Comparison of Detailed Procedure and Standard Field Procedure for the Design of a Continuous Flow Gas Lift Installation

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INTRODUCTION

The proper design of a continuous flow gas lift installation depends on accurate well data. In many instances, gas lift installations are made with a complete lack of vital well information. For this reason a flowing pressure survey is beneficial after the first installation in order to allow a correct respacing of the valves. In many instances, however, good gas lift installations have resulted even with a minimum amount of well information.

It is generally conceded that the most important factor in continuous flow design is the determination of the correct point of gas injection. Past well performance has shown that the lower the gas injection point, the lower the injection gas-oil ratio. The principal governing factors in design are (a) the available injection gas pressure and volume, (b) the wellhead tubing back pressure, (c) the flowing bottom hole pressure, (d) the well fluids, which include oil, gas and water, and (e) the size and depth of the eductor tube.

Two methods are presented whereby the point of gas injection can be determined. Both methods will make use of the maximum surface injection pressure. The first method, which will be referred to as the "Simplified Method," can be used to determine the point of gas injection quickly by the use of a graph. The second method, referred to as the "Detailed Method," was presented originally by Fred H. Poettman and Paul G. Carpenter of the Phillips Petroleum Company and later simplified by the use of charts by C. V. Kirkpatrick. The detailed procedure is explained and a modified version of this method by the use of "Standing's Composite Volume Factor Chart" is presented. Several curves are included showing a comparison of the two methods.

Reference should be made to Fig. 1 which shows continuous flow gas lift nomenclature in common usage today.

DETERMINATION OF THE POINT OF GAS INJECTION BY THE SIMPLIFIED PROCEDURE

In this procedure, maximum benefit is derived from the available injection pressure. This means that the deepest point of injection will be obtained, depending upon the injection gas pressure. This method involves a minimum of time and therefore is quite popular.

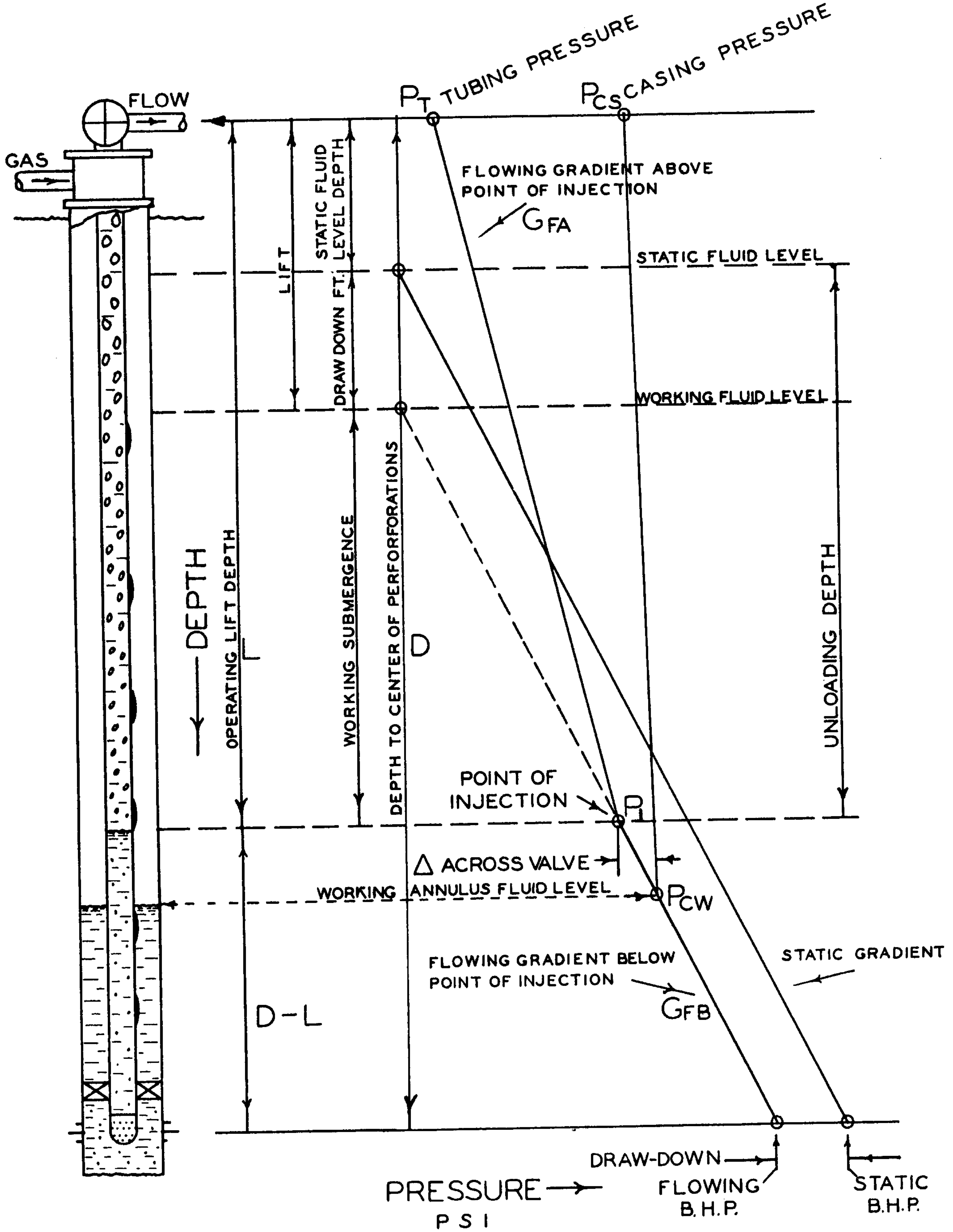
The following step-by-step procedure will serve as a guide for designing an installation on this basis. Plot all information on a sheet of rectangular coordinate paper.

1. Plot depth on the ordinate (vertical) with zero depth at top and maximum depth at bottom.
2. Plot pressure on the abscissa (horizontal) with pressure increasing from 0 at the origin to a maximum.
3. Plot the static bottomhole pressure at the correct depth.
4. Plot the expected flowing tubing pressure at zero depth (top of page).
5. From the PI (Productivity Index) calculate the pressure drawdown necessary to obtain the desired amount of production.
6. Subtract the drawdown from the static bottom hole pressure. This is the expected flowing bottom hole pressure and should also be plotted at the bottom or producing interval depth.
7. From the per cent water and API gravity of the oil, calculate or obtain a static gradient of the mixture.
8. Plot a static gradient line up the hole from both the static BHP point and the flowing BHP point. Extend the static BHP line to the depth line. This will be the static fluid level for zero back pressure. Extend the flowing BHP line to the depth line. This will be the effective lift with zero back pressure.
9. Extend the tubing pressure line down the hole, accounting only for the weight of the gas column in the tubing. Its intersection with the flowing bottom hole pressure line will be the actual "effective lift" for any particular well.
10. Plot the surface injection gas pressure at zero depth.
11. Check the gas column weight.
12. Starting from the surface injection gas pressure, plot the casing pressure down the hole, taking into account the weight of the gas column.
13. Extend the casing pressure line until it intersects the flowing bottom hole pressure line. This point is commonly called the "working annulus fluid level."
14. Subtract 100 PSI from the pressure in the casing at this point. Return up the hole a distance equivalent to 100 PSI on the flowing bottom hole pressure line and note this point. This will be the point of gas injection.
15. Connect, by a straight line, this point of gas injection to the surface flowing tubing pressure. This line represents an average maximum flowing gradient between the tubing pressure and the point of gas injection. In other words, if gas is being injected at this point, a minimum gas-oil ratio for the injection pressure available should be realized.

The following additional steps are offered to help make proper valve selections:

16. Plot the geothermal gradient for the well on the same graph paper. This should be a gradient for the well while flowing. This is usually an unknown factor and may vary considerably from the

FIG. 1 CONTINUOUS FLOW NOMENCLATURE



earth's normal geothermal gradient. For example, a well with 250 F bottom hole temperature and making 3,000 barrels per day, may have more than 200 F surface flowing temperature. Therefore, the best available information as to surface flowing temperatures must be utilized. This surface temperature is then plotted at zero depth. The bottom hole temperature is then plotted at its correct depth. A straight line between these two points will establish the flowing geothermal gradient for the tubing string. (Cooling caused by the expanding gas at the injection point should be considered if it is appreciable).

17. Establish the temperature at the operating valve. (Point established as point of gas injection.)
18. From the surface injection gas pressure, deduct 50 to 100 PSI which will be the opening pressure of the operating valve.
19 Select a gas lift valve to operate at the surface opening pressure as set out in Step 18. In other words, select a valve to open at the desired pressure, accounting for temperature, gas column weight, and back pressure effect on the valve. (All valves do not necessarily incorporate all these variables.)
20. Space the valves starting with casing pressure minus 50 PSI.
21. Take the bottom valve setting at surface setting temperature and select all valve settings. From the bottom up, each valve should be increased from 15 - 25 PSI in opening pressures at setting temperatures.
22. From correct temperatures and gas column weights, check the surface opening pressure of each valve.
23. Make any necessary adjustments in valve settings to make certain that all valves can be opened and that no interference of valves is present.

It should be understood that average gradients, both above and below the point of gas injection, have been used in this particular procedure. For wells making large percentages of water, the flowing gradient below the point of gas injection will be approximately the same as the static gradient. The flowing gradient above the point of gas injection will vary from a high value at the point of injection to a lower value at the surface. However, a straight line from the point of gas injection to the tubing pressure establishes an average gradient between these two points.

The point of gas injection may be solved analytically as follows:

Pi = Pressure in tubing at point of injection

P_t = Tubing pressure

Pcs = Surface Casing Pressure

G_{Fa} = Flowing Gradient above the pt. of gas inj.

G_{Fb} = Flowing Gradient below the pt. of gas inj.

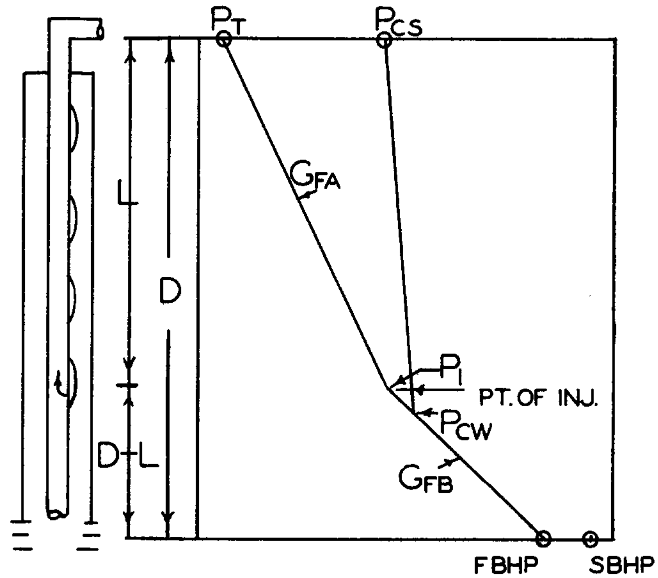
FBHP = Flowing bottom hole pressure

SBHP = Static bottom hole pressure

D = Total Depth

L = Depth to point of gas injection

Pcw = Pressure in casing at working fluid level.



Starting at the top of the hole and summing up pressures to the bottom.

(1) $P_t + G_{Fa}(L) + G_{Fb}(D-L) = FBHP$ (flowing pressure)

(2) Now: $G_{Fa} = \frac{((Pcw - 100) - P_t)}{L}$

substituting (2) in (1)

$$P_t = \frac{((Pcw-100)-P_t)\ (\cancel{L})}{\cancel{L}} + G_{Fb}\ (D-L) = FBHP$$

$$(\cancel{P_t}) + Pcw - 100 - (\cancel{P_t}) + G_{Fb}\ (D) - G_{Fb}\ (L) = FBHP$$

$$L = \frac{(Pcw - 100) + (G_{Fb})\ (D) - (FBHP)}{G_{Fb}}$$

Procedure:

(a) Make one calculation using Pcw = Pcs and solve for a depth.
(b) From this depth obtain a weight of the gas column.
(c) Add Pcs + wt of gas column = Pcw
(d) Using Pcw from (3), solve for another depth.
(e) Repeat the procedure until the assumed value of ΔP corresponds with the value of ΔP for the solved depth.

(3) Sample Calculation:

Given:

Well Depth - 8000 feet
Flowing tubing pressure - 100 psi
Gas S. G. = .65
Flowing BHP for desired production - 2500 psi
Flowing gradient below the point of gas injection = .45 psi/ft
Surface injection pressure - 950 psi

1st Trial

$$L = \frac{(Pcs - 100) + G_{Fb} \times D - FBHP}{G_{Fb}}$$

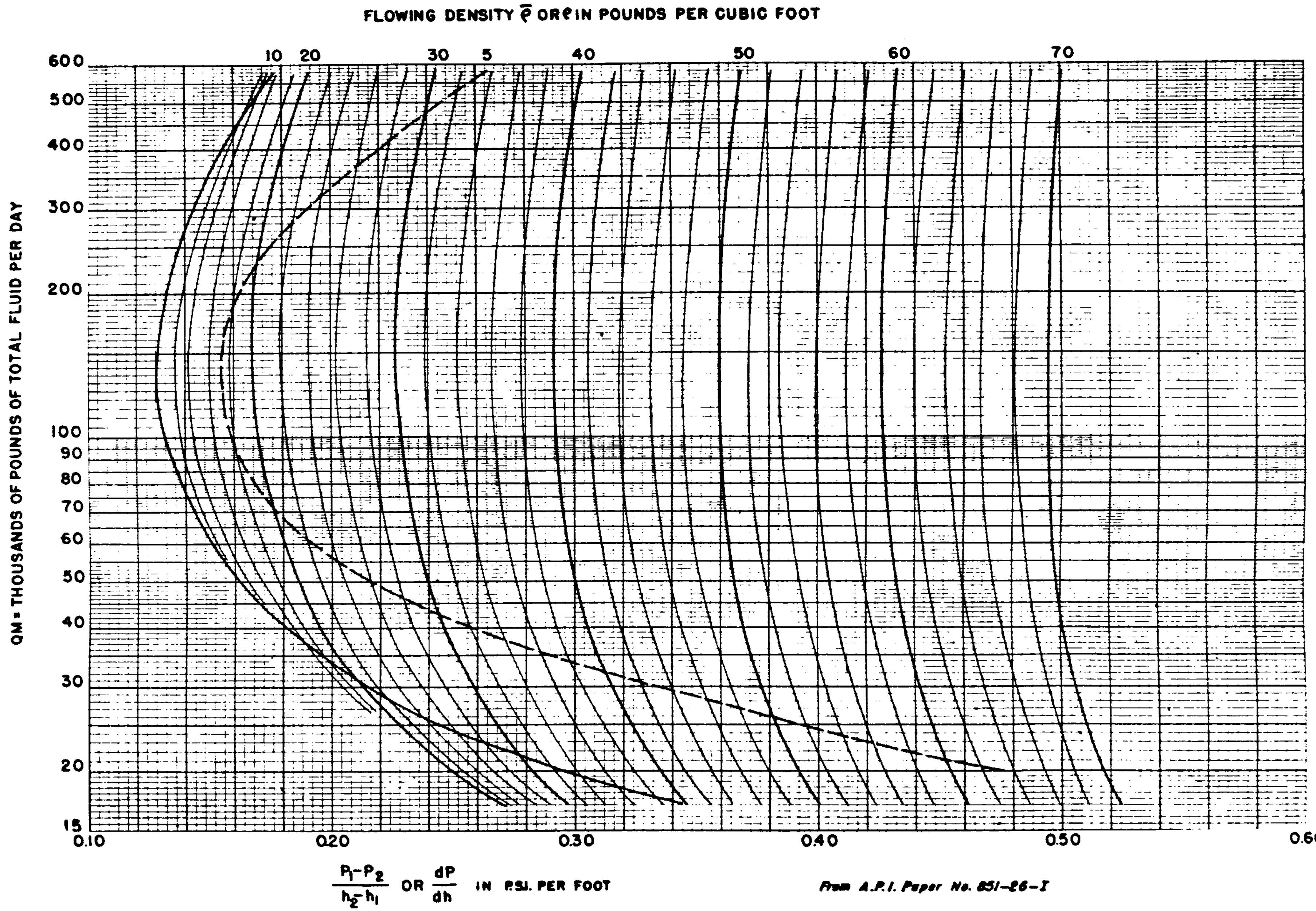


FIG. 2 Pressure traverses for 2.0 inch tubing.
(4.5 - 4.7 lbs. per foot, 1.995 inches I.D.)

$$L = \frac{950 - 100 + (.45)\ (8000) - 2500}{.45}$$

$$L = \frac{1950}{.45} = 4340 \text{ feet}$$

From appropriate charts or from calculations the weight of this gas column is found to be 100 psi.

2nd Trial - Assume Pcw = 950 + 100 = 1050 psi

$$L = \frac{1050 - 100 + (.45)\ (8000) - 2500}{.45}$$

$$L = \frac{2050}{.45} = 4560 \text{ feet} \qquad \text{Gas Column wt} = 105 \text{ psi}$$

3rd Trial - Assume Pcw = 950 + 105 = 1055 psi

$$L = \frac{1055 - 100 + (.45)\ (8000) - 2500}{.45}$$

$$L = \frac{2055}{.45} = 4565 \text{ feet}$$

The gas column weight for 4565 feet is approximately 105 psi. Therefore, 4565 feet is the correct point of gas injection. It is evident that a graphical solution is simpler, and offers less chance for error.

DETERMINATION OF THE POINT OF GAS INJECTION BY THE DETAILED PROCEDURE

1. In order to properly utilize this procedure the following information must be obtaied:

   (a) The producing gas-oil ratio.
   (b) The specific gravity of the injection gas.
   (c) The specific gravity of the solution gas.
   (d) The formation volume factors at different pressures.
   (e) The gas in solution at different pressures.
   (f) The API gravity of the oil.
   (g) The specific gravity of the produced water.
   (h) The amount of oil and water being produced.
   (i) The flowing tubing pressure.
   (j) The static bottom-hole pressure.
   (k) The P. I. of the well.
   (l) The depth to the center of the perforated interval.
   (m) Bottom-hole temperature.
   (n) Estimated surface temperature and temperature gradient.
   (o) Tubing size.

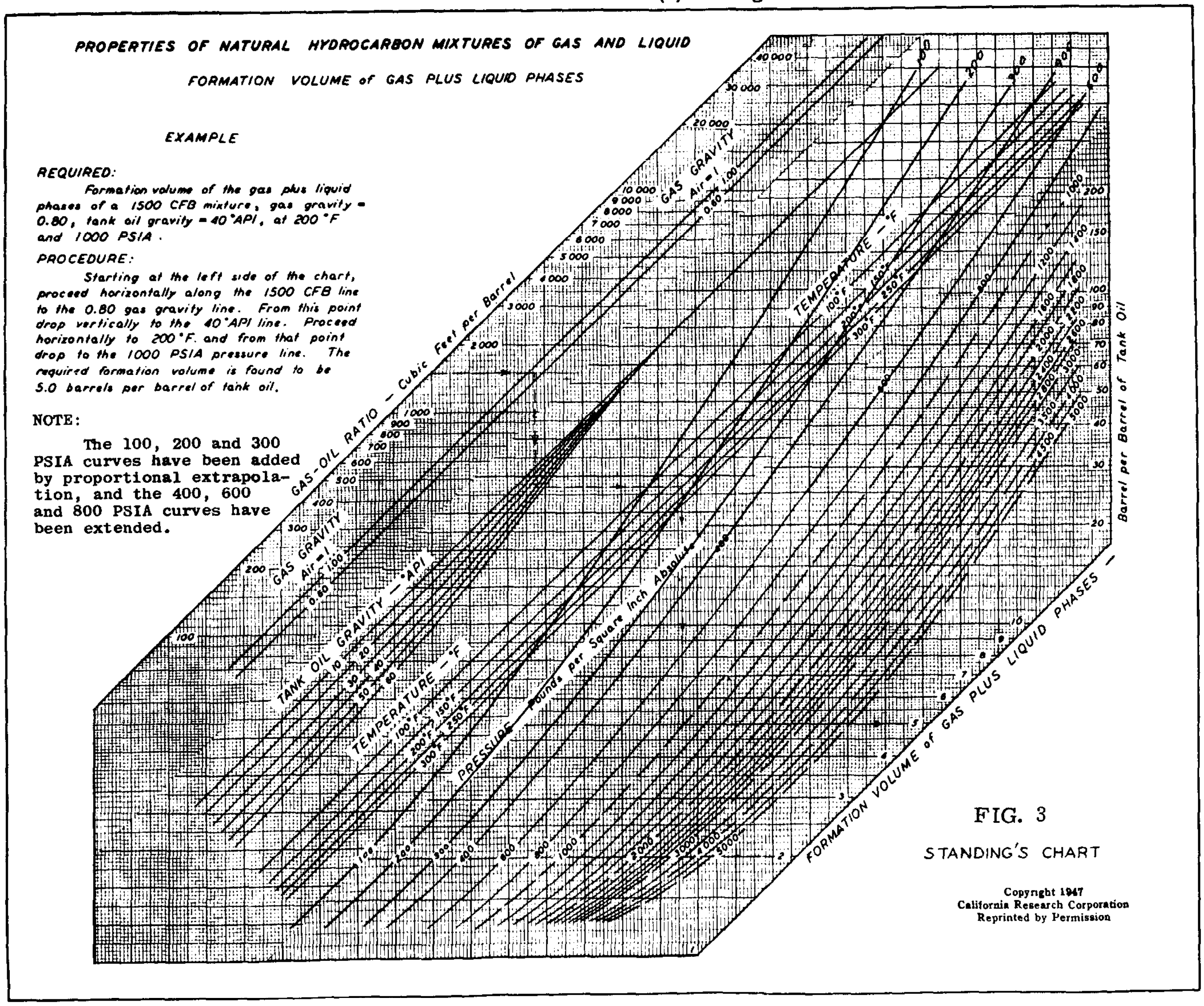
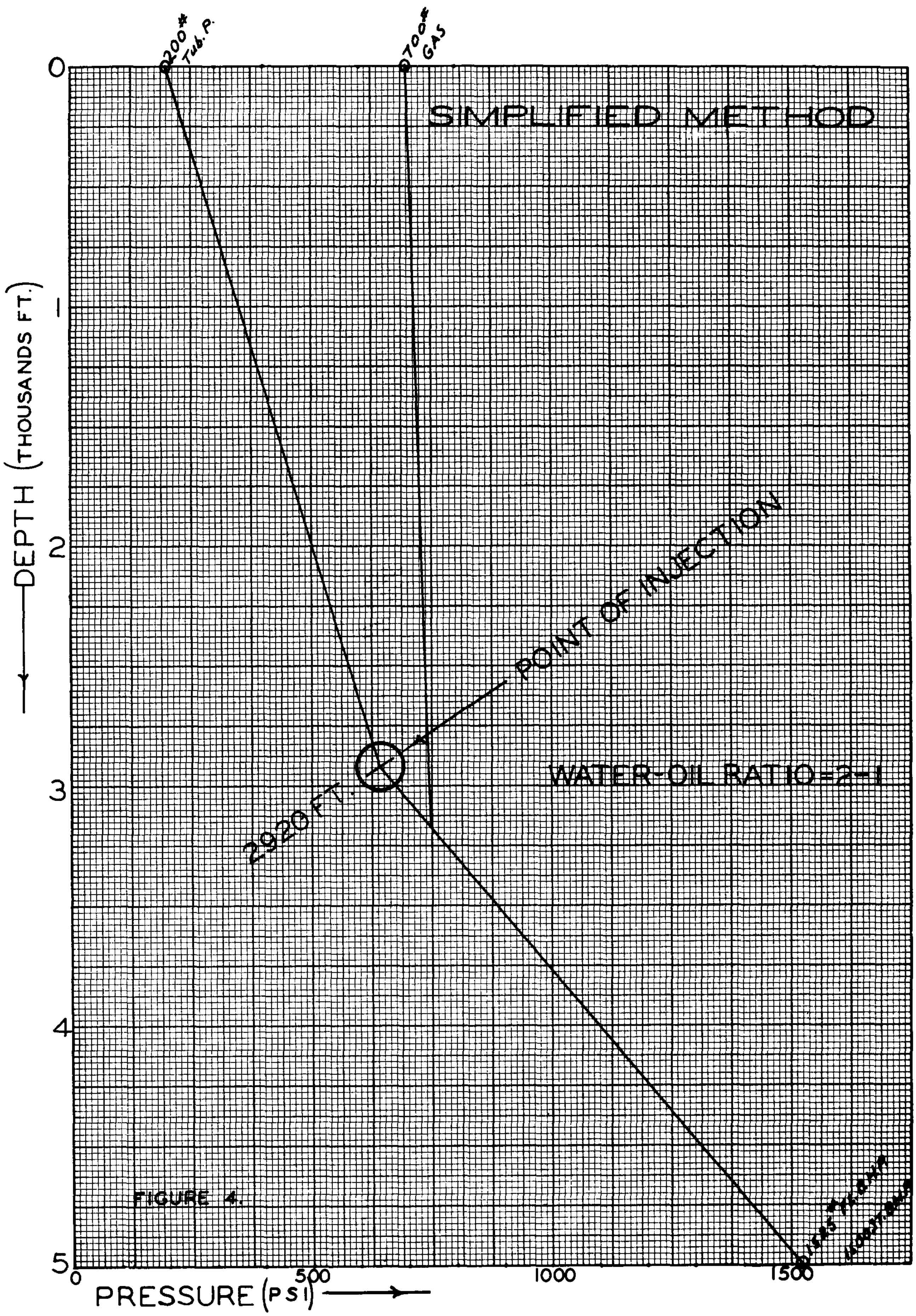
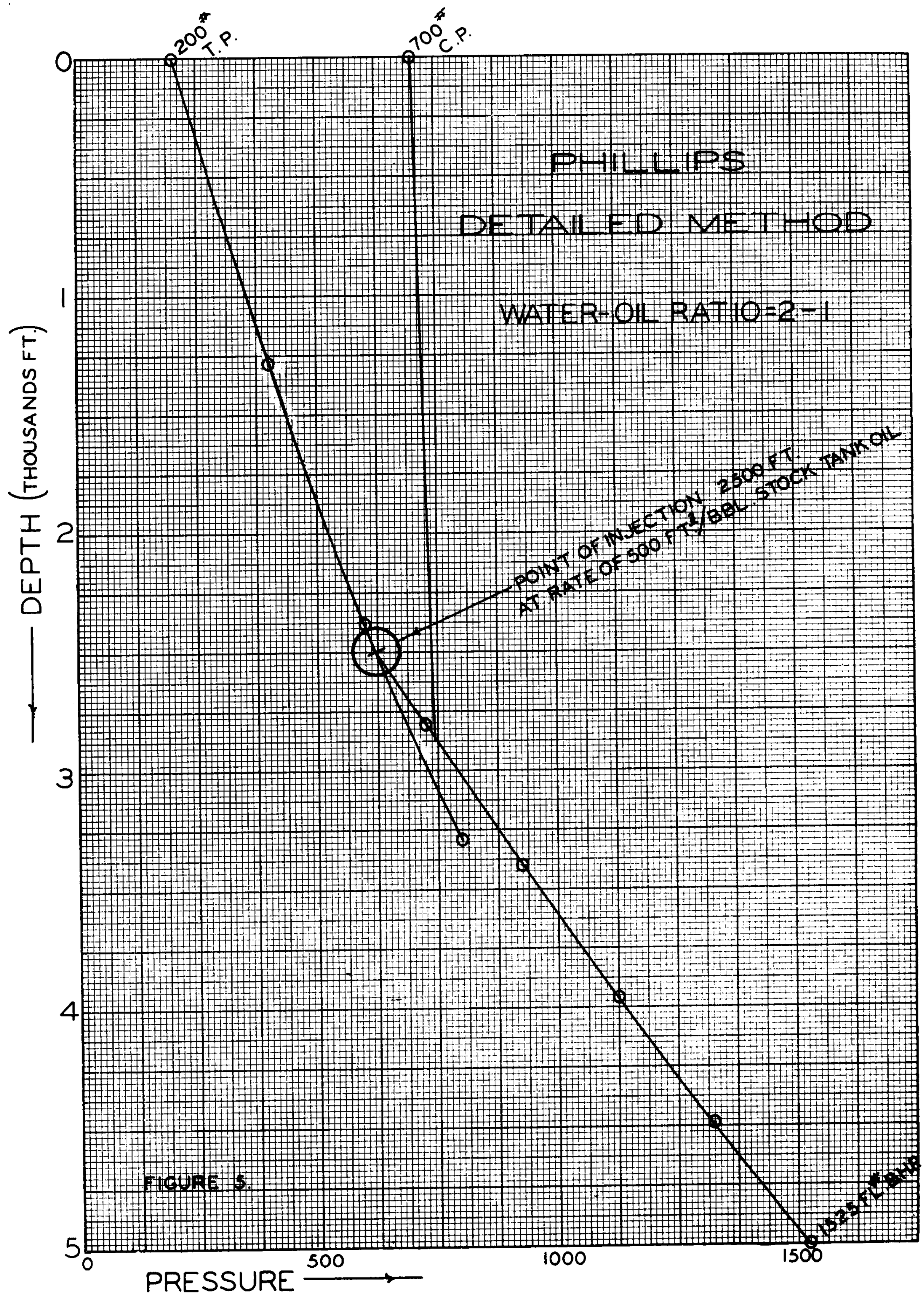


FIG. 3

STANDING'S CHART



200# Tub. P.
700# GAS
SIMPLIFIED METHOD
POINT OF INJECTION
2920 FT.
WATER-OIL RATIO = 2-1
FIGURE 4.
DEPTH (THOUSANDS FT.)
0
1
2
3
4
5
PRESSURE (PSI)
0
500
1000
1500


PHILLIPS
DETAILED METHOD
WATER-OIL RATIO=2-1
200# T.P.
700# C.P.
POINT OF INJECTION 2500 FT.
AT RATE OF 500 FT.³/BBL. STOCK TANK OIL
1525 FL.# BHP
DEPTH (THOUSANDS FT.)
PRESSURE
0
1
2
3
4
5
0
500
1000
1500
FIGURE 5.

2. Using a sheet of rectangular coordinate paper, plot the flowing bottom-hole pressure and the flowing tubing pressure. Plot pressure vs. depth as set out in the simplified procedure.

3. Determine the mass rate of flow below the point of gas injection in pounds per barrel of stock tank oil (S.T.O.).

M_b = wt. of oil + wt of gas + wt of water

M_b = (350) (S.G. oil) + (.0764) (S.G. gas) (Producing G/O + (350)

The total pounds of fluid produced per day is:

$$QM_b = (M_b) \text{ (daily S.T.O. production)}$$

Note: This is to be used on the gradient chart (Fig. 2) to establish a fixed ordinate.

4. Starting with the flowing bottom hole pressure, assume various decreasing pressure points. Select pressure increments close enough to obtain a good curve (try 200 PSI increments for a start).

5. Calculate the flowing density at each one of these pressure points including the flowing bottom hole pressure point. Density is defined as weight per unit volume.

   First calculate the volume in cubic feet occupied at any pressure point by everything associated with one stock tank barrel of oil.

   Total volume = Vol of Oil + Vol Gas + Vol Water

$$= (5.61)\text{ (FVE)} + \text{(Free Gas)} \frac{(Pb)\ (T)\ (Z)}{(P)\ (Tb)\ (1)} + (5.61)\text{ (water oil ratio)}$$

Vol of gas

First - check for gas in solution with the oil at the pressure point you are working with. Subtract this from the producing gas oil ratio. This will be the free gas at this pressure point.

$$\text{Vol gas} = \text{(Free Gas)} \frac{\text{(Base Press)}}{\text{(Pressure)}} \quad \frac{\text{(Temp)}}{\text{(Base Temp)}} \quad \frac{(Z)}{(1)}$$

Where:

Free Gas = (Producing Ratio) minus (gas in solution at P)

P_b = 14.70 psia

T_b = 60° F = 460 + 60 = 520°F

P = Pressure = pressure at assumed pressure point

T = temp. at assumed pressure point

Z = compressibility factor (To be determined from critical temp and pressure and actual temp and pressure).

Density is determined thusly:

$$P = \frac{M}{Vm}$$

where: P = density in lb/ft^3
M = Mass flow rate, lb/STB
V_m = Volume of oil, water, and gas produced per STB, ft^3 .

6. The flowing gradient is then obtained from Fig. 2 (or similar chart) at the pressure point assumed. This chart includes friction.

   Reference to Fig. 2 shows that values are not available for lower density ranges, and that increased gradients are noted for densities less than 10 lb/ft^3. Some controversy exists as to the reliability of this method in these ranges. It is reported that an actual increase in flowing gradient occurs in this so-called "turn-over" range. However, until further reliable information is available, these lower values can be handled by extrapolating a curve as plotted on an arbitrary depth scale, and relating this curve to the actual problem.

7. Once the flowing gradient has been determined in the tubing for the flowing bottom hole pressure, the same procedure is followed in determining a gradient for the next pressure point (FBHP-200).

8. From the two flowing gradients determine an average between them.

$$\frac{G_{F_1} + G_{F_2}}{2} = G_{F_{avg}}$$

where G_{F_1} = Flowing Gradient at point (1)

G_{F_2} = Flowing Gradient at point (2)

9. From the difference in pressure between these points determine the distance between them.

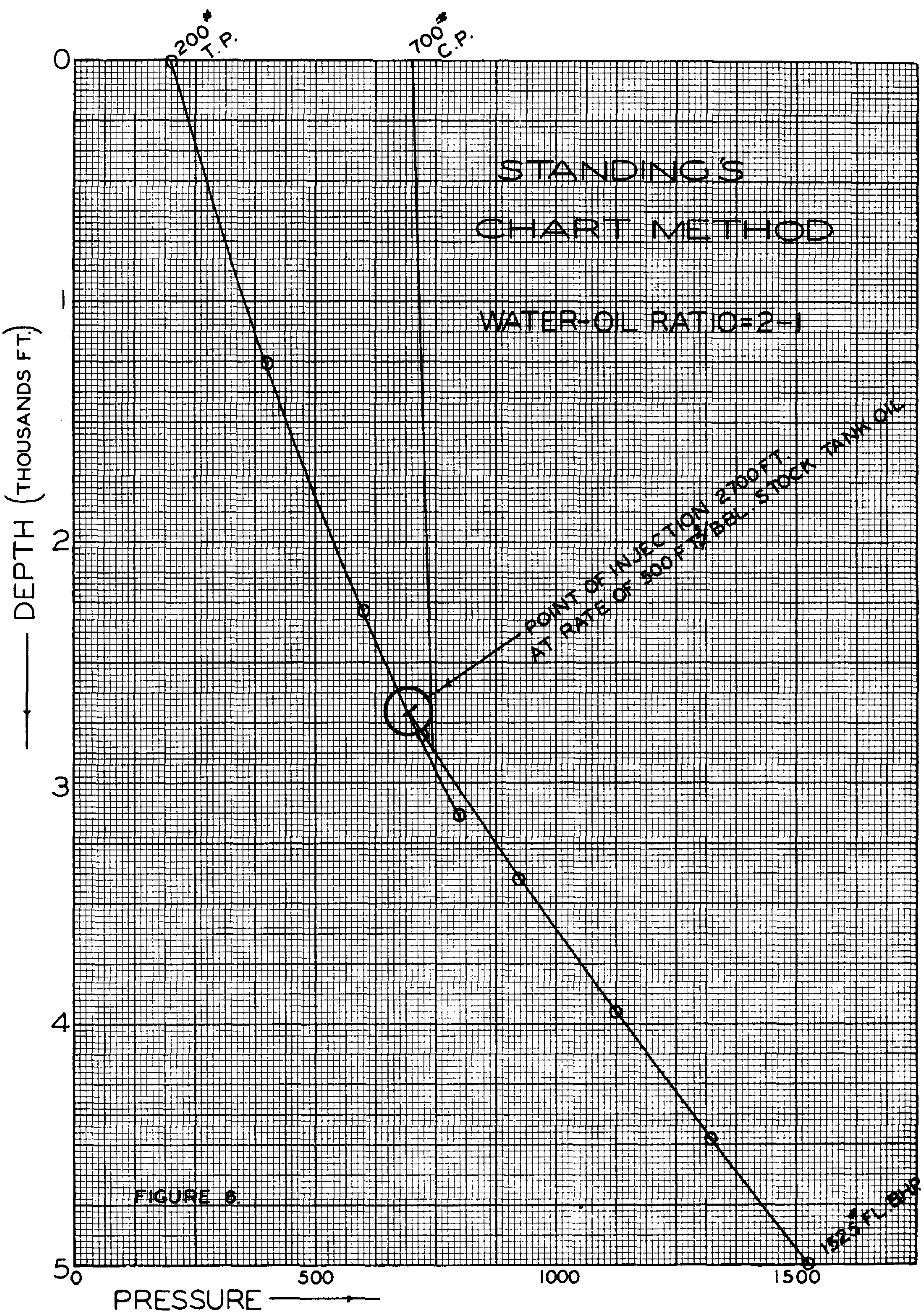
$$\frac{P_1 - P_2}{G_{F_{avg}}} = \frac{\Delta P}{G_{F_{avg}}} = \text{h in feet}$$

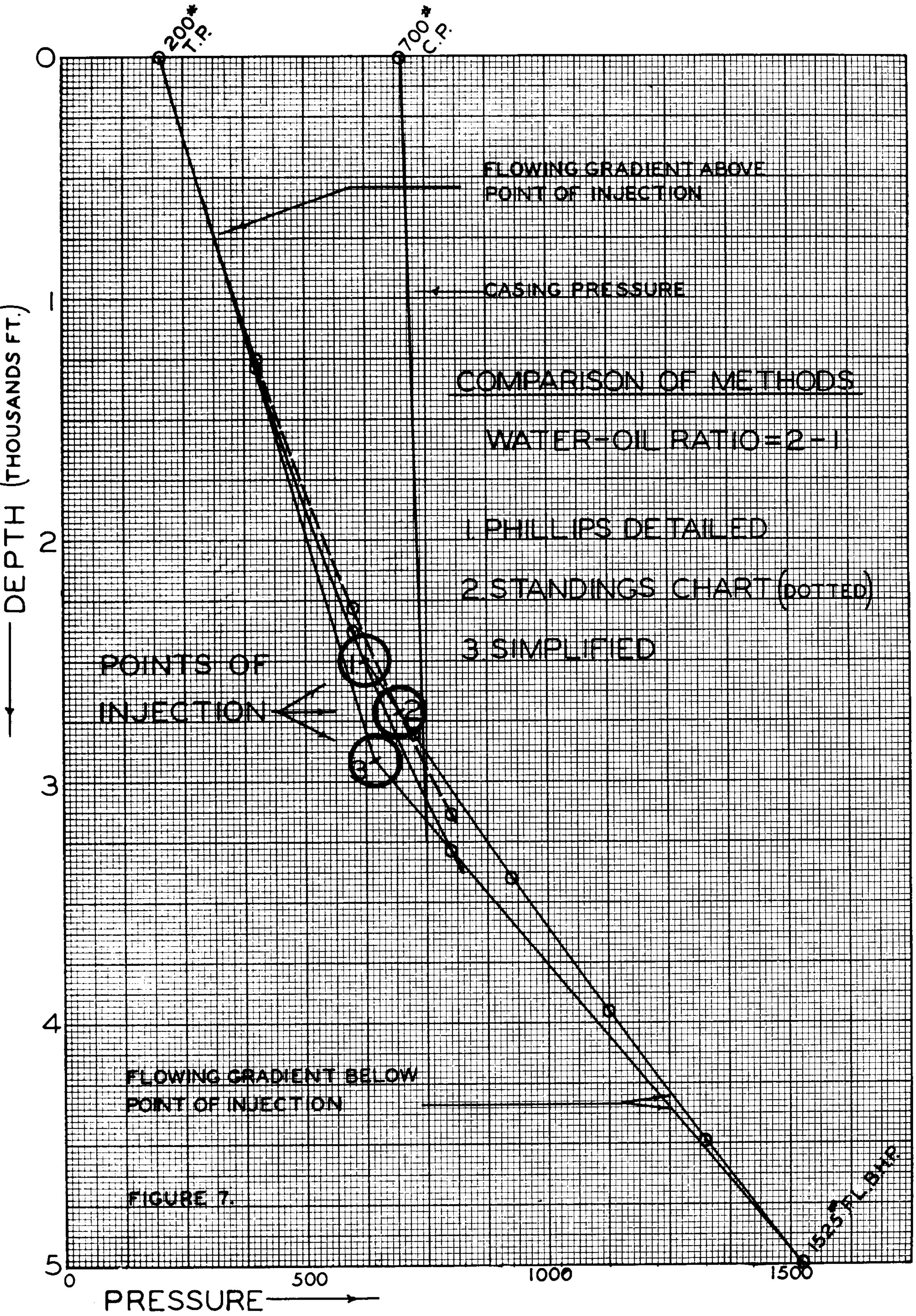
10. This distance is then plotted up from bottom.

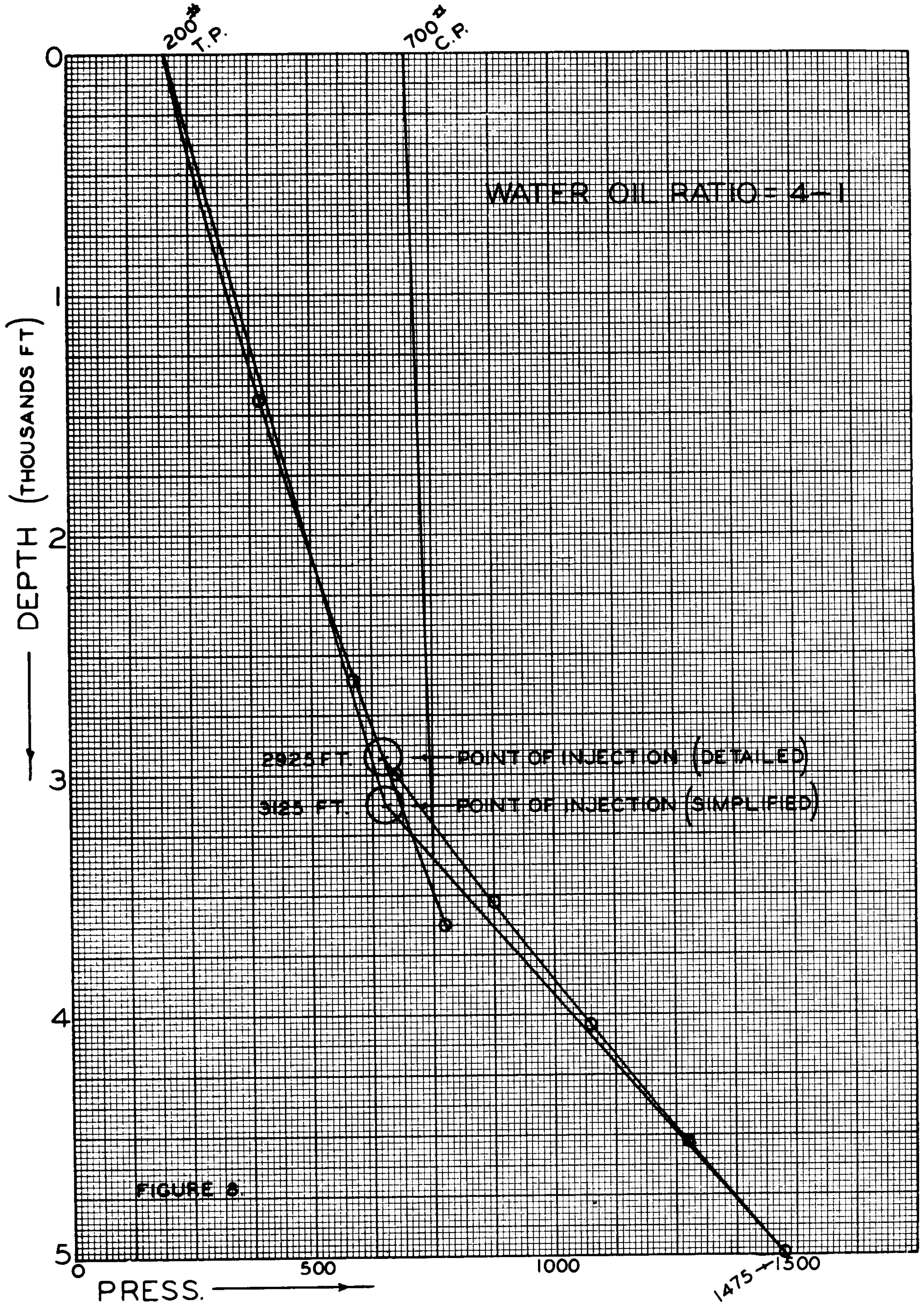
11. The same preceding series of steps is repeated for the next reduced pressure point up the hole. It should be noted here that the mass rate of flow remains the same for all pressure points below the point of gas injection. However, the flowing density changes because of the expanding gas.

12. Using the average flowing gradient between the point of pressure just determined and the one immediately preceding it, another distance is calculated. This point is then plotted on the graph.

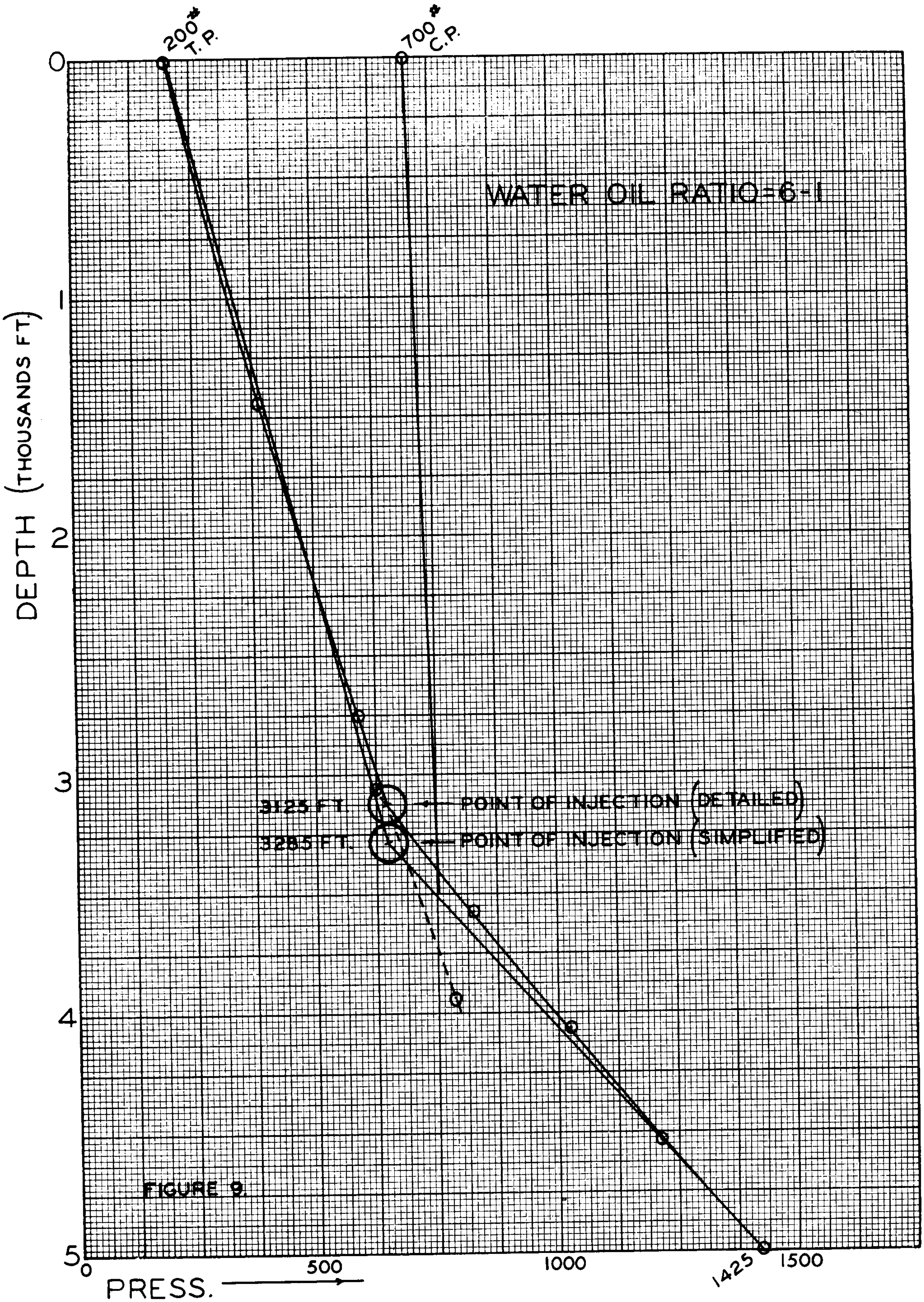
13. This operation is continued until the flowing gradient line below the point of gas injection intersects the depth line on the plot. This is then the point at

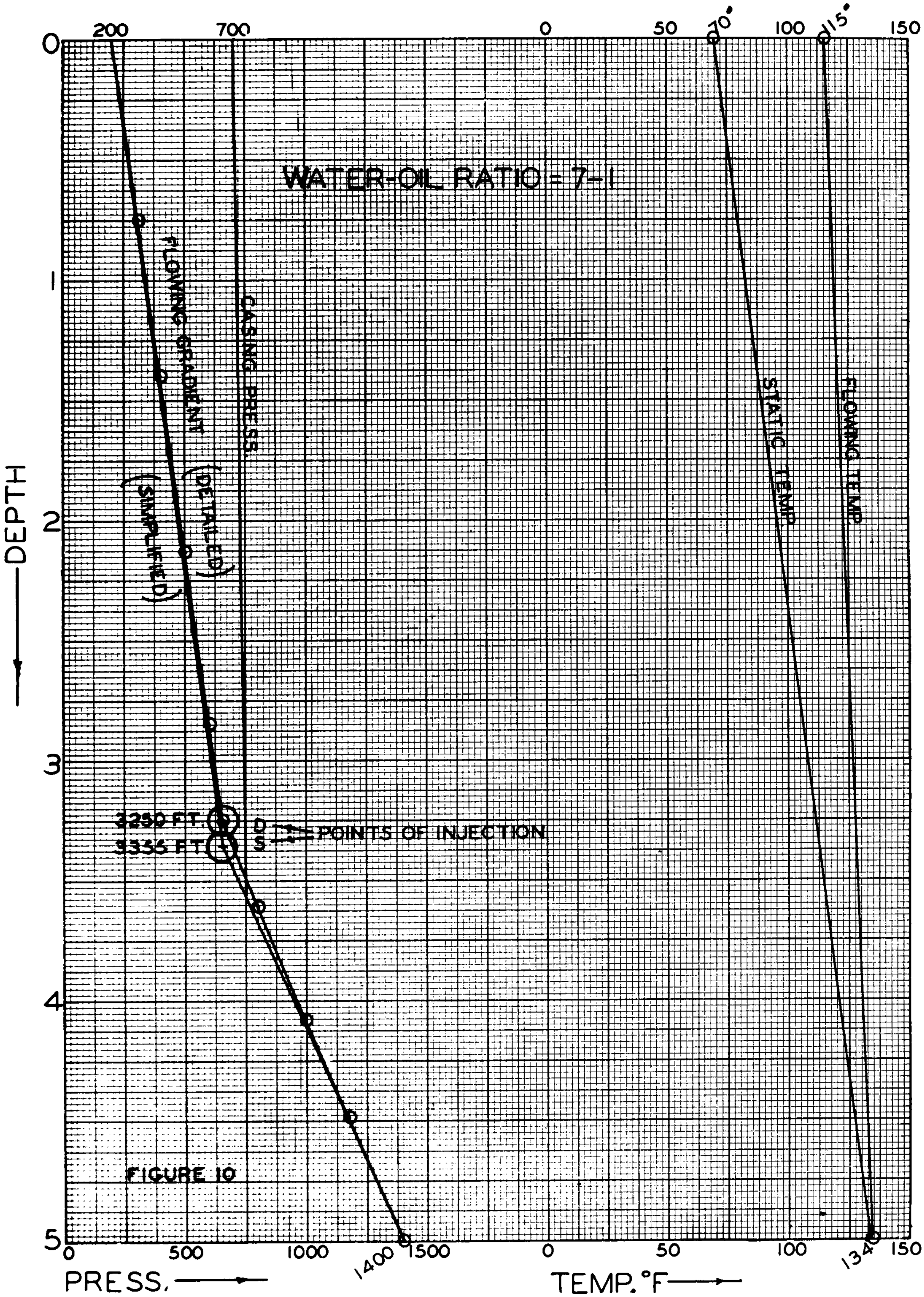

200# T.P.
700# C.P.
STANDING'S
CHART METHOD
WATER-OIL RATIO=2-1
POINT OF INJECTION 2700 FT.
AT RATE OF 500 FT.³/BBL. STOCK TANK OIL
1525# FL. B.H.P.
DEPTH (THOUSANDS FT.)
PRESSURE
0
1
2
3
4
5
0
500
1000
1500
FIGURE 8.


200# T.P.
700# C.P.
FLOWING GRADIENT ABOVE POINT OF INJECTION
CASING PRESSURE
COMPARISON OF METHODS
WATER-OIL RATIO=2-1
1. PHILLIPS DETAILED
2. STANDINGS CHART (DOTTED)
3. SIMPLIFIED
POINTS OF INJECTION
FLOWING GRADIENT BELOW POINT OF INJECTION
1525# FL. B.H.P.
DEPTH (THOUSANDS FT.)
0
1
2
3
4
5
PRESSURE
0
500
1000
1500
FIGURE 7.

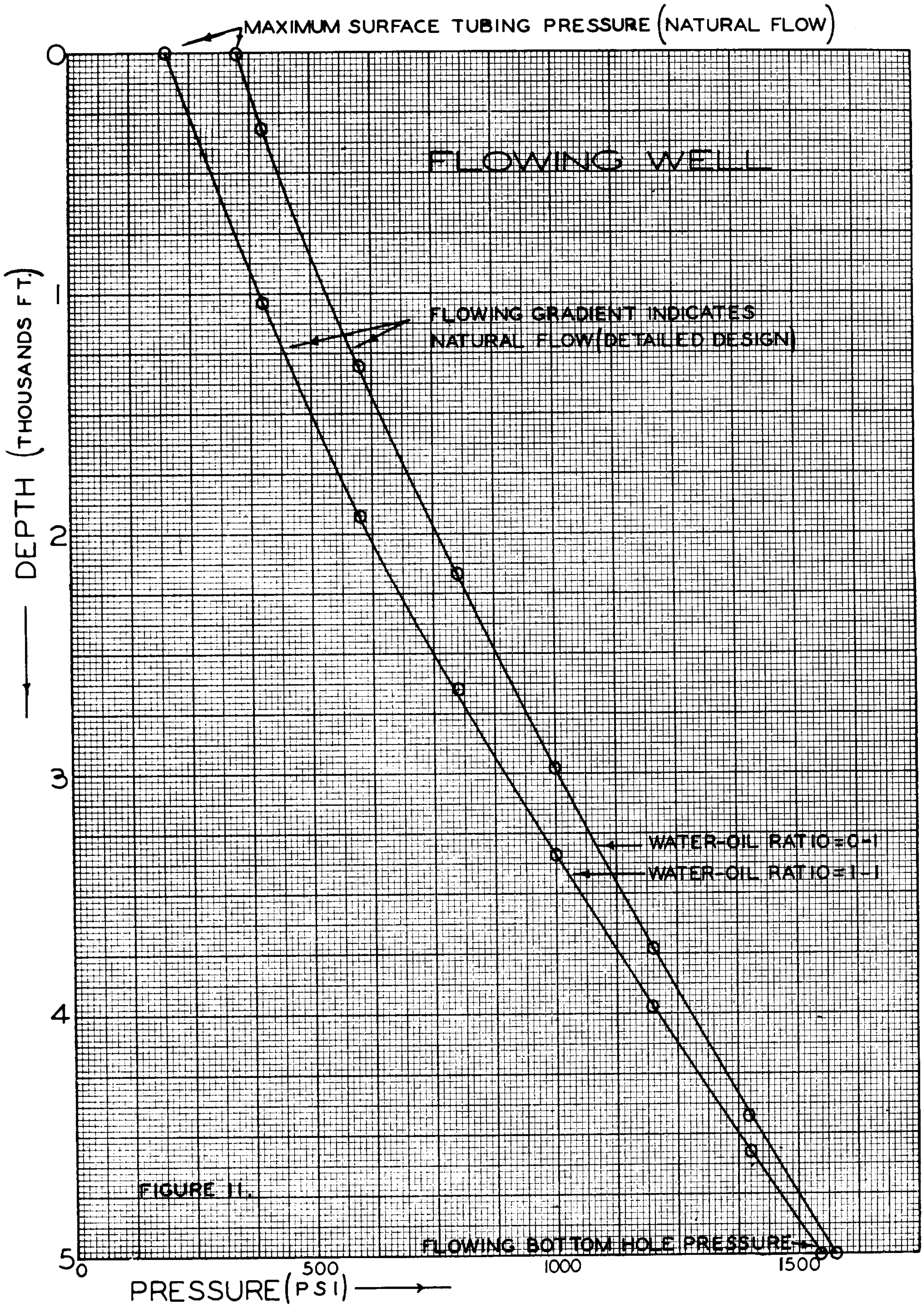


200#
T.P.
700#
C.P.
WATER OIL RATIO = 4-1
DEPTH (THOUSANDS FT)
0
1
2
3
4
5
2925 FT.
POINT OF INJECTION (DETAILED)
3125 FT.
POINT OF INJECTION (SIMPLIFIED)
FIGURE 8.
0
500
1000
1475
1500
PRESS.


200# T.P.
700# C.P.
WATER OIL RATIO=6-1
DEPTH (THOUSANDS FT.)
0
1
2
3
4
5
3125 FT.
POINT OF INJECTION (DETAILED)
3285 FT.
POINT OF INJECTION (SIMPLIFIED)
FIGURE 9.
0
500
1000
1425
1500
PRESS.



WATER-OIL RATIO = 7-1
DEPTH
PRESS.
TEMP. °F
FLOWING GRADIENT
(SIMPLIFIED)
(DETAILED)
CASING PRESS.
STATIC TEMP.
FLOWING TEMP.
3250 FT.
3355 FT.
D
S
POINTS OF INJECTION
FIGURE 10
0
1
2
3
4
5
200
700
0
500
1000
1400
1500
50
70°
100
115°
134°
150


MAXIMUM SURFACE TUBING PRESSURE (NATURAL FLOW)
FLOWING WELL
FLOWING GRADIENT INDICATES NATURAL FLOW (DETAILED DESIGN)
WATER-OIL RATIO = 0-1
WATER-OIL RATIO = 1-1
FIGURE 11.
FLOWING BOTTOM HOLE PRESSURE
DEPTH (THOUSANDS FT.)
0
1
2
3
4
5
PRESSURE (PSI)
0
500
1000
1500

which the flowing bottom hole pressure could be expected to support the fluid in a flowing condition. This is sometimes called the effective lift.

14. The casing pressure is plotted in the same manner, but including the weight of the gas column, until the line intersects the plotted fluid gradient line. The point of gas injection is obtained by moving up the hole an equivalent footage of 100 psi.

15. Calculations must now be started from the tubing pressure and come down the hole by 200 psi increments. To start this procedure, first of all assume some injection gas oil ratio. From the effective lift determined previously a value of 200-300 ft^3 per bbl per 1,000 of effective lift is selected. The steps are the same as outlined above except that a new mass rate of flow is determined which now includes the weight of the injection gas. In figuring Vm, the new volume will also include the volume of the injected gas.

16. Again, working with 200 psi or smaller increments, this curve is plotted until it intersects with the flowing gradient line below the point of gas injection.

17. This point of intersection is then the point of gas injection for this particular injection gas oil ratio.

18. Various injection gas oil ratios should be assumed until one of the curves coincides with the previously established point of gas injection.

19. If a compressor is being selected for the job a further plot of injection pressure vs. injection gas oil ratio, and injection pressure vs. HP should be made to determine the most efficient lift.

The above procedure seems rather tedious and complicated, but can be simplified by mking use of "Standing's Composite Volume Factor Chart" (Fig. 3).[3] It can be seen that the volume occupied by both the oil and gas can be immediately selected from this chart. Therefore, it is only necessary to add the ratio of water per stock tank barrel of oil, to a value from this chart to yield the composite volume factor of oil, gas and water (Jogw). Then the density in $\#/ft^3 = \frac{M}{(5.61)\ (Jogw)}$. The procedure in utilizing the Standing Chart is exactly the same as in the detailed procedure except the volume calculations are simplified.

The detailed method as modified by the use of the Standing Chart can be used to locate the exact point of injection quickly if combined with the "Simplified Method." This is done by substituting the gradient below the point of injection (which does not take into account the formation gas) with the gradient as plotted from the use of "Standing's Chart."

If it is not necessary to determine an exact injection G.O.R., the point of gas injection is determined by returning up the hole a distance equivalent to 100 psi from the point at which the casing pressure line intersects the gradient line (Step 14, "Simplified Procedure"). The difference in pressure should be no less than 25 psi and no more than 100 psi. This differential pressure (25-100 psi) is required in order to allow the well to unload to this point. Once this depth has been reached, the differential can be decreased if desired.

With the advent of gas lift valves that regulate the same gas volume into the tubing as is injected into the casing, the problem of having to calculate injection G.O.R.'s to establish a choke size is eliminated. It is only necessary to regulate different injection volumes into the casing until the most efficient producing G.O.R. is established.

A comparison of these two methods has been made utilizing the following problem:

(1) Depth to the center of the perforated interval 5000 ft.
(2) Static bottom-hole pressure - 1600 psi.
(3) Water specific gravity 1.07.
(4) Water oil ratios - (1, 2, 4, 6, 7).
(5) Desired to produce 100 bbls. of oil per day.
(6) Tubing size - 2-3/8" O.D., EUE, 8 Rd. Thd.
(7) Producing G.O.R. - 500-1.
(8) Specific gravity of the produced gas = .60.
(9) Specific gravity of the injection gas = .60.
(10) Specific gravity of the oil = .802 (45 API).
(11) Surface tubing pressure = 200 psi.
(12) Surface injection gas pressure = 700 psi.
(13) Bottom hole temperature = 134 F.
(14) Surface flowing temperature = 114 F.
(15) Mean surface temperature = 70 F.
(16) Productivity Index (P.I.) = 4.0.

The results of solving this problem by both methods for various water oil ratios are shown in Figs. 6, 7, 8, 9 and 10.

A summary of these results is as follows:

Water-oil Ratio	Depths of Points of Injection Detailed	Simplified	Difference (ft.)
2	2500'	2920'	420'
4	2925	3125	200
6	3125	3285	160
7	3250	3355	105

It is immediately evident that as the per cent of water production increases, the results obtained by the simplified method approach those calculated by the detailed procedure. An installation designed by the simplified method locates the point of injection lower than calculated by the detailed method, providing a safe design. Extreme accuracy in well information must be available to assure correct calculations by the detailed procedure.

As a matter of interest, Fig. 11 shows that for water oil ratios up to 1, the well would flow naturally.

CONCLUSIONS

(1) It should be safe to design a continuous flow installation by the simplified procedure for water oil ratios of 4-1, or greater. However, if enough information is available, the installation should be designed by the detailed procedure. In most cases it will only be necessary to use the detailed procedure to establish the gradient curve below the point of gas injection. Starting from Step 12 of the simplified procedure, the point of injection can easily be located.

(2) If very little information is available, the design of a continuous flow installation for any water oil ratio can be made by the simplified procedure, since such a calculation assures greater submergence. Therefore one or two extra valves may be required. This is amply justified if it is known that pressures in the reservoir are decreasing, or if there is a possibility of increasing water percentages.

(3) If all required information is available, the design of any installation should be made by the detailed procedure, making allowances for changing well conitions.

(4) The use of the "Composite Volume Factor Chart" is permissible in the detailed procedure, but the results obtained máy not check exactly with the detailed calculations. If possible, solution gas and formation volume factor curves should be obtained for each reservoir.

(5) For exceptionally high producing gas-oil ratios, the detailed procedure would be preferred for all water-oil ratios.