tanezzuft Formation average organic richness is 4% TOC and ranges up to 10% TOC, whereas

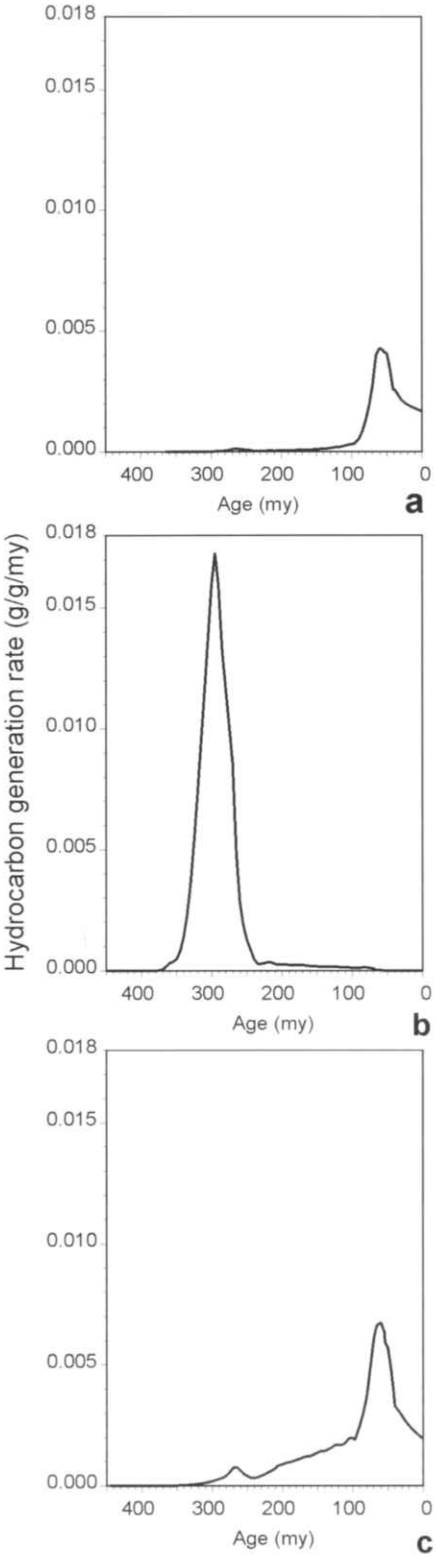

Fig. 19. Rate of hydrocarbon generation versus time for: a) Aouinet Ouenine Formation in M2-NC7A at 2000 m; b) Tanezzuft Formation in M2-NC7A at 3300 m; c) Tanezzuft Formation in Q5-NC7A at 3000 m.

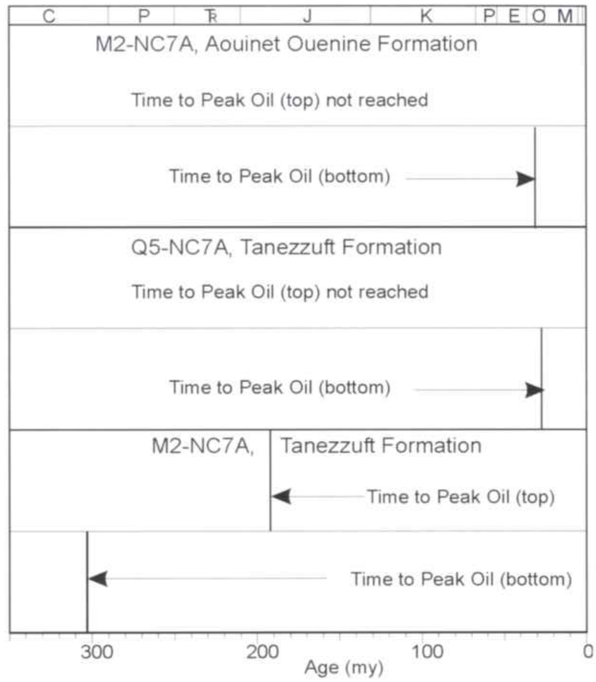

Fig. 20. Silurian and Devonian petroleum systems, time to peak oil generation for the top and bottom of the Aouinet Ouenine Formation in M2-NC7A, and the Tanezzuft Formation in Q5-NC7A and M2-NC7A.

the Aouinet Ouenine source beds have an average organic richness of 2.5% TOC and reach a maximum of 4% TOC. Rock-Eval pyrolysis of 103 samples and visual kerogen analysis of 18 samples indicate that the organic facies predominantly contain type II kerogen. However, the quality of kerogen within the Aouinet Ouenine source beds is more oil-prone compared to the Tanezzuft source beds because the Tanezzuft source beds are more mature.

Over 235 temperature measurements in 44 wells indicate that the average geothermal gradient is 3.1°C/100 m and most of the prospective reservoirs are within the oil preservation temperature limits of less than 150°C. The producing reservoirs include the Ordovician Memouniat Formation, the Silurian Tanezzuft and Acacus formations, the Devonian Tadrart, Ouan Kasa, Aouinet Ouenine, and Tahara formations, the Triassic Ras Hamia and the Jurassic Abreghs formations.

Petroleum system modelling indicates that the maturation of the Tanezzuft source beds range from early generation to mainly gas phase of the hydrocarbon-generative window, whereas the Aouinet Ouenine source beds range from immature to early oil generation phase of the oil window. In the deeper western parts of the basin, the peak oil generation to charge traps from the Tanezzuft source beds was first reached during the Carboniferous-Permian, followed by the second phase of oil generation during the Tertiary. In the source beds of the Aouinet Ouenine Formation, the maximum rate of oil generation was reached during the Tertiary. In the shallower eastern parts of the basin, oil generation within the Tanezzuft source beds peaked during the Tertiary and the Aouinet Ouenine source beds were immature for oil generation.

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