Quantification of the Gas- and Liquid-in-Place and Flow Characteristics of Shale and Other Fine-Grained Facies in Northeastern British Columbia

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Introduction

The total resource potential of gas shales in British Columbia is estimated to be in the hundreds to thousands of trillions of cubic feet (3×10^{10} to 3×10^{11} m^3) of gas and as yet an unquantified amount of liquid hydrocarbons (condensate, natural gas, liquid and oil). Liquid production from shales is particularly important since the liquids currently drive the economics of most unconventional prospects due to depressed gas prices.

Success in developing shales as petroleum reservoirs has not been paralleled with increased understanding of the geological processes that determine gas- and liquid-in-place or their production potential. Simple analyses of the current level of organic maturity has not proved satisfactory in predicting liquids production particularly in areas where maturity, kerogen type, reservoir conditions (pressure and temperature) and rock character changes laterally, such as in northeastern BC.

With the support of Geoscience BC and industry partners, a multifaceted study of strata in northeastern BC has been initiated with the objective to better predict the areal distribution of potential liquid-producing shale and its production potential. The study has two interrelated components: 1) development of better methodologies for quantifying gas- and liquid-in-place in gas shale and shale oil reservoirs and measuring matrix flow characteristics; and 2) quantification of the gas- and liquid-in-place and flow capacity of important shales in northeastern BC using established methodologies and novel ones developed as part of this study. Research is focusing on key horizons, for which considerable data is at hand, including the Muskwa, Exshaw, Montney, Doig, and Buckinghorse formations, Gordondale Member (formerly the informal Nordegg member) and their equivalents. Additionally, various liquid-producing shales from other basins are being studied for comparative purposes.

In the initial stages of this study, the extensive historical data available on the maturity and source rock properties of the important shale horizons will be compiled and stitched together to create regional surfaces of key properties. The gaps in the regional maps will be augmented by additional sampling and analyses. Access to new cores, supplied by the industry partners, provided the opportunity to do analyses for which achieved samples are ill suited. The maps will be integrated with current production data available in the public domain.

Developing a predictive model for liquid production from shales, which is a goal of the study, requires an in depth understanding of the total petroleum system in northeastern BC. The petroleum system of self-sourced shale reservoirs is complex. Hydrocarbons that are generated depend on kerogen type and thermal history, and hydrocarbons that are retained in shales are a fractionated part of the generated hydrocarbons. Retained hydrocarbons are also subject to alteration with additional burial and possible further selective migration of secondary generated hydrocarbons. During production, the retained hydrocarbons are further fractionated, such that the produced product does not necessarily correspond to that retained in the reservoir. Yet a further complication is the high capillary pressure, which is largely responsible for selective migration, retention and production and varies with pore structure and wettability, which in turn depends on mineralogy, fabric, fluids and thermal history.

In this paper, two questions are addressed: 1) what is the utility of measurements of retained hydrocarbons in shales and how can these data be calibrated or corrected for con-

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tamination by oil-based drilling fluids; and 2) what is the impact of contamination by drilling or completion fluids on measured wettability of the shales and how does the wettability and hence capillary pressure vary with lithology and thermal maturation.

Retained Hydrocarbons in Shales

Out of necessity, in this study, there is some dependence on historical data collected on archived core and new analyses of archived core. The most useful measurements for mapping liquid potential of shales, apart from production data, would be a direct measure of the retained hydrocarbons in the rock. The Rock-Eval (Espitalié et al., 1977) type instruments provide a measure of the retained hydrocarbons by heating the samples to 300°C and measuring the amount of hydrocarbons via a calibrated flame ionization detector. The Rock-Eval–type instruments also provide other indices such as T_{max} (temperature at maximum release of hydrocarbons), which is a measure of thermal maturity, and the hydrogen and oxygen indices (to name a few) that help characterize the kerogen in the rock. Many thousands of these types of measurements exist for strata in northeastern BC and provide a wealth of information and a starting point for this study. Newer instrumentation, referred to as S1 analyzers, can characterize thermally desorbed retained hydrocarbons by chromatography (Agilent Technologies, Inc., 2011), which can be used, for example, to calculate the retained liquid gravity.

Two of the major difficulties in using Rock-Eval or S1 analyzer results are the potential impact of oil-based drilling mud, which is commonly used in wells of interest, and the effect of 'aging' on the geochemistry of archived samples. In order to address these issues and to calibrate archived data, two Montney Formation cores, preserved at the well sites, were studied. The cores came from two different areas: one where there is significant liquid production (T_{max} ≈444°C) and a second area of mainly dry gas production (T_{max} ≈465°C). The results are presented below. The wells are referred to here as OW (from the oil window) and DG (from dry gas zone).

Experimental Methodology

Using nitrogen, plugs with a diameter of 0.635 cm (0.25 in.) were cored from preserved whole cores in order to assess the effect of drilling fluid infiltration on organic geochemical properties in tight reservoirs. Sections of the whole core selected for sampling were either 8.89 or 10.16 cm in diameter and greater than 25.00 cm long. Plugs were taken a minimum of one half the diameter of the core from the base ends of the sample, but typically directly in the centre. This ensured that infiltration of drilling fluid from ends of the core sample did not influence results. Plugs were then sectioned into four 1.1 cm pieces and designated zones 1 through 4, where zone 1 is nearest the surface and zone 4 represents the centre of the core (Figure 1). For sample OW-C, an additional subsample (S) from 1 to 2 mm from the core surface was also analyzed.

Organic Geochemistry

A commercial Rock-Eval–type instrument was used to quantify the hydrocarbons within the preserved plugs as recorded by the first peak (S1) on the pyrograms. Thermal desorption gas chromatography (TDGC) was used in conjunction with source rock analysis (SRA) to quantify the relative contribution of various hydrocarbon molecules to the total hydrocarbons present. Thermal desorption has been used to characterize the hydrocarbon molecules present within oil shales (Crisp et al., 1986), but to the authors' knowledge no study has been published using TDGC on tight reservoirs to document and fingerprint the infiltration of drilling fluid.

Results

Results for the S1 analysis are presented in Figure 2 for the OW well and in Figure 3 for the DG well. Each sample is from a different part of the core from the respective wells and hence vary in lithology and fabric.

The S1 values for all samples from both wells are markedly higher toward the margin of the core as a result of contamination by oil-based drilling mud. The S1 decreases from the edge of the core toward the centre. There is little difference between zones 3 and 4 for all but one sample, suggesting zone 4 is not impacted by the drilling mud. The exception is sample DG-A, in which there is a progressive decrease in S1 in all the samples toward the core centre and contamination of even the centre of the core cannot be ruled out. Permeability and other analyses in progress will try to account for the different degrees of core contamination.

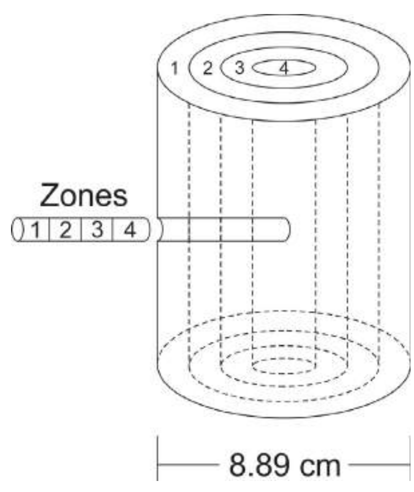

Figure 1. Sampling protocol: a plug was drilled into the core using nitrogen and subsequently sectioned into four subsamples, labelled zones 1 through 4 from the surface to the centre.

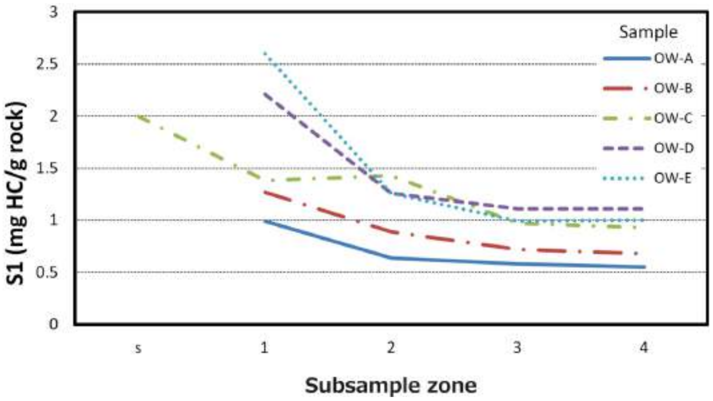

Figure 2. Montney Formation oil-window (OW) core. Variation in S1 (mg HC/g rock) from the surface of the core (zone S) to the centre (zone 4) for five subsamples. Refer to Figure 1 for location of subsample zones. Abbreviation: HC, hydrocarbons.

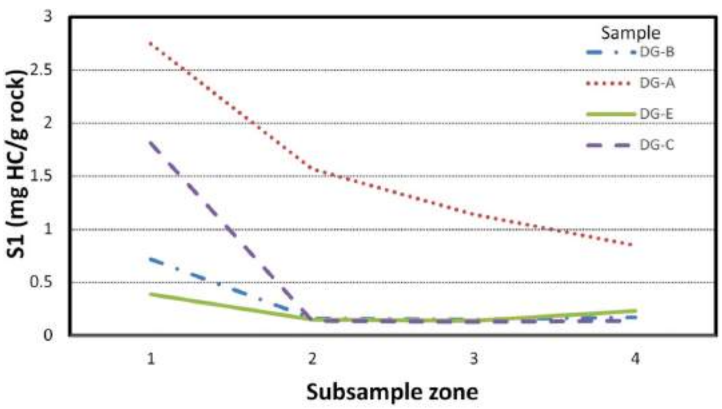

Figure 3. Montney Formation dry gas zone (DG) core. Variation in S1 (mg HC/g rock) from the surface of the core (zone 1) to the centre (zone 4) for four subsamples. Refer to Figure 1 for location of subsample zones. Abbreviation: HC, hydrocarbons.

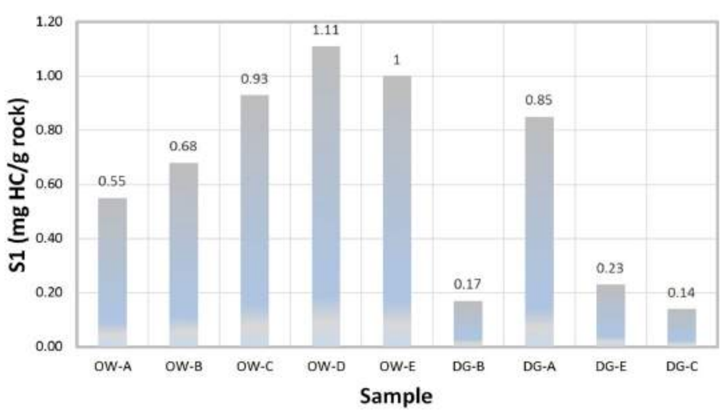

Figure 4. Comparison of the S1 values from the centre subsample of each sample and for both wells. The higher S1 values in the samples from the oil-window (OW) well is anticipated due to indigenous oil-in-place (the well produces liquids). The high S1 value of sample DG-A from the dry gas zone (DG) well is due to contamination throughout by oil-based drilling mud.

The difference in S1 values from the centre zone of each sample are compared for both wells in Figure 4. As anticipated, the samples from the oil window (which produce liquids) have higher S1 values due to indigenous oil-in-place. The exception is sample DG-A, which, as noted above, appears to be contaminated throughout by the oil-based drilling mud.

To further investigate the degree of contamination by oil-based drilling mud, subsamples from sample OW-A were subjected to thermal desorption and the products were analyzed. The most notable trends in the results (Figure 5) are an increase in light condensate and an associated decrease in heavy condensate at the margin of the core due to contamination by oil-based mud. The most notable trend is the increase in C8 hydrocarbons toward the core margin.

Wettability of Shales: Impact of Sampling Techniques, Composition and Maturity

The nanometre- to micrometre-sized pores found in shale and other fine-grained facies result in extremely high capillary pressures. Capillary pressure is one of the principal determinants of hydrocarbon retention, relative permeability and imbibition and thus is important to quantify and is an important metric in this research project. Interfacial tension and pore geometry (size) and wettability (contact angle) determine capillary pressure (Falode and Manuel, 2014). Obtaining reliable measures of contact angles representative of the rocks and fluid systems in the subsurface and understanding compositional and maturity controls on wettability is thus crucial to meeting the broader goals of this research project.

In this paper, the reliability of wettability measurements of drilling-fluid–contaminated core samples was investigated and some preliminary results on the impact of shale composition and thermal maturation are provided.

Impact of Drilling-Fluid Contamination

To investigate the impact of the interaction between rock and drilling fluids during coring on wettability, profiles of contact angles were collected across samples from edge to edge through the centre of the two cores described earlier (Figure 1). Wettability profiles could then be compared to profiles of retained hydrocarbons, which represent varying levels of contamination with oil-based drilling mud. Interaction with both oil- and water-based drilling muds may alter wettability by coating mineral faces that form pore walls. In this

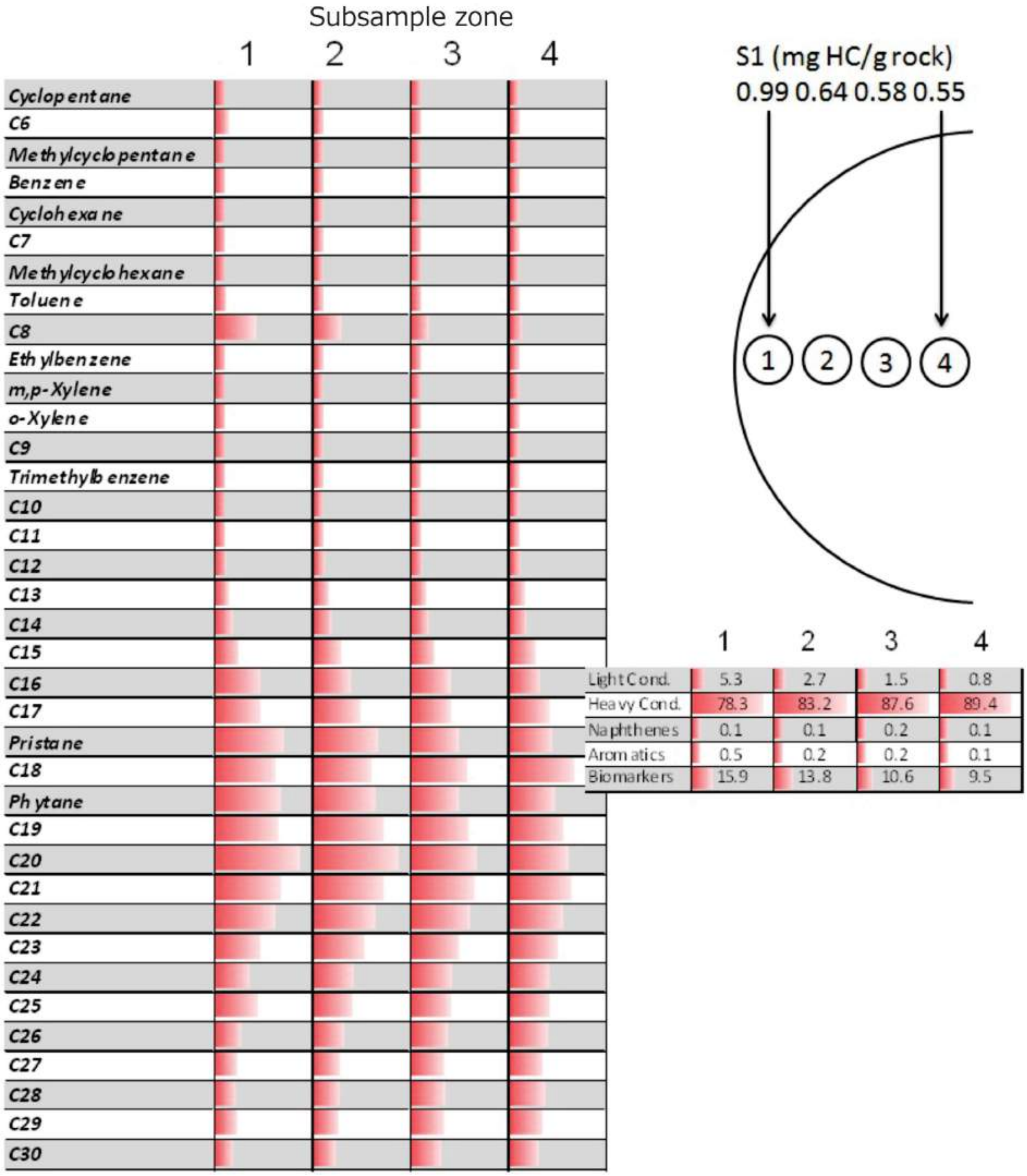

Figure 5. Thermal desorption products of subsamples from sample OW-A. The inset cross-section of the core shows the approximate locations of the subsample zones. The chromatograph data is relative. Abbreviations: Cond, condensate; HC, hydrocarbons.

study, contact angles were measured using the sessile drop method on fresh surfaces prepared under a nitrogen atmosphere.

The contact angle measurements of the two samples across the diameter of the core are shown in Figure 6. The variation in S1 peak across the samples (documented above) is poorly reflected in the contact angle measurements. With the exception of the sample at about 5 cm there appears to be a trend toward lower contact angles (more water wet) at the more invaded margin of the cores. However, the overall trend is within the variability of repeat measurements (~5–10°) and hence must be interpreted with caution. The lack of a more distinct wettability variation with invasion across the samples is probably due to the high proportion of new mineral surfaces exposed when cutting the samples, compared to invaded fluid (about 2–5% of the rock volume).

The two tested samples have significantly different contact angles (Figure 6); the contact angle for the OW sample is about 25° higher than the DG sample. Such results are consistent with preliminary data from other formations in the Western Canadian Sedimentary Basin (WCSB) and Eagle Ford trends in Texas, which suggest the wettability of water-based fluids is lowest in the oil window and decreases with both decreasing and increasing thermal maturity.

Compositional Controls on Wettability

The impact of compositional controls on wettability are being investigated across the WCSB. Preliminary data show a strong correlation between total organic carbon (TOC) and measured contact angles (Bustin, 2014). Contact angles of water in decane and total organic carbon content show positive correlation for Muskwa Formation (R^2 value of 0.72; Figure 7). Contact angles of water in air and total organic carbon content show a positive correlation for Duvernay Formation samples (R^2 value of 0.78; Figure 8). These correlations are expected due to the known hydrophobic nature of organic matter. Other properties display weaker correlations with wettability (e.g., negative correlation of total clays and contact angle). However, with the limited dataset collected thus far, it is not possible to determine if the weaker correlations are spurious correlations (Pearson, 1897) resulting from the fact that the sum of all composition data is a constant (Chayes, 1960), or if in fact mineralogical composition partially controls the observed contact angle variation.

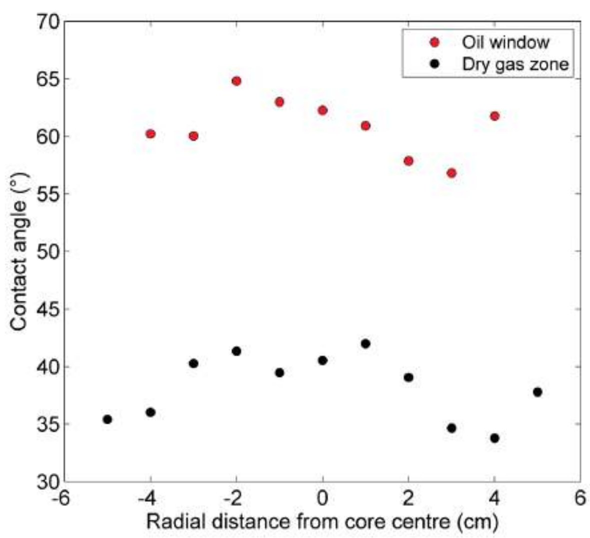

Figure 6. Contact angle profiles from edge to edge through the centre of two core samples. Any systematic variation due to drilling fluid invasion is so small that it is within the variability of repeat measurements (~5–10°).

Even with the limited dataset collected so far, wettability shows a large variation within a single formation (e.g., contact angles between ~20 and 100° for water in decane on Muskwa Formation samples, Figure 7). This variation is significant because it translates to very large capillary pressure differences and hence hydrocarbon distribution.

Summary and Conclusions

In order to establish the utility of Rock-Eval–type data and wettability measurements for mapping and predicting liquid hydrocarbon distribution in shales in northeastern BC, the impact of contamination of core samples by oil-based drilling mud has been investigated. The S1 (mg HC/g rock) analyses that would ideally represent the generated but retained hydrocarbons in fine-grained rocks are strongly contaminated by oil-based drilling mud in Montney Formation strata from the dry gas zone and oil window. Only samples collected from the central 2 cm of 9 cm diameter cores appear to have escaped invasion/imbibition of oil-based drilling mud. Analyses of the hydrocarbons by thermal desorption indicate the invaded portion of core are enriched in light condensate and notably C8 hydrocarbons.

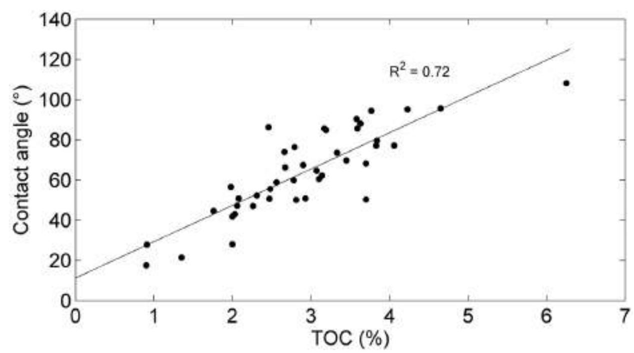

Figure 7. Correlation of contact angle for water in decane to total organic carbon (TOC) for all Muskwa Formation samples analyzed to date. Of all properties measured, TOC yields the strongest correlation with wettability.

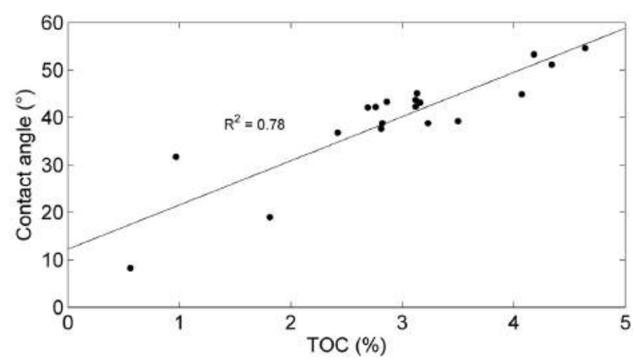

Figure 8. Correlation of contact angle for water in air to total organic carbon (TOC) for all Duvernay Formation samples analyzed to date. Of all properties measured, TOC yields the strongest correlation with wettability.

The invasion of drilling fluids into core of conventional reservoir rocks has been investigated using tracers and other techniques (i.e., Menouar et al., 2002; Tracerco, 2014). Intuitively, it has been assumed, although not demonstrated, that ultra-low permeability rocks are less susceptible to infiltration by completion or drilling fluids. However, because of the high capillary pressures of tight rocks, imbibition may be pronounced, as found in this study. These results clearly illustrate that care must be taken when selecting samples for mapping retained hydrocarbons and that the saturation calculations routinely performed by commercial laboratories, even on preserved cores, must be viewed with extreme caution.

The variation in wettability (contact angles) measured on new core surfaces perpendicular to the core axes do not show a significant trend with degree of invasion/imbibition of drilling oil. Such results probably reflect the dominance of new mineral surfaces created during sample preparation and the relatively small pore volume of the samples. The core from the oil window had higher contact angles (~25º) than the core from the dry gas zone. Such results are consistent with the preliminary mapping data, which shows wettability appears to pass through a minimum in the oil window for the Duvernay, Muskwa and Montney formations. Trends in wettability with maturity can be overprinted by variation in wettability with lithology. Preliminary wettability measurements on the Muskwa and Duvernay formations show a strong dependence on the amount of total organic carbon present, which undoubtedly reflects the strong hydrophobicity of the organic fraction.

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