A SIMPLE PROCEDURE FOR CALCULATING SHUT-IN TUBING PRESSURE (SITP)

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ABSTRACT: *Facilities and Drilling Engineering usually require the expected shut-in tubing pressure (SITP) for oil wells in order to size the wellhead equipment and for surface facilities design. Often times this information is not available and has to be estimated. A simple procedure for calculating the wellhead shut-in tubing pressure has been developed from basic physical laws using reservoir data such as reservoir pressure, producing GOR, oil and gas gravities, production depth and reservoir temperature. Comparison of the predictions with actual measured field data validates the accuracy of t his simple procedure.*

Keywords: GOR, Tubing Pressure, Gravity, Well Ends, Shut-in Tubing Pressure, Gas Density

Received for Publication on 30 June 2014 and Accepted in Final Form 4 July 2014

INTRODUCTION

Shut-in Tubing pressure (SITP) estimates are usually required for selecting well head equipment and for surface facilities design. This information is not always available, especially for newly drilled or completed zones that have not been tested. A simple procedure for estimating SITP from readily available field data is presented in this paper.

PROCEDURE

The following assumptions were made

- Properties of gas and oil are evaluated at the average temperature and pressure of the tubing.
- Temperature corrections for the oil volume are negligible.

The calculation procedure is as follows:

1. Guess a "SITP" (a good start is $P_r/2$)
2. Average tubing temperature, $T_{avg} = 0.5*(T_r + T_{wh})$
3. Average tubing pressure (psia), $P_{avg} = 0.5*(P_r + SITP)$

4. Gas density (Lbm/Cu ft), P_g = (28.97*Y_g*P_{avg}) / (Z*R*T_{avg})
5. Liquid compressibility (psi^{-1}), C_1 = Co* (1 – water cut) + C_w*(water cut)
6. Liquid volume, V_1 in the tubing per stock tank barrel (cu ft),
   V_1 = 5.615 * [1 – {C_1 * (P_{avg} – 14.7)}]
7. Gas volume, Vg in the tubing per stock tank barrel (cu ft).
$$Vg = \frac{Z * GLR * (T_{avg} + 460) * P_s}{P_{avg} * (T_s + 460)}$$
8. Gas gradient (psi/ft), $\Gamma_g = \rho_g / 144$
9. Oil gradient (psi / ft)
$$\Gamma_o = \left(\frac{1415}{131.5 + API} \right) * 0.433$$
10. Liquid gradient (psi/ft),
    $\Gamma_1 = \Gamma_o$ *(1 – Water Cut) 0.433* Water Cut
11. Fluid gradient (psi/ft),
$$\Gamma_f = \frac{V_1 + V_2 * \Gamma_g}{V_1 + V_g}$$
12. Shut-in tubing pressure (psia),

Check if SITP calculated from step 12 and previous SITP are the same within tolerance. If not, use the newly calculated SITP and repeat steps 3 – 13 until convergence is attained.

SAMPLE CALCULATION

The shut-in tubing pressure of a well will be calculated from the information given below:

- Reservoir pressure = 3500 psia
- Reservoir temperature = 200 °F
- Producing depth = 7000 ft TVD
- Gas-Oil Ratio = 1000 SCF/STB
- Oil compressibility = 1.0E-5 psi^{-1}
- Water compressibility = 3.5E-6 psi^{-1}
- Well head temperature = 80 °F
- Gas compressibility factor Z= 1-(7.4E-5*P + 1.33E-8*P^2)
- Gas specific gravity = 0.7
- Oil gravity = 40 °API
- Water Cut = 0%

STEPS

1. Start with an initial guess of P_r/2. SITP = 0.5*3500 = 1750 Psia
2. T_{avg} = 0.5* (2w00 +80) = 140 °F (600 °R)
3. P_{avg} = 0.5* (3500 + 1750) = 2625 psia
4. ρ_g = (28.97*0.7*2625) / (0.8974*10.73*600) = 9.214 Lbm/cu ft.
5. C_1 = 1.0E-5 psi^{-1}
6. V_1 = 5.615* [1- 1E-5*(2625-14.7)] = 5.468 cu ft
7. V_g = (0.8974* 1000* 600* 14.7)/(2625*520) = 5.8 cu ft
8. Γ_g = 9.214/144= 0.064 psi/ft
9. Γ_1 = [141.5/(131.5 + 40)]* 0.433 = 0.3573 psi/ft
10. Γ_f = (5.468*0.3573+5.8*0.064) /(5.468+5.8) = 0.2063 psi/ft
11. SITP = 3500 – 7000 * 0.2063 = 2056 psia

12. Compare calculated SITP (2056 psia) with initial guess (1750 psia). Repeat steps 3 – 12 with new "SITP" estimate until convergence is attained.

In this example, shut-in tubing pressure was estimated to be 2019 psi and convergence was attained after 5 iterations.

COMPARISON WITH FIELD DATA

A comparison of actual measure shut-in tubing pressures from the field with estimates from this method are given in table 1. As can be seen from the table, the calculated shut-in tubing pressures are in relatively good agreement with measured values.

CONCLUSIONS

In conclusion we can state the following:

The estimated shut-in tubing pressure values from this method are comparable with field measured values provided the input data is of acceptable quality. This method can be used to estimate anticipated shut-in tubing pressures for newly drilled or completed zones. In addition, estimates from this method can be used to check and validate field measurements.

ACKNOWLEDGEMENT

We thank the management of Chevron Nigeria Limited and Nigeria National Petroleum Corporation for allowing the publication of this paper.

NOMENCLATURE:

P_r = Reservoir pressure (psia)

P_s = Pressure at standard conditions (psia)

T_r = Reservoir temperature (^oF)

T_s = Temperature at standard conditions (^oF)

T_{wh} = Well head temperature (^oF)

Y_g = Specific gravity of gas

C_o = Oil compressibility (psi^{-1})

GLR = GOR * (1 – water cut) (scf/STB)

H = Producing depth (ft TVD)

Z = Gas compressibility factor

R = Gas constant (psi. cu ft/ [Lbmol. ^oR])

TABLE 1: Comparison of Calculated SITP with Actual Measured Values

Well	Datum, (ft TVD)	Reservoir Pressure (psia)	Oil Gravity (API)	GOR (scf/STB)	Water Cut (%)	Measured SITP (psia)	Calculated SITP (psia)	% Difference

A	8200	2515	37.9	1497	25	1020	1095	+7.4
B	7550	2400	38.5	320	30	340	335	-1.5
C	4946	2120	21.6	245	0	645	707	+10.0
D	6200	2226	26.8	726	55	800	769	-3.9
E	5650	2043	28.7	619	55	900	791	-12.1

Reference to this paper should be made as follows: Akpoturi Peters and Nwakaudu Stanley (2014), A Simple Procedure for Calculating Shut-In Tubing Pressure (SITP). *J. of Engineering and Applied Scientific Research*, Vol. 6, No. 2, Pp. 63 – 65.