Oil Fingerprinting for Production Allocation: Exploiting the Natural Variations in Fluid Properties Encountered in Heavy Oil and Oil Sand Reservoirs

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Summary

The ability to allocate oil production along horizontal wells or in commingled production of heavy oilfields to reservoir location takes advantage of the natural variation in fluid composition in heavy oilfields that occurs over vertical and lateral reservoir scales. In the Peace River oil sands, variations in physical and chemical properties have developed via the complex interplay between biodegradation, oil charging and mixing, and these processes ultimately influence the production behaviour of the resulting oils. A produced oil bears a distinct fingerprint, which is an integration of the fluid contributions from the highest mobility regions of the perforated zone along a production string. The produced fluid composition in combination with a compositional "map" or log along the producing zones could potentially be used to understand the production behaviour of the well and also give an indication of the performance of the system.

In a case study from the Peace River oil sands, a compartmentalized reservoir being produced from two pay zones separated by a shale barrier shows more biodegraded oil in the lower zone as it is in contact with a water leg. A multiple component based statistical correlation based on bitumen molecular concentration data, as well as molecular fingerprints indicated that the upper zone was the dominant contributor (70%) to the production stream. The contribution from the lower zone is impacted by the higher oil biodegradation level, higher oil viscosity and thus lower mobility. We demonstrate that the molecular fingerprint data, which is readily acquired from samples of heavy oil and oil sands, present an opportunity to monitor the progress and efficiency of resource recovery.

Introduction

Reservoir and reservoir fluid heterogeneities are ubiquitous in heavy oil and bitumen reservoirs and adversely impact fluid mobility and therefore recovery, especially in cold production operations. At the reservoir scale, steep gradients in oil composition and associated fluid properties are understood to be the product of preferential biodegradation of different hydrocarbons, which gives oils a distinct molecular signature or "fingerprint" related to level of degradation. This natural variability in oil composition can be used to allocate oil production along a long horizontal well or to assess the contribution of different production streams in a commingled well by mapping the original oil composition distribution (Larter et al., 2008). This is a well established geochemical procedure applied in many heavy oil fields worldwide as part of standard production monitoring procedures (McCaffrey et al., 1996).

Geochemical methods for allocating commingled production within single wells from multiple pay zones (Kaufman et al., 1990) and from multiple fields to commingled pipeline production streams (Hwang et al., 2000) have been developed. The methods are based on the assumption that oils from separate reservoirs or different parts of a reservoir bear different chemical signatures or distinctive chemical fingerprints. In conventional oil fields, variations in petroleum composition may arise from one or a combination of water washing, source maturity, source facies variation, oil biodegradation, charging and mixing of oils from different source rocks or of different maturity. In heavy oils and oil sands reservoir, large-scale vertical and small-scale lateral variations in oil composition and fluid properties developed via interaction of biodegradation and charge mixing, resulting in orders of magnitude variation in viscosity over the thickness of the reservoir and the large molecular variations in single wells. “Maps” of individual oil component or compound class concentrations in a reservoir from delineation or horizontal wells can be used to spatially allocate production oils based on their geochemical fingerprints.

Production allocation can be applied to assessment of recovery from compartmentalized reservoirs based on commingled production oil, allocation of production along horizontal wells in cold production and thermal recovery wells (heel versus toe contribution), and monitoring of steam chamber growth in thermal recovery operations via oil compositional history matching. In this paper, we describe how the natural variation introduced during biodegradation may be employed in production allocation for the heavy oils and oil sands of Alberta, with an example from a commingled production stream.

Method

Production allocation to a well location from analysis of produced fluids is achieved using multivariate statistical comparison of absolute concentrations of oil components or chromatogram fingerprints of oil from core or cuttings samples from the production well or nearby delineation wells to those of the produced oil (Kaufman et al., 1990; McCaffrey et al., 1996). This method identifies the distinguishing components or patterns in the reservoir sample set which is usually related to the molecular components that are most susceptible to biodegradation but are not susceptible to fractionation, preferential production in cold production recovery or evaporation from the samples (e.g., dibenzothiophene rather than naphthalene).

To determine the molecular fingerprint for each solid reservoir sample, 0.5 g of core or drilling cuttings is solvent extracted. An aliquot of the extract or ca. 50 mg of the production oil with added quantification standards is separated by solid phase extraction (e.g., Bennett et al., 2006) to recover a hydrocarbon fraction, which is analysed by gas chromatography – mass spectrometry (GC-MS). The data may be collected as chemical fingerprints (e.g. Fig. 1) and processed into concentrations (μg/g oil or extract) assessed using internal standards. The combination of mass chromatograms as molecular fingerprint data and direct measurement of specific component abundances in oil/bitumen samples are then combined numerically. The data are analysed by principal component regression and regression based chemometrics to derive a compositional model based on the geochemical reservoir sample data. Then the production oil composition is compared to the model to identify the dominant zone of production and proportion of contribution of each part of the reservoir.

Case study

The contribution of two horizontal wells producing from two stacked reservoirs separated by a barrier (Fig. 1) was assessed based on the produced oil from the commingled production stream. Six core samples were collected from a vertical well (Well A; Fig. 1) that intersected two pay zones (upper and lower) very close to the horizontal production wells (Well B; Fig. 1). In this example, we have focused on groups of compounds that appear to respond to biodegradation by showing variations in hydrocarbon composition, i.e. the aromatic sulphur compounds, dibenzothiophene and methyldibenzothiophenes. The aromatic sulphur compound fingerprint shown in Fig. 1 shows subtle changes in distributions, which also translates into changes in abundances supported by the quantitative data. In essence, the ratio of 1-methyldibenzothiophene versus 4-methyldibenzothiophene (abbreviated to 1MDBT / 4MDBT) increases with increasing biodegradation due to the faster removal of 4MDBT. The 1MDBT / 4MDBT ratios are recorded highest in oils recovered from the lower zone indicating that the oil is more biodegraded than the upper zone. The oil residing in the upper zone is better preserved, probably due to the oil column filling down to the shale barrier which acts as an underseal and slows biodegradation in the vertical direction. The oil in the lower zone is more biodegraded since the oil column is in direct contact with the water leg which provides the condition required to support microbial activity. In general, based on the molecular data, we observe two oil populations which may be exploited for employment into production allocation.

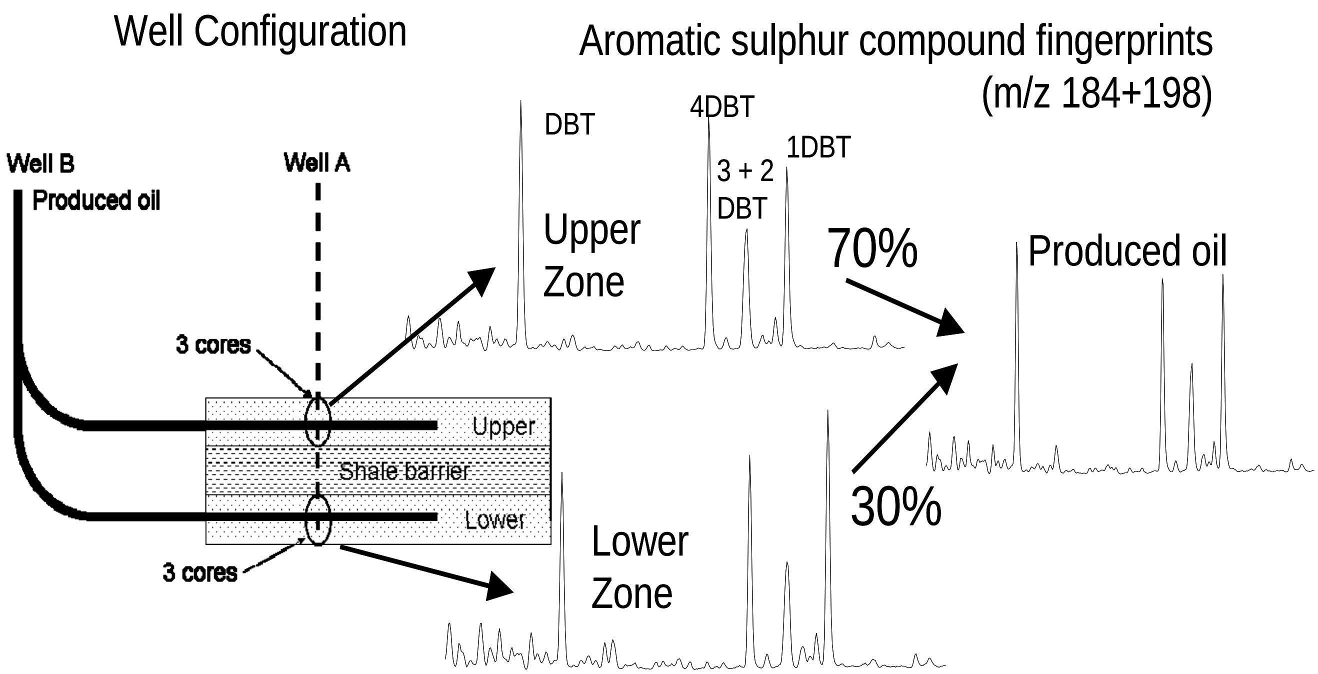

Figure 1: Production allocation based on aromatic sulphur compounds, case study. Aromatic sulphur compound fingerprints (GCMS chromatograms, m/z 184+198) show peaks indicating the relative abundance of each molecular marker.

Figure 2 shows the resulting model developed from multivariate curve resolution (MCR) based on the variation in the C_0 and C_1-DBT concentrations and for the first two principal factors identify the two production zones as end members. Interestingly, the processed data for the produced oil appears to associate closest to the oil composition from the upper zone. By virtue of the lower level of degradation, the dead oil viscosities in the upper zone are much lower than those in the upper zone in a 35:65 ratio at reservoir conditions. Thus, it is likely that the upper zone has a higher fluid mobility and hence has contributed more to the production stream, assuming that the effective permeability and hydraulic drive are very similar in the upper and lower reservoirs. Other components that respond to degradation in this case history includes alkyltoluenes (concentration data and molecular fingerprints) which also show a bias towards the composition of the upper zone supporting the interpretation that the upper zone is dominating the production. These results are consistent with the general trends of increasing viscosity with depth in the Albertan oil sands.

A similar methodology can be applied to cold produced oils from horizontal wells along which cuttings oil has be geochemically characterized. This procedure may identify a dead zone due to low permeability or high oil viscosity. In thermal recovery operations, steam chamber growth can be monitored by sampling the produced fluids and comparing them to oils collected from nearby vertical and horizontal wells; as the steam chamber grows less degraded, better quality oil will be produced from vertical compositionally graded reservoirs and can be allocated three dimensionally based on a multicomponent allocation procedure. This may allow for identification of a thief zone or a region of poor well communication between the injection and production wells in a SAGD operation and may form part of a history match during simulation. These chemical data can also be used to history match multi-component reservoir simulations defined with variable oil compositions as initial conditions.

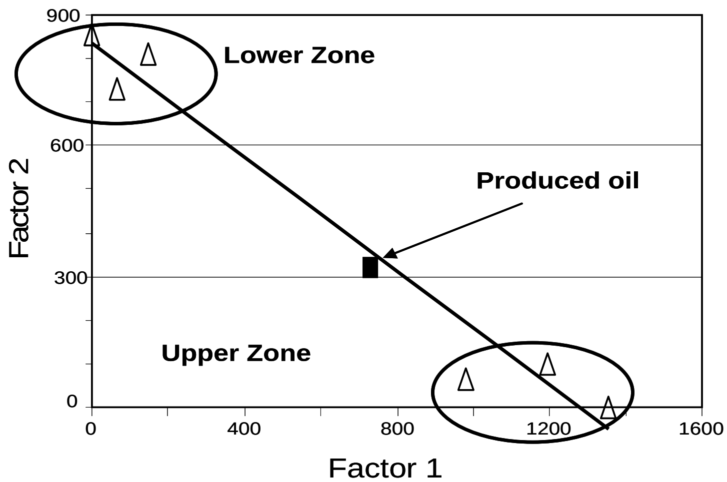

Figure 2: MCR based on aromatic sulphur compounds showing the produced oil affinity to the oil compositions from the upper zone.

Conclusions

Production allocation exploits the natural hydrocarbon compositional variations in the heavy oils and oil sands of Alberta. The procedure uses the hydrocarbon concentration data and fingerprints that show differential responses to the effect of biodegradation, however, charging and mixing also add complexity to fluid distributions encountered in reservoirs. The interpretation may be supported by understanding the biodegradation effects seen in the hydrocarbon composition as they are translated into changes in physical properties e.g. viscosity. The production characteristics of a reservoir that have been intersected by a shale barrier shows that the fluids residing above and below the shale barrier have different hydrocarbon compositions. The oil residing above the barrier has been preserved from intense biodegradation due to the shale acting as a barrier to communication with the water leg that is located beneath the oil leg located below the shale barrier.

Acknowledgements

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