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Introduction of A Risk Management Method by Design a Modified Equation to Calculate the Static Bottom-hole Pressure of Iranian Gas Wells Based on Hierarchy Risk Management and Surface data To Replace and Eliminate Operational Risk (Second Development)

Hamid Babakpour[1*], Moona Batooie[2], Sepideh Sorouri[3], Ashkan Zonnoori[4]
1- **Islamic Azad University, Ahwaz Branch[1]**
2- Petroleum Engineering and Development Company[2]
3- Khatam University of Technology, PA[3]
4- National Iranian South Oil Company[4]

Corresponding author, babakpour.hamid1@gmail.com1*

Abstract
In high H2S gas well doing industrial operations can causeserious environmental, financial & health consequences, risk management plays an important role especially these days that world in war with SARS-COV 2 pandemic we should have stronger boundaries to protect lives. One of the common methods is hierarchy method. In this study by using a combination of this method and design a new correlation to calculate static bottom hole pressure at gas wells we tried to have a strong risk management with a final goal to replace the industrial operation.Inthe past, time-consuming and imprecise trial and error methods& expensive operations were used to calculate static bottom-hole pressure for gas wells. So,a general equation was modified based on field observations to obtain more accurate predictions of static bottomhole pressure. For this purpose, a unique adjustable parameter, based on history matching of wells, has been proposed for each reservoir. Accuracy of this equation was investigated in three Iranian gas reservoirinformation.Good agreement was obtained among the field observations and this proposed equation.The precision of this method depends on field data and with increasing numbers of field tests, the model becomes more accurate.

Keyword: high H2S gas wells, hierarchy method, modified equation, risk management, SARS-COV 2 pandemic, static bottom-hole pressure.

1. Introduction

Periodic measurement of static bottom-hole pressure (SBHP) of wells is essential to monitor the reservoir depletion and gathering information and also, accurate SBHP values are essential for gas reservoir engineering calculations.Thegasreservoir pressure has been calculated from wellhead pressurefor many years [1]. The success of pressure transient analysis often depends on the accurate measurement or estimation of the bottom-hole pressure [2]. Pressure measurement is appropriate method, but it is time consuming and costly, especially with the deep wells, high temperature reservoirs and in the presence of highly corrosive gases. Therefore, the estimation of static pressure via an accurate method is necessary. The equations, based on the average properties of the gas, can be developed for determination of SBHPin gas wells. The methods that have been discussed in literatures, for calculation of gas gradient pressure in tubing and reservoir, are based on the properties of the fluid column in the well with some simple assumptions.

In 1945 Rzasa and Katz developed three methods to calculate the static pressure gradient in gas wells using the trial-and-errormethod. They developed charts from which pressure gradients may be read when the wellhead pressure, the well fluid gravity, depth and the average well temperature should be given [1]. Messer et al.,considered z-factor as a linear function of reduced pressure, Pr, between 10 - 30 for reduced temperatures, Tr, between 1.1 – 3 and used numerical integration method for solving their suggested equation [3].Economides presented two correlations for calculating static bottom-hole gas pressure in either saturated or slightly superheated vapor. Also, he suggested that the vapor density is a linear function of pressure [2]. Bender and Holden used different temperature distribution functions to determine the average temperature in the well columnfor average z-factor calculation [4]. Moreover, other researchers developed some methods to calculate static bottom-hole pressure for gas wells using simplifying assumptions [5]. In this paper, a new equation has been suggested, and used for the comparison with field observations.

2.Theory

2.1. Derivation of Formula

The basis of SBHP calculation technique is energy balance in the wellbore. The general differential form of the energy balance equation describing steady-state flow in pipes [6]:

$$\frac{144}{\rho}dp + \frac{g}{g_c}dL + \frac{v}{g_c}dv + dF = -dw_s \tag{1}$$

Where:

ρ is the fluid density, p is pressure, gis local acceleration, gcisdimensional constant, v is flow velocity, F is energy loss resulting from friction and ws is a total shaft work done by the system.

In a static gas column, the kinetic energy, shaft work and friction effects are zero and can be eliminated from the Eq. (1).

$$\frac{144}{\rho}\mathrm{dp} + \frac{\mathrm{g}}{\mathrm{g_c}}\mathrm{dL} = 0 \tag{2}$$

In American Engineering Unit g=g_c, therefore Eq. (2) is rearranged as below:

$$\mathrm{dp} = \frac{144}{\rho}\mathrm{dL} \tag{3}$$

Using the real gas equation of state (EoS), the gas density can be intended as a function of pressure:

$$\rho_g = \frac{\mathrm{pM}}{\mathrm{zRT}} = \frac{28.97\gamma_g \mathrm{p}}{\mathrm{zRT}} \tag{4}$$

Where*M* is molecular weight of gas ($\frac{lb_{mass}}{lb_{mole}}$), *Z* is gas compressibility factor, *R* is universal gas constant, 10.732 ($\frac{psi.ft^3}{lb_{mole}\cdot {}^\circ R}$), γ_g is gas specific gravity and *T*is theabsolute temperature (˚*R*).

Substitution of Eq. (4) in Eq. (3) yields:

$$\mathrm{dp} = -\frac{0.01875\ \mathrm{ygp}}{\mathrm{zT}}\mathrm{dL} \tag{5}$$

Figure 1 illustrated the schematic of a vertical well geometry. It is obvious that gas density and compressibility factor are functions of pressure and temperature. In addition, temperatureand pressure change with depth. Therefore, solving the differential equation, (Eq. (5), is complicated. To simplify the solution, the z-factor and temperature were assumed to be constant and can be represented by average values. Typically,these average values are determined in an arithmetic average of the surface and bottom-hole temperature and pressure [6].

Substituting an average temperature,$\overline{T}$,and an average z-factor,$\overline{z}$, into Eq. (5), integration from bottom to top of the wellbore,SBHPcan be derived as follow [6]:

$$\int_{\mathrm{pws}}^{\mathrm{pwhs}} \frac{\mathrm{dp}}{\mathrm{p}} = -\frac{0.01875\gamma_g}{\overline{\mathrm{z}}\overline{\mathrm{T}}} \tag{6}$$

$$P_{ws} = P_{whs} \times exp\left(\frac{0.01875\gamma_g H_t}{\overline{z}\overline{T}}\right) \tag{7}$$

Where, H_t is total depth of well (ft), P_{ws} and P_{whs} are static bottom-hole and static wellhead pressures (psia), respectively.

Eq. (7) is general form for calculating the SBHP using surface field data. Because$\overline{z}$depends on P_{ws}, the solution to Eq. (7) involves a time-consuming iterative process.

In this study, a new method has been proposed to solve Eq. (7) for reducing time and improving accuracy of results.

3.Proposed Equation and Method

To improve the correlation results, a positive adjustable and dimensionless parameter, α, which is unique for each reservoir, wasconsidered in Eq. (7). In fact, this parameter is adjusted to eliminate the trial-and-error calculations and can be obtained by matching the measured pressure of the reservoir. Thus, proposed equation is:

$$P_{ws} = P_{whs} \times exp\left(\alpha \times \frac{0.01875\gamma_g H_t}{\overline{z}\overline{T}}\right) \tag{8}$$

For solving this equation, some steps must be done as follows:

I- Give the basic information about reservoir such as: initial reservoir pressure, P_i, initial reservoir temperature, T_i, and mole fraction of components that represented as the reservoir fluid sample.

II- Use the available information of wells in the reservoir such asstatic wellhead pressure, P_{whs}, measured Static bottom-hole pressure, $P_{ws\text{-}gauge}$, static wellhead temperature, T_{whs}, and well depth, H_t, which measured previously.

III- Calculate average pressure and temperature for each well as follow:

$$\overline{\mathrm{P}} = \frac{\mathrm{P_i} + \mathrm{P_{whs}}}{2}$$

$$\overline{\mathrm{T}} = \frac{\mathrm{T_i} + \mathrm{T_{whs}}}{2}$$

IV- Calculate the z-factor of each well. In this work, Wichert and Aziz correlation were used to account inaccuracies in Standing and Katz chart, when the gas contains significant fractions of CO_2 and H_2S [7]. Also,for the effect of high molecular weight gases correction, Sutton’s correlation has been used [8].

V- A range for α from 0 was considered.

VI- For the first value of α, static bottom-hole Pressure, P_{ws_calc}, was calculated for each well by available data of reservoir (T_i, $P_i$and γ_g) and wells (P_{ws_gauge}, P_{whs} and H_t) with Eq. (8).

VII- Calculate Root Mean Square Deviation, *RMSD*, of reservoir for consideringα as follows:

$$\mathrm{RMSD} = \sqrt{\frac{\sum_n \left(\mathrm{P_{wscalc}} - \mathrm{P_{wsgauge}}\right)^2}{\mathrm{n}}} \tag{9}$$

Where, *n* is the number of wells in the reservoir that has been reported $P_{ws_gauge}$for each of them.

VIII- In this step, by the new value of *α* (previous *α*+*ε*), steps VI and VIIwould be repeateduntil α reach to the maximum value in the range.

IX- *RMSD* vs. *α* is plotted. The optimum value of *α* of the reservoir causes to have minimum *RMSD*.

Using optimum *α*, the static bottom-hole pressure of any wells in the reservoir has been computed by Eq. (8) without necessity to use the pressure gauges anymore.

Table 1. Mole fraction of components for three reservoirs.

component	Mole fraction		
	Reservoir 1	Reservoir 2	Reservoir 3
N_2	0.06	0	0.2
Co_2	2.35	10.77	2.42
H_2S	0	24.46	0.07
C1	85.65	63.07	86.85
C2	6.35	0.79	5.81
C3	2.42	0.28	2.57
i-C4	0.56	0.07	0.42
n-C4	1	0.11	0.86
i-C5	0.43	0.07	0.25
n-C5	0.39	0.08	0.25
C6	0.41	0.08	0.15
C7+	0.38	0.22	0.15

Table 2. Initial pressure and temperature of reservoirs.

reservoir	Pi(psia)	Ti (°F)
1	12750	285
2	7531	220
3	4185	180

Table 3. Initial pressure and temperature of reservoirs.

Parameter	Well 1			Well 2		Well 3		
	Test 1	Test 2	Test 3	Test 1	Test 2	Test 1	Test 2	Test 3
P_{ws_gauge} (psia)	12746	12734	12558	12558	12332	11378	11053	10523
P_{whs} (psia)	9389	9400	9336	9296	9035	8178	7927	7390
H_t (ft)	15958	15958	15958	15925	15925	15917	15917	15917
T_{whs} (°F)	195.5	197.5	195.5	199.1	205	209	210	196

Table 4. Measured information of wells in reservoir 2.

Parameter	Well 1	Well 2	Well 3	Well 4
P_{ws_gauge} (psia)	2404	2529	2544	2572
P_{whs} (psia)	1495	1664	1609	1630
H_t (ft)	13650	13284	13690	13595
T_{whs}(°F)	70	68	75	73

Table 5. Measured information of wells in reservoir 3.

Parameter	Well 1	Well 2	Well 3 Test 1	Well 3 Test 2	Well 4
P_{ws_gauge} (psia)	2961	3024	3026	3017	3011
P_{whs} (psia)	2350	2310	2325	2330	2360
H_t (ft)	8010	8772	8482	8482	7868
T_{whs}(°F)	130	131	121	121	118

Table 6. calculated values of α for each reservoir.

reservoir	Average P_{ws}	α
1	11985	1.580
2	2509	1.089
3	3008	1.267

Table 7. Comparison between Pws-gauge and calculated Pws of each well in reservoir 1 by α=1.580.

well	$P_{wsgauge}$ (psi)	Calculated P_{ws} (psi) by Eq. 8	RAE (%) Eq. 8	Calculated P_{ws} (psi) by Eq.7	RAE (%) Eq. 7
Well 1	2404	2362	1.736	2172	9.649
Well 2	2529	2591	2.454	2412	4.629
Well 3	2544	2532	0.461	2343	7.882
Well 4	2572	2559	0.502	2372	7.745

Table 8. Comparison between Pws-gauge and calculated Pws of each well in reservoir 2 by α=1.089.

well		$P_{wsgauge}$ (psi)	Calculated P_{ws} (psi) by Eq. 8	RAE (%) Eq. 8	Calculated P_{ws} (psi) by Eq.7	RAE (%) Eq. 7
Well 1	Test 1	12746	12809	0.495	11509	9.703
	Test 2	12734	12818	0.666	11518	9.547
	Test 3	12558	12677	0.948	11451	8.808
Well 2	Test 1	12332	12337	0.044	11721	6.662
	Test 2	11378	11243	1.180	11108	9.918
Well 3	Test 1	11053	10922	1.186	10165	10.657
	Test 2	10523	10259	2.506	9887	10.543
	Test 3	12558	12743	1.470	9310	11.522

Table 9. Comparison between Pws-gauge and calculated Pws of each well in reservoir 3 by α=1.267.

well		$P_{wsgauge}$ (psi)	Calculated P_{ws} (psi) by Eq. 8	RAE (%) Eq. 8	Calculated P_{ws} (psi) by Eq.7	RAE (%) Eq. 7
Well 1		2961	2993	1.084	2873	2.960
Well 2		3024	3010	0.450	2878	4.820
Well 3	Test 1	3026	3013.	0.397	2885	4.661
	Test 2	3017	3020	0.111	2891	4.174
Well 4		3011	3004	0.207	2885	4.169

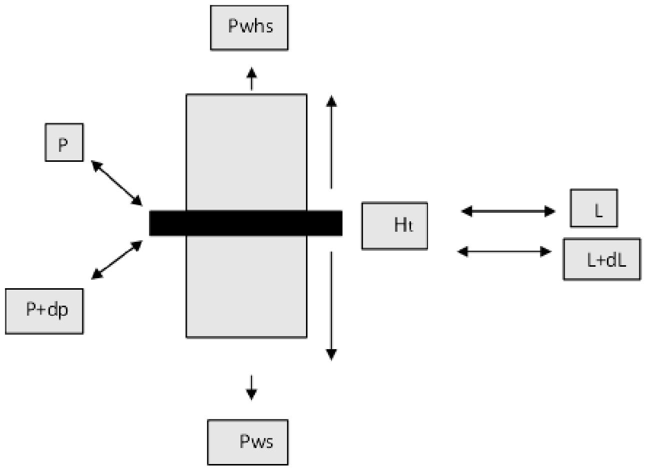

Fig. 1. shematic of a vertical well geometry.

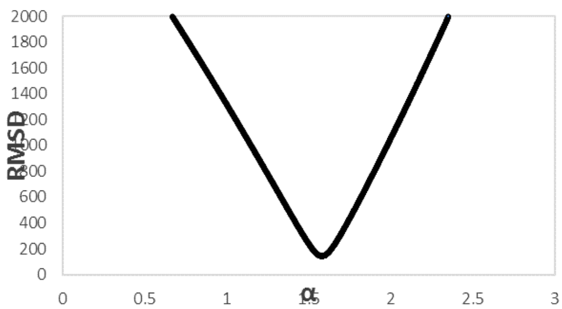

Figure 2. RMSD vs. α for reservoir 1.

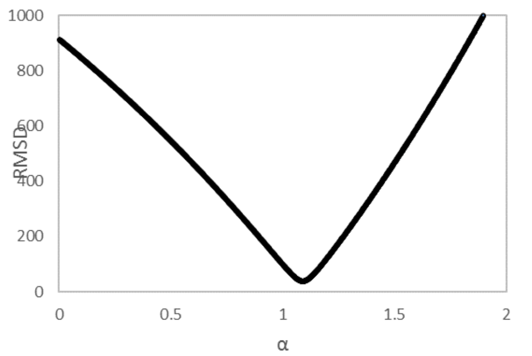

Figure 3. RMSD vs. α for reservoir 2.

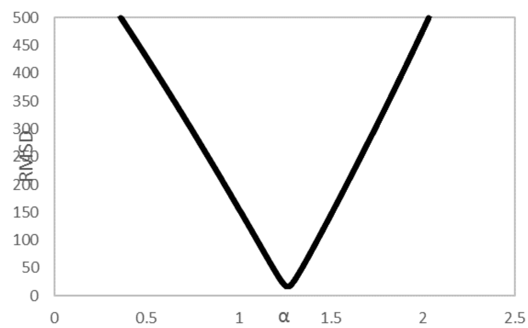

Figure 4. RMSD vs. α for reservoir 3.

4. Results and Discussion

Table I shows the components mole fraction and Table II presents initial pressure and temperature of three Iranian gas reservoirinformation.MeasuredPwhs, Pws-gauge, Twhs and Htof wells in each reservoir are listed in Tables IIItoV. In Figures 2 to 4, RMSD vs. αwas plotted for each reservoir and the optimum values ofαwere selected and listed in Table VI. Using obtainedα of each reservoir,Pws_calcof wells have been calculated by Eq. (8) and also byEq. (7) (Using trial and error method). The results are shown in Tables VIItoIX. Also, Relative Accuracy Error (RAE) of each calculated SBHPis listed in tables VII to IX. According to tables VII to IX, the new model (Eq. (7))haslessRAE than the base model (Eq. (7)). It is important to be noted that, accuracy of this method depends on field data and with increasing numbers of field tests, the results of this model become more reliable.

5. Conclusions

In this work, a modified equation has been applied to forecast theSBHP of gas wells in different reservoirs without using the time-consuming trial and error methods by introducing an adjustable parameter, α. This parameter would be obtained by history matching and used in the proposed equation to predict SBHP in other wells or in other times. The model was found to correlate the observed data with good accuracy and can count as a good way to eliminate operational risk.

6. References

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