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The Geochemical Toolbox to Monitoring Thermal Recovery Operations in Oil Sands and Heavy Oil Reservoirs

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Summary

In this work, we introduce the practical application based on geochemical proxies to monitor in situ upgrading operations of bitumen. The neoformation of novel compounds such as alkylanthracenes and alkylbenzothiophenes in simulated thermal recovery experiments and their observed formation in oils from current thermal recovery pilots show that some molecular changes are suitable to monitor steaming chamber progression and temperature from analysis of produced oils, as well as monitoring more dramatic changes under high temperature *in situ* upgrading conditions. Furthermore, the combination of geochemical baseline studies with these thermal proxies may additionally allow production allocation to track the vertical progression of steam chamber growth during thermal recovery of heavy oil and oil sands. A case study from the Alberta basin is shown to demonstrate the approach based on geochemical proxies in combination with geochemistry baseline studies to monitor thermal recovery operations of oil sands.

Introduction

The world oil inventory is dominated by heavy oil and oil sand bitumens generated almost entirely by the process of biodegradation of conventional oil over geological timescales. These oils are difficult to produce and transport because of their high viscosity. Reservoir heating by steam or electricity and/or solvent injection to mobilize the oil is often essential in very heavy oil and oil sand recovery. During in situ thermal recovery processes the injected steam heats the crude oil or bitumen and lowers its viscosity allowing it to flow. Heat from steam injection can also effect very minor changes in the chemical composition of the oil. However, there is currently no system established to monitor the chemical processes in situ during thermal recovery or in situ upgrading where heat, water and oil all interact in a complex natural reactor. A detailed knowledge of the molecular transformation undergone by heavy oil and bitumen under in-reservoir thermal or catalytic processing allows the chemical composition of the produced oil to be used as a natural tracer to monitor the progression of the steam or upgrading front in the subsurface. The present study describes the chemical changes caused by various reactions occurring during steam injection simulation. We also use a case study from the Alberta basin to demonstrate the use of neo-formed compounds during thermal recovery operations, combined with a geochemical baseline study, for monitoring the vertical advancement and thus assigning the zones where oils are swept (production allocation) during development of the steam chamber.

Examples

The hydrous pyrolysis experiments presented here were performed as part of a thesis work conducted at the University of Calgary (Marcano, N., 2011). In these experiments heavy oil and oil sands core samples were processed under hydrous pyrolysis conditions for time periods of up to seven days with temperatures up to 350 °C. The pyrolysates were analyzed for bulk and molecular composition. The main results demonstrate that the generation of tricyclic condensed aromatic hydrocarbon molecules, some of which are not present, or are at very low concentration in the original oil sand, are good indicators for monitoring the progress of the oil thermal conversion. Hence, the calibration of such systems may be used to track process oil temperature histories from produced oil analysis. Bitumen reactivity in the aqueous environment at temperatures below 300 ºC seems to be low; however, we have shown that neoformation of compounds such as alkylanthracenes, not abundant in unaltered oils (0 - 3 ppm), at thermal recovery conditions suggests some molecular changes are suitable to monitor steaming effects under current thermal recovery operation conditions.

The results also suggest that temperature and heating times are the dominant control factors on hydrocarbon yields. For example, figures 1a and 1b show the formation and increasing concentrations of 2-methylanthracene (2MAN) and alkylbenzothiophenes (alkylBT) with increasing heating time of hydrous pyrolysis of oil sand core samples at 300 °C and 350 °C. It is observed that different neo-formed compounds are produced at different temperature regimes, which may allow the estimation of the minimum temperature conditions reached in the reservoir. The amount and properties of hydrocarbons formed during the thermal reactions may also be significantly influenced by the nature and composition of the starting oil which shows very significant variations across the heavy oil provinces.

Monitoring SAGD operations: a case study from the Alberta oil sands

The dead oil viscosity and hydrocarbon compositions were measured on relatively fresh core samples from a vertical well in the McMurray Formation in the Athabasca Oil Sands. The goal was to generate a reliable baseline dataset for monitoring the subsequent oil thermal recovery by steam assisted gravity drainage (SAGD) operations. Two produced oils collected following recovery by SAGD at the start up and after several months of production were also investigated.

The results show increasing oil viscosity values down the oil column, matched by a concomitant decrease in the concentration of multiple oil components (Fig. 2). Based on the molecular composition results it is determined that the investigated oils are heavily to severely biodegraded and the biodegradation level increases towards a basal zone near the bottom of the oil column at the oil-water contact. This is characteristic of biodegraded reservoirs and allows oils from different depths in the reservoir have distinctive chemical fingerprints.

The produced oils first emanating from the oil zone in contact with the steam (produced oil 1 in Figure 2) showed a highly altered composition that actually correspond to the zone where the wells were placed, at the bottom of the reservoir. The produced oil collected after several months of production (produced oil 2 in Figure 2) shows an improved composition indicating the oil came from few meters higher in the oil column, when compared to the vertical well molecular concentration profiles.

The interaction of steam and bitumen during the SAGD process leads to the generation of neo-formed compounds which appear as a consequence of the thermal conditions achieved during the steaming process. A suite of neoformed anthracenes are encountered in produced oils from thermal operations increasing from trace components in core extracts from vertical wells to ca. 10μg/g in the SAGD produced oils. These components that are generated during exposure of bitumen to thermal conditions are used to assess the temperature history of the produced oils. The determination of the maximum temperature reached in the reservoir during steam injection and the residence times of steam-bitumen interactions during SAGD are other parameters that could potentially be assessed by developing kinetic models for the generation of the identified thermal proxies following laboratory experiments.

Conclusions

- The formation of compounds that are absent or not abundant in unaltered oils, such as alkylanthracenes, is suitable to be used as proxy to monitor steaming effects under current thermal recovery procedures.
- The combination of geochemical baseline studies with the identified thermal proxies may additionally allow production allocation to track the development of steam chamber during thermal recovery of heavy oil and oil sands. Monitoring of all fluid compositions prior to and during a recovery operation assists in optimizing recovery and reducing costs and is thus recommended.
- The formation of different oil components at different temperature regimes during oil thermal process may allow the estimations of the minimum temperatures reached at the reservoir during thermal recovery cycles.

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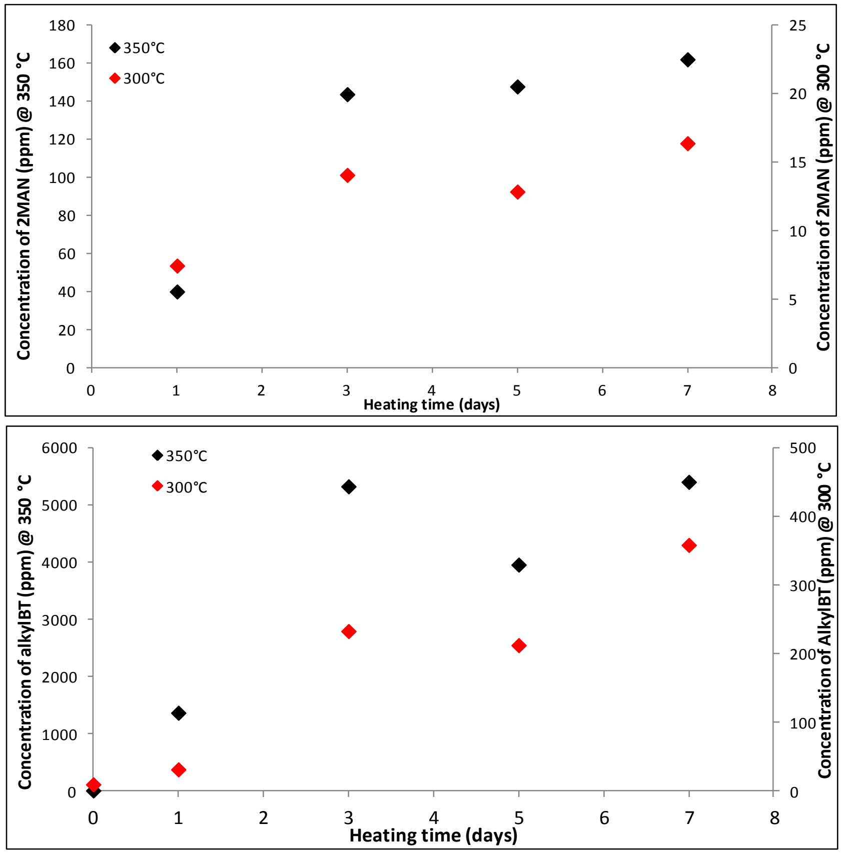

Figure 1: Production of (a) 2-methylanthracene (2MAN) and (b) alkylbenzothiophenes (alkylBT), with increasing heating time of hydrous pyrolysis of oil sand core samples at 300 °C and 350 °C (after Marcano, 2011);

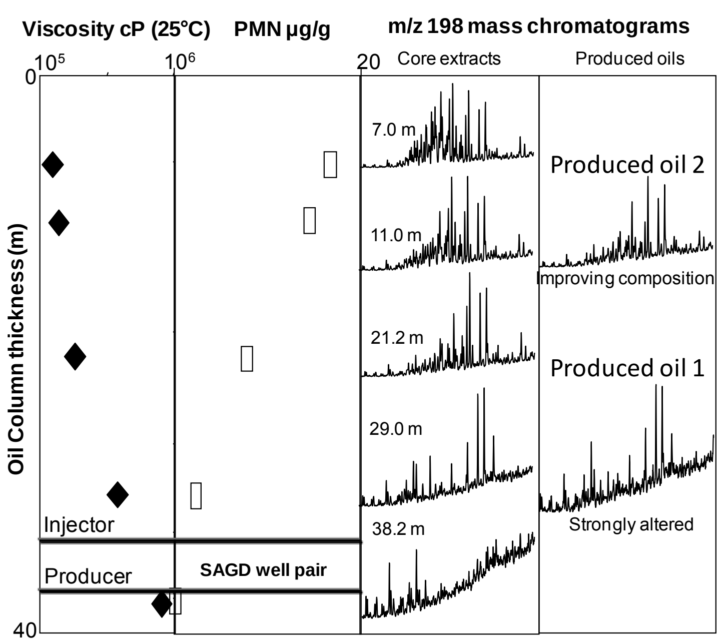

Figure 2: From left to right: viscosity profile built on a vertical well (baseline study), profile of the concentration of pentamethylnaphthalenes (PMN) and mass chromatograms m/z 198 from different depths (also part of the baseline study), and mass chromatograms of the produced oils collected from early SAGD production (1) and after several months of production (2). The variation of the oil molecular composition with increasing production time allocates the later produced oil higher in the oil column, suggesting the advanced of the steam chamber (modified from Bennett et. al, 2012).