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Determining Productivity Index and Inflow Performance Relationship from Swab Test Results Data

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Abstract

Productivity index (PI) and inflow performance relationship have (IPR) been established tools used by petroleum engineers to measure oil well performance. These values are very important especially in designing artificial lift system or well stimulation that will be conducted on a well that is being completed or worked-over. Unfortunately, both PI and IPR can only be accurately determined after the well has been put on production and has reached pseudo-steady state flow conditions. In this work, a simple-to-use method has been developed with which one may estimate the PI and IPR using the results of swabbing operation conducted within the completion or work-over activity. Several field cases of swab tests validated this method. The results demonstrate that the proposed method sufficiently estimates the true PI and IPR and hence can help petroleum engineers in making a fast decision during critical and dynamic situations like well completion or work-over jobs.

Introduction

It is quite often occurred in a completion or work-over job where a productive layer has just been successfully opened but the fluid cannot reach the surface due to insufficient reservoir pressure. To solve the problem and enabling the well to produce, petroleum engineers will do some interventions, for example by conducting artificial lift installation or well stimulation. However, to decide which type of intervention to conduct and how it should be done necessitates the knowledge of well's performance, which, in general, can be expressed in terms of productivity index (PI), inflow performance relationship (IPR), or both.

To obtain these values, engineers basically have two options, either to determine the performance theoretically or empirically. Theoretically, one can use equations derived from pseudo-steady state solution of the diffusivity equation. However, in order to do such rigorous calculation, a set of reliable reservoir rock, fluid, and well data is required, where in reality such comprehensive data may not be available. As a result, this approach is often avoided, especially in a rig job situation where a fast decision is desired. Fortunately, many empirical methods are available and can be used rather easily to replace the theoretical approach in estimating well's performance.

Unfortunately though, both theoretical and empirical approaches can only estimate the PI and IPR accurately if the well has been producing under pseudo-steady state flow condition and stabilized production test data, which includes stabilized flow rate (Q) and stabilized flowing bottom-hole pressure (FBHP), has been obtained. As a result, this can be a circular problem. In one hand, they need a prior knowledge of the PI and IPR in order to find strategies to bring the well to life, but, on the other, the well actually needs to be alive first before accurate PI and IPR can be known.

It is the main idea of this work to solve this problem. In this paper, we propose that although during a rig job well cannot flow due to insufficient reservoir pressure, one can still estimate the PI and IPR by using swab test results. Although it is likely that during swabbing operation the fluid flow is still in a transient state, if stabilized swab rate and fluid level can be achieved, then, arguably, the pseudo-steady state flow condition is nearly approached. Thus, one can then replace stabilized Q and stabilized FBHP data and instead use stabilized swab rate and stabilized bottom-hole pressure corresponding to the stabilized fluid level achieved during swabbing in their calculations. As swabbing after perforation is regularly conducted as an integral part of a completion or work-over job, one can always have the opportunity to make a prediction of well's PI and IPR based on swabbing results. Using this simple predictive method, they can then make a fast decision of what needs to be done during the rig job in order to bring the well into production.

Productivity Index and Inflow Performance Relationship

The liquid flow from the reservoir into the well is determined primarily by the PI of the well. This PI value is the measure of the ability of a well to produce fluids as related to the imposed pressure drawdown. For any given time, PI is defined as the rate of change of the production rate with pressure drawdown, which can be expressed by the following relationship:

$$J = -\frac{dQ}{dP_{drawdown}} \qquad (1)$$

where J is the productivity index, STB/day/psi.

This differential equation suggests that PI is not necessarily constant but rather will be subject to variation throughout the life of a well depending on the particular drawdown condition. Analytically, PI can also be derived from the pseudo-steady state solution of the diffusivity equation. The PI here is expressed in terms of the reservoir parameters as stated in the following equation:

$$J = \frac{k\,h}{162.6 \log\left[\frac{4\,A}{1.781\,C_A {r_w}^2} + s\right]}\left(\frac{k_{ro}}{\mu_o B_o}\right) \qquad (2)$$

where μ_o = oil viscosity, cp
A = drainage area, ft
B_o = oil formation volume factor
C_A = Diet's shape factor
h = net pay thickness, ft
k = absolute permeability, md
k_{ro} = oil relative permeability
r_w = wellbore radius, ft
s = skin factor

and both B_o and μ_o are evaluated at $\left[\frac{\bar{P}_R+P_{wf}}{2}\right]$. In Eq.2, it is clear that the term $\left(\frac{k_{ro}}{\mu_o B_o}\right)$ will be the main factor that regulates the variation of PI as this parameter will be continuously changing as the reservoir keeps depleting.

If, however, PI can be assumed to be constant, for example for solution gas drive reservoirs operating above the bubble point pressure, then Eq. 1 can be simplified to be:

$$J = \frac{Q}{\bar{P}_R - P_{wf}} \qquad (3)$$

where Q = liquid flow rate, STB/day
P_{wf} = flowing bottom-hole pressure (or FBHP), psig
$\bar{p}_R$ = average reservoir pressure (or static bottom-hole pressure, or SBHP), psig

Algebraically, Eq. 3 can be rewritten as:

$$Q = J\left(\bar{P}_R - P_{wf}\right) \qquad (4)$$

where now PI is the proportionality constant that correlates liquid flow rate with pressure drawdown.

As expressed in above equations, to calculate productivity index, an accurate description of average reservoir pressure and flowing bottom-hole pressure must be used to account for the correct drawdown. Average reservoir pressure can be obtained by measuring the static bottom-hole pressure (SBHP) when the well is shut-in, whereas FBHP can be measured with down-hole gauge during pressure survey or predicted using various multiphase flow correlations. In PT. Medco E&P Indonesia, both FBHP and SBHP are acquired during bottom-hole pressure survey where an electric memory recorder is lowered down the hole by means of slickline unit.

Regarding the continuously changing PI, based on their theoretical calculation, Muskat and Evinger (1942) showed that when the pressure drops below the bubble-point pressure and multiphase flow system emerges in the reservoir, a curve rather than a straight-line will result when the varying bottom-hole pressure data is plotted against the varying flow rate data (see Figure 1). They also pointed out that the variation of gas-oil ratio and water saturation in the reservoir along the depletion will constantly change the productivity index with respect to drawdown. Gilbert (1954), also recognizing this PI variation, then proposed the use of a flowing bottom-hole pressure versus flow rate plot for analyzing well performance. He named this curve the inflow performance relationship, or IPR, of a well. Along with PI, IPR has been a valuable tool used by petroleum engineers to indicate oil well performance.

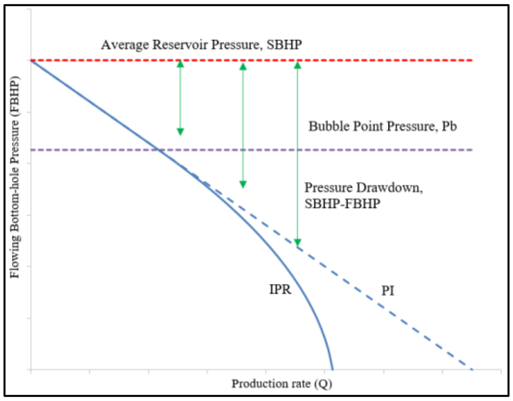

Figure 1: Productivity index and inflow performance relationship plots

In developing their analysis, Muskat and Evinger utilized reservoir rock and fluid properties data as well as their behavior upon pressure depletion. Due to this requirement and complex calculation involved, their theoretical method is not widely used today. Fortunately, several empirical techniques have been proposed for predicting the IPR for conditions where multiphase flow exists in the reservoir. Among the most commonly used methods are Vogel's, Fetkovich's, and Wiggins's method. In general, these methods require at least one stabilized production data at which the stabilized flow rate and FBHP are obtained. Due to their simplicity and reasonable accuracy, these IPR methods gain wide acceptance within oil and gas industries.

Vogel's Inflow Performance Relationship

Vogel (1968) used a computer simulation to generate empirical IPR curves for several theoretical solution gas drive reservoirs. Covering numerous different rock and fluid properties as well as relative permeability characteristics, Vogel plotted dimensionless IPR curves for these cases. Recognizing that most of these curves exhibited the same shape, he used regression analysis and developed a generalized IPR reference curve which follows this relationship:

$$\frac{Q_o}{Q_{o,max}} = 1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2 \qquad (5)$$

where $Q_{o,max}$ is the maximum oil flow rate (STB/day) corresponding to the maximum pressure drawdown or zero FBHP. Vogel also discussed that the curved-shape of IPR plot is the result of PI deterioration as the reservoir pressure drops below the bubble point pressure. He explained that PI decrease occurs due to the increasing gas saturation which in effect reduces oil relative permeability and, thus, increase resistance to oil flow.

Originally, Vogel's method was developed for oil wells producing with zero water cut. However, Ahmed (2010) suggested that this method can be generalized to account for water production by replacing the dimensionless oil rate, $\frac{Q_o}{Q_{o,max}}$, with the dimensionless liquid rate, $\frac{Q}{Q_{max}}$, where Q is the total of oil flow rate (Q_o) and water flow rate (Q_w). This extension has proved to be valid for wells producing at water cuts as high as 97%.

Standing's and Al-Sadoon's Productivity Index

The notion of constant productivity index may seem to be no longer relevant for solution gas drive reservoir producing below the bubble point pressure. This can be regarded as a lost because oftentimes information that comes as single value (*i.e.* PI) is more useful and more desirable than information that comes as a curve (*i.e.* IPR). For example, in a critical and dynamic situation like a rig activity, the expression of well's performance in terms of PI can sometimes be more informative than if it is expressed in terms of IPR curve. Fortunately, Standing (1970) developed a new calculation method that makes PI more general. He introduced the productivity index as formulated by Eq. 4 into Vogel's relationship and arrived at this new formula:

$$J = \frac{Q_{max}}{\bar{P}_R}\left[1 + 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)\right] \qquad (6)$$

Hence, by deriving this relationship, Standing has brought the term productivity index back into discussion, which now no longer be constant but changing with drawdown. Later on, Al-Sadoon suggested that Standing has made an error in deriving his PI prediction. He argued that Eq. 4 should not be used as this equation implies constant PI which is not a correct assumption in the first place. Instead, considering Eq. 1, he differentiated both sites of

Vogel's equation (*i.e.* Eq. 5) with respect to the flowing bottom-hole pressure and yielded

$$J = \frac{Q_{max}}{5 \text{ x } \bar{P}_R}\left[1 + 8\left(\frac{P_{wf}}{\bar{P}_R}\right)\right] \qquad (7)$$

Further, using the knowledge of bubble-point pressure, Beggs reported the following piecewise function for determining the PI and IPR above or below the bubble point pressure:

For $P_{wf} \geq P_b$

$$Q = J\left(\bar{P}_R - P_{wf}\right)$$

For $P_{wf} < P_b$

$$Q = J\left(\bar{P}_R - P_b\right) + \frac{J\,P_b}{1.8}\left[1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2\right]$$

where P_b is the bubble-point pressure (psig).

Data and Method

Figure 2 shows the schematic of reservoir-well configuration during swabbing jobs.

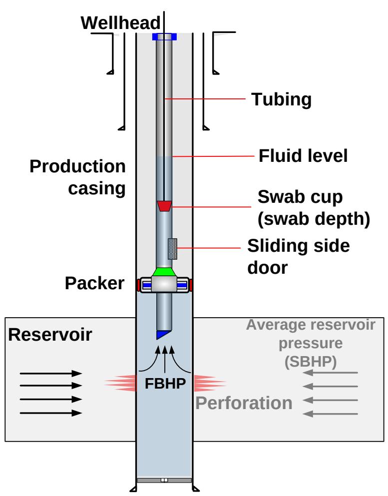

Figure 2: Reservoir-well configuration during swabbing job

The procedure to developing the simple tool for quick-look estimation of present PI and IPR from swab tests is summarized below:

1. Conduct the rig job as per completion or work-over program until the perforation of the interval of interest.
2. Obtain current average reservoir pressure from SBHP survey. If SBHP survey cannot be conducted after perforation, then an estimate of average reservoir pressure should be obtained for example from the same survey performed in adjacent wells.
3. Conduct swab test until stable swab rate and stable liquid level have been achieved.
4. Obtain the current water cut during the swabbing job. If the on-going program is for the reactivation of a cease-flowing well, for example through artificial lift installation or well stimulation, then a reliable water cut data obtained during the times when well was still active can also be used.
5. Record the stable fluid level, swab rate, and the swab depth at which this stabilized level is maintained.
6. Estimate the PI and IPR by following straightforward computational procedure summarized below.

Step 1: Calculate the fluid gradient (FG).

$$FG = 0.432 \text{ x } [(water\ cut \text{ x } water\ sg) + (oil\ cut \text{ x } oil\ sg)]$$

Step 2: Using the stabilized fluid level (FL) and the swab depth (SD), calculate the flowing bottom-hole pressure.

$$p_{wf} = \left[midperf - \frac{(FL + \text{SD})}{2}\right] \text{ x } FG$$

Step 3: Using the stable swab rate, calculate the daily-averaged liquid flow rate.

$$Q = swab\ rate\ \left(\frac{bbls}{minutes}\right) \text{ x } 24\,\frac{\text{hours}}{\text{day}} \text{ x } 60\,\frac{\text{minutes}}{\text{hour}}$$

Step 4: Calculate Q_{max} using Vogel's IPR equation

$$Q_{max} = \frac{Q}{1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2}$$

Step 5: Construct the IPR using Vogel's or other methods

$$\frac{Q}{Q_{max}} = 1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2$$

Step 6: Calculate the productivity index

If constant PI can be assumed, then:

$$J = \frac{Q}{\bar{P}_R - P_{wf}}$$

If multiphase flow exists, but the bubble point pressure data is not available, then use Al-Sadoon's formula:

$$J = \frac{Q_{max}}{5 \text{ x } \bar{P}_R}\left[1 + 8\left(\frac{P_{wf}}{\bar{P}_R}\right)\right]$$

If multiphase flow exists and the bubble point pressure data is available, then use Beggs's formula:

$$J = \frac{Q}{\left(\bar{P}_R - P_{wf}\right) + \frac{P_b}{1.8}\left[1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2\right]}$$

7. Based on the estimate PI and IPR, engineers can then decide whether or not well stimulation or re-perforation is necessary, also artificial lift design which might has been prepared earlier can be applied or modified accordingly to suit well's condition.
8. Complete the rig job.
9. Put the well on production and close monitor the flow rate.
10. When stabilized flow, which indicates pseudo-steady state condition, has been achieved, conduct production test simulatenously with FBHP survey.
11. Determine the true PI and IPR utilizing production test data, SBHP, and FBHP measured or estimated earlier.

Result and Discussion

To verify the developed quick-look method, information from several field cases was analyzed. One field example will be discussed here and hopefully will help to clarify the understanding of the present methodology.

Consider an oil well under a work-over job at which the layer of interest has been perforated. The top and bottom depth of the producing interval are 5213 and 5223 ft, respectively. Average reservoir pressure was obtained from static bottom-hole pressure survey which was conducted prior to workover and the measured value is 1608 psig. Estimate the productivity index and construct the inflow performance relationship of this well. The pertinent data are provided.

Solution

SBHP	: 1608 psig
Swab depth (SD)	: 2800 ft-TVD
Fluid level (FL)	: 2321 ft-TVD (fairly constant for 4 swab runs)
Swab rate	: 2.8 bbls/15 minutes (fairly constant for 4 swab runs)
Water cut	: 40%
Oil specific gravity	: 0.8
Water specific gravity	: 1.0

Step 1: Calculate fluid gradient.

$$fluid\ gradient = 0.432 \text{ x } [(water\ cut \text{ x } water\ sg) + (oil\ cut \text{ x } oil\ sg)]$$

$$= 0.432 \text{ x } [(0.4 \text{ x } 1.0) + (0.6 \text{ x } 0.8)] = 0.380\ \frac{psi}{ft}$$

Step 2: Using the stabilized fluid level and the swab depth, calculate p_{wf}.

$$p_{wf} = \left[midperf - \frac{(FL + \text{SD})}{2}\right] \text{ x } FG$$

$$= \left[5218 - \frac{(2321 + 2800)}{2}\right] \text{ x } 0.380 = 1010\ psig$$

Step 3: Using the swab rate at which stabilized condition is achieved, calculate Q

$$Q = swab\ rate \text{ x } 24 \frac{\text{hours}}{\text{day}} \text{ x } 60 \frac{\text{minutes}}{\text{hour}}$$

$$= \frac{2.78\ bbls}{15\ minutes} \text{ x } 4 \frac{\text{hours}}{\text{day}} \text{ x } 60 \frac{\text{minutes}}{\text{hour}} = 266\ STB/day$$

Step 4: Calculate $\mathrm{Q_{max}}$ using Vogel's IPR equation

$$Q_{max} = \frac{Q}{1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2}$$

$$= \frac{266}{1 - 0.2\left(\frac{1010}{1608}\right) - 0.8\left(\frac{1010}{1608}\right)^2} = 476\ STB/day$$

Step 5: Construct the IPR using Vogel's or other methods

$$\frac{Q}{Q_{max}} = 1 - 0.2\left(\frac{P_{wf}}{\bar{P}_R}\right) - 0.8\left(\frac{P_{wf}}{\bar{P}_R}\right)^2$$

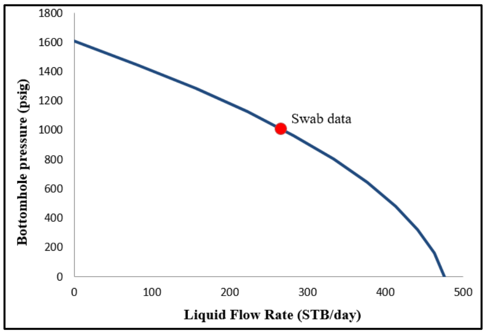

Figure 3: IPR curve constructed based on swab test data of the example well

Step 6: Calculate the productivity index using Al-Sadoon's method for wells below the saturation pressure where a reliable data of the bubble-point pressure is not available.

$$J = \frac{Q_{max}}{5 \text{ x } \bar{P}_R}\left[1 + 8\left(\frac{P_{wf}}{\bar{P}_R}\right)\right] = \frac{476}{5 \text{ x } 1608}\left[1 + 8\left(\frac{1010}{1608}\right)\right]$$
$$= 0.36\frac{STB}{day}/day/psi$$

After obtaining the productivity index and the IPR, engineers then decided to install sucker rod pump for this well. After the work-over program had been completed, the well was put on production. Production test data was then conducted when the well had reached pseudo-steady state flow condition. Based on the obtained stabilized Q and FBHP data, well's PI was calculated and the IPR constructed. It was reported that well's PI and Q_{max} are 0.4 STB/day/psi and 393 STB/day, respectively, which reasonably match what have been predicted based on swabbing results. The similar procedure was used for several other cases and the results are reported in Table 1.

Table 1: Comparison between PI from swab test and the actual PI

Well	PI from Swab	Actual PI	% Deviation
I-0X3	0.36	0.40	10
L-0X1	1.39	1.32	5
L-0X5	0.68	0.75	9

Based on the above actual observations, it is concluded that the proposed quick-look method does a satisfactory job in estimating well's PI and IPR by honoring swab tests results data. Indeed, this method should be used with care due to its inherent simplistic assumption that stabilized swab rate and fluid level during swabbing operation indicate pseudo-steady state flow condition. Hopefully, this work not only helps engineers in making a quick and justifiable decision during rig jobs but also encourages the development of more sophisticated method to determinate of well's PI and IPR by honouring data obtained from swabbing operations.

Conclusions

It is desired to obtain a quantitative yardstick to predetermine productivity index and inflow performance relationship of an oil well under a rig job situation before a decision to install artificial lift or to conduct well stimulation can be made. By utilizing the results from the swab test, one can estimated well's PI and IPR using the method outlined in this paper. By validating the results obtained using this approach with actual field data, it is suggested that the proposed quick-look method can satisfactorily match the true PI and IPR and hence will help petroleum engineers in making a fast and justified decision during a critical and dynamic rig job situation.

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