THRESHOLD PRESSURE IN TIGHT GAS RESERVOIRS OF CENTRAL EUROPEAN FORMATIONS

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ABSTRACT
Increasing development activities for tight gas reservoirs during recent years have stimulated basic research on the flow characteristics of this kind of reservoirs. Investigated tight gas reservoirs are characterized by low porosity, low permeability and occasionally high water saturation which impact flow characteristics of gas reservoirs. In this kind of reservoirs so called nonlinear flow or non-Darcy flow occurs. Despite recent progress, the flow characteristics of tight gas reservoirs have not been thoroughly investigated. One of the important parameter to characterize reservoir in the context of production and basin modeling is threshold capillary pressure [1].

Threshold pressure is defined as the ability of a porous medium saturated with a wetting phase to block the flow of a non-wetting phase. Its value corresponds to the size of the largest pore throat in the porous medium. Therefore, the pressure difference between the non-wetting and the wetting phase must exceed the threshold pressure before the non-wetting phase can start draining the porous medium and flow.

There are several methods for evaluating threshold pressure which has their own advantages and disadvantages [2]. In this study, we present the comparison of estimated threshold pressure from corrected high pressure MICP (Mercury Injection Capillary Pressure) and measured directly by displacement methods. The application of the detailed integrated petrophysical and petrographic data obtained by CAMI (Computerized Analysis of Microscopic Images) show the main factors which affect the values of obtained threshold pressures.

INTRODUCTION
The main target for tight gas exploration in Central Europe is the Rotliegend eolian and fluvial sandstones. The possibility of this type of gas deposits are mainly associated with eolian sandstone complexes with originally fair porosity values. Simulations of reservoir parameters of the Rotliegend sandstone indicate porosity up to 12 % on the burial depth up to 4500-5500 m [3]. It can be associated with the development of secondary porosity formed as a result of the dissolution and/or transformation of cement and detrital grains (feldspars), often leading to inversion of reservoir properties [4]. Although, this formation has been studied for a long time determination of correlation between time of gas

saturation and time of partial loss of porosity and permeability mainly due to burial is still key issue [5]. Accumulations of tight gas might exist also in the Cambrian sandstones of the East European Craton. Although, numbers of diagenesis alterations, mainly quartz cementation, affect vertical and lateral heterogeneity of reservoir properties, prospects are promising for this structure mainly due to: 1) the spread over a wide area, 2) a simple tectonic structure (Baltic Basin), 3) an increase in thickness in the area of gas window.

The Rotliegend and Cambrian sandstones are characterized by low porosity, low or ultra-low permeability and high water saturation which lead to flow characteristics significantly different from that the ones in conventional gas reservoirs.

Threshold Pressure is defined as the overpressure needed for the non wetting phase to start flowing against the capillary forces. If the fluid flow is a linear, the pressure is converted into a pressure per unit length and is called *Threshold Pressure Gradient* (TPG). As one of the most important parameter to characterize flow, TPG has been studied extensively for a long time and several approaches for TPG estimation (like mercury intrusion, continuous injection, step-by-step, residual capillary pressure, dynamic threshold) were introduced that give results with good medium or poor accuracy.

In this study we compare two tight reservoir rocks in order to show which parameters should be taken into consideration before choosing proper approach for TPG estimation.

EXPERIMENTAL

There are several laboratory methods used for evaluation threshold pressure gradient or threshold pressure each having its advantages and disadvantages. In this study, mercury intrusion, continuous flow and step-by-step approaches were applied to estimate threshold pressure which give results with good or medium accuracy. As Egermann (2006) reported mercury intrusion approach ignores the influence of the overburden pressure and dry sample is used which may affect pore space properties. Appropriate synthetic brines for each kind of rock samples, i.e. for each reservoir type, were used. For MICP based method raw data were corrected according to the gas/brine interface and temperature by using in calculations values of IFT measured for the specific system brine/rock taking into account reservoir conditions [6].

In order to see the impact of sample conditions on threshold pressure continuous flow and step-by-step approach was used. All above mentioned methods were extensively described elsewhere [2,7,8]. Accuracy of the measurement was 0.07 kPa for flow methods and 0.01% for MICP.

Experiments were carried out using plugs and cuttings from Cambrian and Rotliegend sandstone reservoirs which are typical tight gas reservoirs located in Central Europe. Selected properties of cores used in this study are shown in Table 1.

RESULTS AND DISCUSSION

The most significant difference between analysed reservoir rocks is porosity which affect other petrophysical properties.

Generally, Cambrian sandstones (quartz arenites) are composed of quartz grains in 95 % and are strongly cemented by quartz (quartz overgrowths and quartz basic cement), resulting in almost total destruction of porosity (Fig.1). Some of Cambrian sandstones (samples 10-15 Table 1) show fracture permeability. The fractures are either empty or filled with clays/mudstone, quartz or bitumens. The content of pores >1 μm is between 8 - 94% and practically there is no microporosity in that rocks.

Pore space of the Rotliegend sandstone (lithic, sublithic, subarcose arenites) is much more complicated and consists mainly of intergranular pores and variable number of micropores (Fig. 1). These sandstones are composed mainly of quartz, feldspars and fragments of rocks. Cement is represented by ferruginous-clay overgrowths, quartz, calcite and anhydrite (basic cement). There is a great diversity in the mineral compositions which affects the rocks and cement as well as diagenesis processes (dissolution, crystallization) and the creation of different amounts of micropores in the analyzed rocks (the content of pores <1 μm is between 44 - 89%).

Table 1 Specification of cores

Core #	Formation	Sample depth [m]	Plug length [cm]	Porosity [%]	Avarage capillary [μm]	Specific area [m^2/g]	Treshold diameter [μm]	Permeability [mD]
1	Cambrian	2324.60	5.43	3.86	2.53	0.02	12.0	0.63
2		2327.20	5.50	4.39	0.47	0.15	1.2	0.08
3		2327.80	5.32	6.25	0.40	0.25	1.0	0.03
4		2328.70	5.28	3.74	0.68	0.08	4.5	0.11
5		2330.40	5.53	5.31	0.89	0.09	4.5	0.32
6		2331.20	5.53	3.11	0.37	0.11	0.9	0.02
7		2333.20	5.55	3.54	0.90	0.06	4.5	0.24
8		2339.70	5.20	2.29	0.15	0.24	1.2	0.06
9		2340.90	5.17	2.17	0.17	0.20	0.9	0.02
10		2282.40	5.23	4.03	0.13	0.45	0.9	0.01
11		2289.50	5.37	5.50	1.13	0.08	3.8	0.24
12		2293.00	5.16	3.45	0.42	0.12	2.0	0.16
13		2290.10	5.23	3.77	0.17	0.14	0.9	0.07
14		2292.20	5.04	4.33	0.11	0.47	0.4	0.40
15		2299.00	4.95	6.02	0.64	0.10	6.0	0.01
16	Rotliegend Sandstone	4245.15	4.59	3.89	0.09	0.69	1.0	0.49
17		4351.25	5.04	5.52	0.09	0.99	2.0	0.38
18		4359.50	5.19	6.18	0.12	0.84	3.0	0.29
19		4460.60	4.92	13.75	0.23	1.04	5.0	0.85
20		4551.00	5.03	7.09	0.11	1.03	4.0	0.13
21		4558.25	4.44	3.23	0.05	0.98	0.4	0.13
22		4642.20	5.52	12.02	0.16	1.28	4.0	4.33
23		4650.25	4.67	14.04	0.19	1.30	3.0	1.18
24		4656.40	5.05	9.83	0.12	1.37	3.0	0.76

In Cambrian sandstones, the results of TPG obtained by mercury intrusion and step-by-step approach were quite similar for samples with average values of porosity for this formation. The highest discrepancy was in the case of samples with relatively high microporosity (surface area ca. 0.5 m^2/g) where mercury intrusion overestimates values of TPG. Underestimation of TPG applying MCIP approach occurs when samples are mesoporous (average capillary over 0.6 μm). These general observations were confirmed by direct correlation of TPG and surface area and inverse correlation with average capillary radius (Table 2).

In the case of samples 10 – 15, the highest discrepancy between analysed methods was observed. It may be caused by distinct potential pathways for hydrocarbon migration in this samples which are presumably fractures together with microstylolites.

In the case of Rotliegend sandstone, an inverse correlation of TPG with depth was found what suggest that, except compaction, diagenesis processes and consequently secondary porosity affect flow through such reservoir (Table 4). Effect of reservoir conditions during TPG estimation increases with decreasing porosity and specific area. In such cases flow methods are more relevant. Underestimation of threshold pressure using mercury injection approach may occur also in the case of very heterogeneous parts of the reservoir especially when very thin beds of various petrophysical properties exist (sample 19).

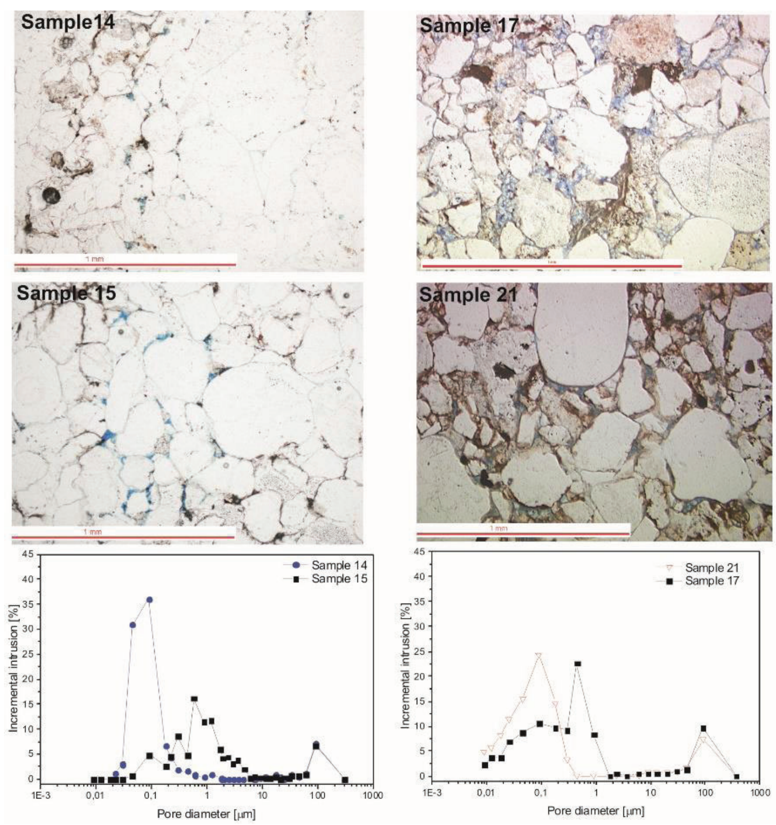

Figure 1. Selected thin sections (sample impregnated with blue resin) and pore size distribution for samples of Cambrian sandstone (sample 14, 15) and Rotliegend sandstone (sample 21 and 17). In the case of Cambrian rocks intergranular pores are observed. The Rotliegend sandstone shows diverse porosity with quite complex microporosity which steers the values of threshold pressure.

Table 2. Correlation coefficients of petrophysical parameters with threshold pressure for Cambrian sandstones

	Depth	*Effective porosity*	*Average capillary*	*Specific surface*	*% of pores >1 µm*	*Treshold diameter*	*Absolute permeability*	*Pth MICP*	*Pth flow*	*Pth step-by-step*	*TPG flow*
Pth MICP	-0.23	-0.27	**-0.62**	**0.82**	**-0.68**	**-0.70**	-0.11	**1.00**			
Pth flow	**0.72**	0.07	-0.25	0.06	-0.31	-0.30	-0.41	0.14	**1.00**		
Pth step-by-step	**0.53**	**-0.48**	**-0.81**	**0.70**	**-0.84**	-0.30	0.12	**0.64**	0.18	**1.00**	
TPG flow	**0.71**	0.06	-0.26	0.07	-0.32	-0.31	-0.41	0.14	**1.00**	0.35	**1.00**
TPG step-by-step	**0.58**	**-0.99**	**-0.94**	**0.69**	**-0.91**	-0.34	0.09	**0.62**	0.30	**1.00**	**0.68**

Table 3. Correlation coefficients of petrophysical parameters with threshold pressure for Cambrian sandstones (with no fractures – Samples 1-9)

	Depth	*Effective porosity*	*Average capillary*	*Specific surface*	*% of pores >1 µm*	*Treshold diameter*	*Absolute permeability*	*Pth MICP*
Pth MICP	0.44	-0.18	**-0.72**	**0.76**	**-0.77**	**-0.83**	**-0.80**	**1.00**
Pth flow	0.35	0.01	**-0.65**	**0.92**	**-0.91**	**-0.88**	**-0.72**	**0.84**
TPG flow	0.38	-0.01	**-0.65**	**0.93**	**-0.91**	**-0.88**	**-0.72**	**0.83**

Table 4. Correlation coefficients of petrophysical parameters with threshold pressure for Rotliegend sandstones

	Depth	*Effective porosity*	*Average capillary*	*Specific surface*	*% of pores >1 µm*	*Treshold diameter*	*Absolute permeability*	*Pth MICP*	*Pth flow*	*Pth step-by-step*	*TPG flow*
Pth MICP	**-0.69**	**-0.67**	**-0.57**	**-0.64**	**-0.63**	**-0.89**	-0.26	**1.00**			
Pth flow	-0.17	-0.34	-0.40	-0.06	-0.28	-0.19	0.15	0.33	**1.00**		
Pth step-by-step	**-0.92**	**-0.85**	**-0.57**	**-0.93**	**-0.61**	**-0.80**	**-0.74**	**0.95**	**0.46**	**1.00**	
TPG flow	**-0.64**	**-0.76**	**-0.66**	**-0.56**	**-0.52**	-0.43	-0.20	**0.52**	**0.72**	**0.80**	**1.00**
TPG step-by-step	**-0.91**	**-0.84**	**-0.56**	**-0.92**	**-0.60**	**-0.79**	**-0.71**	**0.96**	0.44	**1.00**	**0.80**

**In the Tables 1 – 3 above: direct correlation – blue, indirect correlation – red, no correlation – black. If the correlation coefficient is close to 1, it would indicate that the variables are positively linearly related (both variables are increasing or decreasing) and the scatter plot falls almost along a straight line with positive slope. For -1, it indicates that the variables are negatively linearly related (one variable is increasing, second decreasing and vice versa) and the scatter plot almost falls along a straight line with negative slope. Correlation coefficient equal 0 indicates no linear relationship between the variables.*

On Figures 2 and 3 the results of TPG calculations obtained on the basis of using MICP and flow methods are presented. Figure 2 shows the cross plot for Cambrian sandstones (with no fractures) and Figure 3 the cross plot for Rotliegend sandstones. Squares of correlation coefficients for both data sets show good correlation of results.

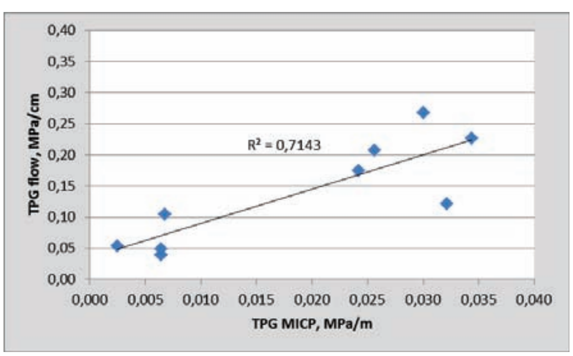

Figure 2. TPG flow vs. TPG MICP for Cambrian sandstones

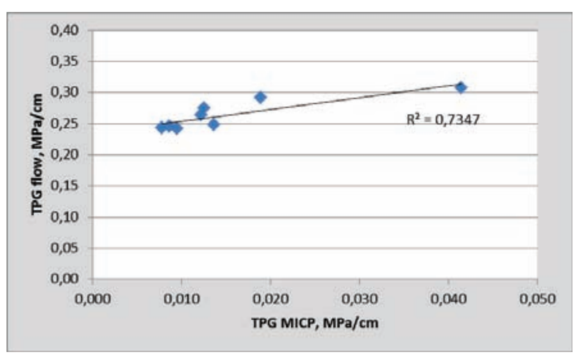

Figure 3. TPG flow vs. TPG MICP for Rotliegend sandstones

CONCLUSION

The analyses conducted in tight sandstones show completely different structure of the pore space due to mineral composition and diagenesis processes which has a strong impact on threshold pressure and consequently on its gradient.

Observed weaker correlations with continuous flow method may be caused by limitation of laboratory equipment (too high minimum flow rate), which generally implies higher values of threshold pressure.

In Cambrian sandstones direct correlation between depth, specific surface and threshold pressure obtained by flow and step-by step method was observed. Estimated correlation between specific surface and threshold pressure for Cambrian rocks without fractures (samples 1 – 9, Table 3) is not typical. Probably, this direct correlation is caused by very low value of specific surface (below 0.2 m^2/g) and suggests slight shift of pore size distribution to lower pore diameters of mesopores.

Moreover, indirect correlations of average capillary, percent of pores > 1 μm and Pth (MICP) and Pth as well as TPG (step-by step) were found.

In the Rotliegend sandstones, indirect correlations between depth, pore space parameters and threshold pressures and their gradients (measured using MICP and step by step method) were observed. Correlation between depth and other analysed parameters shows that evolution of pore space is dependent not only on compaction but also on diagenesis processes (development of secondary porosity).

Obtained results and correlation showed that in the case of Cambrian sandstones without microfactures, mercury intrusion gives very reliable results and might be used as a standard method. For this type of sample, low value of specific surface is a good indicator for choosing MICP approach. In the case of Rotliegend sandstone with more complex pore space distribution, the mercury intrusion approach underestimates the threshold pressure values and another method with higher accuracy should be used to achieve more reliable results.

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