Upper Jurassic source rocks in the Sab’atayn Basin, Yemen:
Depositional environment, source potential and hydrocarbon generation

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ABSTRACT

The Sab’atayn Basin is a major hydrocarbon province in Yemen. Important source rocks occur in Upper Jurassic units (Lam Member of the Madbi Formation, Sab’atayn Formation). Depositional environment, source potential and maturity of the source rocks were investigated using 60 cuttings samples from the Tagina South-1 Well. All samples were analysed for bulk parameters (total organic carbon (TOC), carbonate, sulphur, RockEval). A subset of samples was selected for biomarker analysis, pyrolysis-gas chromatography and isotope investigations.

A carbonate-rich, euhaline, dysoxic to anoxic environment prevailed during deposition of the Lam Member. Bituminous shales within the overlying Sab’atayn Formation formed in a hypersaline, strictly anoxic depositional setting. Changes in the phytoplankton communities coincide with the outlined changes in the water body. Upward decreasing δ13C values suggest changes in carbon cycling due to changing redox conditions.

The Lam Member, at least 500 m thick, is a good to very good source rock with an average TOC of 2.2%. The hydrogen index is controlled by maturity, but reaches 300 mg HC/g TOC in samples with low maturity (type II-III kerogen). The Lam Member produces sulphur-poor, paraffinic-naphthenic-aromatic low-wax oil. Bituminous shales in the Sab’atayn Formation contain up to 11% TOC and a type II (to III) kerogen (HI: up to 427 mg HC/g TOC). These shales are excellent sources for oil (and gas), but their source potential is limited by their relatively low thickness. Both, bituminous shales in the Sab’atayn Formation and the Lam Member are mature. The maturity of the deepest drilled part of the Lam Member is close to the zone of main oil generation. Numeric models show that Cenozoic heat flow is about 50 mW/m². An increase in heat flow during Jurassic rifting is likely, but cannot be quantified. Major hydrocarbon generation occurred during Eocene–Oligocene times (assuming a Late Cretaceous heat flow of 50 mW/m²) or during both, Late Cretaceous and Eocene–Oligocene times (assuming a Late Cretaceous heat flow of 68 mW/m²).

INTRODUCTION

The NW-trending Sab’atayn Basin is a major hydrocarbon province in western Yemen. It is located within the southwestern portion of the Arabian Peninsula (Figure 1). The first commercial field was discovered in 1984 (Ahlbrandt, 2002), but the understanding of the geological evolution of the basin increased significantly only during the 1990s (e.g. Redfern and Jones, 1995; Beydoun, 1997; Beydoun et al., 1998; Brannan et al., 1999). Today it is generally accepted that most of the hydrocarbons are generated from the Upper Jurassic Madbi Formation including the lower Meem and the upper Lam members (Figure 2). Bituminous shales interlayered into evaporitic rocks of the Sab’atayn Formation are considered of secondary importance.

The Tagina South-1 Well, drilled in 2009/10 is located in the southeastern part of the Sab’atayn Basin (Figure 1) at an elevation of about 1,200 m. It offers a great opportunity to study both the bituminous shales within the Sab’atayn Formation and 500 m of the Lam Member (Figure 2).
contribution, organic geochemical techniques are used to study the depositional environment, source potential and maturity of both source rock units. A numerical modelling approach is used to reconstruct paleo-heat flow and the timing of hydrocarbon generation.

GEOLOGICAL SETTING

The NW-trending Sab’atayn Basin (also called Marib-Shabwa-Hajar Basin) is a Mesozoic rift basin in the Arabian Peninsula that follows a deep-seated Proterozoic structural trend (Redfern and Jones, 1995). Basin formation was a consequence of an extensional phase related to the separation of India from Africa-Arabia (Redfern and Jones, 1995; Ziegler, 2001). The stratigraphic subdivision of the basin fill according to Beydoun et al. (1998) is displayed in Figure 2.

Pre-rift deposits are represented by non-marine to shallow-marine clastic rocks (Kuhlan Formation; Beydoun et al., 1998) overlain by shallow-marine carbonates (Shuqra Formation). A latest Triassic to Middle Jurassic age is generally accepted for both formations (see also Al-Wosabi and Wasel, 2011), but Stephenson and Al-Mashaikie (2011) provide evidence for a Late Carboniferous age for the lower part of the Kuhlan Formation.

Late Jurassic (Kimmeridgian–Tithonian) rifting resulted in deposition of the Madbi Formation exceeding 1,500 m in thickness (Worden, 1995, in Seaborne, 1996). It comprises muddy limestones and chalks with shaly horizons. An occasional rich, but low-diversity nanofossil/dinocyst assemblage supports a relatively deep, partly restricted environment (Brannan et al., 1999). Beydoun et al. (1998) subdivide the Madbi Formation into a lower Meem Member and an upper Lam Member. Simultaneously continental sediments filled the grabens along rift margins.

During late stages of the syn-rift phase, ocean circulation in the Sab’atayn Basin became restricted, and an evaporitic succession (Sab’atayn Formation) with an estimated original thickness of about 300 m was deposited (Seaborne, 1996). Massive halite occurs in the basin center, whereas anhydrite
and clastic rocks prevail along the basin margins (Seaborne, 1996). Interbedded thin shales are rich in organic matter (Brannan et al., 1999). The present thickness of the Sab’atayn Formation is strongly controlled by salt tectonics.

The transition to the post-rift stage is represented by shallow-marine limestones (Naifa Formation) and clastic rocks (Sa’ar Formation). A major depositional hiatus occurs at the top of the Sa’ar Formation. Seaborne (1996) speculates that the cause of the hiatus was either a sea-level fall, or gentle uplift associated with rifiting which was occurring to the south and east in the Balhaf Graben and the Say’un-Al Masilah Basin, respectively.
The Qishn Formation (Hauterivian to Late Aptian–Early Albian) comprising the Qishn Clastics Member and the Qishn Carbonates Member is the lowermost unit of the Tawilah Group. Leckie and Rumpel (2003) studied the Qishn Formation in the Say’un-Al Masilah Basin and proposed deposition in tidal estuarine, non-marine, coastal plain and shelf environments. Continental clastics (Harshyat and Mukalla formations) were deposited during Albian and Late Cretaceous times. The total thickness of the Tawilah Group reaches 1,500 m (Seaborne, 1996).

The Hadramawt Group of Paleocene to Middle Eocene age is up to 1,770 m thick (Watchorn et al., 1998). It comprises from bottom to top shelf carbonates (Umm Er Radhuma Formation), marine shales and limestones (Jiza Formation), 300-m-thick gypsum deposited in a sabkha environment (Rus Formation), platform carbonates (Habishiya Formation), and thin sandstones (Watchorn et al., 1998).

Salt Tectonics and Basin Uplift

Although salt movement started as early as Early Cretaceous (Berriasian–Valanginian), salt structures mainly evolved along Paleogene faults (Seaborne, 1996; Csato, 2005). Maximum burial in the Sab’atayn Basin occurred probably during Eocene time (Worden, 2006). Geological evidence including fission track data (Menzies et al., 1997; Watchorn et al., 1998) constrain the uplift and erosion history of the Yemen margin of the Gulf of Aden and the adjacent southeastern part of the Sab’atayn Basin. According to these results minor uplift (no erosion?) occurred between ca. 40 and 31 Ma. A major uplift phase causing erosion and cooling occurred between ca. 25 and 20 Ma. Shale compaction and vitrinite reflectance studies suggest that approximately 400 m of upper Tawilah and younger section have been eroded in the central part of the Sab’atayn Basin (Seaborne, 1996).

Petroleum System

Ahlbrandt (2002) defined the Madbi Amran/Qishn Petroleum System of the Sab’atayn and Masila-Jeza basins. It is based on source rocks in the Upper Jurassic Madbi Formation (Brannan et al., 1999; Hakimi et al., 2011). In the Sab’atayn Basin shaly horizons contain 2% to 5% TOC and Hydrogen Index (HI) values up to 580 mg HC/g TOC (Brannan et al., 1999). These authors also refer to a hot shale (up to 12% TOC; HI > 300) forming the top of the Shuqra Formation in the central Sab’atayn Basin. However, according to Ahlbrandt (2002) these shales are likely part of the overlying Madbi Formation. Shales rich in organic matter (5–15% TOC; HI > 600) also occur within the Sab’atayn Formation (Brannan et al., 1999).

Reservoir horizons in the Sab’atayn Basin occur in the upper part of the Amran Group. They are subdivided into clastic deposits beneath the Sab’atayn salt deposited along the graben margins or as turbidites in the depocenters and coarse clastic units deposited along the basin margins during salt accumulation. The latter are the main reservoirs. The main seal for all reservoirs is provided by the evaporitic rocks. The API gravity of the oil accumulated in Jurassic reservoirs ranges from 29° to 35°, sulphur content from 0.09% to 0.59%, and pristane/phytane ratios from 1.46 to 1.72. Biodegradation is suspected in a seep sample characterized by low API gravity (14°), high sulphur content, and low pristane/phytane ratio of 0.3 (Ahlbrandt, 2002). The Qishn Formation is the main reservoir outside the Sab’atayn Basin where Upper Jurassic salt is absent (Leckie and Rumpel, 2003). Oil generation probably commenced during Late Cretaceous time.

SAMPLES AND METHODS

The well-path of the Tagina South-1 Well is S-shaped. Therefore, measured depth (MD) and true vertical depth (TVD) differ significantly. In this paper all depths are given as TVD. Washed and dried cuttings samples from the depth interval from 1,870 to 4,283 m have been provided by OMV. The sample interval is typically 5 or 2 m. In order to obtain a continuous and representative record, the cuttings samples from the Lam Member have been combined and typically represent a 10 m depth interval. Only in the case of obvious contamination with cavings (samples near the top of the Lam Member) or cement fragments, samples from the Lam Member have been hand-picked. In contrast, all
Sab’atayn samples have been hand-picked in order to focus on thin shaly layers within the evaporitic succession. In the case of some samples, hand-picking did not yield enough material for biomarker analysis.

A total of 60 samples were analysed for total sulphur (S), total carbon (TC), and total organic carbon (TOC, after acidification of samples to remove carbonate) using a Leco CS-300 analyser. TC and TOC contents were used to calculate calcite equivalent (calcite equ. = [TC-TOC]*8.34).

Pyrolysis measurements were performed using a “Rock-Eval 2+” instrument. The S1 and S2 peaks (mg HC/g rock) were used to calculate the Petroleum Potential (PP = S1+S2 [mg HC/g rock], the Hydrogen Index (HI = S2 x 100/TOC [mg HC/g TOC]) and the Production Index [PI = S1/(S1+S2)], (Espitalié et al., 1977). Tmax was measured as a maturation indicator.

For microscopic analysis polished blocks were prepared and mean random vitrinite reflectance (%Rr) was determined using a Leitz microscope and following established procedures (Taylor et al., 1998). Maceral composition was assessed semi-quantitatively using white-light and blue-light irradiation.

Twelve samples were selected for organic geochemical analyses. Representative portions of these samples were extracted for about one hour using dichloromethane in a Dionex ASE 200 accelerated solvent extractor at 75°C and 50 bar. Asphaltenes were precipitated from a hexane-dichloromethane solution (80:1 according to volume) and separated by centrifugation. The hexane-soluble fractions were separated into saturated and aromatic hydrocarbons and NSO compounds using medium-pressure liquid chromatography with a Köhnen-Willsch instrument (Radke et al., 1980).

The hydrocarbon fractions were analysed by a gas chromatograph equipped with a 30 m DB-5MS fused silica capillary column (i.e. 0.25 mm; 0.25 µm film thickness) coupled to a Finnigan MAT GCQ ion trap mass spectrometer. The oven temperature was programmed from 70° to 300°C at 4°C/min, followed by an isothermal period of 15 min. Helium was used as carrier gas. The mass spectrometer was operated in the EI (electron ionisation) mode over a scan range from m/z 50 to m/z 650 (0.7 s total scan time). Individual compounds were identified on the basis of retention time in the total ion current chromatogram and comparison of the mass spectra with published data. Absolute concentrations of different compound groups were calculated using peak areas from the gas chromatograms in relation to those of internal standards (deuteriated n-tetracosane and 1,1’-binaphthyl). The concentrations were normalized to TOC.

Carbon-isotope measurements of individual compounds were performed using a Trace GC Ultra attached to a Delta V isotope ratio (ir) MS (Thermoquest, Finnigan) via a combustion interface (GC Isolink, Finnigan). For calibration, a CO2 standard was injected at the beginning and at the end of each analysis. The GC coupled to (ir) MS was equipped with the column described above and the temperature programme was the same as for GC-MS analysis. Isotopic compositions are reported in the δ notation relative to the PDB standard. The reproducibility of the total analytical procedure is in the range of 0.1– 0.2‰.

Five samples from the Lam Member were investigated using pyrolysis gas chromatography applying a Quantum MSSV-2 Thermal Analysis System©. The thermally extracted (300°C 10 minutes) sample was heated in a flow of helium, and products released over the temperature range 300–600°C (40 K/min) were focussed using a cryogenic trap, and then analysed using a 50 x 0.32 mm BP-1 capillary column equipped with a flame ionisation detector. The GC oven temperature was programmed from 40°C to 320°C at 8°C/minute. Boiling ranges (C₁, C₆-C₁₄ and C₁₅+) and individual compounds (n-alkenes, n-alkanes, alkylaromatic hydrocarbons and alkylthiophenes) were quantified by external standardisation using n-butane. Response factors for all compounds were assumed the same, except for methane whose response factor was 1.1.

1-D and 2-D petroleum system modelling software (PetroMod of IES, Schlumberger) was used to reconstruct paleo-heat flow and the timing of hydrocarbon generation.
Figure 3: Bulk geochemical data in the Lam Member and the Sab’atayn Formation of Tagina South-1 Well. Dolomite and calcite contents of cuttings samples have been measured at the well site using volumetric techniques.
LITHOSTRATIGRAPHY OF TAGINA SOUTH-1 WELL

The exploration Tagina South-1 Well was drilled in the rugged mountainous area of the southern Sab’atayn Basin (Hajr Sector), penetrating sediments from the Eocene to the Jurassic. Total depth (4,283 m) was reached after penetrating a 500-m-thick succession composed of dark argillaceous limestone grading into calcareous claystone (Lam Member). Carbonate contents vary in the Lam Member between 39% and 74% and reach maxima near its top (Figure 3).

The Lam Member is overlain by evaporites of the Sab’atayn Formation (3,783–1,924 m). The abnormally great thickness in Tagina South-1 reflects halokinesis. The Sab’atayn Formation is composed nearly exclusively of halite, but its lower portion (3,620–2,838 m) is lithologically more diverse and includes limestone, anhydrite and bituminous shale (Figure 3). Although the thickness of single dark-grey and black claystone beds rarely exceeds 2 m, their total net thickness is significant and in the order of 75 m. Very rare light grey claystone layers, typically less than 1 m thick (maximum 2 m), and some polyhalite occur in the upper part of the Sab’atayn Formation.

Because the Naifa Formation is missing in Tagina South-1, the Sa’ar Formation (sandstone, varicoloured claystone, minor limestone) overlies the Sab’atayn Formation unconformably with a thickness of 58 m.

The Qishn Formation (Tawilah Group), 50 m thick, follows above a regional unconformity. The Qishn Clastics Member (sandstone with minor claystone) and the overlying Qishn Carbonates Member (alternation of limestone and claystone) are 12 m and 38 m thick, respectively. The Harshiyat Formation, 448 m thick, and the Mukalla Formation, 1,076 m thick, are formed by sandstone with shale interlayers. The top of the Tawilah Group is formed by the Sharwayn Formation. In Tagina South-1 the Sharwayn Formation is only 13 m thick and consists of shale with limestone and dolomite layers.

The uppermost preserved unit in Tagina South-1 is the 269-m-thick Paleogene Umm Er Radhuma Formation. It is dominated by limestone with occasional dolomite and shale layers.

BULK DATA

Amount and Type of Organic Matter

Lam Member

TOC contents within the Lam Member range from 0.91% to 4.55% and are negatively correlated with carbonate contents (Figures 3 and 4a). This correlation suggests that non-calcareous shale layers have a theoretical TOC between 7.5% and 8.0% (Figure 4a). The average (present-day) TOC content of the entire 500 m thick succession is 2.2%. The sulphur content increases with increasing TOC contents (Figure 4b). The resulting TOC/S ratios are below 2.8 (Figure 3) and suggest an oxygen-deficient depositional environment (Berner, 1984).

The HI varies from 146 to 309 mg HC/g TOC and displays clear depth trends (Figure 3). The average HI is 262 mg HC/g TOC in the depth interval from 3,805 to 3,830 m, but only 223 mg HC/g TOC between 3,850 and 3,925 m. Maximum HI values (> 300 mg HC/g TOC) are restricted to the depth interval between 3,934 and 3,964 m and decrease gradually below 3,965 m from 300 to 150 mg HC/g TOC. The downward decrease in HI probably reflects increasing maturity (see below). The HI value of shallow samples indicates the presence of type II-(III) kerogen. Microscopic investigations show that vitrinite particles are very rare. This suggests that the observed kerogen type is rather due to the degradation of marine organic matter than due to a significant admixture of terrestrial organic matter.

Sab’atayn Formation

TOC contents of bituminous shales from the lower portion of the Sab’atayn Formation (3,620–2,838 m) are very high (1.9–11.4%; Figure 3) and negatively correlated with the carbonate content (Figure 4a).
HI values range from 133–427 mg HC/g TOC; (Figure 3) indicating the presence of a type II (to III) kerogen. In contrast, the TOC content of a shaly layer in the upper portion of the Sab’atayn Formation (ca. 2,100 m depth) is low (0.58% TOC).

TOC/S ratios are generally below 2.8 typical for marine, oxygen deficient environments. Only two samples from approximately 3,000 m depth are characterized by relatively low sulphur contents and high TOC/S ratios (Figure 3). The sulphur is incorporated mainly into pyrite and organic matter.

**Maturity-related Parameters**

Measured vitrinite reflectance, T\text{max}, and production index values are plotted versus depth in Figure 5 together with calculated vitrinite reflectance data based on biomarker ratios.

**Vitrinite Reflectance** (VR) increases between 1,930 and 4,280 m from 0.4% to 0.8% Rr (Table 1). Many samples contain vitrinite populations with different reflectance. Normally the darkest population is considered most reliable. However in the case of bitumen-rich rocks, VR can be reduced. In addition,
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VR in some samples is based on a few vitrinite particles only. Samples with less than 10 measurements are considered uncertain and are marked in Figure 5 by a question mark. Moreover two samples might include cavings.

Table 1: Vitrinite Reflectance Values of Rock Sample

| Formation/Member | Depth (TVD, m) | VR (%Rr) | s (%) | n | VR (%Rr) | s (%) | n | Comments |
|------------------|----------------|----------|-------|---|----------|-------|---|----------|
| Sab‘atayn Form.  | 1.927–1.937    | 0.4      | 0.038 | 10|          |        |   | cavings? |
|                  | 2.965–2.975    | 0.35     | 0.040 | 5 |          |        |   | very fine-grained organic matter |
|                  | 3.034–3.044    | 0.65     | 0.058 | 17|          |        |   | solid bitumen? |
|                  | 3.194–3.204    | 0.51     | 0.031 | 15| 0.97     | 2.291  | 5 |          |
|                  | 3.289–3.299    | 0.46     | 0.045 | 13|          |        |   |          |
|                  | 3.314–3.324    | 0.41     | 0.027 | 12| 1.25     | 0.056  | 12|          |
|                  | 3.589–3.594    | 0.55     | 0.168 | 2 |          |        |   |          |
| Lam Member       | 3.784–3.794    | 0.47     | 0.028 | 25| 0.30     |        |   | cavings? |
|                  | 3.874–3.884    | 0.46     | 0.030 | 25| 0.70*    | 0.047  | 6 | two large bright vitrinite particles |
|                  | 3.954–3.964    | 0.57     | 0.041 | 11| ~1.02    |        |   |          |
|                  | 4.004–4.014    | 0.5      | 0.027 | 12|          |        |   |          |
|                  | 4.073–4.083    | 0.41     | 0.029 | 17|          |        |   |          |
|                  | 4.113–4.123    | 0.6      | 0.040 | 20|          |        |   |          |
|                  | 4.173–4.183    | 0.76     | 0.034 | 25|          |        |   |          |
|                  | 4.203–4.213    | 0.74     | 0.032 | 25|          |        |   |          |
|                  | 4.233–4.243    | 0.68     | 0.026 | 40|          |        |   |          |
|                  | 4.273–4.283    | 0.71     | 0.026 | 21| 0.83     | 0.027  | 10|          |

VR: vitrinite reflectance; s: standard deviation, n: number of measurements.

VR in some samples is based on a few vitrinite particles only. Samples with less than 10 measurements are considered uncertain and are marked in Figure 5 by a question mark. Moreover two samples might include cavings.
Tmax values increase in the same depth interval from 430–435°C to 445–450°C. Peters et al. (2005) proposed an equation to transform Tmax values into VR values for type I/II kerogen. These calculated values are generally higher (0.65–0.90% Rr) than measured VR data (Figure 5).

Production Index (PI) is a maturity parameter, but also indicates oil contaminations. There is no simple increase of PI with depth. PI values in the Sab’atayn Formation increase downwards from 0.1 to 0.56 and jump back at the top of the Lam Member. Within the Lam Member PI values vary widely and increase downwards from about 0.15 to 0.27.

Tmax and PI indicate that both, the Lam Member and the lower part of Sab’atayn Formation are within the oil window. VR is probably reduced and, thus, not relevant for maturity assessment. Additional maturity data are discussed in the Maturity Related Organic Geochemistry Parameters section.

### Remaining Source Rock Potential

The sum of S1 and S2 defines the remaining petroleum potential of the mature rock samples. In Figure 6 the remaining petroleum potential is plotted versus TOC contents. Based on TOC and HI, and considering that the remaining petroleum potential is reduced as a result of hydrocarbon generation, the Lam Member is a good to very good source rock for oil and gas (classification of Peters, 1986). Bituminous shales within the Sab’atayn Formation are excellent sources for oil (and gas) (Figure 6). Their source potential is only limited by the relatively low thickness, which does not exceed a few metres within single layers.

The remaining hydrocarbon potential of the drilled section of the Lam Member can be quantified using the “Source Potential Index” (SPI = h x (S1+S2) x ρ/1000) of Demaison and Huizinga (1994), where h is thickness (500 m), S1+S2 the average (remaining) petroleum potential (6.35 mg HC/g rock) and ρ rock density (2.42 g/cm³). These input parameters result in a remaining source potential of ca. 7.7 t/m² surface area.

![Figure 6: Remaining petroleum potential in samples from Tagina South-1 Well.](image-url)
The HI of samples from the upper part of the Lam Member from Tagina South-1 and proprietary data from other wells drilled in the Sab’atayn Basin suggest that the original HI was in the order of 300 mg HC/g TOC. Accepting this information and assuming that the S1 of immature samples is 1.0 mg HC/g Rock, the original SPI is estimated as 9.2 t/m² and, thus, about 1.5 t/m² is calculated to have been already generated.

**PYROLYSIS GAS CHROMATOGRAPHY**

The pyrolysis products of five samples from the Lam Member contain a predominance of normal hydrocarbon doublets of alkenes and alkanes extending to high chain length (C_{30} and beyond). Aromatic hydrocarbons including benzene, toluene, and m-p-xylene are also abundant in the chromatograms. The petroleum type organofacies has been determined using the ternary diagram of Horsfield (1989; Figure 7). Accordingly, the Lam samples produce paraffinic-naphthenic-aromatic low-wax petroleum.

**ORGANIC GEOCHEMISTRY (GC-MS)**

The extractable organic matter (EOM) yields from rock samples between 3,200 and 4,283 m depth vary between 88 and 362 mg/g TOC (Table 2). Highest yields are obtained from bituminous shales.

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**Table 2: Bulk Organic Geochemical Parameters of Oil and Rock Samples**

| Formation /Member | Depth (TVD, m) | TOC (wt.%) | TIC (wt.%) | S (wt.%) | HI (mg/HC/g TOC) | Tmax (°C) | PI | EOM (mg/g TOC) | Sat. HC (%) | Aro. HC (%) | NSO (%) | Asph. (%) |
|-------------------|---------------|------------|------------|----------|------------------|-----------|----|----------------|-------------|-------------|----------|----------|
| Sab’atayn Formation | 3,200–3,205  | 11.40  | 0.42 | 4.83 | 286 | 432 | 0.37 | 362 | 34 | 26 | 28 | 12 |
| | 3,314–3,324 | 5.32 | 3.50 | 4.14 | 427 | 437 | 0.29 | 162 | 25 | 19 | 43 | 13 |
| | 3,504–3,514 | 2.66 | 3.99 | 3.72 | 133 | 443 | 0.41 | 127 | 25 | 24 | 40 | 11 |
| Lam Member | 3,814–3,824 | 1.54 | 7.89 | 1.35 | 251 | 439 | 0.21 | 145 | 17 | 15 | 57 | 11 |
| | 3,884–3,894 | 1.94 | 8.24 | 0.96 | 228 | 438 | 0.16 | 88 | 22 | 20 | 50 | 8 |
| | 3,954–3,964 | 2.42 | 7.93 | 1.05 | 309 | 444 | 0.16 | 121 | 20 | 11 | 59 | 10 |
| | 4,023–4,033 | 2.09 | 7.85 | 1.33 | 263 | 437 | 0.26 | 201 | 33 | 16 | 45 | 7 |
| | 4,073–4,083 | 2.38 | 7.15 | 1.35 | 275 | 439 | 0.25 | 227 | 24 | 16 | 49 | 11 |
| | 4,093–4,103 | 2.62 | 6.94 | 1.48 | 231 | 439 | 0.25 | 171 | 29 | 19 | 44 | 7 |
| | 4,173–4,183 | 3.91 | 5.06 | 2.57 | 106 | 448 | 0.22 | 133 | 26 | 20 | 47 | 7 |
| | 4,213–4,223 | 2.65 | 6.93 | 1.46 | 193 | 446 | 0.24 | 123 | 29 | 17 | 46 | 8 |
| | 4,273–4,283 | 2.36 | 7.48 | 1.31 | 150 | 445 | 0.24 | 95 | 33 | 16 | 42 | 8 |

TOC: total organic carbon; TIC: total inorganic carbon; S: total sulphur; HI – Hydrogen Index = (S2*100)/TOC; Tmax: temperature at which the S2 generation peak occurs; PI: Production Index = S1/(S1+S2); EOM: Extractable organic matter; Sat. = Saturated; Aro. = Aromatic; HC: Hydrocarbons; NSO: Heterocompounds; Asph. = Asphaltenes; n.d. = not detectable.
Table 3: Concentration Ratios of Specific Biomarkers of Rock Samples

| Formation/Member | Depth (TVD, m) | CPI | Pr/n-C17 | Ph/n-C18 | Pr/Ph | C27 Steranes/Phy | C28 Steranes/Phy | C29 Steranes/Phy | C27 Diasteranes/C27 Steranes | C28/C29 Steranes | 20S/(20S+20R) |
|------------------|----------------|-----|----------|----------|--------|-----------------|-----------------|-----------------|-----------------------------|-----------------|---------------|
| Sab’atayn        |                |     |          |          |        |                 |                 |                 |                             |                 |               |
|                  | 3,200–3,205    | 0.79| 0.90     | 2.48     | 0.23   | 0.32            | 0.23            | 0.23            | 0.45                        | 0.22            | 0.51          |
|                  | 3,314–3,324    | 0.85| 0.77     | 1.67     | 0.41   | 0.41            | 0.23            | 0.23            | 0.37                        | 0.41            | 0.69          |
|                  | 3,504–3,514    | 0.82| 0.51     | 1.45     | 0.35   | 0.34            | 0.23            | 0.23            | 0.43                        | 0.40            | 0.54          |
| Lam Member       |                |     |          |          |        |                 |                 |                 |                             |                 |               |
|                  | 3,814–3,824    | 0.97| 0.64     | 1.08     | 0.63   | 0.37            | 0.24            | 0.24            | 0.38                        | 0.63            | 0.64          |
|                  | 3,884–3,894    | 1.08| 0.71     | 0.65     | 1.21   | 0.32            | 0.28            | 0.28            | 0.40                        | 0.93            | 0.71          |
|                  | 3,954–3,964    | 1.03| 0.56     | 0.71     | 0.87   | 0.32            | 0.31            | 0.31            | 0.37                        | 0.91            | 0.83          |
|                  | 4,023–4,033    | 1.06| 0.65     | 0.67     | 1.05   | 0.40            | 0.26            | 0.26            | 0.35                        | 0.65            | 0.75          |
|                  | 4,073–4,083    | 1.02| 0.73     | 0.92     | 0.77   | 0.39            | 0.24            | 0.24            | 0.41                        | 0.41            | 0.60          |
|                  | 4,093–4,103    | 0.99| 0.60     | 0.59     | 1.21   | 0.35            | 0.31            | 0.31            | 0.35                        | 0.79            | 0.88          |
|                  | 4,173–4,183    | 1.04| 0.55     | 0.61     | 0.81   | 0.40            | 0.25            | 0.25            | 0.35                        | 0.77            | 0.70          |
|                  | 4,213–4,223    | 1.04| 0.53     | 0.59     | 1.16   | 0.43            | 0.25            | 0.25            | 0.32                        | 0.78            | 0.79          |
|                  | 4,273–4,283    | 1.03| 0.55     | 0.52     | 1.23   | 0.40            | 0.27            | 0.27            | 0.32                        | 0.87            | 0.85          |

CPI = Carbon Preference Index, Pr = Pristane, Ph = Phytane

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| Formation/Member | Depth (TVD, m) | Ts/(Ts + Tm) | C29 Moretane Index | 22S/(22S+22R) ab C19 Hopenes | Gammacerane Index | DBT/Phen. | MDR | VRc (%) Type I/I | MPI 1 | VRc (%) | Steranes/Hopanes |
|------------------|----------------|--------------|-------------------|-------------------------------|------------------|-----------|-----|----------------|-------|----------|-----------------|
| Sab’atayn        | 3,200–3,205    | 0.42         | 0.24              | 0.59                          | 0.50             | 0.95      | 1.61| 0.68              | 0.51  | 0.71     | 0.78            |
|                  | 3,314–3,324    | 0.41         | 0.25              | 0.58                          | 0.43             | 1.04      | 1.85| 0.70              | 0.57  | 0.74     | 0.80            |
|                  | 3,504–3,514    | 0.44         | 0.22              | 0.59                          | 0.47             | 1.17      | 2.47| 0.73              | 0.56  | 0.74     | 0.20            |
|                  | 3,814–3,824    | 0.43         | 0.23              | 0.57                          | 0.29             | 0.53      | 2.12| 0.72              | 0.58  | 0.75     | 0.36            |
|                  | 3,884–3,894    | 0.47         | 0.18              | 0.60                          | 0.24             | 0.35      | 2.41| 0.73              | 0.57  | 0.74     | 0.24            |
|                  | 3,954–3,964    | 0.46         | 0.22              | 0.58                          | 0.30             | 0.27      | 2.87| 0.75              | 0.63  | 0.78     | 0.32            |
|                  | 4,023–4,033    | 0.45         | 0.21              | 0.59                          | 0.27             | 0.37      | 3.45| 0.77              | 0.64  | 0.79     | 0.24            |
|                  | 4,073–4,083    | 0.46         | 0.20              | 0.57                          | 0.28             | 0.31      | 3.66| 0.78              | 0.67  | 0.80     | 0.55            |
|                  | 4,093–4,103    | 0.52         | 0.21              | 0.56                          | 0.18             | 0.14      | 4.15| 0.80              | 0.69  | 0.81     | 0.41            |
|                  | 4,173–4,183    | 0.49         | 0.18              | 0.57                          | 0.14             | 0.21      | 4.22| 0.82              | 0.71  | 0.83     | 0.34            |
|                  | 4,213–4,223    | 0.52         | 0.16              | 0.57                          | 0.17             | 0.17      | 4.34| 0.83              | 0.73  | 0.84     | 0.43            |
|                  | 4,273–4,283    | 0.55         | 0.15              | 0.57                          | 0.17             | 0.17      | 4.61| 0.86              | 0.73  | 0.84     | 0.62            |

Ts: 18u-Trisnorhopane; Tm: 17u-Trisnorhopane; C29 Moretane Index: 17β:21α-Norhopane/17α:21β-Norhopane, Gammacerane Index: Gammacerane/(Gammacerane + 17α, 21β-Hopane); DBT: Dibenzothiophene; Phen. = Phenanthrene; MDR: Methyldibenzothiophene Ratio (4-MDBT / 1-MDBT); VRc: Vitrinite Reflectance equivalent based on MDR; MPI 1: Methylphenanthrene Index; VRc: Vitrinite Reflectance equivalent based on MPI 1 (Rr < 1.35%).
within the Sab’atayn Formation and from sediments of the Lam Member within the depth interval 4,023–4,103 m, indicating the presence of mature source rocks in the case of the Lam samples. The high yields from bituminous shales might be partly caused by impregnation of mature oil, as seen from the slightly higher relative amounts of asphaltenes and higher production index (Table 2). The relative percentages of saturated hydrocarbons in the extracts of the Lam Member increase with depth (Table 2). In general the saturated/aromatic ratios in Lam samples are higher than in bituminous shales. In the following facies and maturity related organic geochemical parameters are discussed separately.

**Facies-related Organic Geochemical Parameters**

Carbon preference index (CPI; according to Bray and Evans, 1961) values are around 1.0 in sediments of the Lam Member (Table 3). This is either a consequence of the enhanced thermal maturity of the Lam Member, or may indicate a significant contribution of marine sources (microalgae, bacteria) to the long-chain n-alkanes (Tissot and Welte, 1984; Volkman et al., 1998). In contrast, the n-alkanes from the bituminous shales in the Sab’atayn Formation are characterized by a marked even-over-odd carbon number predominance (CPI < 1.0; Table 3; Figure 8). Such a distribution argues for strongly reducing conditions during early diagenesis of the organic matter and/or direct microbial lipid input (Welte and Waples, 1973; Moldowan et al., 1986).

Pristane/phytane (Pr/Ph) ratios show an overall upward decrease from 1.2 to 0.6 in the Lam Member and are as low as 0.2 to 0.4 in the Sab’atayn Formation (Figure 8). Based on the Pr/Ph ratio (Didyk et al., 1978), sediments of the Lam Member were deposited under dysoxic (oxygen concentration < 0.2 ml/l; Pr/Ph > 1.0) to anoxic conditions (Pr/Ph < 1.0; Table 3), while the shales in the Sab’atayn Formation accumulated in a strongly reducing environment. This is also supported by the position of the samples in the pristane/n-C17 versus phytane/n-C18 plot (Figure 9). In the samples from the Sab’atayn Formation, the establishment of photic zone anoxia is further indicated by the presence of aryl isoprenoids in the C16 to C23 range and of isorenieratane, a biomarker for the activity of green sulphur bacteria (Summons and Powell, 1987). In addition, the effect of increasing maturity with depth is visible in Figure 9.

The gammacerane index (gammacerane/(gammacerane+αβ-C30 hopane); Peters et al., 2005) in the lower part of the Lam Member ranges from 0.14 to 0.22 and is between 0.24 and 0.30 in its upper part. Significantly higher values (0.43–0.50) are observed in the Sab’atayn Formation (Figure 8). This supports a dysoxic to anoxic depositional environment during deposition of the Lam Member and suggests that oxygen-reduced conditions are due to salinity stratification (Peters et al., 2005). Strongly reducing conditions and high salinity prevailed during deposition of the bituminous shales in the Sab’atayn Formation.

Hopanes and steranes are present in lower amounts in the extracts from the Lam Member than from the Sab’atayn Formation. The steranes-hopanes ratios vary within the broad range of 0.20 to 0.80 (Table 3) indicating variable contributions of eukaryotes (e.g. phytoplankton) and bacteria to organic matter production. It decreases upwards in the Lam Member, but reaches maxima in the Sab’atayn Formation (Figure 8).

The dibenzothiophene/phenanthrene (DBT/Ph) ratio is significantly lower in the Lam Member than in the Sab’atayn Formation (Table 3; Figure 8). It reflects the amount of free H2S in the environment during organic matter deposition and/or early diagenesis. Information about the depositional environment can be provided by a DBT/Ph versus pristane/phytane diagram (Hughes et al., 1995). The rocks of the Lam Member fall into the field characteristic for marine shale or lacustrine rocks, while the bituminous shales in the Sab’atayn Formation plot close to the field characteristic for marine marls to limestones (DBT/Ph ratios > 1.0; Figure 10). Obviously, the data reflect free H2S in the water column, as indicated by the presence of isorenieratane in the hydrocarbon fractions of the Sab’atayn Formation, and increased incorporation of sulphur into organic matter.

The C28/C29 steranes ratio of crude oils has been reported to increase with decreasing age of their source rocks (Grantham and Wakefield, 1988). The ratios between 0.60 and 0.85, obtained from Lam
Figure 8: Variation of biomarker and isotope ratios in Tagina South-1 Well.
Upper Jurassic source rocks, Sab‘atayn Basin, Yemen

samples (Table 3; Figure 8), are within the range measured in Jurassic source rocks and crude oils. Lower values measured within the bituminous shales of the Sab‘atayn Formation may indicate a lower contribution of organic matter from coccolithophorids, the species responsible for the increase in C_{28}/C_{29} sterane ratios during the Mesozoic, and enhanced contributions from green algae and/or dinoflagellates.

The C_{27} diasteranes/C_{27} regular steranes ratio is higher in the Lam Member than in the Sab‘atayn Formation (Table 3; Figure 8). The ratio has been used as a measure of the effect of clay catalytic transformation of organic matter within sediments. Diasterane formation during diagenesis is favoured under acidic and oxic conditions (Moldowan et al., 1986). The higher relative abundance of C_{27} diasteranes in rocks of the Lam Member as compared to the bituminous shales in the Sab‘atayn Formation can be interpreted as a consequence of changing environmental conditions from euhaline, dysoxic to hypersaline, reducing conditions.

**Maturity-related Organic Geochemical Parameters**

Six different maturity-related biomarker ratios have been determined using samples between 3,200 and 4,283 m TVD.

The methylphenanthrene index (MPI 1; Radke and Welte, 1983) increases from 0.51 to 0.73 (Table 3; Figure 5). Using the relation of Radke et al. (1984) established for type III kerogen it is suggested that VR increases from 0.71% to 0.84% Rr (Figure 5). However, the applicability of the empirical relationship to type-II kerogen has been discussed controversially (Cassini et al., 1988).

Therefore, maturity assessment is based additionally on the methyl dibenzothiophene ratio (MDR), defined as the ratio of 4- to 1- methyl dibenzothiophene concentrations (Radke et al., 1986). This ratio

![Figure 9: Pristane/n-C_{17} versus Phytane/n-C_{18} correlation diagram (after Connan and Cassou, 1980).](http://pubs.geoscienceworld.org/geoarabia/article-pdf/17/4/161/5446415/sachsenhofer.pdf)
is especially useful as a maturity parameter for type-II kerogen and increases from 1.61 to 4.61 (Figure 5). Based on these values and the empirical relationship between MDR and maturity for type-I and type-II kerogen (Radke, 1988), calculated vitrinite reflectance values increase from 0.68% to 0.86% Rr. Thus MPI 1 and MDR yield similar results (Table 3). The obtained data for the C29 moretane index and the Ts/(Ts+Tm) hopane ratios are consistent with the expected increase in maturity (Seifert and Moldowan, 1980; Figure 5).

Sterane and hopane isomerisation values are close to their equilibrium values of 0.55 and 0.60, respectively (Table 3), supporting a VR > 0.7% Rr (Mackenzie and Maxwell, 1981; Mackenzie, 1984).

Importantly the VR estimates based on biomarker ratios (e.g. MPI 1, MDR) and Tmax agree well, but are generally higher than measured VR data. Tmax and MPI 1 values are facies dependant and might yield biased results in the given low-maturity range. Nevertheless, in the present study they are considered more reliable than the measured VR data, which might be suppressed by bitumen impregnations (e.g. Carr, 2000).

**CARBON ISOTOPE**

The C-isotopic compositions of n-alkanes up to C29 and of acyclic isoprenoids are shown in Figure 11. The $\delta^{13}C$ values of n-alkanes and isoprenoids from all rock samples show parallel variation. An increase in $\delta^{13}C$ with increasing carbon number is observed from n-C19 to n-C29 (Table 4; Figure 11). The $\delta^{13}C$ values of short-chain n-alkanes ($< C_{20}$) and the slightly increasing values with increasing carbon number are consistent with the proposed origin from marine organic matter (Murray et al., 1994). The similar isotopic composition of pristane and phytane in all samples (Figure 11) argues for a common source of the acyclic isoprenoids (i.e. chlorophyll) and supports the applicability of pristane/phytane ratios as a redox parameter. The depletion of acyclic isoprenoids in $^{13}C$ relative to short-chain n-alkanes is usually observed due to differences in the isotopic composition between isoprenoids and straight chain carbon skeletons (Schouten et al., 2001).

The samples show a general trend towards lower $\delta^{13}C$ with decreasing depth, with the lowest values in $\delta^{13}C$ of individual compounds from a bituminous shale in the Sab‘atayn Formation (Figure 11). This trend is also visible in a plot of mean $^{13}C$ value for all n-alkanes and isoprenoids versus depth (Figure 8).
results are consistent with the concept of “recycling” of \(^{13}\)C-depleted CO\(_2\) from microbial respiration under anoxic conditions through primary producers (Imbus et al., 1992). The increasing \(\delta^{13}\)C values with depth are interpreted to reflect changes in carbon cycling under changing redox conditions within the water column.

| Compound  | 3,314–3,324 m TVD | 3,814–3,824 m TVD | 3,954–3,964 m TVD | 4,023–4,033 m TVD | 4,073–4,083 m TVD | 4,093–4,103 m TVD | 4,173–4,183 m TVD | 4,213–4,223 m TVD | 4,273–4,283 m TVD |
|-----------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|
| \(n\)-C\(_{15}\) | -29.1              | -29.5              | -29.6              | -29.2              | -29.3              | -29.1              | -29.2              | -28.7              | -28.5              |
| \(n\)-C\(_{16}\) | -29.4              | -29.5              | -29.8              | -29.6              | -29.7              | -29.3              | -29.5              | -28.9              | -28.7              |
| \(n\)-C\(_{17}\) | -30.3              | -29.9              | -30.0              | -29.8              | -29.6              | -29.3              | -29.4              | -29.2              | -29.0              |
| \(n\)-C\(_{18}\) | -30.4              | -30.2              | -30.3              | -30.5              | -29.6              | -29.3              | -29.4              | -29.3              | -29.0              |
| \(n\)-C\(_{19}\) | -30.6              | -30.2              | -29.6              | -30.2              | -29.4              | -29.2              | -29.3              | -29.7              | -29.2              |
| \(n\)-C\(_{20}\) | -30.8              | -30.5              | -30.4              | -29.8              | -29.7              | -29.9              | -29.5              | -29.6              | -29.2              |
| \(n\)-C\(_{21}\) | -30.6              | -30.1              | -30.3              | -30.0              | -29.9              | -30.0              | -29.4              | -29.5              | -29.3              |
| \(n\)-C\(_{22}\) | -30.8              | -30.3              | -30.0              | -29.4              | -29.6              | -29.4              | -29.5              | -29.7              | -29.3              |
| \(n\)-C\(_{23}\) | -30.2              | -29.6              | -29.9              | -29.5              | -29.6              | -29.2              | -29.1              | -29.4              | -28.8              |
| \(n\)-C\(_{24}\) | -30.3              | -30.2              | -30.0              | -29.8              | -30.1              | -29.4              | -29.6              | -29.6              | -29.1              |
| \(n\)-C\(_{25}\) | -29.9              | -29.7              | -30.2              | -29.6              | -29.7              | -29.5              | -29.3              | -29.6              | -28.9              |
| \(n\)-C\(_{26}\) | -30.1              | -30.1              | -29.8              | -30.0              | -29.7              | -29.3              | -29.1              | -29.6              | -28.9              |
| \(n\)-C\(_{27}\) | -29.9              | -29.8              | -29.5              | -29.8              | -29.5              | -29.1              | n.d.               | n.d.               | n.d.               |
| \(n\)-C\(_{28}\) | -30.1              | -29.8              | -30.1              | -29.8              | -30.1              | -29.8              | n.d.               | n.d.               | n.d.               |
| Norpristane | -29.8              | -30.7              | -30.6              | -30.3              | -30.4              | -30.3              | -30.2              | -29.5              | -29.6              |
| Pristane    | -30.4              | -30.5              | -30.7              | -30.9              | -30.4              | -30.3              | -30.2              | -29.8              | -30.0              |
| Phytane     | -30.7              | -30.6              | -30.4              | -30.7              | -30.4              | -30.5              | -30.2              | -29.9              | -29.7              |

PDB: PeeDee Belemnite (int. Standard); n.d. = not detectable.
MODELLING OF THERMAL HISTORY AND HYDROCARBON GENERATION

Input and Calibration Data

Information on lithostratigraphy of the Tagina South-1 Well is summarized in Table 5. Information on lithology and thickness of eroded rocks is taken from literature (e.g. Watchorn et al., 1998). Following Watchorn et al. (1998), it is assumed that no major erosion (but surface uplift) occurred between 40.4 Ma and 25.0 Ma, whereas both significant surface uplift and erosion occurred between 25.0 Ma and 20.0 Ma as a consequence of rift shoulder uplift related to the opening of the Gulf of Aden.

The Tagina South-1 Well was drilled in a central position of the southern Sab'atayn Basin where locally the Sab’atayn Formation is forming a salt dome. Following Seaborne (1996), an original thickness of 300 m is adopted for the Sab’atayn Formation. The precise age of diapirism is poorly constrained, although it is obvious that salt movement is related to Cenozoic faulting. At the location of Tagina South-1 Well the sediments of the Umm Er Radhuma Formation are largely undeformed and overlie the salt dome with a very subtle regional dip. This suggests that at Tagina South halokinetic movements stopped before deposition of the Umm Er Radhuma Formation. In our first model the thickness of the Sab’atayn Formation increases from 300 m to 600 m between 137.4 Ma and 132.5 Ma to account for an Early Cretaceous salt movement phase and from 600 m to 1,859 m between 65.5 Ma and 57.4 Ma (i.e. after deposition of the Sharwayn Formation, but before deposition of the Umm Er Radhuma Formation).

Table 5: Input Data for Thermal Models of Tagina South-1 Well

| Formation/Member     | Present Thickness (m) | Eroded Thickness (m) | Deposition Age | Erosion Age | Lithology     |
|----------------------|-----------------------|----------------------|----------------|-------------|---------------|
|                      | from Ma               | to Ma                | from Ma        | to Ma       |               |
| Habishiya            | 0                     | ??                   | 48.6           | 40.4        | SHALE and SAND|
| Rus                  | 0                     | 300                  | 51.8           | 48.6        | GYPSUM        |
| Jiza                 | 9                     | 133                  | 53.5           | 51.8        | LIMESTONE     |
| Umm Er Radhuma       | 269                   | 93.5                 | 57.4           | 53.5        | LIMESTONE     |
| Sharwayn             | 13                    | 70.6                 | 65.5           |             | SHALE and LIME|
| Mukalla              | 1,076                 | 93.5                 | 93.5           | 70.6        | SANDshaly    |
| Harshiyat            | 448                   | 112.0                | 112.0          | 94.0        | SANDshaly    |
| Qishn Carbonates     | 50                    | 128.0                | 128.0          |             | SHALE and LIME|
| Qishn Clastics       | 21                    | 132.5                | 132.5          |             | SANDshaly    |
| Sa’ar Formation      | 50                    | 142.5                | 142.5          | 137.4       | SANDshaly    |
| Sab’atayn Formation  | 1,859                 | 149.3                | 149.3          | 147.5       | SALT          |
| Lam Member           | 617                   | 155.3                | 155.3          | 149.3       | LIMEshaly    |

Eroded formations are highlighted by grey shading.

Physical parameters for different lithologies pre-defined in the software were used (Table 6) and the absolute ages of Beydoun et al. (1998) were applied. Water depth and temperatures at the sediment-water-interface (SWI) are summarized in Table 7.

The above information was used to reconstruct decompacted subsidence histories and the temperature field through time. The models were calibrated by modifying heat flow and the thickness of eroded rocks (Habishiya Formation) until a satisfactory fit between measured and calculated formation temperatures and vitrinite reflectance was obtained.

Corrected temperature data from three depth levels and additional log temperatures from the deeper part of the drilled section are available. Both data sets have been used to calibrate present-day heat flow, because log temperatures fit well to the corrected temperatures.

Vitrinite reflectance, calculated using the kinetic EASY%Ro approach (Sweeney and Burnham, 1990), was used to calibrate paleo-heat flow. In the Tagina South-1 Well, vitrinite reflectance data calculated
Upper Jurassic source rocks, Sab’atayn Basin, Yemen

from \( T_{\text{max}} \), MDR and MPI 1 (see Figure 5) are considered more reliable than measured data (see Maturity Related Organic Geochemical Parameters section) and have been used for calibration.

Hydrocarbon generation was modelled using kinetic data for a kerogen type II (Tissot in Waples et al., 1992).

1-D Model

Burial history curves are displayed in Figure 12 together with isotherms, calibration data and computed hydrocarbon potential (oil potential, gas potential, transformation ratio). A satisfactory fit between measured and calculated calibration data is obtained with erosion of Paleogene rocks, 470 m thick and a time-constant heat flow of 50 mW/m².

The erosion estimate is similar to that for the central part of the Sab’atayn Basin (Seaborne, 1996), whereas the present-day heat flow is comparable to that determined by Csato et al. (2001; 46 mW/m²).

In agreement with the observed data, the calculated transformation ratio suggests that the Sab’atayn Formation is marginally mature. Near TD (3,072 m TVDs) the transformation ratio is about 60%. This agrees well with the observed decrease of HI from 300 to 150 mg HC/g TOC (Figure 4). Very little gas is generated within the drilled section. Plots of temperature, transformation ratio and hydrocarbon potential versus time are shown in Figure 13a. They show hydrocarbon generation from the Lam Member occurred during Eocene and Oligocene times.

Sensitivity Analysis

In a first sensitivity run, the model was calibrated with measured instead of calculated vitrinite reflectance data. In this model a fit between measured and calculated calibration data can be found using a model with low heat flow (36 mW/m²) during maximum burial in Paleogene time, which increased during late Neogene time to the present-day value of 50 mW/m². In contrast to the observed data, only negligible hydrocarbon generation is predicted in the Lam Member by this model. We consider this result as an additional argument for suppressed vitrinite data.

As vitrinite reflectance is mainly controlled by maximum temperatures, only heat flows around times of maximum temperatures can be determined precisely. Therefore, in contrast to Cenozoic heat flow (50 mW/m²), Mesozoic heat flow is poorly constrained. Moreover it is likely that heat flow was elevated during Late Jurassic rift and Cretaceous post-rift stages. Therefore different Mesozoic heat flow models were tested. These models show that Jurassic heat flow has no influence on model results, but that Late Cretaceous heat flows > 70 mW/m² can be excluded, because it results in an

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### Table 6: Physical Properties Assigned to Lithotypes used for Simulations

| Density (kg/m³) | Porosity (Initial Min.) | Compressibility (1E-7/kPa) Max. Min. | Thermal Conduct. at 20°C (W/m/K) | Heat Capacity at 20°C (kcal/kg/K) | Permeability (log mD) |
|-----------------|-------------------------|--------------------------------------|---------------------------------|---------------------------------|----------------------|
| GYPSUM          | 2,320                   | 1 1                                  | 0 0                             | 1.0 0.6                        | 1.59 0.26            |
| SALT            | 2,740                   | 1 1                                  | 0 0                             | 6.50 2.5                       | 0.21 0.24            |
| SHALE&LIME      | 2,695                   | 53 5                                | 150 2                           | 2.39 2.24                      | 0.21 0.25            |
| SANDshaly       | 2,664                   | 0.05                                | 1,200 10                        | 2.97 2.64                      | 0.188 0.223          |
| LIMESTONE       | 2,710                   | 0.05                                | 150 10                          | 2.83 2.56                      | 0.195 0.223          |
| LIMEshaly       | 2,700                   | 0.37                                | 550 10                          | 2.51 2.31                      | 0.20 0.24            |

### Table 7: Water Depth and Sediment-Water-Interface (SWI) Temperatures used in the Model

| Age Ma | Water depth m | SWI Temp. °C |
|--------|---------------|--------------|
| 0.0    | -1,200        | 22.58        |
| 20.0   | -1,000        | 22.72        |
| 25.0   | -100          | 23.14        |
| 40.4   | 0             | 25.00        |
| 53.0   | 20            | 24.25        |
| 57.0   | 20            | 24.00        |
| 65.0   | 5             | 23.78        |
| 93.0   | 5             | 25.99        |
| 96.0   | 5             | 26.24        |
| 112.0  | 5             | 26.29        |
| 121.0  | 5             | 25.63        |
| 128.0  | 5             | 25.19        |
| 147.0  | 100           | 23.00        |
| 149.0  | 200           | 21.74        |
| 155.0  | 200           | 21.36        |
| 200.0  | 0             | 22.72        |
Figure 12: Burial history and isotherms (time constant heat flow of 50 mW/m²) of South Tagina-1 Well. Measured and calculated calibration data are shown together with petroleum potential and transformation ratio.
Upper Jurassic source rocks, Sab‘atayn Basin, Yemen

overestimation of vitrinite reflectance. Thus, the heat flow model “Rifting” displayed in Figure 13c characterized by a Late Cretaceous heat flow 68 mW/m² is considered a maximum heating scenario. This scenario results in two stage hydrocarbon generation with a first Late Cretaceous hydrocarbon generation phase (Figure 13b).

Obviously both, Eocene–Oligocene heat flow and present-day heat flow are low. A short-term increase in heat flow during Miocene time cannot be completely excluded, but definitely had no influence on the
maturity pattern in the area of the Tagina South-1 Well. This shows that possible thermal effects related to the Cenozoic opening of the Gulf of Aden (Bosworth et al., 2005) had no effect on hydrocarbon generation.

Whereas the geometry of the Umm Er Radhuma Formation in the Tagina South area suggests that halokinetic movements pre-date its deposition, there is strong evidence for younger salt movement in other parts of the Sab’atayn Basin (Seaborne, 1996). To account for this uncertainty, additional models with different ages of diapirism (varying from 53.5–40.4 Ma to 25.0–20.0 Ma) have been tested in an additional set of sensitivity analysis. All applied models resulted in similar thermal and hydrocarbon generation histories suggesting that the precise age of diapirism is of secondary importance only.

2-D Model

A simple 2-D model has been established along a 55-km-long schematic NE-trending cross-section following seismic line QMA-00-231_FSI-08 (Figure 14). The cross-section is characterized by several salt domes. The geometry of the Umm Er Radhuma Formation suggests that salt movement along the cross-section ceased at different times.

Compared to the 1-D model, a good fit with calibration data is obtained in the 2-D model with a slightly lower Cenozoic heat flow (47 mW/m²). The distribution of present-day temperature (Figure 14a) and maturity (Figure 14b) highlights the great impact of Sab’atayn salt on the amount of generated oil and gas (Figures 14c and 14d). Hydrocarbon accumulations are predicted along the basin flanks and underneath the Sab’atayn Formation.

CONCLUSIONS

Depositional Environment

The Lam Member of the Madbi Formation in the Tagina South-1 Well has been deposited in a carbonate-rich, euhaline, dysoxic to anoxic environment. The availability of free H₂S in the environment during organic-matter deposition and/or early diagenesis was restricted, as sulphur is mainly bound in the form of pyrite. Bituminous shales within the lower part of the evaporitic Sab’atayn Formation
formed in a hypersaline, strictly anoxic depositional setting with free H$_2$S. This is supported by the higher relative abundances of sulphur-aromatic compounds in the organic matter and the occurrence of isorenieratane in the hydrocarbon fractions. Changes in the phytoplankton communities coincide with the outlined changes in the water body.

Upward decreasing $\delta^{13}C$ values suggest changes in carbon cycling due to changing redox conditions. The $\delta^{13}C$ values of $n$-alkanes and slightly increasing values with increasing carbon number are consistent with results from marine organic matter. A common source of acyclic isoprenoids (i.e. chlorophyll) is indicated by similar $\delta^{13}C$ values.

Source Potential

The Lam Member is an excellent source rock for oil. TOC contents vary from 0.9% to 4.6%. The average TOC of the studied 500 m thick interval is 2.2%. The hydrogen index (HI) is strongly controlled by maturity, but reaches 300 mg HC/g TOC in shallow samples with relatively low maturity (type II-III kerogen). The remaining source potential of the drilled section is 7.7 ton of hydrocarbons per square metre surface area. The Lam Member produces a sulphur-poor, paraffinic-naphthenic-aromatic low-wax oil.

Bituminous shales in the Sab’atayn Formation contain up to 11% TOC. HI values range from 133 to 427 mg HC/g TOC indicating the presence of a type II (to III) kerogen. The bituminous shales are excellent sources for oil (and gas). The source potential is only limited by their relatively low thickness (typically a few metres in single layers). The bituminous shales produce an oil, which is more sulfur-rich than oil from the Lam Member.

Maturity and Hydrocarbon Generation

Based on Tmax and biomarker ratios, vitrinite reflectance increases from 1,960 to 4,238 m MD from 0.65% to 0.85% Rr. Measured vitrinite reflectance values are typically lower, probably an effect of bituminization. Both, the bituminous shales in the lower part of the Sab’atayn Formation and the Lam Member are mature. The deepest drilled part of the Lam Member is close to the zone of peak oil generation thus proving this southern part of Block 2 to be an oil-generating kitchen area charging potential traps.

Numerical models show that major hydrocarbon generation occurred exclusively during Eocene–Oligocene times (assuming a Late Cretaceous heat flow of 50 mW/m²) or during both, Late Cretaceous and Eocene–Oligocene times (assuming a Late Cretaceous heat flow of ca. 70 mW/m²). In any case, hydrocarbon generation ended before major Neogene basin uplift.

Relatively high amounts of extractable organic matter (EOM) and high production index (PI) values in bituminous shales within the lower part of the Sab’atayn Formation suggest either impregnation with mature oil, or – more likely – that hydrocarbon generation starts at lower temperatures in the bituminous shales than in the Lam Member.

Heat Flow

Present-day heat flow is in the order of 50 mW/m². A similar low heat flow existed during maximum burial in Paleogene time. An increase in heat flow during Jurassic rifting is likely, but cannot be quantified precisely. An increase in heat flow during the Cenozoic opening of the Gulf of Aden cannot be excluded, but had no influence on maturity and hydrocarbon generation.

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