CHAPTER 3

NODAL ANALYSIS

The system analysis approach often called Nodal Analysis has been applied for many years to analyze the performance of systems composed of interactive components. It can be applied to both oil and gas wells. The procedure consists of first selecting an appropriate division point or node. In the whole system, any point can be considered as a node and nodal analysis can be performed. All components upstream from node comprise the inflow section, and all components downstream comprise the outflow section.

A relation between flow rate and pressure drop must be developed for each component in both sections. The flow rate for the specific system or set of components can be determined by satisfying the following relationships:

1) Flow into node = Flow out of node
2) Only one pressure can exist at the note

The average reservoir pressure and the separator pressure are considered to be fixed for any given time in a well flow system. The basic procedure is to calculate the pressure at the node both ways from the fixed pressure points as follows:

Inflow to node:

$$p_R - \Delta p_{(upstream\_components)} = p_{node} \tag{3.1}$$

Outflow from node:

$$p_{separator} + \Delta p_{(downstream\_components)} = p_{node} \tag{3.2}$$

The pressure drop Δp, in any component varies with flow rate q, therefore, a plot of flow rate vs. node pressure for each section will produce two curves, the intersection of which gives the one flow rate which satisfies the two conditions above.

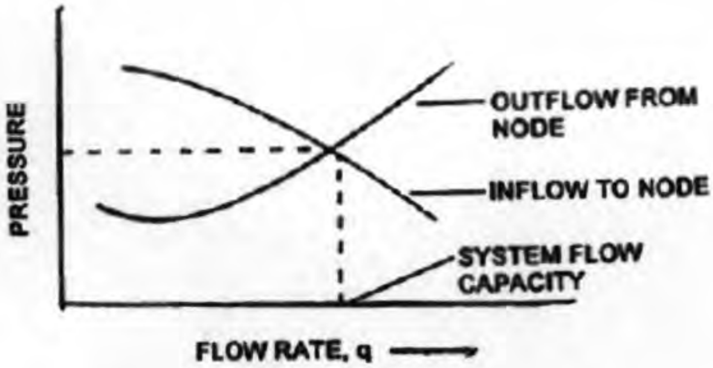

Figure 3.1: Inflow- Outflow crossplot[5]

A change in the pressure drop across an upstream component (inflow section) will leave the outflow curve unchanged, but the intersection point will change, and thus the flow rate will change. Likewise a change in the pressure drop across a downstream component will result in an adjustment in the flow rate. Finally, a change in either of the fixed pressures (the average reservoir pressure or the separator pressure) occurring during the life of the well will result in a change in the flow rate.

A frequently used node or division point is inside the casing at the perforations; i.e., between the reservoir and the piping system. Thus, the flow through the rock, the perforations, and the gravel pack (if installed) is one system, and flow up the tubulars, through the wellhead and through the flow line and manifold to the separator is the second system.

The total system is optimized by selecting the combination of component characteristics which will maximize production rate for the lowest cost.

The system analysis approach is basically used to optimize flowing well performance, but can also be applied to artificial lift situations in oil wells if the effect of the artificial lift system on the pressure is a function of the flow rate. Possible applications include:

1) Selection of tubing and/or flow line sizing
2) Surface choke or subsurface safety valve sizing
3) Analyzing effect of perforation density
4) Analyzing effect of gravel pack design
5) Artificial lift design
6) Predicting the effect of depletion on producing capacity

3.1 Inflow Performance Relationship

The inflow performance relation for a specific well represents the ability of that well to produce fluids against varying bottomhole or well intake pressures. Sometimes this relation is assumed to be a straight line (Figure 3.2). However, except for wells producing above the bubble-point pressure, flow rate usually drops off significantly from a straight line relation at higher wellbore pressure drawdown with two phase flow.

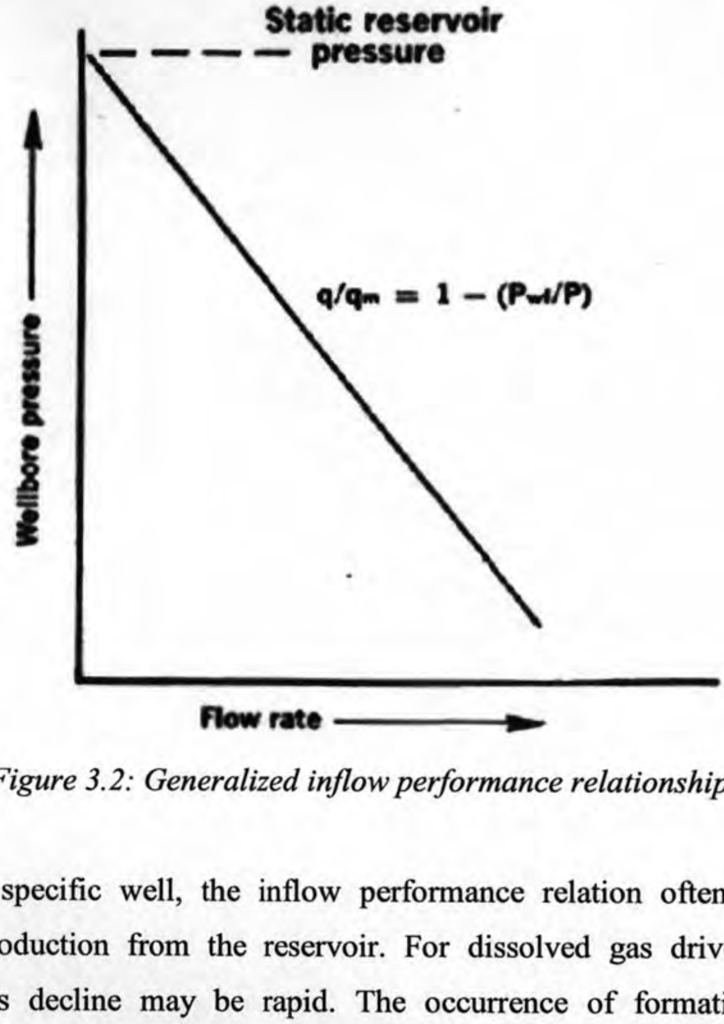

Figure 3.2: Generalized inflow performance relationship [6]

For a specific well, the inflow performance relation often declines with cumulative production from the reservoir. For dissolved gas drive or gas drive reservoirs, this decline may be rapid. The occurrence of formation damage or stimulation also effects the inflow performance relation.

The inflow performance relation can be best determined by flow after flow or isochronal testing of the specific oil well.

There are different methods to determine the inflow performance relation and one of it is Fetkovich method. This method is applied where precision is required. Fetkovich showed that flow after flow, or isochronal, tests could also be applied to oil wells. The basic equation is:

$$q = J'\left(\overline{p}^2 - p_{wf}^2\right)^n \tag{3.3}$$

$\overline{p}$ = shut in reservoir pressure

p_{wf} = well intake pressure

J' = productivity coefficient

n = reciprocal slope of best fit plot of q vs. $\left(\overline{p}^2 - p_{wf}^2\right)$

At least two, preferably four tests at different rates are needed to determine the constants J' and n. An IPR curve can then be drawn by selecting convenient values for q and solving for P_{wf}.

The simplified Vogel IPR curve, is satisfactory for most purposes of well completion designed. Vogel developed the general inflow performance relation of Figure 3.3 through a simulation study involving a wide range of parameters applicable to dissolved gas drive reservoirs. Having one well test measuring static reservoir pressure, and a flow rate with corresponding bottom-hole flowing pressure, Figure 3.3 predicts a flow rate at any other BHFP. Future IPR's can be estimated by displacing the curved downward in proportion to the decline of static reservoir pressure.

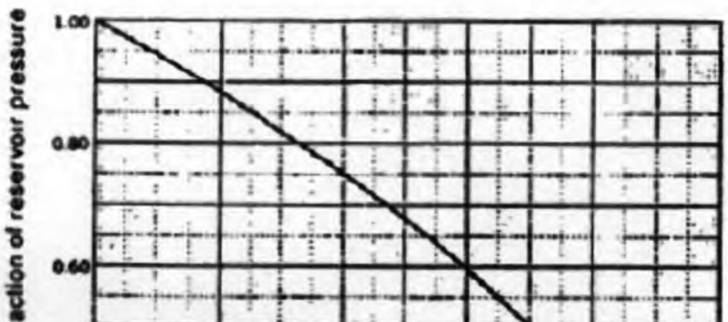

Figure 3.3: Inflow Performance Relation (Vogel) [6]

Strictly, the Vogel work applies to a dissolved gas drive reservoir; however, for practical purposes it can be used to any type of reservoir.

$$\frac{q}{q_m} = 1 - 0.20\frac{p_{wf}}{\bar{p}} - 0.80\left(\frac{p_{wf}}{\bar{p}}\right)^2 \tag{3.4}$$

Where

q = producing rate at given p_{wf}

q_m = producing rate when $p_{wf} = 0$

3.3.1 Productivity Index:

A popular term used to describe well deliverability, represents only one point on the inflow performance curve. Below the bubble point, a PI value should not be extrapolated very far from the flow rate at which it was measured since PI usually declines with

1) Higher wellbore pressure drawdown
2) Cumulative reservoir fluids withdrawal.
3) Degree of formation damage

$$PI = \frac{k_o h \times 10^{-3}}{u_o B_o} \tag{3.5}$$

k_o = oil relative permeability, md

h = zone height, feet

μ_o = oil viscosity, cp

B_o = formation volume factor

3.2 Outflow Performance Relation

Tubing performance data for oil wells involving two phase or three phase vertical flow is difficult to calculate since the average density and the velocity of the fluid is usually unknown due to gas breakout and fluid slip.

Poetmann and Carpenter[5] developed empirical correlations which can be used to approximate multiphase vertical flow. Generally this correlation applies to 2 3/8" to 3 ½" inch OD tubing and flow rates greater than 400 bpd with minimum slippage.

Since this original work, Dun and Ros[5], Hagedorn and Brown[5], Beggs and Brill[5], and other have developed additional vertical flow correlations aimed at improving the accuracy of pressure loss calculations. Most are applicable to all conditions including annular flow. Also vertical flow relations can be used in deviated holes upto 15° to 20° from vertical if suitable corrections are made.

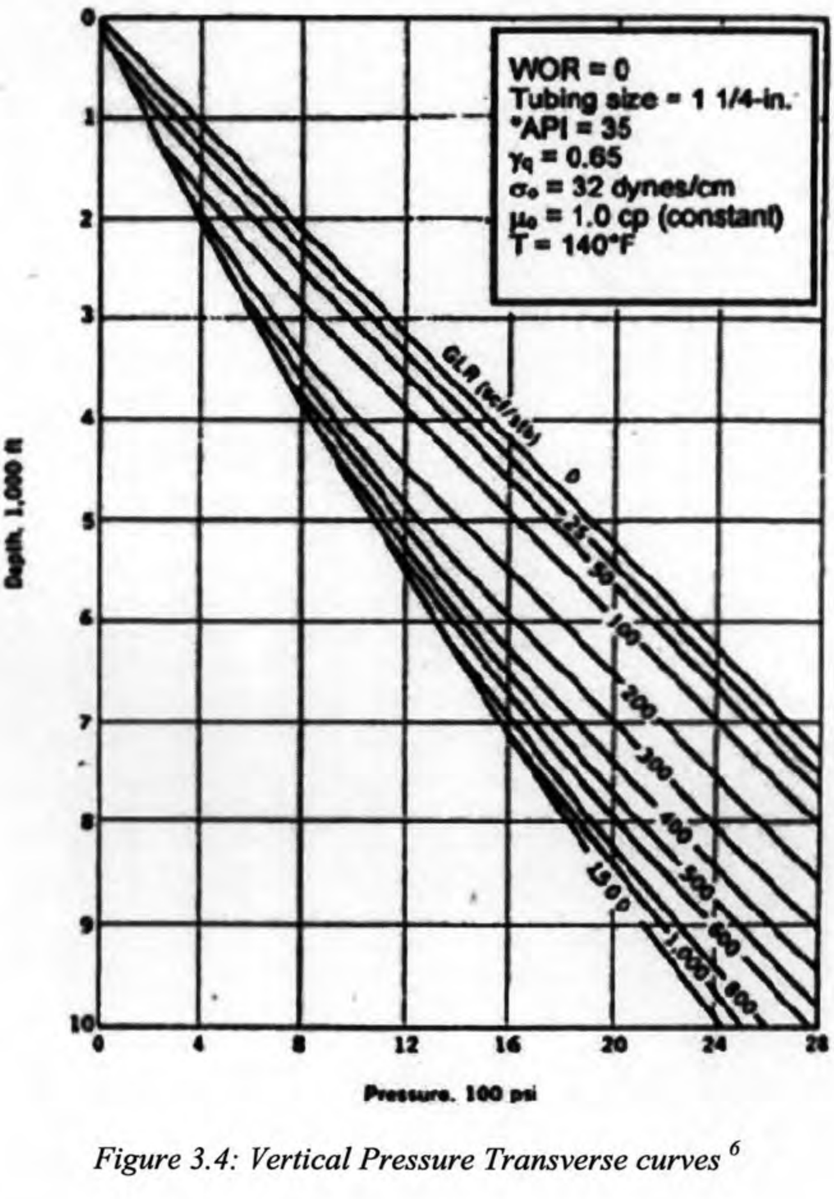

Figure 3.4: Vertical Pressure Transverse curves [6]

No one correlation satisfies all well conditions. Field checks to compare predictions with measured results maybe needed to select the most suitable correlation. Figure 3.4 shows typical pressure traverse curves from the Hagedorn and Brown[5] correlation. Use of curves to obtain flowing pressure drop where surface pressure is known, involves a correction procedure, as follows, to account for the surface pressure:

1) Pick proper curve to fit situation, i.e., flow rate, pipe size, WOR etc.
2) Draw vertical line from surface pressure intersecting gas-liquid ratio to determine pseudo depth.
3) To this pseudo depth, add well depth to determine pressure depth.
4) Move horizontally from pressure depth to proper GLR and read bottom-hole pressure.
5) Subtract surface pressure from BHP to determine pressure drop in tubing.

With gas in the flow steam, the effect of increasing surface pressure is to increase pressure loss in the tubing. Thus, back pressure against the formation is increased due to:

1) The higher pressure loss in the tubing
2) The higher surface pressure

Curves similar to Figure 3.4 are useful for engineering work where approximate pressure drop calculations are required. Computer solutions of various correlations permit more detailed look at the effect of changing variables.

Brill, Doerr, Hagedorn and Brown[5] studied the effect of certain variables on multiphase vertical flow and presented the relationships presented in the sub-sections that follow. These are included to provide a feel for their relative importance.

3.2.1 Effect of tubing size: Although larger tubing sizes show an advantage in the lowering the bottom-hole pressure, the income from the increased production rate must pay out the additional cost of the larger tubulars. Also as tubing becomes larger, flow velocity decrease and may let gas break through the liquid. Resulting liquid fall back and accumulation may kill the well. Field experience indicates that slippage is often more significant than normally considered.

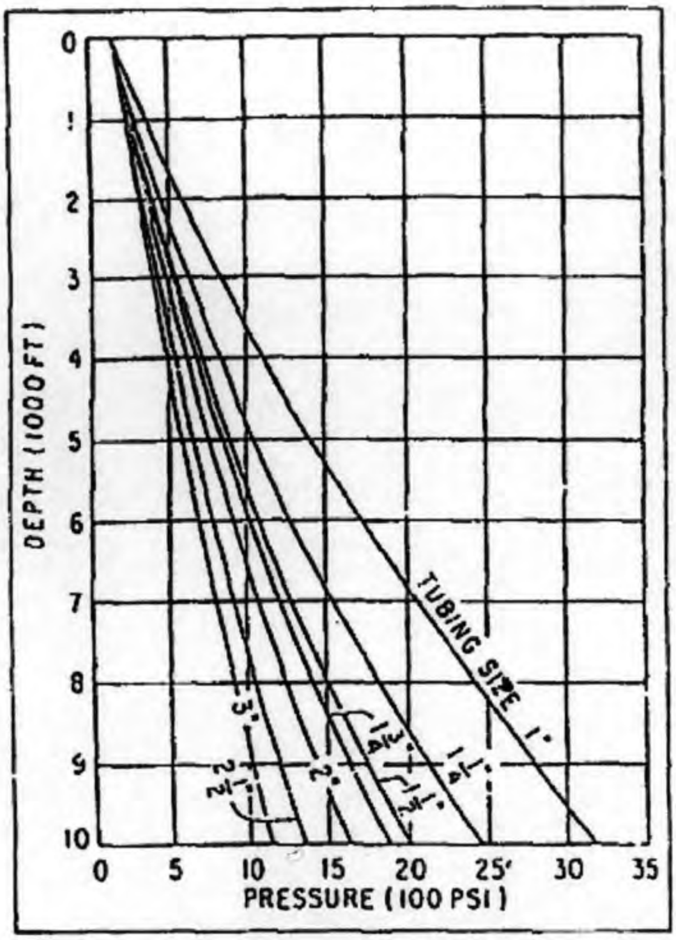

Figure 3.5 Effect of tubing size [6]

3.2.2 Effect of surface flow rate: At low rates, these correlations probably breakdown due to the so called heading effects. Attempt to describe this heading effect mathematically or to predict the rate at which it occurs has not yet been successful.

3.2.3 Effect of Gas Liquid Ratio (GLR): As the GLR increases, the flowing bottom-hole pressure required to produce the rate decreases. However, a point is reached where further increases in GLR actually increase the bottom-hole pressure.

3.2.4 Effect of liquid density: As API gravity increases, the flowing pressure decreases. It should be noted that as API gravity increases, the amount of solution gas at a given pressure level increases. This increases the liquid hold up factor, which in-turn increases density and tends to offset the higher GLR.

3.2.5 Effect of liquid viscosity: Free gas viscosity is assumed to be 0.02cp in the study while liquid viscosity varies with temperature and solution gas.

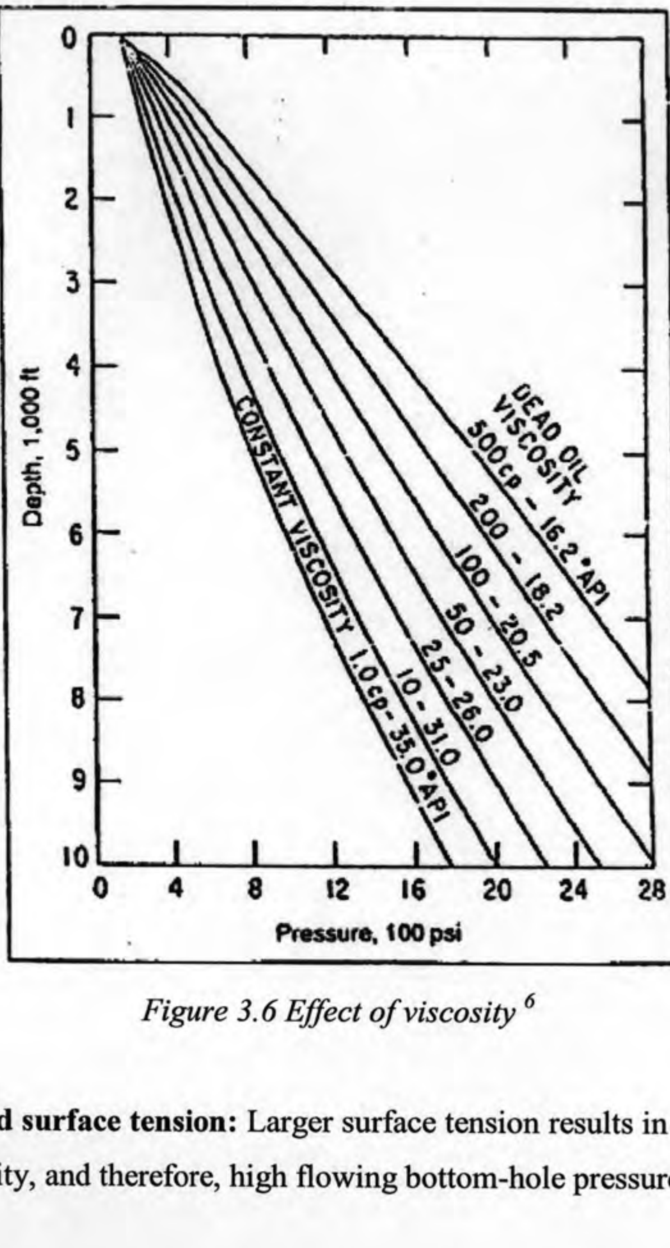

Figure 3.6 Effect of viscosity [6]

3.2.6 Effect of liquid surface tension: Larger surface tension results in greater liquid hold up, higher density, and therefore, high flowing bottom-hole pressure.

3.2.7 Effect of kinetic energy: It is often neglected but can become important with small diameter tubing with high GLRs and low pressure levels.

Pressure drop through tubing restrictions and wellhead in high rate producing situations can be significant. Tubing restrictions include a sliding side door assembly and ball type safety valve. Pressure drop in the flow line involving horizontal two phase flow is as complex as that of vertical two phase flow. A number of correlations have been presented based on empirical data. The best correlation is the one that closely matches the filed data in a specific situation.

The important thing about each correlation is that it has flow regimes at different tubing depths which may not be consistent with each other. The correlations tend to give a range of transverse curves and these ranges tend to be pretty significant to have an impact on the cumulative oil recovery. The bottom-hole pressure determined by each correlation is different and that tends to give rise to different recovery factor. Most of the variation in transverse curves can be seen for high GOR wells and are lesser ranged for low GOR wells.

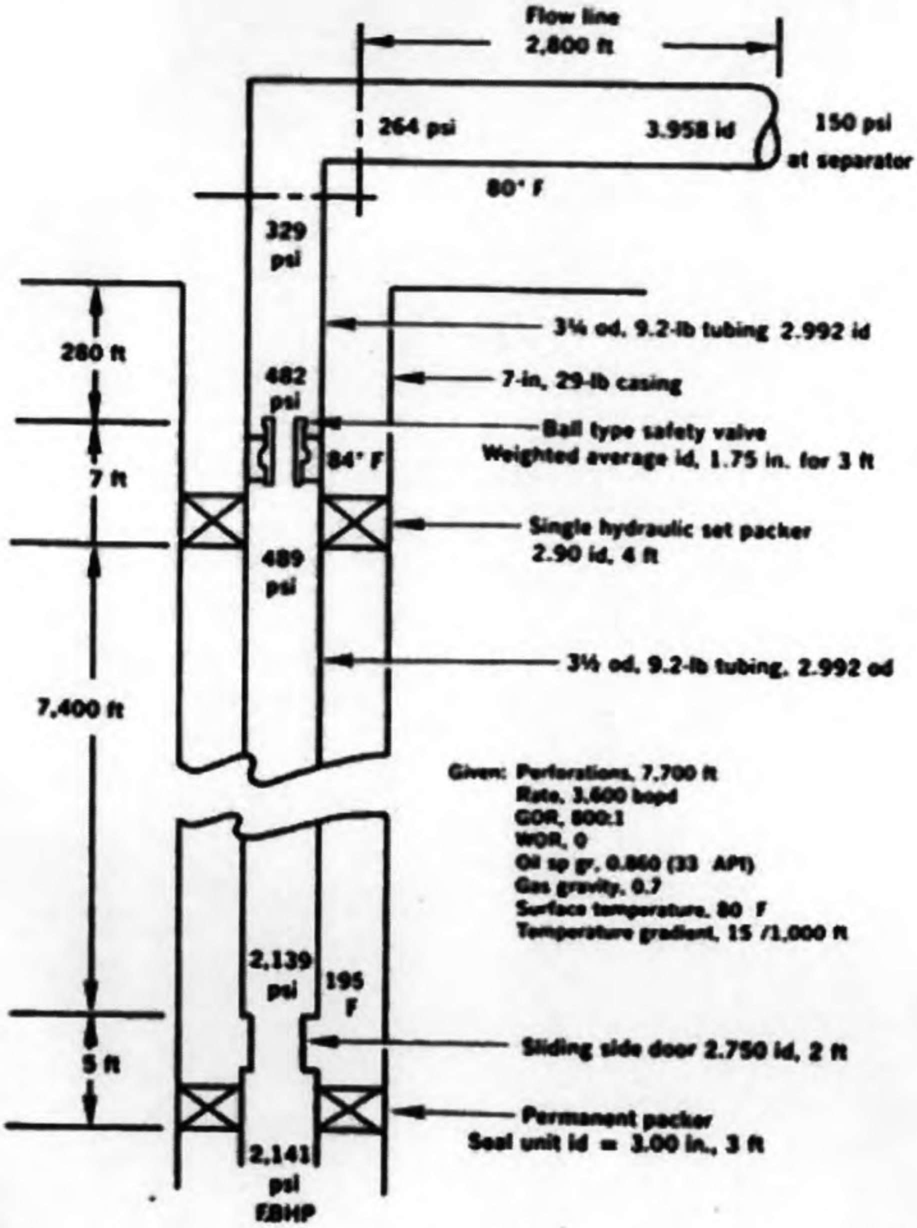

Figure 3.7: Pressure at various points in high flow rate well system [6]

An outflow-inflow cross plot, similar to Figure 3.8, can be made after well deliverability IPR and tubing performance curves for several tubing sizes have been determined for a specific situation. Figure 3.8 shows Vogel IPR curves for two wells. For comparison a P.I. is also shown for well-2 (straight dashed line). Tubing performance curves for three tubing sizes are shown.

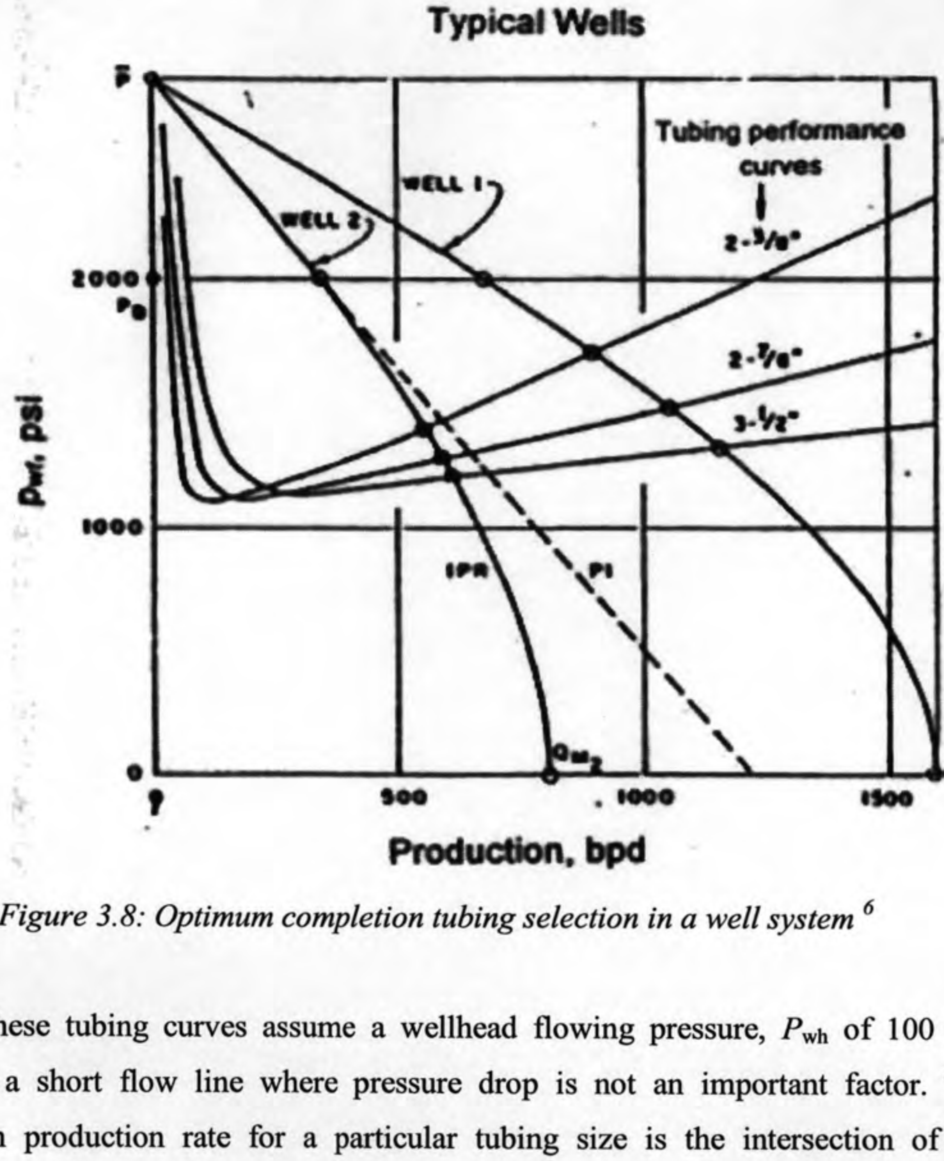

Figure 3.8: Optimum completion tubing selection in a well system [6]

These tubing curves assume a wellhead flowing pressure, P_{wh} of 100 psi, inferring a short flow line where pressure drop is not an important factor. The maximum production rate for a particular tubing size is the intersection of the appropriate deliverability and tubing performance curves.