

# FLUID SAMPLING UNDER ADVERSE CONDITIONS

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## ÉCHANTILLONNAGE DES FLUIDES EN CONDITIONS DIFFICILES

Des échantillons valables sont essentiels pour bien caractériser les fluides de gisements. Si les échantillons ne sont pas représentatifs, toutes les mesures ultérieures seront entachées d'erreurs. Cet article discute les principaux défis en matière d'échantillonnage, en particulier les réservoirs de gaz à condensats, les gradients compositionnels, la teneur en eau des fluides hydrocarbonés, les dépôts d'asphaltènes, les dépôts de paraffines, la contamination par les boues à base d'huile, et les constituants réactifs. Il relate également les principaux progrès technologiques récemment réalisés dans ce domaine et passe en revue les développements des techniques d'échantillonnage telles que les outils de type MDT, les nouveaux outils d'échantillonnage DST, l'échantillonnage par *coiled tubing*, et les méthodes isocinétiques. Il met également l'accent sur leurs limites. On insiste sur l'importance d'un usage optimal de la technologie existante, par combinaison des techniques traditionnelles et des développements nouveaux, qu'il s'agisse du conditionnement correct du puits, de l'interprétation des données du champ, ou surtout d'une manipulation adéquate des échantillons. Cet article insiste aussi sur le besoin d'un meilleur échange d'informations sur l'échantillonnage entre organisations, et rappelle le manque de normes industrielles à jour en matière d'échantillonnage des fluides. Il est proposé de constituer un projet industriel pour identifier et documenter les procédures adéquates.

## FLUID SAMPLING UNDER ADVERSE CONDITIONS

Valid samples are essential to the proper description of reservoir fluids; if the samples are not representative, all measurements on them will be invalid. This paper discusses the principal challenges facing fluid sampling including gas condensate reservoirs, compositional gradients, water content of hydrocarbon fluids, asphaltene deposition, wax formation, oil base mud contamination, and reactive components. It also reports the major technological advances recently made in this field. It reviews developments in sampling techniques such as MDT-type tools, new DST sampling tools, coiled tubing sampling, and isokinetic techniques, and it highlights common limitations. The value of making proper use of existing technology is emphasized, both with traditional techniques and new developments, with reference to correct well conditioning, interpretation of field data, and especially to optimum handling of samples. The paper emphasizes the need for better exchange of sampling knowledge between organizations, and highlights the lack of up-to-date industry standards with respect to fluid sampling. A solution is proposed in the form of a joint industry project to identify and document best practices.

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## MUESTREOS DE FLUIDOS EN CONDICIONES SEVERAS

Es de suma importancia poder disponer de muestras valederas para poder caracterizar correctamente los fluidos de yacimientos. De no ser representativas la totalidad de las muestras, todas las mediciones ulteriores estarán acompañadas de errores. En este artículo se ponen en discusión los principales retos existentes en el aspecto del muestreo, y básicamente, en los yacimientos de gas de condensados, los gradientes composicionales, la proporción de agua en los fluidos hidrocarbonados, los sedimentos de asfaltenos, los sedimentos de parafinas, la contaminación por lodos a base de aceite y, finalmente, los componentes reactivos. También se describen los principales progresos tecnológicos obtenidos recientemente en este aspecto y se examinan sucesivamente los desarrollos intervenidos en las técnicas de muestreo, como, por ejemplo, las herramientas de tipo MDT, las nuevas herramientas de muestreo DST, el muestreo por "colled tubing" y los métodos isocinéticos. Se hace hincapié respecto a sus limitaciones y se insiste acerca de la importancia de un empleo óptimo de la tecnología existente, por combinación de las técnicas convencionales y de los nuevos desarrollos, ya se trate del correcto acondicionamiento de los pozos, de la interpretación de los datos de terreno y, sobre todo, de una manipulación adecuada de las muestras. También se insiste en este artículo respecto a la necesidad de un mejor intercambio de informaciones acerca del muestreo entre las diversas organizaciones y se recuerda la carencia de normas industriales actualizadas en cuanto al muestreo de fluidos. Finalmente, se propone constituir un proyecto industrial para identificar y documentar los procedimientos adecuados.

## INTRODUCTION

Reservoir engineering and production activities are critically dependent on identifying the fluid, or fluids present in the reservoir, and on understanding how hydrocarbons will behave during the life of the development. Determining the optimum production strategy requires knowledge of phase behavior and multiphase fluid flow downhole, in flowlines and in surface facilities, and relies increasingly on compositional simulators tuned to pressure-volume-temperature (PVT) laboratory measurements. In addition to direct use, fluid properties also aid the confirmation and interpretation of other measurements such as fluid gradients and contacts, pressure build-ups, and correlations with other finds.

Chemical analysis and physical property measurements bring their own uncertainties, but it is the reservoir fluid samples themselves that have the biggest influence on the quality of the fluid data. If the samples are not representative, all measurements on them will be invalid. This is compounded by the fact that modern field practices, involving smaller finds and an emphasis on fast track development, may not offer a second chance for sampling.

Sampling operations are continuously under pressure from cost control, operational limitations and sometimes from ignorance. Yet, the risk of financial loss attached to poor fluid characterization, though never properly quantified, can be enormous. Fortunately tremendous progress has been made in fluid sampling technology in recent years, and these developments need to be properly implemented.

An analysis of the most suitable procedures to apply in PVT laboratories for evaluating fluid samples collected under normal conditions has already been performed [1]. This paper evaluates the primary challenges faced when attempting to sample reservoir fluids in difficult circumstances, and explains how the use of new technology together with the extended application of existing knowledge can help address the problems that are encountered.

## 1 CHALLENGES

The type of reservoir fluid to be sampled often has a major influence on the difficulties experienced in sampling. In exploration wells the fluid character,

being one of the objectives of the sampling program, is never known with certainty.

Gas condensate fluids are well known for problems related to drawdown during production, the conflicting need to maintain adequate flow velocity in the tubing, surface measurement problems, and the interpretation of observed laboratory behavior. Thus, there is frequently more uncertainty about the quality of gas condensate fluid samples, which reduces knowledge about the build-up of retrograde condensate around the well during production, itself dependent both on phase equilibria (retrograde liquid formation), fluid composition (via interfacial tension) and flow rates. This liquid build-up is the principal cause of productivity decline for gas reservoirs.

The presence of compositional gradients due to fluid migrations, or to the fluids showing near-critical behavior at reservoir temperature complicates determining the true origin of fluids that are sampled, which is essential for developing a valid model of the reservoir. Near-critical systems are notorious for the phase changes which yield large proportions both of liquid and gas with only small reductions in pressure below the saturation pressure for the system. Since these proportions can exceed critical saturations, both fluids will be mobile to some extent, and the resulting production and samples may be difficult to interpret. These phenomena may not be identified until several wells have been drilled and tested, especially if initial variations have been assigned to poor sample quality.

At the other extreme of the fluid range, very low GOR (gas-oil ratio) oils may cause separation and measurement problems, or prevent proper collection of samples. High oil viscosity can lead to plugging of sample lines and ideally requires special sampling techniques or equipment. Oils which produce stable foams make it very difficult to collect a representative sample of just the separator oil, and oil flow rate data may well be high and unstable due to the effects of entrained gas.

Traditionally, any water in fluid samples has been regarded as a contaminant, and has been eliminated as far as possible, yet most hydrocarbon fluids naturally contain small quantities of water. Water concentrations can however be extremely high (for example, above 5%) in many high pressure-high temperature reservoir fluids. Understanding the effect of this water on phase behavior and fluid production becomes vital. Modeling hydrocarbon systems containing significant water is

still a difficult task, and is further compounded by poor knowledge of actual concentrations in most reservoir fluids. Thus, both an improvement in measurements and interpretation is required in this domain.

Reservoir fluid phase changes can cause additional problems related to solid formation. This is especially important when pressure reduction causes asphaltene deposition, or when temperature reduction produces wax in paraffinic fluids. The formation of gas hydrates is another example involving solids related to phase changes in the produced fluid. Such phase changes can cause plugging, especially in production lines, or can alter wetting in the reservoir. If they occur before or during sampling, they may never be detected by measurements on the fluid which reaches the PVT laboratory.

Another concern relates to loss of sample validity. Maintaining sample integrity, especially during handling, requires appropriate equipment and good procedures that are properly implemented. Often there is an important time lag before procedures evolve to match developments in sampling technology. Trace elements and reactive components of reservoir fluids require special care; component concentrations may have decreased or become undetectable by the time samples arrive in the laboratory.

Samples may also be contaminated by workover fluids, chemical additives, solvents, or residues from other fluid samples. With the increasing use of new formation test tools for sampling, combined with the use of oil base drilling muds, contamination with drilling mud filtrate (which is relatively easy to rectify for water-based muds) is becoming a major challenge.

Hardware limitations can also have an important influence on fluid sampling activities. Traditional problems involve the measurement of flow rates and other parameters important in establishing the separator GOR, determining the sampling depth and conditions, and the homogenization and transfer capability. Operating practices under frontier conditions of pressure and temperature can limit the use of downhole and wellhead sampling equipment.

## 2 SOLUTIONS BASED ON NEW TECHNOLOGY

In recent years significant improvements have been made in wireline sampling tools, notably involving the development of so-called monophasic fluid samplers.

As with other downhole samplers the idea is to sample reservoir fluid while it is essentially under initial reservoir pressure, or at least at a pressure equal to or higher than the saturation pressure below which two phases form and representative sampling becomes impossible down the well. Whereas samples in traditional downhole tools experience a fall in pressure due to cooling as they are recovered from the well, monophasic samplers maintain pressure on samples when brought to the surface, by means of a nitrogen gas charge. This usually eliminates the need for re-compressing and homogenizing the sample before transfer or study, and is widely used for reservoir fluids containing asphaltenic components, whose solubility is very pressure sensitive.

One inconvenience with "monophasic" samples is the lack of the quality information (usually a tentative bubble point) at the well site that is available when re-compressing samples that have become diphasic. However, this can be countered either by intentionally reducing pressure on one of several monophasic samples, or running a traditional sampler above the monophasic sampler in the same wireline run.

For sampling operations in open hole situations, the new generation of formation test tools of the MDT-type has attempted to overcome the major disadvantages of the earlier RFT-type tools, such as limitations to the quantity of fluid extracted, to clean up the fluid sampled, uncertainties as to the type and quality of sample collected, limited control of the pressure drawdown, and handling difficulties due to the large volume of sample collected. Now it is possible to pump large volumes of fluid from the sample location before sampling, and to collect samples at controlled rates. In addition, there are sensors available to help identify the fluid quality. This means that sample contamination by drilling mud filtrate can often be identified and taken into account. The availability of multiple sample chambers of suitable capacity for PVT laboratory work is a major advance. Their use is especially important because it permits greater autonomy when taking multiple samples from numerous locations in the well. This capability is of great value for identifying the presence of compositional gradients with depth, for sampling fluids close to saturation pressure [2] and for resolving problems where production tests may produce commingled fluids from two close intervals. Multiple samples can also help confirm if virgin fluid is being

collected, and generally aid in controlling quality between duplicate samples.

Drill stem tests (DST), in which fluid is produced from the formation into the drill string and, in most cases, to the surface, involve much larger fluid flow rates and production volumes and usually achieve a good clean-up of the well. This is a major advantage over formation test samples, but DSTs typically involve higher cost, and involve fluid production from a larger depth range (the entire perforated or isolated interval, or an unknown proportion of it), so the origin of the fluid sampled is not so precisely known. Traditionally, down hole fluid samples collected using tools inserted in the drill string were of limited value because they involved large volumes of fluid, usually in two-phase condition, with no mixing device to assist in homogenization. Thus samples were primarily used to yield a well-site GOR and a sample of stabilized liquid. New DST sampling tools are now available, which are built with a mechanical mixing device inside the sample chamber, or which house standard wireline-type piston samplers. These tools can be used to collect downhole samples in wells where wireline operations are forbidden for safety reasons. Again collecting multiple, small samples when possible, facilitates subsequent handling and laboratory quality control procedures, usually leading to higher confidence in the property data obtained.

The oil industry has invested significant effort in developing techniques to improve fluid sampling in gas condensate reservoirs, many of which lie at or close to saturation pressure. Because of the dangers presented by two-phase conditions in the well bore, downhole sampling of condensate fluids has traditionally been considered inadvisable. For separator sampling, the major difficulty is to optimize the production rate so that fluid rises in the wellbore with sufficiently high velocity to lift any condensed liquid to the surface, whilst at the same time trying to minimize pressure drawdown in the formation around the well, and operating the separator system under conditions where flow measurement accuracy does not suffer. These are very severe constraints, and, thus, test conditions are rarely, if ever, ideal.

An alternative approach involves isokinetic techniques where sampling occurs on a small "split-stream" of the total production removed in two-phase condition before the well fluid reaches the separator. Again the conflicting objectives of adequate lift velocity and minimum pressure drawdown occur, but

the constraints of separator operation are managed by using accurate, small scale separation equipment in a portable laboratory and sized to the split-stream flow. Although isokinetic sampling of the wellstream has been in use for more than fifty years [3] and [4], there has been no simple solution to the additional difficulties of ensuring that the small split stream flow is withdrawn at the same velocity as the main well production, and of achieving a homogeneous flow of the diphasic fluid upstream of the sampling probe (obviously on the microscopic scale the fluid will still be heterogeneous). The dangers of poor velocity control are shown in Figure 1, based on some of the early work [4] on isokinetic sampling.

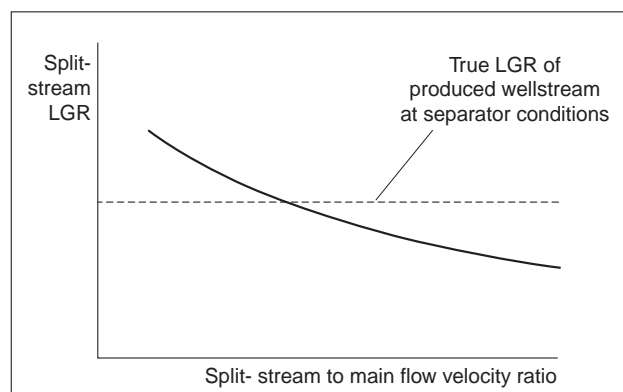


Figure 1

Variation of the liquid/gas ratio (LGR) produced by isokinetic sampling.

This confirms that sampling at too high a velocity leads to the capture of excessive gas and a low liquid to gas ratio (LGR). Too low a velocity produces the inverse effect, i.e. a high LGR. Although significant development work has been carried out on this technique over recent years, very little information has been published. Current guidelines are that isokinetic wellhead sampling is neither reliable at production rates of less than 500 000 Sm<sup>3</sup>/day (17 000 000 Scf/day), nor in rich gas condensate systems, due to the non-uniform distribution of liquid droplets across the diameter of the pipe at the sampling point. The design and positioning of the sampling manifold are also critical. In view of the high cost usually involved in this type of sampling, it is generally recommended only in the most important gas condensate wells, where several sampling techniques can be used for comparison.

A much more recent development of the isokinetic sampling approach has been applied to the measurement of liquid carry-over into separator gas streams. Here samples of gas are collected from the separator outlet line both with any entrained liquid using a probe facing upstream [5], and without entrained liquid, by using a sample probe facing downstream. The technique then relies on the different compositions derived from the samples to calculate the liquid carry-over and adjust measured separator GOR. This approach can therefore be used to improve the quality of reservoir fluid derived from separator samples of gas condensate fluids. Accuracy can, however, suffer either if the carried-over liquid does not have the same composition as that in the separator, if very low carry-over occurs (since the compositional difference between the two samples is masked by analytical error), or if high carry-over occurs and heavy components are not properly quantified by the analyses. Again as the main gas flow must be macroscopically homogeneous, because any significant liquid transport along the walls of the pipe would lead to erroneous results.

Several new sampling developments are still at the experimental stage. These include a technique [6] which uses coiled tubing to bring reservoir fluids to the surface. The high flow velocity necessary for lifting liquid from the well, in the case of a gas condensate fluid, is achieved with only small volumetric flow and, thus, with greatly-reduced pressure drawdown. Hence, there is much less risk of compositional changes in the near-wellbore region of the reservoir. Measurement of gas and liquid flow rates is improved by the use of a small separator designed to handle the total production through the coiled tubing. This application has been initially constrained by service company safety procedures relating to the production of hydrocarbons in coiled tubing, but this practice is now becoming more common.

Another recently-developed technique [7] involves the use of an effective increase in hydrostatic pressure to reduce or eliminate the possibility of the reservoir fluid entering two-phase conditions before it is sampled downhole. It is thus especially useful in addressing the principal challenge when sampling gas condensate and near-critical fluids, namely that pressure drawdown creates two-phase flow conditions which render valid downhole sampling impossible. However, it is not restricted to these fluids. Collection of valid downhole

samples is the best way to avoid the important errors in GOR measurement which affect surface sampling.

Not all advanced solutions to sampling problems involve new hardware. The use of appropriate chemical additives to control hydrates, foaming, and emulsions is well known, and development of new products, notably of an additive to control carry-over [9], can provide novel solutions.

### 3 SOLUTIONS BASED ON THE APPLICATION OF EXISTING KNOWLEDGE

The solution to sampling problems does not, of course, lie solely in the development of new technology—in fact new techniques usually bring their own specific limitations and additional risks; more complicated tools usually require more highly skilled operators, new maintenance procedures and better documentation. Often, a solution can be found in the proper use of existing knowledge. At the most fundamental level, this can involve the correct conditioning of the well before sampling, the collection and detailed interpretation of field data, the development and implementation of appropriate quality control methods, and the use of optimum handling procedures. It can also involve better matching of production rate to separator capacity to ensure optimum removal of liquid from the gas stream.

The increasing availability of formation test tool samples, due to the success of MDT-type tools, can lead to problems if large capacity sample chambers are used (larger than 450 to 600 cm<sup>3</sup>). Such samples are commonly transferred to smaller bottles either in the field, or in the PVT laboratory, when the chamber has been transported directly. A number of these chambers have limited capability for mixing the sample mechanically before transfer, and even if pressure-volume measurements show a sample to be monophasic, the fluid may not be homogeneous. If solids have formed in the chamber, their presence may not be detected before the transfer is made. In order to minimize the risk of loss of sample quality during transfer operations the following steps should be taken:

- Attempt to homogenize the sample, using pressure and heating if possible;
- Transfer the maximum quantity of fluid to storage bottles;
- Check the bubble point of all sub-samples, and measure the flash GOR if doubts exist;

- Measure GOR for any residual fluid which cannot be transferred and must be flashed to ambient conditions;
- Check fluid from both the top and bottom of the sample bottle (measure at least density, but possibly also GOR and even composition if doubts exist).

The last check listed above is now made possible by piston sample bottles which can be inverted to give access to the bottom of the hydrocarbon fluid; when mercury transfer fluid is used, it is always at the bottom of the sample bottle. The main disadvantage of the piston bottle is that leaks “across the piston” can occur leading to sample loss or contamination. For this reason, water-based hydraulic fluids are recommended, since leaks can be identified much more easily.

Greater use of formation test tools for reservoir fluid sampling has been handicapped by the extensive use of oil-based drilling muds in certain regions (notably in the North Sea), because mud filtrate which enters the formation prior to sampling is difficult to clean up entirely and frequently contaminates samples. Contamination can also occur when the tool's probe does not achieve a good seal against the formation, leading to mud from the wellbore being sampled. In contrast to water-based filtrate contamination, which can be separated with negligible effect on the hydrocarbon fluid in most cases, base oil contamination cannot be removed, and influences any measurements made on the fluid samples. The solution to this problem lies in using traditional analytical procedures to identify and quantify contamination levels, and then in attempting to correct for the effect of the base oil on measured properties.

Although synthetic oils are widely used, and these can be more easily detected by analytical procedures, typically gas chromatography (GC), in all cases low concentrations may go undetected, and at high concentrations, for example above 20 to 30 weight percent, it becomes difficult to determine the concentration of contaminating oil with any precision. Also, in many cases the actual composition of the drilling mud base oil may be unknown, not recorded, or incorrectly recorded. Without a good characterization of the contaminant, it becomes impossible to use property simulation packages to correct measured properties to the original reservoir fluid composition.

Two examples of QC analyses of contaminated oils are shown below.

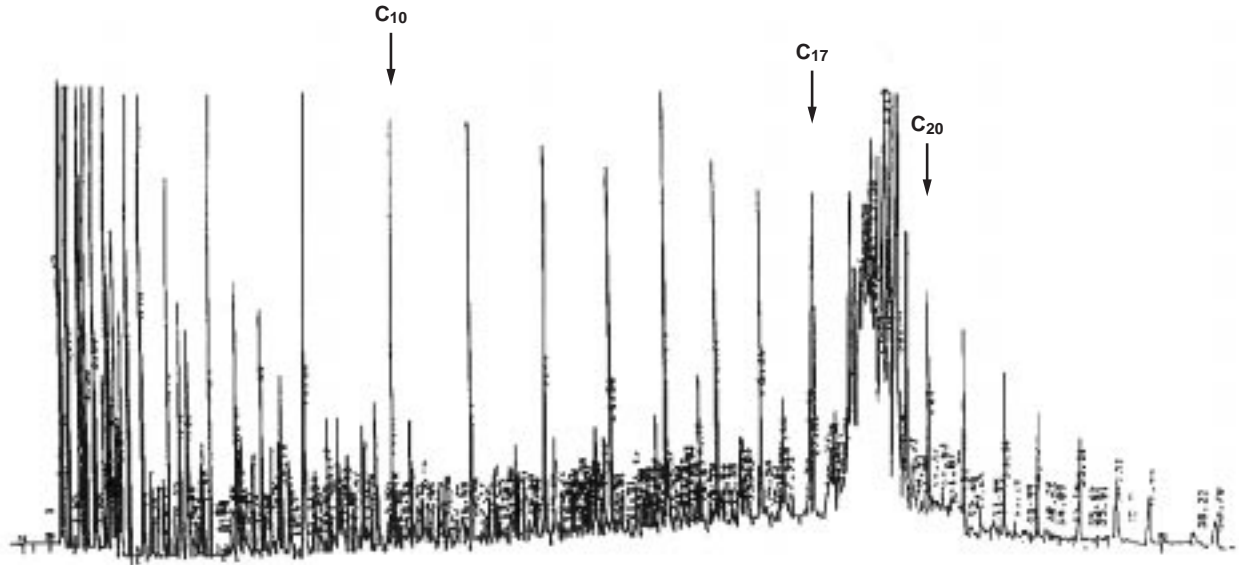


Figure 2  
Sample contaminated with multicomponent mud filtrate.

The first chromatogram clearly shows a large “hump” in the GC trace (Fig. 2). Comparison with normal component trends in natural hydrocarbon fluids confirms that it is almost certainly due to the base oil contamination, though a chromatogram of the base oil itself was not available for comparison in this case. This contamination appears in the region of hydrocarbon components with 18 or 19 carbon atoms ( $C_{18}$  or  $C_{19}$ ), and demonstrates that a compositional analysis reporting components up to only  $C_7$  or  $C_{10}$  as is common, would not have identified the contamination. Here, the problem is essentially to identify what proportion of the

hump derives from the original reservoir fluid, and it may be necessary to interpolate trends in individual components in the carbon-number groups lower and higher than those overlapped by the contamination.

The second example (Fig. 3) shows a much narrower contaminant peak from a synthetic oil, in principle far easier to distinguish from the natural components in the fluid.

However, the main danger here is that the peak shown is “cut-off” on the GC trace, and may indicate the detector response is invalid, i.e. that concentrations

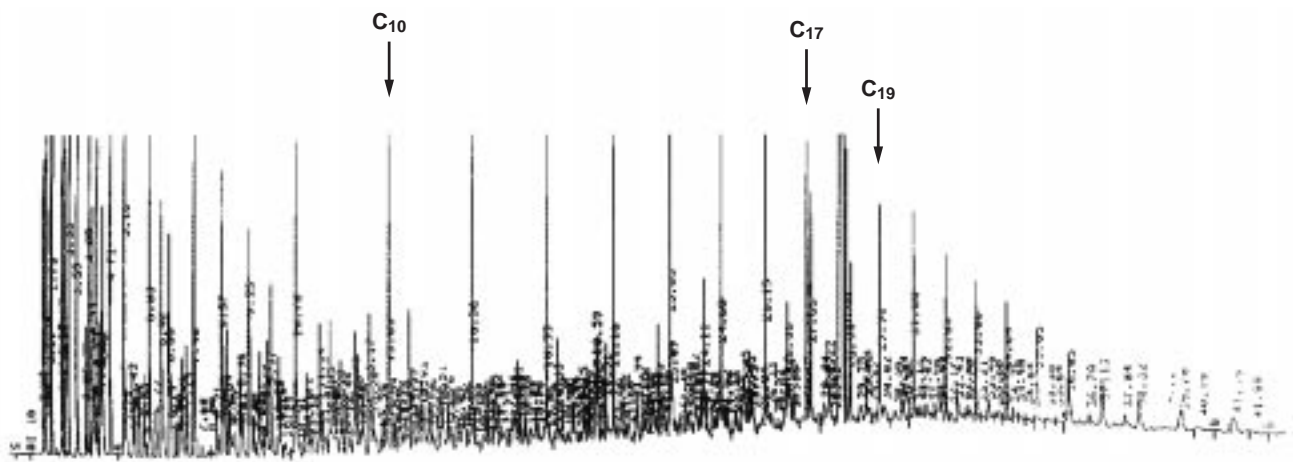


Figure 3  
Sample contaminated with single component mud filtrate.

based on this chromatogram may be erroneous. Much work is underway to try to optimize the analytical methods in these situations [8]. The following approach is recommended to provide the best chance of obtaining valid data on the reservoir fluid:

- Assume that all samples from formation test tools in wells drilled with oil-based mud are contaminated to some extent;
- Collect samples of drilling mud that correspond as closely as possible to that used at the sampled location;
- Perform analyses to at least  $C_{20}$ , and higher if necessary to properly quantify contamination;
- Select the least contaminated sample for PVT measurements.

Where possible, it is a great benefit if a suitable chemical marker can be added to the oil-based mud at a known concentration, as this can aid subsequent quantification.

As mentioned above, use of monophasic downhole sampling tools is advisable to reduce problems related to the flocculation of asphaltenes. This phenomenon, although apparently not irreversible, leads to samples that can be extremely difficult to return to homogeneity. Maintaining pressure may not prevent the formation of wax deposits in paraffinic fluids, and in these cases the heating of samples and storage chambers is essential prior to mixing and transfer. The challenge, above all others, in these situations is to determine that a problem may exist. If samples studied in the laboratory have lost solids during storage or transfer, subsequent production problems may not be anticipated. The best approach is to assume that an oil does contain asphaltenes and waxes until laboratory work shows otherwise. It should be remembered that certain gas reservoirs yield waxy condensate liquids. To eliminate the risk of losing heavy material at the wellsite, it is preferable to ship a downhole sampler to the laboratory for transfer, whenever this is feasible (in view of safety restrictions, tool rental, etc.). Note that transferring a sample from a monophasic sampler to a monophasic shipping bottle (also maintaining pressure via a nitrogen gas buffer) can still lead to loss of any waxes deposited due to temperature reductions.

Increased on-site measurements are now available to counter problems of loss of sample validity with time. This is especially important for chemically active components, such as hydrogen sulphide, which may react with metal surfaces, seals and other components

in the produced fluid. However, these techniques still require that valid samples of reservoir fluid be available at the well site, and data must be subsequently correlated with laboratory property measurements.

Produced water volume measurements are typically of much lower accuracy than those of oil and gas, especially when low flow rates are involved. Furthermore, identifying whether water measured in a separator is free formation water or derived from the hydrocarbon phase may not be straightforward. Also, water production is often not indicated on fluid sample sheets. The use of monophasic well head sampling, when possible, can be beneficial in determining water content in high pressure-high temperature fluids, where knowledge of water content will become increasingly important. Generally, better recording of all water production is recommended.

The solubility of gas in formation water is rarely determined experimentally, and is usually neglected in establishing hydrocarbon fluid properties. In the vast majority of cases this is an acceptable practice, but in the presence of highly soluble gases like hydrogen sulfide and carbon dioxide, all produced gas will be assigned to the hydrocarbon fluid phase even if significant water production has occurred. Additional measurements on produced water are recommended in such cases, either on site or in the laboratory, both to improve fluid characterization, and to better quantify the corrosion potential of produced water.

In certain circumstances, it may be possible to obtain a fluid representative of the reservoir from samples that are individually unrepresentative. Probably the most appropriate situation is when samples are available from both a gas cap and an underlying oil zone, since even if the retrograde gas condensate gas cap is sampled with loss of some condensate, laboratory equilibrium experiments can be used to recover a fluid essentially identical to the reservoir fluid in place [3]. However, since reservoir geology may be very poorly known when samples are collected, such an approach should not be considered as an alternative to attempting to collect valid samples of each reservoir fluid encountered.

Overall, better awareness of the problems to be anticipated is required, as is access to the experience available in petroleum and service companies. This paper outlines a project whose goal is to identify and document the best practices, as described in the next section.



#### 4 SAMPLING BEST PRACTICES

The need for better access to existing knowledge and experience in fluid sampling is evident from the above discussion. It would be ideal if up-to-date industry standards were available, but this is far from the case. The table below provides a summary of the principal sampling guidelines available from standards organizations for sampling petroleum fluids, though the list is not exhaustive since there are many similarities between methods issued by different authorities.

In fact the majority of these methods apply exclusively to the sampling of fluids at atmospheric pressure, because they are of particular importance to custody transfer applications. The *American Petroleum Institute's* RP-44 recommended procedure is the only one of those above which specifically addresses reservoir fluid sampling and the use of equipment at pressures superior to those in pipelines, and is thus the only widely known reference to fluid sampling in the upstream sector of the petroleum industry. However, it is now more than 30 years old, and was written when

liquid sampling was recommended using mercury as the pressure transfer medium. An extensive revision of the RP-44 document should be published in 1998, and it will address the well-established “post-mercury” sampling techniques and early experience with the new generation MDT-type of formation test tool. However, as is typical of much work on industry standards, the publication depends on volunteer work, and has, unfortunately, been delayed for several years. Also, understandably, it is biased towards North American oil field practices, though much more international experience is being incorporated compared to the 1966 edition.

The new edition is likely to contain little or no details on the following:

- Latest experience with MDT sampling;
- Drill stem test tool samplers;
- Measurement methods of liquid carry-over;
- Quality control method developments;
- Isokinetic “split-stream” sampling;
- Coiled tubing sampling.

TABLE 1

A selection of the principal industry standards related to reservoir fluid sampling

Organization	Reference	Title	Date	Comments
American Petroleum Institute (API)	RP-44	<i>Recommended Practice for Sampling Petroleum Reservoir Fluids</i>	1966	New edition pending
American Society for Testing Materials (ASTM)	D 1265	<i>Standard Practice for Sampling Liquefied Petroleum (LP) Gases</i>	1992	Samples unsuitable for PVT analysis
	D 3700	<i>Standard Practice for Containing Hydrocarbon Fluid Samples Using a Floating Piston Cylinder</i>	1978	Procedure uses second, displacement cylinder
	D 4057	<i>Standing Practice for Manual Sampling of Petroleum and Petroleum Products</i>	1989	API equivalent method MPMS (Chapter 8.1)
	D 4177	<i>Standing Practice for Automatic Sampling of Petroleum and Petroleum Products</i>	1983	API equivalent method MPMS (Chapter 8.2)
Association française de normalisation (AFNOR)	NF M 07-001	<i>Méthodes d'échantillonnage des produits pétroliers</i>	1970	Will be incorporated in ISO 3170
Institute of Petroleum (IP)	PMM Part VI	<i>Petroleum Measurement Manual. Part VI: Sampling (Appendix A: Sampling of Unstabilised Crude Oil from Pipelines)</i>	1986	Supersedes IP 51 and IP 206
International Organization for Standardization (ISO)	ISO 3170	<i>Petroleum Liquids - Manual Sampling</i>	1988	Corresponds to D 4057, IP 51
	ISO 3171	<i>Petroleum Liquids - Automatic Sampling</i>	1988	Corresponds to D 4177, IP 206
	ISO 4257	<i>Liquefied Petroleum Gases - Method of Sampling</i>	1988	Similar to NF M 41-001

Some of the other standards already cover use of piston sampling methods, but rely on inert gas availability for the transfer fluid. The common method for sampling LPG uses a sample bottle with a dip-tube to help create the ullage (gas cap), which is totally unsuitable for collecting samples of PVT quality. Although there is a general move to combining existing national standards as international standards, and some recognition that better methods are required for samples at pipeline pressures or above, there appears to be no intention to address the need for improved methods for high pressure reservoir or separator fluids, outside the American Petroleum Institute.

One other set of published recommendations [10] is that developed by the French *Comité des Techniciens* of the *Chambre syndicale de la recherche et de la production du pétrole et du gaz naturel* in 1975. This gives detailed evaluations of surface and wireline downhole sampling methods, together with guidelines for production measurements, but as is the case for the RP-44, it is restricted to methods available at the time, with extensive mercury use.

As a result of these limitations, some operators have developed their own specialist manuals, and many service companies have guidelines for use of their own tools. There are, therefore wide differences in practice, which can lead to problems of interpretation or uncertainty when correlating different sets of fluid data from adjoining license areas, or when assets (and their fluid data) are transferred between operators. Also it is rare to find any guidelines on quality control procedures, so the proper QC of samples, essential to any feedback mechanism that can lead to improved sampling in the future, is often neglected.

Increasingly, operator personnel have a wide range of responsibilities, and none can be expert in all domains. *Documented Best Practices* are required to assist in choosing appropriate sampling methods and equipment, in drawing up the sampling program in conjunction with other test objectives, in identifying which on-site analyses are advisable, and in deciding clear priorities for when the program does not go according to plan.

Among the problems related to non-standard procedures are those which laboratories face when trying to interpret unusual PVT measurements, (e.g. when a fluid indicates a saturation pressure above reservoir pressure), when intended duplicate samples show significant differences, and there is insufficient

information to identify which sample is the more representative, or when sub-samples clearly indicate non-homogeneous conditions during transfer operations. Adequate guidelines may not be available with some sampling tools, resulting in unnecessary loss of sample quality.

This paper outlines a joint industry project to evaluate the state of the art of reservoir fluid sampling, to consult with operators and service suppliers and to draw up industry best practices to correct this situation. The following activities are considered:

- Achieve broad industry membership;
- Review existing sampling methods and experience;
- Identify how far existing and new standards can be relied on for basic operations;
- Press for thorough documentation of sampling tools and related equipment;
- Draw-up recommended Best Practices for established techniques;
- Propose tentative procedures for new or experimental sampling techniques;
- Develop guidelines for laboratory quality control, and sample management;
- Feedback member experience and needs to sampling equipment and service suppliers;
- Monitor new developments and issue frequent updates of tentative methods;
- Tasks could also establish and maintain a list of vendors.

The study should lead to an up-to-date industry standard in fluid sampling methodology. To ensure an unbiased review of commercially available equipment and techniques, the project should be funded by petroleum industry operating companies, though maximum input from, and feedback to service companies will be essential. Interest in this project should be addressed to the author of this paper.

## CONCLUSIONS

This paper reviews the key challenges faced when trying to obtain representative fluid samples from hydrocarbon reservoirs. It demonstrates that significant developments have been made in the last decade on sampling tools and techniques, and that technological progress continues. The major advantages of the new techniques are evident, but new

problems are shown to be created in some cases, and must also be resolved.

Weight is also given to the need to make full use of existing knowledge, and appropriate recommendations are made. The need for easier access to fluid sampling experience is identified, and the lack of any up-to-date industry standard in this field is demonstrated. A joint industry project is proposed to address this need.

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