

A Review of Some Petroleum Geochemical Tools for the Assessment of Heavy Oil and Bitumen Reservoirs.

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Summary

A detailed knowledge of the distribution of fluids in reservoirs containing biodegraded extra-heavy oil, such as the oil sands deposits of Alberta, is essential for the development of efficient recovery strategies. This work presents results from two case studies that demonstrate the application of petroleum geochemistry tools for reservoir characterization, including assessing lateral and vertical distribution of oil quality, compartmentalization studies and the estimation of fluid physical properties based on oil molecular composition.

Introduction

The recovery of heavy and extra-heavy oil faces additional challenges to those encountered during the production of conventional oil reserves. These include significant vertical and lateral variations of fluid quality, oil mixing, the common need to apply thermal recovery methods and the concomitant issues of designing processes plus the environmental effects of heating at high temperatures, reactive oil and mineral assemblages, among other factors. Petroleum geochemistry provides tools that assist with reservoir management and the development of strategies to enable a more sustainable recovery of heavy and extra-heavy oil reserves (Larter and Aplin, 1995). Here we present two case studies to illustrate where the integration of reservoir geology and fluid geochemical data may support well placement and production strategies.

Theory and/or Method

The majority of the world's heavy and extra heavy oil reserves are the product of biodegradation of conventional oil. Petroleum biodegradation is a process involving the oxidation of hydrocarbons and other heteroatomic compounds by anaerobic metabolic pathways, which not only leads to the accumulation of more refractory and heavy material, but also products such as methane gas (and carbon dioxide) and partially oxidized species (e.g. carboxylic acids) (Head et al., 2003; Peters et al., 2005). In the subsurface, biodegradation typically occurs anaerobically (Head et al., 2003; Jones et al., 2008). Compositional gradients are commonly seen throughout heavy oil fields worldwide, with the most altered oils typically located at the bottom of oil legs. Larter et al. (2000,2003), first proposed a biodegradation model that explained the generation of these oil compositional gradients. The model states that most biodegradation takes place at the base of oil columns, near oil-water contacts. The molecular analysis of oil has proven to be a powerful tool in determining relative biodegradation levels. Commonly, many applications of petroleum geochemistry in the oil and gas industry rely on parameters based on ratios of biomarkers and some non-biomarker compounds, which are used for multiple purposes including oil-source rock and oil-oil correlation, assessing levels of thermal maturity of source rocks, and investigating the impact of oil post accumulation processes such as biodegradation. However, the information obtained from peak ratios may be limited for applications related to heavy oil and oil sand reservoir production since the ratios based on the biodegradation resistant compounds

typically don't show significant variations in oil columns where the oil composition may vary significantly due to biodegradation. Also, ratios that are sensitive to biodegradation for example, 9-methylphenanthrene/1-methylphenanthrene, generally increase with increasing levels of biodegradation, but quantitative data reveals that both compounds are removed during biodegradation, but at different rates (Bennett and Larter, 2008). Accurate determinations of the absolute concentrations of the multiple oil components, as well as integrated approaches of geochemistry with geology and reservoir engineering data are instrumental for designing a sustainable recovery strategy of heavy oil deposits.

Examples

Case study I: Molecular composition profiling and estimation of fluid properties

The first case study is based on a 30-m thick oil sand bitumen column with measured dead oil viscosities (at 20 °C) in the range from hundreds of thousands of cP to millions of cP from top to bottom. The oil in this reservoir was characterized by the lack of *n*-alkanes and isoprenoid alkanes due to their removal by biodegradation, as well as the progressive alteration amongst the polycyclic aromatic hydrocarbons (PAH) while the biomarkers, steranes and hopanes showed evidence for alteration only towards the bottom of the oil column. Figure 1 shows how the variations in the molecular composition of the oil, determined by GC-MS, closely emulate variations in the dead oil viscosity. In this case, the significant increase in the viscosity values coincided with a decrease in the concentration of three ring PAH by as much as 90 % of their original concentrations from the top to the bottom of the reservoir section. The concentration gradients are a characteristic feature of oil sand reservoirs, resulting from biodegradation processes and petroleum geochemistry constitutes a powerful tool in these types of reservoirs to assess the distribution (laterally and vertically) of oil quality using small amounts of sample. Based on our results, it appears obvious that the development of baseline data sets containing physical property and oil molecular compositions (i.e. ProxVisc™) prior to steam-assisted thermal recovery operations will help with decision making on well placement to assure steam injectivity and improve recovery factors.

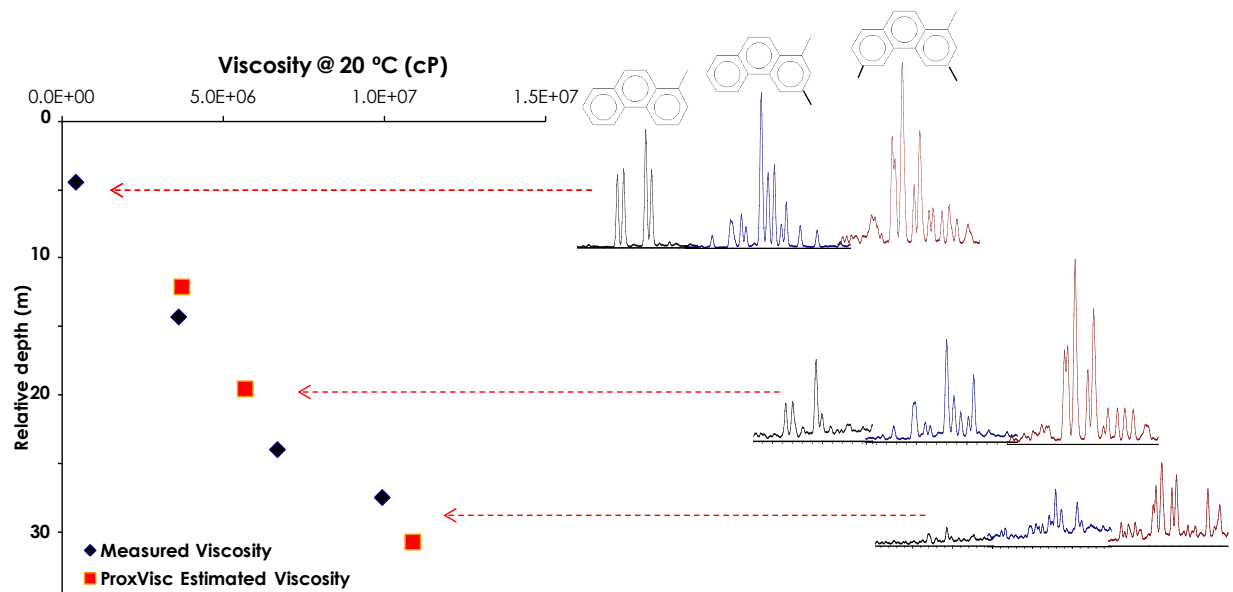


Figure 1: Right: Increasing alteration of C₁-C₃ alkylphenanthrenes indicated by their mass chromatograms (m/z 192, 206, 220), 2) Left: measured dead oil viscosity profile of measured viscosity values and the values estimated using ProXVisc™ model.

Based on the observed natural variation of fluid composition and physical properties in the investigated oil sand reservoir, we developed a correlation model of the variation in oil physical properties and absolute molecular concentrations to be able to estimate viscosity values based on oil geochemical composition. The model was developed using a proprietary method (ProxVisc™), based on multivariate chemometric statistics. The calibration data set consisted of samples with both molecular composition and measured viscosity data, using the concentration of those compounds that display strong correlations with the viscosity variations. Fig.1 shows the estimated dead oil viscosity values (orange dots) along with the true values measured at different depths (blue dots). It also shows the vertical variations in the geochemical profiles corresponding to the distributions of the C₀-C₂-alkylphenanthrenes, which was one of several compound families used for the generation of the model. It is evident that the estimated viscosity values fit the observed gradient and provide information where oil viscosity was not measured directly. This is a particularly powerful tool where no core samples, or only small or contaminated samples (cuttings) are available and a baseline viscosity-geochemistry study for the area of interest has been developed. Additionally, the groups of compounds employed here are considered involatile and therefore analyses of stored cores or cuttings samples are also likely to contain information regarding the original oil fluid quality.

Case study 2: reservoir continuity assessment

The second case study shows an oil column intersected by the presence of a thick shale unit. Fig. 2 shows how the development of two molecular composition gradients, one above and one below the barrier to the fluid flow, allowed the identification of the two flow units. The decreasing oil quality downwards in both compartments suggests two sites of biodegradation, further suggesting the existence of two paleo- oil-water contacts prior to reservoir filling. The natural variation in oil composition and biodegradation level inherent to oil sands and heavy oil reservoir implies that a conventional compartmentalization study based on, for instance, on cluster analysis using traditional molecular ratios of bioresistant components may be misleading in oil sands and heavy oil reservoir studies. Fig. 2 (right) shows, for example, that the ratio $T_s/(T_s+T_m)$ does not show significant variations from one compartment to the other in the investigated reservoir. Compartmentalization studies are key for the designing of thermal recovery strategies, and petroleum geochemistry based on absolute concentration of multiple reactive oil components is the appropriate powerful tool for this purpose.

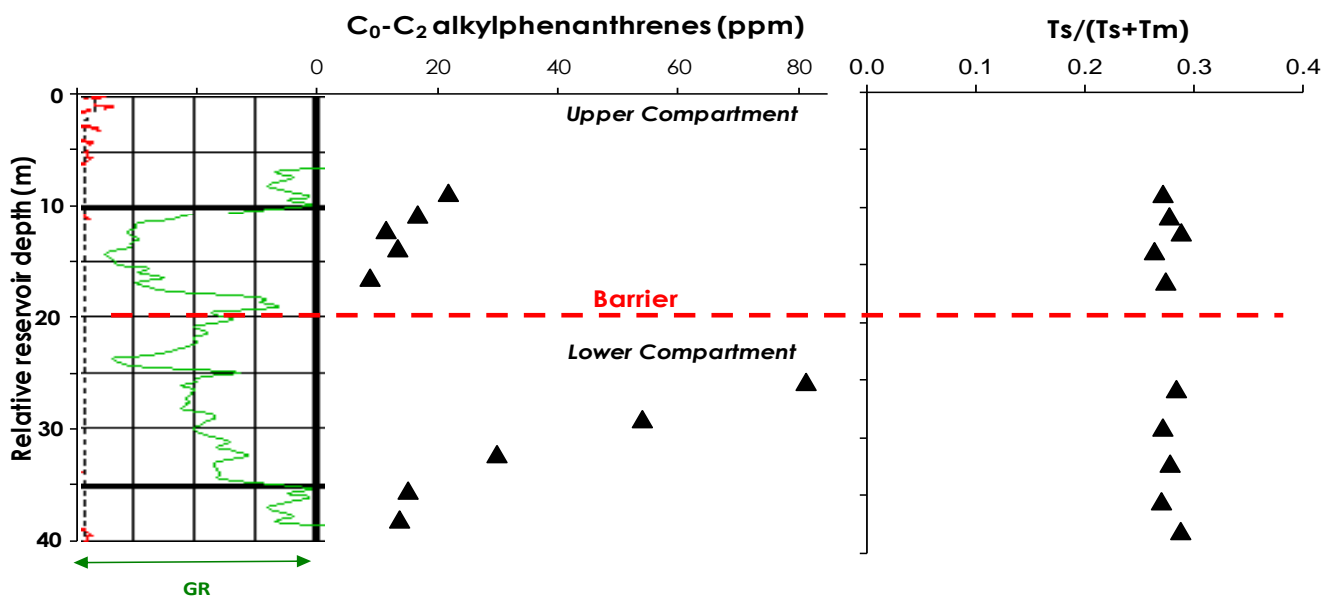


Figure 2: Vertical profiles of $T_s/(T_s+T_m)$ and the concentrations of C₀-C₂-alkylphenanthrenes displaying two compositional gradients in two isolated reservoirs that indicate the shale presents a barrier to vertical fluid communication in the studied reservoir.

Conclusions

Two case studies were presented to illustrate the advances achieved in the development of petroleum geochemical tools for oil sands reservoir management. We showed that petroleum geochemistry, using only a small amounts of sample, provides information on viscosity gradients and barriers that could assist in the design of a sustainable production strategy, leading to a higher oil recovery factor and less environmental impact.

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