3. FLUID SAMPLING AND ANALYSIS OF LABORATORY DATA

3.1 Introduction

3.1.1 Important PVT Data

Oil and gas samples are taken to evaluate the properties of produced fluids at reservoir conditions, in the production tubing, and in pipeline transportation. The key PVT (pressure-volume-temperature) properties to be determined for a reservoir fluid include:

- Original reservoir composition(s)
- Saturation pressure at reservoir temperature
- Oil and gas densities
- Oil and gas viscosities
- Gas solubility in reservoir oil
- Liquid (NGL/condensate) content of reservoir gas
- Shrinkage (volume) factors of oil and gas from reservoir to surface conditions
- Equilibrium phase compositions

Standard experimental procedures are used for measuring these properties, including expansion and depletion studies, and multistage separator tests.

Reservoir fluid samples can also be used in gas injection studies, where oil recovery by vaporization, condensation, and developed miscibility are quantified. Slimtube tests and multicontact gas injection PVT studies are typically used for this purpose.

Less traditional PVT analyses include:

- Analysis of produced water, including salinity and brine composition
- Wax and asphaltene analysis
- Hydrates and emulsions

This chapter summarizes the sampling procedures used to collect fluids, and the experimental methods used to measure fluid properties. A summary of PVT data is given in Table 3-1.

3.2 Sampling Methods

3.2.1 Type of Sampling

The API[1] gives recommended practices for sampling oil and gas wells.

Furthermore, Norsk Hydro has a chapter on Sampling Procedures in their Well Testing Manual[2]. Several sampling methods can be used to collect reservoir fluids, including

- RFT Sampling
- Bottomhole sampling
- Separator sampling
- Wellhead sampling

The choice of method depends primarily on (1) whether the reservoir fluid is an oil or gas, and (2) whether the reservoir fluid is saturated (or nearly saturated) at reservoir conditions. The second condition is determined by whether the well produces single phase fluid into the wellbore at the flowing bottomhole pressure.

Table 3-2 gives a Schlumberger-produced look-up table for determining sample requirements for various situations in the testing of oil and gas condensate reservoirs.

3.2.2 Representative Samples

Before field development starts, the primary goal of sampling is to obtain "representative" samples of the fluid or fluids found in the reservoir at initial conditions. It may be difficult to obtain a representative sample because of two-phase flow effects near the wellbore. This occurs when a well is produced with a flowing bottomhole pressures below the saturation pressure of the reservoir fluid(s).[a]

Misleading fluid samples may also be obtained if gas coning or oil coning occurs.

The best (most representative) samples are usually obtained when the reservoir fluid is single phase at the point of sampling, be it bottomhole or at the surface. Even this condition, however, may not ensure representative sampling (see section 3.2.5).

Because reservoir fluid composition can vary areally, between fault blocks, and as a function of depth, we are actually interested in obtaining a sample of reservoir fluid that is representative of the volume being drained by the well during the test.

Unfortunately, the concept of a "representative" sample is usually

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[a] If a significant positive skin effect exists, then the region near the wellbore that actually is below the saturation pressure may be insignificant (i.e. consisting of a volume that will practically not effect produced fluid sampling). The well testing engineer should quantify the pressure drop due to damage skin (if it exists) at the rate when the well experiences the lowest wellbore flowing pressure. In fact, they should provide an adjusted flowing wellbore pressure plot versus time during sampling that shows the effect of positive skin. The adjusted flowing pressure is probably better to use in evaluating if wellbore conditions were in fact condusive to sampling.

> *A sample that correctly reflects the composition of reservoir fluid at the depth or depths being tested.*

If we suspect or know that a sample is not "representative" (according to this definition), then we tend to do nothing with the sample. Or we question the validity of the PVT analysis done on the "unrepresentative" sample, and consequently don't include the measured data when developing our EOS fluid characterization.

In general, we should not use this definition of "representivity." First of all, it is a definition that costs our industry in terms of wasted money and time, and lost opportunity. Some points to keep in mind are:

> Any fluid sample that produces from a reservoir is automatically representative of that reservoir. After all, the sample *is* produced from the reservoir!
>
> The final EOS fluid characterization of the reservoir fluid(s) should be required to match *all* (accurate) PVT measurements of *all* samples produced from the reservoir, independent of whether the samples are representative of insitu compositions.
>
> *Accuracy of PVT Data* $\neq$ *Representivity of Sample*
>
> Accurate PVT measurements can be made on *both* representative and unrepresentative samples. Inaccurate PVT measurements can also be made on both types of samples; bad PVT data *should* be ignored.

Furthermore, an EOS fluid characterization is used to predict compositional changes during depletion which represent a much greater variation than the compositional differences shown by "representative" and "unrepresentative" samples.

Another misconception in "representative" fluid sampling of gas condensates is that it is difficult to obtain insitu-representative samples in saturated gas condensate reservoirs (with underlying oil). *The exact opposite is true!* We can readily show that if a gas condensate is initially saturated and in contact with an underlying oil zone, then a near-perfect insitu-representative sample can be obtained (at the gas-oil contact). Independent of whether the reservoir gas and reservoir oil samples collected are insitu-representative.

3.2.3 Define the Fluid Type

For a new discovery it is important that the fluid type and saturation conditions can be estimated based on somewhat limited production data. Such data might include producing gas-oil ratio, stock-tank oil and separator gas gravity, reservoir temperature, and initial reservoir pressure. Produced wellstream composition may also be available.

Correlations such as presented by Standing and Glasø (section 4.4) can be used to estimate bubblepoint pressure with an accuracy of 5 to 10%. When composition is available, an equation of state can be used to predict the saturation pressure (bubblepoint or dewpoint) with about the same accuracy. Better predictions can usually be expected for oils, but with accurate composition and C_{7+} properties, dewpoint predictions of gas condensates also can be expected.

Figure 3-1 shows a typical pressure-temperature diagram for a reservoir fluid. The phase envelope defines the locus of bubblepoints and dewpoints joined at the critical point. A reservoir with temperature less than the critical point is defined as an *oil reservoir*. A reservoir with temperature between the critical temperature and the cricondentherm is defined as a *gas condensate reservoir*. If reservoir temperature is higher than the cricondentherm then the reservoir is defined as a *gas reservoir*.

Further qualtitative fluid definitions are sometimes used. For example, oil reservoirs are classified in two categories: *black-oil resevoirs* and *volatile oil reservoirs* (determined according to their initial solution GOR and STO gravity; approximately, black-oil: R_s<150 Sm^3/Sm^3 and volatile oil: R_s>150 Sm^3/Sm^3).

Gas reservoirs are sometimes classified as *wet gas reservoirs* (producing some liquid at surface conditions) or *dry gas reservoirs* (neglible surface liquid production). Furthermore, gas condensate reservoirs are sometimes grouped into the categories *lean gas condensate reservoirs* (GOR>2000 Sm^3/Sm^3) and *rich gas condensate reservoirs* (GOR<1000 Sm^3/Sm^3).

Returning to Figure 3-1, a resevoir fluid is a single phase at conditions outside the phase envelope. Within the phase envelope, two phases (gas and oil) exist. Any time two phases coexist locally (e.g. gas and oil within a pore), each phase separately is in a saturated state; the oil is at its bubblepoint and the gas is at its dewpoint. This fundamental concept is instrumental in understanding reservoir phase behavior.[a]

Initially a reservoir will always be at a pressure and temperature that is one or outside the phase envelope. During production and subsequent pressure reduction in the reservoir, the system may enter the two-phase region.[b]

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[a] Likewise, the concept of saturated phases applies to water and hydrocarbon phases in local equilibrium. For example, in an oil-water system system, *both* phases are saturated - with respect to each other. Even though the oil is highly undersaturated with respect to a gas phase, the oil is still saturated - with respect to water; likewise, water is saturated with components in the oil phase.

[b] After the reservoir enters the two-phase region, differential amounts of reservoir gas and oil are produced, according to relative permeability and viscosity ratios of the two phases. Subsequently, the remaining reservoir fluid does not have the same composition, and its phase envelope will therefore change from the original phase envelope. It is therefore of limited use to design reservoir behavior during depletion based on the original p-T diagram.

In practice there are three types of fluid systems in a given geological formation with vertical hydrodynamic communication. As shown in Figure 3-1, these are:

- Undersaturated System with Uniform Composition
- Saturated System with Uniform Composition
- Saturated and/or Undersaturated System with Compositional Gradient

A primary objective of fluid analyses in new discoveries is to establish the type of fluid system. However, without production from several intervals and/or several wells, it will be difficult to establish the classification with any great certainty.

Ula is an example of an undersaturated oil reservoir with relatively uniform composition. Sleipner is an example of an undersaturated gas condensate reservoir with relatively uniform composition. Troll is a saturated reservoir with fairly uniform composition in the gas cap and in the oil.

Oseberg is an example of a saturated/undersaturated reservoir with significant compositional variation with depth (particularly in the oil). Another exmaple is the Statfjord formation in the Statfjord field.

Eldfisk and Ekofisk fields are examples of undersaturated oil reservoirs with some compositional variation with depth.[3] Interestingly, the variation of composition (bubblepoint) with depth is not the same in the two main geological formations (Ekofisk and Tor).

The Statfjord formation in the Brent field is perhaps the most unusual fluid type.[4] The reservoir is undersaturated throughout, but the composition varies from a somewhat volatile oil at the bottom to a gas condensate at the top. At some depth a transition from bubblepoint to dewpoint occurs - but without a gas-oil contact! The point of transition is marked by a mixture with critical temperature equal to reservoir temperature (at that depth); at the transition, reservoir pressure is higher than the saturation (critical) pressure of the mixture (see Figure 3-1).

3.2.4 Conditioning a Well Before Sampling

A well should normally be "conditioned" before sampling, particularly for gas condensate and saturated oil wells. First the well is produced long enough to clean up all chemicals that were used during the well completion. Next, the rate is stepwise decreased until the flowing bottomhole pressure is larger than the estimated saturation pressure (if possible).

The final flow rate must be large enough to maintain a stable producing GOR and wellhead pressure, even if the flowing bottomhole pressure is less than the saturation pressure. Also, the final flow rate should be maintained long enough to ensure that the producing GOR is more-or-less constant.

A constant producing GOR does not necessarily indicate that the produced wellstream is "representative" of the original reservoir fluid. In fact, it may not be possible to obtain a truly representative sample for reservoir oil and gas condensate systems initially in a saturated state.

Sample containers are usually shipped by boat to land, and thereafter by air or ground transport to the PVT laboratory. As requested by the field operator, compositional analysis and standard PVT experiments are performed on the samples at a PVT laboratory.

3.2.5 RFT Sampling

Repeat Formation Tester (RFT) sampling (open wellbore sampling) is probably the least accurate of all methods of sampling, mostly because of the limited volume of sampling. However, RFT samples should be valid under the following conditions:

- Undersaturated oil
- High Permeability
- Water-based mud used when drilling

If oil-based mud is used during drilling then the samples can only be used for approximate compositional analysis. The hydrocarbon components found in the oil-based mud must be backed out of (subtracted from) the overall composition.

The greatest advantage of RFT sampling is that the fluid is defined for a precise depth. Many reservoirs exhibit compositional variation with depth. Accurate RFT samples can help establish this variation, typically a task that is very difficult.

3.2.6 Bottomhole Sampling

Undersaturated oils are usually sampled with bottomhole containers lowered into the wellbore on a wireline (Figure 3-3, Figure 3-1). The bottomhole sample is taken while the well is flowing at a relatively low rate. The flowing bottomhole pressure should always be higher than the estimated bubblepoint pressure of the reservoir oil.

Bottomhole oil samples can also be taken when a well is shutin. The flowing bottomhole pressure prior to shutin should be higher than the bubblepoint pressure.

The typical procedure for bottomhole sampling includes:

- Install sample container in the production tubing
- Make pressure gradient measurements going into the hole
- Position sampler at the specified depth
- Produce the well at a low, stable rate (following conditioning)

- Sample during the flow test (dynamic sample) or after shuting in the well (static sample)

Traditional bottomhole samplers are often transferred to a sample container while still on the drilling rig. (Norsk Hydro tries to practice transfer on land when possible.) The procedure for this transfer includes:

- Measure the opening pressure of the BH sampler
- Heat the BH sampler to about 80^{o}C
- Mix the sample by agitation/rotation
- Transfer to sample container

The saturation pressure of the sample is measured in the sample container at the prevailing temperature.

To ensure that representative samples have been obtained, at least two (and preferably three) BH samples should have the same bubblepoint pressure at ambient temperature, within 3 to 4%.

3.2.7 Wellhead Sampling

If a produced oil is single phase at the wellhead then a sample can be taken upstream to the choke. Several wellhead sampling methods can be used:

- Fill a membrane sampler by displacing the backpressure fluid (ethylene glycol)
- Fill a piston cylinder sampler
- Fill an open cylinder containing mercury (sometimes not allowed offshore, e.g. in Norway)

Successful wellhead samples should be very accurate if the temperature is above the wax appearance point (WAP). Usually wellhead samples can only be taken from high-pressure, deep wells that are highly undersaturated (e.g. Embla). In general, wellhead (or bottomhole) samples are preferred for asphaltene studies.

3.2.8 Separator Sampling

Separator sampling is used for gas condensates and saturated oils. Separator samples are also taken for gas injection studies requiring large sample volumes, and for special studies involving analysis of asphaltene precipitation, wax (paraffin) point, emulsions, hydrates, and corrosion.

The method relies on sampling separately the gas and oil leaving the primary separator (Figure 3-1). The samples should be taken simultaneously, filling the sample containers at a constant rate of about 1 liter/minute. The 20 liter gas bottles are initially evacuated. The separator oil (about 600 cm^3) can be collected in a membrane bottle by displacing ethylene glycol, a piston cylinder, or a mercury-filled container (not allowed offshore Norway). A good rule-of-thumb is that it takes about one-half hour to collect a set of separator samples.

Criteria for valid separator sampling include:

- Stable separator pressure and temperature, liquid level, and flow rates. Excessive carryover (due to high rates) should be avoided.

- Critical flow through the choke, requiring that separator pressure is less than 1/2 of the wellhead flowing pressure. Sometimes this criterion cannot be achieved, and strictly speaking it is not necessary if separator conditions are stable.

Separator gas and separator oil rates are measured during the sampling to determine the ratio with which to recombine the separator samples. The recombined mixture should yield an overall fluid representing the wellstream that entered the separator. This wellstream hopefully represents the reservoir fluid. Measured separator gas rates are corrected in the laboratory using standard orifice equations.

Separator gas rate is about 3 to 10% accurate (Daniel mixer), and the liquid rate should be 2 to 5% accurate using a rotameter. Carryover of separator oil in the gas stream may be a problem for high-rate gas condensate wells (particularly lean condensate wells). As much as 30-40% of the separator oil (condensate) may be carried over in the gas stream of a lean condensate producing into a standard 20-foot separator. The separator gas sampler may or may not capture the carried-over liquid. Irregardless, the potential error in calculated wellstream composition may be significant for large carryover (low separator efficiency).

Three types of separator sampling can then be requested:

- Standard sampling
- Isokinetic sampling
- Mini-laboratory (Thorton) sampling

Standard separator sampling should almost always be collected for gas condensate and saturated oils.

If carryover is suspected, isokinetic samples can be taken to quantify the separator efficiency, and thereby establish the neccesary corrections to make a valid recombination. A more expensive alternative is the Thorton sampling technique for gas condensates.

3.2.9 Isokinetic Sampling

Isokinetic sampling may be recommended for lean gas condensates with documented low separator efficiency, characterized by significant carryover of separator oil into the separator gas stream. The method is based on sampling the separator gas twice:

- First, a sample of the oil-free gas is taken by sampling in the same direction as gas flows.

- Second, a sample of the separator gas containing the entrained (carryover) separator oil is taken by sampling against the direction of gas flow at a properly controlled sampling rate (isokinetically).

Comparing the two sample compositions, carryover or separator efficiency can be quantified. 1 shows the isokinetic sampling equipment.

3.2.10 Mini-Laboratory (Thorton) Sampling

A mixing block is placed in a vertical 2.3" flowline, upstream from a 5/64" sample line lodged perpendicular to flow. The sampling assembly is located downstream to the choke and upstream to the separator (Figure 3-1). A mini laboratory separator is used to analyze the wellstream sample by conducting a controlled multistage separation, with compositions and separator GORs measured directly, and wellstream recombination calculated onsite.

The mini-laboratory sampling approach is expensive and therefore not usually recommended. Careful separator sampling, eventually with isokinetic sample control of liquid carryover, should usually be sufficient for most gas condensate reservoirs.

3.2.11 Sample Treatment at the PVT Laboratory

When the samples arrive at the PVT laboratory the samples must be checked for quality and possible leakage. Several methods can be used to check sample consistency. It is important to establish which samples should be used for the PVT study, mainly based on these consistency checks.

Bottomhole and wellhead oil samples are brought to the same temperature that was used to determine the bubblepoint on the wellsite. The bubblepoint is determined for each sample, and if the bubblepoints from the laboratory and the wellsite check within 1% for a given sample then it is considered valid.

Several problems may cause lab and wellsite bubblepoints to deviate. If the oil is somewhat volatile (GOR>150 Sm^3/Sm^3) then it may be difficult to measure the bubblepoint graphically using a pressure-volume plot. This is a typical problem for high bubblepoint oils (p_b>250 bar). Another problem is that equilibrium may not have been reached at each pressure when measurements were conducted on the wellsite. Finally, the pressure gauges may have been improperly calibrated.

Separator samples also can be checked for leakage (look in the sample box!). The oil sample is checked by measuring the bubblepoint at separator temperature. If the measured bubblepoint is within about 1-2% of the separator pressure then the oil sample is considered valid.

The pressure in the gas sample bottle is checked against the separator pressure. Note that the opening pressure at room temperature may be larger than separator pressure because the sample container may have been colder than room tempearature when filled at the separator. The basic control relation for checking opening pressure of gas samples is

$$p_{opening} = p_{sp} \frac{T_{opening}}{T_{sp}} \tag{3-1}$$

where pressures and temperatures are given in absolute units. It may be difficult to establish the proper "T_{sp}" in this equation, as the actual temperature may be affected by the atmospheric conditions, as well as temperature reduction during the "flashing" of gas into the sample bottle.

3.3 Compositional Analysis and Quality Control

PVT studies are usually based on one or more samples taken during a production test. Bottomhole samples can be obtained by wireline using a high-pressure container, either during the production test or during a shutin period. Separator samples may also be taken during a production test.

This section discusses how wellstream compositions are determined. The standard approach consists of first separating the high-pressure sample into low-pressure gas and oil samples which are each analyzed using gas chromatography (GC). The overall mixture composition is obtained by mathematically recombining the separated gas and oil compositions.

The standard components quantified in petroleum reservoir fluids include

• *Non-Hydrocarbons*	N_2 CO_2 H_2S
• *Hydrocarbons*	C_1 C_2 C_3 iC_4 nC_4 iC_5 nC_5 C_{6s} C_{7+} (or C_7 C_8 C_9 C_{10+})

Table 3-2 lists example compositions of the main fluid types, together with relevant reservoir and surface properties. Figure 3-1 illustrates the classification of fluid types based on composition in the form of a simple ternary diagram. Also shown is the classification based on producing (initial) gas-oil ratio and oil-gas ratio.

3.3.1 Gas Chromatography

Compositional measurements are made using gas chromatography and sometimes true boiling point (TBP) distillation. Gas chromatography measures the weight (mass) fraction of individual components in a mixture. TBP analysis gives additional information about the amount and properties of heavier components (heptanes and heavier, C_{7+}).

Gas chromatography is based on selective separation of components as temperature is increased in a capillary tube (Figure 3-1)[5]. The sample is injected to the GC, followed by a carrier gas such as helium or nitrogen. As temperature increases, the lighter components separate and move together with the carrier gas to a flaming ion detector (FID).

Instead of a carrier gas, a carrier liquid or supercritical fluid can be used to transport separated components. These methods are referred to as liquid chromatography and supercritical fluid chromatography, respectively.

The FID signal for a component is shown as a peak on the chromatographic line (Figure 3-1). The relative mass of a component is given by the area under the peak, divided by the total area created by all components in the mixture. Note that FID only responds to organic compounds. A particular component can be identified by the time (temperature) when its peak appears. For example, the methane peak appears before the ethane peak, which occurs before the propane peak, and so on.

A thermal capacity detector (TCD) may be used in some chromatographs. This dector measures the difference in thermal capacity between the pure carrier gas and the carrier gas mixed with the component being detected. The difference in thermal capacity is a function of the number of molecules of the component. In contrast to the FID, which measures relative mass of each component, the TCD measures relative moles of each component. Also, the TCD can be used for both hydrocarbon and nonhydrocarbon compounds.

Norsk Hydro uses TCD for non-hydrocarbons, and FID for hydrocarbons.

Accurate quantitative GC analysis depends on reproducible retention times, and known dector response for the range of components being analyzed. Several sources of error in GC analysis are given below:

- Improper handling of the sample before injection
- Method used for injection
- Decomposition of sample during analysis
- Bad chromatographic system; tailing or overuse of the system
- Variation in detector response
- Calibration errors
- Error in response area measurements (integration)

3.3.2 Natural Gas Analysis

A packed column with TCD is used to separate nonhydrocarbon (inorganic) components such as nitrogen, carbon dioxide, and hydrogen sulphide, as well as methane and ethane. Chromatographic separation using FID in a capillary column is used for components methane through decane.

An external standard and response factor are used to quantify the analysis more precisely. The response factor for FID includes (implicitly) the molecular weight to convert from mass to mole fraction. Finally, the FID and TCD analyses are combined using ethane analyses to "bridge" the combination of the two analyses, where normalization with a volume correction is used.

3.3.3 Oil/Condensate GC Analysis

A capillary column with FID is used to analyse atmospheric oil and condensate samples. The analysis can be carried out to carbon numbers 30 or greater, but an internal standard such as squaline is usually needed to ensure accurate quantitative conversion of response areas to mass fractions. Figure 3-1 shows a typical oil chromatogram (of a stock-tank condensate).

Simulated distillation (SIMDIS) by GC analysis may also be used. SIMDIS is usually conducted with a 30-50 m capillary column using Helium as the carrying gas with a diluted sample (1:100), temperatures from 50^o-280^oC at 4^oC/min.

Conversion from mass fraction to mole fraction requires molecular weights of all components. Because molecular weights are not measured, and for a given carbon number the molecular weight may vary by 5 or 10 molecular weight units (depending on the type of hydrocarbons found in the particular carbon number), conversion to mole fractions is only approximate.

Many laboratories use paraffin molecular weights (given by the relation $M_i=14i+2$) to convert GC mass fractions to mole fractions. The molecular weights given by Katz and Firoozabadi[6] for carbon numbers up to C_{45} are probably more accurate for stock tank oils and condensates (Charts 3 and 4 in the *Fluid Properties Data Book*)[7].

3.3.4 True Boiling Point (TBP) Analysis

True boiling point distillation may supplement traditional GC analysis of oil and condensate samples. TBP distillation separates an oil into cuts or fractions according to the range of boiling points used for separation. Figure 3-1 defines typical refined petroleum products in terms of carbon number fractions. Figure 3-1 illustrates the range of carbon number fractions containing various hydrocarbon compounds (e.g. n-alkanes).

The recommended standard[6] uses normal boiling points of paraffins to separate individual carbon number fractions. To avoid decomposition ("cracking") of the oil during distillation, vacuum is applied in four stages to reduce the distillation temperatures for heavier components:

- Atmospheric (1013.0 mbar)
- 100 torr (133.0 mbar)
- 10 torr (13.0 mbar)
- 2 torr (2.6 mbar)

The distillation usually proceeds from C_7 (or C_9) to about C_{25}, plus a residue (~C_{26+}). Figure 3-1 shows a TBP distillation apparatus recommended in ASTM D-2892.[8]

The mass, volume, molecular weight, and density (specific gravity) of each distilled fraction is measured directly. Table 3-4 gives results of TBP distillation of stock-tank oil. Reported densities are at a temperature of 15^oC (60^oF) and atmospheric pressure. Some of the heavier fractions may have a higher pour point than 15°C (i.e the fraction is not fluid at 15°C), and the measured density is made at a higher temperature (Table 3-5). This density is then corrected to the reported value using standard thermal correction tables.

Because the separation of components in a given distillation cut is only approximate, some overlap is observed. For example, the C_{12} cut may contain 10% C_{11} compounds, 85% C_{12} compounds, and 5% C_{13} compounds. The overlap worsens at lower distillation pressures because the difference in distillation temperatures is reduced between cuts. Table 3-6 and Figure 3-1 show the overlap for an example TBP distillation.

The overlap can be corrected to yield an "ideal" distillation curve (Table 3-7). The resulting ideal distillation curve should be quite similar to the simulated distillation curve, as shown in Figure 3-1.

One advantage with TBP analysis is that measured molecular weights are available for converting from mass to mole fraction. Molecular weights are measured using a cryoscopic method (freezing point depression), a method that is sensitive to error and probably reliable at best to about ±2 to 5%. Measured molecular weights are compared with GC-based calculated molecular weights in Table 3-5.

Table 3-8 summaries the GC/TBP analysis of the example stock-tank oil, where results are provided through C_{10+}.

Average boiling points are taken from the tables of Katz and Firoozabadi.[6] With these boiling points and with measured specific gravities the critical properties and acentric factors of the fractions can be estimated from correlations. Critical properties are needed in PVT calculations with an equation of state (EOS). Reservoir, pipeflow, and process simulations may also require EOS calculations.

It is recommended that at least one TBP analysis be measured for each reservoir fluid in a given field. As an extreme example, a field such as Visund might require up to four TBP studies:

- (1) gas cap and (2) equilibrium oil samples in the Brent formation
- (3) gas condensate in the Statfjord formation
- (4) near-critical oil in the Lunde formation

Note that it may be difficult to use several TBP analyses to come up with a single EOS characterization for reservoirs with multiple fluids (e.g. compositional variation or gas cap/oil). The examples in sections 5.5.2 and 5.6.2 discuss the use of TBP data in EOS fluid characterization.

Mass fractions measured from TBP analysis should be reasonably close to mass fractions determined from simulated distillation. However, SIMDIS does not provide properties of the individual fractions (molecular weight and density).

3.3.5 Bottomhole Sample Composition

Table 3-8 shows the reported wellstream composition of a reservoir oil, where C_6, C_7, C_8, C_9, and C_{10+} specific gravities and molecular weights are also reported. In the example report, composition is given both as mole and weight percent, though many laboratories only report molar composition. Experimentally, the composition of a bottomhole sample is determined by (Figure 3-3, Figure 3-1):

- Flashing the sample to atmospheric conditions.
- Measuring the quantities of surface gas and oil.
- Determining the normalized weight fractions of surface samples by gas chromatography.
- Measuring molecular weight and specific gravity of the surface oil.
- Converting weight fractions to normalized mole fractions.
- Recombining mathematically to the wellstream composition.

The most probable source of error in wellstream composition of a bottomhole sample is the surface oil molecular weight which usually is accurate within 5 to 10%. TBP data, if available, can be used to check surface oil molecular weight.

3.3.6 Recombined Sample Composition

Table 3-10 presents the separator oil and gas compositional analyses of a gas condensate fluid, together with recombined wellstream composition. The separator oil composition is obtained using the same procedure as for bottomhole oil samples. This involves bringing the separator oil to standard conditions, measuring properties and compositions of the resulting surface oil and gas, and recombining these compositions to give the separator oil composition which is reported as shown in Table 3-10.

The separator gas sample is introduced directly into a gas chromatograph. Weight fractions are converted to mole fractions using appropriate molecular weights. C_{7+} molecular weight is back-calculated using measured separator gas specific gravity.

The separator oil and gas compositions can be checked for consistency using the Hoffman et al.[9] K-value method and Standing's[10] low-pressure K-value equations (section 3.4.10).

Table 3-12 gives a summary of equations used to correct test separator gas-oil ratio for use in recombination.

3.4 PVT Experiments

3.4.1 Multistage Separator Test

The multistage separator test is conducted on oil samples primarily to provide a basis for converting differential liberation data from a residual oil to a stock-tank oil basis (see section 3.4.4).

Occasionally, several separator tests are conducted to determine the separator conditions that maximize stock-tank oil production. Usually two or three stages of separation are used, with the last stage being at atmospheric pressure and near-ambient temperature (15 to 25°C). The multistage separator test can also be conducted for rich gas condensate fluids.

Figure 3-1 illustrates schematically how the separator test is performed. Initially the reservoir sample is brought to saturation conditions and the volume is measured. The sample is then brought to the pressure and temperature of the first-stage separator. All of the gas is removed and the oil volume at the separator stage is noted, together with the volume, number of moles, and specific gravity of the removed gas. If requested, the composition of gas samples can be measured.

The oil remaining after gas removal is brought to the conditions of the next separator stage. The gas is again removed and quantified by moles and specific gravity. Oil volume is noted, and the process is repeated until stock-tank conditions are reached. The final oil volume and specific gravity are measured at 15.5^{o}C and one atmosphere.

Table 3-13 gives results from a three-stage separator test. Gas removed at each stage is quantified as standard gas volume per volume of stock-tank oil. Sometimes an additional column of data is reported, giving standard gas volume per volume of separator oil; note, you can not add GORs reported relative to separator oil volumes.

3.4.2 Constant Composition Expansion - Oils

For an oil sample the constant composition expansion (CCE) experiment is used to determine the bubblepoint pressure, the undersaturated oil density and isothermal oil compressibility, and the two-phase volumetric behavior at pressures below the bubblepoint. Table 3-14 presents data from an example CCE experiment for a reservoir oil.

The procedure for the CCE experiment is shown in Figure 3-1. A PVT cell is filled with a known mass of reservoir fluid and brought to reservoir temperature. Temperature is held constant during the experiment. The sample is initially brought to a condition somewhat above the initial reservoir pressure, ensuring that the fluid is single phase. As the pressure is lowered, oil volume expands and is recorded.

The fluid is agitated at each pressure by rotating the cell. This avoids the phenomenon of *supersaturation* or *metastable equilibrium* where a mixture remains as a single phase, even though it should split into two phases. Sometimes supersaturation occurs 3 to 7 bar below the actual bubblepoint pressure. By agitating the mixture at each new pressure, the condition of supersaturation is avoided and the bubblepoint can be determined more accurately.

Just below the bubblepoint the total volume will increase more rapidly because gas evolves from the oil. This yields a higher system compressibility. Visually, gas can be seen at the top of the cell (if a visual cell is used). The total volume is recorded after the two-phase mixture is brought to equilibrium. Pressure is lowered in steps of 1 to 15 bar, where equilibrium is obtained at each pressure. When the lowest pressure is reached, total volume is 3 to 5 times larger than the original bubblepoint volume.

The recorded cell volumes are plotted versus pressure, and the resulting curve should be similar to one of the curves shown in Figure 3-1. For a "black oil" the discontinuity in volume at the bubblepoint is sharp. The bubblepoint pressure and bubblepoint volume are easily read from the intersection of the pressure-volume trends from the single-phase and the two-phase regions.

Volatile oils do not exhibit the same clear discontinuity in volumetric behavior at the bubblepoint pressure (Figure 3-1). Instead, the p-V curve is practically continuous in the region of the bubblepoint because undersaturated oil compressibility is similar to the effective two-phase compressibility just below the bubblepoint. This makes it difficult to determine the bubblepoint of volatile oils using a pressure-volume plot.[a] Instead, a windowed cell is used for visual observation of the first bubble of gas at the bubbleopint. Liquid shrinkage below the bubblepoint can also be measured in a visual cell during the constant composition expansion.

Reported data from commercial laboratories usually include bubblepoint pressure, bubblepoint density or specific volume, and isothermal compressibility of the undersaturated oil at pressures above the bubblepoint. The oil's thermal expansion may also be reported, indicated by the ratio of undersaturated oil volume at a specific pressure and reservoir temperature to the oil volume at the same pressure and a lower temperature.

Total volume below the bubblepoint can be correlated by the Y function, defined as

$$Y \equiv \frac{(p_b/p)-1}{V_{rt}-1} = \frac{(p_b/p)-1}{(V_t/V_b)-1} \tag{3-2}$$

where p and p_b are given in absolute pressure units. Plotting Y versus pressure should yield a straight line, as shown in Figure 3-1. The linear trend can be used to smooth total volume data at pressures below the bubblepoint.

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[a] Reported bubblepoint pressures measured at the wellsite on bottomhole samples of volatile oils are obviously subject to large inaccuracy because a pressure-volume plot is used. This should be kept in mind when comparing laboratory-measured bubblepoint with wellsite-determined bubblepoint in the selection (rejection) of valid samples.

3.4.3 Constant Composition Expansion - Gas Condensates

The CCE experiment for a gas condensate reports the total relative volume, defined as the volume of the gas or gas-plus-oil mixture divided by the dewpoint volume. Z-factors are also reported, at the dewpoint pressure and above.[a] Table 3-15 and Figure 3-1 gives example CCE data for a gas condensate.

Wet-gas FVF (or its inverse) is reported at the dewpoint and/or initial reservoir pressure. These values represent the gas equivalent or wet-gas volume at standard conditions produced from one volume of reservoir gas.

Most CCE experiments are conducted in a visual cell for gas condensates. Relative oil (condensate) volumes are reported at pressures below the dewpoint, where relative oil volume is usually defined as the oil volume divided by the total volume of gas-plus-oil; in some reports, however, relative oil volume is defined as the oil volume divided by the dewpoint volume (Norsk Hydro practice).

3.4.4 Differential Liberation Expansion

The differential liberation expansion (DLE) experiment is designed to approximate the depletion process of an oil reservoir, and thereby provide suitable PVT data for calculating reservoir performance. Figure 3-1 illustrates the laboratory procedure of a DLE experiment. Figure 3-1 through Figure 3-1 and Table 3-16 through Table 3-19 give DLE data for an oil sample.

A blind cell is filled with an oil sample which is brought to a single phase at reservoir temperature. Pressure is decreased until the fluid reaches its bubblepoint, where the oil volume is recorded; knowing the initial mass of the sample, the bubblepoint density can be calculated.

The pressure is decreased below the bubblepoint and the cell is agitated until equilibrium is reached. All gas is removed at constant pressure, and the volume, moles, and specific gravity of the removed gas are measured. Sometimes gas compositions are also measured. The remaining oil volume is also recorded. This procedure is repeated 10 to 15 times at decreasing pressures, and finally at atmospheric pressure.

The final oil is cooled, where the resulting "residual" oil volume and specific gravity are measured (or calculated) at 15.5°C. Residual oil composition may also be reported.[b]

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[a] If Z-factors are also reported *below* the dewpoint then they represent ficticious, non-physical quantities that *should not be used*.

[b] *None* of the data reported for the residual oil should be used as data in doing an EOS fluid characterization. The reason is simply that the process used in the lab from the next-to-last stage to atmospheric pressure (and reservoir temperature) is not a single flash as simulated by an EOS. The last-stage depletion process may be conducted differently by various laboratories; usually it is a bleeding process, or bleeding/flash/bleeding process.

Based on measured data, other properties are *calculated*, including differential solution gas-oil ratio (R_{sd}), differential oil FVF (B_{od}), oil density, and gas Z-factor.

3.4.5 Converting from Differential to Stock-Tank Basis

Traditionally the most important step in the application of oil PVT data for reservoir calculations is the conversion of differential solution gas-oil ratio (R_{sd}) and differential oil FVF (B_{od}) to a stock-tank oil basis. For engineering calculations, volume factors R_s and B_o are used to relate reservoir oil volumes to produced surface volumes.

Differential properties R_{sd} and B_{od} reported in the DLE report are relative to *residual oil volume*, i.e., the oil volume at the end of the DLE experiment, corrected from reservoir to standard temperature. The equations traditionally used to convert differential volume factors to a stock-tank basis are:

$$R_s = R_{sb} - (R_{sdb} - R_{sd})\left(\frac{B_{ob}}{B_{odb}}\right) \qquad (3\text{-}3)$$

$$B_o = B_{od}\left(\frac{B_{ob}}{B_{odb}}\right) \qquad (3\text{-}4)$$

where B_{ob} and R_{sb} are the bubblepoint oil FVF and solution GOR, respectively, from a multistage separator flash. R_{sdb} and B_{odb} are differential volume factors at the bubblepoint pressure. The term (B_{ob}/B_{odb}) is used to eliminate the residual oil volume from the R_{sd} and B_{od} data. Note that the conversion from differential to "flash" data depends on the separator conditions because B_{ob} and R_{sb} depend on separator conditions.

The conversions given by Eqs. (3-3) and (3-4) are only approximate. Figure 3-1 shows the conversion of differential B_{od} to flash B_o for the example oil with differential data reported in Table 3-16 through Table 3-19.

A more accurate method was suggested by Dodson et al.[11] Their method requires that some of the equilibrium oil be taken at each stage of a depletion experiment (DLE, CCE, or CVD (see section 3.4.6)) and flashed through a multistage separator. The multistage separation gives R_s and B_o directly. This laboratory procedure is costly and time-consuming, and therefore never used. However, the method is readily simulated with an equation of state model (Whitson and Torp[12]; Coats[13]).

Figure 3-1 shows oil volume factors and solution GORs calculated using the standard conversion given by Eqs. (3-3) and (3-4), compared with the Dodson method (Whitson and Torp procedure) using an EOS. The oil is slightly volatile, and it is seen that the approximate conversion gives approximately the same results as using the more rigorous Dodson method.

Figure 3-1 shows a similar comparison for a highly (near-critical) volatile oil. The difference in both oil volume factor and solution GOR is significant, and clearly the traditional conversion of DLE data can not be used for this type of fluid.

It should be realized that even when dealing with a slightly volatile oil (GOR>125 Sm^3/Sm^3), a modified black-oil (MBO) PVT formulation should be used in reservoir calculations (material balance and simulation). The MBO formulation is compared with the traditional black-oil formulation in Figure 3-1. The main difference is that the MBO treatment accounts for the ability of reservoir gas to volatilize intermediate and heavier components that produce a suface condensate when produced.

The ratio of surface condensate produced from reservoir gas to surface gas produced from reservoir gas is the solution oil-gas ratio R_V (sometimes written r_s). The gas FVF also must be adjusted from the traditional definition to account for the reservoir gas that becomes condensate at the surface (i.e. that the moles of reservoir gas does not equal the moles of surface gas, as is assumed in the traditional definition of gas FVF). The resulting gas FVF is called "dry" gas FVF, with symbol B_{gd}.

3.4.6 Constant Volume Depletion

The constant volume depletion (CVD) experiment is designed to provide volumetric and compositional data for gas condensate (and volatile oil) reservoirs producing by pressure depletion. The stepwise procedure of a CVD experiment is shown schematically in Figure 3-1. Table 3-19 and Table 3-21 give CVD data for an example gas condensate fluid.

The CVD experiment provides data that can be used directly in reservoir engineer calculations, including:

- Reservoir material balance giving recovery of total wellstream (wet gas recovery) versus average reservoir pressure.

- Produced wellstream composition and surface products (sales gas, condensate, and NGLs) versus reservoir pressure.

- Average oil saturation in the reservoir (liquid dropout and revaporization) that occurs during pressure depletion.

For most gas condensate reservoirs producing by depletion, the recoveries and oil saturations versus pressure from the CVD analysis closely approximate actual field performance.[a] If other recovery mechanisms such as water drive and gas

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[a] The basic assumption is that hydrocarbons condensed in the reservoir, *on the whole* (i.e. neglecting local saturation effects near the wellbore), do not flow in significant amounts to production wells. The reason is simply that the relative mobility of oil is much smaller than the reservoir gas mobility.

cycling are considered, the basic data required for reservoir engineering are still taken mainly from a CVD report.

3.4.7 PVT Data Accuracy

The accuracy of PVT measurements is difficult to quantify. Norsk Hydro has, however, studied the problem and Table 3-22 gives guidelines for measurement accuracies of most PVT data.

3.4.8 PVT Consistency Checks

The quality of PVT data may vary from poor to excellent. It may not be obvious, however, when inaccurate data are reported. Several methods can be used to determine the quality of reported PVT data. The recommended consistency checks given below should be used for PVT data that will be used in reservoir studies, or in the development of an equation of state characterization.

3.4.9 Watson Characterization Factor

The C_{7+} molecular weight is highly susceptible to error, with an accuracy ranging from 2 to 10%. Specific gravity of C_{7+}, on the other hand, should be accurate within a fraction of a percent.

The characterization factor K_w was introduced by Watson[14] to qualitatively describe the relative paraffinicity of a petroleum product. K_w is defined as $K_w = T_b^{1/3}/\gamma$, where T_b is the normal boiling point in ^{o}R and γ is the specific gravity relative to water.

Stock-tank oils and condensates contain many hundreds of hydrocarbon compounds. Because STO consists mainly of the C_{7+} material, the characterization or "paraffinicity" of a reservoir fluid can be described by the Watson characterization factor of the C_{7+} fraction.

The following table gives the range of the Watson characterization factor for pure compounds in the three main hydrocarbon families, and for stock-tank oils/condensates.

Hydrocarbon Type	Pure Compound	Stock-Tank Oil/ Condensate (C_{7+})
Paraffin	12-14	12-12.5
Napthene	10-12	
Aromatic	8-10	11-11.5

Whitson[15] gives an approximate relation for K_w that can be used for heptanes-plus,

$$K_{w7+} = 4.5579\, M_{7+}^{0.15178}\, \gamma_{7+}^{-0.84573} \qquad (3\text{-}5)$$

Austad et al. show that for a given formation in a reservoir, K_{w7+} should be very constant, even during depletion and even if the STO gravity varies initially (Figure 3-1).

Based on this observation, it is recommended that K_{w7+} be calculated for each new PVT sample in a field/reservoir. A plot of M_{7+} versus γ_{7+} can be updated with each new sample, where a line of constant K_{w7+} is drawn for the field average. Deviation of ±0.03 in K_{w7+} is acceptable. Larger deviations in K_{w7+} from the field/reservoir average may (probably) indicate an error in the measured M_{7+}.

If larger errors in M_{7+} are found, then potential errors in reported molar composition should be checked.

3.4.10 Hoffman et al. Kp-F Plot

The consistency of separator gas and oil compositions can be checked using a diagnostic plot proposed by Hoffman, Crump, and Hocott.[9] They show that K-values (on a log scale) plotted versus a component factor F_i (on a linear scale) should result in a straight-line relationship.

To apply this method to separator samples, the K-values are calculated first from separator gas and oil compositions, $K_i=y_i/x_i$ where y_i=separator gas molar composition and x_i=separator oil molar composition.

The Hoffman characterization factor F_i is given by

$$F_i = b_i(1/T_{bi} - 1/T_{sp}) \tag{3-6}$$

where T_{bi} is the normal boiling point in ^oR, T_{sp} is the separator temperature in ^oR, and b_i is a component constant given formally by

$$b_i = \frac{\log(p_{ci}/p_{sc})}{1/T_{bi} - 1/T_{ci}} \tag{3-7}$$

where p_{ci} is critical pressure in psia, p_{sc} is standard pressure in psia, and T_{ci} is critical temperature in ^oR.

Standing[10] gives modified values of b_i and T_{bi} to be used with the Hoffman et al. method, as shown in Table 3-23. Standing also gives the expected slope and intercept of the line as a function of pressure and temperature for typical separator conditions,

$$\log K_i p_{sp} = a + c F_i \tag{3-8}$$

where

$$\begin{aligned} a &= 1.20 + 4.5\times10^{-4}\ p_{sp} + 15.0\times10^{-8}\ p_{sp}^2 \\ c &= 0.89 - 1.7\times10^{-4}\ p_{sp} - 3.5\times10^{-8}\ p_{sp}^2 \end{aligned} \tag{3-9}$$

with p_{sp} given in psia.

According to Standing, the correlations for a and c are valid up to pressures of 70 bar and temperatures from 5 to 95°C.

A plot of measured separator K-values using this method should not deviate significantly from the Standing straight line. Heptanes plus, nonhydrocarbons, and components with small amounts (<0.5 mol-%) in either the separator oil or gas sample may deviate from the straight line without causing concern. However, if the key hydrocarbons methane through hexane show significant deviation from the straight line, the compositional analysis should be used with scrutiny.

Figure 3-1 shows a Kp-F plot for the separator sample given earlier (Table3-10).

3.4.11 Correcting GOR for Liquid Carryover

The reported separator GOR (R_{sp}) may be in error for several reasons:

- Incorrect separator oil rate
- Incorrect separator gas rate
- Carryover of separator oil in separator gas stream
- Gas in the oil line
- Incorrect measurement of the "meter factor"
- Combination of the above

It is probably reasonable to say that reported GOR has an accuracy of 5 to 15%, with even greater errors possible for lean gas condensates producing at high rates.

The recombined wellstream z_i composition is calculated from

$$z_i = F_{gsp}\ y_i + (1 - F_{gsp})\ x_i \tag{3-10}$$

where F_{gsp} is the total mole fraction of total wellstream that leaves the separator in the gas stream,[a]

$$F_{gsp} = \left[1 + 23.68 \frac{\rho_{osp}}{M_{osp}\, R_{sp}}\right]^{-1} \tag{3-11}$$

where ρ_{osp} is the separator oil density in kg/m^3, M_{osp} is the separator oil molecular weight (kg/kmol), and R_{sp} is separator gas-oil ratio in Sm^3/sep. m^3.

If the GC analyses are done properly, both separator oil composition x_i and separator gas composition y_i should be correct, even if carryover is a problem.

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[a] When carryover occurs, F_{gsp} calculated using test GOR will *also* include the entrained liquid that is carried over in the gas stream leaving the separator. This is because the measured gas rate includes the amount (moles) of carryover.

The traditional method of sampling gas (downstream) will minimize the amount of carryover that enters the gas sample container. Also, if the gas sample is brought to separator conditions before charging the chromatograph, only equilibrium gas will be removed for analysis, and the carryover separator oil will remain in the sample container.

We can usually assume with reasonable accuracy that the separator gas and oil compositions, as reported, can be used for recombination if the Hoffman et al. plot is acceptable. To obtain a valid wellstream composition from Eq. (3-10), however, the recombination GOR may need to be corrected (for one of several reasons).

If carryover exists then the separator gas rate reflects both the amount (moles) of separator gas n_g *plus* the moles of carryover separator oil Δn_o, the total being expressed as a standard gas volume (Figure 3-1). The separator oil rate reflects the total separator oil rate n_o *less* the moles of separator oil carryover (i.e. $n_o^* = n_o - \Delta n_o$). In terms of an overall molar balance,

$$\begin{aligned} n &= n_g + n_o \\ &= n_g + (n_o^* + \Delta n_o) \end{aligned} \tag{3-12}$$

and in terms of a component molar balance,

$$\begin{aligned} z_i n &= y_i n_g + x_i n_o \\ &= y_i n_g + x_i \Delta n_o + x_i n_o^* \\ &= y_i^* (n_g + \Delta n_o) + x_i n_o^* \end{aligned} \tag{3-13}$$

where y_i and x_i are standard separator samples (i.e. true equilibrium phase) compositions (assuming downstream sampling of the separator gas collects little if any of the carryover separator oil). An isokinetic gas sample, on the other hand, represents the separator gas plus carryover separator oil y_i^*.

Defining the separator oil carryover δ_{osp} as

$$\delta_{osp} \equiv \frac{\Delta n_o}{n_o} \tag{3-14}$$

the effect of carryover on wellstream composition is calculated by first correcting the test gas mole fraction $(F_{gsp})_{test}$ calculated from the test GOR. The corrected gas mole fraction reflects the *true* fraction of the total wellstream that is separator gas (n_g/n),

$$\begin{aligned} (F_{gsp})_{corr} &= \frac{n_g}{n_g + n_o} = \frac{n_g}{n} \\ &= \frac{(F_{gsp})_{test} - \delta_{osp}}{1 - \delta_{osp}} \end{aligned} \tag{3-15}$$

Furthermore, the measured test separator GOR $(R_{sp})_{test}$ can be corrected for carryover to yield the true separator GOR,

$$(R_{sp})_{corr} = (R_{sp})_{true} = (R_{sp})_{test} \; \frac{1/(F_{gsp})_{test} - 1}{1/(F_{gsp})_{corr} - 1} \qquad (3\text{-}16)$$

Table 3-12 and section 4.3.2 discuss the corrections to reported wellsite separator test GOR. The corrections result in a test GOR $(R_{sp})_{test}$ that is then used in Eq. (3-11) to determine $(F_{gsp})_{test}$ (referred to in the equations above).

3.5 References

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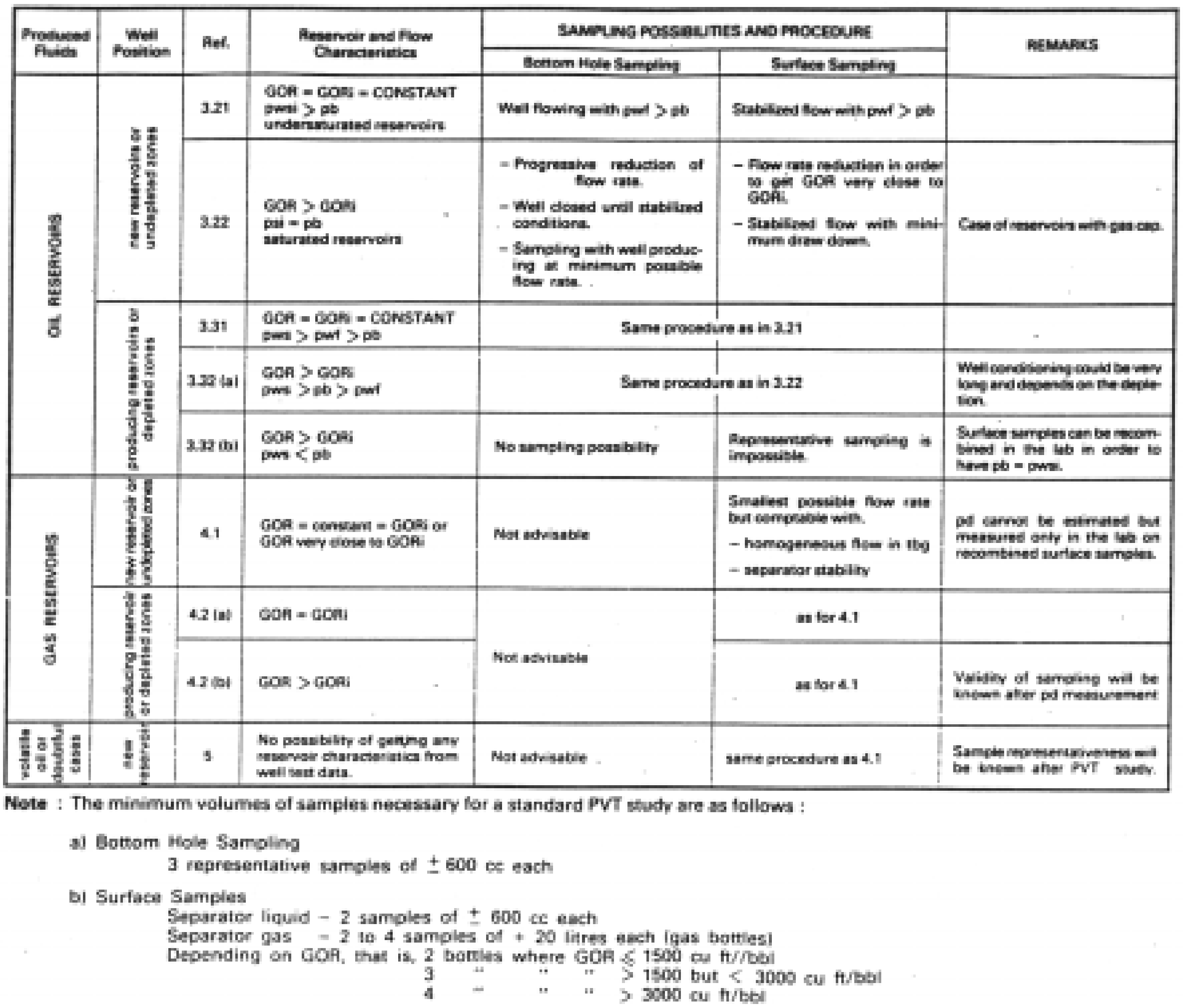
Table 3-1

Laboratory Analysis	**Oils**	**Gas Condensates**
Standard		
Bottomhole Sample Composition Recombined Separataor Composition C_{7+} TBP Distillation C_{7+} Simulated Distillation (SIMDIS)	● ○ ○ ○	○ ● ○ ○
Constant Composition Expansion	●	●
Multistage Surface Separation	●	○
Differential Liberation	●	N
Constant Volume Depletion	○	●
Special		
Multicontact Gas Injection	○	○
Wax Point Determination	○	○
Asphaltene Precipitation	○	○
Slimtube Analysis (MMP/MME)	○	○
Water Analysis Salinity, salt composition, solution gas ratio R_{sw} and solution gas composition, water FVF B_w, density	○	○
	● Standard ○ Can Be Performed N Not Performed	

Table 3-2



Produced Fluids	Well Position	Ref.	Reservoir and Flow Characteristics	SAMPLING POSSIBILITIES AND PROCEDURE		REMARKS
				Bottom Hole Sampling	Surface Sampling	
OIL RESERVOIRS	new reservoirs or undepleted zones	3.21	GOR = GORi = CONSTANT pwsi > pb undersaturated reservoirs	Well flowing with pwf > pb	Stabilized flow with pwf > pb	
		3.22	GOR > GORi psi = pb saturated reservoirs	– Progressive reduction of flow rate. – Well closed until stabilized conditions. – Sampling with well producing at minimum possible flow rate.	– Flow rate reduction in order to get GOR very close to GORi. – Stabilized flow with minimum draw down.	Case of reservoirs with gas cap.
	producing reservoirs or depleted zones	3.31	GOR = GORi = CONSTANT pwsi > pwf > pb	Same procedure as in 3.21		
		3.32 (a)	GOR > GORi pwsi > pb > pwf	Same procedure as in 3.22		Well conditioning could be very long and depends on the depletion.
		3.32 (b)	GOR > GORi pws < pb	No sampling possibility	Representative sampling is impossible.	Surface samples can be recombined in the lab in order to have pb = pwsi.
GAS RESERVOIRS	new reservoir or undepleted zones	4.1	GOR = constant = GORi or GOR very close to GORi	Not advisable	Smallest possible flow rate but compatible with. – homogeneous flow in tbg – separator stability	pd cannot be estimated but measured only in the lab on recombined surface samples.
	producing reservoir or depleted zones	4.2 (a)	GOR = GORi	Not advisable	as for 4.1	
		4.2 (b)	GOR > GORi		as for 4.1	Validity of sampling will be known after pd measurement
volatile oil or doubtful cases	new reservoir	5	No possibility of getting any reservoir characteristics from well test data.	Not advisable	same procedure as 4.1	Sample representativeness will be known after PVT study.

Note : The minimum volumes of samples necessary for a standard PVT study are as follows :

a) Bottom Hole Sampling
3 representative samples of ± 600 cc each

b) Surface Samples
Separator liquid – 2 samples of ± 600 cc each
Separator gas – 2 to 4 samples of + 20 litres each (gas bottles)
Depending on GOR, that is, 2 bottles where GOR ≤ 1500 cu ft//bbl
3 " " " > 1500 but < 3000 cu ft/bbl
4 " " " > 3000 cu ft/bbl

Table 3-3

Component/ Properties	Dry Gas	Wet Gas	Gas Condensate	Near-Critical Oil	Volatile Oil	Black Oil
CO_2	0.10	1.41	2.37	1.30	0.93	0.02
N_2	2.07	0.25	0.31	0.56	0.21	0.34
C_1	86.12	92.46	73.19	69.44	58.77	34.62
C_2	5.91	3.18	7.80	7.88	7.57	4.11
C_3	3.58	1.01	3.55	4.26	4.09	1.01
iC_4	1.72	0.28	0.71	0.89	0.91	0.76
nC_4		0.24	1.45	2.14	2.09	0.49
iC_5	0.50	0.13	0.64	0.90	0.77	0.43
nC_5		0.08	0.68	1.13	1.15	0.21
C_{6s}		0.14	1.09	1.46	1.75	1.61
C_{7+}		0.82	8.21	10.04	21.76	56.40
M_{7+}		130	184	219	228	274
γ_{7+}		0.763	0.816	0.839	0.858	0.920
K_{w7+}		12.00	11.95	11.98	11.83	11.47
GOR, Sm^3/Sm^3	∞	18,700	970	650	265	53
OGR, Sm^3/Sm^3	0	0.000053	0.00103	0.00154		
γ_o		0.751	0.784	0.802	0.835	0.910
γ_{API}		57	49	45	38	24
g		0.61	0.70	0.71	0.70	0.63
p_{sat}, bara		236	452	484	374	194
B_{sat}, m^3/Sm^3		0.0051	0.0039	2.78	1.73	1.16
ρ_{sat}, kg/m^3		154	428	492	612	823

Table 3-4

CUT No.	AET (C)	PRESSURE (mbar)	CORR. WEIGHT	MOLE-WEIGHT	DEN-SITY	CUMUL. VOLUME%	CUNUL. WEIGHT%	CUMUL. MOLE%
6	69.2	1013.0	2.0678	74.0	637.3	2.82	2.10	6.80
7	98.9	1013.0	2.8579	91.9	737.7	6.19	5.00	14.40
8	126.1	1013.0	4.1783	105.0	761.4	10.96	9.24	24.10
9	151.3	1013.0	3.1564	119.6	767.0	14.54	12.45	30.60
10	174.6	1013.0	3.3304	135.5	781.2	18.24	15.83	36.60
11	196.4	1013.0	3.2152	152.1	788.8	21.79	19.09	41.80
12	217.3	133.0	2.6398	166.8	814.6	24.60	21.77	45.60
13	236.1	133.0	3.2922	177.6	821.6	28.09	25.11	50.20
14	253.9	133.0	3.2779	192.0	831.5	31.51	28.44	54.30
13	271.1	133.0	3.4858	205.4	839.0	35.13	31.98	58.50
16	287.3	133.0	3.1219	218.9	845.0	38.34	35.15	62.00
17	303.0	133.0	3.3203	238.1	841.9	41.77	38.52	65.40
18	317.0	13.3	2.0351	249.8	857.2	43.83	40.58	67.40
19	331.0	13.0	2.4673	260.7	856.8	46.33	43.09	69.70
20	344.0	13.0	3.1851	267.7	854.9	49.57	46.32	72.60
21	357.0	13.0	2.9337	281.8	868.5	52.51	49.30	75.20
22	369.0	13.0	1.8715	298.4	869.4	54.38	51.20	76.70
23	381.0	13.0	2.2685	311.4	870.5	56.65	53.50	78.5
24	392.0	13.0	2.6268	326.2	873.6	59.26	56.17	80.40
25	402.0	13.0	2.2631	347.5	876.7	61.51	58.46	82.00
26	413.0	2.6	2.8756	362.8	887.6	64.32	61.38	84.00
27	423.0	2.6	2.7514	368.5	891.1	67.01	64.18	85.00
28	432.0	2.60	1.6452	383.1	896.2	68.60	65.85	86.00
RESIDUE			33.6463	630.0	931.6	100.00	100.00	99.00
SUM			98.5136	241.0	856.4			

+ FRACTION	DENSITY	MOLE WEIGHT	WEIGHT%	MOLE%	VOLUME%
C7+	853.50	252.30	97.90	93.16	97.18
C1O+	868.00	303.10	87.55	69.35	85.46
C15+	885.30	377.00	71.56	45.58	68.49
C20+	898.50	452.20	56.91	30.22	53.67
C25+	911.60	540.40	43.83	19.48	40.74
C29+	921.60	627.60	34.15	13.07	31.40

Table 3-5

Cut	Dens. 15.0C	Dens. 30.0C	Dens. 35.0C	Dens. 50.0C	MW cryo.	MW gc	Carb. nr.
C7-	*637.3				*	*	
C7	*737.7				*	*	
C8	*761.4				*	*	
C9	*767.0				*	*	
C10	781.2				135.5	141.0	9.9
C11	788.8				152.1	155.5	11.0
C12	814.6				166.8	170.8	12.0
C13	821.6				177.6	182.9	12.9
C14	831.5				192.0	196.5	13.9
C15	839.0				205.4	210.3	14.9
C16	845.0				218.9	224.6	15.9
C17	841.9				238.1	239.0	16.9
C18	857.2				249.8	252.5	17.9
C19	856.8				260.7	261.5	18.5
C20	854.9				267.7	274.7	19.5
C21	868.5				281.8	290.2	20.6
C22		859.2			298.4	304.0	21.6
C23		860.5			311.4	315.5	22.4
C24		863.4			326.2	329.9	23.4
C25		866.5			347.5	345.8	24.6
C26			873.8		362.8	363.0	25.8
C27			877.4		368.5	378.1	26.9
C28				872.4	383.1	393.2	27.9
C28+				909.1	630.0		

Table 3-6

CUT NO.	CORR. WEIGHT	MOLE-WEIGHT	DENSITY	N-2	N-i	N	N+1	N+2
6	2.0678	74.0	637.3	0.0	0.0	100.0	0.0	0.0
7	2.8579	91.9	737.7	0.0	0.0	100.0	0.0	0.0
8	4.1783	105.0	761.4	0.0	0.0	100.0	0.0	0.0
9	3.1564	119.6	767.0	0.0	0.0	100.0	0.0	0.0
10	3.3304	135.5	781.2	0.1	14.3	75.5	10.1	0.0
11	3.2152	152.1	788.8	0.2	11.3	78.4	10.2	0.0
12	2.6398	166.8	814.6	0.1	7.6	77.0	15.3	0.0
13	3.2922	177.6	821.6	0.2	17.7	69.7	12.4	0.0
14	3.2779	192.0	831.5	0.2	19.3	69.2	11.3	0.0
15	3.4858	205.4	839.0	0.3	20.2	68.8	10.8	0.0
16	3.1219	218.9	845.0	0.2	18.8	69.7	11.3	0.0
17	3.3203	238.1	841.9	0.2	15.9	72.1	11.8	0.0
18	2.0351	249.8	857.2	0.3	17.4	72.7	9.6	0.0
19	2.4673	260.7	856.8	1.9	41.2	56.6	0.4	0.0
20	3.1851	267.7	854.9	5.2	43.3	47.3	4.2	0.0
21	2.9337	281.8	868.5	4.8	35.2	53.9	6.1	0.0
22	1.8715	298.4	869.4	3.7	35.7	58.1	2.5	0.0
23	2.2685	311.4	870.5	6.2	47.0	46.3	0.6	0.0
24	2.6268	326.2	873.6	5.9	44.5	49.7	0.0	0.0
25	2.2631	347.5	876.7	2.6	37.8	59.6	0.0	0.0
26	2.8756	362.8	887.6	1.5	31.4	52.0	15.0	0.0
27	2.7514	368.5	891.1	3.3	23.3	57.0	14.2	2.2
28	1.6452	383.1	896.2	3.1	19.3	55.5	22.1	0.0
RESIDUE	33.6463	630.0	931.6	0.0	0.0	100.0	0.0	0.0
SUM	98.5136	241.0	856.4					

Table 3-7

FRACTION	WEIGHT%	VOLUME%	CUMUL. VOLUME%
C7-	2.10	2.82	2.82
C7	2.90	3.37	6.19
C8	4.25	4.77	10.96
C9	3.69	4.12	15.08
C10	2.92	3.20	18.28
C11	3.11	3.38	21.66
C12	2.99	3.15	24.81
C13	3.39	3.53	28.34
C14	3.44	3.54	31.88
C16	3.41	3.48	35.36
C16	3.13	3.17	38.53
C17	3.19	3.25	41.78
C18	3.10	3.10	44.87
C19	3.16	3.15	48.03
C20	2.66	2.66	50.69
C21	2.56	2.52	53.22
C22	2.52	2.49	55.70
C23	2.36	2.32	58.02
C24	2.25	2.21	60.23
C25	2.38	2.32	62.55
C26	2.22	2.14	64.69
C27	2.35	2.26	66.95
C28	1.32	1.27	68.22
RESIDUE	34.58	31.78	100.00
SUM	100.00	100.00	

Table 3-8

WELL	34/8-1
DATE	01-AUG-86

WEIGHT OF OIL (g)	98.5136
DENSITY (kg/m3)	847.24
MOLEWEIGHT (STO)	240.12
LOSS (%)	0.553

COMPOSITION OF LIGHT END.

GROUP	WEIGHT%	DENSITY	MOLE WEIGHT	MOLE%
N2	0.000	260.0000	28.0000	0.000
C02	0.000	420.0000	44.0000	0.000
Cl	0.002	260.0000	16.0000	0.030
C2	0.009	358.0000	30.0700	0.072
C3	0.067	507.6000	44.0970	0.365
iso-C5	0.050	563.3000	58.1240	0.206
n-C4	0.209	584.7000	58.1240	0.863
neo-C5	0.005	596.7000	72.1510	0.017
iso-C5	0.222	624.6000	72.1510	0.738
n-C5	0.406	630.9000	72.1510	1.350
C6	1.129	665.9611	85.4676	3.169
C7	2.901	737.7272	91.8668	7.576
C8	4.245	761.3593	104.9967	9.700
C9	3.687	767.0172	119.5922	7.397
C10+	87.067	867.1056	304.8689	68.518
SUM	99.999	847.24	240.12	100

Table 3-9

Component	Wt %	mol %	mol wt.
Nitrogen	0.10	0.29	
Carbon dioxide	0.59	1.05	
Methane	12.58	61.07	
Ethane	1.77	4.58	
Propane	1.79	3.16	
iso-Butane	0.41	0.55	
n-Butane	1.07	1.43	
iso-Pentane	0.52	0.57	
n-Pentane	0.72	0.78	
Hexanes	1.16	1.07	84.50
P	1.06	0.96	
N	0.10	0.11	
A	0.00	0.00	
Heptanes	2.00	1.72	90.70
P	0.00	0.67	
N	0.90	0.81	
A	0.24	0.24	
Octanes	2.89	2.14	105.00
P	1.17	0.80	
N	1.19	0.90	
A	0.53	0.44	
Nonanes	2.21	1.45	118.50
P	1.08	0.65	
N	0.42	0.28	
A	0.71	0.52	
Decanes plus	72.19	20.14	279
SUM	100.00	100.00	
Average molecular weight:			77.90

	z_i - mol %	M_i	ρ_i	$z_i M_i$	$z_i M_i / \rho_i$
C7	1.72	90.7	0.74	156.0	210.0
C8	2.14	105.0	0.76	224.7	296.0
C9	1.45	118.5	0.78	171.8	220.9
Cl0+	20.14	279.0	0.88	5619.1	6407.1
Sum / Aver.	25.45	242.5	0.87	6171.6	7134.0
Kw7+=	11.85				

Table 3-10

	RECOMBINED COMPOSITION		
DATE	11/11-88		
WELL	34/8-3		*R_{sp} = 2638 / 1.157 = 2280 Sm^3 / Sm^3*
BOTTLE NO.	A10996		
TYPE OF SAMPLE	DST2		** Pseudo?? = Lab recomb. Conditions $\neq$ sep. cond.*
TEMP. (C)	56.3		
PRESSURE (bara):	50.3	*field*	
GOR (Sm3/Sm3)	2385	(pseudo) *X 2638 Sm^3 / Sm^3*	
OIL	*721 Field*		
DENSITY (kg/m3):	754.1	(pseudo) *X sep. oil*	15 C
MOLEWEIGHT	115.50		CRYOSCOPY

	GAS PHASE		LIQUID PHASE			RECOMBINED COMPOSITION		
FRACTION	WEIGHT%	MOLE%	WEIGHT%	MOLE%	DENSITY	MOLEWG	WEIGHT%	MOLE%
N2	1.273	0.848	0.015	0.064	260.0		0.910	0.800
C02	2.906	1.232	0.155	0.407	420.0		2.111	1.181
Cl	76.952	89.496	2.259	16.263	260.0		55.379	84.988
C2	7.263	4.506	0.842	3.235	358.0		5.409	4.428
C3	4.908	2.076	1.403	3.674	507.6		3.895	2.174
ISO-C4	1.017	0.326	0.546	1.086	563.3		0.881	0.373
N-C4	2.226	0.714	1.647	3.273	584.7		2.059	0.872
NEO-C5	0.013	0.003	0.015	0.024	596.7		0.013	0.005
ISO-C5	0.744	0.192	1.166	1.867	624.6		0.866	0.295
N-C5	0.907	0.234	1.817	2.909	630.9		1.170	0.399
C-6	0.796	0.174	3.926	5.281	664.4	85.88	1.700	0.488
C-7	0.667	0.139	8.194	10.280	736.3	92.06	2.841	0.763
C-8	0.287	0.053	10.280	11.277	753.4	105.29	3.173	0.743
C-9	0.041	0.006	8.342	8.020	764.6	120.14	2.439	0.499
C-10+	0.000	0.000	59.391	32.341	870.5	212.11	17.154	1.991

	GAS PHASE	LIQUID PHASE	RECOM. COMPOSITION
WEIGHT-% C6+	1.7917	90.13	27.3071
NOLE-% C6+	0.3715	67.20	4.4850
MOLEWEIGHT C6+	89.9680	154.92	149.8737
MOLEWEIGHT C1O+	156.0000	212.11	212.1052
MEAN NOLEWEIGHT	18.6546	115.50	24.6159
MOLE-DISTRIBUTION	93.8429	6.16	100.0000
WEIGHT-DISTRIBUTION	71.1123	28.89	100.0000

GAS GRAVITY	0.6433			
CRITICAL TEMP(K)	205.2575			
CRITICAL PRESS(bara)	46.4660	M7+	160.8	
Z-FACTOR	0.9179	ρ 7+	829.6	
DENSITY (kg/m3)	37.3054			346.4548
VISCOSITY (mpa*s)	0.0131			

FRACTION	GAS PHASE			LIQUID PHASE			RECOM. COMPOSITION		
	P	N	A	P	N	A	P	N	A
C6	97.10	2.90		98.50	1.50		98.00	2.00	
C7	37.50	47.20	15.40	48.50	40.80	10.60	46.70	41.90	11.40
C8	32.50	43.70	23.70	48.20	35.80	16.00	47.20	36.30	16.50
C9	84.60	13.10	2.10	56.70	20.30	23.00	57.00	20.20	22.80

Table 3-11

DATE	11/11-88	
WELL	34/8-3	
BOTTLE NO.	23	
TYPE OF SAMPLE	KOND . DST2	
TEMP. (C)	56.30	
PRESSURE (bara):	50.30	
GOR (Sm3/5m3)	44.40	
OIL		
DENSITY (kg/m3):	783.6	15 C
NOLEWEIGHT	146	CRYOSCOPY

	GAS PHASE		LIQUID PHASE			RECOMBINED COMPOSITION		
FRACTION	WEIGHT%	MOLE%	WEIGHT%	MOLE%	DENSITY	MOLEWG	WEIGHT%	MOLE%
N2	0.255	0.249	0.000	0.000	260.00		0.015	0.064
C02	2.560	1.588	0.000	0.000	420.00		0.155	0.408
Cl	37.202	63.308	0.003	0.027	260.00		2.259	16.268
C2	13.257	12.034	0.041	0.199	358.00		0.842	3.236
C3	17.650	10.924	0.354	1.172	507.60		1.403	3.675
ISO-C4	4.582	2.152	0.286	0.718	563.30		0.546	1.086
N-C4	10.522	4.941	1.074	2.698	584.70		1.647	3.274
NEO-C5	0.063	0.024	0.012	0.024	596.70		0.015	0.024
ISO-C5	3.397	1.285	1.022	2.068	624.60		1.166	1.867
N-C5	3.913	1.480	1.682	3.404	630.90		1.817	2.910
C-6	3.066	0.978	3.982	6.768	664.40	85.89	3.926	5.282
C-7	2.505	0.767	8.561	13.568	736.00	92.12	8.194	10.283
C-8	0.938	0.250	10.883	15.088	753.40	105.31	10.280	11.280
C-9	0.091	0.020	8.875	10.785	764.60	120.14	8.342	8.022
C-10+	0.000	0.000	63.225	43.479	827.00	212.30	59.391	32.321

	GAS PHASE	LIQUID PHASE	RECOM. COMPOSITION
WEIGHT-% C6+	6.5996	9S.S3	90.1340
MOLE-% C6+	2.0149	89.69	67.1880
MOLEWEIGHT C6+	89.4029	155.50	154.9925
MOLEWEIGHT C10+	156.0000	212.30	212.3037
MEAN MOLEWEIGHT	27.2958	146.00	115.5350
MOLE-DISTRIBUTION	25.6598	74.34	100.0000
WEIGHT-DISTRIBUTION	6.0620	93.94	100.0000
GAS GRAVITY	0.9412		
CRITICAL TEMP(K)	256.3946		
CRITICAL PRESS(bara)	45.4203		
Z-FACTOR	0.8095		
DENSITY (kg/m3)	61.8986		734.2313
VISCOSITY (mpa*s)	0.0125		

FRACTION GAS	GAS PHASE			LIQUID PHASE			RECOM. COMPOSITION.		
	P	N	A	P	N	A	P	N	A
C6	97.0	3.0		98.5	1.5		98.5	1.5	
C7	36.3	49.2	14.5	48.7	40.7	10.6	48.5	40.8	10.6
C8	30.7	55.2	14.1	48.3	35.7	16.0	48.2	35.8	16.0
C9	58.3	32.7	9.0	56.7	20.3	23.0	56.7	20.3	23.0

Table 3-12

TEST SEPARATOR GOR CORRECTION FOR WELLSTREAM RECOMBINATION CALCULATIONS

$$(R_{sp})_{lab} = (R_{sp})_{field} \frac{\sqrt{(Z_g)_{field}\,(\gamma_g)_{field}}}{\sqrt{(Z_g)_{lab}\,(\gamma_g)_{lab}}} \frac{(p_{sc})_{field}}{(p_{sc})_{lab}}$$

$$F_{gsp} = \frac{1}{1 + 23.68 \dfrac{\rho_{osp}}{M_{osp}\ (R_{sp})_{lab}}}$$

$$z_i = F_{gsp}\ y_i + (1 - F_{gsp})\ x_i$$

$(R_{sp})_{field}$ = separator gas-oil ratio based on rates calculated in the field, $Sm^3/sep.m^3$

$(R_{sp})_{lab}$ = corrected separator GOR at laboratory conditions, used to determine the physical and mathematical recombination molar ratio F_{gsp}

$(Z_g)_{field}$ = separator gas Z-factor used in field calculation of gas rate

$(Z_g)_{lab}$ = laboratory (true) separator gas Z-factor determined in the laboratory at conditions during gas metering

$(\gamma_g)_{field}$ = separator gas gravity used in field calculations of gas rate

$(\gamma_g)_{lab}$ = separator gas gravity based on measured composition or direct measurement

(ρ_{osp}) = separator oil density at separator conditions during sampling, kg/m^3

(M_{osp}) = separator oil molecular weight

F_{gsp} = mole fraction of total wellstream leaving the separator in the gas stream

y_i = laboratory measured separator gas molar composition

x_i = laboratory measured separator oil molar composition

z_i = wellstream molar composition

Table 3-13

THREE STAGE SEPARATOR TEST OF RESERVOIR FLUID TO STOCK TANK CONDITIONS

Stage	Pressure bar	Temp. °C	Evolved gas 3) Sm^3/m^3	R_s 3) Sm^3/m^3	B_o 4) m^3/m^3	Density of st. tank oil kg/m^3	Gas gravity Air=1
	424.5 1)	114.0 2)		221.8	1.640		0.659
1	70.0	50.0	183.6	38.2	1.140		0.628
2	30.0	50.0	20.1	18.1	1.104		0.662
3	atm	15.0	18.1	0.0	1.000	851.8	0.974
						34.4 API	

1 Bubble point pressure at reservoir temperature

2 Reservoir temperature

3 Standard m^3 gas per m^3 stock tank oil

4 m^3 liquid at indicated pressure and temperature per m^3 stock tank oil

Table 3-14

PRESSURE-VOLUME RELATION OF RESERVOIR FLUID

Pressure	Relative volume V/V_{bp}	Isothermal compressibility bar^{-1}	"Y"
548.7	0.9737	1.78E-04	
525.9	0.9781	1.91E-04	
501.7	0.9824	2.05E-04	
478.3	0.9874	2.19E-04	
452.6	0.9934	2.34E-04	
430.5	0.9985	2.46E-04	
424.5	1.0000	2.50E-04	
412.8	1.0063		4.520
391.4	1.0197		4.294
368.3	1.0363		4.200
338.6	1.0622		4.078
306.4	1.0977		3.944
276.1	1.1416		3.796
239.3	1.2149		3.602
202.7	1.3219		3.399
155.9	1.5512		3.126
116.4	1.9184		2.882
85.9	2.4620		2.696

Best fit V equation above boiling point
$V_{rel} = 1.1617 - 5.120 \text{ X } 10^{-4}\ p + 3.091 \text{ X } 10^{-7}\ p^{2}$

Best fit Y equation
$Y = 2.286 + 0.532 \text{ X } 10^{-2}\ p$

Table 3-15

T = 112 °C

Pressure bara	Relative volume	Rel. (1) liquid %	Volumetric (2) Z-factor	Compositional (3) Z-factor
532.42	0.909		1.2172	1.2171
511.54	0.924		1.1887	1.1927
491.25	0.940		1.1612	1.1693
470.57	0.958		1.1334	1.1459
451.48	0.976		1.1080	1.1247
435.89	0.992		1.0873	1.1076
432.39	0.998		1.0834	1.1038
430.39	0.999		1.0801	1.1017
Pd - 430.00	1.000	Trace	1.0788	1.1007
422.99	1.007	0.045	1.0707	
416.50	1.015	0.218	1.0633	
401.50	1.035	0.787	1.0448	
381.61	1.065	1.606	1.0215	
361.71	1.099	2.550	0.9994	
341.51	1.139	3.460	0.9778	
321.41	1.185	4.354	0.9574	
301.51	1.239	5.507	0.9391	
281.41	1.304	6.714	0.9225	
261.50	1.380	7.528	0.9074	
241.79	1.473	8.179	0.8951	
221.79	1.587	8.848	0.8850	
201.47	1.729	9.230	0.8761	
181.46	1.909	9.701	0.8711	
161.54	2.139	9.912	0.8688	
141.43	2.443	10.076	0.8688	
121.31	2.857	10.097	0.8715	
101.69	3.433	9.972	0.8777	
81.16	4.343	9.726	0.8863	
63.14	5.656	9.395	0.8980	

(1). Retrograde liquid deposit in volume % of sample volume at dewpoint.

(2). $Z = pV/nRT$. Not corrected for liquid deposit below the dewpoint.

(3). Z-factor from the recombined composition in table 4 by the Dranchuc correlation

Table 3-16

DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114 °C

Pressure (bar)	3) Oil Formation Volume Factor B_o	4) Solution Gas-Oil Ratio R_s (Sm^3/Sm^3)	5) Gas Formation Volume Factor B_g (m^3/Sm^3)	Density of saturated oil (kg/m^3)	2) B_t (m^3/Sm^3)
548.7	1.691			643.40	
525.9	1.698			640.50	
501.7	1.714			634.40	
452.6	1.725			630.60	
430.5	1.734			627.40	
424.5	1.736	250.50		626.40	1) 1.736
391.3	1.650	217.10	3.76E-03	643.20	1.775
345.3	1.557	180.90	4.00E-03	662.50	1.835
300.7	1.484	151.20	4.43E-03	679.00	1.924
252.5	1.415	123.60	5.17E-03	696.40	2.071
203.1	1.354	98.30	6.28E-03	712.80	2.309
153.1	1.297	74.60	8.24E-03	729.50	2.747
101.8	1.242	51.50	1.256E-02	746.50	3.741
49.7	1.187	29.10	2.649E-02	764.80	7.050
14.2	1.140	12.60	9.664E-02	781.60	24.129
1.0	1.091			787.40	

Density of residual oil at 15 °C: 859.0 kg/m^3

1) Density at bubble point from single flash: 634.5 kg/m^3
2) Volume of oil and liberated gas at p and tivolume of residual oil
3) m^3 liquid at indicated pressure per m^3 residual oil
4) Standard m^3 gas per m^3 residual oil
5) m^3 gas at indicated pressure per m^3 gas at standard condition

B_o, see fig. 8
R_s, see fig. 9
B_g, see fig. 10
Density of saturated oil, see fig. 14

NORSK HYDRO A/S
Well: 34/8-3A DST1A

Table 3-17

DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114 °C

(Gas properties calculated from molecular composition)

Pressure (bar)	1) Gas viscosity (mPa/s)	Gas gravity (Air = 1)	Compressibility factor, Z	Molecular wieght
391.3	0.0256	0.654	1.0697	18.94
345.3	0.0242	0.662	1.0238	19.18
300.7	0.0226	0.661	0.9844	19.16
252.5	0.0208	0.657	0.9488	19.02
203.1	0.0190	0.656	0.9234	19.00
153.1	0.0174	0.654	0.9135	18.94
101.9	0.0159	0.665	0.9196	19.27
49.7	0.0146	0.702	0.9463	20.33
14.2	0.0135	0.835	0.9763	24.18
1.0	-	2.069	-	59.93

1) For the calculation ref. page 46
Gas viscosity, see fig. 11
Gas gravity, see fig. 12
Compressibility factor, see fig. 13

Table 3-18

DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114.0 °C

MOLECULAR COMPOSITION OF LIBERATED GASES weight % (wt.%) and mol%

Pressure/bar	391.3			345.3			300.7		
	Wt%	mol %	Mol. weight	Wt%	mol %	Mol. weight	Wt%	mol %	Mol. weight
Nitrogen	0.91	0.61		0.99	0.68		0.89	0.61	
Carbon dioxide	2.91	1.25		2.87	1.25		2.87	1.25	
Methane	75.19	88.79		73.92	88.40		74.19	88.61	
Ethane	7.45	4.69		7.26	4.64		7.28	4.64	
Propane	5.67	2.44		5.84	2.54		5.57	2.42	
iso-Butane	1.17	0.38		1.13	0.37		1.10	0.36	
n-Butane	2.60	0.85		2.57	0.85		2.50	0.82	
i so-Pentane	0.99	0.26		1.01	0.27		0.98	0.26	
n-Pentane	1.18	0.31		1.28	0.34		1.22	0.32	
Hexanes	1.07	0.24	84.2	1.42	0.32	84.3	1.35	0.31	84.3
Heptanes	0.71	0.15	90.3	1.30	0.27	90.8	1.34	0.28	91.1
Octanes	0.15	0.03	105.1	0.41	0.07	105.1	0.61	0.11	105.1
Nonanes	0.00	0.00		0.00	0.00		0.08	0.01	118.2
Decanes-plus	0.00	0.00		0.00	0.00		0.02	0.002	156
Sum	100.00	100.00		100.00	100.00		100.00	100.002	
Average molwt.			18.94			19.18			19.16

Table 3-19

VISCOSITY OF RESERVOIR
FLUID AT 114 °C

	Pressure bar	Viscosity mPa.s
	530.0	0.321
	510.5	0.315
	491.5	0.310
	471.5	0.306
	451.5	0.300
Pb	431.5	0.293
	424.5	0.292
	394.5	0.320
	371.3	0.340
	341.9	0.367
	299.4	0.418
	253.7	0.484
	202.3	0.580
	152.1	0.685
	101.5	0.829
	49.5	1.045
	12.1	1.397
	1.0	1.564

Table 3-20

Depletion study of reservoir fluid at 112 °C

	Pressure bara	Retrograde liquid deposit vol % of dewpoint vol.	Cumulative produced fluid mole % of initial fluid	Z-factor, volumetric Z=pV/nRT	Z-factor compositional (D.P.R.)
Pd	430.0	0.00	0.00	1.080	1.102
	407.7	0.67	2.71	1.103	1.074
	372.2	2.43	7.07	1.033	1.033
	321.6	4.86	14.72	0.979	0.982
	271.7	6.75	24.42	0.943	0.942
	220.8	7.82	36.06	0.912	0.913
	170.3	8.22	49.13	0.908	0.903
	121.2	8.04	62.63	0.917	0.907
	62.3	7.40	79.16	0.953	0.943

Mass balance :		Initial fluid amount, moles :	4.513 *
	-	Residual fluid amount, moles :	0.835 **
	=	Produced fluid amount, moles :	3.678
		Recovered fluid amount, moles:	3.572 ***
Recovery % :		3.572 / 3.678 * 100% :	97.12%

* Initial amount of fluid in the condensate cell at 112 °C and 430 bar.
** Residual fluid amount in the condensate cell at 112 °C and 62.3 bar.
*** Total recovery of gas and condensate at standard conditions.

Table 3-21

Composition (mole %) of produced gas from depletion study at 112 °C

Pressure bara	407.7	372.2	321.6	271.7	220.8	170.3	121.2	62.3
N2	0.819	0.817	0.845	0.799	0.867	0.867	0.811	0.836
CO2	1.212	1.210	1.260	1.250	1.242	1.250	1.198	1.262
C1	85.484	85.435	85.920	86.687	87.166	87.816	88.067	88.640
C2	4.499	4.494	4.483	4.491	4.490	4.494	4.357	4.603
C3	2.214	2.214	2.196	2.183	2.172	2.135	2.061	2.099
iso-C4	0.381	0.382	0.378	0.373	0.370	0.355	0.361	0.325
n-C4	0.887	0.892	0.879	0.863	0.854	0.810	0.859	0.729
neo-C5	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.003
iso-C5	0.298	0.301	0.295	0.286	0.282	0.258	0.308	0.235
n-C5	0.396	0.402	0.393	0.379	0.375	0.337	0.427	0.298
C6	0.468	0.482	0.470	0.439	0.435	0.373	0.493	0.292
C7	0.670	0.703	0.678	0.604	0.552	0.494	0.472	0.280
C8	0.606	0.654	0.620	0.526	0.423	0.365	0.289	0.176
C9	0.371	0.410	0.379	0.306	0.204	0.161	0.108	0.075
C10+	1.692	1.599	1.198	0.809	0.563	0.282	0.186	0.144
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Moleweight	22.80	22.80	22.10	21.30	20.70	20.10	19.90	19.30
Gravity (air=1)	0.7857	0.7855	0.7629	0.7348	0.7143	0.6920	0.6866	0.6663
Viscosity (cP)	0.0317	0.0299	0.0265	0.0234	0.0206	0.0183	0.0165	0.0150
C7+	3.339	3.366	2.875	2.245	1.742	1.302	1.055	0.675

Table 3-22

Table 3-23

$$K_i \, p_{sp} = a + c \, F_i$$

$$F_i = b_i \, (1/T_{bi} - 1/T_{sp}) \, ; \; T(^oR)$$

Component		b_i cycle-^{o}R	T_{bi} ^{o}R
Nitrogen	N_2	470	109
Carbon Dioxide	CO_2	652	194
Hydrogen Sulfide	H_2S	1136	331
Methane	C_1	300	94
Ethane	C_2	1145	303
Propane	C_3	1799	416
i-Butane	iC_4	2037	471
n-Butane	nC_4	2153	491
i-Pentane	iC_5	2368	542
n-Pentane	nC_5	2480	557
Hexanes (lumped*)	C_{6s}	2738	610
n-Hexane	nC_6	2780	616
n-Heptane	nC_7	3068	669
n-Octane	nC_8	3335	718
n-Nonane	nC_9	3590	763
n-Decane	nC_{10}	3828	805

Heptanes-plus:

$$n_{7+} = 7.3 + 0.0075 \, T_{sp}(^oF) + 0.0016 \, p_{sp}(psia)$$

$$b_{7+} = 1013 + 324 \, n_{7+} - 4.256(n_{7+})^2$$

$$T_{b7+} = 301 + 59.85 \, n_{7+} - 0.971(n_{7+})^2$$

* Lumped hexanes include 25% 2-methyl pentane, 25% 3-methyl pentane, and 50% normal hexane.

Table 3-24

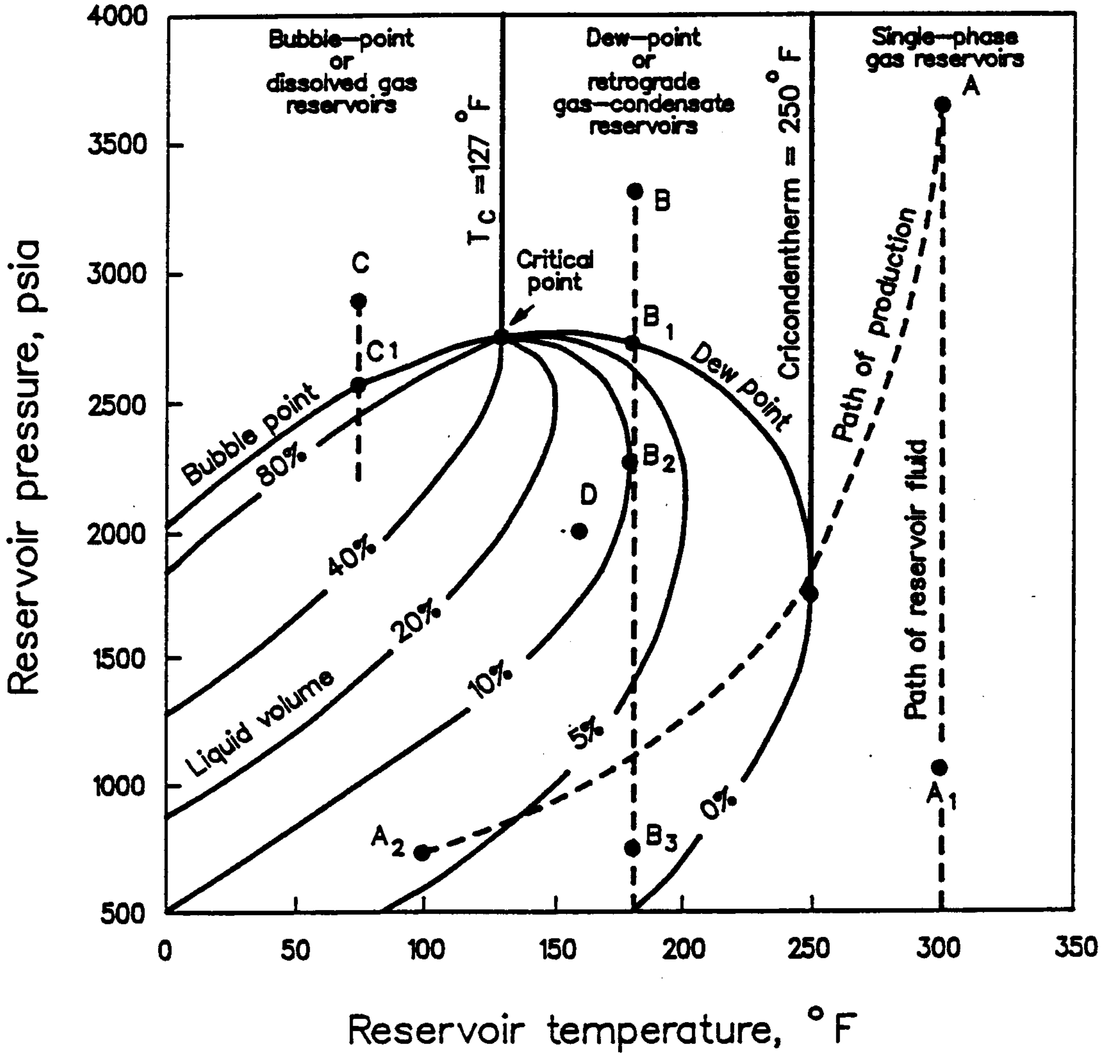

Bubble–point or dissolved gas reservoirs
Dew–point or retrograde gas–condensate reservoirs
Single–phase gas reservoirs
T c =127 °F
Cricondentherm = 250 °F
Critical point
Bubble point
Dew point
Liquid volume
80%
40%
20%
10%
5%
0%
A
A1
A2
B
B1
B2
B3
C
C1
D
Path of production
Path of reservoir fluid
Reservoir pressure, psia
4000
3500
3000
2500
2000
1500
1000
500
Reservoir temperature, °F
0
50
100
150
200
250
300
350

Figure 3-1

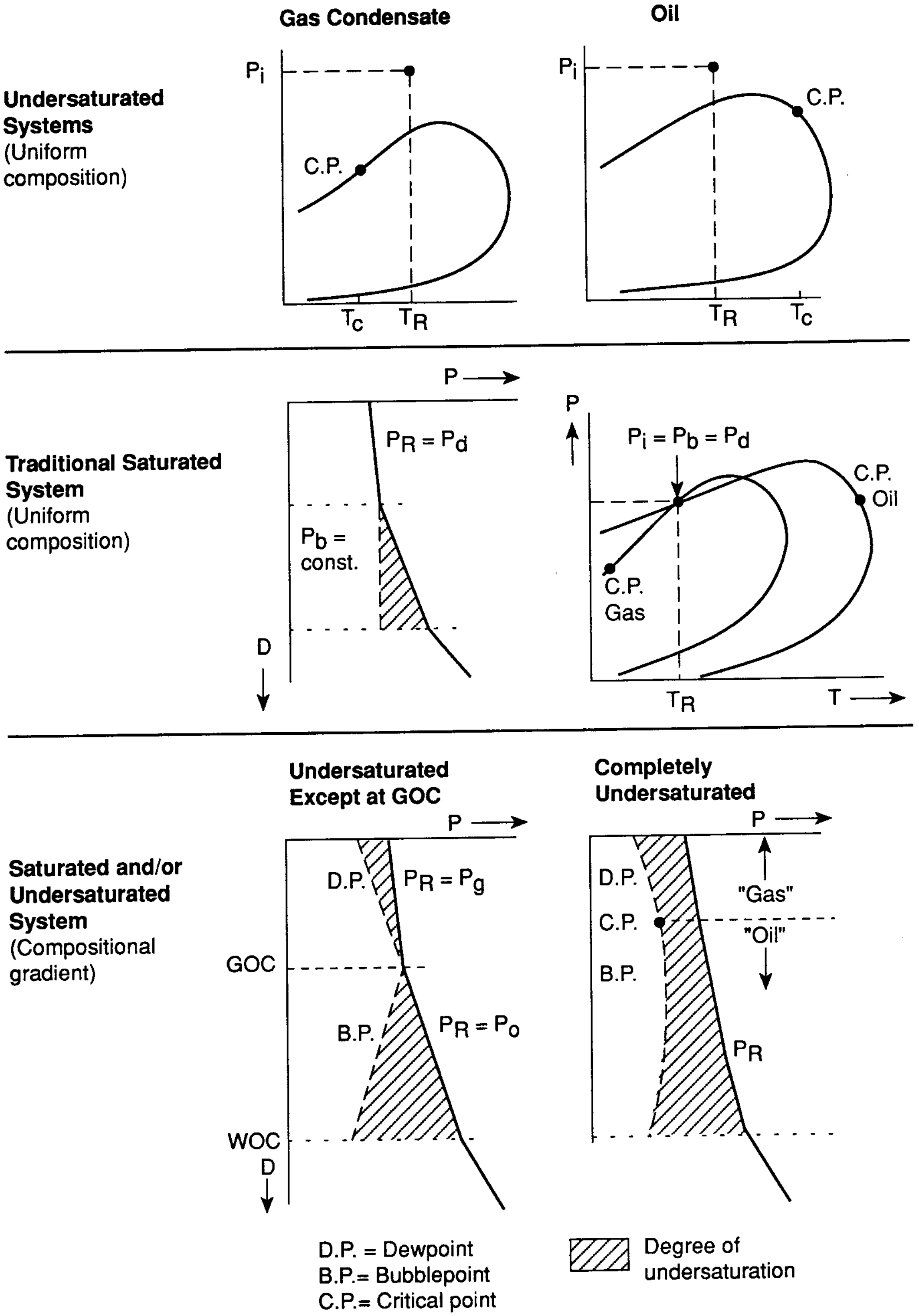

Gas Condensate
Oil
Undersaturated Systems
(Uniform composition)
Pi
C.P.
Tc
TR
Traditional Saturated System
(Uniform composition)
P
PR = Pd
Pb = const.
D
Pi = Pb = Pd
C.P. Oil
C.P. Gas
T
Saturated and/or Undersaturated System
(Compositional gradient)
Undersaturated Except at GOC
Completely Undersaturated
D.P.
PR = Pg
GOC
B.P.
PR = Po
WOC
"Gas"
"Oil"
PR
D.P. = Dewpoint
B.P.= Bubblepoint
C.P.= Critical point
Degree of undersaturation

Figure 3-2

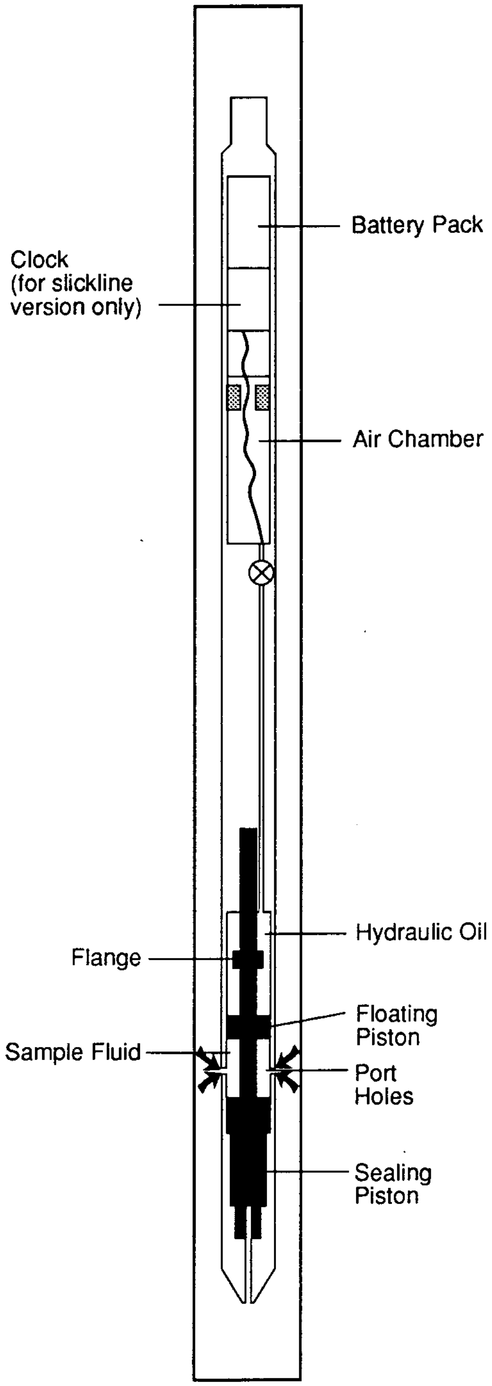

Battery Pack
Clock
(for slickline
version only)
Air Chamber
Hydraulic Oil
Flange
Floating
Piston
Sample Fluid
Port
Holes
Sealing
Piston

Figure 3-3

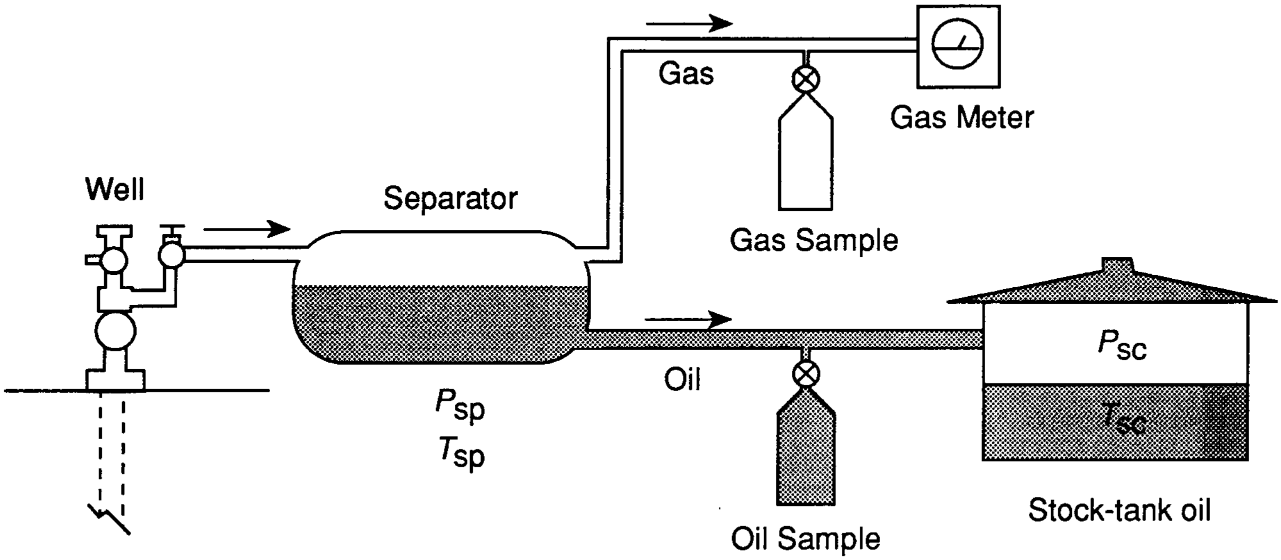

Gas
Gas Meter
Well
Separator
Gas Sample
P_{sc}
Oil
P_{sp}
T_{sp}
T_{sc}
Stock-tank oil
Oil Sample

Figure 3-4

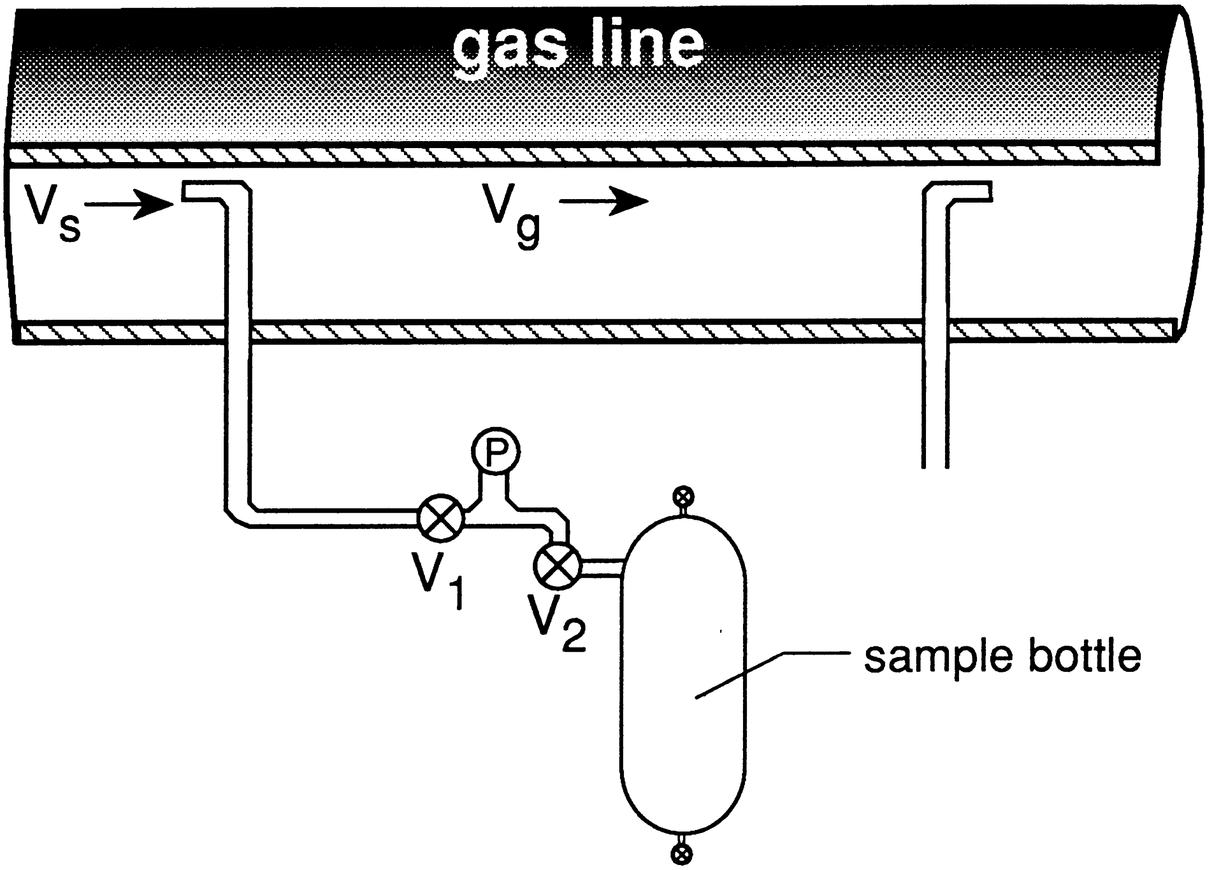


Figure 3-5

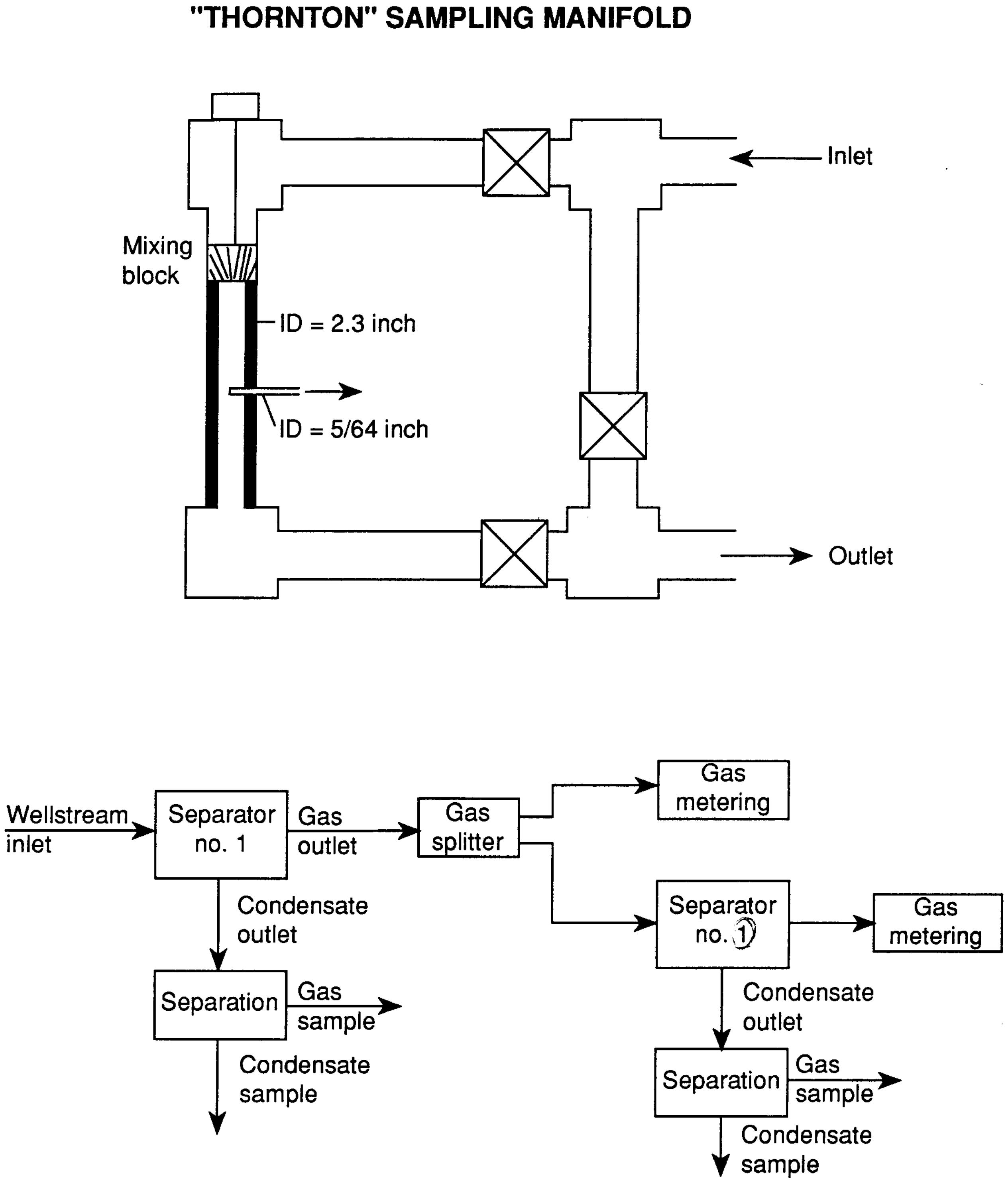

"THORNTON" SAMPLING MANIFOLD
Inlet
Mixing block
ID = 2.3 inch
ID = 5/64 inch
Outlet
Wellstream inlet
Separator no. 1
Gas outlet
Gas splitter
Gas metering
Separator no. 1
Gas metering
Condensate outlet
Separation
Gas sample
Condensate sample
Condensate outlet
Separation
Gas sample
Condensate sample

Figure 3-6

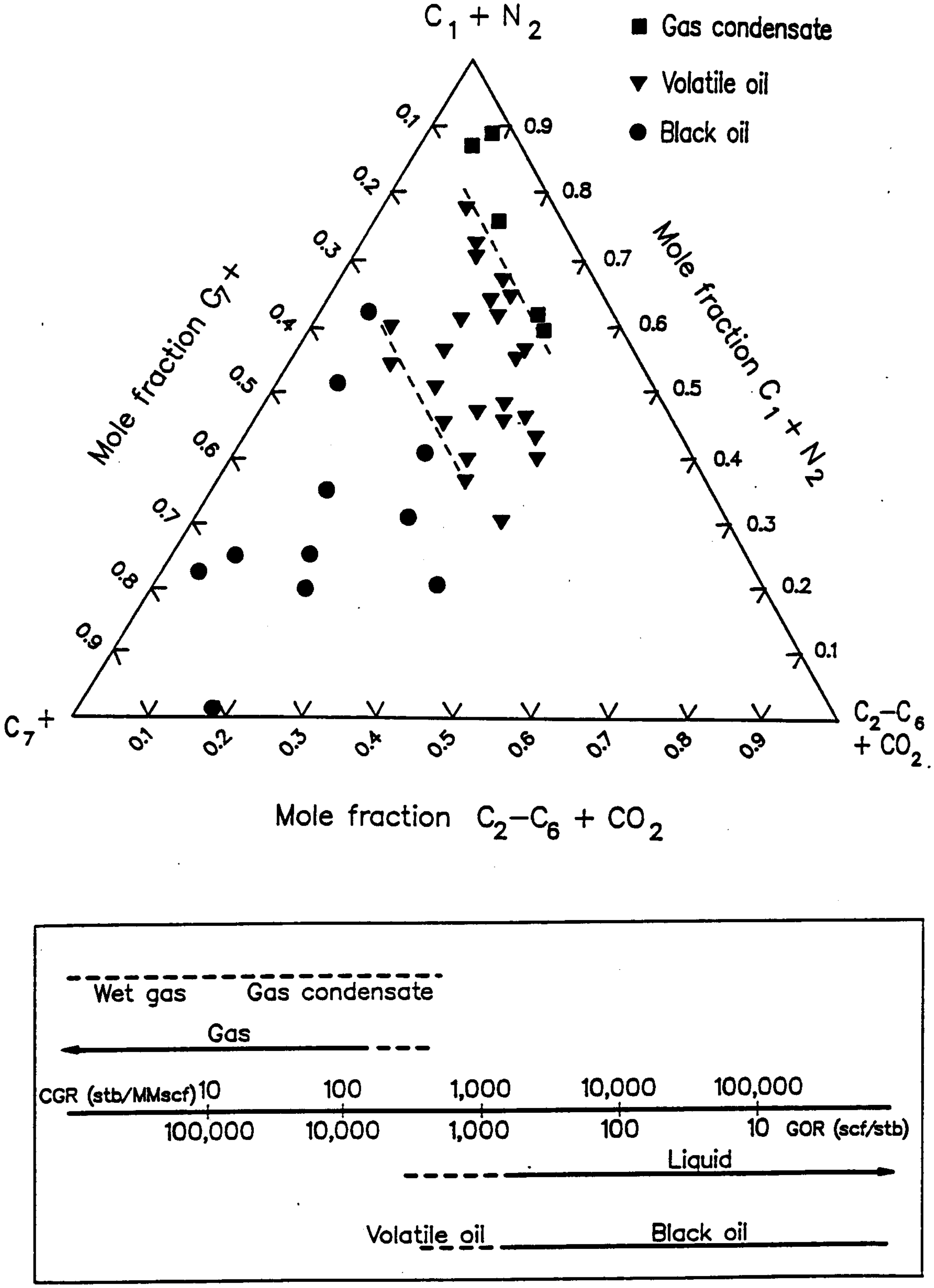

$C_1 + N_2$
Gas condensate
Volatile oil
Black oil
Mole fraction C_7+
Mole fraction $C_1 + N_2$
C_7+
$C_2-C_6 + CO_2$
Mole fraction $C_2-C_6 + CO_2$
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Wet gas
Gas condensate
Gas
CGR (stb/MMscf) 10
100
1,000
10,000
100,000
100,000
10,000
1,000
100
10
GOR (scf/stb)
Liquid
Volatile oil
Black oil

Figure 3-7

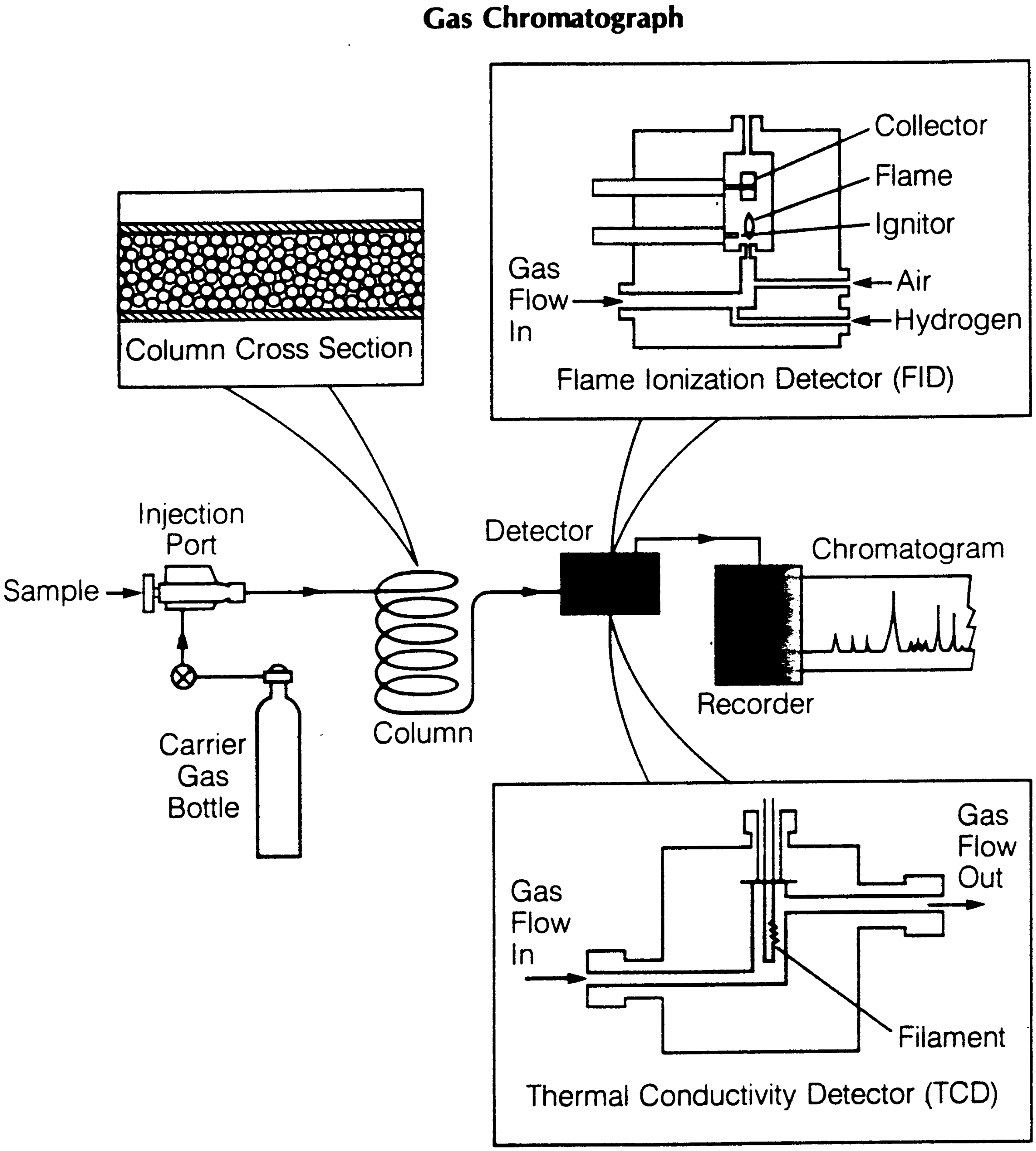

Gas Chromatograph
Collector
Flame
Ignitor
Gas Flow In
Air
Hydrogen
Flame Ionization Detector (FID)
Column Cross Section
Injection Port
Sample
Detector
Chromatogram
Recorder
Carrier Gas Bottle
Column
Gas Flow Out
Gas Flow In
Filament
Thermal Conductivity Detector (TCD)

Figure 3-8

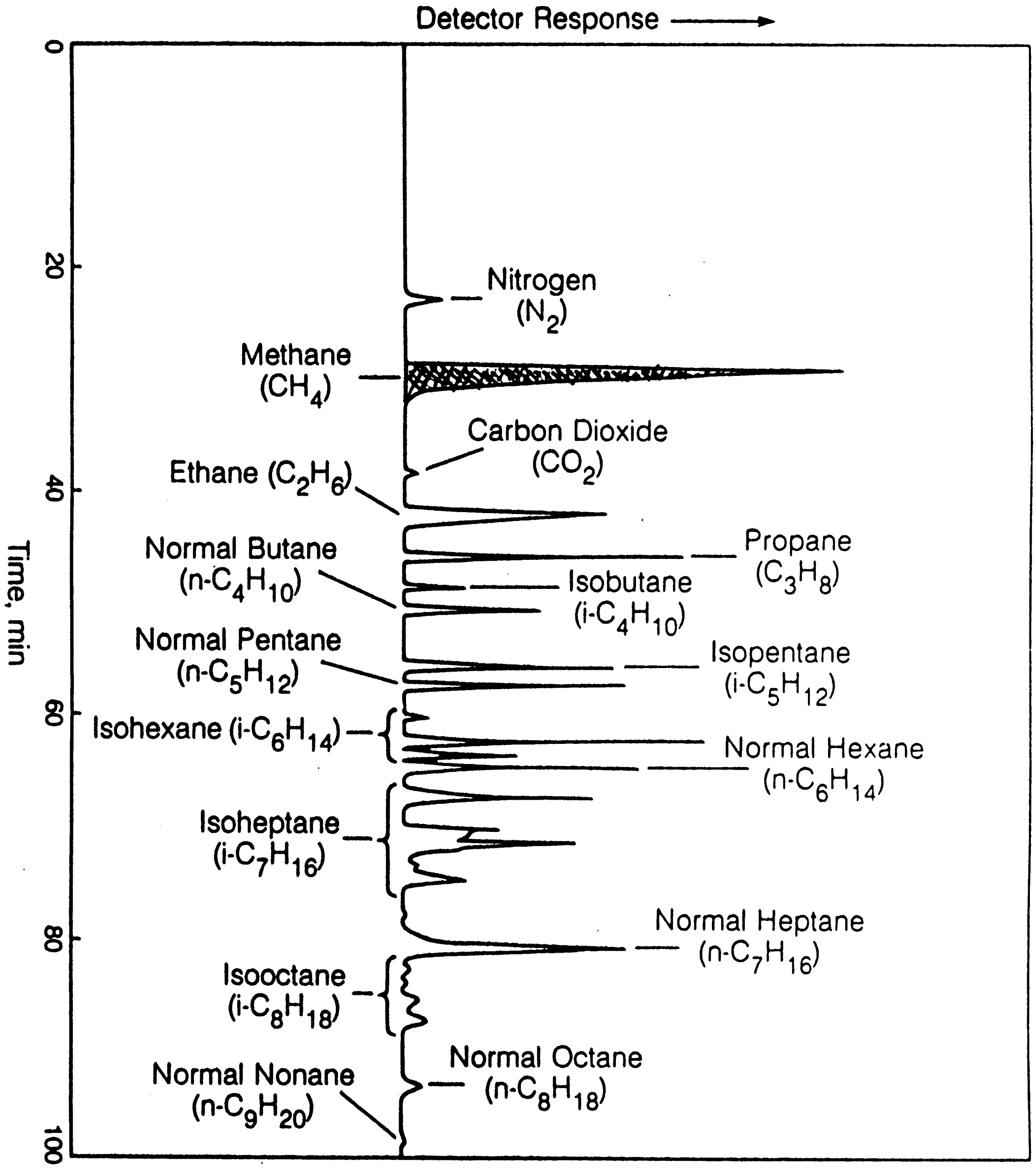

Detector Response
0
20
40
60
80
100
Time, min
Nitrogen (N_2)
Methane (CH_4)
Carbon Dioxide (CO_2)
Ethane (C_2H_6)
Propane (C_3H_8)
Normal Butane (n-C_4H_{10})
Isobutane (i-C_4H_{10})
Normal Pentane (n-C_5H_{12})
Isopentane (i-C_5H_{12})
Isohexane (i-C_6H_{14})
Normal Hexane (n-C_6H_{14})
Isoheptane (i-C_7H_{16})
Normal Heptane (n-C_7H_{16})
Isooctane (i-C_8H_{18})
Normal Octane (n-C_8H_{18})
Normal Nonane (n-C_9H_{20})

Figure 3-9

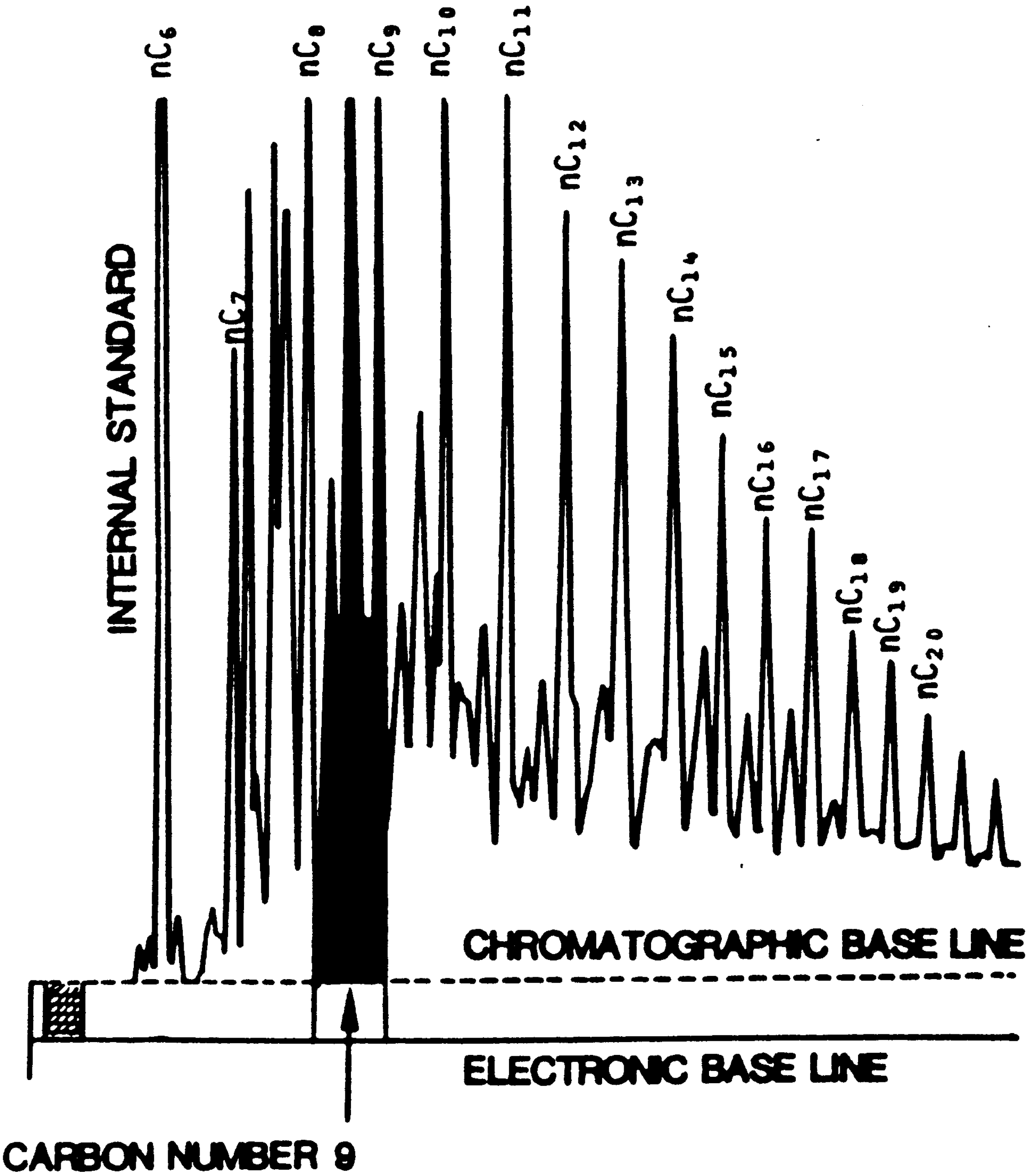

INTERNAL STANDARD
nC6
nC7
nC8
nC9
nC10
nC11
nC12
nC13
nC14
nC15
nC16
nC17
nC18
nC19
nC20
CHROMATOGRAPHIC BASE LINE
ELECTRONIC BASE LINE
CARBON NUMBER 9

Figure 3-10

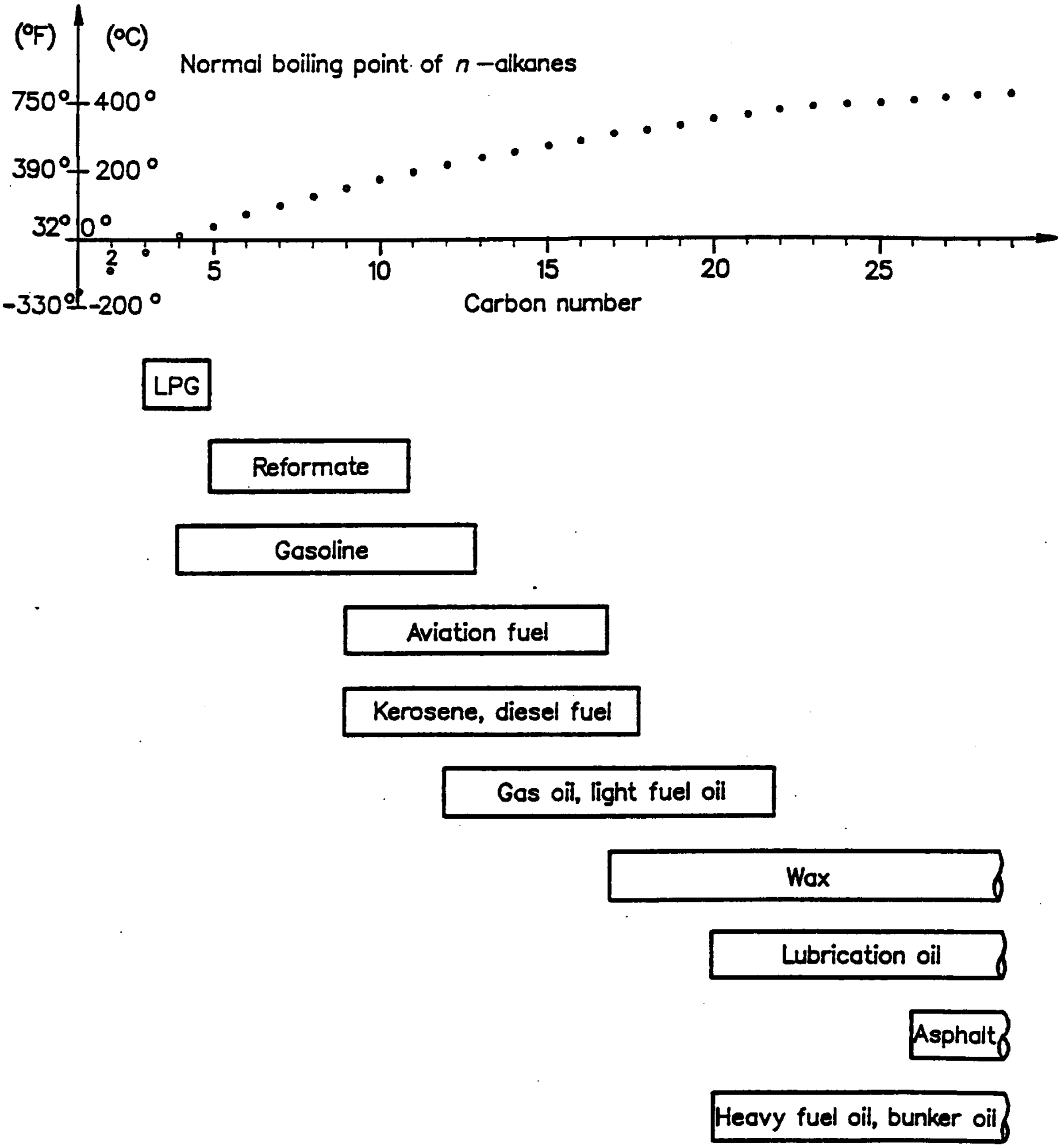

(°F)
(°C)
Normal boiling point of n —alkanes
750°
400 °
390°
200 °
32°
0 °
-330°
-200 °
2
5
10
15
20
25
Carbon number
LPG
Reformate
Gasoline
Aviation fuel
Kerosene, diesel fuel
Gas oil, light fuel oil
Wax
Lubrication oil
Asphalt
Heavy fuel oil, bunker oil

Figure 3-11

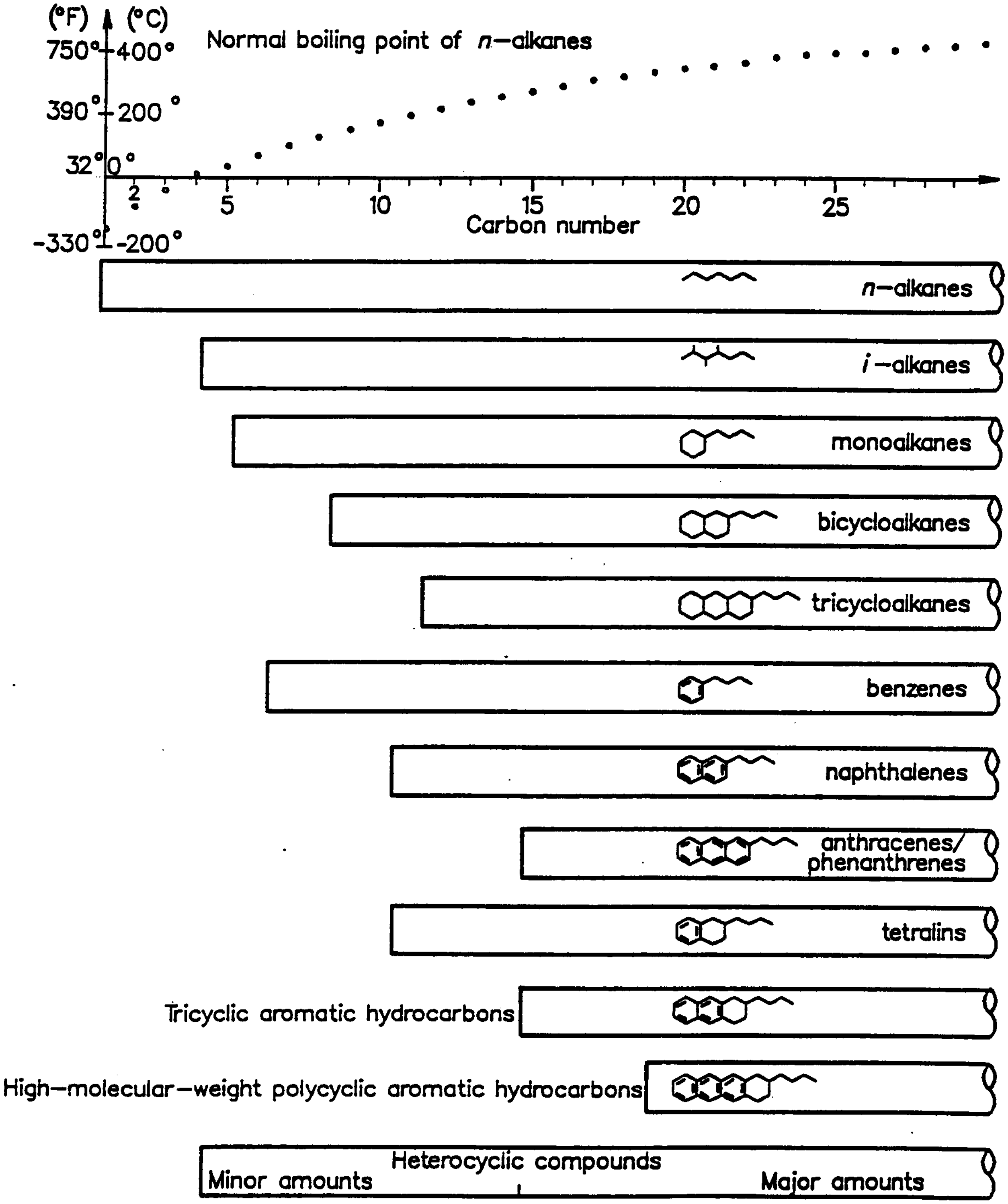

(°F)
(°C)
750°
400°
390°
200°
32°
0°
-330°
-200°
Normal boiling point of *n*–alkanes
2
5
10
15
20
25
Carbon number
n–alkanes
i–alkanes
monoalkanes
bicycloalkanes
tricycloalkanes
benzenes
naphthalenes
anthracenes/
phenanthrenes
tetralins
Tricyclic aromatic hydrocarbons
High–molecular–weight polycyclic aromatic hydrocarbons
Heterocyclic compounds
Minor amounts
Major amounts

Figure 3-12

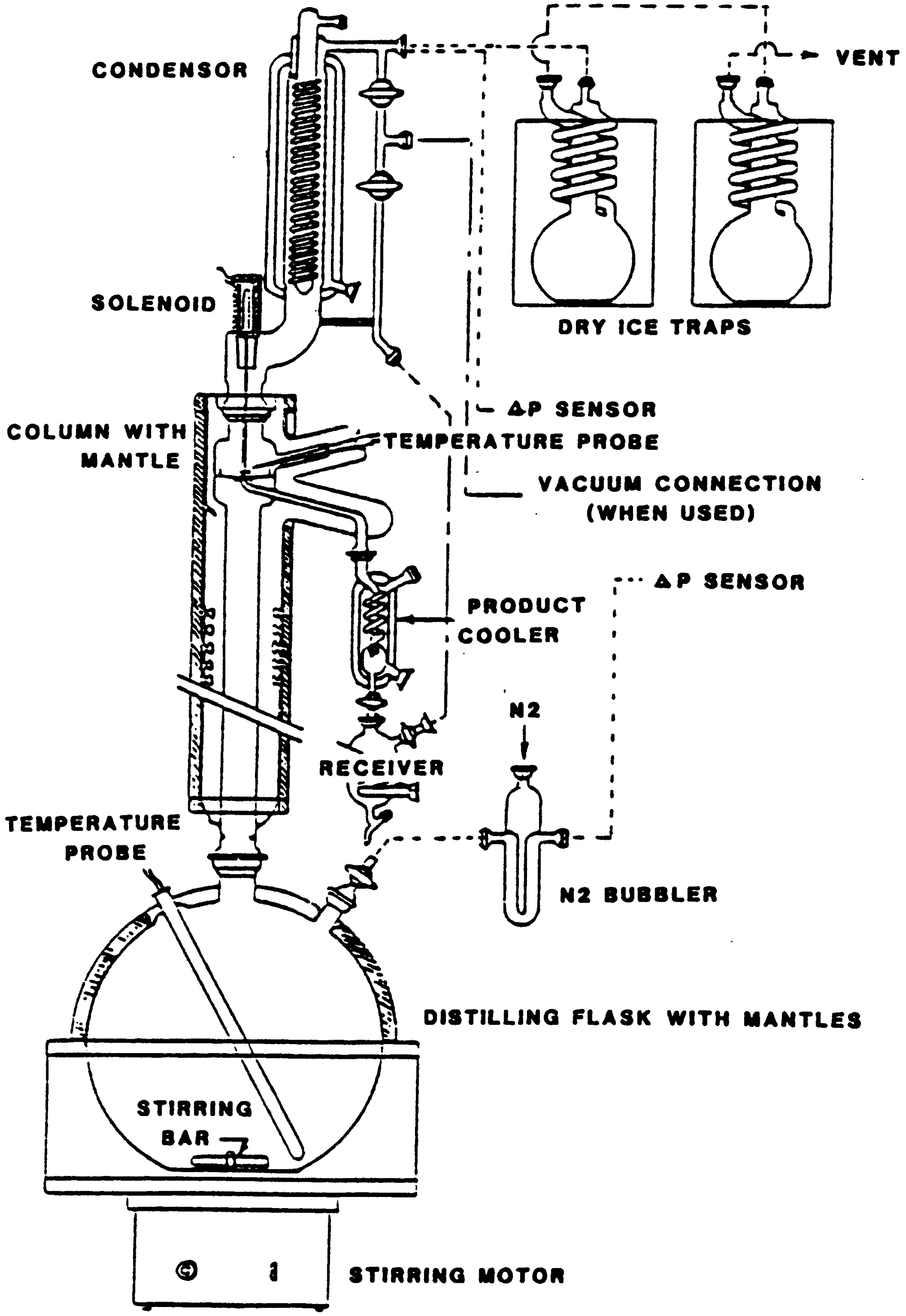
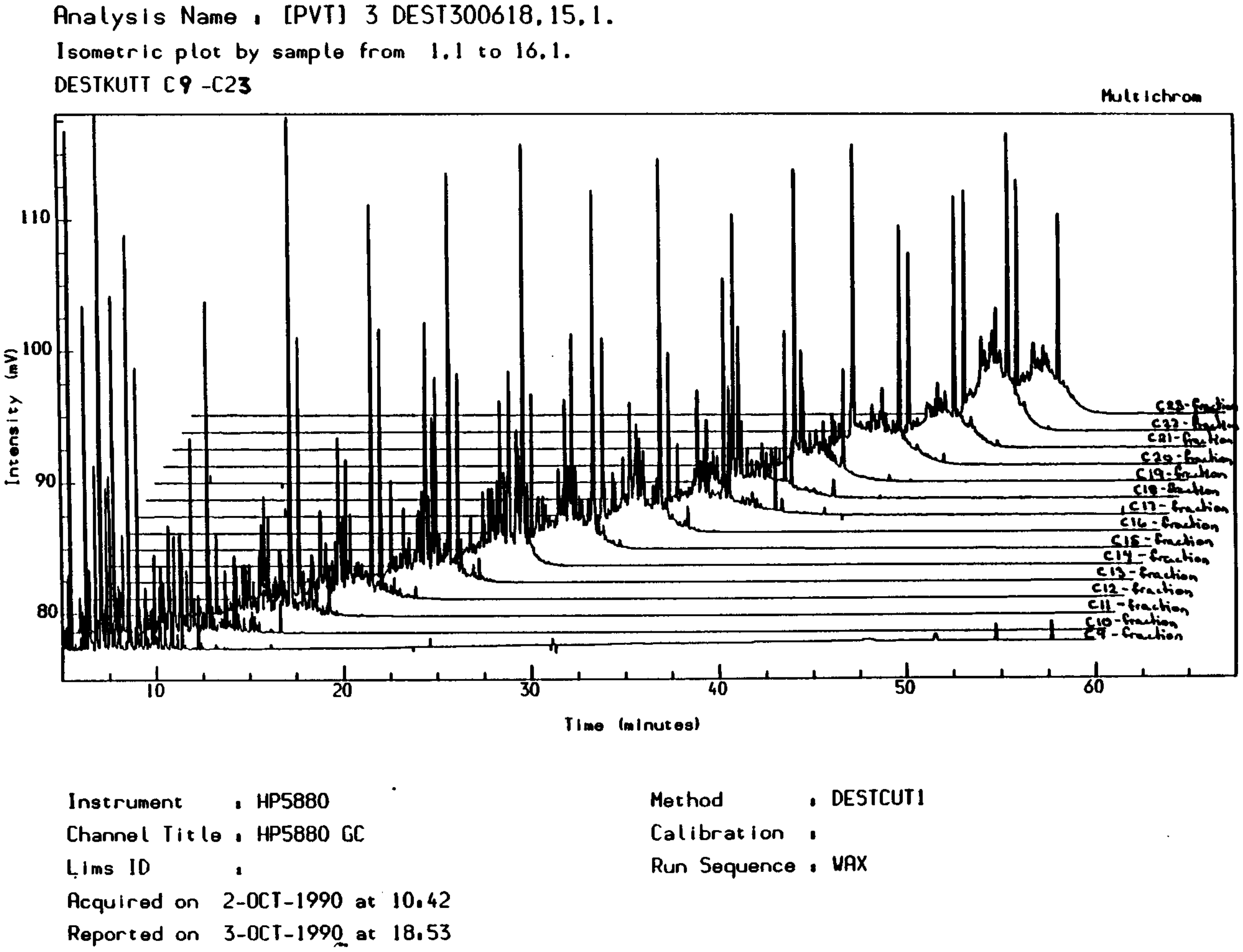

CONDENSOR
VENT
SOLENOID
DRY ICE TRAPS
ΔP SENSOR
COLUMN WITH MANTLE
TEMPERATURE PROBE
VACUUM CONNECTION (WHEN USED)
ΔP SENSOR
PRODUCT COOLER
N2
RECEIVER
TEMPERATURE PROBE
N2 BUBBLER
DISTILLING FLASK WITH MANTLES
STIRRING BAR
STIRRING MOTOR

Figure 3-13



Analysis Name : [PVT] 3 DEST300618.15.1.
Isometric plot by sample from 1.1 to 16.1.
DESTKUTT C9 -C23

Instrument : HP5880
Channel Title : HP5880 GC
Lims ID :
Acquired on 2-OCT-1990 at 10:42
Reported on 3-OCT-1990 at 18:53

Method : DESTCUT1
Calibration :
Run Sequence : WAX

Figure 3-14

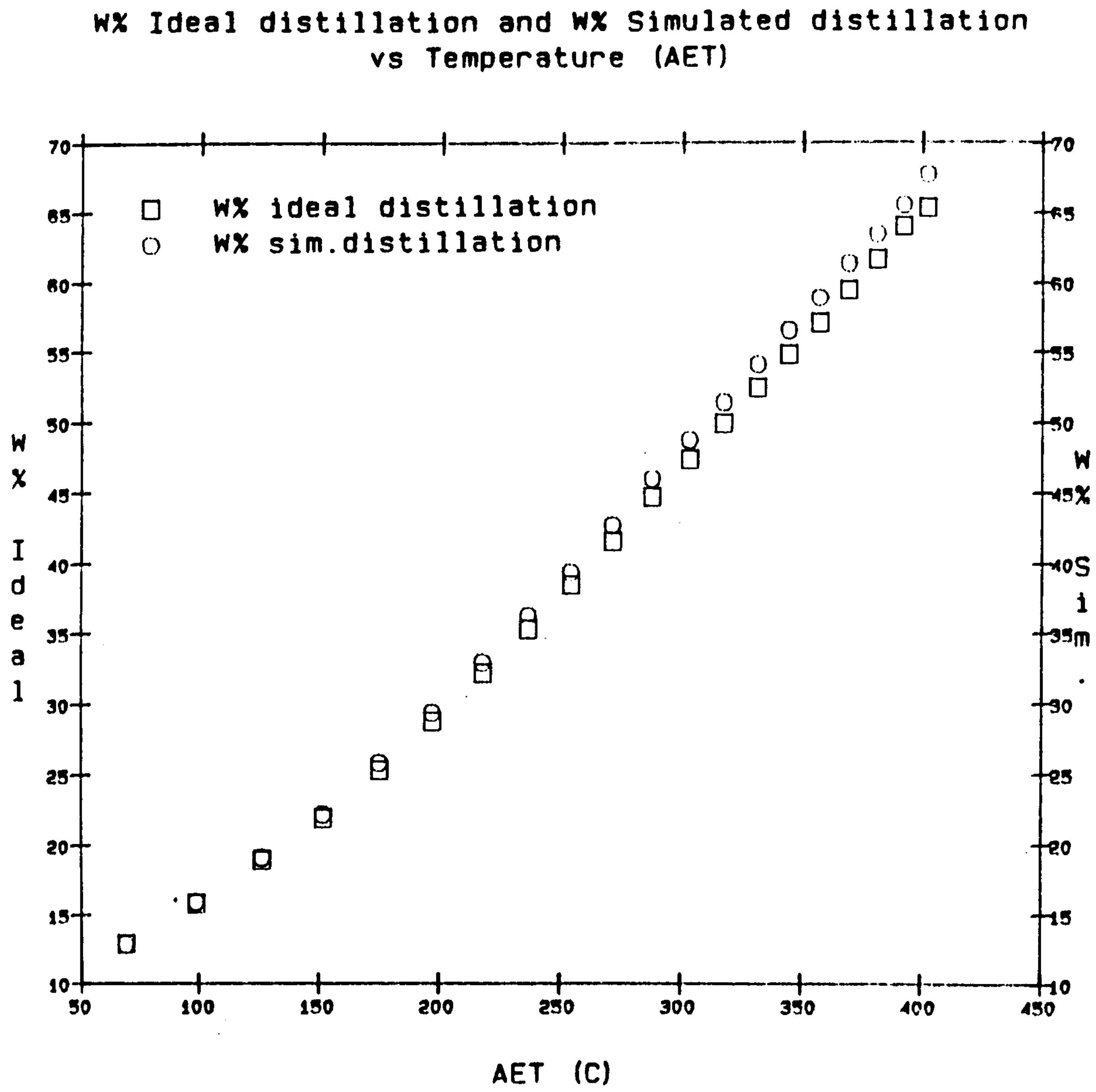

W% Ideal distillation and W% Simulated distillation vs Temperature (AET)
□ W% ideal distillation
○ W% sim.distillation
W% Ideal
W% Sim.
AET (C)
10
15
20
25
30
35
40
45
50
55
60
65
70
50
100
150
200
250
300
350
400
450

Figure 3-15

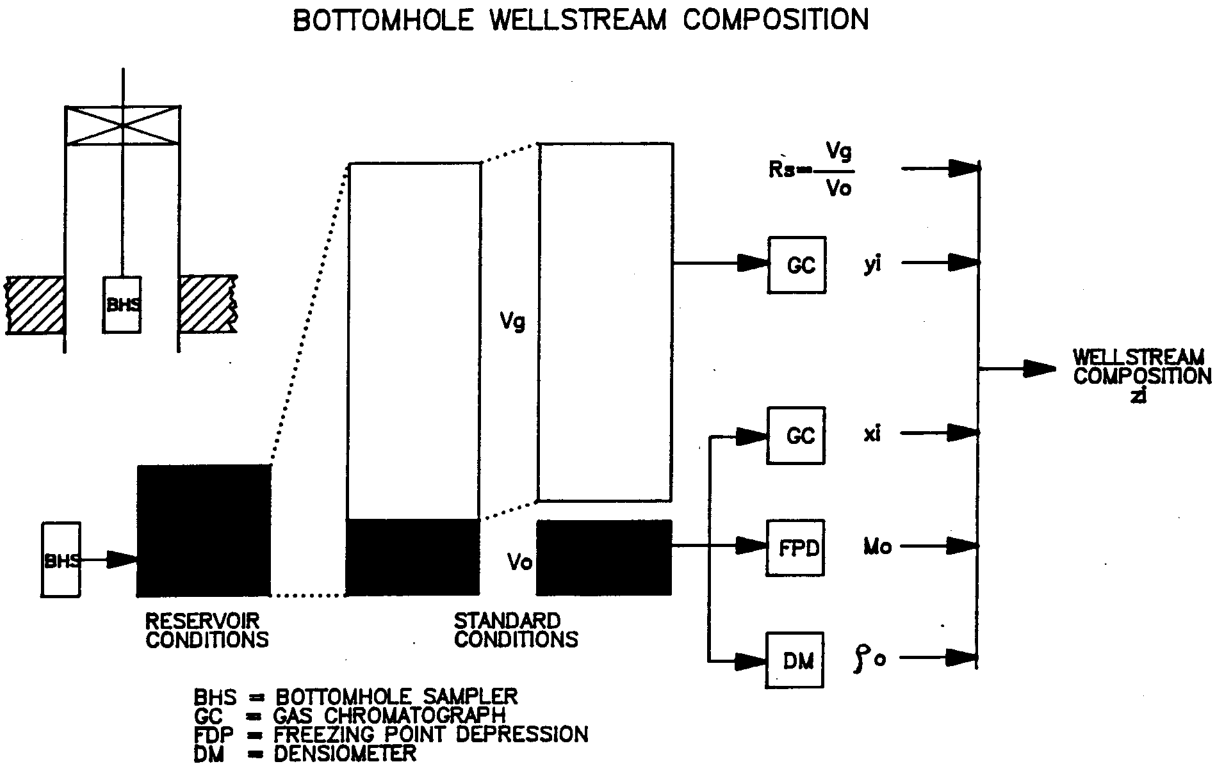

BOTTOMHOLE WELLSTREAM COMPOSITION
BHS
BHS
Vg
Vo
RESERVOIR CONDITIONS
STANDARD CONDITIONS
Rs = Vg / Vo
GC
yi
GC
xi
FPD
Mo
DM
ρo
WELLSTREAM COMPOSITION zi
BHS = BOTTOMHOLE SAMPLER
GC = GAS CHROMATOGRAPH
FDP = FREEZING POINT DEPRESSION
DM = DENSIOMETER

Figure 3-16

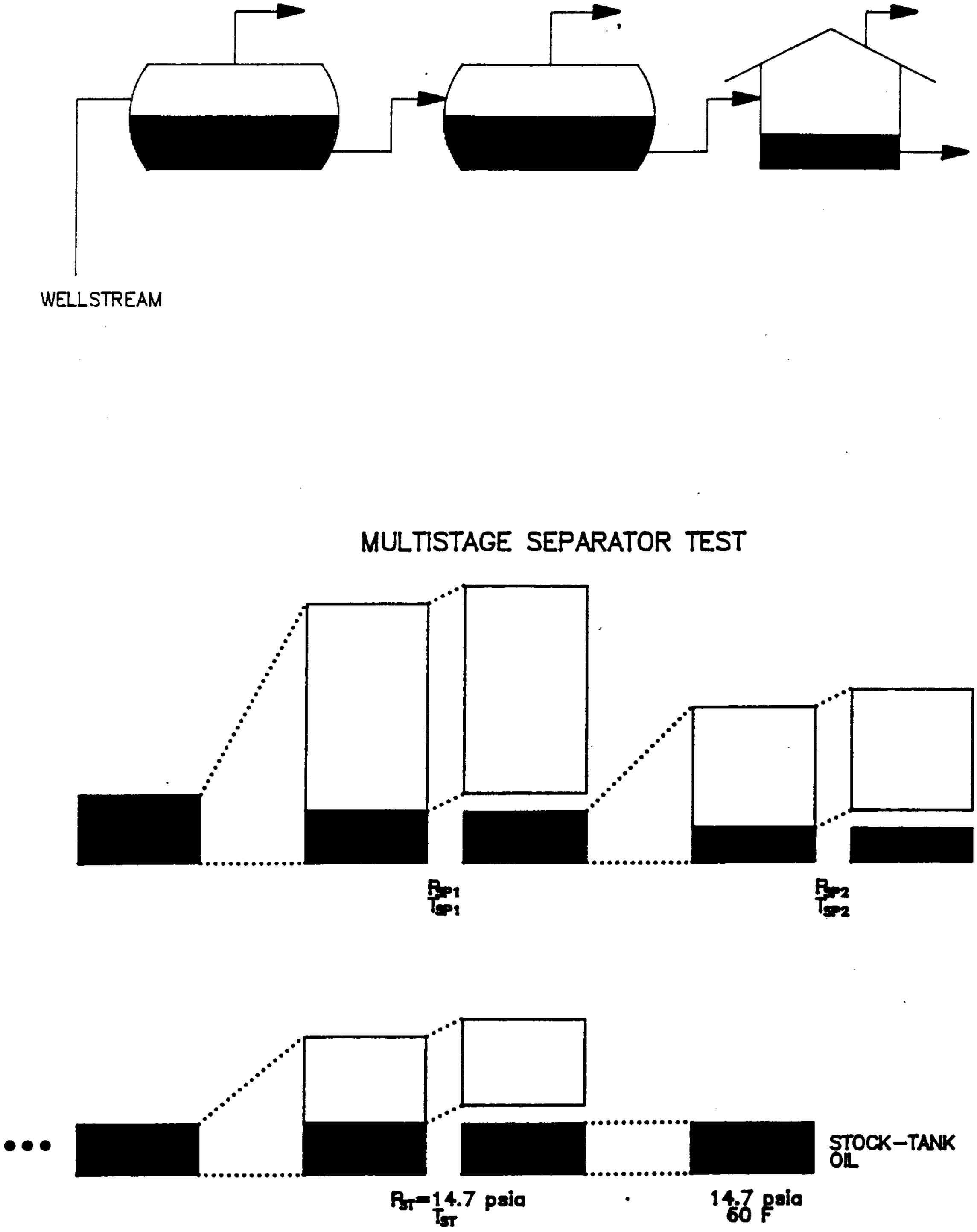

WELLSTREAM
MULTISTAGE SEPARATOR TEST
P_{SP1}
T_{SP1}
P_{SP2}
T_{SP2}
STOCK–TANK OIL
P_{ST}=14.7 psia
T_{ST}
14.7 psia
60 F

Figure 3-17

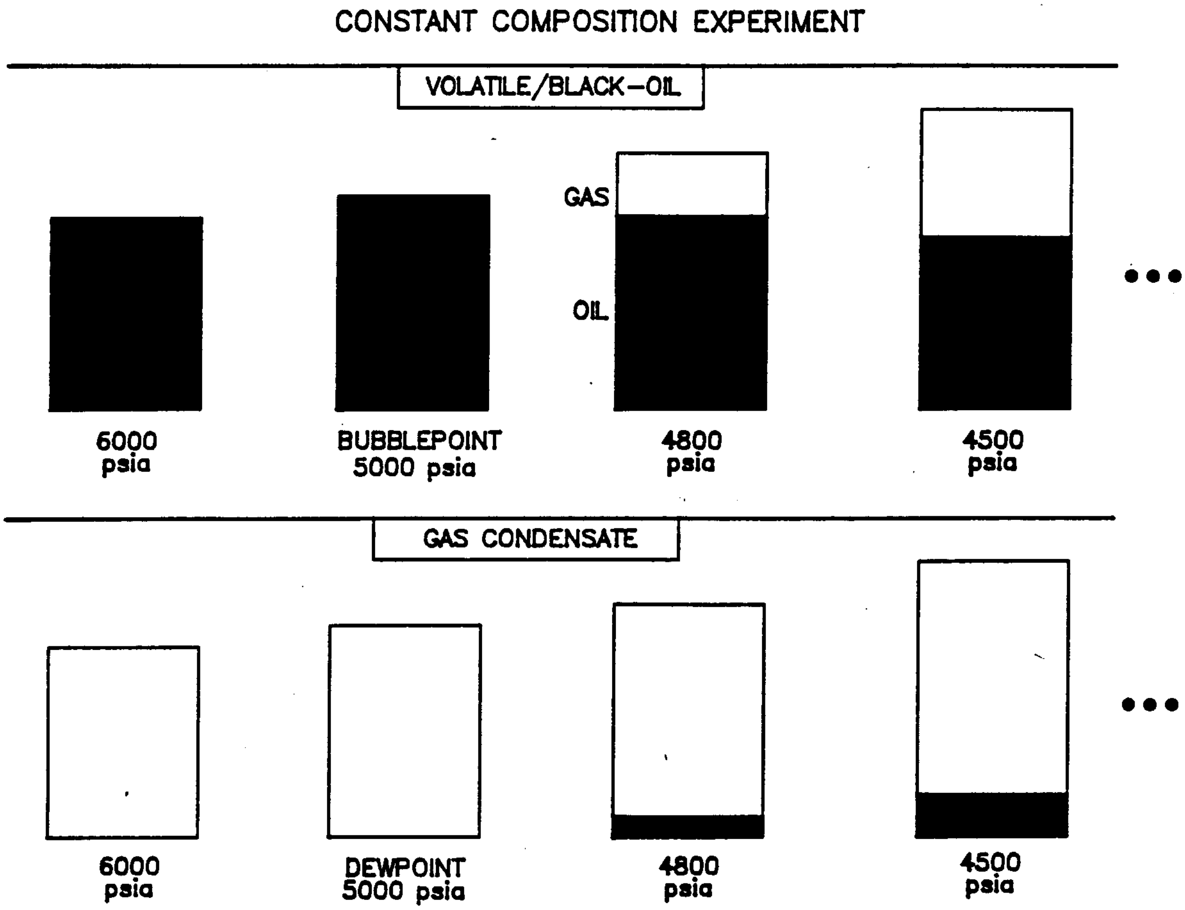

CONSTANT COMPOSITION EXPERIMENT
VOLATILE/BLACK-OIL
GAS
OIL
6000 psia
BUBBLEPOINT 5000 psia
4800 psia
4500 psia
GAS CONDENSATE
6000 psia
DEWPOINT 5000 psia
4800 psia
4500 psia

Figure 3-18

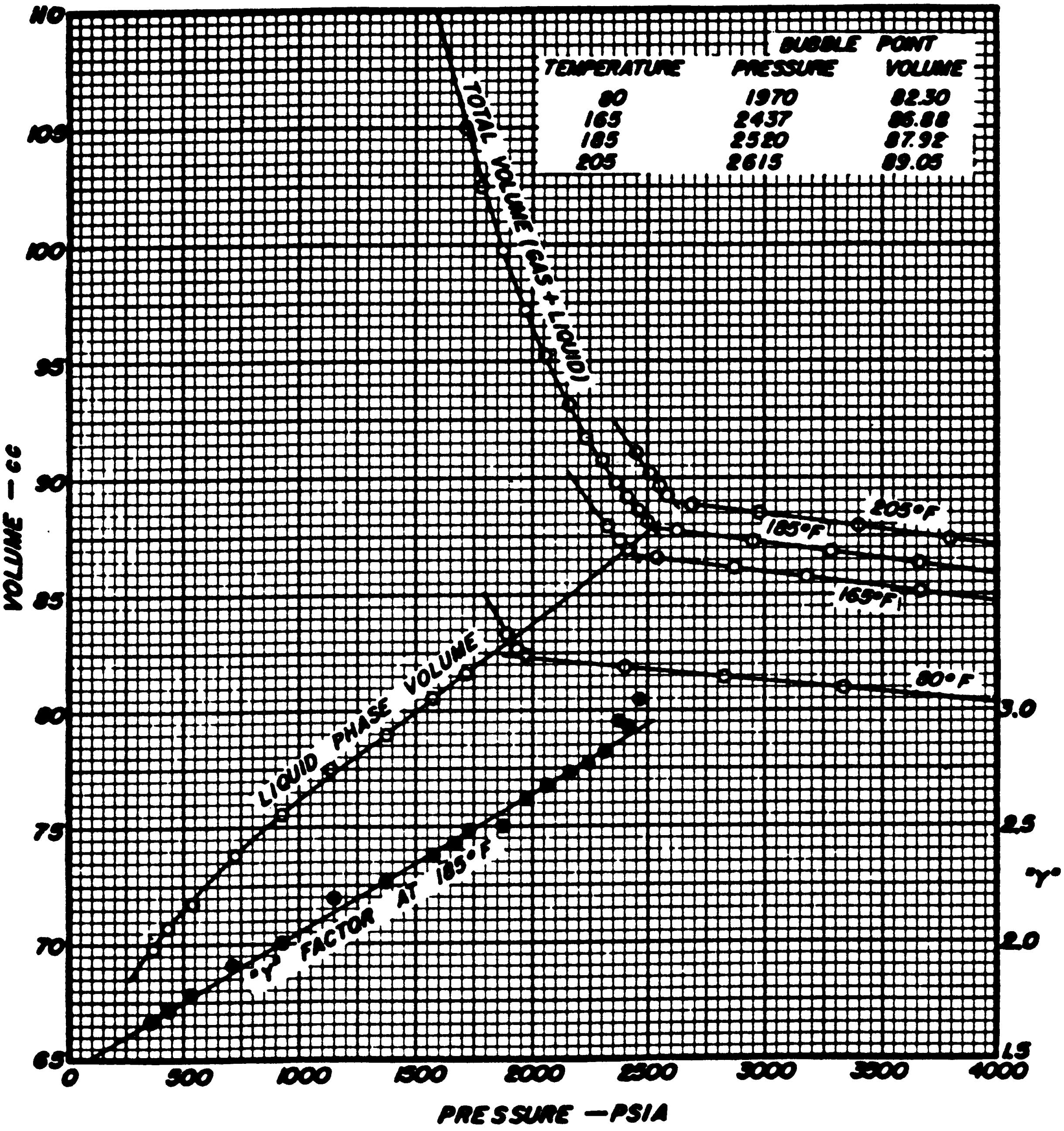

BUBBLE POINT
TEMPERATURE PRESSURE VOLUME
80 1970 82.30
165 2437 86.88
185 2520 87.92
205 2615 89.05
TOTAL VOLUME (GAS + LIQUID)
LIQUID PHASE VOLUME
"Y" FACTOR AT 185°F
205°F
185°F
165°F
80°F
VOLUME — CC
110
105
100
95
90
85
80
75
70
65
"Y"
3.0
2.5
2.0
1.5
0
500
1000
1500
2000
2500
3000
3500
4000
PRESSURE —PSIA

Figure 3-19

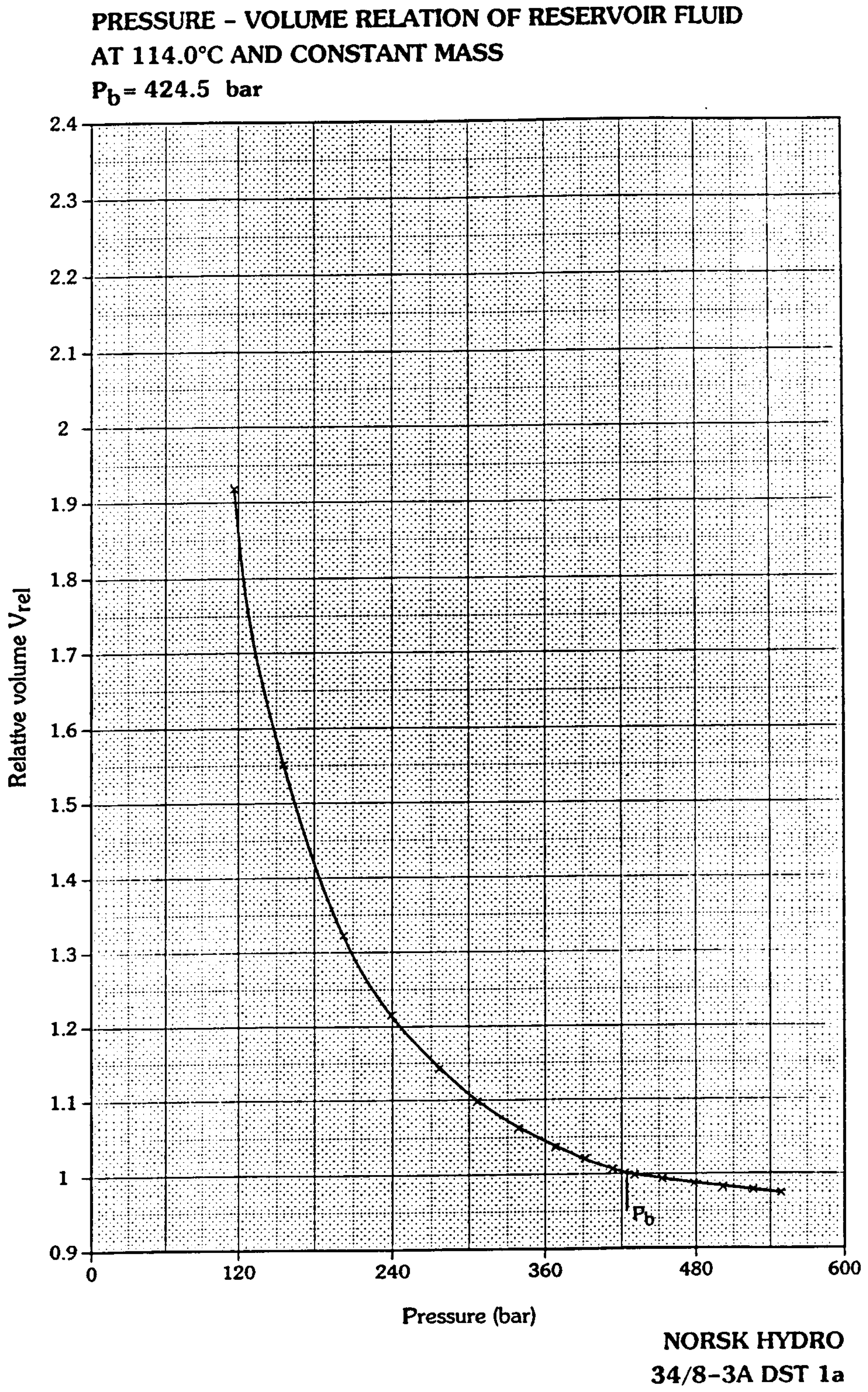

PRESSURE - VOLUME RELATION OF RESERVOIR FLUID
AT 114.0°C AND CONSTANT MASS
P_b = 424.5 bar
Relative volume V_{rel}
2.4
2.3
2.2
2.1
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0
120
240
360
480
600
Pressure (bar)
P_b
NORSK HYDRO
34/8-3A DST 1a

Figure 3-20

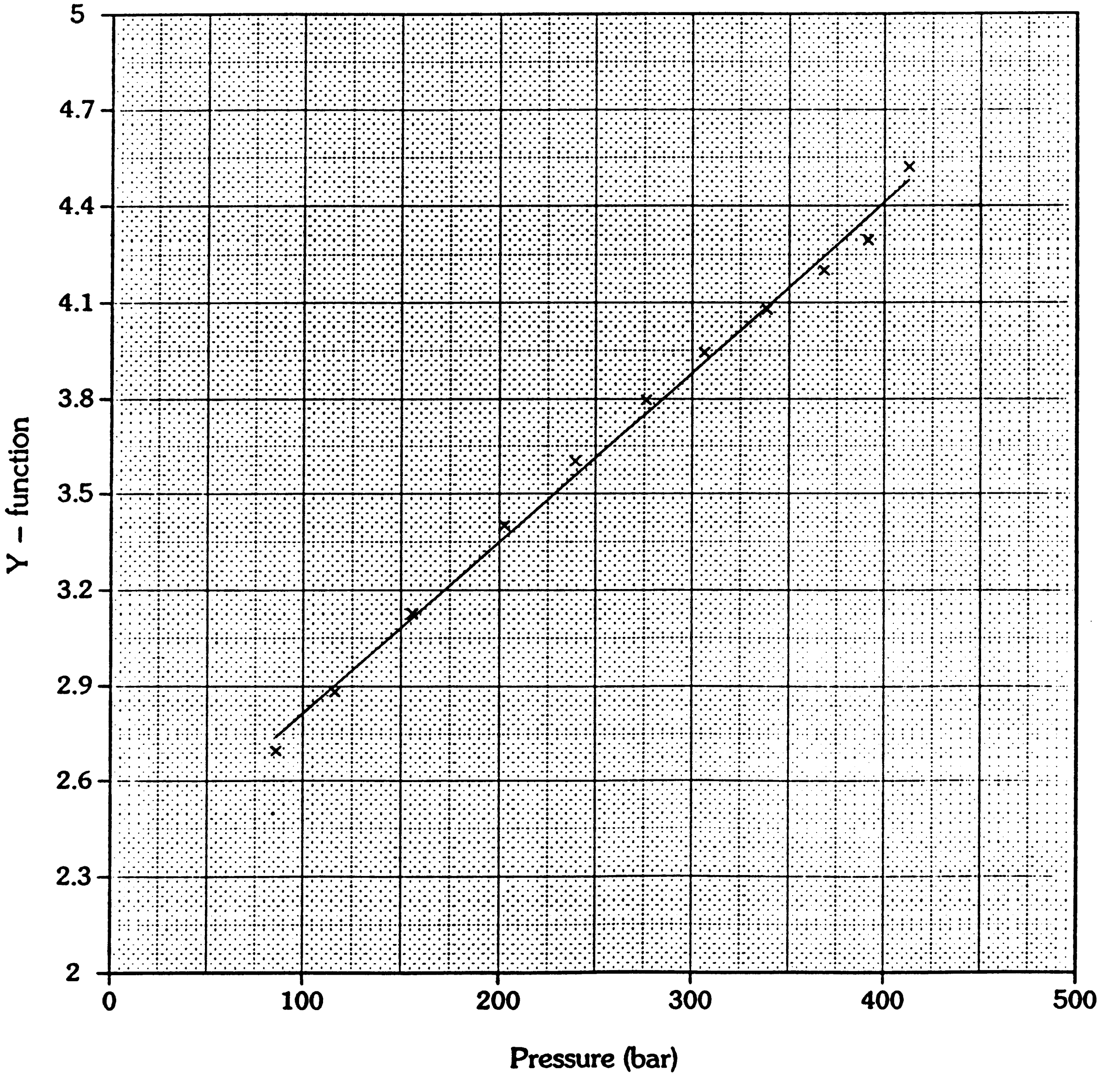
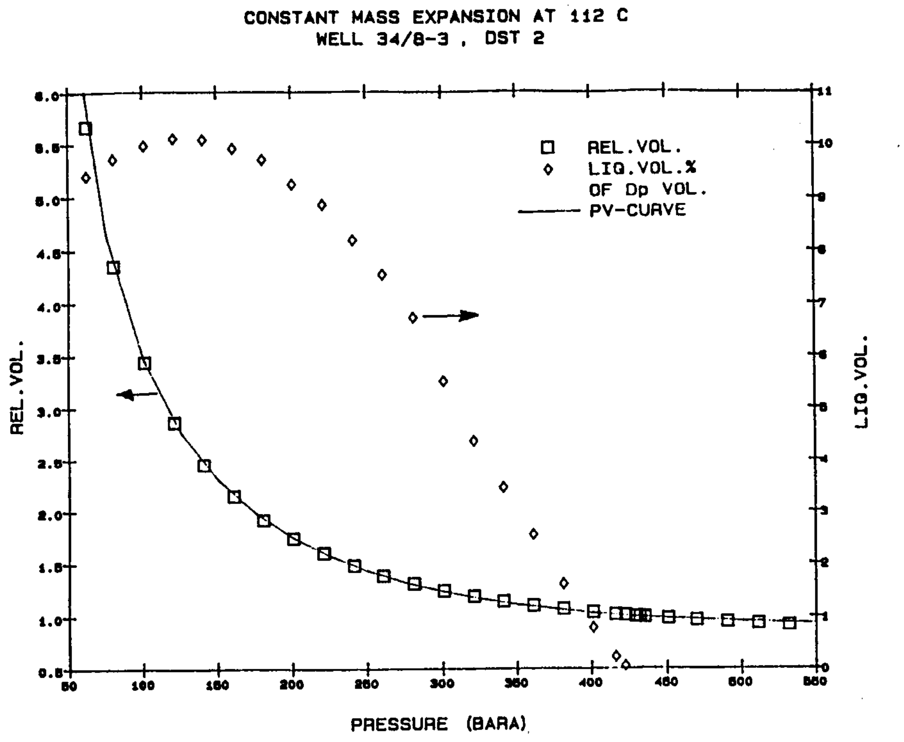

5
4.7
4.4
4.1
3.8
3.5
3.2
2.9
2.6
2.3
2
Y – function
0
100
200
300
400
500
Pressure (bar)

Figure 3-21


CONSTANT MASS EXPANSION AT 112 C
WELL 34/8-3 , DST 2

DEWPOINT : 430 BAR

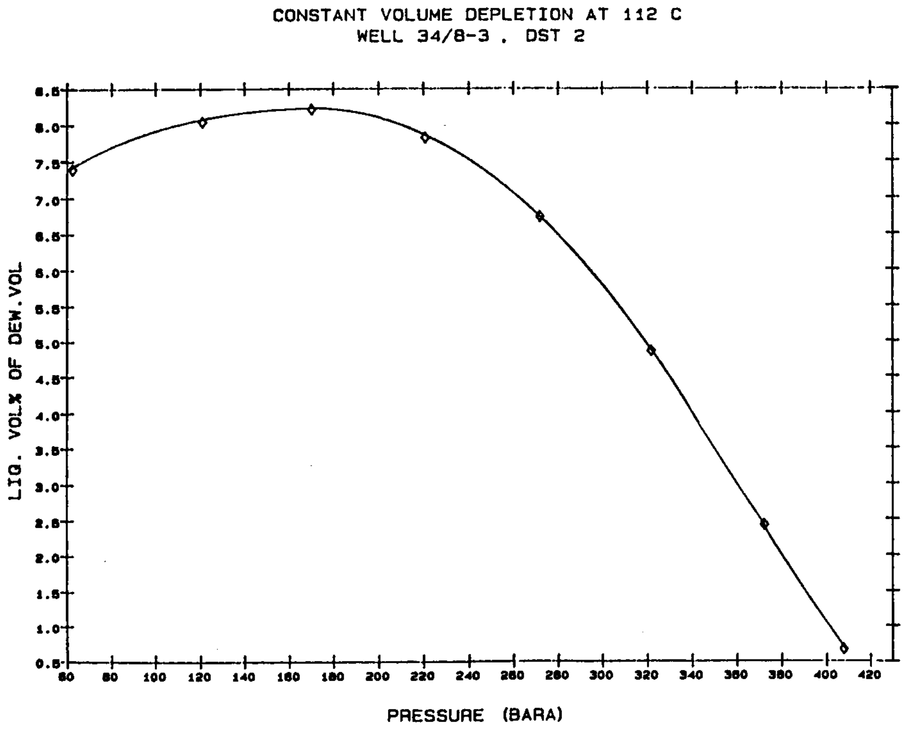

CONSTANT VOLUME DEPLETION AT 112 C
WELL 34/8-3 , DST 2

Figure 3-22

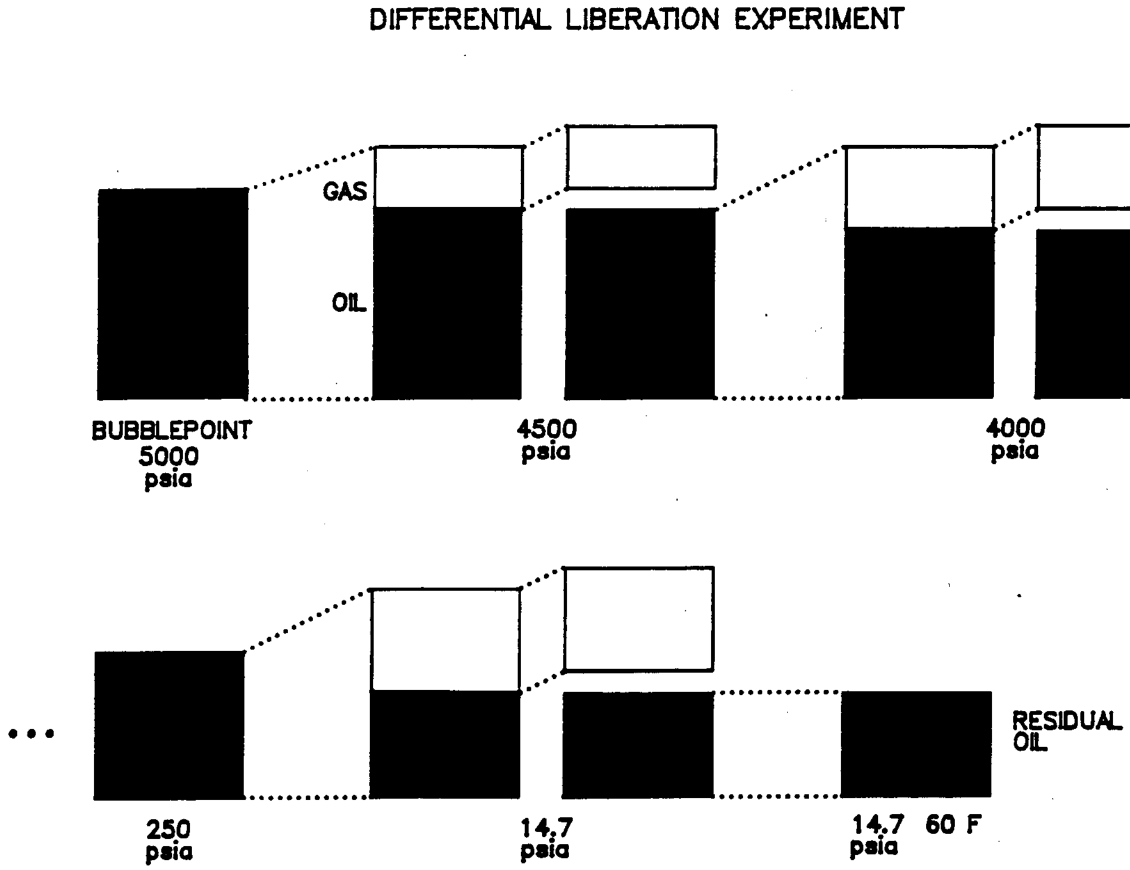

DIFFERENTIAL LIBERATION EXPERIMENT
GAS
OIL
BUBBLEPOINT
5000
psia
4500
psia
4000
psia
• • •
RESIDUAL
OIL
250
psia
14.7
psia
14.7 60 F
psia

Figure 3-23

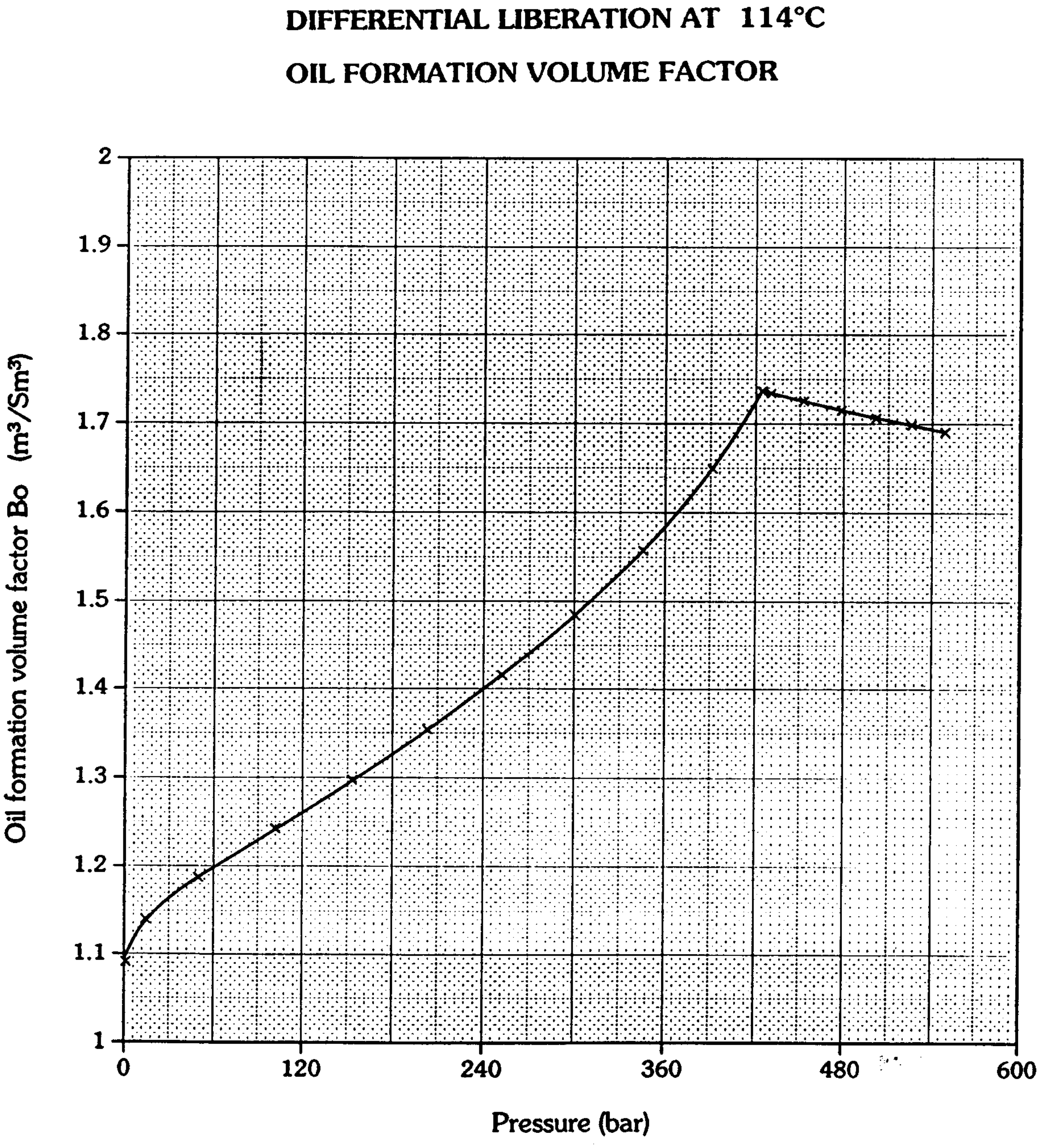

DIFFERENTIAL LIBERATION AT 114°C
OIL FORMATION VOLUME FACTOR
Oil formation volume factor Bo (m³/Sm³)
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0
120
240
360
480
600
Pressure (bar)

Figure 3-24

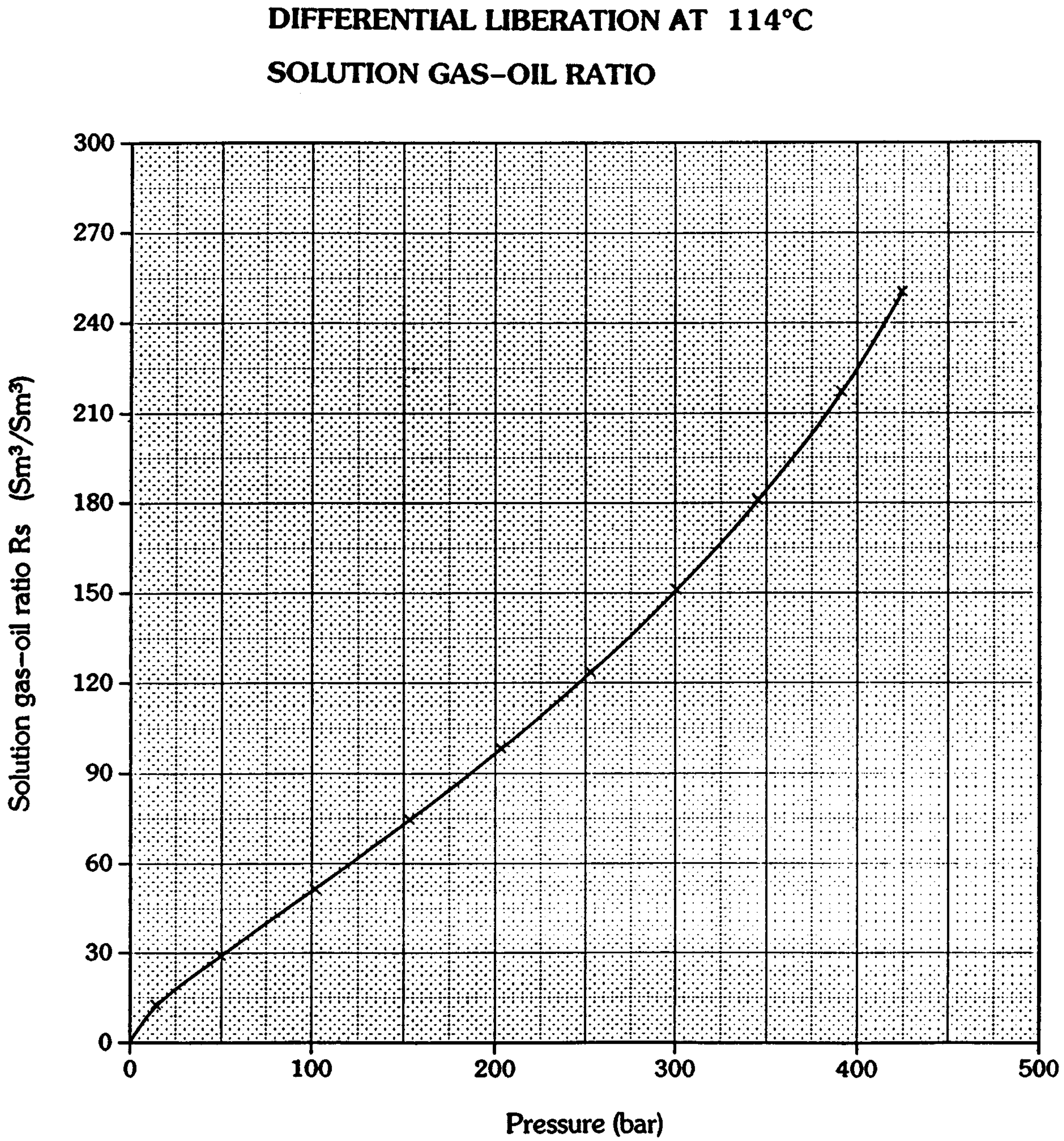

DIFFERENTIAL LIBERATION AT 114°C
SOLUTION GAS-OIL RATIO
Solution gas-oil ratio Rs (Sm³/Sm³)
300
270
240
210
180
150
120
90
60
30
0
0
100
200
300
400
500
Pressure (bar)

Figure 3-25

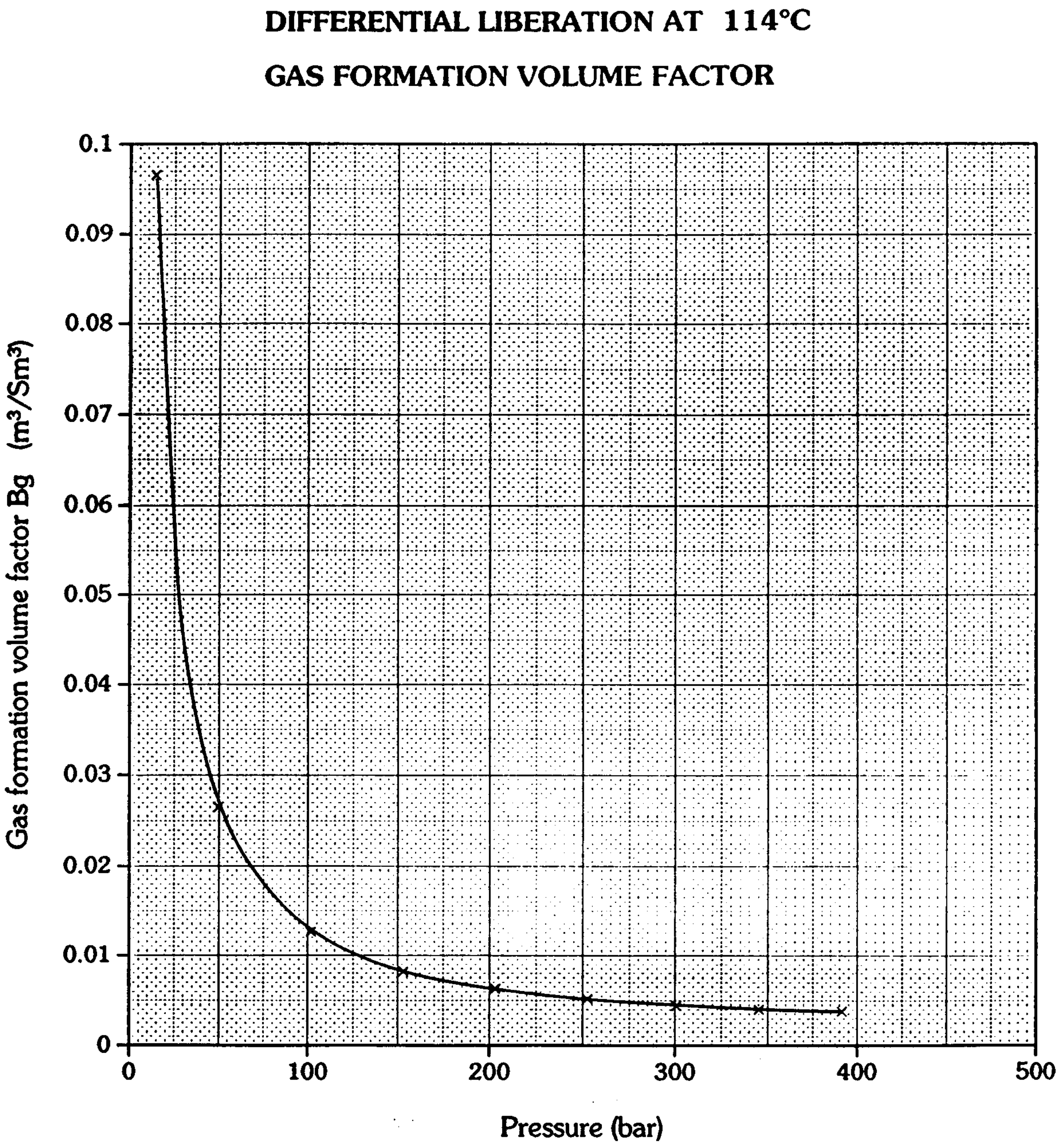

DIFFERENTIAL LIBERATION AT 114°C
GAS FORMATION VOLUME FACTOR
Gas formation volume factor Bg (m³/Sm³)
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0
100
200
300
400
500
Pressure (bar)

Figure 3-26

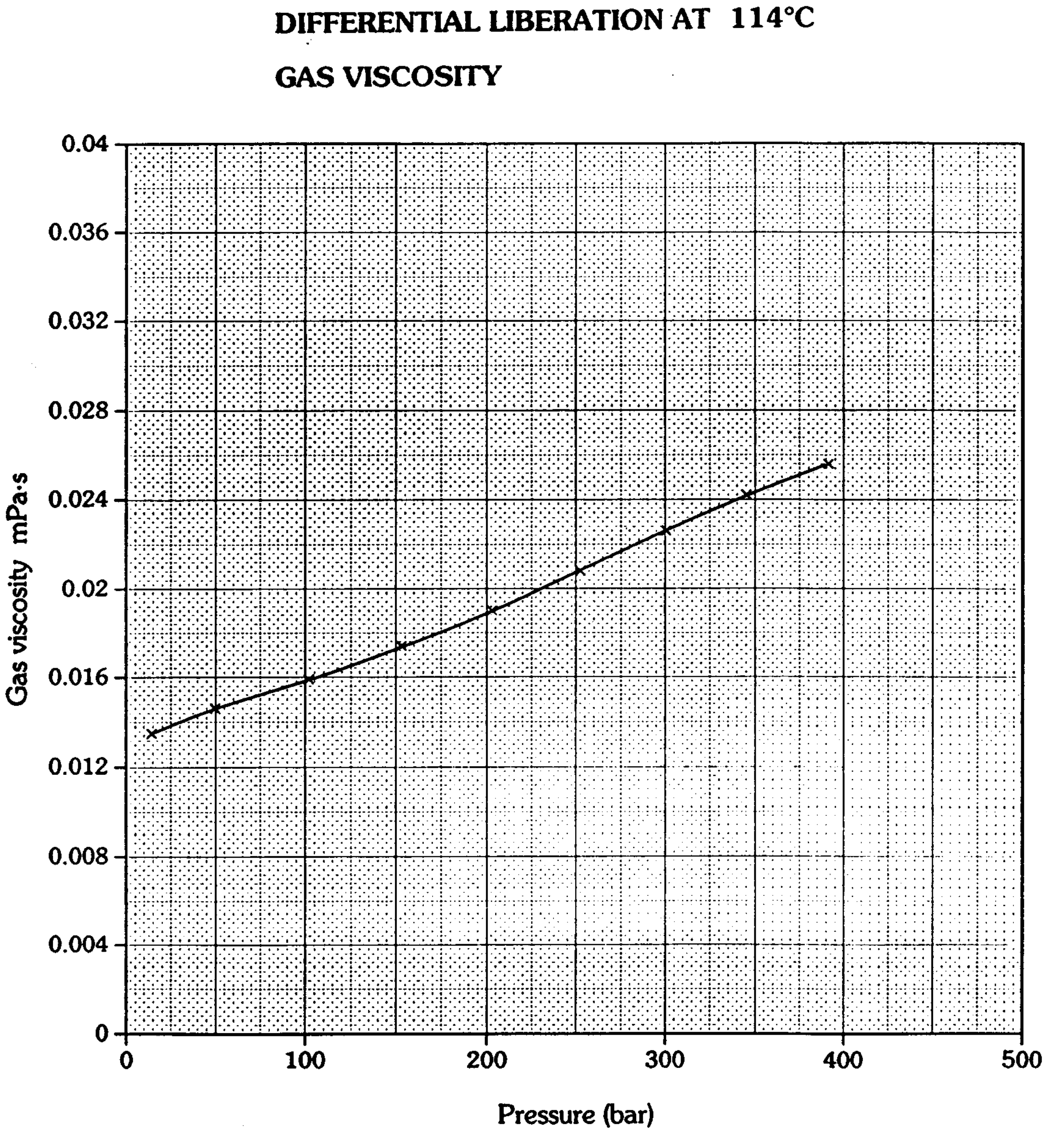

DIFFERENTIAL LIBERATION AT 114°C
GAS VISCOSITY
Gas viscosity mPa·s
0.04
0.036
0.032
0.028
0.024
0.02
0.016
0.012
0.008
0.004
0
0
100
200
300
400
500
Pressure (bar)

Figure 3-27

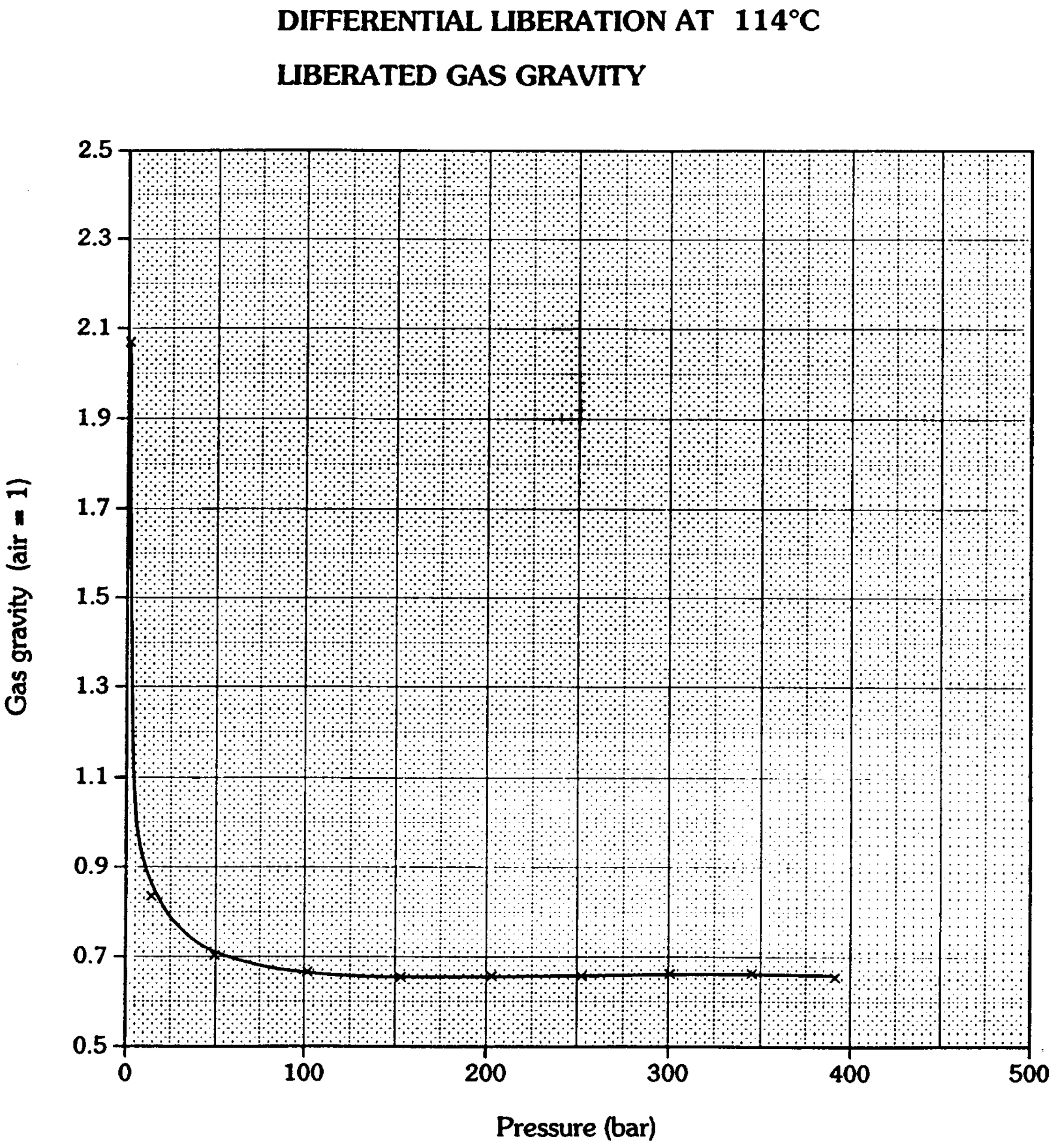

DIFFERENTIAL LIBERATION AT 114°C
LIBERATED GAS GRAVITY
2.5
2.3
2.1
1.9
1.7
1.5
1.3
1.1
0.9
0.7
0.5
Gas gravity (air = 1)
0
100
200
300
400
500
Pressure (bar)

Figure 3-28

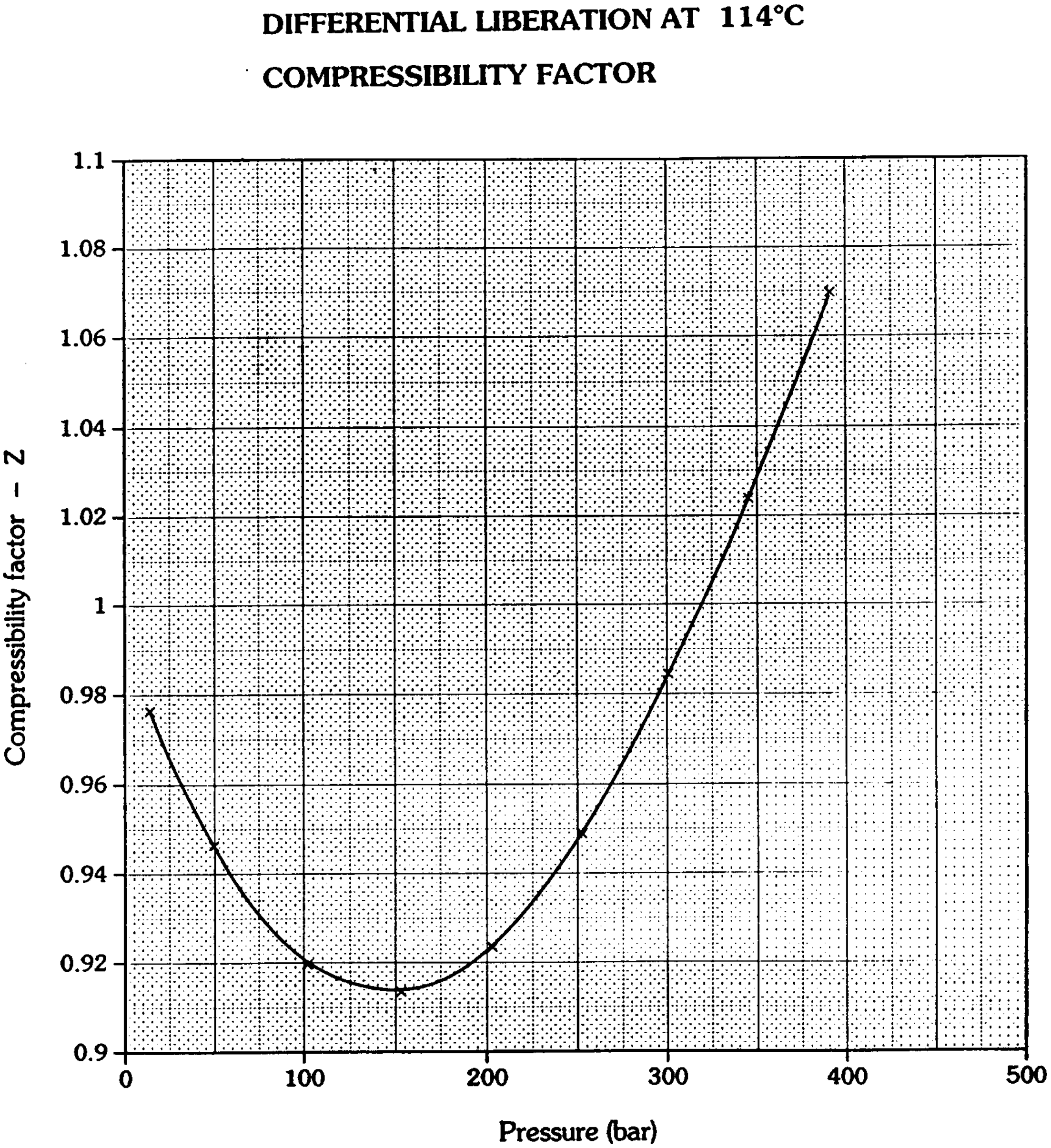

DIFFERENTIAL LIBERATION AT 114°C
COMPRESSIBILITY FACTOR
Compressibility factor – Z
1.1
1.08
1.06
1.04
1.02
1
0.98
0.96
0.94
0.92
0.9
0
100
200
300
400
500
Pressure (bar)

Figure 3-27

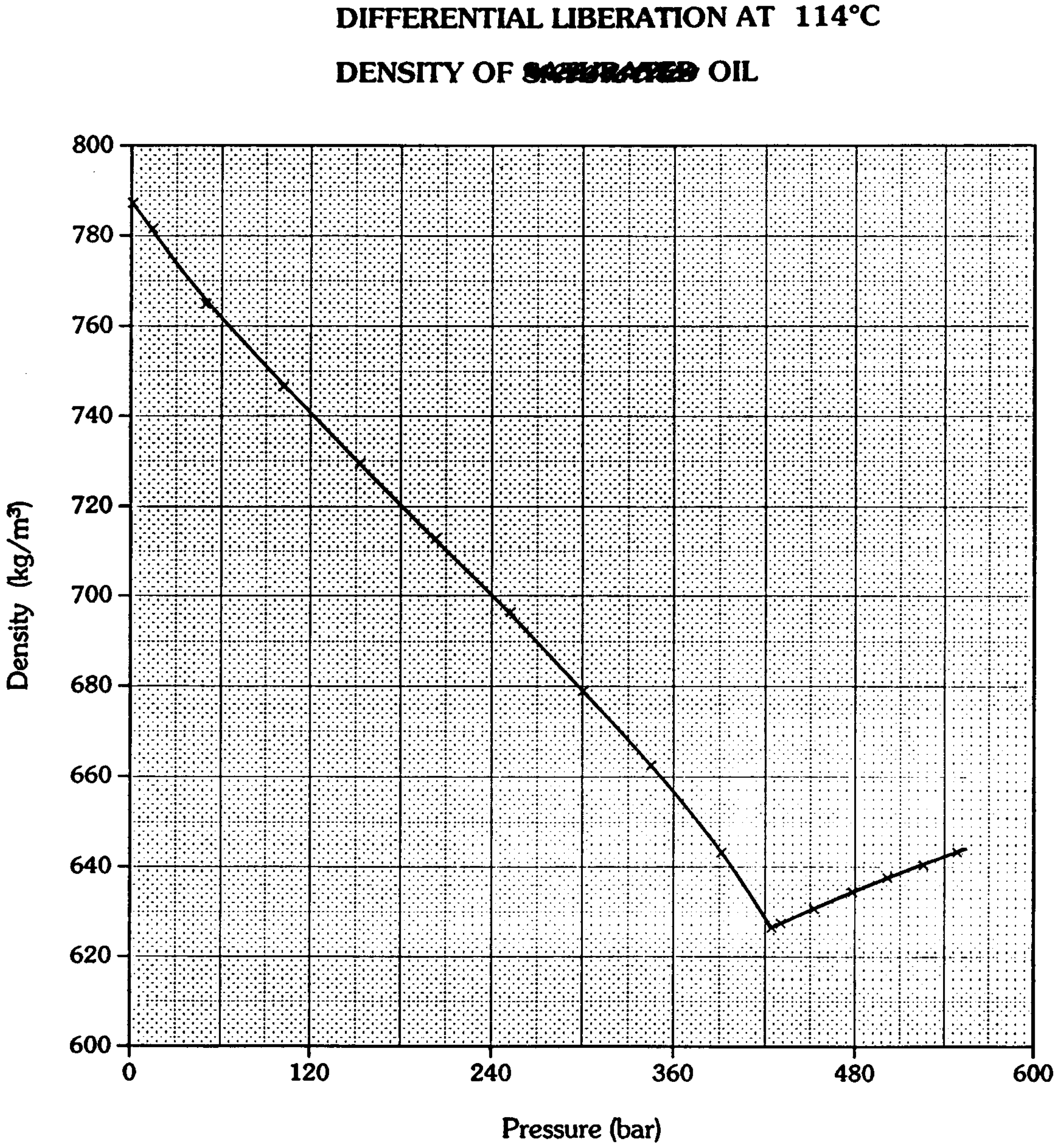

DIFFERENTIAL LIBERATION AT 114°C
DENSITY OF [illegible] OIL
800
780
760
740
720
700
680
660
640
620
600
Density (kg/m³)
0
120
240
360
480
600
Pressure (bar)

Figure 3-30

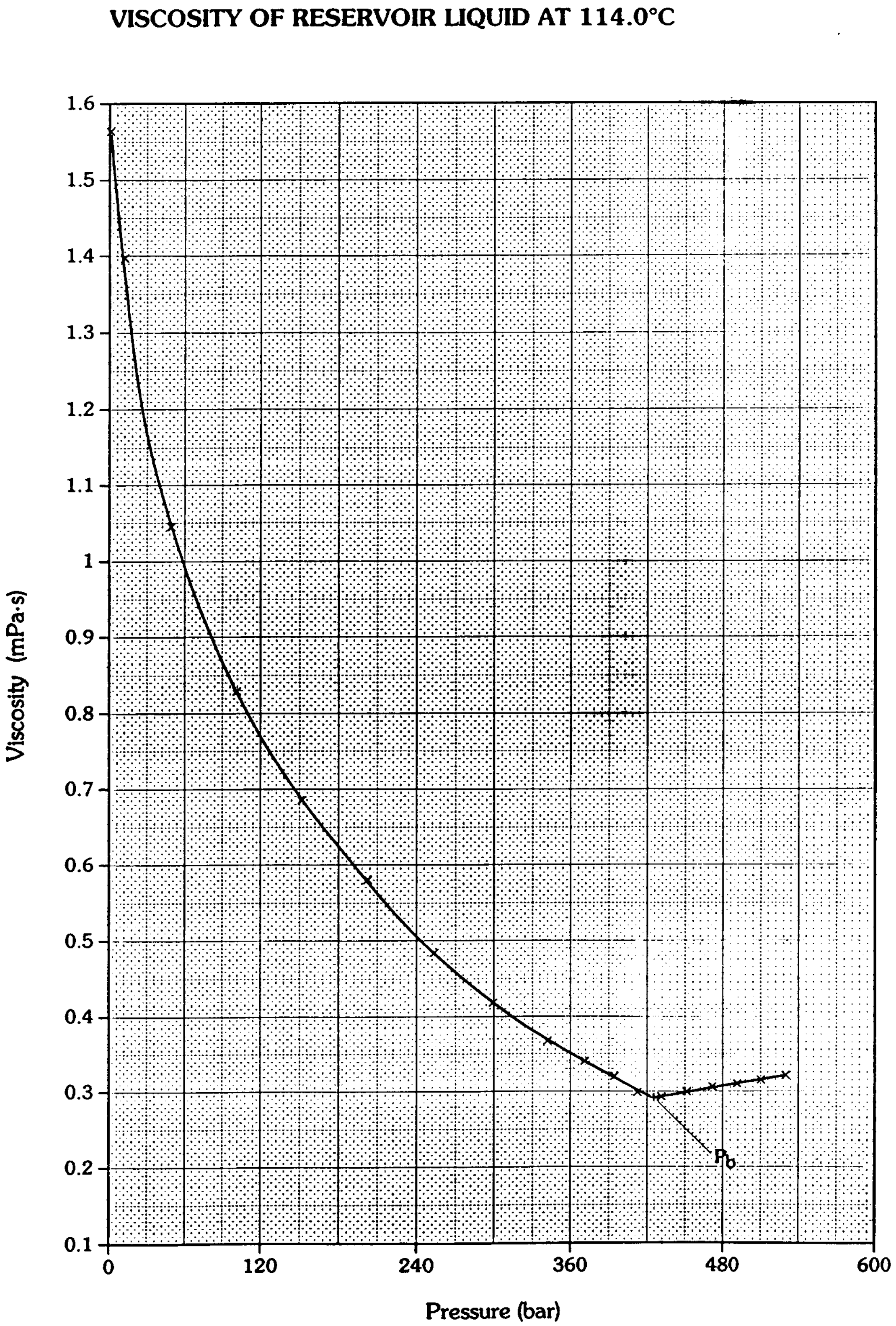
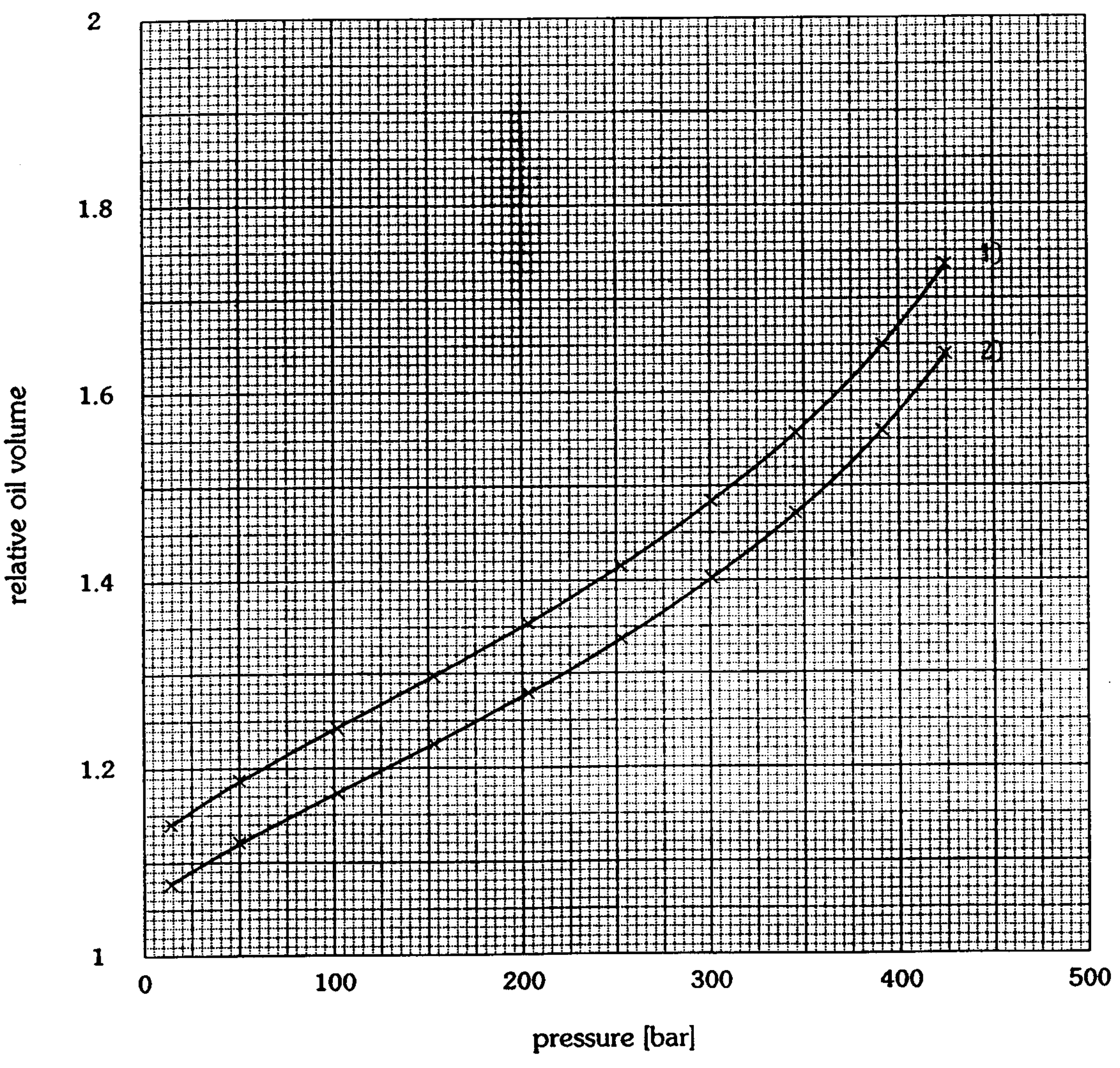

VISCOSITY OF RESERVOIR LIQUID AT 114.0°C
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
Viscosity (mPa·s)
0
120
240
360
480
600
Pressure (bar)
P_b

Figure 3-31



RELATIVE OIL VOLUME

TO STOCK TANK CONDITION

BASIS: THREE STAGE SEPARATOR TEST

1) Oil formation volume factor from differential liberation data at given pressure.
2) Relative oil volume based on three stage flash at given pressure.

Figure 3-32

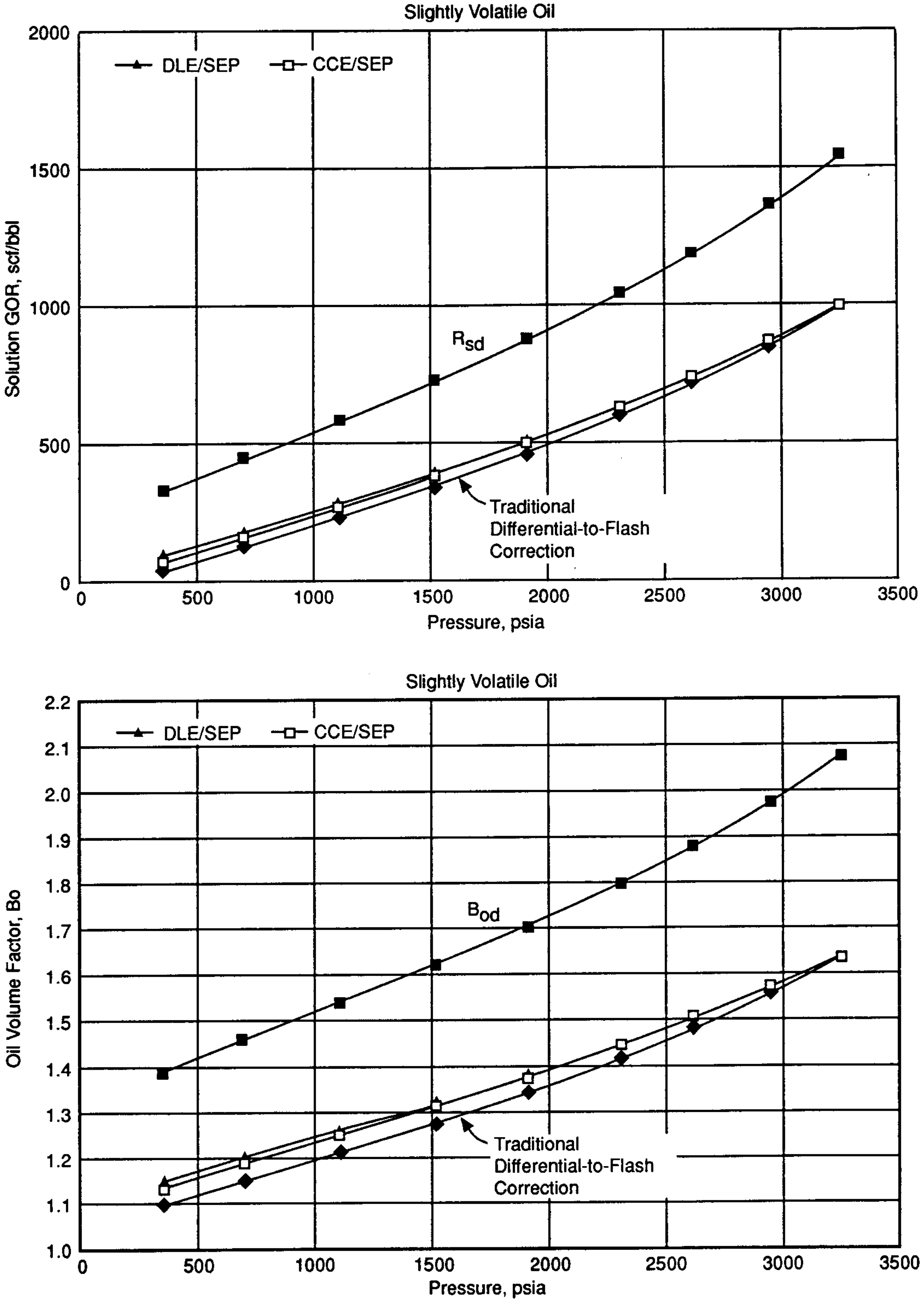

Slightly Volatile Oil
DLE/SEP
CCE/SEP
Solution GOR, scf/bbl
2000
1500
1000
500
0
R_{sd}
Traditional Differential-to-Flash Correction
0
500
1000
1500
2000
2500
3000
3500
Pressure, psia
Slightly Volatile Oil
DLE/SEP
CCE/SEP
Oil Volume Factor, Bo
2.2
2.1
2.0
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1.0
B_{od}
Traditional Differential-to-Flash Correction
0
500
1000
1500
2000
2500
3000
3500
Pressure, psia

Figure 3-33

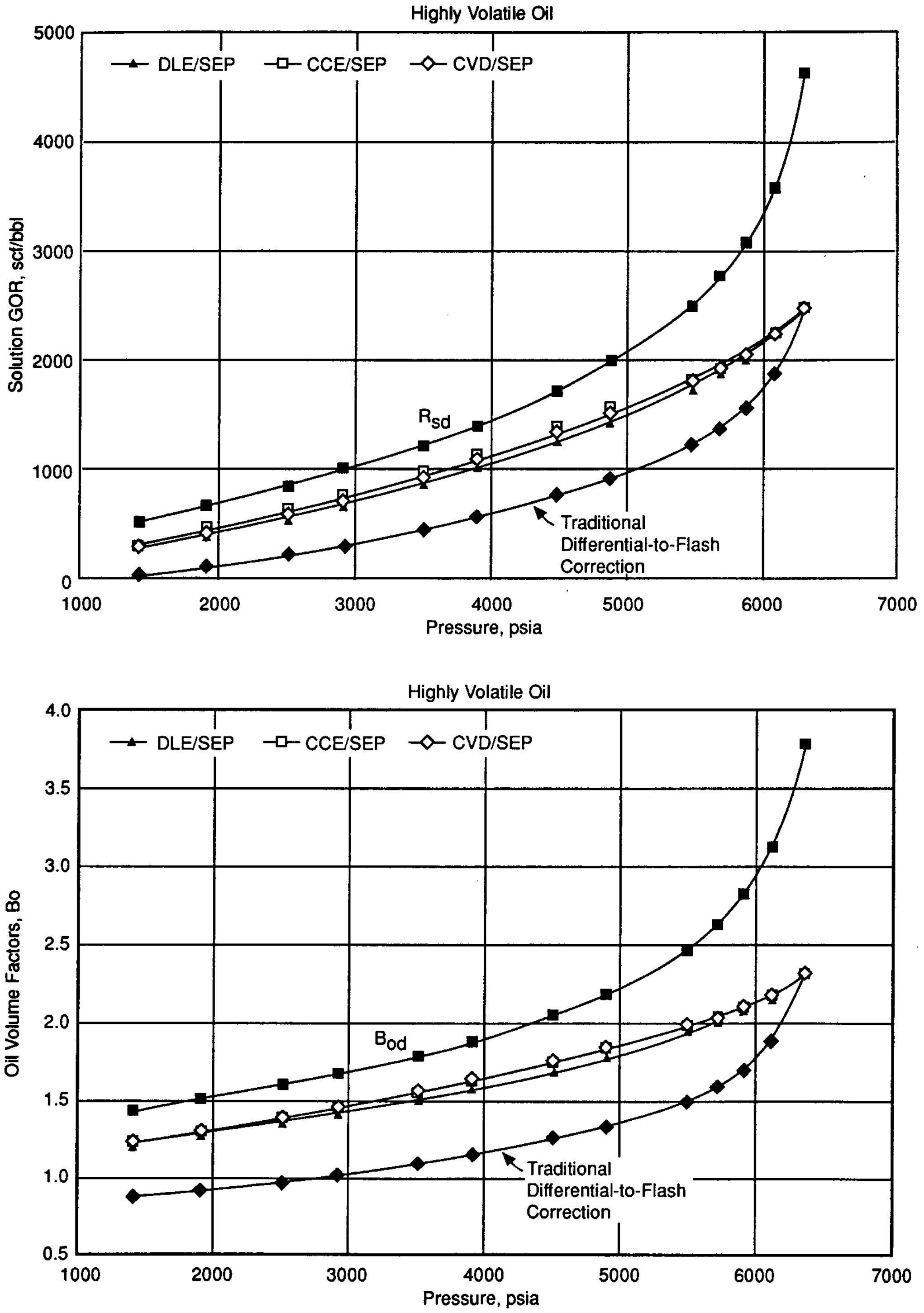

Highly Volatile Oil
DLE/SEP
CCE/SEP
CVD/SEP
Solution GOR, scf/bbl
5000
4000
3000
2000
1000
0
R_{sd}
Traditional Differential-to-Flash Correction
1000
2000
3000
4000
5000
6000
7000
Pressure, psia
Highly Volatile Oil
DLE/SEP
CCE/SEP
CVD/SEP
Oil Volume Factors, Bo
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
B_{od}
Traditional Differential-to-Flash Correction
1000
2000
3000
4000
5000
6000
7000
Pressure, psia

Figure 3-34

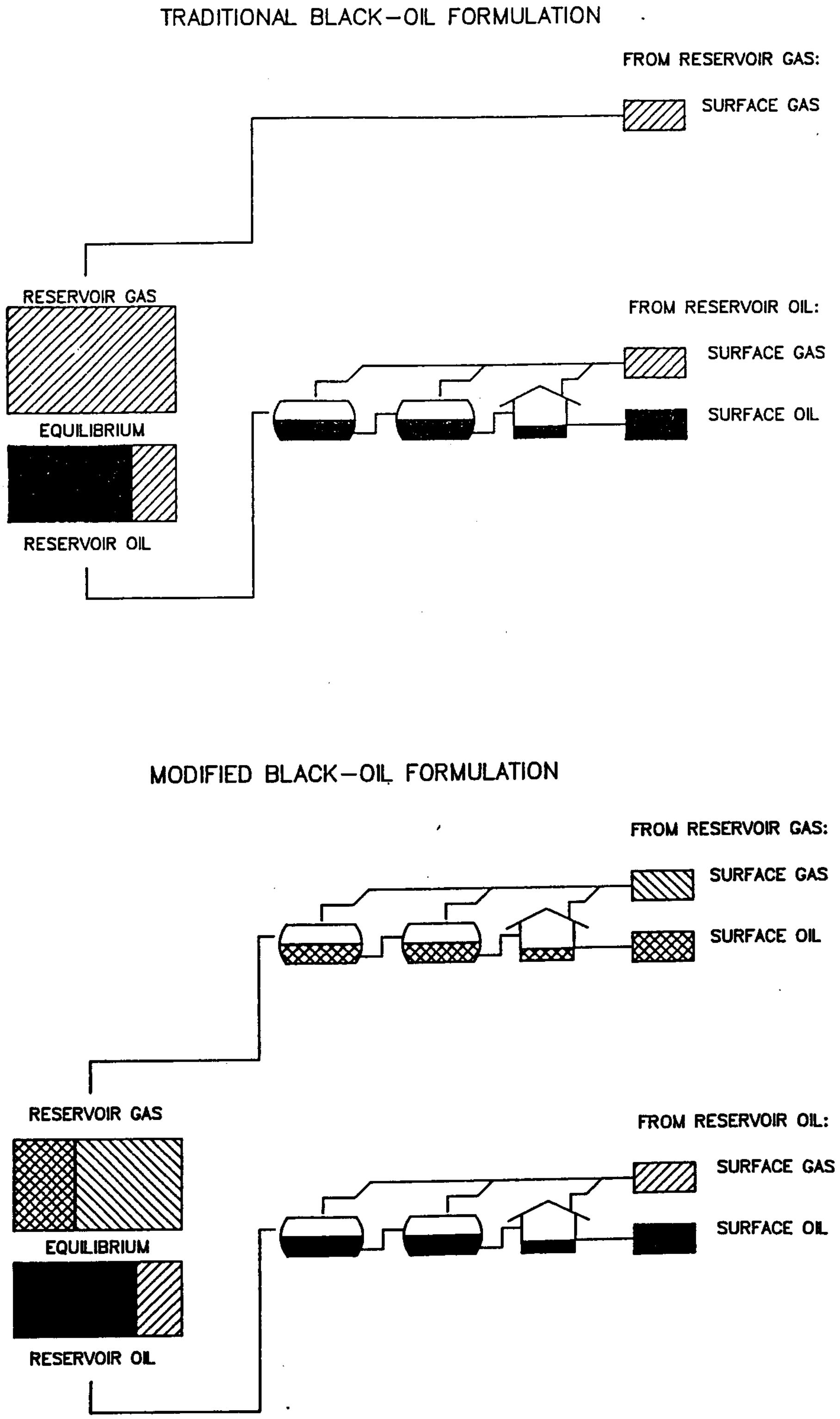

TRADITIONAL BLACK-OIL FORMULATION
FROM RESERVOIR GAS:
SURFACE GAS
RESERVOIR GAS
EQUILIBRIUM
RESERVOIR OIL
FROM RESERVOIR OIL:
SURFACE GAS
SURFACE OIL
MODIFIED BLACK-OIL FORMULATION
FROM RESERVOIR GAS:
SURFACE GAS
SURFACE OIL
RESERVOIR GAS
EQUILIBRIUM
RESERVOIR OIL
FROM RESERVOIR OIL:
SURFACE GAS
SURFACE OIL

Figure 3-27

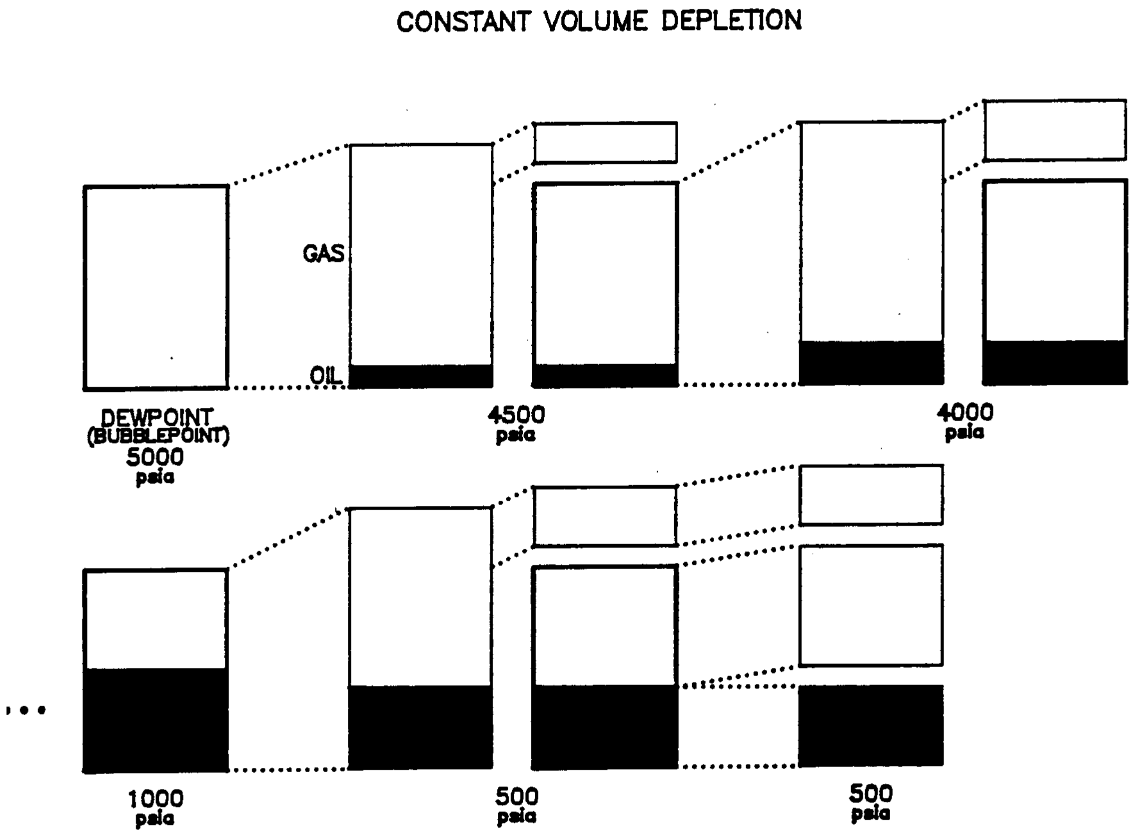

CONSTANT VOLUME DEPLETION
GAS
OIL
DEWPOINT
(BUBBLEPOINT)
5000
psia
4500
psia
4000
psia
• • •
1000
psia
500
psia
500
psia

Figure 3-36

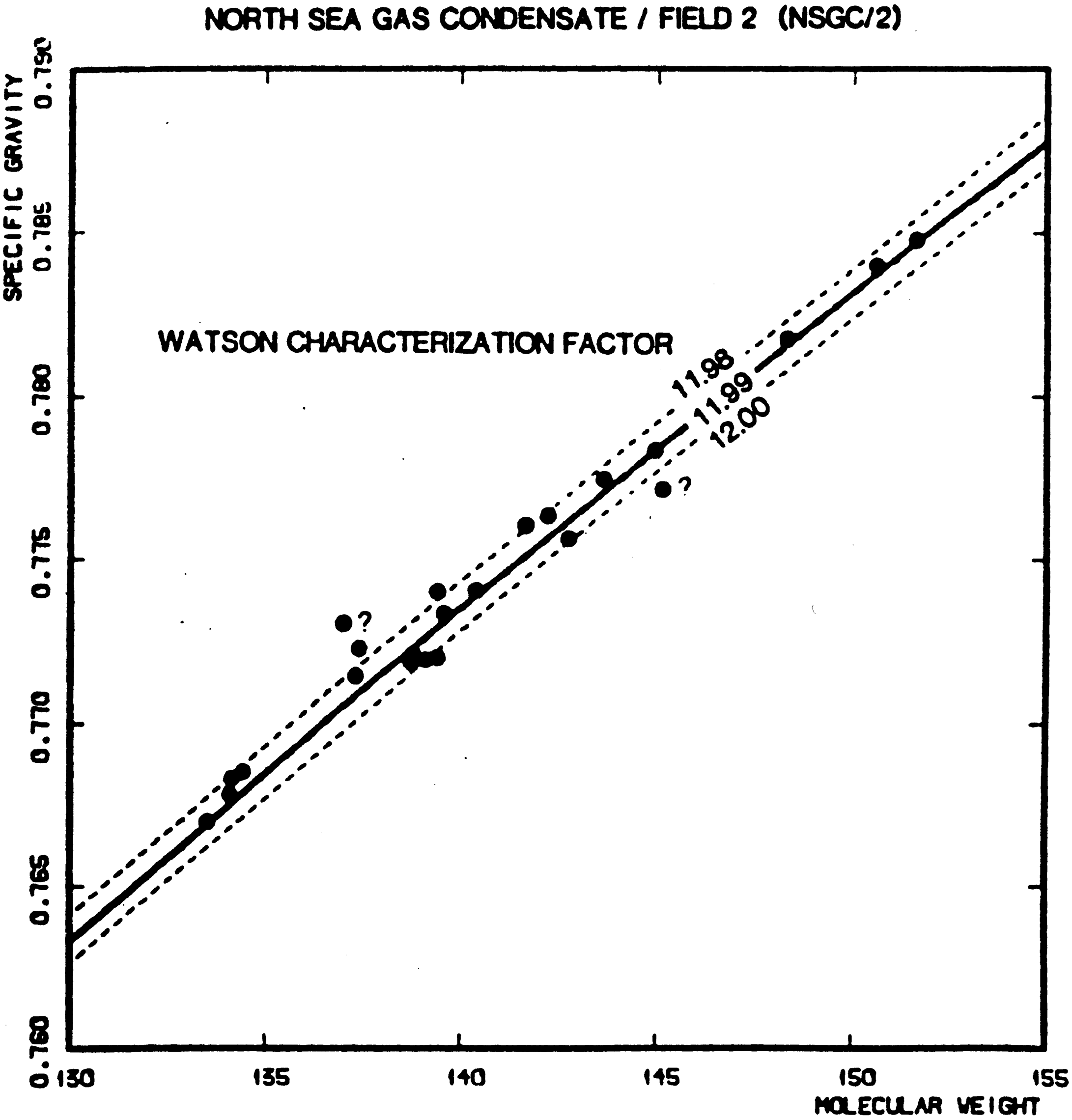

NORTH SEA GAS CONDENSATE / FIELD 2 (NSGC/2)
SPECIFIC GRAVITY
0.790
0.785
0.780
0.775
0.770
0.765
0.760
WATSON CHARACTERIZATION FACTOR
11.98
11.99
12.00
?
?
130
135
140
145
150
155
MOLECULAR WEIGHT

Figure 3-37

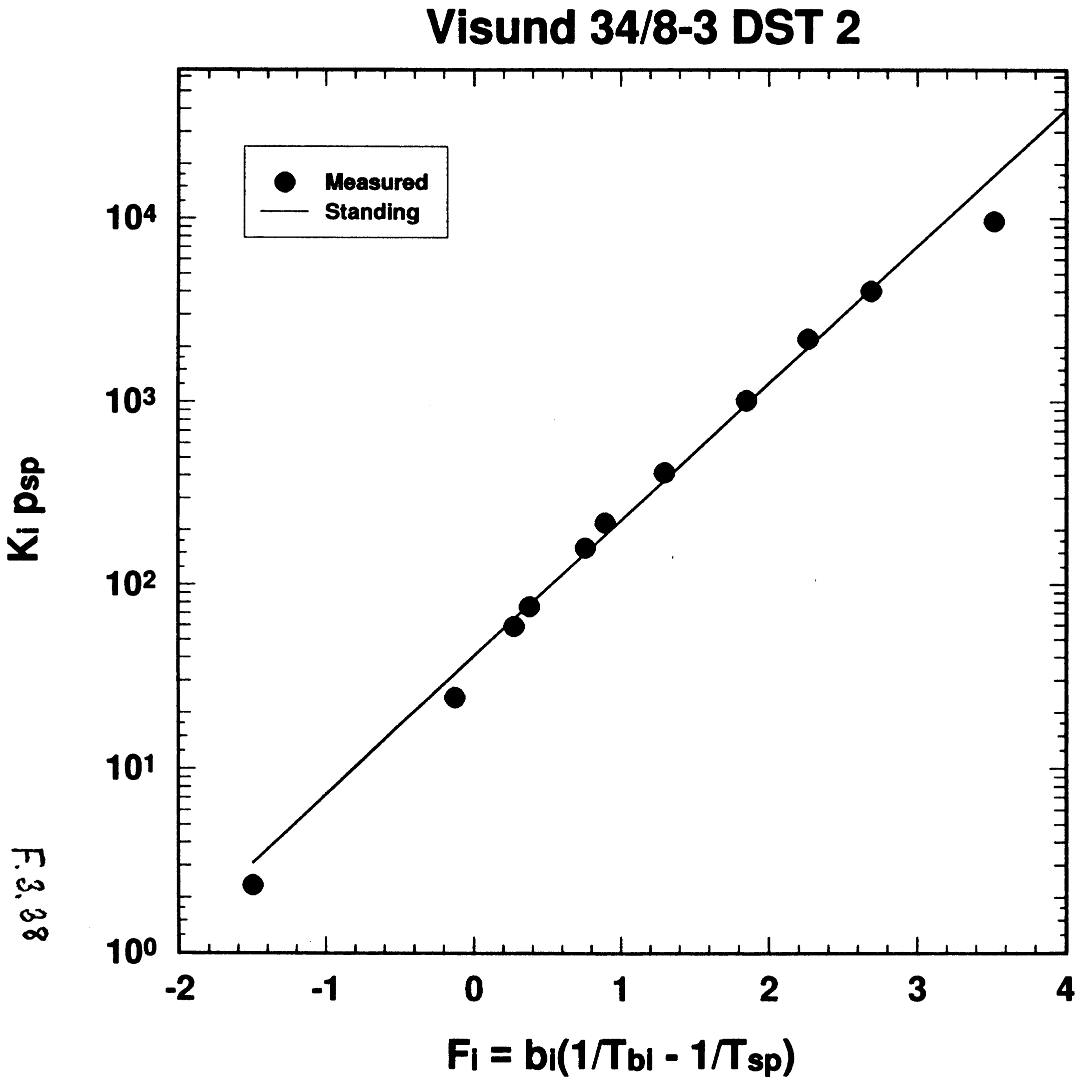
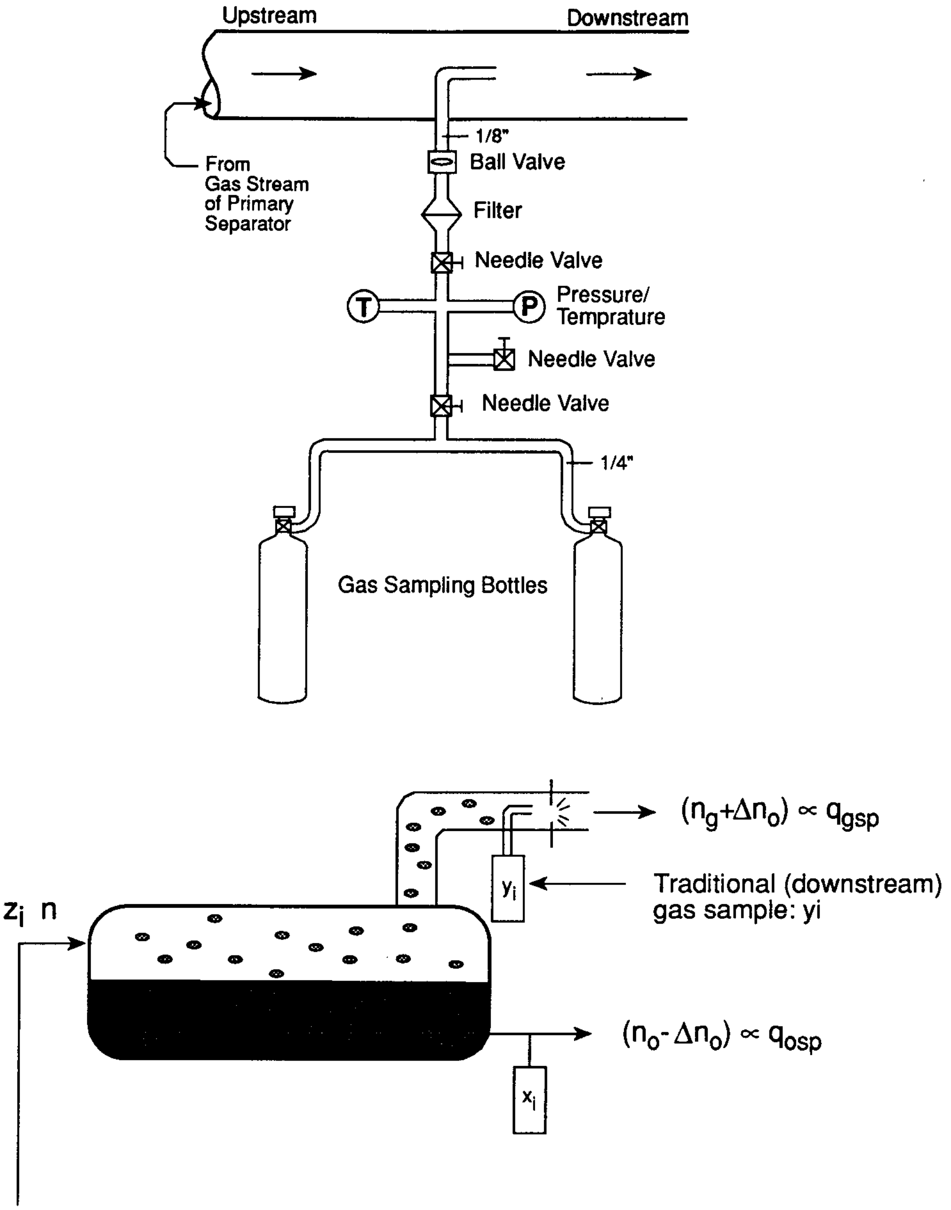

Visund 34/8-3 DST 2
● Measured
—— Standing
$K_i p_{sp}$
10^0
10^1
10^2
10^3
10^4
-2
-1
0
1
2
3
4
$F_i = b_i(1/T_{bi} - 1/T_{sp})$
F.3.38

Figure 3-38



$$n z_i = n_g y_i + n_o x_i$$

$$= \underbrace{(n_g y_i + \Delta n_o x_i)}_{\left(\begin{array}{c}\text{Separator Gas}\\+\\\text{Carryover}\end{array}\right)} + \underbrace{(n_o - \Delta n_o) x_i}_{\left(\begin{array}{c}\text{Separator Oil}\\-\\\text{Carryover}\end{array}\right)}$$

$$\begin{array}{c}=\\\text{Isokinetic Gas}\\\text{Sample}\end{array}$$

Figure 3-39