

Original article

The effect of kerogen content and maturation on physical properties of oil and gas shales

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Abstract:

Organic-rich shales have long held great scientific and practical appeal, serving as effective sources of hydrocarbons. Characterizing these low-permeability rocks is challenging due to their multiscale heterogeneity, anisotropy, and enrichment with kerogen, whose properties vary over a wide range and differ from those of rock minerals. Analyzing segmental and unsystematized published data does not reveal general trends, whereas combining these data can solve this issue. This study explores and compiles kerogen's effect on shale physical properties (elastic, thermal, mechanic, electric, etc.) using published data supplemented by new experimental data on thermal properties of Bazhenov Formation rocks. Using published data, a growing difference in kerogen's density for different kerogen types was revealed since the end of oil window. A three- to fourfold change in kerogen's thermal expansion at the peak oil generation temperature was identified. A positive trend in kerogen's thermal conductivity with maturation was established within the oil window. The methane sorption capacity in a dry mineral matrix is approximately five times that of a wet one. Thermal and elastic anisotropy in shales rise with increasing kerogen content during the early-to-peak oil generation stage. It yields cross-correlation and enables the prediction of challenging anisotropy coefficients from a simpler determinable anisotropy coefficient. Adding new experimental data allowed for a study of kerogen's effect on thermal conductivity reduction with temperature in shales and estimations of kerogen's volumetric heat capacity. Our study highlights the directions for further research, while findings applicable to reservoir characterization and numerical modeling of hydrocarbon generation and recovery.

1. Introduction

Unconventional hydrocarbon (HC) reservoirs, which include source rocks (oil and gas shales), are a promising source of HC for the future development of the petroleum industry. The properties of unconventional reservoirs are significantly different from those of traditional reservoirs because of their genesis and the kerogen presence. Kerogen is the fossilized organic matter (OM), a highly cross-linked, complex

macromolecular geopolymer insoluble in organic solvents and acting as the primary source for HC generation via catagenesis (Vandenbroucke and Largeau, 2007). Unlike the bulk of sedimentary rocks, the kerogen content in oil and gas shales can reach tens of percent, while kerogen properties differ significantly from the properties of rock-forming minerals with very few exceptions (such as density of kaolinite (Schoen, 2015; Mavko et al., 2020)). Data on kerogen physical properties-

elastic (Zeszotarski et al., 2004; Kumar et al., 2012; Li et al., 2018; Charlton et al., 2021) (see values and the extended reference list in Table S1), thermal (Berkovich et al., 2000; Waples and Waples, 2004; Popov, 2019), thermomechanical (Zhang et al., 2007; Gabova, 2021), mechanical (Zeszotarski et al., 2004; Wu and Firoozabadi, 2020; Wang et al., 2024), and electric properties (Yang et al., 2016), as well as density (Guidry et al., 1995; Dang et al., 2016; Cheshire et al., 2017; Craddock et al., 2018), porosity (Vasiliev et al., 2015; Mavko et al., 2020), and specific surface area (SSA) (Suleimenova et al., 2014; Cheshire et al., 2017)-vary in a wide range (Table S1). The variation results from different sources of OM and geological conditions reflected in kerogen type, developed organic porosity, degree of thermal maturity, and chemical composition. The same kerogen or source rock properties from different basins, deposits, and even layers may have differing values due to changes in paleogeographic, paleochemical, biochemical and thermobaric conditions experienced during burial (Vandenbroucke and Largeau, 2007). Injection of supercritical water, in-situ combustion, and other thermal methods for generating and/or extracting hydrocarbons also lead to spatial and temporal changes in petrophysical properties of kerogen and source rocks. The changes must be taken into account when modeling HC generation and/or recovery.

The structural complexity of organic-rich shales occurs on all scales (macro-, micro-, and nanometer) (Hull et al., 2017). Obtaining information about kerogen properties is significantly complicated by the distribution features of kerogen inclusions over the mineral matrix (Vandenbroucke and Largeau, 2007), which can vary significantly even within a small depth range of the same well (Fig. S1). Therefore, a kerogen property measuring requires either the dissolution of all non-kerogen components in the rock (with subsequent preparation and study of the kerogen sample(s)) or the use of advanced techniques without kerogen isolation. The advanced experimental techniques include nanoindenters and quantitative nanomechanical mapping for determination of the hardness and Young's modulus (Zeszotarski et al., 2004; Kumar et al., 2012; Li et al., 2018; Long et al., 2021), loading and failing microcantilever beams for determination of the tensile strength (Hull et al., 2017). Isolation of kerogen from the rock in a sufficient volume for petrophysical analysis is time-consuming and not easy (even at significant OM concentrations). Moreover, the properties of kerogen before and after its isolation with acid treatment may differ significantly due to the possible change in its chemical composition (Zeszotarski et al., 2004; Vandenbroucke and Largeau, 2007). In particular, according to estimates by Suleimenova et al. (2014), the SSA of kerogen isolated by different methods may differ several times. That is why, to assess kerogen properties, calculations (numerical or theoretical modeling) utilizing logging data or core analysis results without kerogen isolation are frequently employed.

Oil and gas shales are characterized by multiscale heterogeneity and anisotropy and are usually represented as a transversely isotropic medium with a vertical axis of symmetry perpendicular to the stratification and preferred orientation of kerogen layers/lenses and clay particles (Vernik and Milovac, 2011). The interpretation of laboratory and field

data for such rocks is considered an exceptionally complex, multi-disciplinary task due to the above-mentioned. Lack of reliable information on the rock properties and their spatial changes complicates the choice of technologies and reduces the efficiency of exploration and development of these objects (Curtis et al., 2012; Yang and Liu, 2020). The interpretation of well logging data (Passey et al., 1990; Jagadisan et al., 2017; Tan, 2020), hydraulic fracturing design (Wang et al., 2024), optimization of thermal methods of oil recovery (Gabova, 2021), and resource estimations (Yang and Liu, 2020) - each of these tasks requires information on the kerogen characteristics and understanding of its influence on source rocks properties.

Although research of kerogen began almost a century ago (Tissot and Welte, 1984; Vandenbroucke and Largeau, 2007), publications that summarize the results of various experimental studies of different kerogen properties are rare. Disparate data does not allow for the identification of general trends. Joint analysis of different published data can resolve this problem. This paper is aimed at (1) generalizing the impact of kerogen on the basic physical properties, namely thermal, thermomechanical, mechanical, elastic, and electrical properties, density and porosity, of organic-rich shales accounting their anisotropy and (2) highlighting the directions of further research.

2. Materials, equipment and research methods

The work is based primarily on published data and dependencies supplemented by our new experimental data on thermal properties and kerogen content. More than 120 published data sources were utilized to analyze the physical properties of oil and gas shales formed under various conditions, including Antrim, Barnett, Woodford, Green River, Eagle Ford, Marcellus, Mahogany, New Albany, Ohio, Haynesville (all USA), Bazhenov and Domanik (Russia), Bowland, Kimmeridge (UK), Longmaxi, Lucaogou, Niutitang, Qingshankou, Qijia Gulong, Qiongzhusi, Yanchang, Xiamaling (all China), Vaca Muerta (Argentina), etc. The shales considered in this work are distinguished from other sedimentary rocks, first of all, by the increased content of OM, which is proportional to the total organic carbon (TOC). The bulk Earth values of organic carbon, which is the main component of OM constituting about 68%-85% (Tissot and Welte, 1984) or 83%-87% (Lin, 2000) of its mass, are defined as 0.5%-0.6% for sedimentary rocks, and are usually considered to be over 2.5% (sometimes 2% and even 1% in heterogeneous sections) in oil and gas shales. In particular, TOC reaches 40% in the Bazhenov Fm with an average 8%-10% (Vasiliev et al., 2015), TOC reaches 30% in the sediments of the Bakken Fm (Li et al., 2019).

The rock properties were determined by a wide range of laboratory petrophysical and geomechanical methods, as well as using interpretation of well logging data. The content, maturity, and other characteristics of OM were determined using pyrolysis, CHNS analysis, lithological, and other methods (Tissot and Welte, 1984; Vandenbroucke and Largeau, 2007). Our experiments have been carried out using pyrolytic (Rock-Eval) and thermophysical methods, with a subsequent complex

interpretation (Spasennykh et al., 2021). Rock-Eval pyrolysis was performed using a pyrolytic analyzer HAWK Resource Workstation (Wildcat Technology) on homogenized rock samples with a working weight of 30-50 mg (rock samples weighing 1-5 g were grounded to a size of less than 0.25 mm or 60 mesh and mixed). Measurements of thermal properties, namely thermal conductivity, volumetric heat capacity, thermal anisotropy coefficient, were carried out using a unique hardware and methodological base based on a non-destructive, non-contact, precision optical scanning technology (Popov, 2019). A detailed description of the technology, metrological and technical characteristics of the installations are given in ISRM Suggested methods (Popov et al., 2016). Coefficient of linear thermal expansion (CLTE) was measured accounting for rock anisotropy over a wide temperature range of 20-300 °C using a dilatometer with a quartz pusher DKT-40 (Chelyabinsk, Russia). The dilatometer was specifically designed for studies of standard core samples and meets the requirements of ASTM E228-95. The metrological and technical characteristics of the DKT-40 unit as well as the improved measurement technique were described in detail by Gabova et al. (2020a). Most of our data were previously published (Chekhonin et al., 2018; Popov, 2019; Gabova, 2021), but the variation of kerogen's thermal conductivity with maturity has not been studied before, and the assessment of the kerogen's CLTE has not been performed.

For estimating the volumetric heat capacity of kerogen and assessing the impact of TOC on the thermal conductivity of shales under varying temperatures, new experimental data from 38 samples of the Bazhenov Fm (characterized by TOC up to 21% and $R_o \approx 0.5\%-0.55\%$) was employed. Samples were extracted from a well in the central part of West Siberian Basin.

When processing experimental data and dependencies, data quality was controlled. Regression analysis methods were used to verify the significance of the established regression equations according to the Student's or Fisher's criteria. Equations that failed this check were not utilized. Values outside the confidence interval (95%) were excluded from the analysis.

Since the publications used contain tabular data and dependencies of properties on both TOC (mass percentage) and the volume fraction V_k of kerogen, if necessary, the recalculation between TOC and V_k was performed according to the formulas (Vernik and Milovac, 2011):

$$\begin{aligned} V_k &= \frac{\text{TOC}}{w} \frac{\rho - \rho_f \phi}{\rho_k (1 - \phi)} \\ \text{TOC} &= V_k w \frac{\rho_k (1 - \phi)}{\rho - \rho_f \phi} \end{aligned} \quad (1)$$

where ρ , ρ_k , and ρ_f are the density of rock, kerogen and pore fluid, respectively; ϕ is the porosity (assumed to be zero if porosity data are not available); w is the proportion of carbon in OM (0.7-0.85 depending on maturity level (Tissot and Welte, 1984; Vernik and Milovac, 2011)).

To unify maturity indicators, the level of organic metamorphism into vitrinite reflectance (R_o) was converted using the data table presented by Passey et al. (2010).

The well-known formulas for elastic moduli (Mavko et

al., 2020):

$$\begin{aligned} E &= \rho V_S^2 \frac{3V_P^2 - 4V_S^2}{V_P^2 - V_S^2} \\ \nu &= 0.5 \frac{V_P^2 - 2V_S^2}{V_P^2 - V_S^2} \end{aligned} \quad (2)$$

were used to calculate the Young's modulus E and the Poisson's ratio ν via the density ρ and the compressional (V_P) and shear (V_S) velocities of elastic waves.

The petrophysical model for organic shales described in (Alfred and Vernik, 2013) was used to explain observed variations of bulk density and total porosity on TOC. The variation of kerogen's CLTE with temperature was estimated by minimization the misfit between the measured (Gabova, 2021) and calculated effective CLTE of two samples with different TOC. The calculations were performed for a two-phase kerogen-matrix 'composite' using the approach described by Shermergor (1977).

3. Results and discussion

3.1 Density

Changing the chemical composition of kerogen during thermal maturation leads to a decrease in the H/C ratio and increase in kerogen density ρ_k (Cheshire et al., 2017; Mavko et al., 2020). The increasing can reach tens of percent (Fig. 1(a)) and is confirmed by studies on synthetic kerogen maturation (Jagadisan et al., 2017). According to experimental studies by Kinghorn and Rahman (1983), kerogen of type I is characterized by the lowest density, compared with kerogen of type II and, further, type III, with the similar degree of their transformation. This is due to the fact that by origin, type I kerogen is primarily aliphatic and hydrogen-rich, type III kerogen is predominantly aromatic and oxygen-rich, while type II kerogen is a mix of aliphatic and aromatic. However, density values determined by Kinghorn and Rahman (1983) are mostly overestimated relative to the other published data (Guidry et al., 1995; Dang et al., 2016; Cheshire et al., 2017; Craddock et al., 2018). The overestimation may be due to insufficient separation of the mineral matrix from kerogen. In Fig. 1(a), all published results are divided into two groups with different trends (depending on kerogen types) of increasing density with thermal maturity. Generalized relationship $\rho_k = 1.30 + 0.26 \ln R_o$ for type II kerogen is obtained after averaging results of Alfred and Vernik (2013), Cheshire et al. (2017), and Craddock et al. (2018).

The density of rocks decreases with an increase in the OM content in the rock (Fig. 1(b)) since minerals are, on average, 1.5-2.5 times denser than kerogen (Schoen, 2015; Mavko et al., 2020), and therefore density logging is often used to estimate TOC (Schmoker, 1979). The difference in absolute values and the trend of changes in rock density with TOC in Fig. 1(b) is explained by two factors. The first one is the significant difference in the densities of the mineral matrix and kerogen, and the second is the different values of kerogen porosity (see the next section) in the studied areas. This can be easily explained using models for calculating the density

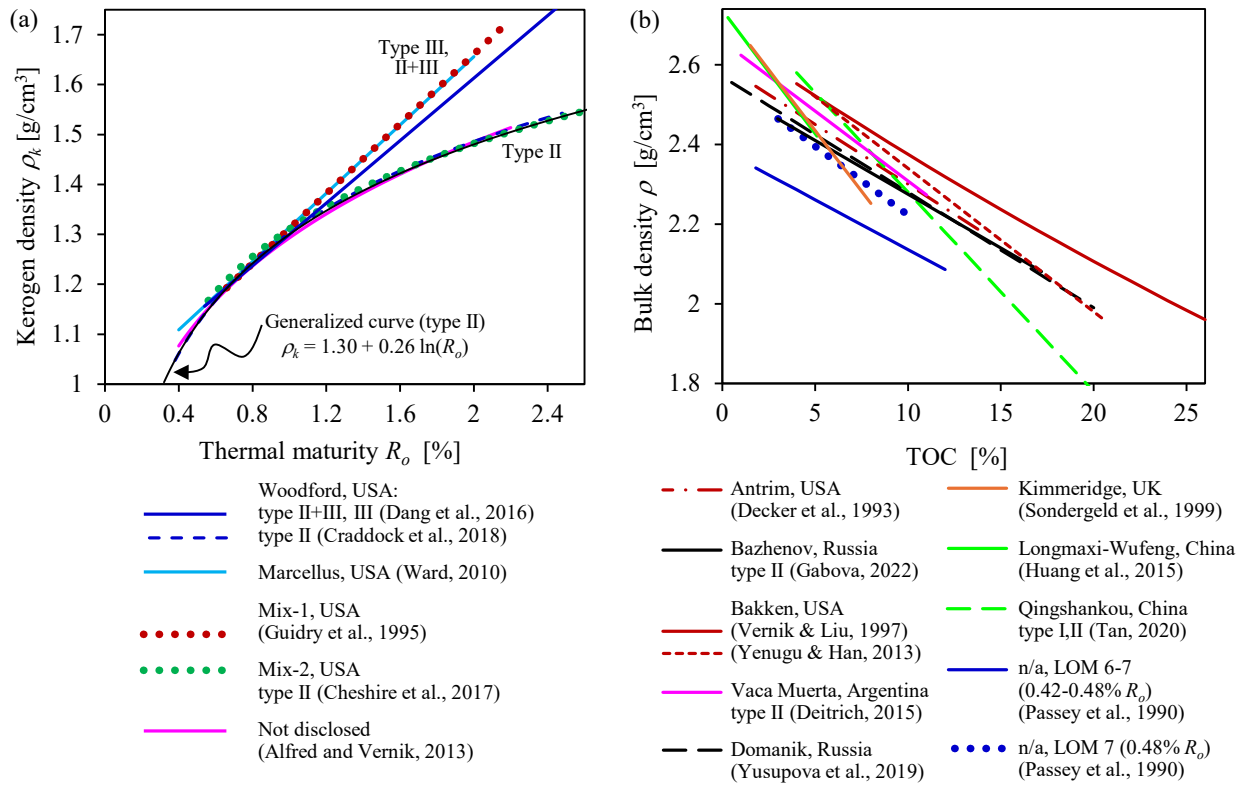


Fig. 1. (a) The dependence of kerogen density ρ_k on its thermal maturity R_o and type for different shale formations and (b) the reduction in the rock density as the OM content increases. Regression equations and some details are given in Tables S2 and S3.

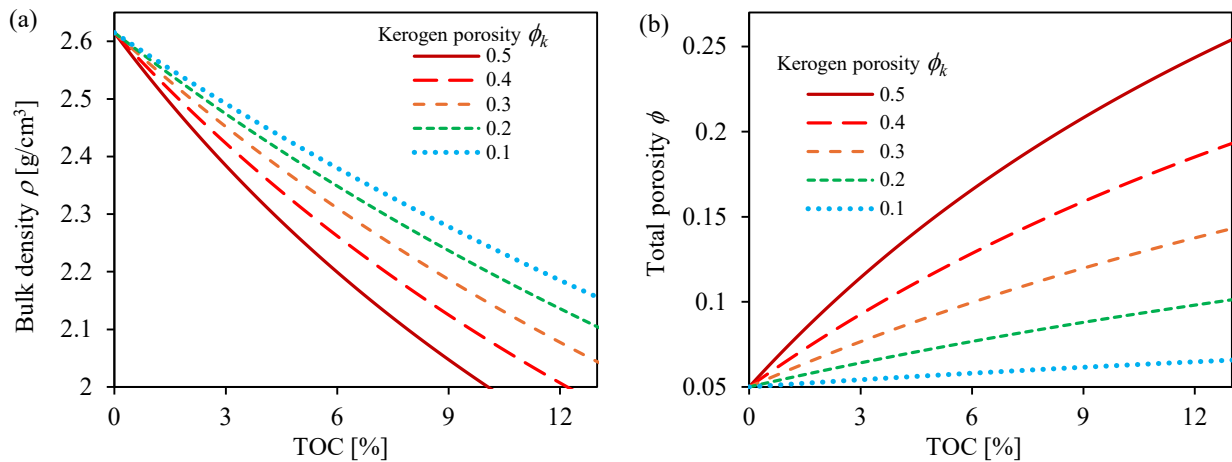


Fig. 2. Dependencies of bulk density (a) and total porosity (b) on TOC at different kerogen porosities ϕ_k obtained with the petrophysical model by Alfred and Vernik (2013).

and porosity of oil and gas shales. Fig. 2 shows an example of such calculating with the petrophysical model by Alfred and Vernik (2013). The calculations were performed assuming that $w = 0.8$, the inorganic domain porosity is 0.05, the mineral density is 2.7 g/cm³, $\rho_k = 1.2$ g/cm³, water is placed in non-kerogen pores, while kerogen pores contain hydrocarbons with density 0.8 g/m³. The greater the kerogen porosity or the higher the density of the mineral matrix and the lower the kerogen density, the greater the decrease in rock density with an increase in the OM content (Fig. 2(a)).

In practice, the analysis of density variation is often complicated by variations in the density of the mineral matrix and porosity (Vernik and Milovac, 2011). Moreover, it is difficult to reliably determine the porosity from core and/or logging data in rocks enriched in OM (Passey et al., 2010). The effect of thermal maturity of kerogen on the bulk density may be insignificant. This occurs when the increase in kerogen density is compensated by the reduced (relative to kerogen) density of generated hydrocarbons, before their migration out of the source rocks (Harris et al., 2019). The association of OM with

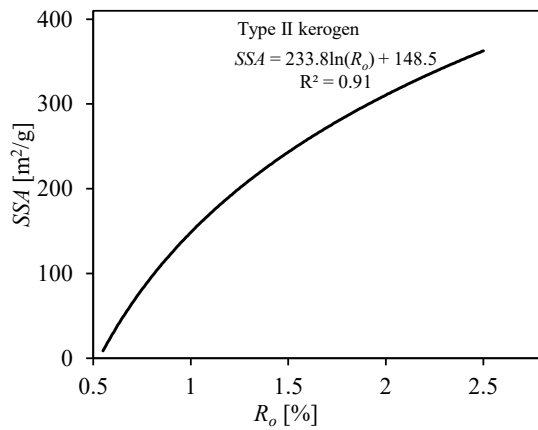


Fig. 3. Change in the SSA of kerogen with the degree of maturity for type II kerogen; the regression is based on the data from Suleimenova et al. (2014) and Cheshire et al. (2017).

pyrite (the volume content is $\sim 7\%$ in average following the estimation by Witkowsky et al. (2012)) can offset the difference. This is due to the high density of pyrite ($4.8\text{--}5\text{ g/cm}^3$) compared with the main rock-forming minerals (Schoen, 2015; Mavko et al., 2020).

Refinement of the kerogen density significantly (by tens of percent) affects the accuracy of estimates of the physical properties of kerogen-bearing rocks when interpreting logging data (Jagadisan et al., 2017).

3.2 Porosity, SSA, and sorption capacity

Along with the chemical composition, the microstructure of kerogen changes as the thermal maturity increases: the pore volume and the SSA increases (Craddock et al., 2018) (Fig. 3), while the average pore radius decreases (Milliken et al., 2013; Yang et al., 2017). The SSA in organic-rich shales increases with rising TOC, as OM serves as the primary storage location, forming a vast network of nanoscale pores through thermal maturation. Loucks et al. (2012) reported that pores in kerogen are absent or extremely rare prior to the ‘oil window’, starting to develop after reaching $R_o = 0.6\%$ or higher. The volume of pores in kerogen reaches its maximum when maturity reaches the peak of the ‘gas window’ (Zhao et al., 2024).

The kerogen porosity can exceed the intergranular porosity with a high content and high degree of kerogen maturity (Vasiliev et al., 2015; Zhang et al., 2018). In this regard, the porosity of rocks enriched with OM at high maturity, which ensures the development of the pore space, often positively correlates with TOC. This is observed, e.g., in large shale formations of oil and gas basins in USA (Zoback and Kohli, 2019), China (Tang et al., 2016; Zhao et al., 2024), Western Siberia (Kalmykov and Balushkina, 2017), etc. (Fig. 4). The maximum of OM porosity is reached at vitrinite reflectance about $1.5\%\text{--}2.0\%$ according to Hu et al. (2015) or $1.8\%\text{--}2.6\%$ according to Klaver (2014).

Obviously, there is no dependence in the absence of a kerogen porosity ϕ_k . If ϕ_k increases, the dependence appears and becomes steeper the more kerogen is consumed to generate hydrocarbons (Fig. 4). This relationship can be easily explained using the petrophysical model mentioned above (see

Fig. 2(b)). When analyzing the ‘ ϕ -TOC’ relationship, it is necessary to take into account that TOC decreases with the OM maturation, but variations in intergranular porosity can obscure the relationship. Intergranular porosity in Fig. 4 is characterized by the curve intersecting with the positive part of the Y-axis. Excessive reservoir pressure often occurs in oil shales during catagenesis (e.g., the formation pressure anomaly ratio reaches 1.8 in Bazhenov Fm (Vasiliev et al., 2015)). It can lead to the development of microcracks at the ‘oil window’ and primary migration (i.e., with local decreases or increases in TOC). Excessive pressure can be caused by a number of reasons. These include the high contrast in thermal expansion coefficients of kerogen and rock matrix and/or the conversion of a portion of the load-bearing kerogen into a fluid (with an increase in the volume of the converted portion). If the OM pore can be compacted plastically, the maximum overpressure is higher than the case when the OM pore cannot be compacted plastically (Qin et al., 2023).

Some researchers note a violation of the ‘ ϕ -TOC’ relationship at porosity values above a certain limit: About 6% for the Marcellus shale (Milliken et al., 2013) and $\sim 2\%$ for the Montney shale (Jarvie, 2012). This may be due to the rock compaction and the features of the distribution of OM in the rock. The pores in kerogen are less susceptible to closure if the kerogen does not carry sufficient load (unlike the mineral matrix). When a volume of OM exceeded some limit, the kerogen, which is softer and more plastic than the mineral skeleton, compacts with partial or complete expulsion of the generated hydrocarbons. The experiments on the Marcellus, Woodford, and Eagle Ford shales (USA) have shown that TOC of about 5% is the critical value necessary to achieve connectivity and the formation of oil-soaked pathways (Gupta et al., 2018).

According to Loucks et al. (2012), the value of kerogen porosity in one sample can vary significantly—from 0 to 40% . The authors explain the different pore development by the difference in kerogen type: type II kerogen is more prone to the development of pores than type III kerogen (the authors give an example of the absence of porosity in type III kerogen of a mature sample of the Atoka Fm, USA). Also in samples with high thermal maturity, areas of porous kerogen are often observed next to non-porous ones, which is associated with a non-uniform distribution of primary porosity in OM or with different types of organic macerals within one sample.

Many researchers, including Vandenbroucke and Largeau (2007), Loucks et al. (2012), Milliken et al. (2013), describe the pore space features and pore types of different shale formations. Porous OM, as well as the clay component of rocks, can retain a large amount of gas due to the significant SSA. In this regard, it is not surprising that there is a positive correlation between TOC and adsorption capacity (Chalmers and Bustin, 2008; Yang et al., 2017; Klewiah et al., 2020; Sun et al., 2022) (Fig. 5).

The sorption capacity decreases (Fig. 5) with increasing moisture content due to competition, since clay minerals begin to affect adsorption to a much lesser extent than in the dry state (Zoback and Kohli, 2019; Sun et al., 2022). As the experimental temperature, pressure, equilibrium time,

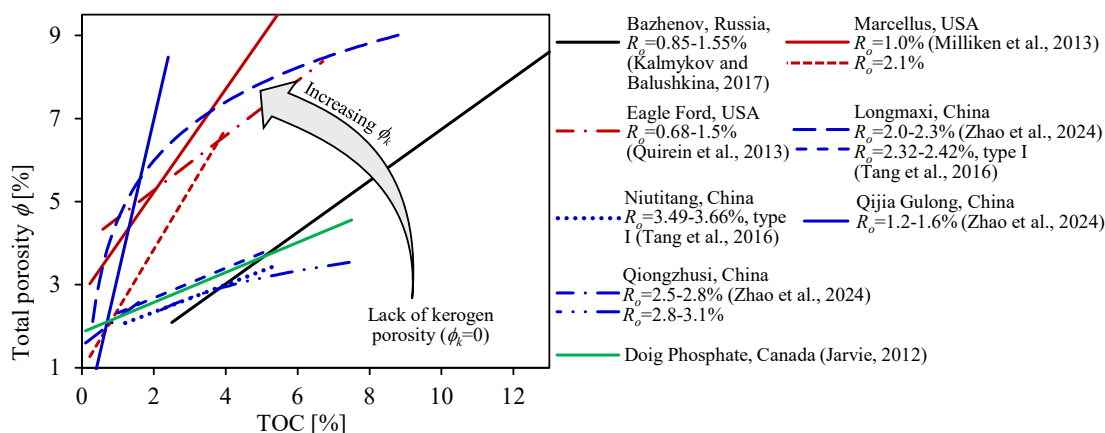


Fig. 4. Correlation of the total porosity ϕ on TOC in shale formations according to various sources; regression equations and details are given in Table S4. The slope angle of curves reflects the impact of kerogen porosity.

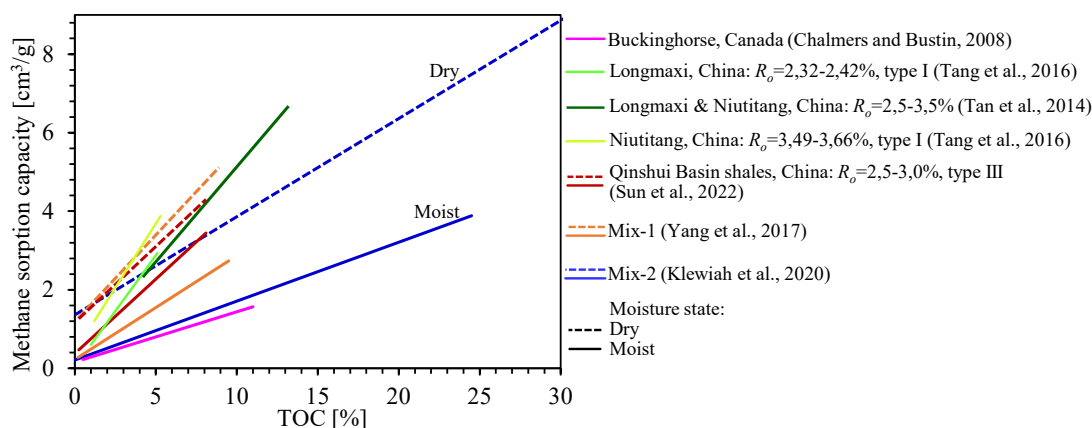


Fig. 5. Effect of TOC on the methane sorption capacity of dry and moisture equilibrated shales according to published data. Regression equations and details are given in Table S5.

and sample pretreatment methods vary across literatures, and information about kerogen type and thermal maturity is not always available, it is difficult to get any quantitative relationships for the sorption capacity. Nonetheless, as shown by the regressions in Fig. 5 at zero TOC, the sorption capacity of the dry mineral matrix is roughly five times higher than that of the wet mineral matrix. More specifically, the ratio is about 3.1 for Qinshui Basin shales (Sun et al., 2022), 5.3 for shales of mix-1 (Yang et al., 2017), 6.5 for shales of mix-2 (Klewiah et al., 2020). Moreover, the contribution to the sorption capacity made by kerogen exceeds that of the mineral matrix of oil and gas shales (as evident from comparing experimental data with the corresponding sorption capacity at zero TOC in Fig. 5). Thus, formation water can significantly reduce the gas sorption capacity and, therefore, the original gas in place (OGIP) estimates. An increase in temperature significantly reduces the portion of sorbed gas (by 30%-50% when the temperature changes from 30 to 75 °C for the gas shales of the Qinshui Basin, according to Sun et al. (2022)). Generally, the gas sorption capacity is higher in shales of higher thermal maturity (Zhang et al., 2012), although there are exceptions (Chalmers and Bustin, 2008). For rocks at the metagenesis stage ($R_o > 2\%$), there is no consistent trend

between thermal maturity and sorption capacity (Yang and Liu, 2020). Differences in OM genesis significantly affect the adsorption capacity (AC_X) of type X oil and gas shales with a trend of ' $AC_I < AC_{II} < AC_{III}$ ' (Zhang et al., 2012; Klewiah et al., 2020), which is confirmed by the simulation results (Yin et al., 2025). The authors explained it by the fact that vitrinite is richer in micropores and is associated with a larger surface area than other macerals. The presence of a clay component also provides additional sites for adsorption, but the sorption capacity is significantly reduced due to its hydrophilicity. As a result, in rocks enriched in OM, clay minerals affect adsorption to a much lesser extent than the kerogen content and its degree of thermal maturity. The above-mentioned trend can be violated, e.g., according to Pan et al. (2022) the methane adsorption capacity of the high-to-over-mature shales of the Lower Yangtze Area (Eastern China) with type III kerogen exhibits the weakest adsorption capacity than that of the marine shales. It should be noted here that excessively high maturity can lead to the decrease of shale porosity and the change of shale pore structure (Curtis et al., 2012). Moreover, there is a drastic change in the chemical structure of OM with the transformation from amorphous carbon to crystalline graphite when R_o arrives at 3.4%-3.5%

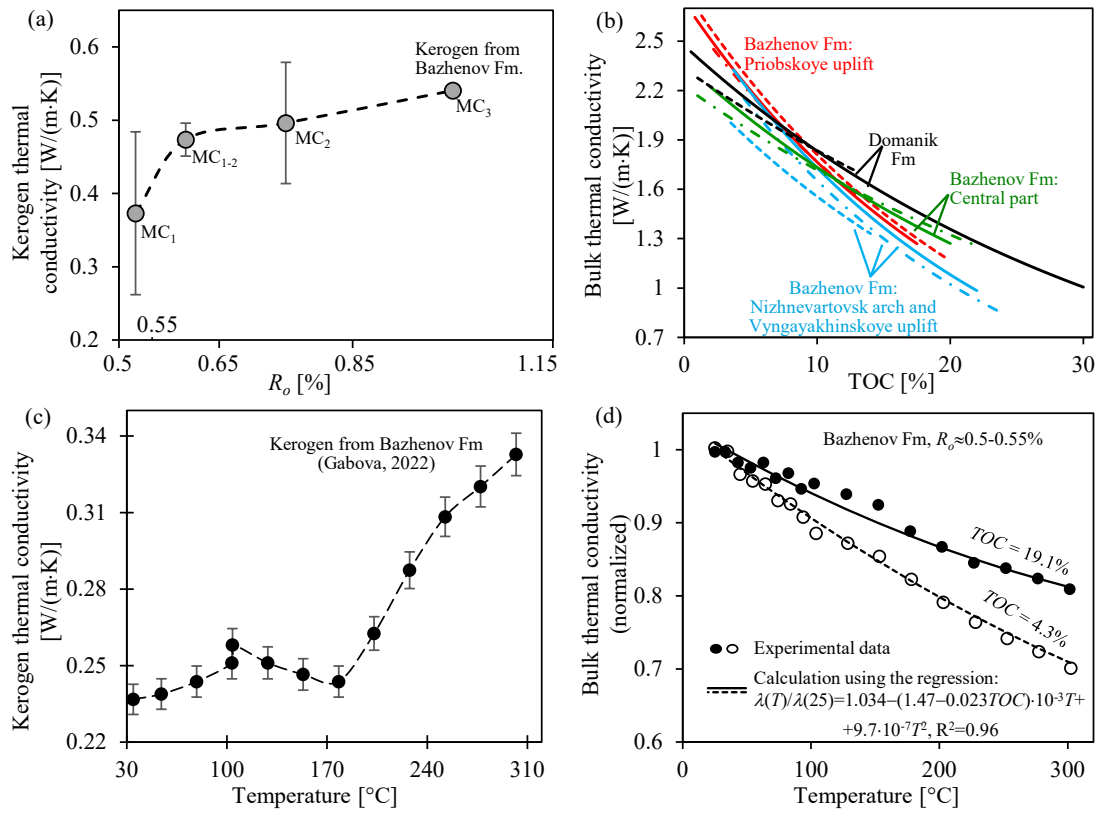


Fig. 6. (a) The average values and standard deviations of kerogen's thermal conductivity at different maturity, (b) Dependences of the thermal conductivity on TOC, (c) The temperature dependence of kerogen's thermal conductivity (Gabova, 2021) and (d) Experimental and calculated bulk thermal conductivity depending on temperature and TOC for two clay-siliceous samples.

(Hou et al., 2019).

Understanding how kerogen porosity develops and the correctness of its quantitative estimate (Passey et al., 2010) is crucial for predicting the ability of low-permeability oil and gas shales to generate hydrocarbons and influence their migration (Curtis et al., 2012). It is also necessary for interpreting well-logging data. Refinement of gas adsorption in shales is necessary to increase the reliability of OGIP estimates and a recovery factor. For example, failure to consider adsorbed gas would lead to the underestimation of OGIP by 30% and the overestimation of the recovery factor by 17% for the Barnett shale (Yang and Liu, 2020). Adequate consideration of sorption is important for both basin and hydrodynamic modeling in unconventional reservoirs, where pressure reduction leads to different relative desorption of components and significantly affects the composition and phase equilibrium of pore fluid. Considering maturity-controlled competitive adsorption in kerogen nanopores is important in evaluating containment security during underground hydrogen storage in depleted shale gas reservoirs (Liang et al., 2026).

3.3 Thermal properties

The thermal conductivity of kerogen increases during mesocatagenesis at the low to moderate maturity range of $R_o \approx 0.5\%-1.15\%$ (Fig. 6(a)). The trend shown in Fig. 6(a) is built based on published experimental data assuming a fixed

kerogen density $\rho_k = 1.14 \text{ g/cm}^3$ (Popov, 2019) to underline that the trend is not attributed to the density increasing with maturation (Fig. 1(a)), while the accounting for $\rho_k(R_o)$ will intensify the trend.

Estimates of the kerogen thermal conductivity for various deposits of the Bazhenov and Domanik Formations are given by Popov (2019) along with the dependences of the rock thermal conductivity on TOC. Since kerogen conducts heat much worse than the mineral matrix, the thermal conductivity of rocks decreases with the growth of TOC (Fig. 6(b), where different lines of the same color correspond to wells of one oilfield, see (Popov, 2019)). In this regard, continuous thermophysical profiling on the core is actively used to evaluate TOC (Popov, 2019), see an example in Fig. S1(b).

The thermal conductivity of rocks enriched in OM decreases with increasing temperature (Wang et al., 2018). The less kerogen there is, the greater the decrease (Fig. 6(d)), which links to the thermal conductivity of kerogen (Fig. 6(c)). Fig. 6(d) illustrates experimental (markers) and calculated (curves) bulk thermal conductivity of Bazhenov Fm rocks, normalized to values at 25 °C, as a function of temperature and TOC. The regression equation in Fig. 6(d) was established based on new experimental data obtained on 5 samples of the Bazhenov Fm and characterized by a range of changes in TOC from 3.5% to 19.1% at $R_o \approx 0.5\%-0.55\%$. With temperature, the thermal conductivity of amorphous substances increases, while that of the mineral matrix decreases (Schoen, 2015). The opposite co-

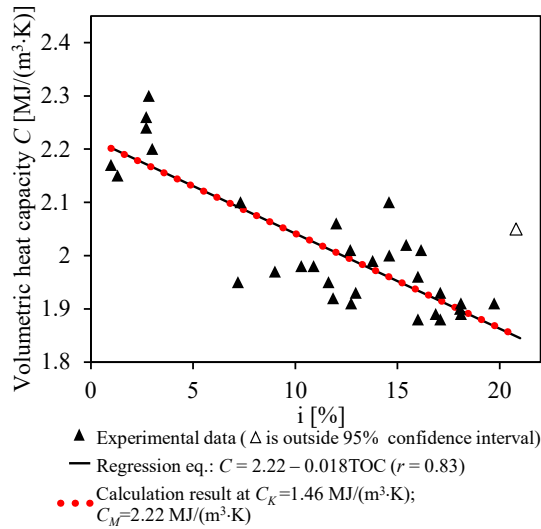


Fig. 7. The dependence of the volumetric heat capacity on TOC for the Bazhenov Fm rocks: the regression equation (black line) based on experimental data (triangles) and using Eq. (3).

tribution of these factors to the value of effective thermal conductivity lead sometimes to the nonlinear behavior of shales' thermal conductivity changes with temperature (Rajeshwar et al., 1979; Gabova et al., 2020b). The presence of a clay component (which varies slightly with temperature changes, but contains bound water, affecting the measurement results) also contributes to this nonlinear behavior.

There are lack of publications with experimental data on the volumetric heat capacity of kerogen (C_k) or on the relationship between the bulk volumetric heat capacity (C) and TOC. Analysis of experimental data (Popov, 2019) shows that the bulk volumetric heat capacity decreases in the presence of kerogen, which indicates lower value of the volumetric heat capacity of kerogen compared with those of rock-forming minerals (Waples and Waples, 2004). One example of the dependence $C(\text{TOC})$ is given in Fig. 7 and compared with the calculations (assuming the absence of porosity) according to the formula:

$$C = C_M(1 - V_k) + C_k V_k \quad (3)$$

where C_M and C_k are the volumetric heat capacities of mineral matrix and kerogen, V_k is the volume fraction of kerogen, determined by Eq. (1) for every rock sample at $\rho = 2.14 - 2.28 \text{ g/cm}^3$, $w = 0.8$, and $\rho_k = 1.15 \text{ g/cm}^3$ (an approximation for the type II kerogen at $R_o \approx 0.6\% - 0.65\%$, see Fig. 1(a)). In this case, the established C_M and C_k values, which ensures a minimum discrepancy between the calculated and experimental values of C , are $2.22 \text{ MJ/(m}^3 \cdot \text{K)}$ and $1.46 \text{ MJ/(m}^3 \cdot \text{K)}$ respectively, i.e., C_k value is within the published range $1.45 - 1.65 \text{ MJ/(m}^3 \cdot \text{K)}$ (Popov, 2019).

Note that the similar estimates C_M and C_k can be obtained from the established regression equation ' $C = a \cdot \text{TOC} + b$ ' assuming the absence of porosity (even if the average density $\langle \rho \rangle$ of the core collection is known instead of the density value of each sample), using the formulas:

$$C_M = b, \quad C_k = b + 100aw\rho_k\langle \rho \rangle^{-1} \quad (4)$$

As the coefficients a and b are about -0.018 and 2.22 , respectively (Fig. 7), $\langle \rho \rangle = 2.19 \text{ g/cm}^3$, $w = 0.8$, and $\rho_k = 1.15 \text{ g/cm}^3$, therefore $C_M = 2.22 \text{ MJ/(m}^3 \cdot \text{K)}$ and $C_k = 1.46 \text{ MJ/(m}^3 \cdot \text{K)}$.

There are only a few publications on the specific heat capacity of kerogen (Berkovich et al., 2000; Waples and Waples, 2004). Berkovich et al. (2000) presented experimental data on the temperature dependence of the kerogen specific heat capacity for Australian oil shales and discovered that the specific heat capacity of kerogen decreases as maturity increases.

The CLTE of kerogen α_k is at least 5-10 times greater than the CLTE of the mineral matrix (Gabova et al., 2020a) that explains the close correlation 'TOC-bulk CLTE' for the parallel ($\alpha_{\parallel}$) and perpendicular ($\alpha_{\perp}$) to bedding components of bulk CLTE (Fig. 8). Hereafter, the subscripts " $\parallel$ " and " $\perp$ " mean the parameter values directed along and across the bedding/lamination. Moreover, α_k increases 3-4 times from 200×10^{-6} to $750 \times 10^{-6} \text{ K}^{-1}$ (Fig. 8(a)) with increasing temperature according to calculations based on experimental data by Gabova (2022) on bulk CLTE of two samples from the Bazhenov Fm with different TOC. A sharp increase in the α_k is observed within the temperature range of $110 - 130 \text{ }^{\circ}\text{C}$. The obtained estimates of the absolute values and the behavior of α_k with temperature are consistent with experimental data for kerogen of Green River shales (Zhang et al., 2007), where the temperature of kerogen transition to a rubber-like state turned out to be about $128 \pm 15 \text{ }^{\circ}\text{C}$, while CLTE varied approximately 5 times, from 104×10^{-6} to $598 \times 10^{-6} \text{ K}^{-1}$. Note that the significant contrast in CLTEs of kerogen and mineral matrix causes the close correlation 'bulk CLTE-TOC' (Fig. 8(b)). Along with non-linear temperature dependence of α_k , it results to the nonlinear behavior of bulk CLTE with temperature for organic-rich shales (Gabova et al., 2020a).

Reliable information on the thermal properties of organic-rich shales, taking into account their anisotropy, is important for the correct calculation of spatiotemporal variations in the formation temperature when modeling the process of hydrocarbon generation/extraction from unconventional reservoirs (Gabova et al., 2020a; Gabova, 2021). Reliable data on the thermal expansion of organic-rich shales is important for accurate thermal stress estimation of rocks (and related fracturing) or for shale porosity/permeability changing under temperature treatment. This is essential for wellbore stability analysis and accurate numerical modeling of in-situ kerogen conversion (Gabova et al., 2020a; Lin et al., 2023).

3.4 Elastic properties

During catagenesis, with increasing maturity, kerogen resists elastic deformation more strongly, i.e. the Young's modulus of kerogen E_k increases (Li et al., 2018; Khatibi et al., 2018; Charlton et al., 2021; Wang et al., 2022). It is explained by an increase in density, mechanical reorientation and alignment of aromatic structures, contributing to reduction of defects in kerogen (Khatibi et al., 2018). Statistically

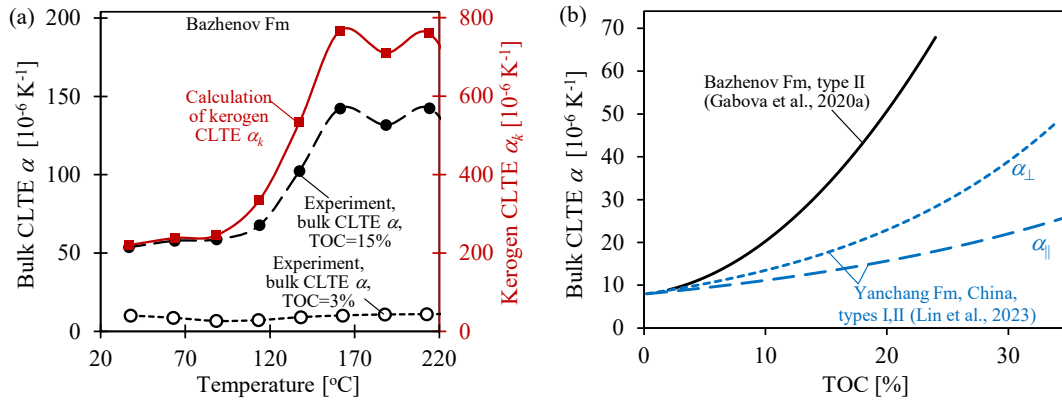


Fig. 8. (a) Experimental data on bulk CLTE (Gabova, 2021) with corresponding calculations of kerogen CLTE and (b) Experimentally determined dependences 'CLTE-TOC' (Gabova et al., 2020a; Lin et al., 2023) (Table S6).

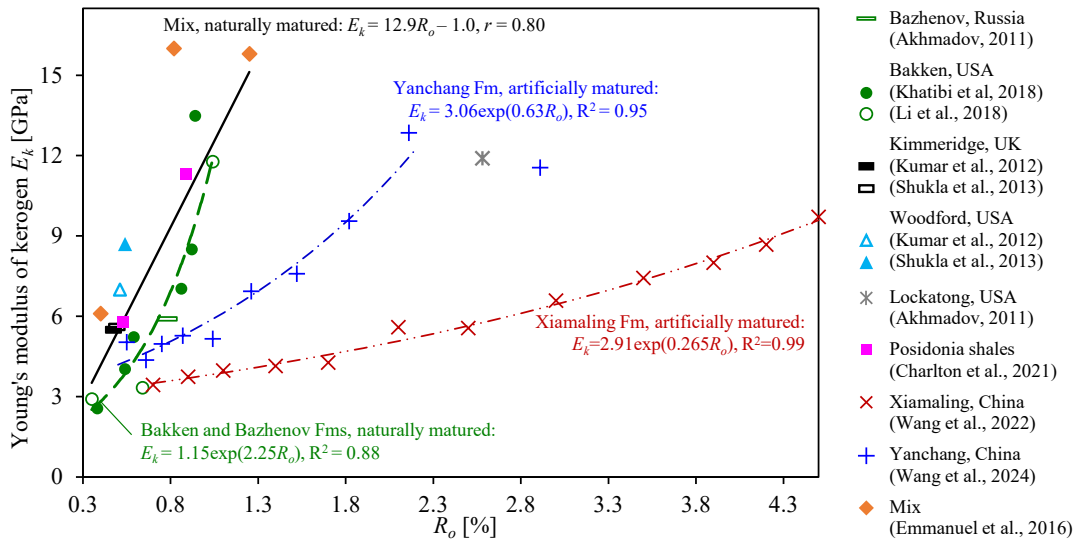


Fig. 9. Data on the Young's modulus of kerogen E_k collected from various sources, with corresponding regression equations (see the text).

significant dependencies, constructed using different data sets (naturally and artificially matured), are shown in Fig. 9. Regression equations and curves for the dataset encompassing all naturally matured data (excluding Lockatong Fm), as well as the dataset including only Bazhenov and Bakken Fms data, are displayed in black and green, respectively.

Note that, firstly, the E_k of naturally high-to-over-mature shales is not well studied (Fig. 9). Secondly, the majority of the data in Fig. 9 differ significantly from the results obtained on artificially matured samples (Wang et al., 2022, 2024). During the maturation process, kerogen porosity increases, which leads to a decrease in E_k . However, in natural environment, the lithostatic pressure is much higher than in the experiment (40-50 MPa), and tectonics is added often. Thus, with all else being equal, the kerogen porosity of natural samples will be significantly lower than that of artificial samples, resulting in a significantly lower E_k in artificial samples, as shown in Fig. 9. The decrease in TOC with thermal maturity also may contribute to the difference. The discrepancy among E_k of artificially matured specimens is likely due to differences

in the experimental procedure. More specifically, Wang et al. (2022) pyrolyzed OM samples isolated by acid treatment, i.e., (1) there was a lack of mineral support and accompanying chemical reactions and (2) there may have been possible changes in the kerogen caused by acid treatment compare to the work (Wang et al., 2024).

With increasing maturity, the elastic wave velocities and the Young's modulus of organic-rich shales increase, while the Poisson's ratio decreases (Prasad et al. (2011); Harris et al., 2019). For example, Harris et al. (2019) show that the elastic wave velocities increase by about 10%, the Young's modulus increases by about 3 times, and the Poisson's ratio decreases by about 35% with an increase in the maturity of the Woodford shales from 0.71 to 1.48% R_o . An increase in the velocities of elastic waves with the degree of maturity was also noted by Vanorio et al. (2008) and Prasad et al. (2011) using combined data from the Bakken, Niobrara, Woodford, and Bazhenov Formations.

Compared with rock-forming minerals (with the exception of kaolinite) of kerogen-containing rocks, kerogen is softer

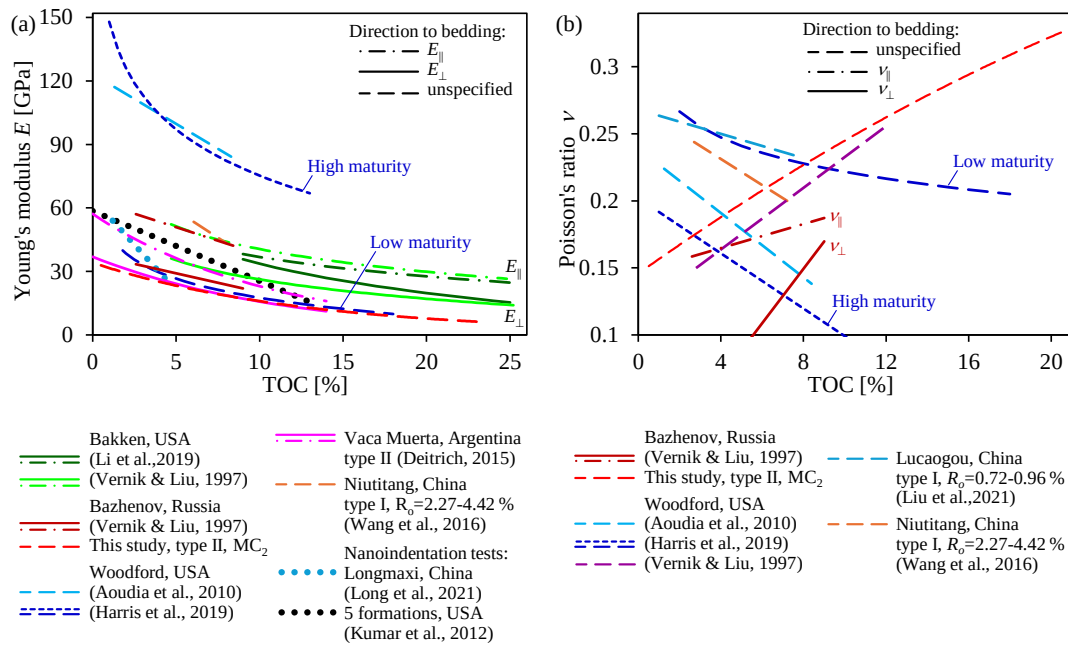


Fig. 10. (a) Dependences of Young's modulus and (b) Poisson's ratio of organic-rich shales on TOC (Table S7). Solid and dash-dotted lines indicate the characteristics across and along rock bedding, respectively.

(Zeszotarski et al., 2004; Kumar et al., 2012), and its bulk modulus, shear modulus, and elastic wave velocities are lower (Mavko et al., 2020). Therefore, an increase in OM fraction leads, as a rule, to a decrease in the velocities of elastic waves and the Young's modulus of oil shales, in contrast to the Poisson's ratio (Fig. 10). It is agreed with the results of molecular dynamics simulation, e.g., Wu and Firoozabadi (2020) established that kerogen has a much lower Young's modulus and a slightly higher Poisson's ratio than other minerals in shale.

There are publications with the absence of a significant relationship between the OM content and the velocities of longitudinal and/or transverse elastic waves (Vernik and Liu, 1997; Sondergeld et al., 2000), dynamic Young's modulus (Liu et al., 2021), and Poisson's ratio (Vernik and Liu, 1997). The exceptions also include the Niutitang gas shales (Wang et al., 2016), where a significant positive correlation of 'E-TOC' was found with TOC < 6.5%. There could be multiple reasons. Firstly, a change in kerogen content might be accompanied by a change in the content of other components with an opposite effect on elastic characteristics (and especially on the Poisson's ratio, which takes into account deformation in two orthogonal directions). An increase in the quartz, feldspar, and calcite fraction leads to an increase in the values of dynamic elastic properties, while an increase in the portion of clay minerals and OM leads to a decrease in these values (Liu et al., 2021). For example, in the Vaca Muerta shale (Argentina), the calcite content correlates with TOC both positively and negatively at different locations due to the features of sedimentation (Ravier et al., 2020). Second reason is the using simplified formulas (Mavko et al., 2020) for calculation dynamic E and ν , see discussion by Bokhonok and Ravazzoli (2016). Thirdly, elastic modules depend on the characteristics of kerogen distribution

in the rock or pore space geometry. In particular, both an increase and a decrease in ν (Fig. 10(b)) are demonstrated with increasing TOC using different rock physics models (Guo et al., 2013; Sayers, 2013b). Finally, elastic modules also depend on the stress field (Dusseault et al., 1983), which may be different in different areas of the studied object.

Understanding the elastic properties of oil and gas shales is important for assessing borehole stability and hydraulic fracturing design (Shukla et al., 2013) and for evaluating the brittleness index to characterize possible failures in rock (Herrmann et al., 2018; Zoback and Kohli, 2019). It also helps to identify sweet spots, where the rock brittleness is a key factor (Vernik and Milovac, 2011). Understanding of elastic anisotropy and its causes is crucial for accurate seismic visualization, accurate reference to wells, correct interpretation of seismic data (Sayers, 2013b), as well as for increased reliability of geomechanical models.

3.5 Compressive and tensile strengths

At the microscale, testing kerogen inclusions (Zeszotarski et al., 2004; Kumar et al., 2012; Emmanuel et al., 2016) or micro-cantilever beams (Hull et al., 2017), the kerogen acts like a high-molecular-weight polymer. It shows ductile properties, higher tensile strength, lower uniaxial compressive strength, stiffness, and hardness compared to brittle inorganic grains. It aligns with the results from a molecular dynamics simulation (Wu and Firoozabadi, 2020). At the macroscale, an organic-rich shale behaves as a heterogeneous composite, where structural features lead to the reduction in compressive σ_c and tensile σ_t strength as TOC increases (Fig. 11). The mentioned structural features include an alternating arrangement of clay and organic aggregates, a mix of brittle/stiff minerals and OM, and nanoscale pore-crack networks, i.e.,

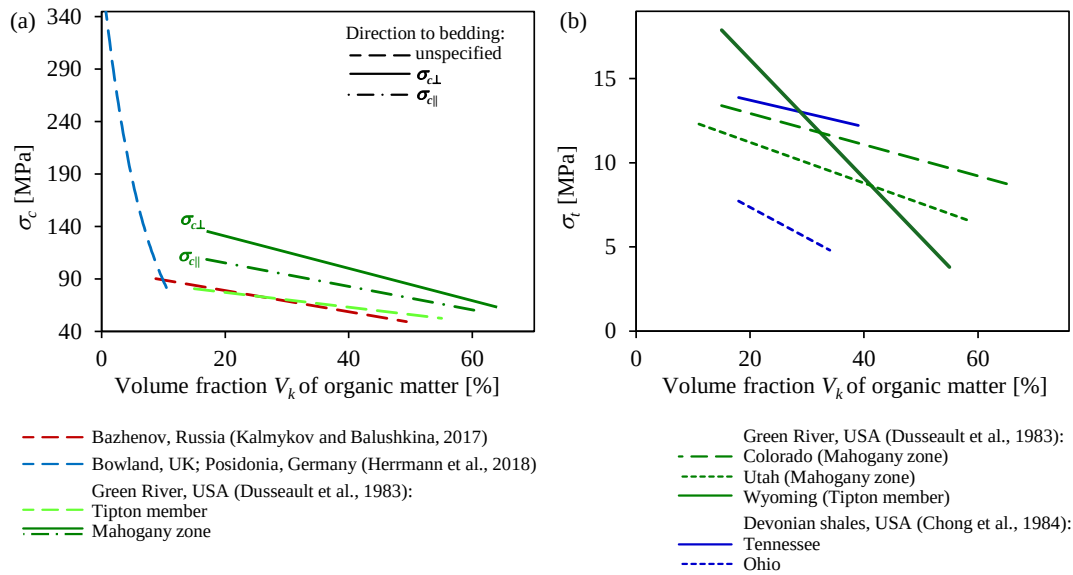


Fig. 11. (a) Dependences of the uniaxial compressive strength and (b) the tensile strength of organic-rich shales on the volume percentage of organic content (see details in Table S8).

the presence of defects/voids/microcracks.

Higher TOC generally correlates with greater porosity and the development of micro-cracks (during thermal maturation and expansion of OM, see Sections 3.2 and 3.3) usually directing to follow the bedding. All defects act as stress concentrators, leading to easier crack initiation and propagation when stress is applied. Loading parallel to the bedding encourages tensile cracks and shear sliding along the bedding plane at lower stress thresholds compared to loading across the bedding, thus $\sigma_{c\parallel} < \sigma_{c\perp}$ as shown in Fig. 11(a). In cases of low kerogen content, the relationship ‘ σ_c -TOC’ cannot be observed due to kerogen not being integrated into the rigid rock matrix structure.

The strength of kerogen-bearing rocks decreases with increasing degree of thermal maturity and temperature, and increases with increasing confining pressure (Closmann and Bradley, 1979; Esemé et al., 2007). For example, the uniaxial compressive strength σ_c decreases by 32% when heated the oil shales from 70 to 120 °C (Esemé et al., 2007); other examples can be found in (Wang et al., 2021) and references therein. The degree of reduction depends on the OM content: According to the study by Esemé et al. (2007), temperature increase from 70 to 120 °C leads to σ_t decrease by 33% and 54% for rocks with OM content about 20% and 50%, respectively. It is important to take into account in the case of high-temperature treatment in organic-rich shales. Molecular dynamics simulation by Wu and Firoozabadi (2020) shows that type III kerogen has the highest σ_t and friction coefficient, while type II kerogen exhibits the highest σ_c and the lowest friction coefficient among the kerogen types.

Understanding the evolution of the mechanical properties of kerogen and kerogen-bearing shales during its maturation is important for assessing borehole stability and optimizing hydraulic fracturing (Shukla et al., 2013; Wang et al., 2024), for exploitation and basin modeling (Esemé et al., 2007).

3.6 Electric properties

Kerogen is a nonpolar substance, which is characterized by low values of dielectric constant ϵ (a real part of the permittivity) before the beginning of hydrocarbon generation (Sweeney et al., 2007). Al-Harashsheh et al. (2009) analyzed experimental data obtained at samples of outcrops of Jordanian oil shales and found that generally the dielectric loss factor (an imaginary part of permittivity) decreases with the increase of TOC. The value of the dielectric constant of kerogen increases with increasing degree of its thermal maturity and aromaticity, but the value of electrical conductivity increases much more strongly (Dabidian et al., 2016). The dielectric constant of organic shales is also controlled by frequency (Josh et al., 2016) and temperature. At low temperatures, the shales have shown high dielectric constant anomalies which, according to some researchers, might be due to polarization effects on electrodes (Zendehboudi and Bahadori, 2015). The electrical conductivity of OM depends on its type and temperature: According to (Yang et al., 2016), the electrical resistivity R_t increases by several orders of magnitude with increasing temperature from 25 to 150 °C. This is, probably, explained by the wettability of kerogen (and therefore the wettability characteristics of organic-rich shales), which is affected by its chemical composition and maturity (Gupta et al., 2018).

Since the electrical conductivity of OM is usually lower than that of the other rock components, there is generally a positive correlation between TOC and R_t (Passey et al., 1990; Kontorovich, 2002; Tan, 2020) (Fig. 12). Accounting for the observation that P-wave velocity in organic-rich shales decreases with increasing OM content (Section 3.4), electric and acoustic logging data are often used to estimate TOC, see the so-called ‘Passey method’ or the $\Delta \log R$ method (Passey et al., 1990). Sometimes, the correlation of ‘ R_t -TOC’ or ‘ ϵ -TOC’ is absent. It is observed by Al-Harashsheh et al. (2009) in outcrops of Jordanian oil shales, and by Passey et al. (1990)

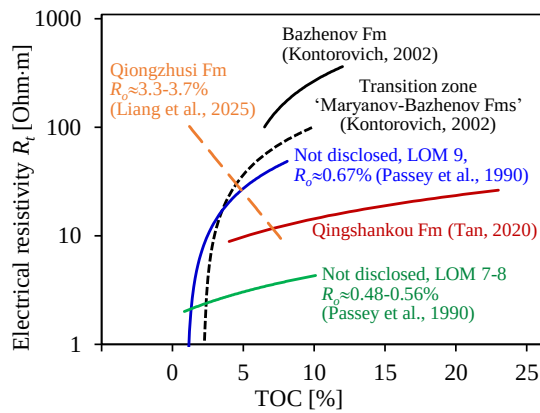


Fig. 12. Dependences of electrical resistivity on TOC in different shale formations according to published data. The regression equations and details are given in Table S9.

in wells with a low maturity.

Moreover, variations in the content of water-wetted clay minerals and pyrite (a highly polarizing material) can significantly reduce the effect of kerogen on the dielectric constant of shales (Dabidian et al., 2016). This, in turn, can lead to a blurring of the relationship between electrical properties and TOC. When subjected to compaction or tectonics, kerogen pores constantly deform and collapse, further influencing the shale resistivity. Passey et al. (2010) observed that the resistivity of some lower mature organic-rich shales ($R_o \approx 1\%-3\%$) was 1-2 orders of magnitude higher than that of over-high mature shales ($R_o > 3\%$), perhaps because the carbon in the OM is recrystallizing to a precursor of mineral graphite (electrically conductive). Xue et al. (2022) and Liang et al. (2025) showed that graphitization leads to the collapse and closure of organic pores and, therefore, to a decrease in resistivity. It can explain a negative correlation between TOC and R_t (see orange curve in Fig. 12). Analyzing the middle member of the Woodford shale, Wang and David (2019) found that an increase in R_o within the range of 0.6%-2.0% leads to an increase in resistivity up to oil generation peak ($R_o \sim 0.85\%$), followed by a decrease in resistivity. Wang and David (2019) explained the increase by pointing out that aromatic and resin compounds are more electrically conductive than aliphatic compounds.

3.7 Anisotropy of physical properties

The contrast between the physical properties of OM and mineral matrix, as well as the peculiarities of kerogen distribution (Figs. S1(a) and S1(b)), significantly affect the anisotropy of rock properties. The anisotropy coefficients of different properties often demonstrate positive trends with kerogen content (Figs. 13(a)-13(c)), which was observed by different specialists mainly focusing on the elastic anisotropy (Li et al., 2019). Apparently, this is a reason for the relationship between the elastic anisotropy (Thomsen's parameters ϵ and γ , the Young's modulus anisotropy) and the thermal anisotropy (Fig. 13(d)). Utilizing the correlation allows us prediction of hard-to-find anisotropy coefficients from an easier-found coefficient.

Popov (2019) examined thermal anisotropy with a basic layered model, employing equations for consecutive and

concurrent connections of thermal conductors (kerogen and mineral matrix layers), and showed that the maximum value of the anisotropy corresponds to TOC about 30%. Simulating Thomsen's anisotropy parameters of Kimmeridge Shale, Carcione (2000) discovered that the peak of ϵ and γ parameters is reached when the kerogen content is $\sim 30\%$. According to Vernik and Liu (1997), the maximum of ϵ in black shales corresponds to TOC of about 15%-20%, while the range is associated with a decrease in the clay content from 50% to 25%. Sayers (2013a) showed that for ellipsoidal shale inclusions in kerogen, the maximum value of parameters corresponds to kerogen content of 20%-40%, and the range is linked to a reduction in inclusion aspect ratio from 0.5 to 0.1.

The thermal conductivity, Young's modulus, and Poisson's ratio of kerogen-bearing shales measured parallel to the bedding plane are usually greater (up to several times) than the corresponding characteristics measured perpendicular to the bedding (Wang et al., 2018; Popov, 2019; Charlton et al., 2021). According to Sayers (2013b), kerogen inclusions reduce Young's moduli E_1 and E_3 and decrease the Poisson's ratio ν_{31} (stress applied perpendicular to the bedding) more than ν_{12} (stress applied parallel to the bedding) for deformation measured parallel to the bedding. At the same time, silt inclusions act to increase the Young's moduli E_1 and E_3 and to decrease the Poisson's ratios ν_{12} and ν_{31} , while the presence of low-aspect ratio pores, contacts between clay particles and bedding-parallel cracks acts to reduce E_3/E_1 and ν_{31}/ν_{12} (Sayers, 2013b). The anisotropy in shales seems to be largely influenced by: (a) The presence of kerogen inclusions, low-aspect ratio pores, contacts between clay particles and bedding-parallel cracks in case of $\nu_{31} < \nu_{12}$; (b) the partial alignment of anisotropic clay particles if $\nu_{31} > \nu_{12}$; (c) all above mentioned factors if $\nu_{31} \approx \nu_{12}$. According to Vernik and Nur (1992), the Thomsen's parameter ϵ of some non-source (TOC < 1%) shales is lower than ϵ of black Bakken shales (TOC is in range 5%-20%), while the maturity level of source rocks affects how the anisotropy parameter depends on confining pressure. Thomsen's parameters change nonlinearly with several maxima-at the maturity peak oil generation $R_o \sim 0.65\%$, peak gas generation $R_o \sim 1.3\%$, and, probably, in the metagenesis stage of OM maturation ($R_o \sim 2.2\%$), see (Vanorio et al., 2008 and Li et al., 2016) with increasing level of thermal maturity as a result of a variety of mentioned above factors. Results in Fig. 13(b) suggest that the difference in TOC may explain the data scattering of Thomsen's parameter ϵ or γ at a fixed degree of thermal maturity observed by Vanorio et al. (2008) and Li et al. (2016). Understanding the elastic anisotropy and its causes is crucial because it strongly influences analyses/interpretations of seismic surveys, sonic logs, and microseismic monitoring (Sayers, 2013b). Thermal anisotropy directly affects temperature-field morphology and heating efficiency (Wang et al., 2021).

Due to the peculiarities of the OM distribution in organic-rich shales and the presence of a clay component with a layered microstructure (caused by the alignment of clay particles during compaction), the uniaxial compressive strength along the bedding is usually less than across it (Fig. 11(a)).

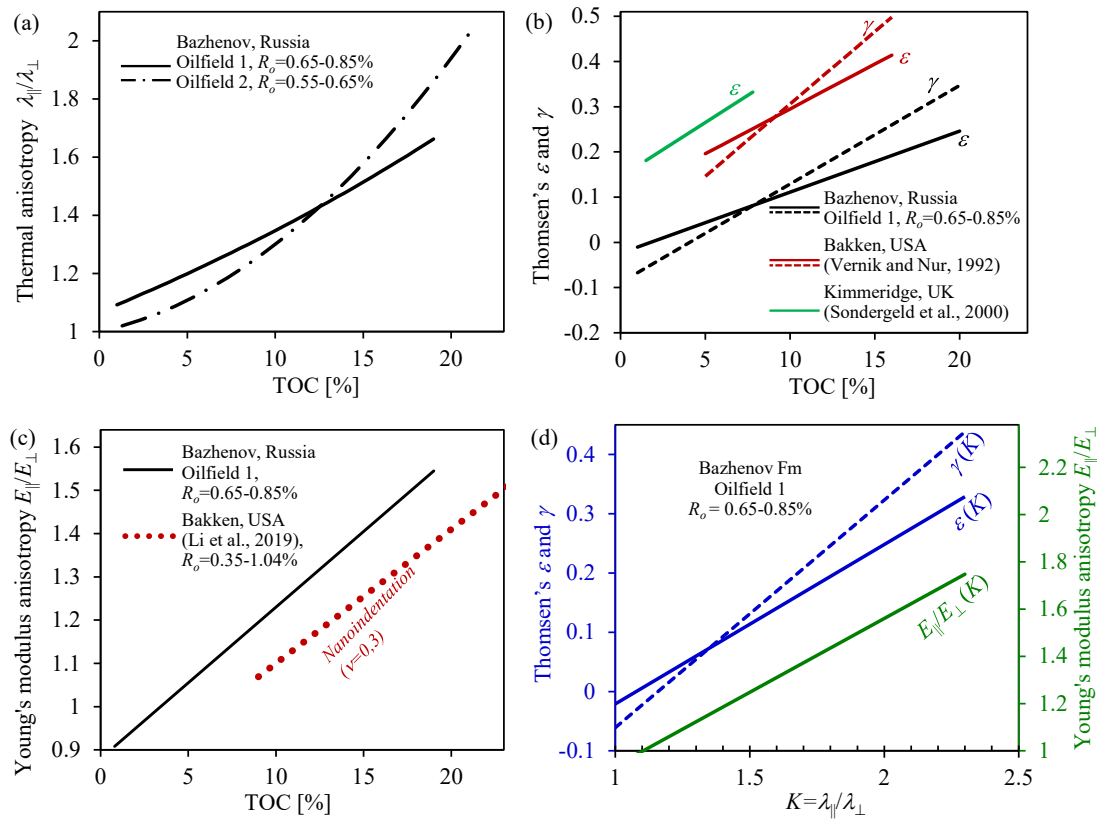


Fig. 13. Dependence of (a) the thermal anisotropy, (b) Thomsen's ϵ and γ parameters, (c) the Young's modulus on TOC and (d) the relationship of acoustic and thermal anisotropy for Bazhenov Fm rocks (Chekhonin et al., 2018). Regression equations are given in Table S10.

And CLTE along the bedding is usually 1.5-2 times less than across it (Gabova et al., 2020a; Wang et al., 2021; Lin et al., 2023). Analyzing the data from low thermal maturity Yanchang shales (Lin et al., 2023) (Fig. 8(b)), a decrease of the CLTE anisotropy with increasing TOC was established: $\alpha_{\parallel}/\alpha_{\perp} = \exp(-0.019\text{TOC})$.

The peculiarities of the OM distribution in organic-rich shales and the presence of clay minerals with bound water contribute to significant electrical anisotropy in oil shales. The electrical resistivity perpendicular to bedding can be up to 25-100 times greater than the resistivity parallel to bedding, while the ratio vary significantly across the section, even within a few meters (Sukhorukova, 2018). According to Revil et al. (2013), the electrical anisotropy of Bakken Fm samples is about 8 that is explained by the extremely high tortuosity of the electrical flow paths in the vertical direction, compared with less tortuous paths along the bedding. Josh et al. (2016) studied high maturity ($R_o = 2.9\%-3.25\%$) shale samples from the REM Fms (Australia) with narrow TOC range (1%-4%) and found that the dielectric permittivity is higher (up to 4 times depending on moisture and frequency) along the bedding than across it. They also studied wax- and graphene-loaded synthetic shales (paraffin and graphene were used to simulate non-conductive immature and highly-conductive overmature kerogen) and showed that the electric anisotropy growth significantly with increasing 'kerogen' content. Both

the dielectric and conduction anisotropy reach a maximum of 4.7 (or 12) as the volume percentage of the non-conductive (or conductive) component rises to 10%, i.e., the conductive OM can more greatly increase the anisotropy than the non-conductive OM.

4. Conclusions

There are five key factors explaining the complex nature of the effect of kerogen on physical properties of organic-rich shales. These factors include: (1) The high contrast between the properties of kerogen and the mineral matrix. (2) The alteration in kerogen properties with maturity, as lighter hydrocarbons are generated. (3) The organic porosity factor, which can appear at high maturity, either completely or partially negate the effect of factor 2. (4) The spatial distribution of kerogen. (5) The presence of a percolation effect for parameters such as permeability. At the same time, the analysis of the available data allows us to derive basic conclusions regarding the impact of kerogen on shale properties, which must be taken into account when dealing with such rock types.

As kerogen content increases, density, thermal conductivity, volumetric heat capacity, elastic wave velocities, Young's modulus, compressive strength, and tensile strength generally decrease, while thermal expansion, SSA, adsorption capacity, and total porosity increase. Regarding the porosity, this trend can be violated when kerogen porosity is negligible (owing

to immature kerogen or because of high effective stress with expulsion of the generated hydrocarbons). The Poisson ratio can exhibit positive, negative, or no correlations with TOC. Such complex behavior as well as violations of the trend between other elastic characteristics and TOC can be caused by various reasons. The reasons include mineralogical features (when increasing kerogen content is associated with the rise of those mineral components, which can have an opposite effect on elastic characteristics), structural features (heterogeneity, distribution of kerogen and pore space geometry), and spatial variation of stress field. Electrical resistivity typically shows a positive correlation with TOC in case of mature kerogen, a negative correlation for overmature kerogen, and may not correlate with TOC for immature kerogen. Regression analysis of published TOC and sorption capacity data shows that the methane sorption capacity of the dry mineral matrix is roughly 3-7 times higher than that of the moisture equilibrated matrix. Thomsen's parameters ϵ and γ , as well as the anisotropy in Young's modulus and thermal conductivity, increase with rising TOC in mature marine shales. Following theoretical estimations, the peak of anisotropy is reached at TOC of about 15-30% depending on the clay content and structural features. The electrical anisotropy is expected to increase significantly with the growth of TOC for shales with immature and overmature OM. Anisotropy in the CLTE decreases with increasing TOC (for shales of low thermal maturity).

Bulk density, porosity, SSA, elastic wave velocities, and Young's modulus of organic-rich shales generally increases with thermal maturity, while the Poisson's ratio, specific heat capacity, and strengths decreases. However, the generating hydrocarbons with the lower (relative to kerogen) density before their expulsion may violate the trend for density and Young's modulus. The gas sorption capacity generally positively correlate with R_o until the metagenesis stage ($R_o > 2\%$), where the correlation disappears. Electrical resistivity typically shows a positive correlation with R_o up to oil generation peak ($R_o \sim 0.85\%$), and a negative correlation after. Thomsen's parameters ϵ and γ change nonlinearly (with several maxima) with increasing level of thermal maturity.

Variations in bulk properties are closely tied to kerogen properties (Table S1), which contrast to rock matrix and alter during maturation. Kerogen exhibits notably lower density, thermal conductivity, and mechanical strength compared to the adjacent rock matrix. It is naturally more compliant (softer and more ductile) and has much higher CLTE than rigid framework minerals. As maturity increases, kerogen SSA, porosity, density, thermal conductivity, Young's modulus, CLTE, and the dielectric constant increase, while the specific heat capacity of kerogen decreases. Analysis of published data on the change in kerogen density with maturity reveals a growing difference in density since the end of the oil window ($R_o \sim 1.35\%$) for kerogen types II (with the new generalized relationship) and types II+III, III.

Analysis of our experimental data for Bazhenov Fm (a typical marine organic-rich shale) revealed that kerogen's thermal conductivity increases with maturation within the range of $R_o \sim 0.5\%$ -1.15%. It was established also that CLTE increases by 3-4 times in the temperature range 25-220 °C, with a

dramatic increase in 110-130 °C, i.e., at the peak oil generation temperature. Kerogen content influences the reduction rate of thermal conductivity of organic-rich shales with temperature: the less TOC, the greater the decrease. Corresponding relationship was established. It was demonstrated how the elastic (Young's modulus anisotropy, Thomsen's parameters ϵ and γ) and thermal anisotropy of the shales increase with increasing kerogen content (at $R_o \approx 0.55\%$ -0.85%). These dependencies yield cross-correlation, enabling the prediction of challenging anisotropy coefficients from a simpler determinable anisotropy coefficient.

The study cannot be considered as an exhaustive analysis covering all key publications, since the review covers only English and Russian-language literature. Moreover, a review of permeability and wettability, important physical characteristics of organic-rich shales, was not conducted in this study and remains a subject for future research. Combining heterogeneous studies (variations in objects/locations, methods and conditions of measurements) under lack of necessary information about type, maturity or TOC of studied objects make the research less transparent than desired. Nevertheless, performed analysis of gathered data allowed us to highlight knowledge/data gaps (related mainly to the effect of thermal maturity and kerogen type) and, therefore, directions of future research. It is necessary to study the effect of maturity on anisotropy in Young's modulus, thermal conductivity, CLTE, and electric properties, as well as on volumetric heat capacity. There is a lack of experimental data on Young's modulus of kerogen in case of naturally high-to-over-mature shales. The dependence of the thermal conductivity of kerogen on maturity requires clarification within the range $R_o = 0.5\%$ -1.15% and extrapolation outside this range. The outcomes of the research can be utilized also for accurate reservoir characterization, resource estimation, and improving the quality of corresponding numerical models-geomechanical models (for optimizing well trajectories, mitigating drilling risks, and designing hydraulic fractures), thermohydrodynamic models of kerogen conversion and/or oil and gas recovery from organic-rich shales.

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Supplementary file

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Conflicts of interest

The authors declare no competing interest.

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