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The New, Generalized Material Balance as an Equation of a Straight Line: Part 2—Applications to Saturated and Non-Volumetric Reservoirs

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ABSTRACT

This paper is the second in a two-part series of papers which features practical applications of the generalized material-balance equation. Applications to initially-saturated and non-volumetric reservoirs are discussed in this paper (Part 2); applications to initially-undersaturated, volumetric reservoirs are discussed in Part 1. Graphical methods to estimate the original oil and gas in-place are presented. The graphical methods are general and are applicable to the full range of reservoir fluids of interest. Example calculations are carried out for gas-cap and water-influx reservoirs. These examples, along with those discussed in Part 1, demonstrate the extraordinary power of the generalized material-balance equation.*

INTRODUCTION

We continue the work started in Part 1[1] by considering applications of the generalized material-balance equation[2] (GMBE) to initially-saturated and non-volumetric reservoirs. Initially-saturated reservoirs include, but are not restricted to, gas-cap reservoirs. Non-volumetric reservoirs include, but are not restricted to, water-influx reservoirs. The end-product of this work is to demonstrate that straight-line methods offered herein are applicable to the full range of reservoir fluids and to a wide range of reservoir conditions. The consequences of ignoring volatilized-oil are also the focus of this work. Volatilized-oil is the stock-tank oil content of the free reservoir gas-phase. Because our nomenclature purposely follows Havlena and Odeh's,[3] virtually all of their algebraic rearrangements of the conventional material-balance equation (CMBE) are equally valid to our work; however, unlike their work, our work is applicable to the full range of reservoir fluids—including volatile-oils and gas-condensates.

For purposes of illustration, we examine a reservoir containing a volatile-oil. The system properties are identical to those discussed in Part 1 except we now extend our study to gas-cap and water-drive systems. Thus, all of the specific conditions noted in Part 1 also apply here. Although we restrict our attention to a volatile-oil system, our conclusions are generic and apply equally well to gas-condensate systems. The extraordinary power of the GMBE will become evident in the examples we consider.

Our approach to study the GMBE is to: (1) consider an example volatile-oil reservoir fluid, (2) develop an equation-of-state (EOS) fluid property description to accurately model its phase behavior, (3) carry out numerical PVT experiments to determine the necessary fluid properties such as B_o, B_g, R_s, and R_v, (4) carry out numerical simulations to predict the performance of different hypothetical reservoirs, and (5) apply graphical methods to estimate the OOIP and OGIP and compare these estimates with the actual OOIP and OGIP. The example reservoirs we study include gas-cap and water-influx reservoirs. All EOS computations carried out here use the Zudkevitch-Joffe[4] modification of the Redlich-Kwong[5] EOS; all reservoir performance simulations use the numerical model[6] discussed in Part 1.

Collectively, these works (Parts 1 and 2) complete the search for a general, straight-line method to estimate the OOIP and OGIP in a reservoir without restrictions on fluid composition. They lead to a new and improved method to analyze reservoir performance. Together with Walsh's work,[2] they lead to a complete and comprehensive understanding of the influence of phase behavior on reservoir performance. They also provide a new, improved, and innovative way to teach reservoir engineering.

MATHEMATICAL DEVELOPMENT

The GMBE is derived in Part 1; for convenience, we re-state it here:

$$F = N_{foi} E_o + G_{fgi} E_g + \Delta W \tag{1}$$

where N_{foi} is the stb of stock tank oil originally in the free oil phase and G_{fgi} is the scf of surface gas originally in the free gas

* References and illustrations at end of paper.

phase. N_{foi} and G_{fgi} are constants, whereas F, E_o, E_g and ΔW are a functions of reservoir pressure and are given by:

$$F = N_p\left[\frac{B_o(1-R_vR_{ps})+(R_{ps}-R_s)B_g}{(1-R_vR_s)}\right] \tag{2a}$$

$$E_o = \frac{(B_o-B_{oi})+B_g(R_{si}-R_s)+R_v(B_{oi}R_s-B_oR_{si})}{(1-R_vR_s)} \tag{2b}$$

$$E_g = \frac{(B_g-B_{gi})+B_o(R_{vi}-R_v)+R_s(B_{gi}R_v-B_gR_{vi})}{(1-R_vR_s)} \tag{2c}$$

and ΔW is the net change in the reservoir water volume. The quantities F, E_o, E_g, and ΔW are typically expressed in units of RB, RB/stb, RB/scf, and RB, respectively. The remaining variables in Eqn. (2) are defined in the nomenclature. Our nomenclature agrees with Havlena and Odeh's[3] except they defined F to be the total fluid withdrawal and we define F to be the total hydrocarbon fluid withdrawal. We adopt this difference to emphasize the important distinction between hydrocarbon and water withdrawal (ΔW). See Part 1. Eqn. (2) is valid if and only if the reservoir fluid is saturated. If the reservoir fluid is undersaturated, Eqn. (2) can be greatly simplified and the resulting simplifications are presented and discussed in Part 1.

The GMBE is quite general and applies to any reservoir fluid and to any distribution of water-, oil-, and gas-phases at any time. Its limitations and assumptions are discussed elsewhere.[2] A companion paper (Part 1) discusses the application of Eqns. (1) and (2) to initially-undersaturated, volumetric reservoirs. This paper (Part 2) is restricted to a discussion of initially-saturated and non-volumetric reservoirs.

INITIALLY-SATURATED, VOLUMETRIC RESERVOIRS

First, consider the case of an initially-saturated, volumetric reservoir. As an example consider a gas-cap reservoir subject to no water influx or production. In this case, ΔW=0 and, if Eqn. (1) is divided by E_o, it becomes

$$\frac{F}{E_o} = N_{foi} + G_{fgi}\frac{E_g}{E_o} \tag{3}$$

Eqn. (3) reveals that a plot of F/E_o vs. E_g/E_o yields a straight line whose slope is G_{fgi} and whose y-intercept is N_{foi}. Havlena and Odeh[3] derived a very similar result. However, their definitions of F, E_o, and E_g applied only to black-oils and dry-gases, whereas our definitions via Eqn. (2) apply without restriction to the full range of reservoir fluids of interest, including volatile-oils and gas-condensates.

Note that N_{foi} does not represent the total OOIP (N), but only a portion of the total OOIP. In general, the OOIP is given by

$$N = N_{foi} + N_{fgi} \tag{4}$$

where N_{fgi} represents the stb of oil in the original (initial) free gas-phase. Similarly, the total OGIP (G) is given by

$$G = G_{foi} + G_{fgi} \tag{5}$$

where G_{foi} is the scf of gas in the initial free oil-phase. The amount of oil in the free gas-phase N_{fgi} is related to the amount of gas in the free gas-phase G_{fgi} by $N_{fgi}=G_{fgi}R_{vi}$. Substituting this relation into Eqn. (4) for N_{fgi} gives

$$N = N_{foi} + G_{fgi}R_{vi} \tag{6}$$

In Havlena and Odeh's development, the total OOIP (N) was equal to N_{foi} because they ignored volatilized-oil (R_v=0). In our development, however, N_{fgi} is not equal to zero because we include and allow for volatilized-oil. It is important to recognized the distinction between N and N_{foi}.

Material-balance developments dealing with saturated reservoirs often use the variable m,[7-9] which is the ratio of the initial free gas-phase volume in the reservoir and the initial free oil-phase volume. The dimensionless constant m is related to G_{fgi} and N_{foi} by

$$m = \frac{G_{fgi}B_{gi}}{N_{foi}B_{oi}} \tag{7}$$

The constants G_{fgi} and m are often used interchangeably to describe a reservoir's initial free-gas content. If we solve Eqn. (7) for G_{fgi} and substitute this result into Eqns. (5) and (6) and note that $N_{foi}=G_{foi}/R_{si}$, we obtain the following expressions for N and G in terms of m:

$$N = N_{foi}\left(1+\frac{mB_{oi}R_{vi}}{B_{gi}}\right) \tag{8}$$

$$G = G_{foi}\left(1+\frac{mB_{oi}}{B_{gi}R_{si}}\right) \tag{9}$$

Note that the definition of m is general and applies without restriction to the nature of the initial gas distribution. For example, m is equally applicable to fully-segregated or fully-dispersed systems.

If we restrict our attention to a class of gas-cap reservoirs whose: (i) initial free gas- and oil-phase volumes are fully segregated and form distinct gas-cap and oil-leg zones; (ii) connate water saturation and porosity are constant throughout the reservoir; (iii) areal extent of the reservoir does not vary appreciably with depth; and (iv) gas-cap and oil-leg thicknesses are constant; then the constant m adopts a special meaning and is equal to the ratio of the gas-cap and oil-leg thicknesses. Note that the constant m depends only on the initial reservoir condition and not on future conditions. Thus, our development is equally applicable to expanding or non-expanding gas-caps. A non-expanding gas-cap implies the gas-oil contact is fixed. Non-expanding gas-cap reservoirs tend to recover less oil than expanding gas-cap reservoirs.

Example. To illustrate the application of Eqn. (3), consider the performance of a volatile-oil reservoir containing a gas-cap and subject to no water influx or production. Consider a gas-cap size corresponding to m=0.50. Table 1 summarizes the attending fluid properties and simulated reservoir performance. This particular volatile-oil is identical to the volatile-oil studied in Part 1. The simulations were carried out assuming a fixed gas-oil contact. The simulations used the same gas-oil relative permeability and phase viscosity data as reported in Part 1. The reservoir performance is summarized in terms of %OOIP and %OGIP recovered, instantaneous and cumulative producing GOR's, and gas saturation. As shown in Table 1, the initial pressure is 4,658 psia and the reservoir produces about 30.9% of the OOIP and 82.4% of the OGIP at the abandonment pressure of 598 psia.

Figure 1 shows a plot of F/E_o vs. E_g/E_o. This figure shows only the early production data corresponding to the first six data points in Table 1 and a pressure range from 3,789-4,658 psia. We limit ourselves to a study of the early production data because reservoir engineers are most interested in determining or confirming reserves early rather than late in the reservoir's life. For convenience, the total fluid withdrawal F in Fig. 1 is normalized by N_{foi}. This type of normalization is not usually possible in practice because N_{foi} is not normally known beforehand. We carry out this normalization for the sake of ease of presentation and so that our examples can be treated as having an oil-leg OOIP (N_{foi}) of 1 stb.

The dots and squares in Fig.1 represent the GMBE and CMBE calculations, respectively. The former calculations were carried out using Eqn. (2); the latter calculations were carried out using the equations given by Havlena and Odeh.[3] Fig. 1 shows that the GMBE and CMBE calculations yield appreciably different results. Their differences result from the fact that the latter calculations ignore the presence of volatilized-oil.

The solid and dashes lines in Fig. 1 represent the best-fit lines through the GMBE and CMBE data points, respectively. The lines were computed using the least-squares method. Although the GMBE and CMBE data points each yield very nearly straight lines, their slopes and y-intercepts differ greatly. The GMBE calculations yield a slope (G_{fgi}) of 1,598 scf and a y-intercept (N_{foi}) of 1.01 stb. Using Eqns. (7)-(9), these values correspond to m=0.49, N=1.20 stb and G=4,431 scf. These values agree within 2% or less of the actual (simulator input) values.

In comparison, the CMBE calculations yield a slope and y-intercept of 3,395 scf and 0.536 stb, respectively. These values reveal that the CMBE over-estimates the size of the gas-cap by 108% and under-estimates the oil in the oil-leg by nearly 46%. Clearly, the error incurred by applying the CMBE to this volatile-oil is indeed significant. Similar errors were noted for the gas-condensates we studied.[10] It is important to note that apparent straight lines do develop when the CMBE is used. Thus, one may not use this fact (apparent linearity) to ascertain that the effects of volatilized-oil are negligibly small.

INITIALLY-UNDERSATURATED, NON-VOLUMETRIC RESERVOIRS

Next, consider the case of an initially-undersaturated, non-volumetric reservoir. As an example consider a water-influx reservoir. In this case, $\Delta W \neq 0$ and either N_{foi} or G_{fgi} is zero depending on whether one treats the initial reservoir fluid as either an oil or gas reservoir. If we treat the initial reservoir fluid as an oil, then $G_{fgi}=0$ and $N=N_{foi}$ and Eqn. (1) can be re-arranged to yield

$$F - \Delta W = N\,E_o \tag{10}$$

Eqn. (10) reveals that a plot of $F-\Delta W$ vs. E_o yields a straight-line which passes through the origin and whose slope is equal to OOIP (N). This plot presumes that the ΔW is known or can be estimated as a function of pressure.

Example. To illustrate application of Eqn. (10), we consider an initially-undersaturated, volatile-oil reservoir subject to water influx and no water production. Table 2 summarizes the fluid properties and simulated reservoir performance. This example considers the same volatile-oil as in the previous example (Table 1), except this example considers an initial pressure slightly greater than the saturation pressure. The reservoir is subject to a total (ultimate) water influx volume of 0.54 RB per stb of OOIP or 20% of the original hydrocarbon pore volume. The rate of water influx is computed using a modified Fetkovitch[11] water-influx model. As shown in Table 2, the initial pressure is 4,998 psia and the reservoir yields about 24.4% of the OOIP and 85.9% of the OGIP at the abandonment pressure of 598 psia.

Figure 2 shows a plot of $(F-\Delta W)$ vs E_o. This figure includes only the early production data corresponding to the first six data points in Table 2 and a pressure range from 4,389-4,998 psia. The quantities $(F-\Delta W)$ in Fig. 2 and F and ΔW in Table 2 are normalized by the OOIP (N) so that our example can be treated as if the OOIP (N) is equal to 1 stb.

The dots and squares in Fig. 2 represent the GMBE and CMBE calculations, respectively. The solid and dashes lines in Fig. 2 represent the best-fit lines through the GMBE and CMBE data points, respectively. The GMBE calculations yield a slope (N) of 0.999. This result agrees very well with the actual (simulator input) value of 1.00 stb. In comparison, the CMBE calculations yield a slope of 0.789 stb. This example shows that the CMBE under-estimates the OOIP by about 21%. Clearly, the error incurred by the CMBE for this volatile-oil reservoir is indeed significant. Even greater errors were noted for the gas-condensates we studied.[10] In this case also, a perfectly acceptable straight line can be drawn through the CMBE data points.

The results in Fig. 2 show that the GMBE and CMBE data points are identical pressures greater than the saturation pressure. This follows from the fact that the GMBE and CMBE are equivalent under these conditions. See Part 1. We intentionally selected a sufficiently high initial pressure to clearly illustrate this result.

INITIALLY-SATURATED, NON-VOLUMETRIC RESERVOIRS

Finally, consider the case of an initially-saturated, non-volumetric reservoir. As an example consider a gas-cap reservoir subject to water influx. Re-arrangement of Eqn. (1) yields:

$$\frac{F - \Delta W}{E_o} = N_{foi} + G_{fgi}\frac{E_g}{E_o} \tag{11}$$

Eqn. (11) reveals that a plot of $(F-\Delta W)/E_o$ vs. E_g/E_o yields a straight line whose slope is equal to G_{fgi} and y-intercept is equal to N_{foi}. This plot presumes ΔW is known or can be estimated as a function of pressure.

Example. To illustrate the application of Eqn. (11), consider a volatile-oil reservoir having a gas-cap and subject to water-influx. Consider a gas-cap size corresponding to m=0.5 and a total (ultimate) water influx volume of 0.54 RB per stb of oil-leg OOIP or 20% of the original oil-leg hydrocarbon pore volume. Table 3 summarizes the simulated reservoir performance. This example assumes the fluid properties in Table 1 apply. It also assumes a fixed gas-oil contact. The initial pressure is 4,658 psia and the reservoir yields 32.1% of the OOIP and 84.8% of the OGIP at the abandonment pressure of 598 psia.

Figure 3 shows a plot of $(F-\Delta W)/E_o$ vs. E_g/E_o. This figure shows only the early production data corresponding to the first six data points in Table 3 and a pressure range from 3,798-4,658 psia. The quantities $(F-\Delta W)/E_o$ in Fig. 3 and F and ΔW in Table 3 have been normalized by N_{foi} so that this example can be treated as having an oil-leg OOIP (N_{foi})of 1 stb.

The dots and squares in Fig.3 represent the GMBE and CMBE calculations, respectively. The solid and dashes lines in Fig. 3 represent the best-fit lines through the appropriate data points. The GMBE calculations yield a slope (G_{fgi}) of 1,574 scf and a y-intercept (N_{foi}), of 1.02 stb. These values correspond to m=0.474, N=1.20 stb, and G=4,459 scf. These values agree within 5% of the actual (simulator input) values.

In comparison, the CMBE calculations yield a slope of 3,415 scf and a y-intercept of 0.532 stb. These values reveal that the CMBE over-estimates the size of the gas-cap by 109% and under-estimates the oil in the oil-leg by nearly 47%. Clearly, the error incurred by the CMBE for this volatile-oil reservoir is indeed significant. Similar errors were noted for gas-condensates we studied.[10]

DISCUSSION

The examples contained in Parts 1 and 2 are intended to illustrate the usefulness of some simple graphical methods to analyze reservoir performance. All the graphical methods are based on the GMBE.[2] The examples discussed herein represent only a small sampling of the utility of the GMBE. The ways in which the GMBE may be used is limited only by our own limitations. Havlena and Odeh[3] presented a much wider variety of plots in their study of the conventional material balance. For example, they discussed plots of F vs $(E_o+mB_{oi}E_g/B_{gi})$, F/E_o vs $\Delta p/E_o$, and other plots. We elect not to discuss these plots here because our nomenclature was purposely developed to be consistent with theirs and this designation permits our work to be directly applicable to theirs if one simply adopts our new definitions of F, E_o, and E_g. A comprehensive examination of the GMBE is given by Ansah.[10] In the following we briefly summarize some of the more pertinent observations of Ansah's that should be of benefit to those who use our work.

Part 1 showed that a plot of F vs. E_o is strictly linear only if the reservoir is initially-undersaturated and volumetric. We have observed, however, that plots of F vs E_o are frequently very nearly linear even if the reservoir is initially-saturated or non-volumetric. The slope of a plot of F vs. E_o for a non-volumetric or initially-saturated reservoir, however, is not equal to N_{foi} even though the plot may appear to be linear. This observation means that plots of F vs. E_o cannot be used to effectively diagnose an initially-saturated or non-volumetric condition. To effectively diagnose a non-volumetric or initially-saturated condition, we alternatively recommend plotting F/E_o vs. either time, F, or ΔP. If any of these plots yield a non-zero slope, then the reservoir must be either initially-saturated or non-volumetric.

By combining Eqns. (1) and (7), Havlena and Odeh[3] showed that a plot of F vs $(E_o+mB_{oi}E_g/B_{gi})$ is strictly linear only if the reservoir is initially-saturated and volumetric and if the correct value of m is used to evaluate the term $(E_o+mB_{oi}E_g/B_{gi})$; the slope of this plot is equal to N_{foi}. We have observed, however, that plots of F vs $(E_o+mB_{oi}E_g/B_{gi})$ are frequently very nearly linear for volumetric, initially-saturated reservoirs even if grossly incorrect values of m are used to evaluate the term $(E_o+mB_{oi}E_g/B_{gi})$; the slope of these plots, however, is not equal to N_{foi} even though they appear linear. Others have observed this behavior, too.[12] This observation means that a plot of F vs $(E_o+mB_{oi}E_g/B_{gi})$ which appears linear or lacks obvious non-linearity cannot be used as a reliable means to uniquely determine m.

CONCLUDING REMARKS

We began this work because—much to our consternation—advances in the development of the material-balance equation have not been commensurate with those in other areas of reservoir simulation. In fact, the nearly sixty-year-old CMBE has been slowly falling out-of-step with the rest of reservoir simulation. Admittedly, tank-type models have their limitations; however, to their credit, material balance is still the guiding principle in all reservoir studies. Although this topic by and of itself may be considered pedestrian, we believe there is still an important place for the material-balance equation and restrictions that are no longer germane should be eliminated. This paper and its companion works[1,2] were presented with this perspective in mind.

This paper is the second in a two-part series and completes our study of the GMBE. We have presented several different algebraic rearrangements of the GMBE and we have developed graphical methods corresponding to each. The main purpose of the graphical methods is to estimate the original oil and gas in-place. Each algebraic rearrangement corresponds to a specific set of production mechanisms. Part 1 considered simple expansion-drive reservoirs, including solution-gas drive reservoirs. Part 2 considered combination-drive reservoirs, including gas-cap and water-influx reservoirs. A wide range of initial fluid compositions have been considered. In all cases, our graphical methods have flawlessly estimated the correct OOIP. None of the preexisting calculation methods were able to achieve this same level of performance.

In summary, this work completes the search for a general, straight-line method to estimate original oil and gas in-place in a reservoir without restrictions on fluid composition. Ultimately, this work leads to better and simpler reservoir engineering practices. No longer will the reservoir engineer have to decide which straight-line method is appropriate for his reservoir. Rather, if in doubt, he should choose the straight-line method based on the GMBE. No longer will the reservoir engineer have to decide which material-balance formulation is correct for his reservoir. Rather, if in doubt, he should choose the GMBE. Our generalized approach to petroleum reservoir engineering seeks to unify rather than to fragment. Although petroleum reservoir engineering does indeed consist of several distinct branches such as dry-gas reservoir engineering, black-oil reservoir engineering, and gas-condensate reservoir engineering; our work clearly shows that each of these branches does, in fact, emanate from the same trunk.

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NOMENCLATURE

B_o = Oil formation volume factor (FVF), RB/stb
B_{oi} = Initial oil FVF, RB/stb
B_g = Gas FVF, RB/scf
B_{gi} = Initial gas FVF, RB/scf
B_w = Water FVF, RB/stb
E_g = Net gas expansion, RB/scf
E_o = Net oil expansion, RB/scf
F = Total hydrocarbon fluid withdrawal, RB
G = Original gas in-place OGIP, scf
G_{foi} = Gas in initial free oil-phase, scf
G_{fgi} = Gas in initial free gas-phase, scf
N = OOIP, stb
N_p = Produced oil, stb
N_{fgi} = Oil in free initial gas-phase, stb
N_{foi} = Oil in initial free oil-phase, stb
p = Pressure, psia
p_i = Initial pressure, psia
Δp = Pressure decline, p_i-p, psia
R_s = Solution gas-oil ratio, scf/stb
R_{si} = Initial solution gas-oil ratio, scf/stb
R_v = Volatile oil-gas ratio, stb/scf
R_{vi} = Initial oil-gas ratio, stb/scf
R_p = Cumulative produced wellhead gas-oil ratio, scf/stb
R_{ps} = Cumulative produced sales gas-oil ratio, scf/stb
S_g = Gas saturation, fraction PV or HCPV
ΔW = Definition, see Appendix A, Part 1.

Greek

μ_o = Oil viscosity, cp
μ_g = Gas viscosity, cp

CONVERSION FACTORS

1 bbl = 0.1590 m^3
1 cf = 0.0283 m^3
1 cp = 0.001 Pa-s
1 psi = 6.894 kPa

Table 1-Performance of a Volatile-Oil Reservoir with a Gas-Cap

FLUID PROPERTIES								RESERVOIR PERFORMANCE						
Pressure P, psia	B_o, RB/stb	B_g, RB/mscf	R_s, scf/stb	R_v, stb/mmscf	E_o, RB/stb	E_g, RB/mscf	E_g/E_o, stb/mscf	Oil Recovery, %OOIP*	Gas Recovery, %OGIP**	Producing GOR, mscf/stb	Cumulative GOR, mscf/stb	S_g, %HCPV	F,*** RB	F/E_o,*** stb
4658	2.70727	0.830	2834	116.0	0.0000	0.000	0.000	0.00	0.00	2.83	2.83	0.0	0.0000	0.0000
4598	2.63143	0.835	2711	111.0	0.0197	0.008	0.388	1.01	0.74	2.71	2.76	4.7	0.0321	1.6289
4398	2.33771	0.853	2247	106.0	0.0968	0.029	0.295	4.39	3.22	2.82	2.76	23.0	0.1433	1.4814
4198	2.20391	0.874	2019	94.0	0.1674	0.056	0.334	7.56	5.71	3.09	2.84	29.3	0.2587	1.5455
3998	2.09309	0.901	1828	84.0	0.2477	0.088	0.355	10.62	8.48	3.73	3.00	34.3	0.3911	1.5788
3798	1.99116	0.933	1651	74.0	0.3428	0.125	0.364	13.41	11.61	4.70	3.25	38.2	0.5459	1.5929
3598	1.90524	0.970	1500	66.0	0.4480	0.165	0.368	15.73	14.90	6.03	3.56	41.3	0.7171	1.6008
3398	1.82832	1.015	1364	60.0	0.5705	0.212	0.372	17.69	18.50	7.74	3.93	44.1	0.9162	1.6060
3198	1.75726	1.066	1237	54.0	0.7119	0.265	0.372	19.38	22.30	9.17	4.32	46.4	1.1443	1.6075
2998	1.68592	1.125	1111	49.0	0.8781	0.326	0.371	20.89	26.31	11.00	4.73	48.7	1.4095	1.6052
2798	1.63232	1.196	1013	44.0	1.0677	0.398	0.372	22.22	30.45	12.64	5.15	50.3	1.7164	1.6076
2598	1.58028	1.281	918	39.0	1.2961	0.483	0.373	23.43	34.85	14.70	5.58	51.7	2.0846	1.6084
2398	1.53414	1.380	833	36.0	1.5597	0.582	0.373	24.48	39.25	16.81	6.02	53.2	2.5083	1.6082
2198	1.49008	1.498	752	33.0	1.8760	0.699	0.373	25.43	43.76	19.22	6.46	54.6	3.0164	1.6079
1998	1.44996	1.642	677	30.0	2.2621	0.842	0.372	26.27	48.41	22.07	6.92	55.9	3.6342	1.6065
1798	1.41304	1.819	608	28.0	2.7354	1.016	0.372	27.04	53.11	24.25	7.37	57.0	4.3927	1.6059
1598	1.36658	2.035	524	26.0	3.3419	1.232	0.369	27.77	58.02	26.54	7.85	58.5	5.3515	1.6013
1398	1.33283	2.315	461	25.0	4.1031	1.509	0.368	28.43	62.82	28.04	8.30	59.7	6.5653	1.6001
1198	1.30465	2.689	406	24.1	5.1137	1.879	0.367	29.06	67.62	29.37	8.74	60.6	8.1781	1.5993
998	1.27171	3.190	344	23.9	6.4971	2.376	0.366	29.68	72.49	29.97	9.17	61.8	10.3716	1.5963
798	1.23937	3.911	283	24.4	8.5008	3.093	0.364	30.29	77.36	29.87	9.59	62.9	13.5439	1.5933
598	1.20516	5.034	212	26.4	11.6874	4.216	0.361	30.95	82.43	28.39	10.00	64.2	18.5645	1.5884

* Based on reservoir OOIP (N).
** Based on reservoir OGIP (G).
*** Normalized by the oil-phase OOIP (N_{foi})

Table 2-Performance of a Volatile-Oil Reservoir with Water Influx

FLUID PROPERTIES						RESERVOIR PERFORMANCE						
Pressure P, psia	B_o, RB/stb	B_g, RB/mscf	R_s, scf/stb	R_v, stb/mmscf	E_o, RB/stb	Oil Recovery %OOIP	Gas Recovery %OGIP	Producing GOR, mscf/stb	Cumulative GOR, mscf/stb	S_g, %HCPV	F,* RB	ΔW,* RB
4998	2.71261	0.932	2909	343.0	0.0000	0.00	0.00	2.91	2.91	0.0	0.0000	0.0000
4798	2.73953	0.942	2909	343.0	0.0269	1.05	1.05	2.91	2.91	0.0	0.0287	0.0016
4698	2.75371	0.947	2909	343.0	0.0411	1.63	1.63	2.91	2.91	0.0	0.0448	0.0037
4658	2.70727	0.830	2834	116.0	0.0523	2.08	2.07	2.83	2.90	3.4	0.0573	0.0050
4598	2.63143	0.835	2711	111.0	0.0725	2.88	2.84	2.75	2.87	8.6	0.0792	0.0067
4398	2.33771	0.853	2247	106.0	0.1510	5.87	5.78	2.98	2.86	26.1	0.1659	0.0149
4198	2.20391	0.874	2019	94.0	0.2239	8.36	8.54	3.49	2.97	32.8	0.2496	0.0261
3998	2.09309	0.901	1828	84.0	0.3069	10.64	11.64	4.48	3.18	37.7	0.3463	0.3096
3798	1.99116	0.933	1651	74.0	0.4043	12.63	15.19	5.90	3.50	41.7	0.4602	0.0559
3598	1.90524	0.970	1500	66.0	0.5124	14.25	18.93	7.62	3.87	44.7	0.5872	0.0742
3398	1.82832	1.015	1364	60.0	0.6393	15.65	22.96	9.14	4.27	47.4	0.7342	0.0952
3198	1.75726	1.066	1237	54.0	0.7849	16.88	27.19	10.87	4.68	49.7	0.9023	0.1179
2998	1.68592	1.125	1111	49.0	0.9557	17.98	31.65	12.96	5.12	52.1	1.0982	0.1424
2798	1.63232	1.196	1013	44.0	1.1508	18.90	36.12	15.23	5.56	53.8	1.3195	0.1688
2598	1.58028	1.281	918	39.0	1.3852	19.71	40.77	18.09	6.02	55.4	1.5818	0.1966
2398	1.53414	1.380	833	36.0	1.6568	20.41	45.36	20.54	6.47	57.1	1.8832	0.2261
2198	1.49008	1.498	752	33.0	1.9822	21.03	50.00	22.88	6.91	58.6	2.2390	0.2570
1998	1.44996	1.642	677	30.0	2.3790	21.59	54.65	25.63	7.36	60.1	2.6679	0.2892
1798	1.41304	1.819	608	28.0	2.8658	22.09	59.24	28.03	7.80	61.6	3.1879	0.3224
1598	1.36658	2.035	524	26.0	3.4882	22.57	64.05	31.09	8.26	63.6	3.8454	0.3570
1398	1.33283	2.315	461	25.0	4.2707	22.98	68.53	33.28	8.68	65.1	4.6641	0.3923
1198	1.30465	2.689	406	24.1	5.3096	23.34	72.86	35.48	9.08	66.6	5.7376	0.4285
998	1.27171	3.190	344	23.9	6.7306	23.69	77.20	37.12	9.48	68.4	7.1958	0.4658
798	1.23937	3.911	283	24.4	8.7884	24.03	81.46	37.30	9.86	70.3	9.2938	0.5038
598	1.20516	5.034	212	26.4	12.0593	24.38	85.89	35.28	10.25	72.5	12.6018	0.5425

* Normalized by the OOIP (N), where $N=N_{foi}$

Table 3-Performance of a Volatile-Oil Reservoir with Both Gas-Cap and Water-Influx

Pressure P, psia	Oil Recovery, %OOIP*	Gas Recovery, %OGIP**	Producing GOR, mscf/stb	Cumulative GOR, mscf/stb	S_g, %HCPV	F,*** RB	ΔW,*** RB	(F-ΔW)/E_o, stb***	E_g/E_o, stb/mscf
4658	0.00	0.00	2.83	2.83	0.00	0.0000	0.0000	0.0000	0.000
4598	1.02	0.75	2.71	2.76	4.73	0.0323	0.0003	1.6252	0.388
4398	4.49	3.30	2.82	2.76	23.06	0.1466	0.0033	1.4804	0.295
4198	7.85	5.94	3.09	2.84	29.38	0.2690	0.0104	1.5443	0.334
3998	11.16	8.94	3.75	3.01	34.40	0.4119	0.0209	1.5782	0.355
3798	14.19	12.36	4.75	3.27	38.35	0.5805	0.0345	1.5933	0.364
3598	16.17	16.00	6.10	3.59	41.47	0.7684	0.0514	1.6006	0.368
3398	18.86	19.96	7.81	3.97	44.24	0.9873	0.0710	1.6061	0.372
3198	20.70	24.14	9.26	4.38	46.54	1.2373	0.0930	1.6074	0.372
2998	22.33	28.54	11.03	4.80	48.90	1.5273	0.1174	1.6056	0.371
2798	23.76	33.04	12.84	5.22	50.54	1.8605	0.1441	1.6075	0.372
2598	25.03	37.77	15.02	5.66	52.12	2.2576	0.1729	1.6084	0.373
2398	26.13	42.46	17.32	6.10	53.75	2.7124	0.2033	1.6087	0.373
2198	27.09	47.21	20.04	6.55	55.30	3.2521	0.2358	1.6077	0.373
1998	27.92	52.02	23.07	7.00	56.74	3.9038	0.2697	1.6065	0.372
1798	28.67	56.81	25.27	7.44	58.22	4.6978	0.3052	1.6058	0.372
1598	29.36	61.73	28.08	7.89	60.17	5.6934	0.3417	1.6013	0.369
1398	29.98	66.45	30.10	8.32	61.77	6.9448	0.3797	1.6000	0.368
1198	30.54	71.09	32.06	8.74	63.23	8.5975	0.4186	1.5994	0.367
998	31.06	75.69	33.56	9.15	65.05	10.8306	0.4585	1.5964	0.366
798	31.57	80.21	34.45	9.54	67.01	14.0449	0.4994	1.5934	0.364
598	32.08	84.83	33.67	9.93	69.27	19.1074	0.5414	1.5885	0.361

* Based on reservoir OOIP (N).
** Based on reservoir OGIP (G).
*** Normalized by the oil-phase OOIP (N_{foi})

FIGURE 1—Volatile-Oil Reservoir with Gas-Cap (m=0.5)

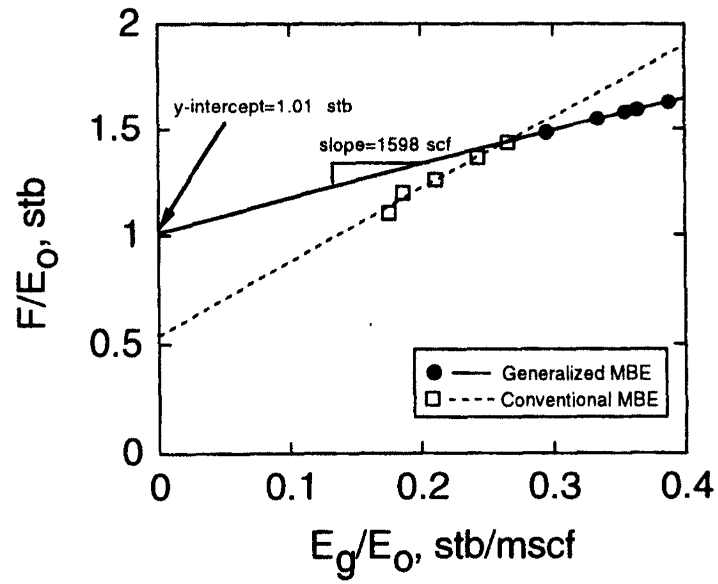

FIGURE 2—Volatile-Oil Reservoir with Water Influx

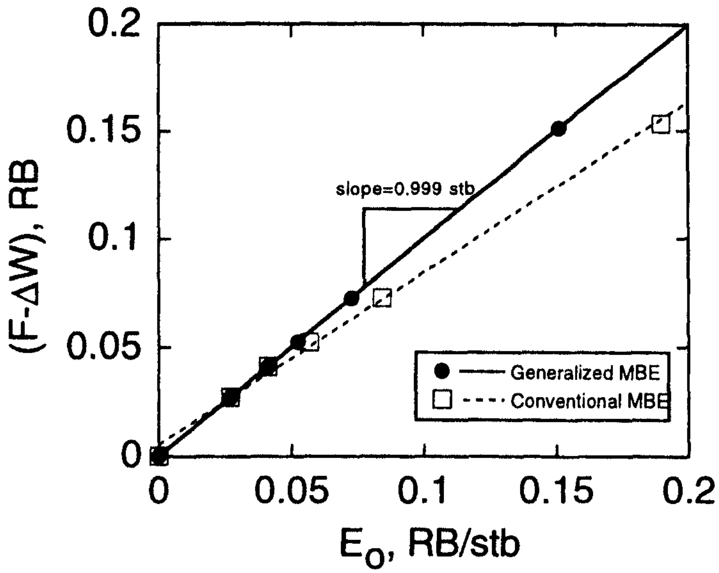

FIGURE 3—Volatile-Oil Reservoir With Gas-Cap (m=0.5) and Water Influx