Well Performance

A simple producing system is illustrated in Figure (1-9).

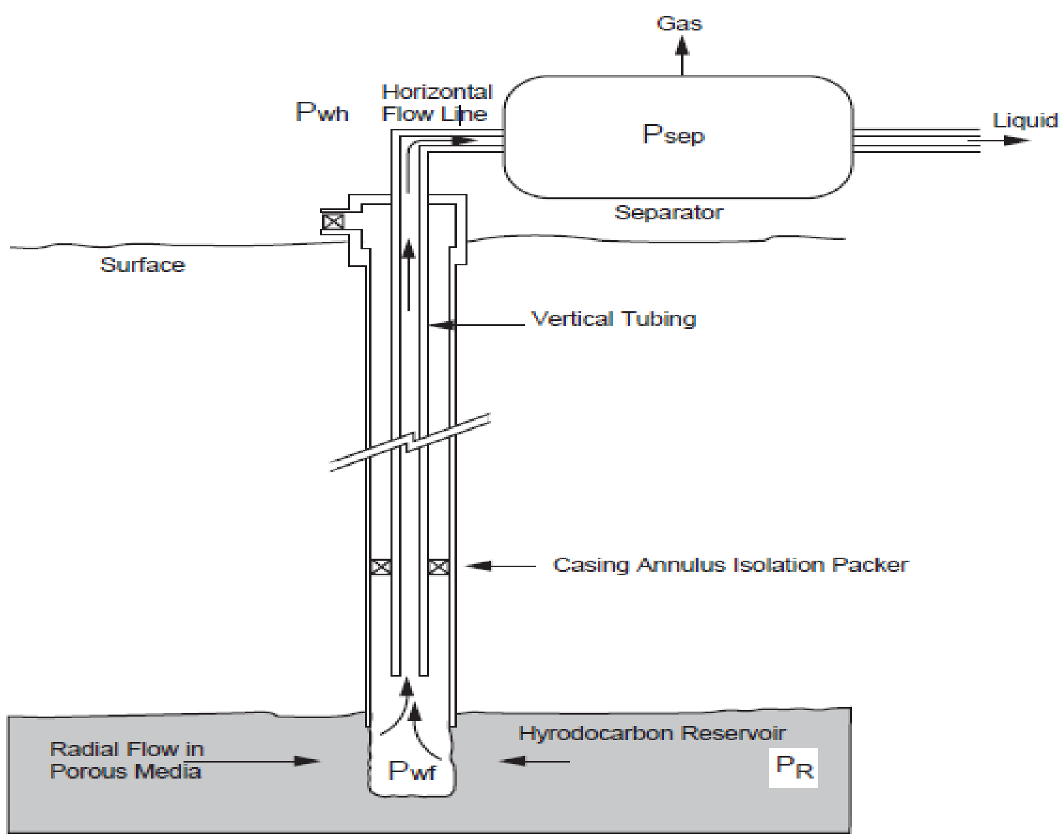

Fig. (1-9): Simplified hydrocarbon production system.

The hydrocarbon fluid flows from the reservoir into the well, up the tubing, along the horizontal flow line and into the oil storage tank. During this process the fluid's pressure is reduced from the reservoir pressure to atmosphere pressure in a series of pressure loss processes Figure (1-10):

1) Across the reservoir
2) Across the completion (perforation/gravel pack etc.)
3) Across the tubing and any restrictions
4) Across the sub surface safety valve
5) Across the surface choke
6) Across flowline

These pressure losses can be grouped into three main components:

1) Summarizes the total pressure losses in the reservoir and completion
2) Summarizes the total pressure losses in the tubing
3) Summarizes the total pressure losses at the surface

A pump or compressor is often used to aid evacuation of fluids (gas/water/oil) from the separator. The separator is operated under gas pressure control and liquid (oil and water) level control. Hence it normally acts as the end point of the flowing system since a pump is necessary to aid evacuation of the liquids from the separator.

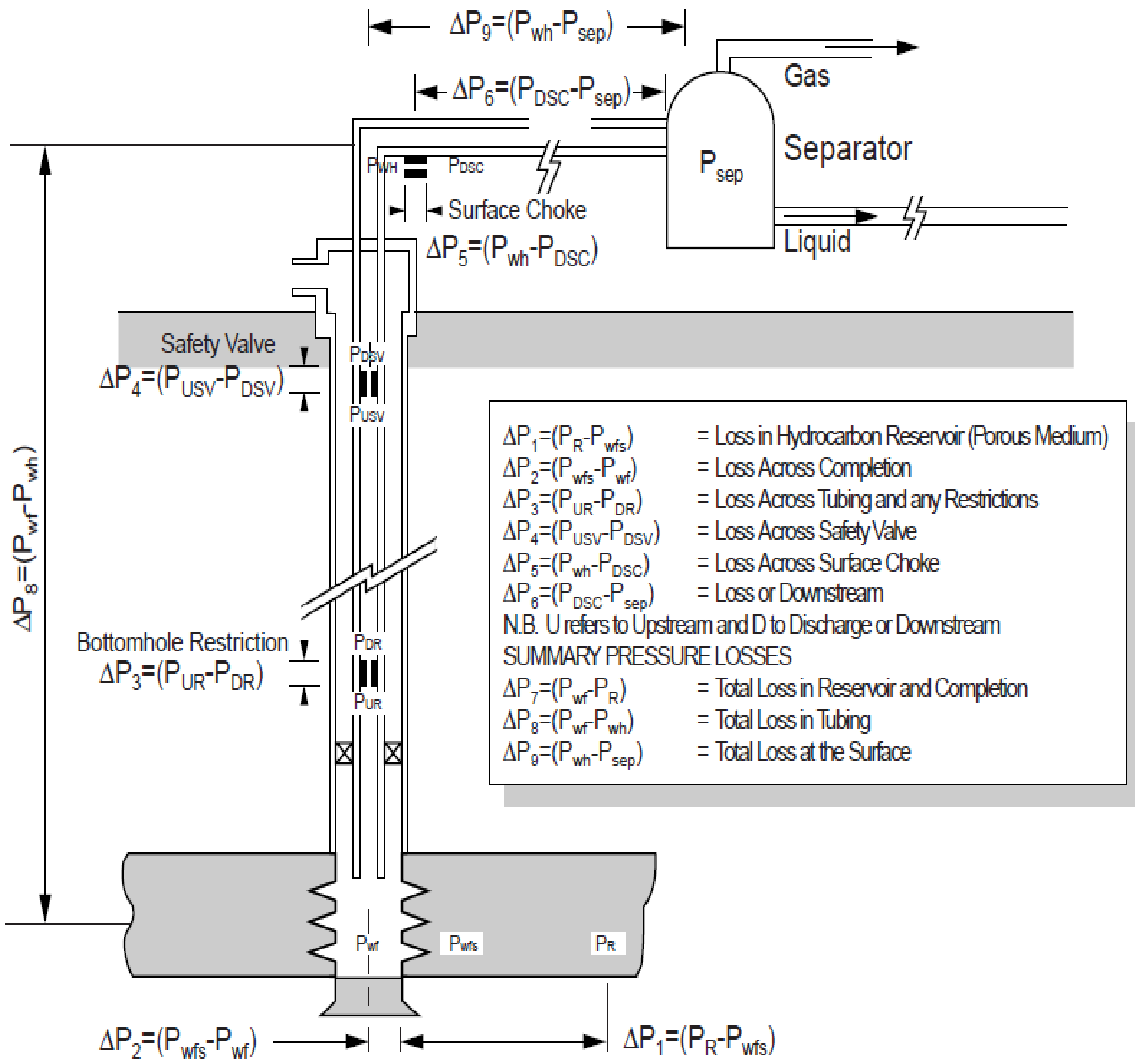

Fig. (1-10): Pressure Losses during Production.

P_R: Reservoir Pressure
P_{wfs}: Flowing sand face Pressure
P_{wf}: Flowing Bottom Hole Pressure
P_{UR}: Upstream Restriction Pressure
P_{DR}: Downstream Restriction Pressure
P_{USV}: Upstream Safety Valve Pressure
P_{DSV}: Downstream Safety Valve Pressure
P_{WH}: Well Head Pressure
P_{DSC}: Downstream surface Choke Pressure
P_{sep}: Separator Pressure

The magnitude of these individual pressure losses depend on **the reservoir properties and pressures**; fluid being produced and the well design. Production Technologists/ Engineers need to understand the interplay of these various factors so as to design completions which maximize profitability from the oil or gas production. There are no standard "rules of thumb" which can be used. Figure (1-11) schematically represents the pressure distribution across the production system shown in Figure (1-10). It identifies the most significant components, flowline, tubing and the reservoir and completion where pressure losses occur.

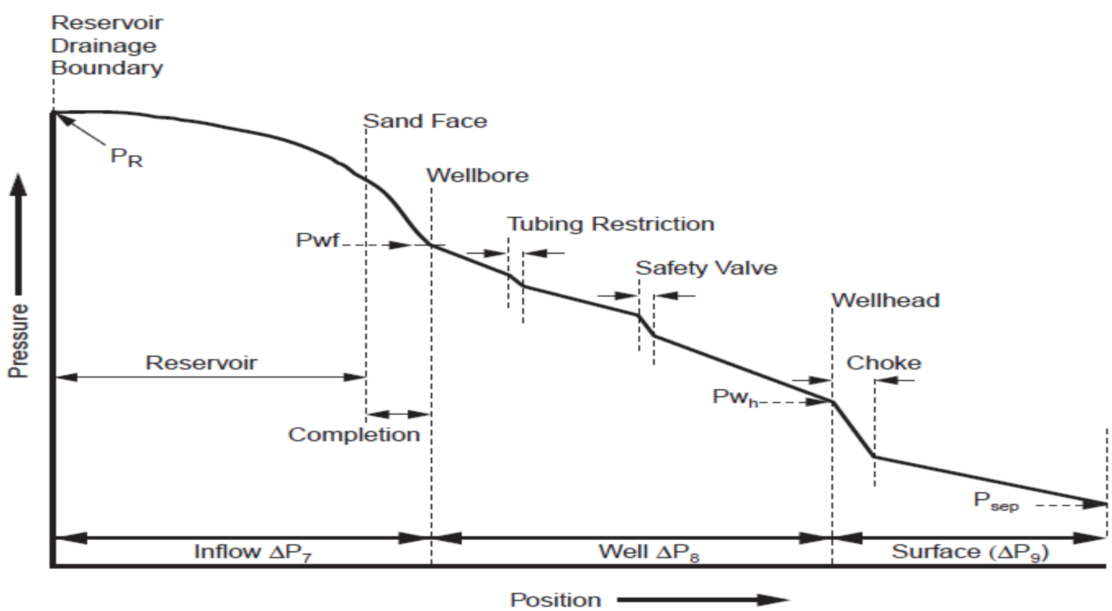

Fig.(1-5): Pressure across production system.

Inflow Well Performance

The flow of oil, water and gas from the formation into the bottom of the well (Well bore), is typified, as far as gross liquid production is concerned, by PI (Productivity Index) of the well or, more generally, by the IPR (Inflow Performance Relationship). The analysis of the production performance is essentially based on the following fluid and well characteristic;

- Fluid PVT Properties.
- Relative permeability data.
- Inflow performance relationship (IPR) & productivity index (PI).

➢ Productivity Index (PI) & Inflow Performance Relationship (IPR)

A commonly used to measure of the ability of the well to produce (give fluids) is the **Productivity Index** (PI), denoted by **J**. **Productivity Index** is the ratio of the total liquid flow rate to the pressure drawdown and could present as a plot of $\mathbf{P_{wf}}$ **versus q**. as shown in Figure (1-12).

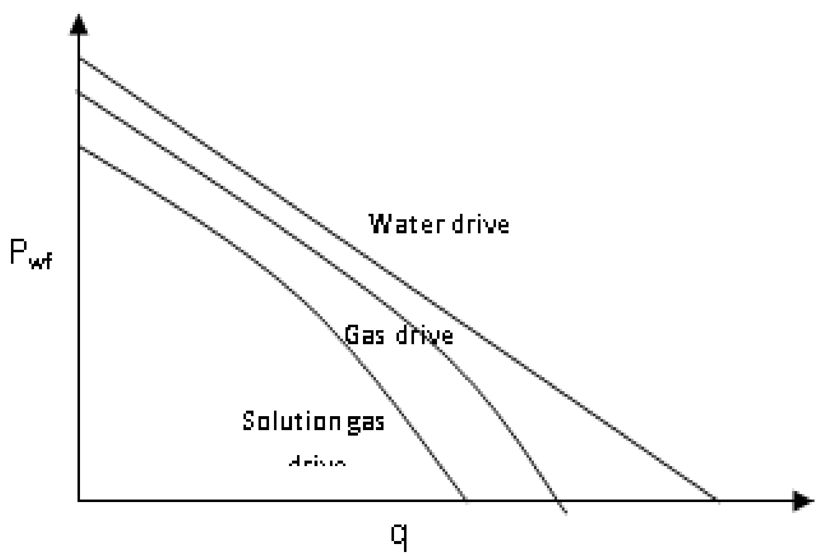

Fig. (1-12): P_{wf} vs Q.

The producing pressure $\mathbf{P_{wf}}$ at the bottom of the well is known as the **flowing BHP**, and the difference between this and the well's static pressure $\mathbf{P_s}$ is the **drawdown**;

Drawdown = $\mathbf{P_s - P_{wf}}$

The productivity index is given by;

$$\mathbf{PI = J = \frac{Q_o}{P_s - P_{wf}} = \frac{Q_o}{\Delta p}} \quad \text{------------------------------------} \quad \mathbf{(1.1)}$$

Where:

q = Oil flow rate, STB/day

J = Productivity index, STB/day/psi

P_s = Static pressure (volumetric average drainage area pressure, p_r), psi

P_{wf} = Bottom-hole flowing pressure, psi

The productivity index is generally measured during a production test on the well. The well is shut-in until the static reservoir pressure is reached. The well is then allowed to produce at a constant flow rate and a stabilized bottom-hole flow pressure.

It is important to note that the productivity index is a valid measure of the well productivity potential only if the well is flowing at pseudosteady state conditions. Therefore, in order to accurately measure the productivity index to a well, it is essential that the well is allowed to flow at a constant flow rate for a sufficient amount of time to reach the pseudostead state as illustrated in Figure (1-13). The Figure indicates that during the transient flow period, the calculated values of the productivity index will vary depending upon the time at which the measurements of $\mathbf{P_{wf}}$ are made.

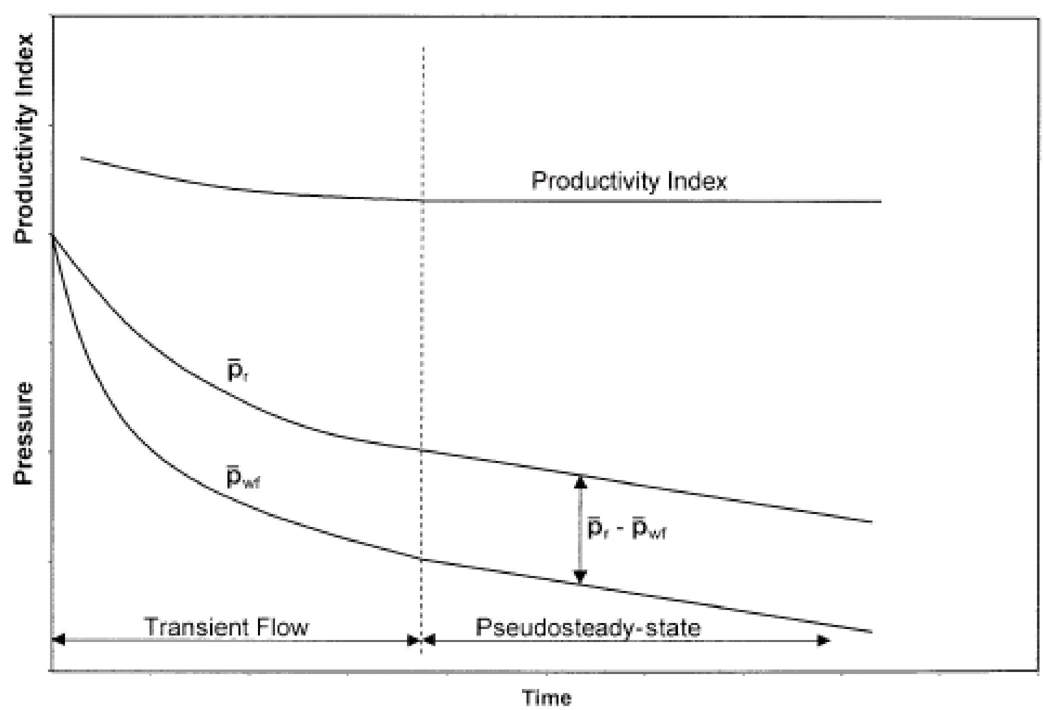

Fig. (1-13): Productivity Index during Flow Regimes.

The productivity index can be numerically calculated by recognizing that ***J*** must be defined in terms of semisteady-state flow conditions;

$$\mathbf{q_o = \frac{0.000708\ k_o h (P_r - P_{wf})}{\mu_o B_o \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]}} \text{ -------------------- } \mathbf{(1.2)}$$

Combine Eq. (1.1) with Eq. (1.2);

$$\mathbf{J = \frac{0.000708\ k_o h}{\mu_o B_o \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]}} \text{ -------------------- } \mathbf{(1.3)}$$

Since most of the well life is spent at a flow regime that is approximating the pseudosteady-state, the productivity index is a valuable methodology for predicting the future performance of wells. Further, by monitoring the productivity index during the life of the a well, it is possible to determine if the well has become damage due to completion , workover, production, injection operations, or mechanical problems. If a measured ***J*** has unexpected decline, one of the indicated problems should be investigated.

The productivity index may vary from well to well because of the variation in thickness of the reservoir; it is helpful to normalize the indices by dividing each by the thickness of the well. This is defined as the specific productivity index **(*J_s*)**.

$$\mathbf{J_s = \frac{J}{h} = \frac{Q_o}{h(P_s - P_{wf})}} \text{ -------------------- } \mathbf{(1.3)}$$

Assuming that the well's productivity index is constant, Eq. (1.1) can be rewritten as:

$$\mathbf{Q_o = J\,(P_s - P_{wf}) = J\Delta p} \text{ -------------------- } \mathbf{(1.4)}$$

Eq. (1.4) indicates that the relationship between q and Δp is a straight line passing through the origin with a slope of ***J*** as in figure (1-14).

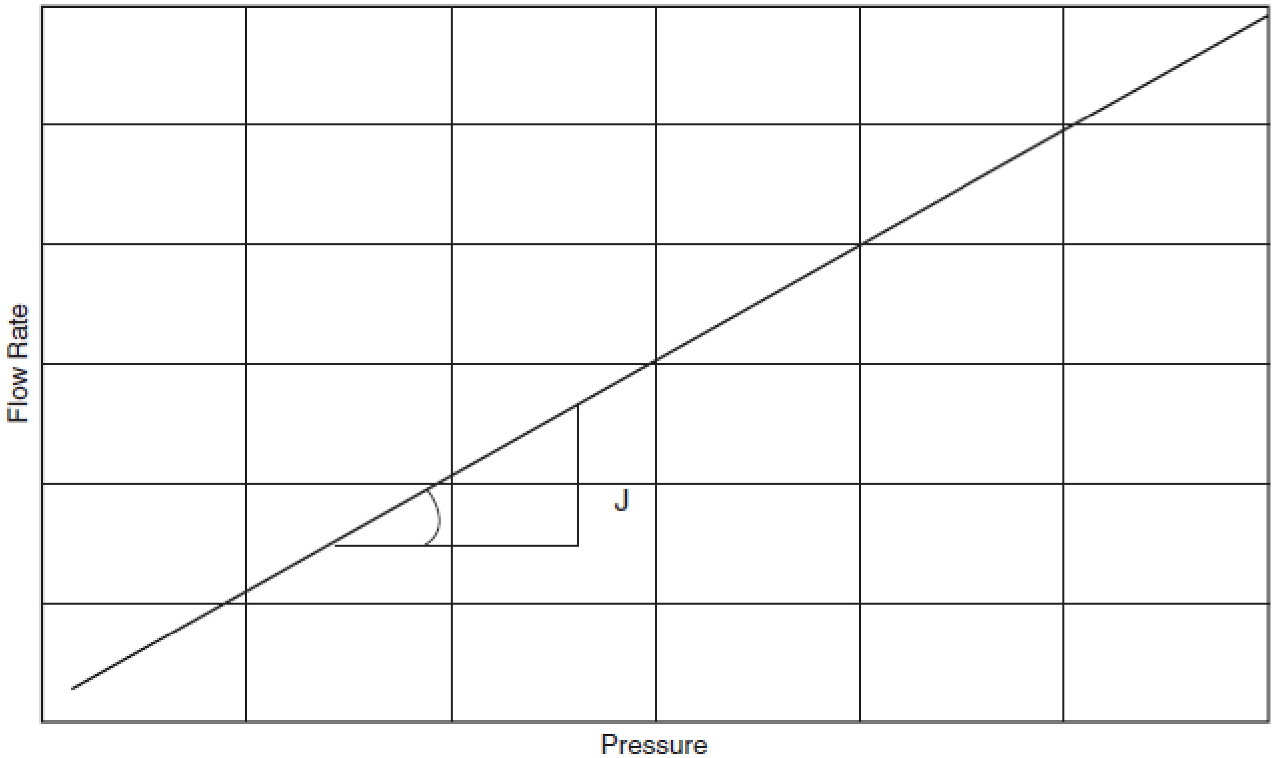

Fig. (1-14): q vs. Δp relationship.

Alternatively, Eq. (1.1) can be written as:

$$\mathbf{P_{wf} = P_s - \frac{q}{J}} \quad \text{------------------} \quad \mathbf{(1.5)}$$

The above expression shows that the plot P_{wf} against q is a straight line with a slope of **(- 1/*J*)** as shown schematically in Figure (1-15). This graphical representation of the relationship that exists between the oil flow rate and bottom-hole flowing pressure is called the **Inflow Performance Relationship** and referred to as **IPR**.

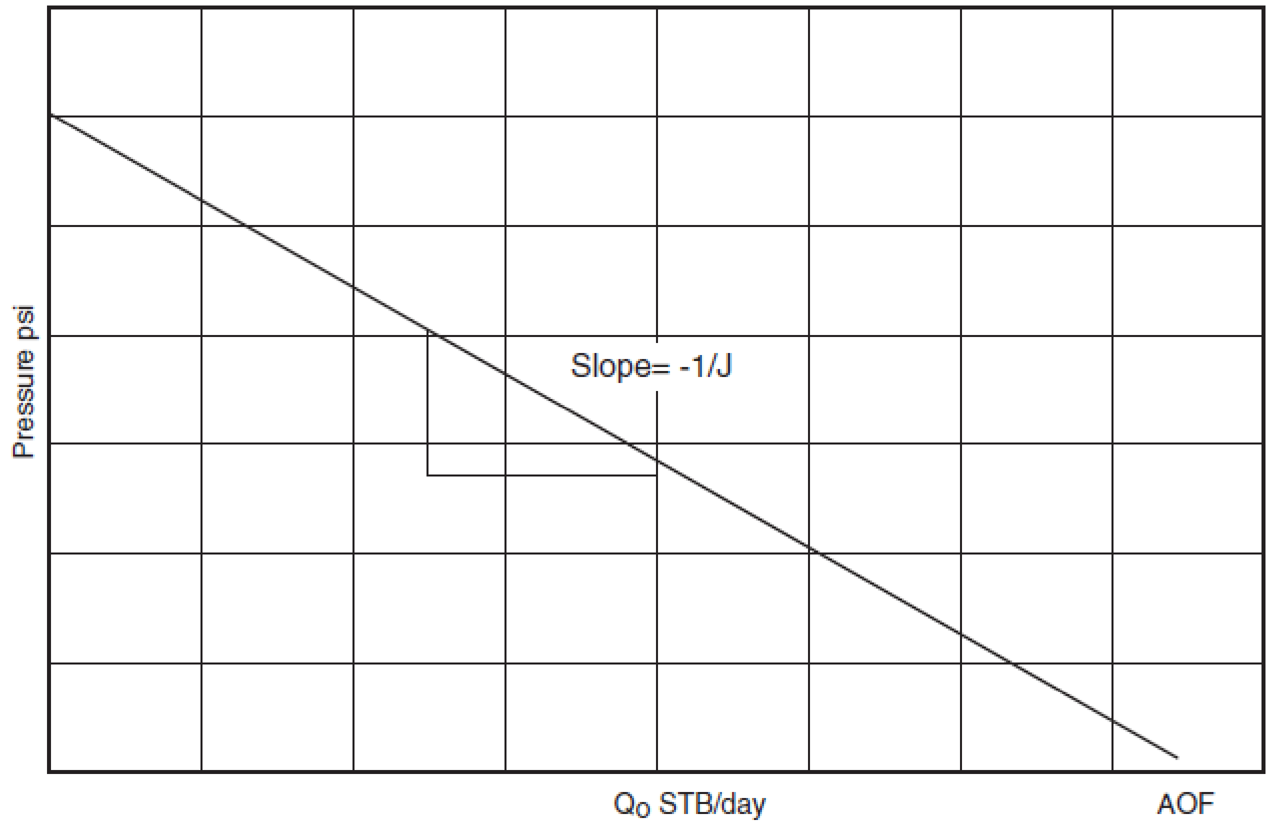

Fig. (1-15): IPR.

Several important features of the straight-line **IPR** can be seen in Figure (1-15);

- When $\mathbf{P_{wf}}$ equals average reservoir pressure, the flow rate is zero due to the absence of any pressure drawdown.
- Maximum rate of flow occurs when $\mathbf{P_{wf}}$ is zero. This maximum rate is called **Absolute Open Flow** and referred to as **AOF**. Although in practice this may not be a condition at which the well can produce, it is a useful definition that has widespread applications in the petroleum industry, (comparing flow potential of different wells in the field). The **AOF** is then calculated by;

  $$\mathbf{AOF = \mathit{J}\, P_S} \quad \text{---} \quad \mathbf{(1.6)}$$

- The slope of the straight line equals the reciprocal of the productivity index.