CORING AND CORE ANALYSIS: CHALLENGES OF OFFSHORE ULTRA DEEP WATER RESERVOIRS

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ABSTRACT

The nature of deep water wells makes obtaining good quality core difficult. The cores are taken from great depths, often more than 25,000 feet below the ocean surface, the reservoirs are under great stress and the cores can be damaged during the coring or retrieval process. The cores are obtained using Synthetic based muds (SBM) and the mud filtrate from these muds can alter the wettability of the core. The filtrate often contaminates the oils obtained by wireline samplers, so the oil required for wettability testing and sample restoration is often not usable. The core data from the exploration well is often the only data available for the simulation engineers to use in developing the reservoir model, so the data is required to be provided in a short time and must be of good quality.

Today it is not unusual at least in the ultra deep wells in the Gulf of Mexico (GoM) to have reservoir conditions that exceed 250°F and 20,000 (138 MPa) psi pore pressure. The logging service companies are busy upgrading their logging tools for current High Temperature-High Pressure (HTHP) conditions, how about core analysis services companies? We are not aware of any commercial lab that can obtain relative permeability, capillary pressure, IFT measurements, and uniaxial pore volume compressibility (PVC) with transverse perm under these conditions. Do we need to?

Two other aspects of high reservoir pore pressures are that few service company labs are equipped to measure viscosity at and above 20,000 psi and there are no HTHP certified viscosity standards to calibrate lab viscometers. Also routine core analysis permeability at low pore pressure may significantly underestimate permeability at reservoir pore pressure because of the effective stress law for permeability. Likewise transverse permeability measured during uniaxial PVC tests at constant pore pressures may underestimate perm reduction during pore pressure depletion.

INTRODUCTION

For the Lower Tertiary Paleogene play in the ultra deep water (water depths > 5,000 feet) Gulf of Mexico the wells are drilled to depths in excess of 25,000 feet (7620m) some have set near depth records of about 33,000ft (TVD). These wells are very expensive to drill and complete with costs up to about $100 million. Reservoir challenges are pore pressures that exceed 20,000 psia (138MPa) beyond the limit of some current logging tools while the temperatures are not as extreme being in the range of 230°F to 260°F

CORING CHALLENGES

Obtaining Representative Rock Samples

The cores from deepwater reservoirs are almost always taken with synthetic base muds (SBM), which are environmentally friendly alternatives to oil base muds. The mud is made out of two liquid components, an external phase made up of the synthetic oil which consists of fluids classified as paraffins, olefins or esters. There is an internal phase of high salinity brine which is usually $CaCl_2$ based. This brine is emulsified and kept in suspension as an internal phase; this is called an invert emulsion. These muds contain large amounts of emulsifiers that are used to keep the internal water phase as a discreet emulsion rather than a continuous phase. The internal brine phase can typically range from 10 to 40% of the total mud volume. The muds also contain strong oil wetting agents that keep the clays (bentonite), weighting agents (usually barite) and cuttings oil wet and in suspension.

The SBM's are designed to be very effective in maintaining the proper fluid characteristics, but these characteristics, strongly oil wetting and strong emulsification properties will also cause problems when the filtrate from the mud enters the core while coring operations are ongoing. The filtrate will invade the core from a distance of a few millimeters to complete invasion. The filtrate carries the chemicals in the external phase of the drilling fluid (synthetic oil) into the core. These chemicals will cause the portion of the core invaded to become less water wet (Tong 2004). Over time the filtrate can diffuse deeper into the core past the invaded zone and affect the wettability of the entire core.

The only effective method to avoid or reduce the problems with the filtrate invasion in the cores and the near well bore region is to add materials to the SBM to bridge off the formation during filtrate invasion and create a filter cake that impedes the invasion. The most common and cost efficient method of reducing filtrate invasion is the use of sized CaCO3 particles, which are usually ground marble. (Rathmell et al, 1999) The CaCO3 particles need to be properly sized for effective bridging of the reservoir. The classic method for determining the size and distribution of the sizes of the particles (PSD) is based on Abrams (Abrams 1977). He stated that the specific distribution of particle sizes (PSD) required to effectively bridge a given pore throat distribution must include particles that are smaller and larger than a third of the pore throat's diameter. This is a guideline only; the use of the permeability plugging apparatus, known as a PPA system (API RP 13I 2004, Neil 1999) is required to obtain the optimum bridging design. Lab studies on non-damaging drill in fluids (DIF) have shown that a mud using properly sized CaCO3 particles creates a thin and tight mud cake that can be removed easily during completion (Vickers et al, 2006 & Quintero et al, 2004). This thin and tight mud cake indicates that no internal filter cake is being produced and the cake is bridged off in the outer few pore diameters of the formation.

This thin and tight mud cake indicates that no internal filter cake is being produced and the cake is bridged off in the outer few pore diameters of the formation. There are two methods of filtrate entering the core, spurt loss and static filtration. Cores are especially vulnerable to spurt loss, due to the small radius, usually 2 inches. The initial spurt can inject a large volume of whole mud and filtrate into the core.

The whole mud contains the base fluids and the emulsified brine (internal phase) and mud solids. The core is only exposed to the drilling fluid as it is cut, the core then enters the inner barrel, usually after 5-10 millimeters, but substantial spurt and static filtrate loss's can still occur. The well bore is exposed both to the mud spurt and static filtration for extended lengths of time, so the potential for deep filtrate invasion is significant.

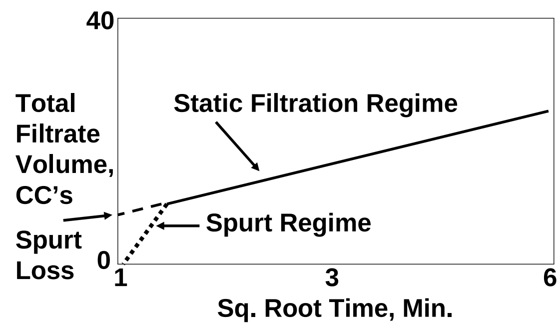

Figure 1 (Davis 1999) Spurt loss and Static Filtration versus Time

Wettability, Core Plug Cleaning, and Restoration

The SBM's that are commonly used are composed of pariffins, olefins or esters. Of the 3 main "base" oils, the paraffins and olefins can cause asphaltene precipitation in cores containing asphaltic crudes. Zhang et al. (2005) wrote that the results of this asphaltene precipitation can cause the core to become less water wet.

Reducing the filtrate invasion and obtaining plug samples from the core at the well site, as soon as the core is on the surface can reduce the effects of the filtrate invasion. The filtrate will have invaded to a certain depth into the core and will continue to diffuse towards the center (un-invaded zone) over time. So removal of a plug from the un-invaded section of the core will provide the best quality plugs for analysis.

Due to the fact that the SBM's can cause wettability changes due to asphaltene precipitation and interaction of the core with the emulsifiers and oil wetting agents, the core must be thoroughly cleaned prior to any special core analysis testing in involving wettability. The core sample is first brought back to water wet conditions by solvent cleaning, which is difficult to achieve when invaded by synthetic mud filtrates. If required, the sample is then restored to reservoir conditions by aging at reservoir temperature at Swi conditions in the presence of crude oil. The problem for the core analyst is that often the only source of crude oil from a deepwater reservoir is samples taken by a wireline formation tester.

The formation tester obtains fluid from the near well bore region and if the formation is deeply flushed by SBM filtrate, the crude oil obtained is contaminated by up to 30% of filtrate. Better oil samples can be obtained by longer pump times, but due to the high daily rig costs, these longer pump-out times are not usually used, and often the longer pump times do not results in significantly better quality samples. So the core analyst has contaminated cores that must be aggressively cleaned to water wet conditions and then must use contaminated oils for restoration. The only method to correct this problem is to reduce the amount of filtrate invasion into the near well bore region during the coring and drilling operations using low invasion muds.

Physical Core Quality

Several basic procedures employed during coring and during core processing can help maintain the quality of the core. The deepwater environment holds many challenges to obtaining good quality cores many of the reservoirs are deep and have very high pore pressures. The dissolved gas from the crude must be allowed to escape slowly from the core during the trip out of the hole. Even if the GOR of the reservoir crude is low (under 200 GOR), the volume of gas at reservoir pressure is considerable. After evolving from the oil this gas must escape through the pore system and exit the core. When the gas first evolves it has essentially no relative permeability, it is similar to trapped gas. As the gas saturation increases the relative permeability to gas increases. As the gas moves through the pore system it can move oil out of the pores and decrease the measured So values in the lab. The rapidly expanding gas can also damage the cores physical structure by creating fractures. The gas can expand so rapidly that the core is fractured and or dilated (Hettema et al, 2002). Proper trip schedules must be developed and followed. The deepwater reservoirs are drilled by high priced drilling rigs, with costs often exceeding $500,000 a day, so there is a lot of incentive to speed the pulling schedule. This is false economy, the core can be damaged and the quality of the core analysis results placed in jeopardy.

CORE ANALYSIS CHALLENGES

The very high pore pressures in the Lower Tertiary Paleogene play in the ultra deep water Gulf of Mexico cause unique challenges for rock and fluid property measurements. In this paper we will discuss two fluid properties; viscosity and IFT, three rock properties; permeability, calculation of net effective stress, and rock strength, and one rock fluid interaction; relative permeability measurements. The intent of this section of the paper is to draw reader's attention to the potential impact of very high pore pressures in core and fluid analysis based on the author's recent experience that is supported by prior literature or to flag the apparent absence of literature and core analysis service company's limited capabilities.

Fluid Properties: Viscosity

We will start our discussion of the impact of high pore pressures with viscosities measurements. Obviously viscosity is one of the most critical parameters in reservoir simulation directly impacting early field life when production is single phase flow determined by rock permeability (effective) and fluid viscosity. Today typically the core and fluid service companies are capable of obtaining viscosity measurements with an upper limit of 20,000 psi (138 MPa) using either a capillary coil viscometer or the electromagnetic viscometer. Thus when fluid samples are obtained at pressures greater than 20,000 psi than the viscosity must be inferred by extrapolation to the higher pressures resulting in increased uncertainties (about 10%) in the viscosity. Several universities have vibrating wire viscometer which has an upper limit of about 30,000 psi. (Caudwell et al, 2004)

A problem more severe than having to extrapolate beyond equipment pressure limit is that the fact that there are no HTHP certified viscosity standards to calibrate lab viscometers, a problem not unique to very high pressures. One can purchase certified viscosity standards that cover a wide range of viscosities that provide viscosity and density as a function of temperature but only at ambient pressure. The US National Institute of Standards and Technology (NIST) provides viscosity data over a wide range of temperatures and pressures even exceeding 30,000 psi but for only a few simple low viscosity hydrocarbons like n-decane. There are no certified standards data for hydrocarbon fluids in the viscosity range of 2.5 to 25 cP at 20,000 psi and 250°F and beyond. These high pressures and temperatures will impact the calibration of both the capillary coil and the electromagnetic viscometers. The correction factor for the electromagnetic viscometer is dependent on the piston used which is dependent on the viscosity. Thus one is unable to directly calibrate the viscometer for fluids with a viscosity > 2cP at high pressures. This probably results in additional uncertainty of at least 10% in viscosity value at 20,000 psi and 250°F.

To address this viscometer calibration problem several Houston based oil companies have contracted Imperial College, London, UK (Caudwell et. al, 2004) to obtain viscosity measurements on a 2 liter batch of two ambient temperature certified viscosity standards of a different viscosities over a very wide range of temperatures and pressures using their vibrating wire viscometer. Because of the nature of the design of the vibrating wire viscometer its calibration should not be sensitive to viscosity of the fluid. Small samples from these new viscosity (secondary) standards will in turn be used to calibrate and QC viscosities measurements provided by local service companies using capillary coil and electromagnetic viscometers.

Fluid Properties: HTHP Interfacial Tension (IFT)

As previously stated the uncertainty in the viscosity measurement may be on-the-order of 10% + 10% = 20% due to pore pressures beyond the pressure limits of the equipment and the lack of viscosity standards to calibrate the viscometers. The uncertain in the interfacial tension (IFT) of live reservoir oils at these HPHT conditions may be nearly an order of magnitude greater. Lab capillary pressure data requires conversion from lab fluids to reservoir fluids (eq. 1).

$$\text{Reservoir Pc} = \text{Lab Pc} *\text{reservoir IFT}*\cos(\theta)/ \text{Lab IFT}*\cos(\theta) \qquad (1)$$

Typically porous plate or centrifuge primary drainage capillary pressure use either an air-brine or mineral oil-brine fluid system. The IFT at ambient temperature and pressure for these fluids are well known. There is very little published data and that which is published is not consistent for IFT on live oils at pressures up to 5000 psi and little or none above 5,000 psi. (Amin & Smith, 1998) A linear extrapolation of IFT data from Hocott (1939) from 4,000 psi to 20,000 psi result in an decrease in IFT from about 30 dynes/cm to 10 dynes/cm.

Most service companies have an upper pressure limit of about 7000 psi for IFT measurements on live fluids by Pendent Drop, a much lower pressure limit than for viscosity. The cost to obtain IFT measurement at pressures approaching 20,000 psi on a single live oil sample may be comparable to obtaining true reservoir conditions steady-state relative-permeability measurements on several core plugs, thus IFT measurements could represent a significant fraction of a SCAL program. Any attempt to extrapolate low pressure IFT data to very high pressures results in a high degree of uncertainty even if one may not expect a strong dependence of IFT on pressure, without any published data to verify.

Most SCAL programs obtain primary drainage Pc as a means to initialize the reservoir simulator to quantify OOIP. The sensitivity to IFT in converting lab measured reservoir rock primary drainage capillary pressure response (correlates with rock permeability), is illustrated in Figure 2, with the uncertainty in OOIP in Table 1. Thus depending on the reservoir height (assuming 300m) and the shape of the capillary pressure curve a 100% uncertainty in IFT can equate to a significant uncertainty, +/- 20%, for a low permeability, ~1mD, reservoir or insignificant uncertainty, +/- 2%, for a high permeability, ~100 mD, reservoir.

Table 1: Uncertainty In IFT (100%) Translates To Uncertainty In OOIP

Perm (mD)	Reservoir Height (m)	% Change in OOIP
1	50	35
1	300	20
100	50	5
100	300	~2

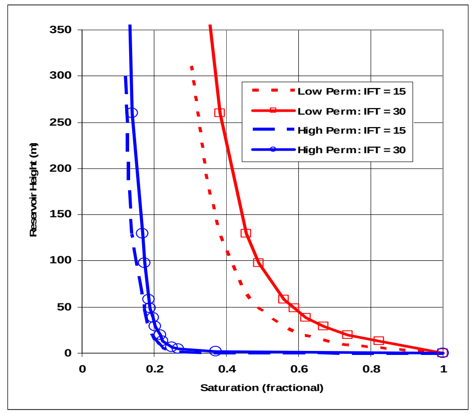

Figure 2. Conversion of Lab Pc to reservoir Pc

Rock Properties: Stress Calculations

Rock properties, mechanical and flow, are impacted by 20,000 psi pore pressure that are not typically seen when lab tests are conducted at pore pressures below 5,000 psi pore pressure.

Before routine core analysis measurement of porosity and permeability can be conducted, the net effective confining stress (NCS) of the reservoir is required, or these measurements need to be obtained over a arrange of stresses, eq. 2. (Worthington et al, 1997)

NCS = (vertical effective stress + maximum horizontal effective stress + minimum horizontal effective stress)/3 (2)

Effective stress = σ = stress – pore pressure (3)

NCS = ($\sigma_v + \sigma_{hmin} + \sigma_{hmax}$)/3 (4)

NCS = ((26000-23000) + 2*(24500-23000)/3 = 2000psi (5)

The Lower Tertiary Play in the ultra deep water Gulf of Mexico is typically greatly overpressure, 5000 psi to 10,000 psi beyond hydrostatic. Thus NCS is the difference of two very large numbers (eq 2 and 3). Values used in eq. 5 are for illustrative purposes only and assume a reservoir depth of about 30,000 ft in 5,000 feet of water and 10,000 feet of salt, about 10,000 psi overpressure in the reservoir sands, and $\sigma_{hmin} + \sigma_{hmax}$.

To obtain vertical stress one integrates a density log from mud line down to the reservoir sands. Typically there are no density data from the mud line down to salt (whose thickness varies from 1000ft to 15,000ft) and through the salt, leaving only the density log data for the rock below the salt which may only be a small fraction of the total thickness below mud-line.

Since the rocks from these depths are much more consolidated than those from the younger age rocks from the deep water GoM, than an uncertainty of even 1000 psi in a NCS of 2000 psi may not result in a significant error in the poroperm data as it would for the unconsolidated high porosity sands in younger age rocks.

However, eq. 3 is a simplification of the effective stress law for pore volume that involves a correction be applied to the pore pressure, eq. 6. This correction term, Biot coefficient or Alpha, is typically assumed to be one. For high porosity unconsolidated rocks it is nearly one and is typically ignored since the bulk compressibility of the formation rock is 20 to 30 times the grain compressibility. However for Lower Tertiary trend in the ultra deep water Gulf of Mexico rocks, one should not ignore the impact of Biot coefficient since the rocks have much lower bulk compressibility and very high overpressures. This is illustrated in eq. 8 using the values in equation eq. 5 and adding the Biot coefficient of 0.8 (eq. 7). Given that for the Biot coefficient to be significantly less than 1.0 requires low compressibility rocks and by their nature the pore volume and the permeability may not significantly change if the NCS is increased from 2000 psi to 6600 psi, but this should be determined by obtaining porosity – permeability data versus NCS for a subset of the routine core analysis plugs.

Effective stress = σ = stress – alpha*pore pressure (6)

Biot Coefficient = Alpha = 1 – Bulk Modulus of rock/Bulk Modulus of grains
= 1 – (1*E006/5*E006) = 0.8 (7)

NCS = ((26000-0.8*23000) + 2*(24500-0.8*23000)/3 = 6,600psi (8)

Rock Properties: Permeability versus Pore Pressure

Different rock properties have different effective stress laws. As just mentioned, for pore volume, Alpha or Biot coefficient is less than one, for porosity, Terzaghi, alpha is equal to one. In the effective stress law for perm the value of alpha is reported to be greater than one. Thus with increasing pore pressure at a constant net effective stress (eq. 6) the permeability will increase. (Al-Wardy & Zimmerman, 2004 & Warpinski & Teufel, 1992). The rational for this is at high pore pressures the volume of the grains inside the pores, that are not part of the load bearing frame work grains are reduced thus effectively increasing the diameter of the flow path and thereby the permeability; Figure 3.

We have found that brine permeability measurements on core samples that the permeability increase is a exponential function of the pore pressure, thus with pore pressures less than 5,000 psi the increase is less than 5% and would be considered within the noise/uncertainty of the permeability measurement. At a pore pressure of 10,000 psi the % increase in permeability over that at 500 psi, has increased to 5% to 25% with a projected increase by 20,000 psi of 10 to 50%.

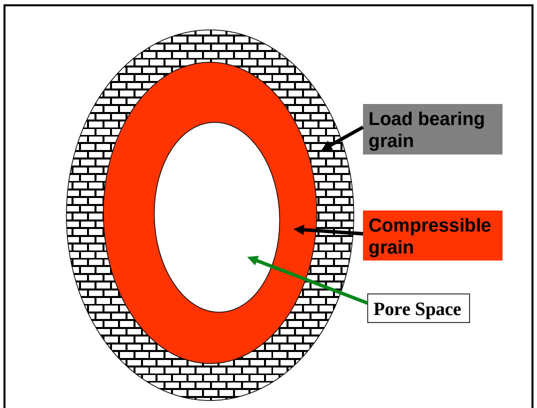

Figure 3: Cross-section of pore throat

What is the impact of this effect of pore pressure on permeability? The main permeability characterization of reservoir rock is based on the air permeability measured on the core plugs at one per foot. These air permeability measurements are conducted at low pore pressures, 10's to a few 100's psi mean pore pressure. Even when brine permeabilities are obtained to compare with air permeability they would typically be done at low backpressure, typically less than 1000 psi. The pore pressure used in oil perm at connate water saturation may depend on the whether live or dead oil is used, but typically the pore pressures would be less than 5,000 psi if only for sake of convenience. Thus all of these permeability measurements are likely to significantly understate the in-situ reservoir permeability when pore pressures are in the 20,000+ psi range.

The "good" news on routine core analysis air permeability understanding reservoir perm is off-set by the fact that the reservoir as it is being produced the pore pressure decreases which would result in lower permeabilties because of the effective stress law. One would expect that pore pressure depletion would result in a perm reduction simplify because of the increase in the net confining stress. Thus now there are two mechanisms that will result in lower permeability during pore pressure depletion, increasing net confining stresses (reducing pore throat size) and decreasing pore pressure (increasing volume of grains within pores). From our preliminary assessment these two effects potentially may be of the same magnitude.

Currently most US core analysis services companies are not equipped to measure transverse permeability on a vertical core plug during uniaxial compaction, simulating reservoir stress-strain at reservoir conditions of stresses, pore pressures, and temperature so we are unable to obtain these data directly.

Rock Properties: Rock Mechanics

As stated earlier, because of the very high cost to drill and complete wells in the Lower Tertiary the number of wells and well productivity is critical to project economics. To maximize well productivity requires large drawndowns and competent rock. Given the high pore pressures, then large pore pressure depletions can be used to increase well productivity. Thus when tests are conducted to measure rock pore volume compressibility (PVC) either as effective pore depletion (constant pore pressure) or true pore pressure depletion, pore pressure depletions in excess of 10,000 psi are evaluated. These tests are typically conducted at ambient temperature. However, Schutjens, et al (1998) reported that for consolidated sands in the North Sea one potentially may obtain much higher values of PVC when the measurements are conducted at reservoir temperature.

We have confirm this behavior for some LT GoM rock samples. Figure 4 compares the PVC at ambient temperature and reservoir temperature (250°F) indicating an increased PVC at reservoir temperature as the effective pore pressure depletion exceeds 8,000 psi.

If at the maximum pore pressure depletion, maximum confining stress, the uniaxial strain conditions are maintained and volumetric strain is monitored one finds that magnitude of the creep is greatly increased at reservoir temperature. Schutjens, et al (1998) had attributed this behavior to stress corrosion cracking of the grains and requires the presence of water.

We have confirmed the importance of the presence of water in our LT GoM rock samples, in that the PVC and the creep are the same at ambient temperature and reservoir temperature if rock sample is 100% saturated with oil and independent of saturating fluids at ambient temperature.

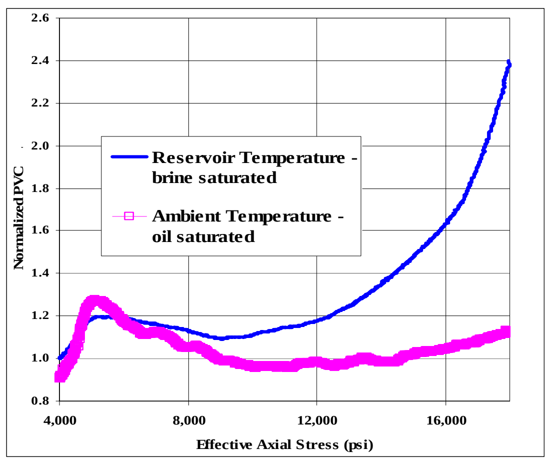

Figure 4: Normalized Pore Volume Compressibility

We have observed a doubling or greater increase in PVC when tests are conducted on LT GoM rock samples at reservoir temperature but since these are relatively consolidated rock samples with low PVC values, then this increase may have only marginal impact on reservoir simulator results (compressibility of the rock fluids not the rock solids may dominate).

However, the observed doubling of the PVC at reservoir temperature is also accompanied by a significant decrease in the Young modulus. Rock strength will be an issue in well completions design and the rock mechanical tests that support this such as UCS, triaxial compaction, and thick wall cylinder (TWC) tests are all routinely conducted at ambient temperature by the service companies. We flag this as an issue, since we are aware of others who are just starting to evaluate the impact of temperature and pore pressure on these rock mechanical measurements that support well completions.

Rock-fluid Interaction

We have already discussed the impact of very high pore pressures on absolute brine permeability, thus one might expect that relative permeability and wettability, drainage and imbibition capillary pressure, potentially might have an altered response. Probably safe to assume that there are few service company labs that conduct true steady-state relative permeability experiments with continuous recycle of fluids at pore pressures of 10,000 psi let alone 20,000 to 25,000 psi pore pressure. How can we be sure we don't need to conduct rel-perm experiments at true reservoir conditions, if we have no data to support that position?

There are other operational considerations apart from true reservoir conditions. Often the crude oils from these Lower Tertiary GoM fields have relatively low GOR's so live oil rel-perm test can be conducted at pore pressures currently available at some service companies. But because the pore pressure may only be a ¼ or a 1/5 of the true reservoir pore pressure the viscosity of the live oil is two to four times less viscous and thus the mobility ratio has significantly changed; becoming more favorable. Also, some of the oils encountered in the ultra deep water Gulf of Mexico Lower Tertiary Trend have concentration of asphlatenes > 1%. For these oils one needs to be concerned about what is the asphaltene flocculation unset pressure that would then determine the pore pressure required to conduct a rel-perm test.

CONCLUSIONS

- To obtain the best quality core analysis and fluid analyses results the coring fluid must be optimized by performing PPA tests to design a coring fluid to reduce spurt and filtrate loss, the best method is to use sized CaCO3 particles.
- To obtain the best quality cores with representative fluid saturations, proper trip rates must be used. For high reservoir pressure Lower Tertiary Paleogene sands, this is especially important.
- At HTHP conditions the uncertainty in the value of IFT may be as large as 100% resulting in an uncertainty in reservoir OOIP the magnitude of which is determined by the shape of the capillary pressure curve and the height of the reservoir.
- In the calculation of net confining stress one can not ignore Biot coefficient.
- Most labs are unable to measure fluid viscosities above 20,000 psia pore pressure and there are no certified HTHP viscosity standards in the range of 2 to 25 cP.
- Routine core analysis permeability measurements at low pore pressure may significantly underestimate permeability at reservoir pore pressures.
- Transverse permeability measured during uniaxial pore volume compressibility tests at constant pore pressures may underestimate permeability reduction during pore pressure depletion tests.
- Do we know that HTHP measurement conditions are required to accurately describe reservoir flow behavior?

- Are there core analysis service company labs that can perform at reservoir pressures and stresses:
    1. relative permeability, wettability measurements, capillary pressure, or IFT?
    2. uniaxial pore volume compressibility with simultaneous measurement of transverse permeability?

ACKNOWLEDGEMENTS

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