geosciences

Article

Assessment of Oil and Gas Potential in Vychegda Trough in Connection with the Identification of Potential Petroleum Systems

Sergey Krivoshchekov * and **Andrey Botalov**

Petroleum Geology Department, Perm National Research Polytechnic University, Komsomolsky Prospect, 29, 614990 Perm, Russia; botalov97@yandex.ru
* Correspondence: krivoshchekov@pstu.ru

Abstract: At present, the study of the oil and gas potential of poorly explored areas of oil and gas basins in the Russian Federation is of great importance due to the possibility of discovering large hydrocarbon accumulations in them. The Vychegda Trough in the north of the Volga–Ural basin is considered to be one of such areas. The research is devoted to the assessment of the oil and gas potential of the Vychegda Trough based on the concept of "petroleum systems", which is widely used in oil and gas geology. A comprehensive analysis of geological and geophysical, petrophysical and geochemical data was carried out, and modern technologies for studying the oil and gas potential of sedimentary basins were applied: paleotectonic, paleogeographic reconstructions and basin modeling. The results of the research allowed us to determine a sufficiently high potential for the discovery of hydrocarbon accumulations and to identify three potential petroleum systems in the basin section: Riphean, Vendian and Devonian–Permian.

Keywords: Vychegda Trough; hydrocarbons; oil and gas potential; paleogeographic and paleotectonic reconstructions; petroleum systems; reservoir rock; seal rock; source rock; organic matter; basin modeling

check for updates

Citation: Krivoshchekov, S.; Botalov, A. Assessment of Oil and Gas Potential in Vychegda Trough in Connection with the Identification of Potential Petroleum Systems. *Geosciences* **2024**, *14*, 57. https://doi.org/10.3390/geosciences14030057

Academic Editors: Daniel Rodrigues do Nascimento Junior, Ana Clara Braga de Souza, Thomas Gentzis and Jesus Martinez-Frias

Received: 4 December 2023
Revised: 12 February 2024
Accepted: 17 February 2024
Published: 21 February 2024

1. Introduction

The Vychegda Trough, as well as many other ancient graben-like structures in the east of the East European Platform, remains poorly studied to date; nevertheless, they attract the attention of many scientists [1–3] because of their allegedly high potential for finding hydrocarbon (HC) accumulations.

In this respect, the authors have carried out research to assess the HC potential at the Vychegda Trough on the basis of the concept of "petroleum systems", which is widely used in oil and gas geology. This concept dates back to the 1970s, when geologists and geochemists had developed methods of the quantitative prediction of HC potential in sedimentary strata [4]. The term "petroleum system" was first introduced by Dow [5] when studying the Williston Basin (USA) in order to determine the genetic relationships between HC and source rocks. A number of scientists worked on this theory independently, so it is known under several names, in particular, the "generative basin" [6], "HC machine" [7] and "independent petroleum system" [8]. The concept was later more rigorously defined by Magoon and Dow [9]. The term "petroleum system" is now widely used in oil and gas geology [10–12], and it is understood as a geological system that includes HC source rocks and genetically related oil and gas, as well as all geological elements and processes that are necessary for the occurrence of HC accumulations. The main elements are the source rock, reservoir rock, seal rock and overburden rocks, the latter contributing to the submergence of the others. The processes include trap formation, HC generation, migration and accumulation. In order for the organic matter (OM) of the source rock to be converted to oil and gas, and for HC to be accumulated and conserved, the aforementioned elements and processes must develop in the right sequence. If at least one element or process is missing or does not occur in the sequence in which it should occur, the petroleum system loses its existence [13]. It is known that petroleum systems are named after one of the main geographical objects of the area under study, by the age or name of the section complex in which source rocks and reservoirs occur. As a rule, the identification of petroleum systems begins with the identification of source rocks and determining their genetic relationships with HC accumulations or manifestations [14].

The Volga–Ural Basin is one of the largest and oldest oil- and gas-producing regions of the Russian Federation [15,16]. Oil and gas fields are being extensively developed here to date; most of them were discovered in the last century and are now in the final stages of development. Therefore, the task of identifying new HC accumulations in promising areas is quite urgent.

The Vychegda Trough is an area in the north of the Volga–Ural Basin that is structurally and evolutionally complex, but quite promising in terms of HC prospectivity. Despite the fact that the area is understudied by deep, exploratory drilling and seismic surveys, there are certain prerequisites indicating the presence of oil and gas potential.

Firstly, various manifestations of HC in the Upper Paleozoic complex were noted during drilling wells [17]. The rocks are saturated with highly viscous oil and bitumen, as well as nitrogen gas with a high helium content and low methane. The rocks are often characterized by the presence of oil manifestations in the form of oily droplets, spots and stains on the core samples. In addition, a number of wells yielded mineralized formation water with flow rates from 4 to 300 m^3/day with dissolved gas (methane up to 32%) and oil film on the surface, and gas bubbling and gushing were observed at some of the wellheads.

Secondly, in the far southeast of the Vychegda Trough at the boundary with the Solikamsk Depression and the Kama Arch, there are known small commercial oil accumulations [18] and identified oil and gas manifestations in a wide interval of the Upper Paleozoic section. In general, accumulations of liquid HC have been discovered in the Timan and Bashkirian sediments at the Cherdyn field, in the Famennian–Tournaisian sediments at the Verkh–Sypanskoye, Vodorazdelnoye and Lesorubnoye fields and in the Tula sediments at the Amborskoye and Doldinskoye fields. The oils are characterized as medium-heavy (0.829–0.906 g/cm^3), sulfurous (0.60–1.89%), low-resin to resinous (6.16–19.41%) and paraffinous (2.03–5.37%).

Thirdly, the area under study is formed by a thick mass of Precambrian rocks, in which direct signs of oil and gas potential have been identified [19–21], namely: saturation with viscous heavy oil, manifestations of nitric helium-bearing gas with a low methane content, bitumen inclusions and an increased chloroform bitumen extracts (B_{chl}) content in Upper Riphean sediments. The results of geological exploration within other basins of ancient platforms indicate prospects of oil and gas occurrence in the Precambrian formations of the Vychegda Trough [22]. Such basins are known not only abroad, but also in our country. The most significant commercial accumulations of oil and gas were found in Eastern Siberia in the Riphean reef sediments of the Yurubchen–Tokhomsk oil and gas accumulation zone of the Baikitsky Basin [23,24]. Additionally, HC inflows and accumulations have been identified in many other areas of the region [25,26]. On the East European Platform, along with the prospecting and exploration of accumulations in the Paleozoic complex, numerous oil manifestations in Proterozoic sediments within the Kama-Belsk Graben have been established. So, significant manifestations from the Riphean age were found in the Republics of Bashkortostan, Tatarstan and Udmurtia (Bavlinskaya, Kaltasinskaya, Oryebashskaya, Polomskaya and Serafimovskaya areas), as well as in the Perm Region (Batyrbaiskaya, Pavlovskaya, Sivinskaya, Sokolovskaya, Tanypskaya and Chernovskaya areas) and Orenburg Region (Olkhovskaya area) [27]. In the Perm Region and the Republic of Udmurtia, commercial accumulations of Vendian oils are known in a number of areas of the Upper Kama Depression [28]: the Vereshchaginskaya, Efremovskaya, Larionovskaya, Sokolovskaya, Sivinskaya, Polomskaya, Sharkanskaya areas and others. Proterozoic oils are heavy (0.94–0.97 g/cm^3), highly viscous, low-sulfur and sulfurous (0.20–1.40%), from low-paraffinic to paraffinic (0.60–3.20%), highly resinous (20–30%), with a low content of gasoline fractions (1–8%). In the Komi Republic, HC manifestations are found in the Ukhta fold of the Timan Ridge [29]. So, at the Yaregskoye field in the Upper Riphean fractured rocks, there are direct signs of oil and gas potential in the form of asphalt inclusions, solid bitumen, thick oil spots and free HC gas emissions. To the north-west of the Yaregskaya area at the Vodniy Promysel field, the drilling of wells from the Upper Riphean shales yielded commercial flows of dry gas (10,000–15,000 m^3/day) containing 95.80% methane. Abroad, Precambrian accumulations and intensive HC manifestations were recorded in Australia (McArthur [30,31] and Amadeus [32] Basins), China (North China [33,34], Sichuan [35–37] and Tirim [38] Basins), Oman (Persian Gulf Basin [39]), India (Bikaner–Nagaur Basin [40]), as well as on the African continent (Taoudeni and Voltaian Basins [41]).

Thus, the aforementioned prerequisites of oil and gas occurrence indicate the possibility of the discovery of commercial HC accumulations in the sedimentary fill of the Vychegda Trough.

In the course of this research, the objective was to assess the prospects of the oil and gas potential in the section of the area under study on the basis of a comprehensive analysis of geological, petrophysical and geochemical data, as well as the implementation of paleotectonic, paleogeographic reconstruction and basin modeling. The final results should help determine the probability of the existence of petroleum systems in the Vychegda Trough.

2. Materials and Methods

The research was based on a comprehensive analysis and interpretation of geological, geophysical, geochemical and petrophysical data, as well as on the application of modern technologies for assessing and forecasting the oil and gas potential of sedimentary basins.

The tectonic structure of the region was studied on the basis of the analysis of aeromagnetic and gravimetric survey data, as well as the results of regional and areal seismic surveys. According to the seismic data and stratigraphic well assessment, volumetric structural models were created for the main reflecting horizons—the surface of the crystalline basement (F) and the Proterozoic–Paleozoic surface (VI). The basis for the construction of a consolidated lithological and stratigraphic section of the territory were the results of scientific research from archival and published sources.

The paleogeographic and paleotectonic framework is of paramount importance for the assessment and prediction of the oil and gas potential to reveal the patterns in sedimentary fill formation. The paleogeographic schemes are based on the generalization of the paleotectonic frameworks of the East European platform formation, as well as on the analysis of lithological and petrographic features and thicknesses of sediments in the wells of the area under study. Paleotectonic reconstructions were made by the backstripping method (the sequential decompaction and removal of younger strata) along the composite regional profile 26-PC-26A-PC-091304-1506p05a-1506p05-120402 (Figure 1).

The authors collected materials of analytical studies of well cores and created a unified database of the geochemical and petrophysical studies of rocks. Porosity and permeability coefficients were analyzed and their dependencies and frequencies were plotted in order to identify reservoir and seal intervals. The source rocks and their properties were traced on the basis of the pyrolysis data interpretation using the Rock-Eval method, the analysis of the elemental composition of kerogen and B_{chl} extracts content and the study of the HC composition of their saturated fraction.

The method of one-dimensional basin modeling was used to reconstruct the burial history of sedimentary complexes, the kinetics of OM maturation and its transformation into HC, as well as the stages of the most intensive potential realization.

In general, the main concept of the study used to assess the oil and gas potential prospects of the region is the theory of petroleum systems.

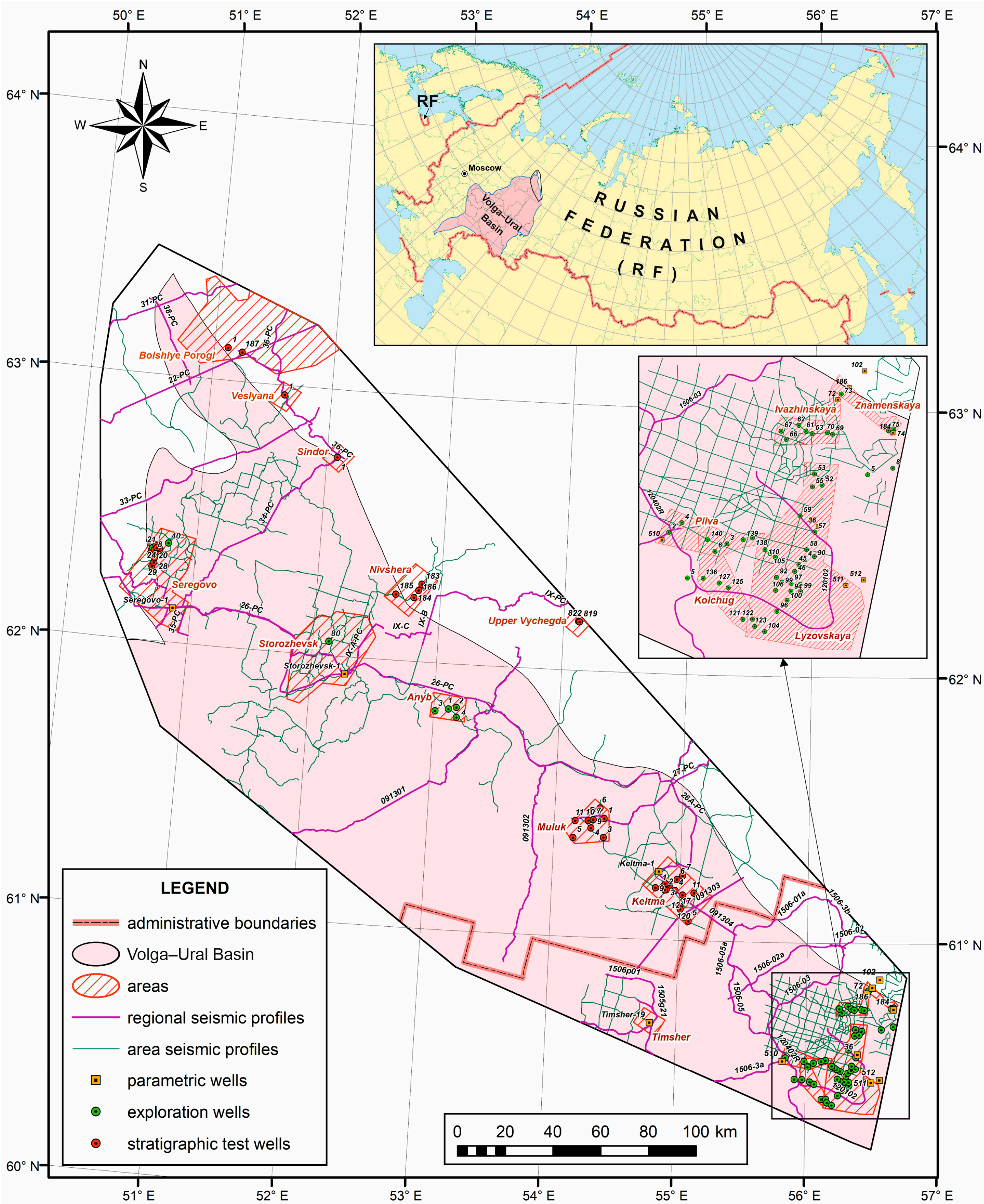


Figure 1. Location, drilling and seismic studies of the Vychegda Trough.

3. Results

3.1. Geological Features of the Area under Study

The Vychegda Trough is an ancient rift with dimensions of 400 × 50–120 km, which is a first-order structure of the Pre-Timan pericratonic trough of the East European Platform. The area is intermediate between the Kanin–Timan Ridge and the Volga–Ural Anticline. According to geophysical surveys, the Vychegda Trough is most pronounced on the basement surface and is bounded by the zones of deep regional faults of the northwestern strike—the West Timan and Pre-Timan faults (Figure 2).

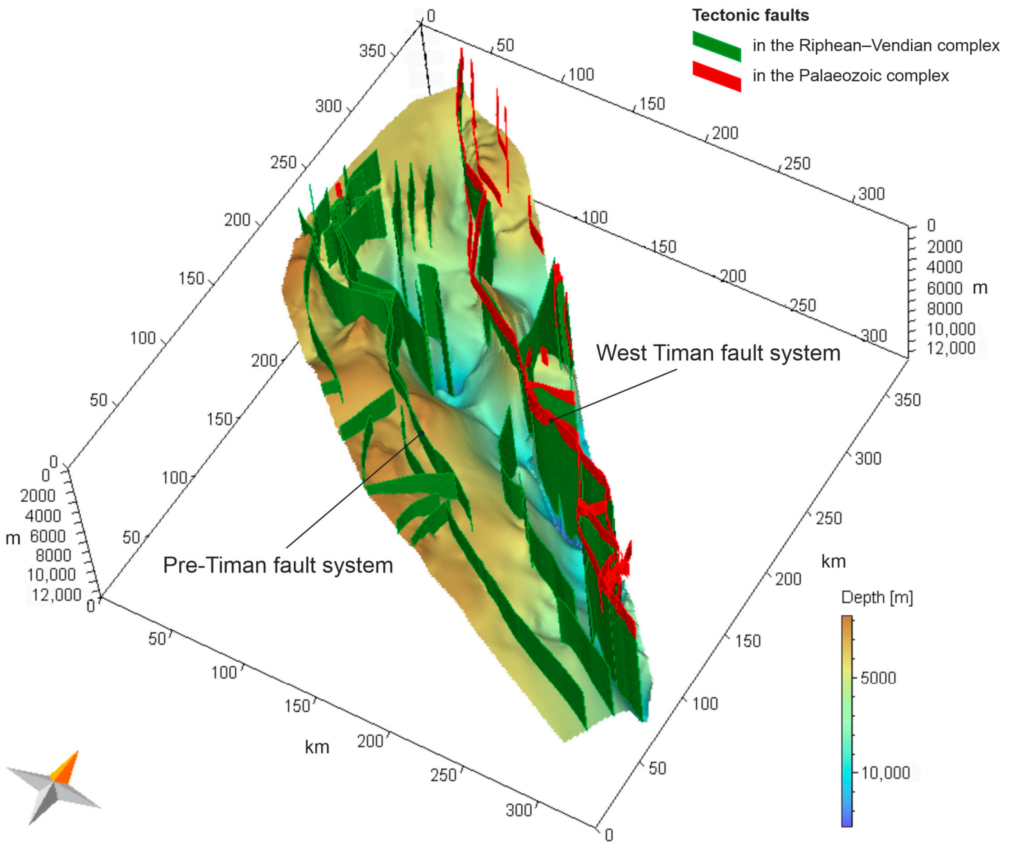


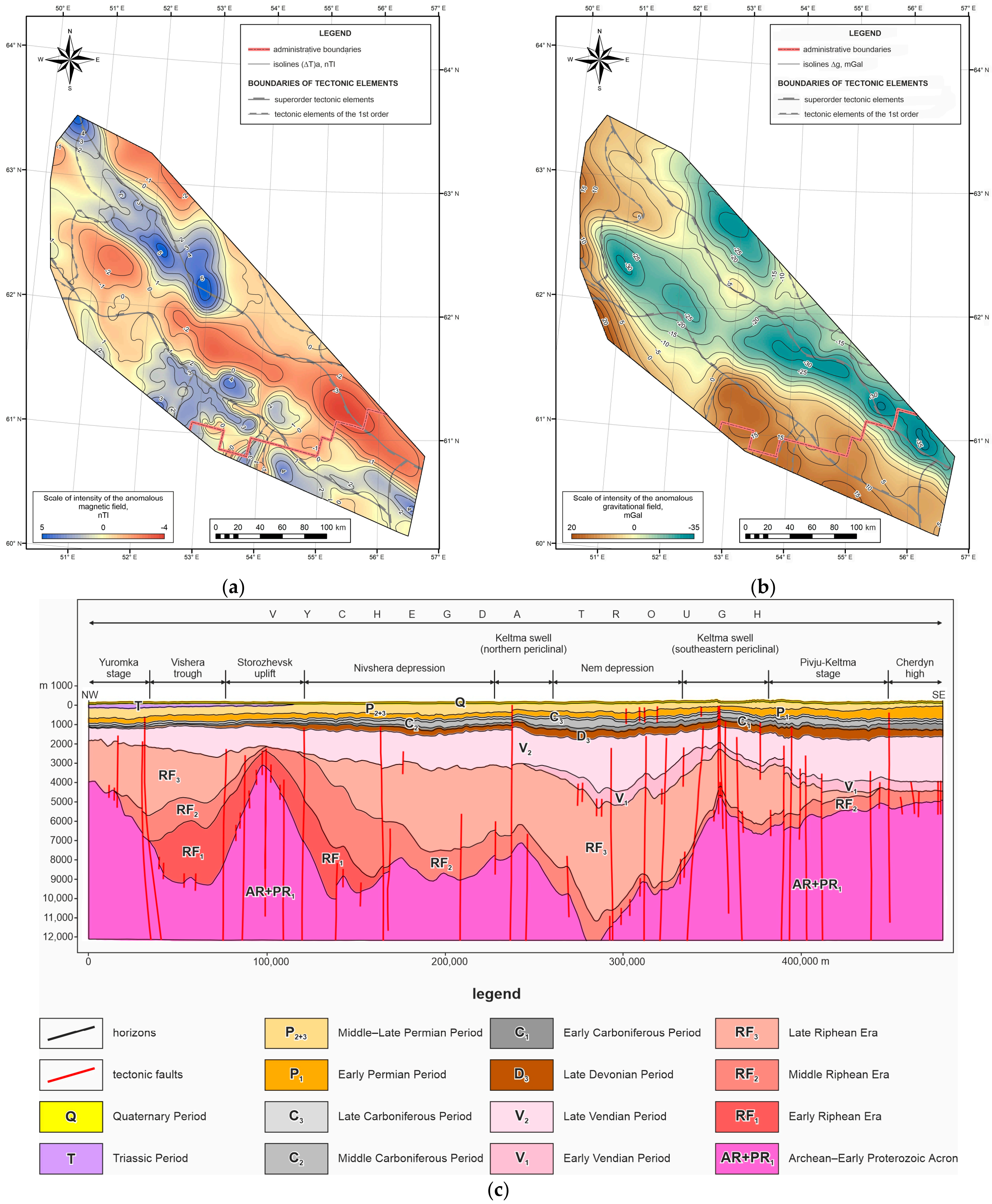
Figure 2. Three-dimensional structural model of the Vychegda Trough on the basement surface with a system of tectonic faults.

The area under study occurs on the basement surface as a graben of the northwestern strike, with a relatively steep northeastern wing and a flatter southwestern wing. The basement has not been penetrated, but according to the results of drilling in the neighboring structures of the Russian Plate—the Mezen Syncline and the Volga–Ural Anticline—it corresponds to the Karelian age.

According to aeromagnetic data (Figure 3a), the boundary with the Timan regional minimum of the magnetic field is marked by areas in the form of positive anomalies of the northwestern strike, indicating that the northeastern side of the Vychegda Trough is overlain by the allochthonous block of the folded Baikal basement of the Timan–Pechora Plate. The gravity field of the Vychegda Trough and the West Timan dislocations shows intense negative anomalies (Figure 3b), indicating the submergence of the crystalline Karelian basement under the folded basement of the Timan ridge. The high deformation of the sedimentary fill and the development of Riphean sediment wedging zones (Figure 3c) demonstrate a rather complex structure of the region, which is associated with the intensive tectonic activity of the basin. The basement submergence depth in the areas of lowered blocks is up to 12,000 m, while in the uplift zones, it decreases to 2500–5000 m.

The reflecting horizons of the Vychegda Trough suggest different structural geometries in a number of horizons of the sedimentary fill. On the surface of the basement (F), there are pronounced structures that complicate the area under study (Figure 4a). So, the following second-order structures are distinguished along the crystalline basement top: Seregovo, Yuromka and Pivju-Keltma stages, Storozhevsk uplift, Keltma and Prupt swells, Emva saddle, Vishera trough, West Veslyana, Nivshera and Nem depression. The Vychegda

Trough is less pronounced along the Proterozoic–Paleozoic surface, but a number of large positive and negative structures of the second order can be traced: Seregovo basin, East Seregovo and Prupt stages, Storozhevsk uplift, Keltma swell, North Keltma and Vishera depression (Figure 4b).



(a) (b) (c)

Figure 3. Maps of (**a**) anomalous magnetic and (**b**) gravitational fields of the Vychegda Trough and neighboring territories, as well as (**c**) regional profile 26-PC (see Figure 1 for profile location).

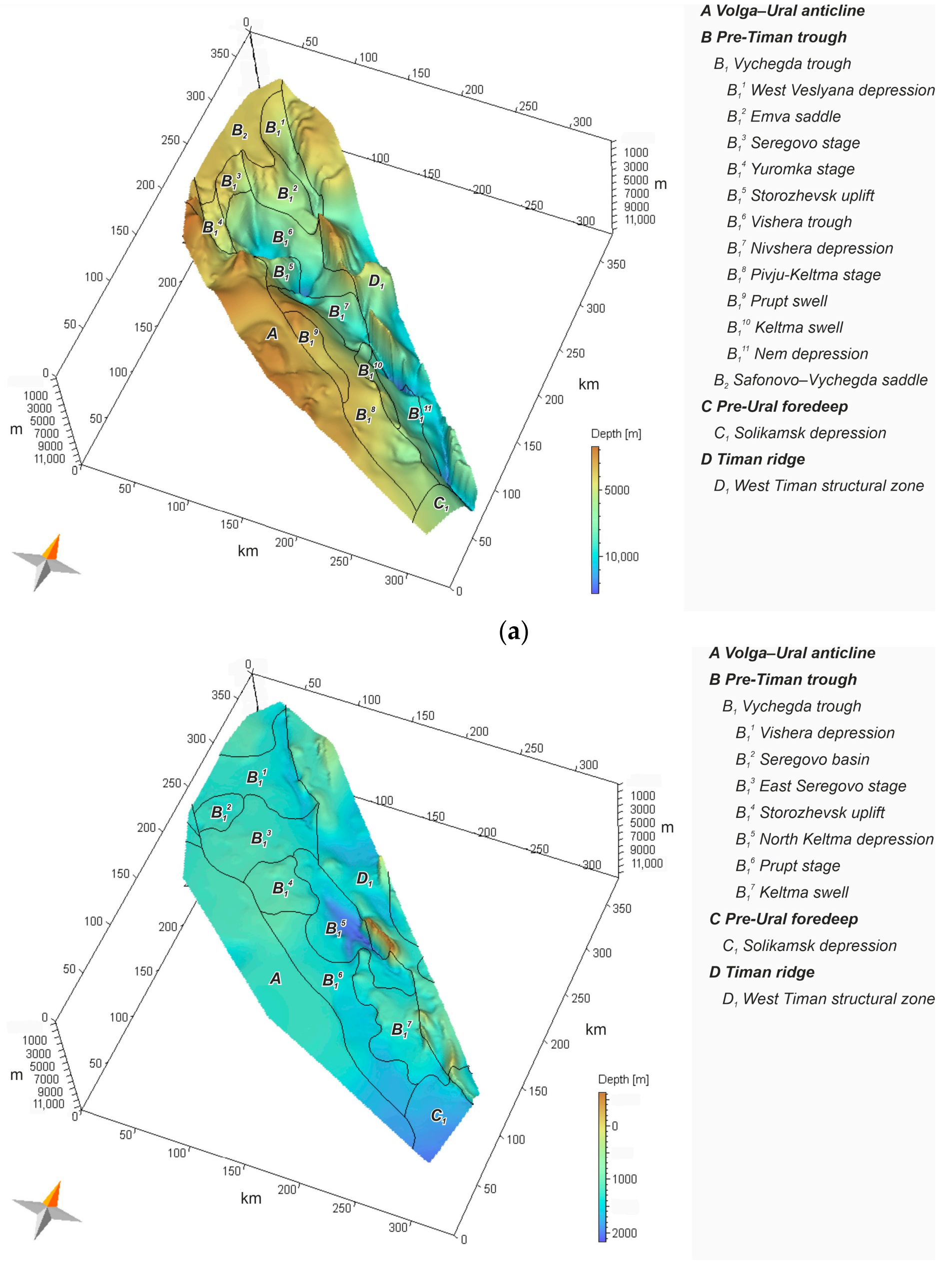


Figure 4. Three-dimensional models: (**a**) basement surface and (**b**) Proterozoic–Paleozoic surface.

The active tectonic regime in the Pre-Cambrian time has largely contributed to the formation of the Vychegda Trough's complex structure. Therefore, additional seismic data is required to trace the structure of the region in the basement and deep-lying horizons in greater detail.

The thickness of the sedimentary fill of the Vychegda Trough in the areas of lowered basement blocks is estimated to be up to 12,000 m, of which a large portion (~70–80%) is Proterozoic sediments (Figure 5).

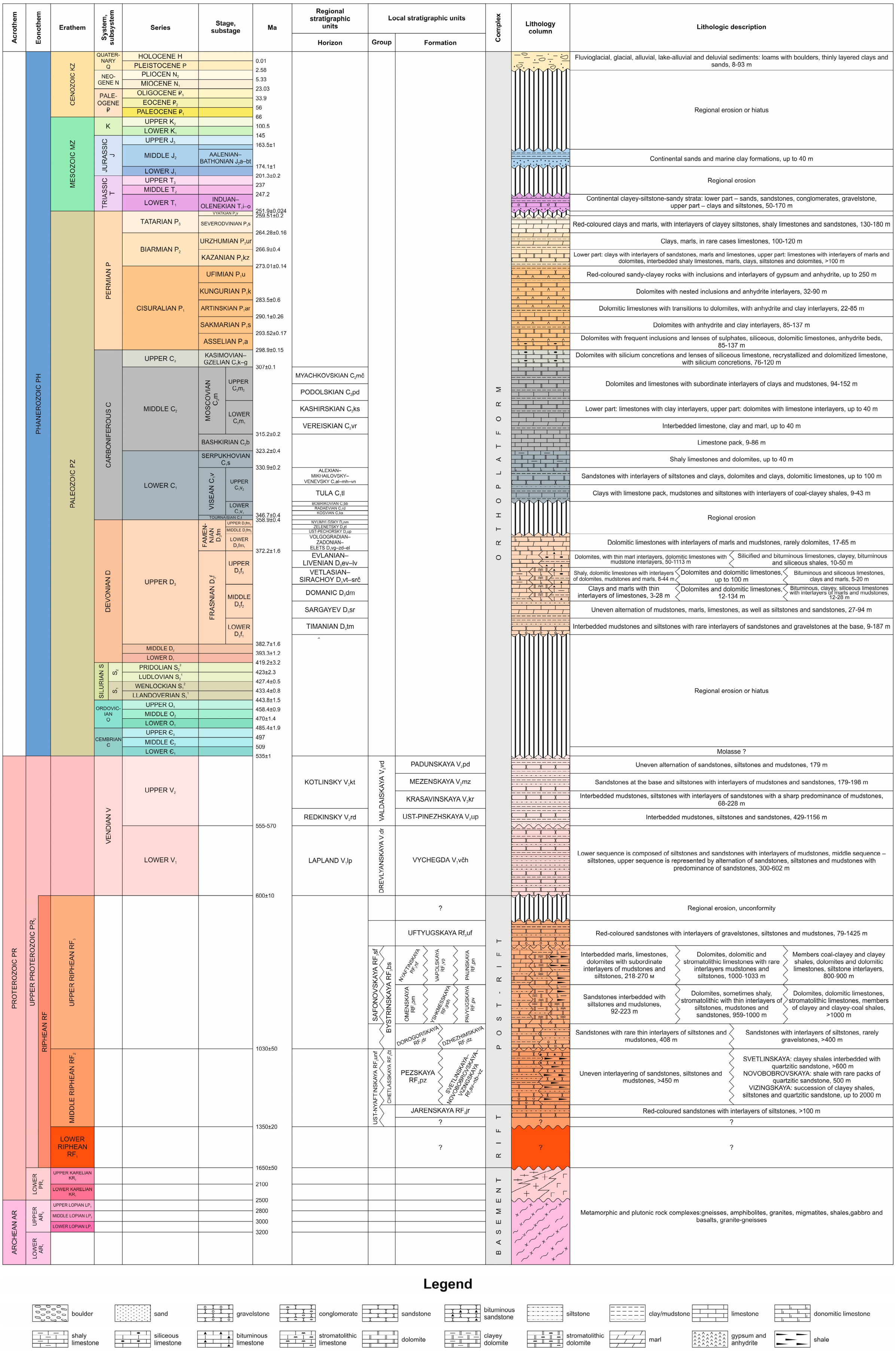


Figure 5. Generalized lithological and stratigraphic section of the Vychegda Trough.

The generalized lithological and stratigraphic section built by the authors demonstrates that deeply metamorphosed Archean–Lower Proterozoic formations, Late Proterozoic and Phanerozoic sediments participate in the structure of the region. The oldest uncovered rocks belong to the rift and post-rift complexes of the sedimentary fill and are represented by clastic sediments of the Middle Riphean (450–3000 m and more) and clastic-carbonate sediments of the Late Riphean (700–3000 m and more). The Riphean complex is overlain transgressively, with a visible angular discontinuity, by the lower part of the orthoplatform complex of the sedimentary fill, composed of clastic sediments of the Early (300–602 m) and Late (850–1800 m and more) Vendian period. The Vendian sediments are overlain with a large stratigraphic discontinuity by the upper part of the orthoplatform complex, composed of Upper Paleozoic rocks with a total thickness of about 1500–2000 m. The Paleozoic stage of the section is composed of clastic-carbonate sediments of the Late Devonian, clastic-carbonate sediments of the Carboniferous and sulfate-rich and clastic-carbonate sediments of the Permian. The sedimentary fill section is completed by clastic sediments of the Mesozoic–Cenozoic period, in particular, the Early Triassic, Middle Jurassic and Quaternary systems with a total thickness not exceeding 350 m. The sedimentary fill is characterized by large erosions as indicators of the active tectonic regime of the basin: at the boundary of the Riphean–Vendian, Early Paleozoic, between the Late Devonian and Early Carboniferous and during the Mesozoic stage of the region's formation.

3.2. Paleogeographic and Paleotectonic Reconstructions

Assessing and forecasting the oil and gas potential in poorly studied areas is impossible without knowledge of their paleotectonics, as well as depositional and paleogeographic environments.

Based on a comprehensive analysis of the lithological and petrographic composition of rocks from 24 wells and 5 outcrops, the thicknesses of the exposed sediments and the use of paleotectonic schemes of the East European Platform development [42], we reconstructed the depositional and paleogeographic environments of the sedimentation of the Vychegda Trough. The paleotectonic reconstructions were made using the backstripping method, which is well-proven in basin modeling practice [43]. The reconstructions were carried out along the composite regional profile 26-PC-26A-PC-091304-1506p05a-1506p05-120402, which extends 480 km across the study area from northwest to southeast. A total of 13 paleogeographic schemes and 18 paleotectonic profiles were built.

The formation of the Vychegda Trough is directly related to the period of the development of the Pre-Timan pericratonic depression of the East European Platform, covering the time from the Early Riphean emplacement to the formation of the modern structural geometry. This period of about 1650 Ma consists of three fundamentally different stages—rift, post-rift and orthoplatform.

Taken together, the rift and post-rift stages correspond to the Riphean age, which was marked by the intensive submergence of the pericratonic sedimentary basins of the East European Platform [44]. The general scheme of paleotectonic reconstructions of the Riphean is shown in Figure 5.

In the Early Riphean ae, active processes of continental rifting contributed to the splitting of the Karelian massif into separate blocks [45], between which a system of a grabens (Kama–Belsk, Vychegda, Kazan–Kazhim, etc.) was formed. The erosion of these blocks resulted in the formation of abundant clastic material that filled the intensively submerging depressions. In the vicinity of the rifting processes, an oceanic basin began to open at the end of the Early Riphean [46], which was named Timan–Ural in modern paleogeodynamic reconstructions.

The Middle Riphean age was marked by the intensive submergence of the region, as shown by paleoreconstructions (Figure 6).

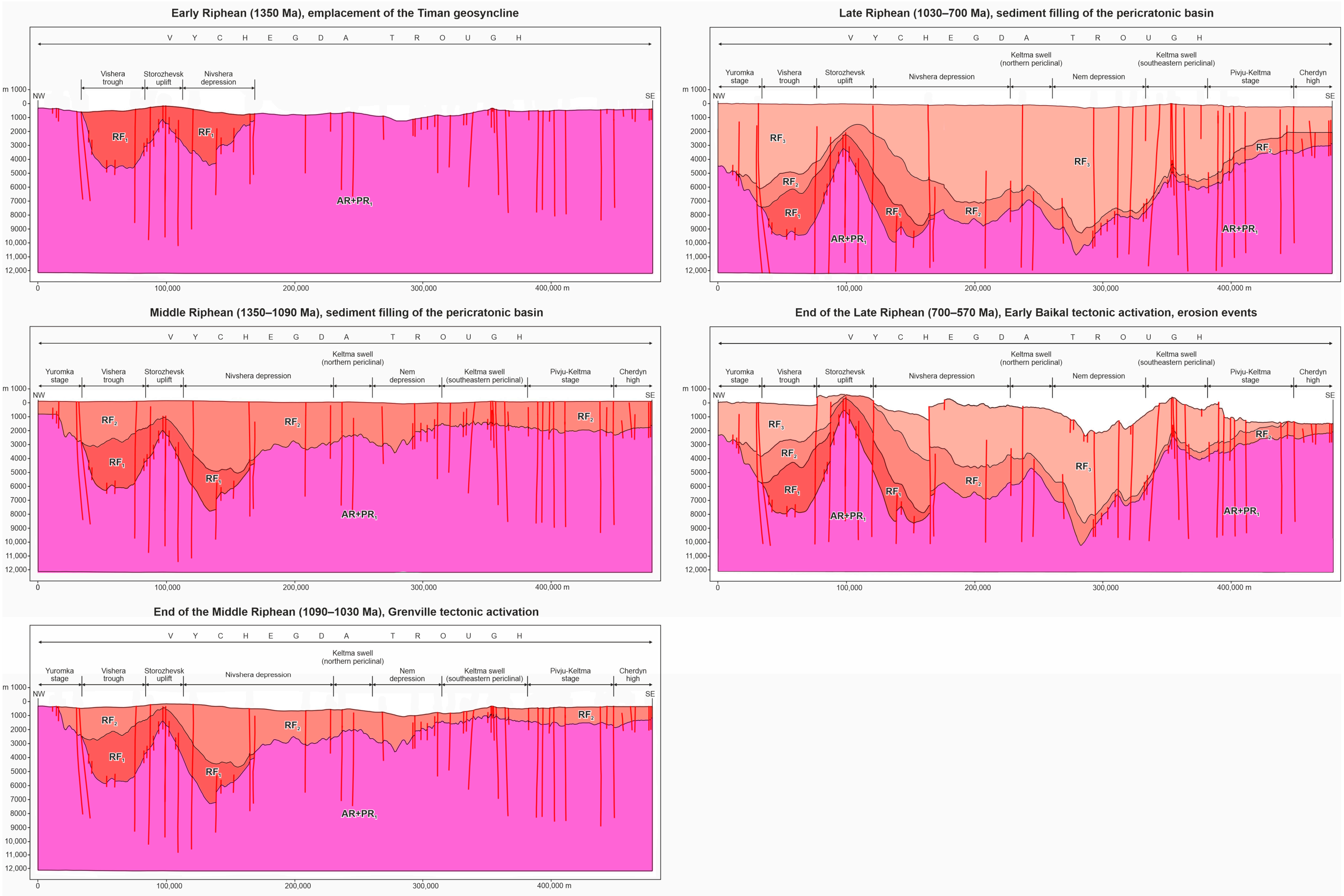
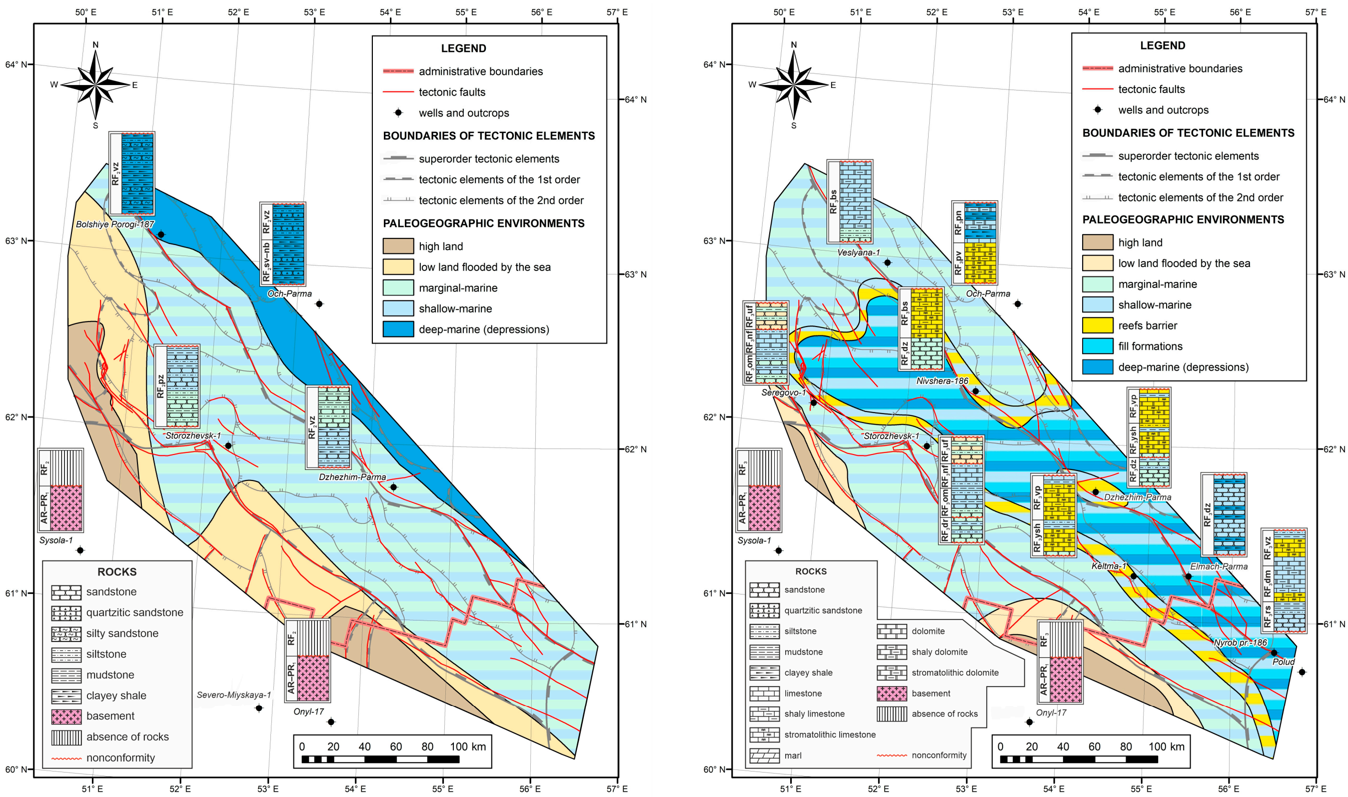


Figure 6. Palaeotectonic reconstructions of the Riphean (see Figure 5 for the names and ages of geological formations).

At this stage, the Timan–Ural oceanic basin opened up to cover a vast territory, including the Vychegda Trough and the Timan Ridge area, which at that time was a single zone of pericratonic sinking. The basin accumulated thick complexes of clastic material (Figure 7a), which was transported from peneplainized blocks of the Karelian basement. This is evidenced by the shallow-water-marine dark-colored interbedded mudstone, siltstone and sandstone strata corresponding to the Pezskaya Formation of the Middle Riphean (450 m), which was penetrated in the Vychegda Trough by the Storozhevsk-1 well. In addition, a coeval of the aforementioned sediments in the bulk of the Svetlinskaya, Novobobrovskaya and Vizingskaya Formations with a total thickness of up to 3000 m was discovered in the Bolshiye Porogi-187 well and in the outcrops of Riphean rocks at the Dzhezhim–Parma and Och–Parma uplands. The rocks are composed of shallow and deep-water-marine and grey-colored clastic sediments and black clayey shales. Thus, the peculiarities of sediment composition and thickness indicate the presence of a compensated marine basin that was filled in a calm tectonic environment.



(**a**) (**b**)

Figure 7. Depositional and paleogeographic environments: (**a**) Middle and (**b**) Late Riphean (see Figure 5 for the names and ages of geological formations).

Based on paleoreconstructions (Figure 7b), the Vychegda Trough and Timan continued to develop in the Late Riphean as a pericratonic subsidence. The beginning of a new transgressive cycle was accompanied by the accumulation of clayey–sandy material in marginal and shallow-marine conditions, corresponding to the Dorogorskaya Formation (Storozhevsk-1 well) and its coeval in the northeastern part of the region, the Dzhezhimskaya Formation (Dzhezhim–Parma outcrop). Our reconstruction of paleogeographic environments shows that carbonate sedimentation was widespread in the Late Riphean age. Large bulks of shelf limestones and dolomites suggest a warm marine environment. A clear indicator of such climatic conditions are barrier-reef stromatolite formations of the Safonovskaya/Bystrinskaya Group, which, according to Bogdanov B.P. [47,48], can be traced in the Vychegda Trough from the Polud transverse uplift along the entire southern Timan. The Late Riphean thick carbonate section is exposed in the southeast of the Vychegda Trough by the Keltma-1 well (1992 m) and crops out in the core of the Dzhezhim–Parma structure, where it is represented by massive stromatolithic dolomites and dolomitic limestones with subordinate interbeds of clayey shales and siltstones of the Yshkmesskaya and Vapolskaya Formations. In addition, in the area of the Och–Parma and Elmach–Parma outcrops, there are same-age rocks of the Pavyugskaya and Paunskaya Formations of deep-water-marine genesis, composed of black clayey–carbonate–shale formations up to 2500 m thick. Based on general geological criteria of carbonate platforms' development, it is likely that the territory of the Vychegda Trough also contains black shale formations of the Late Riphean age which are strong candidates to be regional oil source rocks.

The end of the Late Riphean age was marked by the completion of the post-rift stage of development and the growth of tectonic movements in the basin. Major erosion events occurred at the Riphean–Vendian boundary due to the regional uplift of the territory. As noted in the literature [49], according to the paleotectonic reconstructions of the continents of Pre-Cambrian time, the Early Vendian stage of the East European Platform is associated with the global Lapland continental glaciation, explained by the location of the platform in the southern polar latitudes. The evidence for this is tillites and tillite-like (glacial) rocks in the Early Vendian sediments found in the peripheral areas of the East European Platform [50]. These areas were probably covered by a significant ice cover in the Late Riphean and Early Vendian age. Thus, due to regional inversion movements and glacial erosion, sedimentary formations of the Riphean age in the Vychegda Trough were hollowly dislocated and sheared by the surface of stratigraphic and angular discontinuity.

The formation of the orthoplatform fill in the study area started from the Vendian (Figure 8).

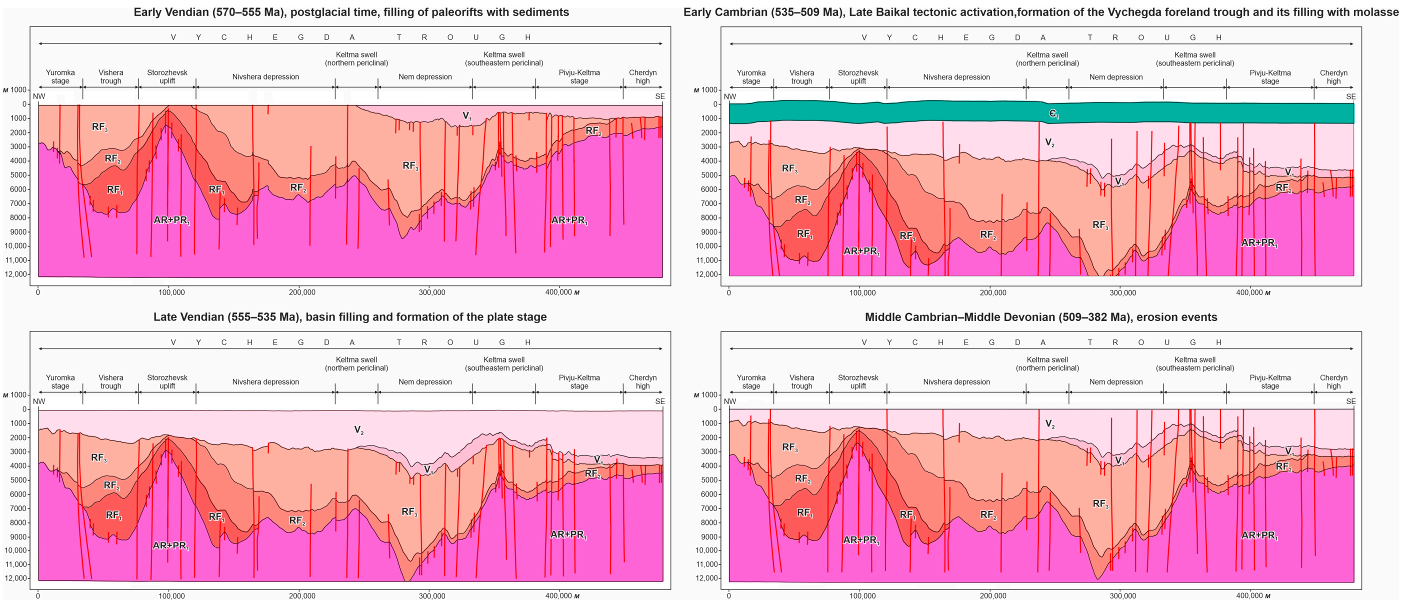


Figure 8. Paleotectonic reconstructions of the Vendian–Early Paleozoic (see Figure 5 for the names and ages of geological formations).

The Vychegda Formation sediments of the Early Vendian age found in the southeast of the Vychegda Trough in the Keltma-1 well (602 m thick) and in the core of the Dzhezhim–Parma fold are especially noteworthy. In all other deep wells and outcrops, the Early Vendian rocks are absent. The sequence is represented by interbedded glauconite-bearing grey-colored siltstones, sandstones and mudstones, which occur on the eroded surface of carbonate rocks of the Safonov Group of the Late Riphean. The formation of the Early Vendian sediments, due to their dark color and glauconite content, took place in shallow-marine conditions in the post-glacial time. The limited distribution of Early Vendian sediments in the Vychegda Trough suggests that their sedimentation was controlled by the Riphean paleorifts, where the most favorable conditions for their accumulation and preservation existed.

Since the Late Vendian period, the tectonic regime of the basin has changed significantly. Inversion processes were replaced by a significant marine transgression (Figure 9), which led to the formation of a large shelf basin. The evidence is the rocks of the Redkinsky and Kotlinsky Horizons exposed by deep boreholes and represented by flysch-like sandy–silty–clayey strata of the Ust–Pinezhskaya, Krasavinskaya, Mezenskaya and Padunskaya Formations with a total thickness of about 2000 m. The sediments are rich in glauconite and pyrite, which is typical of shallow-marine sedimentation conditions. The source of basin filling was the erosion products of granitoids and metamorphic complexes of the Pechora ridge, where island-arc and collisional events occurred at that time [51].

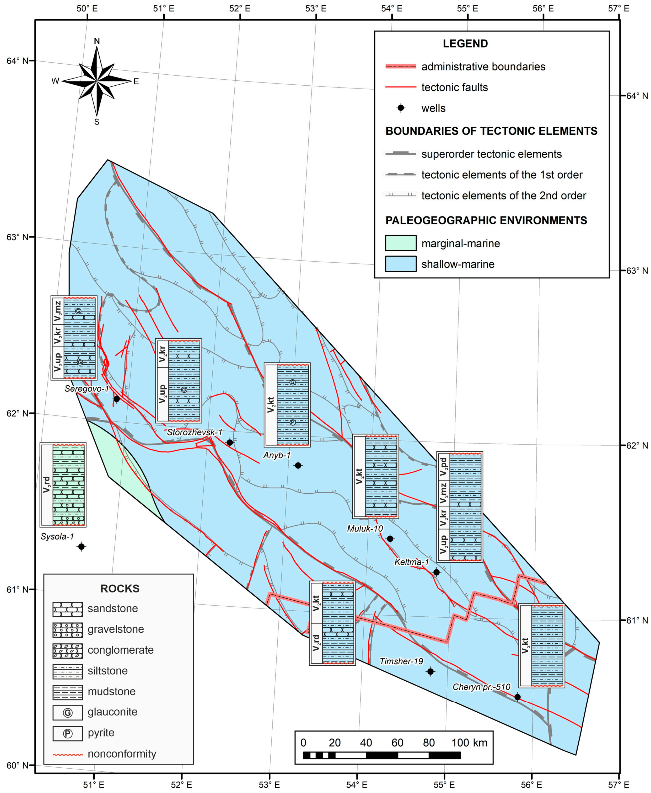


Figure 9. Depositional and paleogeographic environments of the Late Vendian (see Figure 5 for the names and ages of geological formations).

At the boundary of the Late Vendian–Early Cambrian period, the Baikal folding epoch ended and, as a result of collisional processes, the consolidated Pechora block collided with the East European Platform, forming the complex Kanin–Timan fold and thrust system [51]. Throughout the Early Cambrian age, postorogenic molasses, the source of which was Timan, were probably accumulated in the Vychegda Trough. By the end of the Early Cambrian age, the region underwent peneplaination.

Due to the absence of Cambrian, Ordovician and Silurian sediments within the Vychegda Trough, the history of geological development is ambiguous. Nevertheless, according to the paleotectonic schemes of the East European Platform in the interval from the Middle Cambrian to the Silurian age, the area was an uplifted platform exposed to erosion processes. As a result, the Early Cambrian postorogenic molasses that had probably formed in the Vychegda Trough are not preserved due to their erosion.

Throughout the Early and Middle Devonian age, the region continued to develop as an uplifted platform on where older sediments were eroded, which explains their complete absence from the well sections.

Figure 10 shows the results of paleotectonic reconstructions of the period from the Late Devonian to the Cenozoic.

The Late Devonian Frasnian age in the study area is characterized by an extensive transgression [52,53], one of the largest in the Late Paleozoic. The beginning of the transgression was marked by the accumulation of marginal and shallow-marine sandy–silty–clayey sediments of the Timanian Horizon (Figure 11a). The maximum flooding of the transgressive phase occurred in the Semiluk (Domanic) time, characterized by the formation of a shallow-water shelf, barrier reefs and a deep-water uncompensated depression filled with thinly alternating clayey, calcareous and siliceous-limestone and organic-rich sediments (Figure 11b). Subsequently, during the Late Frasnian and Famennian ages, the rate of basin submergence slowed down, thus the area of the deep-water shelf significantly decreased and shifted to the eastern parts of the basin (Figure 11c,d). In general, during the

Middle Frasnian–Famennian time, the basin's development was cyclic, i.e., transgressions alternated with regressions.

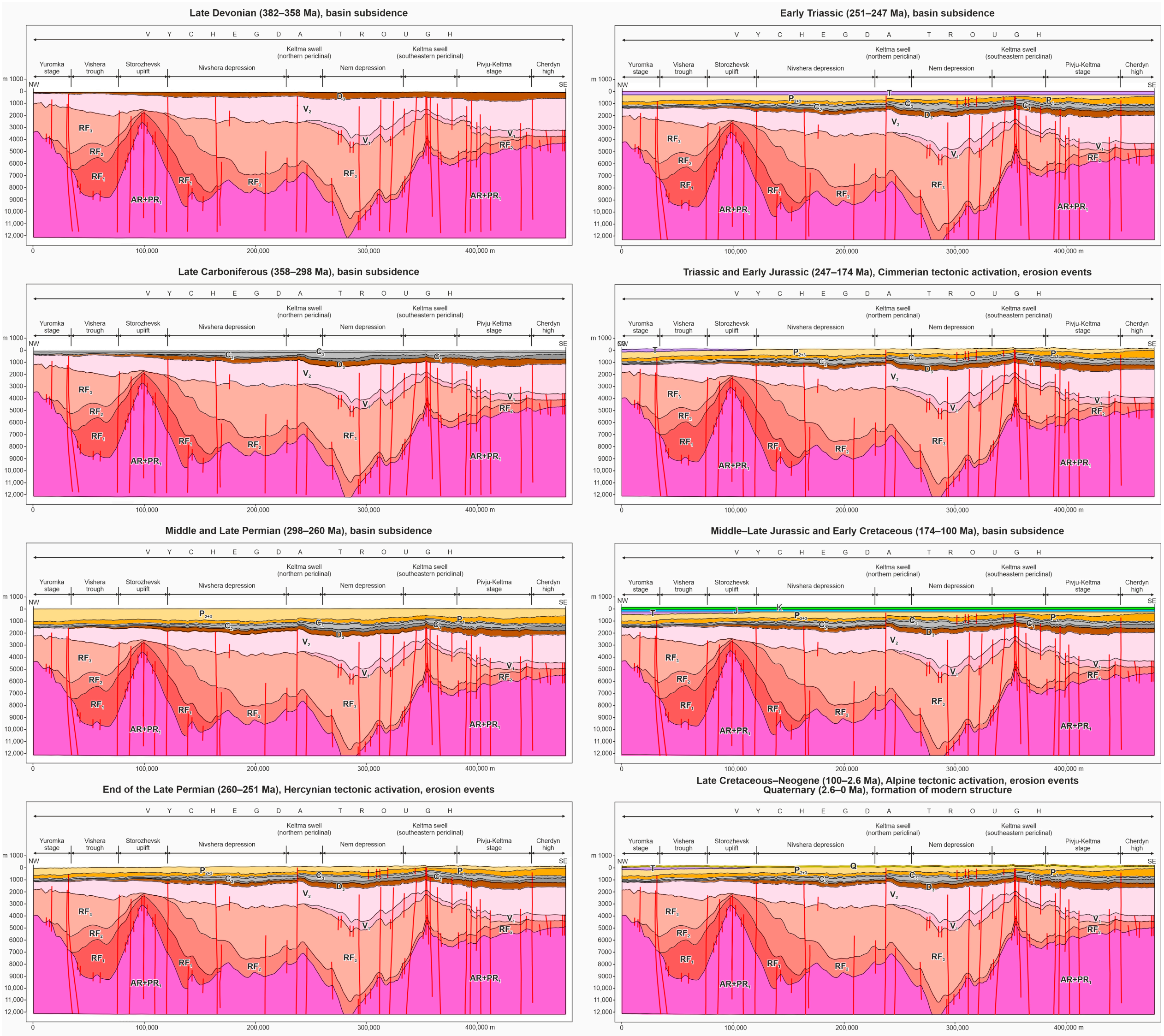
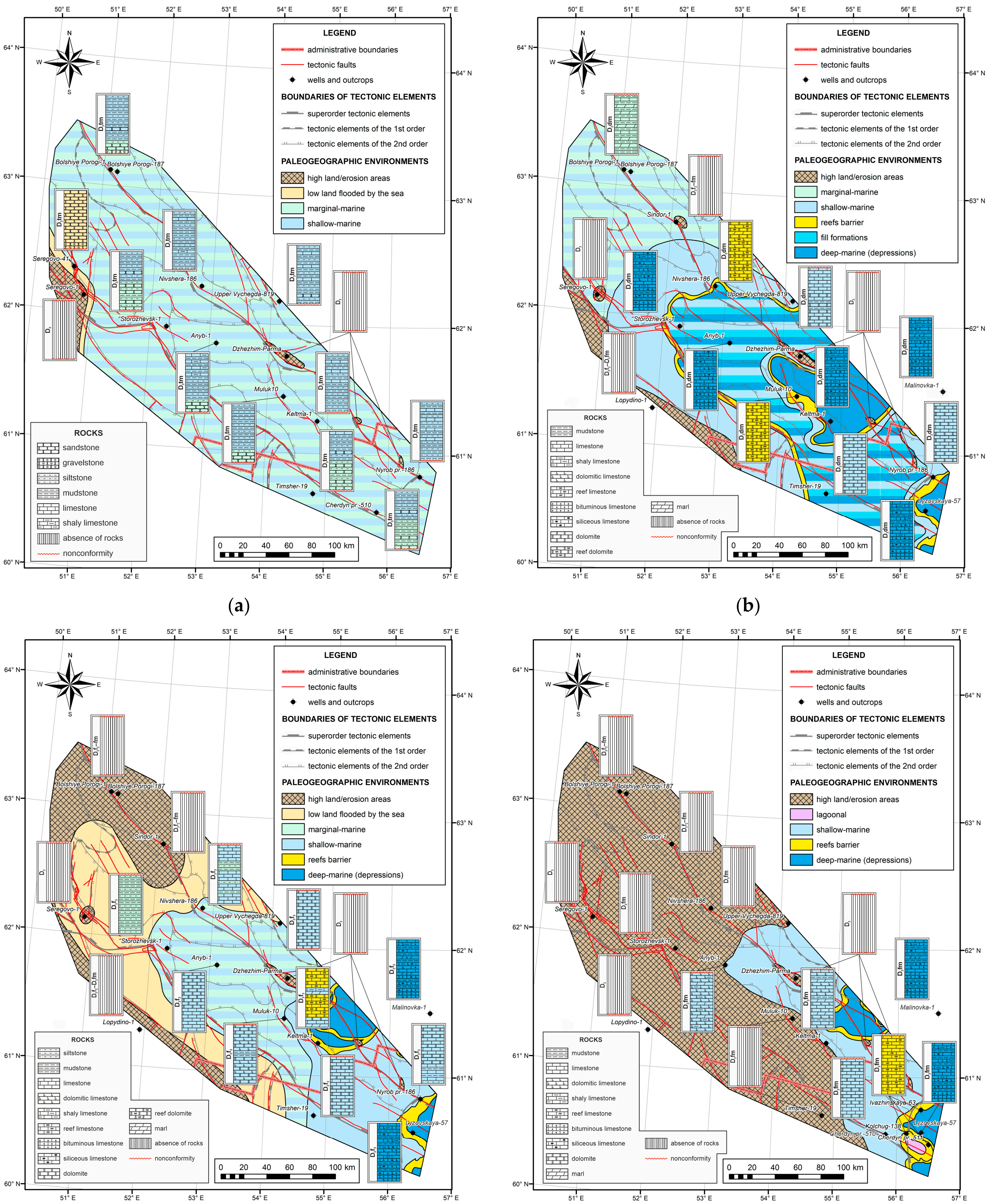


Figure 10. Paleotectonic reconstructions of the Late Paleozoic–Cenozoic age (see Figure 5 for the names and ages of geological formations).

The intensification of tectonic movements due to the Early Hercynian orogeny at the turn of the Late Devonian and the beginning of the Early Carboniferous periods led to the erosion of the basin in the Early Visean time. This is indicated by the stratigraphic discontinuity present in all the studied wells.

A new sedimentation cycle began in the Late Visean age (Figure 12). Early Carboniferous sediments are discontinuous in the Vychegda Trough and the Timan Ridge. This may suggest a short-term marine transgression, during which sediments of carbonate and carbonate–clastic compositions were accumulated in marine and marginal-marine environments.



(**a**) (**b**)

(**c**) (**d**)

Figure 11. Depositional and paleogeographical environments of the Late Devonian age: (**a**) Timanian time; (**b**) Domanic time; (**c**) Late Frasnian time; (**d**) Famennian time (see Figure 5 for the names and ages of geological formations).

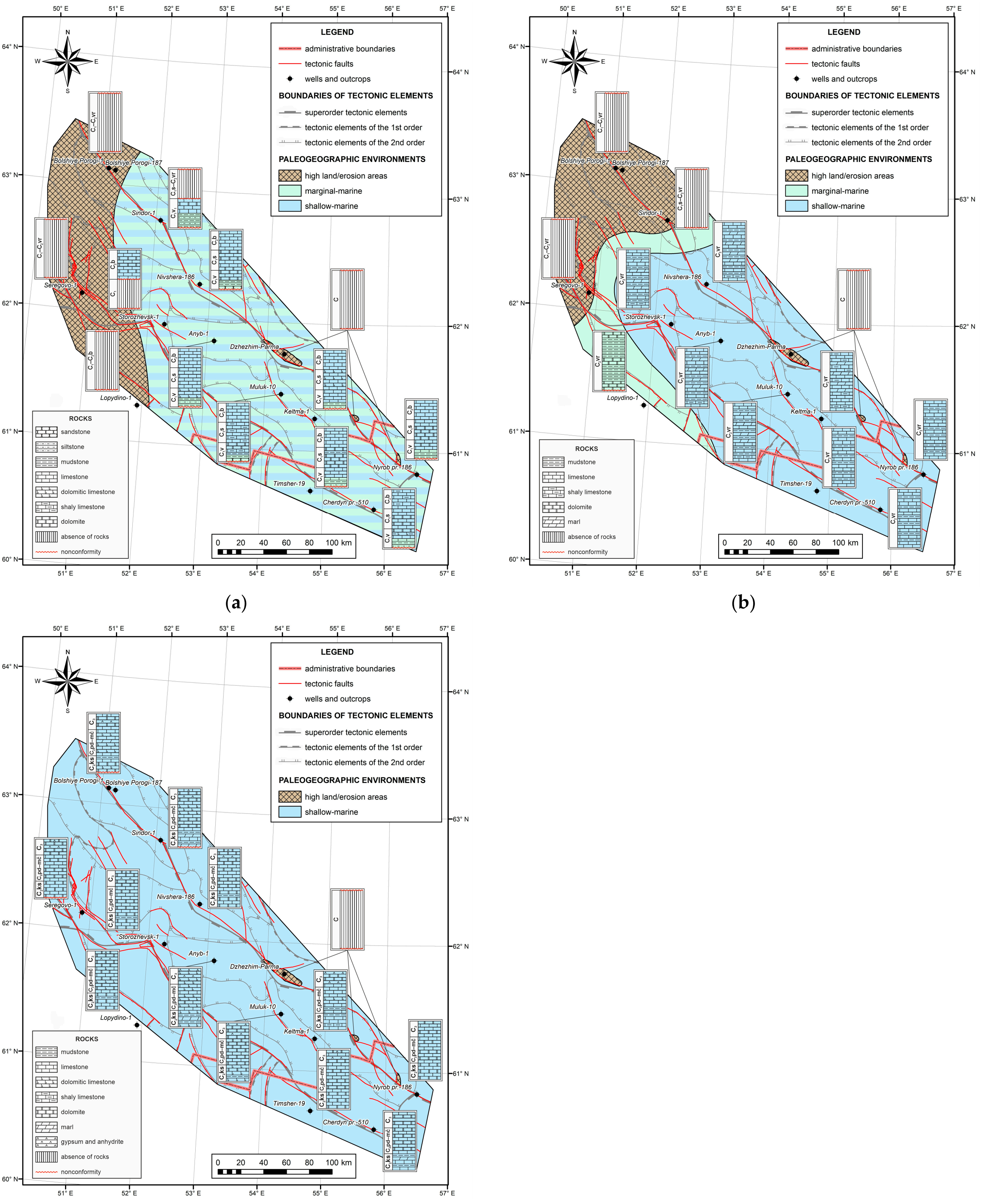


Figure 12. Depositional and paleogeographical environments of the Carboniferous period: (**a**) Late Visean–Bashkirian time; (**b**) Vereiskian time; (**c**) Kashirskian–Late Carboniferous time (see Figure 5 for the names and ages of geological formations).

The end of the Early Carboniferous period was marked by a short-term interruption in sedimentation, after which a large-scale transgression began in the Bashkirian–Moscovian time. The shallow-marine basin was filled with clastic-carbonate sediments. These paleogeographic environments persisted into the Late Carboniferous.

The Permian stage of development is directly related to the Late Hercynian orogenic events in the Urals [54] and the resumption of the West Timan fault system's functioning.

The Early Permian time is characterized by shallow-marine and lagoon conditions of sedimentation, which changed in the Ufimian age to continental conditions with the formation of clastic red-colored sediments (Figure 13a). In the Middle Permian time, the region was again transformed to a shallow-marine basin with the formation of clastic-carbonate sediments (Figure 13b). In the Late Permian time, there was a final transgression followed by the closure of the Ural paleo-ocean, the completion of the Hercynian folding in the Urals [54] and the erosion of Permian sediments.

In the Early Triassic period, continental alluvial, alluvial-lake and lake sedimentation environments developed in the Vychegda Trough (Figure 13c). The Timan was a source of clastic material [55]. Within the western areas of the Pechora Plate, Timan Ridge and Vychegda Trough, there was an interruption in sedimentation from the end of the Early Triassic to the beginning of the Middle Jurassic period, probably due to postorogenic movements in the Urals and the tectonic activity of the Cimmerian fold belts.

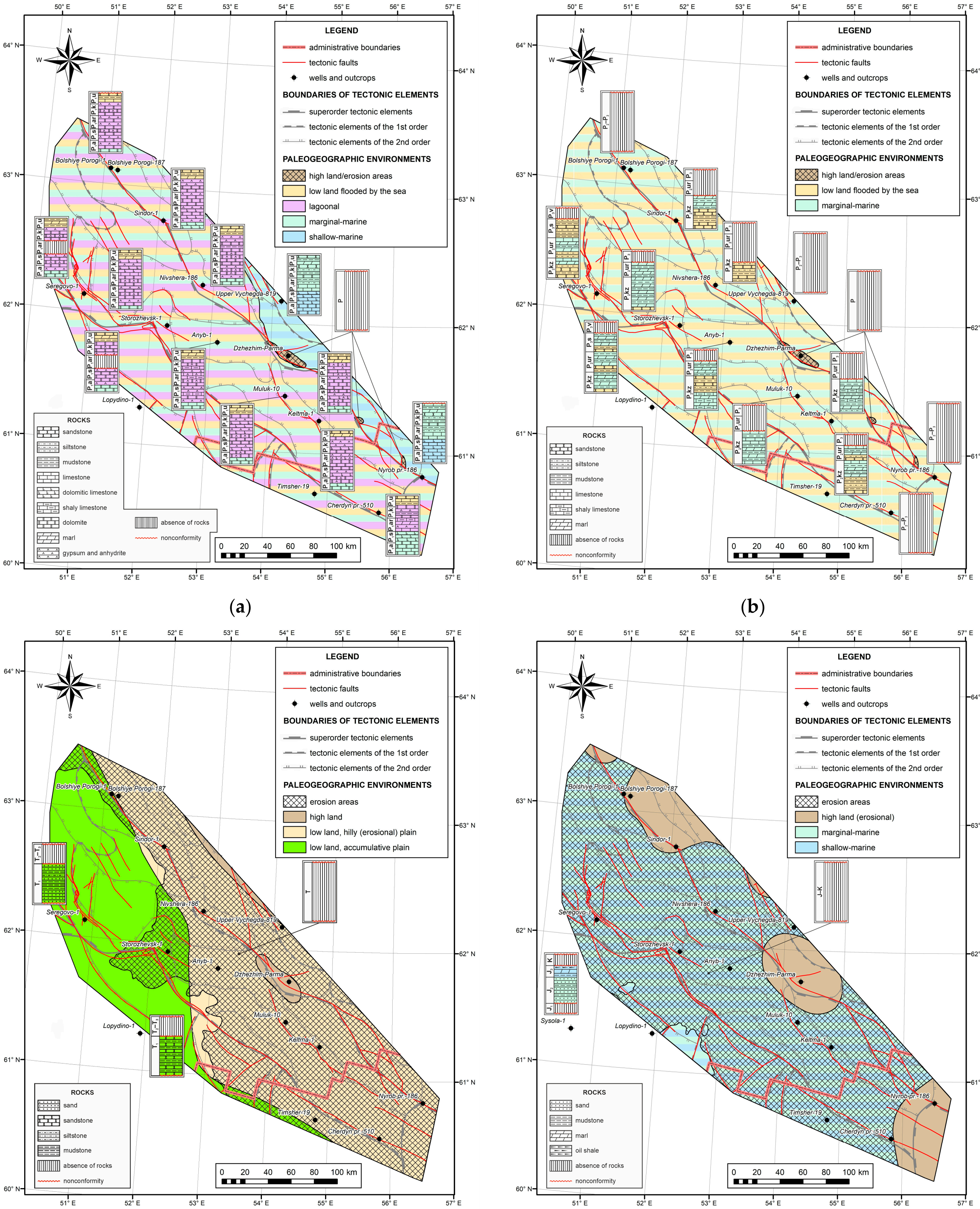
By the beginning of the Middle Jurassic period, the Timan surface was eroded [55] and leveled. In the Middle Jurassic period, a complex of continental sands with interlayers of siltstones and clays was formed under conditions of slow deflection, with continental conditions being gradually replaced by marine ones (Figure 13d). The Late Jurassic period is characterized by large-scale transgressive events associated with the formation of relatively deep-water shale strata [56].

The Early Cretaceous period corresponded to the regressive phase of the Late Jurassic basin not only in many large basins of the world [57–59], but also in the Vychegda Trough. Clastic sediments represented by siltstones and sands were accumulated in marginal-marine conditions. In the Late Cretaceous period, the sea underwent a final regression and the marginal-marine conditions changed to sandy–clayey sediments of continental genesis.

In the Late Cretaceous–Paleogene time (Alpine orogeny), the Urals underwent the processes of epiplatform orogenesis [60], which entailed the uplift of Timan and the adjacent territories of Pre-Timan and the south of the Pechora Plate. A significant part of the accumulated Jurassic and Cretaceous sediments was eroded.

Paleogene and Neogene sediments in the Vychegda Trough were not deposited due to the regional uplift of the Russian Plate in the Alpine cycle of development.

Based on the obtained paleotectonic and paleogeographic data, the formation of the region was significantly influenced by a number of major tectonic regimes that dominated at different time intervals. Firstly, the process of the formation of the Vychegda Trough in the Early Riphean and its subsequent transformation into a pericratonic depression in which the thick strata of Pre-Cambrian carbonate-clastic sediments were accumulated in predominantly marine conditions. Secondly, active tectonics at the end of the Riphean, with the subsequent deep erosion of sediments, as well as orogenic events in the Timan region at the turn of the Vendian and Early Paleozoic, led to a large-scale restructuring of the region. Thirdly and importantly, the Vychegda Trough existed for quite a long time as an uplifted platform, from the Middle Cambrian to the Late Devonian, when, probably, the post-orogenic sediments (molasses) of the Timan folded mountain structure and the upper Vendian horizons were eroded. And finally, no less important is the formation of the upper stage of the orthoplatform complex, corresponding to the Late Paleozoic and some part of the Mesozoic–Cenozoic ages.



(a) (b) (c) (d)

Figure 13. Depositional and paleogeographic environments: (**a**) Early Permian time; (**b**) Middle-to-Late Permian time; (**c**) Early Triassic time; (**d**) Jurassic–Cretaceous time (see Figure 5 for the names and ages of geological formations).

3.3. Characterization of Reservoir Rocks and Seals Rocks

The extent of knowledge about the Vychegda Trough section in terms of permeability and porosity parameters is at the regional level and is selective for the majority of wells in terms of the stratigraphic subdivisions of the section.

Reservoir properties of basin rocks were studied using 746 samples from 27 wells. During the reservoir quality analysis, porosity and permeability were compared and diagrams of sample distribution by porosity and permeability intervals were created for different stratigraphic subdivisions from the bottom to the top of the section.

Due to the extremely poorly studied Riphean sediments and the absence of any direct measurements of porosity and permeability, their characterization is given only on the basis of indirect archive data [61].

The Riphean sediments have rather poor reservoir properties, which is probably due to the unfavorable development of post-sedimentation processes and high compaction of rocks due to their burial at great depths. The oldest rocks were uncovered by drilling in the Storozhevsk-1 well. They are represented by the clastic strata of the Pezskaya and Dorogorskaya Formations, attributed to the Middle and Upper Riphean, respectively. It consists of mudstones, siltstones and sandstones with poor reservoir properties and porosity of up to 5%. However, the porosity of sandstones of the Dorogorskaya Formation is slightly higher and amounts to 7–10%, so it can be classified as a low-porosity reservoir stratum. In the Storozhevsk-1 well, from intervals 2990–3070 m (Dorogorskaya Formation) and 3325–3380 m (Pezskaya Formation), inflows of mineralized water were obtained with rates of 12.00 and 273.61 m^3/day, respectively. The Omenskaya and Nyaftinskaya Formations of the Upper Riphean, which lie higher up the section and were exposed by Storozhevsk-1 and Seregovo-1 wells, are composed of clastic-carbonate rocks characterized by extremely poor reservoir properties (porosity 1–3%, rarely up to 5%). Nevertheless, small inclusions of bitumen were found in thin interbeds of siltstones of the Omenskaya Formation and carbonate rocks (limestones and dolomites) of the Nyaftinskaya Formation, which may indicate the presence of reservoir intervals in these sediments in the past. To the east and southeast, the Omenskaya and Formations are replaced by the carbonate formation of the Vapolskaya and Yshkmesskaya Formations, represented by massive limestones and dolomites. The reservoir properties of these rocks, estimated from the Keltma-1 well, are unfortunately low (porosity is not higher than 3–4%). In a number of intervals (4329–4348 and 4401–4460 m), well logging has shown the presence of fracture-cavern dolomites with porosity of up to 7.80% and 13.60% (Figure 14), but there are no obvious signs of reservoirs. However, according to geochemical studies, increase of B_{chl} extracts (0.08–0.16%) were recorded in limestones and dolomites of the Vapolskaya Formation top, which may suggest micro-accumulation of HC. The Riphean part of the section is completed by the Uftyugskaya Formation of the clastic composition (sandstones and siltstones with rare interlayers of gravels and mudstones), with porosity of 7–10% on average, but there are also significant interlayers, lenses and even the interbedded strata of poorly consolidated sandstones and coarse-grained siltstones with satisfactory reservoir properties (porosity of up to 20% and permeability of up to 1.27 mD in the wells Seregovo-1 and Storozhevsk-1). The drilling of the Storozhevsk-1 well in the interval of 2549–2553 m showed the heavy oil saturation of the sandstones of the Uftyugskaya Formation (Figure 14) and, from the intervals 2803–2817 and 3434–3439, received inflows of mineralized water with rates 6.1 and 4.1 m^3/day, respectively, which indicates the presence of reservoirs in it. Due to the high deformation of the Vychegda Trough and its adjacency to the West Timan thrust, it is fair to expect the increased fracturing of rocks of the Riphean complex and thus higher values of filtration properties.

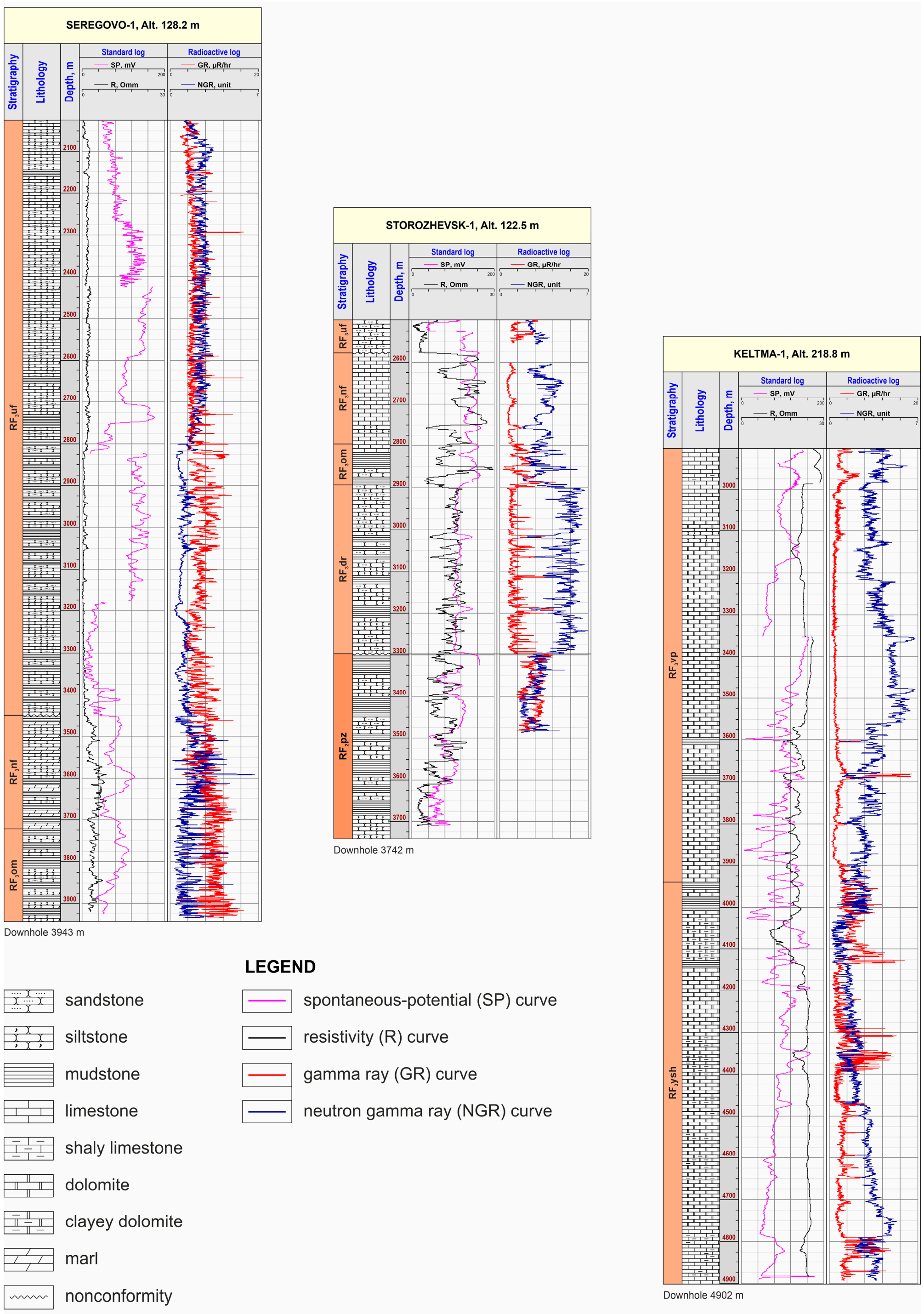
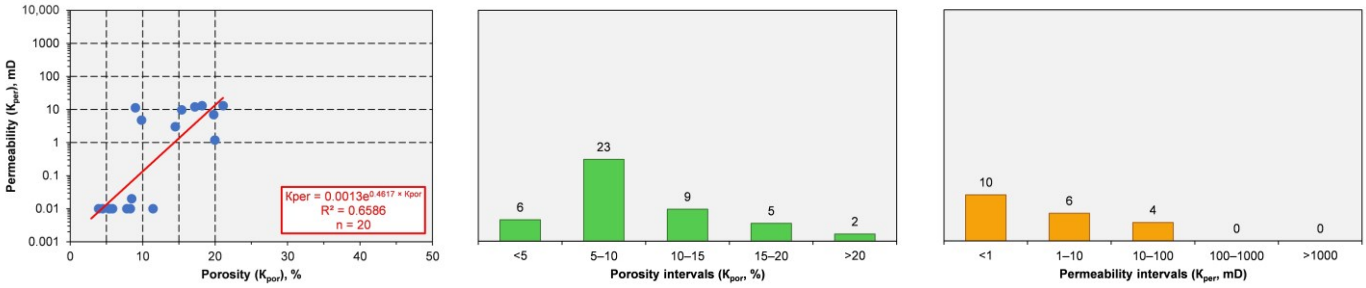


Figure 14. Logs of Riphean rocks in wells Seregovo-1, Storozhevsk-1 and Keltma-1 (see Figure 5 for names and ages of geological formations).

Reservoir properties of rocks composing sections of the Vendian sediments are better studied. The Upper Vendian is represented by interbedded sandstones, siltstones and mudstones in the Redkinsky (Ust–Pinezhskaya Formation) and Kotlinsky (Krasavinskaya, Mezenskaya and Padunskaya Formations) Horizons. The porosity of the studied samples varies from 2.9 to 22.16% and permeability from 0.01 to 13 mD. In the neighboring Mezen Syncline, sandstone beds with porosity of up to 23% and permeability of up to 1350 mD are identified in the section of Vendian sediments. They are particularly typical of the Mezenskaya Formation. According to the scheme of porosity-permeability relations and their frequencies (Figure 15), about 50% of the total number of studied Vendian samples are reservoirs fair to high-porous and low to fair-permeable. Sandstones and siltstones of the Kotlinsky Horizon are considered to be the best reservoirs. Notably, as a result of the testing of wells that penetrated the Vendian complex, the inflows of mineralized formation water were obtained with flow rates of 10.40–180 m^3/day (Seregovo-1 well) and 288 m^3/day (Storozhevsk-1 well).

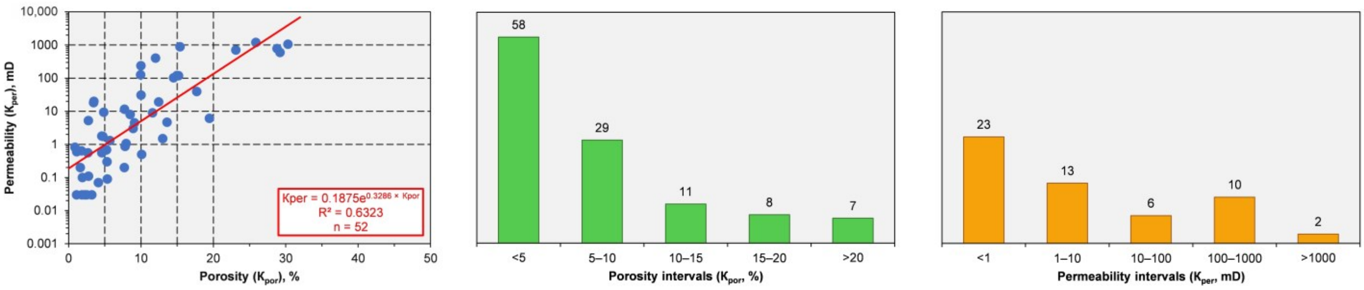


(**a**) (**b**) (**c**)

Figure 15. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Vendian rocks.

The Paleozoic clastic–carbonate complex, due to the higher frequency of drilling compared to the Riphean–Vendian sediments, has a more systematic dataset of rock porosity and permeability studies. In the course of our study, we have analyzed the porosity and permeability of the Upper Devonian, Lower, Middle and Upper Carboniferous and Lower–Middle Permian sediments.

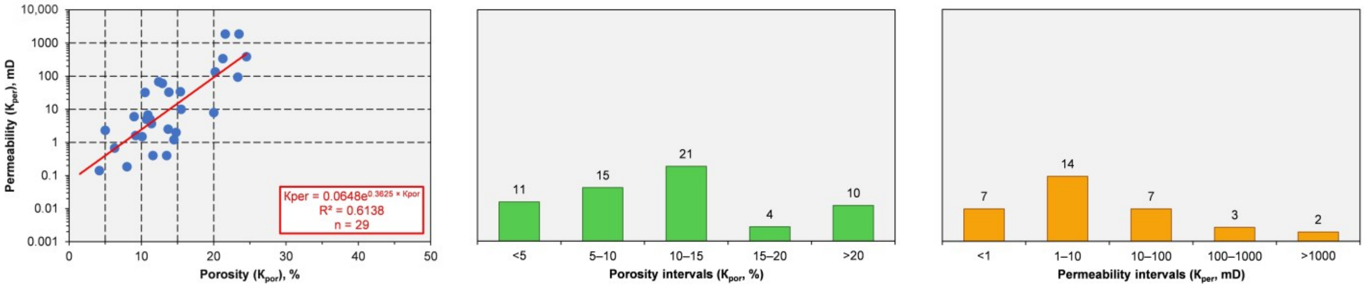
The Upper Devonian rocks can be classified as reservoir rocks with ultralow to high-porous (K_{por} = 0.01–31.98%) and ultralow to good-permeable (K_{per} = 0.03–1055 mD) properties (Figure 16). At the same time, the sandstones of the Timanian Horizon contain reservoir intervals characterized as high-porous (K_{por} = 23.10–30.30%) and good or high-permeable (K_{per} = 598–1204.22 mD). The low oil saturation of rocks of the Timan Horizon was found in several areas of the Vychegda Trough. Among carbonate rocks, limestones and dolomites of the Vetlasian–Sirachoy complex of the Upper Frasnian have good reservoir properties, with porosity and permeability up to K_{por} = 9.94–15.19% and K_{per} = 119.04–403 mD, respectively.



(**a**) (**b**) (**c**)

Figure 16. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Upper Devonian rocks.

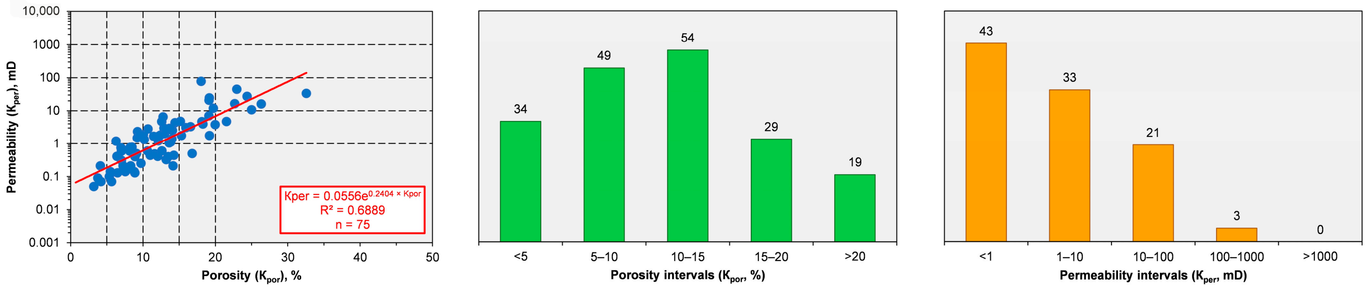
The Lower Carboniferous sediments are, on average, fair-porous and good-permeable reservoir rocks (Figure 17). The best reservoir properties are typical of sandstones (K_{por} = 21.60–23.50%, K_{per} up to 1879 mD) and limestone-dolomites (K_{por} = 20–24.53%, K_{per} = 93.36–389.09 mD) of the Visean Stage. Direct signs of the oil potential of the Visean Stage are noted in the form of the low oil saturation of the Tula rocks.



(**a**) (**b**) (**c**)

Figure 17. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Lower Carboniferous rocks.

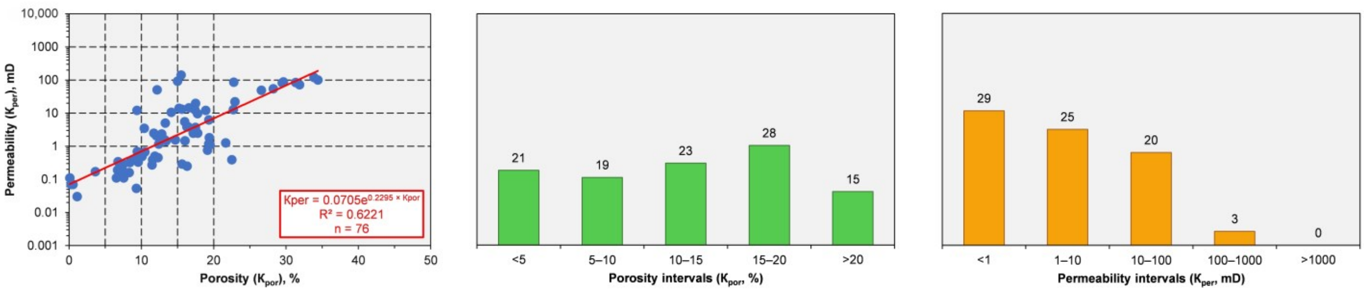
The Middle Carboniferous rocks in general can be characterized as fair-porous and fair-permeable (Figure 18). The highest indices in this section are found for limestones of the Bashkirian Stage (K_{por} = 19.12–26.34%, K_{per} = 11.83–27.22 mD), as well as limestones and dolomites of the Lower and Upper Moscovian Stage (K_{por} = 20.59–32.57%, K_{per} up to 33.45 mD). The Middle Carboniferous sediments, in particular, the limestones of the Vereiskian and Kashirskian Horizons are associated with gas-bearing formations saturated with helium and nitrogen (94–98%), with an insignificant HC gas content (2–6%). Gas flow rates were 8000–140,000 m^3/day. Heavy oil manifestations (density 0.86–0.89 g/cm^3) were recorded in carbonate rocks of the Moscovian Stage throughout the basin.



(**a**) (**b**) (**c**)

Figure 18. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Middle Carboniferous rocks.

The rocks of the Upper Carboniferous, compared to the Middle Carboniferous, have identical porosity values, but slightly higher permeability properties (Figure 19). The most porous and permeable are limestones and dolomites with a porosity of 22.77–34.40% and permeability of 22.08–141.30 mD. No HC manifestations were observed.



(**a**) (**b**) (**c**)

Figure 19. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Upper Carboniferous rocks.

In the Paleozoic section, the Permian sediments contain abundant HC manifestations and even heavy oil saturated layers. The porosity and permeability of the Lower Permian rocks are on average low, but there are intervals of cavernous limestones and dolomites of the Sakmarian, Artinskian and Kungurian ages, characterized as high-porous (K_{por} = 20.91–40.66%) and fair-permeable (K_{per} = 27.29–128.67 mD) (Figure 20).

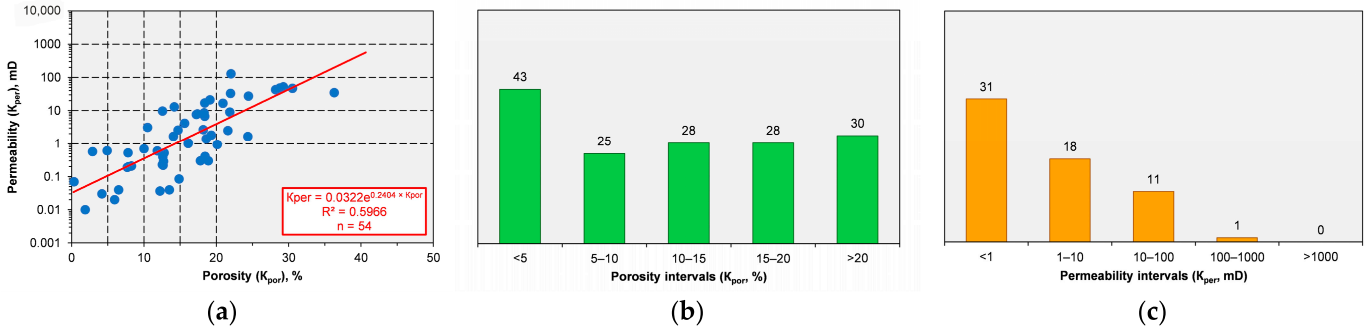


Figure 20. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Lower Permian rocks.

More than half of the Middle Permian rock samples belong to good and high-porous reservoirs (K_{por} = 15.31–46.78%) (Figure 21). High values are characteristic of cavernous limestones and marls of the entire interval, as well as sandstones and siltstones of the Kazanian Stage. Nevertheless, the rocks are low-permeable and relatively high values are found only in sandstones of the Kazanian age (K_{per} up to 17 mD).

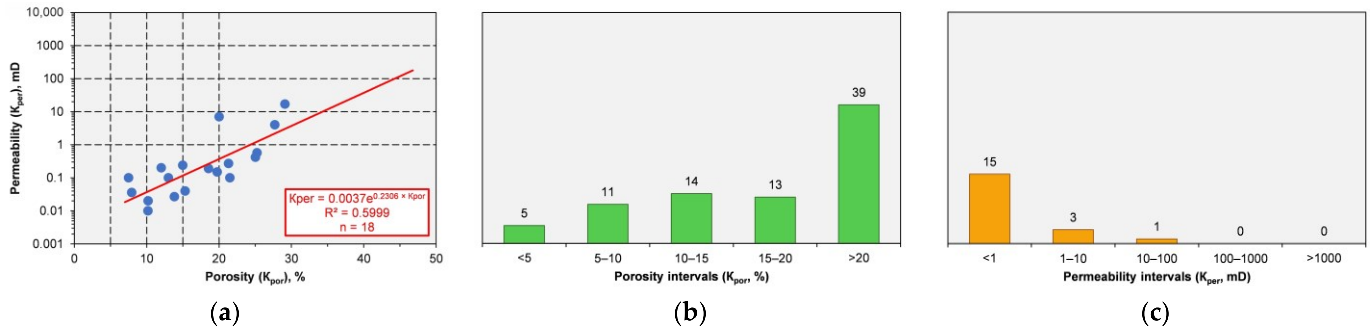


Figure 21. Plot: (**a**) comparison of porosity and permeability and (**b**,**c**) their distribution for Middle Permian rocks.

As noted earlier, the Permian sediments are associated with intensive manifestations of HC. Highly viscous oils and bitumens are found in the section of the Kungurian gypsum–dolomite sequence. Higher up the section, strata with a total thickness of 15–20 m containing high-viscosity oil were identified in sandstones and cavernous limestones of the Kazanian Stage of the Permian. The oils sampled from the formations are very heavy (0.963–0.983 g/cm^3) and sulfurous to highly sulfurous (1.71–2.50%). The exception are two sandy strata in the Kazanian Stage (1.20 and 1.75 m thick) saturated with light oil, the content of which in the rock is 2.20–5%. In addition, dark brown viscous bitumen with an oil odor was found in a number of wells, mine workings and pits up to 5–8 m deep.

Based on well logging data and the core study results, it has been determined that the basin contains seal rocks in a wide interval from the Middle Riphean to the Middle Permian.

The Riphean–Vendian complex of the Vychegda Trough contains a number of strata with sealing properties [62]. These include mudstones of the upper half of the Pezskaya Formation section, which have sufficient regional stability. Higher in the section, intervals of clayey clastic–carbonate sediments of the Omenskaya and Nyaftinskaya Formations of the Upper Riphean may serve as seal rocks. It is also associated with the sealing horizon represented, probably, by evaporite formation: salts, gypsums, anhydrides and dolomites. Riphean salts were found near Seregovo village in the form of a diapir, penetrating Riphean, Vendian and Paleozoic sediments. In addition, other Riphean age salt diapirs (Verkhnesyssky and Yuzhno–Beloborsky) are predicted on regional profiles in the form of seismic recorded anomalies [63]. Unfavorably, this formation is most likely of local character due to the Pre-Vendian erosion of Upper Riphean sediments. In the Vendian section, finely dispersed compacted mudstones of the Ust–Pinezhskaya Formation, which are regionally sustained in area and homogeneous in structure, are considered to be good seal rocks. In the upper part of the Vendian section, the sealing intervals are more heterogeneous in structure, insufficiently regionally sustained in area and characterized more often by pelitic and siltstone–pelitic structures and are often represented by transitional variations between siltstones and clays.

In the Devonian section of the Paleozoic age, the seal rocks are the Lower-Middle Frasnian sediments, in particular, mudstones of the Timanian, shaly limestones and mudstones of the Sargaev and siliceous–clayey varieties of the Domanic Horizons. These rocks are characterized by ultra-low porosity ($K_{por} < 5\%$) and ultra-low permeability (K_{per} on average < 1 mD). The clay pack of the Visean Stage acts as a regional seal rock in the Carboniferous rocks ($K_{por} < 5\%$, $K_{per} < 1.50$ mD); anhydrites of the Kasimovian–Gzhelian Stage can also be classified as the sealing strata, as suggested by the ultra-low porosity and ultra-low permeability of rocks ($K_{por} < 2\%$, $K_{per} = 0.07$–0.11 mD). The gypsum–anhydrite–dolomite sequence of the Kungurian Stage of the Lower Permian is considered to be the next regional seal rocks, which have continuity over the area and section, as well as poor reservoir properties (K_{por} on average 2%). The Middle-Upper Permian section is predicted to contain seal rocks composed of clays with interlayers of siltstones and marls.

Thus, the presence of sustained sealing horizons over the basin area and the extensive development of reservoir intervals allows us to assert the existence of favorable conditions for the accumulation and conservation of HC accumulations in the Vychegda Trough. Oil and gas manifestations established in the basin from Riphean to Permian sediments inclusively are an important criterion for a positive assessment of oil and gas prospects.

3.4. Geochemical Characterization of the Basin Rocks

The results of pyrolytic and chemical-bitumenological analysis, as well as studies of the elemental composition of kerogen and the HC composition of the saturated fraction of B_{chl} extracts from Riphean, Vendian, Upper Devonian, Carboniferous and Permian rocks, were used as input materials for the geochemical characterization of the sedimentary section.

Notably, the geochemical studies of sediments of the Vychegda Trough, as well as the studies of permeability and porosity, have been carried out selectively. Nevertheless, a number of scientists studied the content of total organic carbon (TOC) and bitumen extracts in rocks from deep wells of the southeastern Pre-Timan and from outcrops of the Timan Ridge. In general, the research of Bazhenova O.K. [64–66], Bazhenova T.K. [67], Getsen V.G. [68], Konyukhova V.A. [69], Kuzmin D.A. [70], etc., provided justifications for the identification of possible oil and gas source rocks, calculated the level of the catagenetic transformation and attempted to estimate the initial total HC resources.

The geochemical characterization of the section was carried out from the bottom to the top, from ancient to younger sediments.

The oldest sediments in the study area are clastic rocks of the Pezskaya Formation of the Middle Riphean, uncovered by the Storozhevsk-1 well. The age analogue of the Pezskaya Formation in the West Timan is considered to be clastic and shale rocks of the Svetlinskaya, Novobobrovskaya and Vizingskaya Formations studied in the Bolshiye Porogi-187 well and in outcrops of the Dzhezhim–Parma and Och–Parma uplifts. In the Storozhevsk-1 well we studied mudstones (insoluble residue (IR) = 85.42–95.00%) with a poor TOC and B_{chl} extract content (TOC = 0.02–0.26%, B_{chl} = 0.0025–0.02%), but there is an interval (3445–3450 m) with a TOC concentration of 0.46%. At the Och–Parma outcrop, the values of the TOC and B_{chl} extracts in the shale are several times higher and are

0.28–1.97% and 0.0006–0.31%, respectively. From the analysis of the results of the pyrolytic analysis of mudstones of the Pezskaya Formation, it follows that the rocks have significantly depleted the generation potential ($S_1 + S_2$ = 0.06–0.50 mg HC/g rock), but in general, it is characterized as fair (Figure 22a,b). The temperature at which the maximum generation of HC from the cracking of kerogen occurs during pyrolysis (T_{max}) ranges within 449–535 °C and corresponds to "mature" and "postmature" OM (Figure 22c). The hydrogen index (HI) and productivity index (PI) are 35–208 mg HC/g TOC and 0.09–0.43, respectively, which together are characteristic of the full and/or partial transformation of kerogen to HC. The bitumen coefficient (β = (B_{chl}/TOC) × 100%) < 25% indicates the presence of autochthonous B_{chl} extracts in the Pezskaya Formation (Figure 22d).

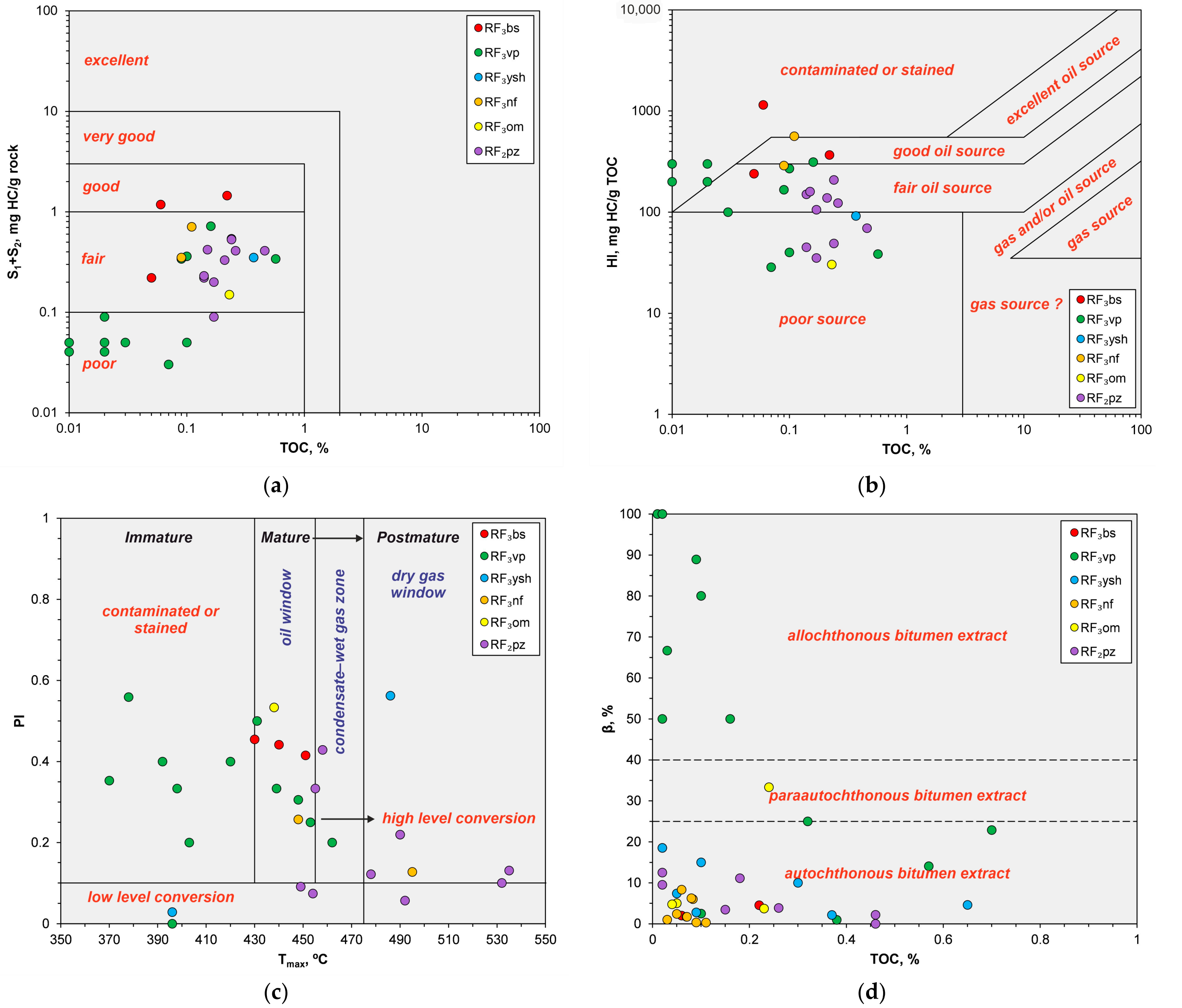


Figure 22. Results of interpretation of geochemical studies of Riphean sediments: (**a**) residual generation potential of rocks; (**b**) dependence of HI on TOC showing the potential of rocks; (**c**) PI-T_{max} relationship; (**d**) dependence of β on TOC (see Figure 5 for names and ages of geological formations).

Upper Riphean clastic–carbonate and shale rocks in the Safonovskaya and its age analogue Bystrinskaya Groups were studied using samples from Keltma-1, Storozhevsk-1, Seregovo-1 and Nevshera-183 wells, as well as from the Och–Parma outcrop. The Safonovskaya Group, consisting of the Omenskaya/Yshkmesskaya and Nyaftinskaya/ Vapolskaya Formations, has poor concentrations of TOC (0.01–0.32%), B_{chl} extracts (0.0003–0.08%) and generative potential ($S_1 + S_2$ = 0.03–0.32 mg HC/g rock). However, in the Keltma-1 well in several intervals of the section, 3044–3049, 3099–3106, 3151–3158 and 4385–4390 m (see Figure 14), composed of shaly limestones and mudstones interbeds (IR = 9–86%), elevated values of TOC (0.37–0.70%) were established against a generally low background. The most OM-rich samples have $S_1 + S_2$ = 0.34–0.72 mg HC/g of rock, which indicates the presence of source rock packs with fair generational properties in the selected intervals of the section. According to T_{max} (448–486 °C) and PI (0.25–0.56), the OM is thermally mature (gradation from "oil window" to dry gas generation). Samples with higher residual potential are also characterized by a higher HI = 92–312 mg HC/g TOC. The intervals distinguished in the Vapolskaya Formation are: 3006–3013, 3044–3049, 3099–3016, 3205–3212, 3384–3391, 3590–3595 and 3680–3887 m (see Figure 14), represented by stromatolitic limestones and dolomites, with increased values of the B_{chl} extract (0.01–0.16%), oil saturation index (OSI = (S_1/TOC) × 100%, if OSI > 100, this indicates the presence of migration HC; OSI = 137.50–200.00%) and bitumen coefficient (β = 50–100%), which clearly indicates the epigenetic nature of the B_{chl} extracts (Figure 22d). Some samples from the studied intervals have low values of T_{max}, with high values of PI, which according to [71,72] confirms the presence of movable HC in the rocks. Among other rocks of the Upper Riphean, shaly limestones (IR = 4.66–9.89%) of the Bystrinskaya Group from the Nivshera-183 well are also notable as they have the highest residual potential ($S_1 + S_2$ = 1.18–1.45 mg HC/g of rock). Proof of the presence of source rocks in the Upper Riphean section is the carbonaceous–clayey shales (IR = 85.50–96.20%) of the Bystrinskaya Group from the Och–Parma outcrop, which have anomalously high concentrations of TOC (0.53–7.40%) and a B_{chl} extracts content of up to 1.80%.

The Vendian formations have been studied at the Keltma, Storozhevsk and Seregovo areas and in wells on the southeastern side of the Vychegda Trough. The most interesting rocks in the Vendian section are mudstones (IR = 80.00–95.00%) of the Ust–Pinezhskaya Formation of the Redkinsky Horizon, which are seen as potential source rocks. TOC contents are 0.01–0.22 and the pyrolytic parameters and B_{chl} extracts content are extremely poor, but in the Storozhevsk-1 and Seregovo-1 wells, due to a higher proportion of clayey sediments, TOC concentrations reach 0.40–0.82% and the generation potential is estimated as fair ($S_1 + S_2$ = 0.39–1.90 mg HC/g rock) (Figure 23a,b). The rocks are mainly located in the so-called "oil window" (T_{max} = 432–466 °C) (Figure 23c). The values of HI (100–725, average 365 mg HC/g TOC) and PI (0.12–0.51, average 0.27) indicate that the rocks are slightly depleted. Clayey rocks (IR = 84.44–99.44%) of the Kotlinsky Horizon contain OM in concentrations of 0.05–0.59% (average 0.17%). The rocks lie in the "oil window", which is confirmed by T_{max} = 433–454 °C. The mudstones of the Kotlinsky Horizon relative to the Ust–Pinezhskaya Formation are characterized by a higher HC generation capacity ($S_1 + S_2$ = 0.28–2.04 mg HC/g rock). The potential of the rocks is partially depleted (HI in average 366 mg HC/g TOC). The B_{chl} extracts of the Vendian complex are generally of an autochthonous type (Figure 23d).

The authors further analyzed the results of the study of the methane–naphthene fraction of B_{chl} extracts from Riphean–Vendian sediments. Of particular importance in this fraction are biomarkers (chemofossils)—normal and isoprenoid alkanes. Their distributions and ratios allow solving various geological and geochemical problems, in particular, to determine the facies-genetic type and the accumulation environment of the initial OM.

From the constructed Connon–Cassou diagram (Figure 24a) and the pristane (i-C_{19})/phytane (i-C_{20}) dependence on the Carbon Preference Index (CPI) (Figure 24b), we conclude that the initial OM type of the Riphean–Vendian sediments is interpreted as sapropelic, formed in shallow-marine reductive geochemical environments. The molecular weight distribution (Figure 24c) and group composition of n-alkanes (Figure 24d) indicate that phytoplankton and its mixture with shallow-marine algae made the main contribution to the formation of OM.

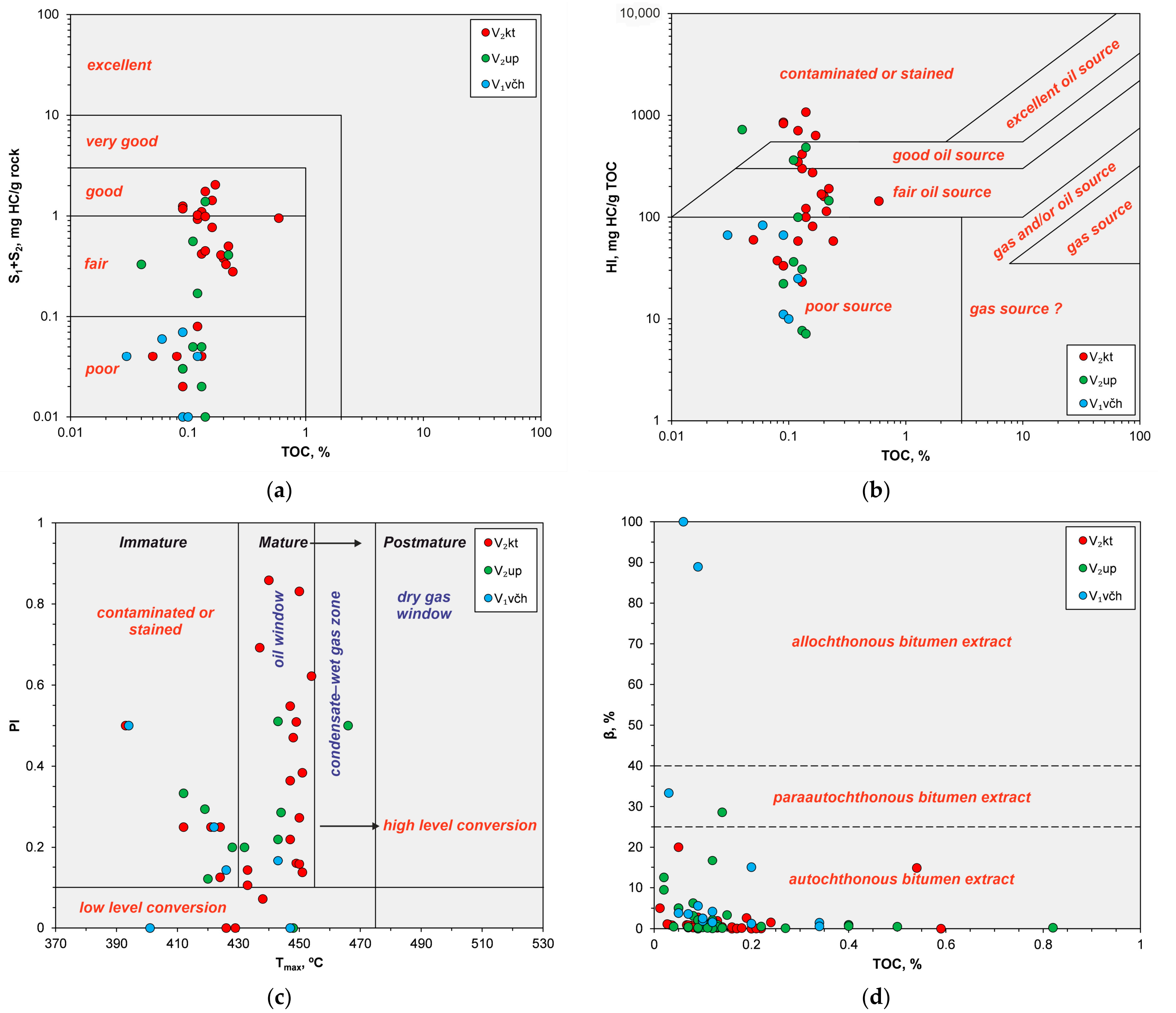


Figure 23. Results of interpretation of geochemical studies of Vendian sediments: (**a**) residual generation potential of rocks; (**b**) dependence of HI on TOC showing the potential of rocks; (**c**) PI-T_{max} relationship; (**d**) dependence of β on TOC (see Figure 5 for names and ages of geological formations).

It is important to note that the Riphean–Vendian complex has a large thickness, its share is about 80% of the section, which may suggest significant oil and gas generation and the accumulation of HC in the past geological eras.

In the Paleozoic part of the section, the main formation capable of producing significant volumes of HC in the eastern part of the Russian Plate is the high-carbon formation of the Domanic age [73,74], but the role of other sediments is not excluded either.

In the Upper Devonian complex, mudstones and shaly limestones (IR = 7.59–97.52%) of the Timan and Sargaev Horizons are considered as oil-producing sediments and are exposed in all areas of the Vychegda Trough. TOC concentrations are poor (0.05–0.69%), the B_{chl} extracts content is poor (B_{chl} = 0.0001–0.15%), but in general, more than 50% of samples can be classified as promising source rocks with fair and good potential and often very good ($S_1 + S_2$ = 0.41–7.70 mg HC/g rock).

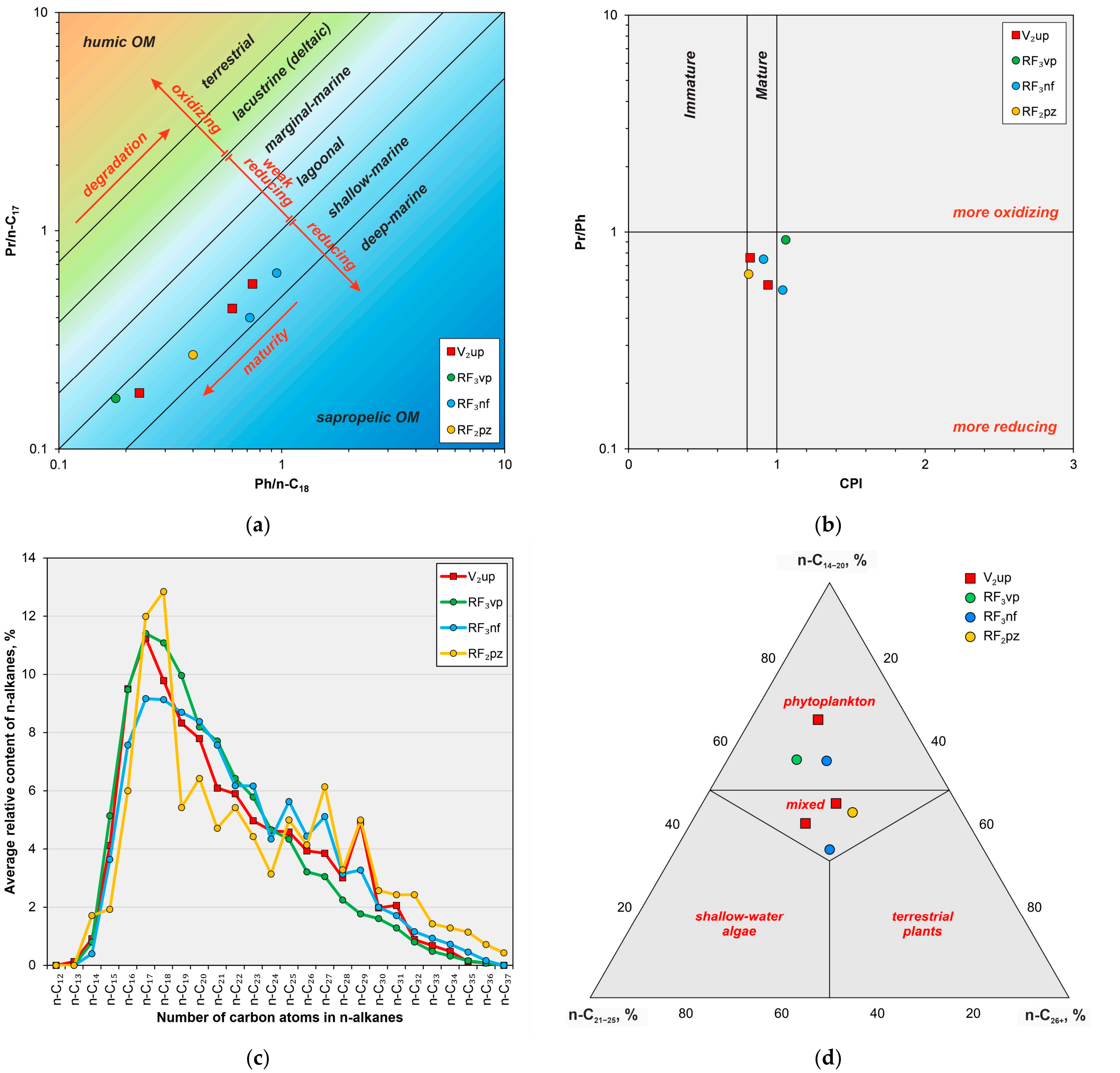


Figure 24. Results of biomarker analysis of OM from Riphean–Vendian sediments: (**a**) Connon–Cassou diagram; (**b**) Pr/Ph dependence on CPI; (**c**) averaged molecular weight and (**d**) group distribution of n-alkanes in the saturated fraction of B_{chl} extracts (see Figure 5 for names and ages of geological formations).

The Domanic Horizon is the richest source rock in terms of generative properties. Clayey and bituminous carbonate rocks (IR = 0.50–80.12%) of the Domanic Horizon are characterized by the highest TOC, which vastly ranges from 0.04 to 11.69%, (average 2.45%), with the highest concentrations recorded in the Storozhevsk-1 well. A distinctive feature of the rocks is the increased B_{chl} extracts content (B_{chl} up to 1.25%, average 0.27%). Samples with anomalous concentrations of TOC have values $S_1 + S_2$ = 1.99–94.49 (average 23.87 mg HC/g rock), which allows them to be classified as source rocks with good, very good and excellent generative potential (Figure 25a,b). The HI, equal to 45.45–975 mg HC/g TOC (average 403 mg HC/g TOC), is characteristic of sapropelic-type OM.

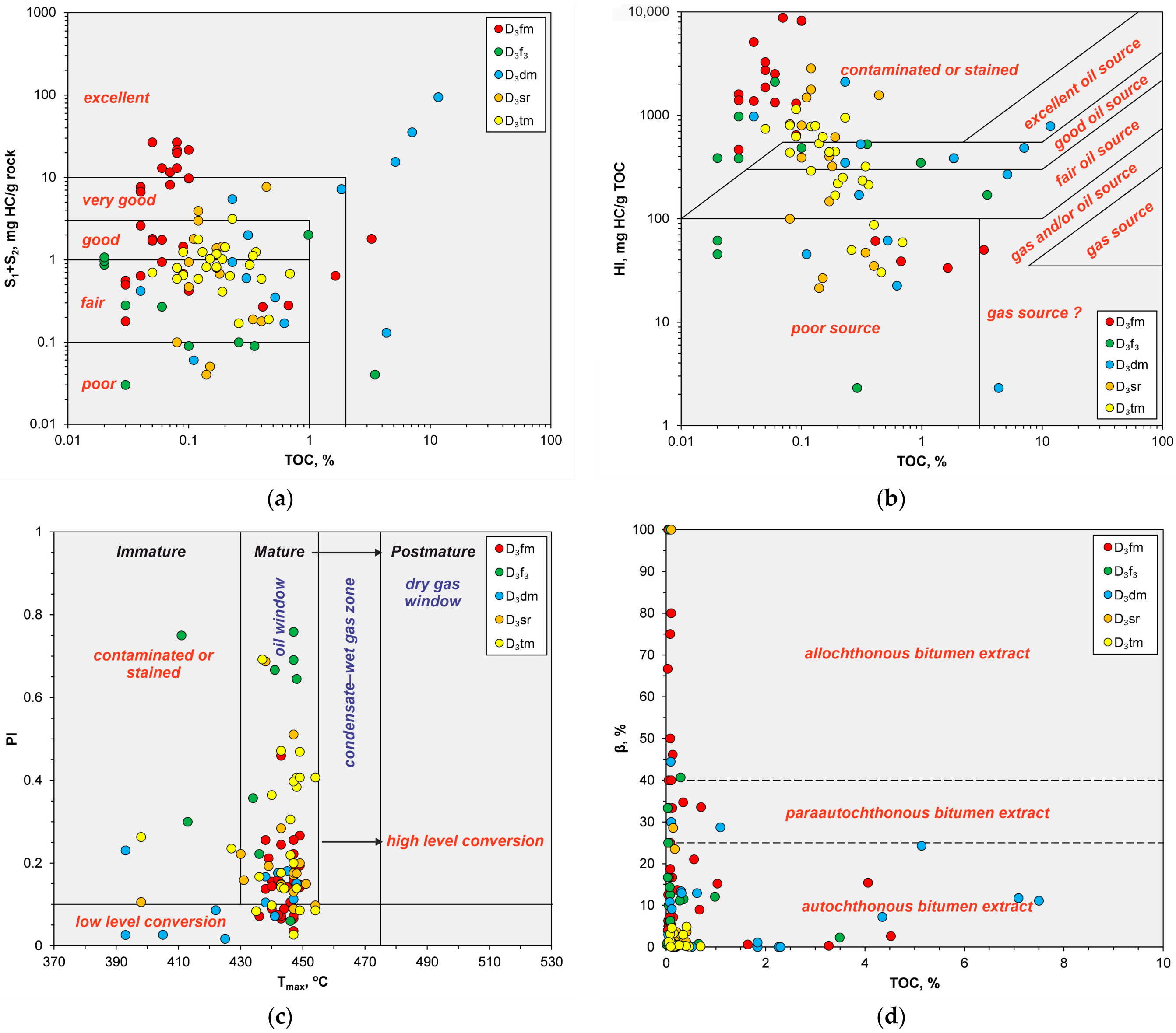


Figure 25. Results of interpretation of geochemical studies of Upper Devonian sediments: (**a**) residual generation potential of rocks; (**b**) dependence of HI on TOC showing the potential of rocks; (**c**) PI-T_{max} relationship; (**d**) dependence of β on TOC (see Figure 5 for names and ages of geological formations).

Higher up the section, according to the results of geochemical studies, clayey sediments of the Famennian Stage are distinguished, well-developed and fairly well studied in the southeast of the region. The interlayers of mudstones (IR = 89.38–94.16%) with a high TOC content (3.27–4.52%) have oil-generating properties. The sediments of the Famennian age are characterized by very good potential (average 7.00 mg HC/g rock, maximum 26.68 mg HC/g rock). Also noteworthy are the increased values of free HC in carbonate sediments (S_1 = 1.50–6.83 mg HC/g rock), indicating that accumulating processes are observed against the background of HC generation.

The Carboniferous complex has been studied extensively from Visean to Upper Carboniferous sediments inclusive. It is concluded from the analysis of the geochemical results that the best HC source rocks indicators are found in mudstones (IR = 90.83–97.43%), often coal-bearing, of the Tula Horizon of the Upper Visean Stage. OM concentrations vary widely: from 0.07 to 17.21% (average 2.40%). The B_{chl} extracts' content of rocks is elevated (B_{chl} on average 0.32%). More than half of the samples have generation potential from good to excellent ($S_1 + S_2$ = 1.01–14.72, average 3.78 mg HC/g rock) (Figure 26a,b).

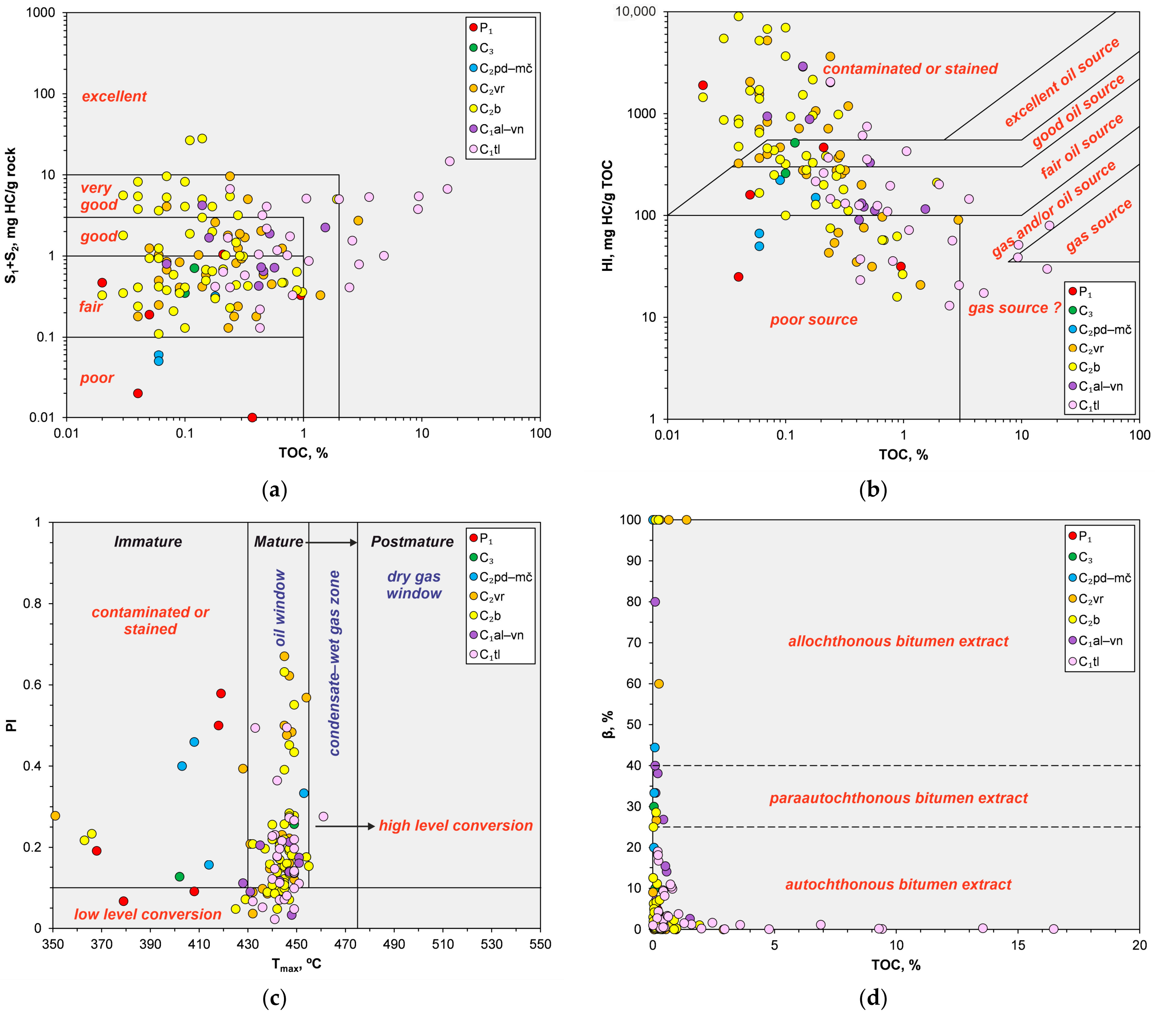


Figure 26. Results of interpretation of geochemical studies of Carboniferous and Lower Permian sediments: (**a**) residual generation potential of rocks; (**b**) dependence of HI on TOC showing the potential of rocks; (**c**) PI-T_{max} relationship; (**d**) dependence of β on TOC (see Figure 5 for names and ages of geological formations).

Higher up the section, the HC source rocks are mudstones and shaly limestones (IR = 17.02–94.05%) of the Bashkirian Stage of the Middle Carboniferous. A TOC content > 0.2% (0.21–1.92%) is typical for 30% of samples. The B_{chl} extracts content is poor (B_{chl} 0.02% on average). The potential of rocks in most parts of the basin is fair ($S_1 + S_2 < 1$ mg HC/g rock), except in the southeastern region, where it varies from fair to excellent ($S_1 + S_2$ = 0.10–28.13 mg HC/g rock).

Properties similar to those of the Bashkirian sediments are typical of mudstones and shaly limestones (IR = 19.84–78.43%) of the Vereiskian Horizon of the Moscovian Stage. The TOC concentrations are 0.10–2.91% (0.30% on average). The B_{chl} extracts content of the rocks is poor (B_{chl} 0.004% on average), except for a number of samples for which the B_{chl} extracts are elevated (0.16–5.00%) and clearly indicate the micro-accumulation of HC. About one third of the samples have a high capacity with respect to HC formation ($S_1 + S_2$ = 1.03–9.64 mg HC/g rock).

The Upper Carboniferous and Permian sediments are very poorly studied by geochemical methods. In general, poor TOC (0.02–0.95%) and potential (0.01–1.05 mg HC/g rock) are observed in the section, but there are intervals of the section with an increased B_{chl} extracts content (B_{chl} up to 0.24%). The rocks are thermally immature (T_{max} = 368–419 °C).

According to the parameter T_{max} (298–438 °C), Paleozoic sediments in most of the Vychegda Trough are thermally immature or located at the initial stage of the "oil window" (Figures 25c and 26c). However, in the eastern near-side zone of the Vychegda Trough, the rocks occur at relatively great depths and are located predominantly in the "oil window" (T_{max} = 425–461 °C). This fact is also confirmed by the results of studying the elemental composition of kerogen (Figure 27).

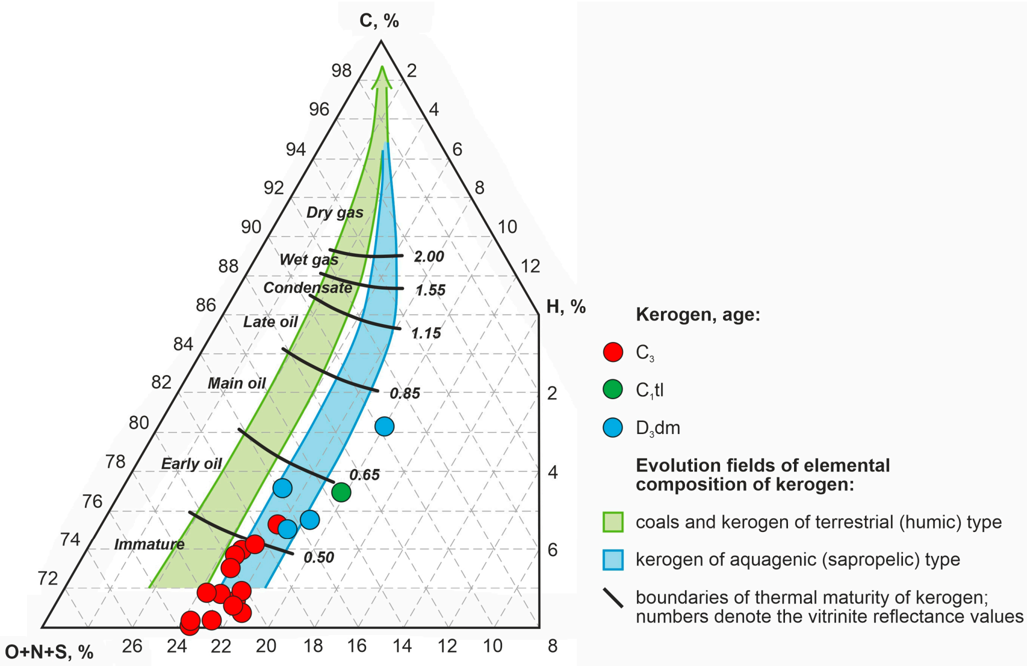
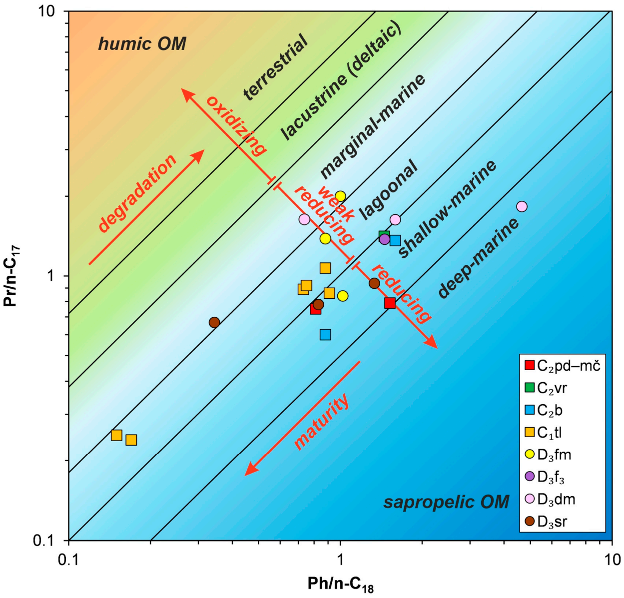


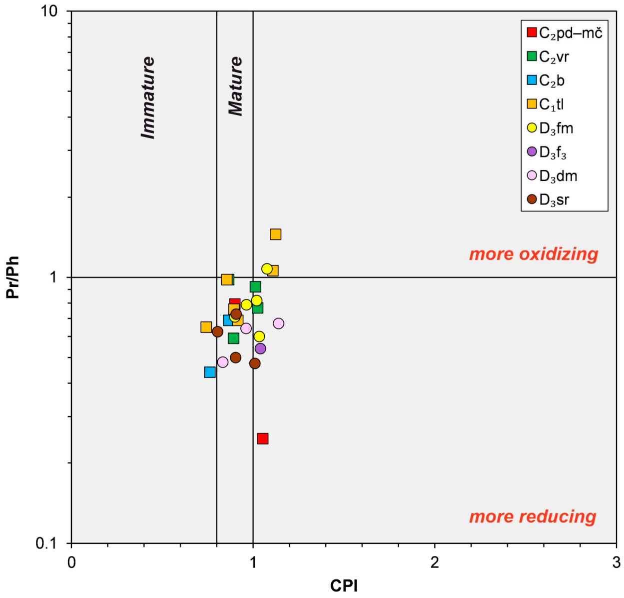
Figure 27. Ternary plot of elemental composition of Devonian and Carboniferous rocks kerogen in% based on the model of evolution of elemental composition of kerogen in catagenesis (see Figure 5 for names and ages of geological formations).

A comparison of the extracts of B_{chl} and TOC of the Paleozoic rocks showed that significant parts of the bitumen extracts are of autochthonous and paraachthonous types. However, bitumen extracts from the Famenian and Moscovian rocks are interpreted as allochthonous, indicating the presence of migrated HC and their possible oil productivity (Figures 25d and 26d).

The results of the interpretation of HC biomarkers of the alkane series for Upper Devonian and Carboniferous rocks are presented in Figures 28 and 29. The constructed plots indicate a mixed and sapropelic type of OM formed in lagoon and marginal-marine weakly reducing environments, as well as shallow- and deep-marine reducing environments. The source of OM was predominantly shallow-marine algae, with a small proportion of phytoplankton and terrestrial plants. Summarizing the above, we can conclude that the sedimentary section contains up to 11 oil and gas producing strata, of which five occur in the Riphean–Vendian complex and six in the Paleozoic. The Riphean rocks have considerably depleted their generational potential, but it is possible that they made the greatest contribution to the formation of the oil and gas potential of the region due to their huge thicknesses. The OM of the Vendian sediments is less transformed, and there are intervals of the section with rather good oil source rocks. The analysis of biomarkers showed that the Riphean–Vendian OM was formed in a marine reducing environment, it corresponds to the sapropelic type, which is the source of the generation of mostly liquid HC. The Paleozoic source rocks are the most promising in terms of HC generation, especially for the southeastern side of the Vychegda Trough, where the rocks are located in the "oil window". The analysis of biomarkers of the Paleozoic strata shows that the rocks are enriched with mixed and sapropelic-type OM, which has the potential to generate both liquid and gas HC. It is worth noting the excellent generation properties of the Domanic and Tula Horizon in wells of a number of areas. However, these intervals of the section due to its shallow depth and it being thermally immature cannot be the sources of numerous HC manifestations in the Paleozoic section. Nevertheless, seismic exploration materials and the results of structural modeling allow us to trace, in the southeastern Pre-Timan area practically unexplored by drilling, certain submerged areas where conditions for HC generation by oil and gas source rocks may well exist. This problem should be studied in more detail.

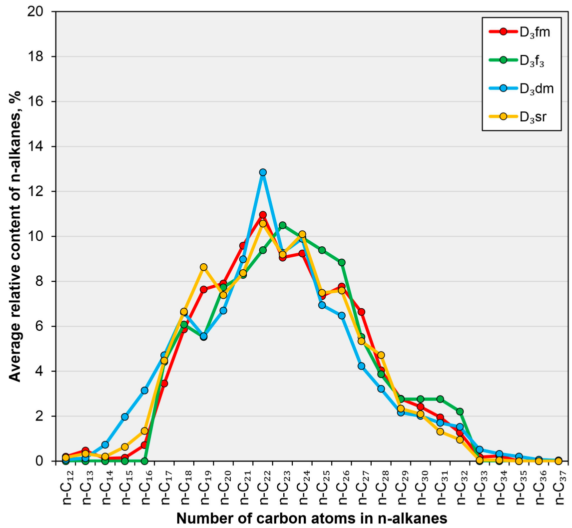


(**a**)

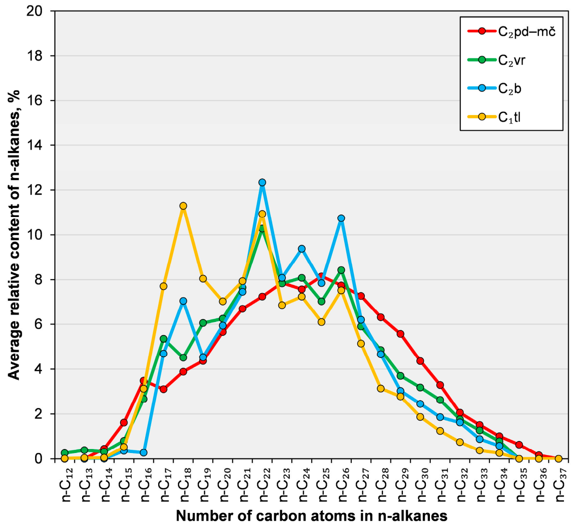


(**b**)

Figure 28. Results of biomarker analysis of OM from Upper Devonian and Carboniferous sediments: (**a**) Connon–Cassou diagram; (**b**) Pr/Ph dependence on CPI (see Figure 5 for names and ages of geological formations).



(**a**)



(**b**)

Figure 29. *Cont.*

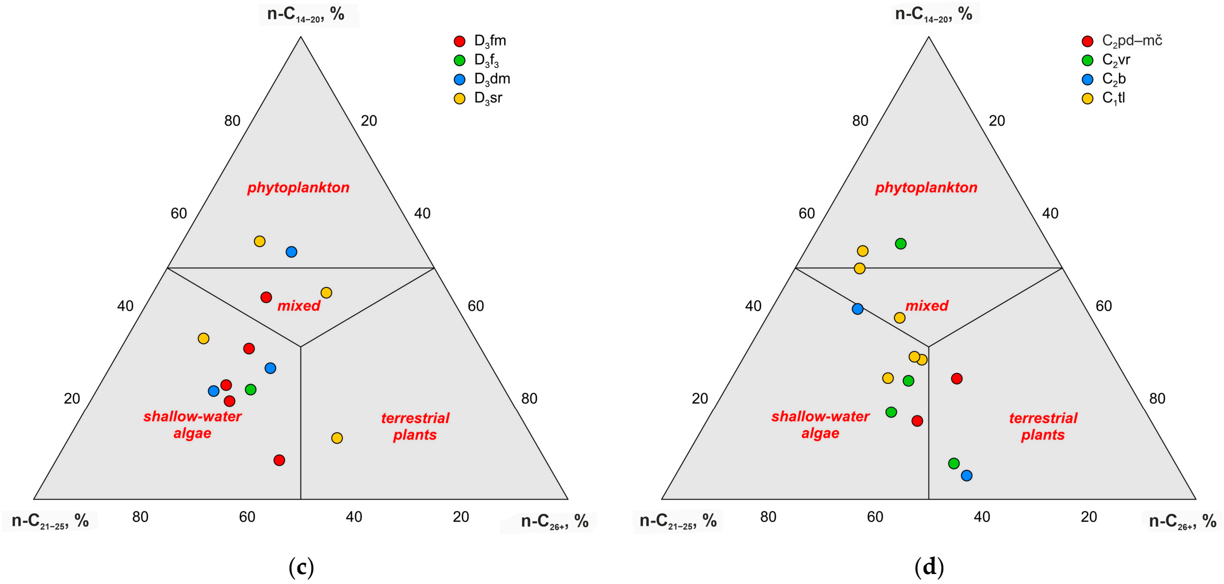


Figure 29. Results of biomarker analysis of OM from Upper Devonian and Carboniferous sediments: (**a**,**b**) averaged molecular weight and (**c**,**d**) group distribution of n-alkanes in the saturated fraction of B_{chl} extracts (see Figure 5 for names and ages of geological formations).

3.5. Results of Basin Modeling

The global experience of geological exploration shows that nowadays it is difficult to imagine the assessment and forecasting of the oil and gas potential of poorly explored areas without modern methods. One of the widely used technologies is basin modeling or HC systems modeling [75–77]. Today, basin modeling is an integral part of the geological exploration process and is performed not only at the regional stage, but also at the prospecting and appraisal, and exploration and production stages [78]. The main question that can be answered by basin modeling is: are there HC in the basin and how many? In general, basin models make it possible to estimate resources and predict the distribution of HC accumulations, select promising sites and optimize the costs of geological exploration.

In this study, based on all available geological, geophysical and geochemical information for the study area, a one-dimensional basin model was built for the parametric Keltma-1 well in order to reconstruct the burial history and warming of the basin, as well as to calculate the processes of the maturation of the OM of the rocks and the dynamics of the realization of oil and gas source potential. Well Keltma-1 is located in the southeast of the region (see Figure 1) and was selected for the simulation due to the fact that it opened a more complete section of the basin. The input data for the model construction are presented in Figure 30.

The stages of sedimentation and erosion events were defined in the model and lithological mixtures were created. The composition of the rocks presented in the well section was determined by core lithological description. The stratigraphic subdivisions were assigned according to the general stratigraphic scale of the Russian Federation, regional and local stratigraphic scales.

Even though the geochemical analysis of the sediments and earlier results of the reconstruction of the initial generation characteristics of rocks [79] allowed the identification of 11 source rocks in the basin, pyrolytic studies in well Keltma-1 revealed only three intervals' generation of HC. These include clayey sediments of the Yshkmesskaya and Vapolskaya Formations of the Upper Riphean and bituminous clastic–carbonate sediments of the Domanic Horizon of the Upper Devonian. The initial values of TOC, HI were set for each source rock's interval and the kinetic spectrum of kerogen degradation was selected according to [80,81]. The kerogen of all three source rocks belongs to Type II (sapropelic).

The boundary conditions, paleo water depth, sediment water interface temperature and heat flow, were incorporated in the model to calculate the thermal regime of the basin (Figure 31).

Age [Ma]	Name top	Depth [m]	Thickness [m]	Event type	Paleodeposition/ erosion [m]	Lithology	SR	Kinetic	TOC [%]	HI [mg HC/g TOC]
0	Q	0	23	Deposition		Sand 50%, clay 50%				
2.58	₽–N	23	0	Erosion	−300					
100.5	J_2–K_1	23	0	Deposition	300					
174.1	T_2–J_1	23	0	Erosion	−150					
247.2	T_1	23	0	Deposition	150					
251.9	P_3v_Erosion	23	0	Erosion	−300					
253	P_3v	23	0	Deposition	300					
259.51	P_3s	23	0							
264.28	P_2ur	23	0							
266.9	P_2kz	23	80			Mudstone 40%, sandstone 25%, siltstone 10%, marl 15%, shaly limestone 10%				
273.01	P_1u	103	80			Mudstone 40%, sandstone 25%, marl 15%, shaly limestone 20%				
278	P_1k	183	59			Dolomite 90%, gypsum-anhydrite 10%				
283.5	P_1ar	242	38			Dolomite 100%				
290.1	P_1s	280	86			Dolomite 45%, limestone 45%, gypsum-anhydrite 10%				
293.52	P_1a	366	86			Dolomite 45%, limestone 45%, gypsum-anhydrite 10%				
298.9	C_3k–g	452	146			Dolomite 45%, limestone 45%, gypsum-anhydrite 10%				
307	C_2m_2	598	109			Limestone 85%, mudstone 15%				
311	C_2m_1	707	108			Limestone 95%, mudstone 5%				
315.2	C_2b	815	31			Limestone 100%				
323.2	C_1s	846	54			Limestone 100%				
330.9	C_1al–mh–vn	900	77			Limestone 90%, dolomite 10%				
332	C_1tl	977	15			Limestone 50%, mudstone 40%, siltstone 10%				
338	C_1t–C_1v_1	992	0	Erosion	−200					
358.9	D_3fm	992	35	Deposition	200	Limestone 90%, mudstone 10%				
362	D_3ev–lv	1027	91			Limestone 80%, mudstone 10%, marl 10%				
366	D_3vt–src	1118	95			Dolomite 70%, shaly limestone 30%				
370	D_3dm	1213	52			Shaly limestone 50%, mudstone 50%	Source Rock	Pepper&Corvi(1995)_TII-S(A)	2.00	400
374	D_3sr	1265	27			Shaly limestone 50%, mudstone 50%				
378	D_3tm	1292	38			Mudstone 45%, siltstone 50%, marl 5%				
382	$Є_2$–D_2_Erosion	1330	0	Erosion	−1500					
509	V_2pd–$Є_1$	1330	197	Deposition	1500	Sandstone 45%, siltstone 35%, mudstone 20%				
540	V_2mz	1527	198			Sandstone 45%, siltstone 35%, mudstone 20%				
545	V_2kr	1725	153			Sandstone 45%, siltstone 35%, mudstone 20%				
550	V_2up	1878	432			Sandstone 45%, siltstone 35%, mudstone 20%				
555	V_1	2310	592			Sandstone 45%, siltstone 35%, mudstone 20%				
570	RF_3–V_1_Erosion	2902	0	Erosion	−2500					
700	RF_3vp_part 2	2902	142	Deposition	2500	Dolomite 50%, limestone 50%				
720	RF_3vp_SR	3044	114			Shaly limestone 50%, mudstone 50%	Source Rock	Dieckmann(2000)_TII	1.90	650
730	RF_3vp_part 1	3158	742			Dolomite 50%, limestone 50%				
840	RF_3ysh_part 2	3900	485			Dolomite 50%, limestone 50%				
870	RF_3ysh_SR	4385	50			Shaly limestone 50%, mudstone 50%	Source Rock	Dieckmann(2000)_TII	1.80	600
880	RF_3ysh_part 1	4435	467			Dolomite 50%, limestone 50%				
935	RF_3dz	4902	576			Sandstone 50%, siltstone 50%				
1030	RF_2	5478	387			Sandstone 30%, siltstone 30%, mudstone 40%				
1350	RF_1	5865	0							

Figure 30. Input data for one-dimensional modeling (see Figure 5 for names and ages of geological formations).

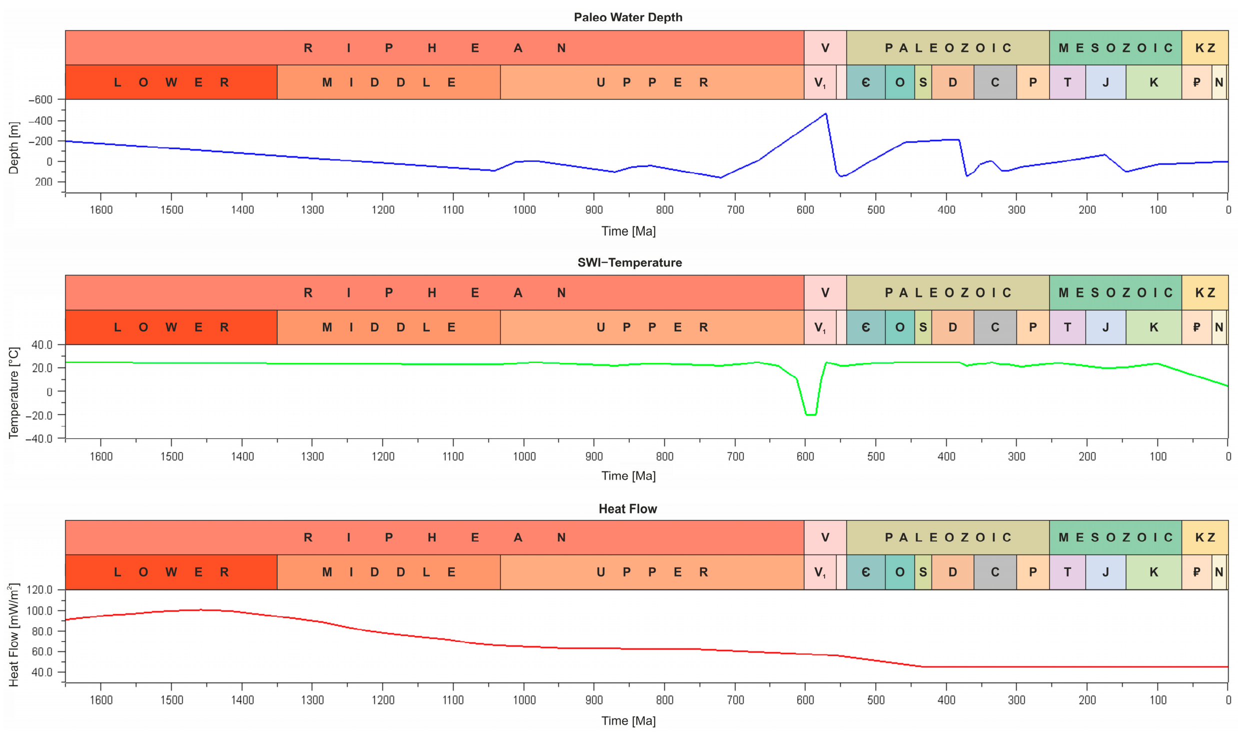


Figure 31. Boundary conditions for one-dimensional modeling (see Figure 5 for names and ages of geological formations).

According to the results of coal petrography studies in rocks of the Carboniferous age, fragments of OM of an unclear genetic nature are found, which does not provide a reliable diagnosis of the maturity level of OM on the vitrinite reflectance. Measurements of formation temperatures are absent. Therefore, the calibration of the one-dimensional basin model for the Keltma-1 well was carried out using measurements of the pyrolytic parameter T_{max} and reservoir pressures (P_R). In addition, using the pyrolysis results and the formula presented in [82], the rock kerogen transformation ratios (TR) were calculated and compared with the constructed curve. The relationships of the modeled curves of the T_{max}, TR and reservoir pressure parameters with the well calibration data are presented in Figure 32. The results showed the high convergence of the modeled curves and actual data, which indicates the sufficient accuracy of the constructed model.

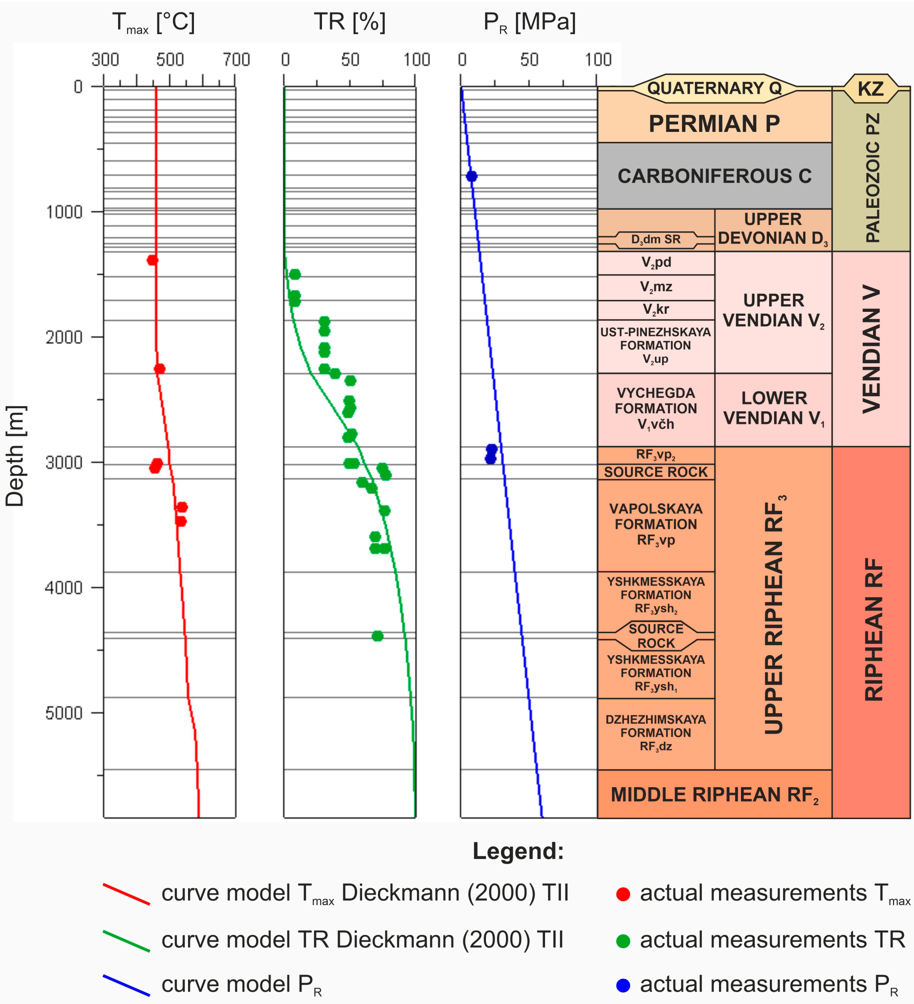
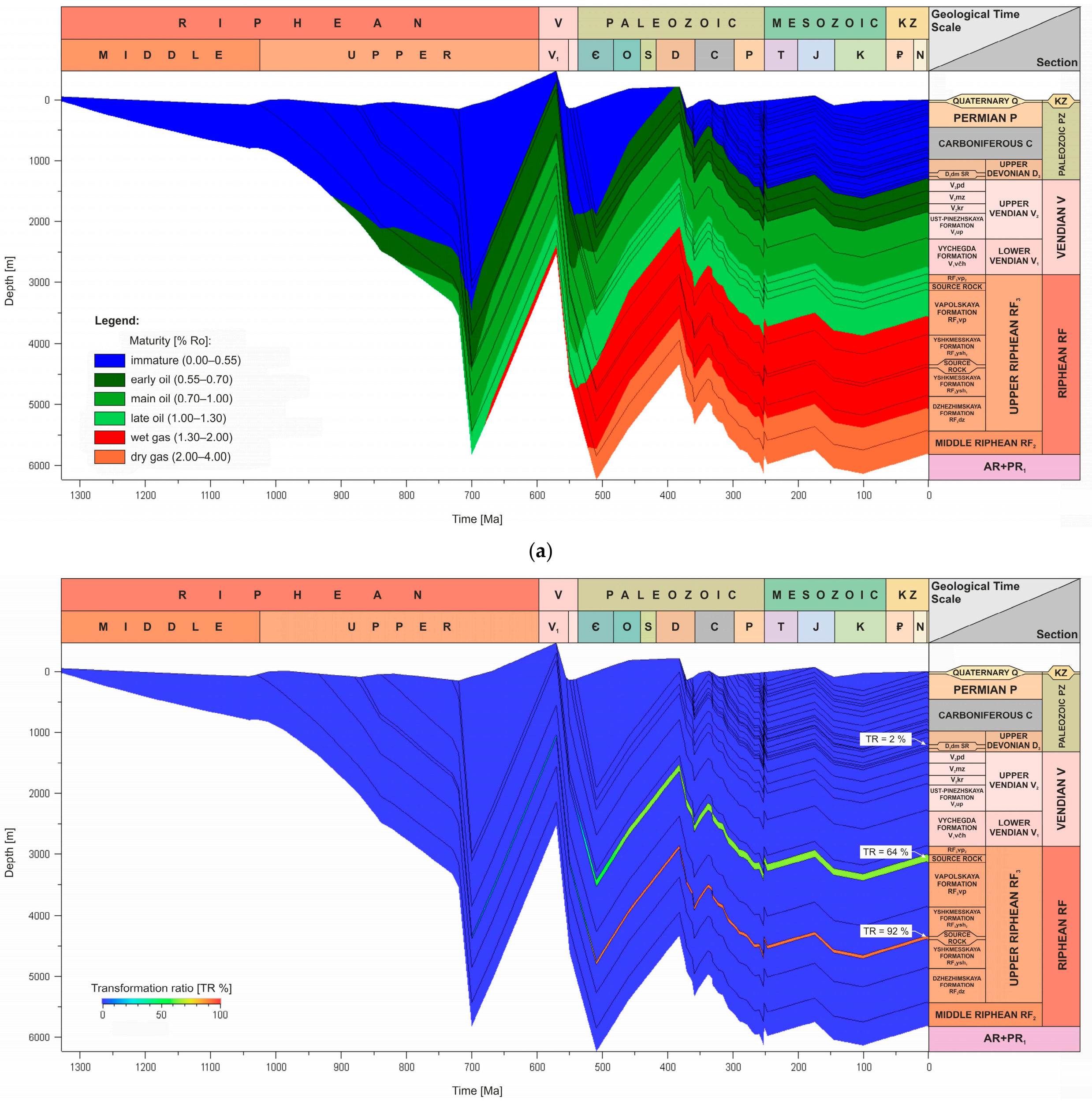


Figure 32. Results of model calibration (see Figure 5 for names and ages of geological formations).

The modeling of OM maturation processes in rocks was carried out on the basis of the Easy%Ro kinetic model [83]. The calculated maturity of the OM of the Riphean source rocks is 1.13–1.62%Ro, which is characteristic of mature and postmature kerogen (late stage of oil generation and condensate generation). The calculated vitrinite reflectance of the Domanic Horizon is 0.46%Ro and confirms the previously obtained conclusions about the low maturity of OM in this formation. The model of the sediment burial and maturation of the OM of the source rocks in time is presented in Figure 33a, from which it is concluded that the Riphean source rocks entered the "oil window" in the time interval of 715–700 Ma. The rocks of the Domanic Horizon did not enter the "oil window".

The next important point in basin modeling is the estimation of the degree of kerogen conversion to HC—the TR ratio, varying from 0 to 100%. The modeling results are presented in Figure 33b.

The ability to generate HC of the Yshkmesskaya Formation was significantly lost during the Late Riphean and Vendian–Early Cambrian time. The current TR is 92%. The potential of the Vapolskaya Formation is relatively higher (TR = 64%) and most of it was exhausted during the Late Vendian and Early Cambrian period. Both source rocks reached their present-day TR values in the Paleozoic–Mesozoic time. The TR of the Domanic source rock is 2%, which confirms its excellent oil-generating properties. The potential of the Domanic Horizon started to be realized from the Middle Permian, but the intensity of OM to HC conversion remains at a low level.



(a)

(b)

Figure 33. Results of one-dimensional modeling: (**a**) model of rocks' OM maturation; (**b**) model of oil and gas source potential realization (see Figure 5 for names and ages of geological formations).

One of the main points in modeling sedimentary basins is the determination of erosion events of accumulated sediments [84], as they are associated with the formation of unconformity.

The modeling results demonstrate the presence of two unconformities in the section of the Keltma-1 well: between the Vendian and Upper Paleozoic complexes, as well as between the Permian and Quaternary sediments (Figure 34). The key conclusion is the absence of catagenetic unconformity between the Riphean and Vendian sediments, which is the most important indicator of the second phase of HC generation from the Riphean source rocks in the Vendian–Paleozoic time. In other words, the Riphean source rocks could be a source of HC not only for Pre-Cambrian accumulations, but also for Paleozoic ones. In general, a similar conclusion of the absence of unconformity between the Riphean and Vendian in the Vychegda Trough was also obtained by Bazhenova T.K. [85].

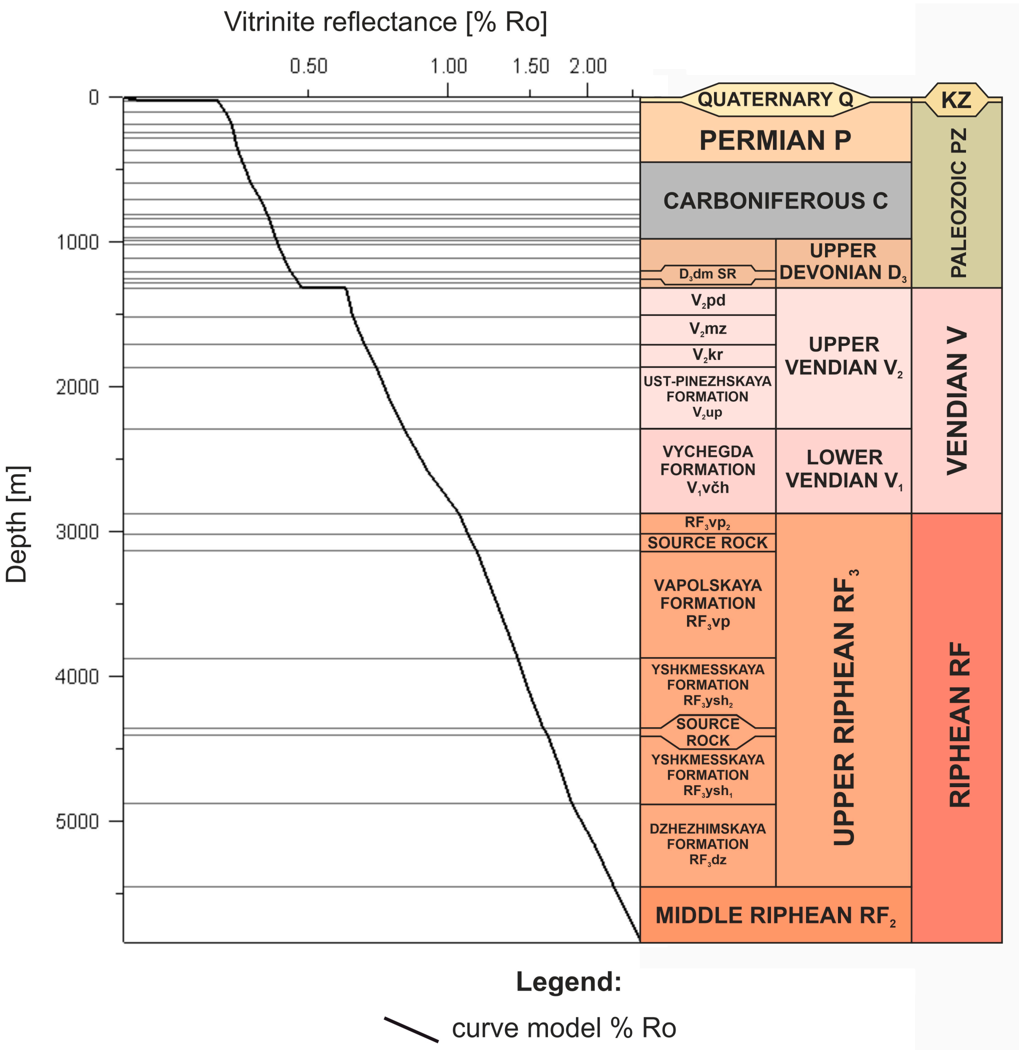


Figure 34. Curve of change of vitrinite reflectance as a function of depth (see Figure 5 for names and ages of geological formations).

In the course of basin modeling, an important point is the definition of HC traps, their type and time of formation. Based on the tectonic history of the Vychegda Trough, it was possible to establish that the main large traps in the area of the Keltmen-1 well are divided into anticlinal, fault, stratigraphic and reef. The selected trap types are plotted on the event chart (Figure 35) taking into account the time of their formation. Anticlinal and fault traps were formed during the tectonic activity of the basin, in particular, at the edges of the Riphean–Vendian, Vendian and Cambrian, Devonian and Cambrian, Permian and Triassic and Late Mesozoic–Cenozoic times. Reef traps formed during the sinking of the basin in the Late Riphean, Late Devonian, and at the edge of the Carboniferous and Permian period. Stratigraphic traps are formed by accumulations from erosion processes' sediments and their subsequent overlap by younger rock complexes. Such traps were formed in the basin after the pre-Vendian, pre-Timanian and pre-Visean erosion.

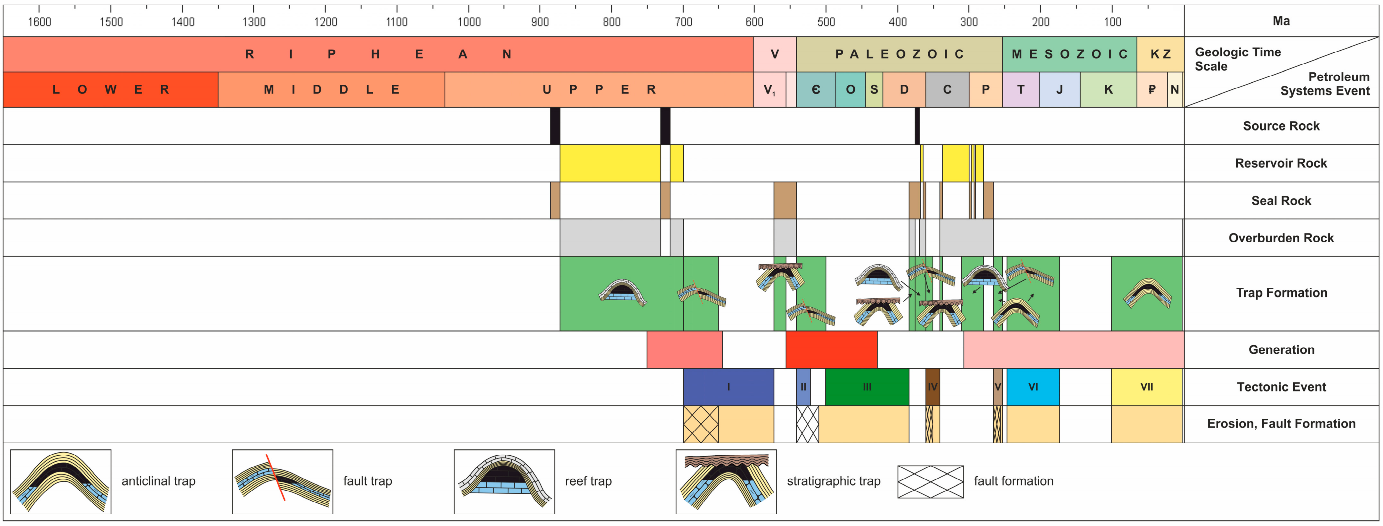


Figure 35. Event chart based on the results of 1D modeling (see Figure 5 for names and ages of geological formations): I—Early Baikalian orogeny; II—Late Baikalian orogeny; III—Caledonian orogeny; IV—Early Hercynian orogeny; V—Late Hercynian orogeny; VI—Cimmerian orogeny; VII—Alpine orogeny.

4. Conclusions

The results of the study suggest the existence of three petroleum systems in the Vychegda Trough: Riphean, Vendian and Devonian–Permian. The prerequisites to this are as follows:

- Firstly, the presence of oil- and gas-producing rocks in a wide interval of the section from the Middle Riphean to the Middle Carboniferous. At least, we can judge about the presence of five oil-source levels in the ancient Riphean–Vendian sediments, which have considerably exhausted their generative potential. In the Paleozoic complex, six oil and gas source rocks can be traced, which in most cases have high generational properties;
- Secondly, the presence of reservoir and seals rocks, which is confirmed by fluid inflows from both Paleozoic sediments and deep-lying Proterozoic horizons;
- Thirdly, the complication of the basin by a system of deep regional faults and high deformation of sediments are favorable signs for the development of HC migration pathways;
- Fourth, the long and complex history of the geological development of the region has contributed to the formation of various types of traps: anticlinal, fault, stratigraphic, reef and their combinations;
- Fifth, in the Vychegda Trough and in the neighboring structures of the West Timan, there are numerous direct signs of oil and gas potential in the Paleozoic and Riphean–Vendian part of the section. The results of geochemical studies often demonstrate increased concentrations of the B_{chl} extract (epigenetic B_{chl} extracts)—a sign of HC micro-accumulations not only in the Paleozoic, but also in the Riphean rocks. In addition, drilling in some areas revealed gas-bearing strata and oil-saturated interbeds in sediments of Carboniferous and Permian age. It is important to note that on the southeastern side of the Vychegda Trough on the border with the northern part of the Solikamsk depression, several small oil fields have been discovered in the Upper Devonian–Tournaisian reef traps.

Consequently, there is an occurrence of very favorable signs of oil potential in the territory of the Vychegda Trough. The absence of commercial HC inflows to date is probably explained by the extremely poor geological and geophysical knowledge of the region, the poor porosity and permeability of rocks and the small thicknesses of strata, or the drilling of wells in unfavorable structural conditions, but by no means with low prospects of oil and gas potential of the region as a whole. The negative results of previous prospecting and exploration works may also be related to the preservation state of accumulations. It can be assumed that rather high tectonic disturbance of the sedimentary fill and repeated large-scale erosion events may have led to the destruction and dispersion of previously formed HC accumulations.

At this stage, the expedient solution to the problem of the oil and gas potential of the Vychegda Trough is to carry out three-dimensional basin modeling. It will answer the fundamental questions concerning the identification of the main oil generating strata, centers and stages the most intensive HC formation, has directions of their migration and time of formation and the preservation of accumulations. The modeling results will also help estimate oil and gas resources, predict the distribution of HC accumulations and select promising sites.

Author Contributions: Conceptualization, S.K. and A.B.; methodology, A.B.; software, A.B.; validation, S.K. and A.B.; formal analysis, A.B.; investigation, A.B.; resources, S.K.; data curation, A.B.; writing—original draft preparation, A.B.; writing—review and editing, S.K.; visualization, A.B.; supervision, S.K.; project administration, S.K.; funding acquisition, S.K. All authors have read and agreed to the published version of the manuscript.

Funding: The research was funded by the Ministry of Science and Higher Education of the Russian Federation (Project No. FSNM-2023-0005).

Data Availability Statement: Data are contained within the article.

Conflicts of Interest: The authors declare no conflicts of interest.

References

1. Savinov, V.N.; Aleksandrova, T.V. Potential for new hydrocarbon field discovery in Proterozoic deposits of Volga-Urals region. *Geol. Oil Gas* **2023**, *2*, 37–51. [CrossRef]
2. Netreba, D.A.; Kovaleva, V.S.; Smolyanova, D.V.; Belyaev, M.O.; Shlygin, D.A.; Shershulina, M.V. Problems and the Riphean deposits hydrocarbon potential of the Republic of Bashkortostan. *Geol. Geophys. Dev. Oil Gas Fields* **2023**, *4*, 5–17. [CrossRef]
3. Bashkova, C.E.; Kozhevnikova, E.E.; Yakovlev, Y.A.; Karaseva, T.V.; Botalova, A.V. The deep structure of the Proterozoic complex of the sedimentary fill of the East European Platform: Oil and gas potential. *Geotectonics* **2023**, *4*, 82–102. [CrossRef]
4. Welte, D.H. Petroleum exploration and organic geochemistry. *J. Geochem. Explor.* **1972**, *1*, 117–136. [CrossRef]
5. Dow, W.G. The application of oil correlation and source rock data to exploration in the Williston Basin. *AAPG Bull.* **1972**, *58*, 1253–1262.
6. Demaison, G.J.; Murris, R.J. The generative basin concept. Petroleum geochemistry and basin valuation. *AAPG Mem.* **1984**, *35*, 1–14.
7. Meissner, F.F.; Woodward, J.; Clayton, J.L. *Stratigraphic Relationships and Distribution of Source Rocks in the Greater Rocky Mountain Region*; Hydrocarbon Source Rocks of the Greater Rocky Mountain Region; Rocky Mountain Association of Geologists: Denver, CO, USA, 1984; pp. 1–34.
8. Ulmishek, G. Stratigraphy aspects of petroleum resource assessment. *AAPG Stud. Geol.* **1986**, *21*, 59–68.
9. Magoon, L.B.; Dow, W.G. The petroleum system. *AAPG Mem.* **1994**, *60*, 3–24.
10. Ismailov, J.J. Conditions of Formation of Oligocene-Miocene Hydrocarbon System on the Territory of the Tersko-Caspian Oil and Gas Basin and Prospects for Searching for Oil and Gas Accumulations. Ph.D. Thesis, Russian State Geological Exploration University named after Sergo Ordzhonikidze, Moscow, Russia, 2022.
11. Mamedov, R.A. Conditions of Hydrocarbon Systems Formation and Assessment of Oil and Gas Potential of the East Siberian Sea. Ph.D. Thesis, Russian State Geological Exploration University named after Sergo Ordzhonikidze, Moscow, Russia, 2022.
12. Polishchuk, A.V. Analysis of Hydrocarbon Systems and Assessment of Oil and Gas Potential of the Jurua Sub-Basin of the Solimoes Basin (Brazil). Ph.D. Thesis, Tyumen Industrial University, Tyumen, Russia, 2022.
13. Al-Hajeri, M.; Al Saeed, M.; Derks, J.; Fuchs, T.; Hantschel, T.; Kauerauf, A.; Neumaier, M.; Schenk, O.; Swientek, O.; Tessen, N.; et al. Basin and petroleum system modeling. *Oilfield Rev. Summer* **2009**, *21*, 14–29.
14. Allen, P.A.; Allen, J.R. *Basin Analysis: Principles and Application to Petroleum Play Assessment*, 3rd ed.; Wiley-Blackwell: Oxford, UK, 2013; p. 640.

15. Vasyutkin, S.A. History and prospects of geological exploration in the Volga-Ural basin. *Bull. Sci.* **2023**, *4*, 375–383. [CrossRef]
16. Ismagilov, R.A.; Farkhutdinov, F.M.; Farkhutdinov, I.M. To the 90th anniversary of the discovery of oil in Bashkortostan. *Drill. Oil* **2022**, *2*, 47–52.
17. Bogdanov, B.P.; Zaborovskaya, V.V.; Gromyko, A.V. Keltmenskiy shaft south of the Komi Republic: A few steps from the discovery of large deposits of high-viscosity oils. *Ural. Geol. J.* **2021**, *2*, 3–29.
18. Karaseva, T.V.; Yakovlev, Y.A.; Belyaeva, G.L.; Bashkova, S.E. New data on oil and gas potential of the Vychegda Trough. *Georesources* **2020**, *20*, 32–38. [CrossRef]
19. Vakhnin, M.G. State of study and prospects of oil and gas potential of the Mezen syneclise. *Geol. Geophys. Dev. Oil Gas Fields* **2016**, *2*, 8–13.
20. Gavrilov, V.P.; Rudnev, A.N.; Dvoretsky, P.I.; Ponomarev, V.A. Prospects of oil and gas potential of the Mezen syneclise. *Oil Gas Geol.* **1998**, *5*, 12–20.
21. Botalov, A.N.; Krivoshchekov, S.N. Geochemical criteria of oil and gas potential of the sedimentary fill of the Vychegda Trough of the Volga-Ural oil and gas basin. In Proceedings of the Geomodel, Gelendzhik, Russia, 4–7 September 2023.
22. Kontorovich, A.E.; Trofimuk, A.A.; Basharin, A.K.; Belyaev, S.Y.; Fradkin, G.S. Global regularities of oil and gas content of the Precambrian Earth. *Geol. Geophys.* **1996**, *37*, 6–42.
23. Stupakova, A.V.; Khvedchuk, I.I.; Sautkin, R.S.; Korobova, N.I.; Sivkova, E.D. Reforming of deposits in ancient oil and gas basins (on the example of deposits of the Baikit anteclise eastern slope of the Siberian Platform). *Georesources* **2019**, *21*, 31–41. [CrossRef]
24. Krinin, V.A.; Porozov, I.I. Zonation of hydrocarbon distribution and oil and gas occurrence within sedimentary fill in the western part of the Siberian Platform. *Oil Gas Geol.* **2020**, *4*, 29–44. [CrossRef]
25. Rapatskaya, L.A. Oil and gas complexes as a material expression of geofluid dynamic systems. *Earth Sci. Subsoil Use* **2022**, *45*, 345–366. [CrossRef]
26. Fomin, A.M.; Konstantinova, L.N.; Gubin, I.A.; Moiseev, S.A. Correlation of Proterozoic-Phanerozoic deep wells sections targeting Aldan-Maya area petroleum potentiality estimation. *Pet. Geol.—Theor. Appl. Stud.* **2022**, *17*, 1–20. [CrossRef]
27. Sergeeva, N.D.; Puchkov, V.N.; Karaseva, T.V. *Upper Proterozoic (Riphean and Vendian) of the Volga-Ural Region in Parametric and Deep Wells*; Kniga-Print: Ufa, Russia, 2021; p. 196.
28. Kozhanov, D.D.; Bolshakova, M.A.; Khopta, I.S.; Mordasova, A.V.; Stoupakova, A.V.; Zaglyadin, Y.A.; Borisova, M.S.; Sakhabov, T.R.; Zavyalova, A.P.; Chupakhina, V.V. Geology and geochemistry of Riphean-Vendian petroleum system (the Northern part of the Volga-Ural Basin). *Georesources* **2021**, *23*, 73–86. [CrossRef]
29. Belokon, T.V.; Balashova, M.M.; Gorbachev, V.I.; Sirotenko, O.I.; Denisov, A.I. *Prospectivity of Riphean and Vendian Sediments of the Eastern Regions of the Russian Platform (Geology, Methods of Prospecting, Exploration and Assessment of Fields of Fuel and Energy Resources)*; Geoinformmark, Geoinform: Moscow, Russia, 1996; p. 38.
30. Cox, G.; Collins, A.S.; Jarrett, A.J.M.; Blades, M.L.; Shannon, A.; Yang, B.; Farkas, J.; Hall, P.A.; O'Hara, B.; Close, D.; et al. A very unconventional hydrocarbon play: The Mesoproterozoic Velkerri Formation of Northern Australia. *AAPG Bull.* **2022**, *106*, 1213–1237. [CrossRef]
31. Jarrett, A.J.M.; Munson, T.J.; Williams, B.; Bailey, A.H.E.; Palu, T. Petroleum supersystems in the greater McArthur Basin, Northern Territory, Australia: Prospectivity of the world's oldest stacked systems with emphasis on the McArthur Supersystem. *APPEA J.* **2022**, *62*, 245–262. [CrossRef]
32. Leila, M.; Keanu, K.; Moretti, I. Controls on generation and accumulation of blended gases ($CH_4/H_2/He$) in the Neoproterozoic Amadeus Basin, Australia. *Mar. Pet. Geol.* **2022**, *140*, 105643. [CrossRef]
33. Xiao, H.; Li, M.; Wang, T.; Chen, D.; Kang, W.; Wang, Y. Discovery of a new Proterozoic paleo-reservoir and its oil source in the Jianchang Sag, Yanliao Faulted-Depression Zone, North China. *Pet. Sci.* **2022**, *19*, 1927–1938. [CrossRef]
34. Xiao, H.; Wang, T.; Li, M.; Chen, D.; Chang, J.; Song, D.; Yang, C.; Hu, Y.; Ali, S. Oil sources and accumulation processes of the Neoproterozoic Luotuoling Formation reservoirs (~930 Ma) in North China Craton. *J. Pet. Sci. Eng.* **2022**, *211*, 110186. [CrossRef]
35. Tang, Y.; Chen, Z.; Simoneit, B.R.T.; Wang, T.-G.; Ni, Z.; Li, M.; Wen, L.; Yang, C. Recognition of in situ oil cracking in the Precambrian-Lower Cambrian petroleum systems of Sichuan basin, southwestern China. *Mar. Pet. Geol.* **2021**, *126*, 104942. [CrossRef]
36. Huang, Y.; Luo, T.; Tao, Z.; He, Z.; Tarantola, A.; He, S.; Guo, X.; Zhang, D.; Sun, Z. Fluid evolution and petroleum accumulation in the Precambrian gas reservoirs of the Sichuan Basin, SW China. *Mar. Pet. Geol.* **2023**, *150*, 106171. [CrossRef]
37. Su, A.; Chen, H.; Feng, Y.; Wang, Z.; Jiang, H.; Zhao, J. Tracking multiple paleo oil charges in the Precambrian dolomite reservoirs of the central Sichuan Basin, China. *Mar. Pet. Geol.* **2023**, *156*, 106423. [CrossRef]
38. Wu, N.; Wang, J.; Cai, Z.; Luo, Z.; Lu, X.; Ma, X.; Liu, X. Discovery of Sinian source rocks in Proterozoic in the Tarim Basin, NW China. *J. Pet. Sci. Eng.* **2020**, *193*, 1–14. [CrossRef]
39. Sitar, K.A.; Georgievskiy, B.V.; Bolshakova, M.A.; Sautkin, R.S. Comprehensive evaluation of Neoproterozoic source rocks formation. *Georesources* **2022**, *24*, 47–59. [CrossRef]
40. Yasin, Q.; Baklouti, S.; Sohail, G.M.; Asif, M.; Xufei, G. Evaluation of Neoproterozoic Source Rock Potential in SE Pakistan and Adjacent Bikaner-Nagaur Basin India Based on Integrated Geochemical, Geological, and Geophysical Data. *Sci. Rep.* **2022**, *12*, 1–20. [CrossRef] [PubMed]
41. Abu, M.; Adeleye, M.A.; Ehinola, O.A. The hydrocarbon prospectivity of the Mesoproterozoic-Paleozoic intracratonic Voltaian Basin, West African Craton, Ghana. *J. Pet. Explor. Prod.* **2021**, *11*, 617–625. [CrossRef]

42. Nikishin, A.; Ziegler, P.A.; Stephenson, R.; Cloetingh, S.; Furne, A.; Fokin, P.A.; Ershov, A.; Bolotov, S.; Korotaev, M.; Alekseev, A.; et al. Late Precambrian to Triassic history of the East European Craton: Dynamics of sedimentary basin evolution. *Tectonophysics* **1996**, *268*, 23–63. [CrossRef]
43. Peters, K.E.; Curry, D.J.; Kacewicz, M. An overview of basin and petroleum system modeling: Definitions and Concepts. *AAPG Hedberg Ser.* **2012**, *4*, 1–16. [CrossRef]
44. Kheraskova, T.N.; Volozh, Y.A.; Antipov, M.P.; Bykadorov, V.A.; Postnikova, I.S. Features of the structure and development of the southeastern part of the East European Platform and the Caspian basin in the late Precambrian–Early Paleozoic. *Geotectonics* **2020**, *5*, 29–54. [CrossRef]
45. Baluev, A.S.; Kolodyazhny, S.Y.; Terekhov, E.N. Comparative tectonics of the White Sea paleorift system and other continental rifting systems. *Lithosphere* **2021**, *21*, 469–490. [CrossRef]
46. Paktovskiy, Y.G. Staging of geological development of an area of the southern Cis-Timan in the Late Proterozoic. *Bull. Perm Univ. Geol.* **2019**, *18*, 108–124. [CrossRef]
47. Bogdanov, B.P.; Putina, I.B. To save from destruction the Great Barrier reef of Australia—Save humanity. *Nor. J. Dev. Int. Sci.* **2019**, *3-2*, 10–22.
48. Bogdanov, B.P.; Zaborovskaya, V.V.; Ovcharova, T.A. The paradigm of the oil and gas industry development in the Timan-Pechora province and its periphery in the XXI century. *Nor. J. Dev. Int. Sci.* **2018**, *6-1*, 14–44.
49. Asming, V.E.; Afonin, N.Y.; Bakunovich, L.I.; Baluev, A.S.; Belashev, B.Z.; Bugaenko, I.V.; Vaganova, N.V.; Vinogradov, A.N.; Danilov, K.B.; Zhuravlev, V.A.; et al. *Structure and Dynamics of the Lithosphere of the White Sea: Monograph*; KarRC RAS: Petrozavodsk, Russia, 2022; p. 239.
50. Maslov, A.V. Vendian of the Middle Urals: A review of some investigations in the beginning of the 21st century. *Lithosphere* **2022**, *22*, 555–578. [CrossRef]
51. Pease, V. Eastern Europe: The Timanian and Uralian Orogens. In *Encyclopedia of Geology*; Elsevier: New York, NY, USA, 2021; pp. 302–310. [CrossRef]
52. Varlamov, A.I.; Mel'nikov, P.N.; Poroskun, V.I.; Fortunatova, N.K.; Petersil'e, V.I.; Iutina, M.M.; Dakhnova, M.V.; Vitsenovskii, M.Y.; Kanev, A.S.; Soboleva, E.N.; et al. Unconventional oil reservoirs in high-carbon carbonate-siliceous Domanik formations, Volga-Urals Province: Results of studies and future development trends. *Oil Gas Geol.* **2020**, *6*, 33–52. [CrossRef]
53. Fortunatova, N.K.; Varlamov, A.I.; Kanev, A.S.; Poroskun, V.I.; Baranova, A.V.; Bushueva, M.A. Structure and assessment of the oil potential of carbonaceous carbonate-siliceous Domanik deposits in the Volga-Ural oil and gas province. *Russ. Geol. Geophys.* **2021**, *62*, 929–946. [CrossRef]
54. Sorokhtin, N.O.; Kozlov, N.E. Geodynamic evolution of the western part of the Russian Arctic and its diamond position. *Oceanology* **2021**, *61*, 977–993. [CrossRef]
55. Vereshchagin, V.N.; Vinogradov, A.P.; Nalivkin, V.D.; Ronov, A.B.; Khabakov, A.V.; Khain, V.E. *Atlas of Lithological and Paleogeographic Maps of the USSR*; Triassic, Jurassic and Cretaceous periods; All-Union Aerogeological Trust: Moscow, USSR, 1968; Volume 3, p. 80.
56. Kotik, O.S.; Saldin, V.A.; Valyaeva, O.V. *Organic Matter of the Upper Jurassic Deposits of the Izhma Shale-Bearing Region of the Timan-Pechora Basin*; Series "Earth Sciences"; Izvestia Komi Scientific Centre of the Ural Branch of the Russian Academy of Sciences: Syktyvkar, Russia, 2020; Volume 46, pp. 96–107.
57. Suslova, A.A.; Stupakova, A.V.; Mordasova, A.V.; Sautkin, R.S.; Gilmullina, A.A. Structural reconstructions of the Eastern Barents Sea at Meso-Tertiary evolution and influence on petroleum potential. *Georesources* **2021**, *23*, 78–84. [CrossRef]
58. Midtkandal, I.; Faleide, J.I.; Faleide, T.S.; Serck, C.S.; Planke, S.; Corseri, R.; Dimitriou, M.; Nystuen, J.P. Lower Cretaceous Barents Sea strata: Epicontinental basin configuration, timing, correlation and depositional dynamics. *Geol. Mag.* **2020**, *157*, 458–476. [CrossRef]
59. Deev, E.V.; Shemin, G.G.; Vernikovsky, V.A.; Drachev, S.S.; Matushkin, N.Y.; Glazyrin, P.A. Northern West Siberian-South Kara composite tectono-sedimentary element, Siberian Arctic. *Geol. Soc. Lond. Mem.* **2022**, *57*, 1–25. [CrossRef]
60. Gulyaev, A.N. Seismotectonics of the Urals. *Izv. Univ. Min. J.* **2019**, *1*, 42–51. [CrossRef]
61. Fortunatova, N.K.; Shvets-Taneta-Guriy, A.G.; Agafonova, G.V.; Pak, K.L.; Gumarov, R.K.; Mushin, I.A.; Frolov, B.K.; Barykin, S.K.; Afanasiev, M.L.; Komissarova, I.N.; et al. *Assessment of Oil and Gas Prospects in the Troughs of Ancient Russian Platforms in Order to Identify New Oil and Gas Perspective Zones and Objects*; All-Russian Research Geological Petroleum Institute: Moscow, Russia, 2012; p. 5187.
62. Dedeev, V.A.; Pimenov, B.A.; Aminov, L.Z.; Paneva, A.Z.; Pesetskaya, A.V.; Morein, V.E.; Zytner, Y.I. *Forecast of Oil and Gas Potential of the Mezen Sedimentation Basin*; Komi Scientific Centre of the Ural Branch of the Academy of Sciences of the USSR: Syktyvkar, USSR, 1989; p. 59.
63. Alexandrova, T.V. Some specific features of geological structure and petroleum potential prospects of the little-known northern lands of the Volga-Urals region. *Geol. Geophys. Dev. Oil Gas Fields* **2014**, *7*, 55–60.
64. Bazhenova, O.K.; Arefiev, O.A.; Sokolov, B.A. Genetic features of the Upper Proterozoic oils. *Rep. Acad. Sci.* **1994**, *337*, 371–375.
65. Bazhenova, O.K.; Arefiev, O.A. Features of the composition of biomarkers of the Pre-Cambrian organic matter of the East European Platform. *Geochemistry* **1998**, *3*, 286–294.
66. Bazhenova, O.K.; Arefiev, O.A. Geochemical peculiarities of Pre-Cambrian source rocks in the East European Platform. *Org. Geochem.* **1996**, *25*, 341–351. [CrossRef]

67. Bazhenova, T.K.; Bogoslovsky, S.A.; Shapiro, A.I.; Vasilieva, V.F.; Rogozina, N.A. Vychegda Trough (Russian Plate)—Organic geochemistry and geothermal history of sedimentary fill. *Oil Gas Geol. Theory Pract.* **2013**, *8*, 1–31. [CrossRef] [PubMed]
68. Getsen, V.G. Riphean complex of the Timan-Pechora province—Possible oil-producing strata. In *Oil and Gas Bearing Complexes of the Pechora Syncline*; Institute of Geology of the Komi branch of the USSR Academy of Sciences: Syktyvkar, Russia, 1981; Volume 85, pp. 27–38.
69. Konyukhova, V.A. Geological and geochemical assessment of oil and gas potential of the Riphean sediments of the north-west of the Mezen syneclise. *MSU Bull. Ser. 4 Geol.* **1998**, *2*, 37–41.
70. Kuzmin, D.A. Geological and Geochemical Prerequisites for Oil and Gas Potential of the Upper Proterozoic Sediments of the Mezen Basin. Ph.D. Thesis, Moscow State University named after Lomonosov, Moscow, Russia, 2006.
71. Lapidus, A.L.; Kerimov, V.Y.; Mustaev, R.N. Caucasus Maykopian kerogenous shale sequences: Generative potential. *Oil Shale* **2018**, *35*, 113–127. [CrossRef]
72. Guliyev, I.S.; Kerimov, V.Y.; Mustaev, R.N.; Bondarev, A.V. The estimation of the generation potential of the low permeable shale strata of the Maikop Caucasian series. *SOCAR Proc.* **2018**, *1*, 4–20. [CrossRef]
73. Zavyalova, A.P.; Karpushin, M.Y.; Stupakova, A.V.; Kalmykov, G.A.; Chupakhina, V.V.; Korobova, N.I.; Borisova, M.S.; Radchenko, K.A. Structure, formation conditions, oil and gas potential of Domanicoid high-carbon formation in the Central and South-Eastern Parts of the Volga-Ural basin. *Georesources* **2023**, *25*, 123–139. [CrossRef]
74. Karpushin, M.Y.; Stupakova, A.V.; Zavyalova, A.P.; Kalmykov, G.A.; Chupakhina, V.V.; Korobova, N.I.; Suslova, A.A.; Radchenko, K.A. Structure and perspectives of oil and gas potential of Fransian-Tournaisian Domanicoid organic-rich formation in the central part of the Volga-Ural basin. *Oil Ind.* **2023**, *4*, 14–19. [CrossRef]
75. Badejo, S.A.; Fraser, A.J.; Neumaier, M.; Muxworthy, A.R.; Perkins, J.R. 3D petroleum systems modelling as an exploration tool in mature basins: A study from the Central North SeaUK. *Mar. Pet. Geol.* **2021**, *133*, 105271. [CrossRef]
76. Gelman, S.E. Modeling the maturation history of the stacked petroleum systems of the Williston Basin, USA. *Mar. Pet. Geol.* **2023**, *155*, 106390. [CrossRef]
77. Lutz, R.; Klitzke, P.; Weniger, P.; Blumenberg, M.; Franke, D.; Reinhardt, L.; Ehrhardt, A.; Berglar, K. Basin and petroleum systems modelling in the northern Norwegian Barents Sea. *Mar. Pet. Geol.* **2021**, *130*, 105128. [CrossRef]
78. Kerimov, V.Y.; Mustaev, R.N.; Serikova, U.S. Modeling strategy of hydrocarbon systems at different stages of geological exploration for oil and gas. *Oil Gas Chem.* **2018**, *1*, 45–49. [CrossRef]
79. Botalov, A.N.; Krivoschekov, S.N. Reconstruction of paleogeochemical data from the Riphean-Vendian sediments of the Vychegda Depression of the Volga-Ural oil and gas province. *Subsoil Use* **2023**, *in press*.
80. Dieckmann, V.; Horsfield, B.; Schenk, H.J. Heating rate dependency of petroleum-forming reactions: Implications for compositional kinetic predictions. *Org. Geochem.* **2000**, *31*, 1333–1348. [CrossRef]
81. Pepper, A.; Corvi, P.J. Simple kinetic models of petroleum formation. Part I: Oil and gas generation from kerogen. *Mar. Pet. Geol.* **1995**, *12*, 291–319. [CrossRef]
82. Pelet, R. Evaluation quantitative des produits forms lors de l'volution gochimique de la matire organique. *Philos. Chem.* **1985**, *40*, 551–556. [CrossRef]
83. Sweeney, J.J.; Burnham, A.K. Evaluation of a simple model of Vitrinite Reflectance based on chemical kinetics. *AAPG Bull.* **1990**, *74*, 1559–1570.
84. Iyer, K.; Hartz, E.H.; Schmid, D.W. Methods to estimate erosion in sedimentary basins. *J. Pet. Geol.* **2021**, *44*, 121–144. [CrossRef]
85. Bazhenova, T.K. Problem of petroleum potential of basal horizons in the basins of ancient platforms in aspect of their katagenetic evolution. *Oil Gas Geol. Theory Pract.* **2008**, *3*, 1–21.