BURIAL AND THERMAL HISTORY RECONSTRUCTION OF SOUTH SAKAR DEPRESSION, BULGARIA

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ABSTRACT: In tectonic aspect, the studied area is located in the South Sakar depression, which in the south-southeast turns into the large hydrocarbon Thrace basin in Turkey. The purpose of this study is buried history modelling and thermal history modelling of the studied region. This enables a reconstruction and characterisation of the sediment filling processes of this part of the basin and assessment of the hydrocarbon generation and migration from tertiary sediments. In the process of buried history reconstruction, periods of sedimentation followed by hiatus and erosion periods are observed. These periods, along with the heat flow changes for the region, have an impact on the maturity of the sediments. In the present study, a 1D thermal maturity model of three litho-stratigraphic units, which are part of shale-marl and terrigenous-limestone-marl formations and are evaluated as potential source rocks in the tertiary section of the depression, is created. The thermal maturity model shows that sedimentary sequences from Eocene to Pliocene Ages can generate liquid and/or gaseous hydrocarbons.

Keywords: petroleum system modelling, thermal history reconstruction

РЕКОНСТРУКЦИЯ НА ИСТОРИЯТА НА ПОТЪВАНЕ И ГЕОТЕРМИЧНАТА ЕВОЛЮЦИЯ НА ЮЖНОСАКАРСКОТО ПОНИЖЕНИЕ, БЪЛГАРИЯ

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РЕЗЮМЕ: В тектонско отношение, изследваният район е разположен в Южносакарското понижение, което на юг-югоизток преминава към големия нефтогазоносен Тракийски басейн в Турция. Целта на настоящата разработка е моделиране на историята на потъване и геотермичната история на изследвания район. Това позволява реконструкция и характеризиране на процесите на образуване на седиментния пълнеж на тази част от басейна и оценка на въглеводородната генерация и миграция от терциерните седименти. В процеса на реконструкцията на историята на потъване се наблюдават периоди на седиментация, последвани от периоди на прекъсване или ерозия. Тези периоди, заедно с измененията на топлинния поток за района, оказват своето влияние върху степента на зрялост на седиментите. В настоящата разработка се прави 1D модел на термичната зрялост на три литолого-стратиграфски единици, влизащи в състава на глинесто-мергелната и теригенно-варовиково-мергелната задруга, които са оценени като потенциални генериращи скали в терциерния разрез на понижението. Моделът на термичната зрялост на Южносакарското понижение показва, че седиментните последователности с възраст от еоценската до плиоценската епохи могат да генерират различни по фазово състояние въглеводородни продукти.

Ключови думи: петролно-системно моделиране, реконструкция на геотермичната история

Introduction

The South Sakar depression, located in South-eastern Bulgaria, is continuation of the large structural unit that goes beyond the borders of our country and is called the Thrace basin. After purposeful geological-geophysical and drilling activities it has been evaluated as a petroleum system with a significant potential (Karahanoglu et al., 1995; Gurgey, 2009; Şen, 2011). The area of research is characterised with a poor exploration for hydrocarbons. The limited data does not allow a complete characterisation of the hydrocarbon potential of the Tertiary sediments. The several studies in this regard give grounds for preliminary assessment of the source rock potential of the Tertiary sediment complex as fair to good (Palakarcheva, Stefanova, 2013; Meracheva et al., 2017a, b). This gives a basis for further studies in order both to reconstruct and characterise the sediment filling processes of this part of the basin, and to model and assess subsequently the hydrocarbon generation and migration from Tertiary sediments.

Geological setting

In earlier publications (Zaneva-Dobranova, Meracheva, 2014; Meracheva, Zaneva-Dobranova, 2018) the issue of the different concepts about the tectonic belonging of the studied area was examined in details. For the purpose of the present study, a tectonic position is assumed (Fig. 1), which is determined according to tectonic zonation of Southern Bulgaria (Zagorchev et al., 2009), the characteristics of the structure, development of the main structure units and the relation between them.

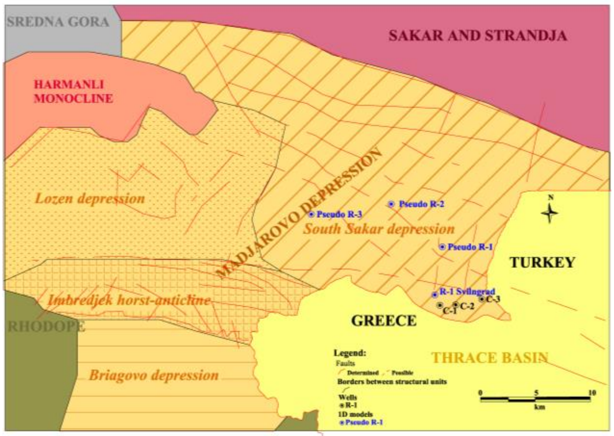

Fig. 1. Tectonic scheme of the studied area (after Zagorchev et al., 2009; with modifications) and location of the 1D models

The tertiary section in the region of research consists of sedimentary rocks of Paleogene and Neogene age (Fig. 2). It overlies discordantly above different level pre-Paleogene fundament and is partly or fully covered by eluvial, proluvial and alluvial sediments of the Quaternary (Kozhoukharov et al., 1995). At the base of the Tertiary section, according to data from the seismic surveys, north of R-1 Svilengrad Well, a zone with unclear configuration and characteristic sand-conglomerate and turbiditic facies is observed.

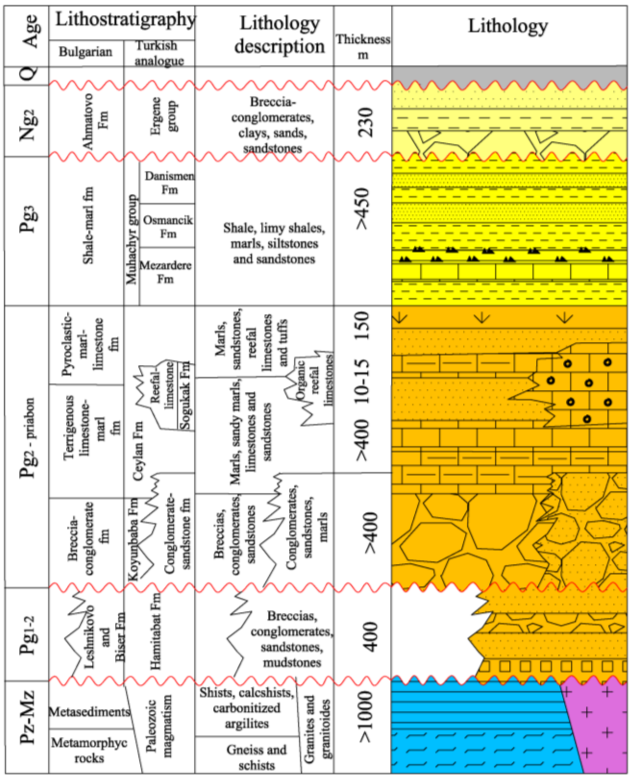

Fig. 2. Lithostratigraphic scheme of the Tertiary section of studied area

These rocks are with similar lithological features and could be assigned to the surface exposed to the west of studied area Biser and Leshnikovo Formations of Palaeocene–Eocene (?) age. In the area of South Sakar Depression, they are considered (Palakarcheva, Stefanova, 2013; Meracheva, Zaneva-Dobranova, 2018) as analogues of the Hamitabat Formation in the Turkish part. Above them or directly on the fundament overlay with transgression the clastic-carbonate rocks of the formations of Priabonian age, assigned to breccia-conglomerate, conglomerate-sandstone, terrigenous-limestone-marl and pyroclastic-marl formations. These sediments are in complex spatial relationships. In some places a smooth lithofacies replacement of the rocks from one formation to the neighbouring is observed. To southeast, their probable correlates are the sediments of the Koyunbaba and Ceylan Formations (Meracheva, Zaneva-Dobranova, 2018). The rocks in the section are followed by the Oligocene deposits of the shale-marl formation, represented by marls, marly limestones, shales, sandstones and siltstones. This formation could be correlated with the lithostratigraphic units of the Muhacir Group on Turkish territory – Mezardere, Osmancik, Danismen Fms. To the west of the South Sakar Depression the section is represented by tuffs, tuffites and reefal limestones. The Paleogene deposits are discontinuously covered by Neogene sedimentary rocks included within the scope of the Ahmatovo Formation.

Methodology and methods of modelling

In this study a petroleum system modelling is carried out in order to reconstruct the burial and thermal history of the studied area. The result of this is used for further petroleum system simulation of hydrocarbon generation and expulsion processes in the studied area, both from the evaluated potential source rocks of shale-marl (analogue of the Mezardere Formation in the Turkish part) and terrigenous-limestone-marl (analogue of Ceylan Formation in the Turkish part) formations, and from deposits, analogues of proven in the central part of the basin the Hamitabat Formation (Hosgörmez, Yalçın, 2005; Gürgey, 2009). For the 1D petroleum-system modelling geological and geochemical data from the deep R-1 Svilengrad Well are used. These data are interpolated in several sections to the north and west of R-1 Svilengrad Well, using for the purpose selected interpreted seismic sections and subsequently calculated thicknesses of the litho-stratigraphic units in the 3D structural model (Meracheva, Zaneva-Dobranova, 2018). Three new 1D models of reconstruction on conditional (pseudo) wells – Pseudo R-1, Pseudo R-2, Pseudo R-3, were created on this basis (Fig. 1).

For reconstruction of burial and thermal history in the software are imported as follows:

- Data of the geological research related to periods of deposition, erosion and hiatus, with their respective ages, lithology and thickness;
- Data obtained from geochemical research of the rocks of shale-marl formation – quantity of Total organic carbon (TOC), Hydrogen index (HI), thermal maturity data (T_{max});
- Thermal maturity calibration data from R-1 Svilengrad well – uncorrected formation temperature, measured in the well (Bottom hole temperature – BHT); maximal temperature, obtained at pyrolysis (T_{max});
- Heat flow data – thermal conductivity of the formation and calculated geothermal gradient for the region.

For the purpose of petroleum system modelling, the geochemical parameters of the source rock, in the range of the shale-marl formation, are averaged. For TOC mean values are assumed to be 1.42 wt%, and for HI mean value is 135 mg HC/g TOC. Initially, burial history curves for the sediment section are reconstructed, considering thicknesses of the sediment formations, their ages and the periods of deposition and erosion.

For the reconstruction of thermal history, one of the modern approaches used in the recent years by the researchers in the petroleum sciences has been applied (Botoucharov, 2005; Hosgörmez, Yalçın, 2005; Huvaz et al., 2007; Hakimi et al., 2018). For this purpose, the necessary calculations from the available data for the area are carried out.

For the calibration and reconstruction of the heat flow and the geothermal history in modelling the temperature-sensitive parameters are used – temperature at pyrolysis (T_{max}) and formation temperature (BHT) (Pepper, Corvi, 1995; Makeen et al., 2016; Hakimi et al., 2018).

When creating the 1D heat flow model, Fourier low equation is used, thus the heat flux values are calculated after measuring the temperature and the thermal conductivity. For these calculations the data of formation temperature measured during the geophysical logging of wells (BHT) are used. Considering that the temperature values measured in this way are lower than the actual temperature of the respective formation, due to the cooling effect of the drilling fluid circulating at the bottom of boreholes, corrections can be made in the cases of sufficient information (Deming, 1994). Therefore, the average values of the thermal conductivity of the rocks in the research area is considered to be analogous to the one determined in the Turkish part of the Thrace basin on a significant number of wells (Engin, 1999). The data obtained from the studies in the Thrace basin in Turkey were taken into account in the simulation of the heat flow and in the creation of a conceptual model of reconstruction of the geothermal history of the research area. These data, as well as the values used in the model for the geothermal gradient, calculated from the measured temperature in R-1 Svilengrad well, are compared with existing studies for the geothermal gradient of this part of Bulgaria (Velinov, Boiadjieva, 1981).

Results of the petroleum system modelling

Petroleum system modelling of burial and subsidence history of the Tertiary sediments

At reconstruction of the burial history of the studied part of the basin, periods of sedimentation, followed by periods of hiatus and erosion are observed (Fig. 3). The large unconformity, with an average thick erosion of 450 m has been recognized during the middle-late Eocene, which is probably related to the Illyrian tectonic phase. Another unconformity is typical for the period of Miocene age, which shows an uplift process. However, these erosion periods together with the heat flow of the area affect thermal maturity range of the sediments.

The burial history curves show typical for this type of basins tectono-stratigraphic phases – syn-rift and post-rift. Both syn-rift phases are characterised by approximately the same rate of sedimentation when relatively thick sediment complexes are deposited. During the post-rift phase, the rate of sedimentation significantly decreases. The transgression that occurred at the end of the Palaeocene – the beginning of the Eocene(?), resulting in a rapid subsidence of the basin, led to deposition of about 1000 m thick sediment complex in most of the studied area (Fig. 3, pseudo-wells P-1, P-2, P-3). This period is characterised by relatively high rate of sedimentation of an average about ~65 m per million years. Afterwards, a short period occurs for the entire basin, characterised by the absence of sedimentation (Fig. 3, R-1 Svilengrad Well), and in some places with an erosion (Fig. 3, pseudo-wells). During the Priabonian Age again a period of intensive sedimentation and subsidence of the sediment basin occurred, which continued until the end of early Miocene. Then, in the researched area, the rate of sedimentation is ~78 m per Ma and a sediment complex is formed with a present-day thickness to about 1300 m. This rapid subsidence, the deposition of a thick sediment sequence for a relatively short time, and the presence of volcanic activity near to the area are an indication of extensional tectonic activity in the formation of the basin, which is also confirmed by the model of burial history curves.

On the burial history curves, a short period during the middle Miocene is observed, when the sediments uplifted to the surface and some of the deposited rocks once again eroded. This period is associated with the wide-spread tectonic phase, during which a large part of the faults, mainly normal faults, formed in the previous tectonic phase, are reactivated and form numerous folds, anticlines and structures. On the burial history curves, it is evident that after the end of the late Miocene, the deposition of medium rate of sedimentation of the overburden rocks started with ~40 m per Ma, which in places in the studied area reached a thickness of over 250 m. For comparison, the rate of sedimentation in the central parts of the basin (Huvaz et al., 2007) is higher, and respectively, the thickness of the sediments deposited during these tectonic phases is greater, which affects the degree of maturity of the organic matter into the sediments. In addition, the deposition of the upper Neogene sediments in the last 7 million years to some extent also influences the maturation of the potential source rock complex with Paleogene age, burying them to a depth where further HC generation processes could potentially take place.

Heat flow modelling and reconstruction of thermal history

The Thrace basin can be classified as a moderate-high heated basin, with geothermal gradient (measured in wells) above the world average. It ranges from 26°C/km to 43°C/km (Huvas, 2007). It should be noted that the central part of the basin is with a much lower geothermal gradient compared to its margins where the research area is located.

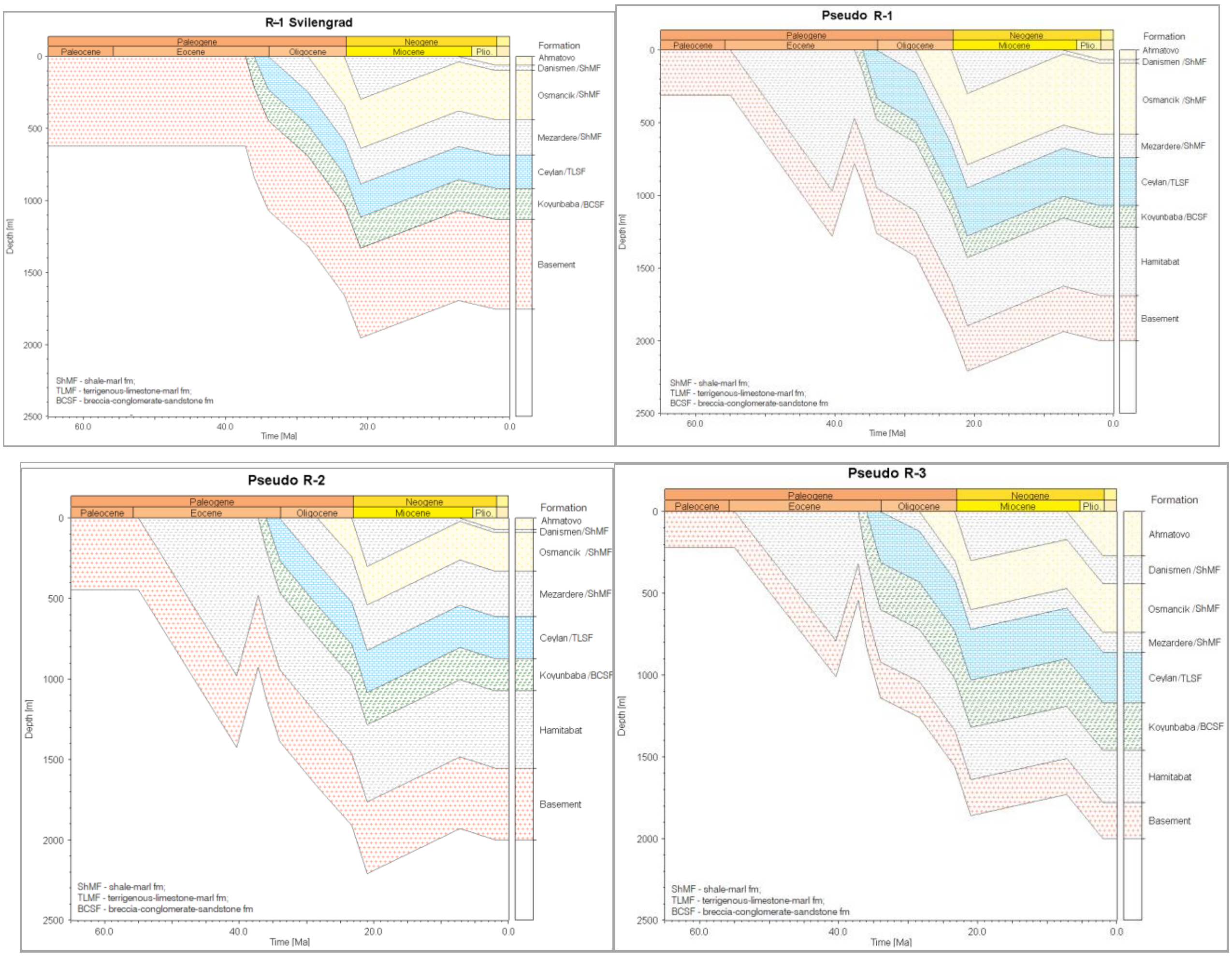

Fig. 3. Burial history reconstruction: 1D models of R-1 Svilengrad Well and pseudo wells R-1, R-2 and R-3

This trend is associated with several factors:

1) At the edges of the fundament and/or the graben margins a high heat flux is usually observed. The heat is concentrated in the high-conductivity rocks of the fundament, not in the relatively low-conductive adjacent sediments. For the conditions of the Thrace basin, it has been found that this factor has a great influence on the thermal gradient changes in the horizontal direction, especially in its northern edges, where the thickness of the sediments decreases significantly;
2) According to the concept of the heat flux distribution in the fundament, the inner parts of a sediment basin, where deposition of sediments is in larger quantities and the earth's crust is thinner (as a result of isostasy), are expected to be cooler compared to areas with a thicker upper crust. This explains the increased values of the geothermal gradient near the highs on the Thrace basin (Sakar-Strandzha Anticlinorium, Central-Thrace High);
3) Lateral thermal conductivity variation is explained with different thermal conductivity of the mineral composition of the rocks;
4) Younger sediments are usually cooler than older ones, resulting in lower geothermal gradient values in areas where sedimentation is higher. This explains the fact that the sediments deposited in the central part of the Thrace basin are cooler and thicker compared to the thinner layers in the margins of the basin.

The created paleo-heat flow model was based on the calibrated thermal maturity data from pyrolysis temperature (T_{max}), which is matched to those obtained in the software (Tmax_Pepper & Corvi, 1995, TIII_TIISA). In order to achieve an acceptable range for the reconstruction of the thermal history of the studied area, multiple scenarios of the paleo-heat flow models have been performed. After the analysis of the sensitivity of the paleo-heat flow model against the influence parameters, a final conceptual model of the heat flow in the region of P-1 Svilengrad Well was obtained. This model shows (Fig. 4), that the values range from 60 to 120 mW/m^2 and are higher than that of the present-day. Until the beginning of the Eocene the values kept constant (60 mW/m^2), then considerably increased from 97 to 107 mW/m^2.

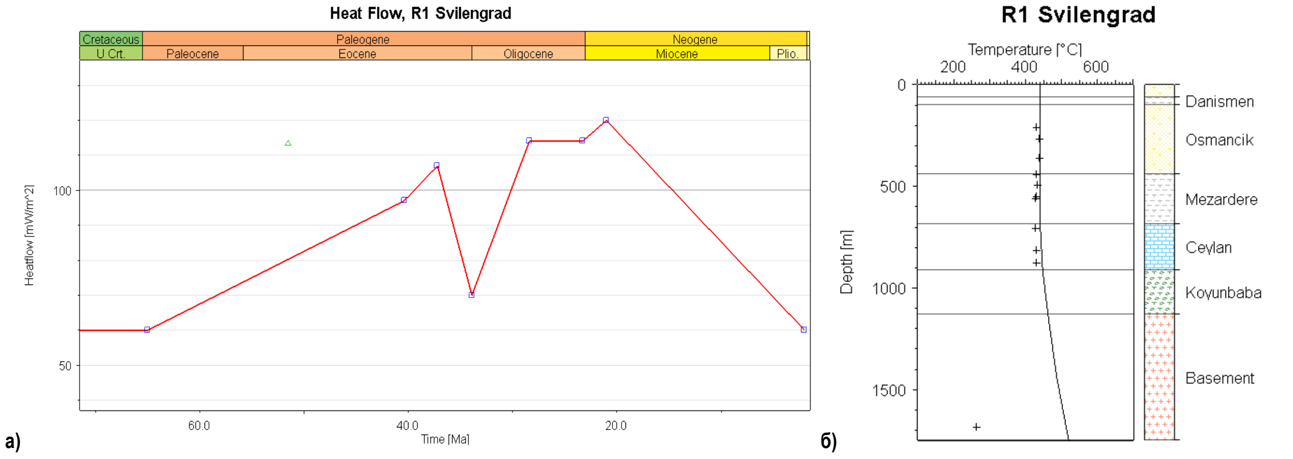

Fig. 4. Paleo-heat flow model for R-1 Svilengrad Well (a), calibrated values optimised modelled by the software with those measured at pyrolysis (b)

Increased values and occurrence of peak values are probably related to tectonic processes of basin opening. These processes influence thermal maturity of organic matter and generation potential of the potential source rock Hamitabat Formation and its analogue sediments on the Bulgarian territory. At the end of the Priabonian, a period of low heat flow values is observed (70 mW/m^2), followed by a new increase in the heat flow values with a trend of constant during the Oligocene (114 mW/m^2). At the end of the Miocene and the beginning of Pliocene, the highest peak in the value of heat flux (120 mW/m^2) was reached, which mark the beginning of new rift phase.

In order to create the temperature model, the present-day heat flow value of 58.5 mW/m^2 is assumed, which corresponds to the optimal present-day temperature modelled in the software with measured bottom-hole temperature in the well (Fig. 5). The model indicates that the paleo-temperature reached peak values during the Miocene, which coincides with the highest paleo-heat flow values at the same time.

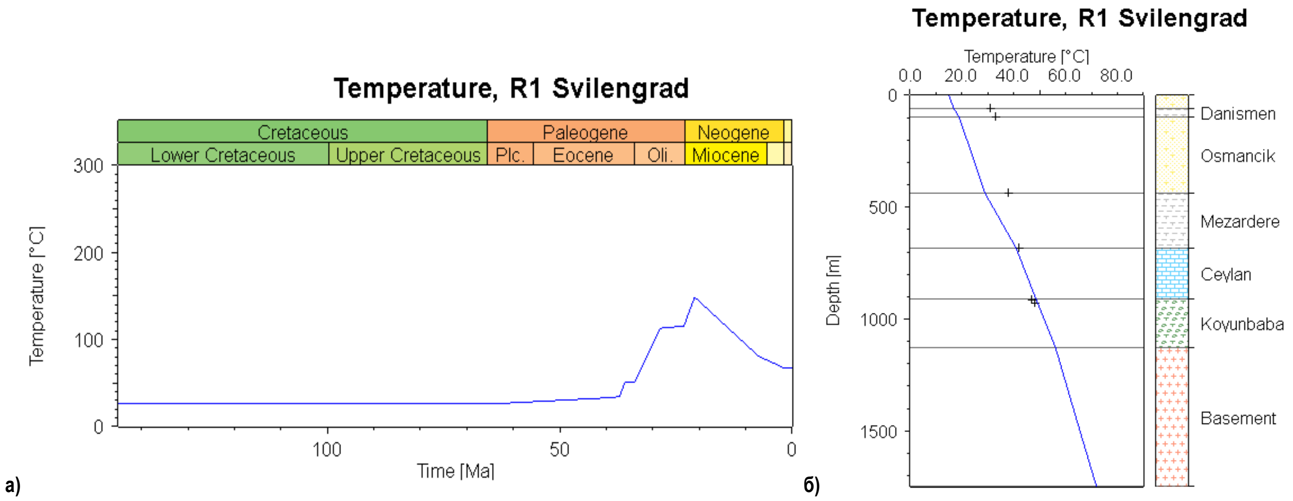

Fig. 5. Paleo-temperature model of R-1 Svilengrad Well (a), calibrated optimal present-day temperature values modelled by the software with measured bottom-hole temperature in the well (b)

This increase in paleo-heat flow and paleo-temperature values during the Miocene probably play an important role for thermal maturity of the organic matter and petroleum generation history of both estimated potential source rock of shale-marl and terrigenous-limestone-marl formations (Meracheva et al., 2017), as well as in the proved source rock Hamitabat Formation in the Turkish part of the basin (Gürgey, 2009).

Thermal maturity history modelling of potential source rock formation

Based on the fact that the sediments of shale-marl formation (analogue of Mezardere Fm.) were evaluated as potential gas generating and the Turkish researchers' suggestion (Hosgörmez, Yalçın, 2005), that Ceylan and Hamitabat Formations are the other two potential HC source rock for most of the oil and gas fields in the Thrace basin, a 1D maturity history modelling of these three lithostratigraphic units is made in this paper. 1D petroleum system thermal modelling was performed on four wells – R-1 Svilengrad – real and Pseudo P-1, Pseudo P-2, Pseudo P-3 – conditional wells. For the Hamitabat Formation, the lowest TOC and HI measured values in the Turkish part of the basin were obtained from the nearest Habiller-2 well. In this well the TOC values are 0.98 wt% and HI values – 164 mg HC/g respectively (Gürgey, 2009). For input parameters of the Ceylan Formation the average values used by the researchers for the analysis and thermal maturity reconstruction models in the basin (Hosgörmez et al., 2005; Hosgörmez, Yalçın, 2005; Palakarcheva, Stefanova, 2013) were taken in this paper – for TOC – 1.08 wt% and for HI – 256 mg HC/g respectively.

The thermal maturity model shows the HC generation zones for all sediment sequences during the different periods (Fig. 6). This hydrocarbon generation zone is simulated on the basis of the method used in the software, with three stages being distinguished: immature; oil window – early oil generation, main oil generation, late oil generation; gas window – wet gas, dry gas. The maturity models for all four simulated wells are similar and show that the potential source rock formations are at different stages of thermal maturity of organic matter.

Main conclusions

Evaluated as potential source rocks of the shale-marl formation, an analogue of the Mezardere Formation, they are in immature stage of maturity of organic matter in the studied area and could only generate biogenic gas. The models of the four wells show that evaluated as potential source rocks of the terrigenous-limestone-marl formation, analogue to Ceylan Formation, entered the oil window at the beginning of the Miocene and are at this stage to date. Thermal maturity models of the sediments, analogous of the proven source rock Hamitabat Formation in Thrace Basin, show that it has reached the peak of oil generation and has entered the oil window area relatively earlier than other potential source rock formations. In the regions of the three pseudo-wells located in the graben, the maturity of the Hamitabat Formation began in the Eocene, which can also be inferred from the burial history modelling. As can be seen from the created maturity models, the lower levels of the formation are adjacent to the gas window, which suggests that in close proximity to the study area where the formation is at a greater depth, it has reached maturity in order to produce gas since the beginning of the Miocene age to the present day.

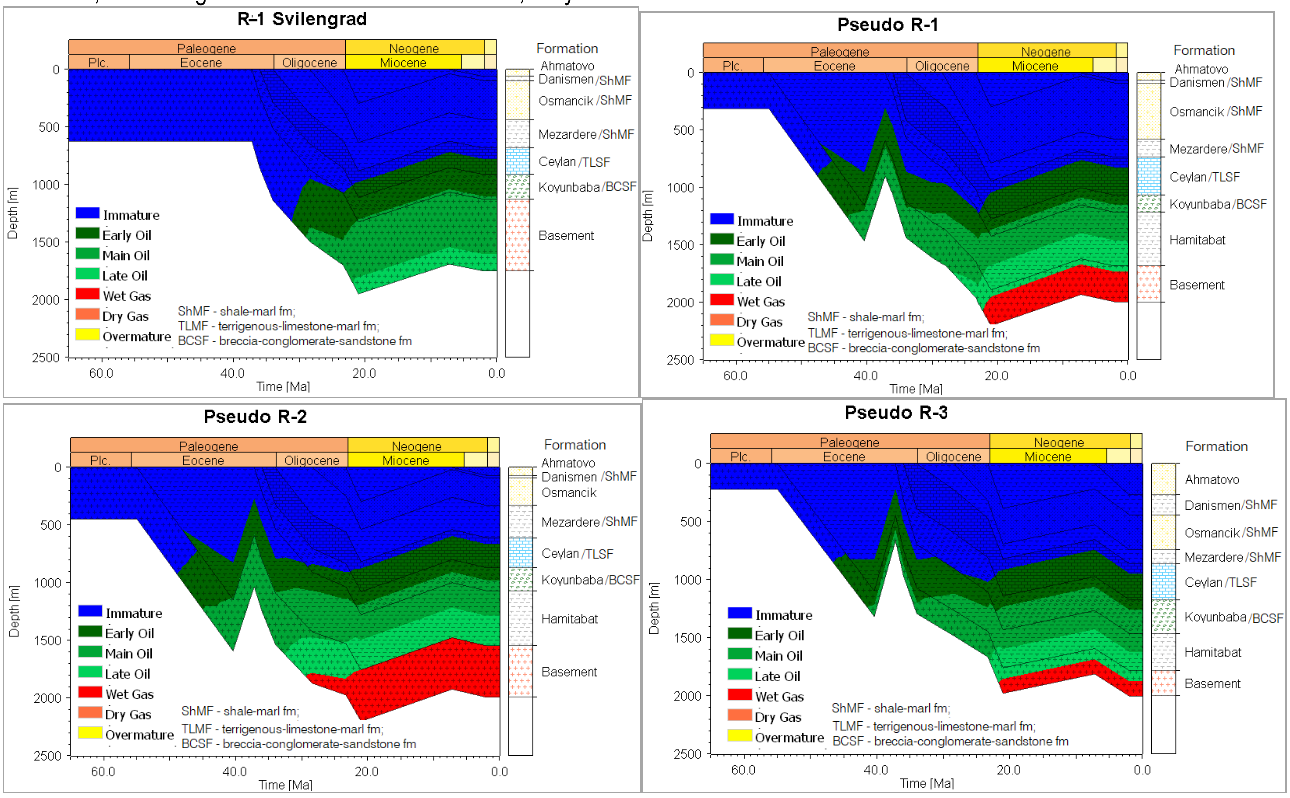

Fig. 6. Thermal maturity models of R-1 Svilengrad well and pseudo-wells – Pseudo R-1, Pseudo R-2, Pseudo R-3

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