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Full Length Article

Fluid distributions during light hydrocarbon charges into oil reservoirs using multicomponent Maxwell-Stefan diffusivity in gravitational field

Julian Y. Zuo [a,*], Oliver C. Mullins [b], Vladislav Achourov [c], Thomas Pfeiffer [a], Shu Pan [d], Kang Wang [e], Terje Kollien [f], Rolando di Primio [f]

[a] HFE, Schlumberger, 150 Gillingham Lane, Sugar Land, TX 77478, USA
[b] SDR, 1 Hampshire St, Cambridge, MA 02139, USA
[c] Schlumberger, Risabergvegen 3, 4056 Tananger, Norway
[d] SRC, Schlumberger, 14910 Airline Road, Rosharon, TX 77583-1590, USA
[e] BGC, Schlumberger, Chuang Xin Building Beijing Tsinghua Science Park, Beijing 100084, China
[f] Lundin, Strandveien 50, 1366 Lysaker, Norway

HIGHLIGHTS

- A reservoir fluid geodynamics model was developed to model asphaltene gradients in oil columns during gas charges.
- Asphaltene instability was also analyzed by the thermodynamic model with the same parameters in the RGF model.
- Asphaltene is unstable at the base of the oil column due to a late gas charge in Well 2.
- A tar mat was formed when asphaltene flocculation occurs at the base of the oil column over geological time.

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ABSTRACT

Hydrocarbon reservoir fluids often undergo dynamic processes such as multiple hydrocarbon charges and biodegradation over geological time. These processes change the spatial distribution of hydrocarbon components in reservoirs and include diffusion, advection and phase change over geologic time. To better understand reservoir fluid geodynamics (RFG), a set of generalized diffusion-advection equations are proposed at isothermal conditions. The Maxwell-Stefan diffusivity in the gravitational field is integrated into the diffusion equations. Thermodynamic models are used to describe nonideality of reservoir fluids and phase separation. The generalized diffusion-advection equations are then simplified for a 1-D diffusion problem. The 1-D diffusion model is applied to the Lundin oilfield case study in Norway. The reservoir fluids are simply grouped into three pseudocomponents: gas (including solution gas), asphaltene and maltene. The Peng-Robinson equation of state is employed to estimate the parameters in the Flory-Huggins regular solution model. A ternary phase diagram including binodal and spinodal phase boundaries is computed based on the thermodynamic model. Asphaltenes are further treated as two forms: nanoaggregates and clusters in the gravitational diffusion term. The new RFG model captures the main physics of the reservoir fluid geodynamic process in the field case. Because gas (light hydrocarbon) charging from the top of the oil column leads to an increase in oil solution gas and a decrease in oil solvency capability to dissolve asphaltenes, asphaltenes are expelled downwards and accumulate at the base of the oil column. In addition, because asphaltene clusters have much bigger sizes than nanoaggregates, they increase the rate of asphaltenes accumulation at the base of the oil column over geological time.

The resulting single RFG model is used to account for two adjacent reservoirs with very different fluid distributions. In fault block 1, there are large, disequilibrium gradients of solution gas and asphaltenes with little asphaltene deposition. In this fault block, the rate of diffusion is reduced by known reservoir baffles. In contrast, in fault block 2, the diffusion and asphaltene migration processes essentially went to completion yielding equilibrated solution gas and asphaltene gradients. In addition, after migration to the base of the oil column, the asphaltenes underwent phase separation with increasing solution gas. The same RFG model is used for both fault blocks but with different rates of diffusion associated with the known difference in reservoir baffling. This RFG model accounts for all measured fluid gradients and asphaltene phase separation in two fault blocks with very different distributions. In addition, the primary

* Corresponding author.
E-mail address: julianzuo@hotmail.com (J.Y. Zuo).

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difference in the two adjacent reservoirs is the extent of reservoir baffling; this parameter created a factor of ten difference in production rates from these fault blocks. This new fluid modeling accounting for the reservoir fluid geodynamic processes in reservoirs is shown to impact major production concerns.

1. Introduction

Oilfield reservoir hydrocarbons consist of dissolved gases, liquids and dissolved solids, the asphaltenes. As such, the reservoir fluids can vary from dry natural gas to tar and everything in between. All parameters associated with an oilfield depend on the specifics of the hydrocarbon composition including economic value, phase behavior, flow characteristics, method of production, required oilfield facilities, and ultimately, resource utilization. In addition, reservoir hydrocarbons can contain variable quantities of CO_2, H_2S and Hg which are especially important for safety, economic and metallurgical concerns. Furthermore, for characterization of the overall composition of the reservoir crude oil (or gas), the spatial variation of composition within the reservoir is enormously important. For example, an impermeable tar mat at the base of the oil column, at the oil-water contact (OWC) precludes both aquifer pressure support and aquifer sweep with oil production. Consequently, water injection into the aquifer, a routine procedure, is rendered ineffective, thereby having a huge impact on field development planning. Other important fluid variations include those of viscosity, gas/oil ratio (GOR), phase behavior, CO_2 content, etc. The accurate assessment of the spatial variations of the reservoir fluids is critically important.

The spatial variation of the rock formation parameters is also inordinately important in determining the economic value of an oil reservoir. In particular, if the oil-bearing formation consists of many small compartments, each of which requires a well for drainage, then the reservoir can be uneconomic, while if the formation consists of a large, permeable compartments, then economic value is much higher [1]. Seismic imaging establishes the earliest view of the reservoir architecture [2]. Nevertheless, seismic imaging has its limits; it has relatively low spatial resolution and has limited sensitivity to fluid type. Hydrocarbon fluid migration into and within reservoirs conform to the reservoir structure; consequently, fluid compositional variation provides additional insights to reservoir architecture [1,3]. The combination of seismic imaging and well-bore geological data, for example obtained from core and wireline logs, allow geologists and geophysicists to develop models of the reservoir architecture as well as how this architecture developed from deposition to current time. This time evolution of the rock formations comprising a reservoir or even a basin is labeled "geodynamics" and is a powerful tool in reducing uncertainty concerning reservoir architecture and formation characteristics. [2]

The delineation of reservoir fluid complexities (and we include tar in this context) has recently been improved significantly. First, the advent of downhole fluid analysis (DFA) within oil wells has enabled the measurement of fluid complexities because of improved accuracy and efficiency [1], both of which are quite important within an economic setting. If a solution is not used due to economic constraints, it is not a solution. DFA allows the oil company to determine fluid complexities in the reservoir when the measurement tool is in the well. Consequently, further DFA measurements to delineate complex fluid columns are justified. This does not apply for surface or laboratory measurements. A variety of fluid properties are now measured using DFA including GOR, relative asphaltene content, some hydrocarbon composition, CO_2, density and viscosity [4]. For gradient analysis, asphaltene gradients measured by DFA remain the fluid property of choice [5]. Asphaltene gradients can be measured very accurately using DFA, specifically optical measurements; the oil color is linear in asphaltene content [6,7] and is primarily due to asphaltene content. Other fluid properties generally show gradients but with greater error in the data. GOR gradients are quite small for lower GOR oils and the error bars for GOR determination, whether downhole or laboratory, are not small. Viscosity measurements tend to have higher uncertainties, and mass density, an integral quantity, tends to exhibit rather small gradients. Biomarkers often exhibit small gradients as well unless biodegradation is taking place.

A second development has been very important to understand the nature and origin of fluid gradients. It is highly desirable to know whether a fluid gradient is equilibrated. If yes, then the implication is that the reservoir is likely connected as a flow unit in production time [1]. This logic follows because large fluid flow in the reservoir is required (during and after trap filling) to equilibrate the asphaltenes. In contrast, very small mass transfer is required to equilibrate the pressure at various points; consequently, pressure equilibration is not as good an indicator for reservoir connectivity [1,8]. Moreover, if the fluid gradients in the reservoir are not equilibrated, then frequently there is a process in geologic time that precluded equilibration. A newly identified scientific arena is "reservoir fluid geodynamics" (RFG) [9] which embodies concepts similar to geodynamics for the evolution for rock formations.

For these myriad purposes, an asphaltene equation of state for asphaltene gradients in the reservoir is required. Such an equation of state had been precluded until relatedly recently because the size of asphaltene molecules and colloidal species in crude oils was unknown. Without a known size or mass m, the force F in Newton's 2^{nd} law for a gravitational field g remains undetermined; $F = mg$. Indeed, the debate of asphaltene molecular weight spanned orders of magnitude [10]. The situation has been resolved, the Yen-Mullins model codifies the molecular and nanocolloidal species of asphaltenes in laboratory solvents and crude oils [11]. With the size known, the gravity term could be added to the Flory-Huggins equation of state (EoS) yielding the Flory-Huggins-Zuo (FHZ) EoS [12–14]. Aside from size, this equation has only a single chemical parameter each to characterize the solvent oil and the asphaltenes, the Hildebrand solubility parameter. For alkanes, the bulk component of crude oil, the Hildebrand solubility is dominated by the Hansen polarizability parameter [15]. The same dominance of polarizability is true even for asphaltenes [15]. Consequently, it is justified to use a single solubility parameter each for the crude oil and for the asphaltenes. The crude oil solubility parameter is heavily dependent on GOR [12–14].

The first application of the FHZ EoS has been to establish the existence of equilibrated asphaltenes in reservoirs, thereby providing a strong indicator of fluid flow connectivity (not compartmentalized). Fig. 1 shows 5 oilfields from 5 different oil companies with equilibrated asphaltenes [14]. In each case, production confirmed connectivity as indicated by equilibrated asphaltenes. In the oil industry, production is the ultimate arbiter.

For the cases presented in Fig. 1, no other fluid gradients gave as clear an indication as to whether the reservoir crude oil was equilibrated. For the cases in Fig. 1D and E, the GOR is low, consequently, there is no gradient. Without a gradient, it becomes unclear whether there was fluid motion in the reservoir to estab-