

Sampling Petroleum Reservoir Fluids

API RECOMMENDED PRACTICE 44
SECOND EDITION, APRIL 2003



**Helping You
Get The Job
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Upstream Segment

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Sampling Petroleum Reservoir Fluids

1 Introduction

Proper management of production from a natural gas or petroleum reservoir can maximize the recovery of the hydrocarbon fluids (gas and oil) originally in the reservoir. Developing proper management strategies requires accurate knowledge of the characteristics of the reservoir fluid. Practices are recommended herein for obtaining samples of the reservoir fluid, from which the pertinent properties can be determined by subsequent laboratory tests.

The objective of reservoir fluid sampling is to collect a sample that is representative of the fluid present in the reservoir at the time of sampling. If the sampling procedure is incorrect or if samples are collected from an improperly "conditioned" well, the resulting samples may not be representative of the reservoir fluid. A non-representative sample may not exhibit the same properties as the reservoir fluid. The use of fluid property data obtained from non-representative samples, however accurate the laboratory test methods, may result in errors in reservoir management. Poor planning can also result in incomplete data being taken during the sampling program. Incomplete data can make it difficult or impossible for laboratory personnel to perform and interpret tests that provide accurate and meaningful fluid property information.

Reservoir fluids found in gas and oil fields around the world vary greatly in composition. In some fields, the fluid is in the gaseous state and in others it is in the liquid state; frequently, gas and liquid coexist in a given reservoir. The rocks which contain these reservoir fluids also vary considerably in composition, and in physical and flow properties. In certain cases, this can serve to complicate the sampling procedure. Other factors, such as producing area, height of the column of hydrocarbon fluid, fracturing or faulting, and water production also serve to distinguish one reservoir from another. The combination of all these factors affects the choice of sampling methods and preparations for sampling.

When a reservoir is relatively small, a properly taken sample from a single well can be representative of the fluid throughout the entire reservoir. For reservoirs which are large or complex, samples from several wells and/or depths may be required. Significant variations in fluid composition often occur in very thick formations, in really large reservoirs, or in reservoirs subjected to recent tectonic disturbances. Additional sampling during the later life of a reservoir is not uncommon because production experience can show that the reservoir is more complex than earlier information indicated.

Methods for sampling reservoir fluids fall into two general categories. They are referred to as subsurface sampling or surface sampling and, as the names imply, each category reflects the location at which the sampling process occurs. Subsurface sampling may also be referred to as downhole or

bottomhole sampling. Modern open-hole wireline formation testers now provide the means of recovering representative samples before the effects of subsequent production take place. Selection of one particular method over another is influenced by the type of reservoir fluid, the producing characteristics and mechanical condition of the well, the design and mechanical condition of the surface producing equipment, the relative expense of the various methods, and safety considerations. Detailed descriptions of recommended sampling methods are presented in subsequent sections of this document. Factors which should be considered in choosing a method are also discussed.

The choice of either the surface or downhole sampling method cannot be considered a simple or routine matter. Each reservoir usually presents certain constraints or circumstances peculiar to it. For example, field operation requirements can impose restrictions on the preparation and execution of a sampling program; sand production or downhole equipment in the well may limit the use of some of the equipment normally used in the sampling operation. Wells that exhibit rapid variations in production rate present special problems in making the necessary measurements with acceptable accuracy. Seasonal or daily weather changes can also influence the sampling operation. Thus, the details of a given sampling procedure often require modification to circumvent local problems. These modifications are usually made based upon on-the-spot judgments. Some of the modifications which can be made to accommodate special situations are presented herein.

Conditioning a well before sampling is almost always necessary. Initial well testing or normal production operations often result in the fluid near the wellbore having a composition which has been altered from that of the original reservoir fluid (for reasons described later). The objective of conditioning the well is to remove this altered (non-representative) fluid. Well conditioning consists of producing the well at a rate which will move the altered fluid into the wellbore and allow it to be replaced by unaltered (representative) fluid flowing in from further out in the reservoir. Well conditioning is especially important when the reservoir fluid is at or near its saturation pressure at the prevailing reservoir conditions because reduction in pressure near the wellbore, which inevitably occurs from producing the well, will alter the composition of the fluid flowing into the wellbore. The types of problems which can be encountered in conditioning a well, and methods for their control are discussed.

Forms for recording the data obtained during well conditioning and sampling operations are included in this document. These data furnish a history of the sampling operation, provide complete identification of the samples, and aid in interpreting the results of the laboratory examination of the samples. The use of these forms (or equivalent computer-

based information) encourages the collection and reporting of all essential data.

The development of modern electronic flow metering allows flow rate data to be collected and recorded very rapidly in “real time.” This includes field calculations and data recording in spreadsheet form, which can now be done with hand-held, laptop, or notebook-type computers. These results can be transmitted electronically (e-mail) or diskettes can be mailed in addition to or instead of hardcopy forms. This type of computer-based data collection will be preferred by many operators.

The use of modern electronic flow metering and computer equipment does not mean that wells can be conditioned any more quickly or that gas and liquid flow rate data will automatically become more representative of reservoir fluid. However, use of such equipment and methods, if properly calibrated and understood, should reduce errors and generally improve the quality of data collected.

Personnel who are inexperienced in reservoir fluid sampling are strongly advised to consult with experienced personnel regarding the planning of a sampling program, particularly if complicating situations are anticipated.

2 References

Unless otherwise specified, the most recent editions or revisions of the following standards, codes, and specifications shall, to the extent specified herein, form a part of this standard.

2.1 REFERENCED STANDARDS

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4. Chapter 4.1 *Proving Systems, Introduction*, First Edition, July 1988 (withdrawn).
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3 Definitions

3.1 bubble point: The state of a liquid-phase system when it is in equilibrium with an infinitesimal amount of vapor phase.

3.2 bubble-point pressure: The fluid pressure in a system at its bubble point. (Often referred to as "saturation pressure.")

3.3 condensate: A liquid formed by condensation from a vapor phase. Within the reservoir, "condensate" is a liquid-hydrocarbon phase formed by retrograde condensation from the vapor phase upon pressure reduction. At the surface, "condensate" is a liquid-hydrocarbon phase formed by condensation from the vapor phase upon pressure and/or temperature reduction.

3.4 dew point: The state of a vapor-phase system when it is in equilibrium with an infinitesimal amount of liquid phase.

3.5 dew-point pressure: The fluid pressure in a system at its dew point. (Often used interchangeably with "saturation pressure.")

3.6 gas saturation: The volumetric percentage of the pore space in a reservoir rock that is occupied by the gaseous phase.

3.7 liquid saturation: The volumetric percentage of the pore space in a reservoir rock that is occupied by a liquid phase.

3.8 productivity index: The rate of liquid production (oil plus water) divided by the difference between the prevailing reservoir pressure and the flowing pressure at the formation face, expressed as flow rate per unit pressure difference.

3.9 reservoir fluid: A natural underground accumulation consisting primarily of hydrocarbon compounds. The reservoir fluid may be either a liquid or a gas and may contain certain non-hydrocarbon compounds. The non-hydrocarbons which are of greatest importance in sampling are nitrogen, carbon dioxide, hydrogen sulfide, helium, and water. Free water (brine) that flows into the well with the reservoir fluid is not considered here to be a part of the reservoir fluid.

3.10 saturated liquid: A liquid that is in equilibrium with a vapor at the prevailing pressure and temperature.

3.11 saturated vapor: A vapor that is in equilibrium with a liquid at the prevailing pressure and temperature.

3.12 saturation pressure: The pressure at which a vapor and a liquid are in equilibrium. "Saturation pressure" is often used interchangeably to describe either "bubble-point pressure" or "dew-point pressure."

3.13 separator gas-oil ratio: The ratio of separator gas rate to separator oil (or condensate) rate, typically expressed in terms of standard gas volume per unit oil volume (e.g., standard cubic ft of separator gas per barrel of separator oil or condensate). This definition requires specification of where the gas rate is measured (primary or total) and, likewise, the oil rate (primary or stock tank-flow rate adjusted to standard conditions).

3.14 separator oil relative-volume factor: The volume of separator oil at separator conditions of pressure and

temperature divided by the volume of stock-tank oil at stock-tank conditions.

3.15 stock-tank oil: The hydrocarbon liquid (oil or condensate) that is collected in a surface storage tank at atmospheric pressure after the produced well fluid has been processed through a gas-oil separation system.

3.16 undersaturated fluid: A liquid capable of holding additional gaseous components in solution or a vapor capable of holding additional liquid components in solution at the specified pressure and temperature.

4 Planning the Sampling Program

4.1 GENERAL

The optimum situation, when the objective is to obtain a sample of the original reservoir fluid, is to collect samples before the bottomhole flowing pressure has dropped below the reservoir fluid saturation pressure. The fluid entering the wellbore under such conditions will be representative of the original reservoir fluid, since the fluid has not been subjected to pressures below the saturation pressure at any point in the near-well region. When the pressure in the near-well region is reduced below the saturation pressure of the original reservoir fluid, the fluid separates into two phases (gas and liquid) having differing compositions. This almost always gives rise to flow rates of gas and liquid that result in a fluid composition in the wellbore which differs from that of the original reservoir fluid, at least during the initial period after flow is established.

The most frequent occurrence in sampling operations is that the pressure at the producing level in the wellbore is reduced (drawn down) below the fluid saturation pressure, while the static (shut-in) reservoir pressure is still above the saturation pressure. Under such circumstances, it is still possible to collect representative samples of the original reservoir fluid, but considerably more effort is required to properly "condition" the well prior to sampling. Methods to do this are described below. If sampling is delayed until the static reservoir pressure drops below the saturation pressure of the original reservoir fluid, representative samples of the original fluid can no longer be obtained. This provides strong incentive for sampling early in the life of a reservoir, especially since the actual saturation pressure will not be known conclusively until samples have been taken and studied in the laboratory.

If the reservoir fluid is known to be undersaturated at the prevailing reservoir pressure (based on well test data and the application of engineering correlations^{23,26,31} to estimate the saturation pressure), sampling may be delayed until other wells have been drilled. The permissible extent of this delay depends upon the degree of undersaturation and the rate of decline of reservoir pressure. The problem with such a strategy is that the saturation pressure of the reservoir fluid is seldom known initially. In situations where the saturation pressure of the fluid is essentially identical to the original res-

ervoir pressure, samples should be taken as soon as possible after the well is completed and cleaned up. Many of the problems associated with well conditioning can be avoided by sampling before the reservoir pressure declines below the original reservoir fluid saturation pressure.

A paradox exists in that the goals of initial well testing (to determine the flow capacity and reservoir limits) often dictate that the near-wellbore pressure be reduced significantly below the saturation pressure of the fluid. Fluid sampling could be done in advance of such testing; however, subsequent well testing might reveal that samples are not needed because the reservoir is too small to merit development. Typically, a field discovery well is subjected to the most severe drawdown pressures and depletion during production testing. Therefore, the second well drilled in the field may be much more suitable for recovery of representative fluid samples. Fluid samples still are usually collected from the discovery well because the fluid properties required to evaluate the reservoir are needed as soon as possible.

Certain circumstances may make it necessary to obtain samples of the fluid being produced from the reservoir after the pressure has declined below the original saturation pressure, whether or not original reservoir fluid samples were obtained from previous sampling. For example, the earlier sampling program might have been insufficient in scope, or properties of the reservoir fluid at a later time might be useful for comparison with the properties predicted from the laboratory test results on the earlier samples. In addition, samples of the prevailing well effluent are often useful in planning sales contracts, in designing processing plants, or in planning enhanced recovery operations. However, taking fluid samples after the static reservoir pressure has declined below the original saturation pressure is poor practice, and is not recommended unless there is no alternative.

4.2 FACTORS THAT INFLUENCE PLANNING

4.2.1 Types of Reservoir Fluids

Reservoirs are usually described in terms of the type of fluid which comprises the major portion of the hydrocarbon accumulation. These fluid-based reservoir descriptions include: conventional crude oil (black oil); volatile oil; near-critical fluid, which may be a highly volatile oil or very rich gas condensate; gas-condensate; wet-gas; and dry-gas reservoirs.

Decisions regarding optimum well conditioning and sampling strategies can be affected by the behavior of the reservoir fluid at both reservoir and surface conditions. Thus, an understanding of the qualitative behaviors of the different fluid types is essential in the planning process. Figure 1 illustrates the behavior of the six classes of reservoir fluids listed above.

In Figures 1a – 1f, the behavior of the fluid (phase envelope) is shown as a function of temperature (T) and pressure (p), and the regions inside the phase envelopes indicate the temperature and pressure conditions at which the reservoir

fluid exists as two separate phases (gas plus liquid). The lines labeled “BP” indicate the conditions of T and p where the fluid exists at a bubble-point state, while “DP” denotes the location of dew-point states. The point labeled “C” denotes the critical point of the fluid. (Detailed discussions of these types of phase diagrams appear in a variety of textbooks^{23,26,31}.)

Figure 1a for a dry gas illustrates that the two-phase region does not intersect the reservoir temperature at any pressure. As a result, the fluid is always in a single-phase (gas) state in the reservoir. Further, the small boxed area on Figure 1a, (“Separator Conditions”) represents the approximate temperatures and pressures at which field surface separators typically operate, relative to the phase envelope. Here we see that at separator conditions the dry gas is not in the two-phase condition; consequently, no liquids can be recovered at conventional field separator operating conditions. Thus, the dry gas is “dry” both in the reservoir and at the surface.

Figure 1b illustrates the behavior of a wet gas. As in Figure 1a, the fluid does not form two phases at any pressure at reservoir temperature; thus, this gas is “dry” in the reservoir. However, at the lower temperatures and pressures encountered in surface separators, the fluid exists as two phases. The wet gas can, then, produce liquid (condensate) in the surface separators.

Figure 1c shows the phase behavior of a gas condensate (sometimes referred to as retrograde gas condensate). Here we see that at high pressures at reservoir temperature the fluid can exist as a single (dense) phase, but as the pressure declines during the production life of the field, the fluid will enter the two-phase region by passing through a dew-point condition. At pressures below the dew-point pressure, liquid will condense (drop out) in the reservoir.

Figure 1d illustrates a critical fluid, characterized by the reservoir temperature being essentially identical to the critical temperature of the fluid. Although not evident from the illustration, a fluid passing through its critical point (as pressure is reduced) will separate into essentially equal volumes of vapor and liquid at the critical pressure. Thus, large saturations of both gas and liquid are formed essentially instantaneously in the reservoir as the reservoir pressure drops below the critical pressure. Even if the reservoir temperature is not exactly equal to the critical temperature (a “near-critical” fluid), two phases of high saturation are formed almost immediately upon pressure reduction below the saturation pressure. If the reservoir temperature is just above the critical temperature, the near-critical fluid will behave as a very rich condensate. If the temperature is just below the critical temperature, the fluid will behave as a very volatile oil. Needless to say, this temperature-sensitive behavior requires accurate reservoir temperature data in order to correctly interpret the laboratory test data on these types of reservoir fluid.

Figure 1e represents the behavior of a volatile oil. This fluid is characterized by having a critical temperature only slightly higher than the reservoir temperature. Thus, while the fluid may be a single-phase liquid at high pressures, it will separate

into two phases at lower pressures, passing through a bubble-point condition as shown in the illustration. Volatile oils are further characterized by the fact that high gas saturations are established at pressures only slightly below the bubble-point pressure (i.e., gas evolves rapidly from the oil and the oil phase shrinks rapidly as pressure is reduced below the bubble point).

Figure 1f shows the behavior of a conventional crude oil (“black oil”). As in Figure 1e, the fluid may be a single-phase liquid at high pressures in the reservoir, but pressure reduction during reservoir depletion will eventually lead to a two-phase condition as the fluid passes through a bubble-point state. In contrast to volatile oils, gas evolution is not as rapid below the bubble point, so gas saturations in the reservoir are established more gradually, and the oil shrinks more gradually than for a volatile oil.

4.2.2 Effect of Reservoir Fluid Type on Planning

If sampling a reservoir is delayed until the pressure has fallen substantially below the original fluid saturation pressure, it is unlikely that the original reservoir fluid can be reproduced exactly in the laboratory. In such a situation, if properly justified, certain of the original fluid properties may sometimes be estimated for oils (but not for condensates and with more difficulty for volatile oils) by extrapolating the sample properties to original reservoir pressure. This practice, however, contains inherent uncertainties and should be avoided whenever possible.

When the sampling of a gas-condensate reservoir is delayed until the pressure has declined below the reservoir fluid saturation pressure, the composition of the well effluent can be significantly different from that of the original fluid²⁵. As the pressure drops below the saturation pressure, a liquid hydrocarbon phase (containing the highest molecular weight constituents) begins to condense from the gas and deposit in the formation. Thereafter, the well effluent will not have the same composition as the original reservoir fluid. Predicting well-effluent compositions at later stages of depletion will be much more difficult if sampling is delayed until the reservoir pressure has declined below the fluid saturation pressure.

When the pressure on a near-critical reservoir fluid drops slightly below the original saturation pressure, the second hydrocarbon phase forms rapidly and can occupy an appreciable part of the total hydrocarbon volume at pressures only slightly below the original saturation pressure. Whether the second phase is a gas (evolved from a volatile oil) or a liquid (deposited from a gas condensate) depends upon the composition of the fluid and the reservoir temperature. In either case, formation of the second phase causes substantial changes in the well effluent composition, and obtaining a representative sample of the original reservoir fluid becomes virtually impossible.

The hydrocarbon fluid in dry-gas or wet-gas reservoirs maintains a uniform composition throughout the depletion of the reservoir since the fluid is always in single phase state in

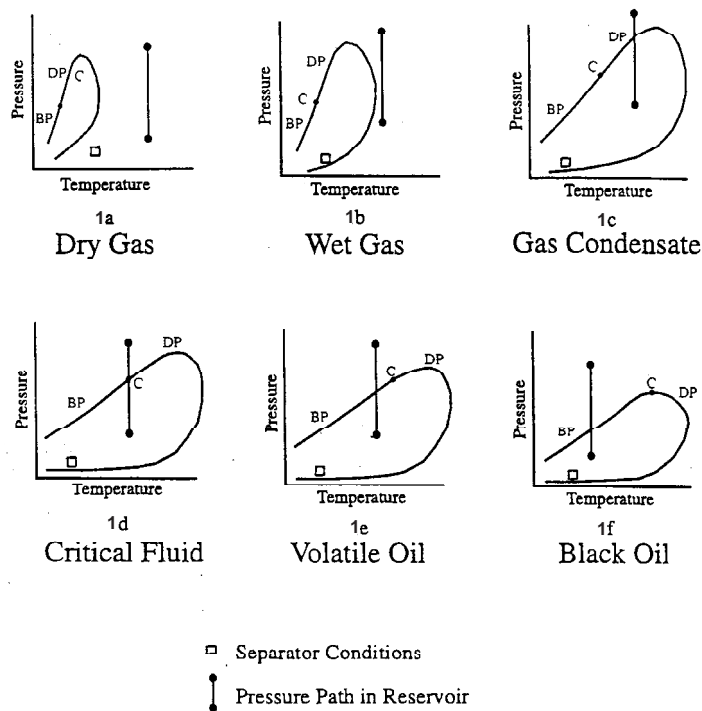


Figure 1—Reservoir Fluid Types

the reservoir. Thus, a representative sample of the original fluid can be obtained at any time during the reservoir life. A dry gas also produces no liquid at typical field separator conditions, so a single-phase sample can be collected at the wellhead or other convenient location. Conversely, a wet gas does partially condense at surface separator conditions, so separator sampling is typically employed. However, since the well-stream composition does not change with time, the separator samples can be taken at any time. Care must be taken, however, since distinguishing between a wet gas and a gas condensate may be difficult, if not impossible, before laboratory testing of the fluid. For the gas condensate, as described above, delay in sampling can have adverse consequences. Again, the best policy is to take samples as early as possible in all cases.

The location of the well selected for sampling should be considered carefully. The composition and physical properties of the reservoir fluid can vary significantly over the area of a large reservoir. Generally, comparisons of gas-oil ratios, tank-oil gravities, and bottomhole temperatures and pressures among the wells in the reservoir will indicate whether significant variations in reservoir fluid properties exist. When the compositions of samples from different wells in the same formation show significant variations, sampling from multiple wells is advisable. The wells selected for sampling should reflect the ranges of gas-oil ratio and tank-oil gravity in the field.

The composition and physical properties of the oil in unusually thick or steeply dipping reservoirs may also vary significantly with depth in the formation^{22,27}. Sampling to determine

such variation in fluid properties requires special techniques to carefully isolate the production at selected intervals over the formation face. The number of intervals to be sampled will depend upon the degree of detail required in the reservoir study. In steeply dipping reservoirs, this may require sampling from several wells to cover the desired range of depths.

The condition of the reservoir fluid in the vicinity of the wellbore must be taken into consideration. This can be done by studying the gas-oil ratio history as it is related to the rate of production. For oils, correlations of reservoir-fluid properties^{23,26,31} may be useful aids in estimating whether the produced fluid is saturated or undersaturated at the reservoir temperature and pressure. If an undersaturated fluid is clearly indicated, sampling is greatly simplified. If a saturated fluid is indicated or if it appears that excess gas is being produced, the task of conditioning the well becomes more involved. Producing a well at high rates of flow can cause alteration of a substantial volume of fluid around the wellbore if the bottomhole flowing pressure is significantly less than the fluid saturation pressure.

The above discussions illustrate that, if the original fluid in the reservoir has never been subjected to pressures below the saturation pressure at any point in the reservoir, proper sampling can yield a representative sample of the original fluid. Very commonly, however, even when the static (shut-in) pressure in the reservoir has always been above the saturation pressure, the pressure at flowing bottomhole conditions may be substantially lower than the saturation pressure. In such

cases, an acceptable (although not perfect) sample of the original fluid can be obtained if the well is properly conditioned. If the static reservoir pressure is above the saturation pressure, proper conditioning will lead to an almost steady-state (pseudo-steady state) condition in which the composition of the fluid entering the wellbore is very near that of the original fluid. Detailed discussions of this phenomenon are given elsewhere^{24,25}. Once the pressure throughout the reservoir is below the saturation pressure, representative samples of the original fluid can no longer be obtained.

Additional complications can occur if fluid production comes from two or more zones (containing fluids of different composition). These fluids, which are commingled in the wellbore can, if not properly identified, give the appearance of a produced fluid which exhibits properties different from any of the fluids in the individual zones. For example, the producing gas-oil ratio from a well might be 12,000 scf/bbl (typical of a gas condensate). However, if the gravity of the stock-tank oil is low enough to be typical of a conventional or "black" oil, commingled production from separate zones or gas coning might be suspected. Beware that API gravity is not an absolute indicator of reservoir fluid type, and is a function of separator conditions.

Similar problems can occur in deviated wells if multi-phase fluids are flowing downhole where a bottomhole sampling tool will lay on the low side of the wellbore and, therefore, sample only the heavy fluid phase. Under these multi-phase conditions, bottomhole samplers should not be used; surface samples should be collected. This situation points out the importance of proper well conditioning and planning²⁸. A review of the producing gas-oil ratio data and estimated saturation pressure of the reservoir fluid might allow prediction of the multi-phase conditions. If there is doubt, perhaps both subsurface and surface samples should be collected for comparison.

4.2.3 Other Considerations

The producing characteristics of each well should also be considered. Desirable producing characteristics are: (1) no water production; (2) gas-oil ratio and tank-oil gravity typical of surrounding wells; (3) relatively high productivity index; and (4) steady flows with no "heading."

A well that produces even small amounts of water can be troublesome. If possible, a well should be eliminated from consideration if the portion of the reservoir it penetrates includes a water contact. If a water-producing well must be considered, adequate precautions must be taken. Give first consideration to the well having the thickest oil column and having its perforations a maximum distance above the oil-water contact.

Generally, it is best not to sample from an oil well near a gas-oil contact. If the gas-cap area cannot be avoided, a well having the thickest oil column and perforations low in the oil zone should be considered. In most instances, sampling for

gas or oil should be done as far as feasible from a gas-oil, gas-water or oil-water transition zone.

4.3 SAMPLING METHODS

As mentioned in Section 1, the choice of sampling method can be influenced by a number of important considerations. These include the volume of sample required by the laboratory, the type of reservoir fluid to be sampled, the degree of depletion of the reservoir, the mechanical condition of the wellbore, and the type of available gas-oil separation equipment.

4.3.1 Subsurface Sampling

4.3.1.1 Bottomhole Samplers

The conventional subsurface method consists of lowering a sampling device, usually called a "bottomhole sampler," down the well to a pre-selected depth. The bottomhole samplers can be used in either open-hole or cased-hole wells, and can be run in tubing. A sample of the fluid in the wellbore at that depth is trapped in a pressure-tight section of the sampler. The sampler is brought to the surface where the sample is repressured and restored to single-phase condition, then it may be transferred to a suitable pressure vessel for transporting to the laboratory. Bottomhole samplers are available in a variety of configurations: design details and operating instructions can be obtained from the vendors of such equipment.

The subsurface sampling method is often used when the flowing bottomhole pressure is greater than the reservoir oil saturation pressure. Some types of bottomhole samplers function poorly with highly viscous and foaming oils. The operator should study the operation of the sampler and then decide if a representative sample can be collected with it. Mechanical obstructions, such as a downhole choke or a bent or collapsed section of tubing can prevent the sampler from reaching the desired sampling depth. Produced sand can also form an obstruction. When a large volume of sample is desired, the relatively small sample provided by a bottomhole sampler requires repetition of the sampling operation. However, modern designs of subsurface samplers incorporate larger volume and/or multiple sample containers^{29,30}.

4.3.1.2 Formation Testers

The modern open-hole wireline samplers^{29,30} consist of a probe and seal assembly that can be extended against the side of the wellbore to achieve a pressure tight flow path between the reservoir layer and the tool flow line leading to one or several chambers that can be selectively opened and closed by control from the surface. A suitable pressure gauge enables accurate measurement of the flow line pressure.

Whereas the bottomhole samplers collect a fraction of whatever fluid is inside the wellbore, the formation testers collect fluid samples directly from the formation. Modern formation tester tools can pump out drilling and completion flu-

ids before collecting an uncontaminated sample of reservoir fluid. This ability to pump out unwanted fluids overcomes the serious disadvantages of earlier designs. However, increasing use of oil base muds during drilling has resulted in common problems with contamination of fluid samples^{30,33}.

Procedures are identical to those used for conventional bottomhole samplers. However, to minimize possible handling incidents that may affect their integrity, samples should be shipped to the PVT laboratory in the sampling chamber whenever possible rather than being transferred into shipping containers at the well site.

4.3.2 Surface Sampling

The surface sampling method consists of taking samples of separator oil and gas (see Figure 2) with concurrent and accurate measurements of the rates of separator oil and gas flow. The reservoir fluid is reconstituted in the laboratory by recombining the oil and gas samples in proper proportion as determined from the producing gas-oil ratio. Large volumes of both oil and gas samples can be easily obtained with this method.

Before samples are taken, fluid flow into the wellbore, in the flow string, in the separators, and through the points where the oil and gas rates are measured must be stabilized. Also, the oil and gas flow rate determinations must be accurate. Therefore, the facilities for making these determinations must be in excellent condition and operated by persons thoroughly instructed in their use. Metering equipment must be properly calibrated. The importance of these calibrations can not be overemphasized. Any errors in the gas-oil ratio measurement will be reflected in the recombination calculations and can prevent the laboratory personnel from properly reconstituting the reservoir fluid.

As an example, recording an incorrect orifice diameter for a gas orifice meter can easily result in a 50% error in bubble-point pressure measured on a recombined oil sample. This is not trivial and helps to illustrate the importance of accurate flow measurement data for surface sampling.

On the other hand, other cases have shown excellent agreement in measured fluid properties between recombined surface samples and subsurface samples, thereby confirming that the surface sample method can provide good results, if good samples are collected and if flow measurement data are accurate and representative.

4.3.3 Wellhead Sampling

This is a less common, but potentially valuable, alternative to the previously mentioned approaches. If a fluid is known to be in the single-phase state at the wellhead conditions of temperature and pressure, this technique can produce the easiest and most reliable results. Typically, it is employed only for oils which are highly undersaturated at wellhead conditions or for dry gases. The problem in using wellhead sampling is knowing that the fluid is truly single-phase at the sampling point.

4.3.4 Relative Advantages of Subsurface and Surface Sampling

The following summary of relative advantages of subsurface and surface sampling should be considered in selecting the more appropriate sampling technique for a given application.

- a. Advantages of subsurface sampling:
 1. Collects the desired sample directly.
 2. Can maintain full pressure on sample (with special sampling tool).
 3. Avoids use of surface separators, and the proper sizing of separators.
 4. Avoids the need for flow rate metering devices, and their proper sizing and calibration (for determination of producing gas-oil ratio).
 5. Requires less sampling information be transmitted to testing laboratory.
 6. Eliminates potential errors in recombination of gas and oil samples required for surface samples.
 7. Fewer sample containers need to be transmitted to the field, since three subsurface samples can supply an adequate quantity of sample for routine laboratory studies.
- b. Advantages of formation testers:
 1. Same advantages as subsurface sampling above.
 2. Collects the desired sample directly from the formation.
 3. Sample represents reservoir fluid over a very narrow depth interval.
 4. Sample not affected by fluid segregation in the wellbore.
 5. Can sample reservoir fluid even if water is standing in wellbore.
 6. Can sample reservoir fluid at original conditions (before any reservoir fluid has been produced).
 7. Controlled pressure draw-down during sample collection.
- c. Advantages of surface sampling:
 1. Relatively easy, convenient and less expensive compared to subsurface sampling (e.g., no rig or wireline unit is required on location).
 2. Avoids loss of production during required shut-in period for subsurface sampling (period of 1 – 4 days, or more for low deliverability wells).
 3. Avoids the potential for getting the subsurface sampling tool stuck or lost if the tubing is damaged or deviated, or if the sampling tool is lowered below tubing level.
 4. Applicable to cases where water is expected in tubing at the depth of the producing formation, where subsurface sampling cannot be used.
 5. Does not require that single-phase fluid be produced into the wellbore.
 6. Preferred method for saturated gas-condensate reservoirs.

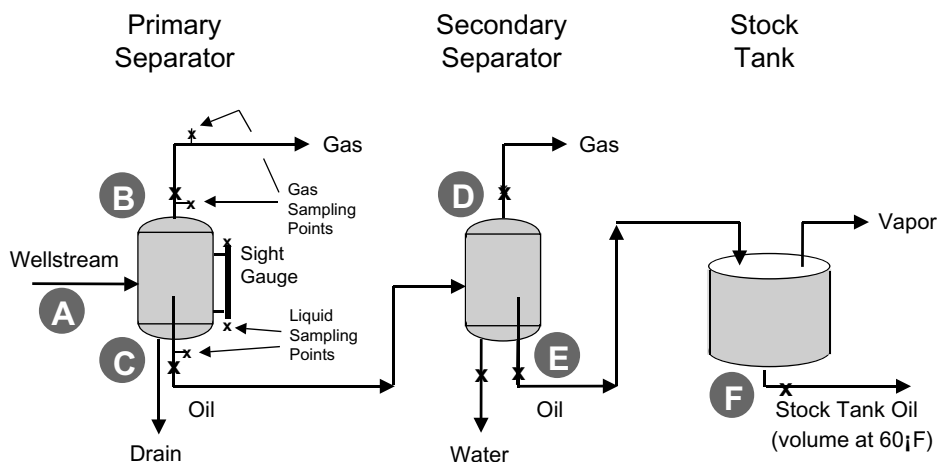


Figure 2—Typical Surface Separator System

7. Applicable to gas condensates, wet and dry gases, where subsurface sampling is generally inappropriate.

8. Applicable to viscous and foamy oils, where obtaining satisfactory subsurface samples may be difficult.

9. Large volumes of samples and replicate samples are easier to obtain than by subsurface samplers.

In general, the advantages reported for subsurface sampling identify disadvantages in surface sampling and vice versa. One exception is the frequent problem of sample contamination by drilling mud or mud filtrate which occurs for formation samples, but which is avoided when there is production to the surface and either surface sampling or subsurface “production” sampling.

5 Preparing the Well for Sampling

5.1 GENERAL

As stated earlier, when the pressure on the original reservoir fluid is reduced below its saturation pressure, significant changes in the composition and properties of the fluid can result. The effect on the reservoir fluid is greatest around the wellbore where the pressure drop is greatest. The objective of well conditioning is to replace the non-representative, near-wellbore fluid by displacing it into the well with original reservoir fluid from the more distant parts of the reservoir. Simply shutting in the well to restore the pressure around the wellbore will not necessarily return the fluid in the affected area to its original condition or composition. Flowing the well at a low flow rate to allow the altered oil to be displaced by unaffected oil is required.

Often, considerable time is required to condition the well at permissible well-conditioning flow rates, and sometimes this is impractical from an operating viewpoint. Considerations such as field production allowables, current income, operating schedules, etc., often preclude as thorough well condi-

tioning as may be desired. Rig charges in remote locations can also preclude adequate conditioning, particularly in exploration wells. Under these conditions, samples collected with modern formation tester^{29,30} tools may be the only option (see 4.3.4 and 6.2.1.3), if all drilling and completion fluids are pumped out of the sampling tool before securing the reservoir fluid sample. The history of the well-conditioning effort and pertinent reservoir data must be reviewed before deciding if the samples are representative of the reservoir fluid. Good well test data are invaluable for judging the quality of the reservoir fluid samples collected²⁸.

Judging when a well is adequately conditioned for sampling requires careful interpretation of the trends in the wellhead and bottomhole pressures, the rates of oil and gas flow, and especially the gas-oil ratio. Obviously, the well to be sampled must have the necessary equipment, in good working order and properly calibrated, if these measurements are to be accurate.

5.2 CONSIDERATIONS OF RESERVOIR FLUID TYPE AND WELL OPERATING CONDITIONS

5.2.1 General

Preparing the well for sampling requires considerations which include an understanding of the type of fluid that is being produced and of the current status of the production operation. For example, difficulties in obtaining samples from a well producing a highly undersaturated oil and one producing a near-critical fluid near its saturation pressure are quite different. Also, the producing history of the well can have a significant impact on conditioning (i.e., samples taken during pre-production [sampling during the drilling/completion process]), those taken at the conclusion of a well testing program, and those taken after a well has been placed on pump may involve considerably different conditioning. All chemical injections which may affect the sample quality should be stopped prior to sam-

pling (e.g., glycol injection, defoamers, etc.). If this is not possible, chemical injection should be minimized, details recorded, and a sample of the injection fluid obtained. The factors pertinent to several typical operations are given below.

5.2.2 Flowing Oil Wells

As explained in Section 4, in oil wells, the reservoir oil, rather than the reservoir gas or a mixture of the two, is the phase for which a sample is desired. Conditioning an oil well prior to sampling is necessary because changes usually occur in the reservoir-oil properties as a result of producing the well. When the bottomhole flowing pressure is less than the saturation pressure of the original reservoir oil, gas breaks out of solution from the oil around the wellbore and is produced. Since the gas had been a part of the reservoir oil, its loss alters the properties of the oil left behind in the formation. The greater the drop in pressure around the wellbore, the greater is the extent of gas release and the farther from the wellbore the altered oil extends. Thus, the composition of the mixture of oil and gas flowing into the wellbore is typically significantly different from the unaltered reservoir oil. The distance that altered (non-representative) oil extends out from the wellbore increases with the duration of production and with the amount of bottomhole pressure drawdown below the prevailing reservoir pressure.

5.2.2.1 Methods

The well should be conditioned by producing it until the non-representative oil has been completely displaced with fresh unaltered oil. The rock properties can be used with correlations^{23,26,31} of the reservoir fluid properties to make a preliminary estimate of the volume of non-representative oil in the vicinity of the well.

Proper conditioning should consist of producing the well at a series of successively lower flow rates, as follows.

a. If the well to be sampled has been flowing at its normal producing rate for at least 24 hours, conditioning begins by making accurate measurements of the oil and gas rates, and measuring the flowing bottomhole pressure. If the oil and gas rates are steady, the flow rate is reduced (by perhaps 30% – 50%) and the gas-oil ratio measured periodically until it has clearly become stabilized. This procedure of reducing rate and measuring gas-oil ratio is repeated until a trend in the gas-oil ratio with flow rate is established. Interpreting the trend can be of aid in following the progress of the well-conditioning effort. Experience has shown that, upon reducing the oil production rate, the gas-oil ratio can remain constant, decrease, or increase. Each of these trends can be interpreted to give guidance to the conditioning effort, as discussed below.

b. In cases where the gas-oil ratio remains constant after the first reduction in producing rate, flow of an undersaturated oil into the wellbore is indicated. This means that the phase condi-

tion and composition of the reservoir oil have not been altered as the oil moves through the formation and into the well. In this event, the well can be considered to be conditioned. (As a check, the bubble point of the reservoir oil can be estimated from the production data and the application of suitable engineering correlations^{23,26,31} to ensure that the estimated bubble-point pressure is below the flowing bottomhole pressure.)

c. When the gas-oil ratio decreases after a rate reduction, the presence of a free-gas saturation in the formation around the wellbore is indicated.

Note: The flowing bottomhole pressure increases upon rate reduction.

The free-gas saturation may have resulted from: (1) the coning of a gas cap into the oil-bearing portion of the formation around the wellbore; or (2) the flowing bottomhole pressure being less than the reservoir oil saturation pressure. When this behavior of the gas-oil ratio is observed, the well is conditioned by continuing to reduce the producing rate by stages. After each rate reduction, the flow is continued until the gas-oil ratio stabilizes. These stagewise reductions in flowing rate are continued until a stabilized (minimum) gas-oil ratio is reached. When additional rate reductions do not affect the gas-oil ratio, the indication is that the non-representative oil around the well has been produced and replaced by representative oil flowing in from greater distances. Correlations^{23,26,31} used with the reservoir temperature and pressure will provide an approximate value of the stabilized gas-oil ratio. If gas coning is a factor, the well can become conditioned in a relatively short time if the rate of flow is reduced enough to eliminate the gas cone, as evidenced by the gas-oil ratio ceasing to change with rate reduction. If the abnormal gas-oil ratio is the result of the producing bottomhole pressure being substantially less than the equalized reservoir pressure, a much larger volume of oil may need to be produced to condition the well than would be the case with gas coning.

d. An increase in the gas-oil ratio after a rate reduction is indicative of simultaneous, commingled production of gas from a gas-bearing zone and oil from an oil-bearing zone. The increase in gas-oil ratio could be caused by the subsidence of an oil cone. Although a representative sample of the reservoir oil can often be obtained, it is better to use a well which does not indicate oil coning, because determining when the well has been adequately conditioned is difficult. The time required for the gas-oil ratio to stabilize may depend more upon the time required for subsidence of the oil cone than on the rate of flow and volume of the non-representative oil which must be displaced by representative oil.

The producing characteristics of a well can impose a severe limitation on the conditioning process. At sufficiently low flow rates, oil wells sometimes flow by “heads” (a surging or “bumping” flow regime). This irregular flow of oil and gas makes it very difficult to measure the gas-oil ratio with

the required accuracy. Wells having a low productivity index are often difficult to condition because a relatively large drawdown in bottomhole pressure will occur even at moderate flow rates. Reducing the flow rate of a low productivity-index well enough to minimize the pressure drawdown can lead to excessive time requirements to condition the well or to “heading” flow. In some cases, this problem can be eliminated by installing smaller diameter tubing. If the tubing is small enough, the velocity of flow in it will be high enough to eliminate “heading” but low enough to maintain a low drawdown in bottomhole pressure.

When adequate conditioning is impractical, all pertinent data taken during the sampling operation and the production history of the well must be analyzed to form a basis for judging if the samples are sufficiently representative to warrant laboratory analysis.

When the subsurface sampling method is to be used, the properly conditioned well is shut-in or, at the option of the operator, produced at a very low “bleed” rate (typically the smallest choke setting). When the surface sampling method is to be used, the flow rate of the conditioned well may be increased, if desired, to a level that the test data have shown will not change the gas-oil ratio.

In summary, oil-well conditioning is the process for eliminating any gas coning and for flushing from the vicinity of the wellbore any reservoir oil which has been altered in composition by being subjected to pressures less than its saturation pressure. The non-representative oil is replaced by representative oil from beyond the immediate wellbore area by producing the well in a series of step-wise flow rate reductions. The stabilized gas-oil ratio is measured after each reduction in flow rate. The well is considered to be conditioned when further reductions in rate of flow have no effect on the stabilized gas-oil ratio. Adequate time must be allowed after each flow rate reduction to ensure that the gas-oil ratio has completely stabilized.

5.2.3 Pumping Oil Wells

The reasons for conditioning a pumping oil well are the same as those for a flowing oil well. The time required for conditioning is governed by the same factors that apply to flowing wells.

Pumping wells are generally undesirable for sampling, but in certain situations they present the only available option. The rate of pumping usually cannot be changed conveniently, the pump and rods must be pulled if the subsurface sampling method is used, and measuring the producing bottomhole pressure is often impractical. However, if preliminary study has indicated that the reservoir fluid is saturated at reservoir pressure, reducing the pumping rate is necessary to allow the formation face pressure to increase and approach the equalized formation pressure.

5.2.3.1 Methods

a. When the surface sampling method is used, the well should be pumped for several days after the oil and gas rates become steady before taking samples. The criteria for judging the progress of the conditioning effort are the same as those used with flowing oil wells. (The well is considered to be conditioned when further reductions in the pumping rate have no effect on the gas-oil ratio).

b. If the subsurface sampling method is used, pumping is stopped after the well is conditioned and the rods and pump (or submersible electric pump) are pulled out of the tubing. After pulling the pump, swabbing the well at a very low rate is desirable to remove any non-representative oil from the bottom of the well. The bottomhole sampler is then lowered to the sampling point and the sample secured.

CAUTION: Swabbing at too high a rate can undo the conditioning process if the bottomhole pressure is pulled down too hard.

c. There is an alternate method of sampling pumping oil wells if certain conditions are met. If it is known from producing data and correlations that the reservoir oil saturation pressure is lower than the lowest pressure rating of either the pump, tubing, or surface wellhead equipment, oil samples can be collected at the wellhead. The operator can raise the back-pressure at the wellhead to a pressure above the saturation pressure while continuing to pump the well, produce sufficient oil to completely displace the tubing and condition the well as discussed above (including confirmation of the gas-oil ratio), and then collect single-phase oil samples at the wellhead.

This is a somewhat risky method as the pressure up to and including the wellhead must be maintained above the reservoir oil saturation pressure at all times. For this method to work, the downhole pump will have to be in good condition to develop and maintain the higher pressure required. However, if these conditions are met, this method does allow collecting a wellhead sample and avoiding pulling the pump.

Note: This method cannot be used for any fluids except relatively low saturation pressure oils.

5.2.4 Gas-condensate Wells

The procedure for conditioning a gas-condensate well prior to sampling is based upon interpreting the changes in the gas-oil ratio that result from reducing the producing rate in a series of steps. When the pressure on a gas-condensate reservoir fluid is reduced below its dew-point pressure, a liquid phase (condensate) is formed. As a result, the vapor phase, which is the dominant produced phase, will have a lower concentration of condensable hydrocarbons (particularly the heaviest hydrocarbons²⁵) and is said to be “leaner” than the original reservoir fluid. This loss of condensable hydrocarbons usually results initially in an increase in the producing

gas-oil ratio. Since the lowest reservoir pressure occurs in the near wellbore area, retrograde liquid (condensate) will first condense immediately around the wellbore. With continued production, the condensate liquid saturation in that area can increase enough (but not in all cases) to allow the liquid to become mobile. Development of this mobile liquid can reduce the well productivity and cause unpredictable but significant short-term changes in the gas-oil ratio in response to changes in the producing rate.

5.2.4.1 Methods

The well is conditioned by placing it on a producing schedule consisting of a series of successively lower rates. After each rate reduction, flow is continued until the gas-oil ratio becomes stabilized. Generally, the trend of the stabilized gas-oil ratio is to decrease as the rate is reduced. At high rates, however, the gas-oil ratio may decrease with increased rate as a result of shear forces on the condensate liquid in the reservoir pore space. These forces are caused by the flowing gas, and they can mobilize the condensate and increase liquid production. Further, high rates can lead to carry-over of separator liquid entrained in the surface separator gas exit stream (and not measured by the liquid flow meter). As a result, care must be exercised to design and operate separators properly to minimize this problem.

The producing rate should be maintained high enough to prevent “heading.” When a well flows by “heads,” achieving the required accuracy in the gas-oil ratio measurements is difficult. In addition, the compositions of the gas and liquid phases in the separator during the time the “head” of condensate liquid flows into it may be different from their compositions between “heads.” Obtaining separator gas and condensate (oil) samples that are representative of steady flow conditions is complicated by the “heading” flow. Thus, the problem of balancing the benefit of high rates to avoid heading (i.e., to lift the wellbore condensate) against the benefit of low rates to minimize pressure drawdown becomes evident. In some cases, smaller diameter wellbore tubing is employed to give higher gas velocities and improved liquid lifting capability for a given pressure drawdown.

5.2.4.2 Split-stream or Iso-kinetic Method

In actual practice, the size of the available surface separator and/or gas metering equipment may not be matched very well to total wellstream flow rate. Methods have been developed to avoid some of these problems by sending only a portion (split-stream) of the total wellstream through a test separator³³. This allows the total wellstream flow rate to be adjusted to avoid the “heading” problems while the split-stream flow rate is optimized to the test separator to achieve sufficient residence time for equilibrium, and to avoid entrained liquid in the exit gas stream. Theoretically, such optimized flow rates should provide more nearly equilibrium

separator gas and liquid streams for sampling. However, the total wellstream must be perfectly homogenized prior to splitting the stream, and the two split-streams must have the same linear velocity (the “iso-kinetic” situation) in order for the separator gas and liquid samples to be representative of the total wellstream. Whether this can be achieved in all cases is controversial and is not accepted by some operators, and certainly many problems can be overcome by correctly sizing separators to increase efficiency at the flow rates tested. The well is considered to be conditioned if the stabilized gas-oil ratio does not change when the producing rate is changed. Again, care must be exercised to ensure that the gas-oil ratio is fully stabilized at each flow rate in the producing schedule.

5.2.4.3 Subsurface Sampling Method

In special cases of extremely tight (low permeability) reservoirs, it may be virtually impossible to get sufficient flow rate to lift the liquids without excessive pressure draw-down and corresponding liquid dropout at bottomhole conditions. In such cases, the operator may consider taking subsurface samples while the well is flowing at a very low “bleed” rate. Transfer of the fluid samples should not be done in the field, but the sampling tools should be shipped to the laboratory and the entire contents of each sampler transferred into a PVT cell under closely controlled temperature and pressure conditions. The results of the laboratory tests should then be compared with actual field gas-oil ratio data to determine if representative samples were collected.

The danger in this method is that some liquid may be standing in the wellbore and the sample collected would be a nonrepresentative mixture of this liquid and reservoir gas. Use of a formation tester tool^{29,30} in this situation should avoid such extraneous liquid, but again, the sample chamber would need to be shipped to the laboratory for sample transfer to a PVT cell.

Note: Traditionally, subsurface samples have not been recommended for gas-condensate reservoir fluids because of the possibility of inadvertently collecting extra condensate liquid (and even drilling and completion fluids) at bottomhole, and the difficulty of getting such samples into single-phase condition before field transfer. Excellent quality samples can however be obtained given the right conditions and proper handling²⁸.

5.2.4.4 Gas-condensate Sampling

In contrast to reservoir oils, where techniques are available to approximate the original fluid (such as by adding extra produced gas to the produced liquid to bring the combined fluid to the original bubble-point pressure, if known), no such procedures are available for condensates. If sampling of a gas condensate is delayed until the static reservoir pressure drops below the dew point of the original reservoir fluid, the opportunity to obtain a sample that closely approximates the origi-

nal fluid is lost. Early sampling is, therefore, critically important in condensate reservoirs.

5.2.5 Wells Producing a Near-critical Fluid

A reservoir which contains a near-critical reservoir fluid presents special difficulties in well conditioning. As described in 4.2.1, when the pressure on this type of fluid drops below the saturation pressure, substantial amounts of both phases form rapidly. Both phases are usually mobile and, therefore, flow into the well. The rates of production (relative mobilities) of the two phases, however, are usually such that the fluid composition in the wellbore is not the same as that of the original reservoir fluid. The composite stream flowing into the wellbore can contain either too much or too little gas in combination with the liquid hydrocarbon phase.

When early production information indicates a near-critical reservoir fluid, sampling should be conducted as soon as possible after the well has been completed. (This is, in fact, a good practice in essentially all situations for any fluid type.) Samples taken after the reservoir pressure has declined only a small amount below the original saturation pressure are, in many cases, of questionable value for determining the original reservoir fluid properties and for use in laboratory tests designed to predict fluid properties at later stages of reservoir depletion.

Conditioning the well is accomplished by flowing it at a succession of slower rates for the purpose of removing the non-representative hydrocarbon phases. The problem lies in determining when the non-representative fluids have been produced. With oil or gas-condensate reservoirs, a stable gas-oil ratio with decreasing flow rate is used as one guide in making that determination. Production from a near-critical reservoir, however, often will exhibit a relatively small change in gas-oil ratio even though the well effluent has undergone a significant change in composition.

5.2.6 Wet- or Dry-gas Wells

As previously explained, the composition of the effluent from a wet-gas or dry-gas reservoir does not change as the reservoir is depleted since the reservoir fluid does not form two phases in the reservoir at any point in the production process. Samples can be taken, therefore, at any convenient time. No conditioning of the well is necessary.

For a wet gas, small amounts of liquid hydrocarbons condense out of the well stream after it reaches the surface and is cooled. When liquid hydrocarbons are known to condense, the well effluent must be processed through conventional separators, though special precautions should be taken to maximize the measurement accuracy for the liquid flow rate which will be small and may fluctuate. Samples of both the separator liquid and gas should be taken and the gas-oil ratio measured using the same general procedure that is used for gas-condensate wells. In some circumstances it may be advantageous to adjust separator conditions such that the produced

fluid is in single-phase condition, thus avoiding the measurement problem for low liquid rates, and collecting more representative samples. Such an approach will, however, not yield any liquid sample that could be used for detailed analysis of the heavier hydrocarbons.

For a dry gas, no liquid hydrocarbons condense at typical field conditions, so samples can be taken at any convenient location in the flow line. However, care must be employed to confirm that a gas is indeed "dry" for such samples to be meaningful. In practice, the produced fluid cannot be identified unequivocally as a wet or dry gas until after samples have been taken and analyzed; thus, the safest practice is to treat such fluids as if they were gas condensates.

5.3 DURATION OF THE WELL CONDITIONING PERIOD

The duration of the conditioning period depends on: (1) the volume of reservoir fluid that has been altered (either from contamination by drilling fluids or from producing the well at flowing bottomhole pressures less than the original fluid saturation pressure), and (2) the rates at which the altered reservoir oil is produced. Since these volumes and rates vary widely, no general rule can be stated for judging the time required for conditioning.

A well having a low productivity index might require such a low flow rate that the conditioning time becomes impractically long. In this case, deciding when valid samples can be obtained becomes a matter of judgment in which sample quality is balanced against the time commitment. Experience has indicated that most oil wells can be adequately conditioned within a week. Some gas condensate and near-critical reservoir fluids could require much longer²⁵.

5.4 FIELD MEASUREMENTS DURING WELL CONDITIONING

Well conditioning typically involves bottomhole pressure and temperature measurements, repeated measurements of wellhead pressure and temperature, separator pressures and temperatures, the flow rate of gas out of the separator(s), stock-tank oil production rate, and water production rate. (In some instances, the primary separator oil flow rate is measured directly and reported, rather than the stock tank rate.) The following discussion focuses on the types of equipment generally used for these measurements and the precautions which, if observed, can improve the accuracy of the measurements. Additional useful information is published by the American Petroleum Institute²⁻²¹.

Since sampling normally occurs at the end of the conditioning period, the data taken at the end of the conditioning period are, in fact, the data associated with the sampling process. As a result, these data must be of the highest possible accuracy if the samples are to be of maximum value. (However, data taken before, during and after the sampling period

are valuable in documenting the stability of conditions throughout the sampling process.)

Tables 1 – 6 are designed to provide a convenient format for recording all necessary data taken during the well conditioning and sampling periods. Tables 7 – 9 are examples of more recent forms used by a service company. If these forms are completed, a complete history of the conditioning process will be available to the laboratory and to the reservoir engineer. A copy of each of the completed tables (or similar tables) should accompany the samples.

Note: The forms discussed in the above paragraph represent older technology¹. Modern field calculations and data recording in spreadsheet form can now be done with hand-held, laptop, or notebook-type computers³², and the results furnished by e-mail or diskettes in addition to hardcopy forms.

5.4.1 Tubing (Wellhead) Pressure and Temperature

Having a continuous record of the wellhead pressure over the test period is usually desirable. The chart on the recording pressure gauge used for this purpose should indicate accurately the date and time of the measurement and the well name or other identification. If a continuous record cannot be made, repeated spot measurements of the tubing pressure should be taken with an accurately calibrated gauge of proper range. At the least, these measurements should be performed as frequently as the flow rate measurements, which are normally taken at hourly intervals.

5.4.2 Gas Rate

The most commonly used method of gas rate measurement employs an in-line orifice meter. Other rate measuring devices such as the orifice well tester, positive-displacement meter, or critical-flow prover may be used when the in-line orifice meter facilities are not suitable. In-line orifice meter (or gas mass meter) installations should conform to specifications^{19,32}. Selection of orifice sizes and computation of gas rate should be made in accordance with American Gas Association recommendations^{18,19,20}. Table 2 provides space to record the values of all the factors used in computing gas rates and the calculated gas rates.

Modern development of electronic flow metering³² allows flow rates to be calculated in “real time” as fast as once every second. Field calculations and data recording in spreadsheet form can now be done with hand-held, laptop, or notebook-type computers, and the results furnished to the laboratory by e-mail or diskettes in addition to hardcopy forms.

The size of the orifice plate installed in the meter run¹⁹ should be chosen such that the differential reading will fall within the upper two-thirds of the chart. This will minimize errors in reading the meter differential. Each chart should be properly labeled to show well identification and when the chart was installed and removed. The chart should be changed before a full revolution has been completed in order

to prevent overlap of the line drawn by the pen. Also, chart rotation speed should be sufficiently rapid to permit separation of the pen scribe lines generated by fluctuating gas rates. Computerized data recording is becoming more common, eliminating the need for charts, and is the preferred method.

The best practice is to send copies of the charts from the gas meter and temperature recorder (or detailed data from computer files) to the laboratory along with the tabulations of other field data. Check in advance with the laboratory about the data requirements.

5.4.2.1 Gas Gravity

Gas gravity is a significant factor in the measurement of gas rate with all types of orifice meters. If measuring the gas gravity in the field is not possible, it can be determined in the laboratory if gas samples or bottomhole samples are submitted. Field-measured values may be desirable, however, if the gas-oil separation system in the field is one which is seldom duplicated in the laboratory. When gas gravity measurements are made in the field, they should be made when the separator temperature or the gas-oil ratio is near a maximum and a minimum as well as when near its average value. When the gas gravity is not measured in the field during sampling, the gravity of gas produced elsewhere in the field (or simply an estimated value) may be used to calculate a preliminary gas rate. Space is provided in Table 2 to record the value used in the calculations of gas rate, and this gravity can be updated at a later time, if appropriate, as laboratory data become available.

5.4.2.2 Gas Temperature

A continuous record of the gas temperature at the meter run should be obtained with a temperature recorder or computerized data collection system^{8–10}. A sensing element installed in a thermowell is desirable. When a thermowell is not installed, measurements from a temperature-sensing element strapped to the underside of the meter run pipe are acceptable. The sensing element should be insulated from atmospheric effects by wrapping it and the adjacent pipe with an insulating material such as cloth or paper. The separator temperature should not be used for the meter run temperature in flow rate calculations since significant differences can exist between these points. Also, try to avoid meter run conditions in which the meter is located a great distance from the separator and is operating at much lower temperatures than the separator, as this could lead to liquid condensation in the gas line and corresponding inaccurate gas rate measurements.

5.4.3 Oil Rate

The oil rate can be measured at either the exit of the primary separator (point “C” at full separator pressure in Figure 2) or at the stock tank (point “F” in Figure 2). Either can be used as indicators of stabilized operation during the conditioning pro-

cess. However, the primary separator oil rate is the value needed for recombination of the separator samples if surface sampling is employed. Measurement of the stock-tank oil rate is acceptable in surface sampling only if the applicable separator oil relative-volume factor (or shrinkage) is measured in the laboratory on the oil sample. Three common methods for oil rate flow are described in 5.4.3.1 and 5.4.3.2, below.

5.4.3.1 Primary Separator Oil Flow Rate

5.4.3.1.1 Liquid Meter

A positive-displacement liquid meter may be installed in the liquid exit line of the separator. When using such a meter, caution should be taken to ensure that it is operating properly, and that no gas is flashing out of solution as the liquid passes through it (meter must be maintained at full separator pressure). If water passes through the meter with the oil, the water rate must be determined independently and its rate subtracted from the rate given by the liquid meter to obtain the oil rate. The meter should be calibrated⁵⁻⁷, as necessary, following procedures given in API Std 1101 *Measurement of Petroleum Liquid Hydrocarbons by Positive Displacement Meter* (withdrawn). If a three-phase (heater-treater) separator is used, the water should exit through a separate line and the water rate "problem" should not be a factor.

5.4.3.1.2 Separator Liquid Buildup Method

This method consists of measuring the time required for the liquid level to pass two index lines placed on the gauge glass while the liquid dump valve is closed. When the volume represented by the distance between the index lines on the gauge glass is known, the liquid accumulation rate can be measured.

A calibration of the volume associated with the distance between the index lines on the sight gauge must be done, as follows. The dump valve is first held in a closed position until the liquid level rises to the top of the gauge glass; the well is then shut-in, or the separator is bypassed. With the dump valve closed, the separator gas is bled off. Two to four hours are usually required for the dissolved gas to escape. When the separator liquid becomes stabilized (no more gas evolution and foaming has stopped) at atmospheric conditions, the two index lines, spaced a convenient distance apart, are drawn on the gauge glass. The separator liquid is then drained into containers of known volume and the total volume of liquid withdrawn while lowering the level from the top index line to the bottom index line is recorded for the calibration.

Water can be used in place of oil to make the calibration. In all cases, a determination should be made that the float which operates the separator-liquid dumping mechanism is within its limits of travel while the liquid level is lowered between the gauge glass markings. Failure to provide for normal movement of the float will result in a significant error in the calibration.

After flow through the separator has resumed and stabilized, the rate of separator-liquid production is determined by

placing the dump valve in a closed position and then noting the time required for the separator liquid to rise between the two index lines on the gauge glass. An erroneous liquid production rate can be detected if three or more measurements are made and compared. The oil rate is found by subtracting the independently measured rate of water accumulation, if any, from the total-liquid buildup rate. For three-phase (heater-treater) separators, the water will be included in the liquid level rise, and its accumulation must be subtracted from the total accumulation. In this case, the water dump valve will also have to be closed.

The construction and method of operation of the separator must be clearly understood when this method is used.

5.4.3.2 Stock-tank Oil Production Rate

5.4.3.2.1 Stock-tank Oil Rate Method

The measurement of stock-tank oil rate (point "F" in Figure 2) can be used to indicate stabilization of operating conditions during well conditioning. In addition, it can be used for purposes of recombination of primary separator samples. However, it is the primary separator oil rate (point "C" in Figure 2) that is directly used in the recombination process. If the stock-tank rate is measured, the final determination of the (primary) oil rate cannot be made until the appropriate relative-volume factor (or shrinkage factor) of the separator oil (volume of primary oil/volume of stock-tank oil) is determined. The separator oil rate is determined by multiplying the tank oil rate by the separator oil relative-volume factor. When applicable relative volume factors are available at the time of the test, the primary oil rate can be calculated during the test. If the applicable relative volume factors are not available, they must be determined by the laboratory (or reliably calculated based on primary separator oil composition) and the separator oil rate calculated at that time.

The stock-tank oil rate method should not be used when it would be impractical to duplicate in the laboratory the field separation method and conditions, or when the field data necessary to permit the relative volume factors to be calculated are missing. The stock-tank calculation method requires data on the pressures and temperatures of all stages of separation, including the stock-tank oil.

5.4.3.2.2 Stock-tank Calculation Method

The stock-tank oil production rate can be measured with a gauge line or a gauge glass in a calibrated (strapped) tank². The usual method consists of measuring the distance from the oil surface to the tank strike plate with a metal tape. Another method employs a "swinging gauge." This method consists of measuring with a steel tape the distance from the oil surface to a point on the tank top, usually the lip of the hatch. Liquid volumes are then found with the tank calibration (strapping) tables. When more than one tank is used during a test, gauging should be taken on all tanks in order to prevent any gaug-

ing errors caused by accidental tank filling or overflow. The oil level on the tapes should be read to the nearest $\frac{1}{8}$ in. (or 2 mm²¹). Gauging should be done at regular intervals over the testing period. Tank oil temperatures should be measured and oil volumes corrected to 60°F (15°C or other accepted standard reference temperature²¹) using appropriate volume correction tables¹⁷.

All of these measurements can also be made using modern electronic transducers connected to computers³. See vendors for overall accuracy specifications.

The accuracy of the oil rate determination can be improved by gauging the tanks frequently (e.g., at approximately each one-ft increase in level), then plotting the gauged levels against time. The slope of the resultant line yields the average total liquid rate. Separate gauging must be done to determine water production rate. For installations where both a calibrated separator and a stock tank are available, good practice suggests determining both the separator and tank-oil production rates.

5.4.4 Water Production Rate

The water production rate (see Figure 2) can be determined by: (a) measuring its rate of accumulation in the stock tank, (b) using a separate meter on a water flow line from the separator, (c) dumping at measured time intervals the liquid from the lower section of the separator into a container and measuring the water volume by independent means, or (d) electronic flow meter measurements.

When the produced water is sent to the stock tanks along with the oil, the water production may be determined by using water-finding paste on the gauge line. At times there may be an emulsion at the water-oil interface, and some means must be used to break it so that a sharp indication will be obtained on the paste. A momentary breaking of the emulsion may be accomplished by moving the gauge line slowly through the water-oil interface several times before taking a reading. Alternatively, a small plate welded to the bottom of the gauge line weight will momentarily eliminate the effect of the emulsion as it passes through the water-oil interface. Several methods¹²⁻¹⁶ are available to determine the amount of water in crude oil.

Water vapor is normally contained in the vapor phase of gas-condensate and wet-gas reservoirs. Frequently, some water vapor will condense in the separator as a result of the lower temperature there. The rate of water accumulation in the separator is dependent upon the separation conditions and the reservoir temperature and pressure. Since the water production is often small, accurate water accumulation rates may not be obtained over short time intervals. Averaging the water production over the test period may be necessary, using tank gauging done at various times during the test.

5.4.5 Separator Pressure

Adequate control of separator pressure can usually be maintained with a back-pressure regulator in good working order. A

pressure variation of $\pm 3\%$ is adequate control. In cases where the separator “floats” on a gas gathering system, a regulator may need to be installed between the separator and the gathering line to obtain adequate pressure control. A pressure gauge installed in the separator shell should be checked to confirm that it is indicating accurately. Usually, the separator pressure variation will be small enough that a recording gauge is unnecessary, but if such an instrument is in use, care should be taken to ensure readings are accurate and updated properly, especially on production installations. If the recording pressure gauge in a meter run is used to observe the separator pressure, care should be taken to determine that there is no pressure regulator between it and the separator. Allowance should be made for any pressure difference between the pressure measurement point and the sampling point, and care should be taken in checking whether pressure readings are relative or absolute. Such factors can add errors exceeding the pressure variation above, especially for low pressure separators.

5.4.6 Separation Temperature

The separator gas-oil ratio can be affected significantly by the temperature of the fluid at the point where the gas and oil are permanently separated. In “low-temperature” separation systems, significant differences in temperature can be found between the point of permanent gas-oil separation and other sections of the gas-oil separation system. In conventional (low-pressure) systems, only insignificant temperature differences are generally found. A study of the separation vessel should be done before choosing the point for temperature measurement to ensure that the measured temperature is that at the point of permanent gas-oil separation. In locations where daily temperature variations are large, sampling is best done at times when the ambient temperature is most stable, such as, early in the morning.

For any type of separator, the use of a recording thermometer (or computerized recording) is preferred to a simple indicating instrument such as a mercury bulb thermometer⁸⁻¹⁰. A continuous record of the temperature can aid in making judgments on the process of the well-conditioning effort and the interpretation of the laboratory data.

5.4.6.1 Conventional (Low-pressure) Separators

When the production is of the type generally referred to as “oil production” and no line heater is in operation upstream of the separator, the separation temperature is usually considered to be the temperature in the inlet flow line at a point immediately upstream of the separator. The temperature can be measured most accurately by inserting a thermometer into a thermowell at that point. If a thermowell has not been installed, the temperature-sensing element may be strapped to the inlet flow line. The element should be wrapped in some type of temporary insulation material such as cloth or paper to eliminate the influence of atmospheric conditions such as

sunshine, wind, or rain on its temperature indications. Another satisfactory location for temperature measurement is in a thermowell in the shell of the separator located a short distance below the gas-oil contact.

When a line heater is in operation, the separation temperature should be measured in the separator at a point below the gas-oil contact.

5.4.6.2 Low-temperature Separators

When the well has a relatively high wellhead pressure, the production is often processed through a so-called “low-temperature” separator. In such separators, the inlet stream is “throttled” across a valve into the separator, and the temperature drop associated with this pressure drop on throttling can lead to additional condensation of liquid in the separator. As part of this process, the bottom (liquid) section of the separator may be heated to stabilize the liquid and/or to melt any hydrates formed as a result of the throttling. In such cases, the best place for temperature measurement is in the gas-phase section of the separator. When the liquid section is not heated, the temperature of the liquid section should be taken.

5.4.6.3 High-temperature (Heater-treater) Separators

Heater-treaters vary widely in design depending on their application. They are used in applications where a need exists to break oil-water emulsions in oils that tend to emulsify. The heater-treater will contain a heating section, but may also have sections for filtering, gravity separation, water washing, gas removal and sometimes electrostatic field separation in one vessel. In heater-treater type separators, care should be taken to measure the temperature in the gas-oil separation section rather than in the oil-heating section.

5.4.7 Frequency of Data Collection During Conditioning

As previously mentioned, a criterion for adequate well conditioning is that the gas-oil ratio be measured at sufficiently low flow rates that its value becomes independent of flow rate. This process, which requires producing the well at a series of incrementally lower flow rates, is time consuming and requires patience on the part of the operator. Variables such as the previous production history, well deliverability, etc., affect the required time period. This precludes the use of generalized rules regarding the necessary conditioning period.

Independent of the time required for well conditioning, certain principles must be followed. At each flow rate during the conditioning process, sufficient time must be allowed for each of the pertinent variables mentioned in 5.4.1 – 5.4.6 to stabilize. Ensuring that each variable has stabilized is best done by carefully recording its value at frequent intervals during the conditioning period. The required frequency will depend on the factors mentioned in the previous paragraph,

but a reasonable plan is to begin by recording readings at 30 min. intervals until stable conditions are observed for a period of at least 12 – 24 hours. The time required to stabilize at the first rate can then be used to guide the duration and frequency of measurements at subsequent flow rates.

6 Conducting the Sampling Operation

6.1 GENERAL

The sampling operation normally includes collecting samples at surface and/or bottomhole conditions and, as necessary, transferring these samples to containers for shipment to a laboratory for analysis. Historically, these operations have relied on the use of mercury (an easily separated, low-compressibility, hydraulic pressure medium) for transfer of samples, and mercury often accompanied the samples during transfer and shipping. The use of mercury provided a simple, direct, and reliable means of transferring reservoir fluid samples. However, because of environmental, safety, and transportation considerations, the use of mercury for sampling purposes has been eliminated in many geographical locations, primarily through the use of piston-operated sampling and shipping containers. Descriptions of mercury-based sampling and transfer operations are not included here, but they can be found in the first edition¹ of API RP 44.

6.2 SUBSURFACE SAMPLING

The operation of taking a subsurface sample can commence as soon as the well is cleaned up of drilling and completion fluids, and is conditioned. After conditioning, the well is either shut-in completely or the flow rate is reduced to a “bleed” rate. The choice of shutting in the well completely or allowing it to flow at a bleed rate is left to those taking the samples. Proponents of the bleed rate method believe that it provides additional assurance that the fluid at the sampling point is representative of the reservoir fluid. Opponents believe that the pressure drop required to maintain flow is sufficient to sometimes generate gas bubbles in the oil column and lead to the collection of erroneous samples.

Shutting in a well is generally done at the surface. Due to the compressibility of the fluids in the wellbore, there will be some bottomhole afterflow following surface shut-in which will allow additional full-pressure reservoir fluid to flow into the wellbore. This in itself may not be sufficient to ensure representative reservoir fluid in the wellbore, but if the well has been properly conditioned the afterflow acts like a short-term bleed and enhances getting better quality samples. Higher compressibility (lighter) reservoir oils will exhibit greater volume afterflow than lower-compressibility (heavier) oils.

The sampling process must be preceded by the selection of (a) the type of subsurface sampling tool to use and (b) the appropriate sampling point in the wellbore. These topics are discussed below.

6.2.1 Sampling Tools

The subsurface sampling method consists of lowering a device, usually called a bottomhole sampler, into the wellbore to a pre-selected point. A portion of the reservoir fluid at that point is trapped in a pressure-tight section of the sampler. The sampler is pulled to the surface with the fluid sample inside. The sample is then commonly pressurized into single-phase state and transferred at the site into a suitable container which is transported to the laboratory. However, for certain cases, the bottomhole sampler (with fluid sample inside) may be transported directly to the laboratory, without field transfer of sample, if shipping regulations permit and any additional tool rental is warranted. Brief descriptions of selected sampler types are given below.

6.2.1.1 Conventional Bottomhole Samplers

Conventional bottomhole samplers incorporate the capability to open and/or close valves at specified times in order to capture a sample of the fluid existing at bottomhole conditions. The valves may be actuated by one of several methods, as follows:

- a. "Jar head" mechanisms actuate the valve(s) by a sudden pull on the wireline supporting the sampler. This jarring action shears a pin in the valve assembly, actuating the valve. Jar heads are most applicable to shallow wells and high gravity (low density) oils, where the jarring action can be transmitted effectively to the sampler.
- b. Self-contained mechanical or electronic clocks in the sampler tool can also be used to activate valves at pre-set times.
- c. Valves can be controlled electronically from the surface.

Samples are captured in conventional bottomhole samplers either by flow-through or evacuated-container techniques. In the evacuated container technique, an evacuated sampler is lowered to the sampling point and a valve on the bottom of the sampler is opened, through which a sample is drawn by vacuum into the sample chamber. Typically, the valve is spring loaded and closes automatically when the combined force exerted by the sample pressure and the valve spring exceeds the opposing force caused by the bottomhole pressure.

In the flow-through technique, the sampler is lowered with the valves on each end of the tool open. Thus, the sample chamber is flushed continuously with wellbore fluid as the tool descends. The tool may be repeatedly raised and lowered near the desired depth prior to closing the valves, in order to increase the likelihood that the tool fills with the fluid existing in the wellbore at the desired sampling depth. This process should be done very slowly for highly viscous oils.

These conventional samplers require a displacing fluid (historically mercury) to transfer sample fluid from the sampler to a shipping container or directly into laboratory equipment. Mercury, water, and glycol are used as displacing fluids. Mercury maintains the best sample integrity, but safety concerns mentioned earlier frequently restrict its use. Prefer-

ential solubilities in water or glycol of portions of the sample restrict their use as displacing fluids.

As mentioned above, a conventional bottomhole sampler may be transported directly to the laboratory prior to transfer of sample. This is done in those cases in which the fluid sample can not be reliably pressured back into single-phase conditions in the field, or in which better temperature and pressure control is needed during reheating of the sample. Both of these operations can be better handled in the laboratory. Sampling a gas-condensate reservoir fluid or sampling a reservoir oil that contains significant asphaltenes and/or waxes are two that would prompt this operation.

6.2.1.2 Piston-type Bottomhole Samplers

New downhole samplers have been designed to eliminate mercury usage by employing a "floating" piston in the sample container to separate the reservoir fluid sample from a hydraulic fluid on the back side of the piston²⁹. Models are available which can be incorporated as part of a drill string or are deployed on a wireline. The piston-cylinder arrangement has the advantages of (a) permitting fluid transfer at the surface without the use of mercury or other displacing fluids contacting the sample and (b) control of the rate of sampling, which can permit collection of fluid in the single-phase state (i.e., avoiding the formation of two phases in the sampler due to reduced pressure in the sample container). However, it must be recognized that any floating piston type sampler containing hydraulic fluid behind the piston has the potential to leak hydraulic fluid by the seal on the piston and contaminate the sample. This is one of the risks with this new type of sampler.

Recently introduced bottomhole sampling tools incorporate a variety of features, and their features are expanding rapidly. New features permit multiple types of information to be determined using a single, modularly-constructed instrument^{29,30}. Example features include capabilities to measure (a) formation pressures for downhole pressure surveys (for identifying fluid types and fluid contacts), (b) pressures at multiple locations simultaneously (for evaluating horizontal and vertical permeability and for locating permeability barriers), and (c) electrical resistance and optical properties of the fluids entering the sampling tool to detect contaminants (e.g., drilling and completion fluids).

Some tools can now be configured to (a) pump out any selected volume of fluid (for near wellbore cleanout) prior to isolating a sample, (b) incorporate packers as an integral part of the tool to isolate the sampling region, (c) collect multiple fluid samples, and (d) control the sample chamber pressure drawdown. Equipment vendors and sampling contractors should be consulted for specific information regarding these bottomhole sampling tools and their capabilities.

These new piston-type samplers offer many apparent advantages over the conventional bottomhole samplers.

Note: With the new piston-type samplers, there is a potential for contamination by the hydraulic fluid.

There is no simpler sampling system than a conventional sampler (essentially a pipe with valves on each end) and the use of mercury to displace the fluid sample. Environmental concerns and regulations about the use of mercury, and a need to maintain the fluid samples in single-phase (monophasic) condition are what have driven the development of the piston-type samplers. If your situation allows the safe use of mercury, there may still be reason to consider using the conventional samplers.

6.2.1.3 Formation Testers

This type of testing tool^{29,30} is run on wireline to the desired depth after accurate positioning performed with the assistance of a gamma-ray tool.

- a. The probe and seal assembly is extended against the side of the wellbore to achieve a pressure tight flow path between the reservoir layer and the tool flow line leading to one or several chambers that is selectively opened and closed by control from the surface. A suitable pressure gauge enables accurate measurement of the flow line pressure. Accurate measurement of temperature is also required, especially at depths where fluid sample is collected for study.
- b. Initial pressure tests are taken at selected levels to identify reservoir fluid pressure gradients and permeability.
- c. From the pressure tests, the levels with the best sampling prospects are chosen (e.g., those that offer good formation-to-tool seal integrity and sufficient permeability) to ensure a reasonably short fill up time.
- d. The pressure gradients previously acquired are also used to select sampling levels away from the oil-water and gas-oil interfaces (see Figure 3).
- e. The sampling pressure must be maintained above the fluid saturation pressure. This is achieved by controlling the flow rate and having a fast-response pressure gauge. Preference is given to tools equipped with controllable throttling valves and quartz pressure gauges.
- f. Sample chambers using a water displacement are also recommended over the air cushion type as a back pressure can be maintained below the sampling piston to avoid flashing the sampled fluid into the chamber. This procedure ensures that a larger quantity (mass) of reservoir fluid is recovered.
- g. Multiple sample chamber systems are recommended to enable duplication of samples and/or multiple level sampling in a single run.
- h. Sample chambers must be free of any contaminants such as residue from previous samples, hydraulic oil, and cleaning solvents. Dead volumes in the flow line must be minimal and where they exist they should be filled with salt saturated water to avoid sample flashing and dissolving gas in the fill-up liquid. Check with the vendors about these details.

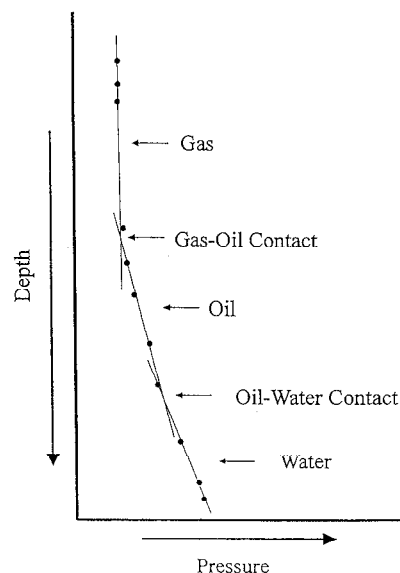


Figure 3—Wellbore Pressure Versus Depth

- i. In the case of multiple sampling at any given level, sampling consistency can be verified by confirming the saturation pressure at surface conditions. However, surface saturation pressures should be determined only on oils, not gas condensates (should they be sampled by this method).
- j. A record of the well and reservoir parameters, plots of gamma ray correlation, pressure, temperature, and the other usual identification data should be attached to the sample containers.

6.2.2 Selecting the Sampling Point

The best place to secure the sample with conventional (non-formation tester) samplers is the lowest point in the wellbore passed by all the fluid entering the wellbore and where the static pressure is no less than the estimated reservoir fluid saturation pressure. If water is present in the tubing, or if a mechanical obstruction is found, collecting the sample at the initially-selected point may be impossible. When water is present, the location of the gas-water or oil-water contact point in the wellbore may be determined from pressure survey data (see 6.2.2.1). If the pressure at that point is at least equal to the estimated saturation pressure of the reservoir fluid, the sample can be collected at a point in the tubing just above the point of contact between the desired fluid and the underlying phase.

For oils, if the pressure at the desired sampling point is less than the estimated saturation pressure of the reservoir oil, the oil-water contact will have to be lowered to a level where the pressure is above the estimated saturation pressure. If the water column cannot be lowered sufficiently or if a mechani-

cal obstruction prevents sampling at the desired point, the use of another well (or surface sampling) must be considered.

Final selection of the sampling point is made following completion of wellbore pressure and temperature surveys, described below in 6.2.2.1 and 6.2.2.2. If a wireline is used to lower the survey tool, good wireline depth control is needed for accurate surveys. The use of downhole tie-in capability with gamma ray and/or casing collar locator sensors to position the tool would be advisable.

6.2.2.1 Pressure Survey

A pressure survey is usually run just before the bottomhole samples are taken. In conventional sampler applications, this is usually done separately from the sampling operation. More contemporary samplers and formation testers permit the pressure (and temperature) measurements to be done in the same bottomhole run as the sampling. In either case, the pressure-recording gauge used for the survey should have been calibrated recently or otherwise known to be accurate. The pressure-gauge calibration can be checked by comparing its measurement of the wellhead pressure with the value obtained at the same time with another instrument of at least equal accuracy (e.g., a dead-weight gauge). Bottomhole pressure gauges may be of the bourdon tube, strain gauge or quartz gauge type. The survey consists of stopping the gauge at various depths to allow the gauge to record the pressure. The stops at each depth should be of sufficient duration (depending upon the type of gauge used and the clock rate, if applicable) to give a clear pressure recording. The gauge depth and the time of day at each depth should be recorded on a form such as Table 4 (or automatically by computer-controlled data logging). At the lowest point of pressure measurement, generally at the midpoint of the formation or completion interval, the pressure instrument should remain stationary for a minimum of 20 min. to permit it to establish pressure-temperature equilibrium with the fluid.

6.2.2.2 Temperature Survey

The preferred instrument for making the wellbore temperature survey is a recording temperature gauge. Temperatures are normally measured during the same operation as the pressure measurements. The instrument should remain stationary at each depth long enough to reach the downhole temperature and to record the temperature clearly. The temperatures should be recorded on a form such as Table 4.

Frequently, a one-point (mid-formation or completion-interval) temperature is sufficient. In this event, maximum registering thermometers may be incorporated in the pressure recording instrument thermometer well. Contemporary practice, however, uses temperatures measured on recording thermometers. In any application, care must be exercised to ensure that the temperature has stabilized at each measurement point, since sometimes the wellbore may have been cooled below

reservoir temperature by the circulation of drilling fluids used in preparation for well logging operations. For reservoir modeling purposes multiple point temperature measurements can be extremely useful, especially where different intervals may not be in communication, or in the case of near-critical fluids.

Some current sampling operations involve automatic, computer-controlled data logging, so that use of forms (e.g., Table 4) is no longer necessary. Nevertheless, care should be taken to see that all data of the types shown in the tables accompanying this document are included in the data logging operations, and a printout (similar to Table 6) should be made before computer equipment is shut down.

6.2.2.3 Locating the Water Level

The presence of water standing in the well can usually be detected by plotting pressure versus depth, as determined from the pressure survey. Gas-oil and oil-water contact points can be identified at the depths where the gradient changes from one representative of gas to oil to water in the wellbore. Figure 3 represents a typical pressure gradient plot, with the contact points detected by changes in slope of the pressure-depth relationship.

The slope of the pressure-depth line is directly proportional to the density of the fluid in the wellbore, thus the most dramatic changes in slope occur at interfaces where the fluids in contact differ most in density (e.g., gas-water). Conversely, an interface between water and a heavy oil (that may have a density very near that of the water) may be reflected in a slope change that is difficult to identify.

6.2.3 Subsurface Sampling Procedure

A detailed description of the proper use and handling of various samplers is not given here. Information of this type is best obtained from the manufacturer or vendor of the instrument. A discussion of general sampling procedure follows:

After the sampler has been run to the desired depth and the sample has been trapped, the sampler is brought to the surface. If desired, the sample can be transferred at the well site to a suitable container for transporting to the laboratory; otherwise, the sample can be transported directly in the sampling tool. In either case, care must be exercised to see that the sample is transported in a vessel that meets all applicable transportation safety regulations (described in 8.1). A minimum of triplicate samples should always be obtained to (a) permit comparison of sample compositions and properties, and (b) provide backup samples in case one container leaks during transit.

For gas-condensate samples, the optimum procedure is to ship the entire subsurface sampling tool section to the laboratory, so that it can be properly heated to ensure that all of the sample fluid is transferred from the sampler to the laboratory apparatus.

Note: Only under special conditions should gas-condensate samples be collected in subsurface samplers (see 5.2.4).

For oil well samples, checks should be made at the well for consistency of samples. This check for sample duplication is referred to here as a “sample quality check” (see 6.2.4). The sample quality check of a reservoir oil sample consists of determining an approximate bubble-point pressure of the sample at the temperature of the sampler or shipping container. (A shipping container is sometimes referred to as a “storage cylinder,” “transfer cylinder,” “transportation cylinder,” or “sample bottle.”) The sample quality check may be conducted either while the sample is in the sampler or after its transfer to a shipping container. The temperature of the sample will usually be close to prevailing ambient temperature. Usually, samples are considered to be satisfactory duplicates if the saturation pressures measured at ambient temperature on the well-site agree within 2% or 50 psi (345 kPa²¹), whichever is less. The agreement in bubble-point pressure is generally accepted as reasonable proof that the samples are representative of the oil at the point of sampling. The data collected during the well-conditioning period (e.g., gas-oil ratio) will usually permit the saturation pressure of the samples to be estimated from correlations^{23,26,31}.

If the oil samples exhibit saturation pressures substantially higher or lower than the estimated pressure, the sampling operation should be reviewed to find an explanation. For example, if the sampler valves are accidentally closed at a point high in the tubing, the sample saturation pressure could, with many oils, be lower than the estimated value based on the producing gas-oil ratio (due to loss of solution gas from the oil at the lower pressures prevailing at the point high in the tubing). By contrast, a foamy oil could give a higher saturation pressure, as could oils from which waxes or asphaltenes have precipitated in the sampler at surface temperature. (Thus, samplers used with wax- or asphaltene-containing fluids should be transferred at elevated temperature.)

Often, the nature of the reservoir fluid at the time of initial sampling is not well known. If a sample quality check is employed on a volatile oil, near-critical fluid or gas condensate, no clearly discernible saturation pressure may be obtained due to the high compressibility of these fluids (in contrast to the case for black oils). Such an inconclusive sample quality check may indicate that the reservoir fluid is not a black oil or, alternatively, it may mean that the sample is a gas. No field tests for sample quality are reliable for near-critical fluids or gas condensates. Typical plots of sample quality check data are shown in Figure 4, which illustrates the clear break in the pressure versus volume plot for a typical oil in contrast to the situation for water- or gas-filled cylinders.

6.2.4 Quality Check of Subsurface Sample

The sample saturation pressure at ambient temperature can sometimes be measured in the field while the fluid sample is still in the sampler (depending on the details of the sampler design). Additionally (or alternatively), the saturation pres-

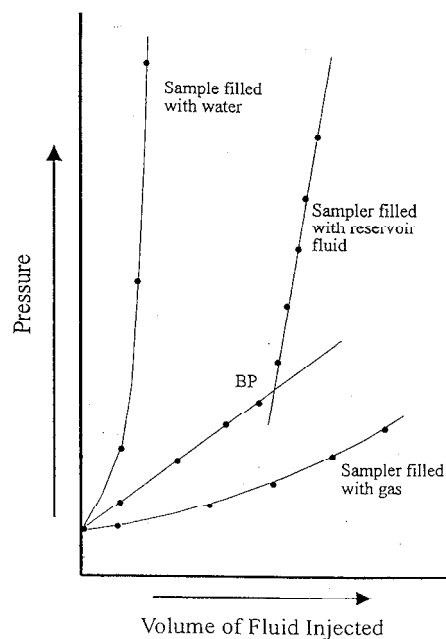


Figure 4—Sample Quality Check

sure can be measured after the sample has been transferred to a shipping container, if such a transfer is made in the field. Either method requires a modest equipment set-up including a calibrated hydraulic fluid injection pump and an accurately calibrated pressure measuring device. A simplified version of such an apparatus is shown in Figure 5.

In all cases, the initial pressure should be recorded when the sampling tool is first opened. “Opening pressures” depend on the tool design, fluid type, temperature, and volume collected, but provide an initial indication of correct tool operation or malfunction, and for replicate samples collected under similar conditions usually give good agreement. When saturation pressures are not available, opening pressures should be used as a basis for quality control.

6.2.4.1 Method

The procedure is as follows:

- Connect the hydraulic fluid filled side of the sampler or shipping container to the calibrated injection pump and purge the connecting line with hydraulic fluid. (If the test is done in the sampler, pump a volume of hydraulic fluid just sufficient to open the sampler valve and read the pressure; record the pressure observed in Table 6 opposite “Sampler Pressure after Valve Opening.”)
- Inject a small volume of hydraulic fluid into the vessel, agitate the contents of the vessel (this can be done by repeatedly inverting or rocking the vessel above and below a horizontal orientation) until the pressure becomes constant, then record the pressure and the pump reading in Table 5.

c. Repeat these steps until the pressure response from hydraulic fluid injection becomes very large, indicating that the vessel contains no vapor space (the sample has been pressured into single-phase liquid).

Note 1: In instances where the sample is single-phase liquid at opening conditions, hydraulic fluid must be removed (backed into the pump) to create a two-phase condition in the sample to begin the measurements.

Note 2: If the piston sticks (becomes erratic in operation), reaches the end of its travel length in the container, or the pressure reaches the maximum recommended working pressure for the container or the pump, the test will have to be terminated.

d. Plot the pump reading versus pressure on the graph in Table 5 (or use a computer spreadsheet for graphing). Draw a line through the points above the break and another line through the points below the break. The intersection of the two lines is approximately the saturation pressure at the vessel temperature. As mentioned above, saturation pressures of different samples that agree within 2% or 50 psi (345 kPa²¹), whichever is less, may be considered to be satisfactory duplicates.

e. For confirmation of the saturation pressure, repeat the pressure-pump reading measurements in decreasing pressure increments until the initial pump reading is reached. Rock the vessel again repeatedly at each pressure step until the pressure becomes constant, and record the pressure and pump reading in Table 5. At the conclusion, plot this data on the same graph with the initial (pressure increasing) data (or use a computer spreadsheet). The indicated saturation pressure should be approximately the same as for the initial data. If there is a significant difference between data sets, the latter will probably be more representative. Some oils are simply much more difficult to get all the evolved solution gas driven back into solution unless the pressure is raised very high (see last paragraph in 6.2.4.2).

6.2.4.2 Alternate Method

If a suitable calibrated pump is not available, the saturation pressure may be measured by an alternative (but somewhat less precise) method as follows:

- a. Bring the sample to a single-phase state by injecting hydraulic fluid until the pressure is well above the expected saturation pressure.
- b. Bleed hydraulic fluid from the sample container in small, sequential amounts into a calibrated receiver.
- c. Rock the container and note the pressure after each portion of hydraulic fluid has been withdrawn.
- d. Record the pressures, temperatures, and fluid volumes in Table 5.
- e. Plot the cumulative volumes against the corresponding pressures on the graph in Table 5, as described above (or use a computer spreadsheet), to locate the saturation pressure. Some loss of accuracy (relative to the previously described pump

technique) may result from less precise volume measurements in the receiver relative to those made using a calibrated pump.

When measuring saturation pressures, adequate agitation (rocking) of the sample is mandatory. The rate at which gas is driven back into solution in the liquid phase can be surprisingly slow in an unagitated fluid sample, and measurements made without the gas and liquid phases being at equilibrium can be very misleading. Some heavier oils containing very little intermediate (ethane through the pentanes) components can be very difficult to single-phase, and may require increasing the pressure several thousand psi above the actual saturation pressure while rocking the container. Thus, care and patience must be exercised to get meaningful saturation pressures.

6.2.5 Sample Transfer to Shipping Container

If the sampler itself is not used to transport the sample to the laboratory, the sample must be transferred to a transfer container for shipping or transport. Whatever vessel is used, it must have an adequate pressure rating and be certified to meet all applicable shipping regulations. Further, the shipping cylinders must be thoroughly cleaned, as described in 8.2; this is particularly important to avoid contamination of the sample from trace amounts of heavy components remaining in the cylinder from previous use.

The primary concern in transferring a bottomhole sample to a shipping container is to maintain the integrity of the sample during the transfer operation. This requires that the fluid in the sampler be maintained in a single-phase condition during the entire sample transfer process or, if the fluid is in a two-phase condition, that the entire contents of the sampler be transferred. (The sampler should be heated if wax or asphaltene are present.) If only a portion of a two-phase sample is transferred, the fluid transferred to the shipping container will differ from the original sample, since the two phases in the sampler almost certainly cannot be transferred in the proportions that exist in the sampler. Because valid transfer is crucial to sample quality, the preferred procedure is to maintain the fluid in a single-phase state and transfer it in its entirety. An important consideration is that pressurizing the sample may produce a single-phase condition, but may not homogenize the sample; thus, thorough agitation (by rocking the cylinder) during the process is important.

In addition, the sample composition must not be altered by either (a) leaks of hydraulic fluid across the piston of piston-type samplers or (b) by selective absorption of components from the sample into a transfer fluid (e.g., water or glycol) in cases where the transfer fluid is in direct contact with the sample. The latter is a particular problem in samples containing carbon dioxide or hydrogen sulfide, which are very soluble in the transfer fluid.

At all stages of the transfer process, the pressure must be maintained substantially higher than the sample saturation pressure. Figure 5 shows a schematic diagram of a transfer

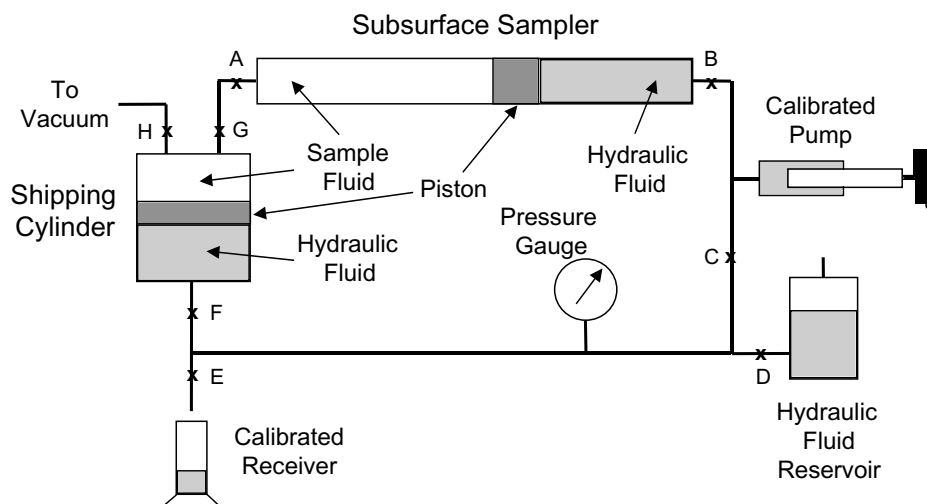


Figure 5—Diagram of Sample Transfer Apparatus

apparatus for piston-type samplers and transport containers. The 1966 edition¹ of API RP 44 should be consulted for transfer apparatus involving direct contact between the sample and mercury (as the hydraulic fluid).

The transfer procedure is as follows.

a. Use the pump to fill all lines between valves B and F with hydraulic fluid (refer to Figure 5). This can be done by loosening the fittings at these valves and pumping until hydraulic fluid appears, then tightening each fitting.

Note: Valves A, B, and F, G, H may be integral parts of the sampler and transfer container, respectively, depending on the design of these vessels. Also, valve H and its line may be arranged somewhat differently from Figure 5 such that valve H simply “tees” into the line from valve A to valve G.

b. With valves A, D, E and F closed and valve C open, slightly open valve B and note the opening pressure of the sampler. Valve B is often spring- or hydraulically-actuated in cases where it is part of the sampler; if so, use the pump to raise the pressure until valve B just opens and record the opening pressure.

c. Open valve G and evacuate through valve H the line between valves G and A, including the sample side of the transfer container.

d. Close valve H.

e. Open valve F and use the pump to bring the hydraulic oil pressure in both the sampler and shipping container to a pressure well above the saturation pressure of the sample.

f. Slightly open valve A and fill the line between that valve and the upper face of the piston in the shipping container with sample fluid, using the pump to keep the pressure on the gauge well above the saturation pressure during this transfer process.

g. Close valve C, then slightly open valve D, allowing hydraulic fluid to drain slowly into the hydraulic oil reservoir

(open to atmospheric pressure) as fluid flows from the sampler to the shipping container. Use the calibrated pump to (1) keep the pressure in the sampler above the saturation pressure and (2) keep track of the amount of sample transferred. When the desired amount of sample has been transferred, close valve D, then valves A and G.

h. Before the transferred sample can be shipped, a vapor space must be created in the shipping container. To do this, slightly open valve E and allow hydraulic oil to drain from the shipping container into an open calibrated receiver. Close valve E, then valve F, when the volume of hydraulic fluid in the receiver equals 10% of the volume of the shipping container. This will result in a 10% vapor space (“ullage” or “outage”) in the shipping container. Such a void volume is required for safety, since very high pressures can result if the temperature increases even slightly in a totally liquid-filled, closed vessel.

Note: Special sample cylinders with an auxiliary gas cap are available for samples which must be retained in single phase (monophasic) condition.

i. Close valve B if it is not self-sealing. Open valve C, then valve D, to relieve pressure in the pump. At this point, the sampler and shipping (transfer) vessel can be disconnected from the transfer apparatus.

6.3 SURFACE SAMPLING

The surface sampling method is satisfactory for nearly all types of reservoir fluids. It consists of taking “companion” samples of the oil and gas outlet streams from a conventional field separator (see Figure 2) while making accurate measurements of the separator oil and separator gas producing rates prevailing at the time of sampling. When multi-stage separation is used, the samples are taken from the first-stage (high-

pressure) separator. The separator gas (point B) and oil (point C) samples are subsequently recombined in the laboratory to obtain a sample representative of the producing wellstream (point A), which usually represents the reservoir fluid. The details of the sampling method are discussed in this section. The simpler techniques of sampling “dry-gas” reservoirs are also discussed.

6.3.1 General Considerations

Generally, the producing rate is not changed after the well has been conditioned. Samples may be taken as soon as it has been determined that the well is properly conditioned, providing that five separator volumes of both oil and gas have flowed through the separator following conditioning. Flushing the separator is necessary to remove oil and gas which was produced prior to the well being conditioned. Flushing is particularly important for high gas-oil ratio wells when the separator has a large liquid holdup. The separator gas and oil samples should be taken at essentially the same time. The time span should be sufficiently short (preferably no more than 1 – 3 hours) to ensure that no significant changes occur in separation conditions, particularly the temperature. Reservoir fluids of the volatile-oil or near-critical type exhibit significant changes in gas-oil ratio with separator temperature. Good practice requires that triplicate samples of both gas and oil be taken to ensure that (a) there is a high likelihood that at least one good sample is obtained and (b) replicate samples can be compared for consistency when they reach the laboratory.

In taking separator oil and gas samples, the goal is to obtain fluids that are representative of those at the point in the separation process where the gas and oil exit from the separator (still at full separator pressure) and their individual flow rates are measured. At that point (see the gas and liquid sampling points identified in Figures 2 and 7), the gas and oil streams should be close to thermodynamic equilibrium with each other, if pressure, temperature and flow rates are stable, and residence time is adequate. The true equilibrium situation is very useful in illustrating the factors that are important to successful sampling. Figure 6a shows the phase diagram for a reservoir fluid; in addition, the phase diagrams are shown for the separator gas and oil formed from the reservoir fluid. Figures 6b and 6c reproduce the separator gas and oil phase diagrams separately, for purposes of clarity. Notice that the separator gas is at its dew point at separator conditions of temperature and pressure, and the separator oil is at its bubble point.

The fact that each phase is in a saturated condition as it leaves the separator has significant effect on sampling requirements. In order to obtain reliable gas and oil samples, the streams must be kept in single phase (monophasic) condition (either gas or liquid) until they enter the appropriate sample container. For the (dew-point) separator gas, this means that the temperature must not be allowed to drop below the separator temperature (line 1 on Figure 6b); nor should the

stream be throttled before it enters the sample container, since the temperature decrease upon pressure reduction could bring the stream into the two phase state (line 2 on Figure 6b). Some operators prefer to limit the sampling pressure in the gas sample containers to approximately 80% of the full separator pressure so as to stay further away from the two-phase region. Similarly, for the (bubble-point) separator oil, the pressure must not be reduced (line 2 on Figure 6c) or gas may come out of solution, nor should the stream be allowed to increase in temperature (line 1 on Figure 6c).

Most of the precautions taken during sampling are associated with avoiding the above problems because, if a stream becomes two-phase, any sample collected will likely be non-representative as a result of disproportionate flow rates of the two phases in the sampling lines and into the sample container. In general, from the time the separator gas leaves the separator until it enters the sample container, it should be kept at a temperature at least as high as the separator temperature and a pressure equal to or less than the separator pressure (area inside the Sampling Region in Figure 6b). Similarly, the separator oil should be kept at a temperature equal to or lower than the separator temperature and a pressure equal to or greater than the separator pressure (area inside the Sampling Region in Figure 6c). In practice, the pressure on the separator oil sample is not increased; thus it becomes important to maintain the temperature no higher than the separator temperature, while minimizing the pressure reduction needed to produce flow of the sample (until it has entered the sample container).

These precautions will help ensure that the gas and oil streams remain in their single phase (monophasic) states from the point at which they exit the separator, through the tubing and sampling equipment, and up to the point they enter the sample containers.

6.3.2 Determining the Gas-oil Ratio at Time of Sampling

The separator gas and oil rates that prevail at the time of sampling must be measured accurately. This is as important as securing representative separator gas and oil samples, since the gas-oil ratio serves as the basis for determining the proportions of gas and oil that will be combined to reconstitute the producing wellstream in the laboratory. In most cases, the producing wellstream will be representative of the reservoir fluid if the well has been properly conditioned. The determination of the gas and oil rates can be made with the methods described in 5.4.2 and 5.4.3. These rate measurements should be made every 30 min. to one hour, for a period of at least 24 hours before sampling time, in order to establish their magnitudes and detect any trends. From this data, the gas-oil ratio that prevailed at sampling time can be established.

Tables 2 and 3 provide spaces for recording the gas-oil ratio data and serve as work sheets for performing the necessary computations. Copies of these completed tables (or com-

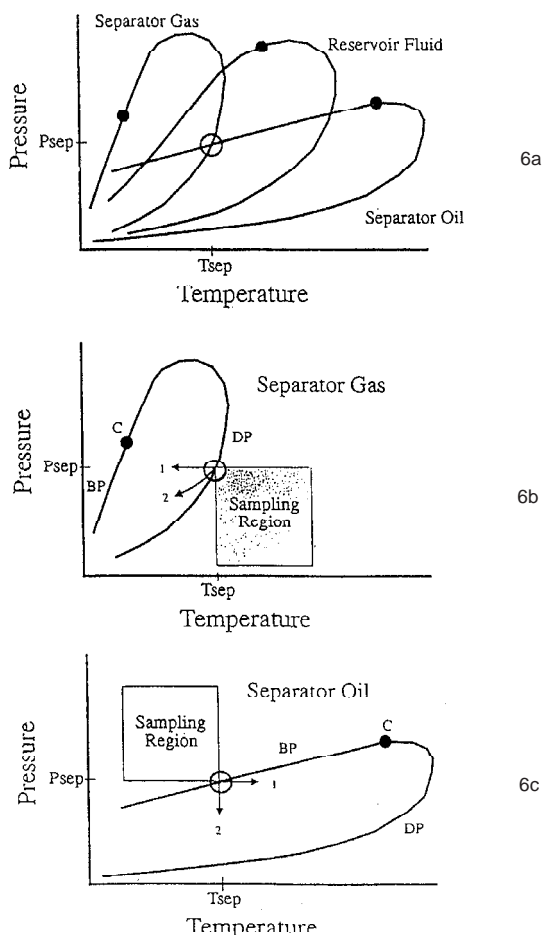


Figure 6—Phase Diagrams for Separator Oil and Gas

puter spreadsheets of similar data) should accompany each set of gas and oil samples. Laboratory and engineering personnel can study the conditions under which the samples were taken. Such information is very valuable, and a single omission or an erroneously recorded value can sometimes render the entire sampling process useless. Diligence is required in determining the gas-oil ratio; an excess of information is never harmful, while too little may waste the expense of well conditioning and sampling.

6.3.3 Selection of Sampling Location on Separator

Samples of gas and oil should be taken from the best possible sample points. These should result in minimum flow restriction from the main separator vessel. In general, samples are taken from the first stage separator (points B and C in Figure 2). Some multi-stage separators may not have suitable taps for sampling first-stage liquid, but second-stage liquid samples can often be taken. This procedure is acceptable if both first- and second-stage gases are sampled, so that the gas (point D in Figure 2) and oil (point E) from the second stage

can be recombined to reconstitute first-stage oil (point C). Then this reconstituted first-stage oil is recombined with first-stage gas. However, this situation increases the potential for flow measurement and sampling errors. Therefore, the simpler case of directly collecting first stage separator oil is preferred, if at all possible.

Potential locations for gas sampling points include the gauge tap near the gas outlet line, the top side of the gas outlet line, and at the meter run upstream of the orifice plate (before the pressure drop occurs). Most separators will have at least one suitable valve tap for gas sampling (see Figure 7). The top side of the gas outlet line is the preferred location.

Liquid samples should be taken at full pressure from the oil line, but they can be taken from the bottom valve of a gas-oil sight gauge, the top valve of an oil-water sight gauge, or the drain valve at the bottom of the separator (see Figures 2 and 7). Sometimes easy sampling points are simply not available, and special arrangements will have to be made, such as collecting the samples further downstream. Care must be taken to understand the operation of the separator and the phase behavior of the fluids being sampled.

Note: The liquid samples should be taken at full separator pressure, not at a reduced pressure downstream of the oil dump (exit) valve. If necessary, a downstream valve may have to be shut-in temporarily to allow full separator pressure to build up at the downstream sampling location. In this case, a sufficient volume should be purged through the line such that fresh separator liquid (not subjected to pressure less than the separator pressure) is available for sampling.

Liquid sampling should be preceded by slowly draining about 100 cc of oil into a cup to clean the valve and to be sure that oil, not water, is being produced. For example, if liquid samples are collected from the drain shown in Figures 2 and 7, the sample will most likely be water. The volume of oil to purge depends on the actual plumbing of the sampling equipment, but it should be at least five times the internal volume of the sampling lines and valves.

6.3.4 Separator Operation

The quality of gas samples is sensitive to the operation of the primary separator. In particular, the separator should be of a design having a mist extractor section, and must be sized and operated in a manner such that there is negligible entrainment of liquid in the gas stream leaving the separator. If entrainment is a problem, special sampling techniques must be employed in an attempt to collect a representative single-phase sample of only the flowing separator gas. This situation is definitely inferior to that of an entrainment-free gas stream; attention to proper separator size and operation is required.

The cycle time of the oil dump valve should be determined before collecting separator oil samples. Separator pressure may be temporarily upset when the dump valve opens, so it is best to collect the oil samples between dumps. If the cycle time is long enough, manually lock the dump valve closed during sampling to avoid upsets. Then be sure to unlock the valve after sampling.

Also, the separator temperature may cycle over a 24-hour period, so arrange collection of samples during those times when the temperature is most stable (late afternoon or early morning).

6.3.5 Sample Volume

The volume of gas and oil samples to be collected will, in general, be determined by the laboratory requirements. Laboratory personnel should be consulted on the volume of sample required. Triplicate samples should always be obtained to (a) provide back-up samples in case some containers leak during transit, and (b) permit replication of sample compositions and properties for quality control.

As a practical guideline, triplicate samples taken in one-gallon or one-liter containers should suffice for most applications. Special studies, and cases in which the separator pressure is low (less than about 100 psig), may require larger volumes of gas sample. Smaller volumes (150-cc or 300-cc

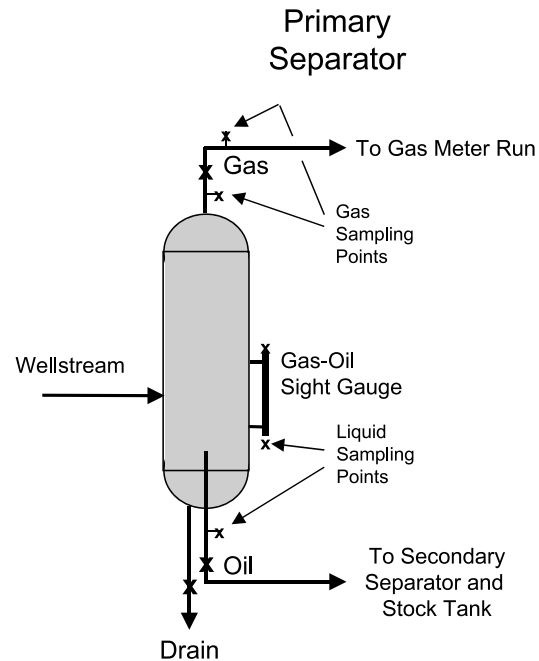


Figure 7—Typical Separator Sampling Points

containers) may be adequate if the laboratory tests consist only of determining composition. If two different volume containers are provided, always use the smaller containers for oil and the larger containers for gas samples. For example, some laboratories provide 600-cc containers for oil samples and 1-gallon to 20-liter containers for gas samples. Special studies may require larger volumes of one or both phases.

Laboratory personnel should be consulted about the sample volume requirements well in advance of actual sampling time. In some cases, sufficient sample containers may not be in stock and special arrangements will have to be made, which may require additional time.

CAUTION: Some sample cylinders are now equipped with pressure relief blowout disks, to guard against cylinder rupture in case outage is not taken and the cylinders are inadvertently overheated. Theoretically, this is an excellent safety precaution and may even be required in many cases to satisfy safety regulations. However, it has been the experience of some commercial PVT laboratories that pressure relief blowout disks result in failure (the disk ruptures inadvertently and the fluid sample is lost) in about one out of ten samples. The experience using cylinders without the pressure relief blowout disks is about one lost sample out of 1000 samples. Therefore, if blowout disks are installed in the sample containers, and it would be difficult to resample in case some samples are lost, it is recommended that at least four sets of samples be collected to lower the risk of sample loss.

6.3.6 Sampling Apparatus

An adequate sampling apparatus (rig) is shown in Figure 8, including high-pressure flexible tubing (or high-pressure hose), valves, pipe nipples, pressure-gauge, and connectors. The pressure gauge range should be selected according to the sample point pressure, and should be checked to confirm that it is indicating accurately.

Note: If the rig is used for collecting both gas and liquid samples, the gas samples should always be collected first, since any minor cross-contamination of samples due to accumulation of fluid in the rig would affect gas samples much more than liquid samples.

It is necessary for the entire sampling rig (tubing, valves, gauges, connectors, nipples, etc.) to be rigorously cleaned with appropriate solvents and blown dry with bottled nitrogen (or dry filtered oil-free compressed air) before using it to collect gas samples. Additional cleaning is not necessary between gas sampling and oil sampling. A preferred method is to use separate rigs for the gas and oil samples.

The length of the high-pressure flexible tubing (see Figure 8) should be just long enough to allow connecting the sampling rig to the selected sampling points on the separator (see Figure 7) while the sample cylinders are safely secured in a convenient location. Excess length of the high-pressure flexible tubing only adds dead volume to the system and increases pressure drop when collecting the samples.

Note: Some operators prefer small-bore tubing ($1/16$ " ID by $1/8$ " OD stainless steel) for extremely small dead volume while others prefer somewhat larger diameter high-pressure hose for connecting the sampling rig to the gas or liquid sampling points.

Also, if the gas or liquid to be sampled contains hydrogen sulfide (H_2S), additional equipment should be brought to the sample site (e.g., a long line through which the sample can be vented away from personnel; or chemical treatment methods provided, such as caustic bath or solid adsorbent to remove the H_2S before any stream is vented to the atmosphere). This equipment should be specifically designed for H_2S service and to meet the requirements for sampling H_2S -containing fluids. Included should be H_2S detectors/monitors and supplemental personnel breathing apparatus. The safety aspects of working with H_2S should be thoroughly reviewed (see Appendix A) prior to initiating the sampling program.

Small portable plastic hand-operated vacuum pumps (or explosion-proof electrical vacuum pumps) are available which can be easily carried to the field and used to evacuate the lines and the sampling rig (connected through the purge valve). The use of such a vacuum pump eliminates the need for the initial gas purge to the atmosphere. However, these hand-operated vacuum pumps do not have the volume capacity or adequate seals to check the vacuum on large cylinders. As mentioned above, testing pre-evacuated vessels for adequate vacuum at the time of sampling should be done only by personnel well trained in vacuum testing procedures.

6.3.7 Separator Gas Sampling Methods

Four methods are described below which, under proper conditions, will secure a representative gas sample. The best method to use at a particular location will depend upon the local conditions and the experience of the sampling personnel. In general, however, the methods described below are given in order of their expected success in field operations. For each method described, the sample containers, sampling rig, and connecting tubing must be capable of safely withstanding the pressure imposed on them during sampling. If not, the method must be modified to prevent over-pressuring the equipment. Equipment should be designed with a safety factor of at least four (burst pressure rating of equipment ≥ 4 times separator pressure).

Before departing for the sampling site, prepare the necessary equipment such as that shown in Figure 8 (see 6.3.6), including the high-pressure flexible tubing or hose, valves, pressure gauge, and connectors. If piston-type containers are to be used, make sure that they are properly pre-loaded with hydraulic fluid (or water if applicable) behind the piston.

6.3.7.1 Gas Method No. 1: Filling an Evacuated Container

This method is especially simple and accurate. The principal undesirable feature of the method is the requirement that the vessel be evacuated before its transport to the sampling point (with possible loss of vacuum during transport) or that a vacuum pump be provided at the well site. Testing pre-evacuated vessels for adequate vacuum at the time of sampling should be done only by personnel well trained in vacuum testing procedures, since improper testing often leads to loss of vacuum or introduction of air into the sample vessel. (Collecting an additional sample may be preferable to vacuum testing.) A clean, evacuated container should never be purged with separator gas and re-evacuated in the field, since any liquid that condenses in the container during the purge may not totally re-evaporate during evacuation in the field.

Sample collection is accomplished by the following steps:

- Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired sample can be collected. Clean any debris from the valve A; open the valve briefly to blow it out, then close it.
- Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.
- If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C, open valve C and valve B to evacuate the sampling rig, then close valve C and disconnect the pump. Slowly reopen valve

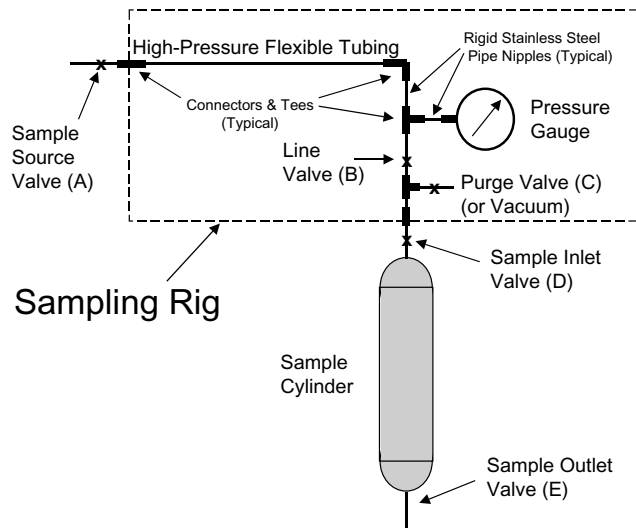


Figure 8—Diagram of Sampling Apparatus

A completely to establish full separator pressure on the entire sampling rig from valve A to valve D and proceed to step f.

d. If a vacuum pump is not available, open valves B and C, then open and close valve A in one quick burst to purge air from the sampling rig, and quickly close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Open valve C, then open and close valve B in one quick burst to purge air from the line connecting valves B and D, and close valve C promptly.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

Reopen valve B to establish full separator pressure on the entire sampling rig from valve A to valve D.

f. Cautiously crack open valve D, while carefully monitoring the pressure gauge, and fill the container slowly. Continuously adjust valve D, as needed, to keep full pressure on the pressure gauge. Filling a large container can take as long as 20 min. Progress of the filling process can be monitored by listening for a hissing sound at valve D (and in the container), and by monitoring the pressure gauge. When you think the container is full, open valve D further while listening to the container and monitoring the pressure gauge.

g. When the container is full, close valve D and then close valve B.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under full pressure. Also, refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

i. Disconnect the sample container. This is the last step in collecting the first sample. The apparatus is now ready for collecting additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from valve A.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

k. Insert sealing plugs into the valves on each sample container; then check the valves for leaks by immersing them in water or painting them with soap solution. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope. After a container is determined to be leak-free, it should be tagged and otherwise prepared for storage or transit.

6.3.7.2 Gas Method No. 2: Filling a Piston-type Container

This is a preferred method for non-mercury gas sample handling if other non-mercury transfer vessels are not available in the laboratory and repressurization is needed. Sample containers are available that contain a floating piston that separates the sample side from the hydraulic-oil side of the container. Use of these containers has the advantage of permitting samples to be maintained at full separator pressure, and to be transferred in the laboratory at full pressure. This type container is required for a mercury-free laboratory if other non-mercury transfer vessels (or oil-less compressors) are not available. A disadvantage is the possibility of contamination of the sample with hydraulic fluid, if the seal on the piston leaks. (Water can be used as the hydraulic fluid to minimize the possibility of contamination, but the operator should first check with the manufacturer to ensure that water will not damage the container.)

If a piston-type container is being used, hydraulic fluid must be pre-loaded behind the piston so that the piston position is fully toward the sampling end. A danger is that inexperienced personnel may not know this, and would attempt to use this type container without a proper fill of hydraulic fluid. In such a case, full pressure will not be maintained on the gas during sampling and the process will be essentially the same as filling an empty container, except the seal on the piston might leak. Check with the manufacturer's instructions so that the operation of the piston-type container is completely understood before commencing the sampling operation.

This sampling technique is as follows:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired sample can be

collected. Clean any debris from the valve A; open the valve briefly to blow it out, then close it.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.

c. If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C, open valve C and valve B to evacuate the sampling rig, then close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B. Open valve D to evacuate the connection and the small dead volume in the container (the internal volume between valve D and the face of the piston when the piston position is at the sampling end), then close valve C and disconnect the pump. Slowly reopen valve B completely to establish full separator pressure on the entire system from valve A to the face of the piston in the container, and proceed to step f.

d. If a vacuum pump is not available, open valves B and C, then open and close valve A in one quick burst to purge air from the sampling rig, and quickly close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Fully open valve D and valve C, then open and close valve B in one quick burst to purge air from the line connecting valves B and D, and the dead volume in the sample container, and close valve C promptly.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

Reopen valve B to establish full separator pressure on the entire sampling rig from valve A through valve D to the face of the piston in the sample container.

f. Cautiously crack open sample outlet valve E, while carefully monitoring the pressure gauge, and allow the incoming gas sample to slowly displace hydraulic oil into a suitable collection vessel. Continuously adjust valve E, as needed, to be sure that the rate of sample collection is sufficiently slow so that full separator pressure is maintained on the sample side of the piston (as indicated by the pressure gauge).

g. The sampling operation can be ended when a desired volume of sample is collected (as indicated by a given volume of hydraulic fluid being displaced to the collection vessel) or by the piston reaching the bottom of the sample container (as indicated by hydraulic fluid ceasing to flow from valve E). Close valves E, D, and B, in that order.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under full pressure. Also, refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

i. Disconnect the sample container. This is the last step in collecting the first sample. The apparatus is now ready for collecting additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from valve A.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

k. Insert sealing plugs into the valves on each sample container; then check the valves for leaks by immersing them in water or painting them with soap solution. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope. After a container is determined to be leak-free, it should be tagged and otherwise prepared for storage or transit.

6.3.7.3 Gas Method No. 3: Purging with Separator Gas

If evacuated or piston-type sample containers are not available, samples can be taken by the gas-purge method. In this method, either (a) separator gas is allowed to flow through the container to purge air from the container (also called the sweep method) or (b) the container is filled with separator gas, then purged to atmospheric pressure several times to remove the air. In either case, the sample is collected following the purging operation.

The purge method is considered clearly inferior to methods Nos. 1 and 2, above, since the potential exists for liquids to condense in the container and accumulate during the purge period(s). If condensation occurs, the liquid tends to stick to the container walls and not be fully displaced from the container. The result will be a sample which contains a disproportionately high concentration of heavy ends.

If the purge method is used, it is mandatory that the sample lines and container be maintained at a temperature higher than the separator temperature in order to minimize the potential for partial condensation of the separator gas. Even this is not completely fool-proof, since condensation can occur due to cooling from the throttling (pressure drop) that occurs across the sample inlet valve D. The sampling steps for the sweep method are given below:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired sample can be collected. Clean any debris from the valve A; open the valve briefly to blow it out, then close it.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.

c. If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C,

open valve C and valve B to evacuate the sampling rig, then close valve C and disconnect the pump. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve D and proceed to step f.

d. If a vacuum pump is not available, open valves B and C, then open and close valve A in one quick burst to purge air from the sampling rig, and quickly close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Open valve C, then open and close valve B in one quick burst to purge air from the line connecting valves B and D, and close valve C promptly.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

Reopen valve B to establish full separator pressure on the entire sampling rig from valve A to valve D.

f. Cautiously crack open valve D, while carefully monitoring the pressure gauge, and fill the container slowly. Continuously adjust valve D, as needed, to keep full pressure on the pressure gauge. Filling a large container can take as long as twenty min. Progress of the filling process can be monitored by listening for a hissing sound at valve D (and in the container), and by monitoring the pressure gauge. When you think the container is full, open valve D further while listening to the container and monitoring the pressure gauge. Open valve D completely.

g. Slightly open valve E and permit gas to flow through the sample container; be sure the flow rate is sufficiently low so that full pressure is always shown on the pressure gauge.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

After several container volumes of gas have passed through the container, close valves E, D, and B, in that order.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under full pressure.

i. Disconnect the sample container. This is the last step in collecting the first sample. The apparatus is now ready for collecting additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from valve A.

Note: Refer to the comments in 6.3.6 about using a long vent line on valve C if H₂S is present.

k. Insert sealing plugs into the valves on each sample container; then check the valves for leaks by immersing them in water or painting them with soap solution. Before inserting

the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope. After a container is determined to be leak-free, it should be tagged and otherwise prepared for storage or transit.

6.3.7.4 Gas Method No. 4: Displacing a Liquid

This method consists of collecting the gas sample by displacing a liquid from an initially liquid-filled sample container. The advantage of this method is that the gas sample is collected at full pressure (just like filling a piston-type container as described in 6.3.7.2); therefore, there is no cooling from throttling and no liquids condense due to pressure drop. The disadvantage of this method is that the liquids typically used (brine, glycol, water) can preferentially absorb (dissolve) certain components from the gas into the liquid, thereby altering the gas sample. In particular, carbon dioxide and hydrogen sulfide are much more soluble in these liquids than are the hydrocarbon components of the gas.

However, if free-draining containers are used (those with a design in which liquid can not get trapped in a depression around the exit port), and the container is maintained in a vertical position during gas sampling, essentially all of the liquid can be drained out. Additional gas (at full separator pressure) is then allowed to flow down through the container to purge out gas that may have been altered by contact with the liquid. Finally, proceed with steps h – k of 6.3.7.3.

These steps are essentially identical to those of Gas Method No. 2 (see 6.3.7.3), except for the extra gas purge step, as described above.

If free-draining design containers are not available, the liquid displacement method is not recommended for gas sampling because of the reasons discussed previously.

6.3.8 Separator Liquid Sampling Methods

Five procedures will be described for taking hydrocarbon liquid (oil or condensate) samples at the separator. The objective of all methods is to obtain a sample of the separator oil with no loss of dissolved gas, as described in 6.3.1, and to avoid entrapping any extraneous contaminating gas or other liquid.

Some containers have dip tubes, connected internally to only one exit port. These are not recommended since their operation can be confusing to the user, unless they are recognized and their configuration clearly understood.

At the conclusion of any oil sampling operation, a vapor space (“outage” volume) must be provided in the oil sample container to provide a compressible cushion to prevent leakage from excessive pressure if the temperature of the container should increase. This is in addition to the use of pressure relief devices, as required to meet shipping regulations. However, the creation of this vapor space must be done without altering the overall composition of the fluid in the container.

Before departing for the sampling site, prepare the necessary equipment as shown in Figure 8 (see 6.3.6), including the high-pressure flexible tubing, valves, pressure-gauge, and connectors. If piston-type containers are to be used, make sure that they are properly pre-loaded with hydraulic fluid behind the piston.

For each method described, the sample containers, sampling rig, and connecting tubing must be capable of safely withstanding the pressure imposed on them during sampling operations. If not, the method must be modified to prevent over-pressuring the equipment. Equipment should be designed with a safety factor of at least four (burst pressure rating of equipment ≥ 4 times separator pressure).

The best sampling method at a particular location will depend upon the local conditions and the experience of the sampling personnel. In general, however, the methods described below are presented in order of their expected success in field operations.

6.3.8.1 Oil Method No. 1: Displacing a Liquid

This method consists of collecting a sample by displacing a liquid that is insoluble in the oil (typically water, glycol-water mixture, or brine) from a sample container initially pre-loaded with the liquid to be displaced. This method has the same drawbacks described in 6.3.7.4. However, it is judged the easiest and safest method for most personnel to follow, particularly those personnel inexperienced in the Evacuated Container Method. The steps are similar to those described in 6.3.8.3:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired oil sample can be collected. Clean any debris from valve A, hold a rag over the valve (or attach a temporary purge line connected to a suitable container), open valve A slowly, purge sufficient oil through the valve, and then close valve A. Remove the rag or temporary purge line.

Note: Refer to the comments in 6.3.6 about using a long vent line if H_2S is present.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.

c. If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C, open valve C and valve B to evacuate the sampling rig, then close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B. Open valve D to evacuate the connection and any dead volume above the liquid in the container, then close valve C and disconnect the pump. Slowly reopen valve B completely to establish full separator pressure on the entire system from valve A to the liquid in the container, and proceed to step f.

d. If a vacuum pump is not available, close valve B and open valve A slowly (the pressure on the gauge should rise to the separator pressure). Close valve A, attach a purge line at the end of the rig below valve C, close valve C, and open valve B to let the pressure deplete to atmospheric. Close valve B, then slowly reopen valve A completely. Slightly open valve B and slowly purge a volume of oil equivalent to several times the volume of the sampling rig, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve B and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8 and attach a purge line at the end of valve C. Open valve D, close valve C, and open valve B slowly to pressure up the connection with the container and any dead volume above the liquid in the container. Close valve B and open valve C to let the pressure deplete to atmospheric. Close valve C, then slowly reopen valve B completely. Slightly open valve C and slowly purge a volume of oil equivalent to several times the volume of the connection, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve C and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to the pre-load liquid in the container. Be sure that valve D is left completely open.

f. Cautiously crack open sample outlet valve E and allow the sample fluid to slowly displace the pre-load liquid into a suitable collection vessel. Continuously adjust valve E, as needed, to be sure that the rate of sample collection is sufficiently slow to keep full pressure in the container (as indicated by the pressure gauge). The operation must be stopped with at least enough pre-load liquid left in the container to provide the "outage" required in step g, below. Close valves E, D, and B, in that order.

g. Open valve E slightly (with valve D closed) and drain into the collection vessel the remaining volume of pre-load liquid equal to approximately 10% of the container volume. Be very alert to rapidly close valve E when the first drop of oil sample exits (usually indicated by a hiss from the solution gas escaping to the atmosphere). This will create the necessary vapor space in the container, without altering the overall composition of the oil sample. Close valve E securely.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under pressure. Also, refer to the comments in 6.3.6 about using a long vent line if H_2S is present.

i. Disconnect the sample container. This is the last step for the first sample and leaves the apparatus ready for collection of additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from source valve A.

k. Wipe the valves on the sample container clean and inspect for any signs of leakage. After a container is determined to be leak-free, insert plugs in the valves, then tag the container and otherwise prepare it for storage or transit. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope.

6.3.8.2 Oil Method No. 2: Filling an Evacuated Container

This method can yield excellent samples. The principle draw-backs of the method are (a) the requirement that the vessel be evacuated before its transport to the sampling point (with possible loss of vacuum during transport) or that a vacuum pump be provided at the well site, (b) that inexperienced sampling personnel tend to be impatient (and not rock the container during the filling process) and thereby do not collect sufficient volume of liquid sample in the container due to initial gas break-out when the oil encounters the reduced pressures in the container, (c) transfer of the oil from the container at the laboratory requires injection of some transfer fluid (e.g., mercury or water) and (d) taking outage may alter the composition of the sample.

Because of the possibility of collecting less than a full container of oil with this method, it is advised that extra containers be collected if there is any doubt about obtaining sufficient volume. Again, check with laboratory personnel about the oil volume requirements. This method is not recommended for collecting samples of very low pressure and/or very heavy (low API gravity) oils.

The sampling steps are as follows:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired oil sample can be collected. Clean any debris from valve A, hold a rag over the valve (or attach a temporary purge line connected to a suitable container), open valve A slowly, purge sufficient oil through the valve, and then close valve A. Remove the rag or temporary purge line.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.

c. If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C, open valve C and valve B to evacuate the sampling rig, then close valve B. Slowly reopen valve A completely to establish full separa-

tor pressure on the entire sampling rig from valve A to valve B. Open valve C to evacuate the connection to valve D, then close valve C and disconnect the pump. Slowly reopen valve B completely to establish full separator pressure on the entire system from valve A to valve D, and proceed to step f.

d. If a vacuum pump is not available, close valve B and open valve A slowly (the pressure on the gauge should rise to the separator pressure). Close valve A, attach a purge line at the end of the rig below valve C, close valve C, and open valve B to let the pressure deplete to atmospheric. Close valve B, then slowly reopen valve A completely. Slightly open valve B and slowly purge a volume of oil equivalent to several times the volume of the sampling rig, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve B and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8 and attach a purge line at the end of valve C. Close valve C, and open valve B slowly to pressure up the connection to valve D. Close valve B and open valve C to let the pressure deplete to atmospheric. Close valve C, then slowly reopen valve B completely. Slightly open valve C and slowly purge a volume of oil equivalent to several times the volume of the connection, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve C and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve D.

f. Slightly open valve D on the sample container and allow the oil to enter the container. Continuously adjust valve D to be sure that the rate of sample collection is sufficiently slow so that full separator pressure remains on the upstream side of valve D (as indicated by the pressure gauge). During the filling process, rock the container many times (approximately 45 degrees above and then 45 degrees below horizontal) to agitate the liquid and increase its contact with the evolved solution gas. As the container is filled, the internal pressure will gradually increase and the amount of gas phase will diminish as the gas re-dissolves into the oil. When sampling is thought to be complete, open valve D further and rock the container additional times. Determining when the flow into the sample container is complete is difficult, so patience is required. When sampling is complete, close valves D and B.

Note: At all times during the sampling process, the sample line and container should be maintained at a temperature equal to or slightly lower than that in the separator, in order to avoid excessive partial vaporization of the oil. Usually, there is no need to take outage on the sample, since the gas which evolves inside the container will generally not go completely back into solution in the oil in the time period required for sampling. If this has been the case, do not take outage and proceed to step h. However, if the container temperature is more than 10°F below separator temperature, the container may completely fill with liquid, particularly if the container is rocked dur-

ing collection of the sample. In such cases, outage should be taken as described in step g, below.

g. To take outage, orient the container in a vertical position, keep valve D closed and quickly open and close valve E in one quick burst to drain some oil from the bottom of the container. The drained oil should amount to only about 2% – 10% of the container contents. This process will cause the oil in the container to partially vaporize, but if the operation is done rapidly (and only once) as described above, there will not be time for gravity segregation and there will be minimal change in overall composition of the original oil in the container.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under pressure. Also refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

i. Disconnect the sample container. This is the last step for the first sample and leaves the apparatus ready for collection of additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from source valve A.

k. Wipe the valves on the sample container clean and inspect for any signs of leakage. After a container is determined to be leak-free, insert plugs in the valves, then tag the container and otherwise prepare it for storage or transit. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope.

6.3.8.3 Oil Method No. 3: Filling a Piston-type Container

This is a preferred method for non-mercury liquid sample collection. It has the advantages that the liquid sample can be kept at the saturation pressure throughout the collection process, which avoids gas break-out from the sample. In addition, the sample does not come into contact with any other fluids during sampling or during transfer in the laboratory. The undesirable feature of the method is that with sample containers, the potential for contamination with hydraulic fluid exists if the seal on the piston leaks. (Water can be used as the hydraulic fluid to minimize the possibility of contamination, but the operator should first check with the manufacturer to ensure that water will not damage the container.)

If a piston-type container is being used, hydraulic fluid must be pre-loaded behind the piston so that the piston position is fully toward the sampling end. A danger is that inexperienced personnel may not know this, and would attempt to use this type container without a proper fill of hydraulic fluid and without proper hydraulic pressure support on the piston seal. In such a case, full pressure will not be maintained on the separator oil during sampling and the process will be essentially the same as filling an empty container, except the

seal on the piston might leak. The manufacturer's instructions should be consulted to ensure that the operation of the piston-type container is completely understood before commencing the sampling operation.

The method is essentially identical to that described in 6.3.8.1 for oil sampling by displacing a liquid. The procedure is the following:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired oil sample can be collected. Clean any debris from valve A, hold a rag over the valve (or attach a temporary purge line connected to a suitable container), open valve A slowly, purge sufficient oil through the valve, and then close valve A. Remove the rag or temporary purge line.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator. Open the line valve B and open the purge valve C.

c. If a vacuum pump is available and personnel are qualified in vacuum techniques, connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8. Connect the vacuum pump to valve C, open valve C and valve B to evacuate the sampling rig, then close valve B. Slowly reopen valve A completely to establish full separator pressure on the entire sampling rig from valve A to valve B. Open valve D to evacuate the connection and the small dead volume in the container (the internal volume between valve D and the face of the piston when the piston position is at the sampling end), then close valve C and disconnect the pump. Slowly reopen valve B completely to establish full separator pressure on the entire system from valve A through valve D to the face of the piston in the container, and proceed to step f. Be sure that valve D is completely open.

d. If a vacuum pump is not available, close valve B and open valve A slowly (the pressure on the gauge should rise to the separator pressure). Close valve A, attach a purge line at the end of the rig below valve C, close valve C, and open valve B to let the pressure deplete to atmospheric. Close valve B, then slowly reopen valve A completely. Slightly open valve B and slowly purge a volume of oil equivalent to several times the volume of the sampling rig, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve B and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8 and attach a purge line at the end of valve C. Open valve D, close valve C, and open valve B slowly to pressure up the connection with the container and any dead volume in the sample container. Close valve B and open valve C to let the pressure deplete to atmospheric. Close valve C, then slowly reopen

valve B completely. Slightly open valve C and slowly purge a volume of oil equivalent to several times the volume of the connection, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve C and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A through valve D to the face of the piston in the sample container. Be sure that valve D is completely open.

Note: This method is not perfect because the oil in the dead volume in the sample container has not been purged under pressure. However, if the piston position is fully toward the sampling end of the container, the amount of oil in the dead volume will be negligible.

f. Cautiously crack open sample outlet valve E, while carefully monitoring the pressure gauge, and allow the sample fluid to slowly displace the pre-load hydraulic oil into a suitable collection vessel. Continuously adjust valve E, as needed, to be sure that the rate of sample collection is sufficiently slow so that full separator pressure is maintained on the sample side of the piston (as indicated by the pressure gauge). The sampling operation can be ended when a desired volume of sample is collected (as indicated by a given volume of hydraulic fluid being displaced to the collection vessel). The operation must be stopped with at least enough pre-load liquid left in the container to provide the “outage” required in step g, below. Close valves E, D, and B, in that order. (If the container has a magnetic indicator to show the position of the piston, then nitrogen gas can be used as the hydraulic fluid behind the piston, and step g can be eliminated so long as approximately 10% volume of nitrogen remains on the hydraulic side of the piston.)

g. Open valve E slightly (with valve D closed) and drain into the collection vessel a volume of hydraulic oil equal to approximately 10% of the container volume. This will create the necessary vapor space in the container without altering the overall composition of the oil sample. (Be sure to leave at least some hydraulic oil behind the piston so that there is pressure support on the seal and very little pressure drop across the seal). Close valve E securely.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under pressure. Also, refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

i. Disconnect the sample container. This is the last step for the first sample and leaves the apparatus ready for collection of additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from source valve A.

k. Wipe the valves on the sample container clean and inspect for any signs of leakage. After a container is determined to be leak-free, insert plugs in the valves, then tag the container and

otherwise prepare it for storage or transit. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope.

6.3.8.4 Oil Method No. 4: Purging with Separator Oil

This method consists of filling an unpurged container from the bottom with separator oil until it is at separator pressure (the container must be vertically oriented). The top valve is then opened very slightly, and oil is permitted to flow up through the container to displace the air and air-contaminated oil. Care must be taken to maintain the pressure in the container equal to the separator pressure during the purge to prevent loss of dissolved gas from the system. A suitable length of connecting hose (purge line) should be available to transmit the effluent oil from the container to a suitable collection vessel.

After at least two container volumes of oil have been displaced out the top valve, the valves are closed (top valve first). For outage, a gas cap may be created by quickly releasing a portion of the sample from the bottom valve while the container is in a vertical position (identical to step g of 6.3.8.2). This method is capable of yielding representative samples. Its main disadvantages are (a) it is considerably messier than other methods due to the production of several container volumes of waste oil, (b) outage must be taken, which can alter the sample composition, and (c) if the separator “oil” is a light condensate, most of it may vaporize when purging from the container and it will be very difficult to determine the actual high-pressure volume displaced. Its main advantages are (1) its simplicity and (2) avoiding contamination by another fluid.

The steps in this method are essentially identical to those described in 6.3.7.3 for the purge method of gas sampling, except that the container is inverted to fill from the bottom and outage must be taken. The detailed sampling steps for purging with separator oil are given below:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired oil sample can be collected. Clean any debris from valve A, hold a rag over the valve (or attach a temporary purge line connected to a suitable container), open valve A slowly, purge sufficient oil through the valve, and then close valve A. Remove the rag or temporary purge line.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator.

c. A vacuum pump is not needed for this method since purging is used.

d. Close valve B and open valve A slowly (the pressure on the gauge should rise to the separator pressure). Close valve A, attach a purge line at the end of the rig below valve C, close valve C, and open valve B to let the pressure deplete to atmo-

spheric. Close valve B, then slowly reopen valve A completely. Slightly open valve B and slowly purge a volume of oil equivalent to several times the volume of the sampling rig, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve B and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8 and invert the container so that it is positioned vertical with the sample outlet valve E on top. Close valve C, close valve E, open valve D, and open valve B slowly to pressure up the container. Be sure that valve D is completely open. Attach a purge line to the top of valve E.

f. Cautiously crack open sample outlet valve E and allow at least two container volumes of oil sample to be slowly displaced through the container into a suitable drain or collection vessel. Continuously adjust valve E, as needed, to be sure that the rate of sample collection is sufficiently slow to keep full pressure in the container (as indicated by the pressure gauge). Close valves E, D, and B, in that order.

g. To take outage, return the container to the initial vertical position with valve E down, keep valve D closed, and quickly open and close valve E in one quick burst to drain some oil from the bottom of the container. The drained oil should amount to only about 2% – 10% of the container contents. This process will cause the oil in the container to partially vaporize, but if the operation is done rapidly (and only once) as described above, there will not be time for gravity segregation and there will be minimal change in overall composition of the original oil in the container. Close valve E securely.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under pressure. Also, refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

i. Disconnect the sample container. This is the last step for the first sample and leaves the apparatus ready for collection of additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from source valve A.

k. Wipe the valves on the sample container clean and inspect for any signs of leakage. After a container is determined to be leak-free, insert plugs in the valves, then tag the container and otherwise prepare it for storage or transit. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope.

6.3.8.5 Oil Method No. 5: Displacing Separator Gas

This method consists of displacing separator gas from the sample container with the separator oil. The sample container

is first pre-filled with separator gas. To accomplish this, the sample container is connected to a suitable gas-sampling point on the separator and gas is allowed to flow at a moderate rate through the container to displace the air in a manner similar to that described in 6.3.7.3. The container should be in a vertical position with the gas entering at the top and displacing the air out the bottom.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

Purging the container at a moderate rate and flowing the gas through it in a vertically downward direction will help to prevent the accumulation of liquid hydrocarbons in the container in an amount that could significantly contaminate the liquid sample taken subsequently (which is the major disadvantage of this method).

When the container has been thoroughly purged, close the container outlet valve, allow the gas pressure to build up to separator pressure, and close the inlet valve. The container may then be disconnected (after releasing pressure in the connecting line) and moved to the liquid sampling point. Repeat the above steps to pre-fill all liquid sample containers with separator gas. The liquid sampling can then be done as follows:

a. Locate an appropriate sample source valve A on the separator (see Figure 7) from which the desired oil sample can be collected. Clean any debris from valve A, hold a rag over the valve (or attach a temporary purge line connected to a suitable container), open valve A slowly, purge sufficient oil through the valve, and then close valve A. Remove the rag or temporary purge line.

Note: Refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

b. Connect the fitting on the flexible tubing of the sampling rig (see Figure 8) securely to valve A on the separator.

c. A vacuum pump is not needed for this method.

d. Close valve B and open valve A slowly (the pressure on the gauge should rise to the separator pressure). Close valve A, attach a purge line at the end of the rig below valve C, close valve C, and open valve B to let the pressure deplete to atmospheric. Close valve B, then slowly reopen valve A completely. Slightly open valve B and slowly purge a volume of oil equivalent to several times the volume of the sampling rig, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve B and remove the purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve B.

e. Connect the sample inlet valve D on the sample container to the fitting on the sampling rig, as shown in Figure 8 and invert the container so that it is positioned vertical with the sample outlet valve E on top (liquid sample will enter the bottom and gas will exit from the top of the container.). Valve D will be closed, since the container is already pre-filled with separator gas. With valve C closed, open valve B slowly to

pressure up the connection to valve D. Close valve B and open valve C to let the pressure deplete to atmospheric. Close valve C, then slowly reopen valve B completely. Slightly open valve C and slowly purge a volume of oil equivalent to several times the volume of the connection, collecting the purged oil in a suitable container (maintain full separator pressure on the pressure gauge during this purge). Close valve C and remove the oil purge line. Full separator pressure should now be on the entire sampling rig from valve A to valve D. Carefully open valve D completely and allow the separator oil to contact the full pressure equilibrium separator gas in the sample container.

f. Cautiously crack open sample outlet valve E and allow the separator oil to slowly displace the separator gas from the container. Continuously adjust valve E, as needed, to be sure that the rate of sample collection is sufficiently slow to keep full pressure in the container (as indicated by the pressure gauge). Close valve E when liquid first appears at this outlet, then close valves D and B.

g. To take outage, return the container to the initial vertical position with valve E down, keep valve D closed, and quickly open and close valve E in one quick burst to drain some oil from the bottom of the container. The drained oil should amount to only about 2% – 10% of the container contents. This process will cause the oil in the container to partially vaporize, but if the operation is done rapidly (and only once) as described above, there will not be time for gravity segregation and there will be minimal change in overall composition of the original oil in the container. Close valve E securely.

h. Slightly open valve C to bleed the connections between valves B and D to atmospheric pressure.

Note: The line from valve A to B, including the pressure gauge, is still under pressure. Also, refer to the comments in 6.3.6 about using a long vent line if H₂S is present.

i. Disconnect the sample container. This is the last step for the first sample and leaves the apparatus ready for collection of additional samples, by repeating steps e – h.

j. Following collection of the last sample, close valve A securely, then open valve B (and valve C if it is not already open) to bleed pressure from all parts of the line and sampling rig before disconnecting the line from source valve A.

k. Wipe the valves on the sample container clean and inspect for any signs of leakage. After a container is determined to be leak-free, insert plugs in the valves, then tag the container and otherwise prepare it for storage or transit. Before inserting the sealing plugs, the threads should be lubricated by stretching Teflon[®] tape into the threads, or by applying pipe dope.

6.3.9 Problems in Sampling Liquids

Conditions can occur that complicate the sampling operation, including (a) the separator temperature can be lower than ambient sampling temperature outside the separator, (b) the oil can contain carbon dioxide and/or hydrogen sulfide, or

(c) the reservoir oil can contain significant concentrations of paraffins (waxes) or asphaltenes.

When the separator temperature is lower than ambient, the sample container should be cooled to a temperature below that of the separator to ensure the collection of a sample that is representative (and sufficient in amount). If the container temperature is higher than the separator liquid temperature, the sample will flash in the container, causing part of the container volume to be filled with vapor and the amount of liquid will be reduced. Such a circumstance can result in an insufficient volume of sample. Care must be taken to avoid loss of the flashed vapors or a non-representative sample will result. (This is not a problem when using the evacuated container or the piston-type container methods).

If the separator oil temperature is between 35°F and 0°F (2 and –18°Celsius), the sample container can be cooled below separator temperature by immersion in a mixture of concentrated brine and crushed ice. Temperatures as low as 0°F (–18°C) can be attained. The temperature of the brine should be checked with a dependable thermometer to know that its temperature is below separator oil temperature.

Hydrogen sulfide and carbon dioxide can react with the container walls in the presence of water in the same manner as described for gas samples. Thus, sample containers for liquids (and gases as well) should be constructed of corrosion-resistant metal such as the non-magnetic 300-series stainless steels (e.g., 316ss), inconel, monel, MP35N or titanium alloy.

Note: If titanium is used, be sure that cadmium plated tools or mercury do not come in contact with the titanium.

Reservoir oils containing components that can precipitate as a solid phase are particularly difficult to sample accurately. Paraffinic and asphaltenic oils may form deposits in the reservoir, in the wellbore and/or in the separator. In general, the paraffins tend to precipitate upon cooling and upon loss of solution gas (e.g., due to pressure drop in the reservoir, wellbore or separator). Asphaltenes generally, but not always, tend to precipitate upon cooling and on contact with lighter hydrocarbon fluids. Further, they may deposit in the reservoir on pressure reduction, even in an undersaturated oil. From a sampling standpoint, precautions to prevent loss of these components from the oil include minimizing pressure and temperature drops in the reservoir, wellbore, separator and in the lines to the sample container. Piston-type subsurface samplers are now available with a special high-pressure nitrogen “hydraulic fluid” so as to maintain high-pressure on the fluid sample until it is received in the laboratory. Sampling of these types of oils is difficult, and the advice of experienced personnel should be sought if precipitation is anticipated.

6.3.10 Sampling Dry-gas Wells

On occasion, a reservoir gas will be so dry that no hydrocarbon liquid will condense at the lower temperature of the wellhead. When such is the case, the reservoir fluid sample

can be taken simply by sampling at the wellhead using one of the techniques previously described for taking a gas sample. The potential danger in this type of sampling is that it is often difficult to know prior to a laboratory study that the sample is definitely dry. Also, sampling equipment must be compatible with wellhead pressure and should be thoroughly clean and dry because even tiny quantities of liquid could lead to erroneous property measurement.

6.3.11 Sampling Highly Undersaturated Liquid-phase Reservoirs

Sometimes the reservoir pressure is so much higher than the saturation pressure of the reservoir fluid that even at the wellhead the pressure will still be high enough to prevent any gas from coming out of solution. In this case, the tubing is completely filled with unaltered reservoir oil, and a sample can be obtained at the wellhead using one of the techniques for taking separator oil samples. Again, the danger in this type of sampling is that it is difficult to know prior to laboratory study if the sample is undersaturated. As in 6.3.10, sampling equipment must be compatible with wellhead pressure.

6.3.12 Pressure and Temperature Surveys

After the separator samples are collected, the well may be shut-in and wellbore pressure and temperature surveys made. A pressure-buildup test can be run to determine reservoir pressure. These surveys may, however, be omitted if recent and accurate measurements are available and if the amount of production from the well since the last survey has been so small that the reservoir pressure has not changed appreciably. The techniques for making these surveys were described in 6.2.2.1 and 6.2.2.2.

7 Forms for Recording Well Conditioning and Sampling Data

The results of the laboratory examination of the samples will have maximum value if all pertinent data taken during the sampling effort are available to the laboratory personnel. These data aid laboratory personnel in conducting their examination and aid the engineers in interpreting more fully the laboratory results.

These forms (see Tables 1 – 9, beginning on page 39) can be used to record the pertinent data on the well which was sampled, to reflect the conditions of flow during well conditioning, and to describe the method and conditions of production processing used while conducting the sampling operation. Use of these forms will promote the collection and recording of pertinent data. Copies of the data forms filled out during the sampling operation, should accompany the samples to the laboratory.

8 Shipping and Cleaning Containers

8.1 SHIPPING RESERVOIR FLUID SAMPLES

Shipping considerations should be part of any fluid sampling program. Failure to comply with domestic and/or international regulations can have significant negative consequences, including holdup and/or confiscation of samples, monetary fines and other legal actions, as well as human injuries. In some cases, an individual can be held liable, even when representing a corporation.

Due in part to world-wide emphasis on environmental awareness, legal shipment of reservoir fluid samples has become increasingly complicated in recent years. Most, if not all, reservoir fluids are categorized as hazardous materials for shipping purposes. The construction and transportation of sample containers within the United States are provided in the Department of Transportation (DOT) Title 49 *Code of Federal Regulations (CFR) Part 173 (49 CFR 173)*, and are regulated by the DOT, the U.S. Coast Guard, and the Federal Aviation Administration. The entire document package is Title 49 *Code of Federal Regulations Parts 1 – End*. To obtain the Code, contact the Superintendent of Documents, U. S. Government Printing Office, Washington, D.C. 20402 (telephone: (202) 783-3238).

Compliance with DOT regulations does not ensure that regulations in foreign countries are met. In recent years, a gradual movement has occurred toward standardization of regulations throughout the international community. Internationally, shipments require UN specification packaging. UN specification packaging will supersede DOT regulations domestically in the next few years. However, at present, significant differences still exist between domestic and some international regulations. No attempt is made here to catalogue all international regulations. However, personnel involved in sampling must be aware that proper compliance with all applicable domestic and international shipping regulations is necessary, and this can require significant time, effort and expense.

8.2 CLEANING SAMPLE CONTAINERS

8.2.1 Cleaning Procedures for Surface Sample Containers

a. Carefully open the bottom valve of container and discard fluid contents into an appropriate drain or receiving container. Depressuring sample containers may produce low temperatures and high fluid velocities that must be considered. The use of protective breathing equipment and goggles are recommended, as appropriate.

Note: Refer to the comments in 6.3.6 and Appendix A about the precautions in case of H₂S.

b. Check regulatory (Interstate Commerce Commission or other regulatory body) date for pressure testing status of sam-

ple containers. If retesting is necessary, clean and send container to certified company for retesting. If qualified, retest in-house by hydrostatic testing procedure.

c. Remove valves from container. Completely disassemble valves, clean all parts thoroughly with appropriate solvent, and inspect all parts. Then either rebuild the used valves, or discard the used valves and obtain new valves.

d. Connect container to a heated pressurized circulating solvent system using two separate solvents. One heated (such as trichloroethane or toluene) to flush and clean out the oil, and another one cold (such as acetone or methanol) to clean out any water.

Note: Some operators are reportedly using hot (190°F) water and detergent in place of the first solvent flush.

e. (Optional) If a steam cleaner is available, it can be used following the first solvent cleaning. Steam clean the vertically oriented container for approximately one hour, or until clean. Then invert the container and continue steam cleaning for another two hours, or until clean. However, if analysis of sulfur compounds is anticipated with the samples to be collected, steam cleaning shall not be used to clean stainless steel containers.

f. Blow dry using low-pressure, dry, filtered air or dry bottled nitrogen.

g. (Optional) With valves removed, visually inspect the inside of the container. If hard carbon deposits or rust are visible, use a glass bead blaster to restore the interior of the container to like-new condition. Then repeat steps e and f.

h. Inspect the container threads and recondition if needed. Install rebuilt or new valves using Teflon[®] tape to seal the threads (stretch the tape into the threads).

i. Leak test the container (with valves installed) to its working pressure with water. Then flush with acetone or methanol, and blow dry with dry filtered air or nitrogen.

j. (Option) Leak test the container by injecting dry nitrogen. Then, submerge it in water to check for leaks. Vent the nitrogen and dry the container surface.

k. Evacuate the container to full vacuum (depending on sampling requirements).

l. Install plugs in the valves. First, stretch Teflon[®] tape onto the plug threads and then screw the plugs into the container valves.

m. Tag the container, and otherwise prepare it for storage or transit

8.2.2 Cleaning Procedures for Subsurface Sample Containers

Check with the sampling vendor and/or tool manufacturer. Subsurface samplers, particularly the modern piston-types and the formation tester-types have complex mechanisms and seals which require expert inspection and maintenance. Just make certain that the fluid sample chambers are free of any contaminants such as residue from previous samples, hydraulic oil, and cleaning solvents. Also, check with the sampling vendor and confirm that all seals have been replaced with new seals and that they will withstand the expected bottomhole temperature and pressure. Also, the seal materials must be able to withstand contact with the reservoir fluid (e.g., a highly aromatic condensate).

9 Safety

Precaution should be taken to ensure that safe practices are employed. All applicable Occupational Safety and Health Administration (OSHA) regulations should be consulted.

The sample containers, sampling rig, and connecting tubing must be capable of safely withstanding the pressure imposed on them during sampling operations. If not, the method must be modified to prevent over-pressuring the equipment. Surface sampling equipment should be designed with a safety factor of four (burst pressure rating of equipment ≥ 4 times separator pressure). Copper tubing and fittings can be hazardous. Copper plumbing should be used with caution and inspected frequently for bad connections, flattening, and kinks. Systems with pressures over 1000 psig or gas containing hydrogen sulfide (H₂S) should be plumbed with stainless steel tubing.

During sampling, sample transferring, and especially during purging, a total commitment to safety precautions is mandatory. Smoking, open flames, vehicles with engines running, and use of matches, in the area are not permitted. All electrical devices must be of explosion proof design. Caution must be exercised when purging and sampling to prevent forming a hazardous atmosphere. The use of protective breathing equipment and goggles is recommended, as appropriate. Special precautions should be taken if H₂S is present (see Appendix A).

Cylinders shall be protected from damage and checked for leaks prior to plugging. Over tightening valves with wrenches is unsafe. Hand tightening of valves is sufficient. Repair, replace, and test valves before use (see 8.2.1). Depressuring sample containers may produce low temperatures and high fluid velocities that must be considered.

Table 1—Reservoir and Well Information

Operator _____ Lease and Well No. _____
 Location, Field, County, State, Country _____

 _____ Sampling Date _____

Reservoir Information

Original Reservoir Pressure _____ (psig) at _____ (ft subsea) Date _____
 Original Reservoir Temperature _____ (°F) at _____ (ft subsea)
 Original Gas-oil Ratio _____ (cu ft/bbl)
 Field Base Conditions _____ (psia) _____ (°F)
 Source of this Reservoir Information _____

Well Information

Producing Formation Name _____ Completion Interval _____ (ft)
 Reference point for all depth measurements _____
 Elevation _____ (ft) Casing Set _____ (ft) Tubing Set _____ (ft) Tubing Diameter _____ (in.)
 Completion Date _____ Initial Production _____ (B/D)
 Cumulative Oil Production from Well _____ (bbl) Date _____
 Cumulative Water Production from Well _____ (bbl) Date _____
 Cumulative Gas Production from Well _____ (MMcf) Date _____

Well Information

	Date	Shut-in (hours)	Depth (ft)	Pressure (psig)	Temperature (°F)	Tank Oil Rate (B/D)
Orig. Shut-in Bottomhole Conditions	_____	_____	_____	_____	_____	_____
Current Shut-in Bottomhole Conditions	_____	_____	_____	_____	_____	_____
Current Flowing Conditions	_____	_____	_____	_____	_____	_____

Table 2—Gas Metering Inspections and Volume Calculations

Operator _____ Lease and Well No. _____

Field, County, State, Country _____

_____ Sampling Data _____

Meter Run Inspection

Meter Run: Proper Design (AGA) (Yes) _____ (No) _____ Thermometer Well (Yes) _____ (No) _____
 Constant Back-pressure Control (Yes) _____ (No) _____
 Meter Tap Connections: Flange _____ Pipe _____

Meter Inspection

Bourdon Tube: Rating _____ (psi) Date of Last Pressure Calibration _____ Differential Manometer: Range _____ (in.)
 Date of Last Differential Calibration _____ Does meter now zero properly? _____

Test Number _____
 Date _____
 Time _____

Separation Stages	1st	2nd	1st	2nd	1st	2nd	1st	2nd	1st	2nd
Separator Pressure (psig)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Separator Temperature (°F)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Meter Run ID (in.)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Orifice Diameter (in.)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Average Static Pressure (psig)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Average Differential (in. of water)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Average Flowing Temperature (°F)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Measured Gas Gravity (Air = 1.00)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Assumed Gas Gravity (Air = 1.00)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Average Atmospheric Temperature (°F)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____
Barometric Pressure (psia)	_____	_____	_____	_____	_____	_____	_____	_____	_____	_____

Factors Used in Computing Coefficient C (AGA Report No. 3)

$$C = F_b \times F_{pb} \times F_{tb} \times F_g \times F_{tf} \times F_r \times Y \times F_{pv} \times F_m$$

F_b (Basic Orifice Factor) _____
 F_{pb} (Pressure Base Factor) _____
 F_{tb} (Temperature Base Factor) _____
 F_g (Gas Gravity Factor) _____
 F_{tf} (Flowing Temperature Factor) _____
 F_r (Reynolds Number Factor) _____
 Y (Expansion Factor) _____
 F_{pv} (Supercompressibility Factor) _____
 F_m (Manometer Factor) _____
 C _____

Gas Volume

$$Q_b = C \sqrt{\frac{\text{(Static Press.)}}{\text{(psia)}} \times \frac{\text{(Differential)}}{\text{(in. of water)}}}$$

Daily Gas Volume (Mcf/D)

$$\left(\frac{24}{1,000} Q_b \right)$$

Remarks (Note deficiencies in the metering installation): _____

Data taken by _____ Data prepared by _____

Note: Attach meter charts (or copies) or explain why they cannot be attached.

Table 3—Gas and Oil Volume Data for Well Conditioning Period

Operator _____ Lease and Well No. _____
 Field, County, State, Country _____
 _____ Sampling Date _____
 Stock Tank No. _____ Tank Strapping _____ (bbl/in.)
 Volume of Calibrated Section of Separator _____ (bbl)
 Separator Liquid Metering (if used) _____
 Name and Type of Meter _____ Is water measured separately? _____ How? _____
 Temperature Compensated Meter: Yes _____ No _____ Date of Most Recent Meter Proving _____ Meter Factor _____

Date	Time	Wellhead Condition			Production in First-stage Separator										
		Choke Size (in.)	Pressure		Separation Fill Rate Oil Plus Water				Metered Rate Oil Plus Water		Water		Oil (B/D) ^a		
			Tubing (psig)	Casing (psig)	Temp. (°F)	(Min and Sec)	(bbl)	(B/D) ^a	Reading	(bbl)	(B/D) ^a	Measured or Metered (bbl)		(B/D) ^a	

Date	Time	Oil and Water Production in Stock Tank or Through Meter								
		Temperature (°F)	Oil Gravity (API)	Gage (ft) (in.)	Volume in Tank or Meter Reading (bbl)	Water Gage (ft) (in.)	Volume Water in Tank (bbl)	Oil Volume (bbl @ 60°F)	Oil (B/D) ^a	Water (B/D) ^a

Date	Time	Gas Production						
		Separator Gas Production (from Table 2)			Gas-oil Ratios			
		1st Stage (Mcf/D) ^b	2nd Stage (Mcf/D) ^b	Total (Mcf/D) ^b	1st Stage Separator Gas (cu ft per bbl 1st stage oil at separator temperature)	2nd Stage Gas (cu ft/bbl tank oil at 60°F)	Total Gas (cu ft/bbl tank oil at 60°F)	Oil Volume (bbl @ 60°F)

^a B/D indicates barrel per day.
^b Mcf/D is Mcf per day measured at _____ psia, _____ °F.
 Note: This form is intended for use with almost any liquid measuring system.
 Therefore, the system of measurement employed determines which columns are used.

Data taken by _____ Data prepared by _____

Table 6—Sample Data

Operator _____ Lease and Well No. _____

Field, County, State, Country _____

(Complete this section when SURFACE SAMPLING method is used)

Separator Pressure _____ (psig) Separator Temperature _____ (°F)

Sample-container Data

	Liquid		Gas		
Container No.	_____	_____	_____	_____	_____
Date	_____	_____	_____	_____	_____
Time	_____	_____	_____	_____	_____
Atmospheric Temperature (°F)	_____	_____	_____	_____	_____
Drier used					
Yes	_____	_____	_____	_____	_____
No	_____	_____	_____	_____	_____

How was outage taken in liquid samples? _____

Gas-sampling method _____

Liquid-sampling method _____

(Complete this section when SUBSURFACE SAMPLING method is used)

Sampling Data

	Sample No. 1	Sample No. 2
Container No.	_____	_____
Date Well Sampled	_____	_____
Time Well Sampled	_____	_____
Well Shut-in Time (hours)	_____	_____
Gas-oil Contact (ft)	_____	_____
Oil-water Contact (ft)	_____	_____
Sampling Depth (ft)	_____	_____
Sampling Depth Pressure (psig)	_____	_____
Tubing Pressure (psig)	_____	_____
Casing Pressure (psig)	_____	_____
Sampler Pressure after Valve Opening (psig)	_____	_____
Sample Transfer Temperature (°F)	_____	_____
Sample Transfer Pressure (psig)	_____	_____
Sample Shipping Pressure (psig)	_____	_____
Outage Taken in Sample Container (cc)	_____	_____
Container Volume (cc)	_____	_____

Remarks: _____

Sampled by _____ Data prepared by _____

Table 7—Surface Sample Data (Alternate Form)

General Information	Operator:		Lease & Well No.:	
	Location:		Field:	
	County:		State:	
	Country:			
	Sampling Company:		Sampling Date:	
	Sampled By:		Test No.:	

Reservoir Information	Producing Zone:		Top:		Bottom:	
	Initial Reservoir Pressure (Unit):		Initial Reservoir Temperature (Unit):		At (Depth Unit):	
	Initial Oil Production:		Date:		Choke:	
	Initial Gas Production:		FWP:		WHFP:	

			Oil Sample		Associated Gas Sample No. 1	Associated Gas Sample No. 2
	Sample Information	Container & Sampling Information	Container No.		Container No.	
Container Type				Container Type		
Container Volume				Container Volume		
Pressure & Temperature Rating				Pressure & Temperature Rating		
Sampling Method				Sampling Method		
Sampling Point				Sampling Point		
Well Flowing & Separator Conditions		Choke Size				
		Sep. Press				
		Sep. Temp.				
		Flowing Time				
		Oil Meter Type		Gas Meter Type		
		Separator Oil Flow Rate		Gas Flow Rate @ Std. Cond.		
		Oil Gravity		Gas Gravity		
				Gas Z		
				F_{pb}		
				F_{tb}		
				$F_g = 1/\sqrt{G}$		
				F_{ff}		
				F_r		
				Y		
				F_{pv}		
BHP			F_m	1.00	1.00	
BHT			$C =$			
@ Depth			Gas Flow Rate @ Separator Conditions			
Sample Information		Start Sampling				
		Finish Sampling				
		Container Temp.				
	Ambient Temp.					

Table 8—Subsurface Sampling Data (Alternate Form)

General Information	Operator:		Lease & Well No.:	
	Location:		Field:	
	County:		State:	
	Sampling Company:		Sampling Date:	
	Sampled by:		Test No.:	

Well Information	All Depths Referenced to:		Elevation:		Open Hole Cased Hole	
	Casing Size:		Tubing Size:		Completion Date:	
	Casing Shoe:		Tubing Shoe:			

Reservoir Information	Producing Zone:		Top:		Bottom:	
	Initial Reservoir Pressure (Unit):		Initial Reservoir Temperature:		At (Depth Unit):	
	Initial Oil Production:		Date:		Choke:	
	Initial Gas Production:		FWP:		WHFP:	

Sampling Information	Container & Sampler Information	Sample No. 1		Remarks
			Container No.	
		Container Type		
		Container Volume		
		Maximum Pressure & Temperature Rating		
		Sampler Type		
		Sampling Time		
	Well Flowing or Shut-in Condition	Choke Size		
		Oil Flow Rate		
		Gas Flow Rate		
		Flowing Time		
		Shut-in Time		
		BHP		
		BHT @ Depth		
	Sample Surface Checks & Transfer	Opening Pressure		
		Sample Temperature		
		Bubble-point Pressure		
		Transfer Method		
		Transfer Pressure		
		Transferred Volume		
		Gas Cap Volume		

Table 9—Open Hole Sampling Data (Alternate Form)

General Information	Operator:		Lease & Well No.:	
	Location:		Field:	
	County:		State:	
	Country:			
	Sampling Company:		Sampling Date:	
	Sampled By:			

Well Information	All Depths Referenced to:		Elevation:	
	Casing Size:		Bit Size:	
	Casing Shoe:			
	Drilling Fluid Type:			
	Density:		R_m @BHT:	
	Viscosity:		R_{mf} @BHT:	
	Fluid Loss:		Source of R_{mf} :	
	pH:			
	Time Circulation:			
	Stopped:			

Reservoir Information	Sampling Depth:	
	TVD:	
	Initial Reservoir Pressure (Unit):	
	Drawdown Mobility:	
	Date:	

Sampling Information	Container & Sampler Information		Sample No. 1:	Remarks
			Container No.	
	Container Type			
	Container Volume			
	Maximum Pressure & Temperature Rating:			
	Tool Type			
	Sampling Time			
	Sampler Preparation & Fluid Identification Information	Form of Disposing Unwanted Fluid		
		Estimated Volume Disposed		
		Estimated Dead Volume		
		Dead Volume Fluid		
		Displaced Fluid Type		
		Sampling Pressure		
		Sampling Temperature		
		Sampled Fluid Resistivity		
	Sample Surface Checks & Transfer	Fluid Identification Record		
		Opening Pressure		
		Sampling Temp.		
		Bubble-point Pressure		
		Transfer Method		
		Transfer Pressure		
	Transferred Volume			
	Gas Cap Volume			

APPENDIX A—HYDROGEN SULFIDE WARNING

Inhalation of hydrogen sulfide (H₂S) at certain concentrations can lead to injury or death. H₂S is an extremely toxic, flammable gas which may be encountered in the production and processing of gas well gas, high-sulfur-content crude oil, crude oil fractions, associated gas, and associated waters. Since H₂S is heavier than air, it can collect in low places in still air. It is colorless and has a foul, rotten-egg odor. In low concentrations, it is detectable by its characteristic odor. Smell cannot be relied upon to forewarn of dangerous concentrations, however, because exposure to high concentrations of the gas (greater than 100 parts per million [ppm]) rapidly paralyzes the sense of smell. A longer exposure to lower concentrations has a similar desensitizing effect on the sense of smell.

Excessive exposure to hydrogen sulfide causes death by

poisoning the respiratory system at the cellular level. There is some indication that the presence of alcohol in the blood aggravates the effects of H₂S in acute poisoning cases. At low concentrations (10 ppm – 50 ppm), H₂S is irritating to the eyes and respiratory tract. Closely repeated, short-term exposures at low concentrations may lead to irritation of the eyes, nose, and throat. Symptoms from repeated exposures to low concentrations usually disappear after not being exposed for an appropriate period of time. Repeated exposures to low concentrations that do not produce effects initially can eventually lead to irritation if the exposures are frequent.

The sense of smell may be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations.

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