VOL. 9, NO. 1, JANUARY 2014 ISSN 1819-6608
ARPN Journal of Engineering and Applied Sciences

www.arpnjournals.com

POROSITY ESTIMATION OF CARBONATE ROCKS WITH MULTISPEC PROCESSING TECHNIQUE

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ABSTRACT

Porosity is known as one of the main properties of reservoir rocks. The exact value of this parameter is difficult to measure. In present paper it is proposed using MultiSpec processing technique as cost-effective alternative method for estimating 2D-porosity from thin sections images of carbonate rocks on base of core samples picked out from carbonate reservoir rocks of Tournasian age in well, situated on southern slope of South-Tatarian Arch (Volga-Ural region, Russia).

Keywords: porosity, carbonate rocks, multispec processing system.

1. INTRODUCTION

Carbonate rocks contain more than 60% of world's hydrocarbon reservoirs [1]. They have reservoir composition that is more complex than one is in clastic rocks. This complexity is due to the influence of chemical, biochemical, biological and hydrodynamic processes of sedimentation. Organisms that produce carbonate material have a powerful chemical and physical impact to the pore space and the matrix of carbonate sediments that can block the effects of gravity. Porosity formation in carbonate rocks distinguish from porosity in sandstones controlled mainly by gravitational laying of clastic particles leading to the formation of interparticle porosity.

Genetic complexity and heterogeneity of carbonate rocks expressed, for example, in the classification of the pore space, suggested in [2]. In carbonate rocks interconnected and unconnected pores distributed. Many biological organisms, e.g., from classes Brachiopoda, Mollusca, Foraminifera, Algae have influence on porous structure. Cavities inside the fossil's body create unconnected porosity that is part of total porosity.

There are estimates of 3D cylindrical core samples porosity. They are expensive and time-consuming, e.g. measurement of interconnected porosity by liquid injection porosimetry. This technique can only evaluate connected pores because the injected fluid cannot get the unconnected pores. An alternative to this method is a digital image processing technique which estimates porosity from thin section images [3-5]. The estimates of porosity in digital method give the total porosity in the 2D image of the section. It is known a number of papers on application of computer programs for processing digital thin sections images to an express 2D evaluation of carbonate reservoir rocks porosity [3, 5, 6].

In present paper MultiSpec processing technique is regarded as useful method for estimate carbonate reservoir rocks porosity. This program was created in Purdue University. It is described in [7] and free available for a network users.

2. SAMPLE CHARACTERISTICS

For the experiment samples were taken from the oil-saturated core samples of Tournaisian age from well on the southern slope of the South-Tatarian Arch (Volga-Ural region, Russia). Tournesian carbonate rocks are unconformably overlapped by sandstones of Visean stage [8]. From bottom to top carbonate section is interpreted as progradational sedimentary sequence of limestones from wackstones to grainstones [8]. The limestones consist of low-magnesium calcite. A characteristic features is the absence of clay minerals in the rocks and micrite decreasing upward in the section [8]. The biogenic component is represented by the forams, pelecypods, bryozoans, algae fossils. Samples are also characterized by vugs, fractures, stylolites, secondary calcite are non-conforming to primary structure of rocks. The absence of clay minerals in the rocks indicates the primary lime mud, saturated by viability of benthic organisms. This type of carbonate sediment is characteristic of the carbonate ramp [8].

The absence of clay components, good contrast between the carbonate component (light colored areas) and pores (black areas) in thin sections under crossed nicols (Figure-1) allow taking images of samples in order to test MultiSpec program for 2D porosity evaluation.

3. THIN SECTION IMAGE ANALYSIS

Processing system MultiSpec includes cluster data using either a single pass or an iterative (ISODATA) clustering algorithm; saves the results for display as a thematic map. Cluster statistics can also be saved as class statistics. Use of clustering followed by ECHO spectral/spatial classification provides an effective multivariate scene segmentation scheme [7]. To get started with an image stored in JPEG, it is necessary to convert it to the format TIFF, which can be accomplished by, for example, program XnConvert. By downloading the image in MultiSpec, the process of clustering can be initiated (Figure-1).

VOL. 9, NO. 1, JANUARY 2014 ISSN 1819-6608
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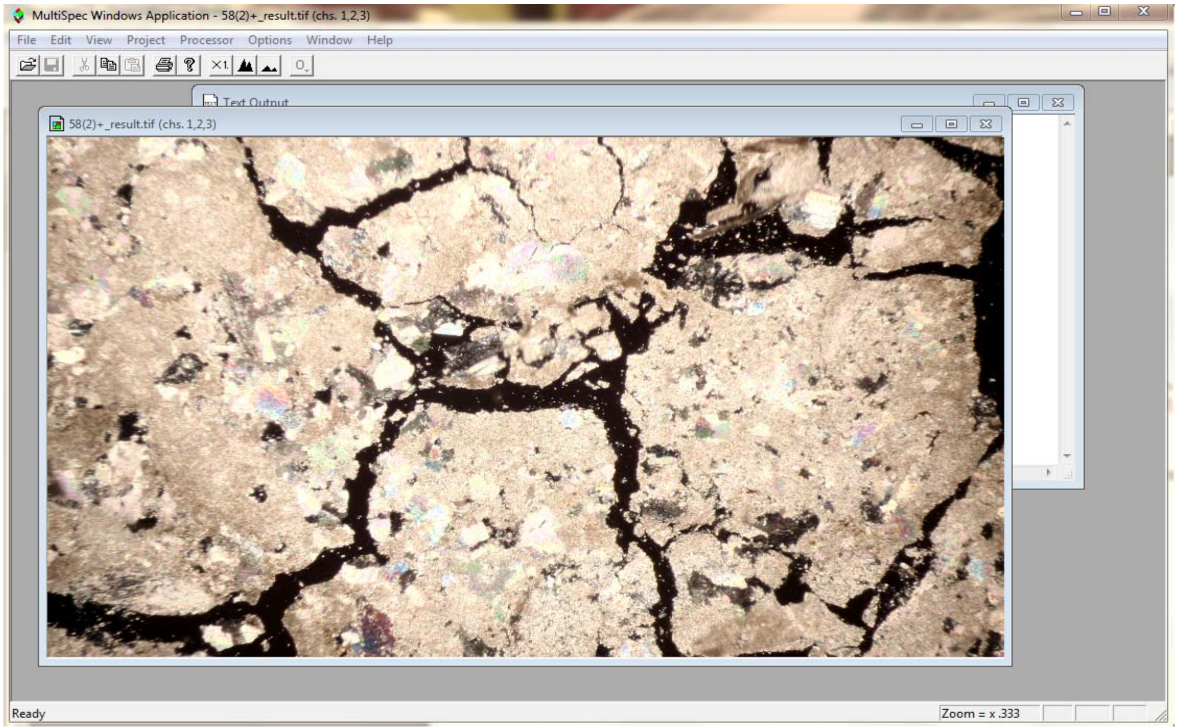

Figure-1. Photo of the thin section is loaded in MultiSpec. Photo is obtained under crossed nicols of a polarizing microscope. Mineral part is light colored area and porosity is dark colored area (sample No. 58).

To process clustering ISODATA algorithm is preferred because it is iterative and more accurate. It is necessary to specify the number of clusters, the percentage of their convergence and the minimum size of one cluster (in pixels).

Elementary operation of the program can be described as following. Pixels are divided into separate groups (or the image is divided into sections) on the basis of similarity of color and painted in one of the bright spectral colors. The total number of colors is given by the number of clusters. The convergence specifies accuracy rate within the range of spectral colors. The minimum size of the cluster allows adjusting the total number of pixels of the same color spectrum, without making it too small (to expand the range of pixels location). Since the pores in the photo are black, the program can recognize them as a separate group. The most justified result can be getting by the parameters indicated in Figure-2.

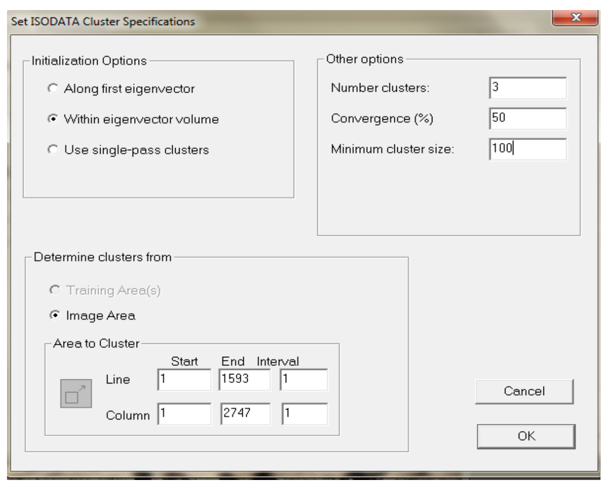

Figure-2. Setup window of algorithm with preferred values.

Finally, we have obtained the desired image in the spectral colors. The spectral color, which marked the pores, is red. It is the set of pixels of third cluster Figure-3.

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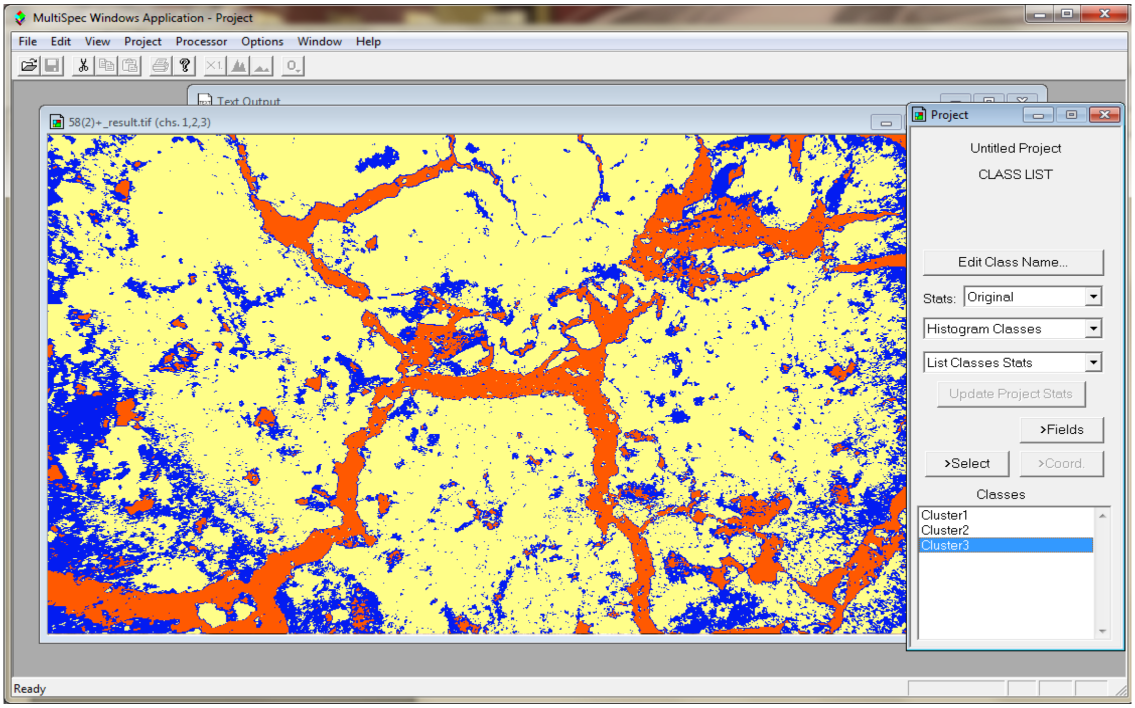

Figure-3. Received image from thin section photo of sample No. 58 (Figure-1): pores are red.

The output text is the final clustering statistics, which reports the number of pixels that correspond to each spectral color, as well as the number of pixels which in one way or another are not included in the classification of the percentage of convergence (Figure-4).

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Classification summary
 Cluster  1 classification size:  1186421
 Cluster  2 classification size:  378414
 Cluster  3 classification size:  285625

 Number of pixels not classified = 2525511
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Figure-4. The final results of the classification.

Porosity is determined by the ratio of pore area to the total area of the image, i.e., the ratio of the number of pixels corresponding to pores to the total number of pixels.

However, it should be noted that the pixel portion corresponding to pores can not fall into the classification and remain unrecorded. Therefore, to calculate the total number of pixels of the third cluster we take the estimated percentage of unclassified pixels (average value of the porosity of studied rocks according to geophysics ~ 0.1).

Thus, to calculate the porosity of the rock from information provided by the program MultiSpec, the following formula can be used:

Porosity (total) = (a +0.1 * b) / c, where a - number of pixels of the third class, b - the number of unclassified pixels, c - the total number of pixels.

4. RESULTS AND DISCUSSIONS

Figure-5 shows the results of typical thin sections imaging using MultiSpec processing system. On Figure-6 one can see the change of 2D-porosity according to results received by MultiSpec program in comparing with 3D-porosity estimates received by liquid injection method and discussed in [8].

Both types of porosity variations reflect the presence of two porous zones [8]. Upper zone (1947-1953 m) and lower zone (1953-1959 m) are characterized more and less oil saturation respectively (Figure-6).

The difference between 2D and 3D porosity is positive or negative. It depends on type of rock and porous space and methodical differences. Liquid injection method gives insufficient results in case of (connected) porosity measurement in the cavernous and fractured samples. In thin sections the total two-dimensional porosity is measured. Therefore it should be expected a significant excess of 2D evaluation of porosity on the 3D evaluation of porosity in the samples with caverns and fractures, as well as in samples with a high proportion of isolated and (or) small pores. In investigated case exceeding is mainly due to the vugs, caverns and fractures (e.g., samples No 8, 16, 18, 22, 24-26, 30, 58 - Figure-5, 6). If the 2D evaluation of porosity below the 3D evaluation of porosity, it can indicate not only on methodical features, but also a significant difference rock fragments analyzed by liquid injection method and method of thin sections imaging. However, in common, both estimates indicate increased porosity of upper carbonate zone as compared to lower.

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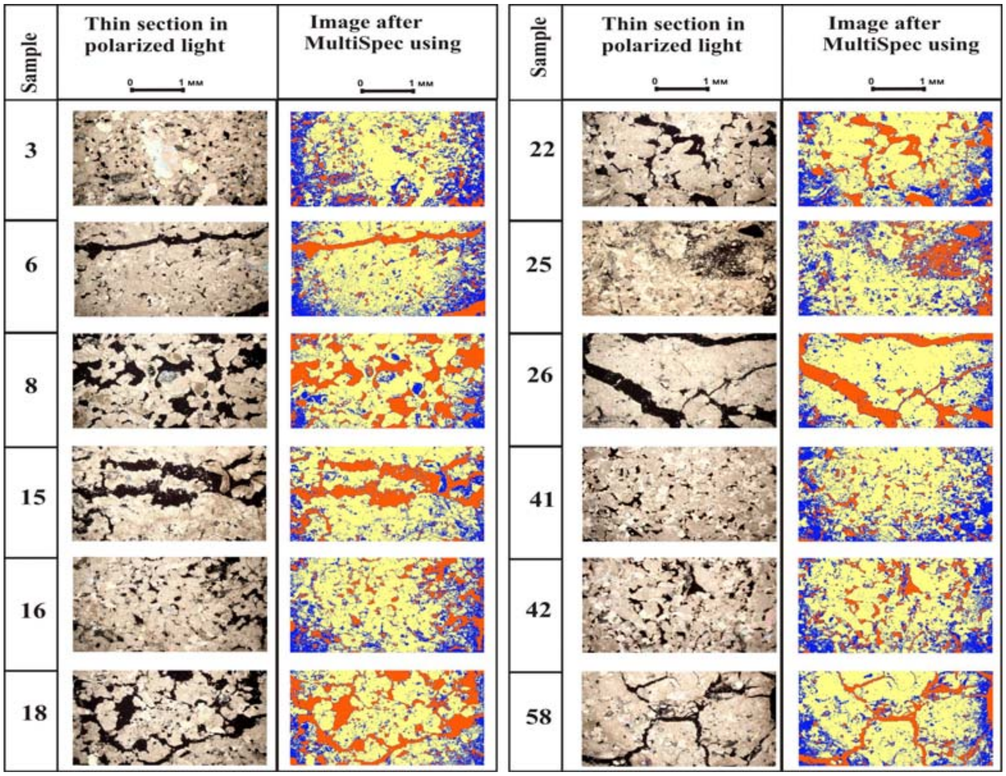

Figure-5. Demonstration of typical samples of Tournasian carbonate section (see Figure-6).

Porosity of investigated carbonate rocks is composed of primary and mostly secondary pores because the primary porosity reduced by cementation and compaction during post-depositional burial. In general primary pore types include interparticle, intraparticle, fenestral, shelter and growth-framework pores. Secondary pores form as a result of later, generally post-depositional dissolution. Such pore types include all of those mentioned above and also vugs (large pores that transect rock fabric) and dissolution-enlarged fractures [9, 10].

Investigated carbonate reservoirs lay beneath unconformity (Figure-6). The porosity values are higher in zone associated with unconformity. Therefore, secondary porosity can be explained by meteoric eogenetic or telogenetic environment [9, 10]. Investigated carbonate rocks consist of mineralogically stabilized to low-magnesium calcite and can be correspond to late eogenetic or telogenetic freshwater exposure of older limestones. Particle selective pores, vugs and caverns formed in these rocks.

Part of secondary porosity (vugs, caverns and fractures) can form in mesogenetic environments in which most fluids are brines that typically are saturated with respect to calcium carbonate. Therefore, these fluids are not capable of dissolving carbonate rocks and creating secondary porosity. Rather, such fluids tend to form dolomite. In investigated limestones there is no dolomite. Carbonate dissolution and porosity formation in deep-burial environment can be due by hydrocarbons history. It is known that carbon dioxide, hydrogen sulfide, and organic acids are formed during maturation of organic matter to hydrocarbons in source rocks. Together these gases and acids can move long distances vertically and laterally to dissolve buried carbonates just ahead of migrating hydrocarbons [9, 10]. This migration was probably stimulated by tectonic deformation. To distinguish in which diagenetic environment porosity formed it is necessary to get data of detailed petrographic study and data on carbon and oxygen isotopic values of carbonate cements associated with environmental porosity [9, 10].

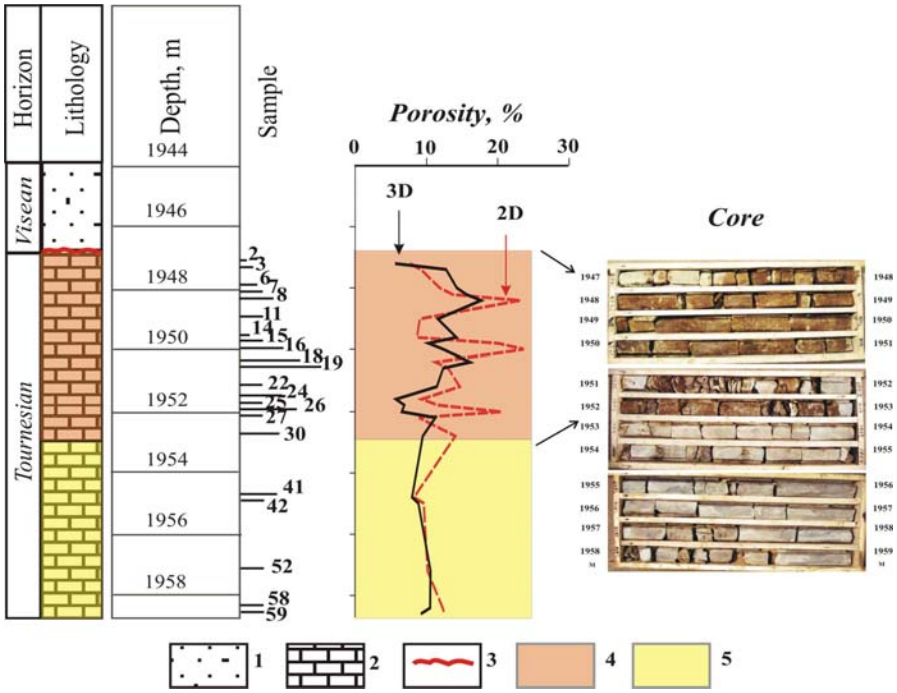

Figure-6. The geological section of well, 3D and 2D-porosity variations along the section.
Legend: 1 - sandstones, 2 - limestone, 3 - unconformity, 4 - high oil saturation, 5 - low oil-saturation.

5. CONCLUSIONS

The porosity of oil-saturated carbonate rocks with a strong color contrast between the mineral part and pores in thin sections under polarized light can be digitized and evaluated using MultiSpec programming system. This evaluation can be used to identify zoning and interpretation of porosity genesis within carbonate reservoir rocks.

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