Chapter 6
Conventional PVT Measurements

6.1 Introduction

This chapter reviews the standard experiments performed by pressure/volume/temperature (PVT) laboratories on reservoir fluid samples: compositional analysis, multistage surface separation, constant composition expansion (CCE), differential liberation expansion (DLE), and constant volume depletion (CVD). We present data from actual laboratory reports and give methods for checking the consistency of reported data for each experiment. Chaps. 5 and 8 discuss special laboratory studies, including true-boiling-point (TBP) distillation and multicontact gas-injection tests, respectively.

Table 6.1 summarizes experiments typically performed on oils and gas condensates. From this table, we see that the DLE experiment is the only test never performed on gas-condensate systems. We begin by discussing standard analyses performed on oil and gas-condensate samples.

6.1.1 General Information Sheet. Most commercial laboratories report general information on a cover sheet of the laboratory report, including formation and well characteristics and sampling conditions. **Tables 6.2 and 6.3**[1,2] show this information, which may be important for correct application and interpretation of the fluid analyses. This is particularly true for wells where separator samples must be recombined to give a representative wellstream composition. Most of these data are supplied by the contractor of the fluid study and are recorded during sampling. Therefore, the representative for the company contracting the fluid study is responsible for the correctness and completeness of reported data.

We strongly recommend that the following data always be reported in a general information sheet: (1) separator gas/oil ratio (GOR) in standard cubic feet/separator barrel, (2) separator conditions at sampling, (3) field shrinkage factor used ($= B_{osp}$), (4) flowing bottomhole pressure (FBHP) at sampling, (5) static reservoir pressure, (6) minimum FBHP before and during sampling, (7) time and date of sampling, (8) production rates during sampling, (9) dimensions of sample container, (10) total number and types of samples collected during the drillstem test, and (11) perforation intervals.

6.1.2 Oil PVT Analyses. Standard PVT analyses performed on reservoir oils usually include (1) bottomhole wellstream compositional analysis through C_{7+}, (2) CCE, (3) DLE, and (4) multistage-separator tests. The CCE experiment determines the bubblepoint pressure and volumetric properties of the undersaturated oil. It also gives two-phase volumetric behavior below the bubblepoint; however, these data are rarely used. The DLE experiment and separator test are used together to calculate traditional black-oil properties, B_o and R_s, for reservoir-engineering calculations. Occasionally, instead of a DLE study, a CVD experiment is run on a volatile oil. Also, the C_{7+} fraction may be separated into single-carbon-number cuts from C_7 through approximately C_{20+} by TBP analysis or simulated distillation (see Chap. 5).

6.1.3 Gas-Condensate PVT Analyses. The standard experimental program for a gas-condensate fluid includes (1) recombined wellstream compositional analysis through C_{7+}, (2) CCE, and (3) CVD. The CCE and CVD data are measured in a high-pressure visual cell where the dewpoint pressure is determined visually. Total volume/pressure and liquid-dropout behavior is measured in the CCE experiment. Phase volumes defining retrograde behavior are measured in the CVD experiment together with Z factors and produced-gas compositions through C_{7+}. Optionally, a multistage-separator test can be performed as well as TBP analysis or simulated distillation of the C_{7+} into single-carbon-number cuts from C_7 to about C_{20+} (see Chap. 5).

6.2 Wellstream Compositions

PVT studies usually are based on one or more samples taken during a production test. Bottomhole samples can be obtained by wireline with a high-pressure container during either production testing or a shut-in period. Alternatively, separator samples can be taken during a production test. Bottomhole sampling is the preferred method for most oil reservoirs, while recombined samples are traditionally used for gas-condensate reservoirs.[3-8] Taking both bottomhole and separator samples in oil wells is not uncommon. The advantage of separator samples is that they can be recombined in varying proportions to achieve a desired bubblepoint pressure (e.g., initial reservoir pressure); these larger samples are needed for special PVT tests (e.g., TBP and slim tube among others).

6.2.1 Bottomhole Sample. **Table 6.4** shows the reported wellstream composition of a reservoir oil where C_{7+} specific gravity and molecular weight are also reported. In the example report, composition is given both as mole and weight percent although many laboratories report only molar composition. Experimentally, the composition of a bottomhole sample is determined by the following (**Fig. 6.1**).

1. Flashing the sample to atmospheric conditions.

2. Measuring the volumes of surface gas, $V_{\bar{g}}$, and surface oil, $V_{\bar{o}}$.

3. Determining the normalized weight fractions, $w_{\bar{g}i}$ and $w_{\bar{o}i}$, of surface samples by gas chromatography.

4. Measuring surface-oil molecular weight, $M_{\bar{o}}$, and specific gravity, $\gamma_{\bar{o}}$.

TABLE 6.1—LABORATORY ANALYSES PERFORMED ON RESERVOIR-OIL AND GAS-CONDENSATE SYSTEMS		
Laboratory Analysis	Oils	Gas Condensates
Bottomhole sample	●	○
Recombined composition	○	●
C_{7+} TBP distillation	○	○
C_{7+} simulated distillation	○	○
Constant-composition expansion	●	●
Multistage surface separation	●	○
Differential liberation	●	N
CVD	○	●
Multicontact gas injection	○	○

● = standard, ○ = can be performed, and N = not performed.

5. Converting $w_{\bar{g}i}$ weight fractions to normalized mole fractions y_i and x_i.

6. Recombining mathematically to the wellstream composition, z_i. Eqs. 6.1 through 6.5 give Steps 1 through 6 mathematically.

$$z_i = F_g y_i + (1 - F_g)x_i; \quad \dots\dots\dots\dots\dots\dots \quad (6.1)$$

$$F_g = \frac{1}{1 + \left[133,300(\gamma/M)_{\bar{o}}/R_s\right]}, \quad \dots\dots\dots\dots\dots \quad (6.2)$$

where $R_s = $ GOR $V_{\bar{g}}/V_{\bar{o}}$ in scf/STB from the single-stage flash;

$$y_i = \frac{w_{\bar{g}i}/M_i}{\sum\limits_{j \neq C_{7+}} \left(w_{\bar{g}j}/M_j\right) + \left(w_{\bar{g}C_{7+}}/M_{\bar{g}C_{7+}}\right)}; \quad \dots\dots\dots \quad (6.3)$$

$$x_i = \frac{w_{\bar{o}i}/M_i}{\sum\limits_{j \neq C_{7+}} \left(w_{\bar{o}j}/M_j\right) + \left(w_{\bar{o}C_{7+}}/M_{\bar{o}C_{7+}}\right)}; \quad \dots\dots\dots \quad (6.4)$$

and $M_{\bar{o}C_{7+}} = \dfrac{w_{\bar{o}C_{7+}}}{\left(1/M_{\bar{o}}\right) - \sum\limits_{j \neq C_{7+}} \left(w_{\bar{o}j}/M_j\right)}. \quad \dots\dots\dots\dots \quad (6.5)$

Surface gas usually contains less than 1 mol% C_{7+} material consisting mainly of heptanes and octanes; $M_{\bar{g}C_{7+}} = 105$ is usually a good assumption. Surface oil contains less than 1 mol% of the light constituents C_1, C_2, and nonhydrocarbons. Low-temperature distillation can be used to improve the accuracy of reported weight fractions for intermediate components in the surface oil (C_3 through C_6); however, gas chromatography is more widely used.

The most probable source of error in wellstream composition of a bottomhole sample is the surface-oil molecular weight, $M_{\bar{o}}$, which appears in Eq. 6.2 for F_g and Eq. 6.4 for x_i. $M_{\bar{o}}$ is usually accurate within ±4 to 10%. In Chap. 5, we showed that the Watson characterization factor, K_w, of surface oil (Eq. 5.35) should be constant (to within ±0.03 of the determined value) for a given reservoir. Once an average has been established for a reservoir (usually requiring three separate measurements), potential errors in $M_{\bar{o}}$ can be checked. A calculated K_w that deviates from the field-average K_w by more than ±0.03 may indicate an erroneous molecular-weight measurement.

Eqs. 6.1 through 6.4 show that all component compositions are affected by $M_{\bar{o}C_{7+}}$, which is backcalculated from $M_{\bar{o}}$ with Eq. 6.5. Fortunately, the amount of lighter components (particularly C_1) in the surface oil are small, so the real effect on conversion from weight to mole fractions of the surface oil usually is not significant.

6.2.2 Recombined Samples. **Tables 6.5 and 6.6** present the separator-oil and -gas compositional analyses of a gas-condensate fluid and recombined wellstream composition. The separator-oil composition is obtained by use of the same procedure as that used for bottomhole oil samples (Eqs. 6.1 through 6.5). This involves bringing the separator oil to standard conditions, measuring properties

TABLE 6.2—EXAMPLE GENERAL INFORMATION SHEET FOR GOOD OIL CO. WELL 4 OIL SAMPLE	
Formation Characteristics	
Name	Cretaceous
First well completed	__/__/19__ (m/d/y)
Original reservoir pressure at 8,692 ft, psig	4,100
Original produced GOR, scf/bbl	600
Production rate, B/D	300
Separator temperature, °F	75
Separator pressure, psig	200
Oil gravity at 60°F, °API	
Datum	8,000
Original gas cap	No
Well Characteristics	
Elevation, ft	610
Total depth, ft	8,943
Producing interval, ft	8,684 to 8,700
Tubing size, in.	$2^7/_8$
Tubing depth, ft	8,600
PI at 300 B/D, B-D/psi	1.1
Last reservoir pressure at 8,500 ft, psig	3,954*
Date	__/__/19__ (m/d/y)
Reservoir temperature at 8,500 ft, °F	217*
Well status	Shut in 72 hours
Pressure gauge	Amerada
Normal production rate, B/D	300
GOR, scf/bbl	600
Separator pressure, psig	200
Separator temperature, °F	75
Base pressure, psia	14.65
Well making water, % water cut	0
Sampling Conditions	
Sample depth, ft	8,500
Well status	Shut in 72 hours
GOR	
Separator pressure, psig	
Separator temperature, °F	
Tubing pressure, psig	1,400
Casing pressure, psig	
Sampled by	
Sampler type	Wofford

*Pressure and temperature extrapolated to the midpoint of the producing interval = 4,010 psig and 220°F.

and compositions of the resulting surface oil and gas, and recombining these compositions to give the separator-oil composition; Tables 6.5 and 6.6 report the results.

Separator gas is introduced directly into a gas chromatograph, which yields weight fractions, $w_{\bar{g}}$. These weight fractions are converted to mole fractions, y_i, by use of appropriate molecular weights; Tables 6.5 and 6.6 show the results. C_{7+} molecular weight is backcalculated with measured separator-gas specific gravity, $\gamma_{\bar{g}}$.

$$M_{\bar{g}C_{7+}} = w_{\bar{g}C_{7+}} \left(\frac{1}{28.97\gamma_{\bar{g}}} - \sum_{i \neq C_{7+}} \frac{w_{\bar{g}i}}{M_i}\right)^{-1}. \quad \dots\dots\dots \quad (6.6)$$

TABLE 6.3—EXAMPLE GENERAL INFORMATION SHEET FOR GOOD OIL CO. WELL 7 GAS CONDENSATE

Formation Characteristics	
Formation name	Pay sand
Date first well completed	__/__/19__ (m/d/y)
Original reservoir pressure at 10,148 ft, psig	5,713
Original produced-gas/liquid ratio, scf/bbl	
Production rate, B/D	_____
Separator pressure, psig	_____
Separator temperature, °F	_____
Liquid gravity at 60°F, °API	_____
Datum, ft subsea	8,000

Well Characteristics	
Elevation, ft KB	2,214
Total depth, ft	10,348
Producing interval, ft	10,124 to 10,176
Tubing size, in.	2
Tubing depth, ft	10,100
Open-flow potential, MMscf/D	_____
Last reservoir pressure at 10,148 ft, psig	5,713
Date	__/__/19__ (m/d/y)
Reservoir temperature at 10,148 ft, °F	186
Status of well status	Shut in
Pressure gauge	Amerada

Sampling Conditions	
Flowing tubing pressure, psig	3,375
FBHP, psig	5,500
Primary-separator pressure, psig	300
Primary-separator temperature, °F	62
Secondary-separator pressure, psig	20
Secondary-separator temperature, °F	60
Field stock-tank-liquid gravity at 60°F, °API	58.5
Primary-separator-gas production rate, Mscf/D	762.14
Pressure base, psia	14.696
Temperature base, °F	60
Compressibility factor, F_{pv}	1.043
Gas gravity (laboratory)	0.737
Gas-gravity factor, F_g	0.902
Stock-tank-liquid production rate at 60°F, B/D	127.3
Primary-separator-gas/stock-tank-liquid ratio	
In scf/bbl	5,987
In bbl/MMscf	167.0
Sampled by	_____

For the example PVT report (Tables 6.5 and 6.6), the separator gas/oil ratio, R_{sp}, during sampling is reported as standard gas volume per separator-oil volume (4,428 scf/bbl). In this report, the units are incorrectly labeled scf/bbl at 60°F, where in fact the separator-oil volume is measured at separator pressure (300 psig) and temperature (62°F). The separator-oil formation volume factor (FVF), B_{osp}, is 1.352 bbl/STB and represents the volume of separator oil required to yield 1 STB of oil (i.e., condensate).

The equation used to calculate wellstream composition, z_i, is

$$z_i = F_{gsp} y_i + (1 - F_{gsp}) x_i, \quad \dots \dots \dots \dots \dots \dots \dots \quad (6.7)$$

where F_{gsp} = mole fraction of wellstream mixture that becomes separator gas. In the laboratory report, F_{gsp} is reported as "primary-

separator gas/wellstream ratio" (801.66 Mscf/MMscf), which is equivalent to mole per mole ($F_{gsp} = 0.80166$ mol/mol). The reported value of F_{gsp} can be checked with

$$F_{gsp} = \left(1 + \frac{2,130 \rho_{osp}}{M_{osp} R_{sp}} \right)^{-1}, \quad \dots \dots \dots \dots \dots \dots \quad (6.8)$$

$$\text{where } M_{osp} = \sum_{i=1}^{N} x_i M_i. \quad \dots \dots \dots \dots \dots \dots \dots \dots \quad (6.9)$$

ρ_{osp} in lbm/ft³ is calculated with a correlation (e.g., Standing-Katz[9]) or with the relation $(62.4 \gamma_o + 0.0136 \gamma_g R_s)/B_o$, where R_s and B_o = separator-oil values in scf/STB and bbl/STB, respectively;

<table>
<tr><td colspan="6">**TABLE 6.4—WELLSTREAM (RESERVOIR-FLUID) COMPOSITION FOR GOOD OIL CO. WELL 4 BOTTOMHOLE OIL SAMPLE**</td></tr>
<tr><td>Component</td><td>mol%</td><td>wt%</td><td>Density* (g/cm^3)</td><td>°API*</td><td>Molecular Weight</td></tr>
<tr><td>H_2S</td><td>Nil</td><td>Nil</td><td></td><td></td><td></td></tr>
<tr><td>CO_2</td><td>0.91</td><td>0.43</td><td></td><td></td><td></td></tr>
<tr><td>N_2</td><td>0.16</td><td>0.05</td><td></td><td></td><td></td></tr>
<tr><td>Methane</td><td>36.47</td><td>6.24</td><td></td><td></td><td></td></tr>
<tr><td>Ethane</td><td>9.67</td><td>3.10</td><td></td><td></td><td></td></tr>
<tr><td>Propane</td><td>6.95</td><td>3.27</td><td></td><td></td><td></td></tr>
<tr><td>*i*-butane</td><td>1.44</td><td>0.89</td><td></td><td></td><td></td></tr>
<tr><td>*n*-butane</td><td>3.93</td><td>2.44</td><td></td><td></td><td></td></tr>
<tr><td>*i*-pentane</td><td>1.44</td><td>1.11</td><td></td><td></td><td></td></tr>
<tr><td>*n*-pentane</td><td>1.41</td><td>1.09</td><td></td><td></td><td></td></tr>
<tr><td>Hexanes</td><td>4.33</td><td>3.97</td><td></td><td></td><td></td></tr>
<tr><td>Heptanes plus</td><td>33.29</td><td>77.41</td><td>0.8515</td><td>34.5</td><td>218</td></tr>
<tr><td>Total</td><td>100.00</td><td>100.00</td><td></td><td></td><td></td></tr>
<tr><td colspan="6">*At 60°F.</td></tr>
</table>

$\gamma_{\bar{o}}$ = stock-tank-oil density; and $\gamma_{\bar{g}}$ = gravity of gas released from the separator oil.

Finally, the value of stock-tank-liquid/wellstream ratio in bbl/MMscf represents the separator barrels produced per 1 MMscf of wellstream. In terms of F_{gsp} and separator properties, this value equals

$$\frac{\text{bbl}}{\text{MMscf}} = \frac{470(1 - F_{gsp})(M_{osp}/\rho_{osp})}{B_{osp}}, \quad \dots\dots\dots\dots \quad (6.10)$$

where $470 = (1$ million scf/MMscf)/[(379 scf/lbm mol)(5.615 ft^3/bbl)].

The separator-oil and -gas compositions can be checked for consistency with the Hoffman *et al.*[10] *K*-value method and Standing's[11] low-pressure *K*-value equations.

6.3 Multistage-Separator Test

The multistage-separator test is performed on an oil sample primarily to provide a basis for converting differential-liberation data from a residual-oil to a stock-tank-oil basis. Occasionally, several separator tests are run to help choose separator conditions that maximize stock-tank-oil production. Usually, two or three stages of separation are used, with the last stage at atmospheric pressure and near-ambient temperature (60 to 80°F). The multistage-separator test can also be conducted for high-liquid-yield gas-condensate fluids.

Fig. 6.2 illustrates schematically how the separator test is performed. Initially, the reservoir sample is at saturation conditions and the volume is measured (V_{ob} or V_{gd}). The sample is then brought to the pressure and temperature of the first-stage separator. All the gas is removed, and the oil volume at the separator stage, V_{osp}, is noted together with the volume of removed gas, $\Delta V_{\bar{g}}$; number of moles of

removed gas, $n_{\bar{g}}$; and specific gravity of removed gas, $\gamma_{\bar{g}}$. If requested, the gas samples can be analyzed chromatographically to give molar composition, y.

The oil remaining after gas removal is brought to the conditions of the next separator stage. The gas is removed again and quantified by moles and specific gravity. Oil volume is noted, and the process is repeated until stock-tank conditions are reached. Final oil volume, $V_{\bar{o}}$, and specific gravity, $\gamma_{\bar{o}}$, are measured at 60°F.

Table 6.7 gives results from four separator tests, each consisting of two stages of separation. The first-stage-separator pressure is varied from 50 to 300 psig, and stock-tank conditions are held constant at 0 psig and 75°F. GOR's are reported as standard gas volume per separator-oil volume, R_{sp}, and as standard gas volume per stock-tank-oil volume, R_s, respectively.

$$\Delta R_{sp} = \frac{\Delta V_{\bar{g}}}{V_{osp}} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.11)$$

$$\text{and } \Delta R_s = \frac{\Delta V_{\bar{g}}}{V_{\bar{o}}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.12)$$

Total GOR is calculated by adding the stock-tank-oil-based GOR's from each separator stage.

$$R_s = \sum_{k=1}^{N_{sp}} (\Delta R_s)_k. \quad \dots\dots\dots\dots\dots\dots\dots\dots \quad (6.13)$$

Separator-oil FVF's, B_{osp}, are reported as the ratio of separator-oil volume to stock-tank-oil volume.

$$B_{osp} = \frac{V_{osp}}{V_{\bar{o}}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.14)$$

Accordingly, the relation between separator gas/oil ratio and stock-tank gas/oil ratio at a given stage is

$$\Delta R_{sp} = \frac{\Delta R_s}{B_{osp}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.15)$$

Because $B_{osp} > 1$, it follows that $R_{sp} < R_s$.

Bubblepoint-oil FVF, B_{ob}, is the ratio of bubblepoint-oil volume to stock-tank-oil volume.

$$B_{ob} = \frac{V_{ob}}{V_{\bar{o}}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.16)$$

The average gas gravity, $\bar{\gamma}_g$, is used in oil PVT correlations and to calculate reservoir densities on the basis of black-oil properties. The average gas gravity is calculated from

$$\bar{\gamma}_g = \frac{\sum_{k=1}^{N_{sp}} (\gamma_{\bar{g}})_k (\Delta R_s)_k}{\sum_{k=1}^{N_{sp}} (\Delta R_s)_k}, \quad \dots\dots\dots\dots\dots\dots \quad (6.17)$$
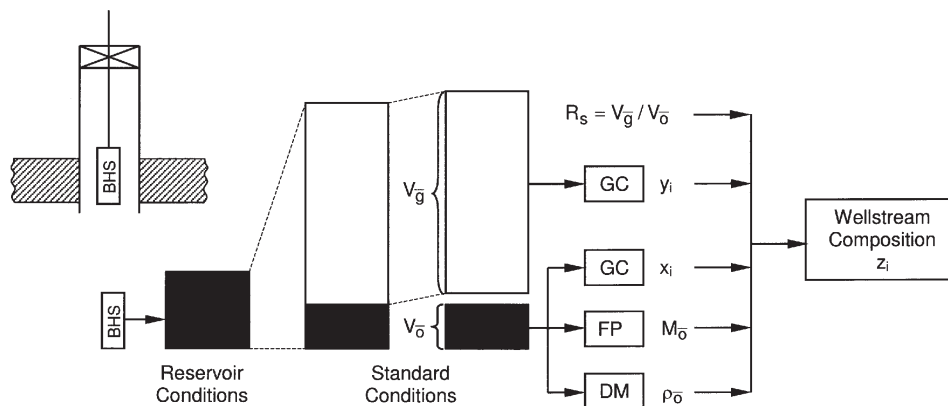

Fig. 6.1—Procedure for recombining single-stage separator samples to obtain wellstream composition of a bottomhole sample; BHS = bottomhole sampler, GC = gas chromatograph, FDP = freezing-point depression, and DM = densitometer.

TABLE 6.5—SEPARATOR AND RECOMBINED WELLSTREAM COMPOSITIONS FOR GOOD OIL CO. WELL 7 GAS CONDENSATE

Separator Products Hydrocarbon Analysis

Component	Separator Liquid (mol%)	Separator Gas (mol%)	Separator Gas (gal/Mscf)	Wellstream (mol%)	Wellstream (gal/Mscf)
CO_2	Trace	0.22		0.18	
N_2	Trace	0.16		0.13	
Methane	7.78	75.31		61.92	
Ethane	10.02	15.08		14.08	
Propane	15.08	6.68	1.832	8.35	2.290
iso-butane	2.77	0.52	0.170	0.97	0.317
n-butane	11.39	1.44	0.453	3.41	1.073
iso-pentane	3.52	0.18	0.066	0.84	0.306
n-pentane	6.50	0.24	0.087	1.48	0.535
Hexanes	8.61	0.11	0.045	1.79	0.734
Heptanes plus	34.33	0.06	0.028	6.85	3.904
Total	100.00	100.00	2.681	100.00	9.159

Heptanes-Plus Properties

Oil gravity, °API	46.6		
Specific gravity at 60/60°F	0.7946		0.795
Molecular weight	143	103	143

Parameters

Calculated separator gas gravity (air = 1.000)	0.735
Calculated gross heating value for separator gas at 14.696 psia and 60°F, BTU/ft³ dry gas	1,295
Primary-separator-gas*/-separator-liquid* ratio, scf/bbl at 60°F	4,428
Primary-separator-gas/stock-tank-liquid ratio at 60°F, bbl at 60°F/bbl	1.352
Primary-separator-gas/wellstream ratio, Mscf/MMscf	801.66
Stock-tank-liquid/wellstream ratio, bbl/MMscf	133.9

*Primary separator gas and liquid collected at 300 psig and 62°F.

TABLE 6.6—MATERIAL-BALANCE CALCULATIONS FOR GOOD OIL CO. WELL 7 GAS-CONDENSATE SAMPLE

Component	Liquid Composition at Specified Pressures (mol%) At 3,500 psig	At 2,900 psig	At 2,100 psig	At 1,300 psig	At 605 psig
CO_2	0.18	0.18	0.18	0.15	0.08
N_2	0.13	0.08	0.06	0.03	0.01
C_1	13.18	45.04	32.22	19.69	11.77
C_2	8.12	14.05	13.99	12.32	7.44
C_3	12.59	9.67	11.25	11.66	9.31
i-C_4	3.44	1.14	1.59	1.85	1.64
n-C_4	5.21	4.82	6.12	7.35	7.17
i-C_5	2.67	1.25	1.77	2.43	2.79
n-C_5	5.74	2.16	3.48	4.62	5.50
C_6	8.47	3.11	4.55	6.40	8.37
C_{7+}	40.27	18.51	24.79	33.50	45.91
Total	100.00	100.00	100.00	100.00	100.00
M_o, g/mol	96.6	54.1	64.3	78.2	95.6
$M_{oC_{7+}}$, g/mol	168.8	160.1	152.1	149.9	150.3
ρ_o, g/cm³	0.3235	0.2642	0.1625	0.0892	0.0398

Wellstream

p_{sp1}
T_{sp1}

p_{sp2}
T_{sp2}

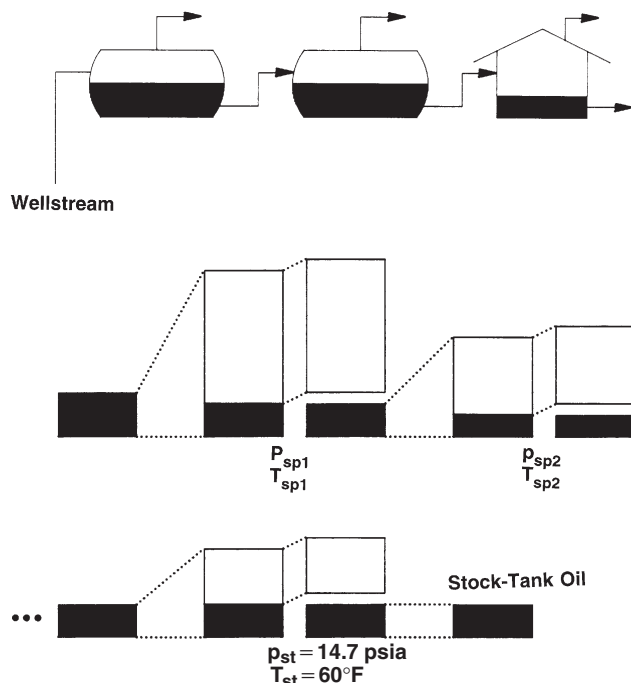**Stock-Tank Oil**

$p_{st} = 14.7$ psia
$T_{st} = 60°F$

Fig. 6.2—Schematic of a multistage-separator test.

where $(\bar{\gamma}_{\bar{g}})_k$ = separator-gas gravity at Stage k. This relation is based on the ideal gas law at standard conditions, where moles of gas are directly proportional with standard gas volume ($v_{\bar{g}}$ = 379 scf/lbm mol).

Table 6.8 gives the composition of the first-stage-separator gas at 50 psig and 75°F. The gross heating value, $H_{\bar{g}}$, of this gas is calculated by Kay's[12] mixing rule and component heating values, H_i, given in Table A-1.

$$H_{\bar{g}} = \sum_{i=1}^{N} y_i H_i. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (6.18)$$

Component liquid yields, L_i, represent the liquid volumes of a component or group of components that can theoretically be processed from 1 Mscf of separator gas (gallons per million standard cubic feet). L_i can be calculated from

$$L_i = 19.73 y_i \left(\frac{M_i}{\rho_i}\right), \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (6.19)$$

where M_i = molecular weight and ρ_i = component liquid density in lbm/ft³ at standard conditions (Table A-1). The C_{7+} material in separator gases is usually treated as normal heptane.

6.4 Constant Composition Expansion

6.4.1 Oil Samples. For an oil sample, the CCE experiment is used to determine bubblepoint pressure, undersaturated-oil density, isothermal oil compressibility, and two-phase volumetric behavior at pressures below the bubblepoint. **Table 6.9** presents data from an example CCE experiment for a reservoir oil.

Fig. 6.3 illustrates the procedure for the CCE experiment. A blind cell (i.e., a cell without a window) is filled with a known mass of reservoir fluid. Reservoir temperature is held constant during the experiment. The sample initially is brought to a condition somewhat above 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 exist as two phases.[13-15] Sometimes supersaturation occurs 50 to 100 psi below actual bubblepoint pressure. By agitating the mixture at each new pressure, the condition of supersaturation is avoided, allowing more accurate determination of the bubblepoint.

Just below the bubblepoint, the measured volume will increase more rapidly because gas evolves from the oil, yielding a higher system compressibility. The total volume, V_t, is recorded after the two-phase mixture is brought to equilibrium. Pressure is lowered in steps of 5 to 200 psi, where equilibrium is obtained at each pressure. When the lowest pressure is reached, total volume is three to five times larger than the original bubblepoint volume.

The recorded cell volumes are plotted vs. pressure, and the resulting curve should be similar to one of the curves in **Fig. 6.4**.[16] For a black oil (far from its critical temperature), the discontinuity in volume at the bubblepoint is sharp and the bubblepoint pressure and volume are easily read from the intersection of the p-V trends in the single- and two-phase regions.

Volatile oils do not exhibit the same clear discontinuity in volumetric behavior at the bubblepoint pressure. Instead, the p-V curve is practically continuous in the region of the bubblepoint because the undersaturated-oil compressibility is similar to the effective two-phase compressibility. This makes determining the bubblepoint of volatile oils in a blind cell difficult. Instead, a windowed cell

TABLE 6.7—SEPARATOR TESTS (RESERVOIR-FLUID) OF GOOD OIL CO. WELL 4 OIL SAMPLE							
Separator Pressure (psia)	Separator Temperature (°F)	GOR[b] (ft³/bbl)	GOR[c] (ft³/bbl)	Stock-Tank Gravity (°API)	FVF[d] (bbl/bbl)	Separator Volume Factor[e] (bbl/bbl)	Flashed-Gas Specific Gravity
50 to	75	715	737			1.031	0.840
0	75	41	41	40.5	1.481	1.007	1.338
100 to	75	637	676			1.062	0.786
0	75	91	92	40.7	1.474	1.007	1.363
200 to	75	542	602			1.112	0.732
0	75	177	178	40.4	1.483	1.007	1.329
300 to	75	478	549			1.148	0.704
0	75	245	246	40.1	1.495	1.007	1.286

[a]Gauge.
[b]In cubic feet of gas at 60°F and 14.65 psi absolute per barrel of oil at indicated pressure and temperature.
[c]In cubic feet of gas at 60°F and 14.65 psi absolute per barrel of stock-tank oil at 60°F.
[d]In barrels of saturated oil at 2,620 psi gauge and 220°F per barrel of stock-tank oil at 60°F.
[e]In barrels of oil at indicated pressure and temperature per barrel of stock-tank oil at 60°F.

TABLE 6.8—FIRST-STAGE SEPARATOR-GAS COMPOSITION AND GROSS HEATING VALUE FOR GOOD OIL CO. WELL 4 OIL SAMPLE*

Component	mol%	gal/Mscf
H_2S	Nil	
CO_2	1.62	
N_2	0.30	
C_1	67.00	
C_2	16.04	4.265
C_3	8.95	2.449
i-C_4	1.29	0.420
n-C_4	2.91	0.912
i-C_5	0.53	0.193
n-C_5	0.41	0.155
C_6	0.44	0.178
C_{7+}	0.49	0.221
Total	100.00	8.793
Heating Value		
Calculated gas gravity (air = 1.000)	0.840	
Calculated gross heating value, BTU/ft³	1,405	
dry gas at 14.65 psia and 60°F		

*Collected at 50 psig and 75°F in the laboratory.

TABLE 6.9—CCE DATA (RESERVOIR-FLUID) FOR GOOD OIL CO. WELL 4 OIL SAMPLE

Saturation (bubblepoint) pressure*, psig	2,620
Specific volume at saturation pressure*, ft³/lbm	0.02441
Thermal expansion of undersaturated oil at 5,000 psi = V at 220°F/V at 76°F	1.08790
Compressibility of saturated oil at reservoir temperature	
From 5,000 to 4,000 psi, vol/vol-psi	13.48×10^{-6}
From 4,000 to 3,000 psi, vol/vol-psi	15.88×10^{-6}
From 3,000 to 2,620 psi, vol/vol-psi	18.75×10^{-6}

Pressure/Volume Relations*

Pressure (psig)	Relative volume (L)†	Y function‡
5,000	0.9639	
4,500	0.9703	
4,000	0.9771	
3,500	0.9846	
3,000	0.9929	
2,900	0.9946	
2,800	0.9964	
2,700	0.9983	
2,620**	1.0000	
2,605	1.0022	2.574
2,591	1.0041	2.688
2,516	1.0154	2.673
2,401	1.0350	2.593
2,253	1.0645	2.510
2,090	1.1040	2.422
1,897	1.1633	2.316
1,698	1.2426	2.219
1,477	1.3618	2.118
1,292	1.5012	2.028
1,040	1.7802	1.920
830	2.1623	1.823
640	2.7513	1.727
472	3.7226	1.621

* At 220°F.
** Saturation pressure.
† Relative volume = V/V_{sat} in barrels at indicated pressure per barrel at saturation pressure.
‡ Y function = $(p_{sat} - p)/(p_{abs})(V/V_{sat} - 1)$.

is used to observe visually the first bubble of gas and the liquid volumes below the bubblepoint.

Reported data from commercial laboratories usually include bubblepoint pressure, p_b; bubblepoint density, ρ_{ob}, or specific volume, $v_{ob}(v = 1/\rho)$; and isothermal compressibility of the undersaturated oil, c_o, at pressures above the bubblepoint (Table 6.9). The table also shows the oil's thermal expansion, indicated by a 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 volumes are reported relative to the bubblepoint volume.

$$V_{rt} = \frac{V_t}{V_{ob}}. \quad\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (6.20)$$

Traditionally, isothermal compressibility data are reported for pressure intervals above the bubblepoint. In fact, the undersaturated-oil compressibility varies continuously with pressure, and, because $V_t = V_o$ ($V_{rt} = V_{ro}$) for $p > p_b$, oil compressibility can be expressed as

$$c = \frac{1}{V_{rt}}\left(\frac{\partial V_{rt}}{\partial p}\right)_T = \frac{1}{V_{ro}}\left(\frac{\partial V_{ro}}{\partial p}\right)_T; \quad p > p_b. \quad\dots\dots (6.21)$$
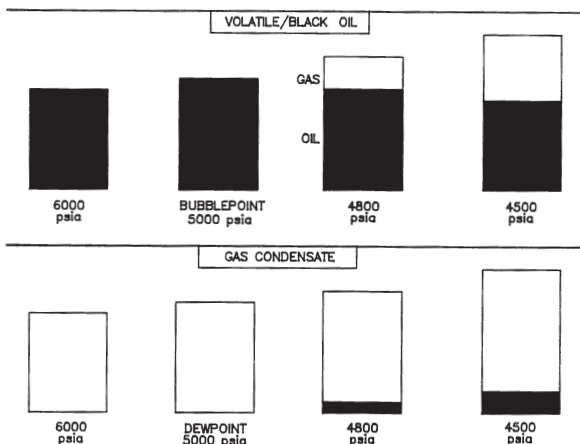

Fig. 6.3—Schematic of a CCE experiment for an oil and a gas condensate.

The V_{rt} function at undersaturated conditions may be fit with a second-degree polynomial, resulting in an explicit relation for undersaturated-oil compressibility (see Chap. 3).

Total volumes below the bubblepoint can be correlated by the Y function,[16,17] defined as

$$Y = \frac{p_b - p}{p(V_{rt} - 1)} = \frac{p_b - p}{p[(V_t/V_b) - 1]}, \quad\dots\dots\dots\dots\dots (6.22)$$

where p and p_b are given in absolute pressure units. As **Fig. 6.5** shows, Y vs. pressure should plot as a straight line and the linear trend can be used to smooth V_{rt} data at pressures below the bubblepoint. Standing[16] and Clark[17] discuss other smoothing techniques and corrections that may be necessary when reservoir conditions and laboratory PVT conditions are not the same.

6.4.2 Gas-Condensate Samples. The CCE data for a gas condensate usually include total relative volume, V_{rt}, defined as the volume of gas or of gas-plus-oil mixture divided by the dewpoint volume. Z fac-
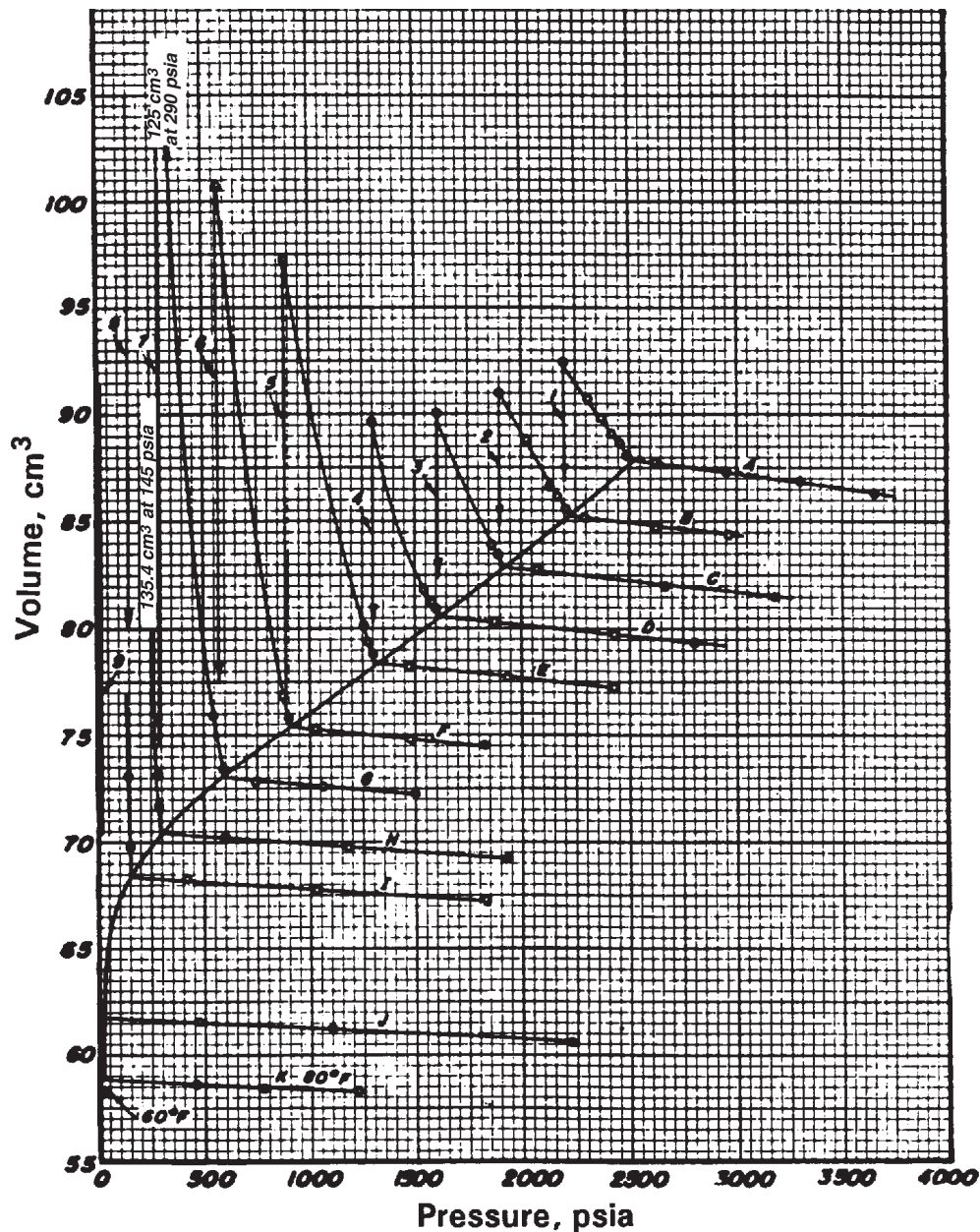
Fig. 6.4—Volume vs. pressure for an oil during a DLE test (after Standing[16]).

tors are reported at pressures greater than and equal to the dewpoint pressure. **Table 6.10** gives these data for a gas-condensate example.

Reciprocal wet-gas FVF, b_{gw}, is reported at dewpoint and initial reservoir pressures, where these values represent the gas equivalent or wet-gas volume at standard conditions produced from 1 bbl of reservoir gas volume.

$$b_{gw} = \left(5.615 \times 10^{-3}\right)\frac{T_{sc}}{p_{sc}}\frac{p}{ZT} = 0.198\frac{p}{ZT}, \quad \ldots\ldots\ldots \text{ (6.23)}$$

with b_{gw} in Mscf/bbl, p in psia, and T in °R.

Most CCE experiments are conducted in a visual cell for gas condensates, and relative oil (condensate) volumes, V_{ro}, are reported at pressures below the dewpoint. V_{ro} normally is defined as the oil volume divided by the total volume of gas and oil, although some reports define it as the oil volume divided by the dewpoint volume.

6.5 Differential Liberation Expansion

The DLE experiment is designed to approximate the depletion process of an oil reservoir[18] and thereby provide suitable PVT data to calculate reservoir performance.[16,19-21] **Fig. 6.6** illustrates the laboratory procedure of a DLE experiment. **Figs. 6.7A through 6.7C and Table 6.11** 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, V_{ob}, is recorded. Because the initial mass of the sample is known, bubblepoint density, ρ_{ob}, 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. Then, the volume, ΔV_g; moles, Δn_g; and specific gravity, γ_g, of the removed gas are measured. The remaining oil volume, V_o, is also recorded. This procedure is repeated 10 to 15 times at decreasing pressures and finally at atmospheric pressure. Residual-oil volume, $V_{\bar{o}r}$, and specific gravity, $\gamma_{\bar{o}r}$, are measured at 60°F.

Other properties are calculated on the basis of measured data (ΔV_g, V_o, Δn_g, γ_g, $V_{\bar{o}r}$, and $\gamma_{\bar{o}r}$), including differential solution gas/oil ratio, R_{sd}; differential oil FVF, B_{od}; oil density, ρ_o; and gas Z factor, Z. For Stage k, these properties can be determined from

Bubblepoint

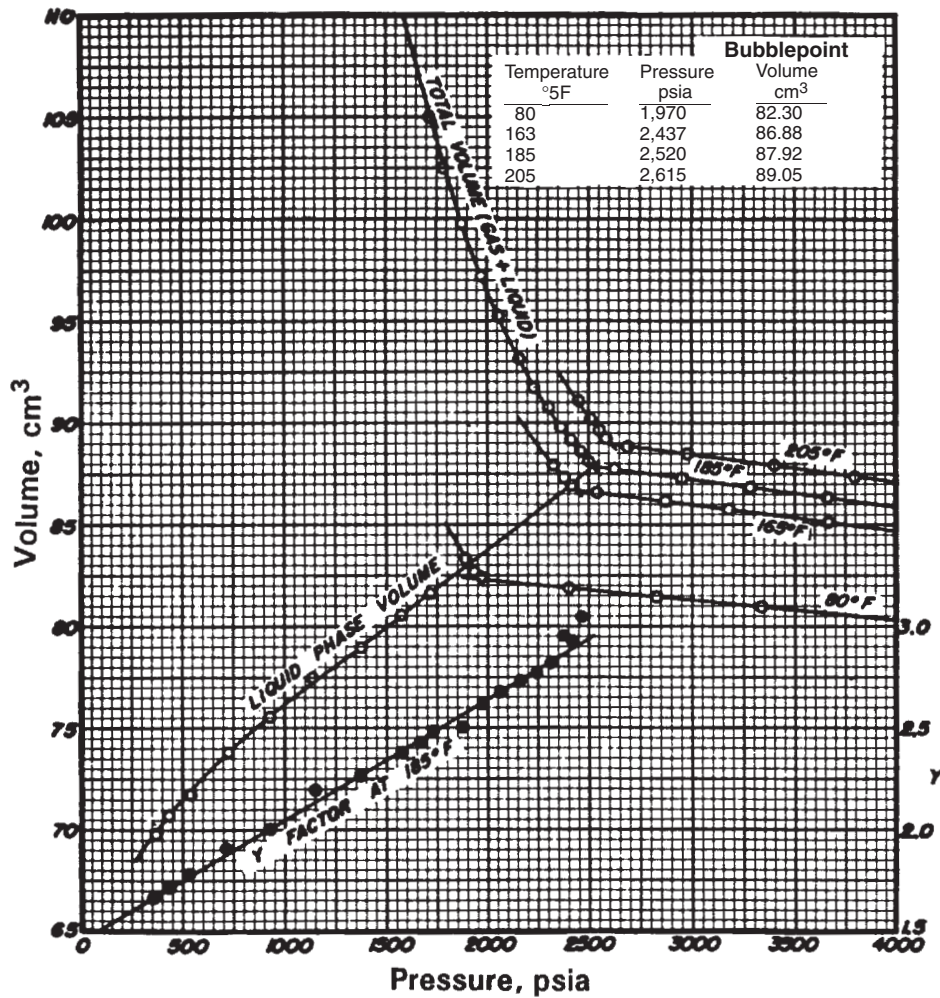| Temperature °5F	Pressure psia	Volume cm³
80	1,970	82.30
163	2,437	86.88
185	2,520	87.92
205	2,615	89.05

Fig. 6.5—PVT relation and plot of Y function for an oil sample at pressures below the bubblepoint.

$$(R_{sd})_k = \frac{\sum_{j=1}^{k} 379(\Delta n_g)_j}{V_{\bar{o}r}}, \quad \dots\dots\dots\dots\dots\dots\dots \quad (6.24)$$

$$(B_{od})_k = \frac{(V_o)_k}{V_{\bar{o}r}}, \quad \dots\dots\dots\dots\dots\dots\dots\dots \quad (6.25)$$

$$(\rho_o)_k = \frac{V_{\bar{o}r}(62.4\gamma_{\bar{o}r}) + \sum_{j=1}^{k}(28.97/5.615)(\Delta n_g)_j(\gamma_g)_j}{(V_o)_k}$$

$$= \frac{350\gamma_{\bar{o}r} + \sum_{j=1}^{k} 0.0764(\Delta R_{sd})_j(\gamma_g)_j}{5.615(B_{od})_k},$$

$$\dots\dots\dots\dots\dots\dots \quad (6.26)$$

$$\text{and } (Z)_k = (1/RT)(p\Delta V_g/\Delta n_g)_k, \quad \dots\dots\dots\dots\dots \quad (6.27)$$

with $V_{\bar{o}r}$ and V_o in bbl, R_{sd} in scf/bbl, B_{od} in bbl/bbl, ΔV_g in ft³, p in psia, Δn_g in lbm mol, ρ_o in lbm/ft³, and T in °R. Note that the subscript $j = 1$ indicates the final DLE stage at atmospheric pressure and reservoir temperature. Reported oil densities are actually calculated by material balance, not measured directly.

6.5.1 Converting From Differential to Stock-Tank Basis. Perhaps the most important step in the application of oil PVT data for reservoir calculations is conversion of the differential solution gas/oil ratio, R_{sd}, and oil FVF, B_{od}, to a stock-tank-oil basis.[16,20] For engineering

calculations, volume factors, R_s and B_o, are used to relate reservoir-oil volumes, V_o, to produced surface volumes, $V_{\bar{g}}$ and $V_{\bar{o}}$; i.e.,

$$R_s = \frac{V_{\bar{g}}}{V_{\bar{o}}} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.28)$$

$$\text{and } B_o = \frac{V_o}{V_{\bar{o}}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.29)$$

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).

$$R_{sd} = \frac{V_{\bar{g}}}{V_{\bar{o}r}} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.30)$$

$$\text{and } B_{od} = \frac{V_o}{V_{\bar{o}r}}. \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.31)$$

The equations commonly used to convert differential volume factors to a stock-tank basis are

$$R_s = R_{sb} - (R_{sdb} - R_{sd})\left(\frac{B_{ob}}{B_{odb}}\right) \quad \dots\dots\dots\dots\dots \quad (6.32)$$

$$\text{and } B_o = B_{od}\left(\frac{B_{ob}}{B_{odb}}\right), \quad \dots\dots\dots\dots\dots\dots\dots \quad (6.33)$$

where B_{ob} = bubblepoint-oil FVF, R_{sb} = solution gas/oil ratio from a multistage-separator flash, and R_{sdb} and B_{odb} = differential volume factors at the bubblepoint pressure. The term (B_{ob}/B_{odb}),

TABLE 6.10—CCE DATA FOR GOOD OIL CO. WELL 7 GAS-CONDENSATE SAMPLE		
Pressure (psig)	Relative volume	Deviation Factor Z
6,000	0.8808	1.144
5,713*	0.8948	1.107**
5,300	0.9158	1.051
5,000	0.9317	1.009
4,800	0.9434	0.981
4,600	0.9559	0.953
4,400	0.9690	0.924
4,300	0.9758	0.909
4,200	0.9832	0.895
4,100	0.9914	0.881
4,000†	1.0000	0.867‡
3,905	1.0089	
3,800	1.0194	
3,710	1.0299	
3,500	1.0559	
3,300	1.0878	
3,000	1.1496	
2,705	1.2430	
2,205	1.5246	
1,605	2.1035	
1,010	3.5665	

Pressure/volume relations of reservoir fluid at 186°F.
* Reservoir pressure.
** Gas FVF = 1.591 Mscf/bbl.
† Dewpoint pressure.
‡ Gas FVF = 1.424 Mscf/bbl.

DIFFERENTIAL LIBERATION EXPERIMENT

Fig. 6.6—Schematic of DLE experiment.

representing the volume ratio, $V_{\bar{o}r}/V_{\bar{o}}$, is used to eliminate the residual-oil volume, $V_{\bar{o}r}$, 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.

Although, the conversions given by Eqs. 6.32 and 6.33 typically are used, they are only approximate. The preferred method, as originally suggested by Dodson *et al.*,[22] requires that some equilibrium oil be taken at each stage of the DLE experiment and flashed through a multistage separator to give the volume ratios, R_s and B_o. This laboratory procedure is costly and time-consuming and is seldom used. However, the method is readily incorporated into an equation-of-state (EOS) -based PVT program.

6.6 Constant Volume Depletion

The CVD experiment is designed to provide volumetric and compositional data for gas-condensate and volatile-oil reservoirs producing by pressure depletion. **Fig. 6.8** shows the stepwise procedure of a CVD experiment schematically, and **Figs. 6.9A through 6.9D and Table 6.12** give CVD data for an example gas-condensate fluid.

The CVD experiment provides data that can be used directly by the reservoir engineer, including (1) a reservoir material balance that gives average reservoir pressure vs. recovery of total wellstream (wet-gas recovery), sales gas, condensate, and natural gas liquids; (2) produced-wellstream composition and surface products vs. reservoir pressure; and (3) average oil saturation in the reservoir (liquid dropout and revaporization) that occurs during pressure depletion. For many gas-condensate reservoirs, the recoveries and oil saturation vs. pressure data from the CVD analysis closely approximate actual field performance for reservoirs producing by pressure depletion. When other recovery mechanisms, such as waterdrive and gas cycling, are considered, the basic data required for reservoir engineering are still taken mainly from a CVD report. This section prov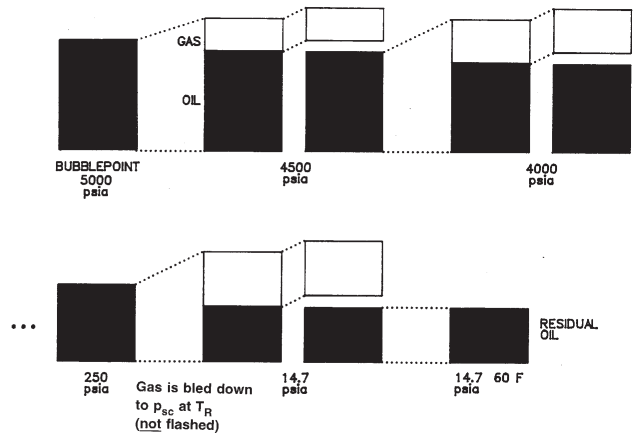ides a description of the data provided in a standard CVD analysis, ways to check the data for consistency,[23-25] and how to extract reservoir-engineering quantities from the data.[23,26]

Initially, the dewpoint, p_d, or bubblepoint pressure, p_b, of the reservoir sample is established visually and the cell volume, V_{cell}, at saturated conditions is recorded. The pressure is then reduced by 300 to 800 psi and usually by smaller amounts (50 to 250 psi) just below the saturation pressure of more-volatile systems. The cell is agitated until equilibrium is achieved, and volumes V_o and V_g are measured. At constant pressure, sufficient gas, ΔV_g, is removed to return the cell volume to the original saturated volume.

In the laboratory, the removed gas (wellstream) is brought to atmospheric conditions, where the amount of surface gas and condensate are measured. Surface compositions $y_{\bar{g}}$ and $x_{\bar{o}}$ of the produced surface volumes from the reservoir gas are measured, as are the volumes $\Delta V_{\bar{o}}$ and $\Delta V_{\bar{g}}$, densities $\rho_{\bar{o}}$ and $\rho_{\bar{g}}$ and oil molecular weight $M_{\bar{o}}$. From these quantities, we can calculate the moles of gas removed, Δn_g.

$$\Delta n_g = \frac{\Delta V_{\bar{o}} \rho_{\bar{o}}}{M_{\bar{o}}} + \frac{\Delta V_{\bar{g}}}{379}. \quad \dots \dots \dots \dots \dots \dots \dots \dots (6.34)$$

These data are reported as cumulative wellstream produced, n_p, relative to the initial moles n.

$$\left(\frac{n_p}{n}\right)_k = \frac{1}{n} \sum_{j=1}^{k} (\Delta n_g)_j, \quad \dots \dots \dots \dots \dots \dots \dots \dots (6.35)$$

where $j = 1$ corresponds to saturation pressure and $(\Delta n_g)_1 = 0$. The initial amount (in moles) of the saturated fluid is known when the cell is charged. The quantity n_p/n is usually reported as cumulative wet gas produced in MMscf/MMscf, which is equivalent to mol/mol.

Surface compositions $y_{\bar{g}}$ and $x_{\bar{o}}$ of the removed reservoir gas and properties of the removed gas are not reported directly in the laboratory report but are recombined to yield the equilibrium gas (wellstream) composition, y_i, which also represents the equilibrium gas remaining in the cell. The C_{7+} molecular weight of the wellstream, $M_{gC_{7+}}$, is backcalculated from measured specific gravity ($\gamma_w = \gamma_g$) and reservoir-gas composition, y. C_{7+} specific gravity of the produced gas, $\gamma_{gC_{7+}}$, is also reported, but this value is calculated from a correlation.

Knowing the cumulative moles removed and its volume occupied as a single-phase gas at the removal pressure, we can calculate the equilibrium gas Z factor from

$$Z = \frac{p \Delta V_g}{\Delta n_g RT}. \quad \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots (6.36)$$

A "two-phase" Z factor is also reported that is calculated assuming that the gas-condensate reservoir depletes according to the material balance for a dry gas and that the initial condition of the reservoir is at dewpoint pressure.
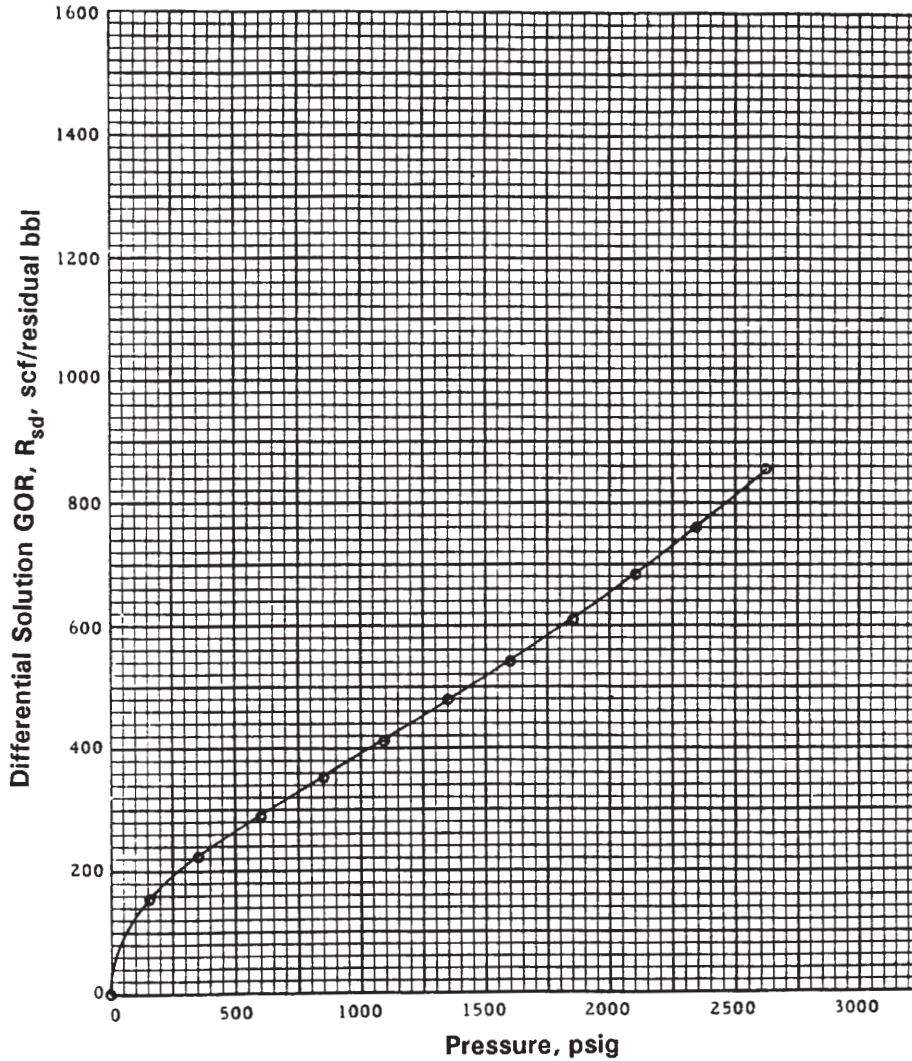
Fig. 6.7A—DLE data for an oil sample from Good Oil Co. Well 4; differential solution gas/oil ratio, R_{sd}.

$$\frac{p}{Z_2} = \left(\frac{p_d}{Z_d}\right)\left(1 - \frac{G_{pw}}{G_w}\right), \qquad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (6.37)$$

where G_{pw} = cumulative wellstream (wet gas) produced and G_w = initial wet gas in place. As defined in Eq. 6.37, the term G_{pw}/G_w equals n_p/n reported in the CVD report. From Eq. 6.37, the only unknown at a given pressure is Z_2, and the two-phase Z factor is then given by

$$Z_2 = \frac{p}{(p_d/Z_d)\left[1 - (n_p/n)\right]}. \qquad \ldots \ldots \ldots \ldots \ldots \ldots (6.38)$$

Theoretical liquid yields, L_i, are also reported for C_{3+} through C_{5+} groups in the produced wellstreams at each pressure-depletion stage. These values are calculated with

$$L_i = 19.73 y_i \left(\frac{M_i}{\rho_i}\right) \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (6.39)$$

and by summing the yields of components in the particular "plus" group. For example, the liquid yield of C_{5+} material at CVD Stage k is given by

$$\left(L_{C_{5+}}\right)_k = \sum_{j=iC_5}^{C_{7+}} (L_j)_k = 19.73 \sum_{j=iC_5}^{C_{7+}} (y_j)_k \left(\frac{M_j}{\rho_j}\right). \quad \ldots \ldots (6.40)$$

Table 6.13 gives various calculated cumulative recoveries based on the reservoir initially being at its dewpoint. The basis for the calculations is 1 MMscf of dewpoint wet gas in place, G_w; the corresponding initial moles in place at dewpoint pressure is given by

$$n = \frac{G_w}{v_{\overline{g}}}$$

$$= \frac{1 \times 10^6 \ \text{scf}}{379 \ \text{scf/lbm mol}} = 2,638 \ \text{lbm mol}. \quad \ldots \ldots \ldots (6.41)$$

The first row of recoveries (wellstream) simply represents the cumulative moles produced, n_p/n, expressed as wet-gas volumes, G_{pw}, in Mscf.

$$G_{pw} = n v_{\overline{g}}\left(\frac{n_p}{n}\right)$$

$$= (2,638 \ \text{lbm mol})(379 \ \text{scf/lbm mol})$$

$$\times \left(1 \times 10^3 \ \text{Mscf/scf}\right)\left(\frac{n_p}{n}\right)$$

$$= 1 \times 10^3 \left(\frac{n_p}{n}\right). \qquad \ldots \ldots \ldots \ldots \ldots \ldots \ldots (6.42)$$

Recoveries in Rows 2 through 4 (Normal Temperature Separation, Total Plant Products in Primary-Separator Gas, and Total Plant Products in Second-Stage-Separator Gas) refer to production when the reservoir is produced through a three-stage separator. **Fig. 6.10**
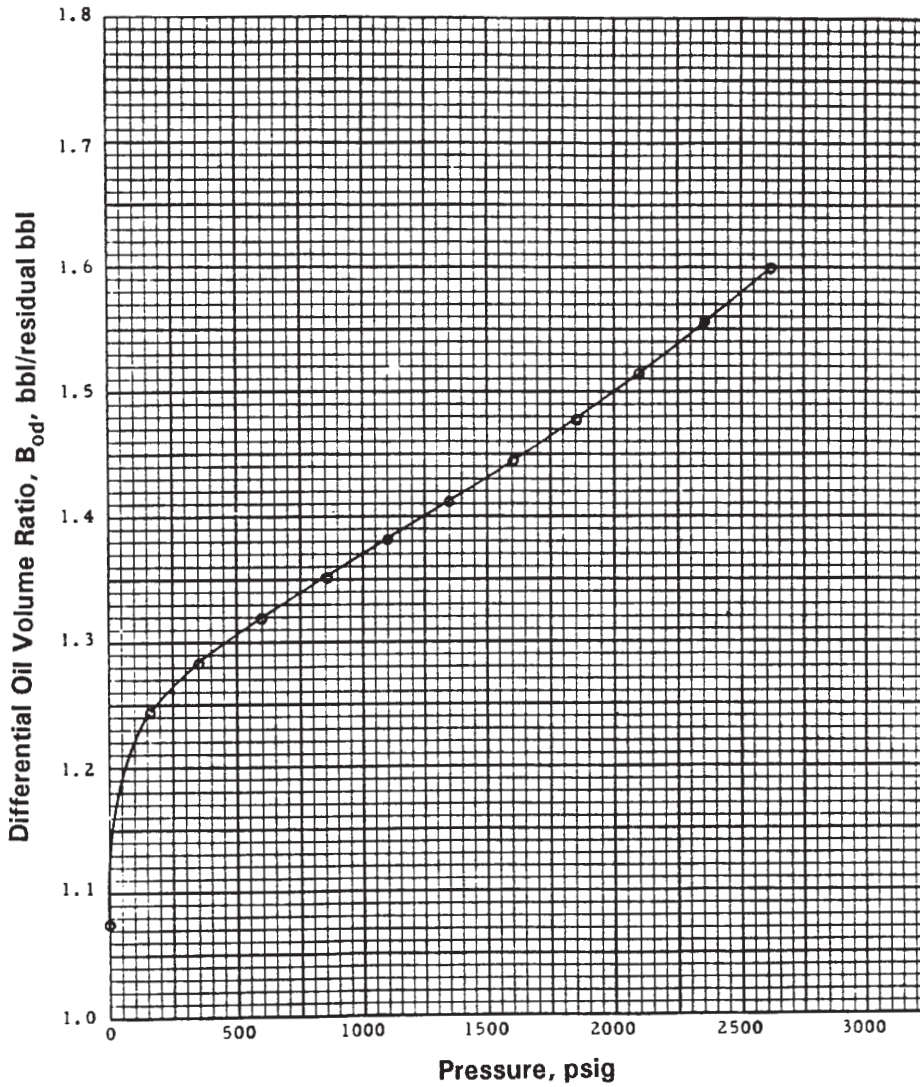
Fig. 6.7B—DLE data for an oil sample from Good Oil Co. Well 4; differential oil FVF (relative volume), B_{od}.

illustrates the process schematically. The calculated recoveries are based on multistage-separator calculations that use low-pressure K values and a set of separator conditions chosen arbitrarily or specified when the PVT study is requested.

6.6.1 Recoveries: "Normal Temperature Separation." *Column 1: Initial in Place.*

In Column 1, Row 2a the stock-tank oil in solution in the initial dewpoint fluid ($N = 135.7$ STB) is calculated by flashing 1 MMscf of the original dewpoint fluid, G_w, through a multistage separator.

Rows 2b through 2d give the volumes of separator gas at each stage of a three-stage flash of the initial dewpoint fluid: 757.87, 96.68, and 24.23 Mscf, respectively. The mole fraction of wellstream resulting as a surface gas $F_{\bar{g}g}$ is given by

$$F_{\bar{g}g} = \frac{G_d}{G_w} = (757.87 + 96.68 + 24.23 \text{ Mscf/lbm mol})$$

$$\times \left(1 \times 10^3 \text{ scf/Mscf}\right)/(379 \text{ scf/lbm mol})$$

$$= 0.8788 \text{ lbm mol/lbm mol}, \quad \ldots\ldots\ldots\ldots\ldots (6.43)$$

where G_d = total separator "dry" gas and the corresponding mole fraction of stock-tank oil is 0.1212 mol/mol. $F_{\bar{g}g}$ is used to calculate dry-gas FVF (see Eq. 3.41). For the dewpoint pressure, this gives

$$B_{gd} = \frac{B_{gw}}{F_{\bar{g}g}} = \frac{(p_{sc}/T_{sc})(ZT/p)}{F_{\bar{g}g}}$$

$$= \frac{(14.7/520)\{[0.867(186 + 460)]/4015\}}{0.8788}$$

$$= 4.487 \times 10^{-3} \text{ ft}^3/\text{scf}. \quad \ldots\ldots\ldots\ldots\ldots\ldots (6.44)$$

The producing GOR of the dewpoint mixture for the specified separator conditions can be calculated as

$$R_p = \frac{G}{N} = \left[(757.87 + 96.68 + 24.23 \text{ Mscf/lbm mol})\right.$$

$$\times \left(1 \times 10^3 \text{ scf/Mscf}\right)\left]/135.7 \text{ STB/lbm mol}\right.$$

$$= 6,476 \text{ scf/STB}. \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (6.45)$$

The dewpoint solution oil/gas ratio, r_{sd}, is simply the inverse of R_p.

$$r_{sd} = r_p = \frac{1}{R_p}$$

$$= 1.544 \times 10^{-4} \text{ STB/scf} = 154.4 \text{ STB/MMscf}.$$

$$\ldots\ldots\ldots\ldots\ldots (6.46)$$

Note that specific gravities of stock-tank oil and separator gases are not reported for the separator calculations.

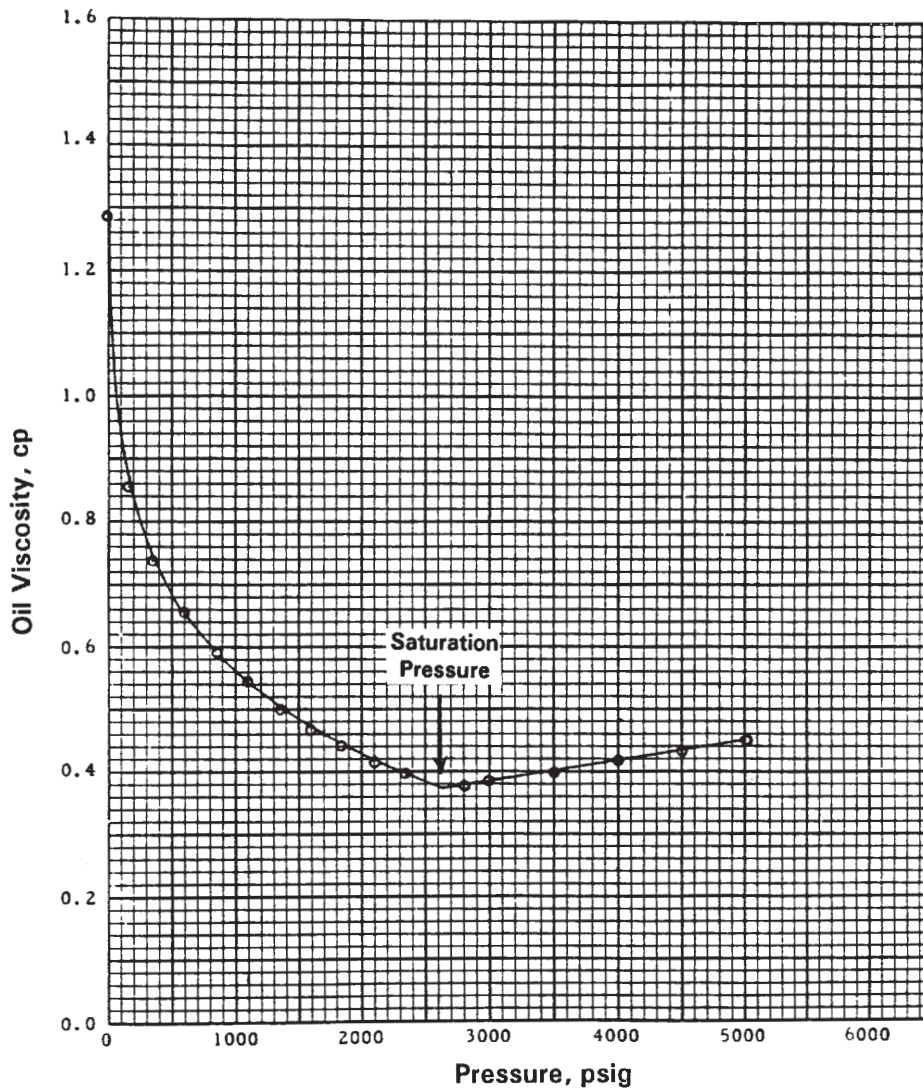**Fig. 6.7C—DLE data for an oil sample from Good Oil Co. Well 4; oil viscosity, μ_o.**

Column 2 and Higher. On the basis of 1 MMscf of initial dew-point fluid, Rows 2a through 2d give cumulative volumes of separator products at each depletion pressure (N_p, G_{p1}, G_{p2}, and G_{p3}). The producing GOR of the wellstream produced during a depletion stage is given by

$$(R_p)_k = \frac{(G_{p1} + G_{p2} + G_{p3})_k - (G_{p1} + G_{p2} + G_{p3})_{k-1}}{(N_p)_k - (N_p)_{k-1}}.$$

$$\ldots\ldots\ldots\ldots\ldots\ldots \text{(6.47)}$$

For 2,100 psig, this gives

$$R_p = \{[(301.57 + 20.75 + 5.61) - (124.78 + 12.09 + 3.16)]$$

$$\times (1 \times 10^3)\}/(24.0 - 15.4)$$

$$= 21,850 \text{ scf/STB.} \quad\ldots\ldots\ldots\ldots\ldots\ldots \text{(6.48)}$$

In terms of the solution oil/gas ratio,

$$r_s = r_p = \frac{1}{R_p}$$

$$= \frac{1}{21,580 \text{ scf/STB}} = 4.58 \times 10^{-5} \text{ STB/scf}$$

$$= 45.8 \text{ STB/scf.} \quad\ldots\ldots\ldots\ldots\ldots\ldots \text{(6.49)}$$

At a given pressure, the mole fraction of the removed CVD gas wellstream that becomes dry separator gas is given by

$$(F_{\bar{g}g})_k = \frac{(G_{p1} + G_{p2} + G_{p3})_k - (G_{p1} + G_{p2} + G_{p3})_{k-1}}{G_w[(n_p/n)_k - (n_p/n)_{k-1}]}.$$

$$\ldots\ldots\ldots\ldots\ldots\ldots \text{(6.50)}$$

For $p = 2,100$ psig, this gives

$$F_{\bar{g}g} = [(301.57 + 20.75 + 5.61) - (124.78 + 12.09$$

$$+ 3.16)](1 \times 10^3)/(1 \times 10^6)(0.35096 - 0.15438)$$

$$= 0.9558. \quad\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(6.51)}$$

The dry-gas FVF at 2,100 psig is

$$B_{gd} = \frac{(14.7/520)[0.762(186 + 460)/2,115]}{0.9558}$$

$$= 6.884 \times 10^{-3} \text{ ft}^3/\text{scf.} \quad\ldots\ldots\ldots\ldots\ldots \text{(6.52)}$$

In summary, the information provided in the rows labeled Normal Temperature Separation gives estimates of the condensate and sales-gas recoveries assuming a multistage surface separation. For example, at an abandonment pressure of 605 psig, the condensate recovery is 35.1 STB of the 135.7 STB initially in place (in solution in the dewpoint mixture), or 26% condensate recovery. Dry-gas recovery is $(685.02 + 37.79 + 10.40) = 733.21$ Mscf of the 878.78

TABLE 6.11—DLE DATA FOR GOOD OIL CO. WELL 4 OIL SAMPLE

Differential Vaporization							
Pressure (psig)	Solution GOR (scf/bbl*)	Relative Oil Volume (RB/bbl*)	Relative Total Volume (RB/bbl*)	Oil Density (g/cm³)	Deviation Factor Z	Gas FVF (RB/bbl*)	Incremental Gas Gravity
2,620	854	1.600	1.600	0.6562			
2,350	763	1.554	1.665	0.6655	0.846	0.00685	0.825
2,100	684	1.515	1.748	0.6731	0.851	0.00771	0.818
1.850	612	1.479	1.859	0.6808	0.859	0.00882	0.797
1,600	544	1.445	2.016	0.6889	0.872	0.01034	0.791
1,350	479	1.412	2.244	0.6969	0.887	0.01245	0.794
1,110	416	1.382	2.593	0.7044	0.903	0.01552	0.809
850	354	1.351	3.169	0.7121	0.922	0.02042	0.831
600	292	1.320	4.254	0.7198	0.941	0.02931	0.881
350	223	1.283	6.975	0.7291	0.965	0.05065	0.988
159	157	1.244	14.693	0.7382	0.984	0.10834	1.213
0	0	1.075		0.7892			2.039
		1.000**					

DLE Viscosity Data at 220°F		
Pressure (psig)	Oil Viscosity (cp)	Calculated Gas Viscosity (cp)
5,000	0.450	
4,500	0.434	
4,000	0.418	
3,500	0.401	
3,000	0.385	
2,800	0.379	
2,620	0.373	
2,350	0.396	0.0191
2,100	0.417	0.0180
1,850	0.442	0.0169
1,600	0.469	0.0160
1,350	0.502	0.0151
1,100	0.542	0.0143
850	0.592	0.0135
600	0.654	0.0126
350	0.783	0.0121
159	0.855	0.0114
0	1.286	0.0093

Gravity of residual oil = 35.1°API at 60°F.
*Barrels of residual oil.
**At 60°F.

Mscf dry gas originally in place, or 83.4%. These recoveries can be compared with the reported wet-gas (or molar) recovery of 76.787% at 605 psig. In addition to recoveries, the calculated results in this section can be used to calculate solution oil/gas ratio, r_s, and dry-gas FVF, B_{gd}, for modified black-oil applications.

6.6.2 Recovery: Plant Products. Rows 3 through 5 consider theoretical liquid recoveries for propane, butanes, and pentanes-plus assuming 100% plant efficiency. Recoveries in Rows 3 and 4 are for the calculated separator gases from Stages 1 and 2 of the three-stage surface separation. Recoveries in Row 5 are for the produced wellstreams from the CVD experiment and represent the absolute maximum liquid recoveries that can be expected if the reservoir is produced by pressure depletion. Fig. 6.10 illustrates the recovery calculations schematically. Liquid volumes (in gal/MMscf of initial dewpoint fluid) at CVD Stage k are calculated from

$$(L_i)_k = 19,730 \left(\frac{M_i}{\rho_i} \right) \left[\sum_{j=1}^{k} \left(\frac{\Delta n_g}{n} \right)_j (y_i)_j \right], \quad \ldots \ldots \ldots \ (6.53)$$
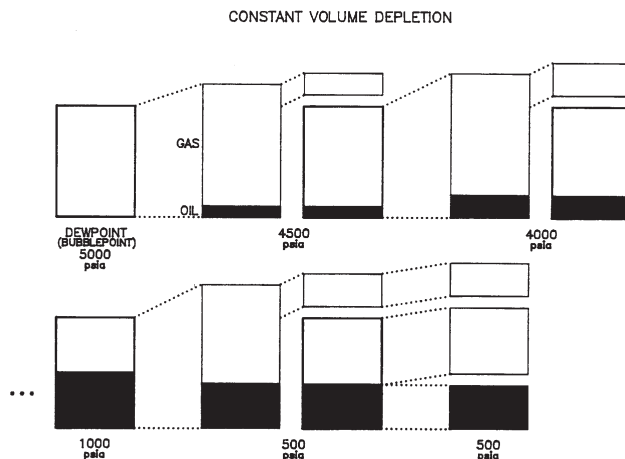

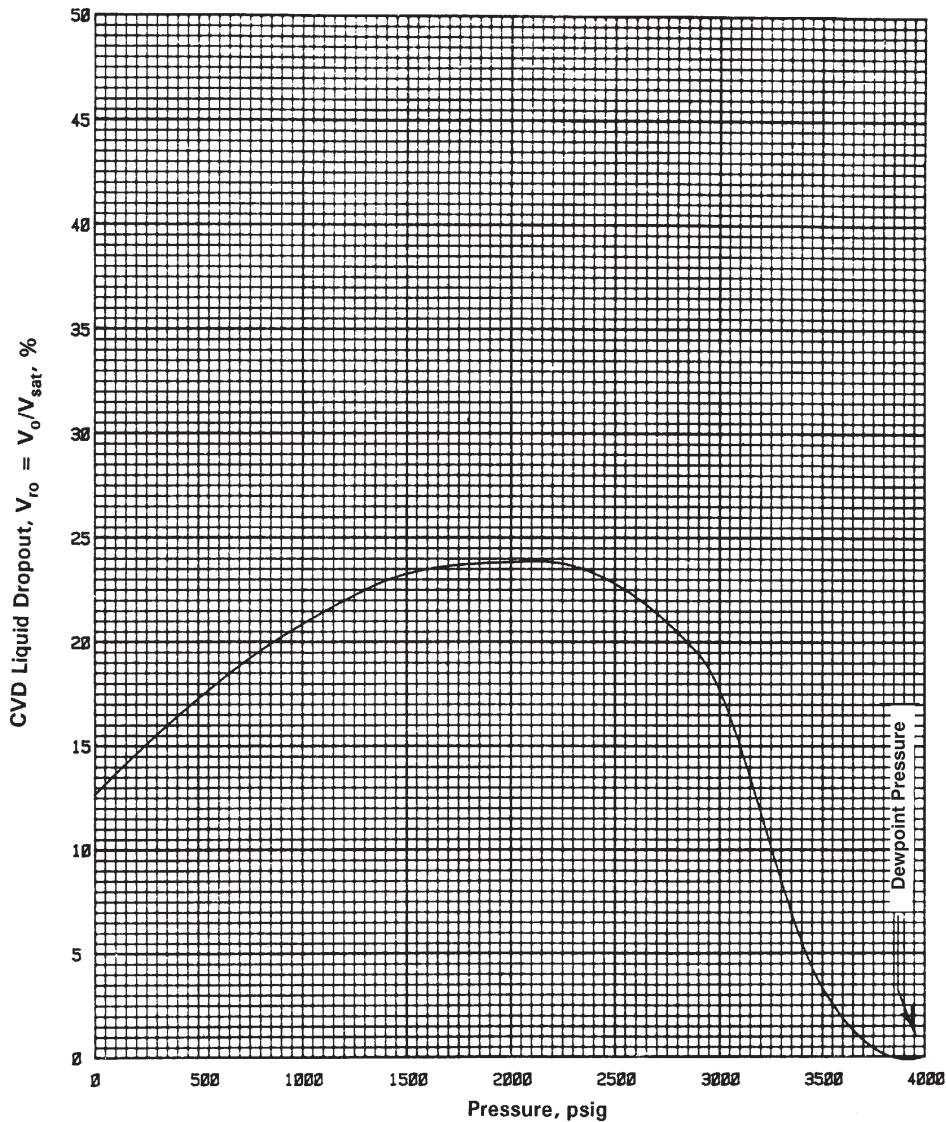Fig. 6.8—Schematic of CVD experiment.

Fig. 6.9A—CVD data for gas-condensate sample from Good Oil Co. Well 7; liquid-dropout curve, V_{ro}.

where $j = 1$ represents the dewpoint, y_i = compositions of well-stream entering the gas plant at various stages of depletion, M_i = component molecular weights, and ρ_i = liquid component densities in lbm/ft^3 at standard conditions (Table A-1).

Calculated liquid recoveries below the dewpoint use the moles of wellstream produced ($\Delta n_g/n$) and the compositions y_i from the separator gas (Rows 3 and 4) or wellstream (Row 5) entering the plant. Column 1 (Initial in Place) gives the total recoveries assuming that the entire initial dewpoint fluid is taken to the surface and processed [i.e., $k = 1$ and $(\Delta n_g/n)_1 = 1$ in Eq. 6.53].

Note that cumulative recovery of propanes from the first-stage separator during depletion (1,276 gal) is larger than the liquid propane produced in the first-stage-separator gas of the original dewpoint mixture (1,198 gal). This means that the stock-tank oil from the separation of original dewpoint mixture contains more propane than the cumulative stock-tank-oil volumes produced by depletion and three-stage separation.

The results given in Rows 3 and 4 cannot be calculated from reported data because surface separator compositions from the three-stage separation are not provided in the report. The results in Row 5 can be checked. As an example, consider the C_3 recoveries for the initial-in-place fluid at 2,100 psig.

$$\left(L_{C_3}\right)_{p_d} = 19,730(44.09/31.66)\left[(1)(0.0837)\right]$$

$$= 2,299 \text{ gal/MMscf} \quad \dotfill \quad (6.54a)$$

and $\left(L_{C_3}\right)_{2100} = 19,730(44.09/31.66)[0.0825(0.05374)$

$$+ \ 0.0810(0.15438 - 0.05374)$$

$$+ \ 0.0757(0.35096 - 0.15438)]$$

$$= 754 \text{ gal/MMscf.} \quad \dotfill \quad (6.54b)$$

For the C_{5+} recoveries at the dewpoint,

$$\left(L_{C_{5+}}\right)_{p_d} = 19,730[(72.15/38.96)(0.0091)$$

$$+ \ (72.15/39.36)(0.0152)$$

$$+ \ (86.17/41.43)(0.0179) + (143/49.6)(0.0685)]$$

$$= 5,513 \text{ gal/MMscf.} \quad \dotfill \quad (6.55)$$

6.6.3 Correcting Recoveries for Initial Pressure Greater Than Dewpoint Pressure. All recoveries given in Table 6.13 assume that the reservoir pressure is initially at dewpoint. This assumption is made because initial reservoir pressure is not always known with certainty when PVT calculations are made. However, adjusting reported recoveries is straightforward when initial pressure is greater than dewpoint pressure. With Q_{Table} as recoveries given in Columns 2 and higher in Table 6.13, Q_d as hydrocarbons in place in Column
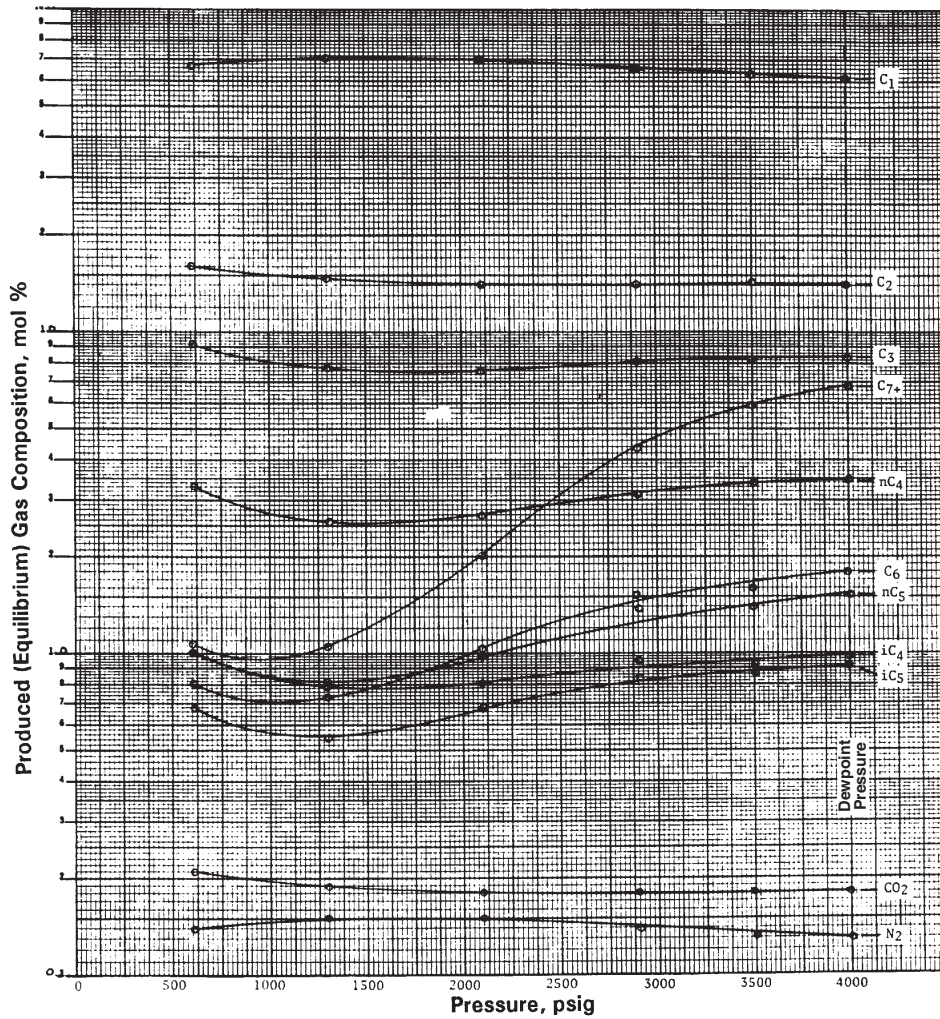
Fig. 6.9B—CVD data for gas-condensate sample from Good Oil Co. Well 7; equilibrium gas compositions, y_i.

1 at dewpoint pressure, and Q as actual cumulative recoveries based on hydrocarbons in place at the initial pressure,

$$Q = Q_d \left[\frac{(p/Z)_i}{(p/Z)_d} - \frac{(p/Z)}{(p/Z)_d} \right]; \quad p \geq p_d, \quad \ldots \ldots \ldots \quad (6.56)$$

$$Q = Q_{\text{Table}} + \Delta Q_d; \quad p < p_d, \quad \ldots \ldots \ldots \ldots \quad (6.57)$$

and $\Delta Q_d = Q_d \left[\frac{(p/Z)_i}{(p/Z)_d} - 1 \right], \quad \ldots \ldots \ldots \ldots \ldots \quad (6.58)$

where ΔQ_d = additional recovery from initial to dewpoint pressure.

For the example report,

$$\Delta Q_d = \left[\frac{(5,728/1.107)}{(4,015/0.867)} - 1 \right] Q_d$$

$$= 0.1173 Q_d, \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \quad (6.59)$$

recalling that moles of material at dewpoint is 2,638 lbm mol, moles of material at initial pressure of 5,728 psig is $n = 2,638(1 + 0.1173) = 2,947$ lbm mol, and the basis of calculations is $G_w = 1.173$ MMscf of wet gas in place at initial pressure of 5,728 psia.

The cumulative wellstream produced at the dewpoint pressure of 4,000 psig is $0.1173(1,000) = 117.3$ Mscf. Recovery at 3,500 psig is $117.3 + 53.74 = 171.0$ Mscf. Likewise, wet-gas recovery

should be increased by 117.3 Mscf for all depletion pressures in the CVD table.

For stock-tank-oil recovery, $Q_d = 135.7$ STB, so $\Delta Q_d = 15.9$ STB. Stock-tank-oil recovery at 4,000 psig is $15.9 + 0 = 15.9$ STB; at 3,500 psig the recovery should be $15.9 + 6.4 = 22.3$ STB, and so on.

On the basis of 1 MMscf wet gas at the dewpoint or 1.1173 MMscf at initial reservoir pressure, the laboratory hydrocarbon pore volume (HCPV), $V_{p\text{HClab}}$, is the same.

$$V_{p\text{HClab}} = (G_w B_{gw})_d$$

$$= (1 \times 10^6) \left\{ \left(\frac{14.7}{520} \right) \left[\frac{0.867(186 + 460)}{4,015} \right] \right\}$$

$$= 3,943 \text{ ft}^3$$

$$= (G_w B_{gw})_i$$

$$= 1.1173 \times 10^6 \left\{ \left(\frac{14.7}{520} \right) \left[\frac{1.107(186 + 460)}{5728} \right] \right\}$$

$$= 3,943 \text{ ft}^3. \quad \ldots \ldots \ldots \ldots \ldots \ldots \ldots \quad (6.60)$$

The actual HCPV of a reservoir is much larger than $V_{p\text{HClab}}$, and the conversion to obtain recoveries for the actual HCPV is simply
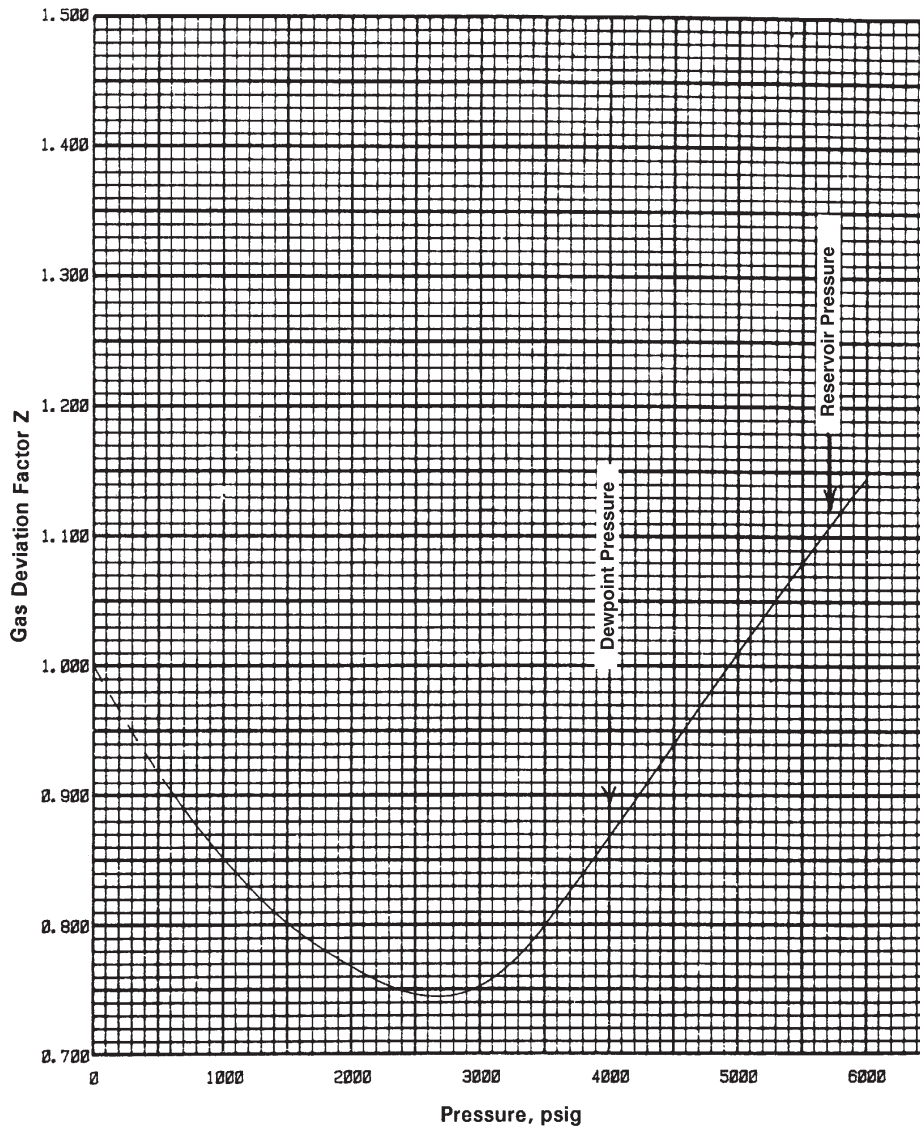
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Fig. 6.9C—CVD data for gas-condensate sample from Good Oil Co. Well 7; equilibrium gas Z factor, Z_g.

$$Q_{actual} = Q_{lab} \frac{V_{pHCactual}}{V_{pHClab}}, \quad \dots\dots\dots\dots\dots\dots \quad (6.61)$$

where Q_{lab} = laboratory value given by Eqs. 6.55 and 6.57. As an example, suppose geological data indicate a HCPV of 625,000 bbl (82.45 acre-ft), or 3.509×10^6 ft³. Then, original wet gas in place is

$$G_w = 1.1173 \times 10^6 \frac{3.509 \times 10^6}{3,943}$$

$$= 994.3 \text{ MMscf} \quad \dots\dots\dots\dots\dots\dots\dots \quad (6.62)$$

and condensate in solution at initial pressure is given by

$$N = 135.7(1.1173) \frac{3.509 \times 10^6}{3,943}$$

$$= 134,900 \text{ STB}. \quad \dots\dots\dots\dots\dots\dots \quad (6.63)$$

6.6.4 Liquid-Dropout Curve. Table 6.11 and Figs. 6.9A through 6.9D show relative oil volumes, V_{ro}, measured in the example CVD experiment. V_{ro} is defined as the volume of oil, V_o, at a given pressure divided by the original saturation volume, V_s. This relative volume is an excellent measure of the average reservoir-oil saturation (normalized) that will develop during depletion of a gas-condensate

reservoir. Correcting for water saturation, S_w, the reservoir-oil saturation can be calculated from V_{ro} with

$$S_o = (1 - S_w)V_{ro}. \quad \dots\dots\dots\dots\dots\dots\dots \quad (6.64)$$

For most gas condensates, V_{ro} shows a maximum near 2,000 to 2,500 psia. Cho et al.[27] give a correlation for maximum liquid dropout as a function of temperature and C_{7+} mole percent in the dewpoint mixture.

$$\left(V_{ro}\right)_{max} = 93.404 + 4.799 z_{C_{7+}} - 19.73 \ln T, \quad \dots\dots \quad (6.65)$$

with $z_{C_{7+}}$ in mole percent and T in °F. The correlation predicts $(V_{ro})_{max} = 23.2\%$ for the example condensate fluid compared with 24% measured experimentally (at 2,100 psig). **Fig. 6.11** shows values of $(V_{ro})_{max}$ vs. T and $z_{C_{7+}}$ from Eq. 6.65.

Considerable attention usually is given to matching the liquid-dropout curve when an EOS is used. Some gas condensates have what is referred to as a "tail," where liquid drops out very slowly (sometimes for several thousand psi below the dewpoint) before finally increasing toward a maximum. Matching this behavior with an EOS can prove difficult, and the question is whether matching the tail is really necessary (see Appendix C).

What really matters for reservoir calculations of a gas-condensate fluid is how much original stock-tank condensate is "lost" because of retrograde condensation in the reservoir. The shape and magni-
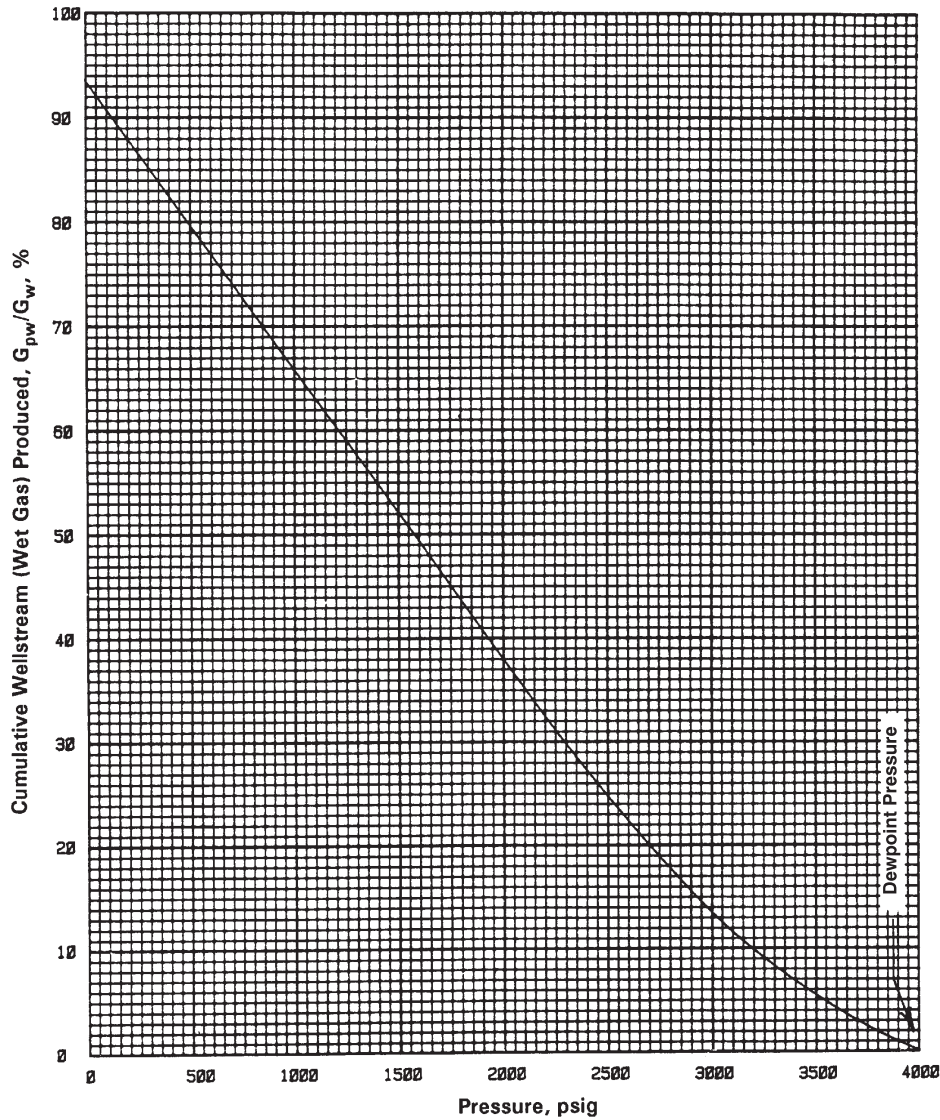
Fig. 6.9D—CVD data for gas-condensate sample from Good Oil Co. Well 7; wet-gas material balance.

tude of liquid dropout reflects the change in producing oil/gas ratio, $r_p \approx r_s$. A tail on a liquid-dropout curve implies that the producing wellstream is becoming only slightly leaner (i.e., r_s is decreasing only slightly). The cumulative condensate recovery is given by

$$N_p = \int_0^{G_p} r_s \, dG_p, \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.66)$$

where G_p = cumulative dry gas produced. Cumulative condensate production is readily evaluated from a plot of r_s vs. G_p.

One of the most important checks of an EOS characterization for any gas condensate, particularly one with a tail, is N_p calculated from CVD data vs. N_p calculated from the EOS characterization. It is alarming how much the surface condensate recovery can be underestimated if the tail is not matched properly. We do not recommend matching the dewpoint exactly with a liquid-dropout curve that is severely overpredicted in the region where measured results indicate little dropout. If the EOS characterization cannot be modified to honor the tail of liquid-dropout curve, it is preferable to underpredict the measured dewpoint pressure and match only the higher liquid-dropout volumes.

In summary, oil relative volume, V_{ro}, is not important *per se*; however, the effect of liquid dropout on surface condensate production should be emphasized. In fact, the effect of shape and magnitude of liquid dropout on fluid flow in the reservoir is negligible, and any EOS match will probably have the same effect on fluid flow from the reservoir into the wellbore (i.e., inflow performance).

6.6.5 Consistency Check of CVD Data. Reudelhuber and Hinds[24] give a detailed procedure for checking CVD data consistency that involves a material-balance check on components and phases and yields oil compositions, density, molecular weight, and $M_{C_{7+}}$. Together with reported data, these calculated properties allow K values to be calculated and checked for consistency with the Hoffman *et al.*[10] method.[11,28] Whitson and Torp's[23] material-balance equations are summarized later. Similar equations can also be derived for a DLE experiment when equilibrium gas compositions and oil relative volumes are reported. Reported CVD data include temperature, T; dewpoint pressure, p_d, or bubblepoint pressure, p_b; dewpoint Z factor, Z_d, or bubblepoint-oil density, ρ_{ob}. Additional data at each Depletion Stage k include oil relative volume, V_{ro}; initial fraction of cumulative moles produced, n_p/n; gas Z factor (not the two-phase Z factor), Z; equilibrium gas composition, y_i; and equilibrium gas (wellstream) C_{7+} molecular weight, $M_{g C_{7+}}$.

The equilibrium gas density, ρ_g; molecular weight, M_g; and wellstream gravity, $\gamma_w = M_g/M_{air}$, are readily calculated at each

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TABLE 6.12—CVD DATA FOR GOOD OIL CO. WELL 7 GAS-CONDENSATE SAMPLE 2*

Component, mol%	Reservoir Pressure, psig							
	5,713**	4,000†	3,500	2,900	2,100	1,300	605	0‡
CO_2	0.18	0.18	0.18	0.18	0.18	0.19	0.21	
N_2	0.13	0.13	0.13	0.14	0.15	0.15	0.14	
C_1	61.72	61.72	63.10	65.21	69.79	70.77	66.59	
C_2	14.10	14.10	14.27	14.10	14.12	14.63	16.06	
C_3	8.37	8.37	8.26	8.10	7.57	7.73	9.11	
$i\text{-}C_4$	0.98	0.98	0.91	0.95	0.81	0.79	1.01	
$n\text{-}C_4$	3.45	3.45	3.40	3.16	2.71	2.59	3.31	
$i\text{-}C_5$	0.91	0.91	0.86	0.84	0.67	0.55	0.68	
$n\text{-}C_5$	1.52	1.52	1.40	1.39	0.97	0.81	1.02	
C_7	1.79	1.79	1.60	1.52	1.03	0.73	0.80	
C_{7+}	6.85	6.85	5.90	4.41	2.00	1.06	1.07	
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
Properties								
C_{7+} molecular weight	143	143	138	128	116	111	110	
C_{7+} specific gravity	0.795	0.795	0.790	0.780	0.767	0.762	0.761	
Equilibrium gas deviation factor, Z	1.107	0.867	0.799	0.748	0.762	0.819	0.902	
Two-phase deviation factor, Z	1.107	0.867	0.802	0.744	0.704	0.671	0.576	
Wellstream produced, cumulative % of initial		0.000	5.374	15.438	35.096	57.695	76.787	93.515
From smooth compositions								
C_{3+}, gal/Mscf	9.218	9.218	8.476	7.174	5.171	4.490	5.307	
C_{4+}, gal/Mscf	6.922	6.922	6.224	4.980	3.095	2.370	2.808	
C_{5+}, gal/Mscf	5.519	5.519	4.876	3.692	1.978	1.294	1.437	
Retrograde Condensation During Gas Depletion								
Retrograde liquid volume, % hydrocarbon pore space		0.0	3.3	19.4	23.9	22.5	18.1	12.6

*Study conducted at 186°F.
** Original reservoir pressure.
† Dewpoint pressure.
‡0-psig residual-liquid properties: 47.5°API oil gravity at 60°; 0.7897 specific gravity at 60/60°F; and molecular weight of 140.

Depletion Stage k [and at the dewpoint ($k = 1$) for a gas-condensate sample] from

$$\left(M_g\right)_k = \sum_{i=1}^{N} (y_i)_k M_i , \quad \dots\dots\dots\dots\dots\dots \quad (6.67)$$

$$\left(\rho_g\right)_k = \frac{p\left(M_g\right)_k}{(Z)_k RT}, \quad \dots\dots\dots\dots\dots\dots\dots \quad (6.68)$$

and $\left(\gamma_g\right)_k = \left(\gamma_w\right)_k = \dfrac{\left(M_g\right)_k}{28.97} . \quad \dots\dots\dots\dots\dots \quad (6.69)$

On a basis of 1 mol initial dewpoint fluid ($n = 1$), the cell volume is

$$V_{cell} = \frac{Z_d RT}{p_d} \quad \dots\dots\dots\dots\dots\dots\dots\dots \quad (6.70)$$

for a gas condensate and

$$V_{cell} = \frac{M_{ob}}{\rho_{ob}} \quad \dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.71)$$

for a volatile oil. Oil and gas volumes, respectively, at Stage k are

$$(V_o)_k = V_{cell}(V_{ro})_k$$

and $(V_g)_k = V_{cell}\left[1 - (V_{ro})_k\right]. \quad \dots\dots\dots\dots\dots \quad (6.72)$

Moles and mass of the total material remaining in the cell at Stage k are given by

$$(n_t)_k = 1 - \left(\frac{n_p}{n}\right)_k ,$$

$$(n_g)_k = \frac{(p)_k(V_g)_k}{(Z)_k RT},$$

and $(n_o)_k = (n_t)_k - (n_g)_k , \quad \dots\dots\dots\dots\dots\dots \quad (6.73)$

and moles and mass of the individual phases remaining in the cell at Stage k are given by

$$(m_t)_k = M_s - \sum_{j=2}^{k}\left(\frac{\Delta n_g}{n}\right)_j (M_g)_j ,$$

$$(m_g)_k = (n_g)_k (M_g)_k ,$$

and $(m_o)_k = (m_t)_k - (m_g)_k . \quad \dots\dots\dots\dots\dots\dots \quad (6.74)$

In Eqs. 6.73 and 6.74,

$$\left(\frac{\Delta n_g}{n}\right)_j = \left(\frac{n_p}{n}\right)_j - \left(\frac{n_p}{n}\right)_{j-1} , \quad \dots\dots\dots\dots\dots \quad (6.75)$$

M_s = saturated-fluid molecular weight, and $(n_p/n)_1 = 0$.

Densities and molecular weights of the oil phase are calculated from

**TABLE 6.13—CALCULATED RECOVERIES* FROM CVD REPORT
FOR GOOD OIL CO. WELL 7 GAS-CONDENSATE SAMPLE**

	Initial in Place	Reservoir Pressure (psig)						
		4,000**	3,500	2,900	2,100	1,300	605	0
Wellstream, Mscf	1,000	0	53.74	154.38	350.96	576.95	767.87	935.15
Normal temperature separation†								
Stock-tank liquid, bbl	135.7	0	6.4	15.4	24.0	29.7	35.1	
Primary-separator gas, Mscf	757.87	0	41.95	124.78	301.57	512.32	658.02	
Second-stage gas, Mscf	96.68	0	4.74	12.09	20.75	27.95	37.79	
Stock-tank gas, Mscf	24.23	0	1.21	3.16	5.61	7.71	10.4	
Total plant products in primary separator‡								
Propane, gal	1,198	0	67	204	513	910	1,276	
Butanes, gal	410	0	23	72	190	346	491	
Pentanes, gal	180	0	10	31	81	144	192	
Total plant products in second-stage separator‡								
Propane, gal	669	0	33	86	149	205	286	
Butanes, gal	308	0	15	41	76	108	159	
Pentanes, gal	138	0	7	19	35	49	69	
Total plant products in wellstream‡								
Propane, gal	2,296	0	121	342	750	1,229	1,706	
Butanes, gal	1,403	0	73	202	422	665	927	
Pentanes, gal	5,519	0	262	634	1,022	1,315	1,589	

*Cumulative recovery per MMscf of original fluid calculated during depletion.
**Dewpoint pressure.
†Recovery basis: primary separation at 500 psia and 70°F, second-stage separation at 50 psia and 70°F, and stock tank at 14.7 psia and 70°F.
‡Recovery assumes 100% plant efficiency.

$$(\rho_o)_k = \frac{(m_o)_k}{(V_o)_k} \quad\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.76)$$

and $(M_o)_k = \dfrac{(m_o)_k}{(n_o)_k},\quad\dots\dots\dots\dots\dots\dots\dots\dots\dots \quad (6.77)$

and the oil composition is given by

$$(x_i)_k = \frac{(n_t)_k(z_i)_k - (n_g)_k(y_i)_k}{(n_t)_k - (n_g)_k}.\quad\dots\dots\dots\dots\dots \quad (6.78)$$

K values can be calculated from $K_i = y_i/x_i$, and $z_i = $ overall composition of the mixture remaining in the cell at Stage k.

$$(z_i)_k = \frac{1}{(n_t)_k}\left[(z_i)_1 - \sum_{j=2}^{k}\left(\frac{\Delta n_g}{n}\right)_j(y_i)_j\right].\quad\dots\dots\dots\dots \quad (6.79)$$

C_{7+} molecular weight of the oil phase can be calculated from

$$\left(M_{oC_{7+}}\right)_k = \frac{(M_o)_k - \sum\limits_{i \neq C_{7+}} (x_i)_k M_i}{\left(x_{C_{7+}}\right)_k}.\quad\dots\dots\dots\dots \quad (6.80)$$

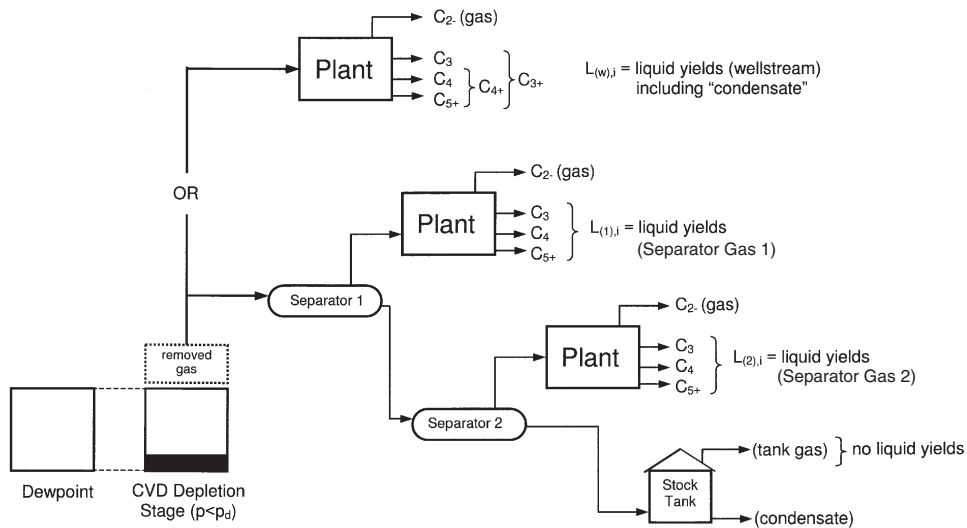Table 6.6 summarizes these calculations for the sample gas-condensate mixture.

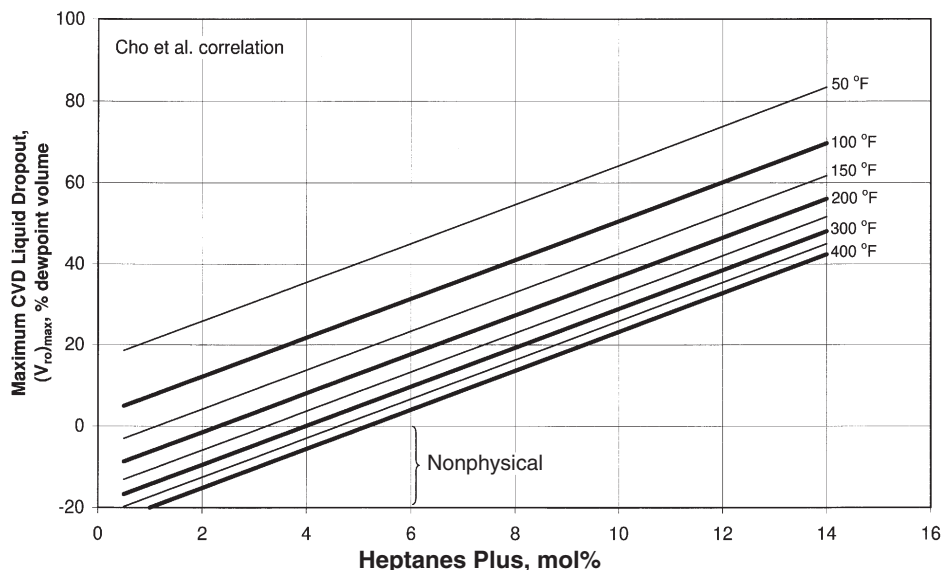Fig. 6.10—Schematic of method of calculating plant recoveries in a CVD report for a gas condensate.

Fig. 6.11—Calculated maximum retrograde oil relative volumes from the Cho *et al.*[27] correlation.

The oil composition at the last depletion state (605 psig for the example condensate) can be measured, but it must be requested specifically. Also, the residual-oil molecular weight, $M_{\bar{o}r}$, and specific gravity, $\gamma_{\bar{o}r}$, remaining after depletion at atmospheric pressure are typically measured and reported as shown in Table 6.12. These values can be compared with calculated values by use of the material-balance equations shown earlier.

The material-balance calculations are more accurate for rich gas condensates and volatile oils. In fact, obtaining reasonable material-balance oil properties for lean gas condensates is difficult. Sometimes it is useful to modify the reported oil relative volumes (particularly those close to the dewpoint) to monitor the effect on calculated oil properties.

An alternative material-balance check that may be even more useful for determining data consistency (particularly for leaner gas condensates) involves starting with reported final-stage condensate composition, $(x_i)_{k=N}$, and adding back the removed gases, $(y_i)_k$, for each stage from $k = N$ to $k = 1$. This results in the original gas composition, $(z_i)_{k=1}$, which can be compared quantitatively with the laboratory-reported composition.

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SI Metric Conversion Factors

°API	141.5/(131.5 + °API)	= g/cm^3
bbl	× 1.589 873	E − 01 = m^3
Btu	× 1.055 056	E + 00 = kJ
cp	× 1.0*	E − 03 = Pa · s
ft	× 3.048*	E − 01 = m
ft^3	× 2.831 685	E − 02 = m^3
°F	(°F − 32)/1.8	= °C
gal	× 3.785 412	E − 03 = m^3
in.	× 2.54*	E + 00 = cm
lbm mol	× 4.535 924	E − 01 = kmol
psi	× 6.894 757	E + 00 = kPa

*Conversion factor is exact.