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# In situ versus produced hydrocarbons in unconventional reservoirs: insight from produced and mud gas geochemistry (Montney resource play, Western Canada).

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## Summary

Due to sustained low gas price in North America over the past 10 years, most of the industry activity has been focused on the liquids-rich gas and light oil fairways of unconventional plays. Production data from the Montney play of Western Canada show that although a broad liquids-rich fairway can be defined at the basin scale, local variations of both fluid distribution and reservoir quality strongly affect the liquid recovery from horizontal wells. The geochemical compositions of both mud gas and produced gas provide a powerful tool to investigate those local variations, their geological controls and their impact on well performance. The high density and large amounts of well data available in the Montney play allows the produced gas composition to be mapped from the field to the basin scales within a well-defined stratigraphic framework. This mapping clearly delineates regional thermal maturity fairways locally modified by hydrocarbon migration pathways and structural discontinuities. It demonstrates that the stratigraphic architecture and the structural framework of the Montney Formation have a strong influence on the lateral and vertical distribution of fluids. Several examples are presented to illustrate the use of gas geochemistry to better constrain the main controls on well productivity and produced fluid composition, from pad to regional scales. Ultimately, this information can be coupled with PVT analysis to tailor the stimulation design and depletion strategy and maximize the liquid recovery from horizontal wells.

## Theory and method

A fundamental aspect of liquids-rich unconventional reservoirs with micro- to nano-darcy permeabilities is that heavier hydrocarbon molecules can be left behind in the reservoir during production, resulting in large differences between in situ and produced condensate-gas or gas-oil ratios (Whitson and Sunjerga, 2012; Jarvie et al, 2015). Produced hydrocarbon are therefore often not representative and tend to be lighter than the reservoir fluids, depending on multiple parameters including reservoir permeability, pore pressure, in situ fluid PVT, stimulation design and depletion strategy. Gas composition provides however an excellent proxy for in situ hydrocarbon composition, because C1 to C5 alkanes do not seem to be strongly fractionated during early production of hydraulically fractured horizontal wells. This observation may be because the early production comes from the close vicinity of hydraulic and reactivated natural fracture surfaces. The mapping of thousands of early production gas analyses shows a geologically consistent distribution from local to regional scales, within the stratigraphic framework. For the purpose of this mapping, the landing zone of over 4,500 horizontal wells in in westernmost Alberta and northeastern British Columbia was allocated visually in 3D to a given stratigraphic unit, based on the correlation of nearly 8,000 wells throughout the basin (Crombez et al., 2016; Davies et al 2018, Euzen et al 2018a). This gas composition mapping outlines the regional thermal maturity windows, locally influenced by gas migration fairways and linear discontinuities interpreted as sealing or conductive faults (Euzen et al 2018b). Mud gas on the other hand systematically shows dryer composition than early production gas from the same wells suggesting that the gas released to the wellbore while drilling is fractionated and leaner than the reservoir gas. Therefore, mud gas composition is likely influenced by both fluid composition and reservoir quality variations along laterals (Chatellier et al, 2018). Produced gas and mud gas geochemistry provide complementary information that can be combined to better constrain in situ fluid composition and potential liquid recovery from horizontal wells.

## Results

The mapping of early production gas dryness (C1/Σ[C1-C5]) from several thousand of wells demonstrates the existence of at least (and probably more than) two hydrodynamic units within the Montney Formation, with different fluid compositions and local trends. For instance, gas composition in the Lower Middle Montney (Smithian) is affected by faults that do not seem to impact the Upper Montney (Spathian; Euzen et al., 2018b). This emphasizes the need for properly assigning individual horizontal wells within a well-defined stratigraphic framework to reveal vertical and lateral changes of hydrocarbon composition at regional scale. Figure 1 illustrates the thermal maturity windows and hydrocarbon migration pathways in the Upper Montney (Spathian) of westernmost Alberta and northeastern British Columbia, based on early production gas dryness mapping.

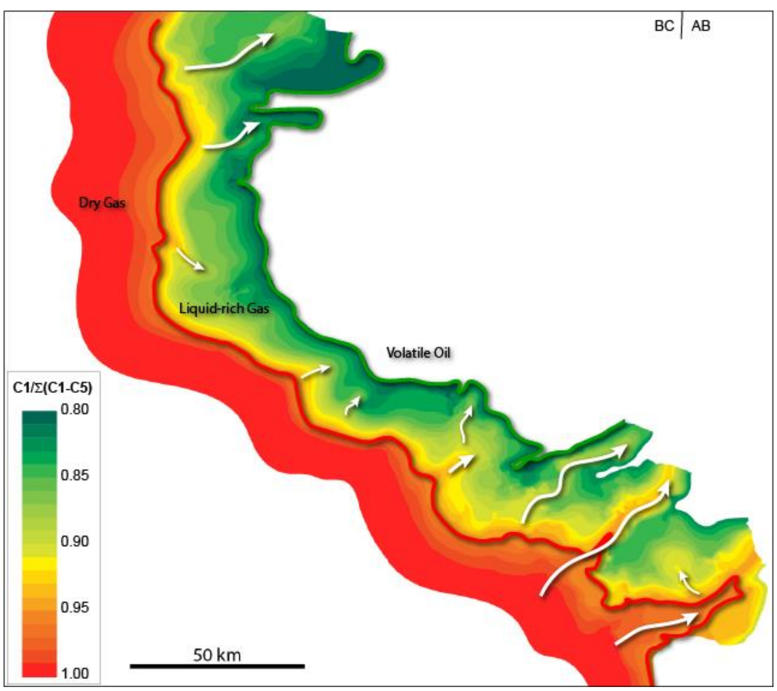


Figure 1: Early production gas dryness (C1/Σ[C1-C5]) in the Upper Montney of westernmost Alberta and northeastern British Columbia. White arrows represent hydrocarbon migration pathways inferred from the gas composition mapping.

The gas dryness consistently decreases up dip across the Upper Montney liquids-rich fairway down to a value of about 0.8 (Fig. 1). Based on production data, this gas dryness threshold seems to coincide closely with the transition between the liquids-rich gas and volatile oil windows in the Upper Montney. In the oil window, the spatial distribution of gas dryness values becomes erratic and cannot be used anymore as a proxy for in situ hydrocarbon composition. The dry gas window was defined downdip of the 0.95 dryness isoline, beyond which only dry gas is produced in the Upper Montney.

In the liquids-rich gas window, the relationship between in situ and produced fluid composition can be investigated by plotting the condensate-gas ratio (CGR) as a function of early production gas dryness. Figure 2 illustrates the average CGR over the first 4,500 hours of production (approximately 6 month of effective production) versus the gas dryness of 524 horizontal wells in the Lower Middle Montney of Regional Heritage area (LST2). This cross-plot shows that the maximum value of average CGR increases with decreasing gas dryness and defines a power relationship between the “maximum CGR” and the gas dryness (grey curve on Fig. 2). Unfortunately, condensate production is not consistently reported across the industry and some of the data points along the X-axis of the cross-plot of Figure 2 are unreliable. Nevertheless, the relationship between gas dryness and CGR can still be used for the wells that do have condensate production data available.

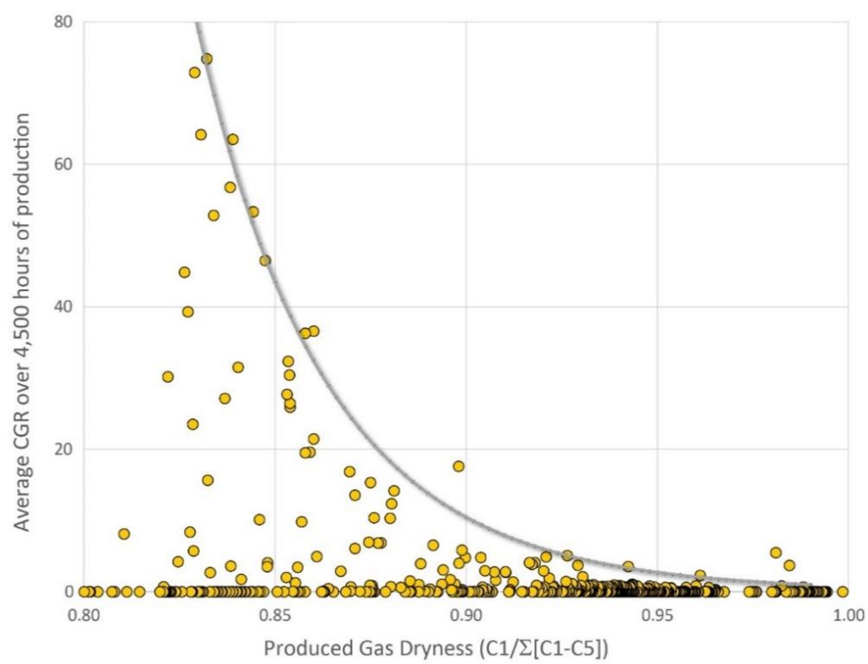


Figure 2: Average CGR over 4,500 hours of production versus produced gas dryness (earliest analysis available) from 524 horizontal wells producing from the lower part of the Middle Montney in regional heritage area (LST2, Euzen et al. 2018a). The grey curve is the envelope of the maximum average CGR and define a power relationship with produced gas dryness.

The maximum CGR curve can be used as a benchmark for optimal liquid recovery and the wells below the curve may be interpreted as leaving high-value liquids behind in the reservoir. There can be multiple causes for this sub-optimal behavior (from a CGR standpoint), and they may

include lower reservoir quality (cementation, bitumen plugging, etc.), pore pressure at or below the saturation pressure of in situ fluids (due to initial reservoir pressure and/or to an aggressive drawdown strategy), or to inefficient fracture treatment.
Figure 3 illustrates the case of 7 wells from close pads in the Doe field, producing from a single stratigraphic interval (LST2) and within a narrow range of gas dryness (0.82-0.83). Figure 3 shows a strong correlation between the proppant concentration and the average CGR over 8,000 hours of production, with a Pearson correlation coefficient $R^2$ close to 0.9. In this example, the wells are interpreted as having similar reservoir quality and in situ fluid composition and the liquid recovery seems dominantly controlled by the proppant concentration in the fracture treatment.

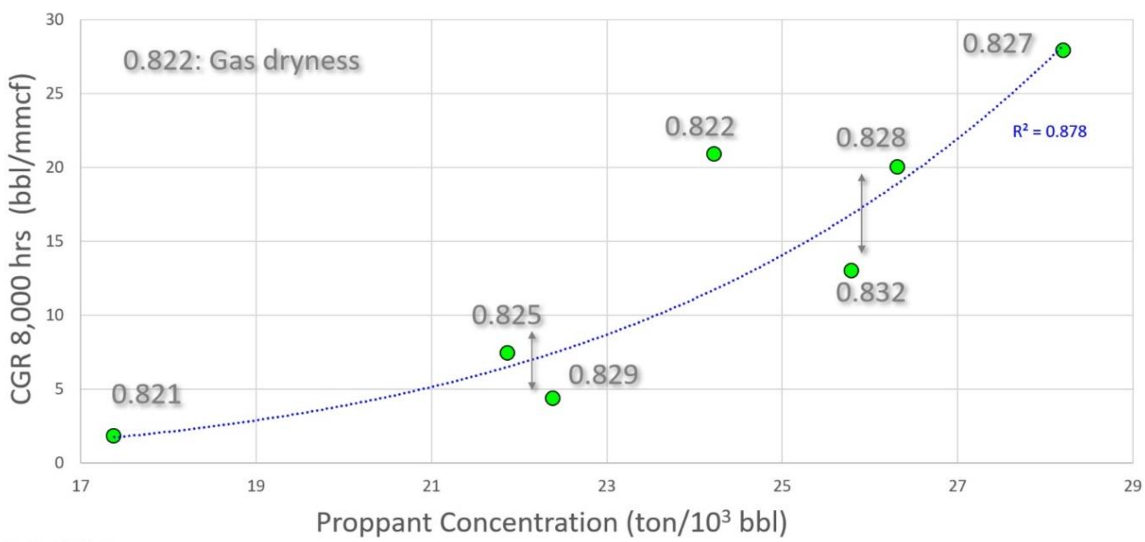


Figure 3: Average CGR over 8,000 hours of production versus proppant concentration in the fracture treatment.

Figure 4 illustrates the relationship between the CGR, the proppant tonnage and produced gas dryness of 82 wells producing from the Upper Montney in the Sunrise field. The overall positive correlation between the CGR and the total volume of proppant injected is poor. However, when the produced gas composition is superimposed, the relation between the CGR and the proppant tonnage improves significantly (colored arrows). Variations of reservoir quality are likely also contributing to the dispersion of datapoints in this cross plot, given that the production from these wells comes from several stratigraphic benches within the Upper Montney.

The difference between mud gas and produced gas compositions was investigated by comparing average mud gas dryness along laterals with early production gas dryness from the same wells. Four wells were selected from two different fields (Pouce Coupe South, wells A and B; Swan, Wells B and C), producing from the same stratigraphic zone (LST2) and with similar produced gas but contrasting mud gas compositions.

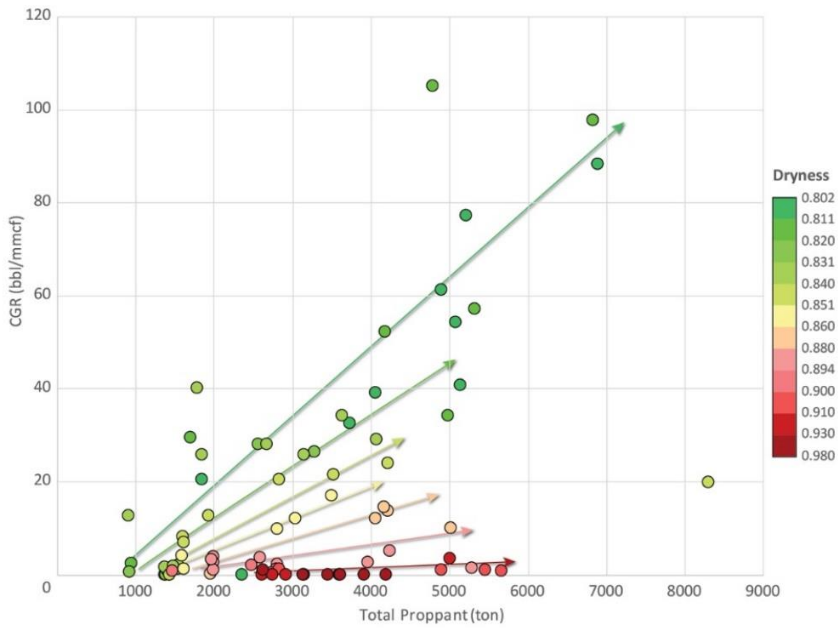


Figure 4: Average CGR over 4,500 hours of production versus proppant tonnage in the fracture treatment and produced gas composition in the Upper Montney of the Sunrise field.

Figure 5 illustrates the mud gas log along the fracked interval (red curve) of those four wells along with the early production gas composition (purple horizontal line). It shows that wells A and B have a relatively homogeneous mud gas composition (dryness of 0.96-0.98) that is much dryer than the produced gas. On the other hand, wells C and D have a more variable mud gas composition (dryness of 0.91-0.96) that is closer to the produced gas dryness. This might suggest that the mud gas in the two wells from Pouce Coupe South is more fractionated due to a lower reservoir permeability compared to the Swan wells. Comparing the gas production from those four wells (Fig. 6) shows that wells C and D have much higher gas rates than wells A and B. Condensate-gas ratio is also higher in the two wells from Swan (Fig. 5) but this might be due to the condensate production not being reported in wells A and B. Also, the two wells from Swan are about 500 meters deeper (TVD) than the wells from Pouce Coupe South and pore pressure might also be responsible for the differences in gas rates. Furthermore, wells A and B were stimulated with higher fracturing fluid volumes (2 to 3 folds) and lower proppant tonnage (a third) than wells C and D. These four wells have the same orientation and lateral length.

In this example, there are too many unknown to positively identify the main control on productivity, but the two pairs of wells are nearly 30 kilometers apart and lateral changes of reservoir quality are more likely than in the previous examples. Furthermore, regional produced gas dryness mapping of the LST2 stratigraphic unit (Euzen et al., 2018b) strongly suggests that the Swan field is located on a gas migration fairway, which also points towards higher permeabilities in this field.

## Novel/Additive Information

It is now well recognized that produced fluids from unconventional reservoirs depart from in situ hydrocarbon compositions due to molecular fractionation during production. Multiple parameters influence horizontal wells productivity and separating geological from operational factors is a major challenge for the industry. Mud gas and early production gas geochemistry combined with produced CGR or GOR data provide complementary sources of information that can be integrated to better understand the difference between in situ and produced fluids and the main drivers that control this fractionation. In future work, pressure and temperature data, as well as additional constraint on the structural framework will be integrated to this gas geochemistry and production data analysis to reduce the number of unknown variables and strengthen our understanding of the main controls on horizontal wells productivity.

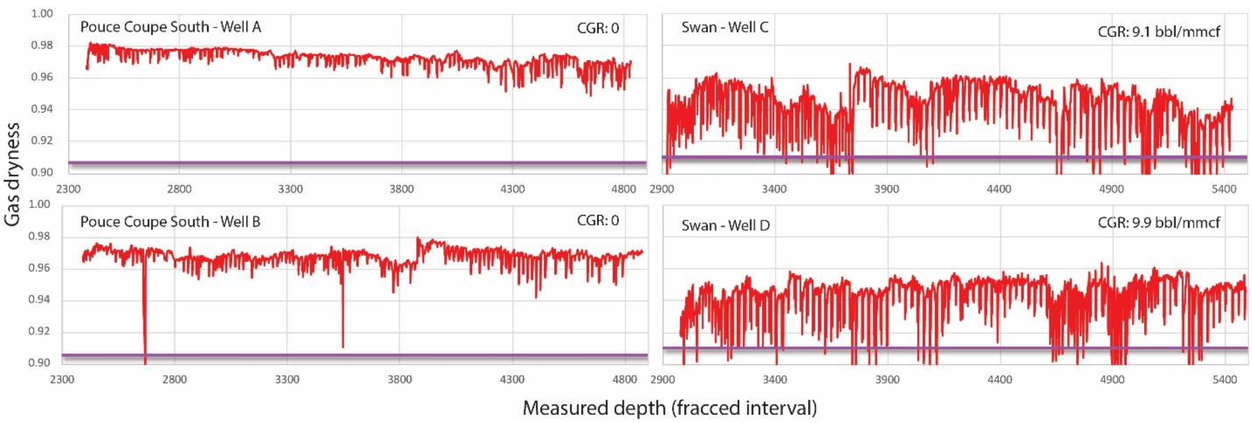


Figure 5: Mud gas (red curves) versus produced gas (purple straight lines) dryness along fracked intervals of 4 wells from Pouce Coupe and Swan fields landed in LST2 stratigraphic unit. The CGR is the average value over 750 hours of production as reported.

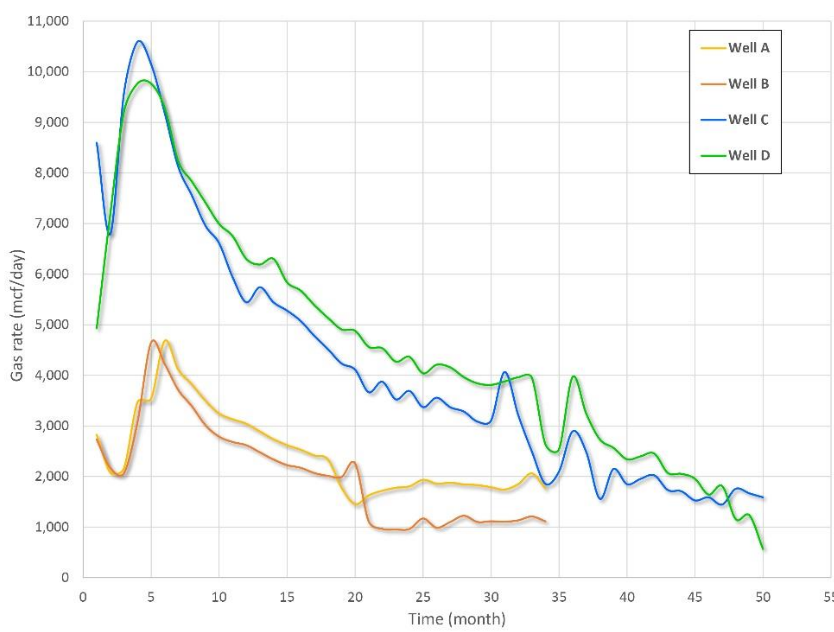


Figure 6: Gas rate production curves of four horizontal wells from Pouce Coupe South (well A and B) and Swan (well C and D) fields.

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