Geochemical evaluation of East Sirte Basin (Libya) petroleum systems and oil provenance

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Geochemical evaluation of East Sirte Basin (Libya) petroleum systems and oil provenance

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Abstract: With cumulative reserves exceeding 23 gigabarrels oil recoverable (GBOR), the East Sirte Basin is a prolific oil province hosting supergiants such as the Amal, Augila–Nafoora and Sarir fields. Production from Precambrian–Oligocene reservoirs yields low sulphur and often highly waxy oils.

The Late Mesozoic–Cenozoic Agedabia and older Hameimat, Maragh and Sarir troughs provide the main structural features of the habitat and control hydrocarbon prospectivity. Paleogene subsidence has facilitated the generative process with Mesozoic basin-fill sediments hosting source rocks for productive petroleum system(s). Traditionally the marine Upper Cretaceous Sirte Shale Formation source was thought to provide the dominant charge. Application of geochemical inversion procedures to oil data, however, indicates a greater diversity in oil provenance. Delineation of eight end-member generic oil families indicates a number of complex contributory petroleum systems, mixed-system hybrid oils also being evident. Non-marine (lacustrine) source inputs are also in evidence, enhanced waxiness differentiating petroleums of such provenance. Systematic screening of the stratigraphic section has additionally identified source potential in Nubian (Triassic and Lower Cretaceous), Rachmat–Tagrifet (Upper Cretaceous), Harash (Paleocene) and Eocene formations.

Assignment of oil provenance has been achieved via multivariate oil data analysis and application of a carbon isotope-based source kerogen-oil correlation procedure. End-member petroleum systems have been definitively identified involving the Sirte Shale Formation, Rachmat–Tagrifet Formations and Nubian (Triassic) as the contributory sources. The remaining major systems rely upon Pre-Upper Cretaceous lacustrine sediments specific to the Hameimat and Sarir troughs. Whereas numerous archetypal Sirte Shale Formation oils were recognized (e.g. Messla, Hamid, Sarir-L etc.), reserves for many of the giant fields, including Amal, Augila–Nafoora and Sarir-C, rely on hybrid system charging.

These results confirm that the prospectivity of the Sirte Basin is not exclusively dependent upon the Sirte Shale Formation, with other petroleum systems in operation, often involving hybrid-sourcing.

An extensive geochemical evaluation of the East Sirte Basin hydrocarbon habitat has been undertaken, providing contemporary support to prospectivity assessment within what otherwise can be regarded as a mature petroleum province. Hosting a number of giant fields, including Amal, Augila–Nafoora, Gialo, Messla and Sarir, the eastern subbasin accounts for some 23 of the 45 gigabarrels oil recoverable (GBOR) discovered to date (Fig. 1). Where aided by use of modern exploration techniques, it is believed that significant potential for realization of further economic discoveries remains. The diversity of the habitat as presently known is reflected in the overview of likely effective reservoirs and source rocks as illustrated in Figure 2.

In the present study an understanding of the operative hydrocarbon habitat has been approached from a petroleum system vantage (Magoon & Dow 1994), employing contemporary geochemical data acquisition practices and interpretative concepts such as 'geochemical inversion' (Bissada *et al.* 1992). Here the petroleum system concept can be used as an effective model to account for discovered hydrocarbon accumulations and, by implication, be applied to evaluation of unexplored or under-explored areas.

For synthesis of such an approach, key objectives to be addressed include:

- crude-oil characterization, leading to the recognition of diversity/multiplicity in generic families, hence petroleum system(s);

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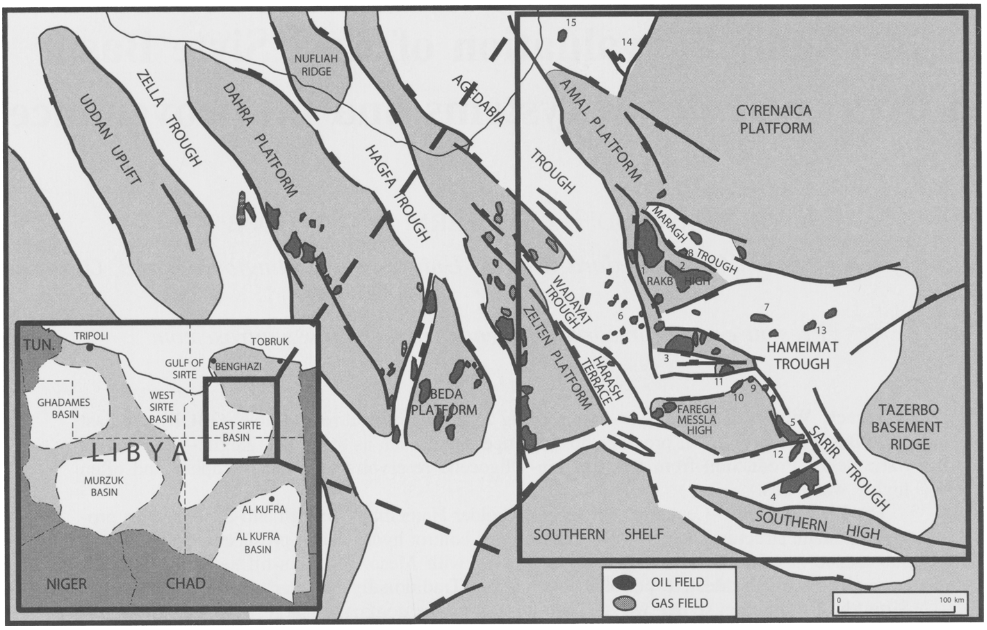


Fig. 1. East Sirte Basin study area identifying major petroleum accumulations, main tectonic elements and depositional centres. Key oilfields include, 1, Amal; 2, Augila–Nafoora; 3, Gialo; 4, Sarir-C; 5, Messla; 6, Intisar/Shatirah area; 7, Bu Attifel; 8, As Sarah–Jakhira; 9, Hamid; 10, Magid; 11, Masrab; 12, Sarir-L; 13, Remel; 14, Antelat and 15, B1-NC152.

- source-rock candidature, characterization and quantification of petroleum potential;
- source-oil assignments, confirming hydrocarbon provenance and the existence, plus any diversity, in operative petroleum system(s).

Application of this knowledge then provides informed and tailored input to basin-modelling procedures leading to:

- evaluation of the circumstances and timing of oil generation and emplacement history, mixed-source aggregate fluids and any post-emplacement/in-reservoir alteration processes;
- quantification of basinal generation and charge volumetrics as input to prospect evaluation and risk analysis.

In the body of this contribution, new data are presented primarily in support of the three former concerns. In part this permits realization of the fourth consideration, revealing that the East Sirte Basin is a complex hydrocarbon habitat where mixed-aggregate oils derived from hybrid petroleum systems are often encountered. This naturally has implications as to the diversity of play types that could be anticipated. The application of thoroughly controlled modelling then provides realistic basin assessment in the formulation of an exploration strategy.

Regional and petroleum geological overview

Reviews by Parsons *et al.* (1980) and Macgregor (1996) reference the Sirte Basin habitat in the context of the wider North African scene. El Alami *et al.* (1989), Ghori and Mohammed (1996) and Ambrose (2000) have provided more local insights.

For the East Sirte Basin a tectonostratigraphic overview is summarized in Figure 2. The basin shows remnant evidence of Early Palaeozoic continental sag with successive deposition of Cambro-Ordovician non-marine clastics (Amal Formation) through Silurian to Permo-Carboniferous aged sediments. With the Amal Formation clastics representative of the oldest sedimentary rocks observed, much of the intervening section was stripped by the Late Permo-Carboniferous (Hercynian) uplift; the resulting broad inversion feature is commonly termed the Sirte Arch.

Subsequent Triassic and later Jurassic–Early Cretaceous rifting led to the progressive fragmentation of the arch. Substantial graben-localized non-marine lacustrine deposition of fine to coarse clastics then took place in the Maragh, Hameimat and Sarir troughs.

The dominant basin architecture was formed by Late Cretaceous rifting, with subsidence occurring

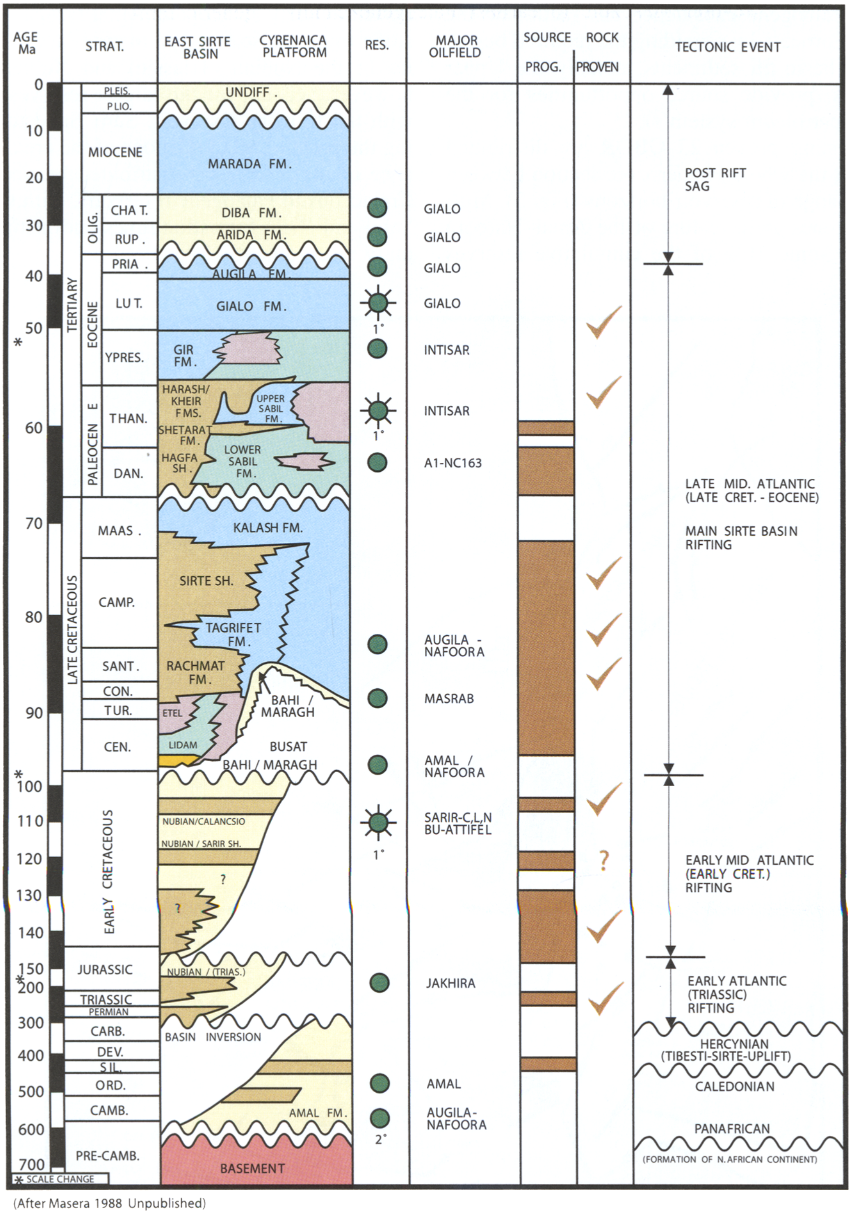


Fig. 2. Stratigraphic correlation chart for the East Sirte Basin with a tectonic overview and identifying proven reservoir intervals, producing fields and prognosed plus confirmed candidate source rocks.

throughout the area at this time and continuing into the Mid-Paleogene. As the main structural feature of the basin, the Agedabia Trough experienced the greatest subsidence and attendant marine sedimentary fill. Subsequent thermal cooling saw onset of a later Paleogene sag phase of subsidence, with the basin depocentre migrating northward into the present-day Gulf of Sirte. Neogene emergence tops the stratigraphic succession with the deposition of a relatively thin veneer of predominantly continental sediments.

Structurally the study area is bounded by major basement highs, including the Cyrenaica Platform (northeast), Tazerbo Basement Ridge (east) and Southern Shelf, with the Zelten Platform providing separation from the West Sirte Basin (cf. Fig. 1).

Whereas Paleogene subsidence has facilitated the generative process by providing the required burial, Mesozoic basin-fill sediments, notably the Upper Cretaceous, provide source opportunities for the operative petroleum system(s).

The existing proven 23 GBOR are distributed throughout the whole Phanerozoic section between a diverse range of reservoir horizons (Fig. 3). Multiple pay zones are a feature of the Amal–Nafoora area, with some 10% of the cumulative reserves hosted in Early Palaeozoic (Amal Formation) sandstone traps. Mesozoic non-marine lacustrine clastics of the Nubian (Triassic) and Nubian (Sarir), however, account for the largest reserves (~50%), with the primary reservoir, Sarir Sandstone, hosting the premier accumulations of the area. The balance of the reserves is distributed between Upper Cretaceous to Paleogene reservoirs, with the Upper Sabil and Gialo formation limestones acting as primary reservoirs.

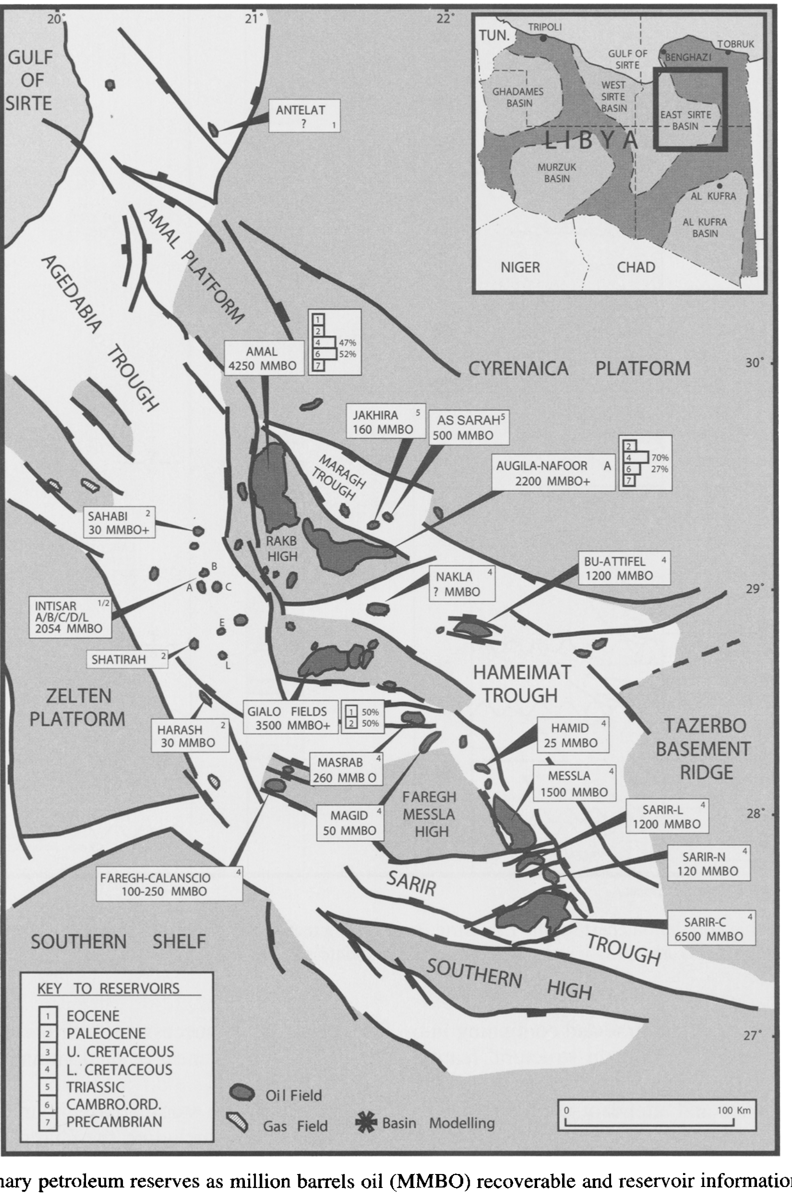


Fig. 3. Summary petroleum reserves as million barrels oil (MMBO) recoverable and reservoir information for a selection of East Sirte Basin fields.

Several Mesozoic to earliest Paleogene candidate source formations have been prognosed for the area (Petroconsultants Ltd 1981; Fig. 2) and so-called 'Nubian' lacustrine siliciclastics of Pre-Late Cretaceous age (commonly termed the Pre-Upper Cretaceous or PUC) deposited as components of:

- Nubian (Triassic), and
- Lower Cretaceous Sarir and Calanscio formations, (collectively termed 'the variegated shales').

Additionally, marine deposits of varying shale to argillaceous lime mudstone lithology have been proposed, including:

- Upper Cretaceous Sirte Shale Formation; Rachmat Formation; Tagrifet Formation and Etel Formation; and
- Paleogene Sheterat Formation and Hagfa Formation.

The distribution of prolific source rocks is not ubiquitous, all candidates being either locally developed within their respective depocentres (e.g. Triassic shales currently identified only within the Maragh Trough) or of highly variable richness (e.g. Sirte Shale Formation; El Alami *et al.* 1989). A regional and vertical intermittence in source-rock development hence provides a constraint on basin-wide prospectivity.

Relaxation of higher heat flows operative during the Mesozoic rifting events (Maragh through Agedabia trough-forming episodes) has resulted in average contemporary geothermal gradients, previously higher values having decayed to *c.*30 °C/km (Gumati & Schamel 1988; Ghori & Mohammed 1996). Present-day heat flows were computed to fall in the range 1.14–1.20 HFU (heat flow units), according to basinal situation (this work). As a consequence of rapid subsidence climaxing in the Paleogene, active generation ensued which, for the various Upper Cretaceous candidate rocks, peaked during the Neogene. Optimal hydrocarbon generation and expulsion in the basin thus occurred relatively late ($<40\sim25$ Ma BP).

Database

A comprehensive crude oil database (Fig. 4), comprising stable isotope and quantified biomarker analyses, was assembled for 60 authenticated petroleums to an analytical specification set by GeoMark Research Inc. Three additional key datasets were abstracted from a 1993 proprietary analytical study by Geomark Research Inc. Multivariate statistical evaluation of the data was achieved using Pirouette™ software for principal component analyses (PCA) and hierarchical cluster analyses (HCA). Data for type oils, representative of the generic families and sub-families recognized, are listed in Table 1.

In excess of 50 km of section from 47 wells have been variously screened for source-rock potential, using conventional Rock-Eval and Pyrolysis-gas chromatography (GeoFina HM) procedures, and incorporated into this study (Fig. 4). Where appropriate, candidate source detailing analyses, including kerogen carbon isotope and kinetic parameter measurements, were performed. For presentation of data, primary source character is attributed to those sediments with S2 $\geq$5 kg/ton, S2 $\geq$3 kg/ton to $\leq$5 kg/ton being ascribed secondary source status. Petroleum potential (PP) is expressed in terms of PP units ($\times 10^6$ $m^3_{(oil\ equiv.)}/km^3_{(rock)}$) with the corresponding barrels/acre-foot equivalent also given in the respective tabulations.

The gas–oil production ratio (GOPR) is a normalized parameter (0 to 1) derived from GeoFina HM measurements. For values above 0.35, the kerogen assemblage is adjudged to be of increasing, to ultimately exclusive, gas-proneness. Elsewhere, parameters and petroleum-system nomenclature employed in this paper are defined in the Appendix.

East Sirte Basin oils inversion analysis

The existence of oil in the East Sirte Basin demonstrates the presence of at least one petroleum system. It follows that a regional oil study can be an efficient way of identifying, evaluating and verifying the uniqueness, or multiplicity, of such system(s). Determination of the diversity of effective source units within the basin can be inferred from the number of generically distinct oil families. Such an approach for the present study has been aided by access to a 60-specimen crude oil dataset embracing comprehensive biomarker and stable isotope information (Table 1).

Initial interpretation has led to conclusions relating to thermal maturation considerations, a preliminary grouping of the oils in terms of contributory source depositional environments and evidence for mixed-charge phenomena. Subsequent application of multivariate statistical analysis techniques to selected parameters then facilitated the definitive segregation into generic oil families. For purposes of graphic clarity, many of the text figures show only those type-oils chosen to be representative of the generic families and sub-families deduced from the inversion procedures subsequently applied.

In terms of bulk compositional data the oils showed limited diversity, with American Institute of Petroleum gravities (°API) in the conventional range of 30–39°. Several lower-gravity oils were observed from shallower reservoirs (K1–12 and Amal–Mesdar pool) but significant biodegradative

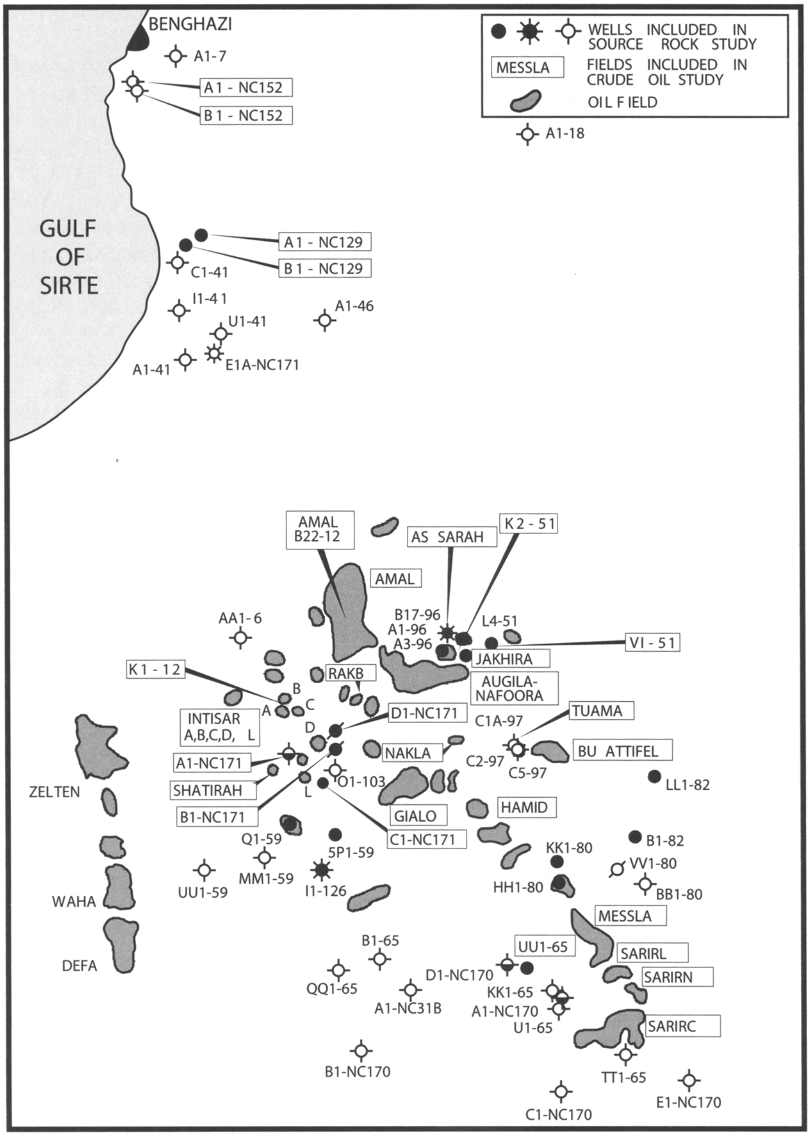


Fig. 4. East Sirte Basin geochemical data acquisition programme: location of crude oils and well sections employed in the study.

processes do not appear to have been operative. Elsewhere, the Intisar oils were of higher gravity (+40° API) but were not extra-mature or condensate-like, as in the case of the E1A-NC171 fluid. Sulphur contents were generally low ($\leq$0.6% and often <0.2%), with higher values again observed only in the case of the shallow-reservoired oils as above and for the younger Augila–Nafoora pools.

The main compositional departure among these oils was the high waxiness observed for the As Sarah, Jakhira, Nakla and Bu Attifel fluids, plus the Sarir-C and some of the deeper-reservoired Amal and Augila–Nafoora petroleums, the former showing an evident fieldwide variation. An implied source control was deduced to be operative here.

Crude oil maturity

As one control on gross compositional character, crude oil maturity was assessed via a range of molecular parameters, including the ethylcholestane

Table 1. *East Sirte Basin crude oil data for the 23-specimen study suite*

OIL	RESERVOIR	D13C(-)	D2H(-)	Cv	PR/PY	29H/H	31H/H	S/H	%28ST	%C29ST	C30X/H	19/23TRI	35/34H	24/23TRI	C27/17	%αααC29ST	C30/29ST	Ts/Tm	19/21TRI	22/21TRI	26/25TRI	26/27TRI	TET/C26TRI	C29ST(S/R)	MDBT
AUGILA-NAFOORA	AML	29.90	104	−2.65	2.14	0.83	0.29	0.29	34.0	30.0	0.22	0.21	0.56	0.66	0.44	32.73	0.07	1.4	0.13	0.25	1.30	0.37	0.45	0.76	2.30
GIALO	OLIGOCENE	27.90	111	−1.64	1.57	0.76	0.76	0.59	36.7	29.2	0.08	0.06	0.69	0.75	0.23	30.82	0.22	1.45	0.16	0.30	1.03	0.62	0.32	0.81	2.11
AMAL	AMAL	31.39		−0.54	1.84	0.76	0.38	0.28	38.3	28.1	0.15	0.09	0.61	0.64	0.37	31.56		1.39	0.16	0.27	1.04	0.45	0.44	0.69	2.46
TUAMA	SARIR	22.10	98	−2.48	2.34	0.78	0.45	0.18	20.0	55.0	2.17	0.56	2.56	0.51	0.61	36.36		7.67	0.48	0.27	1.54	1.04	0.19	1.50	24.00
JAKHIRA	TRIASSIC	34.67	111	2.25	1.91	0.88	0.28	0.07	37.0	30.0	0.49	0.24	0.44	0.67	0.51	48.84	0.00	2.17	0.16	0.25	1.60	0.36	0.53	2.39	6.25
AS SARAH	PUC	34.24	99	1.36	2.06	0.44	0.52	0.09	36.8	33.8	0.64		0.53	0.81	0.44	34.00		2.33	0.14	0.28	1.93	0.53	0.32	>2.00	>6.00
SARIR-L	SARIR	28.45	120	−0.17	1.81	0.79	0.31	0.93	39.0	27.0	0.13	0.13	0.60	0.76	0.30	30.54	0.18	2.11	0.13	0.32	0.95	0.88	0.20	1.01	2.70
MESSLA	SARIR	28.52	116	0.01	1.86	0.77	0.31	1.08	39.0	26.0	0.14	0.09	0.44	0.73	0.28	30.25	0.20	2.33	0.10	0.32	0.96	1.00	0.32	0.92	3.04
BU-ATTIFEL	SARIR	23.27	93	−4.57	2.33	1,45	0.26	0.12	16.0	41.0	1.07	0.60	0.39	0.62	0.64	50.00	0.00	6.29	0.25	0.22	1.83	0.68	0.17	2.02	9.60
NAKLA	PUC	21.65	107	−1.91	2.36	0.79	0.65	0.12	26.1	47.8	0.74		0.61	0.69	0.69	49.00		6.04	0.18	0.24	1.63	0.54	0.32	>2.00	>6.00
A1-129	ANTELAT	26.64	95	0.25	1.59	0.96	0.63	0.56	32.0	36.0	0.08	0.31	1.09	0.70	0.23	39.90	0.11	1.02	0.41	0.37	1.03	0.23	1.13	0.77	2.21
B1-152	U. CRETACEOUS	26.90	88	0.14	1.49	0.76	0.45	0.63	31.0	43.0	0.32	1.15	0.61	0.73	0.68	52.50	0.02	4.65	1.11	0.45	1.11	0.11	2.20	1.24	11.39
SARIR-C238	SARIR	27.68	110	−1.25	2.05	0.79	0.37	0.31	40.0	29.0	0.14	0.20	0.49	0.73	0.41	38.00	0.09	1.39	0.29	0.30	1.04	0.37	0.37	0.82	1.95
K2-51	U. CRETACEOUS	33.62	97	0.39	2.21	0.84	0.33	0.07	32.0	39.0	0.37	0.25	0.54	0.70	0.42	57.50	0.00	2.14	0.16	0.25	1.72	0.33	0.42	1.45	5.64
UU1-65	BUSAT-SARIR	26.71	93	−0.96	3.44	1.02	0.31	0.07	32.0	39.0	0.21	1.37	0.51	0.69	0.36	59.40		1.77	1.22	0.22	1.55	9.00	2.67	1.13	3.68
V1-51	TAGRIFET	34.87	96	0.16	2.44	0.83	0.33	0.07	30.0	38.0	0.29	0.22	0.56	0.66	0.44	42.50	0.00	1.53	0.14	0.22	1.72	0.26	0.41	1.30	1.22
AMAL-B2212	MESDAR	26.52	94	1.52	1.40	0.90	0.52	0.26	33.4	30.8	0.02	0.07	1.21	0.50	0.23	34.50		0.46	0.23	0.48	0.98	0.22	0.91	0.74	1.50
A1-NC171	U.SABIL	27.70	98	2.69	1.57	0.91	0.57	0.89	37.0	27.0	0.20	0.18	0.83	0.70	0.23	30.40		1.94	0.27	0.33	1.08	0.36	0.75		2.48
B1-NC171	U.SABIL	28.00	103	2.41	1.59	0.52	0.30	1.00	37.3	29.3	0.18	0.08	0.57	0.79	0.26	34.50		2.33	0.20	0.39	1.11	0.54	0.44	0.75	2.06
SHATIRAH	U.SABIL	27.94	107	1.58	1.77	0.49	0.84	0.69	38.2	28.8	0.12	0.08	0.83	0.81	0.13	29.00		1.90	0.19	0.39	1.11	0.56	0.33	0.89	
INTISAR-A103	U.SABIL	27.18	106	1.78	1.76	0.79	0.52	0.96	36.0	29.0	0.11	0.25	0.59	0.72	0.13	32.35	0.21	1.99	0.29	0.31	1.07	0.48	0.52	0.91	2.23
E1A-NC171	GIALO	24.39	110	−4.83	2.13	0.80	0.41	0.39	31.6	35.5	0.05	0.35	1.26	0.72	0.04			1.25	0.94	0.31	0.92		1.27	0.77	5.39
K1-12	EOCENE	23.77	74	−3.29	0.60	1.75	0.63	0.12	28.0	37.0	0.00	0.19	2.06	0.31	0.54	40.70		0.25	0.63	1.24	0.94	0.02	12.05	0.55	1.64

Parameters are as follows: D13C ($\delta^{13}C$); D2H ($\delta^{2}H$); C_V(Canonical variable); PR/PY (pristane/phytane); 29H/H (norhopane/hopane); 31H/H (homohopane/hopane); S/H (sterane/hopane); %C28ST (%methylcholestane); %C29ST (%ethylcholestane); C30X/H (diahopane/hopane); 19/23TRI (19/23 tricyclic terpane); 35/34H (pentakis/tetrakishomohopane); 24/23 TRI (24/23 tricyclic terpane); C27/17 (*n*C27/*n*C17 wax factor); % ααα C29S (% ααα ethylcholestane of total ααα steranes); C30/29S (*n*-propyl/ethylcholestane); T_S/T_M; 19/21 TRI (19/21 tricyclic terpane); 22/21 TRI (22/21 tricyclic terpane); 26/25 TRI (26/25 tricyclic terpane); 26/27 TRI (26/27 tricyclic terpane); TET/26 (tetracyclic terpane/26 triterpane); C29S/R (ethylcholestane 20S/20R); and MDBT (4/1 methyldibenzothiopene) ratios.

($\alpha\alpha\alpha$ 20S/R), methylphenanthrene (MPI1) and methyldibenzothiophene (MDBT 4/1) ratio procedures (Radke *et al.* 1986; Bein & Sofer 1987; Radke & Willsch 1994). The majority of the petroleums showed main-phase generative status, with the implication that conventional thermal control and kerogen kinetics apparently controlled their generation and expulsion (Fig. 5). The predominance of regular gravity petroleums is thereby rationalized. A small population of low- and/or high-maturity crudes was corroborated by the methyldibenzothiophene procedure (Fig. 6), the existence of the more mature oils having implications relating to their deep-seated Maragh, Hameimat and Sarir trough provenances. Other than for these petroleums, it was assumed that maturity considerations would not necessarily complicate understanding of generic relationships between the oils studied.

Stable isotope segregation

Stable isotope values (δ^2H, $\delta^{13}C$) were assembled on whole oils, saturate and aromatic fractions. A $\delta^{13}C$ range of 13 ppt (parts per thousand) revealed a considerable diversity among the oils, with isotopically highly depleted (As Sarah) and enriched (Nakla) end-members embracing a broad mid-range, including the Augila–Nafoora, Messla, Sarir, Intisar, Gialo and Coastal Cyrenaica petroleums (Fig. 7). This diversity, previously recognized by El Alami *et al.* 1989, is accentuated in Figure 8; it is noteworthy that the disparate end-members include many of the waxier petroleums. The diagnostic value of this display is, however, of limited empirical use in that many of the waxy petroleums plot in the 'non-waxy' (i.e. marine-source depositional trend) domain as originally conceived by Sofer (1984). As subsequently demonstrated, a conclusion indicating a terrestrial-lacustrine provenance for these oils would have been more appropriate.

Further semi-empirical segregation of the oils was achieved by incorporation of deuterium isotope (^2H) information (Fig. 9). At least five domains can be delineated, the ^2H-depleted petroleums being more indicative of a lacustrine source depositional provenance (Burwood *et al.*

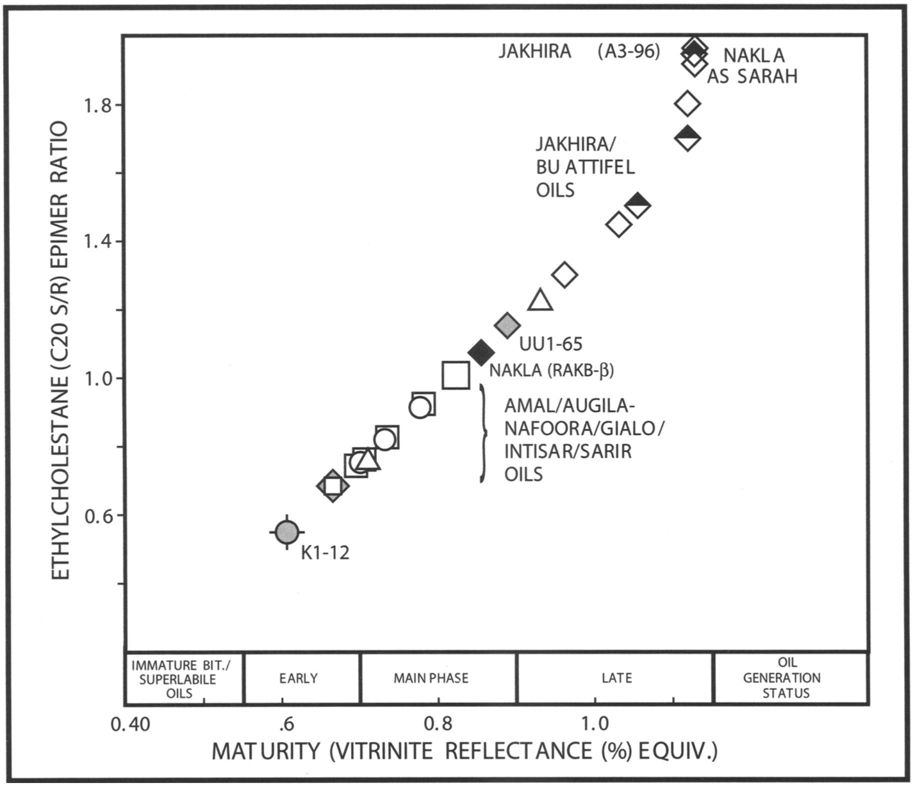


Fig. 5. East Sirte Basin crude oil inversion analysis: maturity assessment by ethylcholestane epimer (C20S/R) ratio procedure.

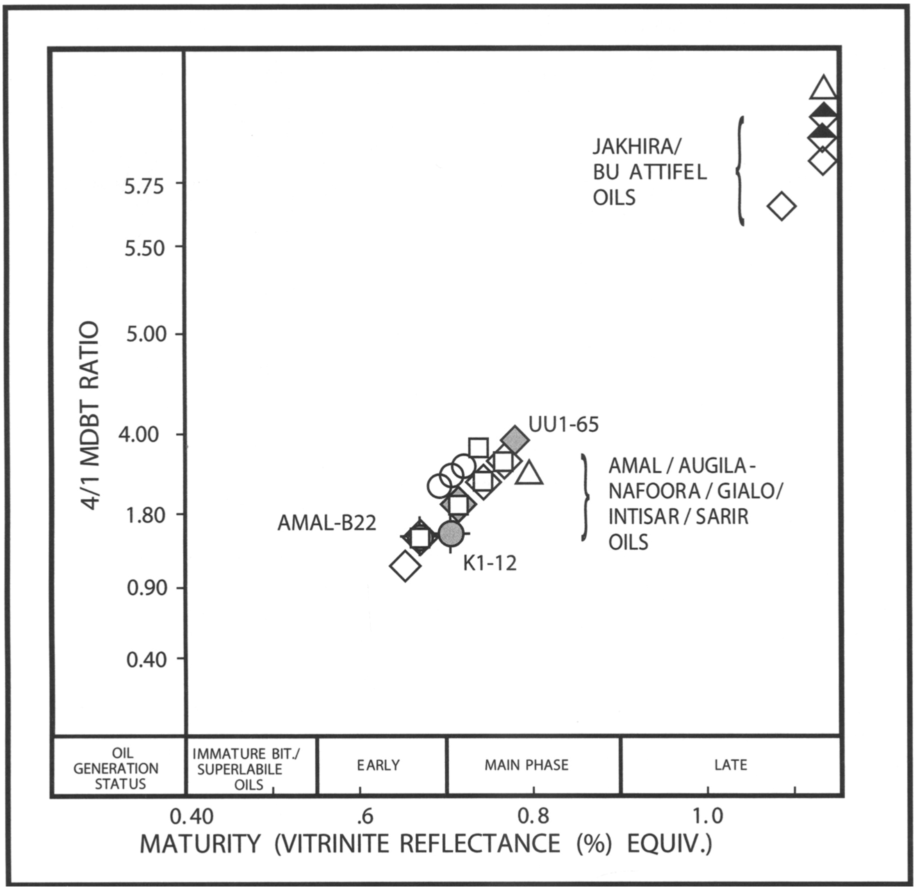


Fig. 6. East Sirte Basin crude oil inversion analysis: maturity assessment by methyldibenzothiophene (4/1 MDBT) ratio procedure.

1995), as could be anticipated for the As Sarah and Nakla end-members. Overall, isotopic composition suggests a large population of oils showing elements of a common, or similar, source provenance thought to be 'marine' in nature. Nevertheless, the existence of non-related disparate lacustrine-derived end-members is also evident, these being potentially available for incorporation into aggregate petroleums of a hybrid provenance.

Biomarker characteristics and inferences

From the biomarker dataset, sterane-based parameters have proved particularly useful in achieving a more intimate generic segregation of the petroleums. In an inversion sense, such oil-derived information can be highly diagnostic in revealing details of the progenic source-rock depositional palaeoenvironment and nature of the constituent organofacies.

As a generality, the sterane/hopane ratio v. *n*C27/*n*C17 cross-plot is informative, indicating a strong correlation between crude-oil waxiness and a non-marine (i.e. lacustrine) source-depositional provenance (Fig. 10).

Ethylcholestane content, as a measure of terrestrial/lacustrine organo-detrital input, is exploited as an environmental marker in Figure 11a and b. A cross-plot of the $\alpha\alpha\alpha$ C29 epimer content against dependent variable considerations of 'waxiness' and 'non-marineness', again represented by *n*C27/*n*C17 and sterane/hopane ratio parameters respectively, confirmed this strong correlation between lacustrine depositional conditions and wax context (e.g. As Sarah and Nakla end-member oil types).

A similar series of displays employing the abundance of *n*-propylcholestane as the strongly diagnostic marker of marine depositional inputs (Moldowan *et al.* 1990) again corroborates a con-

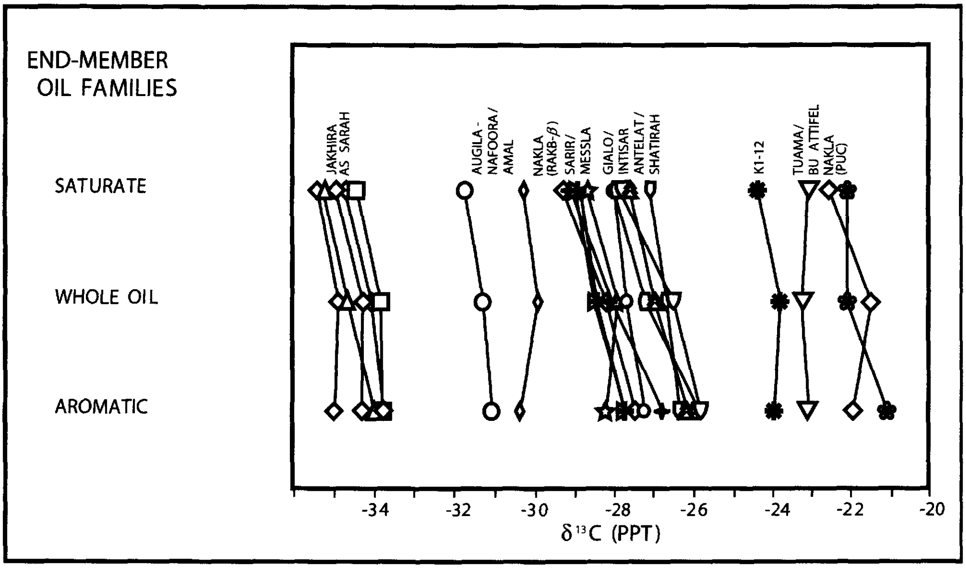


Fig. 7. East Sirte Basin crude oil inversion analysis: carbon-isotope Galimov-style profiles for a selection of 21 key oils, grouped as families (Table 1).

sistent segregation of the petroleums (Fig. 12a, b). On this occasion, oils such as Messla, Gialo, Intisar etc. are positively confirmed to be of marine-source provenance. Nevertheless, among output from the ethyl and *n*-propylcholestane-based diagnostic routines (Figs 11a, b & 12a, b), there appears to be ample evidence for oils of intermediate character, some of which presumably could be aggregates sharing in a hybrid source provenance (e.g. Sarir-C239, Augila–Nafoora, Amal etc.).

With the involvement and interplay between marine- and lacustrine-derived petroleum charge firmly established, other diagnostic markers can be used to advantage. Thus the observation of conspicuous β-carotane and gammacerane contents and high C26/C25 tricyclic terpane ratios provides abundant corroboration for the lacustrine-source provenance of the As Sarah, Jakhira, Nakla, Bu Attifel, UUI-65 petroleums and their derivatives (cf. Table 1).

The Coastal Cyrenaica (Concessions NC 129, 152 etc.) petroleums are exceptional in showing a discernible 18[α]oleanane content, this being interpretable in terms of a source age-dating of Late Cretaceous or younger. Additionally, prominent 2α-methylhopane, 30-norhopane and enhanced pentakishomohopane contents all testify to a highly anoxic, carbonate source-rock provenance. Assumed to have marine depositional affinities, this candidate system is clearly differentiable from that of the main marine source rock (i.e. the Rachmat, Tagrifet and Sirte Shale package), as illustrated in Figures 11a and 13. Further, and in this context, these oils are exceptional, showing high wax contents. An unrelated Harash reservoired oil (K1–12) also shows strong carbonate-source affinities.

Thus, in addition to the lacustrine-derived petroleum system(s) recognized above, there also appears to be a diversity of candidate marine sources. This further expands the scope and complexity for emplacement of mixed hybrid petroleums.

For purposes of a graphic representation of a consensus of the contributory trends recognized from the data inversion processes employed, a cross-plot of the pristane/phytane ratio against carbon-isotopic composition achieves the most explicit results (Fig. 13). Five end-member petroleum systems can be delineated, including the As Sarah (!), UU1–65 (!) and Bu Attifel (!) lacustrine variants, plus the marine carbonate K1–12 (!) curiosity. These systems are well separated from a central domain embracing many of the assumed marine source derived oils (Messla, Intisar, Gialo, Shatirah etc.), which at this stage is provisionally referred to as the Upper Cretaceous (!) petroleum system (i.e. inclusive of the Rachmat, Tagrifet and Sirte Shale section). Subsequent application of source-oil correlation procedures and oil-data multivariate statistics allows further differentiation into the component systems, with recognition of the Sirte Shale (!) system as being the volumetrically predominant contributor.

Additionally, what is most evident from Figure 13 is the existence of hybrid oils and preliminary evidence for the mixing lines identifying their con-

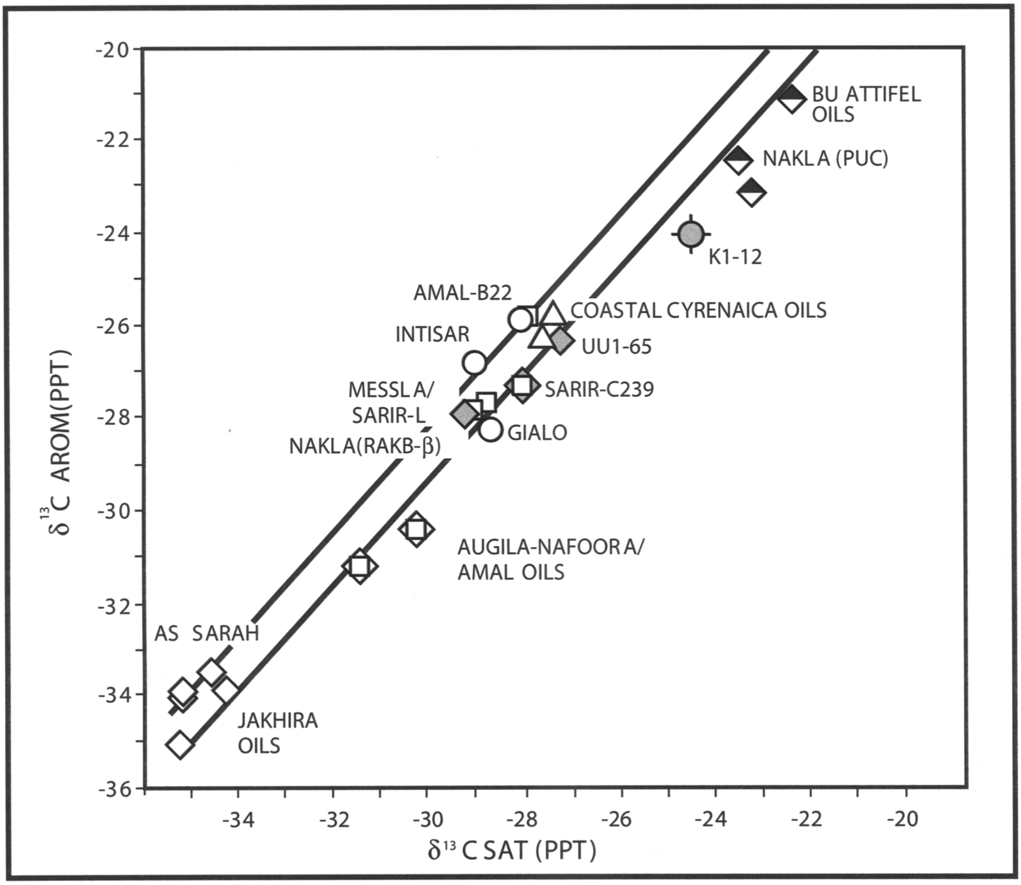


Fig. 8. East Sirte Basin crude oil inversion analysis: carbon-isotope Sofer-style cross-plot of saturate versus aromatic fraction $\delta^{13}C$ values for 22 key petroleums (Table 1).

tributory end-member petroleum systems. In this context, the deeper-reservoired Augila–Nafoora and Amal oils derive from a hybrid Upper Cretaceous–As Sarah (!) system, with the waxy Sarir oils being ascribable to the Upper Cretaceous–U1–65 (!) analogue. Thus, as a result of the oil-data inversion enquiry, the complexity of the East Sirte Basin hydrocarbon habitat is revealed, with recognition of five unique, and at least two hybrid, petroleum systems. A minimum five-fold multiplicity in contributory source rocks is necessary to support this conclusion.

Candidate source-rock inventory

Screening of the 50 km of well section available to the study has permitted evaluation of previously accepted and new candidate sources of Silurian through Eocene age. The cumulative data are presented in terms of Palaeozoic, Triassic, Cretaceous and Paleogene sub-units. For each candidate, a type-well section is employed where feasible and features a comprehensive source rock classification covering intrinsic petroleum potential, kerogen transformation kinetics and carbon isotope signatures (Burwood *et al.* 1988).

Palaeozoic section

Early Palaeozoic. The Silurian is of widespread distribution throughout North Africa; however, the search for source quality sediments of this age in the East Sirte Basin was unsuccessful. An extensive shale section penetrated in A1–46, for instance, failed to show log characteristics suggestive of a basal Silurian (Gothlandian) high gamma-ray zone. Mature sediments with no suggestion of even residual hydrocarbon potential were observed. Although unpromising, these findings do not exclusively eliminate Silurian candidature, the relevant section being locally missing, having been eroded out as a result of the Hercynian orogeny.

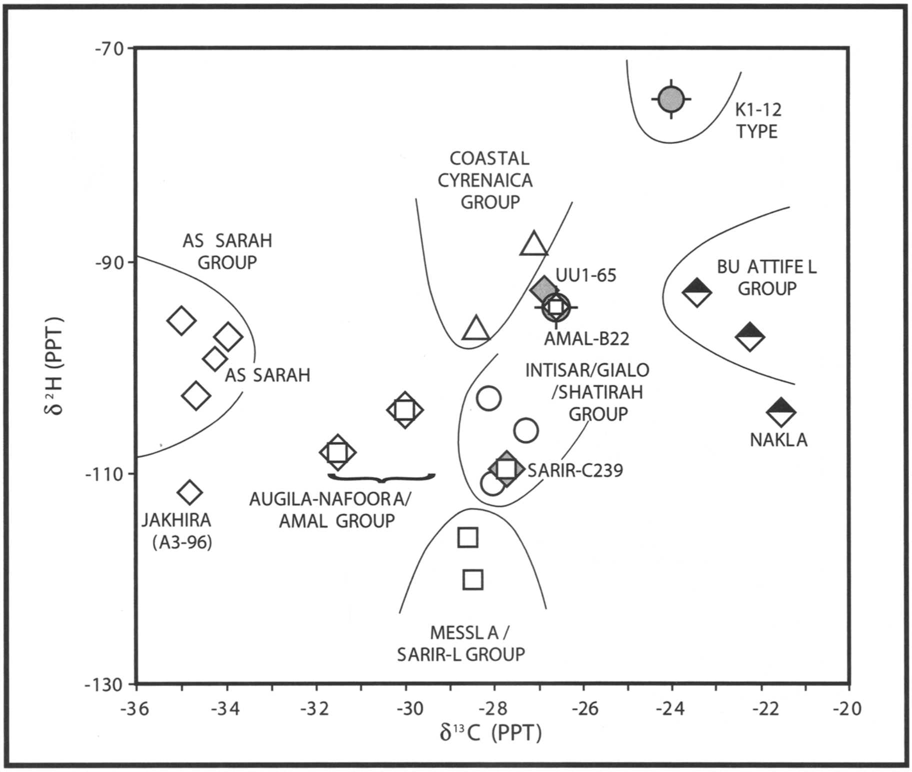


Fig. 9. East Sirte Basin crude oil inversion analysis: carbon and deuterium isotopic cross-plot for 21 key petroleums. Note the segregation into at least six discrete domains implying generic relationships.

Triassic section

Nubian (Triassic). Sediments with prolific source potential were penetrated in the Maragh Trough well L4–51. Dated to be of Anisian age (El Arnauti & Shelmani 1988), a ~30 m-thick effective source interval is characterized by a high gamma ray/low sonic velocity response zone.

Source evaluation data are summarized in Table 2a and identify presently immature sediments equating to high-activation energy Type I kerogen assemblages (Fig. 14). Although highly oil-prone, these kinetic attributes would dictate a forceful thermal regime in order to realize the hydrocarbon potential of these sediments. Progenic hydrocarbons with a highly depleted and diagnostic carbon isotope signature at $\delta^{13}C$ *c*.-34.0 ppt could be anticipated (Fig. 15).

Cretaceous section

Nubian (Sarir Formation). Screening of the Pre-Upper Cretaceous section in numerous Maragh, Hameimat and Sarir trough wells for anticipated lacustrine-style source potential was of only limited success. Other than for some partially spent and intermittently developed potential in A1–96 (Maragh Trough) and A1-NC170 (Sarir Trough), dominantly sand-rich and/or organically lean, vari-coloured sections were encountered. This was thought to imply that any lacustrine-source facies developments were of very localized and limited extent in what are collectively termed the 'variegated shales'.

Data for A1–96 are presented in Table 2b and identify the existence of residual primary source potential, these sediments being adjudged to be oil window mature and partially spent. A $\delta^{13}C$-depleted progenic oil signature of *c*.-30.5 ppt was observed (Fig. 15).

Analogous data for the Sarir Trough well (A1-NC170; Table 2c) again confirmed the development of thinly bedded potential, cumulatively equating to an effective source bed of *c*.30 m. The oil-prone assemblages comprised resistant, high activation energy Type I kerogens with an exceptionally $\delta^{13}C$-enriched progenic oil signature at −17.0 ppt (Figs 14 & 15).

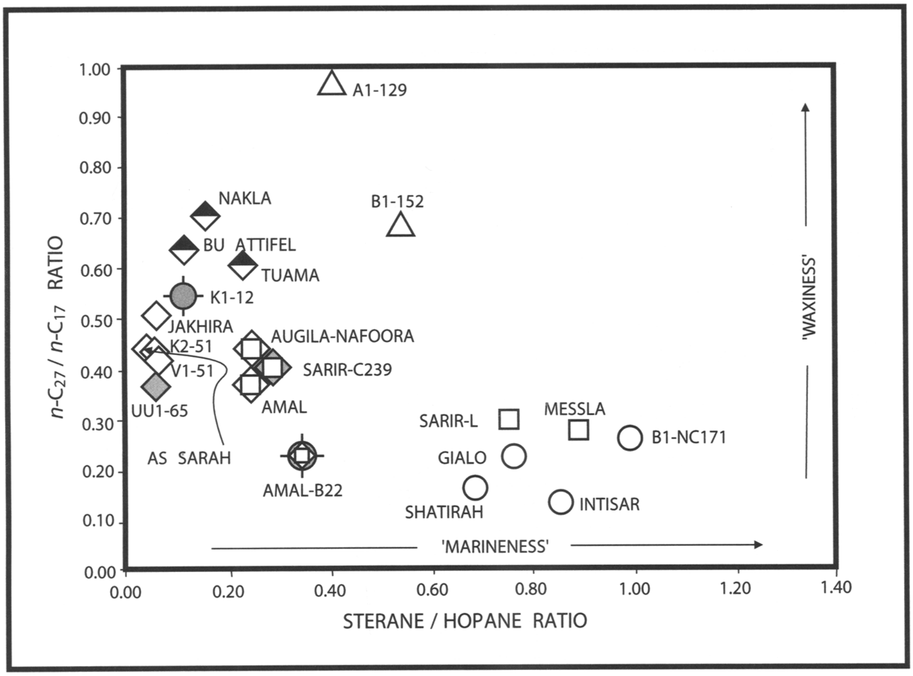


Fig. 10. East Sirte Basin crude oil inversion analysis: wax factor $nC27/nC17$ v. sterane/hopane ratio cross-plot showing a strong correlation between waxiness and non-marine (i.e. lacustrine) source depositional provenance.

Nubian (Calanscio Formation). Data for the Hameimat Trough well C5–97 revealed thinly bedded intervals of partially spent source-quality potential within the varicoloured shales (Table 2d). With instances of residual primary potential, these sediments were adjudged to have possessed attractive precursor source capacity. A highly $\delta^{13}C$-enriched formation mean progenic oil signature at −21.5 ppt (Fig. 15) characterized evident oil-prone potential with anticipated refractory kerogen kinetics.

The range in kerogen carbon isotope signature between the Nubian (Triassic) and Sarir plus Calanscio formation candidates (−34 ppt to −17 ppt) is noteworthy. This indicates an extensive organofacies variation and control as to the progenic hydrocarbon product that could be anticipated from these source rocks.

Etel Formation. Deposited as a result of the Cenorianian to Turonian marine incursions, source-quality potential has been recorded for intervals within the carbonate-evaporite sediments of the Etel Formation (El Alami 1996). In both the Agedabia (well 5P1–59) and Hameimat (well A1-LP4F) troughs, organic-rich sections in excess of 200 m with anticipated oil-prone potential were observed. A $\delta^{13}C$-enriched signature at −22.5 ppt for the source rock in well U1–82 has similarly been recorded.

Rachmat–Tagrifet formations. Comprising the lower part of the Upper Cretaceous source rock package, these marine sediments showed evidence of limited but widespread development. Control for the Rachmat Formation is provided by wells MM1–59 and D1-NC170 from the flanks of the Faregh-Messla High and identified a thick interval of sustained primary source potential (Table 2e). The oil-prone assemblages equated to Type II kerogens, with relatively labile kinetic transformation character (Fig. 14; E_a 52 kcal/mol), and gave a depleted progenic hydrocarbon signature at a $\delta^{13}C$ −28.0 ppt (Fig. 15).

The stratigraphically higher Tagrifet Formation in MM1–59 was less thickly developed but again showed evidence of primary source potential provided by oil-prone Type II kerogen assemblages (Table 2f). A progenic oil signature, comparable to the Rachmat Formation, at $\delta^{13}C$ −27.8 ppt was observed.

Sirte Shale Formation. Considered to be the archetypal source rock in the East Sirte Basin, the Sirte Shale is of variable thickness and richness. At its maximum development, in the Agedabia depocentre, up to 760 m of sediment with total organic carbon (TOC) contents of 1–5% have been recorded (El-Alami *et al.* 1989). In the present study, control was established for well Q1–59 with supporting

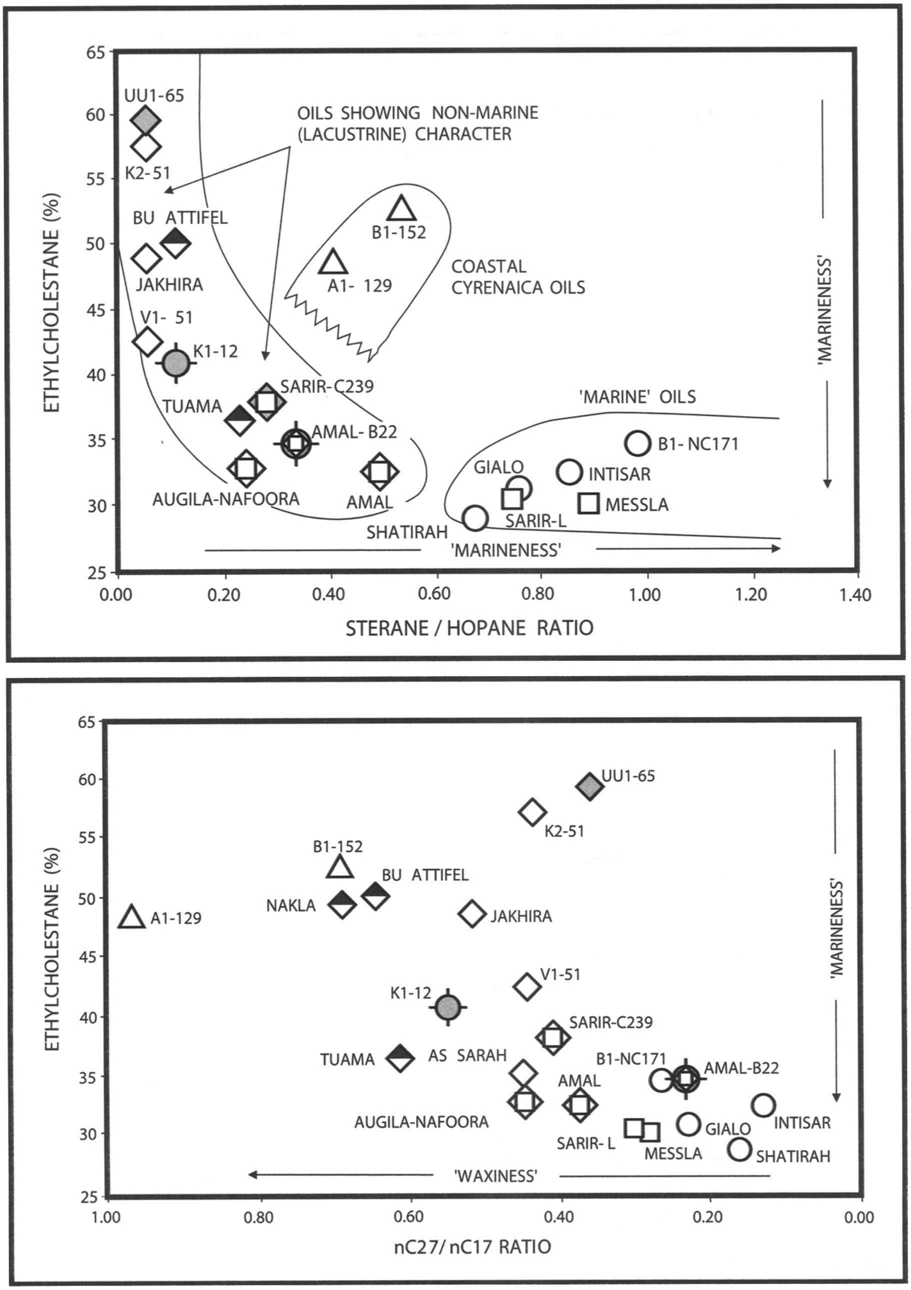


Fig. 11. East Sirte Basin crude oil inversion analysis: ααα ethylcholestane content parameter cross-plot with (**a**) sterane/hopane ratio and (**b**) *n*C27/*n*C17 wax factor confirming the strong direct correlation between the non-marine source detrital input parameters and providing *a priori* generic segregation of the oils into marine, non-marine (lacustrine) and those of intermediate character.

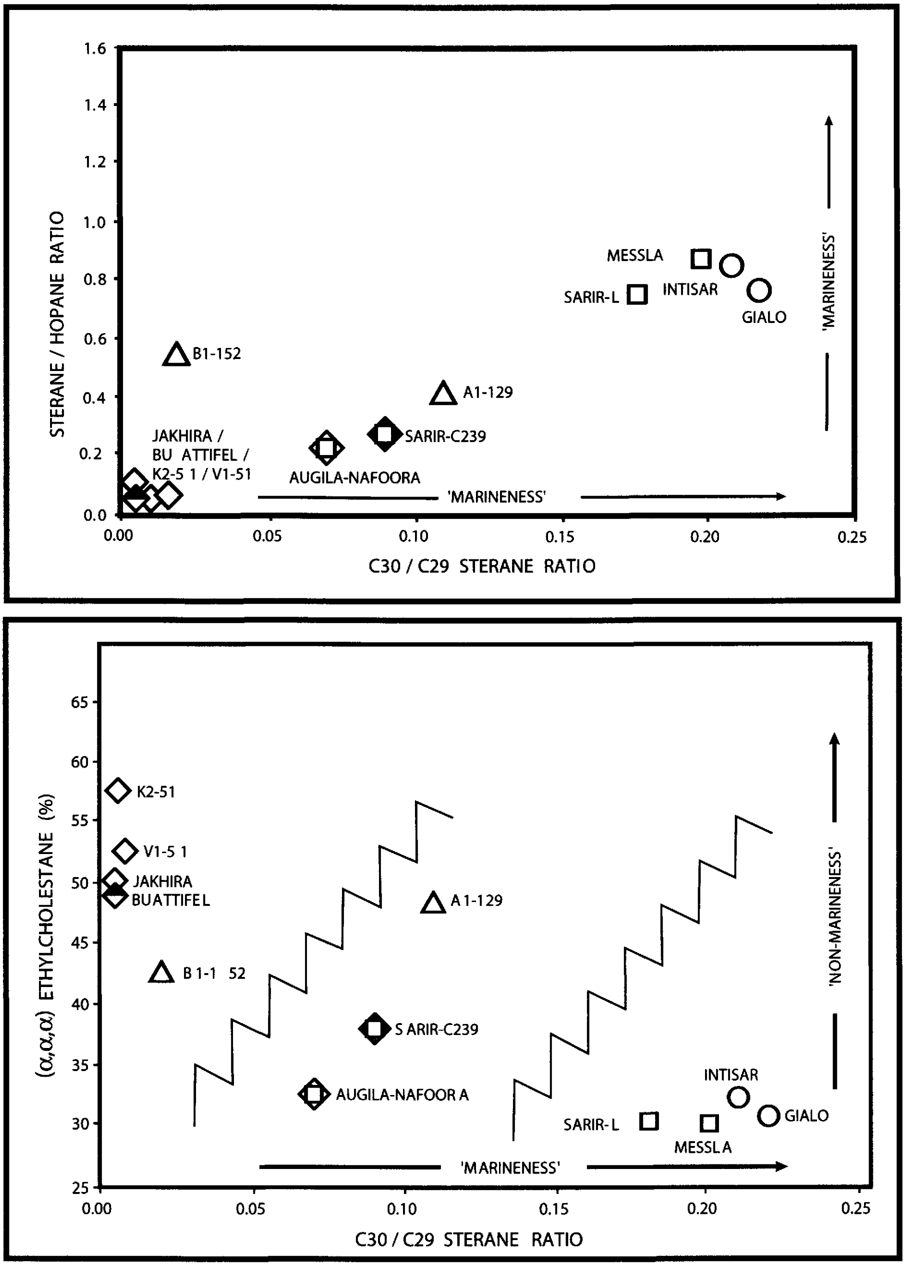


Fig. 12. East Sirte Basin crude oil inversion analysis: *n*-propylcholestane content 'marine' source parameter cross-plot with (**a**) sterane/hopane ratio and (**b**) ααα ethylcholestane content confirming the segregation into oils with non-marine (lacustrine), marine, and intermediate affinities.

data from D1-NC170, both these locations being on the flanks and south of the main Sirte Shale depocentre. A 380 m interval of sustained primary source potential, deriving from Type II kerogens, showed labile transformation kinetics (E_a 52 kcal/mol) and mixed oil-/associated gas-proneness (Table 2g; Fig. 14). Kerogen carbon isotope values embraced a 3 ppt range, a potential-weighted average suggesting a mean progenic hydrocarbon signature at $\delta^{13}C$ −29.0 ppt (Fig. 15).

A cross-comparison of the three Upper Cretaceous candidate source units reveals comparable

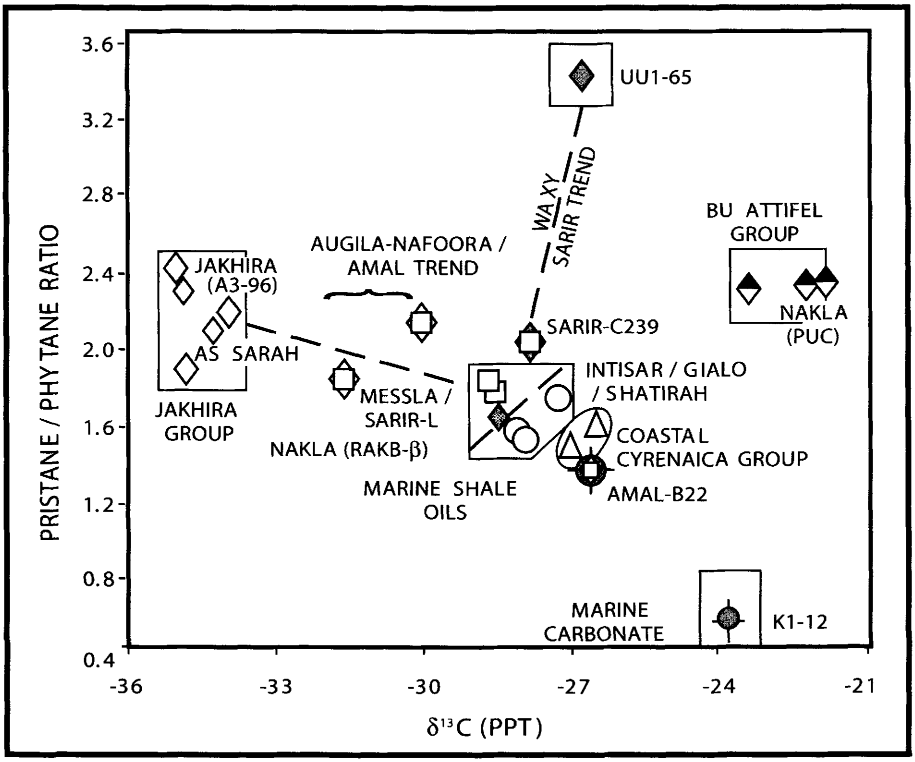


Fig. 13. East Sirte Basin crude oil inversion analysis: pristane/phytane ratio–carbon-isotope value cross-plot segregation of 22 key oils into generic groups. Note the mixing lines accounting for an aggregate composition for those oils of intermediate characteristics as previously identified by the sterane parameters in Figures 11 and 12.

intrinsic petroleum potential varying from 21 to 27 PP units, the main difference being in thickness and hence volumetric significance. In this context, the Sirte Shale is undoubtedly the premier candidate as and where fully developed. Nevertheless, both the Rachmat Formation and, to a lesser extent, the Tagrifet Formation offer substantial source potential that should not be overlooked. It is therefore important to note the subtle differences in carbon-isotopic signature between the candidates (Fig. 15). The lower and earlier-maturing Rachmat–Tagrifet formations show a more $\delta^{13}C$-enriched signature (*c.* −28 ppt) than the stratigraphically higher Sirte Shale mean value (−29 ppt). Although only a narrow isotopic contrast, this observation proves to be invaluable in differentiating between the 'marine-sourced' oils.

In addition, isolated datasets attributable to the Kalash Formation have been obtained. With their source characteristics not dissimilar to that of the Sirte Shale Formation control, these data have not been individually flagged and quantified.

Paleogene section

Hagfa–Kheir formations. In the present study minor source-potential indications were observed for the Hagfa Shale. Again, these sediments showed source rock characteristics similar to that for the Upper Cretaceous candidates. Elsewhere, most of the Paleocene–earliest Eocene-aged section, including the Shetarat and Kheir formations, were adjudged to offer only insignificant to poor hydrocarbon potential.

Harash Formation. As the more basinal Kheir time-equivalent in the central Agedabia Trough, intermittent source indications have been observed for these dominantly carbonate sediments. Basal sediments from control well C1-NC171 revealed thinly developed horizons with secondary oil-prone potential (Table 2h). Kerogen assemblages with labile transformation kinetics (E_a 52 kcal/mol; Fig. 14) were characterized by a highly enriched, and

Table 2. *East Sirte Basin source-rock study: summary source-rock data for the more attractive candidate rock units recognized over the Triassic to Paleogene section*

(a)

Source Unit: Nubian (Triassic) Control well: L4–51 (Maragh Trough)					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −33.8 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+30	4.8	29.7	619	0.14	58 [99]	7.802 E+14	89	691

(b)

Source Unit: Nubian ($Sarir_M$) Control well: A1–96 (Maragh Trough)					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −30.5 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
?	1.9	5.1	268	0.27	–	–	15	119

(c)

Source Unit: Nubian ($Sarir_S$) Control well: A1-NC170 (Sarir Trough)					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −17.0 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+33	2.5	11.2	455	0.16	58 [98]	7.135 E+14	34	261

(d)

Source Unit: Nubian (Calanscio Formation) Control well: C5–97 (Hameimat Trough)					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −21.4 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
?	2.1	5.3			Partially Spent		>15	>115

Continued

Table 2. *Continued*

(e)

Source Unit: Rachmat Formation Control well: MM1–59/D1-NC170					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −28.1 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+260	2.1	8.6	420	0.21	52 [89]	2.181 E+13	26	200

(f)

Source Unit: Tagrifet Formation Control well: MM1–59/01–103					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −27.8 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+65	1.9	6.9	356	0.27	–	–	21	161

(g)

Source Unit: Sirte Shale Formation Control well: Q1–59/DI-NC170					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −29.0 ppt			
Primary Source					Kinetic Data		Petroleum otential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+380	2.4	8.9	366	0.24	52 [63]	4.003 E+13	27	207

(h)

Source Unit: Lower Harash Formation Control well: C1-NC171					Progenic Oil ($\delta^{13}C_{KPY}$) Signature: −23.4 ppt			
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
1<5	0.9	4.2	467	0.19	52 [75]	3.433 E+13	13	97

Continued

Table 2. *Continued*

(i)

Source Unit: Gialo Formation (Gialo Member) Control well: D1-NC171					Progenic Oil ($\delta^{13}C_{KPY}$) Signature:	−25.5 ppt		
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
25<40	0.9	5.5	577	0.13	49 [22]	0.950 E+13	16	125

(j)

Source Unit: Antelat Formation (Eocene) Control well: B1-NC129					Progenic Oil ($\delta^{13}C_{KPY}$) Signature:	−26.6 ppt		
Primary Source					Kinetic Data		Petroleum Potential	
Effective thickness (m)	TOC (%)	S2 (kg/t)	HI	GOPR	E_a (kcal/mol) [%]	A (s^{-1})	PP Units ($\times 10^6 m^3/km^3$)	Bbl /acre-ft
+20	5.4	30.3	558	0.18	52 [60]	2.557 E+13	91	705

$\delta^{13}C_{KPY}$ is the mean value for the formation weighted against S2.
Petroleum Potential (PP) units are in $\times 10^6\,m^3{}_{(oil\ equivalent)}/km^3{}_{(source\ rock)}$ reflecting a 35° API gravity crude oil and a rock density of 2.55 g/cm^3.

TOC (total organic carbon), S2 and HI are mean values for the effective source thickness.
GOPR, gas-oil production ratio, being a PGC parameter comprising the C1 to C5 component, normalized to total pyrolysate.

diagnostic, carbon-isotope signature at $\delta^{13}C$ −23.4 ppt (Fig. 15).

Intermittent minor potential is also developed higher in the Harash section. This shows a more gas-prone character (gas/associated light oil-condensate) with correspondingly less-labile kinetics and variable, but more ^{13}C-depleted, kerogen signatures.

Gialo Formation (Gialo Member). A persistent feature of the Middle Eocene in the central–southern Agedabia Trough is the development of a thin, highly oil-prone interval at the base of the Gialo Member. Of marginal primary source status in the control well D1-NC171, these sediments showed exceptionally labile kerogen kinetics (E_a 49 kcal/mol) and an enriched carbon isotope signature at $\delta^{13}C$ −25.5 ppt (Table 2i; Figs 14 &15). Although thoroughly immature in the type locality, such kinetics would facilitate transformation into hydrocarbons under greater burial depths, as perhaps prevalent in the present-day Agedabia depocentre.

Antelat Formation. Embraced within the alternative stratigraphic nomenclature applied to Coastal Cyrenaica, Eocene sediments penetrated in Concession NC129 wells showed excellent primary source potential (Table 2j). Whether these rocks are representative of a more basinal and effective development of those vestigial sediments recognized as the Gialo Member to the south is presently equivocal.

Source data for the type-section well (B1-NC129) suggested *c.*20 m of sustained, highly oil-prone potential deriving from Type II assemblages with labile transformation kinetics (E_a 52 kcal/mol; Fig. 14). A more ^{13}C-depleted, but diagnostically mid-range, progenic oil signature at −26.6 ppt applied (Fig. 15).

The systematic source-screening undertaken above has resulted in identification and quantification of eight authenticated candidate source rock systems. A synthesis of multivariate oil data analysis output, with carbon isotope-based, source to oil correlation assignments, now provides the basis for definition of the operative petroleum systems.

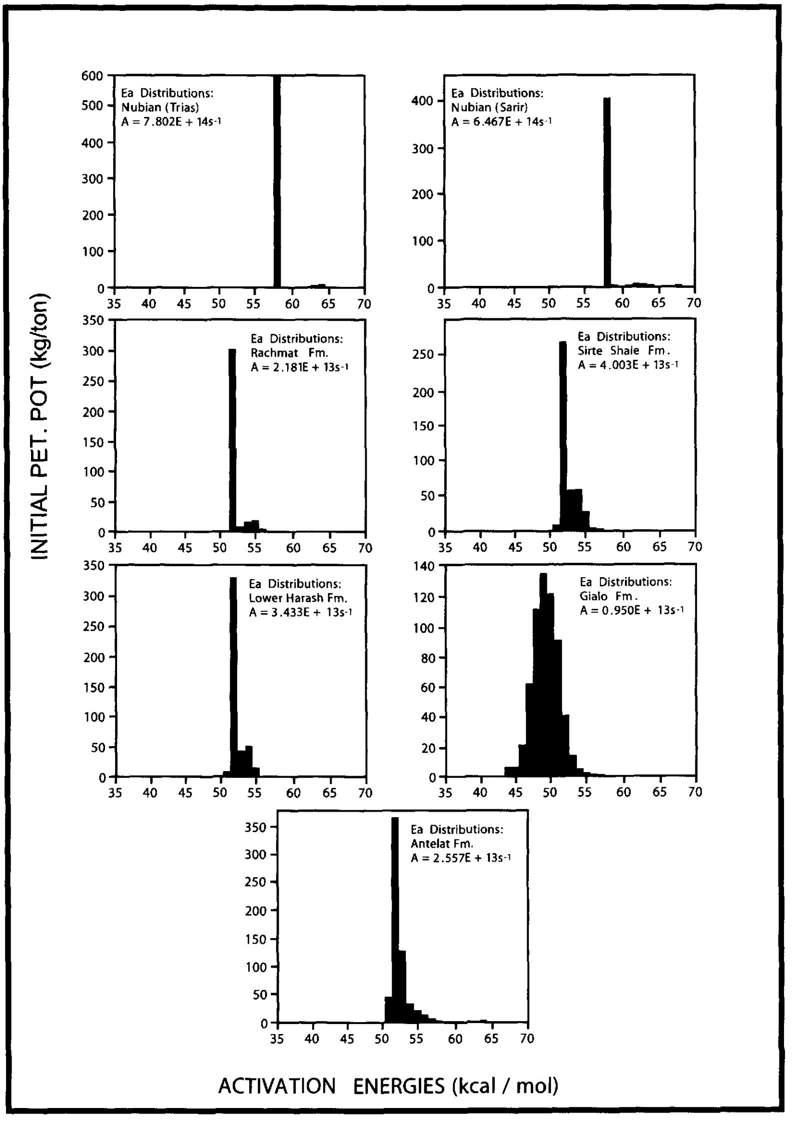


Fig. 14. Candidate source-rock study: kerogen transformation kinetic data for the repertoire of more attractive source rocks recognized. Data acquisition was by the Rock-Eval 5/Optkin procedure using pre-extracted (bitumen-free) rock powders employing a series of four heating rates (2, 5, 15 and 30 °C/min).

Multivariate oil analysis and source-oil correlation assignments

The various two-parameter inversion analysis treatment of the East Sirte oil data has provided evidence for the probable existence of eight end-member petroleum systems and of mixed-charge oils deriving from hybrid systems (Figs 9 & 13).

Corroboration of these observations, with extensions providing the basis for definitive source-oil correlation and petroleum system assignment, has been achieved using multivariate data processing. In this context a selection of parameters (Table 3), with strong palaeoenvironmental connotations and a low sensitivity to maturity effects, have been subject to PCA as illustrated in Figure 16a and b. The loadings-plot (Fig. 16a) reveals those critical source depositional traits that control the relative distribution of the oil families/sub-families in the attendant scores-plot (Fig. 16b). Note the discrimination between the end-member oil families and the evident mixing lines for the waxy Sarir (Sarir-

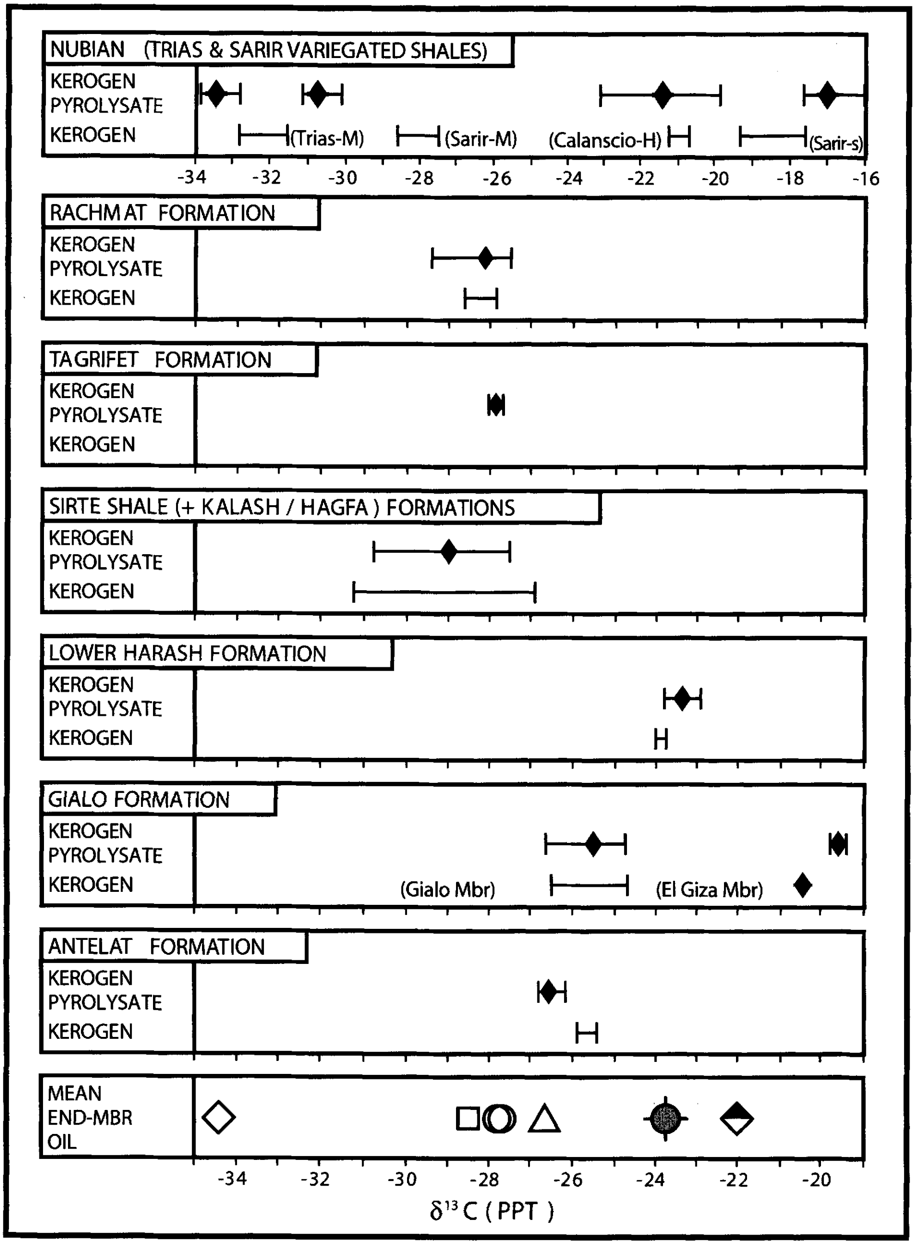


Fig. 15. Candidate source-rock study: kerogen and kerogen pyrolysate carbon isotope signatures for the more attractive source rock units recognized. Weighted mean (◆) pyrolysate values are calculated versus source potential as explained in the text. End-member oil family identities as given in Figure 16.

L to UU1–65) and Augila–Nafoora/Amal (Sarir-L to As Sarah) petroleums. The only equivocal group is that for the mixed Coastal Cyrenaica oils, the relative positioning of this domain suggesting tripartite charge inclusive of the Antelat, K1–12 and another (marine) contribution.

PCA can be extended, via an HCA routine, revealing additional fine structure as to the interrelationships between the oils. Imposition of a correlation coefficient cut-off (≥80%) to the resulting dendrogram (Fig. 17) discriminated 12 groupings of sufficiently consistent composition to be

Table 3. *East Sirte Basin regional oil study: parameters employed for principal component and hierarchical cluster analysis in segregation of generic oil families*

1.	δ^2H whole oil
2.	$\delta^{13}C$ saturates
3.	$\delta^{13}C$ aromatics
4.	Canonical variable (C_V)
5.	nC_{27}/nC_{17} wax factor
6.	C35-hopane/C34-hopane ratio
7.	T_S/T_M ratio
8.	Sterane/Hopane ratio
9.	Pristane/Phytane ratio
10.	C24 tetracyclic terpane/C23 tricyclic terpane ratio
11.	C26/C25 tricyclic terpane ratio
12.	C19/C21 tricyclic terpane ratio
13.	C22/C21 tricyclic terpane ratio
14	Tetracyclic/C26 tricyclic terpane ratio
15.	Norhopane/Hopane ratio
16.	Homohopane (22S+R)/Hopane ratio
17.	Cholestane (% $\alpha\alpha\alpha$20R)
18.	Methycholestane (% $\alpha\alpha\alpha$20R)
19.	Ethylcholestane (% $\alpha\alpha\alpha$20R)

regarded as discrete generic families/sub-families. A specific provenance, as to charge, is thus required for each.

For purposes of source to oil assignments two general approaches are available based on petroleum-matching with either:

- The candidate source bitumen (biomarker route); or
- The candidate source kerogen assemblage (carbon isotope route).

The latter was used on this occasion in view of the extensive and discriminatory dataset that has been assembled. Carbon isotopic correlation via the kerogen pyrolysate signature provides a reliable tool in that it achieves a comparison of the oil-labile part of a precursor source assemblage with the progenic petroleum (Burwood *et al.* 1988). However, it should be noted that isotopic correlation alone does not necessarily or uniquely identify the source of a given oil. Rather, it establishes an *a priori* match, confirmation of which, by a second parameter, most notably diagnostic biomarker fingerprints, is desirable.

Carbon isotopic data for the candidate sources encountered in this study are summarized in Table 4 with their range and mean values illustrated in Figure 15. For the display of data, mean kerogen pyrolysate $\delta^{13}C$ values are weighted against source richness measured as S2 thus:

$$\overline{\delta^{13}C}\text{ (pyrolysate)} = [\Sigma\delta^{13}C\text{ (pyrolysate)} \times S2]/\Sigma S2.$$

Oil to source correlation was achieved by a whole oil/oil fraction v. kerogen pyrolysate profiling procedure as illustrated in Figures 15 and 18. Here, an acceptable correlation was deemed to exist when the whole oil-pyrolysate differential did not exceed ± 1 ppt, with a more stringent correspondence (± 0.5 ppt) conferring a greater degree of confidence.

Oil-to-source assignments, and hence the definition of the contributory petroleum system(s), can now be developed on the basis of the dendrogram and the supporting kerogen pyrolysate carbon isotope signatures, as summarized in Figure 17. An overview of the dendrogram reveals that the 12 generic groupings are distributed between a subordinate collection of oils with 'lacustrine'-source attributes and a major grouping of 'marine'-sourced petroleums. Within this 'marine' grouping, it is noteworthy that there is an evident fine structure between the Intisar, Shatirah and Gialo families and that these petroleums are quite distinct from the Messla genera.

Subtlety in source provenance can thus be anticipated. Elsewhere, the K1–12 Harash-reservoired oil appears to be of unique 'carbonate' provenance and three groupings, necessitating hybrid charge, are also evident.

End-member oil genera/petroleum system allocation. Family 1 oils embrace central Agedabia Trough fields including Intisar, Shatirah, Gialo and the shallow-reservoired Augila–Nafoora petroleums. Two differentiable families (1a and 1c) are evident. In view of their marine-source provenance and $\delta^{13}C$ mid-range signatures, Family 1a (Intisar) is assigned a predominantly Tagrifet Formation origin and constitutes the product of the Tagrifet Formation–Intisar (!) petroleum system (Fig. 19d).

Family 1c oils embrace the Gialo and shallow-reservoir Augila–Nafoora petroleums and are noteworthy in being the most sulphur-rich fluids of the eastern Sirte area. Marine, $\delta^{13}C$, mid-range kerogen signature sourcing again applies, with these petroleums being attributed to a dominantly Rachmat Formation provenance and constituting the Rachmat Formation–Gialo (!) petroleum system (Fig. 19c).

Hamid, Messla and some Sarir field production comprises Family 3, these oils again showing marine-source attributes, but with a somewhat more depleted $\delta^{13}C$ signature. A Sirte Shale Formation provenance, in which any Rachmat and/or Tagrifet Formation contribution is of very subordinate impact, can be attributed to these oils, this constituting the Sirte Shale Formation–Messla (!) petroleum system (Fig. 19a). Nakla, Bu Attifel and Tuama field petroleums comprise the Family 5

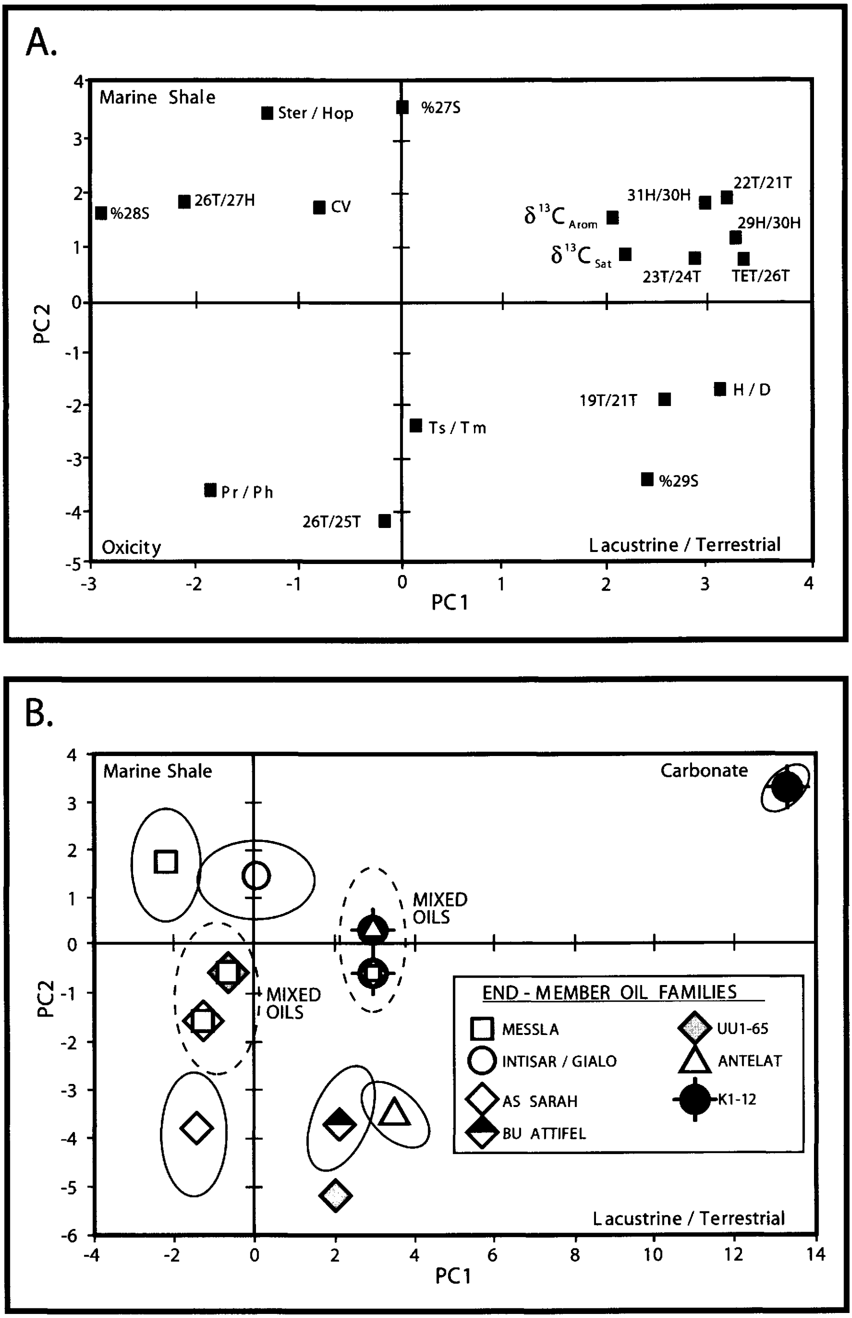


Fig. 16. East Sirte Basin crude oil multivariate principal component analysis (PCA): (**a**) PCA loadings plot using the palaeoenvironmental marker parameters listed in Table 3, and (**b**) PCA scores-plot illustrating the segregation into generically distinct families/sub-families. Note the mixing lines linking the end-member contributors to those petroleums of mixed, aggregate composition.

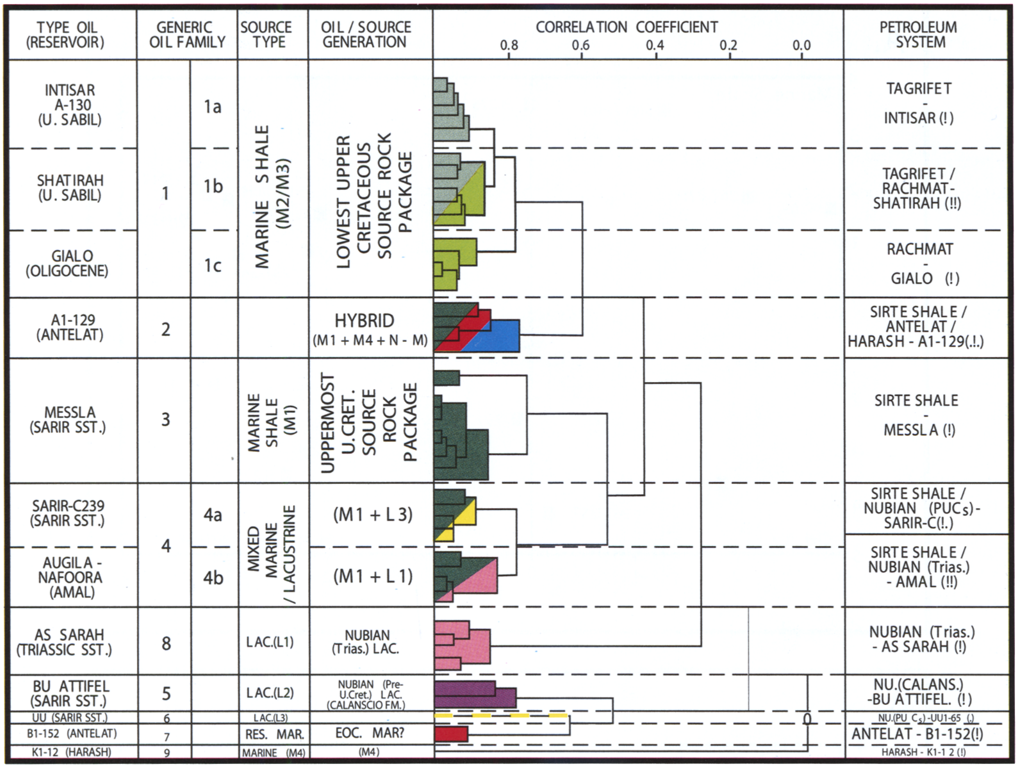


Fig. 17. East Sirte Basin crude oil and source-oil correlation assignment synthesis based upon a hierarchical cluster analysis (HCA) dendrogram. Note the additional generic fine structure revealed by the HCA procedure and the obvious internal diversity among those oils with a marine source provenance attribution.

members. These oils are of lacustrine provenance from the distinctive Pre-Upper Cretaceous Calanscio Formation organofacies, as developed within the Hameimat Trough, and constitute the Nubian Pre-Upper Cretaceous Hameimat Trough (PUC_H)–Bu Attifel (!) petroleum system (Fig. 19g).

The single member of Family 6 (UU1–65) again shows lacustrine attributes, but on this occasion appears to derive from a Pre-Upper Cretaceous organofacies developed within the Sarir Trough. This petroleum system is of considerable significance in contributing the high wax-modifying component to many of the Sarir-C oils and is defined as the Nubian Pre-Upper Cretaceous Sarir Trough (PUC_S)–UU1–65 (.) variant.

Family 7 petroleums comprise the end-member for the Coastal Cyrenaica oils (Concessions NC129, 152) and derive from the Eocene Antelat Formation (Antelat Formation–Antelat (!) petroleum system, Fig. 19e). The Antelat source derived oils show unusual palaeoenvironmental characteristics of both a highly carbonatic/anoxic marine yet 'non-marine/terrestrial' waxy character. A highly restricted, possibly speciality, marine depositional regime could be responsible.

Family 8 petroleums derive from the As Sarah, Jakhira, V1- and K2–51 fields. Of lacustrine provenance, these oils are sourced from an exceptionally $\delta^{13}C$-depleted Nubian (Triassic) organofacies specific to the Maragh Trough. The resulting Nubian (Triassic)–As Sarah (!) petroleum system (Fig. 19b) is of considerable importance in providing the co-charge to the Augila–Nafoora and Amal deep-reservoir fields.

A single oil (K1–12), of unique Harash Formation marine-carbonate source provenance, constitutes Family 9, being the representative of the Harash Formation–K1–12 (!) petroleum system (Fig. 19f). Again, this system is thought to be a subordinate contributor to some of the northern Agedabia Trough fields.

Hybrid petroleum system crude oils. Family 1b oils, embracing the Shatirah and NC171 discoveries, appear to be composite Rachmat–Tagrifet Formation derived petroleums and constitute the

Table 4. *East Sirte Basin source-rock study: kerogen and kerogen pyrolysate carbon isotope values for candidate source rock units*

Candidate Source Unit	Well	Kerogen $\delta^{13}C$* (-ppt)	Kerogen Pyrolysate $\delta^{13}C$ (-ppt)	Mean† $\delta^{13}C$ (-ppt)
Antelat Formation (Eocene)	B1-NC129	25.66	26.49	
		25.42	26.63	
		25.89	26.79	
		25.81	26.16	
		25.68	26.80	26.57
Gialo Formation (Gialo Member)	B1-NC171	24.84	25.59	
		24.68	25.42	
	C1-NC171	24.90	24.71	
	D1-NC171	25.26	24.84	
		25.49	25.27	
	A1-NC170	26.51	26.66	
		26.46	26.02	25.50
Gialo Formation (El Giza Member)	D1-NC171	20.46	19.60	19.60
Lower Harash Formation	C1-NC171	23.77	22.91	
		24.02	23.83	23.37
Hagfa Formation	A1-NC31B	27.36	27.91	
	KK1–65	27.07	27.56	27.61
Kalash Formation	A1-NC31B	28.34	28.48	
	KK1–65	27.37	28.04	28.27
Sirte Shale Formation	A1-NC31B	30.30	30.37	
		27.53	30.19	
	D1-NC170	27.18	28.19	
		27.46	28.34	
		26.89	28.66	
	HH1–80	28.12	27.83	
		30.12	30.82	
		28.60	29.53	
		31.25	28.25	
	JJ1–65	27.93	28.27	
	KK1–65	27.30	29.74	
	O1–1403	28.05	27.86	
		–	27.48	
	TT1–65	28.36	30.08	28.97
Tagrifet Formation	O1–103	–	27.85	27.85
Rachmat Formation	D1-NC170	27.83	29.34	
	01–103	28.06	29.41	28.10
Nubian (Sarir Formation)	A1–96	28.61	31.14	
Maragh Trough		27.47	30.10	30.75
Nubian (Sarir Formation)	A1-NC170	19.33	17.66	
Sarir Trough		18.87	17.36	
		17.58	15.89	16.97
Nubian (Calanscio Formation)	C5–97	20.68	20.22	
Hameimat Trough		20.86	23.16	
		20.92	19.80	
		21.00	22.58	21.44
Nubian (Triassic)	L4–51	32.57	33.80	
Maragh Trough				33.80

*$\delta^{13}C$ measurements referenced against NBS22 at −29.80 ppt
†See text for calculation of weighted mean kerogen pyrolysate values.

Rachmat/Tagrifet–Shatirah(!!) hybrid petroleum system (Fig. 20c).

Family 2 oils contain a variable collection of fluids from the northern Agedabia Trough, including the Coastal Cyrenaica fields, Amal B22–12 (Mesdar Formation reservoir) and an E1A-NC171 condensate, and proved the most equivocal in assigning a provenance. Plotting in the marine

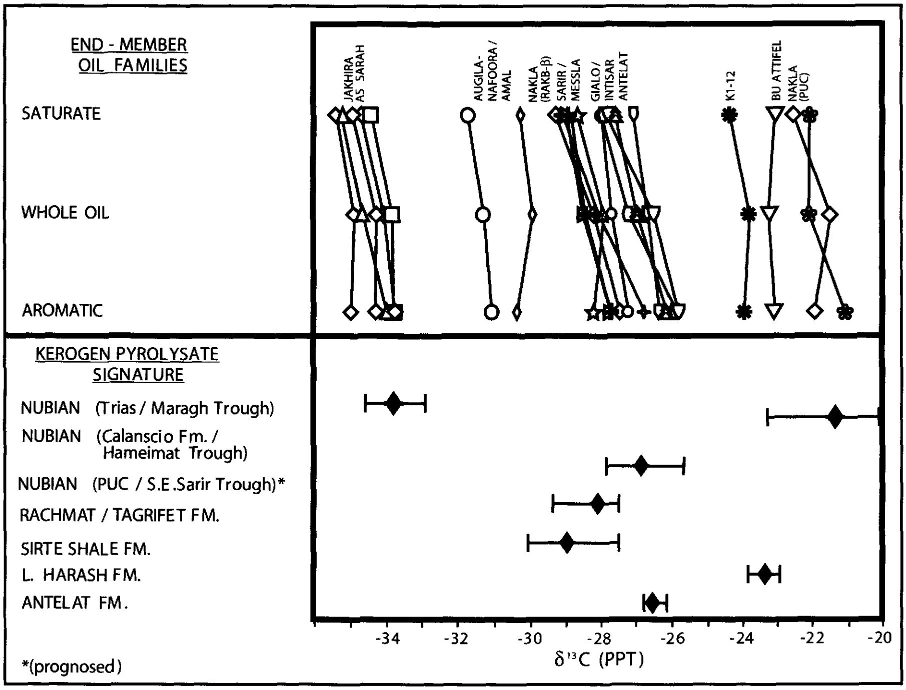


Fig. 18. Carbon isotope-based source-oil correlation assignment for the 21 key oils revealing an isotopic correspondence between the Nubian (Triassic)–As Sarah; Sirte Shale Formation–Messla; Rachmat–Tagrifet Formation/Intisar–Gialo; Antelat Formation–Antelat, Lower Harash Formation–K1–12 and Nubian (Calanscio Formation)–Bu Attifel end-member petroleum systems.

domain of the dendrogram, these petroleums can show both high wax and 'carbonate' source attributes. However, judging from their position within the scores-plot (Fig. 16a), they are not solely an admixture of the Antelat (!) and Kalash (!) systems, but some level of *bona fide* marine-source contribution is also involved.

Family 4 petroleums are essentially derived from the Sirte Shale Formation (!) system, but can be split into two sub-families according to the origin of their co-charge. Sub-family 4a oils comprise the waxy Sarir trend coming from various Sarir Sandstone reservoir locations over the extent of the Sarir-C field. The UU1–65 (!) system (see above) provides the co-charge on this occasion (Fig. 20b).

Sub-family 4b oils embrace the deep-reservoir Augila–Nafoora and Amal petroleums. Here, the highly distinctive As Sarah (!) system (see above) provides the modifying co-charge, these hydrocarbons currently being recognized as exclusive to a Maragh Trough provenance. This hybrid can thus be fully defined as the Sirte Shale Formation/ Nubian (Triassic)–Amal (!!) petroleum system (Fig. 20a).

Petroleum systems: basin-modelling syntheses and exploration implications

The schematics and ranking of each defined petroleum system, with annotation as to oil type, has been quantified in terms of published original recoverable reserves information (GBOR) as illustrated in Figures 19a–g and 20a–c.

The petroleum systems identified within this study display distinct stratigraphic and areal distribution across the Sirte Basin. The recognition of a number of new source horizons, in addition to the traditional Upper Cretaceous marine shales, opens up further opportunities for exploration in the basin. In particular it suggests that a re-evaluation is required of areas previously downgraded because they are outside the main Upper Cretaceous kitchens or beyond reasonable migration distances. Early Cretaceous/Triassic-aged rifts are proven to contain effective and volumetrically significant source facies which may have considerable source potential in the southern and southwestern Sirte Basin. At present their genesis and distribution is not well defined.

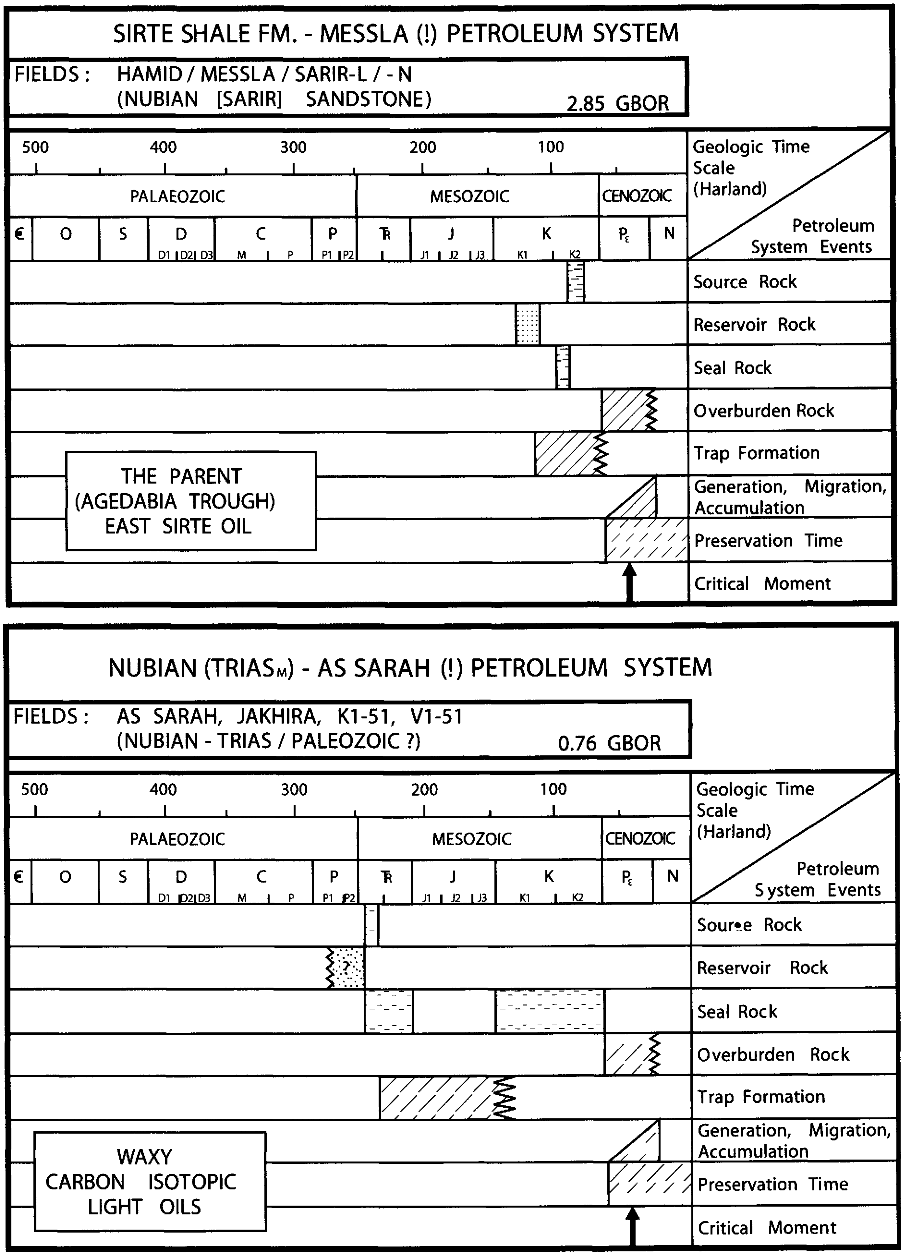
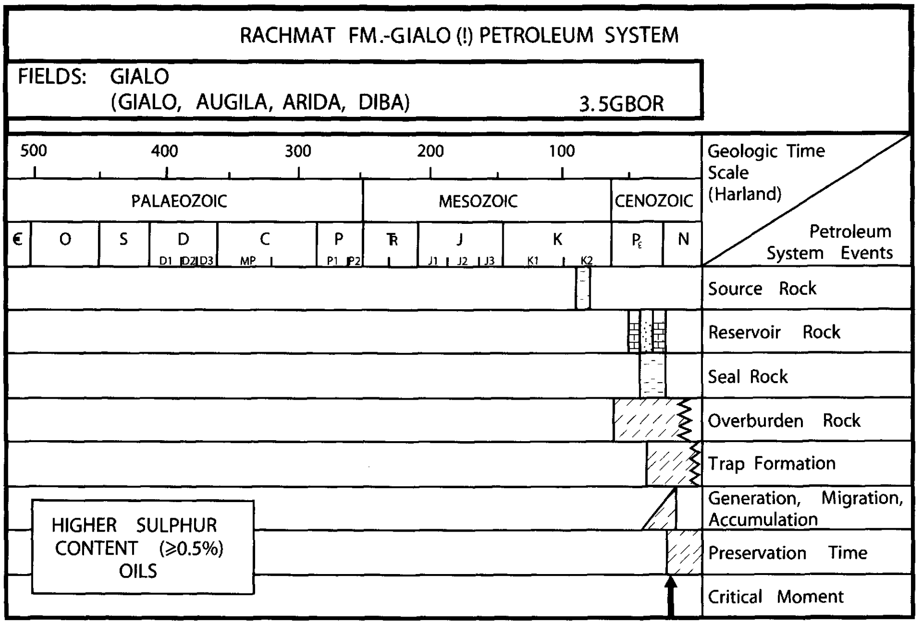
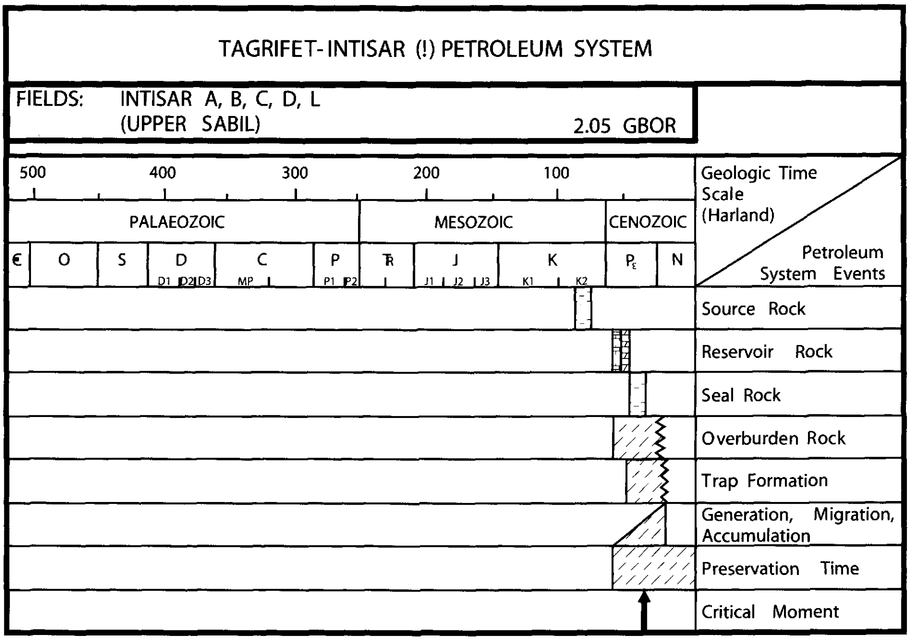


Fig. 19. East Sirte Basin petroleum system summary: proven unique systems involving a single source rock unit.(**a**) Sirte Shale Formation–Messla (!); (**b**) Nubian (Trias$_M$)–As Sarah (!); (**c**) Rachmat Formation–Gialo (!); (**d**) Tagrifet Formation–Intisar (!); (**e**) Antelat Formation–Antelat (!); (**f**) Harash Formation–K1–12 (!) and (**g**) Nubian (Calanscio Formation)–Bu Attifel (!) combinations.

Basin modelling

A number of well sections representative of more basinal locations within the main hydrocarbon kitchens, including the Hameimat, Agedabia and Sarir troughs, have been modelled (1-D TerraMod™ software) to assess the subsidence history and maturation profiles for the area (Figs 21, 22 & 23). The modelling utilized experimentally determined source rock kinetics (cf. Fig. 14), default Type IV kerogen kinetics (for vitrinite reflectance equivalent computation), present-day corrected geothermal





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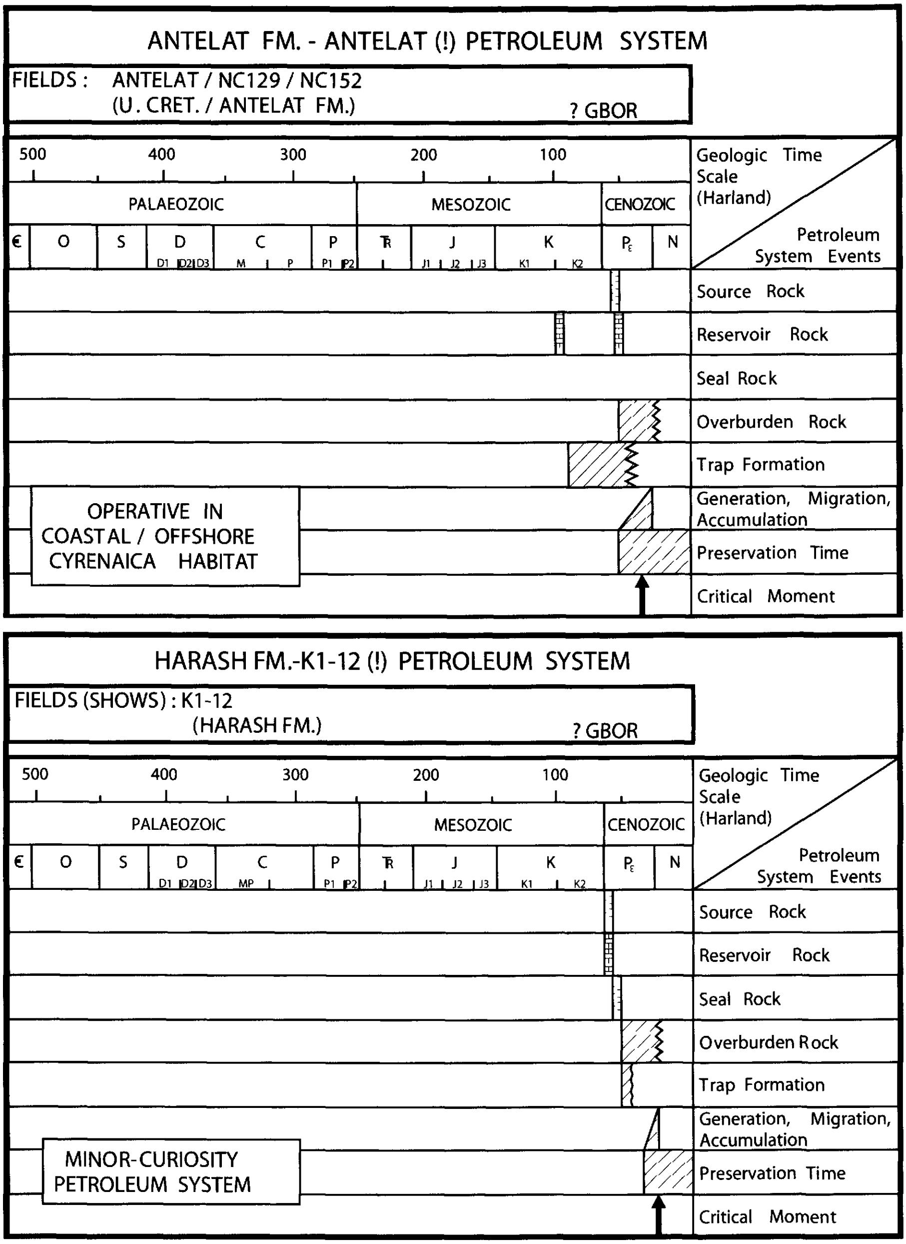
gradient data and available published information (Gumati & Schamel 1988; El Alami *et al.* 1989; Ghori & Mohammed 1996). Suleman and Roy (1987) suggested a range of heat flows in the Sirte Basin from 83 mW/m^2 during early rifting to 51 mW/m^2 at the present day. Bender *et al.* (2001) reported lower average heat flows of 55 mW/m^2 used in modelling of the Hameimat Trough.

This study calibrated the heat flow against available vitrinite reflectance data to obtain a reliable match, and results indicate average values ranging from 1.35 HFU (56 mW/m^2) during the early rift phase to 1.14–1.20 HFU (47–50 mW/m^2) over the later thermal sag phase. The results support the comments by Bender *et al.* (2001) that it is the significant subsidence during the Paleocene and



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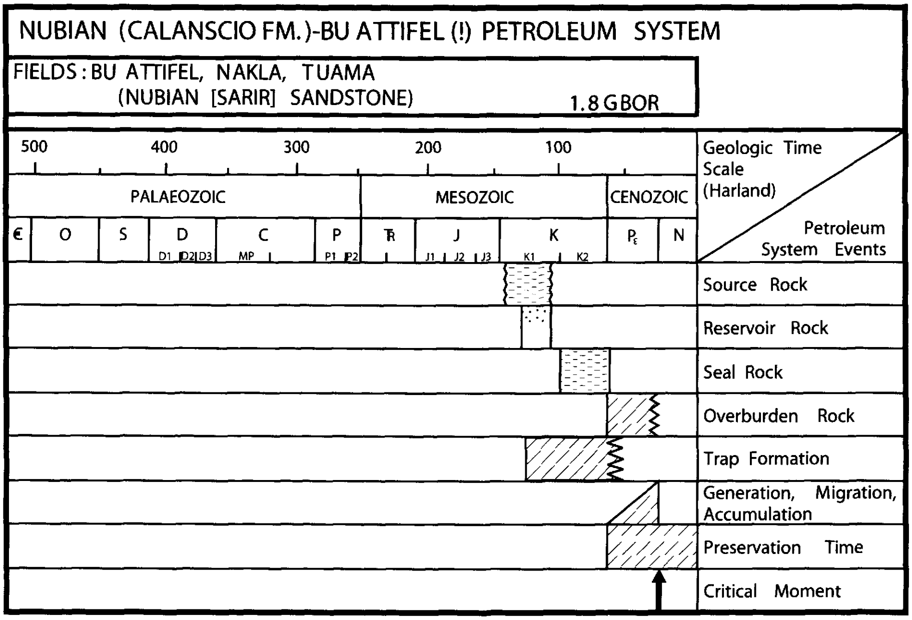
Eocene that drives the onset of oil generation in the basins, with the modelling less susceptible to moderate variations in heat flow through time, and in particular during the early rifting events.

Hameimat Trough

Basin modelling indicates that the Pre-Upper Cretaceous shales (Calanscio Formation) entered the oil window in the Early Eocene, and are currently in the dry gas window (Fig. 21). The overlying Upper Cretaceous shales entered the oil window in the Late Eocene in the deeper parts of the trough. Present-day peak oil window (R_o 0.8%) is at 3600 m (11 800 ft) and the top gas window (R_o 1.3%) is at 4570 m (15 000 ft). Work by Bender *et al.* (2001) provides comparable results to this study, indicating the top mature zone in the Hamei-



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mat Trough in the range 3250–3500 m (10 660–11 480 ft), with top gas at 4570 m (15 000 ft). The Bu Attifel Field has a high GOR (gas–oil ratio; 230–600 m^3/m^3) and high API (Erba *et al.* 1984), which further supports the modelling.

A number of petroleum systems have been identified in the Hameimat Trough area, and a generalized play diagram is presented in Figure 24.

Nubian (PUC_H)–Bu Attifel (!) petroleum system. Within the Hameimat Trough the Nubian (Sarir) sandstones provide the main reservoir, with structural horsts and tilted fault blocks being the dominant trap type. Main fields include Bu Attifel, Nakla and Remel, with combined reserves estimated to be in excess of 1.8 GBOR.

This study confirms a non-marine source for the oils in the Nakla and Bu Attifel fields (Family 5), which is tentatively correlated with Pre-Upper Cretaceous Calanscio Formation shales. Reported restricted marine shales of source rock quality in the Upper Cretaceous Etel Formation (El Alami 1996) may also offer a potential candidate source for these fields, although this may be volumetrically subordinate to the thicker Pre-Upper Cretaceous shales.

Sirte Shale Formation–Messla (!) petroleum system. The thick Upper Cretaceous shales, while oil-mature and a prolific source, do not charge the main Nubian structures in the basin. This is interpreted to be due to a lack of an effective migration route, with the evaporitic Etel Formation forming a barrier (Fig. 24). Hydrocarbons generated from the mature Upper Cretaceous shales in the Hameimat Trough (Family 3) have migrated to the margins of the basin and are interpreted to have sourced the giant Messla and Sarir fields to the southwest, and possibly made a contribution to the Gialo Field to the west and the numerous smaller pools on the flanks of the Messla High.

Agedabia Trough

The Agedabia Trough is the main depocentre in the East Sirte Basin, with in excess of 6000 m (20 000 ft) of Mesozoic and Tertiary sediments. The potential Upper Cretaceous source interval is very thick, in excess of 1400 m (4500 ft) and thus there is a considerable variation in the maturity between the basal shales and the uppermost section, and consequently a range in timing for the onset of oil generation.

Basin modelling of the southern part of the basin, close to the Intisar oilfields, indicates present-day peak oil generation at 3750 m (12 250 ft) and gas generation at 4875 m (16 000 ft). The basal Upper Cretaceous shales (Rachmat Formation) entered the oil window in the Mid-Eocene (45 Ma BP) and the gas window by the end of the Oligocene. The younger and shallower Sirte Shales entered the oil window toward the end of the Eocene and are currently at peak oil maturity (Fig. 22).

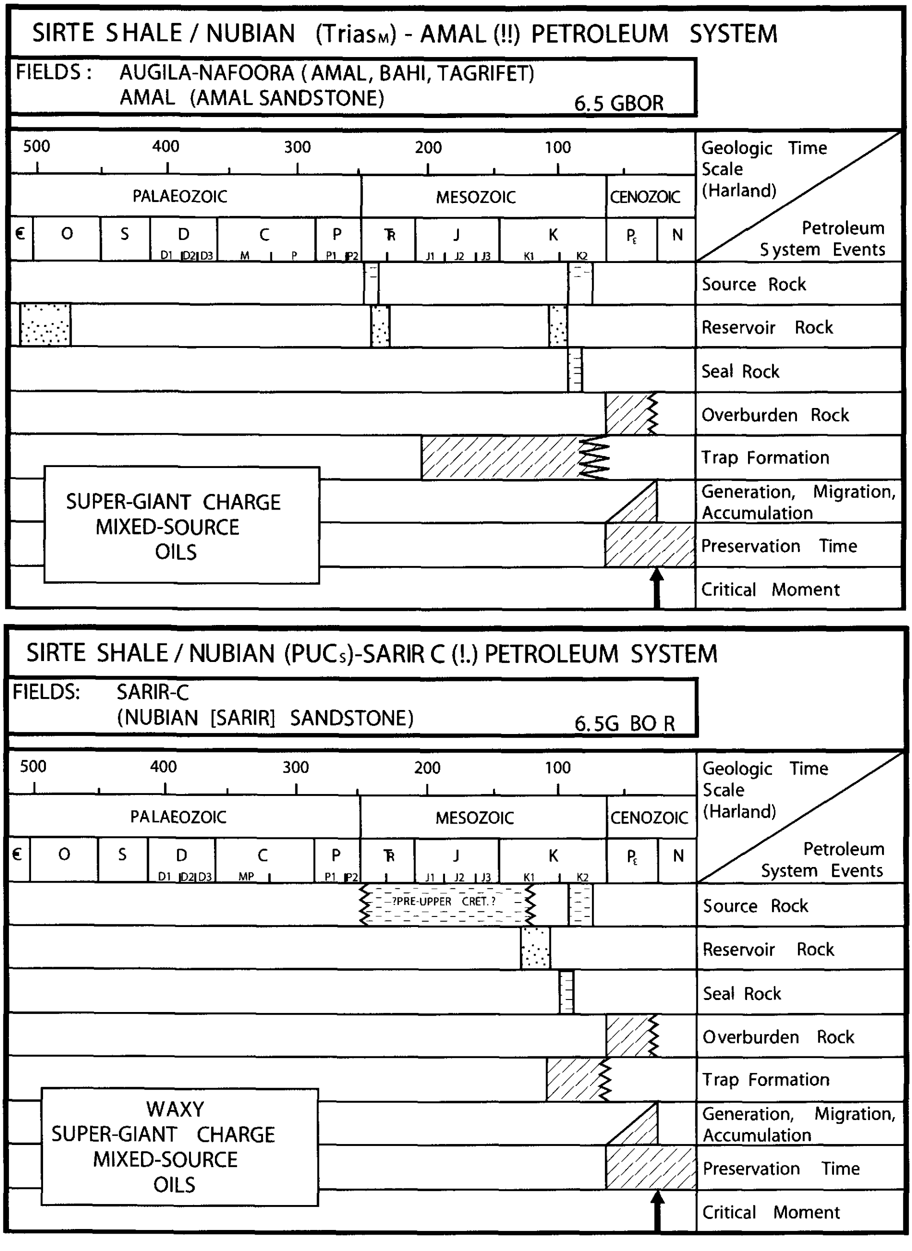
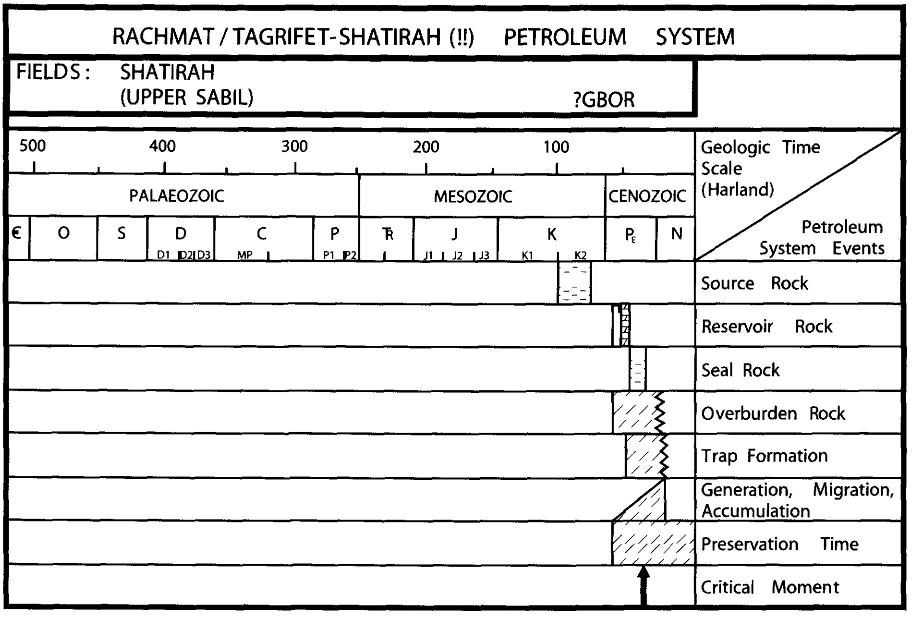


Fig. 20. East Sirte Basin petroleum system summary: hybrid systems involving multiple source rocks and aggregate charging. (**a**) the Sirte Shale Formation–Nubian ($Trias_M$)–Amal (!!); (**b**) the Sirte Shale Formation–Nubian (PLC_S)–Sarir C (!.) and (**c**) Rachmat/Tagrifet Formation–Shatirah (!!) variants.

The Agedabia Trough plunges steeply to the north, driving the entire section down into the gas window. This is demonstrated by the presence of gas discoveries at Sahl and Assoumoud on the northwest flank of the basin.

Tagrifet Formation–Intisar (!) petroleum system. The main play in the southern part of the Agedabia Trough is for Paleocene (Upper Sabil Formation) carbonates, within large reefal build-ups (Intisar pinnacle reefs) and smaller carbonate build-ups and



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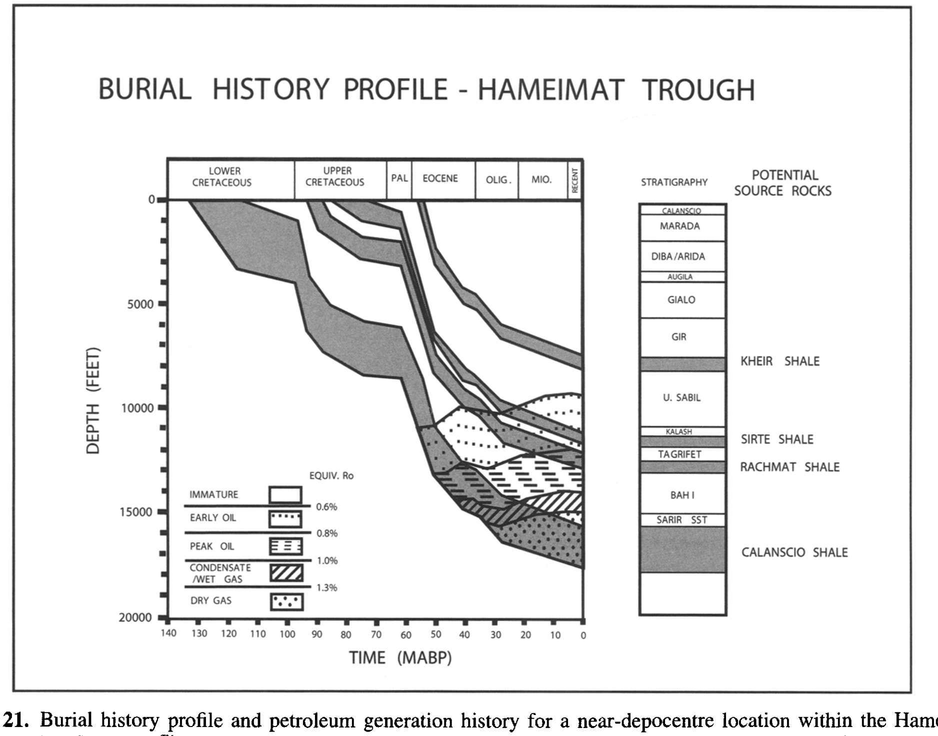

Fig. 21. Burial history profile and petroleum generation history for a near-depocentre location within the Hameimat Trough. 1-D TerraMod™ rifted model using heat flow of 1.35 HFU (Early Cretaceous rift phase) decaying to 1.20 HFU for present day. Vitrinite reflectance isopleths determined from Type IV kerogen kinetics.

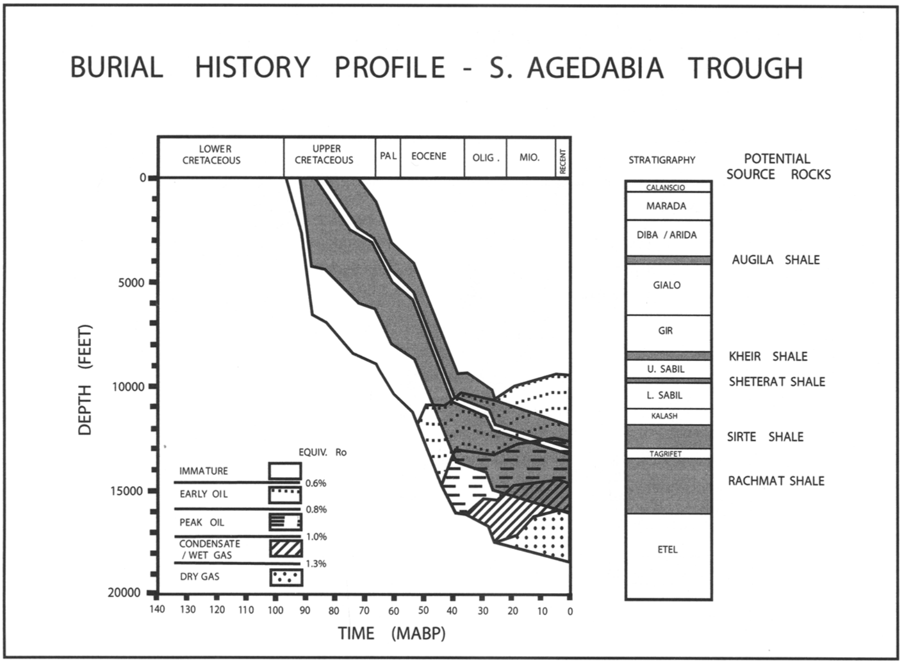

Fig. 22. Burial history profile and petroleum generation history for a near-depocentre location within the southern Agedabia Trough. Modelling as in Figure 21, with variable heat flow declining from 1.22 HFU, at Rachmat time, to 1.14 HFU present day.

structural traps. Reservoir development in the latter is primarily associated with higher energy carbonate facies, which rim the main depocentre. These reservoirs are charged from the underlying mature Upper Cretaceous shales via faults and fractures (Fig. 25).

Rachmat Formation–Gialo (!) petroleum system. The Gialo Field has a number of reservoirs (Paleocene Upper Sabil Formation, Eocene Gialo Formation, Eocene Augila Formation, Oligocene Chadra Member), but primary production is from the Eocene Gialo Formation carbonates. This very large regional structural high contains in excess of 3.5 GBOR. Hydrocarbon charge may have come from both the Hameimat Trough and Agedabia Trough and smaller subordinate basins on the margins of the structure. The main oil analysed was typed as Upper Cretaceous Rachmat-derived oil (Family 1c).

Harash Formation–K1–12 (!) petroleum system. The Paleocene Harash and Hagfa Shales (Family 9) have a relatively poor source quality and are not thought to be a significant source in the area. Deeper source facies have not been demonstrated by drilling, but may be present, although, due to the excessive burial depths, these would be within the dry gas window.

Eocene Antelat Formation–Antelat (!) petroleum system. This petroleum system is developed on the northeast margin of the Agedabia Trough, and could possibly be more correctly defined geographically as being located on the Cyrenaica Platform. Oil analysis indicates a distinct petroleum system, with oils derived from the Eocene Antelat Formation (Family 7). It sources the Antelat Field, for which reserves and detailed reservoir information are currently unavailable. This appears to be a local source restricted to the Coastal Cyrenaica area and volumetrically limited. It may offer potential elsewhere in Cyrenaica or in similar depositional settings in other parts of Libya.

Additional petroleum systems. Additional petroleum systems may exist in the Agedabia Trough and adjacent highs. The Nubian (Sarir) sandstone reservoir has not to date been a major target in the area, and its distribution and quality is poorly known, primarily because of its excessive depth of burial. Recent discoveries on the margins of the Agedabia Trough, however, suggest that deeper Lower Cretaceous Nubian or Cambro-Ordovician

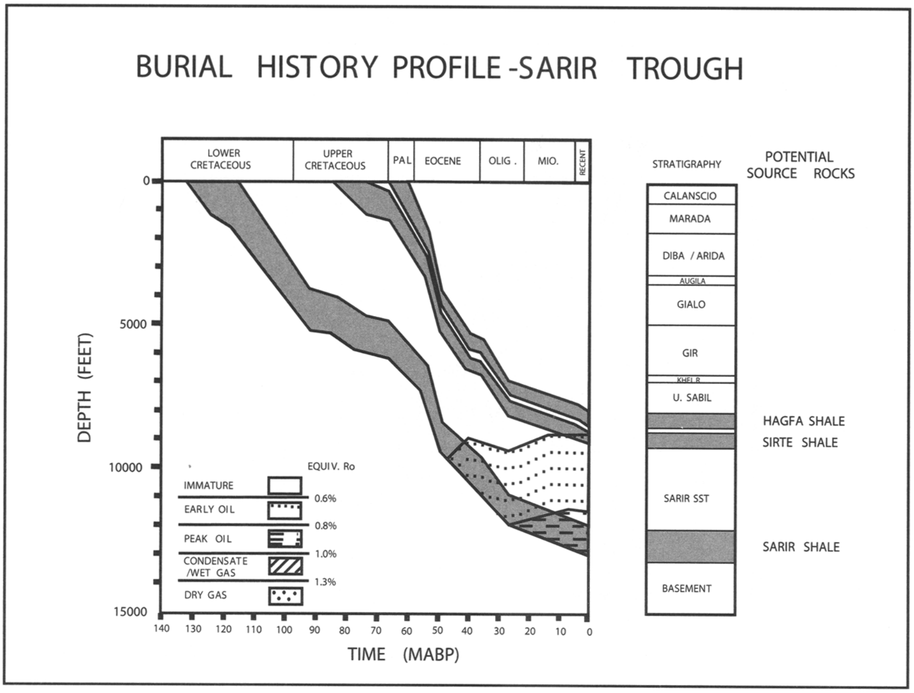

Fig. 23. Burial history profile and petroleum generation history for a near-depocentre location within the Sarir Trough. Modelling as in Figure 21 employing a Sarir rift-phase heat flow of 1.35 HFU declining to 1.20 HFU present day.

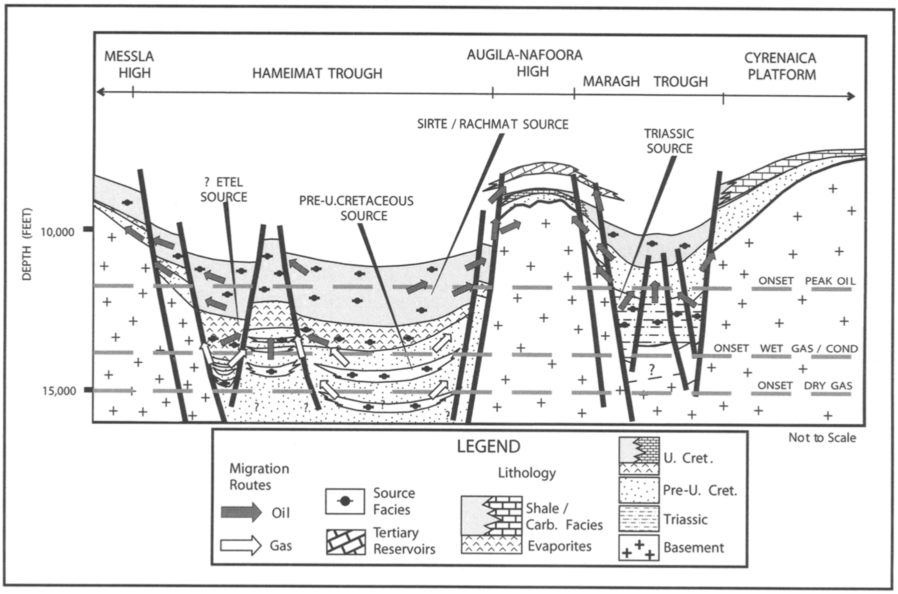

Fig. 24. Petroleum systems charge model for the Hameimat Trough.

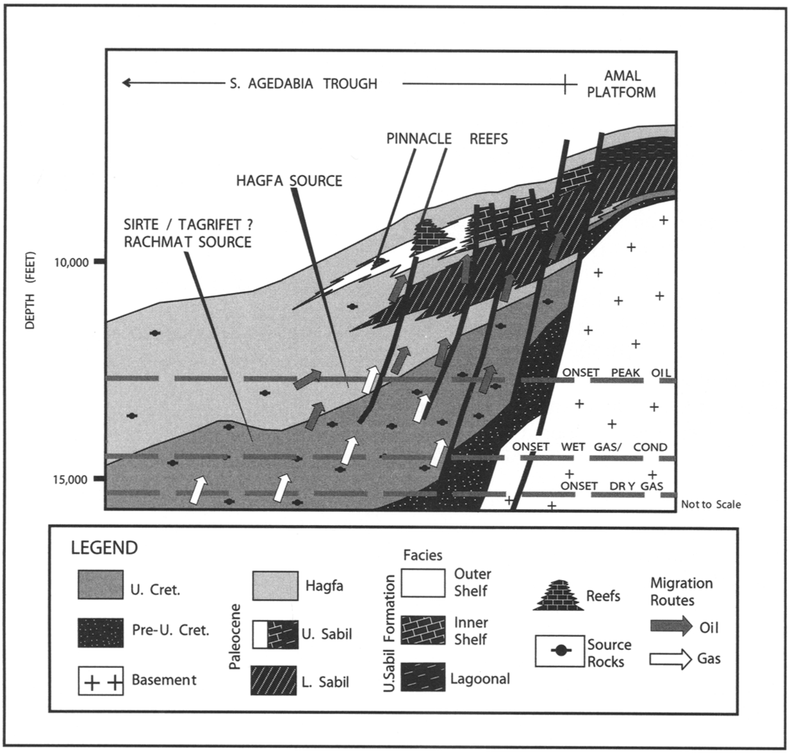

Fig. 25. Petroleum systems charge model for the southern Agedabia Trough.

Amal/Gargaf sandstone reservoir targets, within intra-basinal horsts or basin marginal fault blocks, may prove attractive. However, in such cases, there is clearly a risk of gas charge, especially to the north, and poor reservoir quality due to burial diagenesis.

Sarir Trough

Within the Sarir Trough, basin modelling suggests that the Upper Cretaceous marine shales are immature and have not generated significant volumes of oil (Fig. 23). Present-day peak oil generation is at 3450 m (11 250 ft), and the Early Cretaceous section entered the peak oil window (R_o 0.8%) in the Middle Oligocene (26 Ma BP)

Nubian (PUC_S)–UU1–65 (.) petroleum system. Support for an oil-mature Pre-Upper Cretaceous source in the Sarir Trough comes from the Agoco UU1–65 discovery. Located to the south of the Messla High, on the northern flank of the Sarir Trough, this field is a complex fault/stratigraphic pinchout play with a Nubian (Sarir) sandstone reservoir (Ambrose 2000). The structure is not on a migration route from the Hameimat or Agedabia troughs and can only have been charged from the adjacent Sarir Trough. Analysis of the oil indicates a Pre-Upper Cretaceous source (Family 6), supporting the model for Pre-Upper Cretaceous lacustrine source-rock development within the Sarir Trough. This demonstrates the potential for Pre-Upper Cretaceous source rocks within early rift basins

Hybrid Sirte Shale–Nubian (PUC_S)–Sarir-C (!.) petroleum system. To the east, the giant Sarir Field oil has been demonstrated to have a complex hybrid geochemistry indicating migration from two source rocks (Family 4a). It has clearly received charge from both the Upper Cretaceous marine shales of the Hameimat Trough (by long-distance migration 'spill and fill' via Messla) and also a smaller contribution from the Sarir Trough of non-marine waxy crude.

Maragh Trough

Basin modelling described in Gruenwald (2001) suggests that the peak oil window is at 3350 m (11 000 ft), with generation from the Mid-Eocene, and that the Pre-Upper Cretaceous section

(Triassic) interval is currently within the peak oil window. This modelling assumed a constant heat flow in this actively rifted basin of 62 mW/m^2. The younger Upper Cretaceous shales are only marginally mature over most the trough and are not thought to provide a volumetrically significant charge.

Nubian (Triassic)–As Sarah (!) petroleum system. The Maragh Trough contains two significant discoveries, the As Sarah and Jakhira fields, which have confirmed oil sourced from Triassic-aged shales (Family 8). This petroleum system has generated in excess of 0.76 GBOR in the Maragh Trough and, in addition, contributed to the charge of the giant Augila-Nafoora and Amal fields. The presence of this prolific Triassic source rock demonstrates the potential for early rifts within the Sirte Basin.

Hybrid Sirte Shale Formation/Nubian (Triassic)–Amal (!!) petroleum system. The giant Amal and Augila-Nafoora fields have multi-play reservoirs ranging from Basement, Cambro-Ordovician quartzites, Triassic–Lower Cretaceous Nubian sandstones, Upper Cretaceous sandstones and Upper Cretaceous, Paleocene and Eocene carbonates. The bulk of the reserves are within the lower clastic reservoirs. Oil analysis suggests a complex hybrid charge, with mixed oils within the samples analysed (Family 4b).

Additional petroleum systems. Potential for additional petroleum systems in the Maragh Trough and immediate area has been recently proposed by Gruenwald (2001). He suggests that there is also potential for younger reservoirs of Upper Eocene Augila Formation carbonates and Lower Oligocene Arida Formation sandstones charged by both Triassic source rocks in the Maragh Trough and Upper Cretaceous source rocks from the adjacent Hameimat Trough.

Conclusions

Combination of oil data inversion and multivariate statistical analysis, with the results of a carbon isotope-based source-oil correlation exercise, has permitted segregation of the East Sirte petroleums into their component genera. From this process, the existence of both Upper Cretaceous and younger candidate marine source-rock units, in addition to Pre-Upper Cretaceous lacustrine analogues, were recognized. *In toto* 12 oil family/sub-family genera were discriminated, these deriving from one of eight unique petroleum systems or hybrid mixtures thereof.

The results of maturation modelling for the various basins within the eastern Sirte area are consistent with the generation and accumulation of unique and hybrid oils recognized from the multivariate statistical analysis.

Of greatest volumetric significance was the Sirte Shale Formation–Messla(!) petroleum system, this accounting for the lower wax content Hamid, Messla and Sarir accumulations. This system also provided the base charge for the waxy Sarir, Augila–Nafoora and Amal petroleums, these deriving from the hybrid Sirte Shale Formation/Nubian (PUC_S)–Sarir-C(!!) and Sirte Shale Formation/Nubian (Triassic)–Amal(!!) combinations, respectively.

For the other marine-sourced oils, the Intisar and Gialo petroleums could be differentiated, being attributable to the Tagrifet Formation–Intisar(!) and Rachmat Formation–Gialo(!) systems, respectively. These sources combine to charge the Shatirah(!!) hybrid system.

Among the lesser accumulations, the Pre-Upper Cretaceous lacustrine Nubian (PUC_H)–Bu Attifel(!) and Nubian (Triassic)–As Sarah(!) petroleum systems, yielding high-wax oils, were deduced to be operative in the hinterlands to the Hameimat and Maragh troughs, respectively. The Nubian (PUC_S)–UU1–65(.) system was specific to the Sarir Trough and provides the high wax modifying charge to the waxy Sarir-C petroleums.

In the northern Agedabia Trough/coastal Cyrenaica area the Antelat Formation–Antelat(!) system was deduced to be locally productive, the contributory Eocene source facies exhibiting an unusual marine/non-marine, carbonatic character. Elsewhere, production from minor Lower Harash Formation carbonate source potential was evident in the case of the Harash Formation–K1–12(!) system.

Overall, these results, in revealing the complexity of the East Sirte Basin hydrocarbon habitat, should stimulate the search for hydrocarbons beyond the currently identified areas of mature Upper Cretaceous shales. An additional focus on other potential source horizons and on areas such as Pre-Late Cretaceous-aged restricted rift basins could promote the as yet unrealized potential of the area.

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Appendix

1. Source evaluation parameters

PP units:	Petroleum Potential ($x10^6$ $m^3_{(oe)}/km^3_{(rock)}$), calculated from S2 value (oe, oil equivalent of 35° API fluid; rock, source rock with density of 2.55 g/cm^3). Conversion factor to barrels/acre-ft: ($\times 7.758 \times 10^{-6}$).
GOPR:	Gas-oil production ratio (0.0–1.0). Pyrolysis-gas chromatographic measure of kerogen hydrocarbon product, zero and unity being exclusively oil-prone and gas-prone, respectively.
$\delta^{13}C_{KPY}$	Kerogen pyrolysate (simulated oil) carbon isotope signature. Formation mean values are source-richness weighted against S2 and calculated thus: $\overline{\delta^{13}C}_{(pyrolysate)} = [\Sigma\delta^{13}C_{(pyrolysate)} \times S2/\Sigma S2]$ Values reported v. NBS22 at −29.8 ppt (PDB).
E_a/A:	Kerogen transformation kinetics determined on bitumen-free sediments using the Rock-Eval 5/Optkin procedure. $GT_{(MAX)}$: real (geological) time optimum kerogen transformation temperature at heating rate 1°C/Ma.
C_V:	Canonical variable $[(-2.53\delta^{13}C_{sat}+2.22\delta^{13}C_{arom})-11.65]$

2. Petroleum system nomenclature*

Known/simple (proven source–oil correlation):	(!)
Known/complex (poly system):	(!*)
Known/complex (proven hybrid system):	(!!)
Hypothetical (prognosed with confidence):	(.)
Hybrid/part proven (major source known):	(!.)
Speculative:	(?)

*After Magoon & Dow (1994)

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