Applied PETROLEUM RESERVOIR ENGINEERING

B. C. CRAFT

and

M. F. HAWKINS

Petroleum Engineering Department
Louisiana State University

PRENTICE-HALL, INC.

Englewood Cliffs, N. J.

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Gas-Condensate Reservoirs

1. Introduction. Gas-condensate production may be thought of as a type intermediate between oil and gas. Oil reservoirs have a dissolved gas content in the range of zero (dead oil) to a few thousand cubic feet per barrel, whereas in gas reservoirs one barrel of liquid (condensate) is vaporized in 100,000 standard cubic feet of gas or more, and from which, therefore, a small or negligible amount of hydrocarbon liquid is obtained in surface separators. Gas-condensate production is predominately *gas* from which more or less liquid is *condensed* in the surface separators, hence the name gas-condensate. The liquid is sometimes called by an older name *distillate,* and also sometimes simply oil, since it is an oil. Gas-condensate reservoirs may be approximately defined as those which produce light-colored or colorless stock tank liquids with gravities above 45° API at gas-oil ratios in the range of 5000 to 100,000 SCF/bbl. Allen*,[1] has pointed out the inadequacy of classifying wells and the reservoirs from which they produce entirely on the basis of surface gas-oil ratios; for the classification of reservoirs properly depends upon (a) the composition of the hydrocarbon accumulation and (b) the temperature and pressure of the accumulation in the earth. Reservoirs have been discovered which contain the various hydrocarbons, and sometimes some other compounds, in almost every conceivable set of proportions. Further, while temperatures and pressures increase with depth, because their rates of increase (gradients) vary considerably from area to area, a rather wide variety of pressure-temperature combinations is found in naturally occurring reservoirs. Because of these facts there are no distinct dividing lines between the types into which reservoirs may be divided. They blend into one another, and even overlap, sometimes causing technical and legal misunderstanding.

*References throughout the text are given at the end of each chapter.

Table 2.1. Mole Composition and Other Properties of Typical Single-Phase Reservoir Fluids

Component	Black Oil	Volatile Oil	Gas-Condensate	Dry Gas	Gas
C_1	48.83	64.36	87.07	95.85	86.67
C_2	2.75	7.52	4.39	2.67	7.77
C_3	1.93	4.74	2.29	0.34	2.95
C_4	1.60	4.12	1.74	0.52	1.73
C_5	1.15	2.97	0.83	0.08	0.88
C_6	1.59	1.38	0.60	0.12	....
C_7^+	42.15	14.91	3.80	0.42	....
	100.00	100.00	100.00	100.00	100.00
Mol. wt. C_7^+	225	181	112	157	....
GOR, SCF/bbl	625	2000	18,200	105,000	Inf.
Tank gravity, °API	34.3	50.1	60.8	54.7	....
Liquid color	Greenish black	Medium orange	Light straw	Water white	....

Table 2.1 presents the mole compositions and some additional properties of five single-phase reservoir fluids. The volatile oil type is intermediate between the gas-condensate and the black oil or heavy oil types. Production with gas-oil ratios greater than 100,000 SCF/bbl is commonly called *lean* or *dry gas*, although there is no generally recognized dividing line. In some legal work statutory gas wells are those with gas-oil ratios in excess of 100,000 SCF/bbl, i.e., 10 bbl/M MCF. The term *wet gas* is sometimes used as more or less equivalent to gas-condensate. General trends are noticeable in the methane and heptanes-plus content of the fluids, in the gas-oil ratios, and the color of the tank liquids. While there is good correlation between the molecular weight of the heptanes-plus and the gravity of the stock tank liquid, there is virtually no correlation between the gas-oil ratios and the gravities of the stock tank liquids, except that most black oil reservoirs have gas-oil ratios below 1000 SCF/bbl and stock tank liquid gravities below 45° API. The gas-oil ratios are a good indication of the over-all composition of the fluid, high gas-oil ratios being associated with low concentrations of pentanes and heavier, and vice versa.

The gas-oil ratios given in Table 2.1 are for the initial production of the one-phase reservoir fluids producing through one or more surface separators operating at various temperatures and pressures, which may vary considerably among the several types of production. The gas-oil ratios and consequently the API gravity of the produced liquid will vary with the number, pressures, and temperatures of the separators so that one operator may report a somewhat different gas-oil ratio from another, although both produce the same reservoir fluid. Also, as pressure declines in the black oil, volatile oil, and some gas-condensate reservoirs, there is generally a considerable increase in the gas-oil ratio owing to the reservoir mechanisms which control the relative flow of oil and gas to the well bores. The separator efficiencies also generally decline as flowing wellhead pressures decline, also contributing to increased gas-oil ratios.

What has been said previously applies to reservoirs initially in a single phase. The initial gas-oil ratios of production from wells completed either in the gas cap or in the oil zone of two-phase reservoirs will depend, as discussed previously, upon the compositions of the gas cap hydrocarbons and the oil zone hydrocarbons as well as the reservoir temperature and pressure. The gas cap may contain gas-condensate or dry gas, while the oil zone may contain black oil or volatile oil. Naturally, where a well is completed in both the gas and oil zones, the production will be a mixture of the two. Sometimes this is unavoidable, as where the gas and oil zones (columns) are only a few feet in thickness. Even where a well is completed only in the oil zone, the downward coning of gas from the overlying gas cap may occur to increase the gas-oil ratio of the production.

With deeper drilling in many areas the trend of discoveries has been toward reservoirs of the gas and gas-condensate types. Figure 2.1 based on well test data reported in *Rinehart's Yearbooks*[2] shows the discovery trend for 17 parishes in southwest Louisiana for 1952–56 inclusive. The reservoirs were separated into oil and gas or gas-condensate types on the basis of well test gas-oil ratios and the API gravity of the produced liquid. While oil discoveries predominate at depths less than 8000 ft, gas and gas-condensate discoveries predominate below 10,000 ft. The decline in discoveries below 12,000 ft is due to the fewer number of wells drilled below that depth rather than a drop in the occurrence of hydrocarbons. Figure 2.2 shows the same data for the year 1955 in which the gas-oil ratio is plotted versus depth. The dashed line marked "oil" indicates the general trend of increased solution gas in oil with increasing pressure (depth), and the envelope to the lower right encloses those discoveries which are probably of the gas or gas-condensate types.

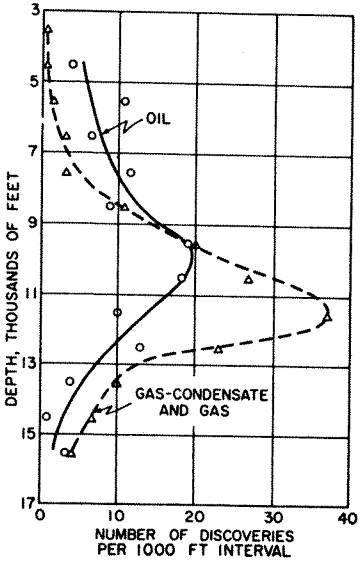

Fig. 2.1. Discovery frequency of oil and gas or gas-condensate reservoirs versus depth. For 17 parishes in southwest Louisiana, 1952–1956, inclusive. (Data from *Rinehart's Yearbooks*.[2])

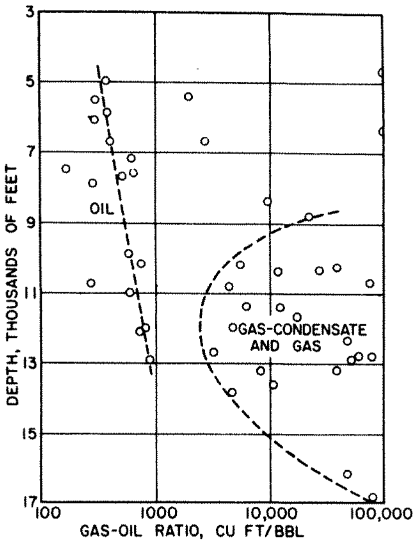

Fig. 2.2. Plot showing trend of increase of gas-oil ratio versus depth. For 17 parishes in southwest Louisiana during 1955. (Data from *Rinehart's Yearbooks*.[2])

Muskat,[3] Standing,[4] Thornton,[5] and Eilerts[6] have discussed the properties and behavior of gas-condensate reservoirs. Table 2.2, taken from Eilerts,[6] shows the distribution of the gas-oil ratio and the API gravity among 172 gas and gas-condensate fields in Texas, Louisiana, and Mississippi. He found no correlation between the gas-oil ratio and the API gravity of the tank liquid for these fields.

2. Reservoir Types Defined with Reference to Phase Diagrams. From a more technical point of view the various types of reservoirs can be defined by the location of the initial reservoir temperature and pressure with respect to the two-phase (gas and liquid) region as commonly shown on pressure-temperature phase diagrams. Figure 2.3 is the *PT* phase diagram of a particular reservoir fluid. The area enclosed by the bubble-point and dew-point lines to the lower left is the region of pressure-temperature combinations in which both gas and liquid phases will exist. The curves within the two-phase region show the per cent of the total hydrocarbon volume which is liquid, for any temperature and pressure. Initially each hydrocarbon accumulation will have its own phase diagram, which depends only upon the composition of the accumulation.

Let us consider a reservoir containing the fluid of Fig. 2.3 initially at 300°F and 3700 psia, point A. Since this point lies outside the two-phase region, it is originally in a one-phase state, commonly called gas as located at point A. Since the fluid remaining in the reservoir during production will remain at 300°F, it is evident that it will remain in the single-phase or gaseous state, as the pressure declines along path A–A_1. Further, the composition of the produced well fluid will not change as the reservoir is depleted. This will be true for any accumulation of this composition where the reservoir temperature exceeds the *cricondentherm* or maximum two-phase temperature, 250°F for the present example. Although the fluid left in the reservoir remains in one phase, the fluid produced through the wellbore and into surface separators, though of the same composition, may enter the two-phase region owing to the temperature decline, as along line A–A_2. This accounts for the production of condensate liquid at the surface

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Table 2.2. RANGE OF GAS-OIL RATIOS AND TANK OIL GRAVITIES FOR 172 GAS AND GAS-CONDENSATE FIELDS IN TEXAS, LOUISIANA, AND MISSISSIPPI

Range of Liquid-Gas Ratio, GPM*	Range of Gas-Oil Ratio M SCF/bbl	Number of Fields Texas	Louisiana	Mississippi	Total	Per Cent of Total
<0.4	>105	38	12	7	57	33.1
0.4 to 0.8	52.5 to 105	33	18	4	55	32.0
0.8 to 1.2	35.0 to 52.5	12	15	5	32	18.6
1.2 to 1.6	26.2 to 35.0	1	8	1	10	5.8
1.6 to 2.0	21.0 to 26.2	1	3	1	5	2.9
>2.0	<21.0	2	5	6	13	7.6
		87	61	24	172	100.0
	Range of Stock Tank Gravity, °API					
	<40	2	1	0	3	1.8
	40 — 45	4	2	0	6	3.6
	45 — 50	12	12	0	24	14.6
	50 — 55	23	17	7	47	28.5
	55 — 60	24	13	12	49	29.7
	60 — 65	19	8	3	30	18.2
	>65	3	1	2	6	3.6
		87	54	24	165	100.0

*Gallons per 1000 SCF

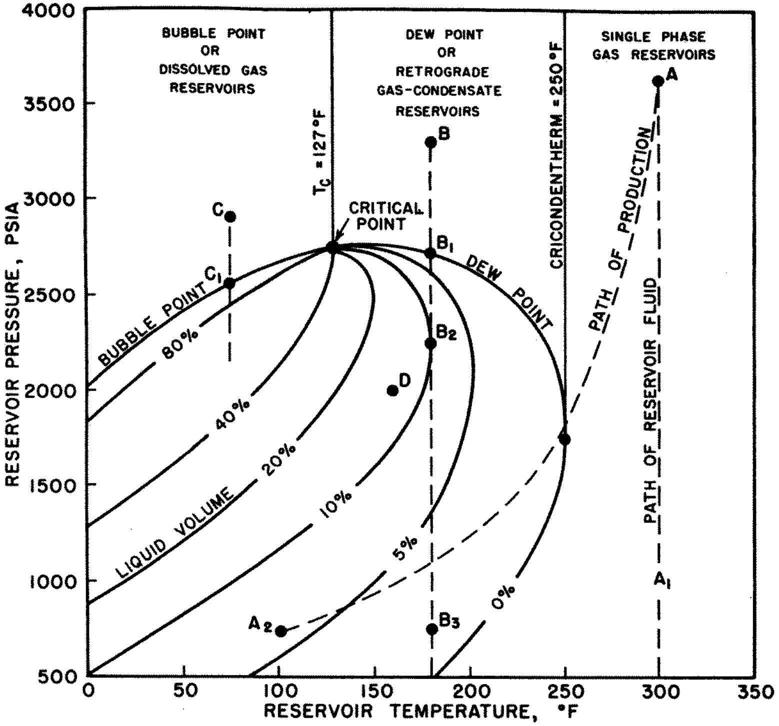

Fig. 2.3. Pressure-temperature phase diagram of a reservoir fluid.

from a gas in the reservoir. Of course, if the cricondentherm of a fluid is below say 50°F, then only gas will exist on the surface at usual ambient temperatures, and the production will be called dry gas. Nevertheless, it may contain liquid fractions which can be removed by low temperature separation or by natural gasoline plants.

Next let us consider a reservoir containing the same fluid of Fig. 2.3 but at a temperature of 180°F and an initial pressure of 3300 psia, point B. Here the fluid is also initially in the one-phase state, commonly called gas where the reservoir temperature exceeds the critical temperature. As pressure declines because of production, the composition of the produced fluid will be the same as for reservoir A, and remain constant until the dew-point pressure is reached, at 2545 psia, point B_1. Below this pressure a liquid condenses out of the reservoir fluid as a fog or dew, and this type of reservoir is commonly called a dew-point reservoir. This condensation leaves the gas phase with a lower liquid content. As the condensed liquid adheres to the walls of the pore spaces of the rock, it is immobile. Thus the gas produced at the surface will have a lower liquid content, and the producing gas-oil ratio therefore rises. This process of *retrograde* condensation continues until a point of maximum liquid volume is reached, 10 per cent at 2250 psia, point B_2. The term retrograde is used because generally vaporization occurs during isothermal expansion, rather than condensation. Actually, after the dew point is reached, because the composition of the produced fluid changes, the composition of the remaining reservoir fluid also changes, and the phase envelope begins to shift; for the phase diagram of Fig. 2.3 represents one and only one hydrocarbon mixture. Unfortunately for maximum liquid recovery, this shift is toward the right, and this further aggravates the retrograde liquid loss within the pores of the reservoir rock.

Neglecting for the moment this shift in the phase diagram, for qualitative purposes *vaporization* of the retrograde liquid occurs from B_2 to the abandonment pressure B_3. This revaporization aids liquid recovery and may be evidenced by decreasing gas-oil ratios on the surface. The over-all retrograde loss will evidently be greater (a) for lower reservoir temperatures, (b) for higher abandonment pressures, and (c) for greater shift of the phase diagram to the right, this latter, of course, being a property of the hydrocarbon system. The retrograde liquid in the reservoir at any time is composed to a large extent of methane and ethane by volume, and so is much larger than the volume of stable liquid which could be obtained from it at atmospheric temperature and pressure. The composition of this retrograde liquid is changing as pressure declines so that 4 per cent retrograde liquid volume at say 750 psia might contain as much stable, surface condensate as say 6 per cent retrograde liquid volume at 2250 psia.

If the accumulation occurred at 3000 psia and 75°F, point C, the reservoir would be in a one-phase state, now called liquid, since the temperature is below the critical temperature. This type is called a bubble-point reservoir; for, as pressure declines, the bubble point will be reached, in this case at 2550 psia, point C_1. Below this point bubbles, or a free-gas phase, will appear. Eventually the free gas evolved begins to flow to the well bore, and in ever increasing quantities. Conversely, the oil flows in ever decreasing quantities, and at depletion much unrecovered oil remains in the reservoir. Other names for this type of liquid (oil) reservoir are depletion, dissolved gas, solution gas drive, expansion, and internal gas drive.

Finally, if this same hydrocarbon mixture occurred at 2000 psia and 150°F, point D, it would be a two-phase reservoir, consisting of a liquid or oil zone overlain by a gas zone or cap. As the compositions of the gas and oil zones are entirely different from each other, they may be represented separately by individual phase diagrams which bear little relation to each other or to the composite. The liquid or oil zone will be at its bubble point, and will be produced as a bubble-point reservoir, modified by the presence of the gas cap. The gas cap will be at the dew point, and may be either retrograde as shown in Fig. 2.4 (a) or nonretrograde, Fig. 2.4 (b).

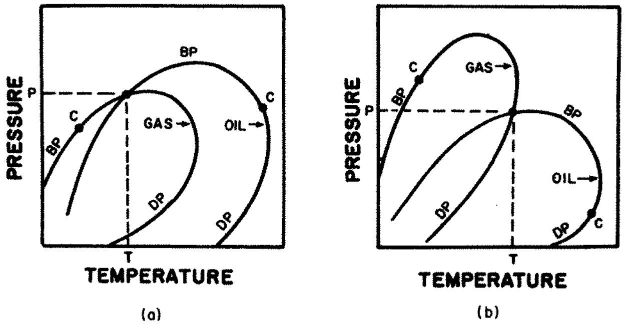

Fig. 2.4. Phase diagrams of a cap gas and oil zone fluid showing (a) retrograde cap gas, and (b) non-retrograde cap gas.

From what has been said in the previous paragraphs, from this more technical point of view, hydrocarbon reservoirs are initially either in a single-phase state (A, B, and C) or a two-phase state (D), depending upon their temperatures and pressures relative to their phase envelopes. Upon volumetric depletion (no water influx) these various one-phase reservoirs may behave as simple, single-phase gas reservoirs (A), where reservoir temperature exceeds the cricondentherm; or retrograde condensate (dew-point) reservoirs (B), where reservoir temperature lies between the critical temperature and the cricondentherm; or dissolved gas (bubble-point) reservoirs (C), where reservoir temperature is below the critical temperature. Where the pressure and temperature lie within the two-phase region, an oil zone will exist with an overlying gas cap. The oil zone will produce as a bubble-point oil reservoir and the gas cap either as a single-phase gas reservoir (A) or a retrograde gas reservoir (B).

3. Calculation of Initial In-Place Gas and Oil for Gas-Condensate Reservoirs. The initial in-place gas and oil (condensate) for gas-condensate reservoirs, both retrograde and nonretrograde, may be calculated from generally available field data by recombining the produced gas and oil in the correct ratio to find the average specific gravity (air = 1.00) of the total well fluid, which is presumably being produced initially from a one-phase reservoir. The method may also be used to calculate the initial oil and gas of gas caps.

Let: R = initial surface gas-oil ratio of the production, SCF of dry or residue gas per barrel of oil (condensate)

γ_o = specific gravity of the tank oil (water = 1.00)

M_o = molecular weight of the tank oil (condensate)

γ_g = average specific gravity of the gas produced from the surface separator(s), air = 1.00

SC = 14.7 psia and 60°F; molar volume = 379.4 cu ft/mole

Then on the basis of one barrel of tank oil and R standard cubic feet of separator or residue gas, the pounds of total well fluid m_w is

$$m_w = \frac{R \times \gamma_g \times 28.97}{379.4} + 350\,\gamma_o$$
$$= 0.07636\,R\gamma_g + 350\,\gamma_o$$

The total moles of fluid in one barrel of oil and R cubic feet of gas is

$$n_t = \frac{R}{379.4} + \frac{350\,\gamma_o}{M_o}$$
$$= 0.002636\,R + 350\,\gamma_o/M_o$$

Hence the molecular weight of the total well fluid M_w is

$$M_w = \frac{m_w}{n_t} = \frac{0.07636\,R\gamma_g + 350\,\gamma_o}{0.002636\,R + 350\,\gamma_o/M_o}$$

and the specific gravity of the well fluid is $M_w/28.97$, or

$$\gamma_w = \frac{R\gamma_g + 4584\,\gamma_o}{R + 132{,}800\,\gamma_o/M_o} \qquad (2.1)$$

The tank oil specific gravity is obtained from the API gravity of the tank oil using the equation

$$\gamma_o = \frac{141.5}{\text{API} + 131.5} \qquad (2.2)$$

Where the molecular weight of the tank oil is not known it may be estimated using the following formula developed by Cragoe:[7]

$$M_o = \frac{44.29\,\gamma_o}{1.03 - \gamma_o} = \frac{6084}{\text{API} - 5.9} \qquad (2.3)$$

Example 2.1 shows the use of Eq. (2.1) to calculate the initial gas and oil in

Example 2.1. Calculate the initial oil and gas in place per acre-foot for a gas-condensate reservoir.

Given:

Initial pressure	2740 psia
Reservoir temperature	215°F
Average porosity	25 per cent
Average connate water	30 per cent
Daily tank oil	242 bbl
Oil gravity, 60°F	48.0° API
Daily separator gas	3100 MCF
Separator gas gravity	0.650
Daily tank gas	120 MCF
Tank gas gravity	1.20

SOLUTION:

$$\text{Average gas gravity} = \frac{3100 \times 0.650 + 120 \times 1.20}{3100 + 120} = 0.670$$

$$\gamma_o = \frac{141.5}{48.0 + 131.5} = 0.7883 \quad \text{(Eq. 2.2)}$$

$$M_o = \frac{6084}{48.0 - 5.9} = 144.5 \quad \text{(Eq. 2.3)}$$

$$R = \frac{3100 + 120}{242} \times 1000 = 13{,}300 \text{ SCF/bbl}$$

$$\gamma_w = \frac{13{,}300 \times 0.670 + 4584 \times 0.7883}{13{,}300 + 132{,}800 \times 0.7883/144.5} = 0.893 \quad \text{(Eq. 2.1)}$$

From Fig. 1.2 $T_c = 425°\text{R}$ and $p_c = 652$ psia using the condensate curves. Then $T_r = 1.59$ and $p_r = 4.20$, from which, using Fig. 1.3, the gas deviation factor is 0.82 at 2740 psia and 215°F. Then the total initial gas in place per acre-foot of bulk reservoir rock is

$$G = \frac{379.4\, pV}{zRT} = \frac{379.4 \times 2740 \times 43{,}560 \times 0.25 \times (1 - 0.30)}{0.82 \times 10.73 \times 675}$$

$$= 1334 \text{ MCF/ac-ft}$$

Since the volume fraction equals the mole fraction in the gas state, the fraction of the total which is produced on the surface as gas is

$$f_g = \frac{n_g}{n_g + n_o} = \frac{R/379.4}{R/379.4 + 350\gamma_o/M_o}$$

$$= \frac{13{,}300/379.4}{13{,}300/379.4 + 350 \times 0.7883/144.5} = 0.9483$$

Then,

$$\text{Initial gas in place} = 0.9483 \times 1334 = 1265 \text{ MCF/ac-ft}$$

$$\text{Initial oil in place} = \frac{1265 \times 10^3}{13{,}300} = 95.1 \text{ bbl/ac-ft}$$

Since the gas production is 94.83 per cent of the total moles produced, then the total daily gas-condensate production in standard cubic feet is

$$\Delta G_p = \frac{\text{Daily gas}}{0.9483} = \frac{3100 + 120}{0.9483} = 3396 \text{ MCF/day}$$

The total daily reservoir voidage by the gas law is

$$\Delta V = 3{,}396{,}000 \times \frac{675}{520} \times \frac{14.7}{2740} \times 0.820 = 19{,}400 \text{ cu ft/day}$$

place per acre-foot of a gas-condensate reservoir from the usual production data. For best accuracy the gas volume should be that from all separators including the stock tank vapors rather than just the gas from the main, high-pressure separator; and, therefore, the gas gravity should be the average of all gases produced. The gas deviation factor at initial reservoir temperature and pressure is estimated from the gas gravity of the recombined oil and gas as shown in Chapter 1, Sec. 8. From the estimated gas deviation factor and the reservoir temperature, pressure, porosity, and connate water the moles of hydrocarbons per acre-foot can be calculated, and from this the initial gas and oil in place.

The gas deviation factor of the total well fluid at reservoir temperature and pressure can also be calculated from its composition. The composition of the total well fluid is calculated from the analyses of the produced gas(es) and liquid by recombining them in the ratio in which they are produced. Where the composition of the stock tank liquid is known, a unit of this liquid must be combined with the proper amounts of gas(es) from the separator(s) and the stock tank, each of which has its own composition. Where the compositions of the gas and liquid in the first or high-pressure separator are known, the shrinkage which the separator liquid undergoes in passing to the stock tank must be measured or calculated in order to know the proper proportions in which the separator gas and liquid must be combined. For example, if the volume factor of the separator liquid is 1.20 separator barrels per stock tank barrel and the measured gas-oil ratio is 20,000 SCF of high-pressure gas per barrel of stock tank liquid, then the separator gas and liquid samples should be recombined in the proportions of 20,000 SCF of gas to 1.20 bbl of separator liquid, since 1.20 bbl of separator liquid shrinks to 1.00 bbl in the stock tank.

Example 2.2 shows the calculation of initial gas and oil in place for a gas-

Example 2.2. To calculate the initial gas and oil in place from the compositions of the gas and liquid from the high pressure separator.

Given:

Reservoir pressure	4350 psia
Reservoir temperature	217°F
Hydrocarbon porosity	17.4 per cent
Std. cond.	15.025 psia, 60°F
Separator gas	842,600 SCF/day
Stock tank oil	31.1 STB/day
Mol. wt. C_7^+ in separator liquid	185.0
Sp. gr. C_7^+ in separator liquid	0.8343
Sp. gr. separator liquid at 880 psig and 60°F	0.7675
Separator liquid volume factor	1.235 bbl at 880 psia/STB, both at 60°F
Compositions of high-pressure gas and liquid	Cols. (2) and (3), Table 2.3
Molar volume at 15.025 psia and 60°F	371.2 cu ft/mole.

SOLUTION (column numbers refer to Table 2.3):

Table 2.3. CALCULATIONS FOR EXAMPLE 2.2 ON GAS-CONDENSATE FLUID

Table 2.3 (Continued from previous page)

(1)	Mole Composition of Separator Fluids (2) Gas	(3) Liquid	(4) Mol. wt.	(5) (3) × (4) lb/mole	(6) Liquid bbl/mole for Each Component	(7) (3) × (6) bbl of Each Component per Mole of sep. liq.	(8) Moles of Each Component in 59.11 Moles of Gas (2) × 59.11	(9) Moles of Each Component in 2.107 Moles of Liquid (3) × 2.107	(10) Moles of Each Component in 61.217 Moles of Gas and Liquid (8) + (9)	(11) Mole Composition of Total Well Fluid (10) ÷ 61.217	(12) Critical Pressure, psia	(13) Partial Critical Pressure, psia (11) × (12)	(14) Critical Temp. °R	(15) Partial Critical Temp. °R (11) × (14)
CO_2	0.0120	0.0000					0.709	0.0000	0.7090	0.0116	1070	12.41	548	6.36
C_1	0.9404	0.2024	16.04	3.247	0.1317	0.02666	55.587	0.4265	56.0135	0.9150	673	615.80	343	313.85
C_2	0.0305	0.0484	30.07	1.455	0.1771	0.00857	1.803	0.1020	1.9050	0.0311	708	22.02	550	17.11
C_3	0.0095	0.0312	44.09	1.376	0.2480	0.00774	0.562	0.0657	0.6277	0.0102	617	6.29	666	6.79
i–C_4	0.0024	0.0113	58.12	0.657	0.2948	0.00333	0.142	0.0238	0.1658	0.0027	529	1.43	735	1.98
n–C_4	0.0023	0.0196	58.12	1.139	0.2840	0.00557	0.136	0.0413	0.1773	0.0029	550	1.60	766	2.22
i–C_5	0.0006	0.0159	72.15	1.147	0.3298	0.00524	0.035	0.0335	0.0685	0.0011	484	0.53	830	0.91
n–C_5	0.0003	0.0170	72.15	1.227	0.3264	0.00555	0.018	0.0358	0.0538	0.0009	490	0.44	846	0.76
C_6	0.0013	0.0384	86.17	3.309	0.3706	0.01423	0.077	0.0809	0.1579	0.0026	440	1.14	914	2.38
C_7^+	0.0007	0.6158	185.0	113.923	0.6336*	0.39017	0.041	1.2975	1.3385	0.0219	300**	6.57	1227**	26.87
	1.0000	1.0000		127.480		0.46706	59.110	2.1070	61.2170	1.0000		668.23		379.23

*185 lb/mole ÷ (0.8343 × 350 lb/bbl) = 0.6336 bbl/mole.

**From Fig. 2.5, after Mathews, Roland, and Katz,[8] for Mol. wt. C_7^+ = 185 and sp. gr. = 0.8342.

1. Calculate the mole proportions in which to recombine the separator gas and liquid. Multiply the mole fraction of each component in the liquid, Col. (3), by its molecular weight, Col. (4), and enter the products in Col. (5). The sum of Col. (5) is the molecular weight of the separator liquid, 127.48. Since the specific gravity of the separator liquid is 0.7675 at 880 psig and 60°F, then the moles per barrel is

$$\frac{0.7675 \times 350 \text{ lb/bbl}}{127.48 \text{ lb/mole}} = 2.107 \text{ moles/bbl for the separator liquid}$$

The separator liquid rate is 31.1 STB/day × 1.235 sep. bbl/STB so that the separator gas-oil ratio is

$$\frac{842{,}600}{31.1 \times 1.235} = 21{,}940 \text{ SCF sep. gas/bbl sep. liquid}$$

Since the 21,940 SCF is 21,940/371.2, or 59.11 moles, the separator gas and liquid must be recombined in the ratio of 59.11 moles of gas to 2.107 moles of liquid.

If the specific gravity of the separator liquid is not available, the mole per barrel figure may be calculated as follows. Multiply the mole fraction of each component in the liquid, Col. (3), by its barrel per mole figure, Col. (6), obtained from data in Table 1.5 and enter the product in Col. (7). The sum of Col. (7), 0.46706 is the number of barrels of separator liquid per mole of separator liquid, and the reciprocal is 2.141 moles/bbl (versus 2.107 measured).

2. Recombine 59.11 moles of gas and 2.107 moles of liquid. Multiply the mole fraction of each component in the gas, Col. (2), by 59.11 moles, and enter in Col. (8). Multiply the mole fraction of each component in the liquid, Col. (3), by 2.107 moles, and enter in Col. (9). Enter the sum of the moles of each component in the gas and liquid, Col. (8) plus Col. (9), in Col. (10). Divide each figure in Col. (10) by the sum of Col. (10), 61.217, and enter the quotients in Col. (11), which is the mole composition of the total well fluid. Calculate the pseudocritical temperature, 379.23°R and pressure 668.23 psia from the composition as shown in Example 1.3. From the pseudocriticals find the pseudoreduced criticals, and then the deviation factor at 4350 psia and 217°F, which is 0.963.

3. Find the gas and oil (condensate) in place per acre-foot of net reservoir rock. From the gas law, the initial moles per acre-foot at 17.4 per cent hydrocarbon porosity is

$$\frac{pV}{zRT} = \frac{4350 \times (43{,}560 \times 0.174)}{0.963 \times 10.73 \times 677} = 4713 \text{ moles/ac-ft}$$

$$\text{Gas mole fraction} = \frac{59.11}{59.11 + 2.107} = 0.966$$

$$\text{Initial gas in place} = \frac{0.966 \times 4713 \times 371.2}{1000} = 1690 \text{ MCF/ac-ft}$$

$$\text{Initial oil in place} = \frac{(1 - 0.966) \times 4713}{2.107 \times 1.235} = 61.6 \text{ STB/ac-ft}$$

Since the high-pressure gas is 96.6 per cent of the total mole production, the daily gas-condensate production expressed in standard cubic feet is

$$\Delta G_p = \frac{\text{Daily hp gas}}{0.966} = \frac{842{,}600}{0.966} = 872{,}200 \text{ SCF/day}$$

The daily reservoir voidage at 4350 psia is

$$\Delta V = 872{,}200 \times \frac{677}{520} \times \frac{15.025}{4350} \times 0.963 = 3777 \text{ cu ft/day}$$

condensate reservoir from the analyses of the high pressure gas and liquid, assuming the well fluid is the same as the reservoir fluid. The calculation is the same as that shown in Example 2.1 except that the gas deviation factor of the reservoir fluid is found from the pseudoreduced temperature and pressure, which are determined from the composition of the total well fluid rather than its specific gravity. Figure 2.5 presents charts for estimating the pseudocritical temperature and pressure of the heptanes-plus fraction from its molecular weight and specific gravity.

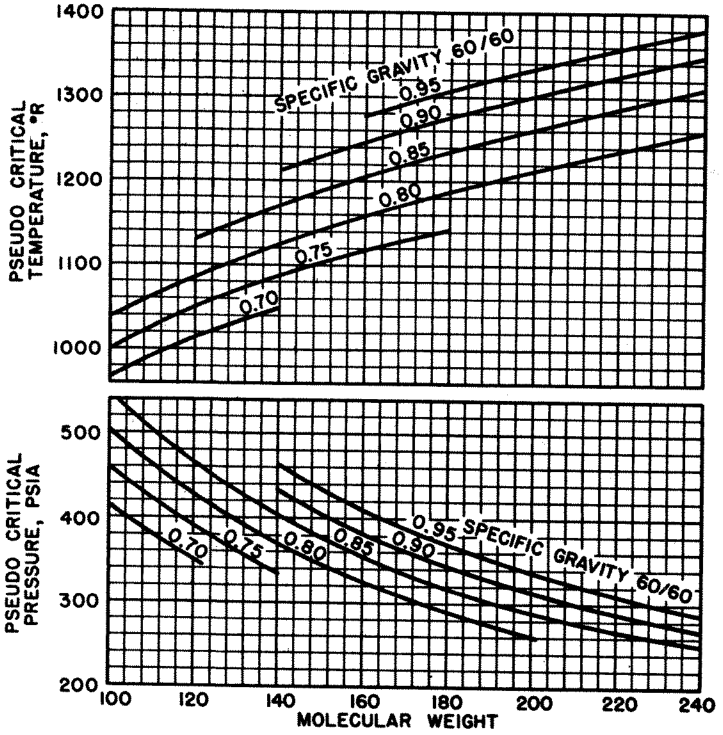

Fig. 2.5. Correlation charts for estimation of the pseudocritical temperature and pressure of heptanes plus fractions from molecular weight and specific gravity. (After Mathews, Roland, and Katz, *Proc.* NGAA.)

4. The Performance of Volumetric Retrograde Gas-Condensate Reservoirs. The behavior of single-phase gas and gas-condensate reservoirs has been treated in Chapter 1. Since no liquid phase develops within the reservoir, where the temperature is above the cricondentherm, the calculations are simplified. When the reservoir temperature is below the cricondentherm, however, a liquid phase develops within the reservoir as pressure declines below the dew point owing to retrograde condensation, and the treatment is considerably more complex, even for volumetric reservoirs.

One solution is to duplicate closely the reservoir depletion by laboratory studies on a representative sample of the initial, single-phase reservoir fluid. The sample is placed in a high-pressure cell at reservoir temperature and initial reservoir pressure. During the depletion, the volume of the cell is held constant to duplicate a volumetric reservoir, and care is taken to remove only gas-phase hydrocarbons from the cell, since for most reservoirs, the retrograde condensate liquid which forms is trapped as an immobile liquid phase within the pore spaces of the reservoir.

Laboratory experiments have shown that with most rocks the oil phase is essentially immobile until it builds up to a saturation in the range of 10 to 20 per cent of the pore space, depending upon the nature of the rock pore spaces and the connate water. As the liquid saturations for most retrograde fluids seldom exceed 10 per cent, this is a reasonable assumption for most retrograde condensate reservoirs. In this same connection it should be pointed out that, in the vicinity of the well bore, retrograde liquid saturations often build up to higher values so that there is two-phase flow, both gas and retrograde liquid. This build-up of liquid occurs as the one-phase gas suffers a pressure drop as it approaches the well bore. Continued flow increases the retrograde liquid saturation until there is liquid flow. Although this phenomenon does not affect the over-all performance seriously, or enter into the present performance predictions, it will (a) reduce, sometimes seriously, the flow rate of gas-condensate wells and (b) affect the accuracy of well samples which are taken assuming one-phase flow into the well bore.

The continuous depletion of the gas phase (only) of the cell at constant volume can be closely duplicated by the following more convenient technique. The content of the cell is expanded from the initial volume to a larger volume at a pressure a few hundred psi below the initial pressure by withdrawing mercury from the bottom of the cell, or otherwise increasing the volume. Time is allowed for equilibrium to be established between the gas phase and the retrograde liquid phase which has formed, and for the liquid to drain to the bottom of the cell so that only gas-phase hydrocarbons will be produced from the top of the cell. Mercury is injected into the bottom of the cell and gas removed at the top at such a rate so as to maintain constant pressure in the cell. Thus the volume of gas removed, measured at this lower pressure and cell (reservoir) temperature, equals the volume of mercury injected when the hydrocarbon volume, now two-phase, is returned to the initial cell volume. The volume of retrograde liquid is measured, and the cycle — expansion to a next lower pressure followed by the removal of a second increment of gas — is repeated down to any selected abandonment pressure. Each increment of gas removed is analyzed to find its composition, and the volume of each increment of produced gas is measured at subatmospheric pressure to determine the standard volume, using the ideal gas law. From this, the gas deviation factor at cell pressure and temperature may be calculated using the real gas law. Alternatively, the gas deviation factor at cell pressure and temperature may be calculated from the composition of the increment using the method of Example 1.3.

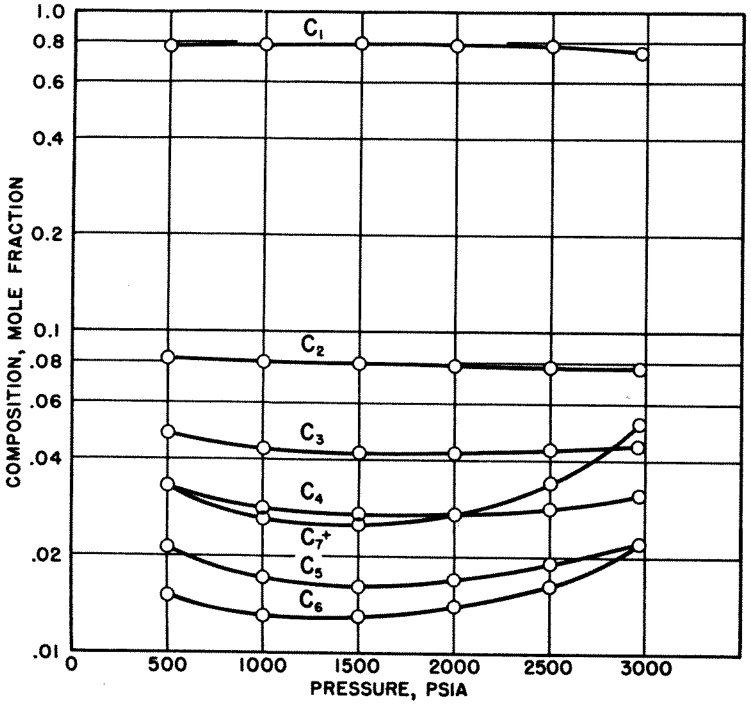

Fig. 2.6. Variations in the composition of the produced gas phase material of a retrograde gas-condensate fluid with pressure decline. (Data from Table 2.4.)

Figure 2.6 and Table 2.4 give the composition of a retrograde gas-condensate reservoir fluid at initial pressure, and the composition of the gas removed from a *PVT* cell in each of five increments, as previously described.

Table 2.4 also gives the volume of retrograde liquid in the cell at each pressure and the gas deviation factor and volume of the produced gas increments at cell pressure and temperature.

The liquid recovery from the gas increments produced from the cell may be measured by passing the gas through small-scale separators,[9] or it may be calculated from the composition for usual field separation methods,[10] or for gasoline plant methods.[11] Liquid recovery of the pentanes-plus will be somewhat greater in gasoline plants than by field separation, but much greater for the propanes and butanes, commonly called liquified petroleum gas, LPG. For simplicity, the liquid recovery from the gas increments of Table 2.4 is calculated in Example 2.3 assuming 25 per cent of

Example 2.3. Calculating the volumetric depletion performance of a retrograde gas-condensate reservoir based on the laboratory tests given in Table 2.4.

Given:

Initial pressure (dew point)	2960 psia
Abandonment pressure	500 psia
Reservoir temperature	195°F
Connate water	30 per cent
Porosity	25 per cent
Standard conditions	14.7 psia and 60°F
Initial cell volume	947.5 cu cm
Mol. wt. of C_7^+ in Initial Fluid	114 lb/lb-mole
Sp. gr. of C_7^+ in Initial Fluid	0.755 at 60°F

Compositions, volumes, and deviation factors given in Table 2.4.

Assume: The same mol. wt. and sp. gr. for the C_7^+ content for all produced gas.

Assume: Liquid recovery from the gas is 25 per cent of the butanes, 50 per cent of the pentane, 75 per cent of the hexane, and 100 per cent of the heptanes and heavier.

SOLUTION (column numbers refer to Table 2.5):

1. Calculate the increments of gross production in M SCF per acre-foot of net, bulk reservoir rock. Enter in Col. (2).

$$V_{HC} = 43{,}560 \times 0.25 \times (1 - 0.30) = 7623 \text{ cu ft/ac-ft}$$

For the increment produced from 2960 to 2500 psia, for example,

$$\Delta V = 7623 \times \frac{175.3 \text{ cu cm}}{947.5 \text{ cu cm}} = 1410 \text{ cu ft/ac-ft at 2500 psia and 195°F}$$

$$\Delta G_p = \frac{379.4\, p\Delta V}{1000\, zRT} = \frac{379.4 \times 2500 \times 1410}{1000 \times 0.794 \times 10.73 \times 655} = 240.1\text{M SCF}$$

Find the cumulative gross gas production, $G_p = \Sigma\, \Delta G_p$ and enter in Col. (3).

Table 2.4. Volume, Composition, and Gas Deviation Factors for a Retrograde Condensate Fluid

(1) Pressure psia	(2) C_1	(3) C_2	(4) C_3	(5) C_4	(6) C_5	(7) C_6	(8) C_7^+	(9) Produced Gas, cu cm at 195°F and Cell Pressure	(10) Retrograde Liquid Volume, cu cm Cell Volume, 947.5 cu cm	(11) Retrograde Volume, Per Cent of Hydrocarbon Volume	(12) Gas Deviation Factor at 195°F and Cell Pressure
	Composition of Produced Gas Increments, Mole Fraction										
2960	0.752	0.077	0.044	0.031	0.022	0.022	0.052	0.0	0.0	0.0	0.771
2500	0.783	0.077	0.043	0.028	0.019	0.016	0.034	175.3	62.5	6.6	0.794
2000	0.795	0.078	0.042	0.027	0.017	0.014	0.027	227.0	77.7	8.2	0.805
1500	0.798	0.079	0.042	0.027	0.016	0.013	0.025	340.4	75.0	7.9	0.835
1000	0.793	0.080	0.043	0.028	0.017	0.013	0.026	544.7	67.2	7.1	0.875
500	0.768	0.082	0.048	0.033	0.021	0.015	0.033	1080.7	56.9	6.0	0.945

Table 2.5. Gas and Liquid Recoveries in Per Cent and Per Acre-Foot for Example 2.3

(1) Pressure, psia	(2) Increments of Gross Gas Production, M SCF	(3) Cumulative Gross Gas Production, M SCF, Σ(2)	(4) Residue Gas in Each Increment, M SCF	(5) Cumulative Residue Gas Production, M SCF Σ(4)	(6) Liquid in Each Increment, bbl	(7) Cumulative Liquid Production, bbl Σ(6)	(8) Average Gas-Oil Ratio of Each Increment, SCF Residue Gas per bbl, (4) ÷ (6)	(9) Cumulative Gross Gas Recovery, per cent, (3) × 100/1580	(10) Cumulative Residue Gas Recovery, per cent, (5) × 100/1441	(11) Cumulative Liquid Recovery, per cent, (7) × 100/143.2
2960	0	0	0	0	0	0	10,600	0	0	0
2500	240.1	240.1	225.1	225.1	15.3	15.3	14,700	15.2	15.6	10.7
2000	245.2	485.3	232.3	457.4	13.1	28.4	17,730	30.7	31.7	19.8
1500	266.0	751.3	252.8	710.2	13.3	41.7	19,010	47.6	49.3	29.1
1000	270.8	1022.1	256.9	967.1	14.0	55.7	18,350	64.7	67.1	38.9
500	248.7	1270.8	233.0	1200.1	15.9	71.6	14,650	80.4	83.3	50.0

2. Calculate the M SCF of residue gas and the barrels of liquid obtained from each increment of gross gas production. Enter in Col. (4) and Col. (6). Assume that 0.25 C_4, 0.50 C_5, 0.75 C_6, and all C_7^+ is recovered as stock tank liquid. For example, in the 240.1M SCF produced from 2960 to 2500 psia, the mole fraction recovered as liquid is

$$\Delta n_L = 0.25 \times 0.028 + 0.50 \times 0.019 + 0.75 \times 0.016 + 0.034$$
$$= 0.0070 + 0.0095 + 0.0120 + 0.034 = 0.0625 \text{ mole fraction}$$

As the mole fraction also equals the volume fraction in gas, the M SCF recovered as liquid from 240.1M SCF is

$$\Delta G_L = 0.0070 \times 240.1 + 0.0095 \times 240.1 + 0.0120 \times 240.1 + 0.034 \times 240.1$$
$$= 1.681 + 2.281 + 2.881 + 8.163 = 15.006\text{M SCF}$$

This gas volume can be converted to gallons of liquid using the gal/M SCF figures of Table 1.5 for C_4, C_5 and C_6. The average of the iso and normal compounds is used for C_4 and C_5.

For C_7^+,

$$\frac{114 \text{ lb/lb-mole}}{0.3794\text{M SCF/lb-mole} \times 8.337 \text{ lb/gal} \times 0.755} = 47.71 \text{ gal/M SCF}$$

0.3794 is the molar volume at standard conditions of 14.7 psia and 60°F. Then the total liquid recovered from 240.1M SCF is 1.681 × 32.04 + 2.281 × 36.32 + 2.881 × 41.03 + 8.163 × 47.71 = 53.9 + 82.8 + 118.2 + 389.5 = 644.4 gal = 15.3 bbl. The residue gas recovered from the 240.1M SCF is 240.1 × (1 − 0.0625) = 225.1M SCF. Calculate the cumulative residue gas and stock tank liquid recoveries from Cols. (4) and (6) and enter in Cols. (5) and (7), respectively.

3. Calculate the gas-oil ratio for each increment of gross production in units of residue gas per barrel of liquid. Enter in Col. (8). For example, the gas-oil ratio of the increment produced from 2960 to 2500 psia is

$$\frac{225.1 \times 1000}{15.3} = 14{,}700 \text{ SCF/bbl}$$

4. Calculate the cumulative per cent recoveries of gross gas, residue gas, and liquid. Enter in Cols. (9), (10), and (11). The initial gross gas in place is

$$\frac{379.4\,pV}{1000\,zRT} = \frac{379.4 \times 2960 \times 7623}{1000 \times 0.771 \times 10.73 \times 655} = 1580\text{M SCF/ac-ft}$$

Of this, the liquid mole fraction is 0.088 and the total liquid recovery is 3.808 gal/M SCF of gross gas, which are calculated from the initial composition in the same manner as shown in Part 2 above. Then

$$G = (1 - 0.088) \times 1580 = 1441\text{M SCF residue gas/ac-ft}$$

$$N = \frac{3.808 \times 1580}{42} = 143.2 \text{ bbl/ac-ft}$$

At 2500 psia, then

$$\text{Gross gas recovery} = \frac{100 \times 240.1}{1580} = 15.2 \text{ per cent}$$

$$\text{Residue gas recovery} = \frac{100 \times 225.1}{1441} = 15.6 \text{ per cent}$$

$$\text{Liquid recovery} = \frac{100 \times 15.3}{143.2} = 10.7 \text{ per cent}$$

the butanes, 50 per cent of the pentanes, 75 per cent of the hexane, and 100 per cent of the heptanes-plus is recovered as liquid.

The results of the laboratory tests and calculations of Example 2.3 are plotted versus pressure in Fig. 2.7. The gas-oil ratio rises sharply from 10,060 SCF/bbl to about 19,000 SCF/bbl near 1600 psia. Maximum retrograde liquid and maximum gas-oil ratios do not occur at the same pressure because, as pointed out previously, the retrograde liquid volume is much larger than its equivalent obtainable stock tank volume, and there is more stock tank liquid in 6.0 per cent retrograde liquid volume at 500 psia than in 7.9 per cent at 1500 psia. Revaporization below 1600 psia helps to reduce the gas-oil ratio; however, there is some doubt that revaporization equilibrium is reached in the reservoir, and field gas-oil ratios generally remain higher than the predicted. Part of this is probably due to the lower separator efficiency of liquid recovery at the lower pressure and higher separator temperatures. Lower separator temperatures occur at higher wellhead pressures owing to the greater cooling of the gas by free expansion in flowing through the choke. Although the over-all recovery at 500 psia abandonment pressure is 80.4 per cent, the liquid recovery is only 50.0 per cent, owing to retrograde condensation. The cumulative production plots are slightly curved because of the variation in the gas deviation factor with pressure and with the composition of the reservoir fluid.

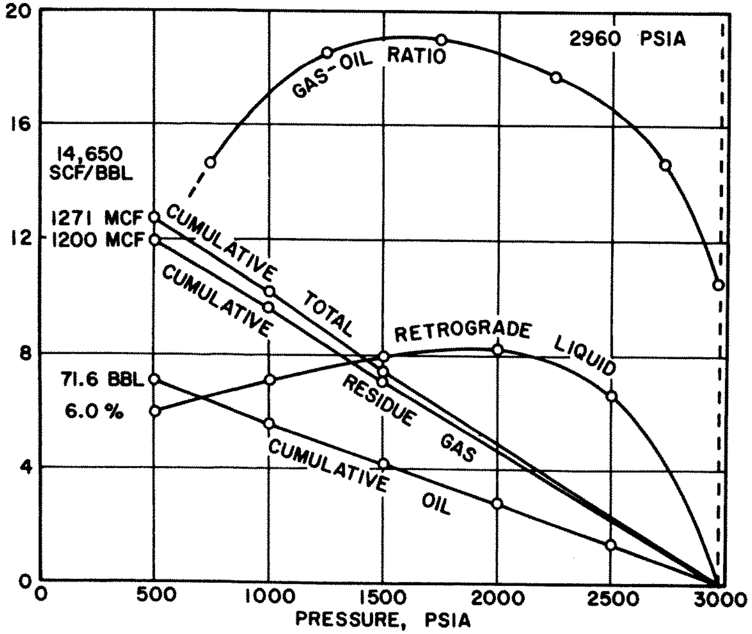

Fig. 2.7. Gas-oil ratios, retrograde liquid volumes, and recoveries for the depletion performance of a retrograde gas-condensate reservoir. (Data from Tables 2.4 and 2.5.)

The volumetric depletion performance of a retrograde condensate fluid, such as given in Example 2.3, may also be calculated from the initial composition of the single-phase reservoir fluid using *equilibrium ratios*. An equilibrium ratio (K) is the ratio of the mole fraction (y) of any component in the vapor phase to the mole fraction (x) of the same component in the liquid phase, or $K = y/x$. These ratios depend upon the temperature and pressure, and, unfortunately, upon the composition of the system. If a set of equilibrium ratios can be found which are applicable to a given condensate system, then it is possible to calculate the mole distribution between the liquid and vapor phases at any pressure, and reservoir temperature, and also, the composition of the separate vapor and liquid phases, as shown in Fig. 2.6. From the composition and total moles in each phase it is also possible to calculate with reasonable accuracy the liquid and vapor volumes, at any pressure.

The prediction of retrograde condensate performance using equilibrium ratios is a specialized technique. Standing[4] and Rodgers, Harrison, and Regier[9] give methods for adjusting published equilibrium ratio data for condensate systems to apply to systems of different compositions.[12,13,14,15] They also give step-by-step calculation methods for volumetric performance. These methods consist of starting with a unit volume of the initial reservoir vapor of known composition. An increment of vapor phase material is assumed to be removed from the initial volume at constant pressure, and the remaining fluid expanded to the initial volume. The final pressure, the division in volume between the vapor and retrograde liquid phases, and the individual compositions of the vapor and liquid phases are then calculated using the adjusted equilibrium ratios. A second increment of vapor is removed at the lower pressure, and the pressure, volumes, and compositions are calculated as before. An account is kept of the produced moles of each component so that the total moles of any component remaining at any pressure is known by subtraction from the initial. This calculation may be continued down to any abandonment pressure just as in the laboratory technique.

Standing[4] points out that the prediction of condensate reservoir performance from equilibrium ratios alone is likely to be in considerable error, and that some laboratory data should be available to check the accuracy of the adjusted equilibrium ratios. Actually, the equilibrium ratios are changing because the composition of the system remaining in the reservoir or cell changes. The changes in the composition of the heptanes-plus particularly affect the calculations. Rodgers, Harrison, and Regier[9] point out the need for improved procedures for developing the equilibrium ratios for the heavier hydrocarbons to improve the over-all accuracy of the calculation.

Jacoby, Koeller, and Berry[16] studied the phase behavior of eight mixtures of separator oil and gas from a lean gas-condensate reservoir at recombined ratios in the range of 2000 to 25,000 SCF/bbl and several temperatures in the range of 100 to 250°F. The results are useful in predicting the depletion performance of gas-condensate reservoirs for which laboratory studies are not available. They show that there is a gradual change in the surface production performance from the volatile oil to the rich gas-condensate type of reservoir and that a laboratory examination is necessary to distinguish between the dew-point and bubble-point reservoirs in the range of 2000 to 6000 SCF/bbl gas-oil ratios.

5. Use of Material Balances with Retrograde Condensate Reservoirs. The laboratory test on the retrograde condensate fluid in Example 2.3 is itself a material-balance study of the *volumetric* performance of the reservoir from which the sample was taken. The application of the basic data and the calculated data of Example 2.3 to a volumetric reservoir is straightforward. For example, suppose the reservoir had produced 12.05 MMM SCF of gross well fluid when the average reservoir pressure declined from 2960 psia initial to 2500 psia. According to Table 2.5 the recovery at 2500 psia under volumetric depletion is 15.2 per cent of the initial gross gas in place, and therefore the initial gross gas in place is

$$G = \frac{12.05 \times 10^9}{0.152} = 79.28\text{MMM SCF}$$

Since Table 2.5 shows a recovery of 80.4 per cent down to an abandonment pressure of 500 psia, the initial *recoverable* gross gas or the initial *reserve* is

$$\text{Initial reserve} = 79.28 \times 10^9 \times 0.804 = 63.74\text{MMM SCF}$$

Since 12.05MMM SCF has already been recovered, the *reserve* at 2500 psia is

$$\text{Reserve at 2500 psia} = 63.74 - 12.05 = 51.69\text{MMM SCF}$$

The accuracy of these calculations depends, among other things, upon the sampling accuracy and the degree to which the laboratory test represents the volumetric performance. Generally there are pressure gradients throughout a reservoir which indicate that the various portions of the reservoir are in different stages of depletion. This is due to greater withdrawals in some portions and/or to lower reserves in some portions, because of lower porosities and/or lower net productive thicknesses. As a consequence the gas-oil ratios of the wells will differ, and the average composition of the total reservoir production at any prevailing average reservoir pressure will not exactly equal the composition of the total cell production at the same pressure.

Although the gross gas production history of a volumetric reservoir will follow more or less closely the laboratory tests, the division of the production into residue gas and liquid will follow with less accuracy. This is due to the differences in the stage of depletion of various portions of the reservoir, as explained in the preceding paragraph, and also to the differences between the calculated liquid recoveries in the laboratory tests and the actual efficiency of separators in recovering liquid from the fluid in the field.

The previous remarks apply only to volumetric single-phase gas-condensate reservoirs. Unfortunately, most retrograde gas-condensate reservoirs which have been discovered are initially at their dew-point pressures, rather than above it. This indicates the presence of an oil zone in contact with the gas-condensate cap. The oil zone may be negligibly small or commensurate with the size of the cap; or it may be much larger. The presence of a small oil zone will affect the accuracy of the calculations based on the single-phase study, and is more serious for a larger oil zone. Where the oil zone is of a size at all commensurate with the gas cap, the two must be treated together as a two-phase reservoir, as explained in Chapter 4, Sec. 2.

Many gas-condensate reservoirs are produced under a partial or total water drive. When the reservoir pressure stabilizes or stops declining, as occurs in many reservoirs, the recovery will depend upon the value of the pressure at stabilization and the efficiency with which the invading water displaces the gas phase from the rock. The liquid recovery will be lower for the greater retrograde condensation, since the retrograde liquid is generally immobile and is trapped together with some gas behind the invading water front. This situation will be aggravated by permeability variations, as shown in Fig. 5.15, because the wells become "drowned" and are forced off production before the less permeable strata are depleted. In many cases the recovery by water drive will be less than by volumetric performance, as explained in Chapter 1, Sec. 12.

Where an oil zone is absent or negligible, the material balances, Eqs. (1.29) and (1.33), may be applied to retrograde reservoirs under both volumetric and water-drive performance just as for the single-phase (nonretrograde) gas reservoirs for which they were developed.

$$\frac{p_{sc}G_p}{T_{sc}} = \frac{p_iV_i}{z_iT} - \frac{p(V_i - W_e + B_wW_p)}{zT} \tag{1.29}$$

$$G(B_g - B_{gi}) + W_e = G_pB_g + B_wW_p \tag{1.33}$$

These equations may be used to find either the water influx W_e or the initial gas in place G, or its equivalent V_i from which G can be calculated. Both equations contain the gas deviation factor z at the lower pressure. It is included in the gas volume factor B_g in Eq. 1.33. Because this deviation factor applies to the gas-condensate fluid remaining in the reservoir, when the pressure is below the dew-point pressure, in retrograde reservoirs it is a *two-phase* gas deviation factor. The actual volume in Eq. (1.5) includes the volume of both the gas and liquid phases, and the ideal volume is calculated from the total moles of gas and liquid, assuming ideal gas behavior. For volumetric performance this two-phase deviation factor may be obtained from such laboratory data as obtained in Example 2.3. For example, from the data of Table 2.6 the cumulative gross gas production down to 2000 psia is 485.3M SCF/ac-ft out of an initial content of 1580.0M SCF/ac-ft. Since the initial hydrocarbon pore volume is 7623 cu ft/ac-ft, Example 2.3, the two-phase volume factor for the fluid remaining in the reservoir at 2000 psia and 195°F as calculated using the gas law is

$$z = \frac{379.4 \times pV}{(G - G_p)RT} = \frac{379.4 \times 2000 \times 7623}{(1580.0 - 485.3)10^3 \times 10.73 \times 655} = 0.752$$

Table 2.6 gives the two-phase gas deviation factors for the fluid remaining in the reservoir at pressures down to 500 psia, calculated as above for the gas-condensate fluid of Example 2.3. These data are not strictly applicable where there is some water influx, because it is based on cell performance in which vapor equilibrium is maintained between all of the gas and liquid remaining in the cell; whereas in the reservoir some of the gas and retrograde liquid are enveloped by the invading water, and are prevented from entering into equilibrium with the hydrocarbons in the rest of the reservoir. The deviation factors of Col. (4), Table 2.6 may be used with volumetric reservoirs, and, with some reduction in accuracy, with water-drive reservoirs.

Table 2.6. TWO-PHASE AND SINGLE-PHASE GAS DEVIATION FACTORS FOR THE RETROGRADE GAS-CONDENSATE FLUID OF EXAMPLE 2.3

(1)	(2)	(3)	(4)	(5)	(6)
			Gas Deviation Factors		
Pressure, psia	G_p[a] M SCF/ac-ft	$(G - G_p)$[a] M SCF/ac-ft	Two-phase[b]	Initial Gas[c]	Produced Gas[a]
2960	0.0	1580.0	0.771	0.780	0.771
2500	240.1	1339.9	0.768	0.755	0.794
2000	485.3	1094.7	0.752	0.755	0.805
1500	751.3	828.7	0.745	0.790	0.835
1000	1022.1	557.9	0.738	0.845	0.875
500	1270.8	309.2	0.666	0.920	0.945

[a] Data from Table 2.5 and Example 2.3.

[b] Calculated from the data of Table 2.5 and Example 2.3.

[c] Calculated from initial gas composition using correlation charts.

Where laboratory data such as given in Example 2.3 have not been obtained, the gas deviation factors of the initial reservoir gas may be used to approximate those of the remaining reservoir fluid. These are best measured in the laboratory, but may be estimated from the initial gas gravity or well-stream composition using the pseudoreduced correlations. While the measured deviation factors for the initial gas of Example 2.3 are not available, it is believed that they will be closer to the two-phase factors Col. (4) than those given in Col. (5) of Table 2.6, which are calculated using the pseudoreduced correlations, since the latter method presumes single-phase gases. The deviation factors of the produced gas phase are given in Col. (6) for comparison.

6. Comparison Between the Predicted and Actual Production Histories of Volumetric Condensate Reservoirs. Allen and Roe[14] have reported the performance of a retrograde condensate reservoir which pro-

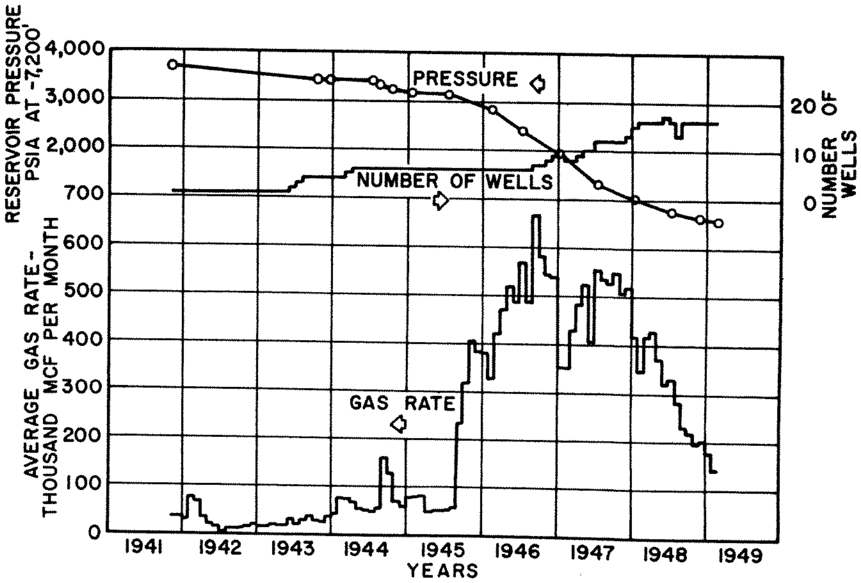

Fig. 2.8. Production history of the Bacon Lime Zone of an eastern Texas gas-condensate reservoir. (After Allen and Roe,[14] *Trans.* AIME.)

duces from the Bacon Lime Zone of a field located in East Texas. The production history of this reservoir is shown in Figs. 2.8 and 2.9. The reservoir occurs in the lower Glen Rose Formation of Cretaceous age at a depth of 7600 ft (7200 ft subsea), and comprises some 3100 acres. It is composed of approximately 50 ft of dense, crystalline, fossiliferous dolomite with an average permeability of 30 to 40 millidarcys in the more permeable stringers, and an estimated average porosity of about 10 per cent. Interstitial water is approximately 30 per cent. The reservoir temperature is 220°F and the initial pressure was 3691 psia at 7200 ft subsea. Since the reservoir was very heterogeneous regarding porosity and permeability, and since very poor communication between wells was observed, cycling (Sec. 7 and, Chapter 7, Sec. 8) was not considered feasible. The reservoir was therefore produced by pressure depletion, using three-stage separation to recover the condensate. The recovery at 600 psia was 20,500MM SCF and 830,000 bbl of condensate, or a cumulative (average) gas-oil ratio of 24,700 SCF/bbl, or 1.70 GPM (gallons per MCF). Since the initial gas-oil ratios were about 12,000 SCF/bbl (3.50 GPM), the condensate recovery at 600 psia was 100 × 1.7/3.5, or 48.6 per cent of the liquid originally contained in the produced gas. Theoretical calculations based on equilibrium ratios predicted a recovery of only 1.54 GPM (27,300 gas-oil ratio), or 44 per cent recovery, which is about 10 per cent lower.

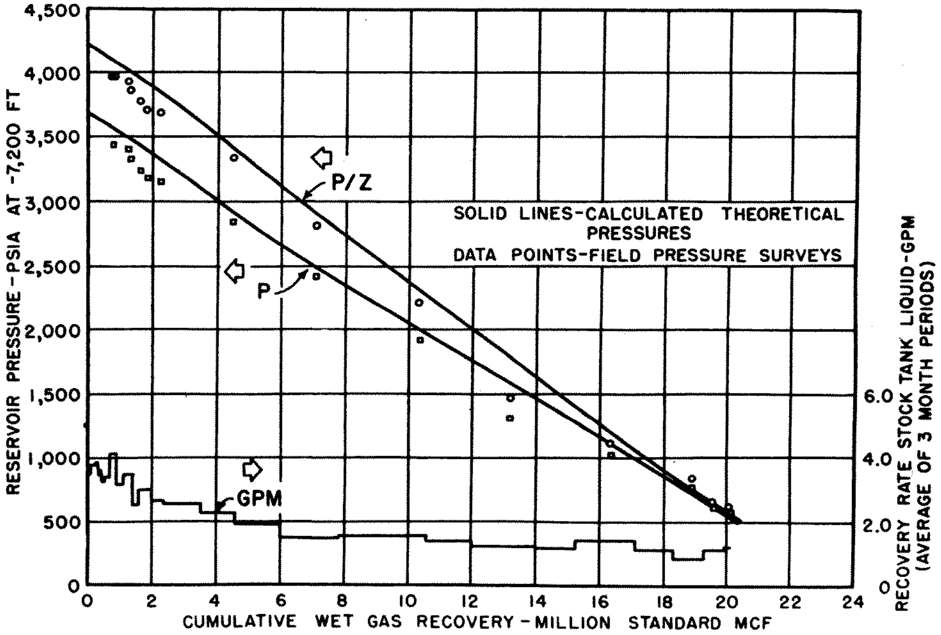

Fig. 2.9. Calculated and measured pressure and p/z values versus cumulative gross gas recovery from the Bacon Lime Zone of an eastern Texas gas-condensate reservoir. (After Allen and Roe,[14] *Trans.* AIME.)

The difference between the actual and predicted recoveries may have been due to sampling errors. The initial well samples may have been deficient in the heavier hydrocarbons owing to retrograde condensation of liquid from the flowing fluid as it approached the well bore (Sec. 2.4). Another possibility suggested by the authors is the omission of nitrogen as a constituent of the gas from the calculations. A small amount of nitrogen, always below one mole per cent, was found in several of the samples during the life of the reservoir. Finally, the authors suggest the possibility of retrograde liquid flow in the reservoir to account for a liquid recovery higher than that predicted by their theoretical calculations, which of course presume the immobility of the retrograde liquid phase. Considering the many variables which influence both the calculated recovery using equilibrium ratios and the field performance, the agreement between the two appears good.

Figure 2.10 shows good general agreement between the butanes-plus content calculated from the composition of the production from two wells and the content calculated from the study based on equilibrium ratios. The liquid content expressed in butanes-plus is of course higher than the stock tank GPM (Fig. 2.9) because not all of the butanes, nor, for that matter, all of the pentanes-plus are recovered in the field separators. The higher actual butanes-plus content down to 1600 psia is undoubtedly due

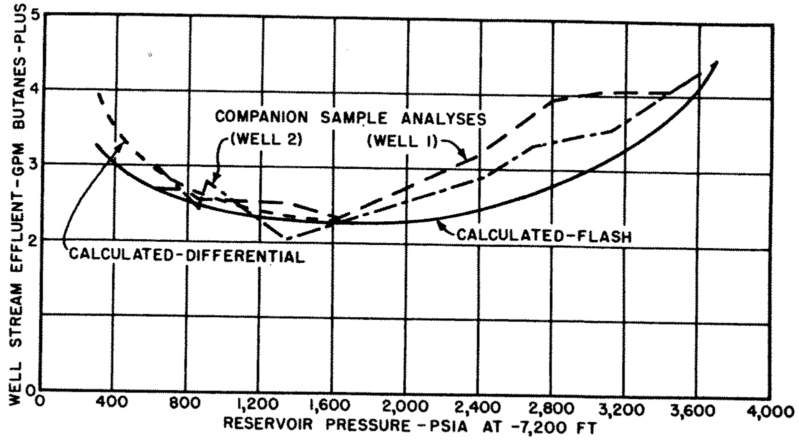

Fig. 2.10. Calculated and measured butanes-plus in the well streams of the Bacon Lime Zone of an eastern Texas gas-condensate reservoir. (After Allen and Roe,[14] *Trans.* AIME.)

to the same causes given in the preceding paragraph to explain why the actual over-all recovery of stock tank liquid exceeded the recovery based on equilibrium ratios. The stock tank GPM in Fig. 2.9 shows no revaporization; however, the well-stream compositions below 1600 psia in Fig. 2.10 clearly show revaporization of the butanes-plus, and therefore certainly of the pentanes-plus, which make up the majority of the separator liquid. The revaporization of the retrograde liquid in the reservoir below 1600 psia is evidently just about offset by the decrease in separator efficiency at lower pressures.

Figure 2.10 also shows a comparison between the calculated reservoir behavior based on the *differential process* and the *flash process*. In the *differential process* only the gas is produced and is therefore removed from contact with the liquid phase in the reservoir. In the *flash process* all of the gas remains in contact with the retrograde liquid, and for this to be so the volume of the system must increase as the pressure declines. Thus the differential process is one of constant volume and changing composition, and the flash process is one of constant composition and changing volume. Laboratory work and calculations based on equilibrium ratios are simpler with the flash process, where the over-all composition of the system remains constant; however, the reservoir mechanism for the volumetric depletion of retrograde condensate reservoirs is essentially a differential process. The laboratory work and the use of equilibrium ratios discussed in Sec. 4 approaches the differential process by a series of step-by-step flash processes. Figure 2.10 shows the close agreement between the flash and differential calculations down to 1600 psia. Below 1600 psia the well performance is closer to the differential calculations because the reservoir mechanism largely follows the differential process, provided that only gas phase materials are produced from the reservoir, i.e., the retrograde liquid is immobile.

Figure 2.11 shows the good agreement between the reservoir field data and the laboratory data for a small (one well), noncommercial, gas-condensate accumulation in the Paradox limestone formation at a depth of 5775 ft in San Juan County, Utah. This afforded the authors, Rodgers, Harrison, and Regier,[9] a unique opportunity to compare laboratory *PVT* studies and studies based on equilibrium ratios with actual field depletion under closely controlled and observed conditions. In the laboratory a 4000 cu cm cell was charged with representative well samples at reservoir temperature and initial reservoir pressure. The cell was pressure depleted so that only the gas phase was removed, and the produced gas was passed through miniature three-stage separators, which were operated at optimum field pressures and temperatures. The calculated performance was also obtained, as explained previously, from equations involving equilibrium ratios, assuming the differential process. The authors conclude that the model laboratory study can adequately reproduce and predict the behavior of condensate reservoirs. Also, they found that the performance can be calculated from the composition of the initial reservoir fluid, provided representative equilibrium ratios are available.

Table 2.7 shows a comparison between the initial compositions of the Bacon Lime and Paradox limestone formation fluids. The lower gas-oil ratios for the Bacon Lime are consistent with the much larger concentration of the pentanes and heavier in the Bacon Lime fluid.

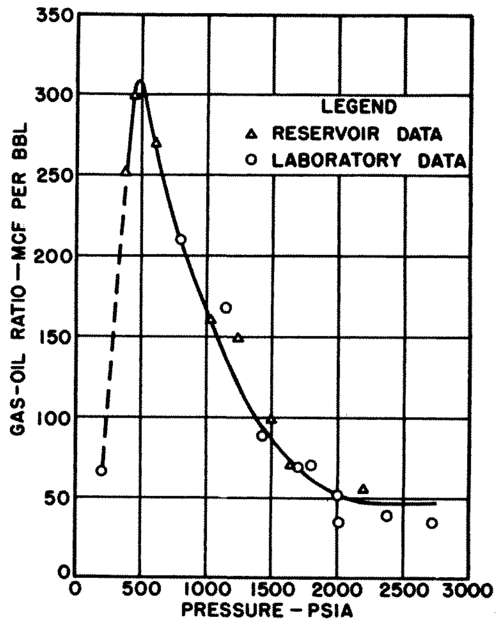

Fig. 2.11. Comparison of field and laboratory data for a Paradox limestone gas-condensate reservoir in Utah. (After Rodgers, Harrison, and Regier,[9] courtesy AIME.)

Table 2.7. COMPARISON OF THE COMPOSITIONS OF THE INITIAL FLUIDS IN THE BACON LIME AND PARADOX FORMATIONS

	Bacon Lime	*Paradox Formation*
Nitrogen	?	0.0099
Carbon dioxide	0.0135	0.0000
Methane	0.7690	0.7741
Ethane	0.0770	0.1148
Propane	0.0335	0.0531
Butane	0.0350	0.0230
Pentane	0.0210	0.0097
Hexane	0.0150	0.0054
Heptane-plus	0.0360	0.0100
	1.0000	1.0000
Mol. wt. C_7^+	130	116.4
Sp. gr. C_7^+ (60°F)	0.7615	0.7443

7. Cycling and Water Drive in Condensate Reservoirs. Because the liquid content of many condensate reservoirs is a valuable and important part of the accumulation, and because through retrograde condensation a large fraction of this liquid may be left in the reservoir at abandonment, the practice of gas cycling has been adopted in many condensate reservoirs. In gas cycling the condensate liquid is removed from the produced (wet) gas, usually in a gasoline plant, and the residue or dry gas is returned to the reservoir through injection wells. The injected gas maintains reservoir pressure and retards retrograde condensation. At the same time it drives the wet gas toward the producing wells. Because the removed liquids represent part of the wet gas volume, unless additional dry (make-up) gas is injected, reservoir pressure will decline slowly. At the conclusion of cycling, i.e., when the producing wells have been invaded by the dry gas, the reservoir is then pressure depleted (blown down) to recover the gas plus some of the remaining liquids from the portions not swept.

Although cycling appears to be an ideal solution to the retrograde condensate problem, there are a number of practical considerations which make it less attractive. First, there is the deferred income from the sale of the gas, which may not be produced for ten to twenty years. For example, the present worth of gas produced 15 years hence, discounted at five per cent, is less than fifty per cent. Second, cycling requires additional expenditures, usually some more wells, a gas compression and distribution system to the injection wells, and a liquid recovery plant. Third, it must be realized that even where reservoir pressure is maintained above the dew point, the liquid recovery by cycling may be considerably less than 100 per cent.

Cycling recoveries may be broken down into three separate recovery factors or efficiencies. When dry gas displaces wet gas within the pores of the reservoir rock, the microscopic *displacement* efficiency is in the range of 70 to 90 per cent. Then, owing to the location and flow rates of the production and injection wells, there are areas of the reservoir which are not swept by dry gas at the time the producing wells have been invaded by dry gas, resulting in *sweep* efficiencies in the range of 50 to 90 per cent; i.e., 50 to 90 per cent of the initial pore volume is invaded by dry gas. Sweep efficiencies are commonly measured by potentiometric model studies (Chapter 7, Sec. 8). Finally, many reservoirs are stratified in such a way that some stringers are much more permeable than others, so that the dry gas sweeps through them quite rapidly. While much wet gas remains in the lower permeability (tighter) stringers, dry gas will have entered the producing wells in the more permeable stringers, eventually reducing the liquid content of the gas to the plant to an unprofitable level.

Now suppose a particular gas condensate reservoir has a displacement efficiency of 80 per cent, a sweep efficiency of 80 per cent and a permeability stratification factor of 80 per cent. The product of these separate factors gives an over-all condensate recovery by cycling of 51.2 per cent. Under these conditions cycling may not be particularly attractive, since retrograde condensate losses by depletion performance seldom exceed 50 per cent.

However, during pressure depletion (blow down) of the reservoir following cycling, some additional liquid may be recovered from both the swept and unswept portions of the reservoir. Also, liquid recoveries of propane and butane in gasoline plants are much higher than those from stage separation or low temperature separation, which would be used if cycling is not adopted. From what has been said, it is evident that whether to cycle is a problem whose many aspects must be carefully studied before a proper decision can be reached.

Cycling is also adopted in nonretrograde gas caps overlying oil zones, particularly where the oil is itself underlain by an active body of water. If the gas cap is produced concurrently with the oil, as the water drives the oil zone into the shrinking gas cap zone, unrecoverable oil will remain not only in the original oil zone but also in that portion of the gas cap invaded by the oil. On the other hand, if the gas cap is cycled at essentially initial pressure, the active water drive will displace the oil into the producing oil wells with maximum recovery. In the meantime some of the valuable liquids from the gas cap may be recovered by cycling. Additional benefit will accrue, of course, if the gas cap is retrograde. Even where water drive is absent, the concurrent depletion of the gas cap and the oil zone results in lowered oil recoveries; and increased oil recovery is had by depleting the oil zone first and allowing the gas cap to expand and sweep through the oil zone.

When gas-condensate reservoirs are produced under an active water drive such that reservoir pressure declines very little below the initial pressure, there is little or no retrograde condensation and the gas-oil ratio of the production remains substantially constant. The recovery will be the same as in nonretrograde gas reservoirs under the same conditions, and will depend upon (a) the initial connate water, S_{wi}, (b) the residual gas saturation, S_{gr}, in the portion of the reservoir invaded by water, and (c) the fraction, F, of the initial reservoir volume invaded by water. As the gas volume factor B_{gi} in SCF/cu ft remains substantially constant because reservoir pressure does not decline, the fractional recovery is

$$\text{Recovery} = \frac{V_i\phi(1 - S_{wi} - S_{gr})B_{gi}F}{V_i\phi(1 - S_{wi})B_{gi}} = \frac{(1 - S_{wi} - S_{gr})F}{(1 - S_{wi})} \tag{2.4}$$

where V_i is the initial gross reservoir volume, S_{gr} is the residual gas saturation in the flooded area, S_{wi} is the initial connate water saturation, and F is the fraction of the total volume invaded. Table 1.8 shows that residual gas saturations lie in range of 20 to 50 per cent following water displacement. The fraction of the total volume invaded at any time or at abandonment depends primarily upon well location and the effect of permeability stratification in edge-water drives; and primarily upon well spacing and the degree of water coning in bottom water drives.

Table 2.8 shows the recovery factors calculated from Eq. (2.4) assuming

Table 2.8. RECOVERY FACTORS FOR COMPLETE WATER-DRIVE RESERVOIRS BASED ON EQ. (2.4)

S_{gr}	S_w	$F = 40$	$F = 60$	$F = 80$	$F = 90$	$F = 100$
20	10	31.1	46.7	62.2	70.0	77.8
	20	30.0	45.0	60.0	67.5	75.0
	30	28.6	42.8	57.1	64.3	71.4
	40	26.7	40.0	53.4	60.0	66.7
30	10	26.7	40.0	53.4	60.0	66.7
	20	25.0	37.5	50.0	56.3	62.5
	30	22.8	34.3	45.7	51.4	57.1
	40	20.0	30.0	40.0	45.0	50.0
40	10	22.2	33.3	44.4	50.0	55.6
	20	20.0	30.0	40.0	45.0	50.0
	30	17.1	25.7	34.2	38.5	42.8
	40	13.3	20.0	26.6	30.0	33.3
50	10	17.7	26.6	35.5	40.0	44.4
	20	15.0	22.5	30.0	33.8	37.5
	30	11.4	17.1	22.8	25.7	28.5
	40	6.7	10.0	13.6	15.0	16.7

a reasonable range of values for the connate water, residual gas saturation, and the fractional invasion by water at abandonment. The recovery factors apply equally to gas and gas-condensate reservoirs since under active water drive there is no retrograde loss.

Table 2.9 shows a comparison of gas-condensate recovery for the reservoir of Example 2.3 by (a) volumetric depletion, (b) water drive at initial pressure of 2960 psia, and (c) partial water drive where the pressure stabilizes at 2000 psia. The initial gross fluid, gas, and condensate, and the recoveries by depletion performance at an assumed abandonment pressure of 500 psia are obtained from Example 2.3 and Tables 2.4 and 2.5. Under complete water drive the recovery is 57.1 per cent for a residual gas saturation of 20 per cent, a connate water of 30 per cent, and a fractional invasion of 80 per cent at abandonment, as may be found by Eq. (2.4) or Table 2.8. As there is no retrograde loss, this figure applies equally to the gross gas, gas, and condensate recovery.

Where a partial water drive exists and the reservoir pressure stabilizes at some pressure, here 2000 psia, the recovery is approximately the sum of the recovery by pressure depletion down to the stabilization pressure, plus the recovery of the remaining fluid by complete water drive at the stabilization pressure. As the retrograde liquid at the stabilization pressure is immobile, it will be enveloped by the invading water, and the residual hydrocarbon saturation (gas plus retrograde liquid) will be about the same as for gas alone, or 20 per cent for this example. The recovery figures of Table 2.9 by depletion down to 2000 psia are obtained from Table 2.5. The additional recovery by water drive at 2000 psia may be explained using the figures of

Table 2.9. COMPARISON OF GAS-CONDENSATE RECOVERY BY VOLUMETRIC PERFORMANCE, COMPLETE WATER DRIVE, AND PARTIAL WATER DRIVE

(Based on the data of Tables 2.4 and 2.5 and Example 2.3. S_w = 30 per cent; $S_{gr} = S_{or} + S_{gr}$ = 20 per cent; F = 80 per cent.)

Recovery Mechanism	Condensate Recovery		Gas Recovery		Gross Recovery	
	bbl/ac-ft	per cent	MCF/ac-ft	per cent	MCF/ac-ft	per cent
Initial in-place	143.2	100.0	1441	100.0	1580	100.0
Depletion to 500 psia	71.6	50.0	1200	83.3	1271	80.4
Water drive at 2960 psia	81.8	57.1	823	57.1	902	57.1
(a) Depletion to 2000 psia	28.4	19.8	457	31.7	485	30.7
(b) Water drive at 2000 psia	31.2	21.8	553	38.4	584	37.0
Total by partial water drive, (a) + (b)	59.6	41.6	1010	70.1	1069	67.7

Table 2.10. At 2000 psia the retrograde condensate volume is 625 cu ft/ac-ft, or 8.2 per cent of the initial hydrocarbon pore volume of 7623 cu ft/ac-ft, 8.2 per cent being found from the *PVT* data given in Table 2.4. If the residual hydrocarbon (both gas and condensate) saturation after water invasion is assumed to be 20 per cent, as previously assumed for the residual gas saturation by complete water drive, the water volume after water drive is 80 per cent of 10,890, or 8712 cu ft/ac-ft. Of the remainder, i.e., 2178 cu ft/ac-ft, since the pressure is assumed to stabilize at 2000 psia, 8.2 per cent or 625 cu ft/ac-ft will be condensate liquid and 1553 free gas. The reservoir vapor at 2000 psia prior to water drive is

Table 2.10. Volumes of Water, Gas, and Condensate in One Acre-foot of Bulk Rock for the Reservoir of Example 2.3

	Initial Reservoir Volumes, cu ft/ac-ft	*Volumes After Depletion to 2000 psia cu ft/ac-ft*	*Volumes After Water Drive at 2000 psia cu ft/ac-ft*
Water	3267	3267	8712
Gas	7623	6998	1553
Condensate	....	625	625
Total	10,890	10,890	10,890

$$\frac{2000 \times 6998 \times 379.4}{1000 \times 0.805 \times 10.73 \times 655} = 938.5\text{M SCF/ac-ft}$$

The fractional recovery of this vapor phase by complete water drive at 2000 psia is

$$\frac{6998 - 1553}{6998} = 0.778 \text{ or } 77.8 \text{ per cent}$$

If $F = 0.80$ — or only 80 per cent of each acre-foot, on the average, is invaded by water at abandonment — the over-all recovery reduces to 0.80 × 0.778, or 62.2 per cent of the vapor content at 2000 psia, or 584M SCF/ac-ft. Table 2.5 indicates that at 2000 psia the ratio of gross gas to residue gas, after separation, is 245.2 to 232.3, and that the gas-oil ratio on a residue gas basis is 17,730 SCF/bbl. Then 584M SCF of gross gas contains residue gas in the amount of

$$584 \times \frac{232.3}{245.2} = 553\text{M SCF/ac-ft}$$

and tank or surface condensate liquid in the amount of

$$\frac{553 \times 1000}{17{,}730} = 31.2 \text{ bbl/ac-ft}$$

Table 2.9 indicates that for the gas-condensate reservoir of Example 2.3, using the assumed values for F and S_{gr}, best over-all recovery is obtained by straight depletion performance. Best condensate recovery is by active water drive since no retrograde liquid forms. The value of the products obtained depends, of course, upon the relative unit prices at which the gas and condensate are sold.

PROBLEMS

2.1. A gas-condensate reservoir initially contains 1300M SCF of residue (dry or sales gas) per acre-foot and 115 bbl of condensate. Gas recovery is calculated to be 85 per cent and condensate recovery 58 per cent by depletion performance. Calculate the value of the initial gas and condensate reserves per acre-foot if the condensate sells for \$2.50 per barrel and the gas sells for 20 cents per thousand standard cubic feet. *Ans:* \$221.00, \$166.75.

2.2. A well produces 45.3 bbl of condensate and 742M SCF of sales gas daily. The condensate has a molecular weight of 121.2 and a gravity of 52.0° API at 60°F.

(a) What is the gas-oil ratio on a dry gas basis? *Ans:* 16,380.
(b) What is the liquid content expressed in barrels per million standard cubic feet on a dry gas basis? *Ans:* 61.1.
(c) What is the liquid content expressed in GPM on a dry gas basis? *Ans:* 2.57.
(d) Repeat parts (a), (b), and (c) expressing the figures on a wet or gross gas basis. *Ans:* 17,200, 58.1, and 2.44.

2.3. The initial daily production from a gas-condensate reservoir is 186 bbl of condensate, 3750M SCF of high pressure gas, and 95M SCF of stock tank gas. The tank oil has a gravity of 51.2° API at 60°F. The specific gravity of the separator gas is 0.712 and of the stock tank gas, 1.30. The initial reservoir pressure is 3480 psia and reservoir temperature is 220°F. Average hydrocarbon porosity is 17.2 per cent. Assume standard conditions of 14.7 psia and 60°F.

(a) What is the average gravity of the produced gases? *Ans:* 0.727.
(b) What is the initial gas-oil ratio? *Ans:* 20,700.
(c) Estimate the molecular weight of the condensate. *Ans:* 134.3.
(d) Calculate the specific gravity (air = 1.00) of the total well production. *Ans:* 0.866.
(e) Calculate the gas deviation factor of the initial reservoir fluid (vapor) at initial reservoir pressure. *Ans:* 0.865.
(f) Calculate the initial moles in place per acre-foot. *Ans:* 4131.
(g) Calculate the mole fraction which is gas in the initial reservoir fluid. *Ans:* 0.964.
(h) Calculate the initial (sales) gas and condensate in place per acre-foot. *Ans:* 1511 and 73.0.

2.4. (a) Calculate the gas deviation factor for the gas-condensate fluid whose composition is given in Table 2.1 at 5820 psia and 265°F. Use the critical values of C_8 for the C_7^+ fraction. *Ans:* 1.072.

(b) If half of the butanes and all of the pentanes and heavier are recovered as liquids, calculate the gas-oil ratio of the initial production. Compare with the measured gas-oil ratio. *Ans:* 15,300.

2.5. Calculate the composition of the reservoir retrograde liquid at 2500 psia for the data of Tables 2.4 and 2.5 and Example 2.3. Assume the molecular weight of the heptanes-plus fraction is the same as for the initial reservoir fluid. *Ans:* $C_1 - C_7^+$; 0.405; 0.077; 0.055; 0.065; 0.056; 0.089; 0.253.

2.6. Estimate the gas and condensate recovery for the reservoir of Example 2.3 under partial water drive, if reservoir pressure stabilizes at 2500 psia. Assume a residual hydrocarbon saturation of 20 per cent and $F = 52.5$ per cent. *Ans:* 681.1M SCF/ac-ft; 46.3 bbl/ac-ft.

2.7. Calculate the recovery factor by cycling in a condensate reservoir if the displacement efficiency is 85 per cent, the sweep efficiency is 65 per cent, and the permeability stratification factor is 60 per cent. *Ans:* 0.332.

2.8. The following data are taken from a study on a recombined sample of separator gas and separator condensate in a *PVT* cell with an initial hydrocarbon volume of 3958.14 cu cm. The wet gas GPM and the residue gas-oil ratios were calculated using equilibrium ratios for production through a separator operating at 300 psia and 70°F. The initial reservoir pressure was 4000 psia, which was also close to the dew-point pressure, and reservoir temperature is 186°F.

Composition in Mole Per Cent

Pressure, psia	4000	3500	2900	2100	1300	605
CO_2	0.18	0.18	0.18	0.18	0.19	0.21
N_2	0.13	0.13	0.14	0.15	0.15	0.14
C_1	67.72	63.10	65.21	69.79	70.77	66.59
C_2	14.10	14.27	14.10	14.12	14.63	16.06
C_3	8.37	8.25	8.10	7.57	7.73	9.11
i-C_4	0.98	0.91	0.95	0.81	0.79	1.01
n-C_4	3.45	3.40	3.16	2.71	2.59	3.31
i-C_5	0.91	0.86	0.84	0.67	0.55	0.68
n-C_5	1.52	1.40	1.39	0.97	0.81	1.02
C_6	1.79	1.60	1.52	1.03	0.73	0.80
C_7^+	6.85	5.90	4.41	2.00	1.06	1.07
	100.00	100.00	100.00	100.00	100.00	100.00
Mol. wt. C_7^+	143	138	128	116	111	110
Gas deviation factor for wet gas at 186°F	0.867	0.799	0.748	0.762	0.819	0.902
Wet gas production, cu cm at cell *P* and *T*	0	224.0	474.0	1303	2600	5198
Wet gas GPM (calculated)	5.254	4.578	3.347	1.553	0.835	0.895
Residue gas-oil ratio	7,127	8,283	11,621	26,051	49,312	45,872
Retrograde liquid, per cent of cell volume	0	3.32	19.36	23.91	22.46	18.07

(a) Based on an initial reservoir content of 1.00MM SCF of wet gas, calculate the wet gas, residue gas, and condensate recovery by pressure depletion for each pressure interval. *Ans:* For 4000–3500 psia, 53.71M SCF, 48.46M SCF, and 5.85 bbl.

(b) Calculate the dry gas and condensate initially in place in 1.00MM SCF of wet gas. *Ans:* 891.6M SCF, 125.1 bbl.

(c) Calculate the cumulative recovery and per cent recovery of wet gas, residue gas, and condensate by depletion performance at each pressure. *Ans:* at 605 psia, 767.5M SCF, 739.2M SCF, and 29.7 bbl; 76.74, 82.90, and 23.74 per cent.

(d) Place the recoveries at an abandonment pressure of 605 psia on an acre-foot basis for a porosity of 10 per cent and a connate water of 20 per cent. *Ans:* 675M SCF, 650M SCF, and 26.14 bbl.

2.9. If the retrograde liquid for the reservoir of Prob. 8 becomes mobile at 15 per cent retrograde liquid saturation, what effect will this have on the condensate recovery?

2.10. If the initial pressure of the reservoir of Prob. 8 had been 5713 psia with the dew-point at 4000 psia, calculate the additional recovery of wet gas, residue gas, and condensate per acre-foot. The gas deviation factor at 5713 psia is 1.107 and the GPM and GOR between 5713 and 4000 psia are the same as at 4000 psia. *Ans:* 104M SCF, 92.7M SCF, and 13.0 bbl.

2.11. Calculate the value of the products by each mechanism in Table 2.9 assuming (a) \$2.00 per barrel for condensate and 10 cents per M SCF for gas; (b) \$2.50 per barrel and 20 cents per M SCF; and \$2.50 per barrel and 30 cents per M SCF.

2.12. In a *PVT* study of a gas-condensate fluid 17.5 cu cm of wet gas (vapor) measured at cell pressure of 2500 psia and temperature of 195°F was displaced into an evacuated low-pressure receiver of 5000 cu cm volume which was maintained at 250°F to insure that no liquid phase developed in the expansion. If the pressure of the receiver rose to 620 mm Hg, what is the deviation factor of the gas in the cell at 2500 psia and 195°F, assuming the gas in the receiver behaved ideally? *Ans:* 0.790.

2.13. Using the assumptions of Example 2.3 and the data of Table 2.4, show that the condensate recovery between 2000 and 1500 psia is 13.3 bbl/ac-ft and the residue gas-oil ratio is 19,010 SCF/bbl.

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