**ORIGINAL PAPER**

# Comparison of the Dakhla Formation source rock potential between Komombo Basin and Gebel Duwi, Upper Egypt

Moamen Ali[1] · Mohamed Darwish[2] · Mahmoud A. Essa[1] · Ahmed Abdelhady[3]

## Abstract

The Campanian-Maastrichtian Dakhla Formation consists mainly of dark gray, laminated shale with siltstone and sandstone inter-beds containing highly organic matter and is a potential source rock. The main objectives of the present research are to correlate the geochemical characteristics of the Dakhla Formation east and west of the River Nile in Upper Egypt and to discuss the main reasons for their variations. Fifty-nine samples were collected from the Komombo Basin and examined along with 230 published ditch and core samples from Gebel Duwi. These data indicate that the quality of the Dakhla source rock potentially varies from fair to good in the Komombo Basin with TOC 0.46–2.66 wt.% and good to excellent in Gebel Duwi with TOC of 2.1–14 wt.%. Additionally, the Dakhla Formation kerogen is type III and type I/II kerogen in the Komombo Basin and Gebel Duwi, respectively; the organic matter of the Dakhla Formation in the Komombo Basin is mostly of terrigenous origin, while in Gebel Duwi, it is mostly of marine origin. Based on vitrinite reflectance (%Ro) and $T_{max}$ values, the analyzed samples of Dakhla source rock are in the immature to early mature stage for oil and gas generation in both areas where the $T_{max}$ values have a range of 422–444 °C in the Komombo Basin and 412–435 °C in the Gebel Duwi area, while %Ro values range from 0.43 to 0.78% in the Komombo Basin.

**Keywords** Komombo · Gebel Duwi · Dakhla Formation · Source rock potential · Upper Egypt

## Introduction

The Komombo Basin is situated in the southern Western Desert, approximately 65 km northwest of Aswan (Fig. 1a). This basin is considered a half-graben (Fig. 2), intracontinental rift basin; it is considered the only producing basin in southern Egypt (Ali et al. 2017a). Bosworth et al. (2008) mentioned that the stress regime created in North and Central Africa associated with the creation of the South Atlantic was responsible for the creation of the Komombo Basin. This basin is bounded by a major normal fault striking NW-SE that is situated to the NE side of the Komombo Basin and down-thrown towards the southwest. Many minor normal faults are also characterized by the same NW-SE direction (Fig. 1b). The Komombo Basin contains approximately 13100 ft. of sediments (Fig. 3), mainly clastic rocks (shale and sandstone) with some carbonate deposits (Ziegler 1992).

The main objective of the current research is to (1) identify the geochemical characteristics of the Dakhla source rock in the Komombo Basin; (2) compare the results for the Komombo area to the geochemical characteristics for the Dakhla source rock in Gebel Duwi, the Qusier area discussed by El-Kammar (2015), El-Shafeiy et al. (2017), and Fathy et al. (2018); and (3) explain the main reasons for the characteristic variations in the Dakhla source rock in the two areas. Rock-Eval pyrolysis and total organic carbon (TOC) data for the Dakhla source rock in the Komombo area, as well as geochemical data for the same source rock at Gebel Duwi in the Qusier area are examined.

## Stratigraphy

The stratigraphic column of the Komombo Basin is representative of non-marine and shallow marine sequences deposited

---

✉ Moamen Ali
   momen.mohamed@science.au.edu.eg

[1] Geology Department, Assiut University, Assiut, Egypt

[2] Geology Department, Cairo University, Cairo, Egypt
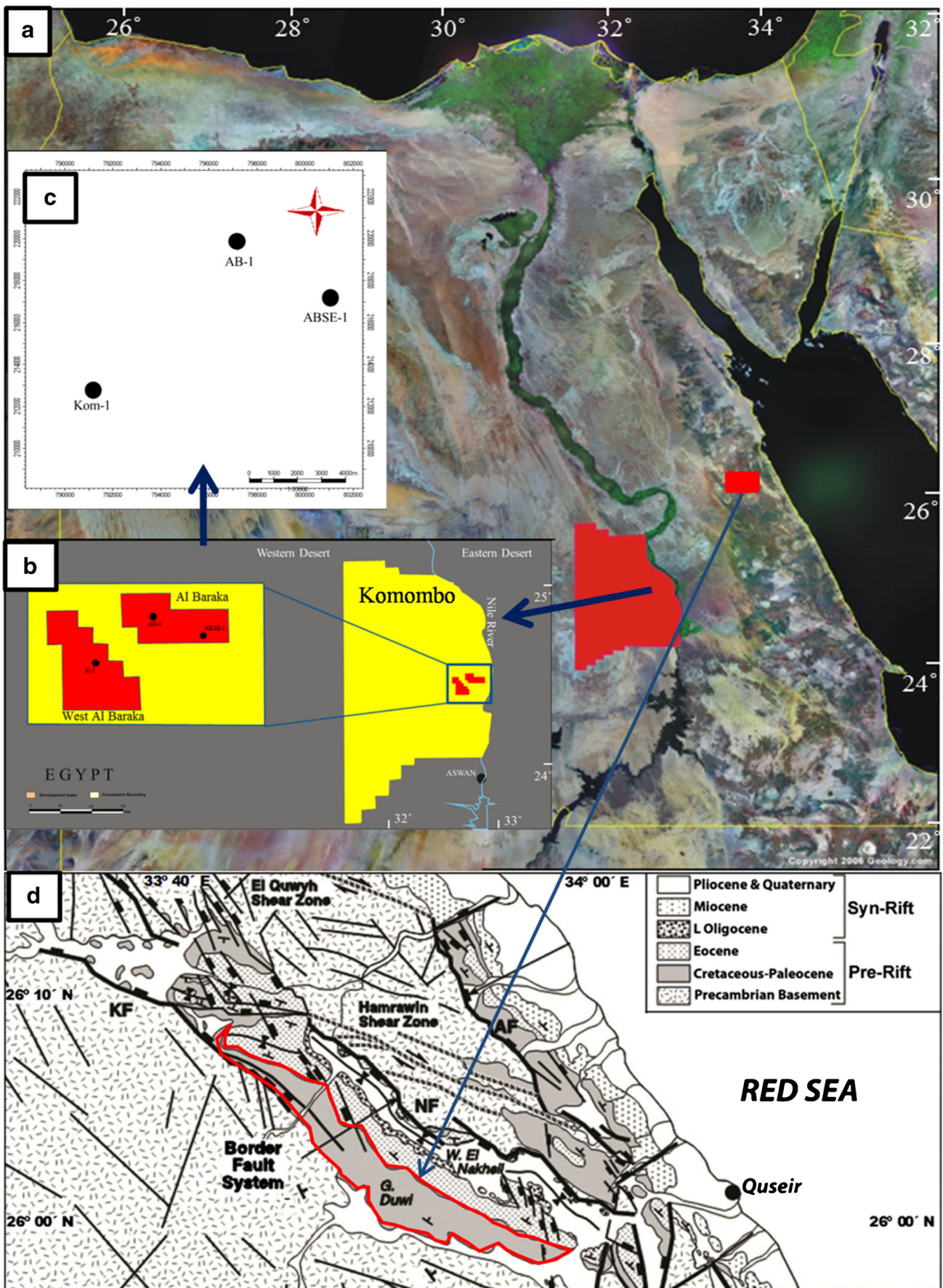
[3] DEA Company, Cairo, Egypt

**◄ Fig. 1** **a** Landsat map showing the study area within Gebel Duwi and Komombo Basin, southern Egypt (Ali et al. 2017b). **b, c** Base maps showing the location of the used boreholes. **d** Geologic map shows the stratigraphic units of the Gebel Duwi (modified after Khalil and McClay (2002))

during the Cretaceous period (Abdelhady et al. 2016). The stratigraphic succession is composed of seven formations from bottom to top, and these are the Six Hills, Abu Ballas, Sabaya, Maghrabi, Taref, Quseir, and Dakhla Formations (Fig. 3). In this regard, Selim (2016) indicated that the Dakhla Formation is representative of an open marine system. This formation is mainly composed of grey to dark grey, altered laminated shale with some siltstone and sandstone interbeds (Fig. 4a, b). Awad and Ghobrial (1965) classified this formation into 3 members from top to base: Kharga shale member, Baris Oyster mudstone member, and Mawhoob shale member, with total thickness at the type section of approximately 700 ft.

The areal distribution of the Dakhla Formation is widespread across the central and southern areas of the Eastern and Western Deserts and along the Red Sea coast in downthrown faulted blocks. In the north, the facies changes to limestone and chalks of the Khoman and Sudr formations. To the south of Kharga, the Paleocene is completely or partially replaced by Paleocene limestone (Ammonite Hill member) (Barthel and Herrmann-Degen 1981).

The stratigraphic column of the Komombo Basin contains several shale intervals. According to Ali et al. (2018), the Hauterivian-Early Barremian shale represents the main source

rock in the Komombo Basin. Despite that, the Campanian-Maastrichtian Dakhla Formation (Abu El Ella 2006, 2011) consists mainly of argillaceous limestone, calcareous shale, and shale of marine origin with high-organic contents; therefore, the Dakhla Formation is a promising potential source rock. The thickness of the Dakhla Formation in Komombo ranges between 400 ft in the flank and 800 ft in the depocenter of the basin (Ali 2017). On the other hand, Gebel Duwi is located in the Qusier area of the Eastern Desert, Egypt (Fig. 1c). A detailed stratigraphic description of Gabel Duwi by El-Kammar (2015) mentioned that the maximum thickness of the Dakhla Formation there is 540 ft. El-Kammar et al. (2013) supposed that the Dakhla Formation is Maastrichtian-Early Paleocene and is representative of shallow to deep marine deposits because it contains planktonic and nanoplanktonic foraminifera, dinoflagellates, and palynomorphs. According to Fathy et al. (2018), the $CaCO_3$ content and the carbonate/siliciclastic ratio indicate that the Dakhla Formation oil shales were deposited during a relative sea-level rise in a deep marine setting under a warm/wet climate with an elevated chemical weathering intensity, and these shales consist of two members (Hamama and Beida members) of the Maastrichtian-Paleocene age.

## Data and methods

Fifty-nine ditch samples were analyzed from three wells in various parts of the Komombo Basin to identify the
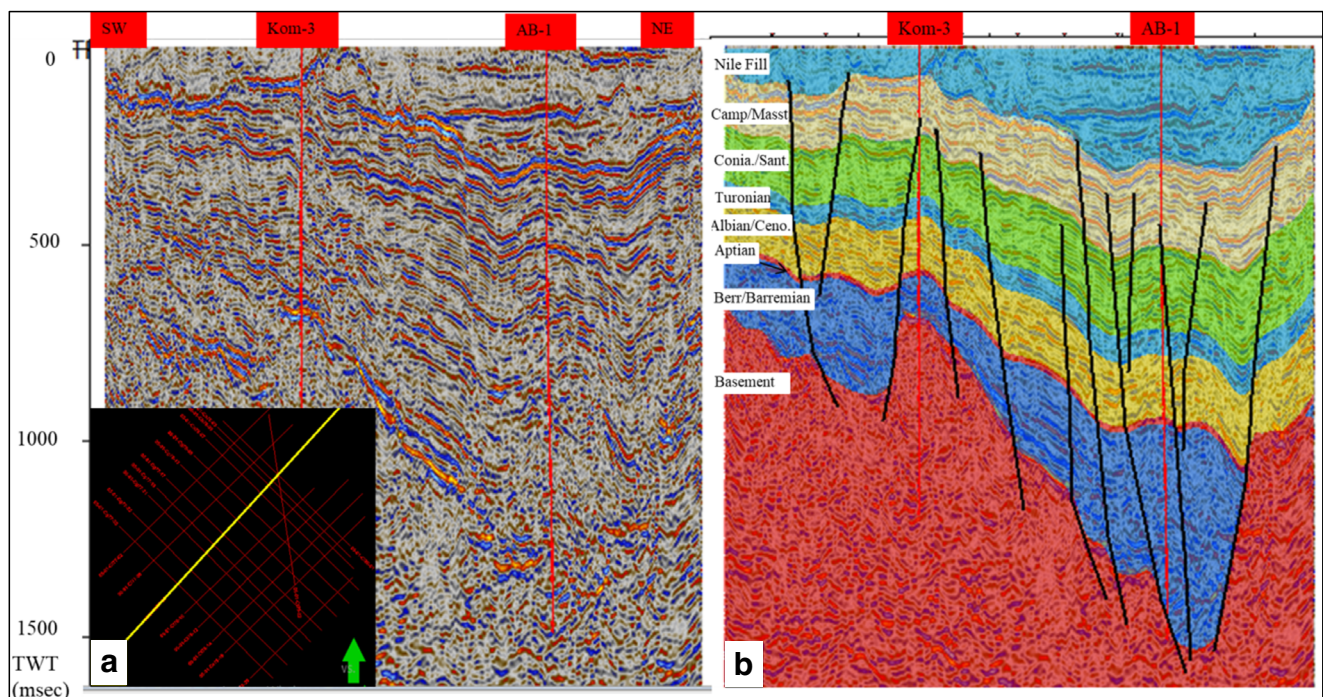


**Fig. 2** **a** Uninterpreted NE-SW 2D seismic section (05-01-Cf77-08) crossing the Komombo basin, Upper Egypt and **b** interpreted NE-SW 2D seismic section showing the half graben basin and the main seismic horizons in the study area (Ali et al. 2019)
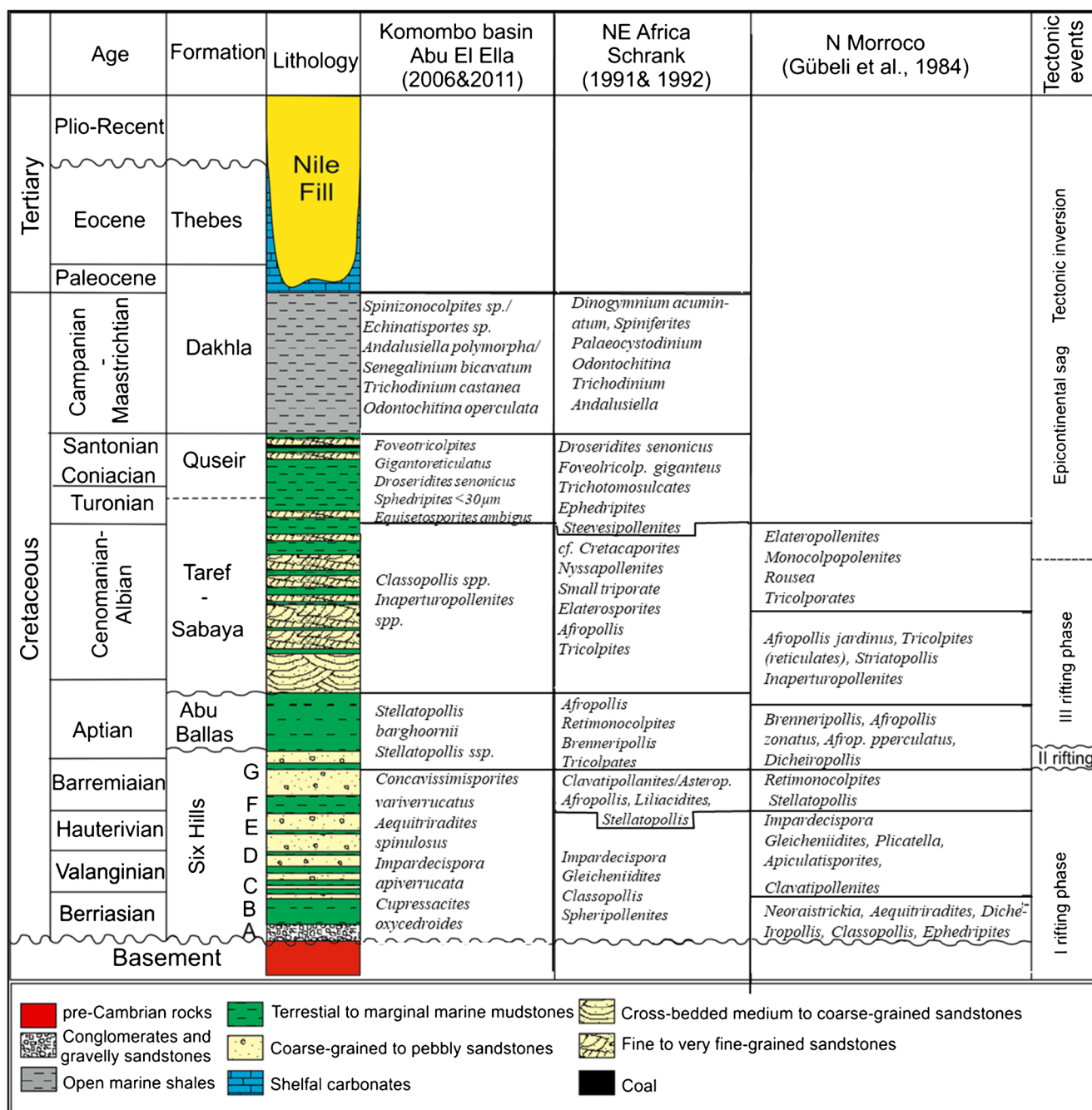
| Age | | Formation | Lithology | Komombo basin Abu El Ella (2006&2011) | NE Africa Schrank (1991& 1992) | N Morroco (Gübeli et al., 1984) | Tectonic events |
|---|---|---|---|---|---|---|---|
| Tertiary | Plio-Recent | | Nile Fill | | | | Tectonic inversion |
| | Eocene | Thebes | Nile Fill | | | | |
| | Paleocene | | | | | | |
| Cretaceous | Campanian - Maastrichtian | Dakhla | | *Spinizonocolpites sp./ Echinatisportes sp. Andalusiella polymorpha/ Senegalinium bicavatum Trichodinium castanea Odontochitina operculata* | *Dinogymnium acuminatum, Spiniferites Palaeocystodinium Odontochitina Trichodinium Andalusiella* | | Epicontinental sag |
| | Santonian Coniacian Turonian | Quseir | | *Foveotricolpites Gigantoreticulatus Droseridites senonicus Sphedripites <30µm Equisetosporites ambigus* | *Droseridites senonicus Foveolricolp. giganteus Trichotomosulcates Ephedripites Steevesipollenites* | | |
| | Cenomanian-Albian | Taref - Sabaya | | *Classopollis spp. Inaperturopollenites spp.* | *cf. Cretacaporites Nyssapollenites Small triporate Elaterosporites Afropollis Tricolpites* | *Elateropollenites Monocolpopolenites Rousea Tricolporates* / *Afropollis jardinus, Tricolpites (reticulates), Striatopollis Inaperturopollenites* | III rifting phase |
| | Aptian | Abu Ballas | | *Stellatopollis barghoornii Stellatopollis ssp.* | *Afropollis Retimonocolpites Brenneripollis Tricolpates* | *Brenneripollis, Afropollis zonatus, Afrop. pperculatus, Dicheiropollis* | II rifting |
| | Barremiaian Hauterivian Valanginian Berriasian | Six Hills (G F E D C B A) | | *Concavissimisporites variverrucatus Aequitriradites spinulosus Impardecispora apiverrucata Cupressacites oxycedroides* | *Clavatipollanites/Asterop. Afropollis, Liliacidites, Stellatopollis, Impardecispora Gleicheniidites Classopollis Spheripollenites* | *Retimonocolpites Stellatopollis* / *Impardecispora Gleicheniidites, Plicatella, Apiculatisporites, Clavatipollenites* / *Neoraistrickia, Aequitriradites, Dicheiropollis, Classopollis, Ephedripites* | I rifting phase |
| Basement | | | | | | | |

Legend: pre-Cambrian rocks; Terrestial to marginal marine mudstones; Cross-bedded medium to coarse-grained sandstones; Conglomerates and gravelly sandstones; Coarse-grained to pebbly sandstones; Fine to very fine-grained sandstones; Open marine shales; Shelfal carbonates; Coal

**Fig. 3** Stratigraphic chart of the Komombo Basin showing that the stratigraphic succession is representative of non-marine and shallow marine deposits are during Cretaceous (Berriasian-Maastrichtian) (Selim 2016)

geochemical characteristics of the Dakhla source rock. The Kom-3 well is located on the western flank, and wells AB-1 and ABSE-1 are located in the depocenter of the Komombo Basin (Figs. 1b, c and 2). The ditch samples were analyzed by Vinci Technologies Rock-Eval 6 Turbo apparatus and a Leco SC 632 instrument (for more details on this method, see Espitalié et al. (1977) and Peters et al. (2005)). The geochemical analyses of the selected samples were performed at the Stratochem Laboratory, Cairo, Egypt. In addition, previously published data from 230 ditch and core samples that were

previously published (El-Kammar 2015; El-Shafeiy et al. 2017; Fathy et al. 2018) for Gebel Duwi in the Qusier area were used for comparison purposes.

The interpretation of source rock parameters and the Rock-Eval pyrolysis data method are discussed in detail by Espitalié (1986), Peters (1986), and Peters and Cassa (1994). The evaluated parameters are S1, S2, S3, the HI, the OI, and the productivity index (PI). On the other side, S1 measures the amount of free hydrocarbons that can be volatilized out of the rock without cracking the kerogen (mg HC/g rock); S1

**Fig. 4** Examples of the Dakhla open marine deposits in Komombo Basin, AB-5 well (Selim 2016)
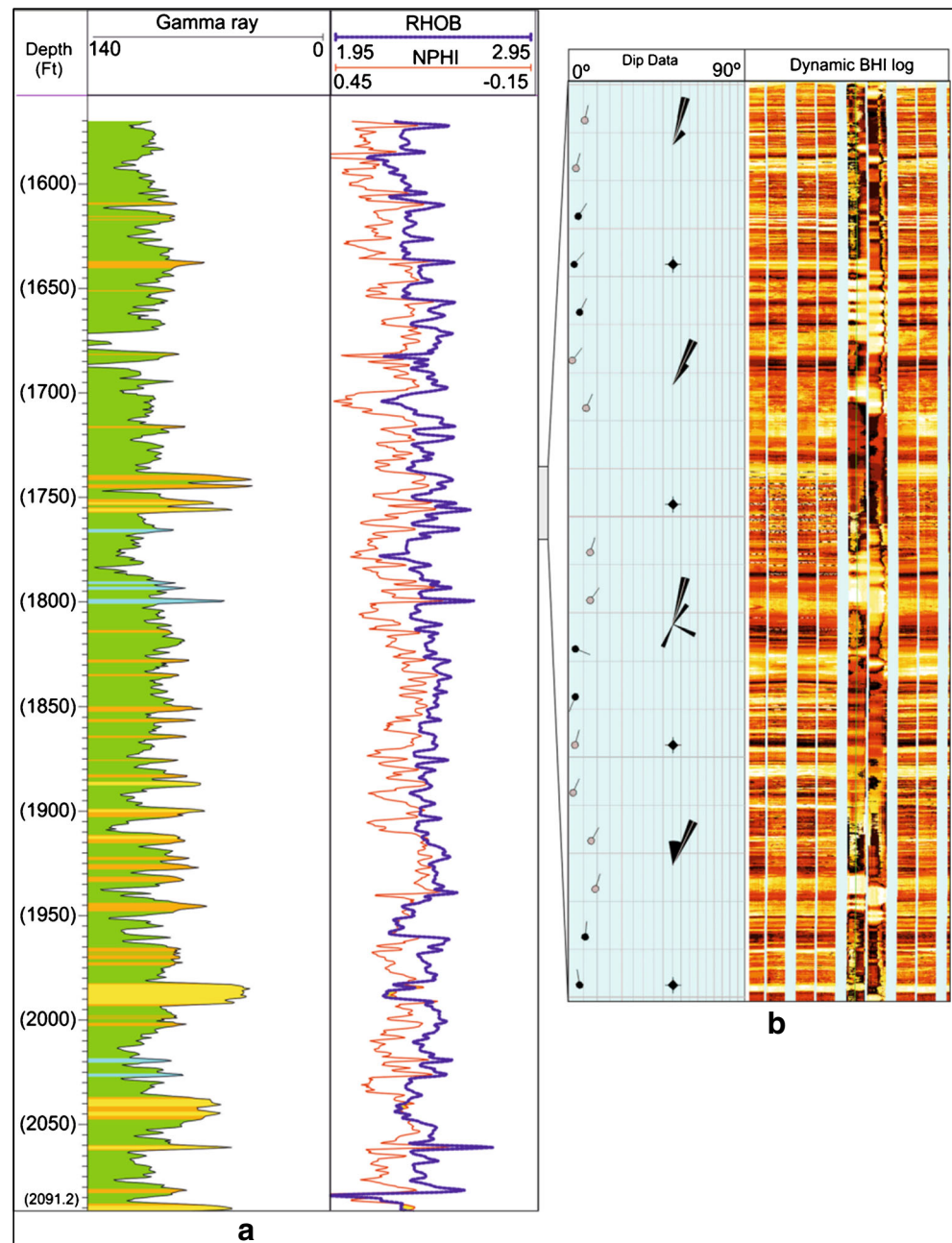


increases at the expense of S2 with maturity. S2 measures the hydrocarbon yield from cracking of kerogen (mg HC/g rock) and is a more realistic measure of source rock potential than TOC because TOC includes "dead carbon" incapable of generating petroleum (Peters and Cassa 1994). S3 represents the amount of generated $CO_2$, and $T_{max}$ (°C) represents the temperature at maximum generation of S2. The HI [HI = (S2/TOC) × 100, mg HC/g TOC] is proportional to the amount of hydrogen in the kerogen and thus indicates the potential of the rock to generate oil. The OI [OI = (S3/TOC) × 100, mg $CO_2$/g TOC] is related to the amount of oxygen in the kerogen. The production or productivity index [PI = S1/(S1 + S2)] gradually increases with depth for fine-grained rocks as

thermally labile components in the kerogen (S2) are converted to free hydrocarbons (S1).

## Results and Discussion

### Organic richness and Rock-Eval Pyrolysis data

The collected and analyzed ditch samples of the Dakhla Formation in the Komombo Basin range from 1900–2700 ft in well AB-1, 1300–2100 ft in well ABSE-1, and 1420–1810 ft in well Kom-3. The organic richness is determined by TOC and S1 + S2 (Waples 1979 and Peters 1986). The TOC and

Rock-Eval pyrolysis data of the Dakhla Formation in the Komombo Basin are summarized in Figs. 6, 7, and 8. The TOC values of the analyzed ditch samples range between 0.46 and 2.66 wt.% (avg. 1.58 wt.%), which is consistent with fair to good source rock for hydrocarbon generation. If S1 + S2 yields are more than 6 mg HC/g rock, then the material represents good to excellent source rock, and values less than 6 mg HC/g rock represent poor to fair source rock (Peters 1986; Peters and Cassa 1994). The S1 + S2 yields range from 1.71 to 6.67 (mg HC/g rock). These data indicate poor to good source rock and are proportioned with TOC values (Figs. 5, 6, and 7).

S1 values in wells AB-1 and ABSE-1 are zero, thus they may indicate that the Dakhla source rock in the Komombo Basin has not reached the mature stage. In contrast, the S1 values in well Kom-3 range from 0.13 to 1.58 (mg HC/g rock); however, well Kom-3 lies in the western flank of the Komombo Basin, not in the depocenter like wells AB-1 and ABSE-1. The S1 yields in well Kom-3 may therefore be concluded to mark oil that migrated from the Hauterivian-early Barremian B member, which represents the main source rock in the Komombo Basin (Ali et al. 2018).

According to El-Kammar (2015), the TOC values of 70 analyzed samples of the Dakhla source rock collected from a tunnel in Gebel Duwi range from 2.03 to 12.07 wt.%, (avg. 4.51 wt.%). The TOC values indicate that the source rock has elevated quantities of organic matter, which is representative of good to excellent source rock. These samples display S1 values ranging from 0.18 to 2.39 mg HC/g rock (avg. 0.58), and S2 yields are in the range of 10–112 mg HC/g rock (avg. 34), indicating good to excellent source rock (El-Kammar 2015; Fathy et al. 2018). El-Shafeiy et al. (2017) interpreted organic-rich core samples of the Dakhla Formation at Gebel Duwi in the Qusier area, which were drilled by the Egyptian Mineral Resources Authority (EMRA); TOC contents range from 2 to 14 wt.%, (avg. 6 wt.%) for the Hamama member and TOC values average 2.4, 4.3, and 2.1 wt.% for the lower, middle, and upper parts of the Bedia member, respectively.

Overall, the source rock quality of the Dakhla Formation varies from fair to good source rock in the Komombo Basin, west of the River Nile (TOC 0.46-2.66 wt.% and S1 + S2 0.62–7.17 mg HC/g rock) and good to excellent source rock in the Qusier area, east of the River Nile (TOC 2.1–14 wt.% and S1 + S2 10.52–58.5 mg HC/g rock). This, in turn, indicates that the productivity (the amount and concentration of organic matter in the sedimentary basin) of the Dakhla Fm. in Gebel Duwi is higher than that in the Komombo Basin because productivity depends on many factors, such as nutrient availability, temperature, light intensity, and general water chemistry (Demaison and Moore 1980; Emerson 1985). Alternatively, the preservation of organic matter (OM) may be another reason, where the resistance of OM to degradation is affected by three factors: (a) the type of OM deposited; (b) the concentration and nature of the oxidizing agent; and (c) the sediment accumulation rate (Emerson 1985).
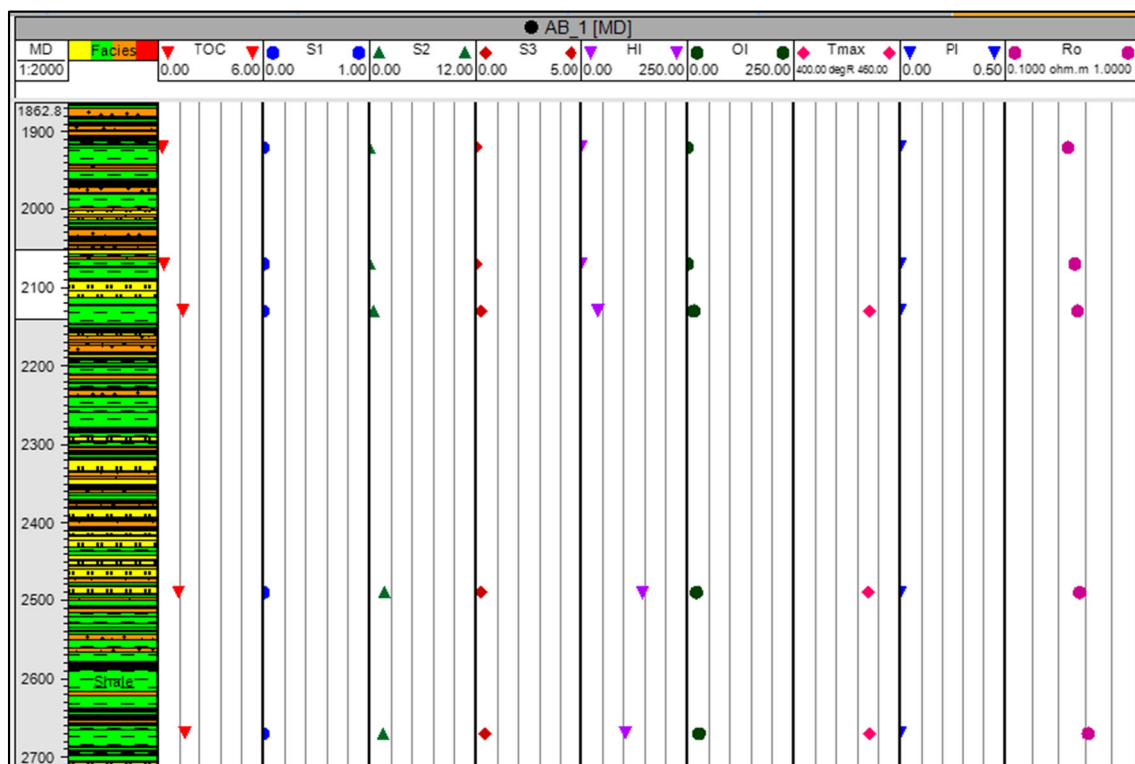


Fig. 5 Lithological and geochemical logs of the Dakhla source rock in AB-1 well, Komombo Basin, showing Rock-Eval pyrolysis data as well as TOC and % Ro values
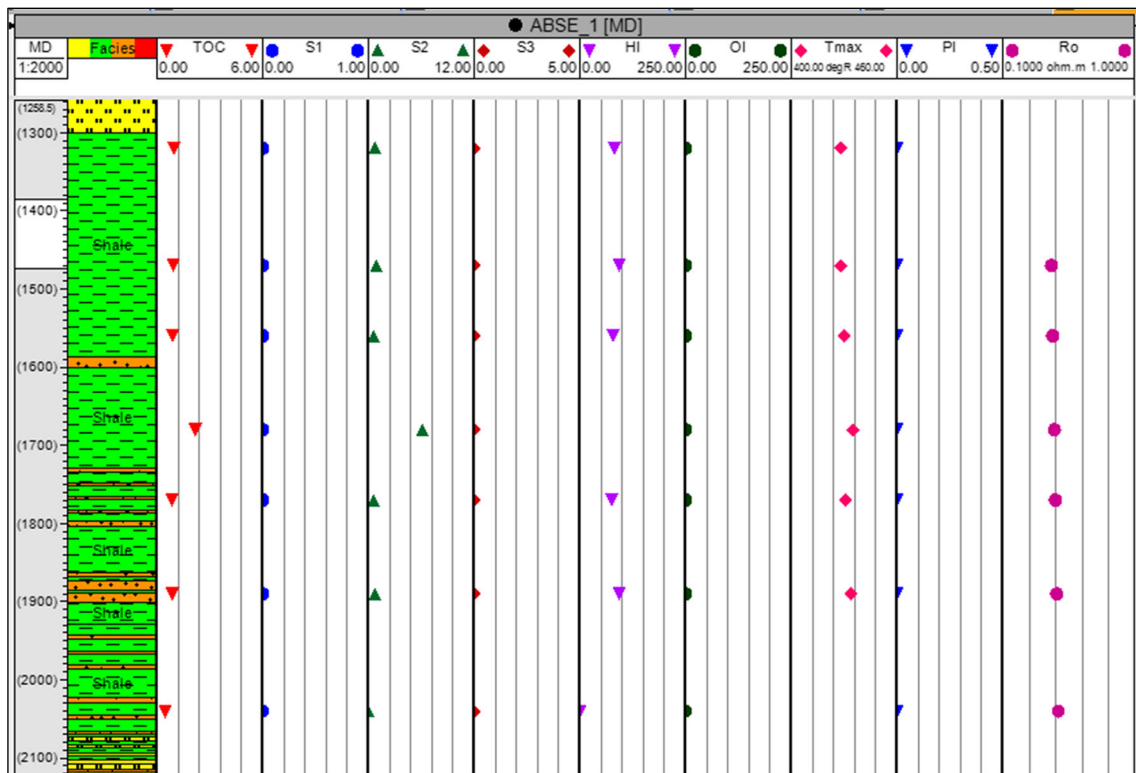
**Fig. 6** Lithological and geochemical logs of the Dakhla source rock in ABSE-1 well, Komombo Basin, showing Rock-Eval pyrolysis data as well as TOC and % Ro values

Therefore, the authors suppose that the OM of the Dakhla Fm. in Gebel Duwi experienced excellent survival and was deposited where anoxia developed in an aqueous environment with high rates of sedimentation because the source rock is oil-prone. On
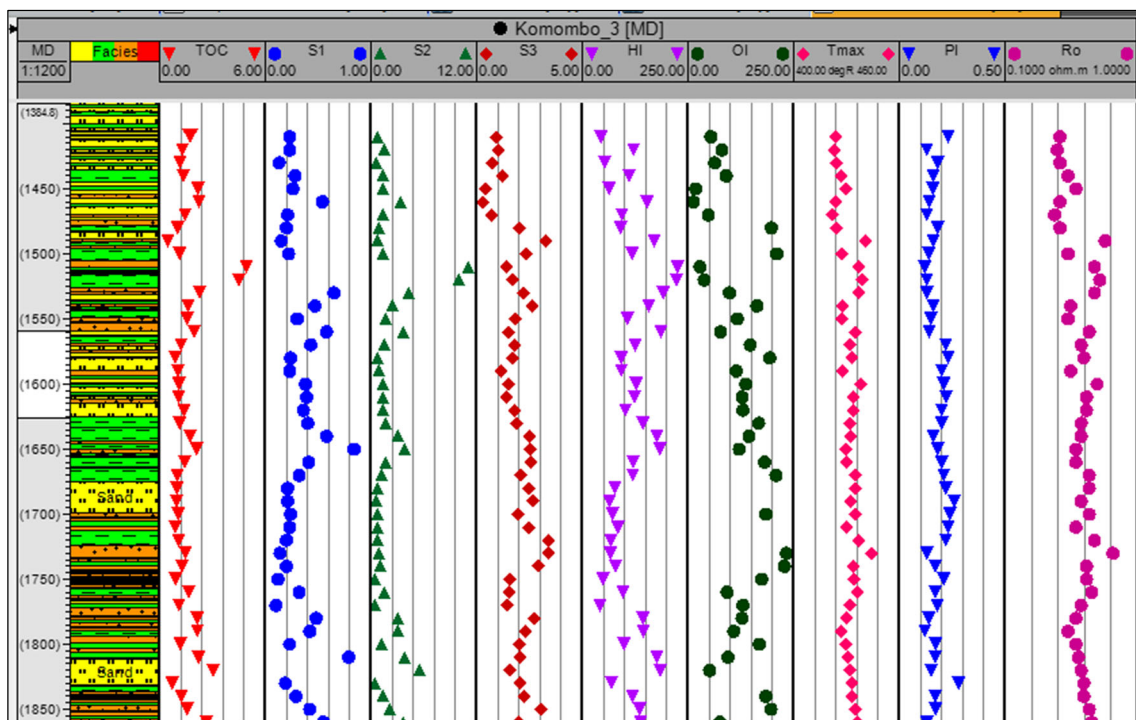


**Fig. 7** Lithological and geochemical logs of the Dakhla source rock in Kom-3 well, Komombo Basin, showing Rock-Eval pyrolysis data as well as TOC and % Ro values

**Table 1** AB-1 and ABSE-1 wells kerogen composition

| Well name | Depth (ft.) | | Organic matter % | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Lipids | | | Humic | | Other | |
| | | | Unstructured | | | | | | |
| | From | To | Undifferentiated | Amorphous | Micrinized | Inertinite | Vitrinite | Type (VR) | Type (VL) |
| AB-1 | 2190 | 2220 | | 20 | | 15 | 10 | 50 | |
| | 2580 | 2610 | 20 | | | 5 | 25 | 50 | |
| ABSE-1 | 1470 | 1500 | 80 | | | 5 | 15 | | |
| | 1680 | 1710 | 50 | | | 10 | 40 | | |

the other hand, the OM of the Dakhla Fm. in the Komombo Basin was deposited in an oxic environment with high sedimentation rates because the source rock is gas-prone.

## Kerogen Type

The kerogen is classified into three major categories: liptinite (exinite), vitrinite, and inertinite, based on physical properties (Stach et al. 1982). Liptinite–exinite components, which are derived from high-lipid organic materials such as pollens, cuticles, spores, phytoplanktonic algae and resins, which are related to Types I and II kerogen (highly oil-prone). Vitrinite is derived from lignified tissues produced from land plants of terrestrial origin, and it is predominately Type III kerogen (gas-prone). Inertinite represents oxidized organic material

with high-carbon content and shows no hydrocarbon potential (Stach et al. 1982; Cornford 1984; Hunt 1996; Miles 1989).

The visual kerogen compositions of the selected samples from wells AB-1 and ABSE-1 (Table 1) are mostly dominated by OM high in undifferentiated and amorphous unstructured lipids (20–80%) and low to medium in vitrinite and recycled vitrinite (15–50%), with small inertinite contents (5–15%). The lipid OM is predominantly amorphous with some structure and terrestrial material. Structured lipids consist mostly of sporinite, suberinite, resinite, and cutinite, thus suggesting a terrestrial origin for most samples (Abdelhady et al. 2016). Therefore, the expected kerogen type of the Dakhla source rock from the coal petrography is Type III (Table 1).

The HI (mg HC/g TOC) is one of the most commonly used parameters to determine that kerogen type (Espitalié et al. 1977). Peters and Cassa (1994) and Petersen and Nytoft

**Fig. 8** Plot of TOC vs S2 values shows Type III kerogen for the Dakhla source rock samples in Komombo Basin (Langford and Blanc-Valleron 1990)
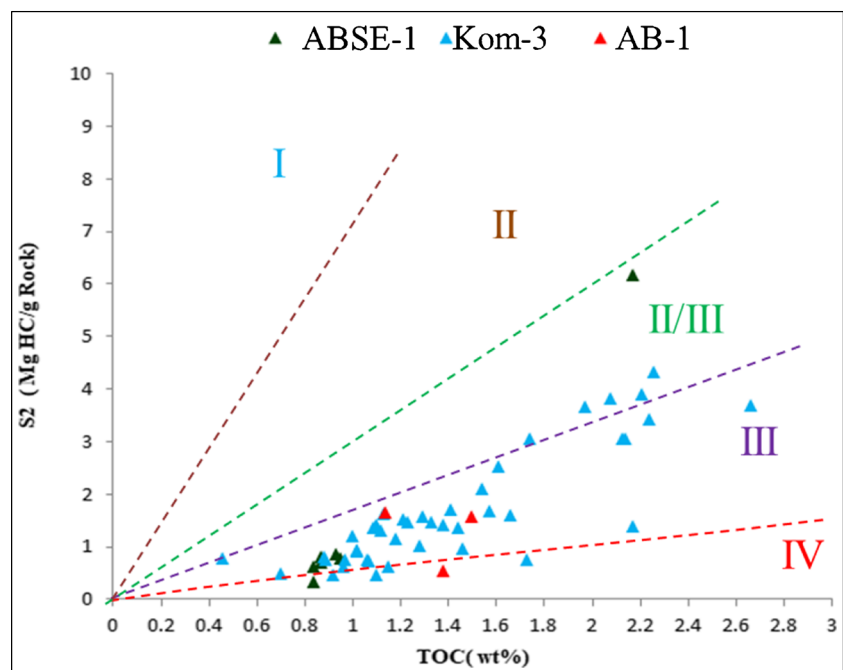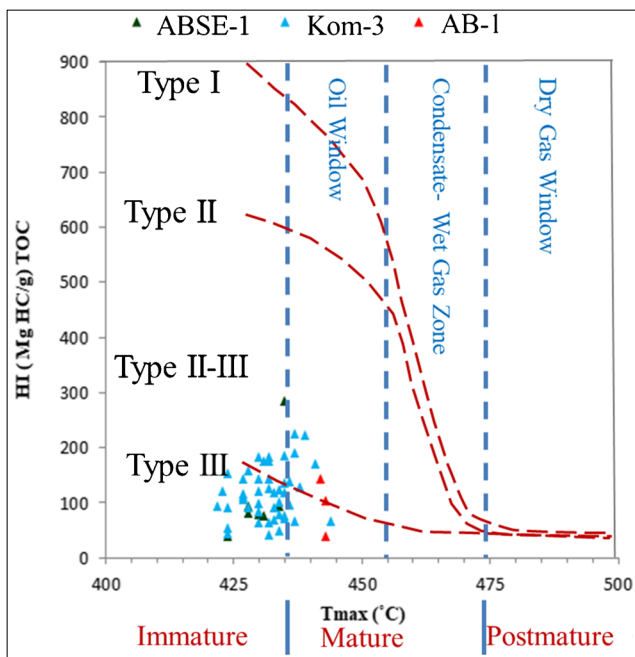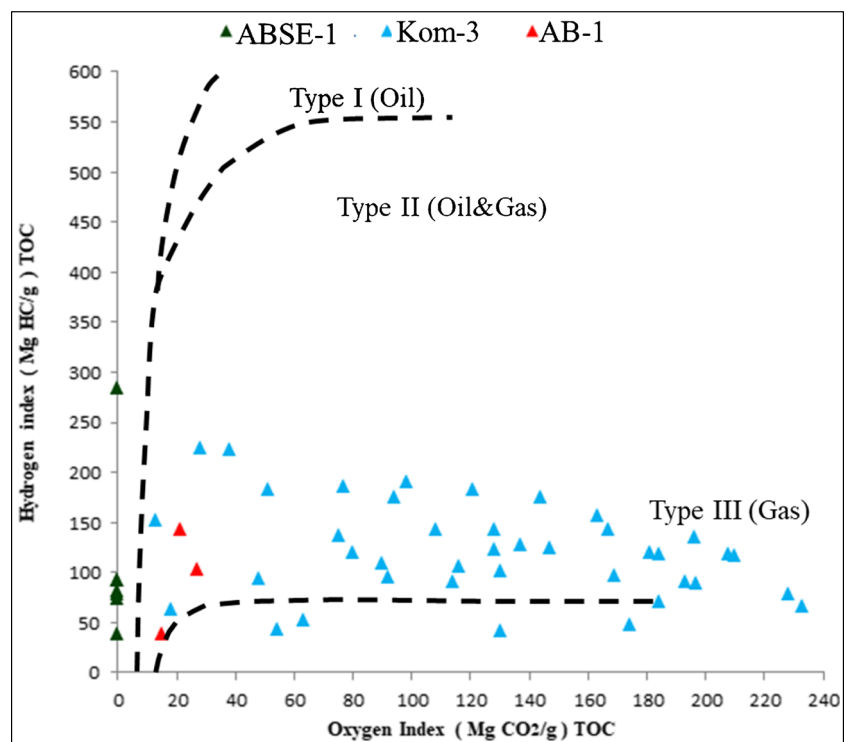
**Fig. 9** Plot of Tmax versus HI shows that the Dakhla Fm. in the Komombo Basin is Type III kerogen and it is immature to early mature stage for oil generation (Espitalié 1986)

(2006) supposed that Type I kerogen (oil-prone) is associated with high HI values > 600 mg HC/g TOC, in contrast with Type II (oil- and gas-prone) with HI values of 350 to 600 mg HC/g TOC; Type III kerogen (gas-prone) is identified by HI values from 50 to 200. Type IV kerogen is associated with low HI less than 50 (Tissot et al. 1974; Demaison et al. 1983). The

HI values of the Dakhla source rock samples in the Komombo Basin range between 40 and 285 (avg. 115 mg HC/g TOC), indicating Type III kerogen. The number of analyzed ditch samples showing Type III kerogen (HI < 200 mg HC/g TOC) was 56 out of a total of 59 samples. The Dakhla Formation is deemed to be Type III kerogen based on the S2 and TOC diagram (Langford and Blanc-Valleron 1990) (Fig. 8). The HI vs. $T_{max}$, HI vs. OI and HI vs. %Ro plots indicate that the kerogen type of the Dakhla source rock is Type III (gas-prone) (Figs. 9, 10, and 11, respectively). Therefore, all plotted data show that the Dakhla source rock of the Komombo Basin is Type III kerogen, and the Dakhla Formation's OM is mostly of terrestrial origin and thus deemed gas-prone.

According to El-Kammar (2015)), the analyzed samples of the Dakhla source rock in Gebel Duwi show HI values ranging from 381 to 1023 mg HC/g TOC (avg. 711 mg HC/g TOC). Fifty samples among 64 analyzed rock samples show Type I kerogen, where HI values are more than 600 mg HC/g TOC. Figure 12 confirms the existence of Types I and I/II kerogen, where HI and OI values are plotted on a modified van Krevelen diagram. El-Shafeiy et al. (2017) confirmed that the kerogen type of the Dakhla Formation is Type II with the exception of the lowermost and middle Hamama member and the middle part of the Beida member that contains Type I kerogen. Therefore, the OM of the Dakhla source rock is mainly of marine origin and thus considered oil-prone with rare gas.
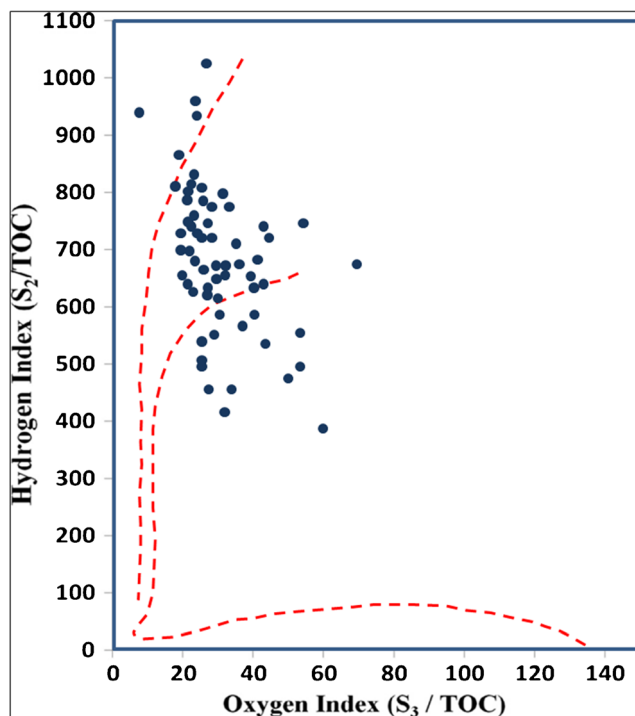
**Fig. 10** HI versus OI cross plots indicate that most of the Dakhla Formation samples in Komombo Basin belong to kerogen Type III (van Krevelen 1961)

**Fig. 11** Plot of Ro% versus HI shows that the Dakhla Fm. in the Komombo Basin is Type III kerogen and it is immature to early mature stage for oil generation (Espitalié 1986)
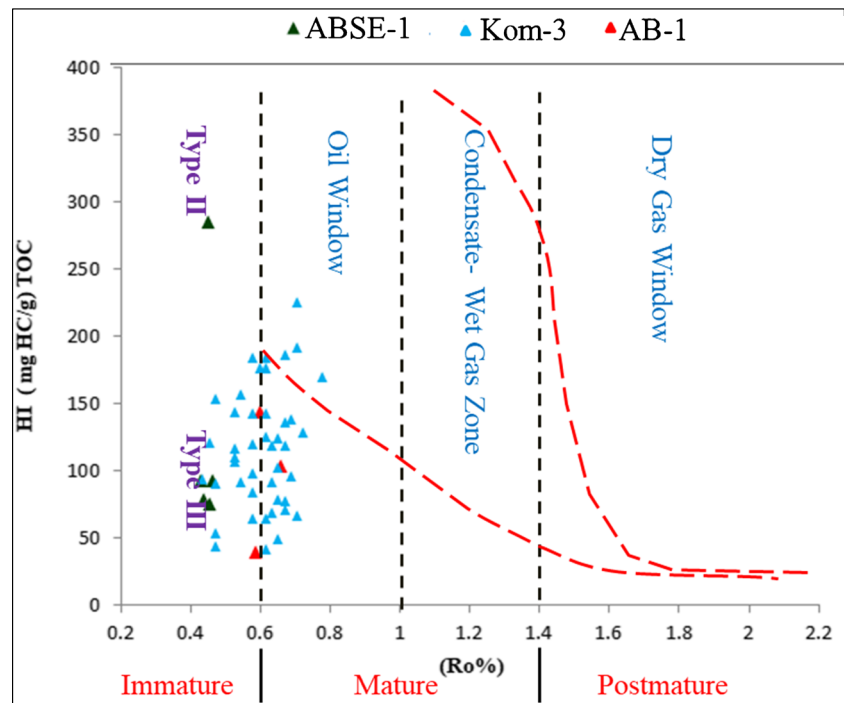


The quality of the Dakhla source rock can be concluded to vary from Type III kerogen in the Komombo Basin to Type I/II kerogen in Gebel Duwi because the OM of the Dakhla source rock in the Komombo Basin is mostly terrestrial in origin, but it is mostly of marine in Gebel Duwi.



**Fig. 12** HI versus OI cross plots indicate that most of the Dakhla Formation samples at Gebel Duwi belong to kerogen I and I/II (van Krevelen 1961)

We believe that the main reason for this situation is that the OM of the Komombo Basin was derived from sources external to the water body (allochthonous) and has high amounts of land plant remains. On the other hand, the OM was produced within the immediate water body (autochthonous) at Gebel Duwi and has high-lipid organic materials such as algae, leaves, spores, and pollen.

## Thermal maturity

$T_{max}$ and vitrinite reflectance (%Ro) data are used to evaluate the thermal maturity level of the Dakhla Formation. $T_{max}$ values less than 435 °C indicate that the kerogen is immature, whereas values greater than 460 °C indicate the end of the oil window and the start of the wet gas zone (Espitalié et al. 1977). Based $T_{max}$ majority of the Dakhla Formation in the Komombo Basin is immature to early mature (Fig. 9), with $T_{max}$ values ranging between 422 and 444 °C. Furthermore, the %Ro values are widely used to establish the level of thermal maturity of source rocks (Dow 1977; Waples et al. 1992). The %Ro is the most reliable maturity parameter for calibrating and measuring the thermal maturity of organic matter (Grassmann et al. 2005). The %Ro values for the Dakhla source rock in the Komombo Basin are in the range from 0.43 to 0.78%Ro. In this regard, Dow (1977) and Senftle and Landis (1991) suggested that when the %Ro values are in a range of 0.6 to 1.35, the source rock is mature. Thus, most of the analyzed ditch samples from the Dakhla source rock in the Komombo area are interpreted to be immature to early mature for hydrocarbon generation (Fig. 11). Figure 13 shows

**Fig. 13** Vitrinite reflectance log of Kom-3 well, showing a positive relationship with depth and the top of the oil window is at approximately 1300 ft
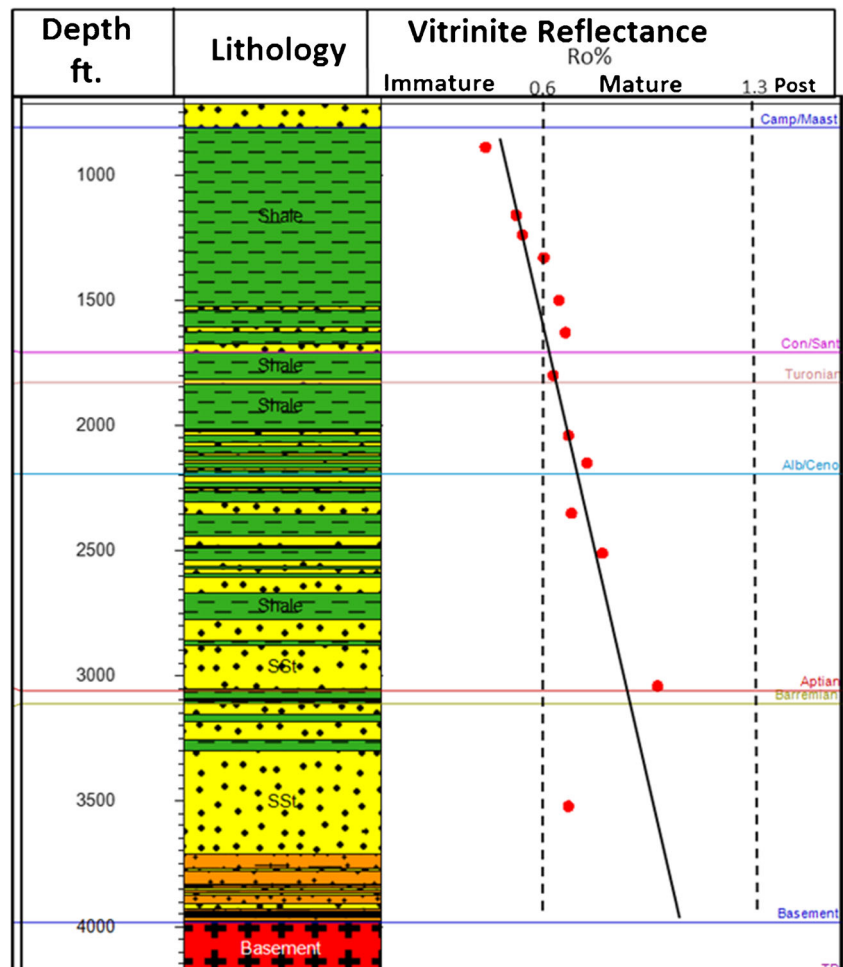


that the %Ro values in well Kom-3 are positively related to depth and show increased maturity with increasing burial depth. Based on this maturity profile, the top of the oil window (defined by 0.6%Ro) should be encountered in the middle of the Campanian-Maastrichtian section at approximately 1300 ft. This result means that the Campanian-Maastrichtian Dakhla Formation consists of immature to early mature source rocks. The $T_{max}$ values of the same source rocks in Gebel Duwi range between 412 and 435 °C, indicating that most of the analyzed rock samples are in the immature to early mature stages.

## Conclusions

The results for rock samples that were collected and analyzed to evaluate the organic geochemical characteristics of the Dakhla source rock in the Komombo Basin and at Gebel Duwi in the Qusier area indicate that the quality of the Dakhla source rock varies from fair to good in the Komombo Basin and from good to excellent at Gebel Duwi. The source rock quality varies from Type III kerogen in the

Komombo Basin to Type I/II kerogen at Gebel Duwi. The OM of the Dakhla Formation in the Komombo Basin is mostly terrestrial in origin, while the OM is mainly of marine origin at Gebel Duwi. The Type III kerogen in the Komombo Basin is considered gas-prone, while the Types I/II kerogens at Gebel Duwi are considered oil-prone with rare gas. Based on the measured %Ro and $T_{max}$ values, the Dakhla Formation is mostly in the immature to early mature stage for hydrocarbon generation in both areas, with the $T_{max}$ values in the Komombo Basin and Gebel Duwi ranging from 422–444 °C and 412–435 °C, respectively. The %Ro values vary between 0.43 and 0.78 in the Komombo Basin. According to the hydrocarbon potential and maturity, the Dakhla source rock can be concluded not to have reached the oil and gas generation window in either area.

# References

Abdelhady A, Darwish M, El Araby A, Hassouba A (2016) Evaluation of Neocomian shale source rock in Komombo Basin, Upper Egypt. Int J Innov Sci Eng Technol 3:376–382

Abu El Ella N (2006) Biostratigraphy and lithostratigraphy of Komombo-1, Komombo-2, Komombo-3, Nuqra-1 and Kharit-1 Wells, Upper Egypt. Earth Resources Exploration (EREX internal report

Abu El Ella N (2011) Biostratigraphic studies for the AlBaraka oil field, Upper Egypt. Earth Resources Exploration (EREX) internal report

Ali M (2017) Tectonostratigraphy and petroleum system analysis of Al Baraka Oil Field, Komombo Basin, South Western Desert, Egypt (Master thesis 1-186)

Ali M, Darwish M, Abdelhady A, Essa MA (2017a) Structural and lithostratigraphic evolution of Al Baraka Oil field, Komombo Basin, Upper Egypt as deduce from 2D seismic lines and well logging data. J Basic Environ Sci 2:149–169. 1

Ali M, Darwish M, Abdelhady A, Essa MA (2017b) Case study of seismic interpretation in in Al Baraka Oil Field, Komombo Basin, Upper Egypt, the fifth international conference for young scientist in basic and applied science

Ali M, Darwish M, Essa MA, Abdelhady A (2018) 2D seismic interpretation and characterization of the Hauterivian–Early Barremian source rock in Al Baraka Oil Field, Komombo Basin, Upper Egypt. J Afr Earth Sci 139:113–119

Ali M, Abdelhady A, Abdelmaksoud A, Darwish M, Essa MA (2019) 3D static modeling and petrographic aspects of the Albian/Cenomanian Reservoir, Komombo Basin, Upper Egypt. Nat Resour Res 28:1–23

Awad GH, Ghobrial MG (1965) Zonal stratigraphy of the Kharga Oasis. Geol Survey Egypt, paper 34, 77 pp

Barthel KW, Herrmann-Degen W (1981) Late Cretaceous and Early Tertiary stratigraphy in the Great Sand Sea and its SE margins (Farafra and Dakhla Oases), SW Desert, Egypt. Mitt Bayer Strrtssl, Palaont Hist Geol 21:141–182

Bosworth W, El-Hawat AS, Helgeson DA, Burke K (2008) Cyrenaican "shock absorber" and associated inversion strain shadow in the collision zone of northeast Africa. Geology 36:695–698

Cornford C (1984) Source rocks and hydrocarbons of the North Sea. In: Glennie KW (ed) Introduction to the Petroleum Geology of the North Sea. Blackwell Scientific Publications, Hoboken, pp 171–204

Demaison GJ, Moore GT (1980) Anoxic environments and oil source bed genesis, vol 64. AAPG Bull, pp 1179–1209

Demaison GJ, Hoick AJJ, Jones RW, Moore GT (1983) Predictive source bed stratigraphy: a guide to regional petroleum occurrence: Proceedings of the 11th World Petroleum Congress. London 2(p): 17–29

Dow WG (1977) Kerogen studies and geological interpretations. J Geochem Explor 7:79–99

El-Kammar AM (2015) Source-rock evaluation of the Dakhla Formation black shale in Gebel Duwi, Quseir area, Egypt. J Afr Earth Sci 104: 19–26

El-Kammar AM, Morsy RS, Sharabi S (2013) Biostratigraphical, petrographical and mineralogical characterization of the Upper Cretaceous–Lower Tertiary sedimentary succession of Wassief area, Red Sea, Egypt. Presented and Abstracted in the Annual Meeting of Geological Society, Cairo.

El-Shafeiy M, Birgel D, El-Kammar A, El-Barkooky A, Wagreich M, Tahoun S, Peckmann J (2017) Integrated palaeo-environmental proxies of the Campanian to Danian organic-rich Quseir section, Egypt. Mar Pet Geol 86:771–786

Emerson S (1985) Organic carbon preservation in marine sediments. In: Sundquist ET, Broecker WS (eds) The carbon cycle and atmospheric OOj: natural variations from Archean to Present: American Geophysical Union, Geophysical Monograph 32, p 78–86

Espitalié J (1986) Use of Tmax as a maturation index for different types of organic matter. Comparison with vitrinite reflectance. In: Burrus J (ed) Thermal Modeling in Sedimentary Basins. Editions Technip, Paris, pp 475–496

Espitalié J, Laporte JL, Madec M, Marquis F, Leplat P, Paulet J, Boutefeu A (1977) Méthode rapide de caracterisation des roches mères de leur potentiel pétrolier et de leur degré d'évolution. Rev Inst Fr Pétrol 32: 23–42

Fathy D, Wagreich M, Gier S, Mohamed RSA, Zaki R, El Nady MM (2018) Maastrichtian oil shale deposition on the southern Tethys margin, Egypt: insights into greenhouse climate and paleoceanography. Palaeogeogr Palaeoclimatol Palaeoecol 505: 18–32

Grassmann S, Cramer B, Delisle G, Messner J (2005) Geological history and petroleum system of the Mittelplate oil field, Northern Germany. J Afr Earth Sci 94:979–989

Gübeli AA, Hochuli PA, Wildi W (1984) Lower Cretaceous turbiditic sediments from the Rif chain (northern Morocco)-palynology, stratigraphy and palaeogeographic setting. Geol Rundsch 73:1081–1114

Hunt JH (1996) Petroleum geochemistry and geology, 2nd edn. Freeman and Company, New York 743p

Khalil SM, McClay KR (2002) Extensional fault-related folding, northwestern Red Sea, Egypt. J. Struct. Geol. 24:743–762

Langford FF, Blanc-Valleron MM (1990) Interpreting Rock-Eval pyrolysis data using graphs of pyrolyzable hydrocarbons versus total organic carbon. AAPG Bull 74:799–804

Miles JA (1989) Illustrated glossary of petroleum geochemistry. Clarendon Press, Oxford 137p

Peters KE (1986) Guidelines for evaluating petroleum source rock using programmed pyrolysis. AAPG Bull 70:318–329

Peters KE, Cassa MR (1994) Applied source rock geochemistry. In: Mogoon LB, Dow WG (eds) the petroleum system-from source to trap, vol 60. American Association of Petroleum Geology, Memoir, Tulsa, pp 93–120

Peters KE, Walters CC, Moldowan JM (2005) The Biomarker Guide, Volume 2: Biomarkers and isotopes in the petroleum exploration and Earth history. Cambridge University Press, Cambridge

Petersen HI, Nytoft HP (2006) Oil generation capacity of coals as a function of coal age and aliphatic structure. Org Geochem 37:558–583

Schrank E (1991) Mesozoic palynology and continental sediments in NE Africa (Egypt and Sudan)—a review. J Afr Earth Sci 12:363–373

Schrank E (1992) Nonmarine Cretaceous correlations in Egypt and northern Sudan: palynological and palaeobotanical evidence. Cretac Res 13:351–368

Selim SS (2016) A new tectono-sedimentary model for Cretaceous mixed nonmarine–marine oil-prone Komombo Rift, South Egypt. Int J Earth Sci Geol Rundsch (2016):105

Senftle JT, Landis CR (1991) Vitrinite reflectance as a tool to assess thermal maturity. In: Merrill RK (ed) Source and migration processes and evaluation techniques: AAPG Treatise of Petroleum Geology, Handbook of Pet Geol, p 119–125

Stach E, Mackowshy MT, Teichmuller M, Taylor GH, Chandra D, Teichmuller R (1982) Stach's textbook of coal petrology, 3rd edn. Bebruder Bornotraeger, Berlin 428p

Tissot BP, Durand B, Espitalie J, Combaz A (1974) Influence of the nature and diagenesis of organic matter in formation of petroleum, vol 58. AAPG Bull, pp 499–506

van Krevelen DW (1961) Coal: typology-chemistry-physics-constitution. Elsevier Science, Amsterdam

Waples DW (1979) Simple method for oil source bed evaluation. AAPG Bull 63:239–245

Waples DW, Kamata H, Suizu M (1992) The art of maturity modeling: Part 1. Finding a satisfactory geological model. Am Assoc Pet Geol Bull 76:31–46

Ziegler PA (1992) Geodynamics of rifting and implications for hydrocarbon habitat. Tectonophysics 215:221–253.5