

Molecular and Isotope Geochemistry of Liquid Hydrocarbons from the Montney Formation

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Introduction

Assessing unconventional resources from the Montney Formation is rather complex because fluid migration has occurred within the formation and also from adjacent formations, which makes the Montney a hybrid petroleum system containing in-situ and migrated hydrocarbons. Fundamental organic geochemistry studies of the Montney Formation were performed in the 1990's when only its conventional resources were exploited. More recent studies are often restricted to bulk geochemical parameters such as rock-eval and total organic carbon content analyses (e.g. Egbobawaye, 2017). The total organic carbon content (TOC) of the entire formation varies from 0.16 to 3.83% with an average of 0.8% (Ibrahimbas and Riediger, 2004; Rokosh et al, 2012), and the kerogen ranges from type II/III to III/IV and IV (Riediger, 1997; Crombez et al., 2017; Egbobawaye, 2017), with thermal maturity within the oil window (e.g. Rokosh et al, 2012). The industry continues to produce gas/condensate petroleum from the Montney Formation, and some attention has been focused on the organic and isotope geochemistry of its natural gas resources (Tilley and Muehlenbachs, 2013; Wood and Sanei, 2016). However, little is known about the geochemical processes favoring the accumulation of low-molecular-weight liquid hydrocarbons (C₇-C₁₅) in different stratigraphic intervals, which significantly increase the value of the play.

In this study, we have analyzed condensate petroleum from the Montney Formation, with the purpose of conducting a petroleum geochemistry screening. The assessment used a non-biomarker based approach as these fluids lack biomarkers, and consists of the molecular and stable carbon isotope analysis of selected liquid hydrocarbons in the C₇-C₂₀ range. The findings have been correlated to the up-to-date knowledge on the occurrence and formation pathways of natural gas from the same region.

Methods

The whole-oil analysis of the condensates was performed by AGAT Laboratories Ltd. according to their established methods for gas chromatography - flame-ionization detection (GC-FID) on a Restek Rtx-1 (Catt# 10153) column. The abundance of aliphatic and aromatic hydrocarbons from the condensates was measured via gas chromatography – mass spectrometry (GCMS) using an HP 6890 GC coupled to an HP 5973 mass selective detector (MSD) operating in electron ionization mode (70 eV). 1 µL of prepared sample was injected using an HP 7683 auto-sampler. Compounds separated on an Agilent HP-5ms Ultra Inert column (30 m x 250 µm with 0.25 µm of a bonded and cross-linked 5%-phenyl/95%-methylpolysiloxane), with helium as carrier gas (1 mL/min). The temperature of the GC oven was programmed at 40 °C for 5 min, then ramped to 325 °C at 4 °C /min, and held isothermally for 15 min. The aliphatic fractions were also analyzed via gas chromatography – isotope ratio mass spectrometry (GC-irMS), using the same GC conditions as indicated for GCMS. Samples were run through a Thermo Trace GC – GC-IsoLink system interfaced to a Thermo MAT 253 mass spectrometer via a

Thermo Conflo IV. All isolated hydrocarbon species were quantitatively converted to CO₂ by passing the sample gas mixture through the combustion furnace (maintained at 1030 °C). The δ¹³C values of the species were calculated by the instrument software (ISODAT 3.0), and are expressed in the usual per mil notation (‰) relative to the international V-PDB standard.

Results

For this sample set composed of five condensate samples from a field in Northeast British Columbia, low-molecular-weight hydrocarbons at C₇-C₁₀ are prominent although *n*-alkanes of up to C₃₄ were also detected. The molecular distribution is to some extent bimodal in all samples, and consists of a group of light hydrocarbons with major intensity at C₆-C₇, and a group of heavier hydrocarbons with prominent C₁₃-C₁₄ peaks. Typical aliphatic compounds indicative of source and thermal maturity, such as steranes and hopanes, were not detected. Thermal maturity ratios using aromatic compounds, including the methyl-phenanthrene index and alkylnaphthalene ratios, showed limited variation and suggest high thermal maturity (yet in the oil window). Other aromatic ratios, based on smaller molecules (e.g. alkylbenzenes), suggest in contrast a more variable thermal maturity. We investigated whether the contrasting maturity trends result from a source effect or represent a consequence of the mixing of several hydrocarbon charges. Two contrasting isotope trends were also distinguished in the carbon isotope ratios of the *n*-alkanes: one trend features decreasing δ¹³C values with increasing carbon number in the lower-end hydrocarbons, and a second trend displays increasing δ¹³C values with increasing carbon number in the higher-end hydrocarbons. Sulfur compounds such as dibenzothiophene and its alkylated isomers were also detected, whereas oxygenated compounds were absent. Hence, we conclude that the samples are neither homogeneous in their isotopic nor in their molecular composition, suggesting a high likelihood of several sources of hydrocarbons as well as the accumulation of multiple charges in the same reservoir.

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