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New rock typing method for diagenetically modified carbonate reservoirs

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The paper evaluates an efficiency of the existing rock typing methods for diagenetically modified carbonate reservoirs and proposes a new alternative rock typing index.

Four existing rock typing techniques are applied to the target formation, subjected to considerable diagenetic alterations. Applied techniques do not provide sufficient results in terms of reliable correlation between porosity, permeability and irreducible water saturation, which is crucial for geological modelling. Therefore, a new rock typing index named *KØS* and calculated as a function of permeability (k), porosity (φ) and irreducible water saturation (S_{wir}) is proposed for proper characterization of the carbonate formation. Contribution of depositional and diagenetic processes and associated microfeatures into parameters of the index is demonstrated by means of X-ray microCT and NMR experimental data.

Comparative analysis of the proposed index with the existing ones shows that the *KØS*-derived rock types demonstrate the highest correlation coefficients between the key reservoir parameters. The defined rock types have distinguishable microstructures that confirm validity of the rock classification approach.

All the entities of the *KØS* index are used for reserves calculations and commonly measured during routine core analysis: this enables its implementation at the most carbonate fields.

Keywords: carbonate rocks; diagenesis; rock typing; NMR; X-ray microCT; reservoir characterization; dolomitization; leaching

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1. Introduction

Carbonate rocks are characterized by complex void structure since they undergo abundant secondary geological processes during the diagenesis stage (Moore, 2001). Fracturing, fabric and non-fabric selective dissolution of mineral matrix and fossil skeletons increase primary depositional porosity, while the precipitation of cement from chemically active fluids can clog porous channels (Huang et al., 2017).

Rock typing is dividing rock samples into clusters that can be characterized by a common set of equations, describing relationships between the key rock parameters, used for the reserves and production rate calculation (Gholami et al., 2009; Shvalyuk et al., 2022a). Petrophysicists commonly apply permeability-porosity plots for rock typing of clastic rocks, which properties are considerably controlled by grain-size distribution, defined by depositional settings (Gholami et al., 2009). In contrast to clastic formations, distinguishing of carbonate rock type (RT) clusters on porosity-permeability plots is complicated due to significant diagenetic alterations (Al-Farisi et al., 2009; Buiting et al., 2013; Skalinski, 2013). Moreover, the resulted rock types often contradict to microstructural studies (Dernaika et al., 2018).

The Dunham scheme is widely used for classification of carbonate rocks based on their microtexture (Dunham, 1969). The Dunham classification provides semi quantitative characterization of grain size, defined mainly by depositional settings. However, Dunham classification does not enable proper rock typing due to several factors: (i) semi quantitative characterization can be subjective, and depends on a particular lithology specialist; (ii) development of secondary pores can completely overprint the original depositional rock microtexture.

In order to provide a quantitative carbonate rock typing, F.J. Lucia proposed a classification method based on combination of the porosity and permeability data with lithological classes defined by the Dunham scheme (Lucia, 2007). The Lucia method does consider grain size, however, it cannot discriminate the genesis of porosity and permeability (Rebelle et al., 2014; Dernaika et al., 2019).

Besides the Lucia classifier, other rock typing methods, such as standard and modified flow zone indexes (*FZI*) (Amaefule et al., 2006; Izadi, Ghalambor, 2013; Tiab et al., 2016), and Winland R35 (Kolodzie, 1980; Pittman, 1992; Mirzaei-Paiaman et al., 2018) are commonly applied for both clastic and carbonate formations (Skalinski et al., 2010, 2015; Fitzsimons et al., 2016; Haikel et al., 2018; Yarmohammadi et al., 2020). All these indexes are calculated as a function of porosity, permeability, and irreducible water saturation, and differ in the type of equation, which are derived for the particular formation accounting for its specifics. In the current research, we apply four existing rock typing indexes, which

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principally differ in their concepts and input parameters. The detailed information on their principles is described in subsection 2.1.

The most recent studies on carbonate rock typing utilize an integrated application of geological classifications (Dunham, 1969; Lucia, 1995; Loucks et al., 2012), microstructural parameters (Giao et al., 2017; Binabadat et al., 2019; Sun et al., 2019; Wang et al., 2020; Zhang et al., 2023) and hydraulic units concepts (Kolodzie, 1980; Tiab et al., 2016; Dakhelpour-Ghoveifel et al., 2019). The extensive use of microstructural characteristics for rock typing is currently available due to implementation of digital thin section analysis, microcomputed tomography (CT), scanning electron microscopy (SEM), and nuclear magnetic resonance (NMR) method. However, these costly high-resolution techniques are often either not affordable because of budget or time constrains, or not available in many laboratory facilities. Moreover, for brown fields, which require reassessment of reserves, microstructural digital data can be absent. In addition, it can be challenging to identify multiparametric rock types by means of well logging methods. This, in turn, leads to devaluation of the results of sophisticated approaches referenced above. Moreover, achieved feasible result for a particular reservoir does not guarantee the efficient application of similar approach for another formation.

The current research originates from an applied study, aimed at characterization of a carbonate formation, subjected to considerable diagenetic alterations. All attempts to apply the existing techniques fail to provide rock typing that could be further used for spatial modeling of the studied reservoir properties. In this work, we first provide a brief theoretical overview of the existing classification methods and evaluate their efficiency for rock typing of the studied carbonate formation. The novelty of this work is that we suggest an alternative integrated classification index, combining porosity, permeability and irreducible water saturation. In order to prove its efficiency, we scrutinize and validate consistency of the resulted rock types with microstructural characteristics, derived by various high-resolution experimental methods.

2. Materials and Methods

The current work consists of two parts: i) application of the existing methods of rock typing (modified *FZI* and Lucia *RFN* classifiers) for the target carbonate reservoir with diagenetic alterations (subsection 3.1) and ii) development of a new rock typing index that accounts the reservoir specifics (subsection 3.2). The efficiency of all applied rock typing methods is validated by routine (RCAL) and special core analysis (SCAL) results, comprising the key reservoir properties and microstructure. A general workflow of our research is depicted in Figure 1.

2.1 Information on Target Formation

The target field belongs to the Timan-Pechora Basin. The reservoir is composed of limestones and dolomites of the Famennian stage of the late Devonian period. The rock collection consists of 37 core plugs with an average size of 30×30 mm. The carbonate rock samples under study are subjected to partial dolomitization, leaching, and microfracturing. The average porosity of the samples varies from 4.1% to 21.3%, and the permeability – from 0.01 to 750 mD.

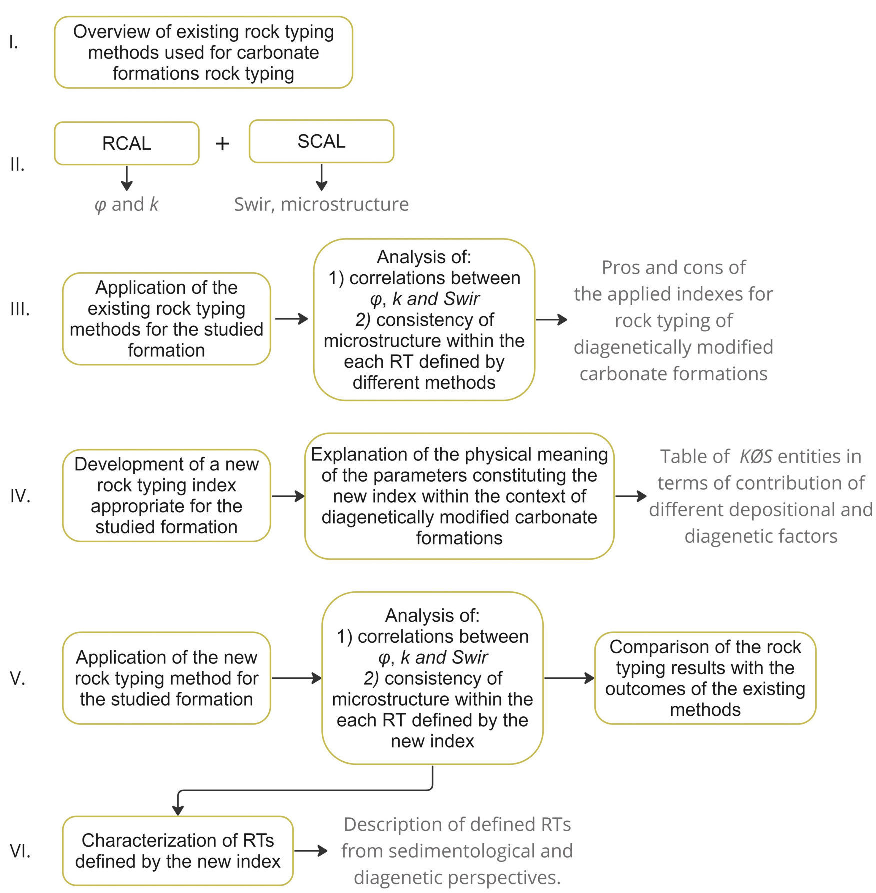


Fig. 1. A flowchart for reliable rock typing of diagenetically modified carbonate formation based on core data analysis

2.2 Overview of Rock Typing Methods

This section provides theoretical overview of the existing rock typing indexes that are successively applied in this study. These indexes utilize the key reservoir parameters, namely porosity (φ), permeability (k) and irreducible water saturation (S_{wir}).

Subdivision of samples between different rock types is done based on analysis of a cumulative frequency curve of the applied index values. The number of rock types is identified based on substantial changes in the cumulative curve trend. Samples, belonging to an interval with the same index frequency trend, are assigned to one rock type.

2.2.1 Flow Zone Indicator (FZI_1) as a Function of Porosity and Permeability

Amaefule et al. (2006) and Tiab et al. (2016) derived two complex parameters, namely reservoir quality index (*RQI*) and flow zone indicator (*FZI*), which can be applied to subdivide rocks by flow units:

$$RQI_1 = 3.14 \cdot \sqrt{\frac{k}{\varphi}} \quad (1)$$

$$FZI_1 = RQI_1 \cdot \frac{1-\varphi}{\varphi} \quad (2)$$

Since the coefficients are based on Kozeny-Carman equation, they shall sufficiently classify intergranular void structure, which fluid flow capacity depends on the grain sizes, sorting, and shapes. Since all these characteristics depend on the energy of deposition, the rock types, derived from *FZI*, theoretically can also be differentiated based on depositional settings (Tiab et al., 2016), unless diagenesis overprints the primary porosity network.

Presumption that the rocks with the same *FZI* value belong to the same lithofacies, and thus have the same pore types, explains high correlation between permeability and porosity within *FZI*-derived rock types, often observed in clastic reservoirs. Consequently, 3D distribution of such reservoir properties can efficiently be done based on depositional model.

2.2.2 Modified FZI_2 as a Function of Porosity and Irreducible Water Saturation

The second rock typing index (FZI_2) is calculated as a function of φ and S_{wir}:

$$RQI_2 = 3.14 \cdot \frac{\varphi \cdot (1 - S_{wir})}{\varphi - \varphi \cdot (1 - S_{wir})} \cdot \sqrt{\varphi^3} \quad (3)$$

$$FZI_2 = RQI_2 \cdot \frac{1-\varphi}{\varphi} \quad (4)$$

This index appears to be most effective for low-permeable rocks, which measurement of S_{wir} values can be much more accurate than k, if values of the latter are close to the lower limit of measurement of a standard permeameter (Shvalyuk et al., 2022b). FZI_2 classes, similarly to FZI_1 ones, can be associated with depositional facies. For clean high-permeable clastic reservoirs applying these indexes produces similar rock types.

2.2.3 Modified FZI_3 as a Function of Porosity, Permeability, and Irreducible Water Saturation

The third flow zone indicator (FZI_3) is derived from Poiseuille's and Darcy's equations. It is calculated as a function of φ, k and S_{wir} (Izadi, Ghalambor, 2013):

$$FZI_3 = \frac{3.14\sqrt{\frac{k}{\varphi}} \cdot (1 - S_{wir})}{\frac{\varphi}{1-\varphi}(1 - S_{wir})^2} \quad (5)$$

The index integrates all key reservoir parameters, and theoretically shall account for the bulk rock properties, as well as for void structure characteristics.

2.2.4 Lucia Rock Typing Method for Carbonate Reservoirs (RFN): Function of Porosity and Permeability

F.J. Lucia proposed specifically for classification of carbonate rocks Rock Fabric Number (*RFN*), which integrates φ and k (Lucia, 1995):

$$RFN = 10^{\left(\frac{C \cdot log\varphi + A \cdot logk}{D \cdot log\varphi + B}\right)} \quad (6)$$

where coefficient A = 9.7982; B = 12.0838; C = 8.6711; D = 8.2965.

2.3 Experimental Workflow of Core Analysis

First, the samples are cleaned from hydrocarbons by toluene and methanol in a Soxhlet extractor. Then the samples are dried, and their helium porosity and permeability are measured. The dry samples are analyzed with X-ray microcomputed tomography (CT). Further they are saturated with a model of brine (NaCl) and subjected to low-field nuclear magnetic resonance (NMR). Upon completing NMR tests of the samples in fully saturated state (S_w = 100%), their centrifuging is performed in gas-brine system in order to measure S_{wir}.

Samples are dried until reaching constant weight at a temperature of 105 °C under vacuum in an automatic oven. Porosity and permeability are measured using an automated porosimeter-permeameter in a Hassler core holder using helium.

X-ray microCT-scanning is performed for a central part of samples for a virtual cylinder with a height and diameter of 10 mm. The applied resolution – 5 μm/voxel. The results of microCT-scanning include 2D images, 3D models of opened and closed pores and pore radius distribution.

For centrifuging and NMR, the samples are saturated under vacuum with NaCl solution with mineralization of 180 g/L. The selected NaCl concentration corresponds to ionic strength and electrical resistivity of the formation water. Centrifuging is performed with stepwise capillary pressure increase up to 1.5 MPa (16 steps).

NMR relaxometry theoretically allows obtaining a detailed characterization of the whole range of pore size distribution from the measured transverse relaxation time (T_2) curve. For a fully water-saturated rock the T_2 value of a single pore is proportional to its surface-to-volume ratio. It is widely accepted that the surface relaxation mechanism dominates in rock porous medium (Coates et al., 1999; Pires et al., 2019; Wu et al., 2019). Thus, the calculation of pore sizes distribution from T_2-spectra can be done by means of the following formula (Zhao et al., 2017):

$$\frac{1}{T_2} = \frac{1}{T_{2\,surface}} = \rho \cdot \frac{S}{V} = \rho \cdot \frac{3}{r_c} \quad (7)$$

where ρ is surface relaxivity (μm/s); S/V is the surface-to-volume ratio.

Applying an average surface relaxivity value for carbonate rocks from literature can result in considerable errors. Thus, in order to account for variability of this parameter, NMR-derived spectrum for each sample is calibrated on the capillary pressure test and microCT data (Hidajat et al., 2004; Fleury et al., 2007). As a result, highly detailed pore radius distribution curves are obtained within the whole detected range from 0.01 up to 600 μm.

Based on their size, pores can be classified as nano-, micro- and mesopores (Loucks et al., 2012; Sokolov et al., 2013; Lu et al., 2021). The nanopores are presumed to have pore radii less than 1 μm, micropores – from 1 to 62.5 μm, and mesopores – larger than 62.5 μm (Fleury et al., 2007; Da Silva et al., 2015; Lima et al., 2020). Nanopores are filled with bound water (Westphal et al. 2005), while the other two types contain free water as well (Hidajat et al., 2004; Müller-Huber et al., 2016; Markovic et al., 2022).

3. Results and Discussion

3.1 Comparative Analysis of Efficiency of Different Rock Typing Methods for Carbonate Reservoirs Characterization

The applied rock typing indexes are calculated using porosity (φ) and irreducible water saturation (S_{wir}), and permeability (k). The first two parameters are rock bulk properties, while permeability, being dependent on the total effective pore volume, also characterizes the pore network morphology.

In order to assess the efficiency of different rock typing methods, the relationships between porosity (φ), permeability (k), irreducible water saturation (S_{wir}) and structural coefficient $(k/\varphi)^{1/2}$ are constructed and analyzed (Figures 2–5). The criteria of methods' efficiency include i) the value of determination coefficient (R^2) between porosity, permeability and irreducible water saturation; and ii) the consistency in microstructural characteristics within one RT. If the determination coefficient is less than 0.25 within a rock type, efficiency of the rock typing index is considered to be low. If determination coefficient has value between 0.25 and 0.49, than the efficiency is moderate. Rock typing index efficiency ranked as high, if $0.49 \leq R^2 \leq 0.81$, and very high, if $R^2 > 0.81$.

3.1.1 FZI_1 and RFN

The regressions between the referenced above parameters for FZI_1 and *RFN* are shown in Figures 2 and 3 accordingly. The correlation between φ and k (Figures 2a, 3a), within each FZI_1 and *RFN*-derived rock type, demonstrate a high value of R^2. It is, however, expected since these indexes are calculated based on φ and k values. Correlations between S_{wir} and k (Figures 2b, 3b), S_{wir} and $(k/\varphi)^{1/2}$ (Figures 2c, 3c), are characterized by lower R^2 values than those for φ and k, because these rock typing indexes do not include S_{wir} in their formula. In general, efficiency of *RFN* and FZI_1 can be estimated as high and moderate, correspondingly. Although, application of *RFN* produces several rock types that form statistically unrepresentative clusters at the cross-plots and illogical correlations between the key parameters (e.g. for 1st RT and 4th RT).

Unfortunately, a little constancy in microstructure is observed within the rock types, defined by means of FZI_1 and *RFN*. The samples within the rock types are characterized by wide variation of microtextures, mineralogy and pore network characteristics, determined by microCT, capillary and NMR tests (discussed in details further).

3.1.2 FZI_2

FZI_2 is calculated based on bulk properties, namely φ and S_{wir}. The FZI_2-derived classes can be separated by threshold values of porosity, permeability and irreducible water saturation at the corresponding cross-plots φ–k (a), k–S_{wir} (b) and S_{wir}–$(k/\varphi)^{1/2}$ (c) in Figure 4. Theoretically, that enables distinguishing the classes along a borehole by applying the boundary values to the corresponding well logs. However, correlations between the parameters are characterized by low determination coefficients. Thus, this index cannot be considered as efficient for carbonate rock typing.

3.1.3 FZI_3

Since FZI_3 index includes all main rock characteristics, i.e. φ, k, S_{wir}, the first suggestion is that it could be effective for carbonate rock typing. However, despite the complexity,

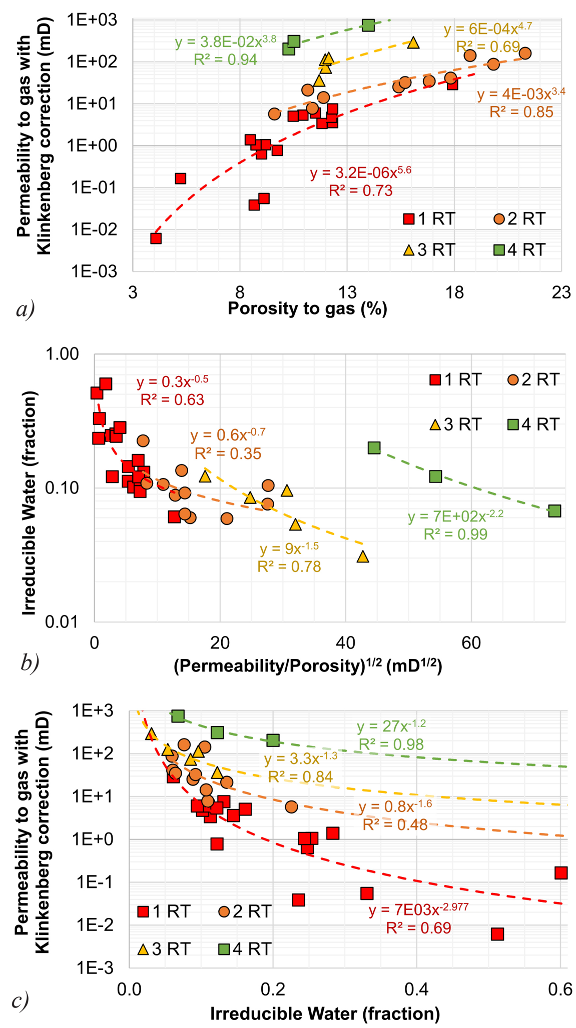


Fig. 2. FZI_1 rock typing: cross-plots of a) permeability versus porosity; b) permeability versus irreducible water saturation; c) irreducible water saturation versus structural coefficient

this index produces controversial rock typing in terms of distribution of samples between the classes, determination coefficients, and microstructures (Figure 5). For example, more than half of the samples are allocated to the 1st rock type (1st RT). Although this rock type is characterized by moderate and high R^2 values, the samples have considerably different microstructures. The other three RTs with very limited number of samples have much lower values of R^2 and little consistency in microstructure within the rock types. Consequently, the efficiency of FZI_3 for rock typing of carbonates cannot be considered as high.

3.1.4 Summary on Rock Typing Methods Application

The performance of the discussed rock typing methods for diagenetically modified carbonate rocks is summarized in Table 1. In addition, the values of R^2 determination coefficient for all utilized methods are demonstrated in Table 2. The applied rock typing indexes are based on the reservoir models that do not properly incorporate both depositional and diagenetic process contribution into permeability, porosity and irreducible water saturation of the studied carbonate reservoir. Therefore, results of methods performance show that their application does not enable obtaining both hydraulically and geologically meaningful differentiation of the samples for the target reservoir.

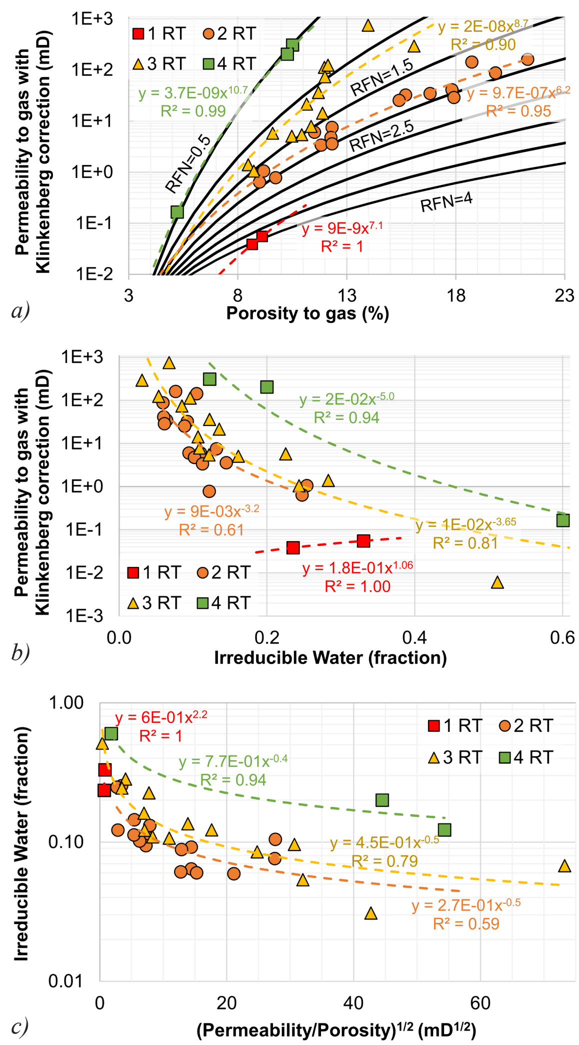


Fig. 3. RFN rock typing: cross-plots of a) permeability versus porosity; b) permeability versus irreducible water saturation; c) irreducible water saturation versus structural coefficient

3.2 Proposed Rock Typing

According to the results of the comparative analysis, none of the applied methods produces sufficiently effective rock typing for diagenetically modified carbonate reservoir. This motivated us for development of an alternative index for rock typing of such formations. The index should primarily reflect relative contribution of depositional and diagenetic process into permeability, porosity and irreducible water saturation, in order to enable geologically and hydraulically meaningful differentiation of the samples. Measurement of these parameter is quite abundant that insures statistically representative dataset. While microCT and NMR tests are time-consuming, costly, and usually performed for limited number of samples. Thus, they can be more effectively used to verify the established rock types and review the boundaries between them, rather than for mass rock typing.

3.2.1 KØS Rock Typing Index Definition

The equation for the proposed rock typing index, namely *KØS*, is as follows:

$$KØS = \log \frac{(k/\varphi)^{1/2}}{\frac{1-S_{wir}}{S_{wir}}} \quad (8)$$

In the following paragraphs we discuss the physical meaning of the parameters that constitute the new index.

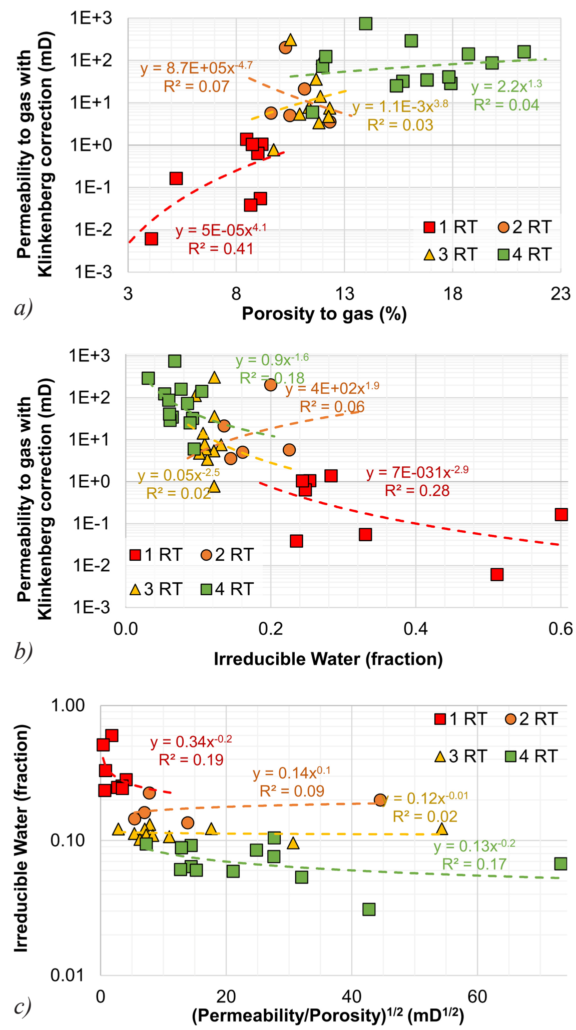


Fig. 4. FZI_2 rock typing: cross-plots of a) permeability versus porosity; b) permeability versus irreducible water saturation; c) irreducible water saturation versus structural coefficient

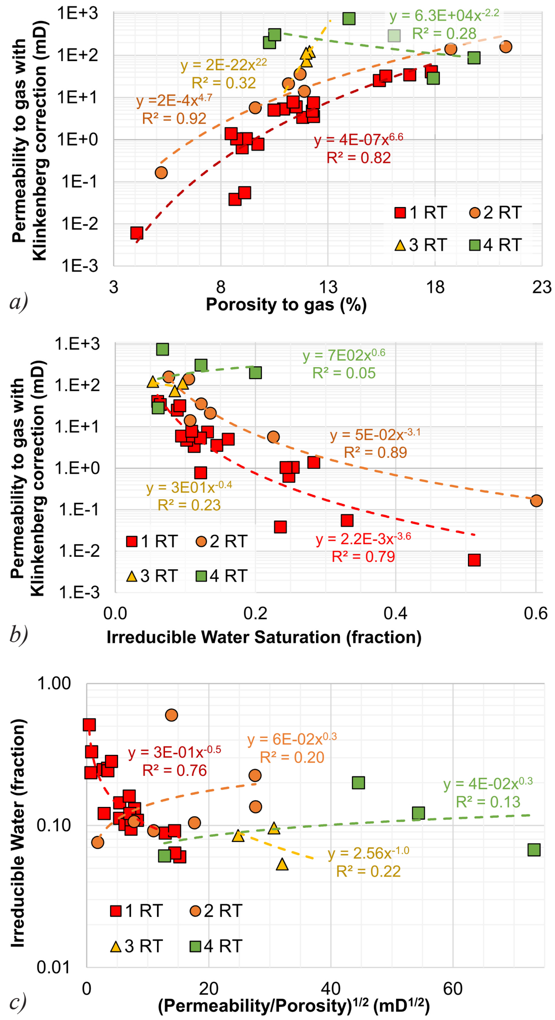


Fig. 5. FZI_3 rock typing: cross-plots of a) porosity-permeability; b) irreducible water saturation versus permeability; c) structural coefficient (the square root of the permeability to porosity ratio) versus irreducible water saturation

Next, we consider their possible combinations for different types of diagenetically modified carbonates, illustrated by microCT images, and finally we evaluate the efficiency of the proposed index in terms of correlations between the key reservoir properties.

The structural coefficient $(k/\varphi)^{1/2}$, calculated as the square root of the permeability to porosity ratio, reflects void network morphology, defined by the pores size and shape, connectivity and tortuosity . The structural coefficient is widely applied in hydrodynamic modelling (Tiab et al., 2012; Chiu et al., 2018). In carbonate rocks, higher $(k/\varphi)^{½}$ values reflect higher contribution of interconnected leached channels into permeability in comparison with the primary depositional pores.

The ratio of free fluid content $(1–S_{wir})$ to S_{wir}, characterizes the fraction of larger pores, contributing to permeability, to the smaller ones filled in with bound water. The smallest pores are mainly associated with depositional microtextures, while larger pore channels, being the main flow passes, are formed as the result of diagenetic dissolution. Therefore, the ratio $(1–S_{wir})/S_{wir}$ can be considered as a ratio coefficient between diagenetic and depositional porosity, although this assumption is not completely valid because some part of depositional pores also contribute to permeability in carbonates. Table 3 describes possible combinations of permeability, porosity, and irreducible water saturation values in carbonate rocks from sedimentological and diagenetic perspectives.

3.2.2 KØS-based Rock Types

Within the studied sample collection four rock types are identified by means of *KØS* index. The 1st RT has the worst reservoir quality and the lowest *KØS* value, whereas the 4th RT has the best reservoir quality and the highest *KØS* value. The characteristics of the rock types are shown in Table 4.

3.2.3 Relationships between Porosity, Permeability and Irreducible Water Saturation within the Identified Rock Types

The *KØS* rock typing enables obtaining reliable regressions between the key reservoir parameters for each RT (Figures 6–7). Since these regressions are used for geological and flow modelling, high values of the determination coefficients are of great importance (Table 5).

The defined RTs form distinguishable clusters characterized by individual correlation equations between the permeability and porosity (Figure 6). Determination coefficients are relatively high for all rock types, except for the first one (Table 5). The dispersion of permeability within this RT (Table 5) is caused by presence of leached channels in one of the samples (sample #15 with a permeability of 0.78 mD). Nevertheless, as discussed further, the assignment of all five samples to the same class is valid from a microstructural point of view and based on a high correlation of irreducible water saturation with other parameters (Table 5, Figure 7).

Irreducible water saturation is commonly calculated based on a correlation with porosity. However, in carbonates subjected to diagenetic dissolution the correlation between these parameters is relatively low. In our study, we explore dependency of irreducible water saturation from permeability and structural coefficient (Lucia, 2007). Within all *KØS* rock types determination coefficients between irreducible water saturation and these parameters have remarkably high values (Figures 7a and 7b).

The high values of the determination coefficients within the *KØS* rock types support the validity and applied value of the proposed classification index.

3.2.4 Microstructural Characterization of KØS Rock Types

Microstructural characterization of the defined RTs is provided based on the analysis of microCT and NMR data. CT-scans provides characterization of the rock mineral composition, microtexture, and pore network (Figures 8, 9). NMR enables construction of a complete pore size distribution curve (Figure 10).

The translation of the T_2 values into pore sizes distribution is provided by means of the equation 7. In order to select a proper value of surface relaxivity coefficient (ρ), T_2-spectra are calibrated on the pore sizes distributions, derived from microCT and capillary tests (Coates et al., 1999; Shvalyuk et al., 2022b). The values of ρ for each RT are listed in Table 4.

The 1st RT is composed of dolomite mudstone, according to the microCT-images. The dolomite content (C_{dol}) amounts to more than 97%. The porosity varies from 3 to 10%, while the permeability does not exceed 1 mD. The porosity is represented by isolated intergranular pores and vugs

Method	Pros	Cons
FZI_1	• High determination coefficient in correlation between φ, k. • The concept bases on the difference in grain and pore morphology (size, shapes, etc.), theoretically enabling mapping the rock types with depositional settings.	• Regressions between S_{wir} and permeability / structural coefficient have insufficient correlation, because dissolution can considerably increase permeability due to development of pore channels, while the leaching effect on S_{wir} can be diverse. • Defined rock types can considerably vary in microstructure that creates difficulties in their geological interpretation. • Thus, this index should be used mainly for rocks with primary intergranular porosity.
RFN	• High determination coefficient in correlation between φ, k, S_{wir}. • The fabric number of a rock reflects its grain-size distribution and consequently can be mapped to Dunham classes.	• The defined rock types can form statistically unrepresentative clusters at φ, k, S_{wir} cross-plots and controversial correlations between the key parameters. • Defined rock types can considerably vary in microstructure that creates difficulties in their geological interpretation. • Thus, this index should be used mainly for rocks with primary intergranular porosity.
FZI_2	• The rock types can be separated by threshold values of porosity, permeability and irreducible water saturation at the corresponding cross-plots. • Theoretically this enables distinguishing these classes along a borehole by applying the boundary values to the corresponding well logs. • The rock types form distinguishable groups of curves at $S_{wir} – P_c$ graphs	• Correlations φ, k, S_{wir} between the parameters are characterized by low determination coefficients. • Defined rock types largely vary in microstructure that creates difficulties in their geological interpretation.
FZI_3	• FZI_3 index includes all main rock characteristics, namely φ, k, S_{wir}.	• Despite the complexity, this index produces controversial rock typing in terms of distribution of samples between the classes, determination coefficients, and microstructures.

Table 1. Comparative analysis of the efficiency of the applied existing methods for rock typing of diagenetically modified carbonates

Method	Porosity vs. Permeability	Irreducible water saturation vs. Permeability	Irreducible water saturation vs. Structural coefficient
FZI_1	1st RT: R^2 = 0.73 2nd RT: R^2 = 0.85 3rd RT: R^2 = 0.69 4th RT: R^2 = 0.94	1st RT: R^2 = 0.69 2nd RT: R^2 = 0.48 3rd RT: R^2 = 0.84 4th RT: R^2 = 0.98	1st RT: R^2 = 0.63 2nd RT: R^2 = 0.35 3rd RT: R^2 = 0.78 4th RT: R^2 = 0.99
RFN	1st RT: R^2 = 1.00 2nd RT: R^2 = 0.95 3rd RT: R^2 = 0.90 4th RT: R^2 = 0.99	1st RT: R^2 = 1.00 2nd RT: R^2 = 0.61 3rd RT: R^2 = 0.81 4th RT: R^2 = 0.94	1st RT: R^2 = 1.00 2nd RT: R^2 = 0.59 3rd RT: R^2 = 0.79 4th RT: R^2 = 0.94
FZI_2	1st RT: R^2 = 0.41 2nd RT: R^2 = 0.07 3rd RT: R^2 = 0.03 4th RT: R^2 = 0.04	1st RT: R^2 = 0.28 2nd RT: R^2 = 0.06 3rd RT: R^2 = 0.02 4th RT: R^2 = 0.18	1st RT: R^2 = 0.19 2nd RT: R^2 = 0.09 3rd RT: R^2 = 0.02 4th RT: R^2 = 0.17
FZI_3	1st RT: R^2 = 0.82 2nd RT: R^2 = 0.92 3rd RT: R^2 = 0.32 4th RT: R^2 = 0.28	1st RT: R^2 = 0.79 2nd RT: R^2 = 0.89 3rd RT: R^2 = 0.23 4th RT: R^2 = 0.05	1st RT: R^2 = 0.76 2nd RT: R^2 = 0.20 3rd RT: R^2 = 0.22 4th RT: R^2 = 0.13

Table 2. The values of determination coefficient (R^2) between porosity, permeability and irreducible water saturation correlations obtained using four existing rock typing methods (RT_1–RT_4)

of nano- and microsize, thus, the rock type has the lowest permeability among the other rock classes (Table 4).

The 2nd RT can be subdivided into two subgroups different in the dolomite content. The 1st subgroup composed of dolomitized (C_{dol} = 30 ÷ 70%) wackestone/packstone with isolated nano- and interconnected micropores (Figures 9, 10). The 2nd subgroup consists of packstones with less dolomite content, varying from 0% to 30%. Porosity is represented by isolated vugs and interconnected dissolution-enhanced channels of microsize. The porosity and permeability of the 1st subgroup have lower ranges in comparison with the 2nd subgroup (Table 4). Thus, increase of dolomite cementation causes feasible reduction of permeability due to deterioration of the pores connectivity. Since the both subclasses have similar microtextures and pore types, which define the permeability and irreducible water saturation, these subclasses form consistent correlations between the reservoir properties, and are assigned to the same rock type.

The 3rd RT includes grainstones, which can also be divided into two subgroups according to their mineralogical composition. The 1st subgroup is represented by dolomitized limestone (C_{dol} = 20 ÷ 40), while the 2nd subgroup is composed completely of limestone (C_{dol} = 0 ÷ 8). Permeability of the both subclasses is controlled by dissolution-enlarged channels of micro and mesosize. As the result, despite on different dolomite content, the subgroups have comparable ranges of reservoir properties with high correlations that justifies assignment of the samples to the same rock type.

The 4th RT comprises wackestones/packstones that have the highest permeability values (Table 4) among the all rock types due to developed system of interconnected microfractures and dissolution channels of mesosize. Since the rock matrix contains a large proportion of fine carbonate mud, S_{wir} values can reach up to 20%.

The study shows that each rock type has distinguishable microstructural characteristics controlled by contribution of depositional settings and diagenetic process (mainly dissolution and dolomite cementation). Dolomite cementation

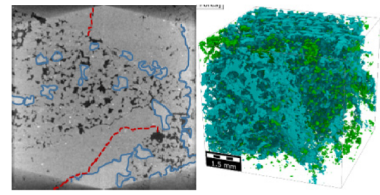
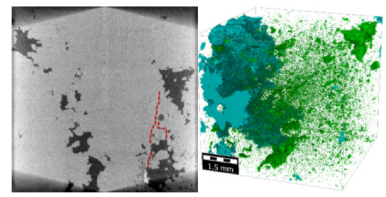
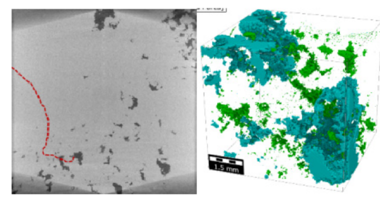
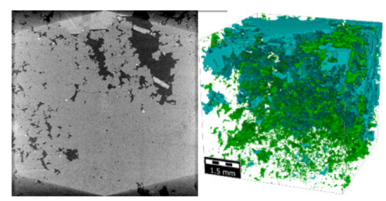
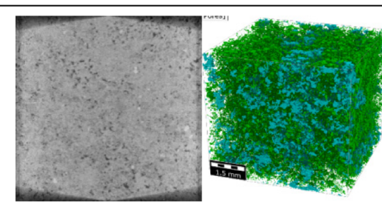
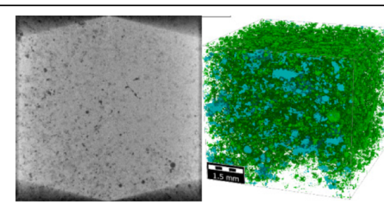
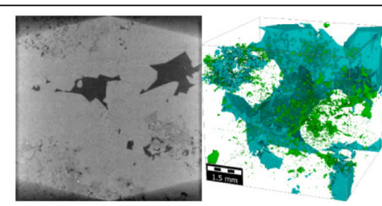
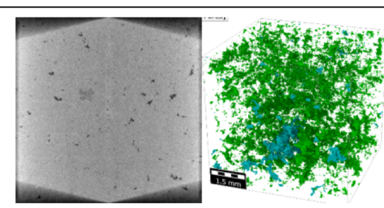
	Permeability (*k*) and porosity (φ) values	Irreducible water saturation values (S_{wir})	Characteristic microCT-scans
1	High *k* / High φ (filtration via intergranular pores and leached channels)	1. High $\frac{1-S_{wir}}{S_{wir}}$ (low S_{wir}) – grainstone / bindstone with well connected porous network, possibly enhanced by dissolution.	
		1.2 Low $\frac{1-S_{wir}}{S_{wir}}$ (high S_{wir}) – micrite-rich carbonate rock (e.g. wackestone, packstone) considerably leached or fractured.	
2	High *k* / Low φ (filtration via fractures / leached channels)	2.1 High $\frac{1-S_{wir}}{S_{wir}}$ (low S_{wir}) – cemented carbonate rock subjected to diagenetic fracturing possibly enhanced by dissolution.	
		2.2 Low $\frac{1-S_{wir}}{S_{wir}}$ (high S_{wir}) – micrite-rich carbonate rock (mudstone / wackstone) with fractures possibly enhanced by leaching.	
3	Low *k* / High φ (filtration is restricted with poor connectivity of pores)	3.1 High $\frac{1-S_{wir}}{S_{wir}}$ (low S_{wir}) – cemented carbonate rock with abundant poorly-connected or isolated pores (e.g. vugs).	
		3.2 Low $\frac{1-S_{wir}}{S_{wir}}$ (high S_{wir}) – micrite-rich carbonate rock (e.g. wackestone / packstone), with isolated pores and thin pore throats filled in mainly with bound fluid; not subjected to diagenetic leaching.	
4	Low *k* / Low $\varphi \rightarrow$ tight rock (filtration is restricted with low porosity)	4. High $\frac{1-S_{wir}}{S_{wir}}$ (low S_{wir}) – cemented carbonate rock (with high content of spirite).	
		4.2 Low $\frac{1-S_{wir}}{S_{wir}}$ (high S_{wir}) – micrite-rich carbonate rock (e.g. mudstone / wackestone) with poorly or not developed porous network.	

Table 3. Theoretical analysis of KØS entities in terms of contribution of different depositional and diagenetic factors

RT	Lithology and Dominant Pore Size	Dominant type of Porosity	*KØS* (m)	*φ* (%)	*k* (mD)	S_{wir} (%)	C_{dol} (%)	*ρ* (μm/s)
1st RT	Dolomite mudstone with isolated nano- and micropores	Isolated interparticle pores and vugs	< -0.2	4÷10	0.01÷0.78	12÷60	>97	2.2
2nd RT (subgroup #1)	Dolomitized wackestone/packstone with isolated nano- and interconnected micropores	Vugs and interconnected channels	-0.2÷0.13	8÷17	0.6÷35	6÷28	30÷70	2.9
2nd RT (subgroup #2)	Packstone with interconnected micopores	Interconnected channels and vugs	-0.2÷0.13	10÷20	3.6÷88	6÷16	<30	5.2
3rd RT (subgroup #1)	Dolomitized grainstone with interconnected micropores	Dissolution-enlarged channels	0.13÷0.69	12÷16	32÷294	3÷10	20÷40	7.0
3rd RT (subgroup #2)	Grainstone with interconnected micro- and mesopores	Dissolution-enlarged channels	0.13÷0.69	11÷21	16÷162	8÷14	<8	11.1
4th RT	Wackestone/Packstone with interconnected mesopores	Large dissolution channels and microfractures	>0.69	10÷14	203÷750	7÷20	<5	17.3

Table 4. Summary table of KØS-derived rock types quantitative characteristics

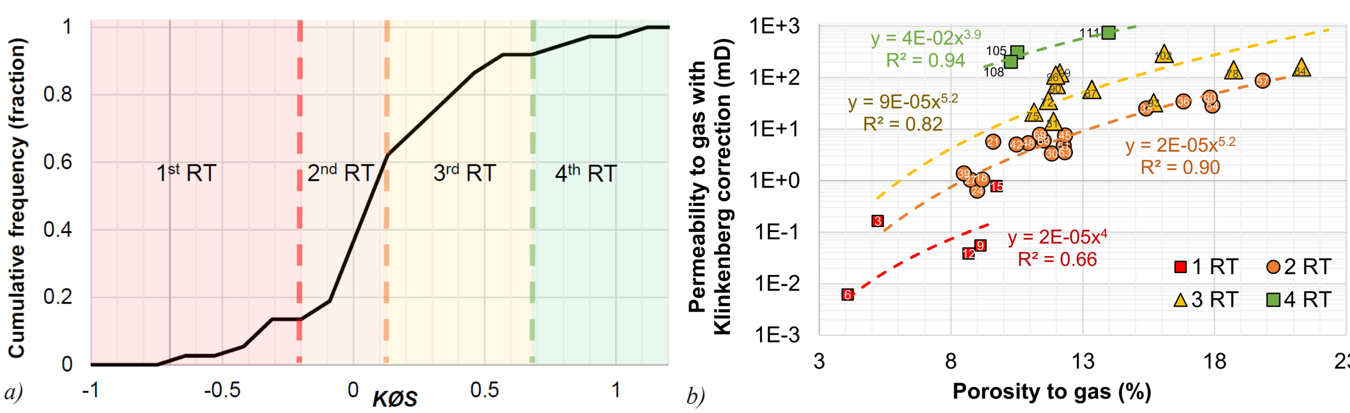


Fig. 6. a) Cumulative frequency curve of KØS; b) Porosity-permeability cross-plot. Color of points corresponds to the rock types defined by KØS parameter.

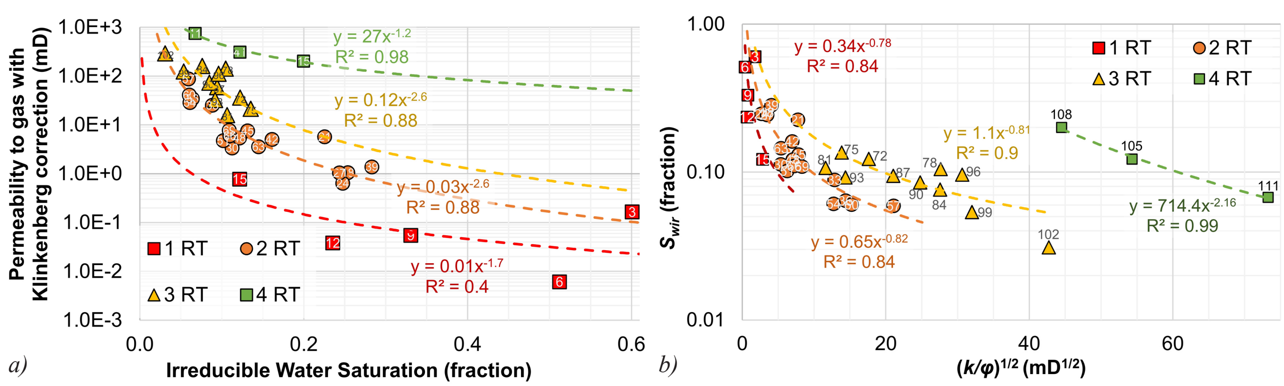


Fig. 7. a) Irreducible water saturation versus permeability cross-plot; b) The structural coefficient (the square root of the permeability to porosity ratio) versus irreducible water saturation cross-plot. Colour of points corresponds to rock types defined by KØS parameter

Method	Porosity vs. Permeability	Irreducible water saturation vs. Permeability	Irreducible water saturation vs. Structural coefficient
KØS	1st RT: R^2 = 0.66 2nd RT: R^2 = 0.90 3rd RT: R^2 = 0.82 4th RT: R^2 = 0.94	1st RT: R^2 = 0.40 2nd RT: R^2 = 0.88 3rd RT: R^2 = 0.88 4th RT: R^2 = 0.98	1st RT: R^2 = 0.84 2nd RT: R^2 = 0.84 3rd RT: R^2 = 0.90 4th RT: R^2 = 0.99

Table 5. The values of determination coefficient (R^2) between porosity, permeability and irreducible water saturation correlations obtained using KØS rock typing method

reduces the reservoir quality. Dissolution of primary pores and fractures leads to development of interconnected vugs and channels, which become the main contributors to the permeability.

4. Summary and Conclusions

The paper provides an extended comparative analysis of four existing classification methods, evaluates their efficiency regarding rock typing of carbonate formations, and proposes a new alternative rock typing index. We can highlight the most important points as follows:

1. The results demonstrate that the existing techniques (modified *FZI*, Lucia-*RFN* classifiers) do not enable reliable rock typing that could be further used for spatial modeling of the diagenetically modified carbonate reservoirs. This is mainly caused by the fact that these models do not properly incorporate both depositional and diagenetic process contribution into permeability, porosity and irreducible water saturation of such carbonate reservoirs. Therefore, their application does not enable obtaining both hydraulically and geologically meaningful differentiation of the samples.

2. The research suggests a new rock typing index that proved to be efficient for classifying diagenetically modified carbonate reservoirs. This proposed index (*KØS*) is a function of integrated parameters, derived from permeability (k), porosity (φ), and irreducible water saturation (S_{wir}) (Equation 8). The contribution of depositional and diagenetic processes and associated microfeatures into the integrated parameters is investigated using experimental studies (Table 3). Comparative analysis of the efficiency of the new index with the existing ones shows that the *KØS*-derived rock types have the highest determination coefficients (values varies from 0.40 up to 0.99 with an average R^2 equal to 0.84) between the permeability, porosity and irreducible water saturation (Tables 2 and 5).

3. The defined *KØS* rock types have distinguishable microstructures (Table 4, Figures 8–10) that confirm validity of the rock classification approach. The permeability trends within the rock types is associated with two major digenetic process – dissolution and dolomite cementation. Development of dissolution porosity considerably increases permeability, while S_{wir} can remain relatively high, if the rock matrix is rich with micrite.

4. The new *KØS* rock typing index produces the consistent geologically-minded classification of the studied diagenetically modified carbonate reservoir due to integrating the key parameters, responding to both depositional and diagenetic settings. All the entities of the *KØS* index are used for reserves calculations and, thus, are commonly measured during petrophysical laboratory study. The index can be recommended for further application for carbonate reservoirs.

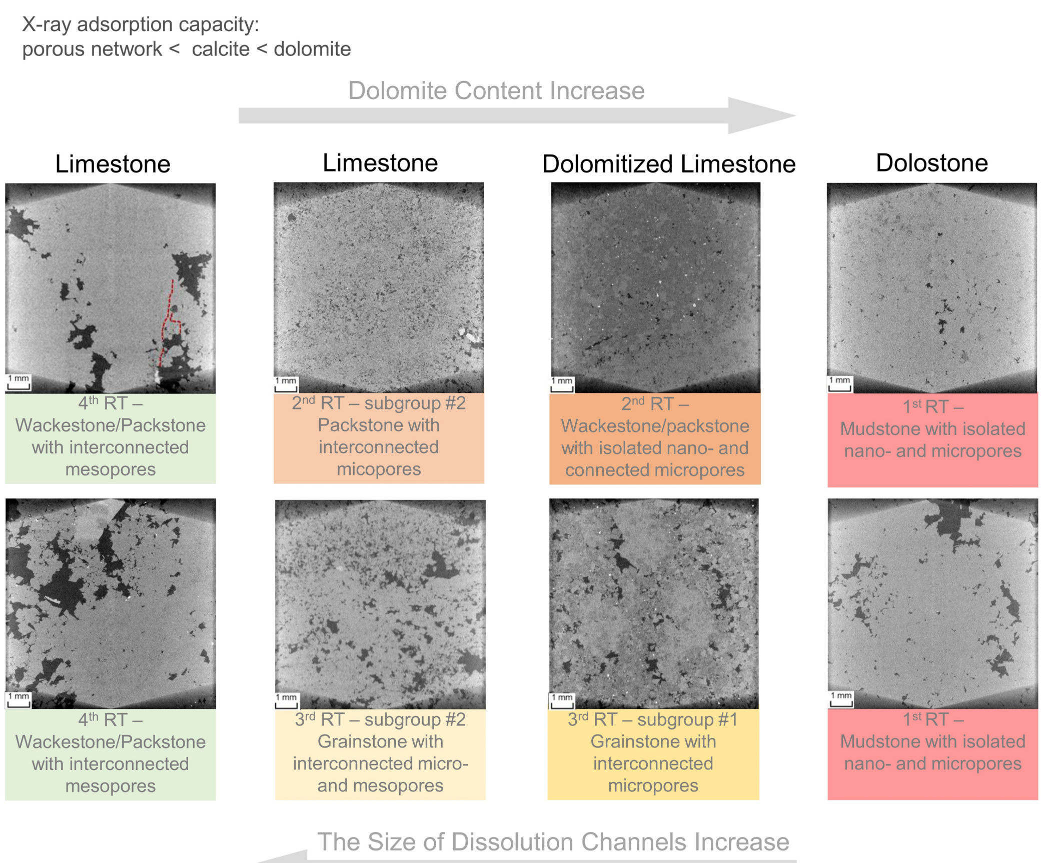


Fig. 8. Alteration of the microstructure within the KØS rock types

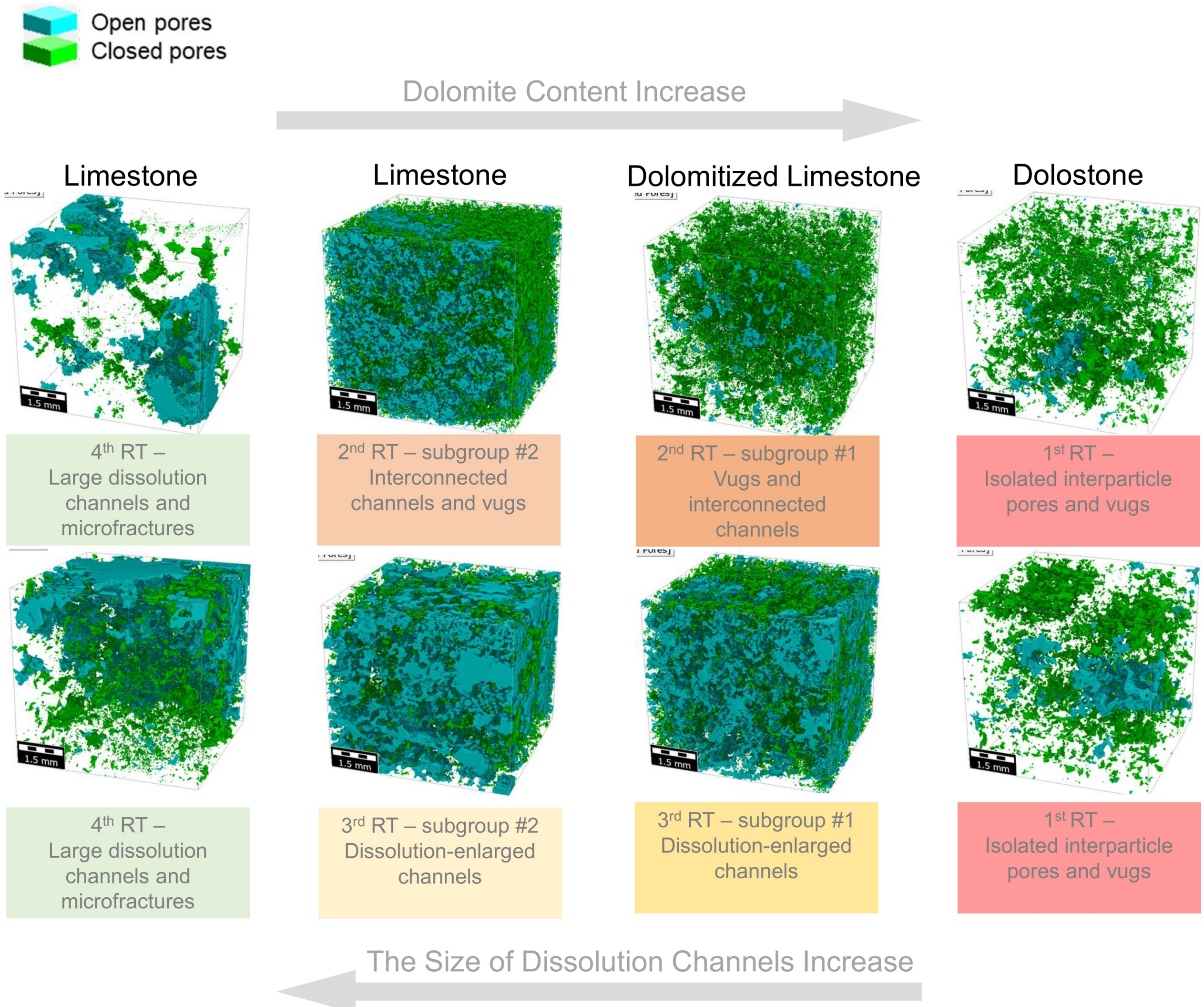


Fig. 9. Alteration of the void structure within the KØS rock types.

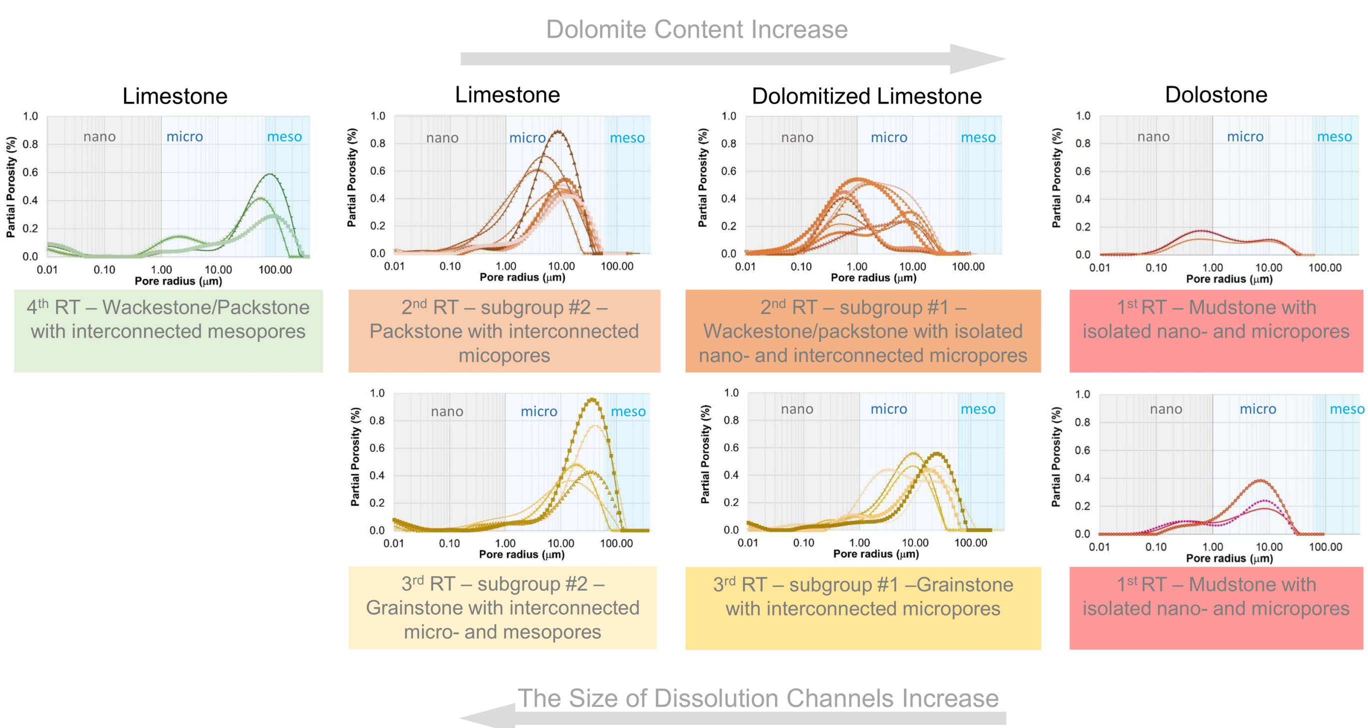


Fig. 10. NMR-derived pore size distributions for different KØS rock types

Nomenclature

C_{dol} – dolomite content, %
CT, microCT – X-ray microcomputed tomography
FZI – flow zone index
KØS – new rock typing index
NMR – nuclear magnetic resonance
R^2 – determination coefficient
r_c – pore throat radius, mAcknowledgments
RFN – rock fabric number
RT – rock type
RQI – reservoir quality index
k – absolute permeability, mD
$(k/\varphi)^{1/2}$ – structural coefficient, m
φ – total porosity, %
ρ – surface relaxivity, µm/s
S/V– the surface-to-volume ratio, m^{-1}
S_w – water saturation volume, %
S_{wir} – irreducible water saturation volume, %
T_2 – relaxation time, s

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Scientific supervision and text reviewing: A. Tchistiakov, M. Spasennykh.

Funding acquisition: A. Tchistiakov, M. Spasennykh.

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ОРИГИНАЛЬНАЯ СТАТЬЯ

Новый метод рок-типизации диагенетически преобразованных карбонатных пород

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В статье проводится сопоставление эффективности применения существующих методов рок-типизации карбонатных пород и предлагается альтернативный классификатор.

Для рок-типизации карбонатного коллектора, подвергшегося интенсивному диагенезу, были использованы четыре известных индекса. Однако выделенные с их помощью рок-типы характеризовались низкими коэффициентами корреляции между ключевыми параметрами, использующимися для построения геологической модели и подсчета запасов. Авторами предложен новый индекс *KØS*, который рассчитывается как функция коэффициентов проницаемости (k), пористости (φ), и остаточной водонасыщенности (S_{wir}). Влияние процессов осадконакопления и диагенеза на параметры нового индекса изучалось методами рентгеновской микротомографии (X-ray microCT) и ядерного-магнитного резонанса (NMR).

Сравнительный анализ предложенного индекса KØS с существующими показал, что у рок-типов, выделенных с его помощью, уравнения регрессии имеют наиболее высокие коэффициенты корреляции между подсчетными параметрами. Более того, каждый выделенный рок-тип обладает отличительной микроструктурой, что подтверждает правомерность предложенного подхода для классификации горных пород.

Так как все компоненты индекса *KØS* используются при подсчете запасов, и их определение входит в стандартные программы исследования керна, предлагаемый индекс может применяться практически на всех месторождениях углеводородов.

Ключевые слова: карбонатные породы, диагенез, рок-типизация, ЯМР, рентгеновская микротомография, характеристика пород-коллекторов, доломитизация, выщелачивание

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