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Challenges of Heavy Oil Fluid Sampling and Characterization
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Abstract
A significant portion of the world’s hydrocarbon reserves is found in heavy oil reservoirs. Heavy oils are often found in shallow and highly unconsolidated reservoirs, or sometimes in deep, tight formations. Often the high asphaltic content of these oils results in relatively higher oil density and viscosity; hence, their lower reservoir mobility poses significant challenges to both sampling and PVT data measurements. Furthermore, modeling these fluids for reservoir evaluation requires special techniques to capture their unique phase behavior.

The challenges of representative down-hole or surface fluid sample acquisition demand customized sampling methods to deal with:

- low oil mobility
- sand production from unconsolidated formations
- high asphaltene content and resulting high gradients
- formation of water-in-oil emulsion during co-production of water or gas lift operations or addition of diluents

In addition, the prerequisite for laboratory measurement is special sample preparation to remove emulsified water. These high viscosity oils exhibit slower gas liberation below the bubble point and hence delayed gas-phase formation, thus making “true” oil property measurements a challenge. Difficulties associated with fluid modeling include characterizing apparent bubble point behavior, large viscosity changes with pressure and temperature, and asphaltene dropout.

In this paper, we present a comprehensive methodology for heavy oil sampling and characterization in unconsolidated sands as well as in low permeability reservoirs. We present field examples to highlight the challenges and illustrate the methodology for fluid sampling, down-hole fluid analysis, laboratory PVT data acquisition, and modeling. Sampling methods for heavy and asphaltic oils were custom designed with special tools and sensors to obtain representative samples and precise down-hole fluid analysis data. New laboratory techniques were developed to prepare the samples for analysis and to distinguish between the “true” and “apparent” bubble point behavior exhibited by the heavy oil due to its non-equilibrium behavior. Fluid models based on a special equations of state (EoS) were employed for accurate description of heavy oil fluid phase behavior. In particular, we successfully applied the industry’s first EoS for asphaltene gradients in heavy oil reservoirs that match down-hole fluid data.

Introduction
Bitumen, extra heavy oil, and heavy oil constitute 70% of the world’s total in-place oil resources\(^1,2\) with heavy oil resources alone accounting for about two-thirds of unconventional liquid hydrocarbon production. The heavy oil and bitumen reservoirs in Canada, Russia, the Middle East, and China, and the extra-heavy oil reservoirs in Orinoco Belt, Venezuela, constitute the majority of the world’s heavy oil resources\(^2\). The high asphaltic content and extremely high viscosity of heavy oils pose major challenges to many reservoir and production operations including fluid sampling, hydrocarbon recovery, flow assurance, and processing.

Heavy oils are generally defined\(^3\) as oils having stock tank API gravity less than the low 20’s with viscosity of several tens to several thousands of centipoise (cP). Heavy oils are further characterized as hydrocarbon fluids with significant asphaltene content, often in excess of tens of weight percent and exhibiting strong asphaltene gradients areally and/or vertically. In
addition, heavy oils are often found in reservoirs with unconsolidated formations; yet they sometimes occur in extremely low permeability (shale) reservoirs. The high oil viscosity frequently results in low mobility of heavy oils, thus presenting complex flow characteristics and unique operational challenges. In addition, the tendency for quick and stable emulsion formation coupled with the slow release of solution-gas below the bubble point pressure poses severe challenges to production operations such as fluid sampling, hydrocarbon recovery, and flow assurance. Note that heavy oils might on occasion exist in the reservoir as a Pickering emulsion (e.g. stabilized by clay) that can be stable for geologic time although this has never been demonstrated. Pickering emulsions can form in the drilling and sampling processes and are very hard to break.

The heavy oil characteristics discussed above also make laboratory PVT measurements a formidable task. The non-equilibrium nature of extra heavy oil phase behavior due to the slow release of solution-gas renders laboratory equilibrium measurements challenging, and the resulting data may fall short of describing the actual fluid behavior in the field. For the same reason, PVT modeling of heavy oil is more complex and requires special techniques. Thus, in order to provide an accurate fluid characterization for reservoir engineering applications, it is critical to have a clear understanding of these key issues and ways to resolve them.

Sample Challenges
Down-hole or surface sampling operations in heavy oil reservoirs are highly complicated for several reservoir and operational constraints as listed below:

- High fluid viscosity and the resulting low mobility of the fluid
- Artificial lift systems used to move the oil from bottomhole to surface
- Formation of water-in-oil emulsions due to lift operations or high turbulent flow rates, or flow through constrictions such as valves and elbows
- Sand and fines production in unconsolidated formations
- Presence of high levels of asphaltene
- Ultra-low permeability and tight-sand reservoirs, and shale oil

Most heavy oil reservoirs require artificial lift systems to move the fluids from bottomhole to surface because of low reservoir energy and high oil viscosity. The fluid lift systems can range from high pressure gas (N2) lift, sucker rod pumps, electrical submersible pumps (ESP), or progressive cavity pumps (PCP). Once such artificial lift systems are installed, wire-line formation tester (WFT) sampling is usually not an option. Since heavy oil accumulations are often found in shallow and unconsolidated sands, migration and production of fines pose a severe impediment to down-hole fluid sampling operations. Also, instantaneous pressure changes and faster fluid movement during clean-out periods and sampling operations might accelerate the sand and fines production. The sand entering the WFT tool string has the potential to plug up filter screens and flowlines, erode sensitive tool components, deteriorate the pump performance, and slow down or kill mechanical operations involved during WFT sampling.

Often, high drawdown pressures required to mobilize heavy oils may enhance the potential for two-phase (oil and gas) flow in the near-wellbore regions - particularly when the oil is at or near saturated conditions; this is another serious challenge to surface or down-hole sampling. The low mobility and the resulting slow flow rates may tend to increase near-wellbore clean-up time, thus increasing operational risks. However, the high viscosity of the oil may slow down invasion of external fluids introduced during drilling, completion, and acidization jobs, and thus requires removing relatively smaller volumes of near-wellbore fluids. High levels of asphaltenes usually present in heavy oils may further hinder sample acquisition by flocculating and precipitating as solids under severe drawdown.

PVT Data Measurement Challenges
One of the critical steps in PVT measurements is the preparation of down-hole samples for measurements. Generally, heavy oil down-hole samples may suffer from two problems: 1) separation of solid-forming asphaltene compounds from the oil during transportation and handling and, 2) emulsions formed in the oil during sampling and/or drilling operations. There could also be instances of Pickering emulsions in heavy oil reservoirs that are stable for geologic time. In any event, before attempting measurements, the sample should be restored to down-hole conditions as closely as possible. The restoration process should get all of the dropped-out asphaltenes back in solution, break all the emulsions in the oil, and remove the resulting free water.

For restoration, the sample is brought to original reservoir conditions by heating to reservoir temperature and pressurizing to the initial reservoir pressure. The sample bottle is then continuously agitated for a long period of time (up to 5 days). It is important to maintain the sample bottle pressure to be above the asphaltene onset pressure because once the asphaltene deposits on the bottle and remains on the wall for a long time, it may not be re-dissolved - even after long agitation. After restoration, the water content of the sample is determined by drawing a sub-sample and breaking up all the emulsified water
in the sub-sample. If water content is found to be higher than 1% by weight, the excess water in the sample should be removed by a non-chemical method. A thermal heat cycling method is employed to break the emulsion and separate the water from the sample. In this process, the high pressure sample is heated to 40 to 50 °F above the reservoir temperature and agitated for several hours. Then the sample is allowed to cool down to room temperature naturally. The resulting free water is removed by draining it under reservoir pressure. This cycle is repeated until the water level drops below 1 wt% or when no more free water is produced in the sample bottle.

Accurate equilibrium PVT measurements of heavy oil is quite complex due to its high viscosity and a strong tendency of gas micro-bubbles formed below the bubble point pressure to disperse within the oil rather than to immediately coalesce into a bulk gas phase. Often termed as “foamy” behavior, this process leads to extended super saturation conditions resulting in non-equilibrium phase behavior. An equilibrium condition can be forced by vigorous mixing in addition to providing longer periods of time for attaining equilibrium before measuring equilibrium PVT properties. However, these equilibrium PVT properties may not accurately represent the “foamy” oil (i.e. with dispersed gas micro-bubbles) PVT properties in the field.

**PVT and Viscosity Modeling Challenges**

Applying either a compositional EOS model or a black oil correlation to heavy oils is quite challenging for several reasons. First, the extra heavy oils exhibit non-equilibrium phase behavior due to their “foaminess” below the bubble point, the extent of which is a function of pressure depletion rates in these tests. Equations of state based on equilibrium thermodynamics cannot capture these non-equilibrium effects. In addition, the C7+ fraction of the oil can be in excess of 70 to 80% containing different classes of components with carbon numbers as high as C100+. The heavy fraction may contain a wide class of hydrocarbon components such as polycyclic and closed ring aromatic compounds, and solid-forming organic compounds like asphaltene, resin, and paraffin. Thus, the heavy oil phase behavior can be quite complex exhibiting solid-liquid-vapor equilibrium in the operating range of pressures and temperatures. Although a cubic EOS is capable of predicting standard phase behavior, they fall short of describing solid phase and capturing accurately solid dropout conditions. More complex equations of state such as PC-SAFT or coupled equations like cubic plus association (CPA) equations, may be required to capture solid-liquid-gas phase behavior. Often, other models such as Flory-Huggins or modified Flory-Huggins-Zuo equations may be necessary to predict strong asphaltene gradients and conditions for tar mat formation in the oil column.

Heavy oil viscosity models are generally based on simple exponential functions of temperature. However, the presence of asphaltic components and their instability under certain conditions make heavy oil viscosity behavior highly complex and increasingly non-linear. In addition, the presence of dispersed micro-bubbles in the oil below the bubble point causes the viscosity to exhibit complex characteristics requiring dispersion viscosity models.

Using field examples, we will discuss the inherent issues and challenges associated with fluid sampling, down-hole fluid analysis, laboratory PVT data measurements, and modeling of two heavy oils: one with 8-9° API gravity and viscosity of a few thousand cP, and a highly-asphaltic oil (~25 wt%) with middle-20’s API gravity and viscosity of several tens of cP. We will also highlight a few practical solutions to overcome some of these difficulties. Table 1 provides some basic data on the two examples discussed in the rest of the paper.

**Table 1. Two Field Examples of Heavy Oil - Basic Properties**

<table>
<thead>
<tr>
<th>Reservoir Location</th>
<th>API Gravity</th>
<th>GOR scf/stb</th>
<th>Viscosity cP</th>
<th>Asphaltene wt%</th>
<th>Issues, Challenges, &amp; Solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>South America</td>
<td>8-9°</td>
<td>120</td>
<td>2000</td>
<td>—</td>
<td>Sampling, PVT Measurements, &amp; Modeling</td>
</tr>
<tr>
<td>GOM 1</td>
<td>25°</td>
<td>300</td>
<td>30</td>
<td>25</td>
<td>Sampling, Down Hole Fluid Analysis, &amp; Modeling</td>
</tr>
</tbody>
</table>

**Extra-Heavy Oil: South American Field**

This extra-heavy oil occurs in a South American field with highly unconsolidated sands. The average reservoir pressure and temperature range between 800 and 1450 psia, and 120 °F and 145 °F, respectively. The stock tank oil gravity is about 8-9° API. The live oil viscosity ranges from 600 to 3000 cP at reservoir conditions. The solution gas-oil ratio is 120 to 130 scf/stb. The high oil viscosity impedes the separation of solution gas from the oil below its true bubble point, resulting in dispersed gas micro-bubbles in the oil until diffusion/buoyancy forces enable the gas bubbles to coalescence into a distinct gas phase. This unique behavior poses severe challenges to fluid sampling and PVT measurements, thus requiring a careful choice of tools and customized procedures.
**Sampling Method, Tools and Procedures:** The objective of the heavy oil sampling program was to obtain adequate volumes of representative single-phase oil samples for laboratory analysis. The following sampling challenges had to be addressed: a) adequate near-wellbore cleaning to minimize sample contamination by drilling mud filtrate and, b) optimal drawdown to minimize sand production and avoid two-phase flow, while mobilizing the oil from the reservoir to the sample chamber. During surface sampling, measurement uncertainty in producing gas-oil ratio (GOR) is a concern due to large drawdown and incomplete gas separation from the oil. Another challenge with surface samples is the slow dissolution of gas while recombining them to prepare the reservoir fluid. Many of these sampling problems can be eliminated through bottomhole sampling (BHS) by wireline formation tester (WFT) with appropriate tool selection and procedures as identified in Table 2.

<table>
<thead>
<tr>
<th>Problem/Issue</th>
<th>Requirement</th>
<th>Tool Selection</th>
<th>Design/ Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand Production</td>
<td>Optimal Drawdown</td>
<td>Dual-Packer Option</td>
<td>Pump Configured</td>
</tr>
<tr>
<td>Two-Phase Flow</td>
<td>Control Sand Production</td>
<td>Coarse/Fine Filters</td>
<td>Close to Sampling Point</td>
</tr>
<tr>
<td>Adverse Oil Mobility</td>
<td>Pumping Specs.</td>
<td>Flow Control Pump</td>
<td></td>
</tr>
<tr>
<td>Mud Filtrate Contamination</td>
<td>Adequate Pump-out Volume Before Sampling</td>
<td>Extra High Pressure Pump with</td>
<td>High Rate During Cleaning</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Variable Constant Rates</td>
<td>Low Rate During Sampling</td>
</tr>
<tr>
<td>Fluid Quality Monitoring</td>
<td>Fluid Component Analyzer to Identify Contaminants</td>
<td>Optical Fluid Analyzers</td>
<td>Fluid Analyzers Positioned</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Resistivity Cell</td>
<td>above and below Pump</td>
</tr>
<tr>
<td>Single-Phase Samples</td>
<td>Sample Bottle Type</td>
<td>Single-Phase Sample Bottles</td>
<td>Close to Sampling Point</td>
</tr>
<tr>
<td>Adequate Volumes</td>
<td>Volume &amp; Number of Samples</td>
<td></td>
<td>Location</td>
</tr>
</tbody>
</table>

The key components of a wireline formation tester (WFT) tool include an extra high-pressure variable rate pump-out module to maintain flow rates at required levels during cleaning and sampling, properly sized screens to prevent plugging of flowlines by sands and fines, a resistivity cell, and two optical fluid analyzers to monitor fluid quality and detect two-phase conditions. Single-phase pressure compensated bottles were used in a low-shock sampling mode for sample collection to avoid flashing the samples and to maintain them in single-phase condition at all times.

A sampling simulation program was used to estimate optimum pump-out rates to minimize the probability of sand production while mobilizing the oil in a single-phase condition. Using expected reservoir and fluid parameters, the pump-out volume and pump-out time required for adequate cleaning were also estimated. Several simulation runs were made varying fluid viscosity, permeability anisotropy, drilling fluid invasion, flow rates, and the MDT position to cover a range of sampling conditions. Specific sampling procedures were developed to reduce the possibility of two-phase flow in the reservoir, minimize fluid contamination levels, and finally, to avoid flashing the samples during withdrawal in the sample chambers. In addition, procedures for on-site sample transfer and shipping were developed to preserve sample integrity.

A special pump-out module that is capable of strictly operating at pre-set constant or variable rates equipped with an extra high pressure displacement unit was positioned above the sample bottles. This allowed the control of pump-out rate at ~1 cc/sec during pumping operations and the pressure drawdown at low values. The pump-out rate was further reduced to 0.5 cc/sec during sample collection. The maximum pressure drawdown was kept below 15 psi during the entire sampling operation. A double filter arrangement was used with a coarse outer filter, 0.015" in size, and a fine inner filter, 0.005" in size, to control and eliminate sand production. No sand production was observed as evidenced by the near-infrared (NIR) responses observed in the fluid analyzer.

One critical difficulty encountered with the spectroscopy-based fluid analyzer was its inability to accurately estimate the percent of water content of the pumped out fluid, particularly with this extremely dark oil. The water content is estimated from the primary water absorption peaks in the NIR region. The impact of emulsions that are stable in dark fluids on the NIR response is to artificially elevate the entire absorption spectrum by wavelength-dependent light scattering, which is from dispersed water droplets in oil or even emulsion. Although the fluid analyzer accounts for this effect to some extent, it is not reliable because the oil was too dark and the corrections were inadequate. Later, during laboratory analysis, a more robust correction method was developed for this type of oil. The fluid analyzer was also used to check for any produced sediment. Anomalous spikes in the optical density in all the channels of the analyzer will indicate any sand grains passing through the analyzer. But during the entire sampling operation, no such anomalous behavior was observed. Qualified personnel were on-site to coordinate and monitor the entire sampling operation. As a result, several high quality samples were captured for detailed compositional and PVT analysis.

Typical fluid analyzer responses in various channels during sampling are shown in Figure 1a as a function of time. Figure 1b provides a plot of the reservoir pressure along with the pump-out volume as a function of time during the same time window.
As observed from the spectrometer traces, a fairly clean fluid was flowing into the sample chamber with small amounts of water mixed with it.

**Figure 1a. Fluid analyzer responses (composition, resistivity and water/oil fractions).**

**Figure 1b. Pressure vs. time and pump-out volume.**

**PVT Measurements:** Because of slower solution gas liberation and re-dissolution\(^9,15\), due diligence was exercised in selecting equipment and customizing procedures for sample preparation and PVT measurements. The sample preparation involved removal of both free and emulsified water from the samples by non-chemical methods. The dewatering process consisted of pressurizing the sample above the reservoir pressure and subjecting it to repeated heating and cooling cycles from room temperature to a temperature 40-50°F above the reservoir temperature and draining the free water at each heating-cooling cycle until the water content is below 1% in the sample. A Karl-Fischer type titration was performed on a sub-sample to determine the water content of the sample.

A direct mixing PVT cell was custom designed to facilitate faster equilibrium during PVT measurements especially for measuring the bubble point. However, even with this PVT cell, non-equilibrium conditions may persist during measurement if customized procedures are not strictly adhered to. In an equilibrium test, the pressure-volume curve exhibits a sharp change in the slope at the bubble point; however, it is difficult to detect such sharp slope changes in a poorly conducted, non-equilibrium test\(^15\) (Figure 2a). Monitoring pressure response as a function of time and its rate of change in both non-equilibrium (without stirring) and equilibrium (with vigorous stirring) tests, as shown in Figure 2b, would help identify true equilibrium conditions. A sharp drop in pressure (segment 1 in Figure 2b) was observed as soon as the cell volume was expanded, indicating the behavior of an incompressible liquid. As the gas slowly evolved, a gradual pressure build-up (segment 2) was observed but the equilibrium condition was not reached even after 20 hours without stirring. On the other

**Figure 2a. Equilibrium and non-equilibrium heavy oil bubble point measurement.**

**Figure 2b. Pressure response vs. time near bubble point for equilibrium and non-equilibrium behaviors.**
hand, with the initiation of vigorous mixing after 20 hours, equilibrium condition was reached rapidly as indicated by sections 3 and 4 in Figure 2b. Thus by ensuring equilibrium, the true bubble point pressure was repeatedly measured within about 50 psi (see Figures 3a and b). Similar procedures were followed for other PVT tests. A second set of tests were conducted without the stirrer “on” to mimic non-equilibrium (unconventional) conditions. Figures 4a and 4b show the oil formation volume factor and GOR behavior that differs from a conventional test. These results are consistent with observations by other researchers 

A capillary-flow viscometer was used to measure the oil viscosity although it was noted that the effect of dispersed gas micro-bubbles (below the bubble point) on the oil viscosity may not be captured during viscosity measurements by capillary flow. It was also recognized that due to the saturated condition of the oil at each pressure step below the bubble point in the differential liberation test, small pressure drops experienced in the capillary flow viscometers will liberate additional solution gas leading to non-representative viscosity data. Therefore, it was necessary to conduct several viscosity measurements above each saturation stage in the differential liberation, and use an extrapolation technique to determine the viscosity at the desired differential liberation pressure.

PVT Modeling: PVT data interpretation and modeling for heavy oils require a robust method for defining pseudo-components that represent the C7+ fraction of the oil. Since equilibrium EOS models do not capture the oil properties with dispersed gas bubbles, these models were deliberately tuned with unconventional data obtained without agitation of the sample in the PVT cell after 48 hours at each pressure depletion step. Although this may not provide the accurate description of non-equilibrium behavior exhibited by these heavy “foamy” oils, it was assumed that this approach will provide a closer description of the oil behavior than the one predicted by the equilibrium EOS model. Similarly, solid-forming compounds such as wax and asphaltenes should also be properly characterized using either PC-SAFT or FHZ equations for predicting solid-liquid-vapor equilibrium. Very little information on foamy oil viscosity models is available in the literature. The first
theoretical work by Einstein on viscosity of suspensions in a medium relates the viscosity of suspension to the viscosity of the medium as follows:

$$\mu_f = \mu_o^{1-\varphi} \mu_g^\varphi$$

(1)

where $\mu_f$, $\mu_o$, and $\mu_g$ are the viscosity of foamy oil, oil, and gas, respectively, and $\varphi$ is the fraction of the dispersed gas volume with respect to the total volume at any given condition. In addition, viscosity models that correlate viscosity to pressure, temperature, and GOR should be used to capture large variations of heavy oil viscosity over the operating conditions as simple temperature-dependent correlations are inadequate.

**Gulf of Mexico: High Asphalitic Oil**

Many of the offshore reservoirs in the Gulf of Mexico (GOM) contain asphalitic crude with gravity of 25° API or above and GOR of a few hundreds of scf/stb. As given in Table 1, this particular oil has an asphaltene content in excess of 25 wt% with an API gravity of ~27° and GOR of several hundred scf/stb. Asphalene dropout is, in general, highly pressure sensitive and in this particular crude occurs at a fairly high pressure. In addition, offshore deep water drilling involves use of OBM (oil-based mud) or SBM (synthetic oil-based mud) and hence fluid contamination is another sampling issue that needs to be tackled. In order to provide reliable PVT and flow assurance data, it is critical that samples are collected in pressure compensated bottles and maintained at the reservoir condition until ready for analysis. In addition, special sampling probes and procedures are necessary to obtain “cleaner” fluids within reasonable pump-out time as explained below. Another sampling issue became apparent during sampling, i.e., in one section of the sand, the fluid analyzer responses started indicating possible severe asphaltene gradient as discussed later in this section.

The special sampling probe was part of a customized focused-sampling tool assembly (Figure 5a) in which the probe facilitates pumping out fluids through two concentric sections and thus accelerates the near-wellbore clean-up time by an order of magnitude. Figures 5b and 5c show schematics of the probe cross-section and the expected flow pattern through the probe when operated correctly. In addition, three fluid analyzers were used to monitor the contamination levels of the fluids passing through them. As the pumping continued, the most contaminated fluid was flowing through the guard section while the least contaminated fluids were passing through the sample section as expected. However, we encountered a surprise of finding significantly different amounts of asphaltenes in two of the samples collected at depths differing by only 65.4 feet TVD in the same sand.
The contamination levels of these samples were not consistent with the coloration (optical density) from the NIR response (a measure of the contamination level). The observed inconsistency is explained below.

Figure 6 shows plots of depth vs. gamma ray, pressure, GOR, and fluid coloration or optical density measured by the fluid analyzer. It should be noted that the samples denoted A and B were taken within a depth difference of 65.4 feet and showed enormous optical density (OD) difference (0.86 vs. 2.05). This is too large a difference in coloration to account for the contamination difference observed in these two samples. This large OD difference implies that the fluids are significantly different in composition, particularly in their asphaltene content. Further analysis of these two samples in the laboratory confirmed this speculation showing significantly higher asphaltene content in sample B. Samples were collected in both pressure-compensated bottles and high-pressure bottles. Asphaltene analyses were performed only on samples from pressure-compensated bottles. Figure 6 appears to indicate that a large asphaltene gradient exists over a small vertical interval. Figure 7 shows an expanded section of the log data. The heavy oil interval is fairly clean in gamma ray without obvious barriers. The large asphaltene gradient indicated by the analyzer prompted further review of the down-hole fluid data and subsequent application of the newly developed Yen-Mullins model and the Flory-Huggins-Zuo EoS.

**Application of New Asphaltene Gradient Equation**

In the past, there had been no valid equation of state for asphaltene gradients in reservoirs. Indeed, standard cubic EoS treatments of heavy oil often yielded no gradient which is observationally known to be in error. The primary limitation precluding asphaltene EoS development for gradients is that asphaltene molecular and colloidal structures in crude oil were unknown. This has essentially been resolved and codified in the Yen-Mullins model (see Figure 8). With the size resolved, the first equation of state for asphaltene gradients has been developed, the Flory-Huggins-Zuo (FHZ) EoS.

For low GOR oils such as mobile heavy oils, the FHZ EoS is dominated by the gravity term and is shown in Equation 2. Mobile heavy oils can be produced and sampled conventionally and typically have viscosities below 1000 cP at reservoir conditions.

\[
\frac{\% \text{Asph}_i}{\% \text{Asph}_0} = \exp \left\{ - \frac{\Delta \rho Vg}{kT} \right\}
\]  

(2)
Figure 7. Heavy oil section of log showing a large asphaltene (fluid coloration) gradient over a limited vertical interval. The fluid color is known to be linear in asphaltene content.

Figure 8. Prototypical structures of asphaltene molecules and nanocolloidal species found in crude oil. In mobile heavy oils with asphaltenes nearing 20%, asphaltene clusters dominate (right in figure).

where %Asphi is asphaltene content in the crude oil at height i, h is height above the reference height 0, \( \Delta \rho \) is the density contrast between the asphaltene and the oil, \( V \) is the volume of the asphaltene particle, \( k \) is Boltzmann’s constant, and \( T \) is temperature.

The numerator in the argument of the exponential is simply Archimedes buoyancy (times height \( h \)), and has been proved valid for 2,000 years. The exponential is of the form \( \exp\{-\Delta E/kT\} \) and is the Boltzmann distribution which is well known in statistical mechanics. The Boltzmann distribution gives the ground and excited state population of any equilibrated system at temperature \( T \). For gravitation fields, small objects such as (negatively buoyant) asphaltene clusters can be elevated above the base of the column by thermal energy at temperature \( T \). Indeed, this same equation can be used to account for the pressure gradient of the earth’s atmosphere; thermal energy is able to lift air molecules to significant heights above the surface of the earth as discussed by Physics Nobel Laureate Richard Feynman 22.

For the heavy oil case in Figure 7, all parameters of Eq. 2 are known. Here we use the diameter of the asphaltene particle as an unknown instead of assigning it the size of 5 nanometers. If the asphaltene particle size deviates significantly from that shown in Figure 8, then our simple model would not apply.

Figure 9 shows that the log data agrees closely with expectations with only one tightly constrained parameter; the size of the asphaltene cluster is found to be 5.27 nm here versus the conventional 5.0 nm (see Figure 8). Similar results have been reported in Ecuador 23 and Saudi Arabia 24. The simple match reported here between log data and the asphaltene EoS is the first reported in a deep water setting. Viscosity of heavy oil depends exponentially on asphaltene content. Thus, understanding asphaltene gradients is of paramount importance. Moreover, if the reservoir continues down structure, a tar mat could be present due to the enormous asphaltene gradient with corresponding increasing viscosity.
Summary and Conclusions

• The low oil mobility often coupled with sand production from unconsolidated formation poses formidable challenges in the acquisition of representative fluid samples either down-hole or at the surface. This is further complicated in the presence of high asphaltene contents in the oil and with co-production of water leading to the formation of emulsions.

• Carefully selected sampling tools and equipment, and customized tool-string design in conjunction with special techniques, procedures, and diligent quality control are necessary to ensure that representative fluid samples are gathered.

• A field example of an extra heavy oil reservoir located in South America with oil gravity of 8-9° API and viscosity of a few thousand cP is used to illustrate the methodology employed in the acquisition of high quality representative samples.

• A GOM field containing highly graded asphaltic oil illustrates the difficulties of not only sampling this reservoir but also of performing down-hole fluid analysis to quantify the observed severe asphaltene gradients. Again, a judicious choice of tool-string design coupled with a set of sophisticated fluid analysis tools made it possible to obtain good quality samples and high-precision asphaltene measurements down-hole.

• The laboratory PVT data measurement on extra heavy oil is a challenging task due to the “foaminess” of the oil below its true bubble point, which often leads to lower “pseudo” bubble points and non-equilibrium PVT conditions. Several laboratory techniques to overcome these difficulties were implemented to obtain equilibrium-condition PVT data for modeling purposes.

• Because of the slow release of solution gas from extra heavy oils and the complex solid-liquid-vapor phase equilibrium exhibited by high-asphaltic oils, the modeling of these fluids is challenging.

• A mimicked non-equilibrium set of data coupled with measured equilibrium data were used to model extra-heavy oil using equilibrium EoS methods. An industry-first asphaltene EoS based on Flory-Huggins-Zuo\textsuperscript{21} theory coupled with the correct physics of asphaltene molecular and colloidal structures\textsuperscript{20} was applied successfully to quantify the high asphaltene gradients observed down-hole in a GOM field.

• It is highly recommended that fluid sampling, laboratory analysis, and modeling efforts for heavy and asphaltic oils
should be addressed with methods custom-tailored to each individual reservoir and fluid characteristics. This will ensure that high quality samples and PVT data are acquired and accurate fluid models are built using new EoS methods and techniques that capture the physics of the fluid behavior of these complex fluids.

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