A VOLUMETRIC MODEL TO ESTIMATE THE AMOUNT OF GAS IN A NEWLY DISCOVERED ROCK RESERVOIR

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ABSTRACT

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A volumetric calculation of the amount of gas in a rock reservoir requires in practice numerical integration of a volume integral. The distributions of porosity- and gassaturation values throughout the reservoir have then to be known: Since in all practical cases these distributions are only partially known, the calculation of the amount of gas in the reservoir can only be made using a model of the reservoir from which the overall distributions are derived. The model is based on premises that have to be specified separately.

The problem of finding suitable distributions is most urgent for a newly discovered reservoir. Therefore an example of such a case has been picked out and general geological and physical considerations have been used as the principal premises in order to arrive at a starting model, named the Continuous Conformal Model (CCM).

The construction and computational procedures are illustrated by a numerical example.

INTRODUCTION

According to the volumetric method, estimates are made of the volume of gas initially in place in a reservoir from the available data concerning size and physical properties. It is one of the oldest methods, and descriptions can be found in various textbooks, e.g. in Amyx *et al.* (1960), Campbell (1959) and Moody (1961).

The accuracy of the estimate will in the first place depend on the amount and quality of the available data. Moreover the resulting estimate will be influenced by a certain amount of personal judgement, needed to assess the average values of porosity, gassaturation and expansion factor (v. d. Laan, 1968). In fact this judgement depends on the degree of confidence with which the actual values of these entities can be extrapolated throughout the reservoir.

In the case of a newly discovered reservoir, apart from a structural map, the only available data are those of the discovery well. Extrapolation of these well data throughout the reservoir on the basis of extraneous premises leads to the distribution patterns needed for further computations. In this case the assignment of the porosity and saturation values throughout the reservoir has been made on the assumptions that the layer sequence found in the discovery well remains continuous and conformal. Continuous stratigraphy includes that each layer has the same rock properties throughout the reservoir, which means that the porosity value found for any layer in the well is valid for that layer throughout the reservoir, as shown in the cross section fig. 1. Conformal stratigraphy means that each layer keeps the same vertical thickness throughout the reservoir. These assumptions define the model of the reservoir named the Continuous Conformal Model (CCM).

The next chapter gives a short review of the various definitions and formulas used for the computation of the gas-initially-in-place, which is based on volumetric integrals rather than on average values for the reservoir porosity and saturation.

The procedure to calculate the amount of gas in the model of an actual reservoir is illustrated by a numerical example for a non-dissolved gas, ignoring small quantities of gas dissolved in water.

FORMULAS AND DEFINITIONS

If the porespace in a rockvolume V is filled with gas and water, it can be stated that the volume that is occupied by the gas V_g together with that occupied by the water V_w equals the porespace V_p, so,

$$V_g + V_w = V_p \qquad (1)$$

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Defining the effective porosity ϕ as the fraction of the rockvolume that is occupied by the interconnected pores, the watersaturation S_w as the fraction of this porespace that is occupied by the water and the gassaturation S_g as the fraction of the porespace that is occupied by the gas, one gets:

for the porevolume $V_p = \phi V$ (2)

for the watervolume $V_w = S_w V_p = \phi S_w V$ (3)

for the gasvolume $V_g = S_g V_p = \phi S_g V$ (4)

and also $S_g + S_w = 1$ (5)

The gasvolume at any other pressure/temperature ratio is found by applying the gaslaw:

$$PV/TZ = R \quad (6)$$

R being the gasconstant for an ideal gas and Z representing the dimensionless deviation factor from an ideal gas for the reservoir gas at pressure P and temperature T.

The gasvolume $(V_g)_{sc}$ at standard conditions with the pressure and temperature specified at these conditions, is then,

$$(V_g)_{sc} = (TZ/P)_{sc} . \phi . S_g . (P/TZ)\, V \quad (7)$$

For a non-homogeneous rockvolume where porosity-, saturation- and pressure/temperature values are variable throughout the volume, the total amount of gas $(V_g)_{sc}$ is found by determining the gasvolume dV_g in each homogeneous rockvolume element dV separately, and totalling all dV_g values. In principle this amounts to the determination of the volume integral:

$$(V_g)_{sc} = (TZ/P)_{sc} \iiint (P/TZ) \,.\, dV_g = (TZ/P)_{sc} \iiint \phi . S_g . (P/TZ) . dV \quad (8)$$

Since the entities ϕ, S_g, P/TZ and dV are never given as analytic functions, the integration has to be carried out by numerical means. This is achieved by dividing the reservoir into a finite number of grossrock volume units ΔV_i in such a way, that each can be assigned characteristic values for the porespace $(\Delta V_p)_i$ the gasvolume $(\Delta V_g)_i$ and P/T ratio $(P/TZ)_I$

There may be a part of a unit of gross rock volume ΔV_i that does not contribute to the gasvolume because of lack of gas porosity. We define the gas containing part as the unit of net rock volume $(\Delta V_{net})_i$ and the net/gross ratio (NGR) as the ratio between the part of the net unit volume with gas porosity and the gross unit volume.

$$(NGR)_i = \frac{(\Delta V_{net})_i}{\Delta V_i} \quad (9)$$

Next the pore volume is found to be

$$(\Delta V_P)_i = \phi_i \, (\Delta V_{net})_i \quad (10)$$

The total amount of gas is found by adding the gasvolumes of all units, so

$$(V_g)_{sc} = (TZ/P)_{sc} \sum_V (P/TZ)_i \, (\Delta V_g)_i = (TZ/P)_{sc} \sum_V \phi_i \, (S_g)_i \, (P/TZ) \, (\Delta V_{net})_i \quad (11)$$

and by defining the average values for the total reservoir as:

$$\text{average NGR} = \overline{NGR} = \frac{\Sigma \, (\Delta V_{net})_i}{\Sigma \, \Delta V_i} = \Sigma \frac{(\Delta V_{net})_i}{V} \quad (12)$$

$$\text{average } \phi = \overline{\phi} = \frac{\Sigma \, \phi_i \, (\Delta V_{net})_i}{\Sigma \, (\Delta V_{net})_i} \quad (13)$$

$$\text{average } S_g = \overline{S_g} = \frac{\Sigma \, \phi_i \, (S_g)_i \, (\Delta V_{net})_i}{\Sigma \, \phi_i \, (\Delta V_{net})_i} \quad (14)$$

$$\text{average } P/TZ = \overline{(P/TZ)} = \frac{\Sigma \, \phi_i (S_g)_i \, (P/TZ)_i \, (\Delta V_{net})_i}{\Sigma \, \phi_i \, (S_g)_i \, (\Delta V_{net})_i} \quad (15)$$

and defining the average expansion factor $\overline{E}$ as:

$$\overline{E} = \overline{(P/TZ)} \,.\, (TZ/P)_{sc} \quad (16)$$

equation (11) can be written in the conventional form for the gas initially in place

$$(V_g)_{sc} = \overline{NGR} . \overline{\phi} . \overline{S_g} . \overline{E} . V \quad (17)$$

A reservoir is often subdivided into columnar parts with a constant cross-section F and consisting of a number of layers with individual thicknesses ΔZ_i and a total height $\Sigma \, \Delta Z_i$. When applying formulas (9), (10), (12), (13), (14) and (15) to those parts the Δ V's can be replaced by Δ Z's. In formulas (11) and (17) this replacement yields the values for volumes per unit area or column heights.

From the formulas it will be clear, that the basic requirement for determination of the total amount of gas consists in the assignment of net gross ratio, porosity, saturation and P/TZ values for each volume unit ΔV_i of the total reservoir.

THE DATA

For the subsequent development of the model the following data will assumed to be available.

a. A contourmap of a relevant horizon, showing the complete outline of the reservoir.
b. The porosity, saturation and pressure/temperature values with depth and all other relevant information of a single well, preferably located at or near the top of the reservoir.

THE DESIGN OF THE MODEL

In order to obtain a workable model with these data, the first necessity is the introduction of an interpolation method, that makes it possible to determine the total rockvolume and parts thereof. The method used here is based on an analytic relation between contour depth and contour area of the form

$$\frac{\sqrt{F_{Z+c}} - \sqrt{F_Z}}{\sqrt{F_{Z+C}} - \sqrt{F_Z}} = \frac{c}{C} \quad (18)$$

where

F_Z = known area of a mapcontour at depth Z

F_{Z+C} = known area of the next mapcontour at contour distance C below F_Z

F_{Z+c} = area of a contour between these mapcontours at a given distance c below F_Z.

From (18) it follows that the area of any intermediate contour between two successive mapcontours is a function of its depth c below the upper one, thus

$$F_{Z+c} = \left[\frac{c\sqrt{F_{Z+C}} + (C-c)\sqrt{F_Z}}{C}\right]^2 \qquad (19)$$

and integrating F_{Z+c} between 0 en C yields the colume of a contourslab between two successive mapcontours as the well-known approximation of the pyramidal formula

$$\Delta V_{cs} = 1/3\, C\,(F_Z + F_{Z+C} + \sqrt{F_Z F_{Z+C}}). \qquad (20)$$

The gross rockvolume is then found by adding the volumes of all successive slabs, thus

$$V = \Sigma\ \Delta V_{cs} \qquad (21)$$

Before deciding on the most suitable way to subdivide the volume, the item to consider is the well data for ϕ, S_g and $^P/_{TZ}$.

Under the given circumstances only the well data of the discovery well can be used as key values for the distribution throughout the reservoir, and general geological and physical considerations are virtually the only available premises on which the distributions can be based. In this case this has led to the choice of postulating a continuous and conformal stratigraphy.

As mentioned, continuous stratigraphy means, that each layer has the same rockproperties throughout the reservoir, which means, that the porosity value found for any layer in the well is valid for that layer throughout the reservoir, as shown in the cross section fig. 1.

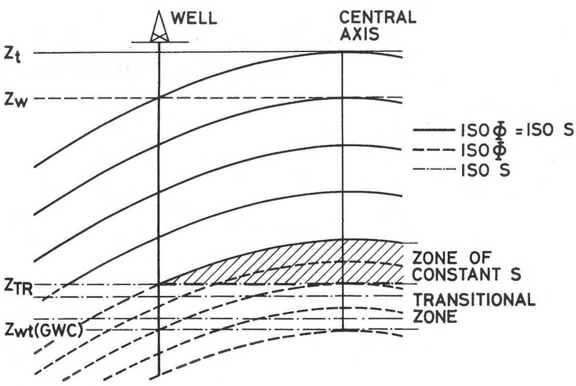

FIG. 1
CCM LINES OF EQUAL POROSITY AND EQUAL SATURATION

Conformal stratigraphy means, that each layer keeps the same vertical thickness throughout the reservoir, and from these two properties it follows, that in the cross-section all iso-porosity lines run parallel to the surface of the horizon given by the contourmap (see fig. 1). For the iso-saturation surfaces this cannot be true for the whole of the reservoir, since the lowermost saturation surface, the watertable is a horizontal plane.

At this point a further simplification in the model as compared to actual reservoir conditions has been made by assuming the model to be divided into two saturation zones:

a. A lowermost zone, the transitional zone, from a point where the watersaturation values, due to capillary forces, show a distinct increase with depth, down to the watertable. Within this zone the iso-saturation surfaces are taken to run horizontal;
b. The part of the reservoir above the transitional zone, where the saturation values are taken to be directly dependent on the corresponding porosity values and thus where the iso-saturation surfaces coincide with the iso-porosity surfaces.

As a consequence of this, the schematic vertical crossection of fig. 1 shows that, if the well is not located at the highest point of the reservoir, no saturation values can be deduced in that part of the reservoir comprised by the contour through the well and bounded at the top by the lowermost conform iso-saturation surface in the well and at the bottom by the upper boundary of the transitional zone (this part is hachured in the cross section of fig. 1). For this part of the reservoir a constant value of the gas saturation is assigned in line with the observed well data immediately above the transitional zone.

The $^P/_{TZ}$ values in a reservoir show as a rule only modest variations, as normally P, T and Z are all slowly increasing with depth. For this reason and because it leads to considerable simplification, a single $^P/_{TZ}$ value has been used for the reservoir model. The actual value used is the well value for $^P/_{TZ}$ at a depth where the amounts of gas above and below are estimated to be approximately equal.

A reservoir model defined in this way has three important properties. First at any given contour depth the total thickness of net rock, and the total amount per unit area of both pores and gas in situ are constant. Second, once these three values are known along the entire height of the central axis of the reservoir, they can also be derived for any other given contour depth. Third, the amount of gas $(V_g)_{sc}$ at standard pressure and temperature can be found by multiplying the in situ amount with a constant expansion factor E.

For ease of the integration the subdivision of the model will be based on the constancy along the contour lines of the entities mentioned above. The first step in this procedure is to pick the depths of top reservoir Z_t, upper boundary reservoir at well Z_w, upper boundary transitional zone Z_{tr} and the watertable Z_{wt} (= GWC) in such a way, that the chosen interval Δz is an aliquot part of the distances between these levels. This usually results in a slightly longer central axis than is actually measured, but it simplifies the computations without effecting the gasvolume, as for the extensions of this axis above and below the reservoir the values for the porosity or the saturation are always zero. Care should be taken however, that the top-bottom distance taken in the well section agrees exactly with that on the map. The reservoir is then subdivided into N horizontal slices, each with a thickness Δz, and at the edge bounded by a vertical surface through the contours situated at $\frac{1}{2}\Delta z$. Next, the vertical edges of the slices are extended down to the watertable. In this way the model is divided into a central column with a height $N\Delta z$ and an area of the contour at depth $Z_t + \frac{1}{2}\Delta z$, surrounded by (N-1) hollow columns, the contour mantles. The n-th mantle has a height of $(N-n)\Delta z$ and an area, equal to the difference in area of the contours at depth $Z_t + (n+\frac{1}{2})\Delta z$ and $Z_t + (n-\frac{1}{2})\Delta z$.

The "contoured" gross rock volume of the reservoir is found by totalling the volumes of the central column and its surrounding mantles thus

$$V = N\Delta z\, F_{Z_t+\frac{1}{2}\Delta z} + \sum_{n=1}^{n=N-1} (N-n)\Delta z \left[F_{Z_t+(n+\frac{1}{2})\Delta z} - F_{Z_t+(n-\frac{1}{2})\Delta z}\right] \qquad (22)$$

The difference between the gross rock volume calculated with the pyramidal formula (20) and (21), and the stepwise contoured volume according to (22) is negligable for small values of Δ_Z.

The reservoir of the model can thus thought to be subdivided in $\frac{1}{2}N(N+1)$ ringshaped volume elements, that can be provided, either individually or in groups, with all values necessary for the volumetric calculations. The further calculations needed to determine the total amount of gas in the model will be demonstrated in the next chapter on the basis of an example shown in figure 2 and tables I-IV. The value for $\Delta z = 5$ m was chosen here for reasons of conciseness.

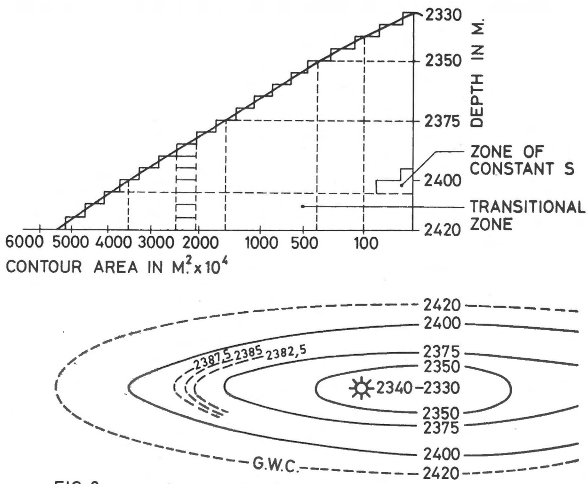

FIG. 2
SUBDIVISION SCHEME OF RESERVOIR MODEL

THE CALCULATIONS

Starting from the upper boundary of the reservoir at the well Z_w, the well data are first standardized for the chosen height interval by subdividing all the N intervals of 5 m into the values for net rock, pores and gas. An excerpt of this procedure is shown in table I for the interval between 2395 and 2400 m. These per interval standardized wellvalues for net rock, pore and gas heights are then entered in columns 3, 4 and 5 of Table II under the heading well data.

ORIGINAL WELL DATA				STANDARIZED WELL DATA				
DEPTH	Δh	$\emptyset$	S_g	DEPTH INTERVAL	Δh	Δh_{net}	$\emptyset\Delta h$	$\emptyset S_g \Delta h$
2394.7	1.2	.16	.77		.3	.3	.048	.037
				2390 - 2395	5.0	5.0	.730	.460
					.9	.9	.144	.111
2395.9	.6	-	-		.6	-	-	-
2396.5	.4	.15	.72		.4	.4	.060	.043
2396.9	.1	-	-		.1	-	-	-
2397.0	.7	.12	.63		.7	.7	.084	.053
2397.7	1.1	-	-		1.1	-	-	-
2398.8	.7	.11	.72		.7	.7	.077	.055
2399.5	.3	.15	.63		.3	.3	.045	.028
2399.8	.3	-	-		.2	-	-	-
				2395 - 2400	5.0	3.0	.410	.290
					.1	-	-	-
2400.1	.4	.16	.75		.4	.4	.064	.048

DEPTH INTERVAL 2395 - 2400 Δz = 5 m

NET COLUMNHEIGHT Δz_{net} = 3.0 m; SF = 0.600

PORE COLUMNHEIGHT $\Delta z_p = \emptyset\Delta z_{net}$ = 0.410 m; $\emptyset$ = 0.137

GAS COLUMNHEIGHT $\Delta z_g = \emptyset S_g \Delta z_{net}$ = 0.290 m; S_g = 0.707

TABLE I

STANDARIZATION OF WELL DATA

In accordance with the principle of conformity the values for net rock height and pore height at the well are now transferred to the central axis, starting from the level top reservoir Z_t (columns 7 and 8). For the gas values (column 5) this applies only down to the upper boundary of the transitional zone Z_{tr}, so this leaves in column 10 on the lower part of the central axis a number of 5 intervals open.

The first two intervals, belonging to the zone of constant saturation have been assigned an $S_g = .7$, a figure slightly lower than the $S_g = .75$ the quotient of column 5 and 4, measured just above the transitional zone. For the remaining three intervals, which are situated within the transitional zone, the saturation values measured in the well for these intervals are applicable. All needed S_g values have been listed in column 9. Multiplication of the pore height values of

	WELL DATA				COLUMNAR VALUES CENTRAL AXIS							
	1	2	3	4	5	6	7	8	9	10	11	12	13
	DEPTH	Δz	Δz_{net}	$\emptyset \Delta z_n$	$\emptyset S_g \Delta z_n$	Δz	Δz_n	$\emptyset \Delta z_n$	S_g	$\emptyset S_g \Delta z_n$	Δz_n	$\Sigma \emptyset \Delta z_n$	$\Sigma \emptyset S_g \Delta z_n$
Z_t	2330					5	4.00	1.00		.83	4.00	1.00	.83
	2335					5	5.00	1.10		.87	9.00	2.10	1.70
Z_w	2340	5	4.00	1.00	.83	5	0.00	0.00		.00	9.00	2.10	1.70
	2345	5	5.00	1.10	.87	5	0.00	0.00		.00	9.00	2.10	1.70
	2350	5	0.00	0.00	.00	5	1.00	0.12		.09	10.00	2.22	1.79
	2355	5	0.00	0.00	.00	5	5.00	1.22		.92	15.00	3.44	2.71
	2360	5	1.00	0.12	.09	5	5.00	1.15		.83	20.00	4.59	3.54
	2365	5	5.00	1.22	.92	5	5.00	1.07		.73	25.00	5.66	4.27
	2370	5	5.00	1.15	.83	5	5.00	0.95		.62	30.00	6.61	4.89
	2375	5	5.00	1.07	.73	5	5.00	0.85		.51	35.00	7.46	5,40
	2380	5	5.00	0.95	.62	5	5.00	0.73		.46	40.00	8.19	5.86
	2385	5	5.00	0.85	.51	5	3.00	0.41		.29	43.00	8.60	6.15
	2390	5	5.00	0.73	.46	5	2.60	0,24		,18	45.60	8.84	6,33
	2395	5	3.00	0.41	.29	5	5,00	1.21	.70	.85	50.60	10.05	7.18
	2400	5	2.60	0.24	.18	5	4,40	0.97	.70	.68	55.00	11.02	7.86
Z_{tr}	2405	5	5.00	1.21	.53	5	5.00	0.87	.438	.38	60.00	11.89	8.24
	2410	5	4.40	0.97	.22	5	5.00	1.12	.227	.25	65.00	13.01	8.49
	2415	5	5.00	0.87	.08	5	5.00	0.83	.092	.08	70.00	13.84	8.57
Z_{wt}	2420	5	5.00	1.12	.00								
	2425	5	5.00	0.83	.00								
	2430												

$\overline{NGR}$ = .750
$\overline{\emptyset}$ = .198
$\overline{Sg}$ = .602

TABLE II DERIVATION OF CENTRAL AXIS VALUES FROM WELL DATA.

	1	2	3	4	5	6	7
	contour depth in m.	area map contour in mx10^4	volume cont.slab in mx10^6	area intermed contour in mx10^4	mantle height above Z_{wt} in m.	area mantle crosssect. in mx10^4	mantle volume in mx10^6
Top Res Z_t	2330	0	0		90	6.25	5.63
	2.5			6.25			
	5				85	50.00	42.50
Upper res.	7.5			56.25			
Bound. Z_w	2340				80	100.00	80.00
	2.5			156.25			
	5				75	150.00	112.50
	7.5			306.25			
	2350	400	26.67		70	172.18	120.52
	2.5			478.43			
	5				65	177.90	115.64
	7.5			656.33			
	2360				60	205.97	123.58
	2.5			862.30			
	5				55	234.03	128.72
	7.5			1096.33			
	2370				50	262.10	131.05
	2.5			1358.43			
	5	1500	222.88		45	304.00	136.80
	7.5			1662.43			
	2380				40	349.91	139.96
	2.5			2012.34			
	5				35	383.30	134.16
	7.5			2395.64			
	2390				30	416.70	125.01
	2.5			2812.34			
	5				25	450.09	112.52
	7.5			3262.43			
	2400	3500	607.61		20	463.96	92.59
Upper Bound	2.5			3725.39			
tr.zone Z_{tr}	5				15	471.87	70.78
	7.5			4197.26			
	2410				10	500.00	50.00
	2.5			4697.26			
	5				5	528.13	26.41
	7.5			5225.39			
Watert. Z_{wt}	2420	5500	892.50				
Gross rock volume			1749.66				1748.36

TABLE III COMPUTATION OF DEPTHS, AREAS AND ROCKVOLUMES FROM MAP DATA

column 8 with these saturation values then completes the gas height values in column 10. Columns 11, 12 and 13 give the cumulative values from the top downwards of the values in column 7, 8 and 10.

Next the volumes of the individual mantles are calculated. On table III, column 1 the absolute depths at the intervals are shown. Top reservoir Z_t is at 2330 m; at the well the upper boundary of the reservoir Z_w is at 2340 m, the upper boundary of the transitional zone Z_{tr} is at 2405 m, and the water-table Z_{wt} is at 2420 m. The only important condition here is, that the positions of these four levels are correct in relation to each other, in other words, that the mapped horizon is conform, but not necessarily coincident with the upper boundary of the reservoir.

In column 2 the measured areas of the map contours are listed and from these the volumes of the successive contourslabs and the gross rock volume are calculated by means of formulas (20) and (21) and listed in column 3. In column 4 the areas of the mantle boundary contours have been calculated with formula (19), and the corresponding heights of these mantles have been listed in column 5. The differences of the successive area values in column 4 yields the crossection areas for the mantles, listed in column 6. Multiplication of height and area gives the mantle volumes listed in column 7 and adding these, gives the total rock volume, according to formula (22) which is, even at Δz=5 m, only slightly smaller than that calculated in column 3.

The final computation sheet for determination of the CCM values of the reservoir is shown in Table IV, which has a lay-out somewhat resembling the upper part of figure 2. Rows, 1, 2 and 3 from left to right correspond to the columns 5, 6 and 7 of Table III, read upwards. Rows 4 and 6 correspond with columns 11 and 12 of Table II. The gross rock volume is taken over from Table III, the net rock volume and the pore volume per mantle are given in rows 5 and 7, with on the right the total amounts. The CCM values for $\overline{NGR}$ and $\overline{\phi}$ can then be calculated with formulas (12) and (13).

The cumulative gas column heights for the mantle parts above the transitional zone are taken from column 13 in Table II and listed in row 8.

The gas volumes are found in row 9, with the cumulative figure on the right representing the total amount of gas above the transitional zone. Within this zone the calculations have to be carried out per interval slice Δz. To this end the poreheights are tabulated per interval. These values are taken from column 8 Table II. Starting with the values for the interval just below Z_{tr}, row 10 starts one place to the left of rows 8 and 9. This continues for each successive interval until in the last row 14 representing the deepest interval all values of the central axis from top to bottom correspond with the complete row from left to right. Rows 11, 13 and 15 give the corresponding mantle pore volumes in the transitional zone and since the saturation per slice is constant, it can be multiplied with the total pore volume per slice to arrive at the gasvolumes which are shown to the right of rows 11, 13 and 15.

1. mantle height above wt. in m.	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90			
2. mantle area in $m^2 \times 10^4$	528.13	500.00	471.87	462.96	450.09	416.70	383.30	349.91	340.00	263.00	234.03	205.97	177.90	172.18	150.00	100.00	50.00	6.25	Total gross rock volume 1748.36		
3. gross rock vol. in $m^3 \times 10^6$	26.41	50.00	70.78	92,59	112.52	125.01	134.16	139.96	136.80	131,05	128.72	123.58	115.64	120.52	112.50	80.00	42.50	5.63			
4. net. height above wt. in m.	4.00	9.00	9.00	9.00	10.00	15.00	20.00	25.00	30.00	35.00	40.00	43.00	45.60	50.60	55.00	60.00	65.00	70.00	Total net rock volume 1134.65		
5. net. rock vol. in $m^3 \times 10^6$	21.13	45.00	42.47	41.67	45.01	62.51	76.66	87.48	91.20	91.73	93.61	88.57	81.12	87.12	82.50	60.00	32.50	4.38		$\overline{NGR} = \frac{1134.65}{1748.36} = 0.649$	
6. por. col. height above wt. in m.	1.00	2.10	2.10	2.10	2.22	3.44	4.59	5.66	6.61	7.46	8.19	8.60	8.84	10.05	11.02	11.89	13.01	13.84	Total pore volume 242.49		
7. pore volume above wt. in $m^3 \times 10^6$	5.28	10.50	9.91	9.72	9.99	14.33	17.59	19.81	20.10	19.55	19.17	17.71	15.73	17.30	16.53	11.89	6.51	0.87		$\bar{\phi} = \frac{242.49}{1134.65} = 0.214$	
8. gas col. height above tr.zone in m.	-	-	-	0.83	1.70	1.70	1.70	1.79	2.71	3.54	4.27	4.89	5.40	5.86	6.15	6.33	7.18	7.86			gas volumes
9. gas vol. above tr. zone in $m^3 \times 10^6$	-	-	-	3,84	7,65	7.08	6.52	6.26	8.24	9.28	9.99	10.07	9.61	10.09	9.23	6.33	3.59	0.49	----------	----------	-----108.27
10. por.col. height 1st. int.trz. in m.	-	-	1.00	1.10	0.00	0.00	0.12	1.22	1.15	1.07	0.95	0.85	0.73	0.41	0.24	1.21	0.97	0.87	Trans.zone pore vol.	Sg	
11. porevol. 1st. int. trz. in $m^3 \times 10^6$	-	-	4.72	5.09	0.00	0.00	0.46	4.27	3.50	2.80	2.22	1.75	1.30	0.71	0.36	1.21	0.49	0.05	28.93	0.438	12.67
12. por.col. height 2nd int. trz. in m.	-	1.00	1.10	0.00	0.00	0.12	1.22	1.15	1.07	0.95	0.85	0.73	0.41	0.24	1.21	0.97	0.87	1.12			
13. porevol. 2nd int. trz. in $m^3 \times 10^6$	-	5.00	5.19	0.00	0.00	0.50	4.68	4.02	3.25	2.49	1.99	1.50	0.73	0.41	1.81	0.97	0.44	0.07	33.06	0.227	7.50
14. por. col. height 3rd int.trz. in m.	1.00	1.10	0.00	0.00	0.12	1.22	1.15	1.07	0.95	0.85	0.73	0.41	0.24	1.21	0.97	0.87	1.12	0.83			
15. porevol. 3rd int. trz. in $m^3 \times 10^6$	5.28	5.50	0.00	0.00	0.54	5.08	4.41	3.74	2.89	2.23	1.71	0.84	0.43	2.08	1.46	0.87	0.56	0.05	37.67	0.092	3.46

$$E = \frac{288}{1.033} \quad \frac{250}{350 \times 1.04} = 191.48$$

Total gasvolume in situ 131.90

Total gasvolume $25.3 \times 10^9 m^3$ at 1 atm. and 15°C

$$\bar{S}_g = \frac{131.90}{242.49} = 0.544$$

TABLE IV COMPILATION SHEET.

The value for the total gas volume in situ is found by adding the gas volumes listed on the right of rows 9, 11, 13 and 15. According to formula (14) the ratio between total gasvolume and total porevolume gives the value for the average gassaturation $\overline{S_g}$ of the reservoir.

The pressure and temperature conditions throughout the reservoir were taken to be equal to those prevailing at a depth of 2390 m in the well where the amount of gas upwards and downwards are estimated to be approximately equal. At this point P = 250 kg/cm² and T = 77°C. The gas deviation factor at standard pressure 1 atm. and temperature 15°C was taken unity, and the deviation factor at reservoir conditions was found to be 1.04.

The expansion factor was calculated with formula (16), and the preliminary estimate for the gas initially in place in the reservoir using the CCM method was found to be $25.3 \times 10^9 m^3$ at 1 atm. and 15°C.

FINAL REMARKS

The paper shows the application of the volumetric method for a case with a very limited amount of factual data and consequently a rather large freedom in choice of assumptions that are needed to make the calculations possible. A particular set of assumptions has in this case led to a workable model and a value for the gas initially in place of the reservoir that may be regarded as a preliminary estimate.

The purpose of the paper lies not so much in the model itself, but mainly intends to show where, how and on what grounds outside assumptions have to be made in order to come to a clearly defined model applicable for such a case. It should also be clear that at the onset the lack of factual information with regard to the actual distributions of the relevant parameters throughout the reservoir will severely hamper the accuracy of any model and consequently that of the estimate, and that this situation can only be improved as the information of further appraisal and development wells can be included into the reservoir model.

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