A BLIND STUDY OF FOUR DIGITAL ROCK PHYSICS VENDOR LABS ON POROSITY, ABSOLUTE PERMEABILITY, AND PRIMARY DRAINAGE CAPILLARY PRESSURE DATA ON TIGHT OUTCROPS

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Vienna, Austria, 27 August – 1 September 2017

ABSTRACT

Estimation of reservoir rock properties using multi-scale imaging of the pore structure, followed by mathematical modeling of the segmented images *i.e*. Digital Rock Physics (DRP) is a promising technique. However, DRP workflows are highly variable in terms of imaging tools, resolution of those tools, segmentation algorithms, handling of unresolved porosity, gridding of the resolved pore structure, and mathematical modeling of flow properties. As a result, users familiar with physical measurements of reservoir properties struggle to judge the quality of DRP data, and to incorporate DRP data in commercial workflows in a suitable manner.

In this work, we present a DRP study on tight rocks (k_{abs} < 10 mD) conducted at 4 digital vendor labs, anchored to high quality physical measurements conducted in our lab. We selected core plugs from a set of six outcrop rocks. We cleaned the plugs, measured porosity (φ) and absolute permeability (k_{abs}), and then split the plugs in 4 quarters. Four commercial DRP labs conducted blind porosity and permeability predictions on those quarter plugs using (a) only micro-CT based tools, and (b) all the tools accessible to DRP service providers. We also compare primary drainage capillary pressure (P_c) calculated by 4 DRP vendors on quarter plugs with centrifuge based gas-water measurements conducted in-house on companion plugs.

As a result of this blind study, we gained insights into workflows, strengths/weaknesses of DRP predictions carried out by 4 vendors. Various levels of physical measurements (lab-based k_{abs}, and φ data, MICP, or none) are used by different vendors to anchor DRP data. DRP predictions for porosity were from 37% to 96% of the measured values, whereas permeability is within a factor of 0.4 to 4 from the experimental measurements. At low P_c values, predictions by the 4 DRP vendors generally agreed with each other, and with experimental measurements. However, the values diverged significantly at high P_c. Based on this study, we conclude that the dominant source of error in DRP data is highly specific to a given sample, technique, or operator. A lot more uncertainty quantification is necessary to allow DRP data to be used instead of physical measurements for business decisions on tight rocks. We outline learnings for hydrocarbon resource owners and DRP data providers so that commercial workflows could benefit from DRP-based data.

INTRODUCTION

DRP on hydrocarbon reservoir rock aims to provide a pore-scale understanding of the fluid displacement phenomena and predict flow properties of reservoir rocks. Due to recent advances in high resolution imaging and high performance computing, even individual pore-scale flow events can be dynamically observed [1]. Despite significant potential of DRP, the level of confidence to apply DRP data for business decisions is highly variable. The value of DRP data depends on the owner of an asset, expertise of the DRP lab, rock quality/homogeneity, presence of analog data, and timescale of evaluation.

Frederich *et al*. compared DRP with experimentally measured rock properties [2]. They claimed that DRP-based measurements were predictive and approved for business use. Masalmeh *et al*. conducted a joint experimental and DRP-based approach to evaluate the predictive capability of pore-scale modeling for a homogenous carbonate reservoir [3]. They tuned the DRP predictions of primary drainage and primary imbibition capillary pressure to the corresponding experimental data. They used these matched parameters to predict relative permeability and compared with experimental data measured on the same rock samples. They indicated a good match between tuned-DRP and experimental data for water relative permeability, while oil relative permeability showed discrepancies.

Cense and Marcelis compared 3 pore-scale reconstruction and pore-network extraction techniques on high quality sandstones [4]. They observed a 3% mismatch in porosity (φ), and up to a 3x mismatch in permeability (k), indicating a good match in the threshold pressure; but poor match with experimental data regarding the shape and endpoint of the capillary pressure curve. Kalam *et al*. conducted a DRP validation study on 95+ reservoir cores from 4 reservoirs and concluded that DRP is capable of generating fairly accurate SCAL data [5]. Schembre-McCabe *et al*. showed two examples where digital rock data was used along with experimental data to reduce uncertainty to create business value [6]. They found that the image segmentation process is subjective due to the presence of sub-resolution features, and therefore additional independent information can improve the quality of DRP-based predictions. DRP-based predictions have also been used for tight rocks with extremely low permeability or during Enhanced Oil Recovery studies [7] [8] [9] [10]. ExxonMobil Upstream Research evaluated the use of DRP on a Middle Eastern carbonate reservoir for SCAL measurements, and concluded that DRP was unable to provide an acceptable substitute to experimentally measured, high-quality SCAL data [11]. However, since this evaluation the number of DRP service providers, resolution of imaging tools, and the perceived quality of DRP data has improved significantly.

Sorbie and Skauge reviewed the success of pore-scale network modeling for multiphase flow in porous media [12]. They concluded that pore-scale modeling cannot reliably predict two-phase flow functions in pores with mixed wettability in “blind” tests. Therefore in this work, we restricted the scope to water-wet systems. We picked 6 outcrops (3 carbonates, and 3 sandstones), with tight but measurable porosity and permeability. We then compared experimental data for k, φ and primary drainage P_c with values reported by 4 DRP vendors in blind tests for the 6 outcrop plugs.

Objectives of This Study

1) To understand whether porosity (φ), absolute permeability (k), and primary drainage capillary pressure (P_c) can be estimated using DRP for tight rocks
2) To understand the limitations of the technology, which will allow the user to incorporate DRP data in the right context for a given business need
3) To test whether DRP-based predictions are consistent among 4 selected vendors offering commercial DRP services, and whether these values are consistent with physical measurements carried out in our lab
4) To develop a working knowledge about DRP workflows, data quality, and potential pitfalls in interpretations of DRP data
5) To present a "DRP user perspective" and to motivate research on topics that enable the use of DRP data in the right context along with other sources of data

What is Not Addressed in This Study (Out of Scope)

We made best efforts to minimize extraneous variables that might influence the outcome of this study. However, we would like to recognize the following aspects before the reader proceeds to interpret the findings from our study: (1) Proprietary steps in image acquisition and analysis could not be influenced. (2) Only the primary drainage process was evaluated using DRP, as the rock is water-wet during this process. All other displacement processes are expected to be wettability sensitive, and those are beyond the scope of this study. (3) Routine properties (k and φ) were measured in our lab on plugs. Then the plugs were cut in 4 quarters along their axes. The DRP study on quarter plugs was conducted in parallel at 4 vendor sites, so there was no possibility to conduct a "post DRP" measurement in our lab. Primary drainage P_c was measured in our lab on companion plugs, which were chosen based on the good match in their k-φ values (e.g. within 10%) to the DRP plugs, and taken from the same piece of outcrop rock sample.

EXPERIMENTAL PROCEDURE AND DRP WORKFLOWS

Three carbonates – Austin Chalk (AC), Indiana Limestone (I), Carthage Marble (CM), and 3 sandstones – Scioto (S), Torrey Buff (T), and Crab Orchard (CO) were picked (0.01md $< k < 1$ mD). Plugs were cleaned using a flow-through method with a methanol-water mixture to remove salt from the lubricating fluid used during plugging. Fresh batches of fluids were used intermittently, and the effluent was tested for the presence of salt. Sample cleaning took 1 week for the 4 better quality plugs (AC, I, S, and T), and 3+ weeks for the 2 tightest plugs (CO and CM). Once no salt was detected for 24+ hours, the plugs were dried in a humidity oven to retain clay-bound water. Pore volume, porosity, grain volume, and Klinkenberg corrected gas permeability were measured under a net confining stress of 800 psi (typical condition for routine core analysis). K-φ measurements for the 2 tightest rocks involved special care to avoid artifacts due to leaks, temperature variations in the lab, and large dead volumes. The experimental results are summarized in Table 1 (shaded grey). Plugs were then cut in 4 quarters without using any lubricating fluid and quarters were sent for DRP studies. Companion plugs used for P_c measurements were cleaned following the same protocol, saturated with brine and centrifuge based primary drainage air-brine P_c measurements were conducted.

In phase I, we restricted the DRP labs to only use µCT based imaging tools that have resolution of ~1 µm. All labs took a scoping scan of the whole plug at a resolution of 20-30 µm to qualitatively evaluate the plug and to select a location for a sub-plug. Vendor C conducted physical poro-perm measurements on the 6 quarter plugs they received. Three vendors (B, C, and D) drilled sub-plugs and imaged the sub-plugs at a higher resolution of ~1 µm. Two vendors (C and D) also conducted Mercury Injection Capillary Pressure (MICP) measurements on part of the quarter plug supplied to them. All vendors used proprietary workflows to segment the collected µCT image to simulate phase distribution and flow. In phase II, the DRP labs used the highest resolution tool available to refine their digitally calculated k-φ values on the same samples. Using either nano-CT or FIB-SEM based tools with resolutions of 20 – 50 nm, DRP labs calculated primary drainage P_c. The P_c results were normalized to a consistent interfacial tension (IFT = 28 mN/m) and contact angle (θ = 0° for primary drainage) for typical oil-water fluid properties.

RESULTS AND DISCUSSION

Phase I: Porosity (φ) and Absolute Permeability (*k*) Based on Micro-CT

DRP-based poro-perm results reported by 4 vendors are summarized in Table 1 along with experimental measurements on core plug. For the 2 tightest samples, three vendors were unable to calculate permeability due to lack of sufficient resolution based on the µCT tool to resolve pore throats in the 2 tightest rocks. MICP based pore-throat size distributions for all samples are plotted in Figure 1, and the portions of the pore throat sizes “visible” to the µCT are shaded grey. For the 2 tightest samples (CO and CM), none of the pore throats could be resolved, and therefore no connected pathway could be extracted from µCT images. Reported permeability values from vendor A were based on extrapolation of poro-perm trends from better quality rocks, so permeability of CO and CM reported by vendor A was deemed unreliable and excluded in subsequent analysis.

If the resolved image has a sufficient number of connected pathways, then permeability will be controlled by those dominant pathways. However, a significant number of voxels have a CT contrast in-between the bright grains and dark pores. These voxels containing sub-resolution porosity contribute to the total porosity but may or may not significantly affect the permeability. The CT number of each voxel could be used to calculate the total amount of pore space within that voxel, but the CT number does not indicate how the sub-resolution porosity is distributed and connected within the voxel. Each DRP vendor used their own proprietary poro-perm transforms to handle sub-resolution porosity.

Phase II: k-φ Based on Highest Resolution Tool Available for DRP

Three DRP labs (B, C, and D) used either nano-CT or SEM-based techniques to recalculate k and φ. The hatched area in Figure 1 highlights the new connected pathways visible using nano-CT/SEM but not to µCT based rock evaluation. Vendor A did not have access to any higher resolution techniques, therefore it did not provided any new data in Phase II. *K*-*φ* values in Table 1 indicate that whenever a DRP-based permeability was calculated in phase I, the value did not change appreciably in phase II. This is despite the higher number of pore throats being visualized in phase II. Nano-CT or SEM enabled analysis of the tightest rocks (CO and CM) by resolving pore throats that were previously not resolved using µCT. Therefore, it is essential to use a DRP technique with the appropriate resolution for a given rock fabric and for a desired level of accuracy.

K-*φ* calculated in phase II using the DRP approach on quarter plugs by 4 vendors are compared against experimentally measured values on the intact plug in Figure 2. Porosity calculated from imaging was found to be less than the measured porosity, *i.e*. all points in Figure 2(a) lie below the 45 degree line. Slopes of the best fit lines through the 6 data points for each vendor indicate the fraction of total porosity captured using DRP. Vendors B and C reported the maximum (86% and 96% respectively) fraction of measured porosity. However, it is important to remind the reader that vendor C carried out physical measurements for *k* and *φ* on their quarter samples. Therefore, vendor C had an opportunity to compare DRP predictions with physical measurements on the same sample, while the other 3 vendors did not. Vendor A reported 72%, whereas D could visualize only 37% of the total porosity. The slopes calculated above are based on at best 6 pairs of data (3 carbonates and 3 sandstones). The regression minimizes the sum of squares of the error between DRP data and a model, so the slope is biased by higher porosity rocks. Therefore, these slopes should not be used in a quantitative manner.

A similar regression exercise is summarized for absolute permeability in Figure 2(b). DRP-based permeability data on 4 quarters of the same plug had a variation of up to one order of magnitude. Based on a regression model, vendors A and C over predicted permeability by a factor of 4.4 and 1.6, respectively. On the contrary, B, and D under predicted lab measurements of permeability by a factor of 0.49 and 0.40, respectively. The caveat about physical measurements carried out by vendor C applies here as well. Vendor A systematically over predicted DRP permeability compared to experimentally measured data. DRP workflow employed by vendor A was the simplest of the 4 vendors evaluated in this study. Vendor A takes a single CT scan of the whole plug, and runs a DRP simulation to get "digital" *k* and *φ* values. The vendor has conducted physical and DRP measurements on numerous sandstones and carbonates. From this catalog, vendor A derived an empirical correlation between digital and physical values. The "digital" values obtained from imaging were plotted on this catalog, and "corrected digital" values were reported. From the cross-plot, it is clear that vendor A under predicts porosity, while systematically over predicting permeability.

Vendor B did not perform any physical measurement or benchmarking. They slightly under predicted porosity, while under predicting permeability by a factor of 2. Vendor D's workflow involves MICP measurements, which were used to select optimal imaging parameters. Vendor D did not use MICP as a fitting parameter. Vendor D systematically under predicts both *k* and *φ*. Vendor C also took a scoping scan followed by a detailed scan on a mini-plug, as well as conducted a physical MICP experiment on part of the sample. They measured k and φ experimentally on the quarter plugs, but claimed that the physical data was not used in any benchmarking of digital P&P data. DRP data reported by vendor C slightly under predicts porosity, while over predicting permeability by 60%.

Based on the numbers from Table 1 and Figure 2, the variation among the 4 DRP vendors seems unacceptable. Possible reasons for the mismatch include (1) imaging of non-representative elements, (2) issues with segmentation, (3) inaccurate physical measurements, or (4) inherent variability within a core plug. Three vendors conducted a scoping scan to pick the best region to investigate in detail, but still the issue of non-representative sampling cannot be discounted. Segmentation algorithms are proprietary for all vendors, so we could not understand their differences, or whether any algorithm could lead to systematic errors. Segmentation is not completely automated, so some degree of subjectivity might be involved. The DRP vendors could not quantify the level of uncertainty in segmentation. In contrast, physical measurements were conducted on an experimental setup where the pressure transducers and pump flow rates have been calibrated against traceable standards. We took utmost care to minimize and quantify leaks and dead volume, and all measurements were repeated 3 times. Uncertainty in measurements was found to be smaller than the size of the symbol plotted in Figure 2 for the 4 higher quality outcrops. For the 2 lower quality samples, uncertainty in porosity was about 2% (as shown in Table 1).

Phase II: Primary Drainage Capillary Pressure (P_c) Measurements Using DRP

Vendors B, C, and D used a combination of µCT and higher resolution techniques, whereas vendor A used only µCT images to derive P_c (Figure 3, assuming oil-water IFT γ_{ow}= 28 mN/m.) MICP data are also rescaled for water-oil IFT and plotted. For conventional systems, primary drainage P_c is crucial to determine the original in-place volume, to calibrate well log data, and to quantify the transition zone. In Figure 3, oil-water P_c is plotted up to 160 psi, which will correspond to more than 1000 feet oil column above free water level assuming typical light oil and brine properties.

DRP data from the 4 quarters are consistent with MICP measurements on 2 out of the 4 quarter plugs for the Austin Chalk outcrop in Figure 3(a). DRP data from B (■) indicate higher irreducible water saturation (S_{wir}) than C (▲). DRP-based P_c data from A (◆), and D (●) are measured only up to 5 psi and 25 psi respectively, so we could not define the asymptotic S_{wir} from these 2 datasets. Vendor A used only µCT based images with a nominal resolution of 1 µm, so it was expected that vendor A would only be able to define part of the capillary pressure curve. For a simplistic pore model with a spherical geometry, capillary pressure (P_c) can be converted to pore-throat radius (r) using the Young-Laplace equation $P_c = 2\gamma_{ow}\cos\theta/r$. When images are acquired at a resolution of 1 µm, we expect digital P_c up to about 15 psi. When the image resolution is ~40 nm, the highest reported P_c is expected to be ~400 psi.

MICP can measure P_c to a significantly higher value than DRP-based predictions, however, several limitations with MICP are documented in literature [13] [14]. Mercury is not a reservoir fluid, and it interacts with the rock differently than oil, water, or gas. Due to extremely high pressures imposed at the end of a MICP test (~60,000 psi), mercury can damage clays and intricate pore structure, leading to non-representative S_{wir} values. MICP data can also be erroneous due to conformance correction or lack of sufficient equilibration time at each pressure step [15]. DRP data by C (▲) in Figure 3(a) track closely with MICP (▬) measured on part of the same quarter of the Austin Chalk outcrop plug, even at high pressures. As a result, C reported $S_w < 2\%$ at the highest DRP-based $P_c = 130$ psi. Displacement of water to such low saturation seems surprising given the low permeability of the rock. S_{wir} extrapolated from DRP data from B and D are in the 10-20% range, which appears reasonable. For Austin Chalk, the DRP-based P_c measured by B, C, and D using different workflows match well at low P_c values. A (◆) under predicted P_c, possibly due to strong anchoring to an erroneous MICP-based model.

Primary drainage P_c was calculated on 3 other outcrops and plotted in Figure 3. DRP predictions for “I” indicate higher variation within the 4 DRP vendors. When $S_w > 0.6$, DRP data from vendors A, B and C agree, whereas for $S_w < 0.6$, C (▲) reported significantly higher capillary pressure than B (■) and D (●). For $S_w < 0.6$, P_c is controlled by submicron pore throats, *i.e*. micrite in carbonates. According to the MICP pore throat distribution in Figure 1, “I” has a much wider pore throat size distribution than “AC” and has significant number of pores in the sub-micron scale. Therefore, treatment of micrite using multi-scale imaging techniques in DRP becomes much more crucial for *I* compared to AC. Although, vendors B, C and D had sufficient resolution to visualize most of the micritic porosity in these rocks, they used different techniques to transition from P_c controlled by larger pore throats to P_c controlled by micrite. Differences in these proprietary workflows associated with this transition could be a reason for this mismatch.

Another important finding is the inconsistency between the MICP-based P_c curve measured by C (▬) and D (▬) on their respective quarter plugs. For all 4 higher permeability samples, C reported a more optimistic (lower P_c at a given S_w) P_c curve than vendor D. Sample heterogeneity is unlikely as the data are based on 2 quarters of the same plugs. D (▬) selected fewer pressure steps than C (▬), so we postulate that the differences in the experimental protocol might be the reason for this mismatch. Given the low quality of these samples, it is likely that relative permeability effects interfered with MICP [15]. This interference might have contributed to the mismatch between MICP reported by C and D. If the data were affected by any relative permeability artifact, the real P_c curve could be even more optimistic than MICP-based curve from C (▬).

Comparison of DRP-Based Pc with Centrifuge Measurements

A set of companion plugs from the 4 better quality outcrops (AC, I, S, and T) were used for centrifuge based primary drainage gas-brine P_c measurements. Based on the MICP and poro-perm measurements on the two tighter samples (CO and CM), it was estimated that the conventional centrifuge would not provide sufficient driving force to displace fluids out of these rocks. Therefore, P_c was not measured using a centrifuge for these 2 plugs. Average saturations obtained from the centrifuge tests were converted to face saturations using the Hassler-Bruner technique. A power-law relationship between normalized water saturation (S_{wn}) and capillary pressure *i.e.* $P_c = P_{cth} + A(S_{wn}^B - 1)$ was assumed, where $S_{wn} = (S_w - S_{wir})/(1 - S_{wir})$. Irreducible water saturation (S_{wir}), threshold capillary pressure (P_{cth}), and two other fitting parameters in the model (A, and B) were varied to obtain a set of solutions for which calculated average saturations at each centrifuge speed are within 2% of the experimental values. From these solutions, centrifuge based optimistic bound (COB), and pessimistic bound (CPB) were chosen and plotted in Figure 4. P_c calculated by 4 DRP vendors, along with 2 MICP measurements were re-scaled to gas-brine fluid properties (IFT = 72 mN/m) and plotted alongside experimentally calculated bounds.

A comparison of DRP and physical measurements in Figure 4 indicates that both datasets agree at low P_c, but diverge as S_w declines and P_c increases. In general, the agreement is better for the 2 sandstones compared to 2 carbonate samples. A comparison of MICP and centrifuge P_c data indicates that MICP erroneously asymptotes towards S_{wir} = 0, which might lead to overestimation of the in-place hydrocarbon volumes. We have high confidence in centrifuge based measurements for capillary pressure, due to validation with the porous plate technique and decades of experience comparing those data with saturations found in hydrocarbon reservoirs. DRP based P_c measurements by A (◆) and C (▲) are anchored to MICP data. Therefore these DRP data are expected to have the shortcomings of the underlying MICP data. DRP data from B and D are not anchored to MICP, however those data differ from experimental measurements as shown in Figure 4. In general, DRP-based P_c data appear more optimistic *i.e*. indicate a higher amount of hydrocarbon in-place compared to centrifuge measurements. Due to large differences between centrifuge vs. DRP-based P_c data, we recommend that DRP-based Pc data should not be used for in-place estimation in absence of calibration to experimental data.

Centrifuge based optimistic (COB) and pessimistic bounds (CPB) indicate the level of uncertainty based on experimental data. Uncertainty in DRP-based P_c is non-trivial to calculate, and not reported by any DRP vendor in this study. In the absence of uncertainty quantification of DRP-based data, it becomes hard to compare it against P_c data measured using centrifuge. Therefore, we recommend that the DRP vendors should comment about level of uncertainty in the P_c calculations so that the data can be used in the right context.

CONCLUSION

DRP-based k, φ and primary drainage Pc data: DRP based data reported by 4 vendors did not quantitatively match the physical measurements for *k*, *φ* and primary drainage P_c carried out at our lab, despite commercial DRP services being available for almost 10 years. So, we suggest caution when using DRP results in a quantitative manner without validation with experimental data on at least a subset of plugs. DRP-based permeability was off by a factor of up to 4x, whereas porosity was off by up to 60% for tight rocks. The *k*-*φ* trends reported by each vendor are internally consistent, and clustered around physical data. However, the DRP predictions for *k*-*φ* are not consistent among the 4 selected vendors, e.

g. up to 1 order of magnitude scatter in permeability. DRP-based P_c data agreed with centrifuge data at low values of P_c, but deviated at higher values.

DRP workflows and user's perspective: We gained working knowledge about the DRP service offered by each vendor in terms of the number of scans with various resolutions and degrees of experimental calibration. Plug selection, imaging, segmentation, and modeling can all introduce errors. Dominant sources of error could be highly specific to a given sample, technique, or operator. Most physical measurements are carried out on a plug-scale, whereas most DRP measurements are carried out on multiple length scales like plugs (1 inch), sub-plugs (mm), and SEM images (10 – 100 µm). Representative sampling and upscaling techniques are available and employed to overcome this problem. However, a user should be careful when dealing with DRP data for heterogeneous rocks. Currently, DRP service providers typically provide one value of a rock property, without providing any quantification of uncertainty. DRP measurements are carried out on a voxel scale, which allows the technique to quantify heterogeneity of the plug/mini-plug. Such analysis should be utilized to quantify error and uncertainty. Uncertainty quantification in DRP-based data is necessary to enable appropriate comparisons with physical measurements and improve the utility of DRP data for subsurface assessments.

ACKNOWLEDGEMENTS

We thank ExxonMobil Upstream Research Company management for continued support.

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Table 1. Porosity (*φ*, %) and absolute permeability (*k*, mD) measurements (shaded grey) with DRP-based predictions by 4 vendors based on micro-CT workflow (resolution ~ 1 µm, phase I), and based on a combined micro-CT and SEM or nano-CT based workflow (resolution ~ 40 nm, phase II) are summarized.

Phase I (µCT only)	Lab φ (%)	DRP A	B	C	D	Lab k (mD)	DRP A	B	C	D
Austin Chalk (AC)	29	17.80	22.37	29	9.35	7.81	35.2		8.8	3.104
Indiana Limestone (I)	17	12.70	19.49	16.50	6.44	5.92	24.9	26	15.2	2.409
Carthage Marble (CM)	2 – 4	4	2.35		0.70	0.002	0.036			
Scioto Sandstone (S)	18	15.40	15.15	17.50	8.58	1.38	8.1	0.6	1.2	0.539
Torrey Buff (T)	16	15.50	14.22	7.50	6.33	1.2	3.9	1.7	1.13	0.337
Crab Orchard (CO)	4 – 6	1.10	6.10		4.17	0.005	0.001			
Phase II (all tools)		A	B	C	D		A	B	C	D
Austin Chalk (AC)	29	17.80	22.37	29	6.87-10.40	7.81	35.2	5.4	8.8	1.43
Indiana Limestone (I)	17	12.70	19.49	16.50	6.44	5.92	24.9	31.6	14.2	2.41
Carthage Marble (CM)	2 – 4	4	2.35	1.3	0.70	0.002	0.036	0.008	0.001	
Scioto Sandstone (S)	18	15.40	15.15	18	8.58	1.38	8.1	1.5	1.2	0.54
Torrey Buff (T)	16	15.50	14.22	13.6	6.33	1.2	3.9	0.8	1.3	0.34
Crab Orchard (CO)	4 – 6	1.10	6.10	4.3	4.17	0.005	0.001	0.002	0.008	

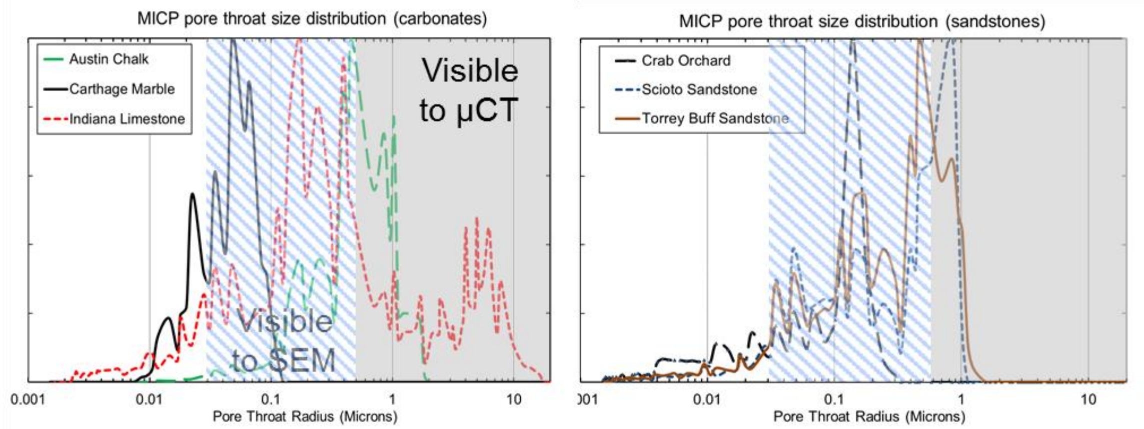


Figure 1. Pore throat size distribution interpreted from MICP measurements on all 3 carbonates (left), and 3 clastics (right) outcrop conducted on portions of the quarter plugs supplied to vendor C. Shaded area represents the pore throats visible to µCT, whereas the hatched area indicates the pore throats visible in a SEM with 40-50 nm resolution that are not visible during µCT based evaluation.

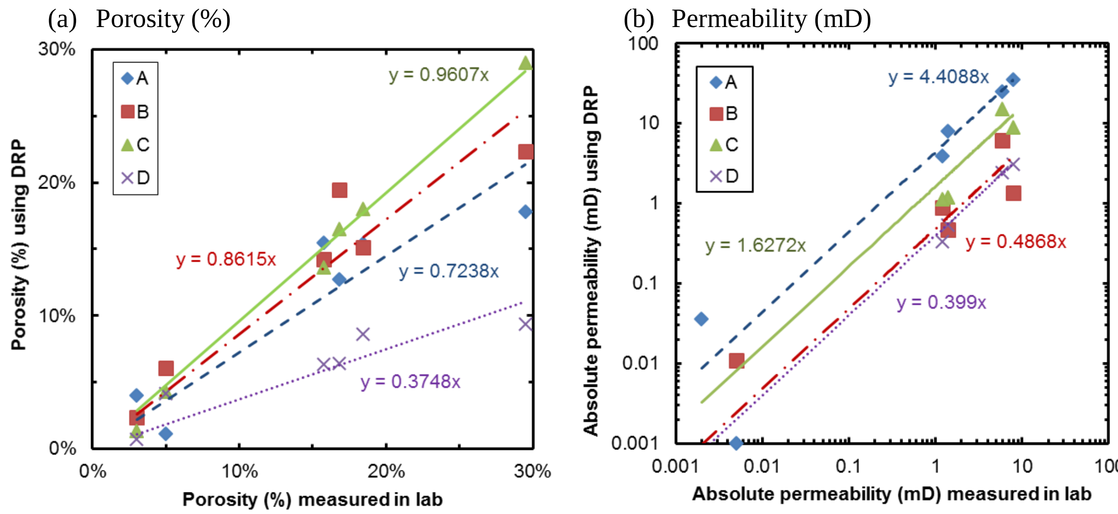
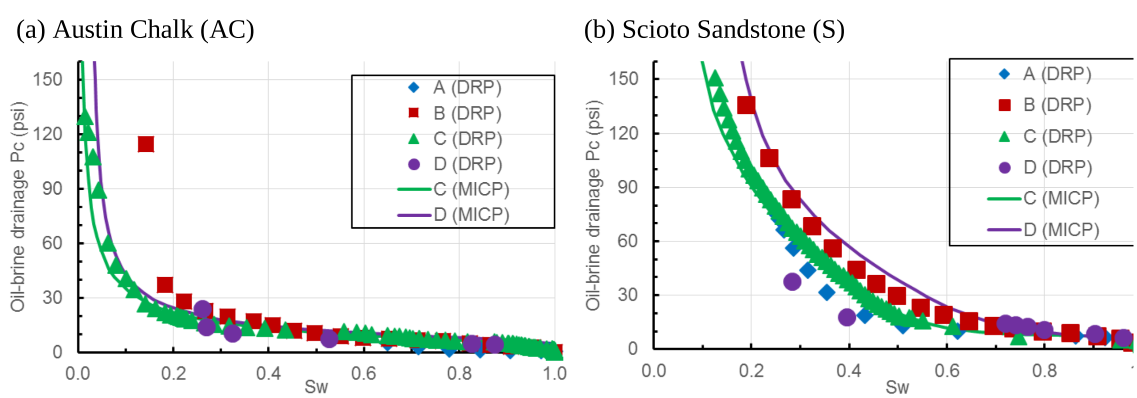


Figure 2. Cross-plots of (a) porosity (%), and (b) permeability (mD, log scale) measurements in lab vs. calculated using DRP based on highest resolution tool by 4 DRP vendor labs are shown.



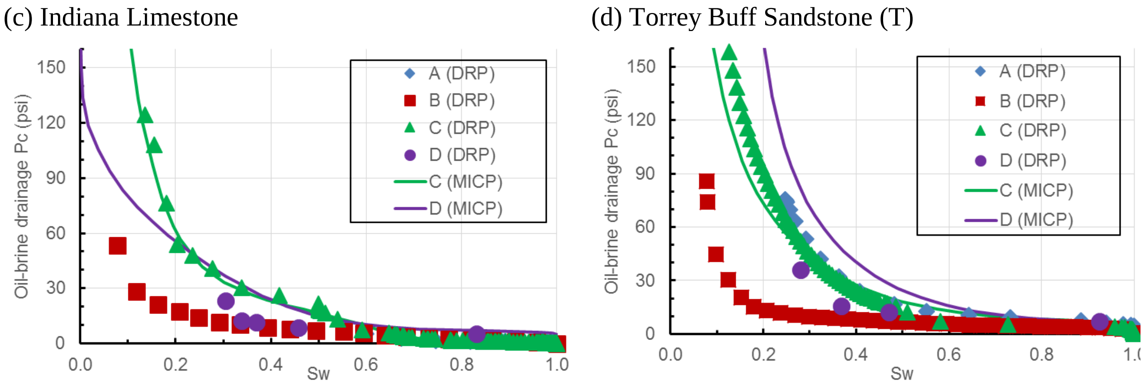


Figure 3. A comparison of DRP-based primary drainage P_c for Austin Chalk (AC), Indiana Limestone (I), Scioto (S), and Torrey Buff (T) calculated by 4 vendors is plotted along with IFT-scaled MICP curve.

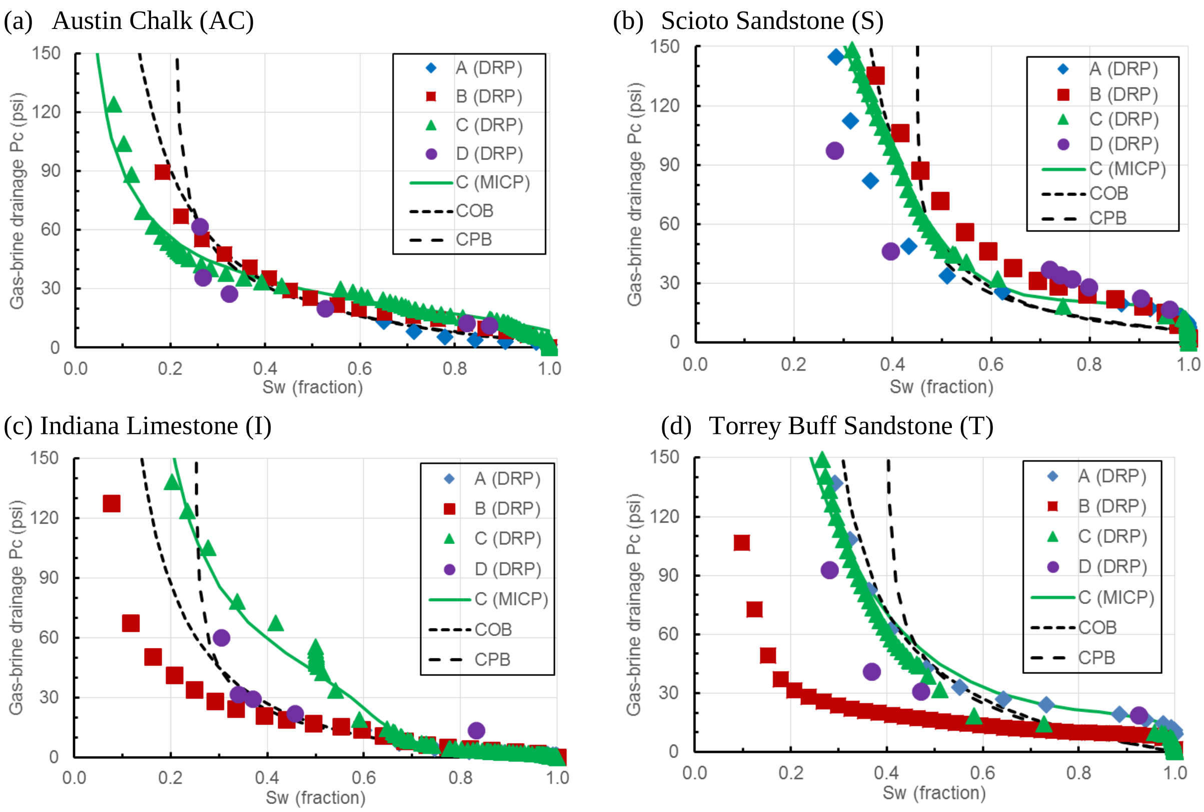


Figure 4. A comparison of DRP-based primary drainage P_c by 4 vendors on four quarters of the same plugs, along with MICP measurements conducted by vendor C on parts of the quarter plugs. Centrifuge based optimistic bound (COB) and pessimistic bound (CPB) are plotted for comparison for the four outcrops.