STUDY OF DRILL CUTTINGS POROSITY FOR FORMATION EVALUATION

S. T. Dang, M. M. Rolke, C. H. Sondergeld and C. S. Rai
Mewbourne School of Petroleum and Geological Engineering
University of Oklahoma

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ABSTRACT

Petrophysical measurements on drill cuttings have an economic appeal especially in unconventional formation evaluation. Drill cuttings are readily available, a byproduct of drilling, and can potentially provide a variety of reservoir quality parameters, such as total organic carbon, porosity, mineralogy, thermal maturity, pore structure and habit, mechanical elastic properties, etc. While log and core data are only available for a limited number of wells, drill cuttings are available for all wells. Therefore, the determination of porosity using drill cuttings can provide a more spatially detailed representation of a formation, which is critical because shale plays can be both vertically and laterally heterogeneous. Porosity is a primary variable controlling hydrocarbon storage of within a formation. There are multiple laboratory methods to directly measure porosity in cores — Low Pressure Pycnometer (LPP), High Pressure Pycnometer (HPP), Nuclear Magnetic Resonance (NMR), Mercury Injection (MICP), etc. A challenge arises when porosity is obtained from drill cuttings due to the inability to directly measure bulk volume of a sample. This study presents the application of a new methodology to measure the porosity from drilling cuttings.

Conventional approaches to calculate porosity require measuring two of three variables namely pore, grain or bulk volume. Our approach uses measures of high-pressure pycnometer grain density on dry drilling cuttings; volume of oil occupying pore space is quantified by NMR measurements.

Initial results on 3 tight sands and 27 shale samples show the new approach is promising for the estimation of porosity. 90% of the cutting porosities made on tight sands and shales are within 1.5% p.u. of the core porosities. This error is believed to be due to sample loss during the saturation process or excess oil on the surface of the cuttings.

INTRODUCTION

Petrophysical characterization is critical to a successful exploration program. Logging While Drilling (LWD) is a routine practice, in which reservoir properties are estimated from combinations of different log responses in real-time. These parameters later will be compared to core data, which are generally accepted as more reliable. However, core acquisition is costly and is limited to very few wells.

The workflow to determine petrophysical properties for unconventional reservoirs is more complicated and uncertain than the conventional counterpart. Shale is typically heterogeneous (Ross and Bustin, 2008[1]; Nobakht et al., 2013[2]), therefore, more spatially detailed reservoir description is essential, especially in evaluating completion efficacy (Prioul et al., 2016[3] and Cipolla et al., 2011[4]). Drill cuttings are available as a byproduct of the drilling process. Different drill bits can provide different qualities of cuttings; however, when cuttings larger than 1 mm (20 mesh size) are available, they can be a cost-effective alternative to various reservoir characterizations. While some routine core analyses, such as organic richness (TOC), mineralogy (from X-Ray Diffraction or FTIR, Ballard, 2007[5]; Sondergeld and Rai, 1993[6]), or producibility (from Rock-Eval® or SRA®), are quite easily performed on cuttings, porosity and mechanical properties are difficult to measure (Dang et al., 2017[7]). This is due to the irregularity of cutting shape and the miniature scale of cuttings.

In this study, we focus on proposing a new method that help to reasonably estimate cutting porosity, as well as addressing difficulties while measuring this parameter.

EXPERIMENTAL APPROACH

There are two major approaches to porosity measurements: first, is the measurement of bulk volume and grain volume (Eq. 1), and second, is the measurement of bulk density and grain density (Eq. 2). The first method requires good control on sample mass conservation (Karastathis, 2007[8]). The last approach usually suffers from a large uncertainty in the estimated bulk density due to presence of residual fluids. Common to both approached is the measurement of bulk volume. These concerns make the estimation of cutting porosity challenging.

$$\emptyset = \frac{V_{bulk} - V_{grain}}{V_{bulk}} \quad \text{(1)}$$

$$\emptyset = \frac{\rho_{grain} - \rho_{bulk}}{\rho_{grain} - \rho_{fluid}} \quad \text{(2)}$$

Attempts to measure the bulk volume of cuttings through the injection of fluids, such as mercury, oil or water into a known volume pycnometer containing cutting samples were not successful due to the variable wettability of cuttings. Mercury injection suffers from a

large and unknown conformance effect (Bailey, 2009[9]), which limits bulk volume determination. **Fig.1** shows bulk volume measured by MICP after low pressure (20 psi) injection for cutting samples (1-2mm); the results are underestimated, compared to the true bulk volume. True bulk volume of cuttings is calculated from the bulk volume estimated from a rock plug (from which the cuttings are generated), then normalize cuttings' weight to plug's weight. With a small injection pressure, oil or water can help to overcome conformance effect on cutting surface. However, for tight rocks having small capillary tubing size, even under low pressure, the intrusion of wetting phase can happen. Unfortunately, organic rich shales typically include both water-wet and oil-wet flow paths (Odusina et al., 2011[10]). Some previous studies also proposed using powder pycnometer to measure solid volume of cuttings, these measurements have to reply of the consistency of powder packing, and cutting surface roughness (Meazza et al., 1996[11], Egermann et al., 2006[12]

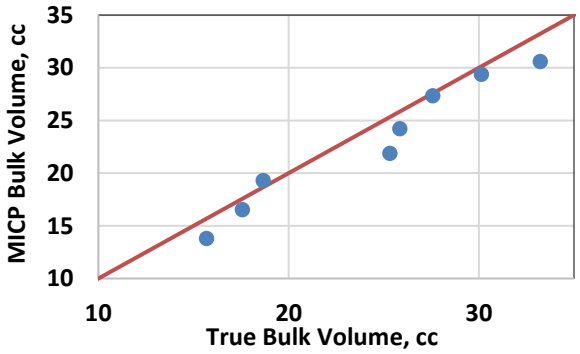

Fig. 1 Comparison between true bulk volume and bulk volume measured by mercury Injection for rock cutting samples. Because of conformance effect, MICP generally underestimates bulk volume. The error ranges from 2.5% to 12%.

To overcome the challenge of measuring bulk volume for cutting samples, we propose the following approach (**Equations 3-7**). First, cuttings are prepared by sieving above 1mm (20 mesh), dried at 100ºC for 24 hours; this protocol was determined through thermogravimetric analyses (TGA) (Sondhi and Solano, 2009[13]). 100ºC is efficient to remove surface or free water. Clay-bound water requires higher temperature to be eliminated. Therefore, the porosity estimated from this study, should be considered as effective porosity. The drying step is critical to accurately estimate sample mass (m_{bulk}) and rock grain density (ρ_{grain}). Grain density is estimated, using high-pressure pycnometer (HPP), with He as the purge gas and pressure of 250 psi. Drill cuttings are collected in a Teflon (PTFE) filter mesh bag (**Fig. 2**) for the saturation with dodecane (ρ=0.75 g/cc). We saturate for 24 hours at a constant hydrostatic pressure of 7000 psi, after which, the samples are assumed to be 100% saturated. Shale generally includes reactive clays (O'Brien and Chenevert, 1973[14]), so, dodecane is selected as the injected fluid, instead of brine.

Applying simple oil-gas capillary pressure conversion, 7000 psi is considered high enough to saturate pores having throats larger than 1 nm. The difference of NMR T2 volume or sample mass between dry and saturated cuttings include oil fraction injected in pore space (V_{oil}) and oil fraction coating on the cuttings 'surface. NMR spectra run on saturated cuttings allowed us to differentiate these two oil fractions.

Detailed derivation for the equation used for this approach:

$$\phi = V_{oil} / V_{bulk} \quad (3)$$

$$V_{bulk} = m_{bulk} / \rho_{bulk} \quad (4)$$

$$V_{bulk} = m_{bulk} / (\rho_{grain} \times (1- \phi)) \quad (5)$$

Substituting V_{bulk} from Eq. 5 to Eq. 3, we have:

$$\phi = V_{oil} / (m_{bulk} / (\rho_{grain} \times (1- \phi))) \quad (6)$$

Solving Eq. 6 for porosity, ϕ:

$$\phi = V_{oil} \times \rho_{grain} / (V_{oil} \times \rho_{grain} + m_{bulk}) \quad (7)$$

Fig. 2 Cutting samples were sieved, then collected in PTFE filter mesh bag, ready for the saturation process.

Protocols to measure m_{bulk} and ρ_{grain} have been well established (Karastathis, 2007), the accuracy of porosity calculated from this method, depends on how V_{oil} is quantified. T2 distribution for both dry and saturated cutting samples were acquired using the benchtop Oxford Geospec2™ instrument with operating frequency of 12 MHz, and echo spacing of

114μs (**Fig. 3**). The difference in mass before and after saturation was also recorded. **Fig. 4** shows the good agreement between the oil volumes measured by mass difference and NMR gain. NMR volume gain include oil fraction injected in pore space and oil fraction coating on the cuttings' surface

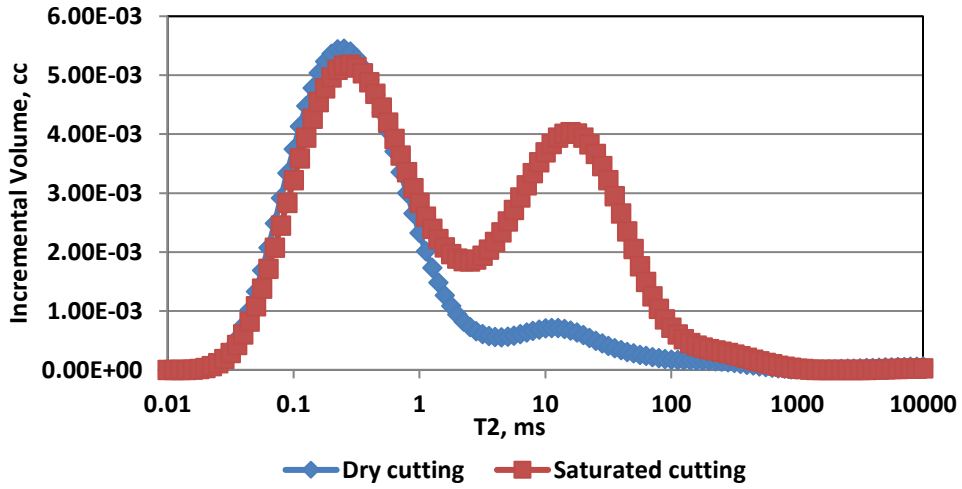

Fig. 3 NMR T2 distribution for a Barnett cutting sample before and after saturation. 'Dry cutting' NMR signal shows the existence of clay-bound water with T2 less than 1ms. The porosity estimated from this study should be considered as effective porosity, not total porosity. Note the increase of NMR T2 peak at 10-50 ms due to the injection of dodecane.

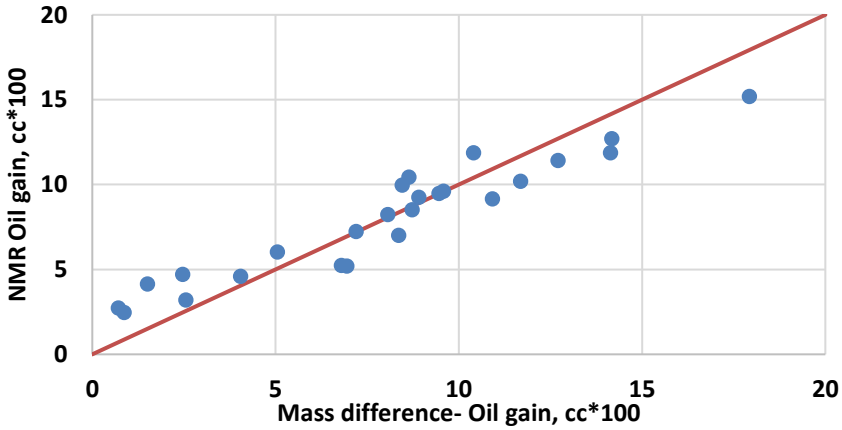

Fig. 4 Injected dodecane volume measured by two different methods: mass gain versus NMR volume gain. NMR volume gain include oil fraction injected in void space and oil fraction coating on the cuttings' surface. Note the error range of mass measures is about 5×10^{-4} g, equivalent to 7×10^{-4} cc; the error range of NMR measures is about 5×10^{-2} g

For the same mass, 1-2mm (10-20 mesh) cuttings have an average surface area 20-40 times more than a core plug. This leads to the overestimation of V_{oil} due to the extra layer of

dodecane coating on the cutting surface, which is supposed not to be included in the porosity calculation. Mass difference between dry and wet cuttings cannot exclude this unwanted oil fraction from calculation. However, by setting a T2 cutoff at 70 ms, we can identify the amount of oil actually occupying pore spaces (see **Fig. 5**). In this study, we propose using the difference in NMR before and after saturation with T2 relaxation times less than 70 ms to better estimate of porosity.

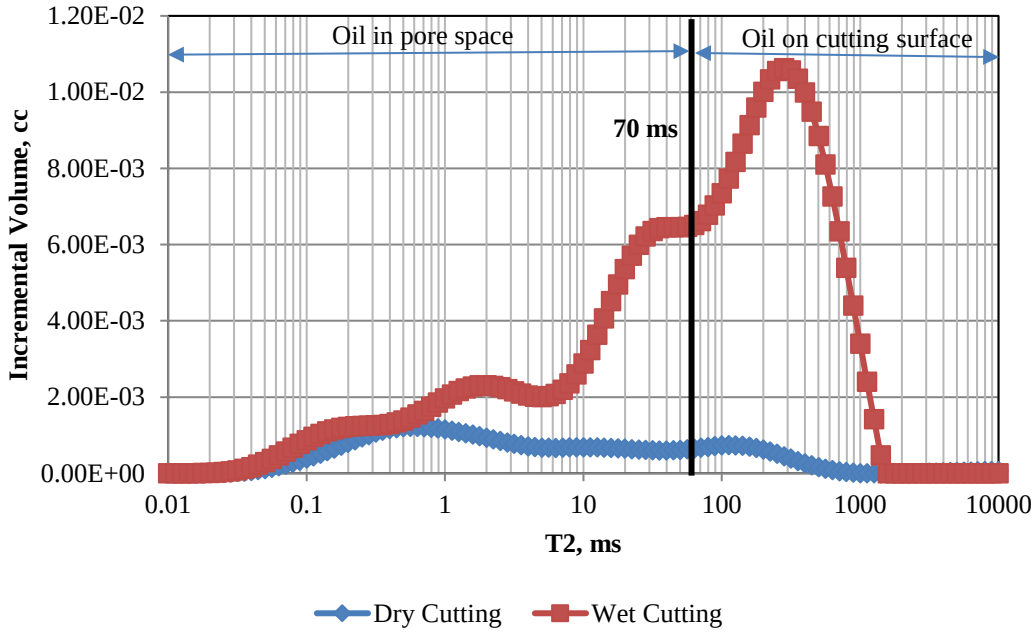

Fig. 5: The increase in NMR T2 amplitude due to the dodecane saturation of cutting samples. T2 cutoff of 70 ms is used to distinguish the volume of oil injected into pore space and the volume of oil coating on the surface of cuttings.

EXPERIMENTS AND SAMPLES

Three outcrop sand and 27 shale samples were selected to test this method. 1" ×1" plugs were attained for each of these samples. While shale samples would be subjected to crushed helium porosity measurement (Karastathis, 2007), sand samples porosity were measured by the combination of high pressure helium pycnometer test (HPP) and T2 NMR. High pressure He pycnometer test allows estimation of air occupying the void space; T2 NMR allows to estimation of liquid occupied void space.

By crushing and sieving, we also create cutting samples with mesh size above 20 mesh (>1-2mm). The purpose is to compare the results from traditional core porosity test and this new protocol for cutting porosity.

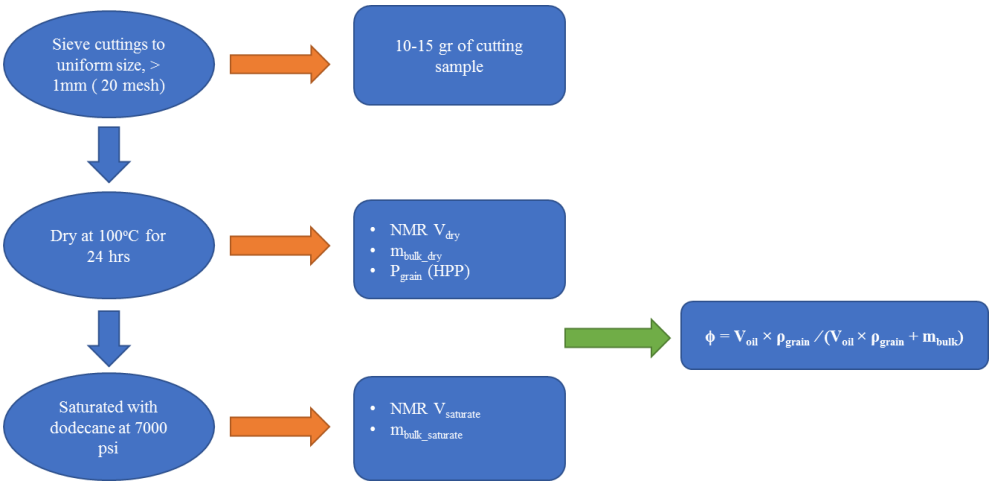

Fig. 6 Flow charts for the proposed new method of cuttings analysis.

RESULTS

We performed conventional core porosity tests along with the proposed method on cuttings for total 30 samples. Porosity for the core measurements range from 1 to 19 p.u with a controlled error of 0.5-1 p.u. **Fig. 7** shows the comparison between results on cutting and core samples. 90% of the cutting porosities are within 1.5%. of the core porosities. The results confirm that the proposed method can be used to estimate cutting porosity with a reasonable range of error. Note the cutting size will impact the quality of the test, sample size above 20 mesh (> 1mm) is recommended.

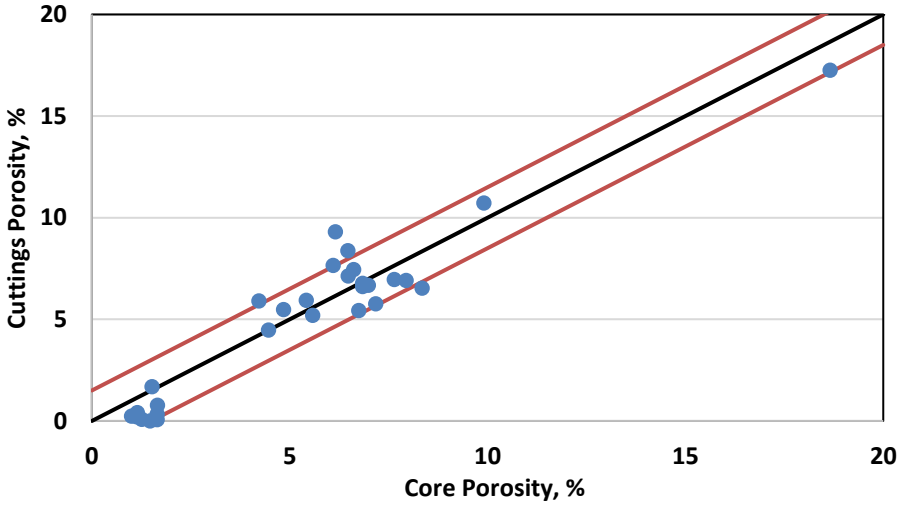

Fig. 7: Comparison of core porosity using conventional methods (standard error of 0.5-1 p.u) versus with cutting porosity (propagated error of 1-1.5 p.u) measured by proposed method in this study. 90% of the cutting porosities are within 1.5 p.u.

CONCLUSIONS

Despite the depth-registration issue, petrophysical characterization on cuttings is promising because of its cost efficiency and availability. This helps to study the heterogeneity of shale formations in both horizontal and vertical scales. In shale, heterogeneity governs both storage and success in completion. This study introduce a new workflow to quantify cutting porosity, which is one of the most difficult reservoir properties to be measured from cuttings. The results show that estimated cutting porosity agrees well with measured porosity from core, with a reasonable error range.

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