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APPENDICES

APPENDIX

A1. Determination of Gas Compressibility Factor (Z)

The gas compressibility or Z-factor is a function of the pseudoreduced pressure and temperature of the gas. The pseudoreduced values are defined as:

$$p_{pc} = \frac{p}{p_{pc}}$$

$$T_{pc} = \frac{T}{T_{pc}}$$

where

$p =$ pressure of interest

$T =$ temperature of interest

$p_{pc} =$ pseudocritical pressure

$T_{pc} =$ pseudocritical temperature

If the gas composition is known, the pseudocriticals are calculated from

$$p_{pc} = \sum_{i=1}^{N} y_i p_{ci}$$

$$T_{pc} = \sum_{i=1}^{N} y_i T_{ci}$$

where

$y_i =$ mol fraction of i th component

$p_{ci} =$ critical pressure of i th component

$T_{ci} =$ critical temperature of i th component

$N =$ number of component

If the gas composition is unknown, the pseudocriticals may be estimated from

$p_{pc} =$ 709.6-58.7γ_g

$T_{pc} =$ 170.5+307.3γ_g

where

$$p_{pc} = \text{ psia}$$

$$T_{pc} = \ ^{\circ}R$$

One of the simplest equations, which gives values sufficiently accurate for two-phase flow calculations, was published by Brill and Beggs and modified by standing. The equation is

$$Z = A + (1-A)EXP(-B) + Cp_{pr}^{D} \qquad \text{(A1.1)}$$

where

$$A = 1.39\,(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.101$$

$$B = p_{pr}(0.62 - 0.23T_{pr}) + p_{pr}^{2}\left[0.066/(T_{pr} - 0.86) - 0.037)\right] + 0.32p_{pr}^{6} / EXP\left[20.723(T_{pr} - 1)\right]$$

$$C = 0.132 - 0.32\log T_{pr}$$

$$D = EXP(0.715 - 1.128T_{pr} + 0.42T_{pr}^{2})$$

If the gas contains impurities, corrections can be made to p_{pc} and T_{pc} according to Wichert and Aziz as

$$T'_{pc} = T_{pc} - \varepsilon,$$

$$P'_{pc} = \frac{p_{pc}T'_{pc}}{T_{pc} + \varepsilon(B - B^{2})}$$

where

$$\varepsilon = 120(A^{0.9} - A^{1.6}) + 15(B^{0.5} - B^{4})$$

$B =$ mol fraction H_2S

$A =$ mol fraction $CO_2 + B$

These corrected pseudocritical value are then used to calculate the pseudoreduced values for use in Equation A1.1.

A2. Determination of Solution or Dissolved Gas

Vasquez and Beggs presented correlations for several fluid properties, which were based on data from more than 600 measured PVT analyses. The correlation for R_s gives R_s as a function of pressure, temperature, oil API gravity and gas gravity. The gas depends on the separator pressure and temperature. Vasquez and Beggs based their gas gravity on a reference pressure of 114.7 psia and presented an equation for correcting γ_g for other separator pressures.

If separator conditions are unknown, the uncorrected gas gravity may be used in the correlations for R_s and B_0 . The gas gravity correction equation is:

$$\gamma_{gc} = \gamma_g\left[1.0 \div 5.912\times10^{-5}(API)T\log(p/114.7)\right]$$

where

$\gamma_{gc} =$ corrected gas gravity

$\gamma_g =$ gas gravity resulting from a separation at p, T

$p =$ separator pressure, psia

$T =$ separator temperature, $^\circ$F

API = oil gravity, $^\circ$API

The dissolved or solution gas at any pressure less than or equal to bubblepoint pressure is calculated from

$$R_s = C_1\gamma_{gc}p^{c_2}EXP\left[C_1(API)/(T+460)\right] \qquad \text{(A2.1)}$$

where

$R_s =$ solution gas, scf/STB

$p =$ pressure of interest, psia

$T =$ temperature of interest, $^\circ$F

The values of the constants depend on the API gravity of the oil and are given by

Constant	API $\leq$ 30	API > 30
C_1	0.0362	0.0178
C_2	1.0937	1.1870
C_3	25.7240	23.9310

The method for estimating R_s is used in the HP petroleum Fluids Pac. Other correlations for R_s were published by Standing and Lasater.

If the initial solution gas, $R_{sl} = R_{sb}$ is known, Equation A2.1 may be solved for bubblepoint pressure, p_b.

Although frequently ignored in two-phase flow calculation, an equation for calculating gas in solution in water, as published by Craft and Hawkins is given

$$R_{sw} = R_{swp}\left[1 - XY \times 10^{-4}\right]$$

where

R_{sw} = gas dissolved in brine, scf / STB

R_{swp} = gas dissolved in pure water, scf / STB

X = $3.471T^{-0.837}$

Y = water salinity, ppm

T = temperature, °F

$$R_{swp} = C_1 + C_2 p + C_3 p^2$$

where

$$C_1 = 2.12 + 3.45\times10^{-3}T - 3.59\times10^{-5}T^2$$

$$C_2 = 0.0107 - 5.26\times10^{-3}T + 1.48\times10^{-11}T^2$$

$$C_3 = -8.75\times10^{-7} + 3.9\times10^{-9}T - 1.02\times10^{-11}T^2$$

A3. Determination of Formation Volume Factor

The formation volume factor of a fluid is a convenient parameter to use for converting from standard volumes to actual or in- situ volumes existing at any pressure and temperature in the system. Equations are given for gas, oil, and water.

(a) Gas. The gas formation volume factor is defined as the actual volume occupied by a given quantity of gas at some pressure and temperature, divided by the volume which the gas would occupy at standard conditions. It is calculated from

$$B_g = \frac{p_{sc} ZT}{T_{sc} p} \tag{A3.1}$$

For pressure in psia and temperature in °R, using P_{sc} = 14.7 psia and $T_{sc} = 520\,°\mathrm{R}$, Equation A3.1 becomes

$$B_g = \frac{0.0283ZT}{p}$$

(b) Oil. The Vasquez and Beggs method may be used to estimate B_o as a function of γ_g, API, R_s and T. The equation is

$$B_o = 1 + C_1 R_s + C_2 (T - 60)(API / \gamma_{gc}) + C_3 R_s (T - 60)(API / \gamma_{gc})$$

where

B_o = volume / standard volume. e.g. bbl/STB

R_s = solution gas at p . T . scf / STB

T = temperature of interest. °F,

p = pressure of interest. psia

API = oil API gravity

γ_{gc} = gas gravity

The constants are determined from

Constant	API ≤ 30	API > 30
C_1	$4.677X10^{-4}$	$4.670X10^{-4}$
C_2	$1.751X10^{-5}$	$1.100X10^{-5}$
C_3	$-1.811X10^{-9}$	$1.337X10^{-9}$

The oil formation volume factor decreases at pressures above the bubblepoint pressure and is calculated from

$$B_o = B_{ob} EXP[C_o (p_b - p)]$$

where

B_{ob} = oil FVF at p_b

p_b = bubblepoint pressure, psia

p = pressure of interest , psia

C_o = oil isothermal compressibility , psi^{-1}

(c) Water. The equation given in the HP petroleum Fluids Pac is

$$B_w = B_{wp}(1 + XY \times 10^{-4})$$

where

$B_w =$ formation volume factor for brine in contact with gas, bbl / STB

$B_{wp} =$ FVF for pure water , bbl / STB

Y = water salinity , ppm

$$X = 5.1\times10^{8} p + (T-60)(5.47\times10^{-6} - 1.95\times10^{-10} p) + (T-60)^2(-3.23\times10^{-8} + 8.5\times10^{-13} p)$$

$$B_{wp} = C_1 + C_2 p + C_3 p^2$$

where

$$C_1 = 0.9911 + 6.35\times10^{-5} T + 8.5\times10^{-7} T^2$$

$$C_2 = 1.093\times10^{-6} - 3.497\times10^{-9} T + 4.57\times10^{-12} T^2$$

$$C_3 = -5\times10^{-11} + 6.429\times10^{-13} T - 1.43\times10^{-15} T^2$$

$T =$ °F

$p =$ psia

A4. Determination of Statistical Parameters

The statistical parameters used in this thesis are defined below:

The percent relative error (d_i) is the relative deviation of a calculated pressure drop from a corresponding measured pressure drop and given by

$$d_i = \frac{\Delta p_{wf_{meas}} - \Delta p_{wf_{cal}}}{\Delta p_{wf_{meas}}} \times 100$$

where,

$\Delta p_{wf_{cal}} =$ calculated pressure drop in well

$\Delta p_{wf_{meas}} =$ measured pressure drop for same condition

The average percent relative error (d) is the ratio of sum of the relative error and the number of cases considered and is given by

$$d = \frac{\sum_{i=1}^{N} d_i}{N}$$

The average absolute percent error (d_a) is the average of the absolute values of the relative errors and is given by

$$d_a = \frac{\sum_{i=1}^{N} |d_i|}{N}$$

The standard deviation of percent difference values (σ) from the average percent difference is given below

$$\sigma = \sqrt{\frac{\sum_{i=1}^{N} (d_i - d)^2}{N-1}}$$

where

N = the total number of cases considered

A5. Determination of friction factor

In Guo's four-phase flow model, Nikuradse's correlation is used to determine the Moody friction factor for completely turbulent flow

$$f = \left[\frac{1}{1.74 - 2\log\left(\frac{2e}{d_H}\right)} \right]^2$$

where

e = tubing wall roughness, ft

d_H = hydraulic diameter, ft

A6. Determination of temperature

In the incremental calculation, the equation that has been developed by Kirkpatrick is employed to determine the temperature at each length increment. The Kirkpatrick's model is given by:

$$T_{fz} = T_{BH} - g_{tf} Z / 100 \qquad \text{(A6.1)}$$

where,

T_{fz} = temperature of fluid at any depth, $^\circ$F

T_{BH} = bottomhole pressure, $^\circ$F

g_{tf} = flowing temperature gradient of the fluid, °F/100ft

Z = well depth or distance above fluid entry, ft

The procedure for determining the temperature at each length increment is as follows:

1) From the known wellhead temperature (T_{fz}), bottomhole temperature (T_{BH}), and well depth (Z), Equation A6.1 can be employed to determine the flowing temperature gradient (g_{tf}). For the known average temperature, the wellhead temperature (T_{fz}) is assumed and then the flowing temperature gradient (g_{tf}) is determined from that equation.
2) After the flowing pressure gradient (g_{tf}) is obtained, Equation A6.1 is employed again to determine the temperature at the selected length increment (T_{BH}).
3) In this study, a linear variation of temperature with depth is assumed. The determined temperature (T_{BH}) from step 2 becomes the wellhead temperature (T_{fz}) for next selected length increment and then determine the temperature at that selected length increment (T_{BH}).
4) The temperature at each selected length increment is calculated until the total depth is reach.

Vitae

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