National Exams December 2018

17-Pet-A3, Fundamental Reservoir Engineering

3 hours duration

NOTES:

1. If doubt exists as to the interpretation of any question, the candidate is urged to submit with the answer paper, a clear statement of any assumptions made.
2. This is a CLOSED BOOK exam.
3. Approved Casio or Sharp calculator is permitted.
4. FIVE (5) questions constitute a complete exam paper.
5. The first five questions as they appear in the answer book will be marked.
6. All questions are of equal value unless otherwise stated and all parts in a multipart question have equal weight.
7. Clarity and organization of your answers are important, clearly explain your logic.
8. Pay close attention to units, some questions involve oilfield units, and these should be answered in the field units. Questions that are set in other units should be answered in the corresponding units.
9. **A formula sheet** is provided at the end of questions

Question 1 (20 Marks)

Explain (briefly in one or two sentences) the following reservoir engineering concepts.

a) Critical gas saturation
b) Dry gas reservoir
c) Reservoir rock
d) Trap
e) Volumetric reservoir
f) Wet gas reservoir
g) Original oil in place
h) Residual oil saturation
i) Infinite acting
j) Threshold pressure

Question 2 (20 Marks)

The production data for a volumetric dry gas reservoir is provided in the following table. Use the provided data to:

a) Calculate the reservoir initial pressure
b) Calculate the original gas in place
c) Calculate the cumulative gas that can be produced when the reservoir pressure drops to 1000 psia.
d) Calculate gas recovery factor when the reservoir pressure drops to 1000 psia.

Pressure (psia)	Gas compressibility factor	Cumulative production (MMMSCF)*
Initial pressure	0.85	0
2500	0.80	500
1500	0.75	1000
1000	0.70	?

* MMM=10^9

Question 3 (20 Marks)

Two exploration wells 3000 ft apart have been drilled into a newly discovered oil reservoir. Well #1 is an observation well (it does not produce oil and has a pressure gauge in the hole to measure the pressure response due to production well #2). Use the reservoir date given in the following and calculate the pressure at well #1 (observation well) after five days of production from Well#2 at a flow rate of 500 STBD.

Reservoir external radius, r_e	4000 ft
Total compressibility, c_t	5×10^{-6} psi^{-1},
Oil viscosity, μ	1 cP,
Oil formation volume factor, B_o	1. 2 bbl/STB,
Reservoir permeability, k	50 mD,
Formation thickness, h	50 ft,
Initial reservoir pressure, p_i	2000 psia,
Formation porosity, ϕ	0.15,
Well radius, r_w,	0.3 ft.
Skin factor of well#1	1

Question 4 (20 Marks)

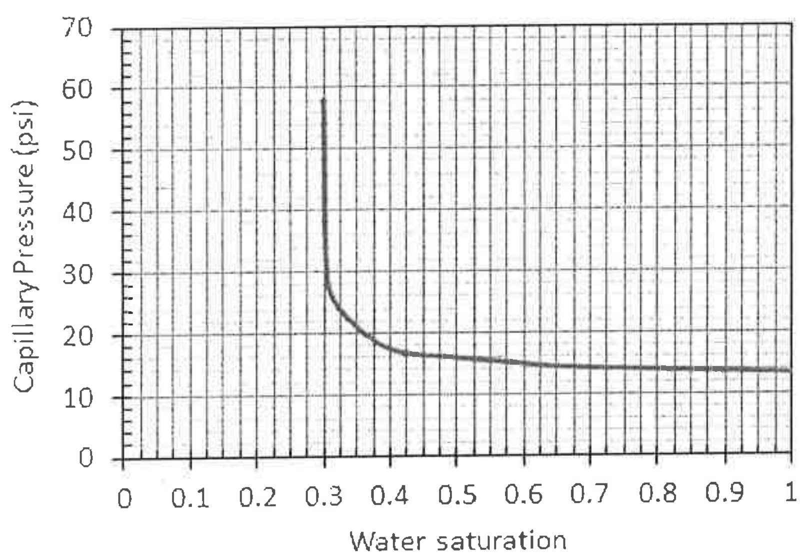
A cylindrical core of 10 cm in length and 5 cm^2 cross-sectional flow area with an absolute permeability of 0.5 Darcy has been used to perform a core flood test. Use the following data obtained from a steady-state core flood test to calculate oil and water effective and relative permeabilities when water saturation in the core is 40%. Oil and water viscosities are 3.52 and 1 cp, respectively. Core length = 10 cm, cross-sectional area of the core = 5 cm^2.What is the pressure difference between inlet and outlet of the core when water saturation is 40%?

Water saturation	0	0.2	0.4	0.6	0.8	1
Water rate (mL/sec)	0	0	0.0220	0.0561	0.1100	0.2750
Oil rate (mL/sec)	0.0780	0.0546	0.0260	0.0098	0.0013	0

Question 5 (20 Marks)

The capillary pressure data for an oil reservoir is shown in the following graph. The depth of free water level for this reservoir is estimated to be 6000 ft and the oil and water densities are 50 and 65 lb_{mass}/ft^3, respectively. Use the given data to answer the following questions.

a) What is the depth of water oil contact?
b) Estimate thickness of the transition zone?



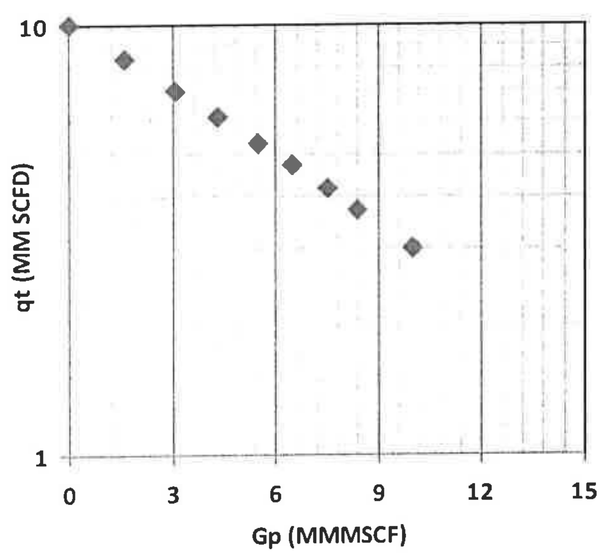
Question 6 (20 Marks)

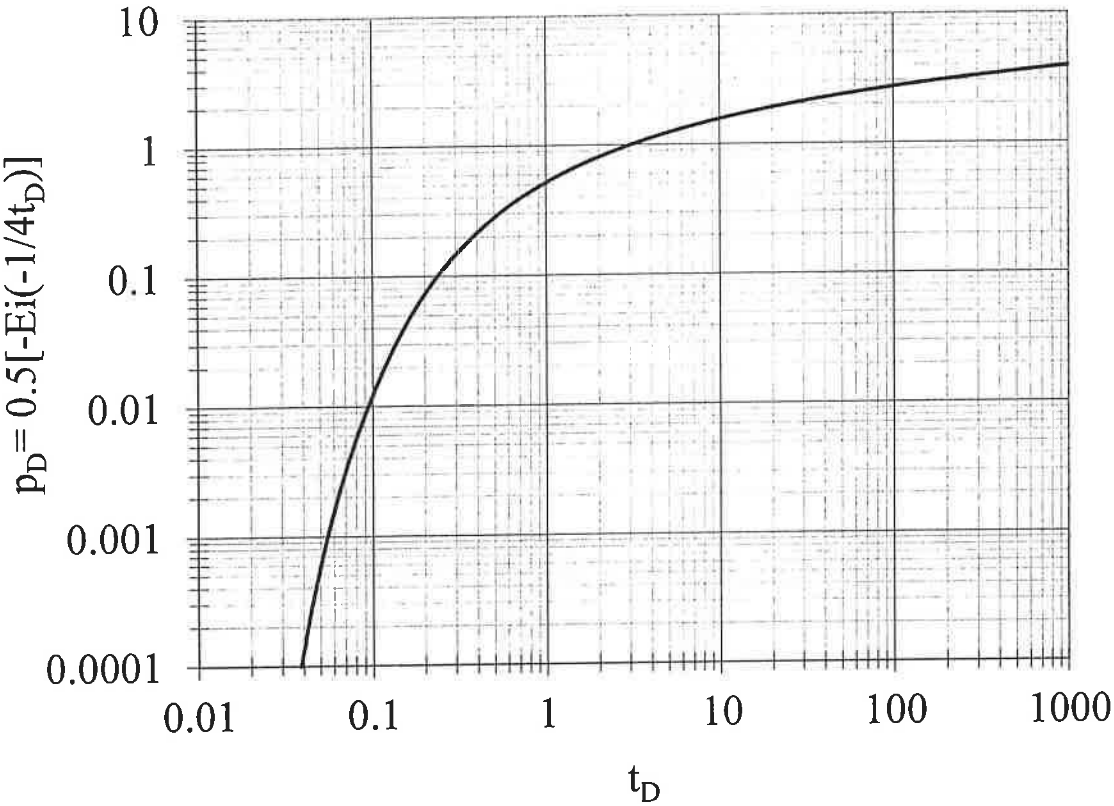
Geological and log data from a saturated oil reservoir show that the original oil zone is three times larger than the original gas cap. Use the following information to calculate the original gas in place and thickness of the oil zone.

Well spacing = 400 acres,
Porosity = 17%,
Initial gas saturation in the oil zone = 0.0,
Initial water saturation in the oil and gas zones = 0.2,
Initial reservoir pressure = 3400 psia,
Bubble point pressure = 4000 psia,
Current reservoir pressure = 2800 psia,
Reservoir temperature = 160 °F,
Initial oil formation volume factor (FVF) = 1.33 bbl/STB,
Oil formation volume factor (FVF) at bubble point = 1.35 bbl/STB,
Oil formation volume factor (FVF) at 2800 psia = 1.25,
Water influx at 2800 pisa = 1 MMbbl,
Cumulative oil production = 2 MMSTB at 2800 psia,
Cumulative gas production = 2.6 MMMSCF at 2800 psia,
To find gas compressibility factor, use $Z = 1\text{-}0.0001 \times p$,
To find solution gas oil ratio, use $R_{so} = 0.2 \times p$.

Question 7 (20 Marks)

Estimate the gas production rate from a dry gas reservoir after 8 years using the following production data:





Plot of dimensionless pressure versus dimensionless time

Formula Sheet

Real gas law

$pV = ZnRT$

where p in psia, T in °R, V in ft^3, R=10.732 psi-ft^3/(lb$_{mol}$-°R)

Gas formation volume factor, $B_g = 0.02827\dfrac{ZT}{p}$ in $\dfrac{\text{ft}^3}{\text{SCF}}$, where p in psia, T in °R.

Hydrostatic and capillary pressures

$p = \rho\frac{g}{g_c}\frac{h}{144}$,

$p_c = p_o - p_w$,

where p is pressure in psia, g=32.17 ft/sec^2, g_c=32.17 (1b$_{mass}$-ft)/(lb$_f$-sec^2), h in ft and ρ is density in lb$_{mass}$/ft^3, subscripts o and w stand for oil and water, respectively.

Equation for steady-state linear and radial flows in oil field units.

$$q = -\frac{1.127kA}{\mu B_o}\left(\frac{dp}{ds} \pm 0.433\gamma\sin\theta\right), \qquad + \text{ for upward flow and - for downward flow.}$$

$$q = \frac{7.08kh(p_r - p_w)}{\mu B_o[\ln(r/r_w) + s]}, \quad \bar{p} = \frac{1}{V}\int_V p\,dV$$

where q is in STBD, dV=2πrhdr, A is the cross-sectional area in ft^2, γ is oil specific gravity, θ is slope with horizontal level in degree, k is permeability in Darcy, h is formation thickness in ft, r is radius in ft, p is pressure in psia, $\bar{p}$ is the average pressure in psia, s is skin, B_o is the oil formation volume factor in bbl/STB, and μ is viscosity in cP.

Darcy equation in Darcy's unit- Linear

$q = -\dfrac{kA}{\mu}\dfrac{dp}{dx}$, k is permeability in Darcy, A is area in cm^2, μ is viscosity in cp, L is length in cm, and p is pressure in atm.

Transient flow equations in field units:

$$\eta = \frac{6.33k}{\phi\mu c}, \qquad t_D = \frac{\eta t}{r^2}$$

$p_D = \frac{1}{2}(\ln t_D + 0.809)$ only if t_D>100,

$$p(r,t) = p_i - \frac{0.141q_o\mu_o B_o}{kh}(p_D + S)$$

where ϕ is porosity, t is time in day, t_D is the dimensionless time, k is permeability in Darcy, h is formation thickness in ft, r is radius in ft, p is pressure in psia, c is the oil compressibility in psi^{-1}, B_o is the oil formation volume factor in bbl/STB, μ is the oil viscosity in cP, S is skin factor, and p_D is the dimensionless pressure. The subscript i denotes the initial condition.

Pseudo critical pressure and temperature

$$T_{pc} = 168 + 325\gamma_g - 12.5\gamma_g^2 \quad \text{in}\,{}^oR$$

$$p_{pc} = 677 + 15.0\gamma_g - 37.5\gamma_g^2 \quad \text{in } psia$$

Reduced temperature: $T_r = \dfrac{T}{T_c}$, Reduced pressure: $p_r = \dfrac{p}{p_c}$

where γ_g is the gas specific gravity (Air=1)

Gas reservoirs material balance equation

$$\frac{p}{Z} = \frac{p_i}{Z_i}\left(1 - \frac{G_p}{G}\right)$$

where p is pressure in psia, G_p is the cumulative gas production, and G is the original gas in place. The subscript i denotes the initial condition.

Oil reservoir material balance

$$\underbrace{N\left(B_t - B_{ti}\right)}_{\text{oil expansion}} + \underbrace{Nm\frac{B_{ti}}{B_{gi}}\left(B_g - B_{gi}\right)}_{\text{gas expansion}} + \underbrace{\left(1+m\right)NB_{ti}\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta p}_{\text{rock and water expansion}} + \underbrace{W_e}_{\text{water influx}}$$

$$= \underbrace{N_p\left[B_t + B_g\left(R_p - R_{soi}\right)\right]}_{\text{oil and gas production}} + \underbrace{B_w W_p}_{\text{water production}}$$

$$B_t = B_o + B_g\left(R_{soi} - R_{so}\right)$$

where c_w is water compressibility in psi^{-1}, c_f is the rock compressibility in psi^{-1}, S_w is the initial water saturation, Δp is pressure drop in psi, N is the initial oil in place in STB, N_p is the cumulative oil production in STB, B_t is the two-phase formation volume factor in bbl/STB, B_g is the gas formation volume factor in bbl/SCF, R is the gas oil ratio in SCF/STB and m ratio of reservoir gas volume to the reservoir oil volume in the primary gas cap and dimensionless, W_p is the cumulative water production in STB, W_e is the cumulative water influx in bbl, B_w is the water formation volume factor. The subscript i denotes the initial condition.

Decline curve analysis

Exponential decline: $q = q_i e^{-Dt}$,

Harmonic decline: $q = q_i/(1 + Dt)$

Hyperbolic decline $q = q_i(1 + bDt)^{-1/b}$

Cumulative production $G_p = \int qdt$

where q is rate in SCFD, G_p is the cumulative production in SCF, t is time in day , D is the decline rate in 1/day and subscript i stands for the initial condition.

Conversion Factors

1 m^3 = 6.28981 bbl =35.3147 ft^3

1acre = 43560 ft^2

1ac-ft = 7758 bbl

1Darcy = 9.869233×10^{-13} m^2

1 atm =14.6959488 psi =101.32500 kPa=1.01325 bar

1 cP = 0.001 Pa-sec

1 m = 3.28084 ft = 39.3701 inch

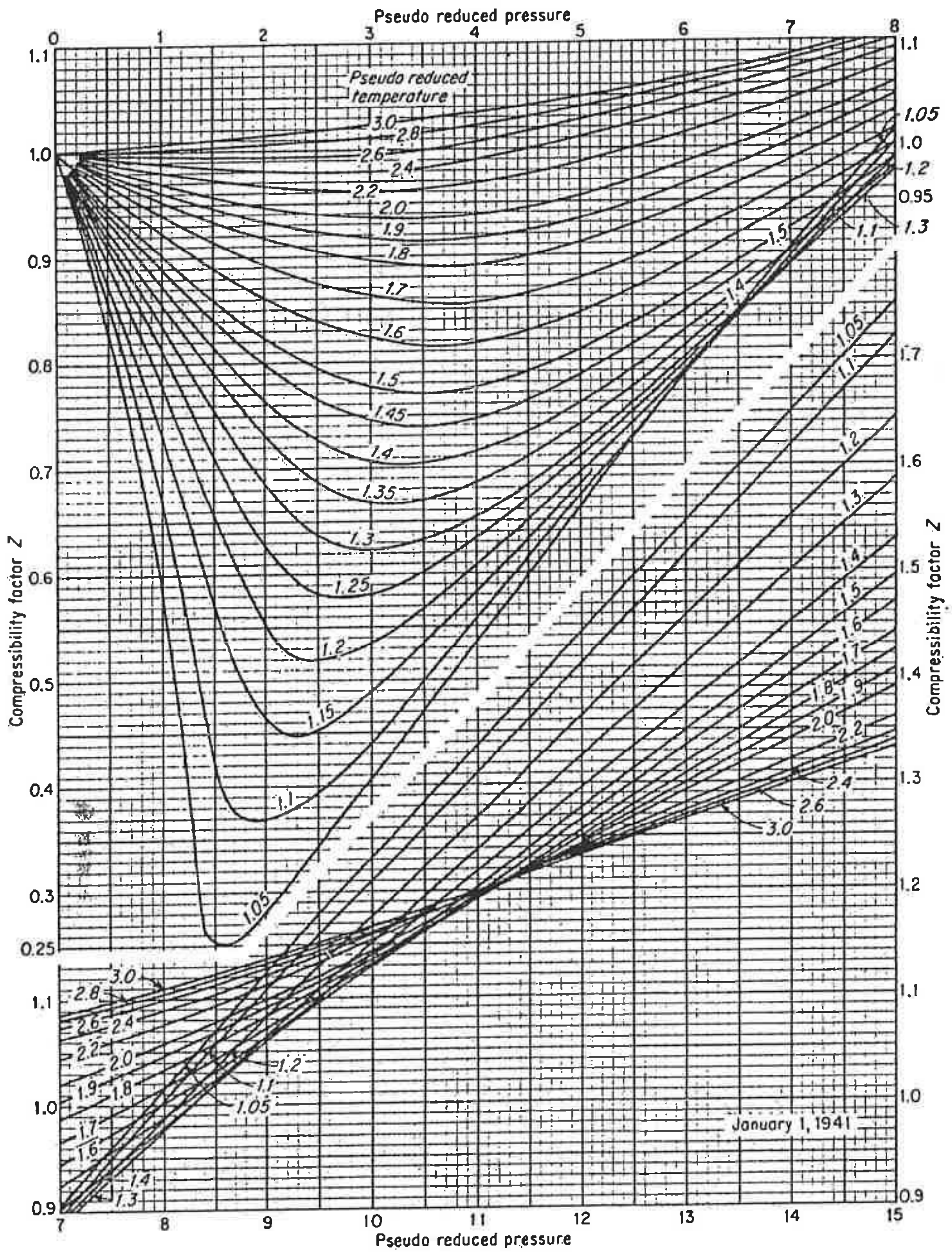


Fig. 4-16. Compressibility factor for natural gases. *(Standing and Katz, 4-87. Courtesy AIME.)*

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degree of conformity to the theorem of corresponding states must be considered.

The *P-V-T* relations for methane-nitrogen mixtures were determined by Keyes and Burks (4-55) and for a natural gas containing 8.5 and 18.8 mole % nitrogen by Eilerts, Carlson, and Mullens (4-30). Table 4-10 gives the analyses of the natural gases, and Table 4-11 gives a comparison of the compressibility factors computed from Fig. 4-16 and the reduced temperature and pressure, with the experimental values for these compressibility factors. The calculated compressibility factors are lower than the measured values by about 2 per cent at the higher temperatures and intermediate pressures. The factors for the gases with nitrogen are lower on the average over the full range of temperature.

Reamer, Olds, Sage, and Lacey (4-72) have measured the compressibility of four mixtures of methane and carbon dioxide from 100 to 460°F and up to 10,000 psia, with data at 100 and 280°F reproduced in Table 4-12. For gases with 1 or 2 mole % carbon dioxide, the pseudocritical chart is reliable but, for higher percentages, a correction may be necessary as indicated by comparing computed compressibilities with the measured compressibilities in Table 4-12.

Likewise, for methane–hydrogen sulfide mixtures,