Inflow Performance Test

The following stepwise procedure is offered for obtaining data in an inflow performance test:

1) Closed the well (shut in) for (24-72 hrs) to obtained pressure build up test.
2) With the recording pressure gauge on bottom, place the well on its lowest production rate and obtain a flowing pressure recording. Ample time must be allowed for the production rate and flowing BHP to stabilized. If possible at least 48 hours should be allowed for each rate. (The well open to flow for 48 hrs in order to reach the stabilized condition, pseudo steady state regime).
3) After that change the well production rate for different values of rates and recorded the BHP for each rate, allowing approximately 48 hrs to production (at least three values).
4) Plot IPR curve **(q vs. p_{wf})** on Cartesian paper.
5) Again shut the well in and obtain a BHP buildup survey.

Importance of Knowing the IPR of a Well

An allowable production from a certain well = 50 bbl/day (only oil, zero water cut), in order to make the allowable rate, a pump has been installed in the well. For the first few years of its life, the well has produced 50 bbl/day. However, recently production has been less than the allowable.

One of two things has happen:

1. The reservoir (formation) is no longer capable of producing from the well 50 bbl/day.
2. There is some mechanical defect in the well's equipment resulting in a low lifting efficiency (from the bottom of the well to the surface). To know the exact problem that cause the reduction in production is to determine the well's IPR. The result might be either as shown in Figure (1-16) curve.

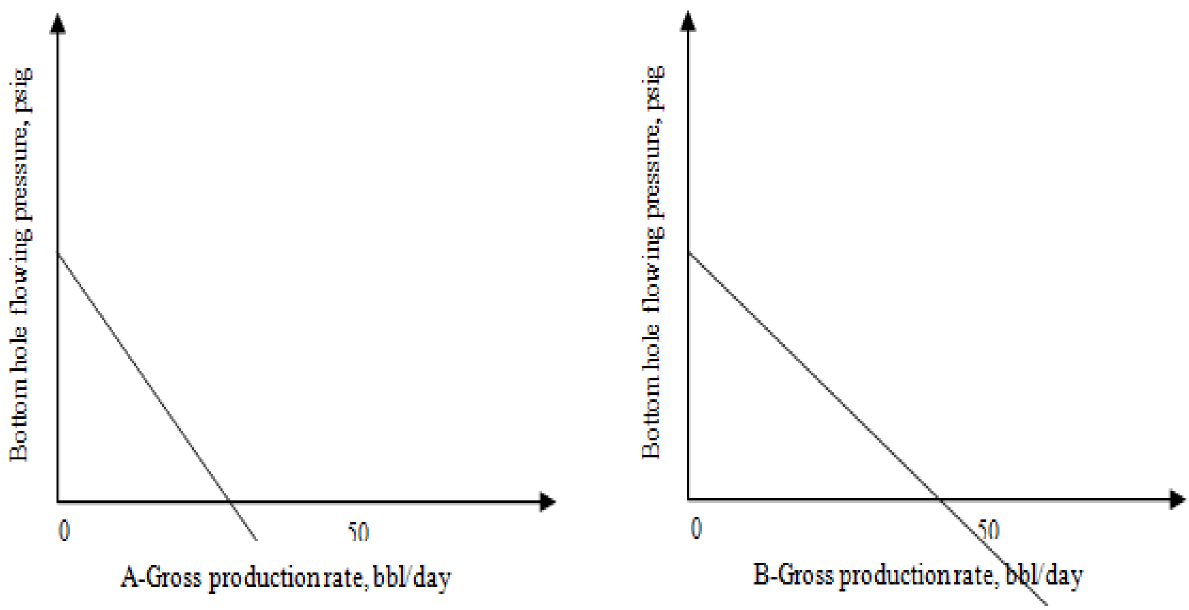


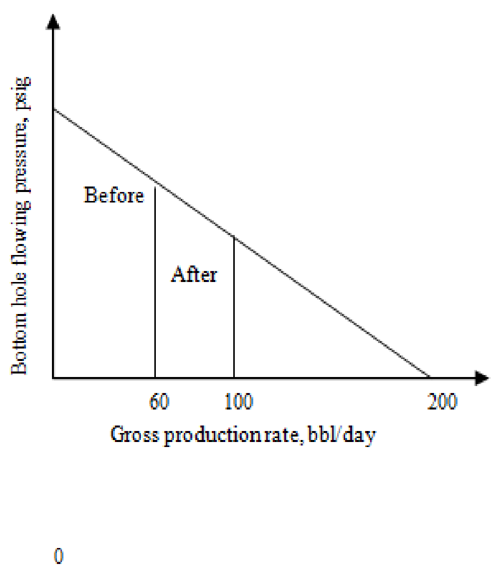
Fig. (1- 16): IPR showing formation incapable of desired production rate.

If the IPR were as illustrated in Figure (1-16A), the well's owner could be certain that no amount of pump changing would result in a production rate of 50 bbl/day and would either have to become reconciled to a below-allowable rate or else undertake a formation-stimulation workover such as a fracturing or an acidizing job. If, on the other hand, the IPR were as illustrated in Figure (1-16B), the owner would be reasonably sure that a mechanical workover of the equipment in the well would restore production to its allowable rate.

As a second example of the importance of knowing the IPR, suppose that a company has been carrying out a formation-stimulation program on some of its wells and that to gauge the success of this program, "before" and "after" *production*-rate, figures are used. Let the results on two wells (both cutting zero water) be as follows:

Well	Before treatment	1 week after treatment
A	60, flowing	100, flowing
B	35, pumping	36, pumping

The treatment would probably be accounted successful on well A and unsuccessful on well B. but while this may in fact be true, insufficient evidence has been presented to warrant such a conclusion; the before and after IPR`s of the well's might be as illustrated in figures (1-17) and (1-18).



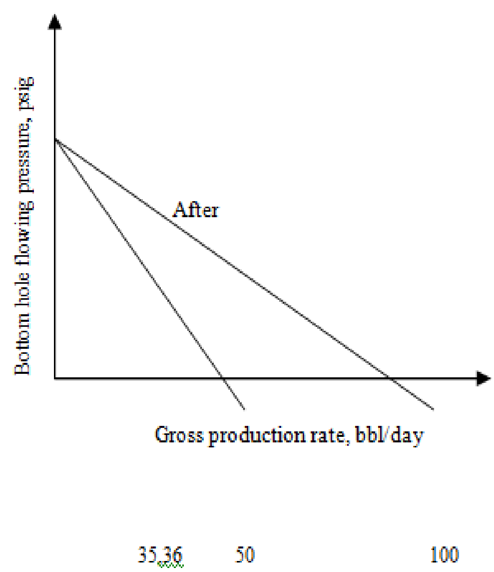


Fig. (1-17) formation stimulation a failure despite increased production rate

Fig. (1-18) formation stimulation a success despite unaltered production rate

The treatment has had no effect at all on the IPR of well A; that is, the formation inflow performance has not been improved in any way, so the treatment was completely unsuccessful. The production increase from 60 to 100 bbl/day was fortuitous and might have been caused by the treatment dislodging some tubing obstruction, by different-sized tubing having been run into the hole after the job or by a different choke having been inserted in the flow line at the surface.

On the other hand, the treatment on well B has increased the formation's potential considerably and was an undoubted success. Why then were the before and after rates almost identical? There are several possible reasons: the pump might not have been properly seated after the treatment; the pump might have been damaged in some way when it was pulled for the treatment to be undertaken; the producing GOR of the formation might have been increased by the treatment, resulting in reduced pump efficiencies; or the truth of the matter may lie with one or more of various other possible explanation.

Factors Influencing Shape of IPR

The discussion that follows will concentrate on effects resulting from the pressure of free gas in the formation and, consequently, will lead to some conclusions relating to the dependence of producing GLRs on drawdown. In oil reservoir, gas does not be free until BHP of formation reaches value less than bubble point pressure value. So at pressure below bubble point pressure gas being free and the free gas could moving when saturation of free gas (S_g) be greater than critical gas saturation (S_{gc}, at this value gas be able to moving).

It is evident from the form of the radial- flow equation that the greater part of the pressure drop (from static pressure to flowing BHP) in a producing formation occurs in the neighborhood of the well bore (pressure drop is occurring within 20 ft of the well bore).

Suppose the flowing BHP at the well is below the bubble point of the oil. As oil moves in toward the well, the pressure on it drops steadily, allowing gas to come out of solution. The free gas saturation in the vicinity of the oil body steadily increases, and so the relative permeability to gas steadily increases at the expense of the relative permeability to oil. The greater the drawdown, that is, the lower the sand-face pressure at the well , the more market this effect will de , so that it would be reasonable to expect the PI (which depends on the effective oil permeability) to decrease and the producing GOR (which depends on the effective gas permeability) to increase as the drawdown is increased. Such an argument leads to the conclusion that a curved IPR, as shown in Figure (1-19), is to be expected whenever the flowing BHP is below the bubble-point pressure.

Last as long as the value of the flowing BHP remains above the saturation pressure, no free gas will be evolved in the formation and the PI will remain constant; that is, the portion of the IPR applicable to values of the flowing BHP higher than the saturation pressure will be a straight line, as shown in Figure (1-19).

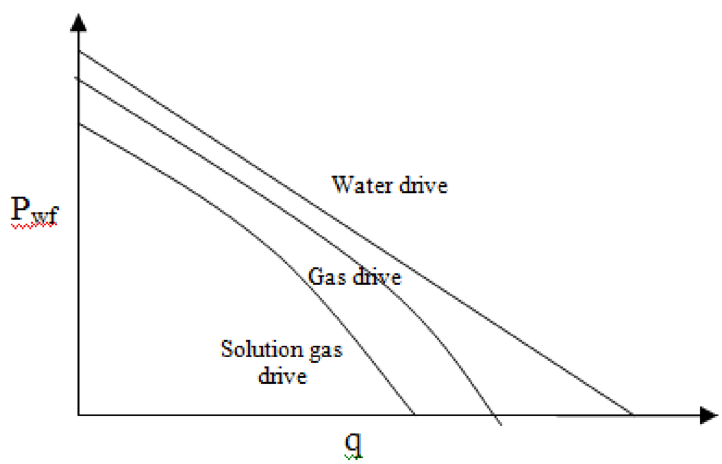


Fig. (1-19): P_{wf} vs. q.

1. Stratified Formation

Practically every production formation is stratified to some extent; that is to say, it contains layers of differing permeability. To illustrate the type of effects that such stratification may have upon the shape of the IPR and upon the dependence of GOR on production rate, consider an example in which there are three different zones having permeabilities of 10,100, and 1 md, respectively. It will be assumed that there is no vertical communication between the zones, except through the well bore itself as shown in Figure (1-20). Production from this formation will evidently be drawn chiefly from the

100 md zone, with the result that the static pressure in this zone will drop below those in the other two, the 1 md zone exhibiting the highest static pressure.

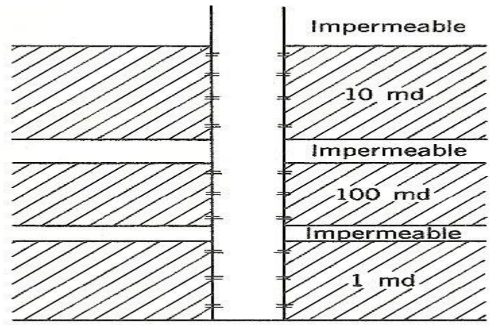


Fig. (1-20) Idealized stratified formation.

Suppose that a stage has been reached in which the pressure in the 100 md zone is 1000 psig, that in the 10 md zone is 1200 psig, and that in the 1 md zone is 1500psig, the well is now tested at various production rates to establish the IPR. If the individual IPRs of the three zones are as illustrated in Figure (1-21), the composite IPR, which will be the sum of these three curves, will have the shape shown. It follows as a generalization that many wells will, because of stratification and subsequent differential depletion of the zones on production, exhibit a composite IPR curve of the type illustrated in Figure (1-22) that is the say, an improving PI with increasing production rate at lower rates, but a deteriorating PI at the higher rates.

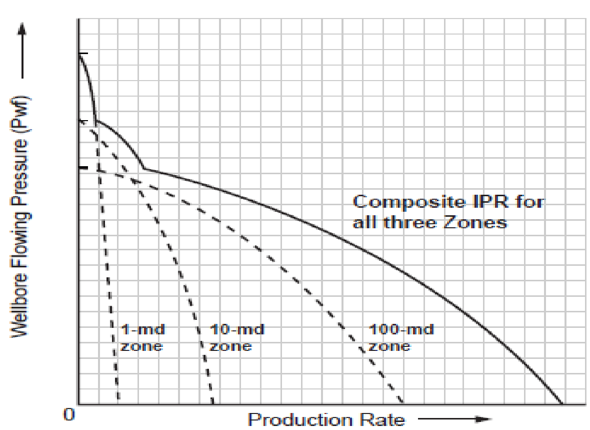


Fig. (1-21): Composite IPR for heterogeneous formation.

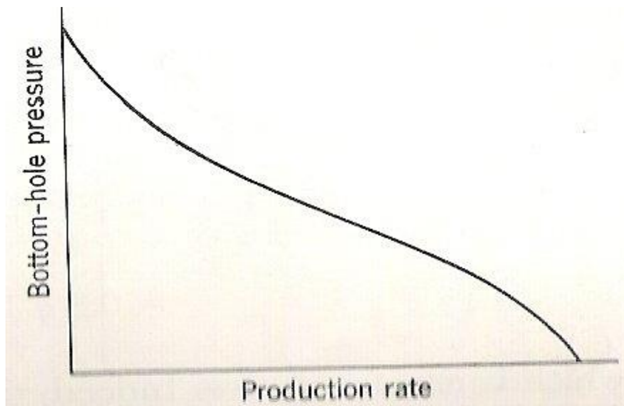


Fig. (1-22): Typical IPR Curve.

At the low rates the flowing BHP will be high and only the higher-pressured layers will contribute to the production. These layers will be those with the greater degree of consolidation and cementing, that is, with the higher values of the gas/oil permeability ratio. In other words, the producing layers at the low rates of flow are those which produce with a high GOR.

As the well's rate of production is gradually increased, the less consolidated layers will begin to produce one by one (at progressively lower GORs) and so the overall ratio of the production will fall as the rate is increased. If, however, the most highly depleted layers themselves produce at high ratios owing to high free gas saturation.

2. Effect of water cut on IPR

If water is moving from the water source to the well stringers in the formation, it is possible to determine whether, at the well bore, the pressure in the water is greater than or less than the pressure in the oil sands (that is, whether it is high-pressure or low-pressure water) from an analysis of the gross IPR and three or four water-cut values taken at different gross rates. The method of approach may be illustrated by means of an example.

Problem (1-1): A series of tests is made on a certain well with the following results;

Gross rate, bbl/day	water cut, water/gross%	flowing BHP,psig
47	85	1300
90	60	920
125	48	630
162	45	310

Determine the static pressure and the productivity index of the oil and water zones, respectively. Based on the results, at what rate could water be expected to flow into the oil sand if the well left shut down?

Referring to Figure (1-23).

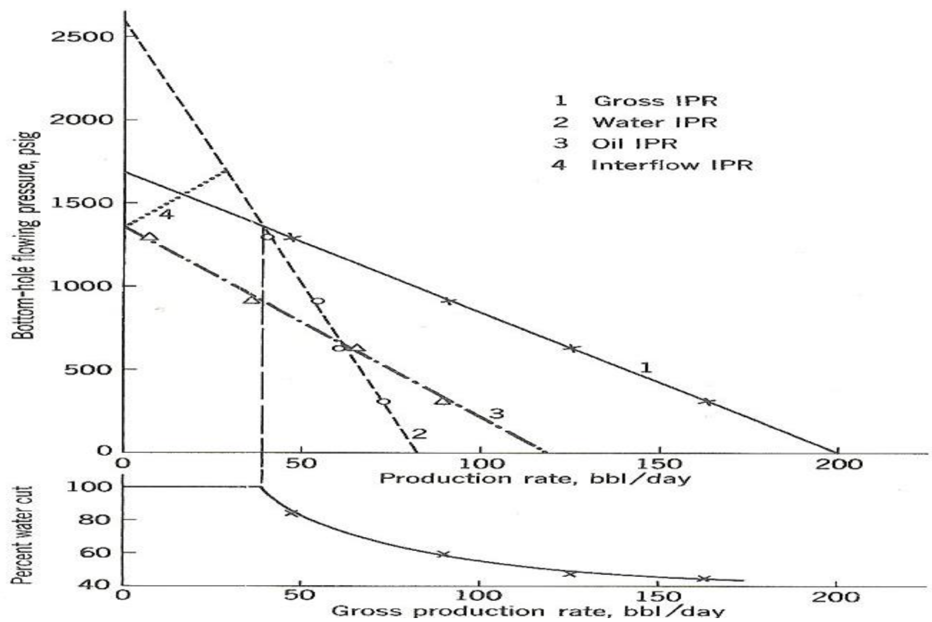


Fig. (1-23): IPR and water-cut curves: high-pressure water.

The first step is to plot the gross IPR (line 1).

From the gross rate and the measured water cuts the water and oil IPRs are calculated as follows (line 2 and 3):

$$q_o = q_t - q_w \qquad (1.7)$$

$$q_o = q_t\ (1- q_w/q_t) \qquad (1.8)$$

$$q_o = q_t\ (1- wc) \qquad (1.9)$$

Gross rate, bbl/day	water cut, water/gross%	water rate, bbl/day	oil rate, bbl/day	flowing BHP,psi
47	85	40	7	1300
90	60	54	36	920
125	48	60	65	630
162	45	73	89	310

Then plot water cut ratio versus gross rate.

Evidently, from the figure,

Static pressure of oil zone = 1350 psig

PI of oil zone = 120/1350 = 0.089 bbl/(day)(psi)

Static pressure of water zone = 2600 psig

PI of water zone = 82/2600 = 0.0315 bbl/(day)(psi)

When the well is shut in, it might be expected (from the gross IPR) that the BHP would stabilized at about 1700 psig and that water would flow into the oil zone at some 28 bbl/day.

It is of interest to note the shape of the water cut versus rate curve (also shown on Figure (1-23), which is typical of high-pressure water, namely, a 100 percent cut (pure water) is obtained at low rates, the oil content gradually increasing with the offtake rate. In Figure (1-24) the case of low-pressure water is similarly illustrated, and the typical water cut versus rate curve is shown; namely, the cut starts at or near zero and increases with rate.

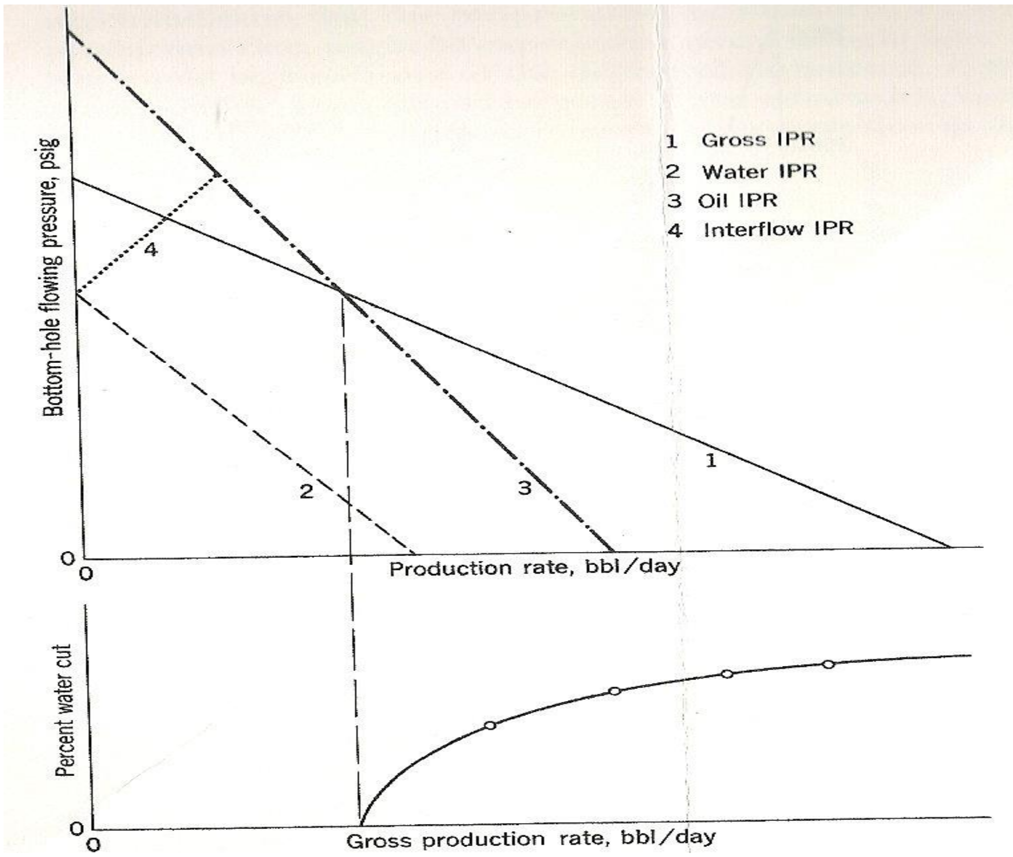


Fig. (1-14): IPR and water-cut curves: low-pressure water.

Problem (1-2): A productivity test was conducted on a well. The test results indicate that the well is capable of producing at a stabilized flow rate of **110** STB/day and a bottom-hole flowing pressure of **900** psi. After shutting the well for **24** hours, the bottom-hole pressure reached a static value of **1300** psi.

Calculate:

- Productivity index
- AOF
- Oil flow rate at a bottom-hole flowing pressure of 600 psi
- Wellbore flowing pressure required to produce 250 STB/day

Solution:

1- $J = \frac{q}{P_r - P_{wf}}$

$$J = \frac{110}{1300-900} = 0.275 \text{ STB /psi}$$

2- $AOF = J\,(P_r - 0)$

$$AOF = 0.275(1300 - 0) = 375.5 \text{ STB /day}$$

3- $Q_o = J(P_r - P_{wf})$

$$Q_o = 0.257(1300 - 600) = 192.5 \text{ STB / day}$$

4- $P_{wf} = P_r - \left(\frac{1}{J}\right) Q_o$

$$P_{wf} = 1300 - \left(\frac{1}{0.275}\right) 250 = 390.9 \text{ psi}$$

Equation (1.4) suggests that the inflow into a well is directly proportional to the pressure drawdown and the constant of proportionality is the productivity index. Muskat and Evinger (1942) and Vogel (1968) observed that when the pressure drops below the bubble-point pressure, the IPR deviates from that of the simple straight-line relationship as shown in Figure (1-25).

Recalling Equation (1.2):

$$\mathbf{J} = \left[\frac{0.00708\,hk}{\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s}\right]\left(\frac{k_{ro}}{\mu_o B_o}\right) \quad \text{---} \quad \mathbf{(1.10)}$$

Treating the term between the two brackets as a constant c, the above equation can be written in the following form:

$$\mathbf{J} = \mathbf{C}\left(\frac{k_{ro}}{\mu_o B_o}\right) \quad \text{---} \quad \mathbf{(1.11)}$$

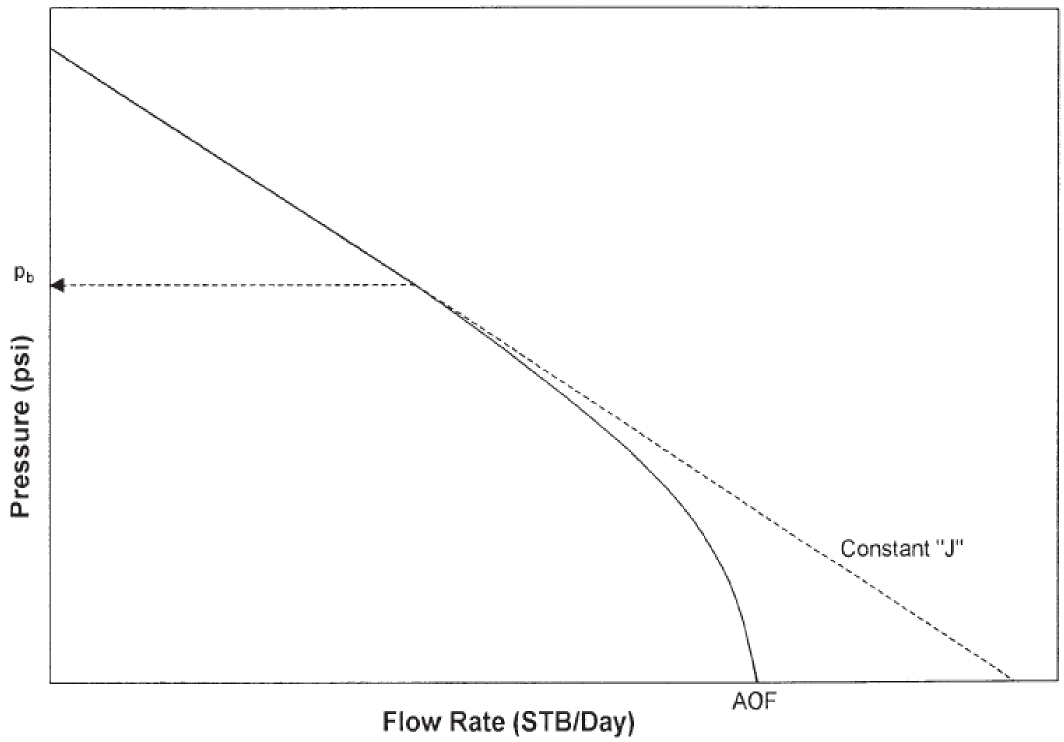


Fig. (1-25): IPR below P_b.

With the coefficient c as defined by:

$$\mathbf{C} = \frac{0.00708\,kh}{\ln\left(\frac{r_e}{r_w}\right)+0.75+s} \quad \text{----------} \quad \mathbf{(1.12)}$$

Equation (1.11) reveals that the variables affecting the productivity index are essentially those that are pressure dependent, i.e.:

- Oil viscosity μ_o
- Oil formation volume factor B_o
- Relative permeability to oil k_{ro}

Figure (1-26) schematically illustrates the behavior of those variables as a function of pressure. Figure (1-27) shows the overall effect of changing the pressure on the term $(k_{ro}/\mu_o B_o)$. Above the bubble-point pressure $\mathbf{P_b}$, the relative oil permeability $\mathbf{k_{ro}}$ equals unity ($\mathbf{k_{ro}}$ =1) and the term $(k_{ro}/\mu_o B_o)$ is almost constant. As the pressure declines below $\mathbf{P_b}$, the gas is released

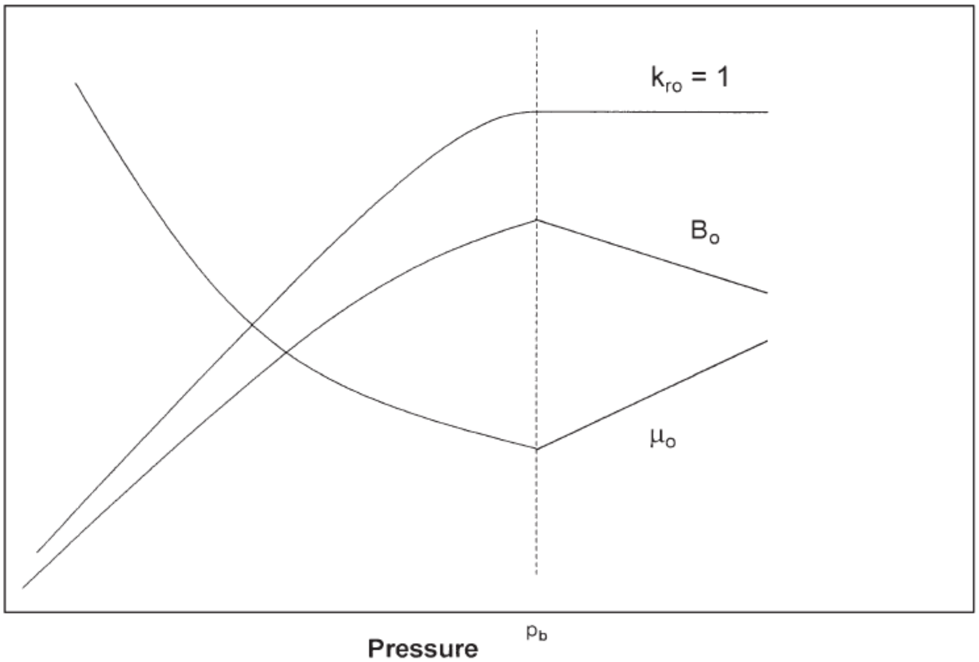


Fig. (1-26): Effect of pressure on B_o, μ_o, and k_{ro}

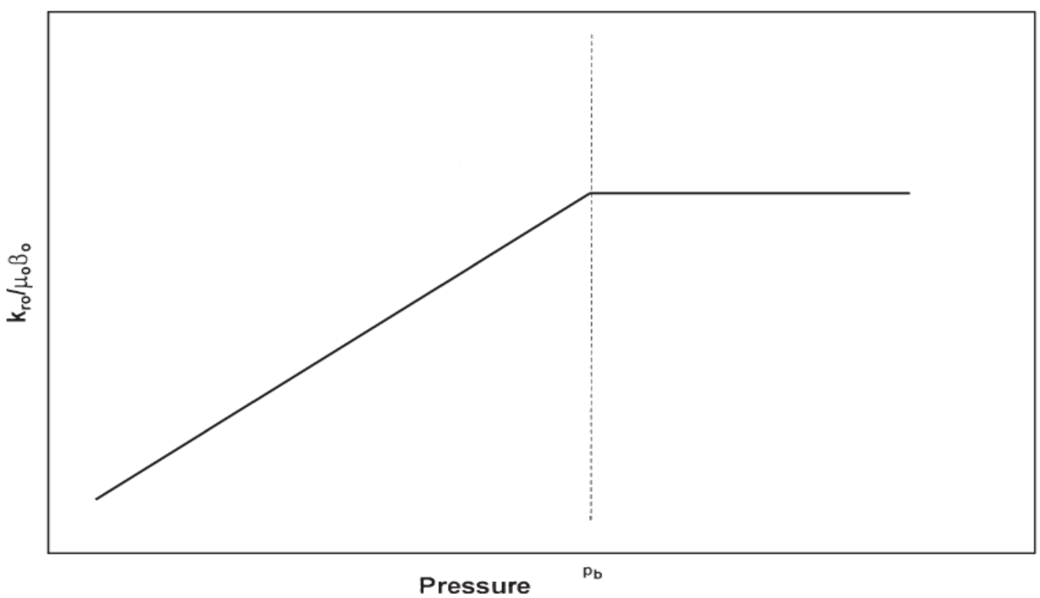


Fig. (1-27): k_{ro}/μ_oB_o Effect as a function of pressure

From solution, which can cause a large decrease in both k_{ro} and (k_{ro}/μ_oB_o). Figure (1-28) shows qualitatively the effect of reservoir depletion on the IPR.

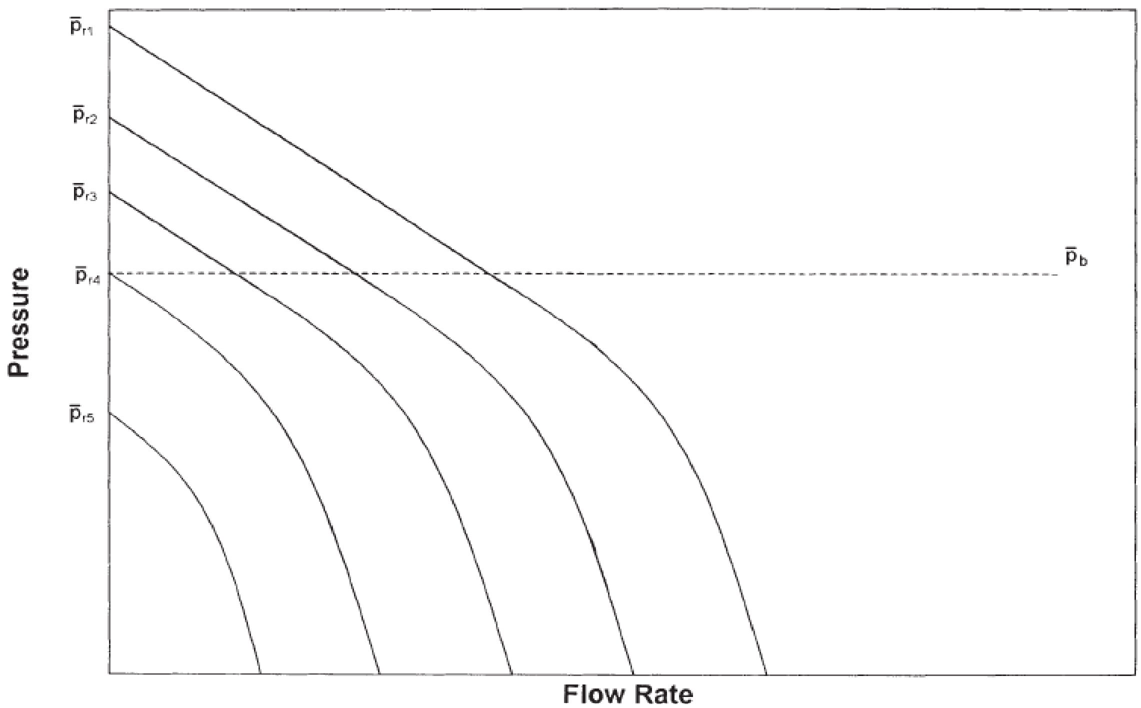


Fig. (1-28): Effect of reservoir pressure on IPR