Lecture Six

Gradient Curves (Working Chart)

6.1 Practical application of vertical multiphase flow

The accuracy of vertical multiphase flow correlations is good enough that the following are some of the uses that can be made of them.

(1) Select correct tubing sizes (tubing or annular flow).

(2) Predict when a well will quit flowing and hence predict time for artificial lift.

(3) Design artificial lift installations.

(4) Determine flowing bottom hole pressures.

(5) Determine PIs of wells.

(6) Predict maximum flow rates.

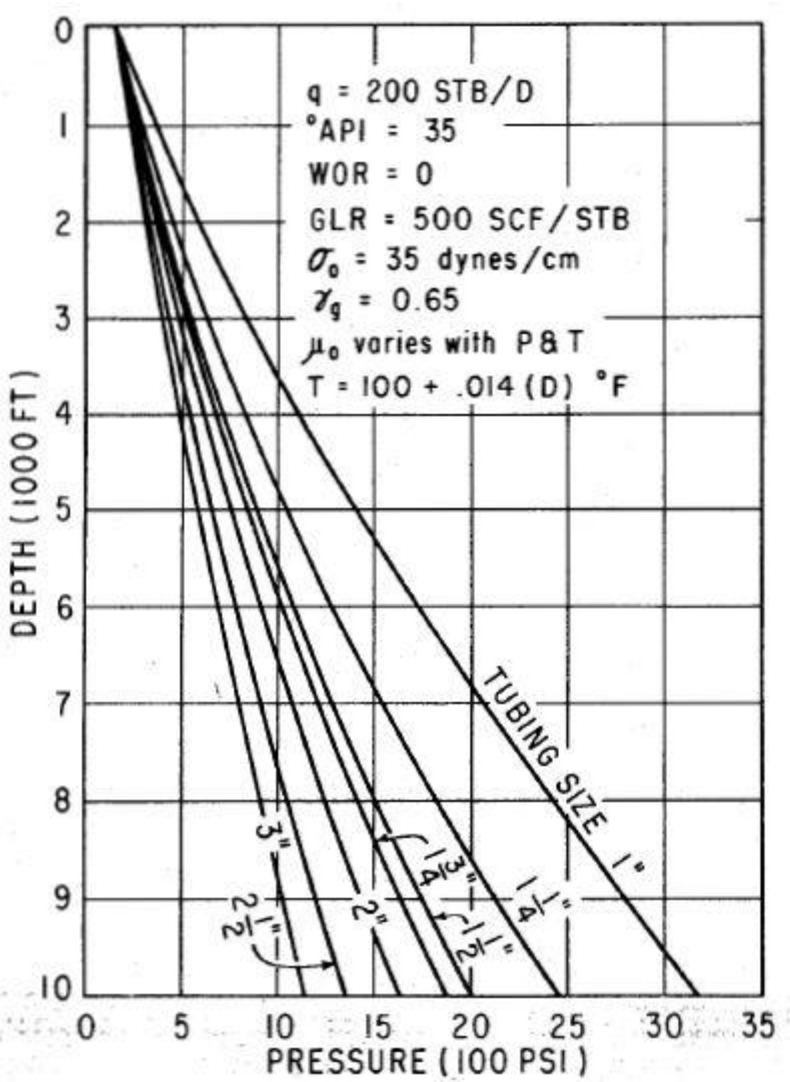
An understanding of the effect of various variables such as tubing diameters, flow rates, gas - liquid ratios, viscosity, density, etc., is necessary for good well completion and production practices. These selections of completion strings must be made prior to the drilling of the well.

We have two choices in making use of vertical multi phase flow correlations. The calculation can be made by computer or "working curves" can be used. Most companies have available at least one program for vertical multiphase flow , and there are numerous sets of working curves available either by widely published sets of curves or through restricted company published curves . If time permits the computer calculations are recommended, but there are numerous occasions where the production engineer must make use of working curves.

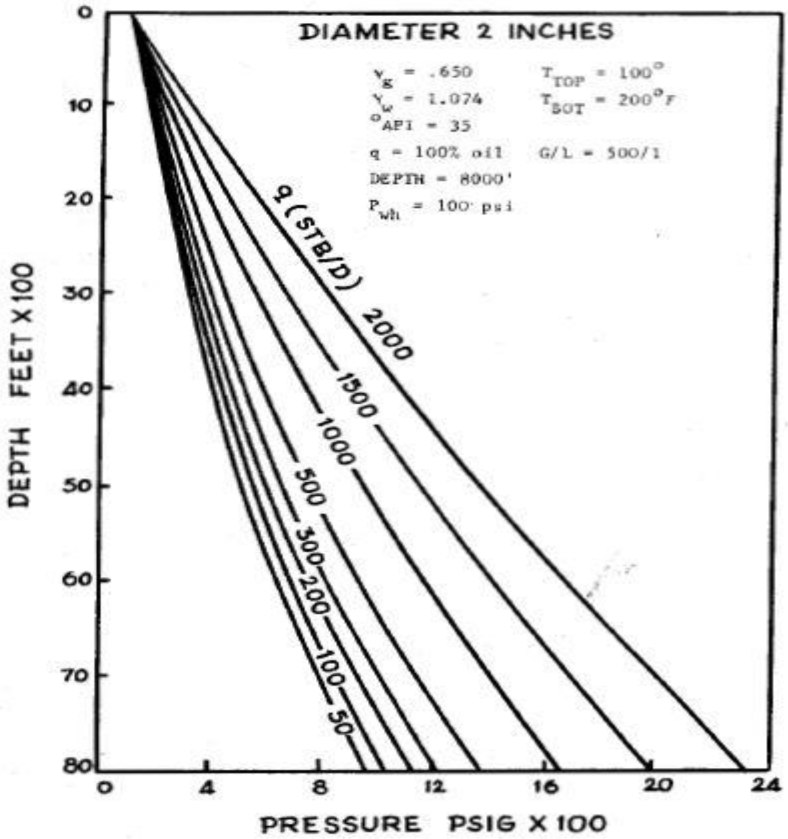
6.2 Effect of variables

In showing the effect of various variables, reference should be made to Brill, et al and Lopez. Many of 40 the figures are selected from their work in which the Hagedorn and Brown correlation was used. Other correlations would show the same general trends. The effects of such variables as tubing size, flow rate, viscosity, etc., are given in the following sections. Typical flowing wells have been selected to show these effects of variables.

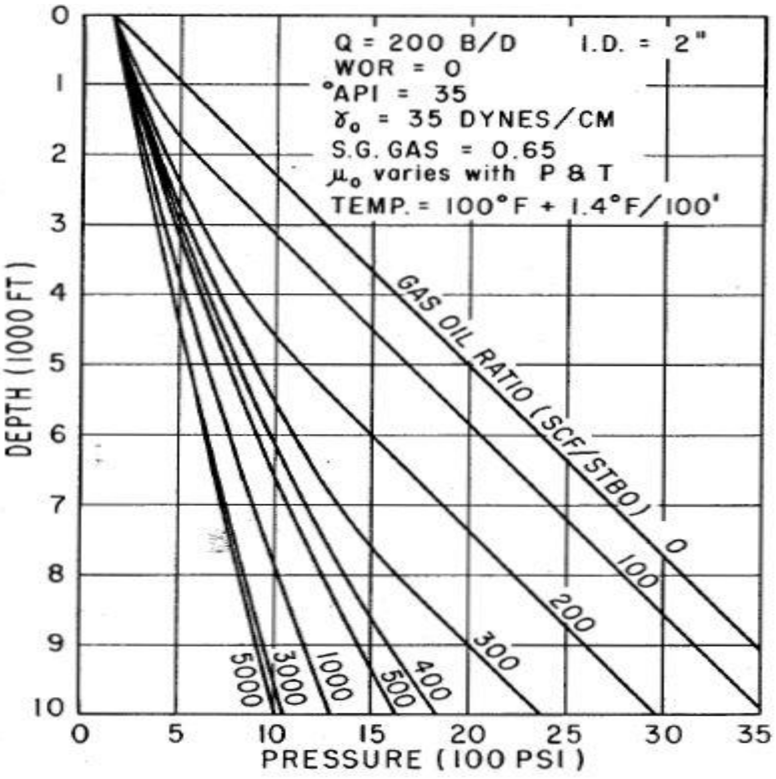
6.2.1 Effect of tubing size



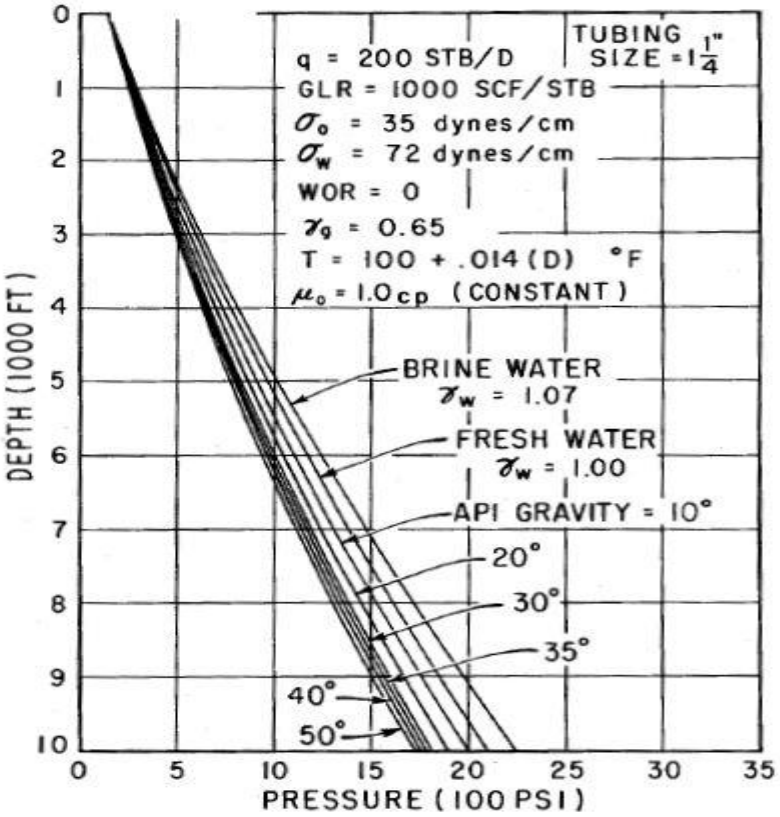
6.2.2 Effect of flow rate



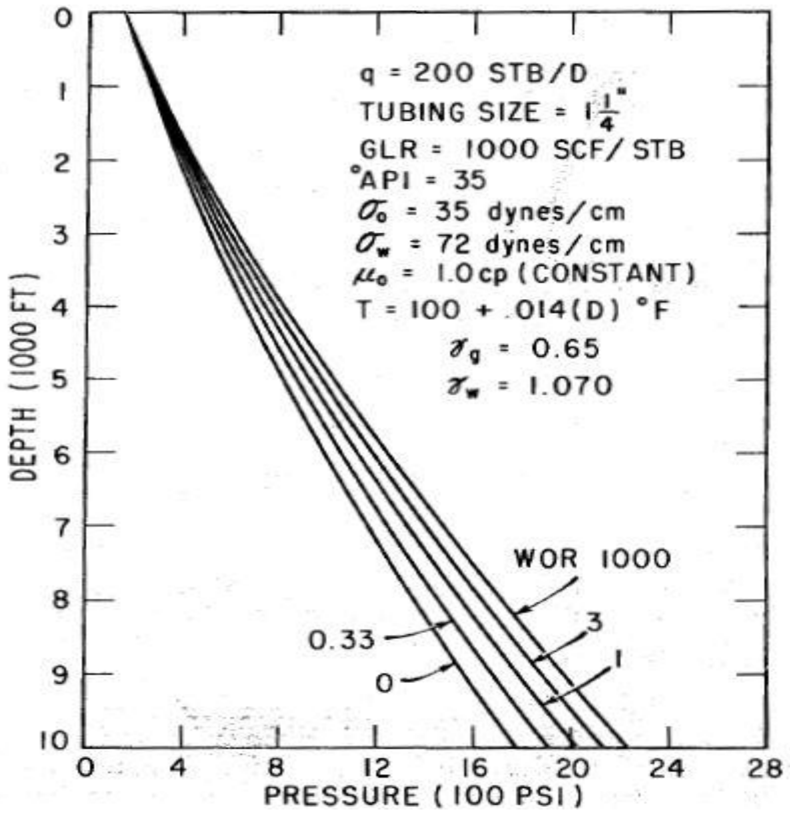
6.2.3 Effect of gas - liquid ratio



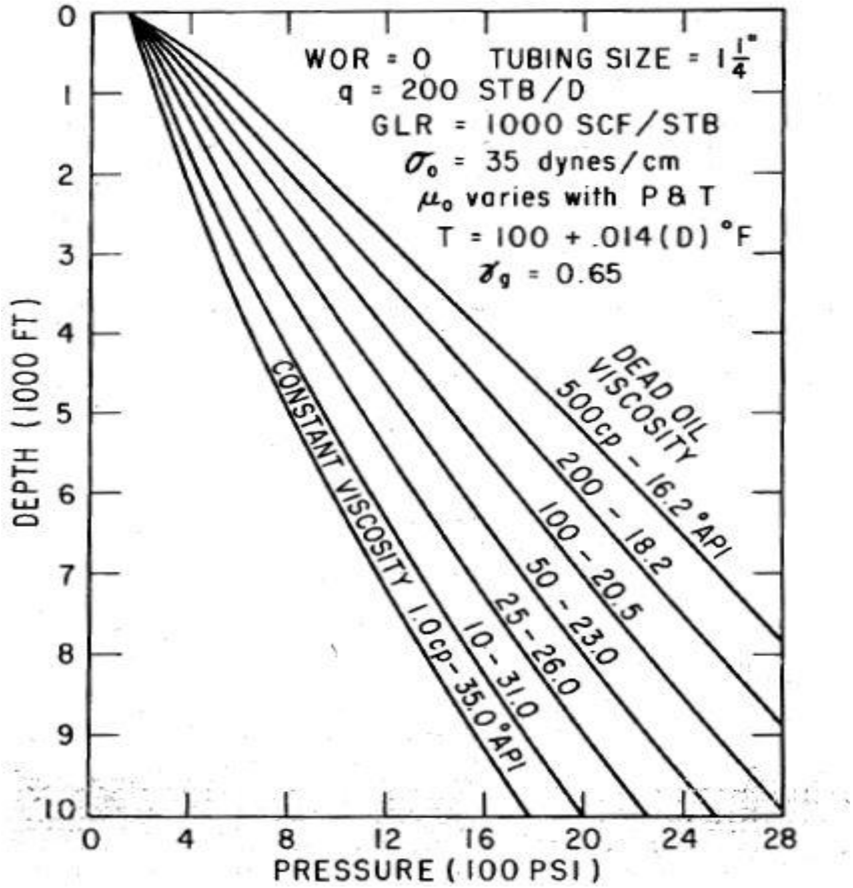
6.2.4 Effect of density



6.2.5 Effect of water - oil ratio



6.2.6 Effect of viscosity



6.3 Gradient Curves (Working chart)

Gradient curves are graphical presentations of pressure vs length or depth of flowline or tubing, respectively, for a set of fixed flow and fluid parameters. Figure 6.1 is a typical gradient curve for 2 7/8-in. tubing with 1000 BPD liquid production at 50% oil. The fixed fluid properties, such as specific gravity of gas, etc. are presented on the top right of the plot. On each gradient curve, a family of curves is presented for a number of gas/liquid ratios. These curves are computer generated and are used for design calculations in the absence of a computer program. Gradient curves are used to calculate one of the terminal pressures when the other terminal pressure and the appropriate flow and fluid properties are known.

Brown et al. (1980) presented a number of gradient curves for a wide range of tubing size and flow rates using the Hagedorn and Brown (1965) correlation. A few of these are appended for the solution of some of the problems. Figures 6.2 through 6.5 are a set of sample gradient curves presented by Brown. The gradient curves for the horizontal flow zero length or depth. To use these gradient curves for vertical flow in tubing start at atmospheric pressure at curves is presented in Example Problem 6.1 wellhead pressures, a concept of equivalent length is used. The use of these gradients

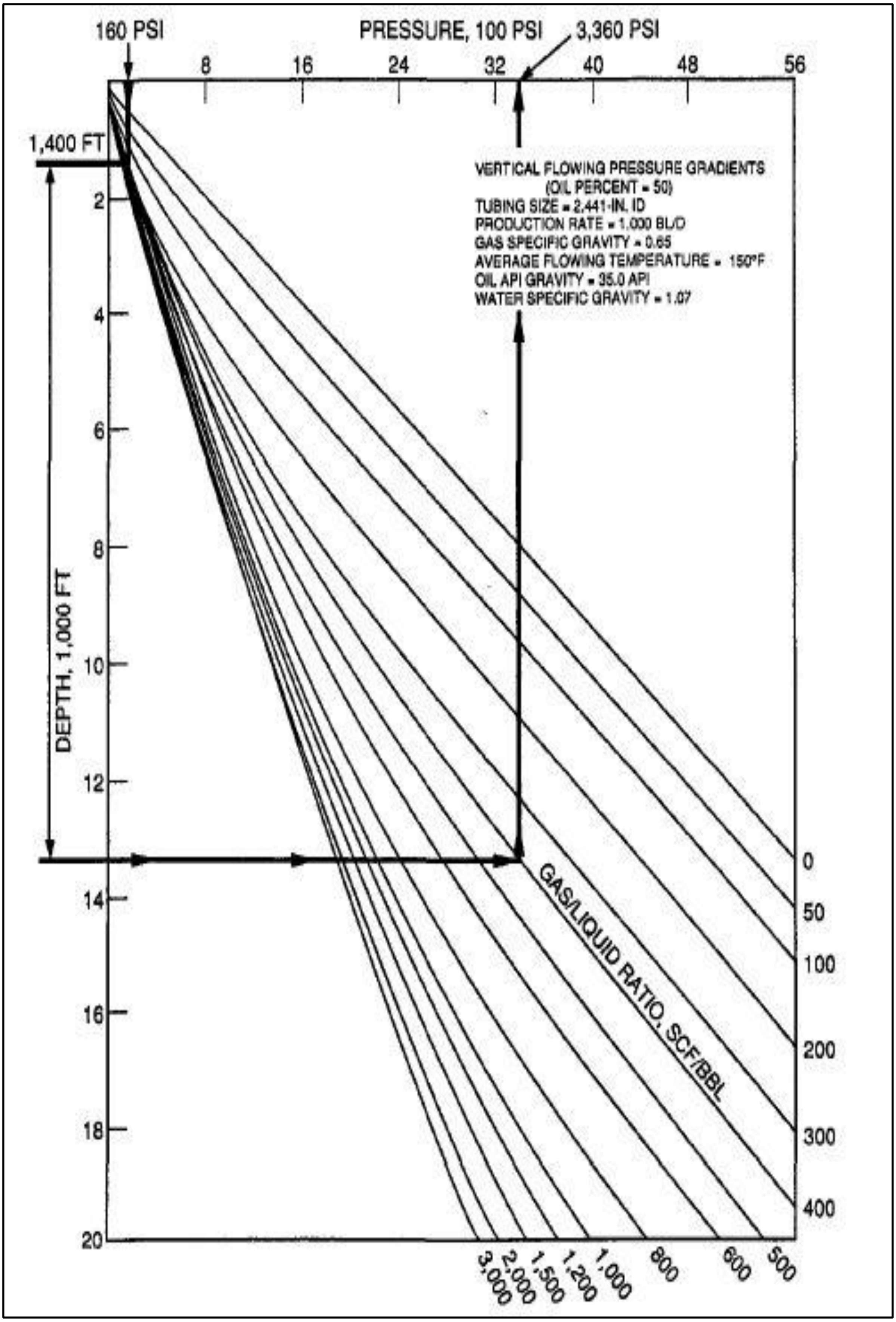


Figure 6.1: Vertical Flowing Pressure Gradients

Example 6.1:

Given,

P_{wh} = 100 psig, Wellhead temperature = 70°F, GLR = 400 scf/bbl, T_{res} = 140°F, Sp.gr = 0.65, Depth = 5,000 ft (mid-perf.), Tubing ID = 2 in, API Gravity = 35° API, Calculate and plot the tubing intake curve.

Solution

A plot of the bottomhole flowing pressure vs flow rate is obtained based on pressure gradients in the piping.

Using Figure 6.2, start at the top of the gradient curve at a pressure of 100 psig. Proceed vertically downward to a gas liquid ratio of 400 scf/bbl. Proceed horizontally from this point and read an equivalent depth of 1,600 ft. Add the equivalent depth to the depth of the well at mid-perforation. Calculate a depth of 6,600 ft. on the vertical axis, and proceed horizontally to the 400 scf/bbl GLR curve. From this point, proceed vertically upward and read a tubing intake pressure for 200 BPD of 730 psig.

Repeat this procedure for flow rates of 400, 600, and 800 BPD using Figures 6.3 through 6.5 respectively. Plot the P_{wf} vs q values tabulated above as shown in Figure 6.6 to complete the desired tubing intake curve.

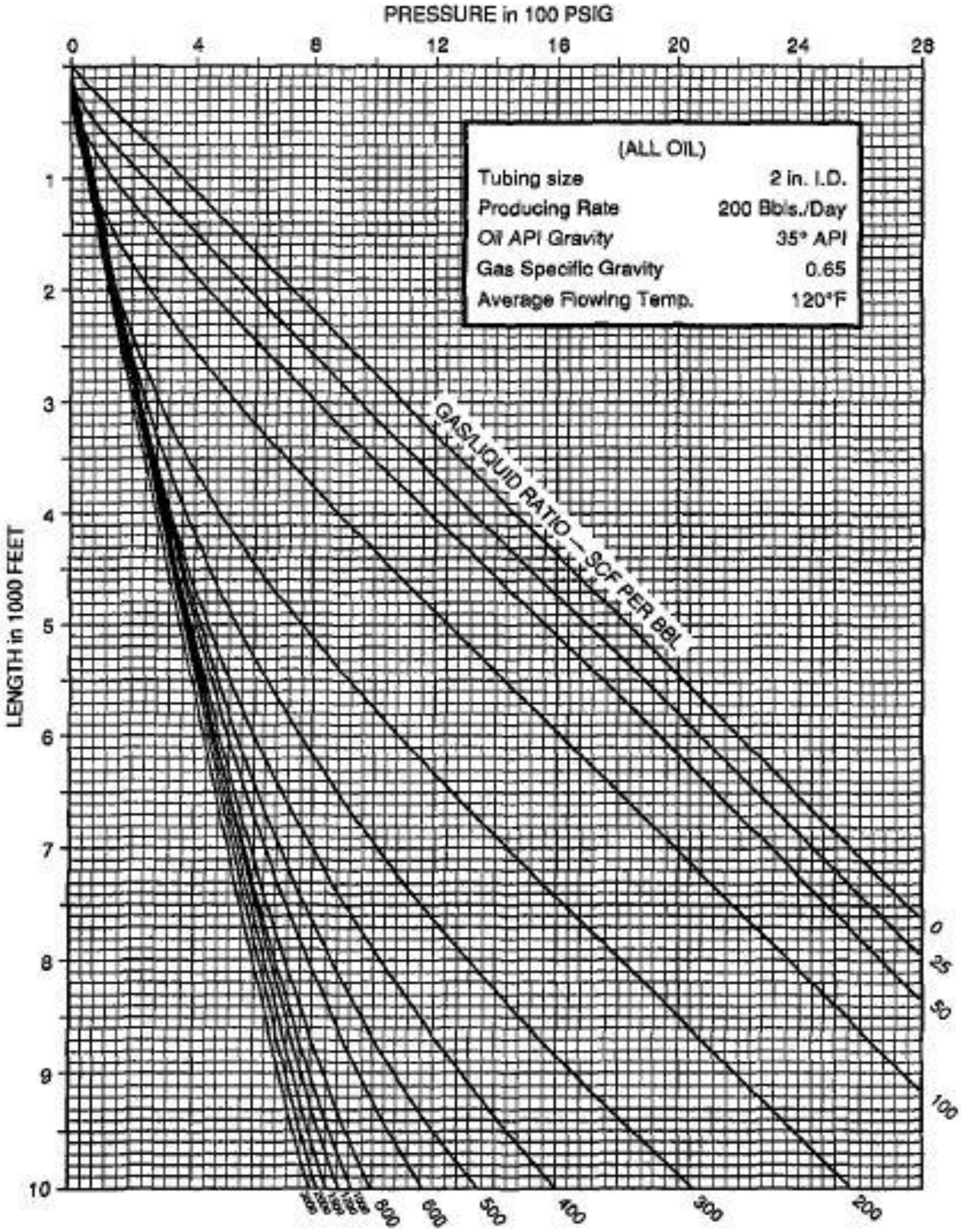


Figure 6.2: Vertical Flowing Pressure Gradients

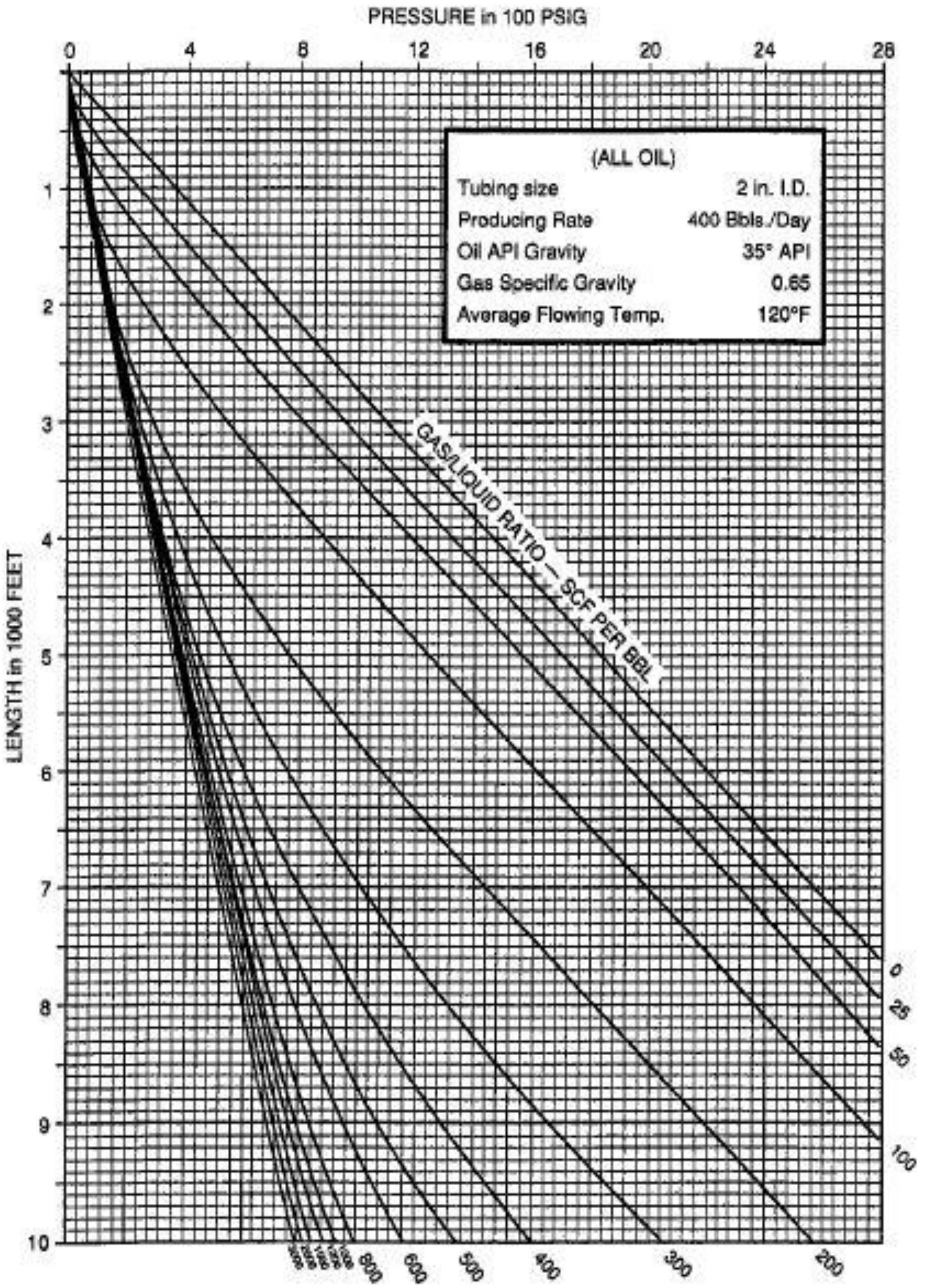


Figure 6.3: Vertical Flowing Pressure Gradients

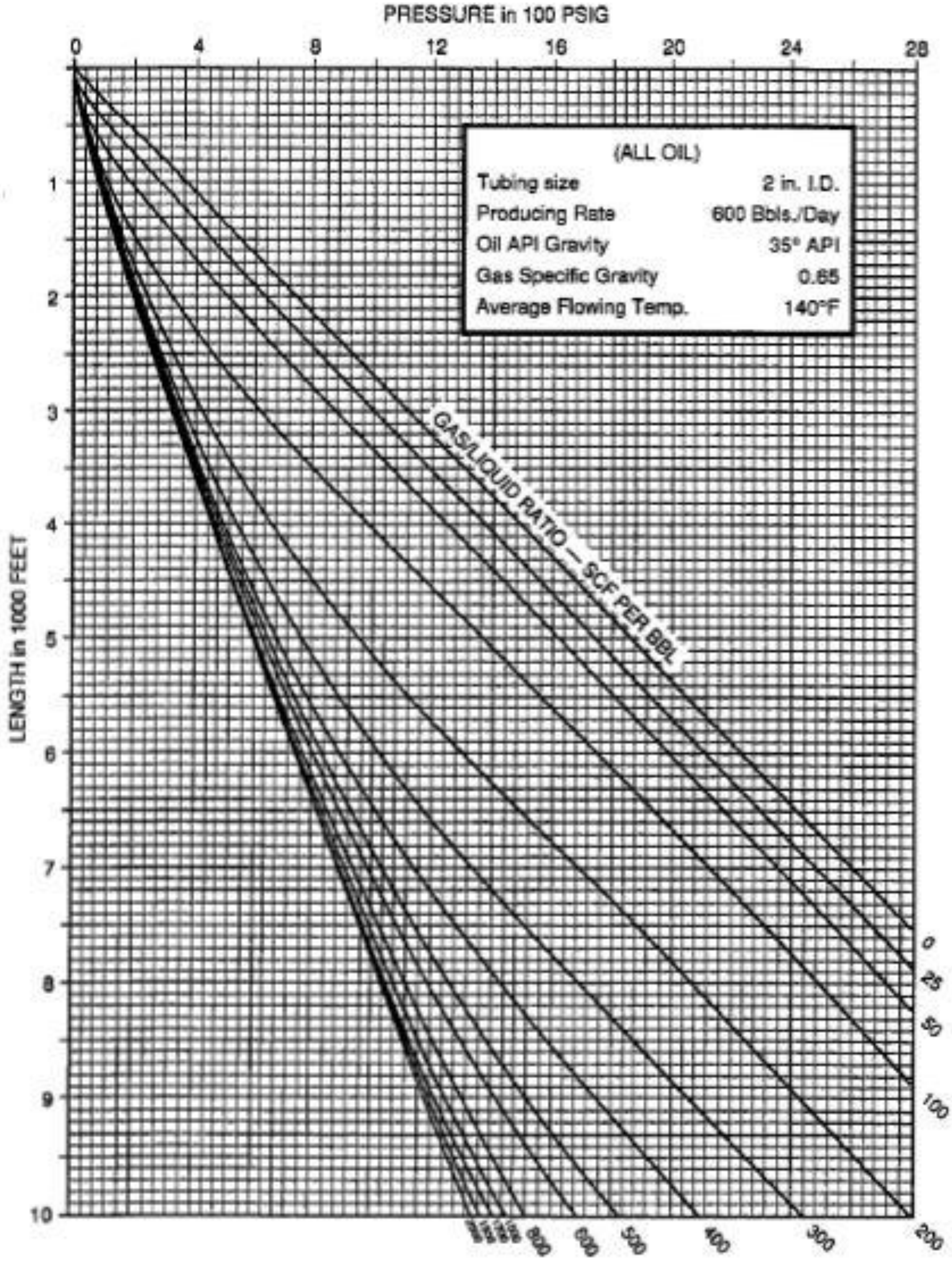


Figure 6.4: Vertical Flowing Pressure Gradients

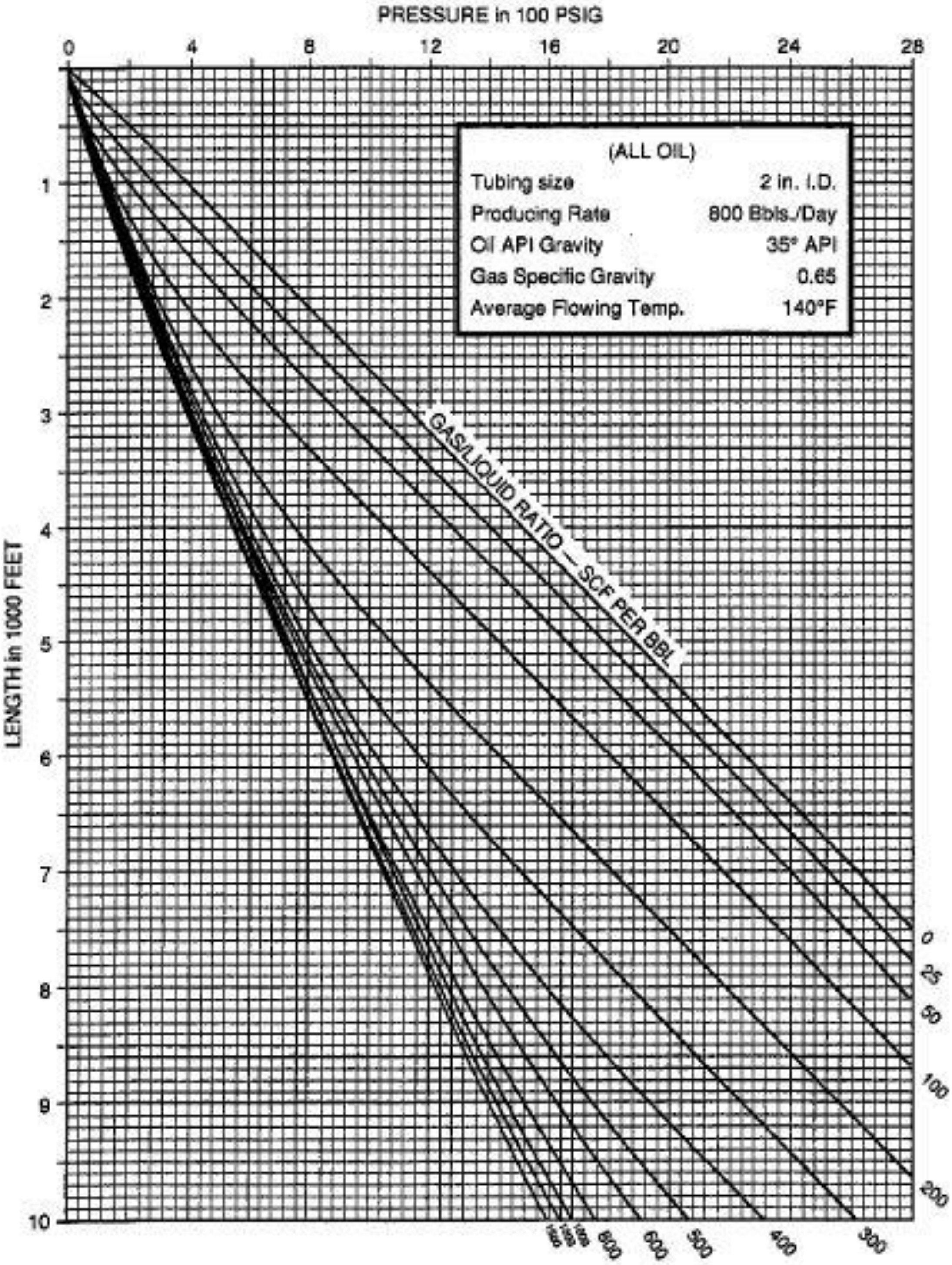


Figure 6.5: Vertical Flowing Pressure Gradients

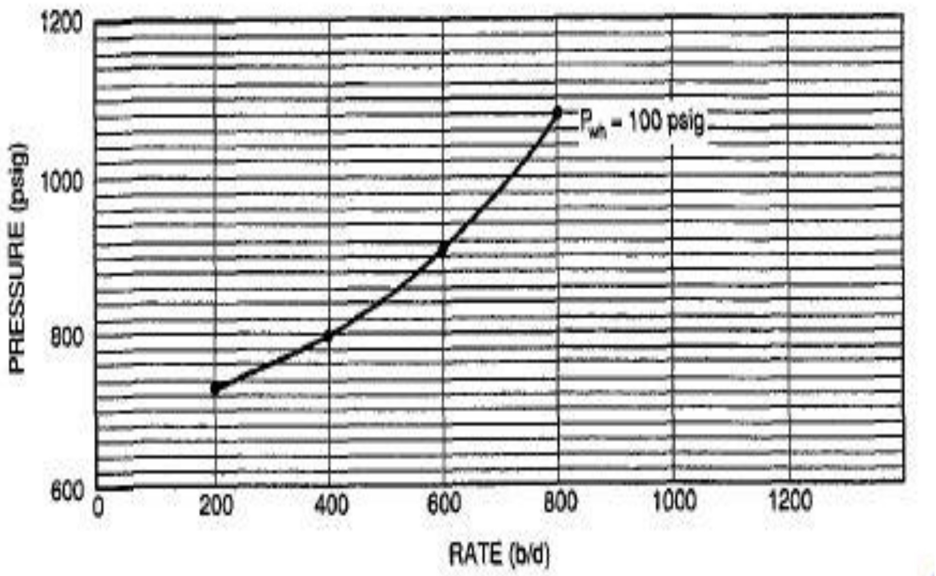


Figure 6.6: This figure shows a tubing intake or outflow performance curve for a wellhead pressure of100 PSIG.

Example 6.2:

Determine P_{wf} and P_{wf} minimum, given: q = 200 bpd (all oil) d tubing= 2 in. depth= 7000 ft, G /O = 500 scf/bbl, P_{wh}= 120 psi

Solution:

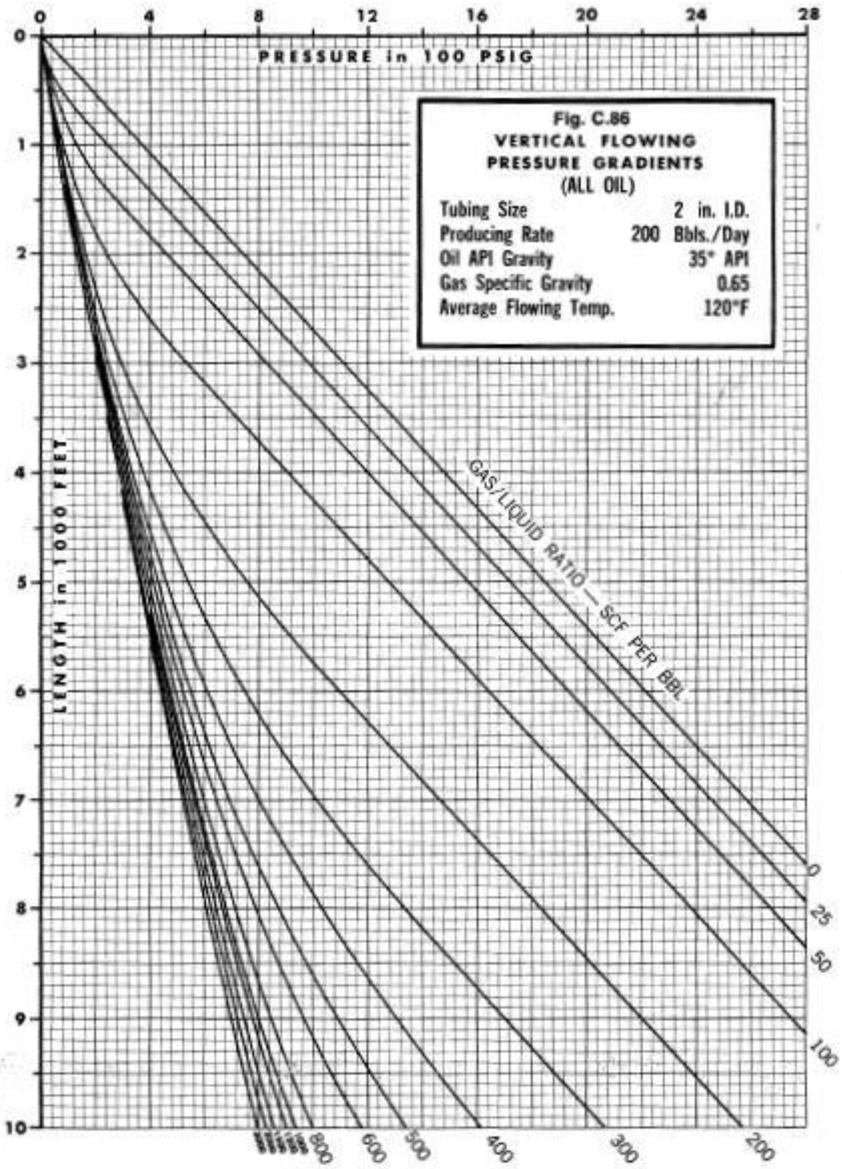
Refer to Fig. C.86

(a) Find P_{wf} for G/O = 500.

1- Finding the equivalent depth of 1800 ft for 120 psi,

2- Find P_{wf} 1,060 psi

(b) Find P_{wf} for G/O maximum = 3,000 scf/bbl. This gives the minimum flowing gradient. Following the same procedure we find P_{wf} = 680 psi.



Example 6.3:

Find the average productivity index for a well (Flowing pressure above bubble point), given:

Given: $2\frac{1}{2}$ in. tubing
q_L = 1000 bpd (95% water)
p_{wh} = 80 psi
d = 9000 ft
G/L = 400 scf/bbl
$\bar{p}_R$ = 2,600 psi

Solution:

A new problem arises here in that the well is making 95 % water. In this case use the all water curve of Figure C.110. When the well produces in excess of 85-90 % water it is appropriate to use all water curves. Curves are available for all oil, 50 % oil and 100 % water. Interpolations can be performed, but will generally give results very near the answer obtained when using the curve nearest the percentage of 100 % oil; 100 % water or 50%. For example when water production is greater than 75 %, use all water curves, but interpolate when in doubt. A computer solution to account for exact percentages of water and oil is much better.

Following our same solution procedure we first find P_{wf} = 2,175 psi.

$$\text{Average PI} = \frac{q}{\bar{p}_R - p_{wf}} = \frac{1,000}{2,600 - 2,175} = 2.35$$