CHAPTER 3

LABORATORY ANALYSIS OF RESERVOIR FLUIDS

Accurate laboratory studies of PVT and phase-equilibria behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be made on a reservoir fluid sample. The amount of data desired determines the number of tests performed in the laboratory. In general, there are three types of laboratory tests used to measure hydrocarbon reservoir samples:

1. **Primary tests**
   These are simple, routine field (on-site) tests involving the measurements of the specific gravity and the gas-oil ratio of the produced hydrocarbon fluids.
2. **Routine laboratory tests**
   These are several laboratory tests that are routinely conducted to characterize the reservoir hydrocarbon fluid. They include:
   - Compositional analysis of the system
   - Constant-composition expansion
   - Differential liberation
   - Separator tests
   - Constant-volume depletion
3. **Special laboratory PVT tests**
   These types of tests are performed for very specific applications. If a reservoir is to be depleted under miscible gas injection or a gas cycling scheme, the following tests may be performed:
   - Slim-tube test
   - Swelling test

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The objective of this chapter is to review the PVT laboratory tests and to illustrate the proper use of the information contained in PVT reports.

COMPOSITION OF THE RESERVOIR FLUID

It is desirable to obtain a fluid sample as early in the life of a field as possible so that the sample will closely approximate the original reservoir fluid. Collection of a fluid sample early in the life of a field reduces the chances of free gas existing in the oil zone of the reservoir.

Most of the parameters measured in a reservoir fluid study can be calculated with some degree of accuracy from the composition. It is the most complete description of reservoir fluid that can be made. In the past, reservoir fluid compositions were usually measured to include separation of the component methane through hexane, with the heptanes and heavier components grouped as a single component reported with the average molecular weight and density.

With the development of more sophisticated equations-of-state to calculate fluid properties, it was learned that a more complete description of the heavy components was necessary. It is recommended that compositional analyses of the reservoir fluid should include a separation of components through C_{10} as a minimum. The more sophisticated research laboratories now use equations-of-state that require compositions through C_{30} or higher.

Table 3-1 shows a chromatographic "fingerprint" compositional analysis of the Big Butte crude oil system. The table includes the mole fraction, weight fraction, density, and molecular weight of the individual component.

CONSTANT-COMPOSITION EXPANSION TESTS

Constant-composition expansion experiments are performed on gas condensates or crude oil to simulate the pressure-volume relations of these hydrocarbon systems. The test is conducted for the purposes of determining:

- Saturation pressure (bubble-point or dew-point pressure)
- Isothermal compressibility coefficients of the single-phase fluid in excess of saturation pressure
- Compressibility factors of the gas phase
- Total hydrocarbon volume as a function of pressure

(*text continued on page 140*)

Table 3-1
Hydrocarbon Analysis of Reservoir Fluid Sample

Composition of Reservoir Fluid Sample
(by Flash, Extended-Capillary Chromatography)

Component Name	Mol %	Wt %	Liquid Density (gm/cc)	MW
Hydrogen Sulfide	0.00	0.00	0.8006	34.08
Carbon Dioxide	0.25	0.11	0.8172	44.01
Nitrogen	0.88	0.25	0.8086	28.013
Methane	23.94	3.82	0.2997	16.043
Ethane	11.67	3.49	0.3562	30.07
Propane	9.36	4.11	0.5070	44.097
iso-Butane	1.39	0.81	0.5629	58.123
n-Butane	4.61	2.66	0.5840	58.123
iso-Pentane	1.50	1.07	0.6244	72.15
n-Pentane	2.48	1.78	0.6311	72.15
Hexanes	3.26	2.73	0.6850	84
Heptanes	5.83	5.57	0.7220	96
Octanes	5.52	5.88	0.7450	107
Nonanes	3.74	4.50	0.7640	121
Decanes	3.38	4.50	0.7780	134

Total Sample Properties

Molecular Weight	100.55
Equivalent Liquid Density, gm/scc	0.7204

Undecanes	2.57	3.76	0.7890	147
Dodecanes	2.02	3.23	0.8000	161
Tridecanes	2.02	3.52	0.8110	175
Tetradecanes	1.65	3.12	0.8220	190
Pentadecanes	1.48	3.03	0.8320	206
Hexadecanes	1.16	2.57	0.8390	222
Heptadecanes	1.06	2.50	0.8470	237
Octadecanes	0.93	2.31	0.8520	251
Nonadecanes	0.88	2.31	0.8570	263
Eicosanes	0.77	2.11	0.8620	275
Heneicosanes	0.68	1.96	0.8670	291
Docosanes	0.60	1.83	0.8720	305
Tricosanes	0.55	1.74	0.8770	318
Tetracosanes	0.48	1.57	0.8810	331
Pentacosanes	0.47	1.60	0.8850	345
Hexacosanes	0.41	1.46	0.8890	359
Heptacosanes	0.36	1.33	0.8930	374
Octacosanes	0.37	1.41	0.8960	388
Nonacosanes	0.34	1.34	0.8990	402
Triacontanes plus	3.39	16.02	1.0440	474
Totals	100.00	100.00		

Plus Fractions	Mol %	Wt %	Density	MW
Heptanes plus	40.66	79.17	0.8494	196
Undecanes plus	22.19	58.72	0.8907	266
Pentadecanes plus	13.93	45.09	0.9204	326
Eicosanes plus	8.42	32.37	0.9540	387
Pentacosanes plus	5.34	23.16	0.9916	437
Triacontanes plus	3.39	16.02	1.0440	474

(*text continued from page 137*)

The experimental procedure, as shown schematically in Figure 3-1, involves placing a hydrocarbon fluid sample (oil or gas) in a visual PVT cell at reservoir temperature and at a pressure in excess of the initial reservoir pressure (Figure 3-1, Section A). The pressure is reduced in steps at constant temperature by removing mercury from the cell, and the change in the *total* hydrocarbon volume V_t is measured for each pressure increment.

The saturation pressure (bubble-point or dew-point pressure) and the corresponding volume are observed and recorded and used as a reference volume V_{sat} (Figure 3-1, Section C). The volume of the hydrocarbon system as a function of the cell pressure is reported as the ratio of the reference volume. This volume is termed the *relative volume* and is expressed mathematically by the following equation:

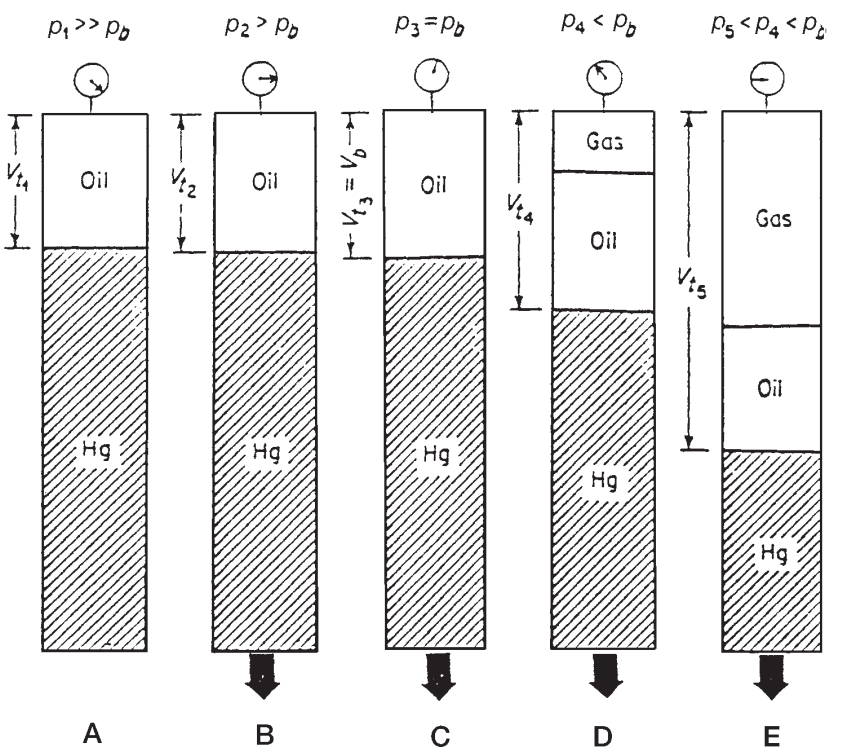


Figure 3-1. Constant-composition expansion test.

$$V_{rel} = \frac{V_t}{V_{sat}} \tag{3-1}$$

where V_{rel} = relative volume
V_t = total hydrocarbon volume
V_{sat} = volume at the saturation pressure

The relative volume is equal to **one** at the saturation pressure. This test is commonly called pressure-volume relations, flash liberation, flash vaporization, or flash expansion.

It should be noted that no hydrocarbon material is removed from the cell; thus, the composition of the total hydrocarbon mixture in the cell remains fixed at the original composition.

Table 3-2 shows the results of the flash liberation test (the constant composition expansion test) for the Big Butte crude oil system. The bubble-point pressure of the hydrocarbon system is 1,930 psi at 247°F. In addition to the reported values of the relative volume, the table includes the measured values of the oil density at and above the saturation pressure.

The density of the oil at the saturation pressure is 0.6484 gm/cc and is determined from direct weight-volume measurements on the sample in the PVT cell. Above the bubble-point pressure, the density of the oil can be calculated by using the recorded relative volume:

$$\rho = \rho_{sat}/V_{rel} \tag{3-2}$$

where ρ = density at any pressure above the saturation pressure
ρ_{sat} = density at the saturation pressure
V_{rel} = relative volume at the pressure of interest

Example 3-1

Given the experimental data in Table 3-2, verify the oil density values at 4,000 and 6,500 psi.

Solution

Using Equation 3-2 gives:

• At 4,000 psi

Table 3-2
Constant-Composition Expansion Data

Pressure-Volume Relations
(at 247°F)

Pressure, psig	Relative Volume (A)	Y-Function (B)	Density, gm/cc
6500	0.9371		0.6919
6000	0.9422		0.6882
5500	0.9475		0.6843
5000	0.9532		0.6803
4500	0.9592		0.6760
4000	0.9657		0.6714
3500	0.9728		0.6665
3000	0.9805		0.6613
2500	0.9890		0.6556
2400	0.9909		0.6544
2300	0.9927		0.6531
2200	0.9947		0.6519
2100	0.9966		0.6506
2000	0.9987		0.6493
b≫1936	1.0000		0.6484
1930	1.0014		
1928	1.0018		
1923	1.0030		
1918	1.0042		
1911	1.0058		
1878	1.0139		
1808	1.0324		
1709	1.0625	2.108	
1600	1.1018	2.044	
1467	1.1611	1.965	
1313	1.2504	1.874	
1161	1.3694	1.784	
1035	1.5020	1.710	
782	1.9283	1.560	
600	2.4960	1.453	
437	3.4464	1.356	

(A) Relative volume: V/V_{sat} or volume at indicated pressure per volume at saturation pressure

(B) Where Y-function $\dfrac{(p_{sat} - p)}{(p_{abs}) \bullet (V/V_{sat} - 1)}$

$$\rho_o = \frac{0.6484}{0.9657} = 0.6714 \text{ gm/cc}$$

• At 6,500 psi

$$\rho_o = \frac{0.6484}{0.9371} = 0.6919$$

The relative volume data frequently require smoothing to correct for laboratory inaccuracies in measuring the total hydrocarbon volume just below the saturation pressure and also at lower pressures. A dimensionless compressibility function, commonly called the *Y-function*, is used to smooth the values of the relative volume. The function in its mathematical form is only defined below the saturation pressure and is given by the following expression:

$$Y = \frac{p_{sat} - p}{p(V_{rel} - 1)} \tag{3-3}$$

where p_{sat} = saturation pressure, psia
p = pressure, psia
V_{rel} = relative volume at pressure p

Column 3 in Table 3-2 lists the computed values of the Y-function as calculated by using Equation 3-3. To smooth the relative volume data below the saturation pressure, the Y-function is plotted as a function of pressure on a Cartesian scale. When plotted, the Y-function forms a straight line or has only a small curvature. Figure 3-2 shows the Y-function versus pressure for the Big Butte crude oil system. The figure illustrates the erratic behavior of the data near the bubble-point pressure.

The following steps summarize the simple procedure of smoothing and correcting the relative volume data:

Step 1. Calculate the Y-function for all pressures below the saturation pressure by using Equation 3-3.

Step 2. Plot the Y-function versus pressure on a Cartesian scale.

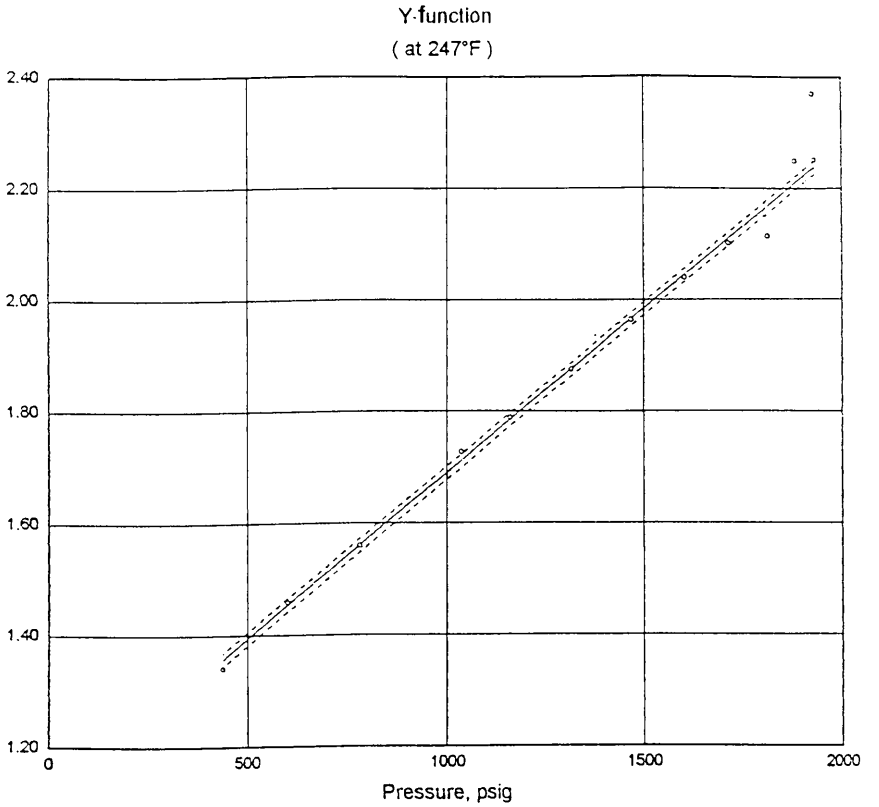


Figure 3-2. Y-function versus pressure.

Step 3. Determine the coefficients of the best straight fit of the data, or:

$$Y = a + bp \tag{3-4}$$

where a and b are the intercept and slope of the lines, respectively.

Step 4. Recalculate the relative volume at all pressure below the saturation pressure from the following expression:

$$V_{rel} = 1 + \frac{p_{sat} - p}{p(a + bp)} \tag{3-5}$$

Example 3-2

The best straight fit of the Y-function as a function of pressure for the Big Butte oil system is given by:

$$Y = a + bp$$

where $a = 1.0981$

$b = 0.000591$

Smooth the recorded relative volume data of Table 3-2.

Solution

Pressure	Measured V_{rel}	Smoothed V_{rel} Equation 3-5
1936	—	—
1930	—	1.0014
1928	—	1.0018
1923	—	1.0030
1918	—	1.0042
1911	—	1.0058
1878	—	1.0139
1808	—	1.0324
1709	1.0625	1.0630
1600	1.1018	1.1028
1467	1.1611	1.1626
1313	1.2504	1.2532
1161	1.3696	1.3741
1035	1.5020	1.5091
782	1.9283	1.9458
600	2.4960	2.5328
437	3.4464	3.5290

The oil compressibility coefficient c_o above the bubble-point pressure is also obtained from the relative volume data as listed in Table 3-3 for the Big Butte oil system.

Table 3-3
Undersaturated Compressibility Data

Volumetric Data
(at 247°F)

Saturation Pressure (p_{sat})	1936 psig
Density at p_{sat}	0.6484 gm/cc
Thermal Exp @ 6500 psig	1.10401 V at 247°F/V at 60°F

Average Single-Phase Compressibilities

Pressure Range, psig			Single-Phase Compressibility, V/V/psi
6500	to	6000	10.73 E-6
6000	to	5500	11.31 E-6
5500	to	5000	11.96 E-6
5000	to	4500	12.70 E-6
4500	to	4000	13.57 E-6
4000	to	3500	14.61 E-6
3500	to	3000	15.86 E-6
3000	to	2500	17.43 E-6
2500	to	2000	19.47 E-6
2000	to	1936	20.79 E-6

The oil compressibility is defined by Equations 2-94 through 2-96 and equivalently can be written in terms of the relative volume as:

$$c_o = \frac{-1}{V_{rel}} \frac{\partial V_{rel}}{\partial p} \tag{3-6}$$

Commonly, the relative volume data above the bubble-point pressure is plotted as a function of pressure as shown in Figure 3-3. To evaluate c_o at any pressure p, it is only necessary to graphically differentiate the curve by drawing a tangent line and determining the slope of the line, i.e., $\partial V_{rel}/\partial p$.

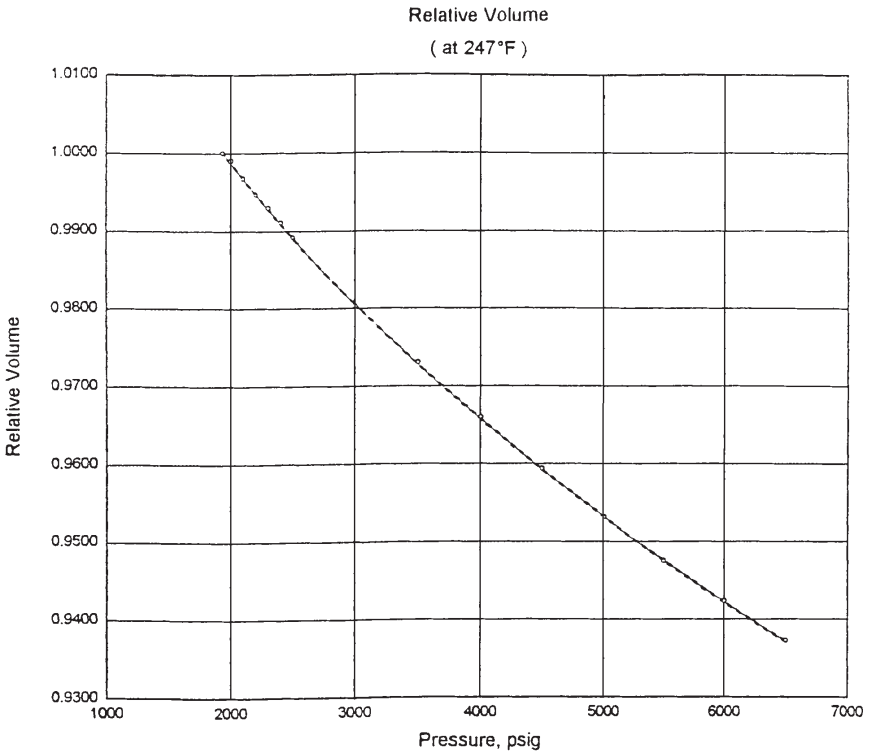


Figure 3-3. Relative volume data above the bubble-point pressure.

Example 3-3

Using Figure 3-3, evaluate c_o at 3,000 psi.

Solution

• Draw a tangent line to the curve and determine the slope.

$$\partial V_{rel} / \partial p = -14.92 \times 10^{-6}$$

• Apply Equation 3-6 to give

$$c_o = \left(\frac{-1}{0.98}\right)\left(-14.92 \times 10^{-6}\right) = 15.23 \times 10^{-6} \text{ psi}^{-1}$$

It should be noted that Table 3-3 lists the compressibility coefficient at several ranges of pressure, e.g., 6,500–6,000. These values are determined by calculating the changes in the relative volume at the indicated pressure interval and evaluating the relative volume at the lower pressure, or

$$c_o = \frac{-1}{[V_{rel}]_2} \frac{(V_{rel})_1 - (V_{rel})_2}{p_1 - p_2} \tag{3-7}$$

where the subscripts 1 and 2 represent the corresponding values at the higher and lower pressure range, respectively.

Example 3-4

Using the measured relative volume data in Table 3-2 for the Big Butte crude oil system, calculate the average oil compressibility in the pressure range of 2,500 to 2,000 psi.

Solution

Apply Equation 3-7 to give

$$c_o = \frac{-1}{0.9987} \frac{0.9890 - 0.9987}{2500 - 2000} = 19.43 \times 10^{-6} \text{ psi}^{-1}$$

DIFFERENTIAL LIBERATION (VAPORIZATION) TEST

In the differential liberation process, the solution gas that is liberated from an oil sample during a decline in pressure is continuously removed from contact with the oil, and before establishing equilibrium with the liquid phase. This type of liberation is characterized by a varying composition of the total hydrocarbon system.

The experimental data obtained from the test include:

- Amount of gas in solution as a function of pressure
- The shrinkage in the oil volume as a function of pressure
- Properties of the evolved gas including the composition of the liberated gas, the gas compressibility factor, and the gas specific gravity
- Density of the remaining oil as a function of pressure

The differential liberation test is considered to better describe the separation process taking place in the reservoir and is also considered to simulate the flowing behavior of hydrocarbon systems at conditions above the critical gas saturation. As the saturation of the liberated gas reaches the critical gas saturation, the liberated gas begins to flow, leaving behind the oil that originally contained it. This is attributed to the fact that gases have, in general, higher mobility than oils. Consequently, this behavior follows the differential liberation sequence.

The test is carried out on reservoir oil samples and involves charging a visual PVT cell with a liquid sample at the bubble-point pressure and at reservoir temperature. As shown schematically in Figure 3-4, the pressure is reduced in steps, usually 10 to 15 pressure levels, and all the liberated gas is removed and its volume is measured at standard conditions. The volume of oil remaining V_L is also measured at each pressure level. It should be noted that the remaining oil is subjected to continual compositional changes as it becomes progressively richer in the heavier components.

The above procedure is continued to atmospheric pressure where the volume of the residual (remaining) oil is measured and converted to a volume at 60°F, V_{sc}. The differential oil formation volume factors B_{od} (commonly called the *relative oil volume factors*) at all the various pressure levels are calculated by dividing the recorded oil volumes V_L by the volume of residual oil V_{sc}, or:

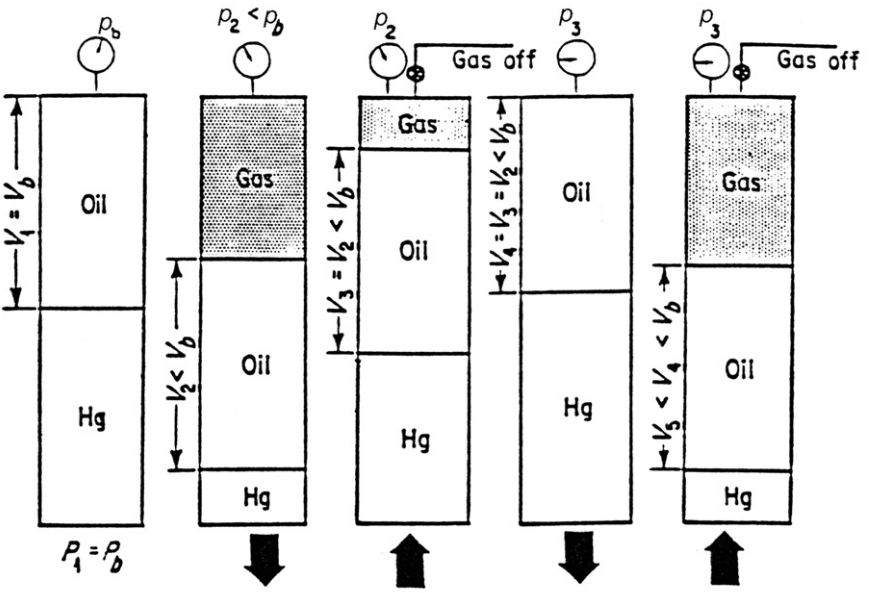


Figure 3-4. Differential vaporization test.

$$B_{od} = \frac{V_L}{V_{sc}} \tag{3-8}$$

The differential solution gas-oil ratio R_{sd} is also calculated by dividing the volume of gas in solution by the residual oil volume.

Table 3-4 shows the results of a differential liberation test for the Big Butte crude. The test indicates that the differential gas-oil ratio and differential relative oil volume at the bubble-point pressure are 933 scf/STB and 1.730 bbl/STB, respectively. The symbols R_{sdb} and B_{odb} are used to represent these two values, i.e.:

$$R_{sdb} = 933 \text{ scf/STB} \quad \text{and} \quad B_{odb} = 1.730 \text{ bbl/STB}$$

Column C of Table 3-4 shows the relative total volume B_{td} from differential liberation as calculated from the following expression:

$$B_{td} = B_{od} + (R_{sdb} - R_{sd})\, B_g \tag{3-9}$$

where B_{td} = relative total volume, bbl/STB
B_g = gas formation volume factor, bbl/scf

Table 3-4
Differential Liberation Data

	Differential Vaporization (at 247°F)						
Pressure, psig	Solution Gas/Oil Ratio, R_{sd} (A)	Relative Oil Volume, B_{od} (B)	Relative Total Volume, B_{td} (C)	Oil Density, gm/cc	Deviation Factor, z	Gas Formation Volume Factor, (D)	Incremental Gas Gravity (Air = 1.000)
b≫1936	933	1.730	1.730	0.6484			
1700	841	1.679	1.846	0.6577	0.864	0.01009	0.885
1500	766	1.639	1.982	0.6650	0.869	0.01149	0.894
1300	693	1.600	2.171	0.6720	0.876	0.01334	0.901
1100	622	1.563	2.444	0.6790	0.885	0.01591	0.909
900	551	1.525	2.862	0.6863	0.898	0.01965	0.927
700	479	1.486	3.557	0.6944	0.913	0.02559	0.966
500	400	1.440	4.881	0.7039	0.932	0.03626	1.051
300	309	1.382	8.138	0.7161	0.955	0.06075	1.230
185	242	1.335	13.302	0.7256	0.970	0.09727	1.423
120	195	1.298	20.439	0.7328	0.979	0.14562	1.593
0	0	1.099		0.7745			2.375
	@ 60°F = 1.000						

Gravity of residual oil = 34.6°API at 60°F
Density of residual oil = 0.8511 gm/cc at 60°F
(A) Cubic feet of gas at 14.73 psia and 60°F per barrel of residual oil at 60°F
(B) Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F
(C) Barrels of oil plus liberated gas at indicated pressure and temperature per barrel of residual oil at 60°F
(D) Cubic feet of gas at indicated pressure and temperature per cubic feet at 14.73 psia and 60°F

The gas deviation z-factor listed in column 6 of Table 3-4 represents the z-factor of the liberated (removed) solution gas at the specific pressure and these values are calculated from the recorded gas volume measurements as follows:

$$z = \left(\frac{V\,p}{T}\right)\left(\frac{T_{sc}}{V_{sc}\,p_{sc}}\right) \tag{3-10}$$

where V = volume of the liberated gas in the PVT cell at p and T
V_{sc} = volume of the removed gas at standard column 7 of Table 3-4 contains the gas formation volume factor B_g as expressed by the following equation:

$$B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{z\,T}{p} \tag{3-11}$$

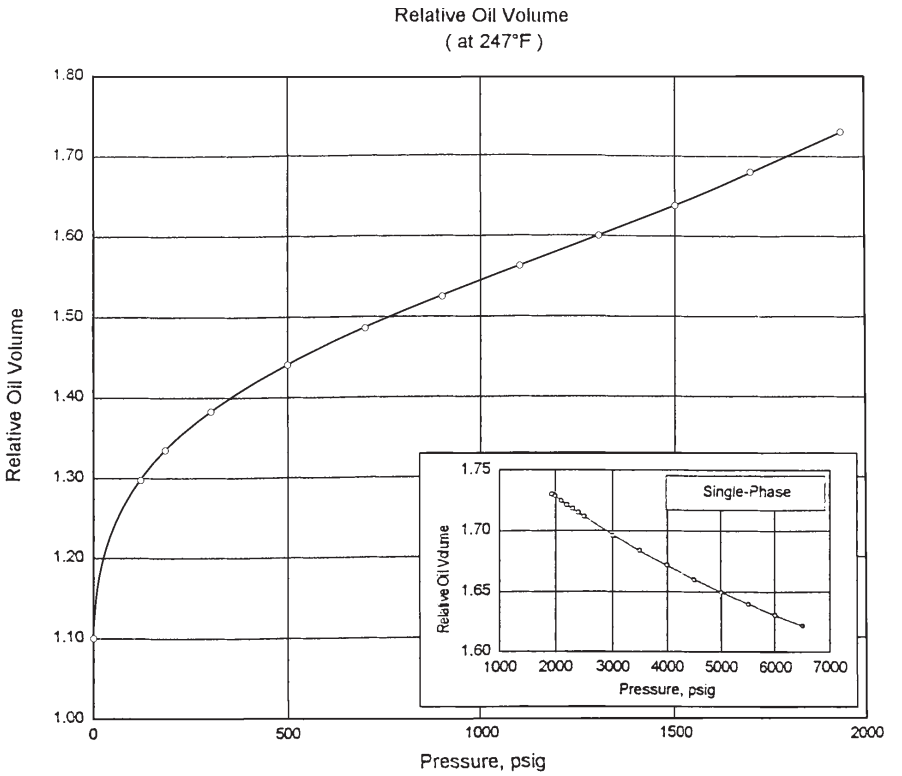
where B_g = gas formation volume factor, ft^3/scf
T = temperature, °R
p = cell pressure, psia
T_{sc} = standard temperature, °R
p_{sc} = standard pressure, psia

Moses (1986) pointed out that reporting the experimental data in relation to the residual oil volume at 60°F (as shown graphically in Figures 3-5 and 3-6) gives the relative oil volume B_{od} and that the differential gas-oil ratio R_{sd} curves the appearance of the oil formation volume factor B_o and the solution gas solubility R_s curves, leading to their misuse in reservoir calculations.

It should be pointed out that the differential liberation test represents the behavior of the oil in the reservoir as the pressure declines. We must find a way of bringing this oil to the surface through separators and into the stock tank. This process is a flash or separator process.

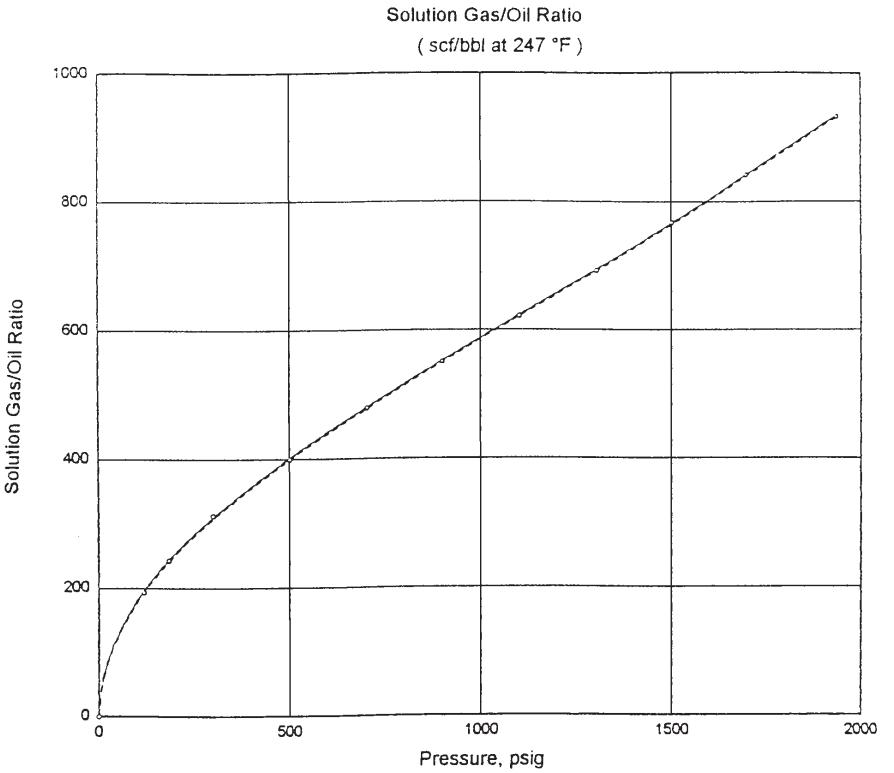
SEPARATOR TESTS

Separator tests are conducted to determine the changes in the volumetric behavior of the reservoir fluid as the fluid passes through the separator (or separators) and then into the stock tank. The resulting volumetric behavior is influenced to a large extent by the operating conditions, i.e., pressures and temperatures, of the surface separation facilities. The primary objective of conducting separator tests, therefore, is to provide the essential laboratory information necessary for determining the optimum surface separation conditions, which in turn will maximize the stock-tank oil production. In addition, the results of the test, when appropriately combined with the differential liberation test data, provide a means of obtaining the PVT parameters (B_o, R_s, and B_t) required for petroleum engineering calculations. These separator tests are performed only on the original oil at the bubble point.



Relative Oil Volume Expression:		LEGEND
y= a + b (Xi)^i + c (Xi)^j + d (Xi)^k		
where:		o Laboratory Data
a= 1.09883e+ 00	i= 1.075	- - - - - - Confidence Limits
b= -1.08945e- 04	j= 0.449	——— Analytical Expression
c= 2.52865e- 02	k= 2.000	Saturation Pressure: 1,936 psig
d= 6.59813e- 08		
Note: Xi (incremental 'X') = pressure, psig		
Confidence level:	99 %	**Differential Vaporization**
Confidence interval:	+/- 0.00028	**Figure B-1**
'r squared':	.999997	

Figure 3-5. Relative volume versus pressure.



Solution Gas/Oil Ratio Expression: $y = a + b(Xi)^i + c(Xi)^j + d(Xi)^k$	LEGEND
where: a= -2.13685e- 01 i= 0.515 b= 1.69108e+ 01 j= 1.482 c= -5.05326e- 03 k= 1.906 d= 2.58392e- 04 Note: Xi (incremental 'X') = pressure, psig	o Laboratory Data - - - - - - Confidence Limits ——— Analytical Expression Saturation Pressure: 1936 psig
Confidence level: 99 % Confidence interval: +/- 1.47 scf/bbl 'r squared': .999966	**Differential Vaporization** **Figure B-2**

Figure 3-6. Solution gas-oil ratio versus pressure.

The test involves placing a hydrocarbon sample at its saturation pressure and reservoir temperature in a PVT cell. The volume of the sample is measured as V_{sat}. The hydrocarbon sample is then displaced and flashed through a laboratory multistage separator system—commonly one to three stages. The pressure and temperature of these stages are set to represent the desired or actual surface separation facilities. The gas liberated from each stage is removed and its specific gravity and volume at standard conditions are measured. The volume of the remaining oil in the last stage (representing the stock-tank condition) is measured and recorded as $(V_o)_{st}$. These experimental measured data can then be used to determine the oil formation volume factor and gas solubility at the bubble-point pressure as follows:

$$B_{ofb} = \frac{V_{sat}}{(V_o)_{st}} \tag{3-12}$$

$$R_{sfb} = \frac{(V_g)_{sc}}{(V_o)_{st}} \tag{3-13}$$

where B_{ofb} = bubble-point oil formation volume factor, as measured by flash liberation, bbl of the bubble-point oil/STB
R_{sfb} = bubble-point solution gas-oil ratio as measured by flash liberation, scf/STB
$(V_g)_{sc}$ = total volume of gas removed from separators, scf

The above laboratory procedure is repeated at a series of different separator pressures and at a fixed temperature. It is usually recommended that four of these tests be used to determine the optimum separator pressure, which is usually considered the separator pressure that results in minimum oil formation volume factor. At the same pressure, the stock-tank oil gravity will be a maximum and the total evolved gas, i.e., the separator gas and the stock-tank gas will be at a minimum.

A typical example of a set of separator tests for a two-stage separation system, as reported by Moses (1986), is shown in Table 3-5. By examining the laboratory results reported in Table 3-5, it should be noted that

Table 3-5
Separator Tests

Separator Pressure (psig)	Temperature (°F)	GOR, R_{stb}*	Stock-Tank Oil Gravity (°API at 60°F)	FVF, B_{otb}**
50	75	737		
to 0	75	41	40.5	1.481
		778		
100	75	676		
to 0	75	92	40.7	1.474
		768		
200	75	602		
to 0	75	178	40.4	1.483
		780		
300	75	549		
to 0	75	246	40.1	1.495
		795		

**GOR in cubic feet of gas at 14.65 psia and 60°F per barrel of stock-tank oil at 60°F*
***FVF is barrels of saturated oil at 2.620 psig and 220°F per barrel of stock-tank oil at 60°F*
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the optimum separator pressure is 100 psia, considered to be the separator pressure that results in the minimum oil formation volume factor. It is important to notice that the oil formation volume factor varies from 1.474 bbl/STB to 1.495 bbl/STB while the gas solubility ranges from 768 scf/STB to 795 scf/STB.

Table 3-5 indicates that the values of the crude oil PVT data are dependent on the method of surface separation. Table 3-6 presents the results of performing a separator test on the Big Butte crude oil. The differential liberation data, as expressed in Table 3-4, show that the solution gas-oil ratio at the bubble point is 933 scf/STB as compared with the measured value of 646 scf/STB from the separator test. This significant difference is attributed to the fact that the processes of obtaining residual oil and stock-tank oil from bubble-point oil are different.

The differential liberation is considered as a multiple series of flashes at the elevated reservoir temperatures. The separator test is generally a one- or two-stage flash at low pressure and low temperature. The quantity of gas released will be different and the quantity of final liquid will be different. Again, it should be pointed out that the oil formation volume

Table 3-6
Separator Test Data

Separator Flash Analysis

Flash Conditions psig	°F	Gas-Oil Ratio (scf/bbl) (A)	Gas-Oil Ratio (scf/STbbl) (B)	Stock-Tank Oil Gravity at 60°F (°API)	Formation Volume Factor Bofb (C)	Separator Volume Factor (D)	Specific Gravity of Flashed Gas (Air = 1.000)	Oil Phase Density
1936	247							0.6484
28	130	593	632			1.066	1.132*	0.7823
0	80	13	13	38.8	1.527	1.010	**	0.8220
			Rsfb = 646					

**Collected and analyzed in the laboratory by gas chromatography*
***Insufficient quantity for measurement*
(A) Cubic feet of gas at 14.73 psia and 60°F per barrel of oil at indicated pressure and temperature
(B) Cubic feet of gas at 14.73 psia and 60°F per barrel of stock-tank oil at 60°F
(C) Barrels of saturated oil at 1936 psig and 247°F per barrel of stock-tank oil at 60°F
(D) Barrels of oil at indicated pressure and temperature per barrel of stock-tank oil at 60°F

factor, as expressed by Equation 3-12, is defined as "the volume of oil at reservoir pressure and temperature divided by the resulting stock-tank oil volume after it passes through the surface separators."

Adjustment of Differential Liberation Data to Separator Conditions

To perform material balance calculations, the oil formation volume factor B_o and gas solubility R_s as a function of the reservoir pressure must be available. The ideal method of obtaining these data is to place a large crude oil sample in a PVT cell at its bubble-point pressure and reservoir temperature. At some pressure a few hundred psi below the bubble-point pressure, a small portion of the oil is removed and flashed at temperatures and pressures equal to those in the surface separators and stock tank. The liberated gas volume and stock-tank oil volume are measured to obtain B_o and R_s. This process is repeated at several progressively lower reservoir pressures until complete curves of B_o and R_s versus pressure have been obtained. This procedure is occasionally conducted in the laboratory. This experimental methodology was originally proposed by Dodson (1953) and is called the Dodson Method.

Amyx et al. (1960) and Dake (1978) proposed a procedure for constructing the oil formation volume factor and gas solubility curves by using the differential liberation data (as shown in Table 3-4) in conjunction

with the experimental separator flash data (as shown in Table 3-6) for a given set of separator conditions. The method is summarized in the following steps:

Step 1. Calculate the differential shrinkage factors at various pressures by dividing each relative oil volume factor B_{od} by the relative oil volume factor at the bubble-point B_{odb}, or:

$$S_{od} = \frac{B_{od}}{B_{odb}} \tag{3-14}$$

where B_{od} = differential relative oil volume factor at pressure p, bbl/STB
B_{odb} = differential relative oil volume factor at the bubble-point pressure p_b, psia, bbl/STB
S_{od} = differential oil shrinkage factor, bbl/bbl of bubble-point oil

The differential oil shrinkage factor has a value of one at the bubble-point and a value less than one at subsequent pressures below p_b.

Step 2. Adjust the relative volume data by multiplying the separator (flash) formation volume factor at the bubble-point B_{ofb} (as defined by Equation 3-12) by the differential oil shrinkage factor S_{od} (as defined by Equation 3-14) at various reservoir pressures. Mathematically, this relationship is expressed as follows:

$$B_o = B_{ofb}\, S_{od} \tag{3-15}$$

where B_o = oil formation volume factor, bbl/STB
B_{ofb} = bubble-point oil formation volume factor, bbl of the bubble-point oil/STB (as obtained from the separator test)
S_{od} = differential oil shrinkage factor, bbl/bbl of bubble-point oil

Step 3. Calculate the oil formation volume factor at pressures above the bubble-point pressure by multiplying the relative oil volume data V_{rel}, as generated from the constant-composition expansion test, by B_{ofb}, or:

$$B_o = (V_{rel})\,(B_{ofb}) \tag{3-16}$$

where B_o = oil formation volume factor above the bubble-point pressure, bbl/STB
V_{rel} = relative oil volume, bbl/bbl

Step 4. Adjust the differential gas solubility data R_{sd} to give the required gas solubility factor R_s

$$R_s = R_{sfb} - (R_{sdb} - R_{sd})\frac{B_{ofb}}{B_{odb}} \tag{3-17}$$

where R_s = gas solubility, scf/STB
R_{sfb} = bubble-point solution gas-oil ratio from the separator test, scf/STB
R_{sdb} = solution gas-oil ratio at the bubble-point pressure as measured by the differential liberation test, scf/STB
R_{sd} = solution gas-oil ratio at various pressure levels as measured by the differential liberation test, scf/STB

These adjustments will typically produce lower formation volume factors and gas solubilities than the differential liberation data.

Step 5. Obtain the two-phase (total) formation volume factor B_t by multiplying values of the relative oil volume V_{rel} below the bubble-point pressure by B_{ofb}, or:

$$B_t = (B_{ofb})\ (V_{rel}) \tag{3-18}$$

where B = two-phase formation volume factor, bbl/STB
V_{rel} = relative oil volume below the p_b, bbl/bbl

Similar values for B_t can be obtained from the differential liberation test by multiplying the relative total volume B_{td} (see Table 3-4, Column C) by B_{ofb}, or

$$B_t = (B_{td})\ (B_{ofb})/B_{odb} \tag{3-19}$$

It should be pointed out that Equations 3-16 and 3-17 usually produce values less than one for B_o and negative values for R_s at low pressures. The calculated curves of B_o and R_s versus pressures must be manually drawn to B_o = 1.0 and Rs = 0 at atmospheric pressure.

Example 3-5

The constant-composition expansion test, differential liberation test, and separator test for the Big Butte crude oil system are given in Tables 3-2, 3-4, and 3-6, respectively. Calculate:

- Oil formation volume factor at 4,000 and 1,100 psi
- Gas solubility at 1,100 psi
- The two-phase formation volume factor at 1,300 psi

Solution

Step 1. Determine B_{odb}, R_{sdb}, B_{ofb}, and R_{sfb} from Tables 3-4 and 3-6:

B_{odb} = 1.730 bbl/STB $\quad$ R_{sdb} = 933 scf/STB

B_{ofb} = 1.527 bbl/STB $\quad$ R_{sfb} = 646 scf/STB

Step 2. Calculate B_o at 4,000 by applying Equation 3-16:

$B_o = (0.9657)\ (1.57) = 1.4746$ bbl/STB

Step 3. Calculate B_o at 1,100 psi by applying Equations 3-14 and 3-15.

$$S_{od} = \frac{1.563}{1.730} = 0.9035$$

$B_o = (0.9035)\ (1.527) = 1.379$ bbl/STB

Step 4. Calculate the gas solubility at 1,100 psi by using Equation 3-17:

$$R_s = 646 - (933 - 622)\left(\frac{1.527}{1.730}\right) = 371 \text{ scf/STB}$$

Step 5. From the pressure-volume relations (i.e., constant-composition data) of Table 3-2 the relative volume at 1,300 PSI in 1.2579 bbl/bbl. Using Equation 3-18, calculate B_t to give:

$B_t = (1.527)\ (1.2579) = 1.921$ bbl/STB

Applying Equation 3-19 gives:

$B_t = (2.171)\ (1.527)/1.73 = 1.916$ bbl/STB

Table 3-7 presents a complete documentation of the adjusted differential vaporization data for the Big Butte crude oil system. Figures 3-7 and 3-8 compare graphically the adjusted values of R_s

Table 3-7
Adjusted Differential Liberation Data

Differential Vaporization
Adjusted to Separator Conditions*

Pressure, psig	Solution Gas-Oil Ratio, R_s (A)	Formation Volume Factor, B_o (B)	Gas Formation Volume Factor (C)	Oil Density, gm/cc	Oil-Gas Viscosity Ratio
6500	646	1.431		0.6919	
6000	646	1.439		0.6882	
5500	646	1.447		0.6843	
5000	646	1.456		0.6803	
4500	646	1.465		0.6760	
4000	646	1.475		0.6714	
3500	646	1.486		0.6665	
3000	646	1.497		0.6613	
2500	646	1.510		0.6556	
2400	646	1.513		0.6544	
2300	646	1.516		0.6531	
2200	646	1.519		0.6519	
2100	646	1.522		0.6506	
2000	646	1.525		0.6493	
b≫1936	646	1.527		0.6484	
1700	564	1.482	0.01009	0.6577	19.0
1500	498	1.446	0.01149	0.6650	21.3
1300	434	1.412	0.01334	0.6720	23.8
1100	371	1.379	0.01591	0.6790	26.6
900	309	1.346	0.01965	0.6863	29.8
700	244	1.311	0.02559	0.6944	33.7
500	175	1.271	0.03626	0.7039	38.6
300	95	1.220	0.06075	0.7161	46.0
185	36	1.178	0.09727	0.7256	52.8
120		1.146	0.14562	0.7328	58.4
0				0.7745	

***Separator Conditions**

Fist Stage	28 psig at 130°F
Stock Tank	0 psig at 80°F

(A) Cubic feet of gas at 14.73 psia and 60°F per barrel of stock-tank oil at 60°F
(B) Barrel of oil at indicated pressure and temperature per barrel of stock-tank oil at 60°F
(C) Cubic feet of gas at indicated pressure and temperature per cubic feet at 14.73 psia and 60°F

and B_o with those of the unadjusted PVT data. It should be noted that no adjustments are needed for the gas formation volume factor, oil density, or viscosity data.

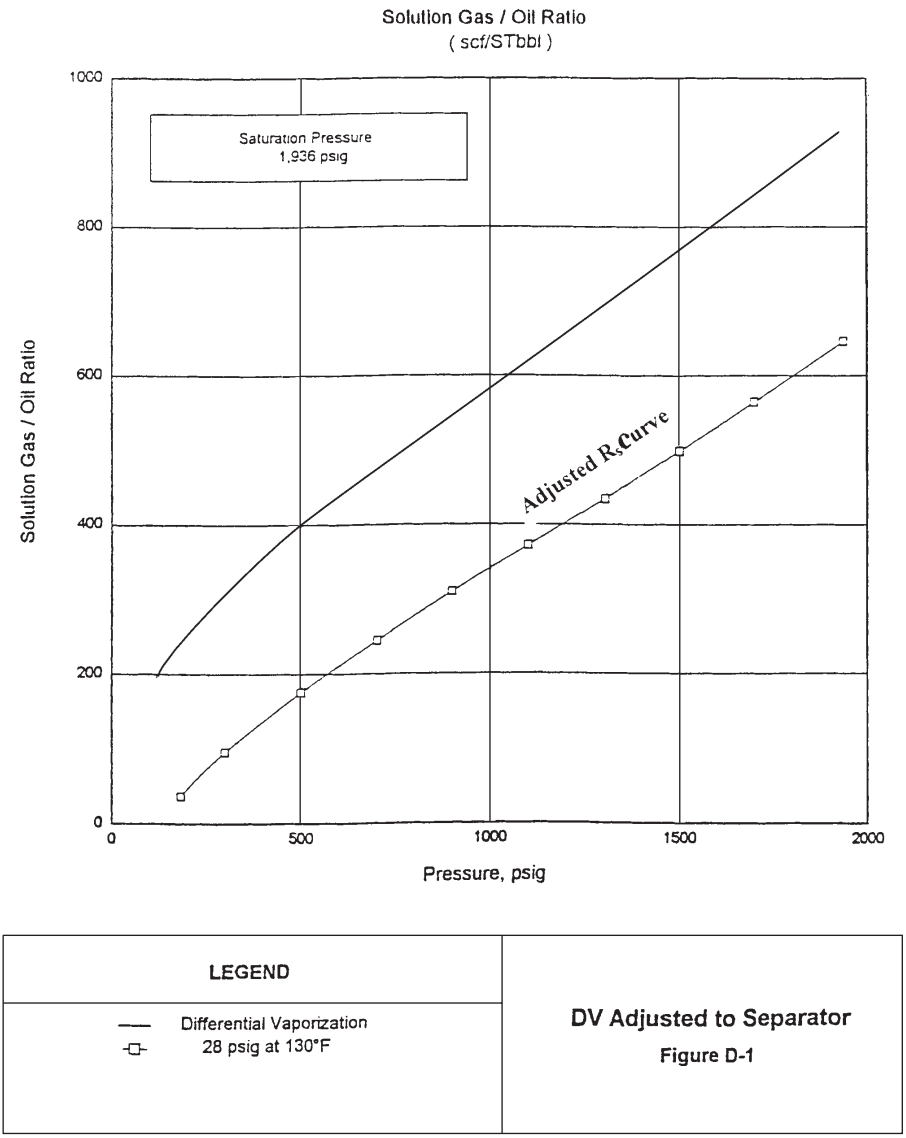

Figure 3-7. Adjusted gas solubility versus pressure.

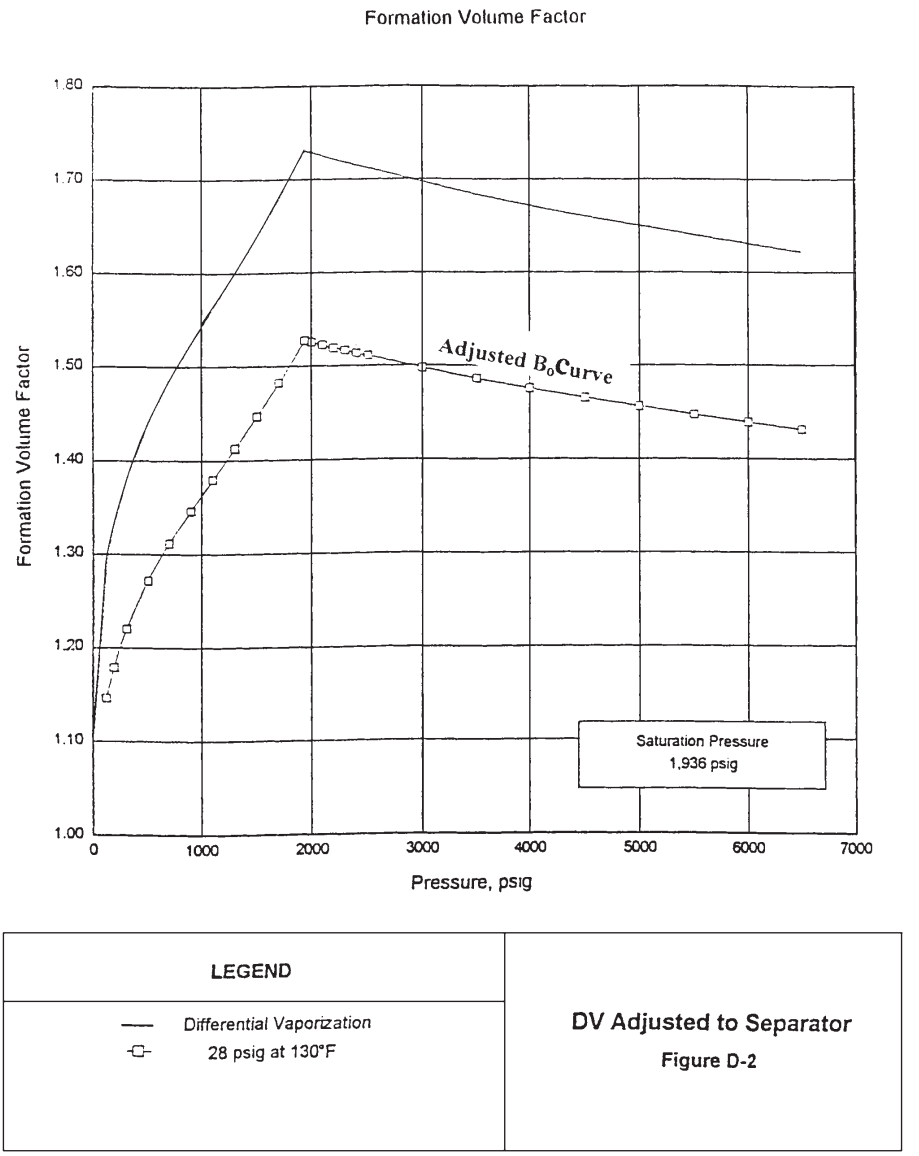

Figure 3-8. Adjusted oil formation volume factor versus pressure.

EXTRAPOLATION OF RESERVOIR FLUID DATA

In partially depleted reservoirs or in fields that originally existed at the bubble-point pressure, it is difficult to obtain a fluid sample, which usually represents the original oil in the reservoir at the time of discovery. Also, in collecting fluid samples from oil wells, the possibility exists of obtaining samples with a saturation pressure that might be lower than or higher than the actual saturation pressure of the reservoir. In these cases, it is necessary to correct or adjust the laboratory PVT measured data to reflect the actual saturation pressure. The proposed correction procedure for adjusting the following laboratory test data is described in the subsequent sections:

- Constant-composition expansion (CCE) test
- Differential expansion (DE) test
- Oil viscosity test
- Separator tests

Correcting Constant-Composition Expansion Data

The correction procedure, summarized in the following steps, is based on calculating the Y-function value for each point below the "old" saturation pressure.

Step 1. Calculate the Y-function, as expressed by Equation 3-3, for each point by using the old saturation pressure.

Step 2. Plot the values of the Y-function versus pressure on a Cartesian scale and draw the best straight line. Points in the neighborhood of the saturation pressure may be erratic and need not be used.

Step 3. Calculate the coefficients a and b of the straight-line equation, i.e.:

$$Y = a + bp$$

Step 4. Recalculate the relative volume V_{rel} values by applying Equation 3-5 and using the "new" saturation pressure, or:

$$V_{rel} = 1 + \frac{p_{sat}^{new} - p}{p(a + bp)} \tag{3-20}$$

To determine points above the "new" saturation pressure, apply the following steps:

Step 1. Plot the "old" relative volume values above the "old" saturation pressure versus pressure on a regular scale and draw the best straight line through these points.

Step 2. Calculate the slope of the Line S. It should be noted that the slope is negative, i.e., $S < 0$.

Step 3. Draw a straight line that passes through the point ($V_{rel} = 1$, p_{sat}^{new}) and parallel to the line of Step 1.

Step 4. Relative volume data above the new saturation pressure are read from the straight line or determined from the following expression at any pressure p:

$$V_{rel} = 1 - S\,(p_{sat}^{new} - p) \tag{3-21}$$

where S = slope of the line
p = pressure

Example 3-6

The pressure-volume relations of the Big Butte crude oil system is given in Table 3-2. The test indicates that the oil has a bubble-point pressure of 1,930 psig at 247°F. The Y-function for the oil system is expressed by the following linear equation:

$$Y = 1.0981 + 0.000591p$$

Above the bubble-point pressure, the relative volume data versus pressure exhibit a straight-line relationship with a slope of –0.0000138.

The surface production data of the field suggest that the actual bubble-point pressure is approximately 2,500 psig. Reconstruct the pressure-volume data using the new reported saturation pressure.

Solution

Using Equations 3-30 and 3-31, gives:

Pressure, psig	Old V_{rel}	New V_{rel}	Comments
6500	0.9371	0.9448	Equation 3-21
6000	0.9422	0.9517	
5000	0.9532	0.9655	
4000	0.9657	0.9793	
3000	0.9805	0.9931	
$p_b^{new} = 2500$	0.9890	1.0000	
2000	0.9987	1.1096	Equation 3-20
$p_b^{old} = 1936$	1.0000	1.1299	
1911	1.0058	1.1384	
1808	1.0324	1.1767	
1600	1.1018	1.1018	
600	2.4960	2.4960	
437	3.4404	3.4404	

Correcting Differential Liberation Data

Relative oil volume B_{od} versus pressure:

The laboratory-measured B_{od} data must be corrected to account for the new bubble-point pressure p_b^{new}. The proposed procedure is summarized in the following steps:

Step 1. Plot the B_{od} data versus gauge pressure on a regular scale.

Step 2. Draw the best straight line through the *middle pressure range* of 30%–90% p_b.

Step 3. Extend the straight line to the new bubble-point pressure, as shown schematically in Figure 3-9.

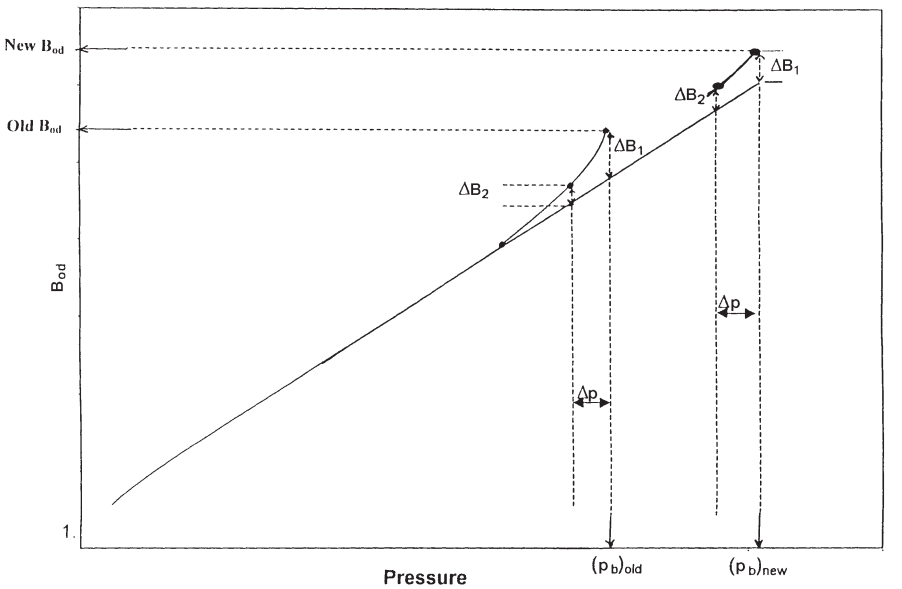

Figure 3-9. Correcting B_{od} for the new p_b.

Step 4. Transfer any curvature at the end of the original curve, i.e., ΔB_{o1} at p_b^{old}, to the new bubble-point pressure by placing ΔB_{ol} above or below the straight line at p_b^{new}.

Step 5. Select any differential pressure Δp below the p_b^{old} and transfer the corresponding curvature to the pressure ($p_b^{new} - \Delta p$).

Step 6. Repeat the above process and draw a curve that connects the generated B_{od} points with original curve at the point of intersection with the straight line. Below this point, no change is needed.

Solution gas-oil ratio:

The correction procedure for the isolation gas-oil ratio R_{sd} data is identical to that of the relative oil volume data.

Correcting Oil Viscosity Data

The oil viscosity data can be extrapolated to a new higher bubble-point pressure by applying the following steps:

Step 1. Defining the *fluidity* as the reciprocal of the oil viscosity, i.e., $1/\mu_o$, calculate the fluidity for each point *below* the original saturation pressure.

Step 2. Plot fluidity versus pressure on a Cartesian scale (see Figure 3-10).

Step 3. Draw the best straight line through the points and extend it to the new saturation pressure p_b^{old}.

Step 4. New oil viscosity values above p_b^{old} are read from the straight line.

To obtain the oil viscosity for pressures above the new bubble-point pressure p_b^{new}, follow these steps:

Step 1. Plot the viscosity values for all points *above* the old saturation pressure on a Cartesian coordinate as shown schematically in Figure 3-11, and draw the best straight line through them, as Line A.

Step 2. Through the point on the extended viscosity curve at p_b^{new}, draw a straight line (Line B) parallel to A.

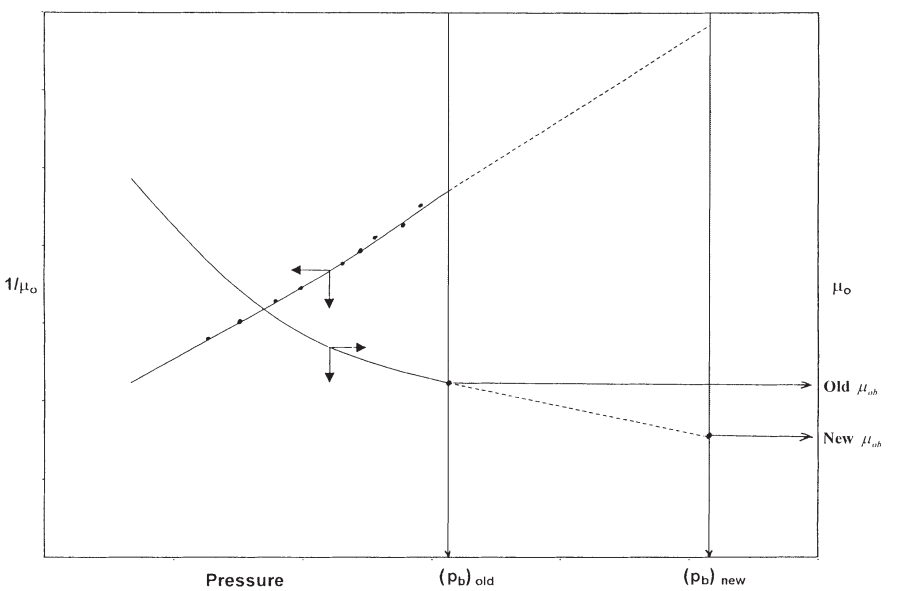

Figure 3-10. Extrapolating μ_o to new p_b.

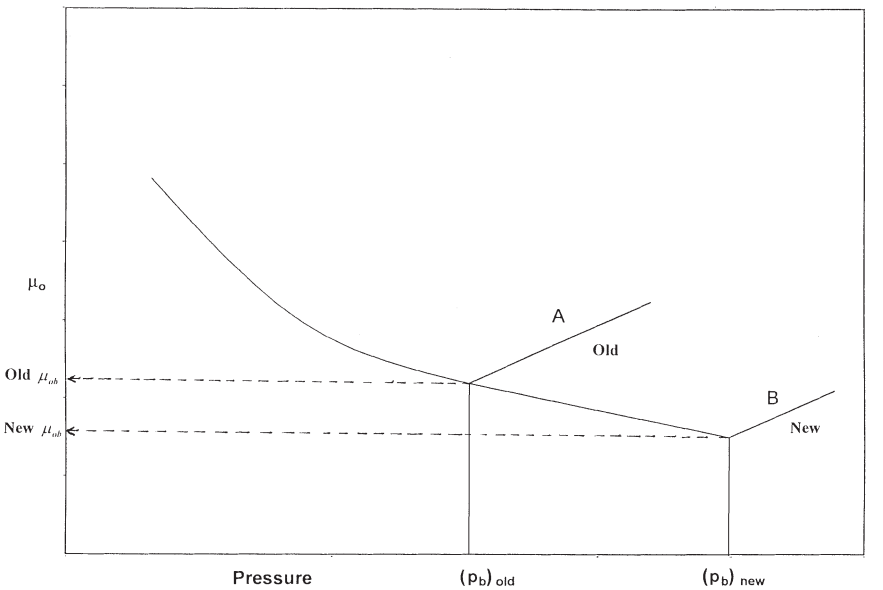

Figure 3-11. Extrapolating oil viscosity above new p_b.

Step 3. Viscosities above the new saturation pressure are then read from Line A.

Correcting the Separator Tests Data

Stock-tank gas-oil ratio and gravity:

No corrections are needed for the stock-tank gas-oil ratio and the stock-tank API gravity.

Separator gas-oil ratio:

The *total* gas-oil ratio R_{sfb} is changed in the same proportion as the differential ratio was changed, or

$$R_{sfb}^{new} = R_{sfb}^{old} \left(R_{sdb}^{new} / R_{sdb}^{old} \right) \tag{3-22}$$

The *separator* gas-oil ratio is then the difference between the new (corrected) gas solubility R_{sfb}^{new} and the unchanged stock-tank gas-oil ratio.

Formation volume factor:

The separator oil formation volume factor B_{ofb} is adjusted in the same proportion as the differential liberation values:

$$B_{ofb}^{new} = B_{ofb}^{old} \left(B_{odb}^{new} / B_{odb}^{old}\right) \quad (3\text{-}23)$$

Example 3-7

Results of the differential liberation and the separator tests on the Big Butte crude oil system are given in Tables 3-4 and 3-6, respectively. New field and production data indicate that the bubble-point pressure is better described by a value of 2,500 psi as compared with the laboratory-reported value of 1,936 psi. The correction procedure for B_{od} and R_{sd} as described previously was applied to give the following values at the new bubble point:

$$B_{odb}^{new} = 2.013 \text{ bbl/STB} \qquad R_{sbd}^{new} = 1{,}134 \text{ scf/STB}$$

Using the separator test data as given in Table 3-6, calculate the gas solubility and the oil formation volume factor at the new bubble-point pressure.

Solution

• Gas solubility: from Equation 3-22

$$R_{sb} = 646\left(\frac{1134}{933}\right) = 785 \text{scf/STB}$$

Separator GOR = 785 − 13 = 772 scf/STB

• Oil formation volume factor

Applying Equation 3-23 gives

$$B_{ob} = 1.527\left(\frac{2.013}{1.730}\right) = 1.777 \text{ bbl/STB}$$

LABORATORY ANALYSIS OF GAS-CONDENSATE SYSTEMS

In the laboratory, a standard analysis of a gas-condensate sample consists of:

- Recombination and analysis of separator samples
- Measuring the pressure-volume relationship, i.e., constant-composition expansion test
- Constant-volume depletion test (CVD)

Recombination of Separator Samples

Obtaining a representative sample of the reservoir fluid is considerably more difficult for a gas-condensate fluid than for a conventional black-oil reservoir. The principal reason for this difficulty is that liquid may condense from the reservoir fluid during the sampling process, and if representative proportions of both liquid and gas are not recovered then an erroneous composition will be calculated.

Because of the possibility of erroneous compositions and also because of the limited volumes obtainable, subsurface sampling is seldom used in gas-condensate reservoirs. Instead, surface sampling techniques are used, and samples are obtained only after long stabilized flow periods. During this stabilized flow period, volumes of liquid and gas produced in the surface separation facilities are accurately measured, and the fluid samples are then recombined in these proportions.

The hydrocarbon composition of separator samples is also determined by chromatography or low-temperature fractional distillation or a combination of both. Table 3-7 shows the hydrocarbon analyses of the separator liquid and gas samples taken from the Nameless Field. The gas and liquid samples are recombined in the proper ratio to obtain the well-stream composition as given in Table 3-8. The laboratory data indicate that the overall well-stream system contains 63.71 mol% methane and 10.75 mol% heptanes-plus.

Frequently, the surface gas is processed to remove and liquefy all hydrocarbon components that are heavier than methane, i.e., ethane, propanes, etc. These liquids are called *plant products.* These quantities of

Table 3-8
Hydrocarbon Analyses of Separator Products and Calculated Wellstream

Component	Separator mol %	Separator Gas mol %	Separator Gas GPM	Wellstream mol %	Wellstream GPM
Hydrogen Sulfide	Nil	Nil		Nil	
Carbon Dioxide	0.29	1.17		0.92	
Nitrogen	0.13	0.38		0.31	
Methane	18.02	81.46		63.71	
Ethane	12.08	11.46		11.63	
Propane	11.40	3.86	1.083	5.97	1.675
iso-Butane	3.05	0.49	0.163	1.21	0.404
n-Butane	5.83	0.71	0.228	2.14	0.688
iso-Pentane	3.07	0.18	0.067	0.99	0.369
Pentane	2.44	0.12	0.044	0.77	0.284
Hexanes	5.50	0.09	0.037	1.60	0.666
Heptanes-plus	38.19	0.08	0.037	10.75	7.944
	100.00	100.00	1.659	100.00	12.030
Properties of Heptanes-plus					
API gravity @ 60°F	43.4				
Specific gravity @ 60/60°F	0.8091			0.809	
Molecular weight	185	103		185	

Calculated separator gas gravity (air = 1.000) = 0.687
Calculated gross heating value for separator gas = 1209 BTU per cubic foot of dry gas @ 15.025 psia and 60°F

Primary separator gas collected @ 745 psig and 74°F
Primary separator liquid collected @ 745 psig and 74°F

Primary separator gas/separator liquid ratio	2413 scf/bbl @ 60°F
Primary separator liquid/stock-tank liquid ratio	1.360 bbl @ 60°F
Primary separator gas/wellstream ratio	720.13 Mscf/MMscf
Stock-tank liquid/wellstream ratio	219.4 bbl/MMscf

liquid products are expressed in gallons of liquid per thousand standard cubic feet of gas processed, i.e., gal/Mscf, or GPM. McCain (1990) derived the following expression for calculating the anticipated GPM for each component in the gas phase:

$$GPM_i = 11.173\left(\frac{p_{sc}}{T_{sc}}\right)\left(\frac{y_i M_i}{\gamma_{oi}}\right) \tag{3-24}$$

where p_{sc} = standard pressure, psia
T_{sc} = standard temperature, °R
y_i = mole fraction of component i in the gas phase
M_i = molecular weight of component i
γ_{oi} = specific gravity of component i as a liquid at standard conditions (Chapter 1, Table 1-1, Column E)

McCain pointed out that the complete recovery of these products is not feasible. He proposed that, as a rule of thumb, 5 to 25% of ethane, 80 to 90% of the propane, 95% or more of the butanes, and 100% of the heavier components can be recovered from a simple surface facility.

Example 3-8

Table 3-8 shows the wellstream compositional analysis of the Nameless Field. Using Equation 3-24, calculate the maximum available liquid products assuming 100% plant efficiency.

Solution

• Using the standard conditions as given in Table 3-8 gives:

$$GPM = 11.173\left(\frac{15.025}{520}\right)\left(\frac{y_i M_i}{\gamma_{oi}}\right) = 0.3228\left(\frac{y_i M_i}{\gamma_{oi}}\right)$$

• Construct the following working table:

Component	y_i	M_i	γ_{oi}	GPM_i
CO_2	0.0092			
N_2	0.0031			
C_1	0.6371			
C_2	0.1163	30.070	0.35619	1.069
C_3	0.0597	44.097	0.50699	1.676
i-C_4	0.0121	58.123	0.56287	0.403
n-C_4	0.0214	58.123	0.58401	0.688
i-C_5	0.0099	72.150	0.63112	0.284
n-C5	0.0077	72.150	0.63112	0.284
C_6	0.0160	86.177	0.66383	0.670
C_7^+	0.1075	185.00	0.809	7.936
				15.20 GPM

Constant-Composition Test

This test involves measuring the pressure-volume relations of the reservoir fluid at reservoir temperature with a visual cell. This usual PVT cell allows the visual observation of the condensation process that results from changing the pressures. The experimental test procedure is similar to that conducted on crude oil systems. The CCE test is designed to provide the dew-point pressure p_d at reservoir temperature and the total relative volume V_{rel} of the reservoir fluid (relative to the dew-point volume) as a function of pressure. The relative volume is equal to one at p_d. The gas compressibility factor at pressures greater than or equal to the saturation pressure is also reported. It is only necessary to experimentally measure the z-factor at one pressure p_1 and determine the gas deviation factor at the other pressure p from:

$$z = z_1 \left(\frac{p}{p_1} \right) \frac{V_{rel}}{(V_{rel})_1} \tag{3-25}$$

where z = gas deviation factor at p
V_{rel} = relative volume at pressure p
$(V_{rel})_1$ = relative volume at pressure p_1

If the gas compressibility factor is measured at the dew-point pressure, then:

$$z = z_d \left(\frac{p}{p_d} \right) (V_{rel}) \tag{3-26}$$

where z_d = gas compressibility factor at the dew-point pressure p_d
p_d = dew-point pressure, psia
p = pressure, psia

Table 3-9 shows the dew-point determination and the pressure-volume relations of the Nameless Field. The dew-point pressure of the system is reported as 4,968 psi at 262°F. The measured gas compressibility factor at the dew point is 1.043.

Example 3-9

Using Equation 3-26 and the data in Table 3-9, calculate the gas deviation factor at 6,000 and 8,100 psi.

Table 3-9
Pressure-Volume Relations of Reservoir Fluid at 262°F
(Constant-Composition Expansion)

Pressure, psig	Relative Volume	Deviation Factor, z
8100	0.8733	1.484
7800	0.8806	1.441
7500	0.8880	1.397
7000	0.9036	1.327
6500	0.9195	1.254
6000	0.9397	1.184
5511	0.9641	1.116
5309	0.9764	1.089
5100	0.9909	1.061
5000	0.9979	1.048
4968 Dew-point pressure	1.0000	1.043
4905	1.0057	
4800	1.0155	
4600	1.0369	
4309	1.0725	
4000	1.1177	
3600	1.1938	
3200	1.2970	
2830	1.4268	
2400	1.6423	
2010	1.9312	
1600	2.4041	
1230	3.1377	
1000	3.8780	
861	4.5249	
770	5.0719	

**Gas Expansion Factor = 1.2854 Mscf/bbl*

Solution

• At 6,000 psi

$$z = 1.043\left(\frac{6000 + 15.025}{4968 + 15.025}\right)(0.9397) = 1.184$$

• At 8,100 psi

$$z = 1.043\left(\frac{8100 + 15.025}{4968 + 15.025}\right)(0.8733) = 1.483$$

Constant-Volume Depletion (CVD) Test

Constant-volume depletion (CVD) experiments are performed on gas condensates and volatile oils to simulate reservoir depletion performance and compositional variation. The test provides a variety of useful and important information that is used in reservoir engineering calculations.

The laboratory procedure of the test is shown schematically in Figure 3-12 and is summarized in the following steps:

Step 1. A measured amount of a representative sample of the original reservoir fluid with a known overall composition of z_i is charged to a visual PVT cell at the dew-point pressure p_d ("a" in Figure 3-12). The temperature of the PVT cell is maintained at the reservoir temperature T throughout the experiment. The initial volume V_i of the saturated fluid is used as a reference volume.

Step 2. The initial gas compressibility factor is calculated from the real gas equation

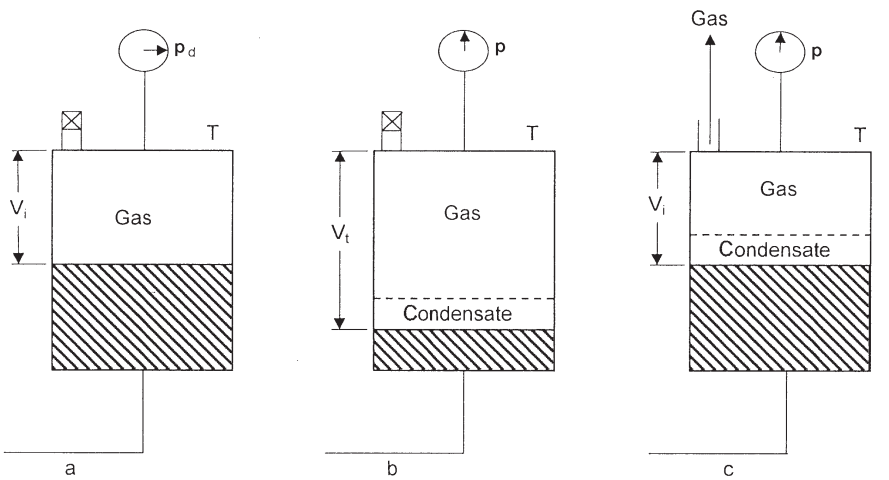

Figure 3-12. A schematic illustration of the constant-volume depletion test.

$$z_d = \frac{p_d V_i}{n_i RT} \tag{3-27}$$

where p_d = dew-point pressure, psia
V_i = initial gas volume, ft^3
n_i = initial number of moles of the gas = m/M_a
R = gas constant, 10.73
T = temperature, °R
z_d = compressibility factor at dew-point pressure

Step 3. The cell pressure is reduced from the saturation pressure to a predetermined level P. This can be achieved by withdrawing mercury from the cell, as illustrated in column b of Figure 3-12. During the process, a second phase (retrograde liquid) is formed. The fluid in the cell is brought to equilibrium and the gas volume V_g and volume of the retrograde liquid V_L are visually measured. This retrograde volume is reported as a percent of the initial volume V_i, which basically represents the retrograde liquid saturation S_L:

$$S_L = \left(\frac{V_L}{V_i}\right) 100$$

Step 4. Mercury is reinjected into the PVT cell at constant pressure P while an equivalent volume of gas is simultaneously removed. When the initial volume V_i is reached, mercury injection is ceased, as illustrated in column c of Figure 3-12. This step simulates a reservoir producing only gas, with retrograde liquid remaining immobile in the reservoir.

Step 5. The removed gas is charged to analytical equipment where its composition y_i is determined, and its volume is measured at standard conditions and recorded as $(V_{gp})_{sc}$. The corresponding moles of gas produced can be calculated from the expression

$$n_p = \frac{p_{sc}(V_{gp})_{sc}}{R\ T_{sc}} \tag{3-28}$$

where n_p = moles of gas produced
$(V_{gp})_{sc}$ = volume of gas produced measured at standard conditions, scf
T_{sc} = standard temperature, °R
p_{sc} = standard pressure, psia
R = 10.73

Step 6. The gas compressibility factor at cell pressure and temperature is calculated from the real gas equation-of-state as follows:

$$z = \frac{p(V_g)}{n_p\ R\ T} \tag{3-29}$$

Another property, the two-phase compressibility factor, is also calculated. The two-phase compressibility factor represents the total compressibility of all the remaining fluid (gas and retrograde liquid) in the cell and is computed from the real gas law as

$$z_{\text{two-phase}} = \frac{p\ V_i}{(n_i - n_p)\,RT} \tag{3-30}$$

where $(n_i - n_p)$ = the remaining moles of fluid in the cell
n_i = initial moles in the cell
n_p = cumulative moles of gas removed

The two-phase z-factor is a significant property because it is used when the p/z versus cumulative-gas produced plot is constructed for evaluating gas-condensate production.

Equation 3-30 can be expressed in a more convenient form by replacing moles of gas, i.e., n_i and n_p, with their equivalent gas volumes, or:

$$z_{\text{two-phase}} = \left(\frac{z_d}{P_d}\right)\left[\frac{p}{1 - (G_p/GIIP)}\right] \tag{3-31}$$

where z_d = gas deviation factor at the dew-point pressure
P_d = dew-point pressure, psia
P = reservoir pressure, psia
GIIP = initial gas in place, scf
G_p = cumulative gas produced at pressure p, scf

Step 7. The volume of gas produced as a percentage of gas initially in place is calculated by dividing the cumulative volume of the produced gas by the gas initially in place, both at standard conditions

$$\%G_p = \left[\frac{\sum (V_{gp})_{sc}}{GIIP}\right]100 \tag{3-32}$$

or

$$\%G_p = \left[\frac{\sum n_p}{(n_i)_{original}}\right]100$$

The above experimental procedure is repeated several times until a minimum test pressure is reached, after which the quantity and composition of the gas and retrograde liquid remaining in the cell are determined.

The test procedure can also be conducted on a volatile oil sample. In this case, the PVT cell initially contains liquid, instead of gas, at its bubble-point pressure.

The results of the pressure-depletion study for the Nameless Field are illustrated in Tables 3-10 and 3-11. Note that the composition listed in the 4,968 psi pressure column in Table 3-10 is the composition of the reservoir fluid at the dew point and exists in the reservoir in the gaseous state. Table 3-10 and Figure 3-13 show the changing composition of the wellstream during depletion. Notice the progressive reduction of C_{7+} below the dew point and increase in the methane fraction, i.e., C_1.

The concentrations of *intermediates,* i.e., C_2–C_6, are also seen to decrease (they condense) as pressure drops down to about 2,000 psi and then increase as they revaporize at the lower pressures. The final column shows the composition of the liquid remaining in the cell (or reservoir) at the abandonment pressure of 700 psi; the predominance of C_{7+} components in the liquid is apparent.

The z-factor of the equilibrium gas and the two-phase z are presented. (Note: if a (p/z) versus G_p analysis is to be done, the two-phase compressibility factors are the appropriate values to use.)

(*text continued on page 182*)

Table 3-10
Depletion Study at 262°F

Hydrocarbon Analyses of Produced Wellstream-Mol Percent

	Reservoir Pressure, psig							
Component	**4968**	**4300**	**3500**	**2800**	**2000**	**1300**	**700**	**700***
Carbon dioxide	0.92	0.97	0.99	1.01	1.02	1.03	1.03	0.30
Nitrogen	0.31	0.34	0.37	0.39	0.39	0.37	0.31	0.02
Methane	63.71	69.14	71.96	73.24	73.44	72.48	69.74	12.09
Ethane	11.63	11.82	11.87	11.92	12.25	12.67	13.37	5.86
Propane	5.97	5.77	5.59	5.54	5.65	5.98	6.80	5.61
iso-Butane	1.21	1.14	1.07	1.04	1.04	1.13	1.32	1.61
n-Butane	2.14	1.99	1.86	1.79	1.76	1.88	2.24	3.34
iso-Pentane	0.99	0.88	0.79	0.73	0.72	0.77	0.92	2.17
n-Pentane	0.77	0.68	0.59	0.54	0.53	0.56	0.68	1.88
Hexanes	1.60	1.34	1.12	0.98	0.90	0.91	1.07	5.34
Heptanes plus	10.75	5.93	3.79	2.82	2.30	2.22	2.52	61.78
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Molecular weight of heptanes-plus	185	143	133	125	118	114	112	203
Specific gravity of heptanes-plus	0.809	0.777	0.768	0.760	0.753	0.749	0.747	0.819
Deviation factor-z								
Equilibrium gas	1.043	0.927	0.874	0.862	0.879	0.908	0.946	
Two-phase	1.043	0.972	0.897	0.845	0.788	0.720	0.603	
Wellstream produced—								
Cumulative percent of initial	0.000	7.021	17.957	30.268	46.422	61.745	75.172	
GPM from smooth compositions								
Propane-plus	12.030	7.303	5.623	4.855	4.502	4.624	5.329	
Butanes-plus	10.354	5.683	4.054	3.301	2.916	2.946	3.421	
Pentanes-plus	9.263	4.664	3.100	2.378	2.004	1.965	2.261	

**Equilibrium liquid phase, representing 13.323 percent of original wellstream.*

Table 3-11
Retrograde Condensation During Gas Depletion at 262°F

Pressure, psig	Retrograde Liquid Volume Percent of Hydrocarbon Pore Space
4968 Dew-point pressure	0.0
4905	19.3
4800	25.0
4600	29.9
4300 First depletion level	33.1
3500	34.4
2800	34.1
2000	32.5
1300	30.2
700	27.3
0	21.8

(*text continued from page 179*)

The row in the table, "Wellstream Produced, % of initial GPM from smooth compositions," gives the fraction of the total moles (of scf) in the cell (or reservoir) that has been produced. This is *total* recovery of wellstream and has not been separated here into surface gas and oil recoveries.

In addition to the composition of the produced wellstream at the final depletion pressure, the composition of the retrograde liquid is also measured. The composition of the liquid is reported in the last column of Table 3-10 at 700 psi. These data are included as a control composition in the event the study is used for compositional material-balance purposes.

The volume of the retrograde liquid, i.e., liquid dropout, measured during the course of the depletion study is shown in Table 3-11. The data are reshown as a percent of hydrocarbon pore space. The measurements indicate that the maximum liquid dropout of 34.4% occurs at 3,500 psi. The liquid dropout can be expressed as a percent of the pore volume, i.e., saturation, by adjusting the reported values to account for the presence of the initial water saturation, or

$$S_o = (LDO)\,(1 - S_{wi}) \tag{3-33}$$

where S_o = retrograde liquid (oil) saturation, %
LDO = liquid dropout, %
S_{wi} = initial water saturation, fraction

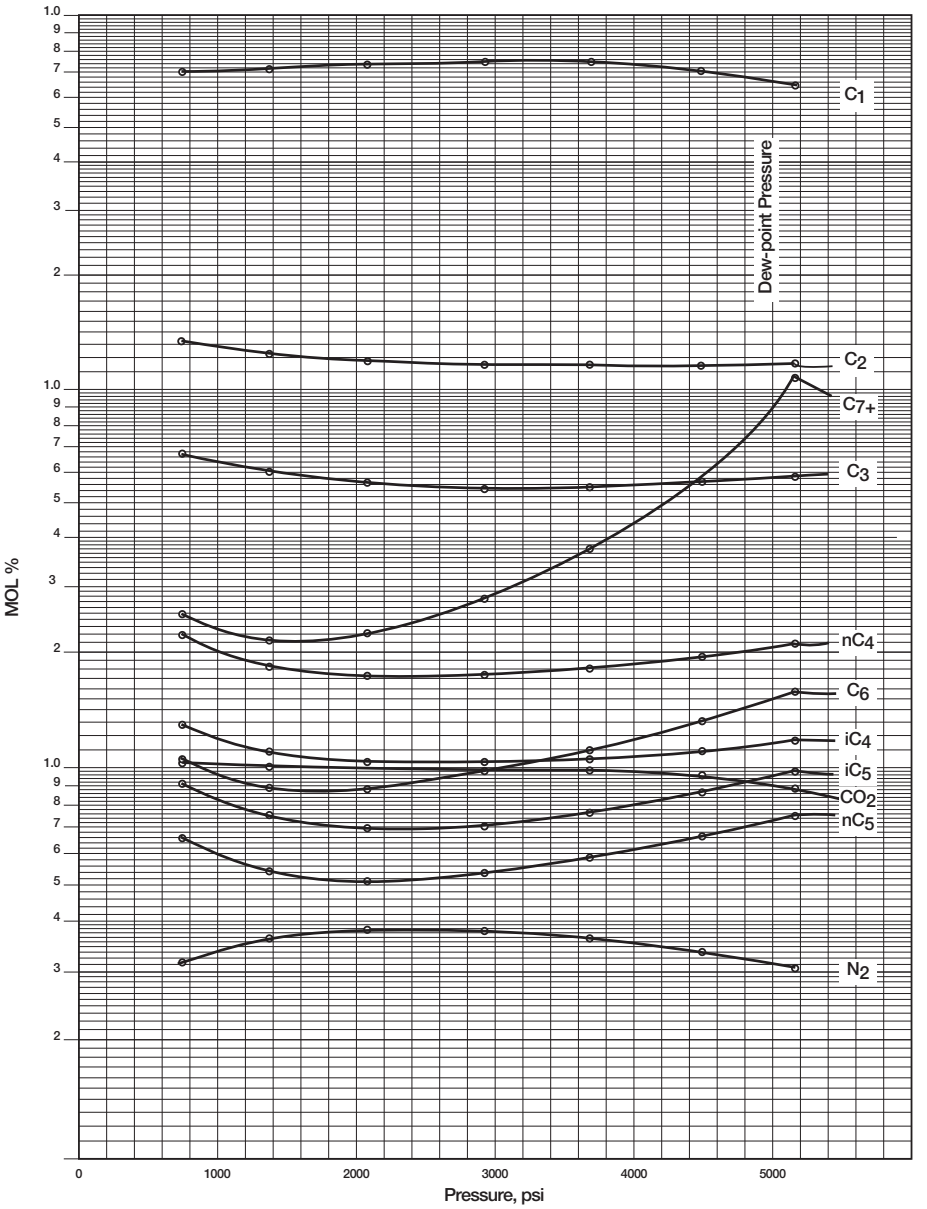

Figure 3-13. Hydrocarbon analysis during depletion.

Example 3-10

Using the experimental data of the Nameless gas-condensate field given in Table 3-10, calculate the two-phase compressibility factor at 2,000 psi by applying Equation 3-31.

Solution

The laboratory report indicates that the base (standard) pressure is 15.025 psia. Applying Equation 3-31 gives:

$$z_{2\text{-phase}} = \left[\frac{1.043}{4968+15.025}\right]\left[\frac{2000+15.025}{1-0.46422}\right] = 0.787$$

PROBLEMS

Table 3-12 shows the experimental results performed on a crude oil sample taken from the Mtech field. The results include the CCE, DE, and separator tests.

- Select the optimum separator conditions and generate B_o, R_s, and B_t values for the crude oil system. Plot your results and compare with the unadjusted values.
- Assume that new field indicates that the bubble-point pressure is better described by a value of 2,500 psi. Adjust the PVT to reflect the new bubble-point pressure.

(*text continued on page 188*)

Table 3-12
Pressure-Volume Relations of Reservoir Fluid at 260°F
(Constant-Composition Expansion)

Pressure, psig	Relative Volume
5000	0.9460
4500	0.9530
4000	0.9607
3500	0.9691
3000	0.9785
2500	0.9890
2300	0.9938
2200	0.9962
2100	0.9987
2051	1.0000
2047	1.0010
2041	1.0025
2024	1.0069
2002	1.0127
1933	1.0320
1843	1.0602
1742	1.0966
1612	1.1524
1467	1.2299
1297	1.3431
1102	1.5325
862	1.8992
653	2.4711
482	3.4050

Table 3-12 (Continued)
Differential Vaporization at 260°F

Pressure, psig	Solution Gas-Oil Ratio (1)	Relative Oil Volume (2)	Relative Total Volume (3)	Oil Density, gm/cc	Deviation Factor, z	Gas Formation Volume Factor (4)	Incremental Gas Gravity
2051	1004	1.808	1.808	0.5989			
1900	930	1.764	1.887	0.6063	0.880	0.00937	0.843
1700	838	1.708	2.017	0.6165	0.884	0.01052	0.840
1500	757	1.660	2.185	0.6253	0.887	0.01194	0.844
1300	678	1.612	2.413	0.6348	0.892	0.01384	0.857
1100	601	1.566	2.743	0.6440	0.899	0.01644	0.876
900	529	1.521	3.229	0.6536	0.906	0.02019	0.901
700	456	1.476	4.029	0.6635	0.917	0.02616	0.948
500	379	1.424	5.537	0.6755	0.933	0.03695	0.018
300	291	1.362	9.214	0.6896	0.955	0.06183	1.188
170	223	1.309	16.246	0.7020	0.974	0.10738	1.373
0	0	1.110		0.7298			2.230
	at 60°F = 1.000						

Gravity of Residual Oil = 43.1°API at 60°F

(1) Cubic feet of gas at 14.73 psia and 60°F per barrel of residual oil at 60°F
(2) Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F
(3) Barrels of oil plus liberated gas at indicated pressure and temperature per barrel of residual oil at 60°F
(4) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.73 psia and 60°F

Table 3-12 (Continued)
Separator Tests of Reservoir Fluid Sample

Separator Pressure PSI Gauge	Separator Temperature, °F	Gas-Oil Ratio (1)	Gas-Oil Ratio (2)	Stock-Tank Gravity, °API @ 60°F	Formation Volume Factor (3)	Separator Volume Factor (4)	Specific Gravity of Flashed Gas
200 to 0	71	431	490			1.138	0.739*
	71	222	223	48.2	1.549	1.006	1.367
100 to 0	72	522	566			1.083	0.801*
	72	126	127	48.6	1.529	1.006	1.402
50 to 0	71	607	632			1.041	0.869*
	71	54	54	48.6	1.532	1.006	1.398
25 to 0	70	669	682			1.020	0.923*
	70	25	25	48.4	1.558	1.006	1.340

**Collected and analyzed in the laboratory*
(1) Gas-oil ratio in cubic feet of gas @ 60°F and 14.75 psi absolute per barrel of oil @ indicated pressure and temperature
(2) Gas-oil ratio in cubic feet of gas @ 60°F and 14.73 psi absolute per barrel of stock-tank oil @ 60°F
(3) Formation volume factor in barrels of saturated oil @ 2051 psi gauge and 260°F per barrel of stock-tank oil @ 60°F
(4) Separator volume factor in barrels of oil @ indicated pressure and temperature per barrel of stock-tank oil @ 60°F

(*text continued from page 184*)

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