Review Of Various Methods For Estimating Pressure Gradients In Gas Lift Wells

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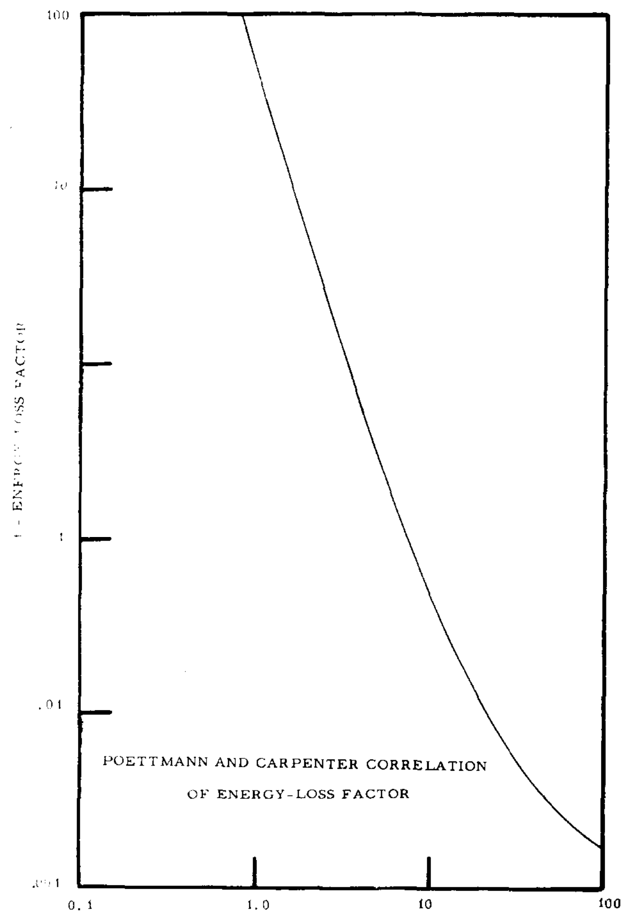
INTRODUCTION

In reviewing the literature one finds many methods for estimating pressure gradients in gas lift wells. Generally, most methods differ only in their prediction of energy loss due to friction. Some investigators [1,3,5,6,8], have correlated friction or energy loss factors from field data with Reynolds' number. Yocum [2], found that the correlation of the two-phase flow friction factor with the square of the Froude number gave the best results. Similarly Tek [7] correlated the friction factor with the 2 phase Reynolds' number. Other parameters used in correlation with the friction factor are slippage [4 8], and superficial velocity ratios [9].



$DV\rho = \frac{1.4737 \times 10^{-5} MQ}{D}$

FIGURE 1

Because of the complexity of the problem most investigators choose the empirical approach to predicting pressure drops in multiphase flow systems. As Tek [7], points out the classical approach to estimating pressure gradients in vertical flow strings would have to be based upon the formulation and solution of Navier-Stokes equations, and this presents a formidable task even with the advent of present computer techniques. It is difficult to describe what actually occurs in multiphase flow much less formulate the boundary conditions necessary for an analytical solution.

In general, all methods are limited in their application to specific flow conditions. Therefore, it is the purpose of this paper to review the assumptions, fundamental procedures and applications for a variety of the most commonly known methods of estimating pressure gradients in gas lift wells.

DISCUSSION

There are generally 2 equations used in determining pressure gradients in 2 phase flow. They are equations based either on the energy-balance or pressure-balance. Poettmann and Carpenter chose to use the energy-balance equation

$$144 \frac{dP}{dh} = \bar{p} = \frac{f\, Q^2 M^2}{7.413 \times \bar{p} \times D^5 \times 10^{10}} \qquad (1)$$

where

$\frac{dP}{dh}$ = pressure gradient (psi/ft)
$\bar{p}$ = integrated average density (lb/cu ft) of the two-phase mixture between two points in a vertical conduit.
QM = total mass flow (lb/day)
D = inside diameter of tubing (ft), and
f = dimensionless correlating function for the total energy loss.

These investigators correlated the energy-loss factor "f" with the numerator of the Reynolds' number, $\frac{DV\rho}{\mu}$ using field data. They reported that since the energy loss due to viscous shear is negligible, the viscosity term in Reynolds' number could be neglected. Thus their correlating parameter with "f" was

$$DV\,\rho = 1.4737 \times 10^{-5} \frac{MQ}{D} \qquad (2)$$

and is shown in Figure 1. It should be noted that Poettmann and Carpenter's correlations were based on 2.0

and 2.5 in. tubing, production rates from 5 to 1500 BPD and gas-oil ratios from 31 to 1500 cu ft per bbl. The field data were taken from 49 flowing and gas-lift wells.

This method produced good agreement between observed and calculated results. The standard deviation from the algebraic average of calculated and observed pressure was 8.3%. Quite likely, this correlation should be used only for the multiphase flow of gas and liquid through vertical tubing and should not be extended to flow through casing or to flow involving very high gas-oil ratios.

Baxendell and Thomas extended the energy-loss correlation of Poettmann and Carpenter so that it might be applicable to high-rate flow conditions. In their method the equations (see Equation 1 and 2) of Poettmann and Carpenter are utilized, but an extension was made to the energy loss curve. Figure 2 indicates this extension of the energy-loss factor, f, and is based

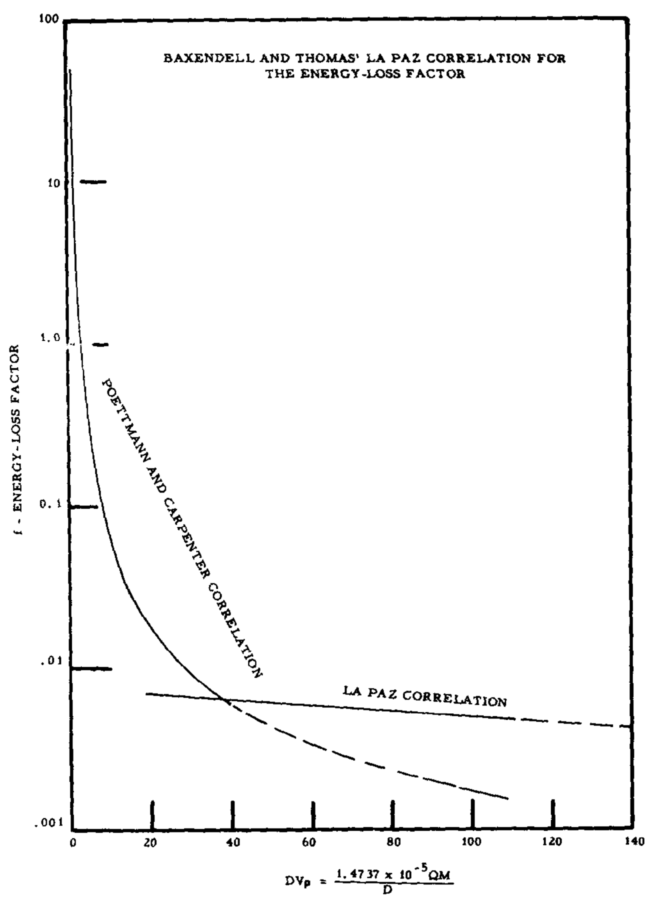


FIGURE 2

on data from the La Paz field in Venezuela. These investigators used high flow rate data, above 900 BPD for 2-7/8 in. O D tubing for their correlation of "f" with "DVp". It is interesting to note that they found this correlation to be applicable to a wide range of conduit sizes and crude types at high flow rates.

For annular flow Baxendell and Thomas point out that an equivalent diameter should be used so that in Equation (1)

$$D^5 = (D_c^2 - D_t^2)2\ (D_c - D_t) \qquad (3)$$

where

D_c = casing ID and

D_t = tubing OD

Furthermore, the diameter used in Equation (2) should be redefined as

$$\frac{QM}{D} = \frac{QM}{(D_c + D_t)} \qquad (4)$$

Baxendell and Thomas concluded that while there were insufficient readings for any satisfactory statistical analysis, it would appear that an average accuracy of the order of + 5% could be expected at the higher rates.

In 1962 Brown and Fancher[5] proposed a correlation for the friction factor which included 2 parameters neglected by Poettmann and Carpenter. These parameters were the viscosity and the gas-liquid ratio. Brown and Fancher changed Poettman and Carpenter's Reynolds' number, (Equation 2), to

$$DV\ p = \frac{1.437 \times 10^{-5}\ MQ}{D\mu^{0.18}} \qquad (5)$$

They then correlated the friction factor with this pseudo Reynolds' number for various ranges of gas-liquid ratios. In comparing their correlation to Poettmann and Carpenter's only a small deviation was found for gas-liquid ratios below 1500 SCF/bbl and QM/D'S between 15 and 50. This is noted in Figure 3 where a comparison is made of the 2 methods. The close agreement of the data points indicates that both methods are very reliable for this moderately low gas-liquid ratio of 324 SCF/bbl. However, a quite different conclusion is drawn from Figure 4. It is quite evident from this plot that Poettmann and Carpenter's prediction of pressure with depth was considerably in error. At 1200 ft, for example, the actual pressure was about 230 psi whereas the Poettmann and Carpenter method predicts a pressure of approximately 590 psi. The Brown and Fancher method estimates a pressure of 210 psi at this same depth.

From their results Brown and Fancher concluded that for high gas-liquid ratios and low flow rates, pressure gradients are dependent mainly on the friction term due to the decrease in flowing density.

Tek has presented a new method for correlating the data on multiphase flow through vertical pipe. This method is based on a "2 phase f factor" concept which was developed and successfully applied to horizontal multiphase flow. Tek defined the 2 phase Reynolds' number function as being

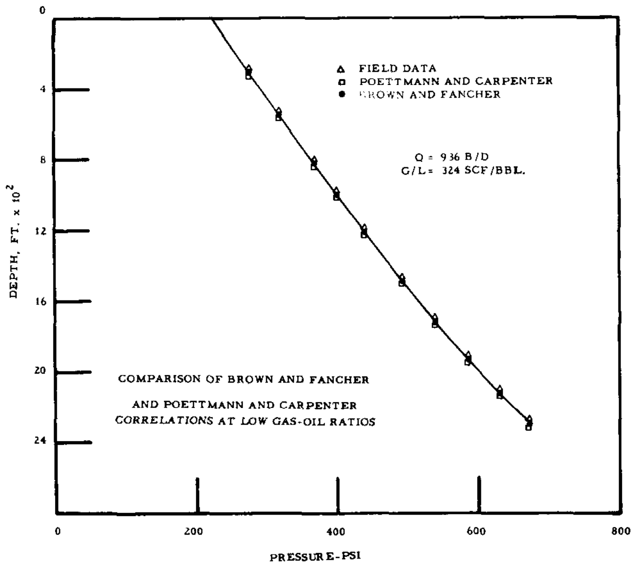


FIGURE 3

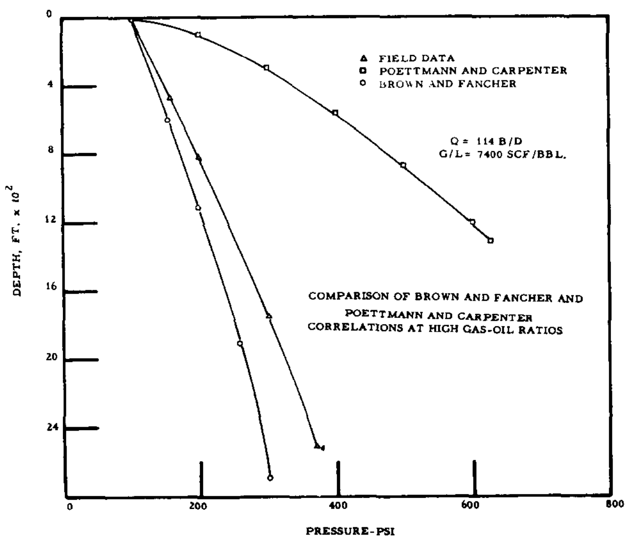


FIGURE 4

$$R_1 = R_G^{\,a} R_L^{\,b} \qquad (6)$$

where

$$a = \frac{K}{1 + K}$$

$$b = \frac{1}{e^{0.1K}}$$

R_G = Reynolds' number of gas phase

R_L = Reynolds' number of liquid phase, and

K = mass ratio of gas to liquid, based on separator and stock-tank quantities.

The constants a and b were chosen so that the 2 phase Reynolds' number function would be reduced to the single-phase Reynolds' number whenever K is equal to zero or infinity. This simply means that when only liquid is present R_1 is equal to R^2 and when only gas is present R_1 is equal to R_g.

Figure 5 shows the two-phase friction factor plotted as a function of the two-phase Reynolds' number R_1 for various mass ratios. The data used as a basis for this correlation were taken from 31 wells having pressure ranged from 240 psia to 2,571 psia and well depths from 1,053 to 10,800 ft.

The mass ratio was based on separator gas and stock-tank liquid quantities. Actually, the insitu value of "K" should change from point to point because the gas is constantly coming out of solution as the gas and liquid flow vertically upward through the tubing.

Tek reports that on the basis of data available from 31 flowing and gas-lift wells, this correlation resulted in a standard deviation of 7.3%.

An excellent paper based on a pressure-balance equation was presented by Ros[8]. His equation was

$$\frac{dP}{dh} = \text{static gradient} + \text{friction gradient} + \text{acceleration gradient}$$

Ros proposed that the various flow regimes can be divided into three main regions, those with low, intermediate and high gas throughputs, respectively. For these regions he developed slip, hold-up and friction correlations. Ros found the accuracy of his correlation to be between 3 and 10 percent depending on the region of flow. Because Ros' correlations are rather complicated a detailed presentation of his work is not within the scope of this paper.

An analytical study of the flow of fluids through small vertical conduits was made by Gaither, Winkler, and Kirkpatrick[9]. Their work was based on 2 phase gas-water mixtures and small tubing, 1-1/4 in. or less. They also considered the basic energy equation, Equation (1), presented by Poettmann and Carpenter; however, in their development of a 2 phase energy loss equation they included a superficial velocity ratio. A superficial velocity is defined as the calculated velocity of a single-phase gas or liquid flowing in the conduit, in the absence of the other phase. The velocity ratio is expressed as

$$R_V = \frac{.00504\ T_g\ Z R_{gL}}{P_{gf}} \qquad (7)$$

where:

Z = gas compressibility factor at P_{gf} and T_g

P_{gf} = flowing pressure, psia

R_{gL} = gas-liquid ratio, SCF/bbl.

T_g = temperature of gas, R.

A second parameter used by Gaither, et. al., for correlating the test data was R_g, the ratio of the total flowing pressure gradient to the energy loss gradient. The third parameter used was Q/D^3, the ratio of the producing rate in barrels per day to the diameter of the conduit cubed.

Figure 6 compares the energy loss correlations of these investigators to Poettmann and Carpenter's correlations. It is noted that Gaither's values of "f"

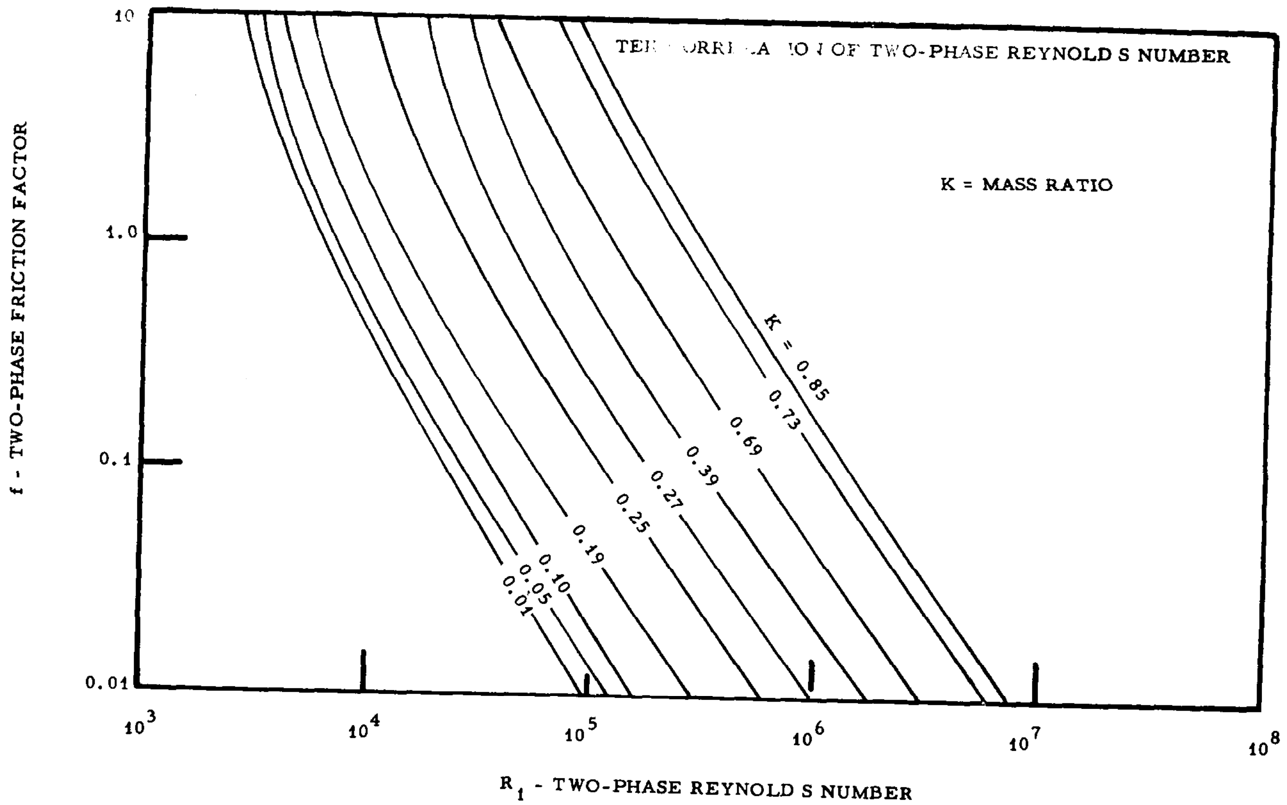


FIGURE 5

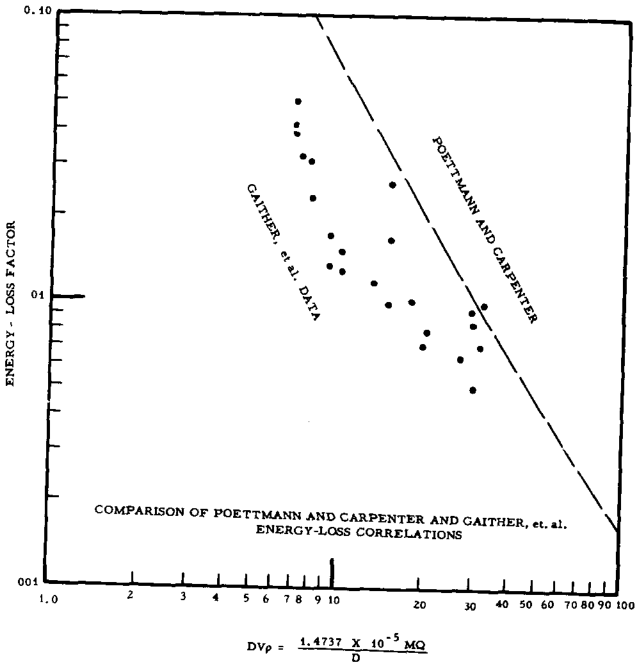


FIGURE 6

are significantly lower than Poettmanns except at high Reynolds' numbers. It should be pointed out that Gaither's data were obtained on one inch and 1-1/4 in. tubing whereas Poettman used 2 and 2-1/2 in. tubing.

In the U. S. we have few, if any wells, producing through big pipe at high flow rates. Yet, a good correlation should predict this condition accurately. In an attempt to compare the various methods of estimating pressure gradients in gas lift wells field data were obtained from various engineers and a comparison of calculated and observed results made. This comparison is shown in Figure 7. In this plot it is noted that the flow rate is rather high, 23,850 BPD and the GOR low at 116.2 cu ft/bbl. For these conditions both Poettmann and Carpenter's method and Brown and Fancher's method gave the poorest result. Baxendell's method was only slightly better. Beasley's equation was developed from measurements taken during P.I. tests in wells from 1 reservoir in Kuwait. His empirical formula is

$$\frac{dP}{dh} = \frac{W}{144B_t} + \frac{4.74B_t}{W(D_c - D_t)\, 1.0075^{(W/B_t - 27.94)^2}}$$

where:

W = weight of oil and gas associated with 1 cu ft of stock tank oil, lb/cu ft

B_t = 2 phase formation volume factor.

Beasley's equation appeared to give somewhat better results as the standard error was about 12% at 2,000 ft of depth. Rather significant is the fact that when the basic energy loss equation, Equation (1), was applied using a constant friction factor of 0.038 the results

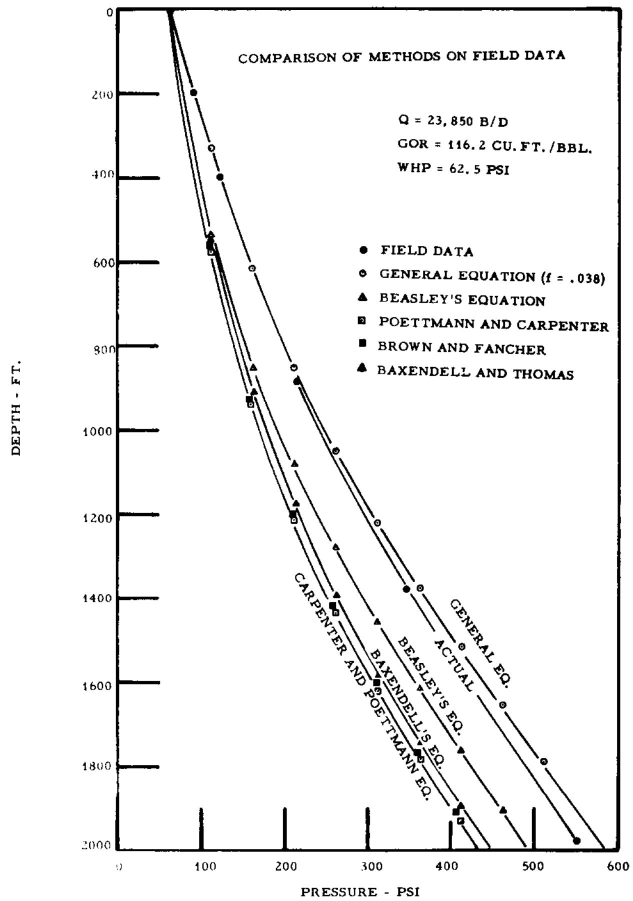


FIGURE 7

were remarkably good. The error using this equation was only 3.9%.

Figure 7 is a typical plot taken from many field tests in this set of data. It should be mentioned that all these methods gave slightly poorer results for higher gas-oil ratios.

CONCLUSIONS

In choosing a particular method for estimating pressure gradients in flowing and gas-lift wells, one must pay strict attention to the conditions upon which the method was based. The data to be utilized should be within the recommended ranges of application for the method employed. If ranges of applications are not stated, one should use a method developed for similar pipe size and flow conditions. Special cases may arise in which the temperature gradient and liquid viscosity can not be considered negligible.

It was the experience of these authors to find very little reliable gas solubility data especially in the low pressure region. Since the gas-liquid ratio has been shown to be an extremely important parameter, inaccurate solubility data can cause rather large errors in estimating the pressure gradients.

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