ARTIFICIAL LIFT

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Summary

This chapter discusses the most common methods used in the oilfield for producing or augmenting the liquid flow rate produced by oil wells. The relation between flow rate and pressure drawdown, defined as Inflow Performance, is presented as the basis for selection and design of the artificial lift systems. The characteristics and performance of positive displacement and dynamic displacement pumps are discussed in detail. The injection of gas into the wellbore, either continuous or intermittent, and the use of plunger lift systems for artificial lift, is also discussed.

1. Introduction

Artificial lift refers to those technologies that are used in hydrocarbon wells to produce liquids at a rate in excess of the rate that could be obtained by natural flow through the utilization of the reservoir pressure alone. This includes not only those wells that are not able to flow naturally but all the wells that flow naturally but at rates that are not considered economic.

These systems are designed provide the energy necessary to move the fluids from the bottom of the well to the surface at a desired rate and delivery pressure. This energy supplements the flowing pressure available at the bottom of the well that depends on the productivity of the reservoir. Proper selection and design of an artificial lift system is totally based on the reservoir's characteristic relationship between dynamic pressure and flow rate. This is known as the Productivity or the Inflow Performance Relation (IPR) of the formation.

1.1. Inflow Performance Relation

The hydrocarbon production system represented schematically in Figure 1 includes the reservoir characterized by a static reservoir pressure (SBHP = 1000 psi, 69 bar) a vertical wellbore with a dynamic producing bottom hole pressure (PBHP = 500 psi, 34.5 bar) and a surface tubing pressure (Pt), connected to surface flowlines and processing facilities.
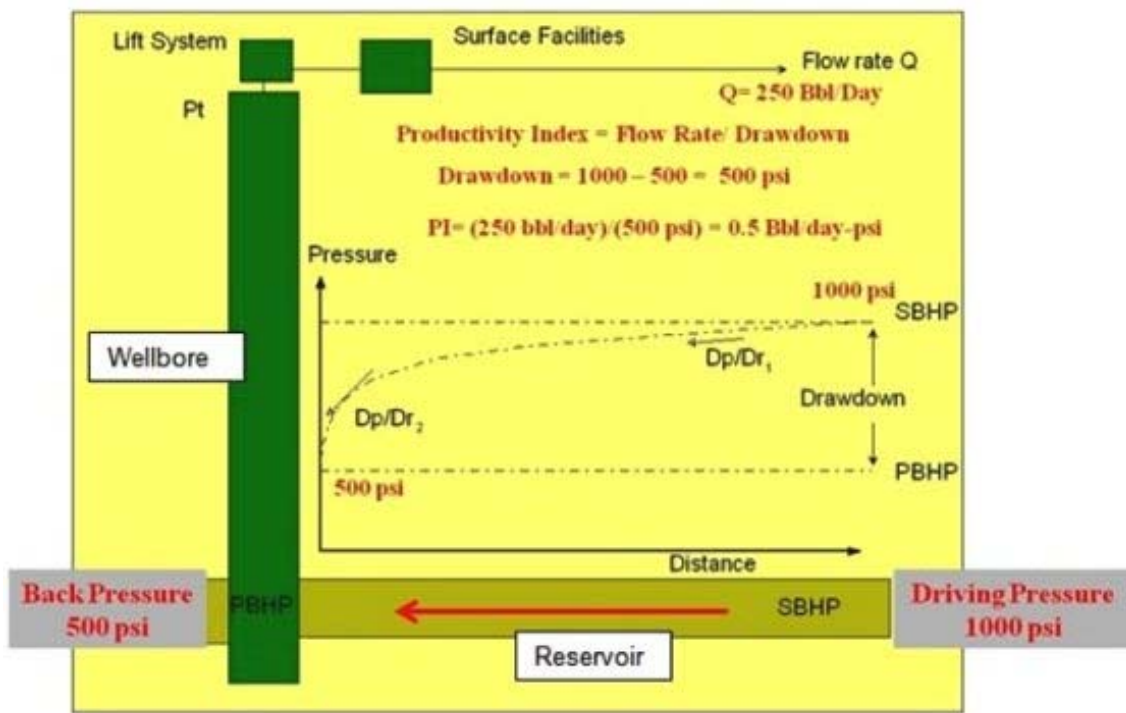

Figure 1. Schematic Representation of the Hydrocarbon Production System including the Reservoir, the Wellbore and the Surface Facilities

The formation inflow performance relation may be expressed as a productivity index that is defined as the ratio of the flow rate to the pressure drop between the reservoir driving pressure (1000 psi, 69 bar) and the back pressure at the bottom of the well (500 psi, 34.5 bar). In this example the productivity is computed as 0.5 Barrel (Bbl) per day per psi (1.15 $m^3 day^{-1} bar^{-1}$).

In the majority of wells produced by artificial lift the productivity of the formation is not a constant but decreases as the drawdown increases thus yielding a non linear inflow

relation that can be represented as a graph of flowing bottom hole pressure vs. flow rate as shown in Figure 2.

The relation indicates that in order to increase the flow from the reservoir the bottom hole pressure has to decrease causing an increase in the drawdown pressure. The increment in production for a given increase of the drawdown pressure is not constant but becomes less as the pressure decreases.

The maximum production is achieved when the bottom hole pressure approaches zero so that the drawdown equals the available reservoir pressure. The corresponding flow rate is defined as the reservoir's open flow potential, Qmax.
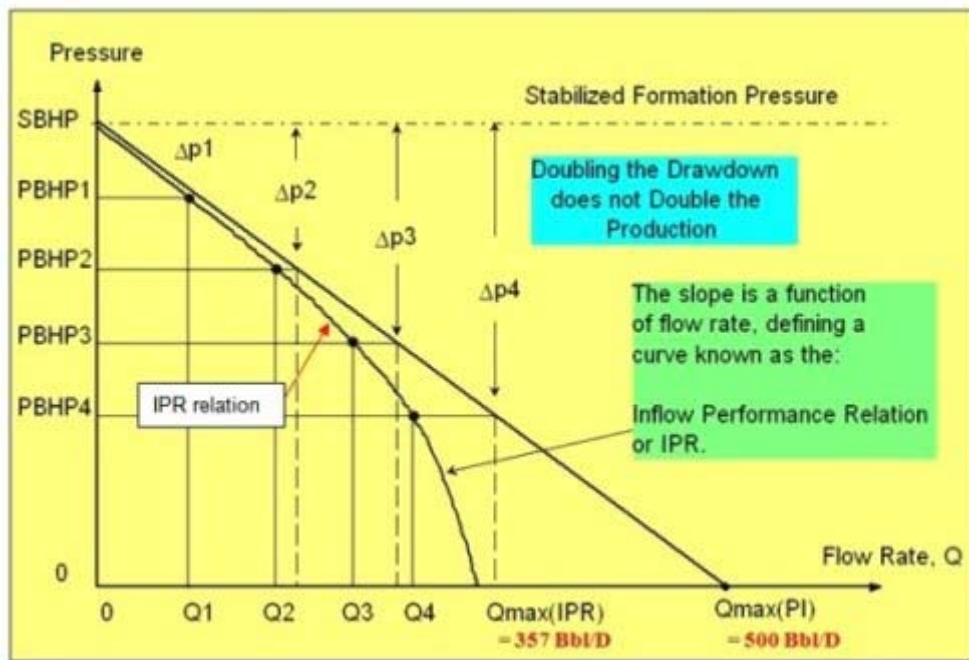

Figure 2. Productivity and Inflow Performance Curves Describe the Relation between Bottom hole Pressure and Flow Rate

1.2. Vertical Lift Performance

The fluid that is produced at the bottom of the well has to flow to the surface overcoming the sum of the tubing head pressure plus the hydrostatic pressure due to the flowing fluid mixture (generally a mixture of oil, water and gas) plus the friction forces due to flow in the tubing and any other energy losses that depend on the type of flow pattern that is developed (Figure 3).
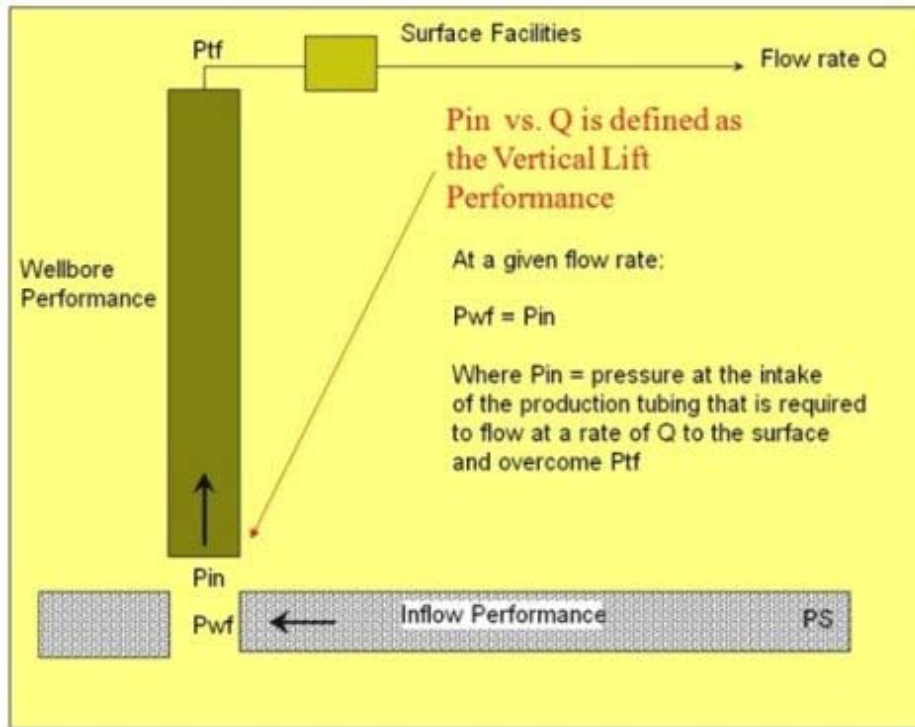
Figure 3. Schematic Representation of the Relationship between Inflow Performance and Vertical Lift Performance
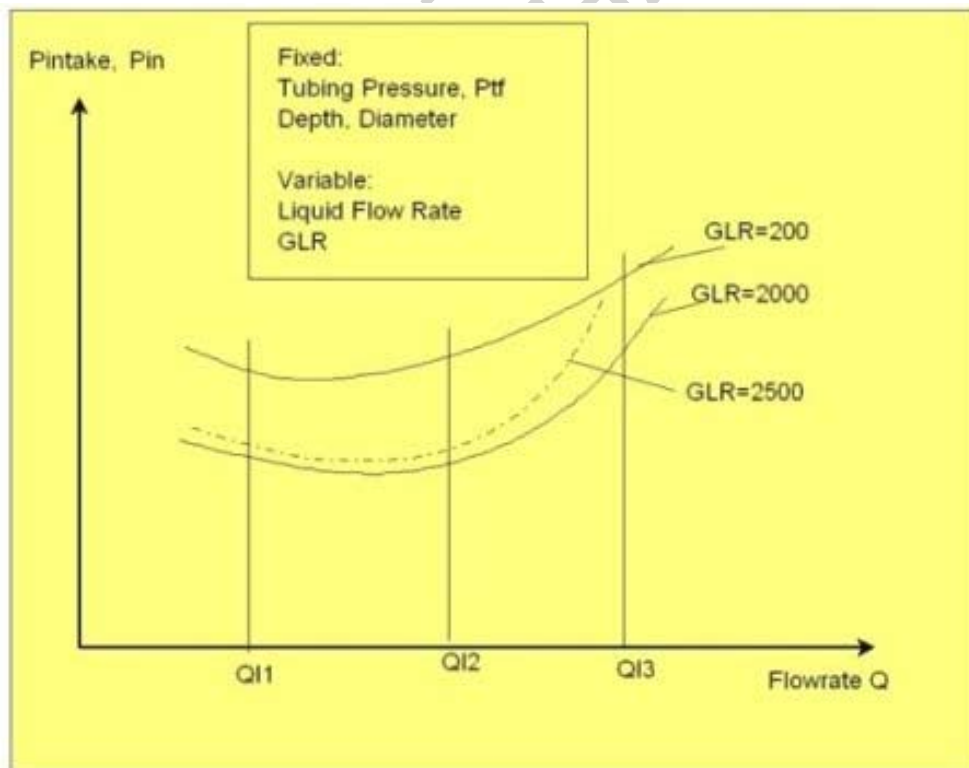

Figure 4. Effect of Variation of the Gas-to-Liquid Ratio and Liquid Flow Rate on the Tubing Intake Pressure

The pressure required at the intake of the tubing (bottom of tubing) to be able to flow the fluid mixture to the surface is defined as the tubing intake pressure (Pin or PIP), and is represented as a function of liquid rate and Gas-to-Liquid Ratio (GLR) in Figure 4 for a case with constant depth, diameter and pressure at the top of the tubing.

The general shape of the tubing performance curves reflect the increasing intake pressure as the liquid rate increases for a constant GLR due to the increased pressure drop as mixture velocity increases. For a constant liquid rate, the trend is for the intake pressure to decrease as the GLR increases, up to a point where the frictional effects overtake the reduction in hydrostatic pressure caused by an increased fraction of gas. Note that in the previous figure all other parameters are fixed: depth to intake, tubing diameter and tubing head flowing pressure (Ptf).

At a given time in the life of a flowing well, the gas to liquid ratio is dependent on the flow conditions in the reservoir rock as expressed by relative permeability and gas saturation. To control the flow rate from the well, the only practical parameter at our disposal (once the tubing has been installed) is the tubinghead pressure. For a given tubing size, tubing depth and gas liquid ratio, the tubing intake pressure is a function of liquid rate and tubinghead pressure, as illustrated by the VLP (Vertical Lift Performance) curves in Figure 5.
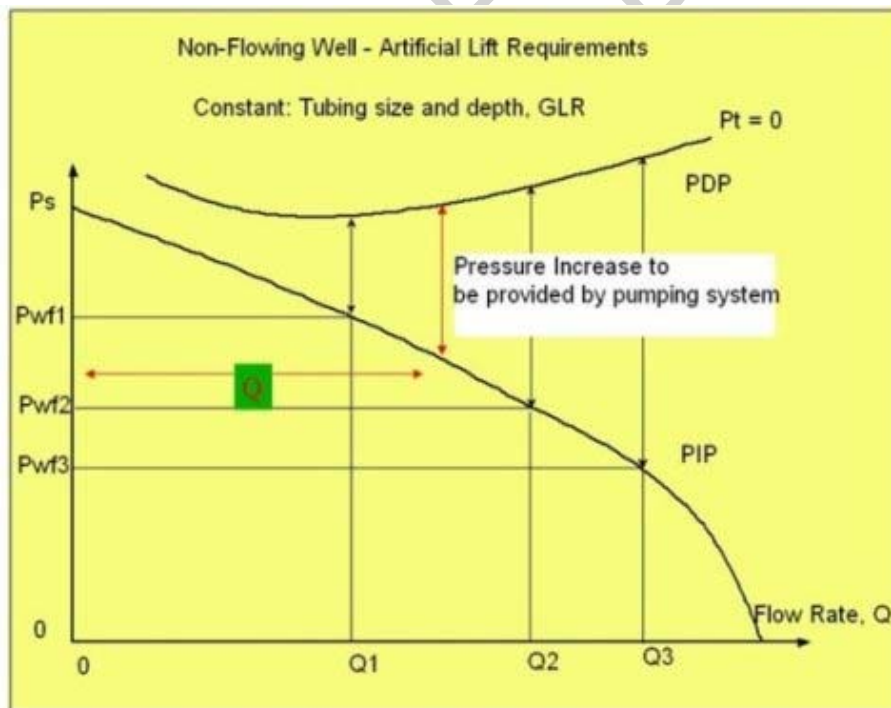

Figure 5. Intersection of the VLP and IPR Curves Defines the Flow Rate Produced by the Well.

As the tubing head pressure (Pt) is reduced from 300 psi (20 bar) to zero, the tubing intake pressure for a given liquid rate decreases causing an increase of the drawdown pressure between the wellbore and the reservoir and a corresponding increase of the flow rate from the reservoir. The point of intersection of the VLP curve, corresponding

to a given tubinghead pressure (for example the VLP curve for 100 psi, (7 bar) and the IPR curve for the formation, represents an equilibrium condition and the well will flow at the rate indicated as Q2. An increase in tubinghead pressure will cause an increase in the VLP pressure and a corresponding decrease in flow rate. Further decrease in tubinghead pressure, say to zero, will result in achieving the maximum production rate from the well, in this case equal to Q3.

1.3. Artificial Lift Objectives

For the conditions illustrated in the preceding figure, once the tubing pressure is reduced to zero and flow rate Q3 is achieved, it is not possible to produce fluid from the well at a higher rate without modifying the installation or introducing some form of artificial lift. The first option is to install a downhole pump that admits fluid at a low pressure and discharges the fluid to the bottom of the tubing at a sufficient pressure to flow to the surface. A second option is to modify the flowing system so that the tubing intake pressure for a given liquid rate is reduced so that the fluid can flow to the surface with the available bottom hole pressure. This can be accomplished either by reducing the hydrostatic pressure (reduce the density of the flowing mixture) or reducing the frictional losses (modifying the tubing diameter and friction factor) or a combination of the two by injecting gas at some depth. This is known as artificial lift by Gas Lift.

Pumping
When the reservoir pressure has depleted to such a low value that it is not possible to reduce the tubing intake pressure to a value comparable to the available bottom hole pressure, as shown in Figure 6, the well will not flow naturally at any rate, and a pumping system has to be installed to provide additional energy to the flowing fluid.
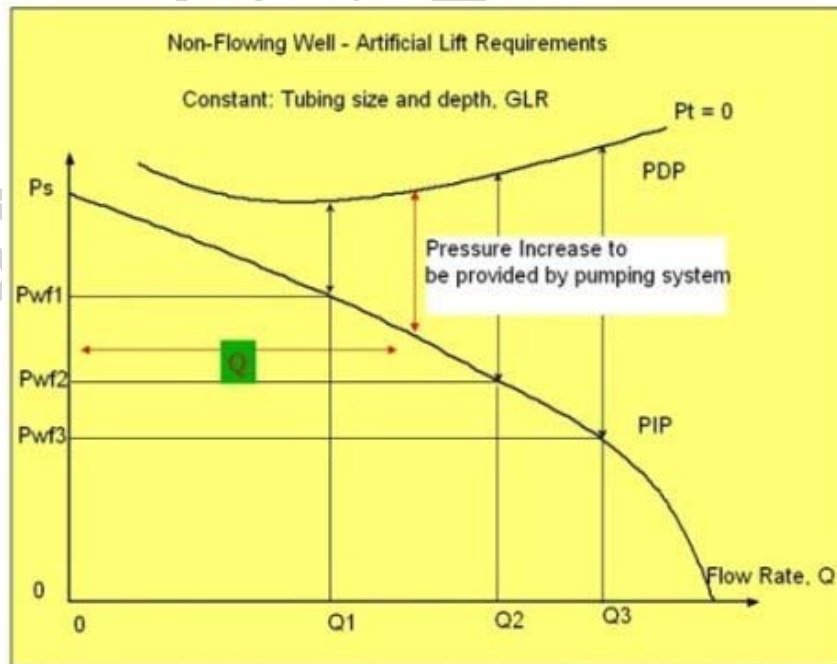

Figure 6. The Absence of an Intersection between the VLP and the IPR Relations Indicates the Need for an Artificial Lift System.

At a given flow rate Q, the vertical distance between the VLP curve and the IPR relation, represents the pressure increase to be provided by the pump. As the flow rate increases the two curves diverge (increase in tubing intake pressure and decrease in flowing bottom hole pressure) so that the pump has to impart more energy to the flowing fluid. Given a Pump Intake Pressure (PIP) and a Pump Discharge Pressure (PDP) the power required by the pump is the product of the flow rate (Q) and the pressure increase through the pump (PDP-PIP). This product defined as the pump's hydraulic horse power (HHP). It is a minimum value since it does not consider the inefficiencies of the pump and prime mover. The actual power that must be supplied to the pumping system for operation will be greater than the hydraulic power and will depend of the type of pumping system that is selected.

Gas Lift

When the reservoir pressure and the productivity of the well are sufficiently large so that there is adequate producing bottom hole pressure, then well flow can be established or augmented by reducing the gradient of the fluid mixture in the tubing through injection of additional gas in the flowing stream. The following Figure 7 shows the effect of increasing the Gas-to-Liquid-Ratio (GLR) from 150 standard cubic feet per barrel, scf/Bbl = (26 Standard $m^3 \cdot m^{-3}$) which is the GLR produced from the formation, to 600 scf/Bbl (107 Standard $m^3 \cdot m^{-3}$), on the flowing pressure distribution for a fixed liquid rate of 500 Bbl per day (80 m^3 per day).
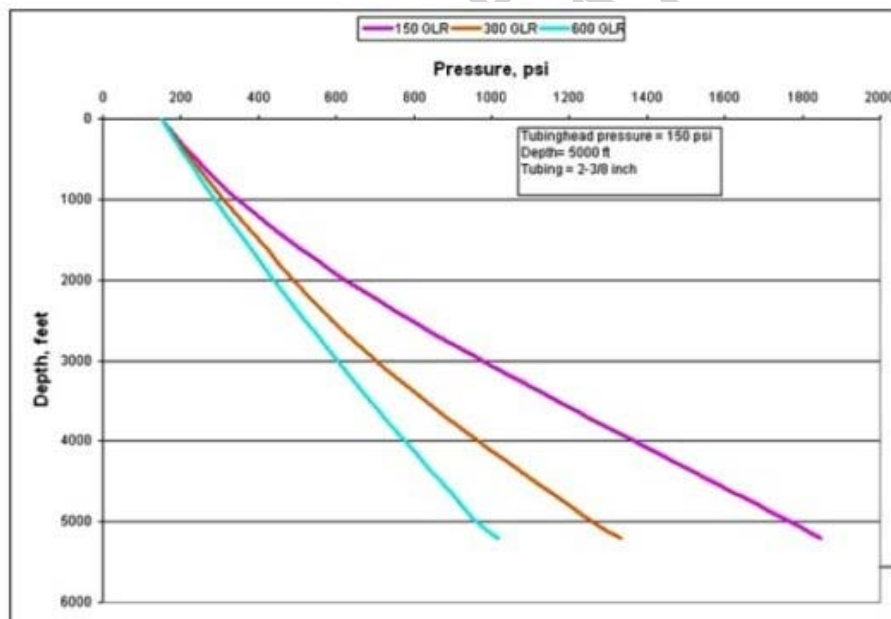

Figure 7. Wellbore Pressure vs. Depth Traverses for Various Gas-to-Liquid Ratios

The 150 psi (10 bar) tubing head pressure is kept constant since it is a requirement imposed by the processing facilities at the surface. Note how the tubing intake pressure (at 5200 feet, 1585 m) is reduced from a value of 1850 psi (128 bar) for 150 GLR to a low value of 1020 psi (70 bar) when the GLR is increased to 600 scf/Bbl (106 Standard $m^3 \cdot m^{-3}$). The reduction in tubing intake pressure would cause sufficient drawdown at the formation to flow the well at this relatively high flow rate depending on the reservoir

inflow performance. Figure 8 shows the corresponding tubing intake pressure relations computed at the formation depth as a function of liquid rate. The parabolic IPR curve indicates an absolute open flow potential of 700 Bbl/day (111 m^3 per day) for the formation.

Natural flow with a tubing head pressure of 150 psi (10 bar) cannot be maintained at any liquid flow rate since the VLP curve for this pressure is above the IPR curve. Injecting additional gas in the tubing (at the tubing intake depth) to achieve a GLR of 300 scf/Bbl (53 Standard m^3·m^{-3}), lowers the VLP curve so that it intersects the IPR curve at a flow rate of 350 Bbl/day (55 m^3 per day).

Further increasing the injected gas rate lowers the VLP curve so that for 600 GLR it is possible to flow the well at a rate of about 500 Bbl/day (80 m^3 per day). Assuming that this is the desired liquid rate from the well, the gas lift installation is then designed to achieve a 600 scf/Bbl (107 Standard m^3·m^{-3}) gas to liquid ratio.
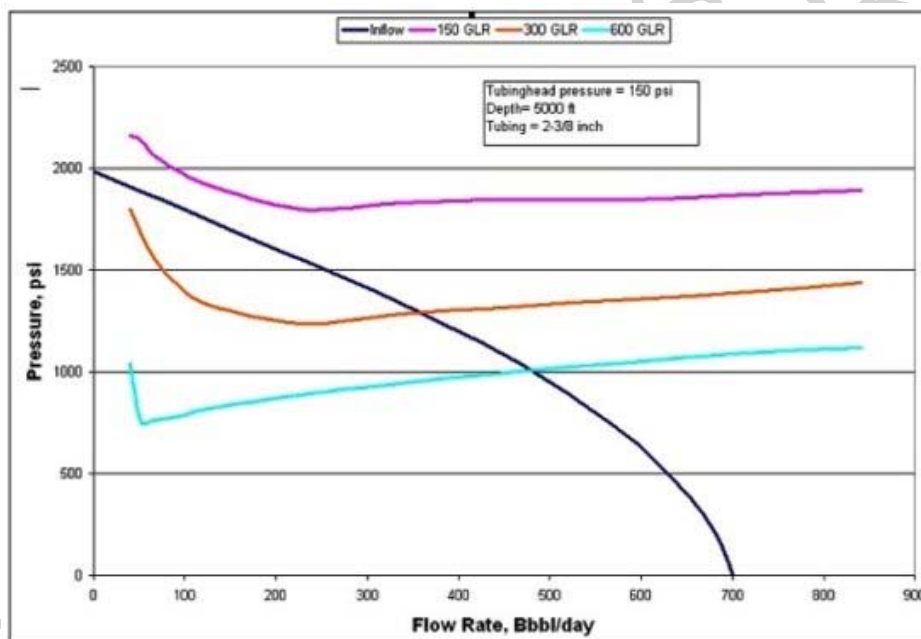

Figure 8. Pressure vs. Flow rate IPR and VLP Relations for different Gas-to-Liquid Ratios

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WWW Links to some equipment manufacturers and software suppliers

ESP systems: http://www.bakerhughesdirect.com/cgi/clift/myHomePage/welcome.jsp

ESP systems: http://www.slb.com/content/services/artificial/submersible/index.asp

Artificial Lift: http://www.weatherford.com/weatherford/groups/public/documents/production/

Rod pumps: http://www.hfpumps.com

Plunger Lift systems: http://www.fergusonbeauregard.com/

Pumping Calculators: http://www.hfpumps.com/calc.html

Pumping units: http://www.lufkin.com/oilfield/

QRod: free predictive rod pumping software: www.echometer.com

SRod software: https://srodsrv.lufkin.com/WebSROD/SROD/WebSROD.asp

Xrod software: http://www.gotheta.com/xrod-v.asp

Biographical Sketch

A. L. Podio is currently Research Professor in the Petroleum and Geosystems Engineering Department at the University of Texas at Austin where he taught and directed research in the areas of Drilling and Production. He holds BS, MS and PhD degrees in Petroleum Engineering from the University of Texas. He has been a distinguished speaker and technical editor for SPE, has published numerous articles in international journals and holds seven US patents.