Lithology and Mineral Resources, Vol. 39, No. 6, 2004, pp. 530–540. Translated from Litologiya i Poleznye Iskopaemye, No. 6, 2004, pp. 610–621.

Oil and Gas Potential of Deep- and Ultradeep-Water Zones of Continental Margins

V. E. Khain and I. D. Polyakova

Geological Institute, Russian Academy of Sciences,
Pyzhevskii per. 7, Moscow, 119017 Russia
e-mail: khain@ilran.ru; inna@ilran.ru

Received March 3, 2004

Abstract—Oil- and gas-bearing basins of the World Ocean spreading to the continental shelf and foothill are considered. Large hydrocarbon resources, including oil pools have been discovered in the deep-water basins. The basins are confined to passive continental margins and characterized by the common mechanism of formation. Oil and gas (hereafter, petroleum) generation and accumulation are dictated by the optimum specifics of source and reservoir rocks accumulated under favorable conditions of rifts and deep-sea fans. Halokinesis played an important role in the formation of traps and migration of hydrocarbons. The global experience shows that the northern, eastern, and southern shelves of the Russian seas, as well as their continental slopes and foothills, have a big petroleum potential.

The energy demands of many countries stimulated an intense development of prospecting for hydrocarbons in the bottom of seas and oceans. Investigations and the consequent discovery of oil and gas (hereafter, petroleum) fields progressively shift off the coast. During the two last decades, petroleum geologists have discovered more than 20 oil- and gas-bearing (hereafter, petroliferous) basins that extend beyond the shelf to the continental slope and foothill. The basins contain enormous hydrocarbon resources, and oil resources play a significant role among them. According to data reported in the major journals related to petroleum deposits (AAPG Bulletin, AAPG Explorer, Marine and Petroleum Geology, and First Break) in 2001–2003, the currently developed large deep-water oil and gas fields are confined to the following basins located at passive margins of the Atlantic Ocean: South American Basin (Roncador, Marlin, Albacora, and Barracuda), Mexican Basin (Crazy Horse, Mars, Mad Dog, and Trident), North American Basin (Shelburne, Shubenacadie, Newburn, and Tantallon), West African Basin (Agbami, Bonga, Erha, Bosl, Dalia, and Girassol), and North European Basin (Ormen Lange). Mainly gas fields are known in the Indian Ocean. They are situated near the coasts of North and Western Australia (Callirhoe, Geryon, Io, Scarborough, Brecknock, and Sunrise), in the Bay of Bengal near the coasts of southeastern India (Godavari), and in the Strait of Mozambique. In the Pacific Ocean, only rare hydrocarbon fields have been found so far (generally, near the shores of Southeast Asia). The majority of the listed fields and their proven reserves are illustrated in the schematic Fig. 1 compiled by H.S. Pettingill and P. Weimer (Shirley, 2002).

New petroleum fields are being discovered every year. They include a steadily increasing number of deep-water and ultradeep-water giant fields that start at a depth of 500 and 2000 m or more, respectively. It would be expedient to use the available information on the deep-water basins of the world in the prospecting for new perspective petroleum areas on shelves and continental slopes of Russia.

CONTINENTAL SLOPE OF THE WORLD OCEAN: A NEW LARGE BASE OF HYDROCARBON RESOURCES

According to H.S. Pettingill and O. Weimer, the oil equivalent related to deep-water and ultradeep-water petroliferous basins is equal to 9.2 Gt (as of September 2001). New discoveries made in 2002–2003 on the continental slope and foothill off Angola, Gabon, Nigeria, southeastern India, western Ireland, and the Strait of Mozambique indicate that the hydrocarbon resources have significantly increased over the last two years. The distribution of oil and gas pools is described below with several known fields as example.

The Atlantic margin of southeastern Brazil incorporates two large petroliferous basins (Campos and Santos). According to Meisling *et al.* (2001), the Campos Basin is noted for a higher commercial petroleum potential. Its proved (demonstrated) and probable (inferred) reserves are estimated at 1.9 Gt of oil and 266 bln m^3 of gas that make up 78% and 43% of the total identified resources of oil and gas, respectively, in Brazil. The commercial hydrocarbon potential of the Campos Basin was initially revealed in 1974 on land where more than 30 hydrocarbon fields were discovered by 1989. After 10 years, hydrocarbons were already extracted from depths of 500–2500 m in giant fields, such as Marlin, Albacora, and Roncador. The

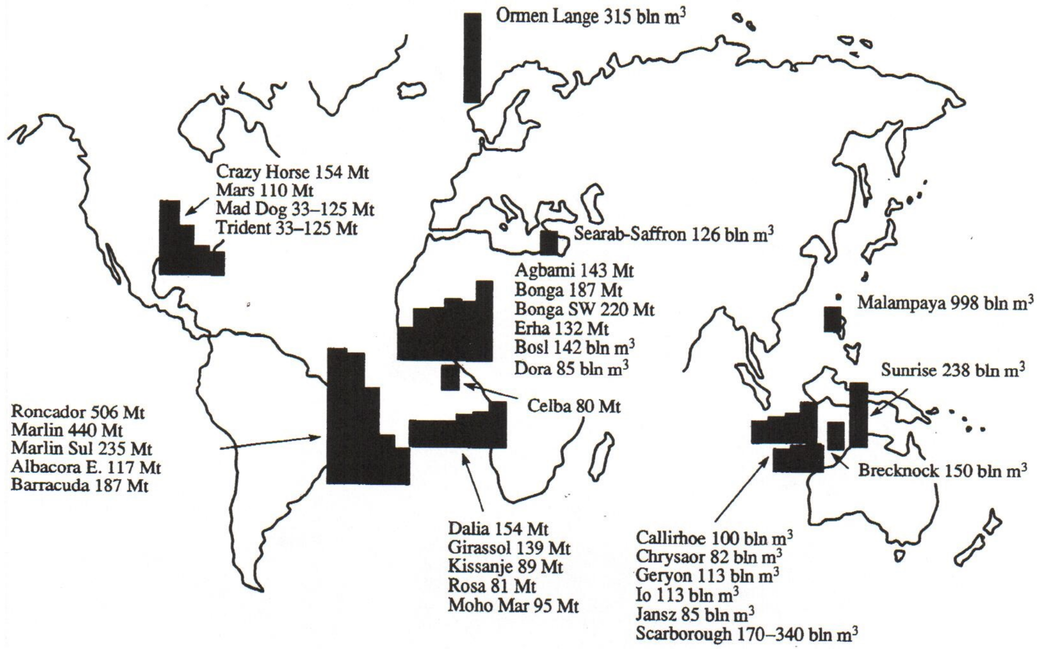

Fig. 1. Large discoveries of oil (Mt) and gas (bln m^3) on continental slopes of deep-water depressions as of September 2001 (Shirley, 2002).

Santos Basin is characterized by a lower petroleum potential. The prospecting drilling carried out on the shelf over many years resulted in the discovery of several noncommercial gas and condensed gas pools. The Tubarao field discovered in the southwestern part of the basin extends beyond the continental shelf.

Large hydrocarbon pools have also been discovered at depths ranging from 500 to 3000 m on the opposite (African) side of the Atlantic Ocean—the continental slope of the passive margin near Ghana, Nigeria, Cameroon, Equatorial Guinea, Congo Democratic Republic, Gabon, and Angola. Many experts believe that West Africa will begin to play a leading role in the world in the exploitation of deep-water areas of the World Ocean. Here, petroleum geologists have discovered 17 fields with the total resource of 1.43 Gt and the average oil equivalent (OE) reserve of 85 Mt in each field. British geologists R. Night, D. Harbinson, and D. Westwood scrutinized the petroleum potential of this region (Shirley, 2001). They noted that the average production in the West African fields can be five times higher than the expected production in the Gulf of Mexico by 2005. The annual total output of the largest fields of West Africa will be as high as 250 Mt OE or about 40% of the world output of hydrocarbons extracted from deep-water oil fields.

Particularly high perspectives are related to the Lower Congo Basin (Angola) that incorporates 14 deep-water fields with approximately 2.2 Gt OE. The basin occupies both the land and marine areas down to a depth of 3500 m.

New large gas deposits with a total reserve of 1.360 tln.m^3 have been discovered in the deep-water Orange River delta on continental slope in the southern area off Namibia. The total hydrocarbon reserve in two blocks of the basin with the total area of about 32000 km^2 may be several times higher than the above value (Shirley, 2003b).

The New Scotia petroliferous basin, 80000 km^2 in area, is situated at depths ranging from 200 to 4000 m on the continental slope of the North American Basin. The total gas and oil reserves of the basin are estimated at 4.2–11.6 tln m^3 and 0.44–0.99 Gt, respectively (Kidston *et al.*, 2002). The oil potential is significant and corresponds to the high oil/gas ratio that is common for other deep-water Circum-Atlantic regions. The discovery of oil and gas fields in the Nova Scotia Basin compelled petroleum geologists to revise the petroleum potential of the Canadian continental slope of the Beaufort-Mackenzie Basin, Jeanne d'Arc Basin in the Newfoundland shelf, Labrador shelf, and Sverdrup Basin in the Arctic Islands. Lithostratigraphic investigations of sediments in canyons and deep-water channels are already carried out in the Jeanne d'Arc Basin (Deptuck *et al.*, 2003).

The discovery of oil and gas in the Indian Ocean has considerable promise. For the present, only hydrocarbon pools near Indian shores and in the Strait of Mozambique are known. The Godavari gas field discovered at a depth of 900 m in the Bay of Bengal has a total reserve of 198 bln m^3. The recoverable reserve currently estimated at 142 bln m^3 can increase in the future (Shirley, 2003a).

Recently, new petroliferous basins have been discovered in deep-water areas of inland seas. Basins with a large gas potential have been discovered in the deep-water part of the Nile delta (Samuel *et al.*, 2003) and Algerian margin (Cope, 2003) in the Mediterranean Sea. Prospecting is in progress at a waterdepth of more than 1000 m.

Examples cited above indicate that the development of hydrocarbon resources in the shelf–slope basins promotes the creation of a new raw material base for the nearest future and even the present day in some regions.

EVOLUTION OF SHELF–SLOPE BASINS AT PASSIVE CONTINENTAL MARGINS

The evolution of shelf–slope basins started with the continental rift systems transformed after the breakup of the Gondwana supercontinent and the subsequent spreading of the seafloor into passive continental margins. These basins were characterized by the similar formation mechanism and scenario. Their evolution can be divided into three stages: synrifting, early spreading, and mature spreading. At the first stage, the continental rifting is accompanied by vigorous basaltic eruptions and the formation of relatively small lacustrine basins. At this stage, organic-rich clays (shales) with lenses of sandstones and interlayers of carbonates, salts, and volcanic rocks were accumulated in the Neocomian in the Campos and Santos basins (southeastern margin of Brazil), as well as the Niger and Lower Congo basins located at the opposite margin of West Africa. The rifting affected the North Atlantic as early as the Late Triassic–Lower Jurassic. In the Nova Scotia Basin, grabens and semi-grabens were filled with continental terrigenous sediments, basalts, and salts (in the uppermost part of the sequence). In the deep-water part of the Gulf of Mexico in the Central Atlantic, dispersed continental rifting took place in the Late Triassic–beginning of the Middle Jurassic.

The second (early spreading) stage is characterized by the initial opening of the basin and accumulation of thick salt layers therein owing to a restricted supply of seawater and arid climate. The regional-scale deposition of salts took place in the Aptian in basins of the South Atlantic and in the Early–Middle Jurassic in the North and Central Atlantic. At first, the salts temporarily isolated the lower rift complex. However, they subsequently promoted the active halokinesis and communication between the lower complex and the overlying units via salt windows.

The third stage was marked by the full-scale opening of the ocean, the development of a system of deep (up to 10–12 km) rift troughs extending into the shelf, and the simultaneous formation of rifts (transversal relative to the future margins) that produced triple junctions. River valleys developed along them terminated as deltas in the form of promontories at the margins (e.g., the Benue Rift at the head of the Gulf of Guinea and the Godavari Rift at the southwestern margin of the Bay of Bengal). The triple rift junctions served as the origin of deep-water basins (e.g., Brazil, Argentine, Angola, and Cape basins) within the single Atlantic Ocean. Passive continental margins appeared on slopes of the basins restricted from the ocean by the continental slope. The margins underwent a noticeable tectonic reactivation. This is evident from reconstructions of the evolution of some petroliferous basins in many regions of the Atlantic.

At the third (Late Cretaceous–Cenozoic) stage, the Atlantic rift margin of southeastern Brazil underwent a reorganization of older structures, volcanism, and folding (Cobbold, *et al.*, 2001). Mountain ridges arose and the drainage network changed in the adjoining land, leading to the expansion of terrigenous fans in the water areas to the continental slope and foothill. Surface deformations of the Aptian salts produced salt diapirs and provided the ascent of hydrocarbons to the upper sedimentary sequence through the windows between the diapirs. This was accompanied by increase in the number of anticlinal traps often related to diapirs and faults and rapidly filled with hydrocarbons.

Faults reactivated during the postrifting evolution of the Lower Congo Basin (Lavier *et al.*, 2000). Horizontal displacements were most active as a result of intense sedimentation and periodic reactivation. In the Cenozoic, the basin evolved on the passive inclined margin with a 600-m-high continental slope. During the Eocene–Oligocene, deep-water oceanic currents washed the slope and shelf, and terrigenous material with the enclosed salt bodies was transported downward the slope. This led to the formation of underwater scours and channels filled with turbidites at the site of salt domes. The Oligocene–Middle Miocene interval was marked by rise of the Congo margin by 330 m and increase in the transportation of turbidites to the deep-water zones. The recent Congo Fan extends to a depth of more than 5000 m and overlies the oceanic crust.

Listric faults played a significant role in the formation of petroliferous basins. This is especially obvious in the Nigeria Basin.

In the Nova Scotia Basin, the mature spreading stage was marked by the accumulation of predominantly deltaic terrigenous sediments on the mobile salt substratum. In the Cretaceous and Cenozoic, the basin floor was so much uplifted that submarine canyons situated on both the shelf and continental slope were exposed. This created favorable conditions for the formation of thick fans of turbidite sediments that subsequently served as oil source rocks and reservoirs.

The examples cited above demonstrate that the tectonic reactivation at the third stage of the development of the shelf–slope basins enhanced oil and gas accumulation. Differences in the evolution of basins were related to different timings of the rifting and spreading in separate parts of Pangea that governed the stratigraphic range, structure, and composition of the sedimentary cover. The comparison of geodynamic settings in different areas of the Atlantic showed that the rifting started in the northern and central parts in the Late Triassic–Early Jurassic and in the Late Jurassic–Early Cretaceous i.e., 100 Ma later in the South Atlantic.

PETROLEUM SOURCE ROCKS

Shelf–slope petroliferous basins of passive margins have some specific features affecting petroleum generation and accumulation. First of all, they incorporate two main types of high-grade and very high-grade source rocks. The first type includes black shales with large resources of liquid hydrocarbons in marginal basins of the Atlantic. The second type is represented by sediments that contain abundant terrestrial plant detritus and produce hydrocarbon (often, medium-volatile) gases. They are encountered on passive margins of the Atlantic and Indian oceans.

In order to demonstrate the oil generation potential of source rocks of the first type included in the subsalt and suprasalt complexes, let us briefly consider their geochemical characteristics. The subsalt oil source rocks accumulated at the rifting stage of the basin formation under lacustrine (often, saline) conditions. According to Mello *et al.* (1988, 1989), the Lower Cretaceous Lagoa Feia Formation in the Campos Basin has a high source potential (Fig. 2). It is composed of siliceous–carbonate mudstones with a high TOC content (up to 5%), high generation potential (up to 38 kg HC/t rocks), and hydrogen index HI (up to 850 mg HC/g OM). The OM composition of this sequence is mainly composed of amorphous sapropelic material (80–90%) that is sufficiently mature and capable of the intense generation of liquid hydrocarbons. The comparison based on the biomarkers and carbon isotopy of bitumoid-containing oils showed that the Lagoa Feia Formation is the principal generator of liquid hydrocarbons in the basin. It is not excluded that the accumulation of organic-rich sediments was accompanied by the input of deep gas fluids with nitrogen, sulfur, and phosphorus into the rift basin that increased its bioproductivity. In the Campos Basin, the Lagoa Feia Formation is of commercial importance in the Marlin, Albacora, Roncador, and Barracuda fields.

The Neocomian Guaratiba Formation in the Santos Basin represents an analogous source sequence, which is catagenetically altered to the overmature state (Meisling *et al.*, 2001). However, hydrocarbon pools genetically related to the Guaratiba Formation have recently been discovered in the northern part of this basin. It is evident that the Guaratiba Formation did not completely lose its generation potential due to the high lipid content in organic matter. The overlying hydrocarbon pools in the Tubarao field in the Santos Basin are related to the Upper Cretaceous (Itajar and Tubarao) source sequences.

No less productive source rocks are developed on the opposite West African margin of the Atlantic Ocean in the Niger and Congo river deltas. In terms of geochemical characteristics, the Upper Cretaceous Akata Shale (Nigeria) and Paleogene Landana Clay (Angola) are highly competitive with the Lagoa Feia Formation and belong to the world-class source rocks. They host large oil fields, such as Bonga, Southwestern Bonga, Erha, and Agbami. The Lower Congo Basin incorporates two Upper Cretaceous (Bicomazy and Labe) and two Tertiary (Landana and Malembo) oil source formations (Fig. 3).

The suprasalt oil source formations accumulated in deep-water fans of large rivers under the influence of marginal filters described by Lisitsyn (2004). The mixing of river and marine waters is accompanied by not only the settling of approximately 93% of sedimentary material, but also the avalanche accumulation of organic carbon because of thickening of the photic layer accessible for the development of plankton. The bioproductivity of this layer is promoted by upwelling that emerges near the continental slopes and delivers the essential nutrients from deep waters. Consequently, high-quality source sediments are accumulated in such areas to produce a large mass of liquid hydrocarbons.

The second type of oil source formations characterized by a high concentration of the terrestrial plant detritus initially accumulated in coastal and shallow-water zones. The subsequent offshore displacement of progradation complexes promoted the deposition of the terrigenous organic material at marginal filters and the oceanic plankton material in fans that extended to not only the shelf, but also the continental slope and foothill where oil source sediments were finally formed. This type of deposits is known in Nigeria, Brunei, southeastern Borneo, and southeastern India. Such sequences include the Bonga, Erha, and Agbami medium-volatile gas fields (Nigeria) and the Godavari gas field (the Bay of Bengal, India).

PETROLEUM RESERVOIRS

Petroleum reservoirs in the outer zone of passive margins are also characterized by very specific features. They originated during the reactivation of ancient faults in the territory. The supply of large masses of sediments to water areas significantly activated strike-slip faults. Canyons and/or diverging channels originated above the older faults and tectonic structures reflected in the seafloor topography (Kolla *et al.*, 2001). The development of many perioceanic basins culminated with the formation of large submarine fans that covered passive continental margins and locally extended to the continental slope and foothill. This is evident from the recent Congo River Fan (Fig. 4).

Canyons and diverging channels served as transit zones for turbidite sediments and sites for the deposition of the rewashed (mainly coarse-grained) sand and gravel. Wynn *et al.* (2002) revealed that these zones are marked by various erosion structures that are also developed at the recent European margin, e.g., the spoon-shaped Agadir Canyon, which serves as the tran-

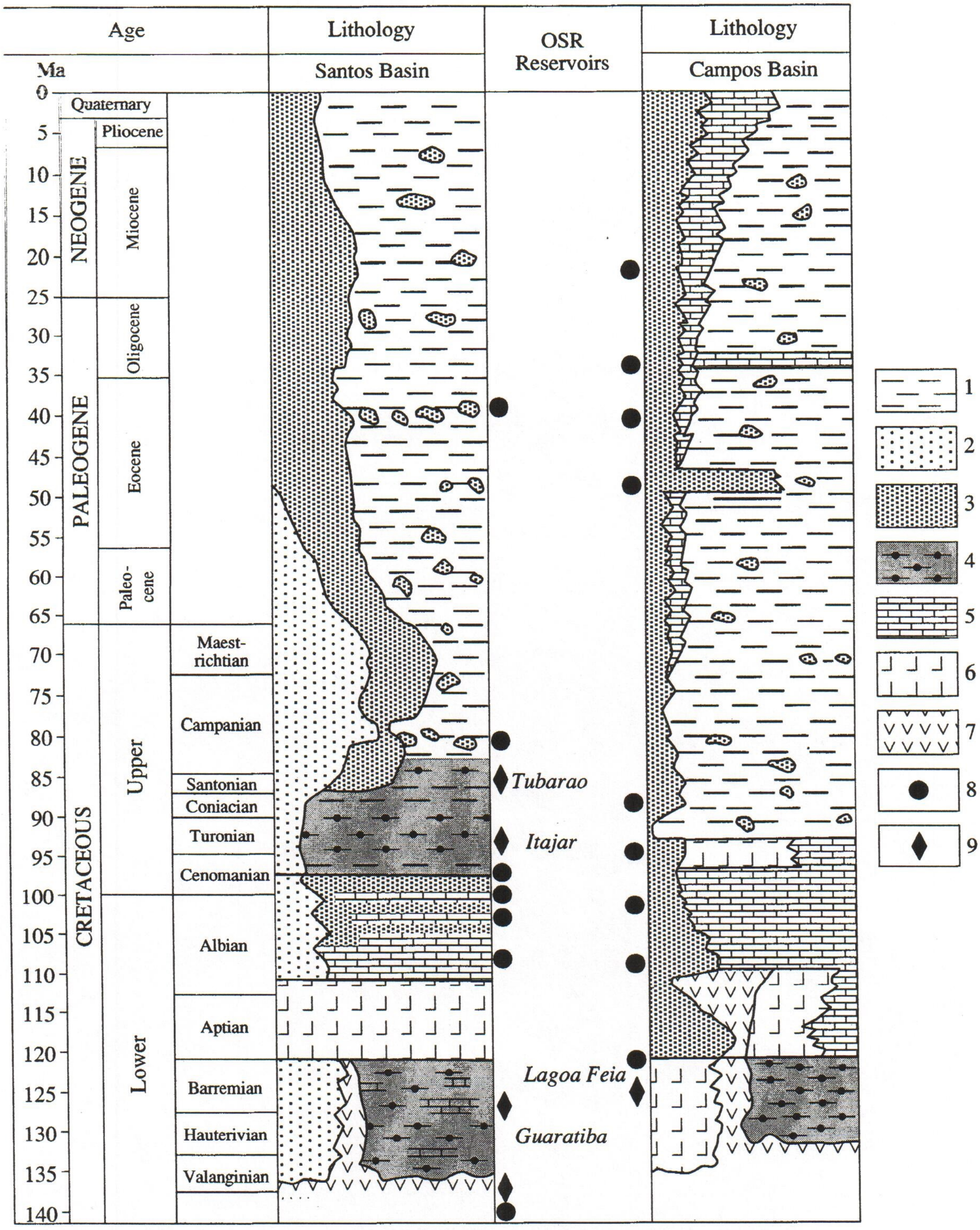

Fig. 2. Composite lithostratigraphic columns of the Santos and Campos basins showing oil source rocks (OSR) and reservoir rocks (after Meisling *et al.* 2001, simplified). (1) Clays and shales; (2) fine-grained sandstones; (3) coarse-grained sandstones; (4) bituminous clays and shales; (5) carbonates; (6) salt; (7) volcanics; (8) reservoirs; (9) OSR.

sit zone for the transport of sediments from the Moroccan shelf to the Agadir Basin slope and Madeira abyssal plateau, and the V-shaped Lisbon Canyon in the west of the Portuguese margin. Isolated spoon- and V-shaped scours in the areas of intense erosion are united into the kilometer-scale diverging channels. Sedimentary layers in such structures resemble waves with a length of up to 1–2 km and height of up to 4 m.

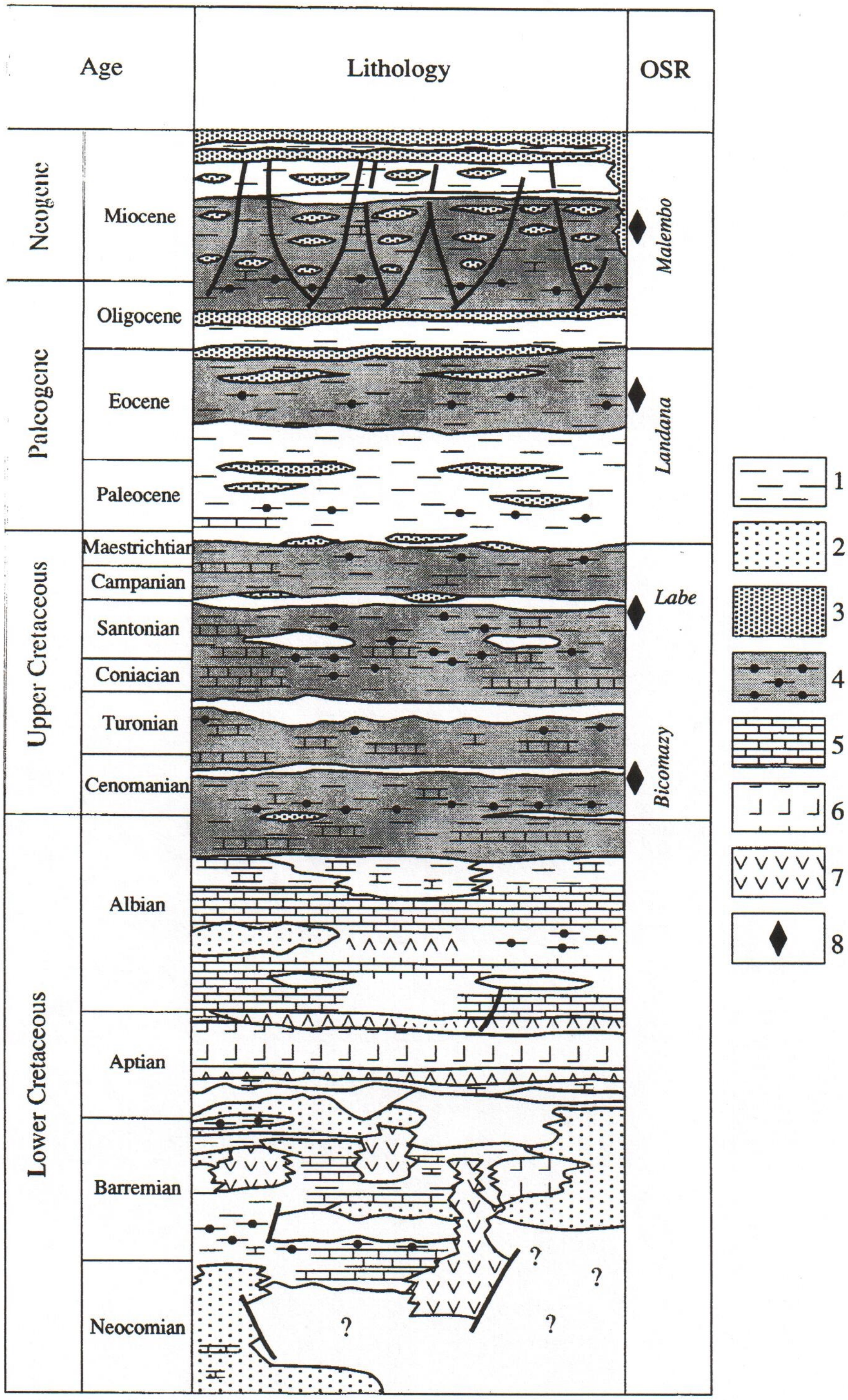

Fig. 3. Composite lithostratigraphic column of the Lower Congo Basin showing oil source rocks (OSR) (after Valle *et al.*, 2001, simplified). (1) clays, shales; (2) fine-grained sandstones; (3) coarse-grained sandstones; (4) bituminous clays and shales; (5) carbonates; (6) salt; (7) volcanics; (8) OSR.

The channels cut through clayey sequences and, together with them, form deep-water fans. Sometimes, they represent paleodeltas similar to those that produced by the Niger, Congo, Amazon, Mississippi, Indus, Gang, Nile, and other large rivers. The Tertiary clayey sequence of the Congo Fan often includes sand lenses associated with a dense network deep-water channels (Fig. 5). In the southern part of the Brazilian continental margin, they form the Sao Tome deep-water turbidite system (Fig. 6). Some channels have a rather complicated structure. For example, the deepening of the Nile Delta was accompanied by the formation of

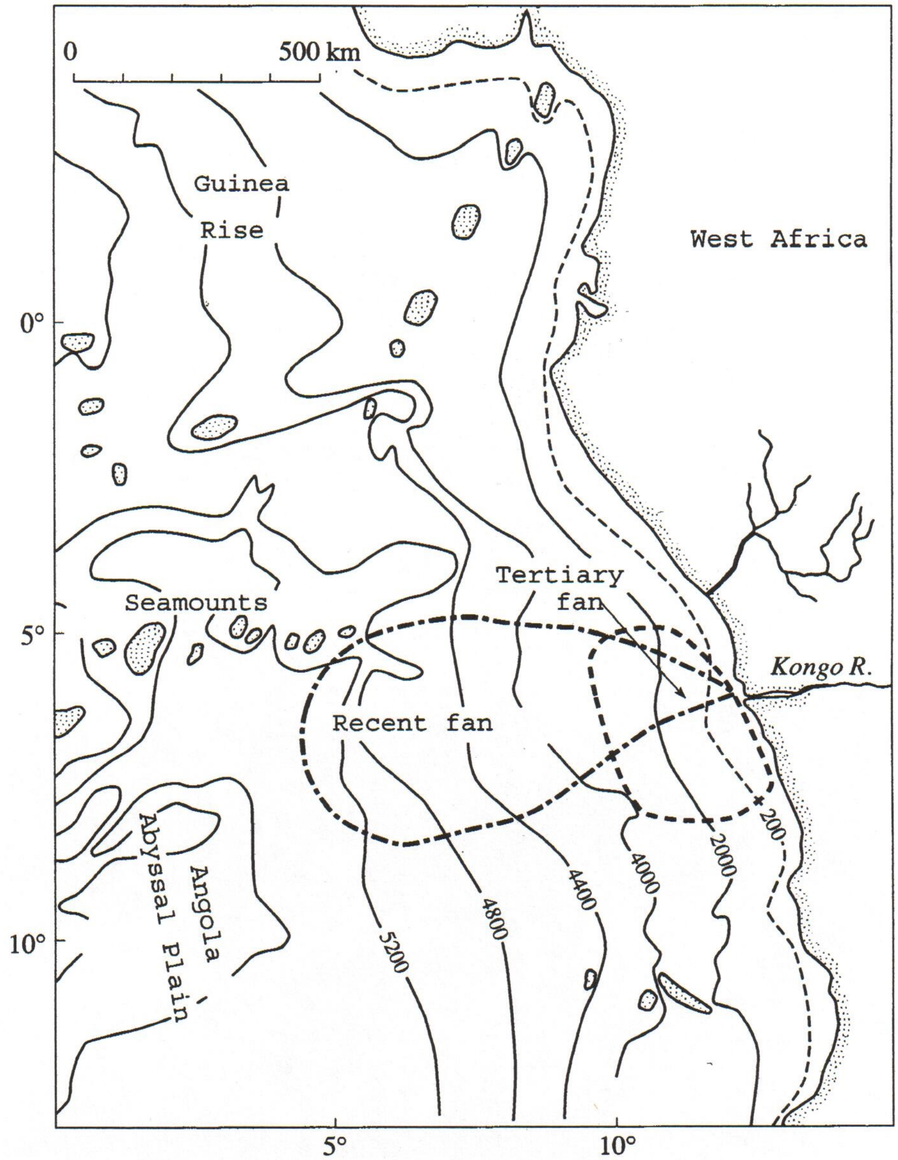

Fig. 4. Bathymetric map of the Gulf of Guinea (West Africa). Configurations of the Recent and Tertiary fans of the Congo River are shown (after Piper and Normark, 2001).

secondary channels over the initial channels and the development of double thalwegs and specific scars on the channel walls. Consequently, the deep-water zones were complicated by a network of channels that hosted reservoirs with a significant hydrocarbon potential. Based on the volumetric ratio of sediments, one can distinguish predominantly clayey or sandy fans with the corresponding prevalence of oil source rocks or reservoir rocks.

However, such general description of fans seems to be insufficient for the elucidation of their specific petroleum potential. Piper and Normark (2001), who studied numerous fans off America using the seismic and deep-water drilling data, concluded that the architecture of fans and its discrete elements are of great importance in petroleum geology, particularly in the case of sandy sediments in thalwegs and walls of the channels. Here, filtration-capacity properties of sediments are appreciably variable. They are relatively stable in the lateral direction and sufficiently variable in the vertical direction at contacts with the clayey deposits. The mapping of the sand channels is a difficult task, because many of them have a predominant sinuous shape in the plan view. Deep-sea channels and fans were revealed by the sidescan sonar survey of the seafloor and the 3-D seismic profiling that made it possible to decipher several morphological features.

The majority of basins with well-developed sediment transit systems are petroliferous structures that contain very large hydrocarbon pools. The channels host not only lithological traps, but also structural traps related to uplifts, salt domes, and faults. When studying

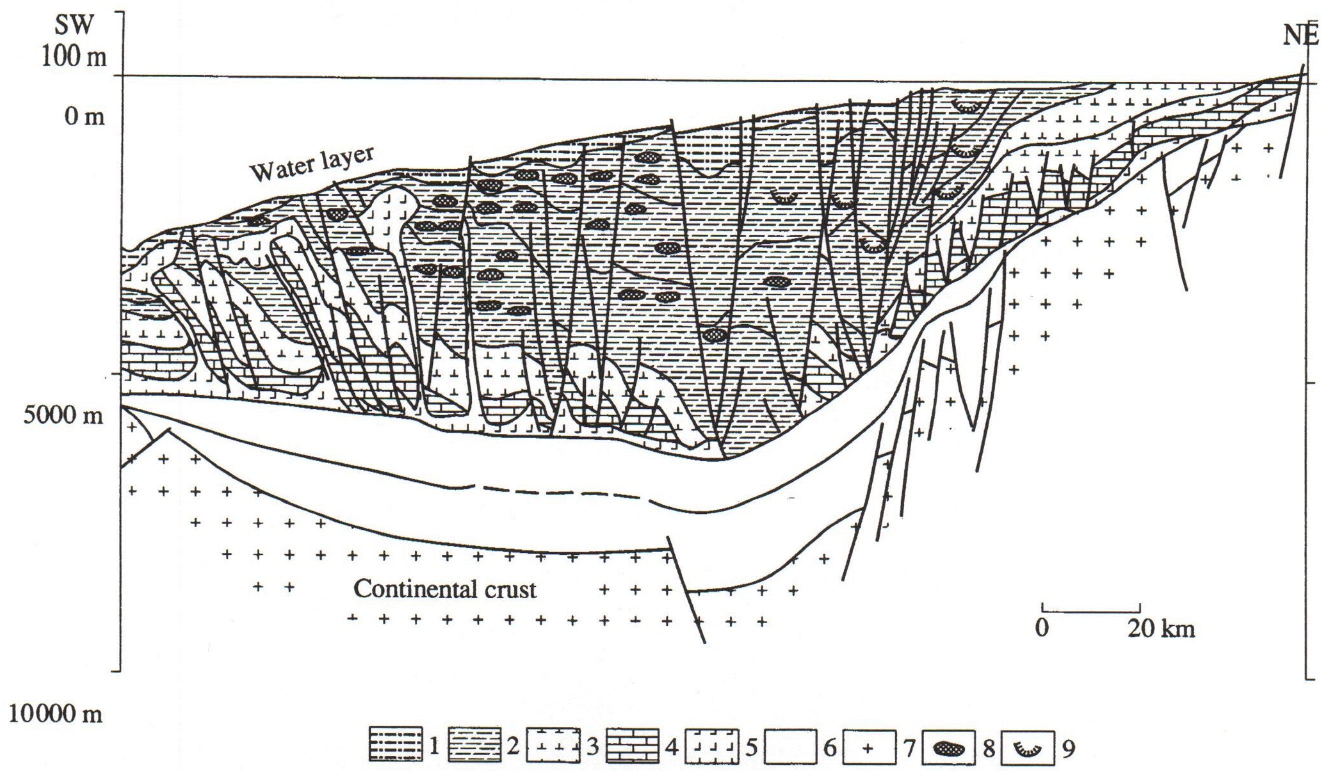

Fig. 5. Cross-section of the Tertiary fan of the Congo River (after Piper and Normark, 2001). (1) Pliocene–Pleistocene; (2) Oligocene and Miocene; (3) Upper Cretaceous and Eocene–Paleocene; (4) Albian; (5) Loma evaporites, (6) pre,- syn,-, and postrifting sediments; (7) basement; (8) systems of deep-water channels; (9) canyons.

these traps, petroleum geologists tend to estimate the influence of deep-water conditions of sedimentation on reservoir productivity. D. Larue scrutinized 450 reservoirs in the series of alluvial, coastal, and deltaic submarine fans in Texas and came to the following very important conclusions (Shirley, 2003c). Despite the interrelation of reservoir productivity with specific features of sedimentation and mechanism of sedimentary material transport, the deep-water zones do not basically differ from other sedimentary systems with respect to mining efficiency. Hence, the risk for petroleum companies during the exploration in deep-sea conditions is not significantly higher than that in other well-studied areas.

ROLE OF SALTS IN PETROLEUM FORMATION AND ACCUMULATION

Processes of petroleum formation and accumulation were significantly governed by the regional salt accumulation at the initial rifting and early spreading. Salt sequences initially isolated deposits of the rift complex and served as a screen for fluids. The salts experienced surface deformations during the subsequent tectonic reactivation. The halokinesis produced diapirs and windows between them. The diapirs promoted the formation of traps, whereas the windows served as pathways for hydrocarbon migration to the overlying sedimentary units. In addition, the high thermal conductivity of salts lowered the temperature of the subsalt complex, slightly neutralized the impact of basaltic volcanism, and, thus, preserved the hydrocarbon generation potential of the deep-seated rocks.

The cross section of the Gulf of Guinea (Fig. 7) shows that salt bodies divided the sedimentary cover into small basins locally overlapped by salts, resulting in the autonomous development of processes of petroleum generation and accumulation within these small basins.

THE RUSSIAN PERSPECTIVES

What practical conclusions for Russia can be derived from the facts listed above? Although hydrocarbon resources of the Russian shelves are not completely clear, we must take into consideration the foreign experience and think about the potential reserves of our continental margins, including the Arctic, Pacific, and southern margins.

In the Arctic periphery, the continental slope and foothill of the Barents, Kara, and Laptev seas facing the Nansen Deep in the Eurasian Basin of the Arctic Ocean deserve attention. This basin started to form at the very beginning of the Eocene and accumulated a thick sequence of terrigenous sediments delivered from the mainland by the Ob, Yenisei, and Lena rivers. The

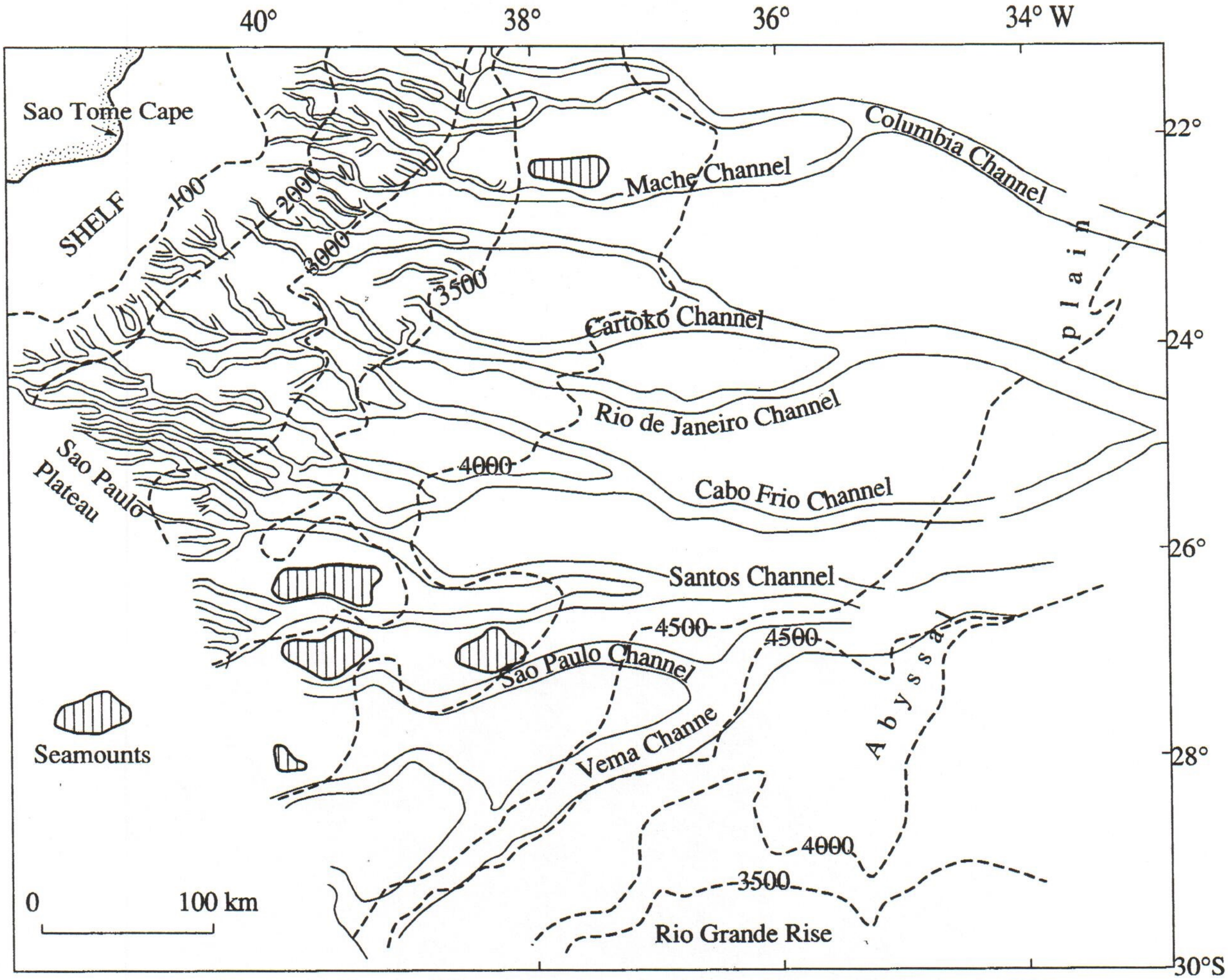

Fig. 6. Physiographic map of the continental margin off South Brazil (after Viana *et al.*, 2003).

transverse (relative to the slope margin) Saint Helena, Voronin, and Ust'-Lensk graben-rifts could serve as the primary channels for the transportation of sediments to the deep-water zones. The continental slopes and foothills adjoining these rift structures represent the sites where one can expect the presence of turbidite fans that are most favorable for hydrocarbon accumulation.

Conditions are more variable and several regions can be favorable at the Pacific margin. The first region is the slope and foothill of the Central Okhotsk Rise facing the South Okhotsk Basin, where the complete Paleogene sequence overlain by thick Neogene sediments has recently been discovered. The eastern margin of Sakhalin Island facing the Deryugin Basin is already an object of active study by petroleum geologists. The western margin of Kamchatka facing the TINRO Basin is also worthy of attention. In the Russian part of the Bering Sea, the continental slope and foothill of the northwestern margin of the Aleut Basin adjoining the Koryak Highland (especially, the Khatyrka River delta area) are of indubitable interest. Finally, the zone extending along Kamchatka and the Kuril Islands adjoining the Komandorskaya Basin (Bering Sea) and Northwestern Basin (Pacific Ocean) has a high oil potential.

Within the southern Russian margin, the perspective objects include the Caucasian margin of the Black Sea and its continental slope and foothill that simultaneously represent the slope of the Tuapse Trough. They include the Oligocene–Lower Miocene Maikop Formation and younger Miocene sediments. As known, this formation is a regional-scale oil-bearing unit in the Caucasus. In the Maikop Formation, clays are supplemented with thick sandstones, and development of turbidite fans can be expected on the slope of the Tuapse Trough. However, like counterparts in the Kuril–Kamchatka region, deposits of the continental slope and foothill at the Caucasian margin are deformed into a system of folds and thrusts that make up the accretionary prism.

CONCLUSIONS

The exploration and exploitation of hydrocarbon pools of the continental slope and foothill is undoubtedly a new and important stage in the global develop-

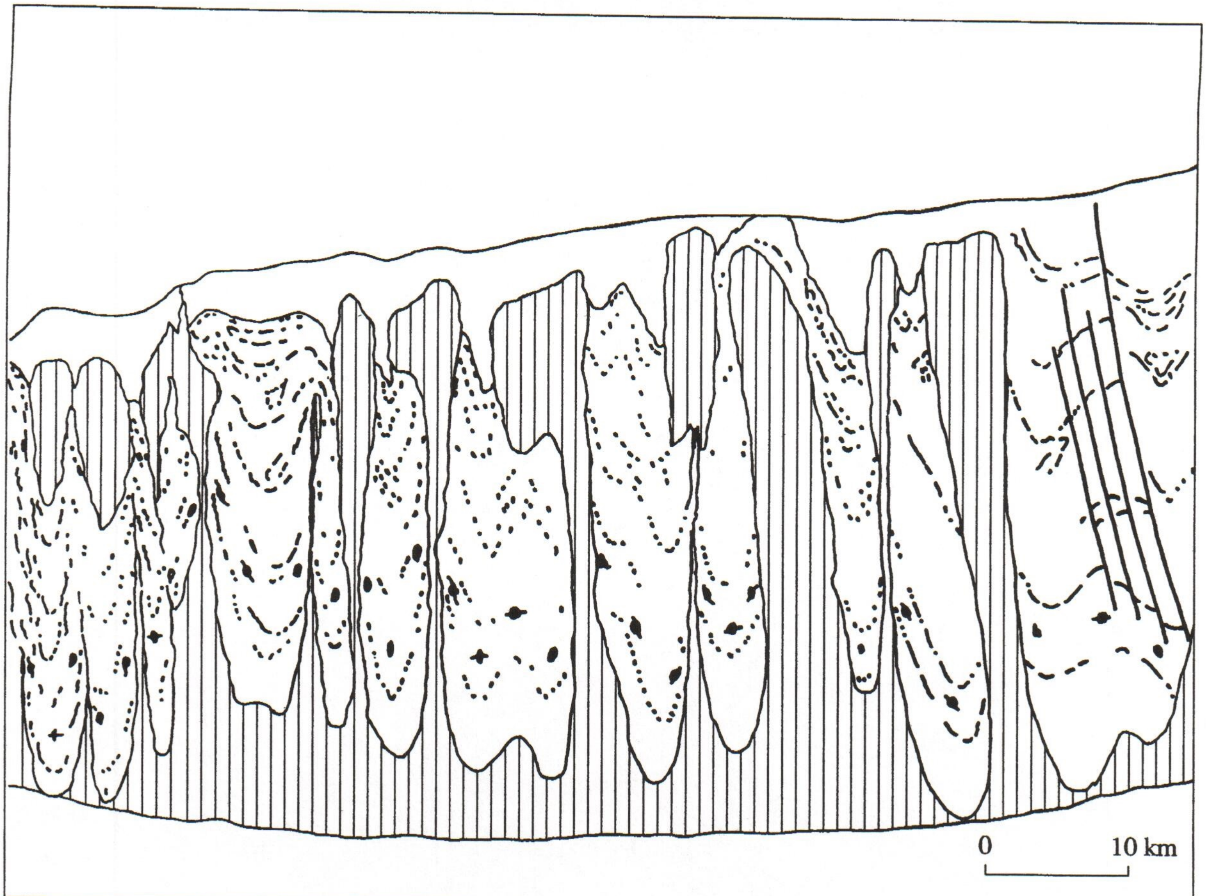

Fig. 7. Cross section of salt structures in the deep-water zone of the Gulf of Guinea (after Lafond *et al.*, 2003).

ment of these energy resources. The corresponding efforts already had a significant success. They resulted in the discovery of several giant and supergiant petroleum fields, particularly at the Atlantic margin. Although the works formulated above are a rather remote perspective for our country and their possible results may be modest, the possibilities arising in this respect must necessarily be taken into account.

ACKNOWLEDGMENTS

This work was supported by the Russian Foundation for Basic Research (project no. 02-05-64392) and the Foundation of the President of the Russian Federation for the Support of Leading Scientific Schools (project no. NSh 1980.2003.5).

REFERENCES

Cobbold, P.R., Meisling, K.E., and Mount, V.S., Reactivation of an Obliquely Rifted Margin, Campos and Santos Basins, Southeastern Brazil, *AAPG Bull.*, 2001, vol. 85, no. 11, pp. 1925–1944.

Cope, M.J., Algerian Licensing Round May Offer Opportunity for Exploration Plays in Deep Offshore Frontier, *First Break*, 2003, vol. 21, pp. 37–42.

Deptuck, M.E., MacRae, R.A., and Shimeld, J.W., Revised Upper Cretaceous and Lower Paleogene Lithostratigraphy and Depositional History of the Jeanne d'Arc Basin, Offshore Newfoundland, Canada, *AAPG Bull.*, 2003, vol. 87, no. 9, pp. 1459–1483.

Kidston, A.G., Broun, D.E., Smith, B.M., and Geoph, P., Optimistic Assessment for Hydrocarbon Potential of Deep Water Scotian Slope, Offshore Nova Scotia, *First Break*, 2002, vol. 20, pp. 662–665.

Kolla, V., Bourges, Ph., Urruty, J.-M., and Safa, P., Evolution of Deep-Water Tertiary Sinuous Channels Offshore Angola (West Africa) and Implications for Reservoir Architecture, *AAPG Bull.*, 2001, vol. 85, no 8, pp. 1373–1405.

Lafond, C., Jones, I.F., Bridson, M., Houllevigue, H., and Kerdraon, Y., Imaging Deepwater Salt Bodies in West Africa, *Leading Edge*, 2003, vol. 22, no. 9, pp. 893–896.

Lavier, L.L., Steckler, M.S., and Brigaud, F., An Improved Method for Reconstructing the Stratigraphy and Bathymetry of Continental Margins: Application to Cenozoic Tectonic and Sedimentary History of the Congo Margin, *AAPG Bull.*, 2000, vol. 84, no. 7, pp. 923–939.

Lisitsyn, A.P., Flows of the Sedimentary Substance, Natural Filters, and Sedimentary Systems of the "Living Ocean", *Geol. Geofiz.*, 2004, vol. 45, no. 1, pp. 15–48.

Meisling, K.E., Cobbold, P.R., and Mount, V.S., Sedimentation of an Obliquely Rifted Margin, Campos and Santos Basins, Southeastern Brazil, *AAPG*, 2001, vol. 85, no. 11, pp 1903–1924.

Mello, M.R., Koutsoukos, E.A.M., Hart, M.B., *et al.*, Late Cretaceous Anoxic Events in Brazilian Continental Margin, *Org. Geochem.*, 1989, vol. 14, no. 5, pp. 529–442.

Mello, M.R., Telnaes, P.C., Gaglianone, M.I., *et al.*, Organic Geochemical Characterisation of Depositional Palaeoenvironments of Source Rocks and Oil in Brazilian Marginal Basins, *Org. Geochem.*, 1988, vol. 13, no. 1, pp. 31–45.

Piper, D.J.W. and Normark, W.R., Sandy Fans - from Amazon to Hueneme and Beyond, *AAPG Bull.*, 2001, vol. 85, no. 8, pp. 1407–1438.

Samuel, A., Kneller, B., Raslan, S., Sharp, A., and Parsons, C., Prolific Deep-Marine Slope Channels of Nile Delta, Egypt, *AAPG Bull.*, 2003, vol. 87, no. 4, pp. 541–560.

Shirley, K., Angola Hottest of the Hot Offshore, *AAPG Explorer*, 2001, pp. 1–5.

Shirley, K., Global Depths Have Great Potential, *AAPG Explorer*, 2002, pp. 16–17.

Shirley, K., India Gas Find Has Major Impact, *AAPG Explorer*, 2003a, p. 8.

Shirley, K., Different Data Gave New Insights, *AAPG Explorer*, 2003b, pp. 14–15.

Shirley, K., Deepwater Pools Share Attributes, *AAPG Explorer*, 2003c, pp. 22–23, 25.

Valle, P.J., Gjelberg, J.G., and Helland-Hansen, W., Tectonostratigraphic Development in the Eastern Lower Congo Basin, Offshore Angola, West Africa, *Mar. Petrol. Geol.*, 2001, vol. 18, no. 8, pp. 909–927.

Viana, A., Figueiredo, A., and Faugeres, J.-C., *et al.*, The Sao Tome Deep-Sea Turbidite System (Southern Brazil Basin): Cenozoic Seismic Stratigraphy and Sedimentary Processes, *AAPG Bull.*, 2003, vol. 87, no. 5, pp. 873–894.

Wynn, R.B., Kenyon, N.H., and Masson, D.G., Characterization and Recognition of Deep-Water Channel-Lobe Transition Zones, *AAPG Bull.*, 2002, vol. 86, no. 8, pp. 1441–1462.