A well may be produced with or without a choke at the surface to control the flow rate. Most flowing wells have surface chokes for one or more of the following reasons:

- to reduce the pressure and improve safety
- to maintain a fixed allowable production limit
- to prevent sand entry from the formation
- to produce the well and reservoir at the most
- efficient rate
- to prevent water and gas coning
- to match the surface pressure of a well into a multi-well gathering line and to prevent back flow

In addition, any situation requiring control or reduction of the well's flow rate will normally be met by the installation of a surface choke.

The surface choke is also used to ensure that pressure fluctuations downstream from the wellhead do not affect the performance of the well. To achieve this condition, flow through the choke must be of a critical velocity. The corresponding critical flow rate is reached, when the upstream pressure is approximately twice the downstream pressure.

There are several different types of chokes currently in use. They may be divided into two broad categories: variable or adjustable chokes and positive or fixed orifice.

Positive chokes have a fixed-orifice dimension which may be replaceable and is usually of the bean type (Figure 1). The flow path is normally symmetric and circular. Fixed orifice chokes are commonly used when the flow rate is expected to remain steady over an extended period of time.

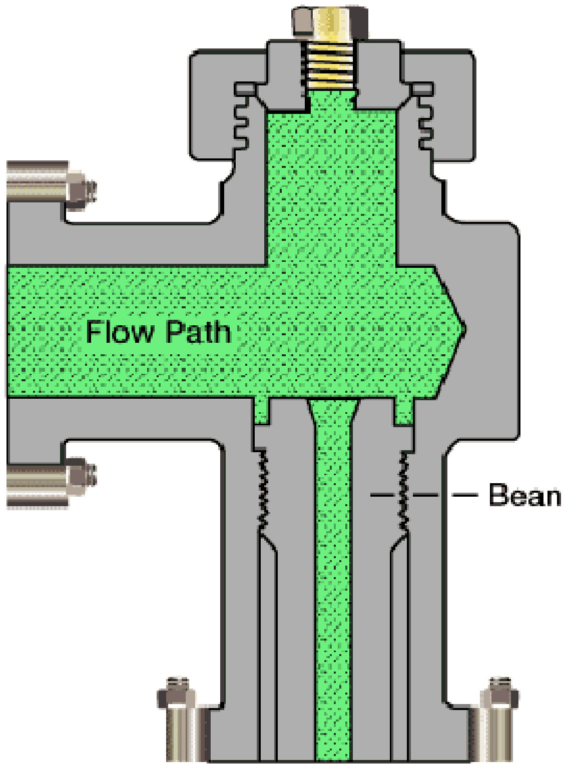


Figure 1

Normal beans are 6 inches long and are drilled in fractional increments of $\frac{1}{64}$ th-inch up to $\frac{1}{2}$ -inch. Smaller bean inserts, known as X-type, are used to provide closer control. Ceramic, tungsten carbide, and stainless steel beans are used where sand or corrosive fluids are produced. Changing the size of a fixed orifice choke normally requires shutting off flow, removing and replacing the bean.

Some continuously variable or adjustable chokes operate similarly to a needle valve and allow the orifice size to be varied through a range from no flow to flow through a full opening (Figure 2).

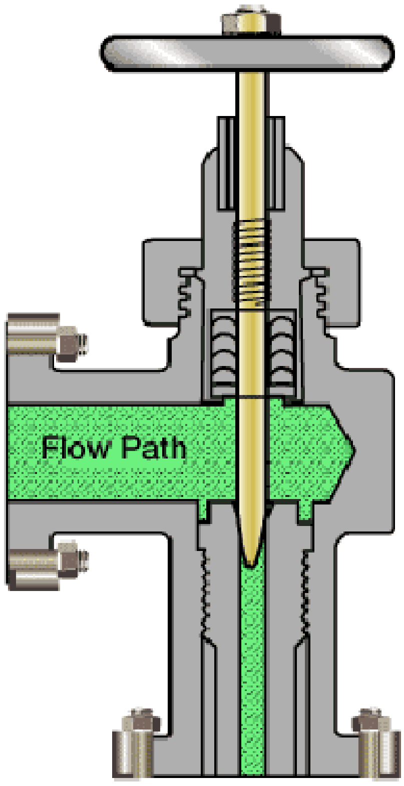


Figure 2

Flow control is obtained by turning the hand wheel which opens or closes the valve. Graduated stem markings indicate the equivalent diameter of the valve opening. Another type uses two circular discs, each of which has a pair of orifices. One disc is fixed while the other can be rotated so as to expose the desired flow area or block the flow altogether (Figure 3).

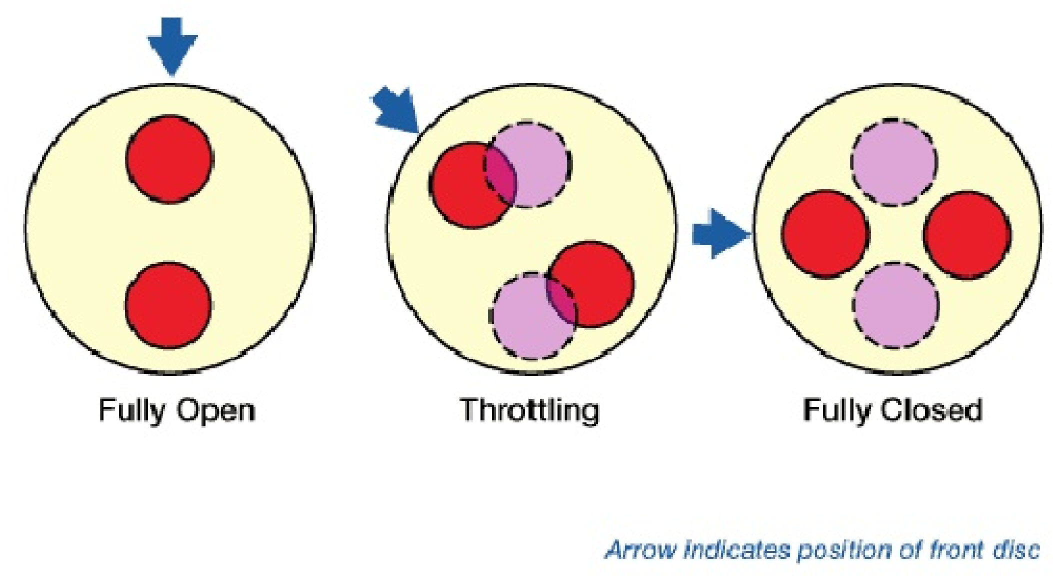


Figure 3

Because of their variable size opening the calculation of flow rates through adjustable chokes may not be as accurate as through orifice chokes. However, adjustable chokes may be used to control wells where changes in the production rates may be required periodically to meet market demands or allowables.

Variable chokes are often used on water flood injection wells where variation in injection rates must be effected with minimal disruption. Variable chokes are particularly vulnerable to erosion from suspended sand particles and are not normally used in areas where this is a significant problem.

The bodies of both types of chokes are L-shaped and the end connections may be fully flanged, fully threaded, or a combination of each.

It is important in the design of the surface control system to understand the pressure versus flow rate performance of the choke at critical flow rates. Good correlations for single-phase flow of either gas or liquid through a choke are available, but they are not applicable to the multiphase flow situation we normally encounter in our wells. The performance correlations for multiphase flow through chokes are derived empirically and apply only at critical flow rates.

CHOKE PERFORMANCE RELATIONSHIPS

The equation describing the relationship between upstream pressures, gas or liquid ratios, bean size, and flow rates at critical velocities in field units is as follows:

$$p_{tf} = \frac{600 \cdot R^{0.5} \cdot q}{S_2}$$

Where:

R = GLR, Mcf/bbl

q = flow rate, BOPD

S = choke size, 64-th of an inch

p_{tf} = THP, psia

From the nature of this equation, we see that for a given orifice size and GLR, the tubing head pressure plots as a straight line function of flow rate q.

A typical plot is shown in Figure 1 .

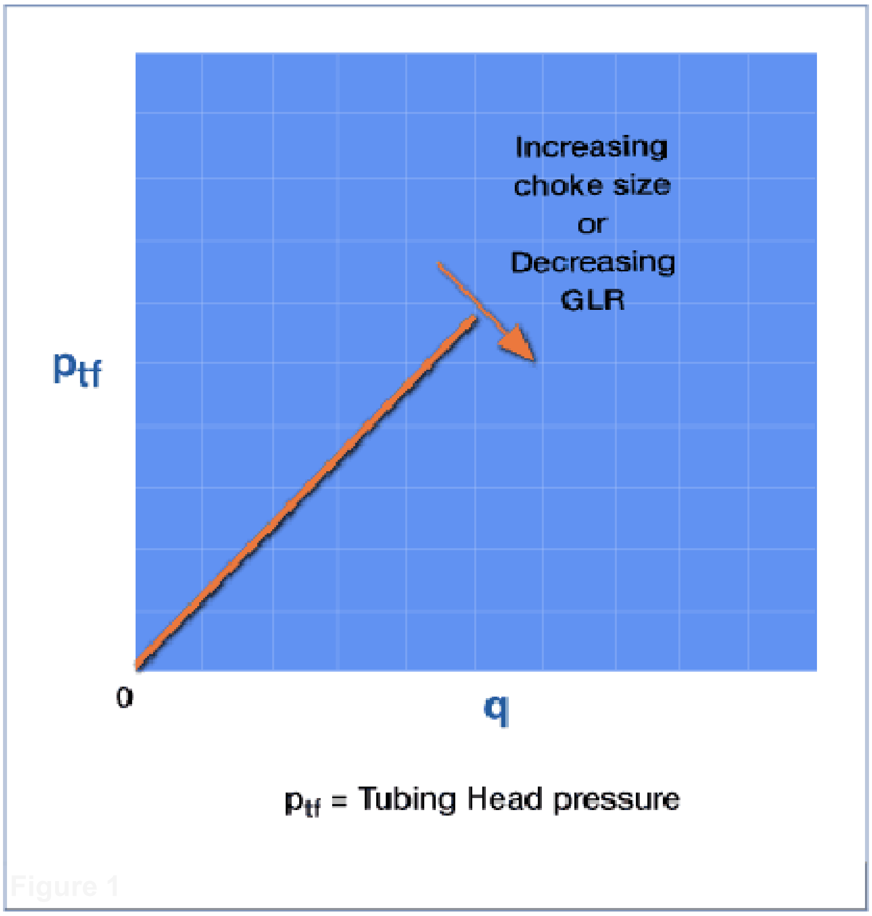


Figure 1

Note that as the orifice size increases or the GLR decreases, the line shifts downward.

Gilbert (1954), while checking for choke erosion in the Ten Section Field, California, further refined the theoretical formula to yield more accurate pressure measurements, using this empirical relationship:

$$p_{tf} = \frac{435 \cdot R^{0.546} \cdot q}{S^{1.89}}$$

where p_{tf} is in psig.

He found that these new values for the constant and the exponent agreed more accurately with empirical data. He later presented the new version of the equation as a nomogram to make it practical for field use

Ros (1961) developed a theoretical formula to account for critical flow through a restriction. The equation he developed was later adapted to oil field use and converted to graph form by Poettmann and Beck (1963). Their conversion applies to oil gravities of 20, 30, and 40 degrees, API.

Integrating the IPR, THP, and Choke Performance

We now turn to methods of calculating the flow rate attainable by a well under various operating conditions. We know that the IPR curve gives the whole range of bottomhole flowing pressures and rates possible for any given productivity index and average reservoir pressure. But what will the actual production rate be? That depends on the vertical flow performance and surface control facilities.

The most basic surface control system is one where there is no surface choke and where the wellhead and surface line pressure losses are minimal. For this condition we may analyze the well's performance by simply constructing a tubing head pressure curve.

The procedure is straightforward. For a series of bottomhole pressures and flow rates, we calculate the pressure losses in the tubing using the appropriate pressure gradient curves for the well in question (Figure 1).

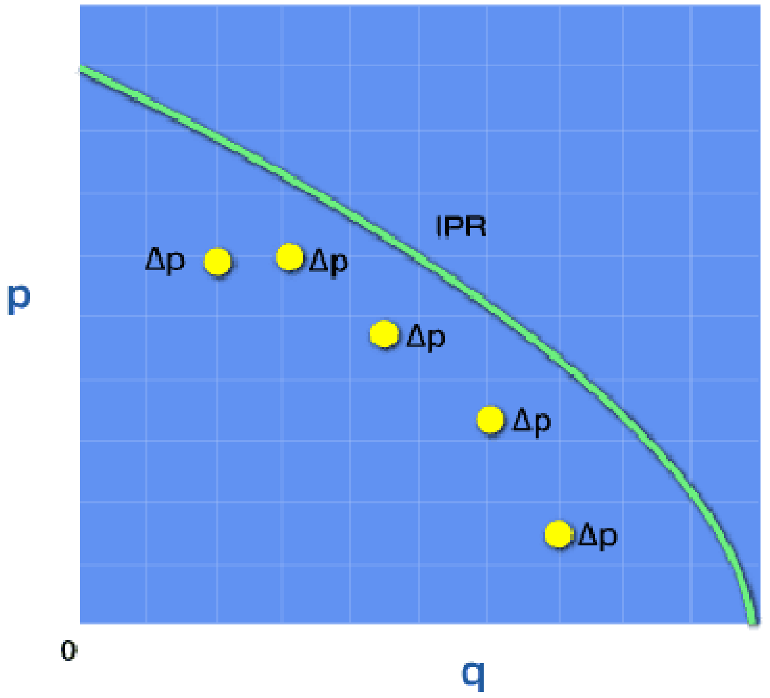


Figure 1

By joining the calculated tubing head pressure points we obtain the desired THP curve (Figure 2).

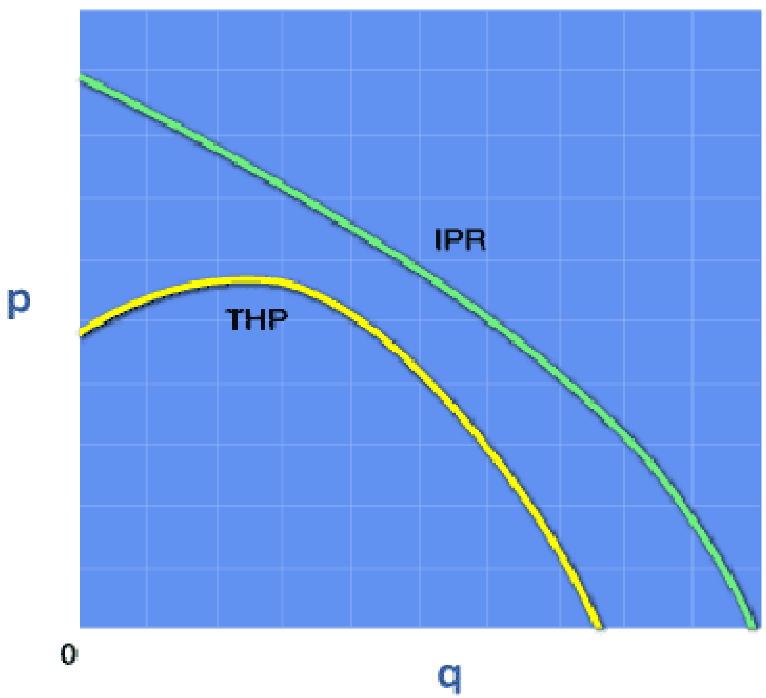


Figure 2

For any given constant THP, then, we can use this curve to estimate the flow rate, q. In unrestricted flow, the maximum flow rate is given by the intersection of the THP curve and the surface line pressure upstream of the gathering lines (Figure 3). Calculating the well's flow rate in this manner is referred to as the "bottom-up" method.

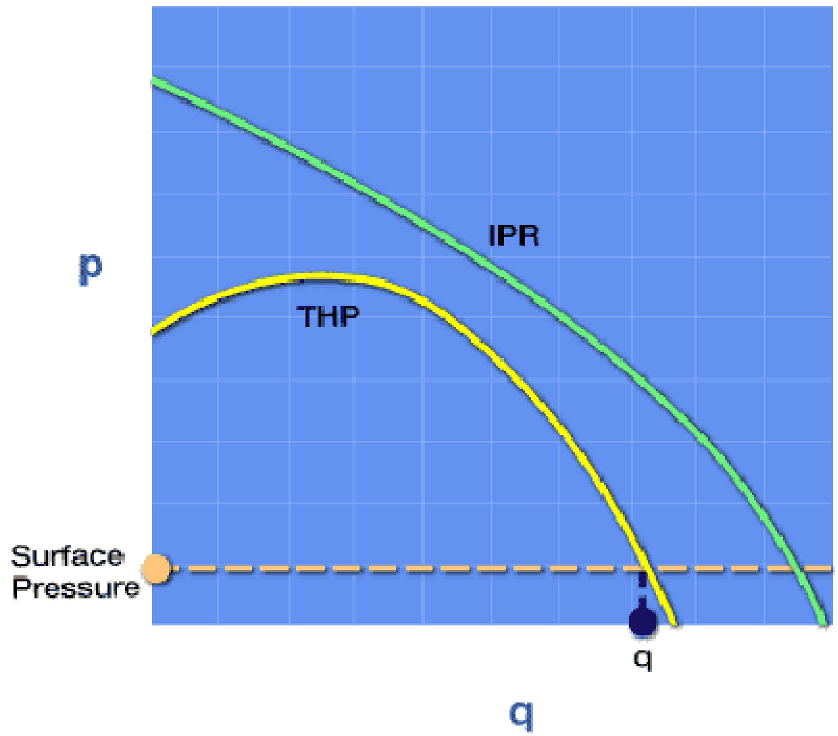


Figure 3

Another way of performing the same analysis is the "top-down" method. In this method, we start our calculation with the known value of surface pressure. We then calculate the vertical pressure differences for several flow rates (Figure 4) and join the values to give the bottomhole flowing pressure needed to sustain the various rates.

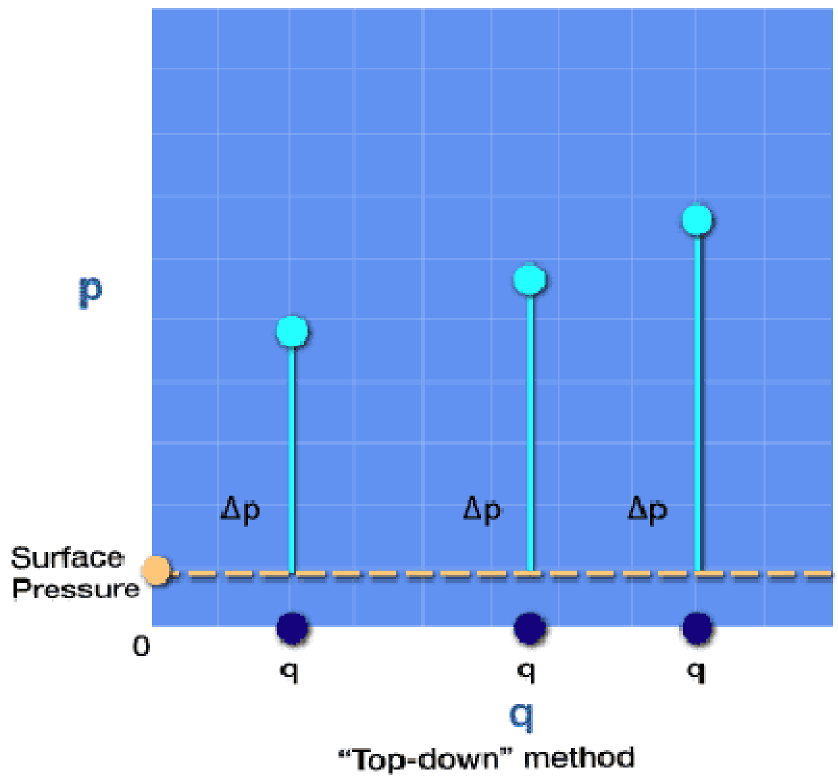
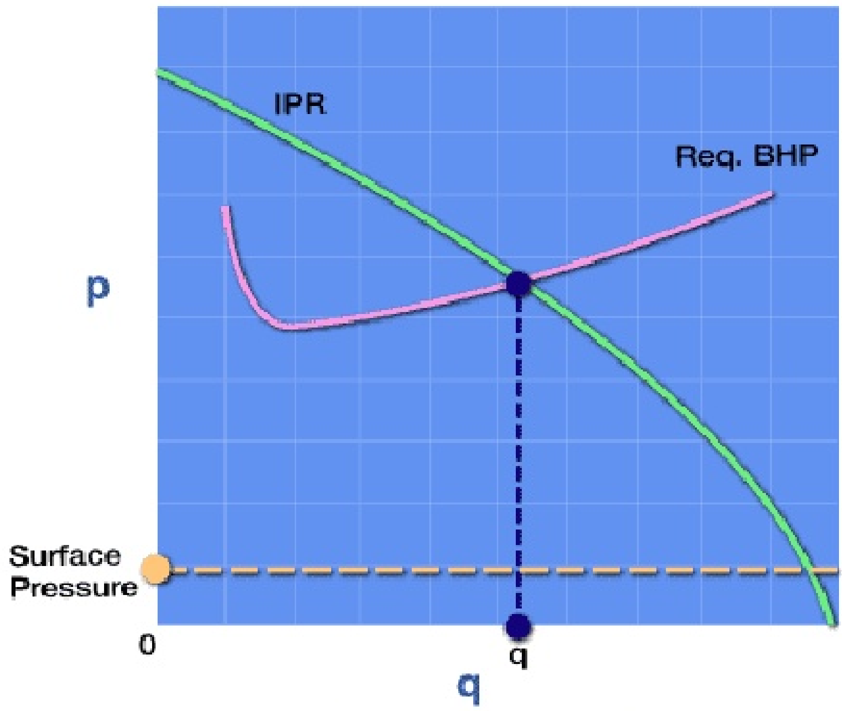


Figure 4

This required BHP curve is put on a graph with the IPR (Figure 5). The intersection of these curves determines the flow rate for the assumed surface pressure.



"Top-down" method
Req. BHP = Required bottomhole flowing pressure

Figure 5

In both the top-down and bottom-up methods, it is possible to consider different operating or downhole equipment conditions such as different tubing sizes or GLR. In this way, we may determine optimal flowing conditions for a well by plotting several different performance curves. By analyzing a range of variables the production engineer can then choose the appropriate tubing size or, in planning a gas lift system, the optimum GLR for a particular well so as to achieve an optimal design.

Generally, the wellhead pressure must be sufficient to move oil through flow lines, separators, and other surface equipment. The pressure required at the wellhead depends upon the rate of flow and the nature of the surface equipment. To complete the analysis, we must calculate the pressure-rate relationship for the various pieces of equipment through which production must flow. By plotting in sequence such curves on our IPR diagram, we can calculate the flow potential of any system, and then learn which specific component controls the flow rate.

Example:

A well has the following data: tubing = 7000 ft of 2½-inch gathering line - 2500 ft of 2½-inch separator pressure = 150 psig

$\bar{p}_R$ = 2000 psig

GLR = 800 Scf/bbl

q = 3000 BOPD, water cut = zero.

We are asked to estimate the well's production rate and to specify the piece of equipment that controls it.

We may estimate the well's performance by calculating the performance of each component in our system moving upstream from the separator. This is a top-down method. We begin by assuming three arbitary flow rates and, with appropriate multiphase horizontal flow rate correlations such as those presented in Volume 1 of Brown's text (1977) we calculate the pressure losses in the gathering line. Because the pressure just upstream of the separator is 150 psig we can use these calculations to plot three tubing head pressure values (Figure 6).

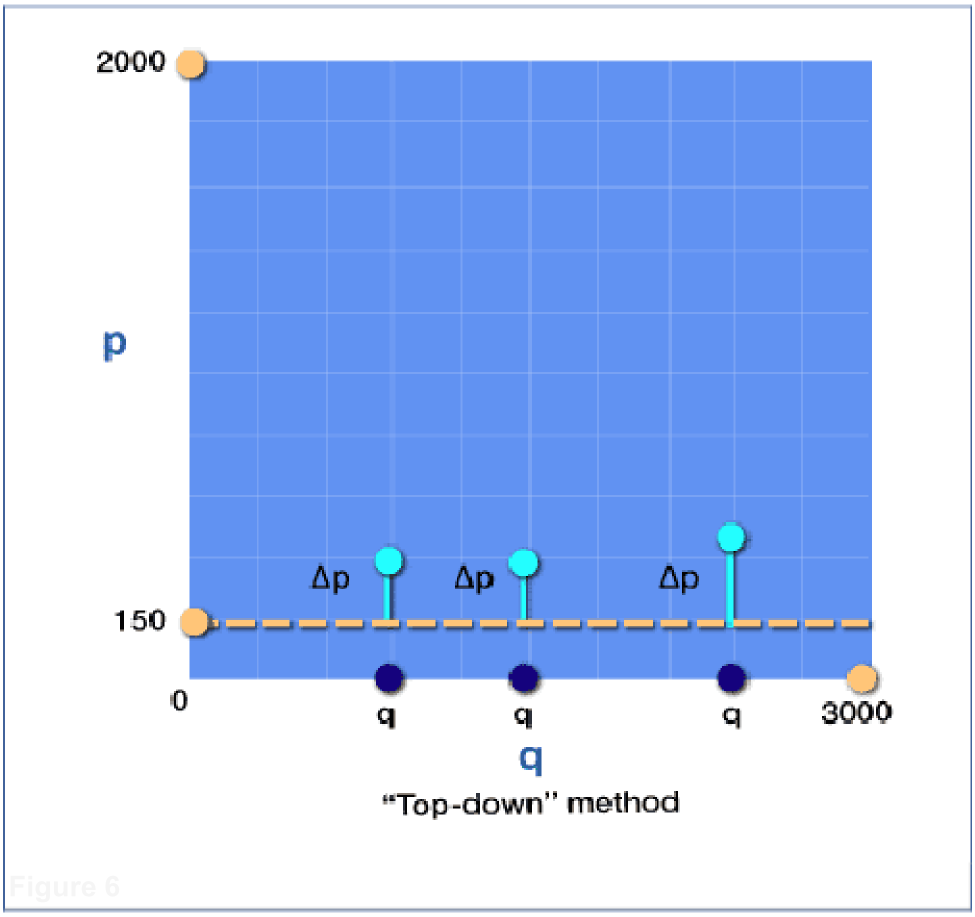


Figure 6

We can plot these values of pressure versus flow rate and obtain the required tubing head pressure curve as shown in Figure 7.

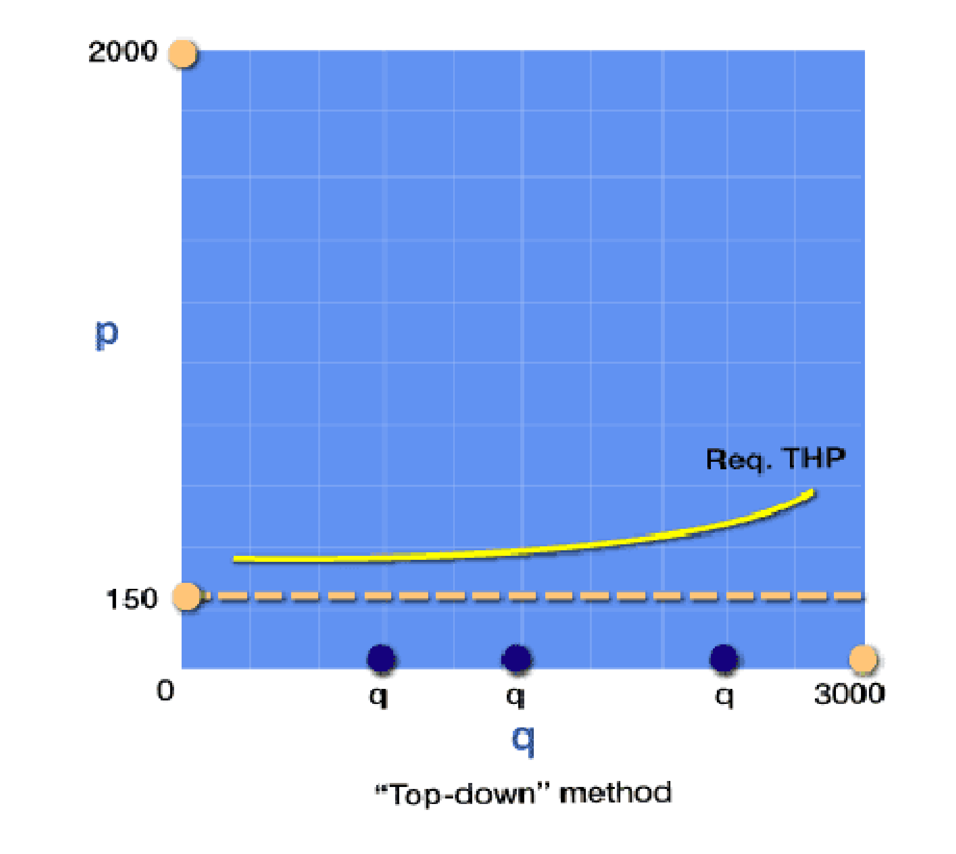


Figure 7

For the same assumed flow rates, and the given tubing size, we now calculate the vertical pressure increases between the surface and the formation, and add them to the required THP's to give a plot of required bottomhole flowing pressures (Figure 8).

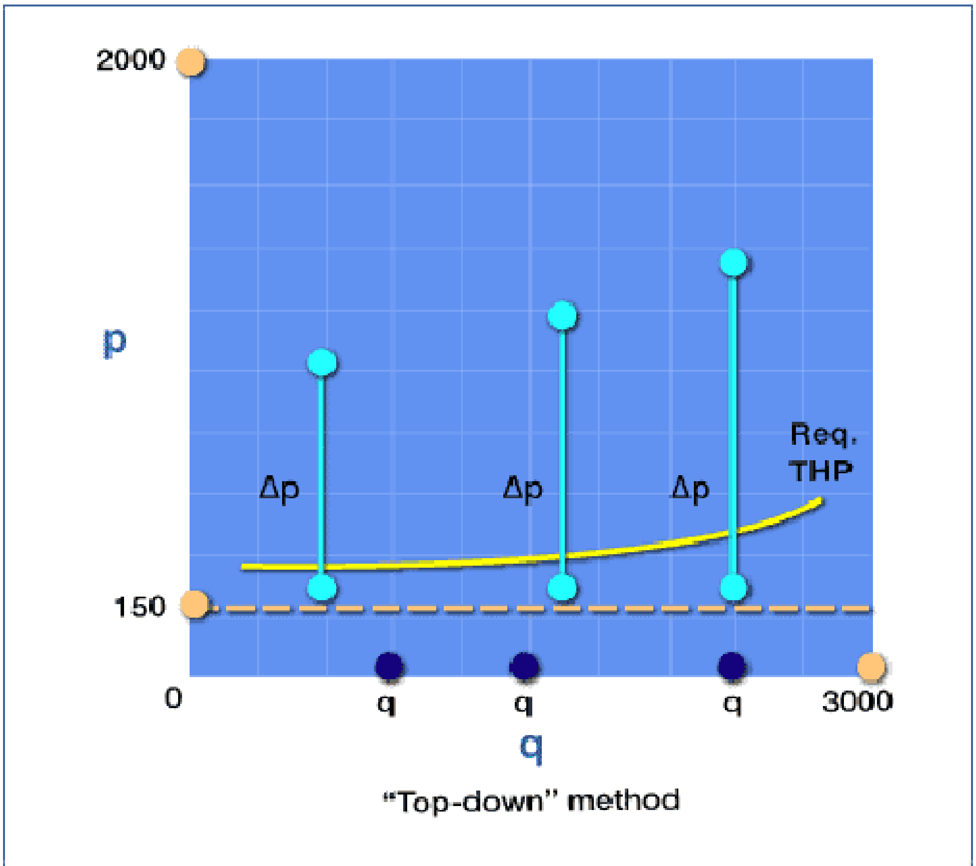


Figure 8

This will be equal to the calculated tubing head pressure for a given rate plus the vertical pressure gain from surface to formation for that rate. Joining these points will give us the required BHP curve shown in Figure 9.

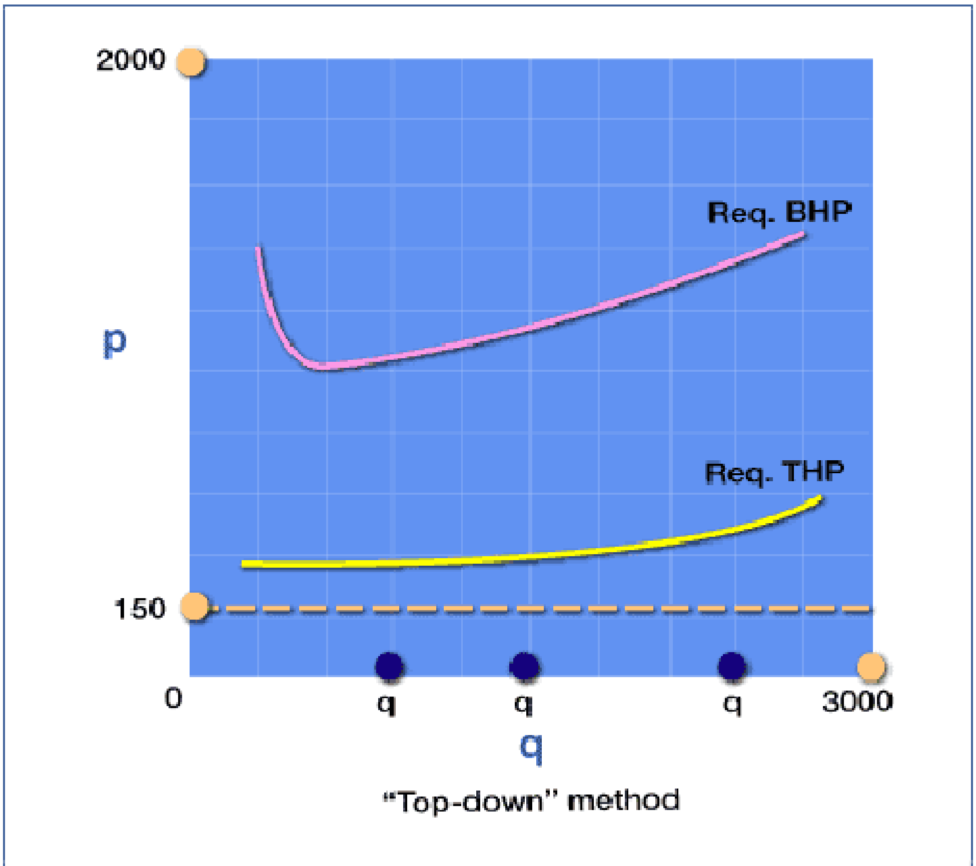
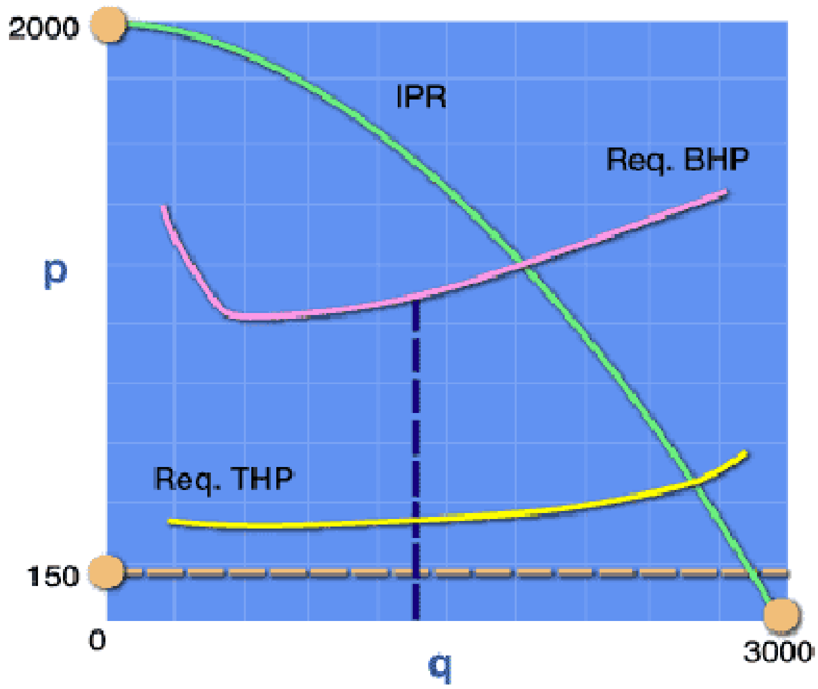


Figure 9

It represents the effect of production through the wellbore and surface equipment for the specific case of a pressure on the upstream side of the separator equal to 150 psi.

Now we add our inflow performance curve (Figure 10), which runs from our average reservoir pressure of 2000 psi to our pumped-off potential of 3000 BOPD. The point of intersection of the IPR with the required BHP curve is our system design. It represents the flowing rate for the well which will provide 150 psi at the separator. In this case it occurs at about 1800 BOPD.



“Top-down” method

Figure 10

We can also use the "bottom-up" method of calculating this flow rate. Starting with the IPR we assume flow rates and generate a THP curve for the well in the usual way (Figure 11).

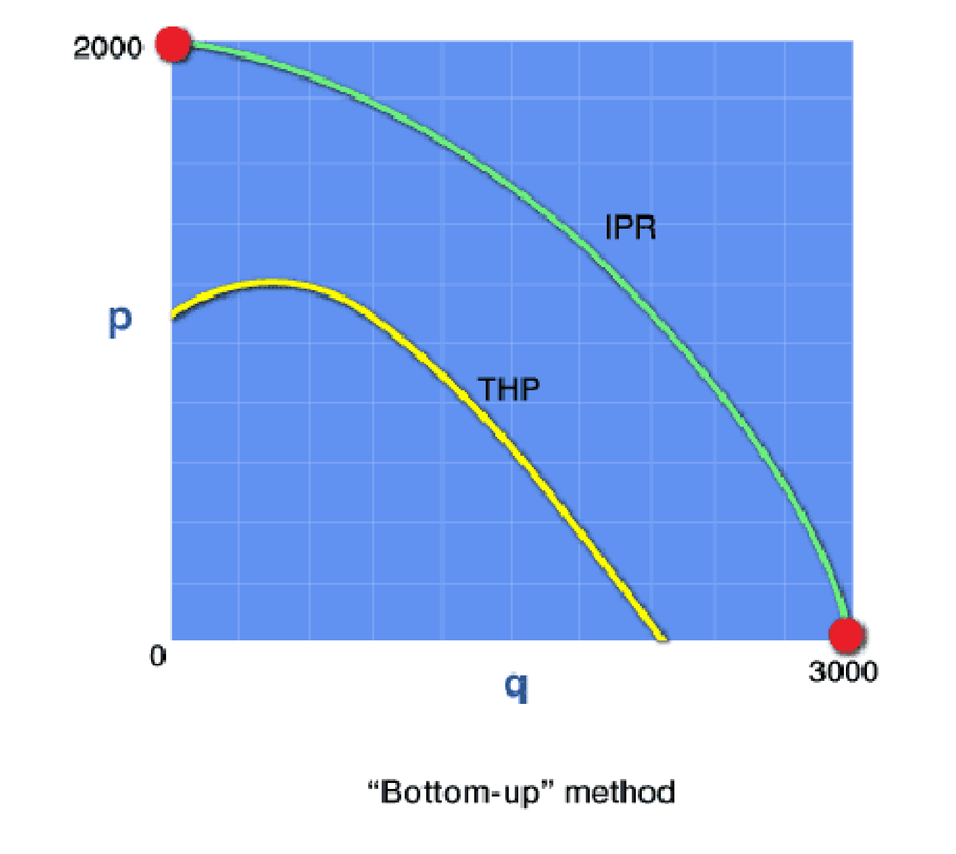


Figure 11

By subtracting calculated pressure losses in the gathering lines for these flow rates from the THP curve we obtain a curve representing the pressure-rate relationship at the downstream side of the gathering line. The pressure at this point is also the pressure at the inlet to the separator. The intersection of this curve and the separator pressure is the flowing rate under the assumed conditions (Figure 12).

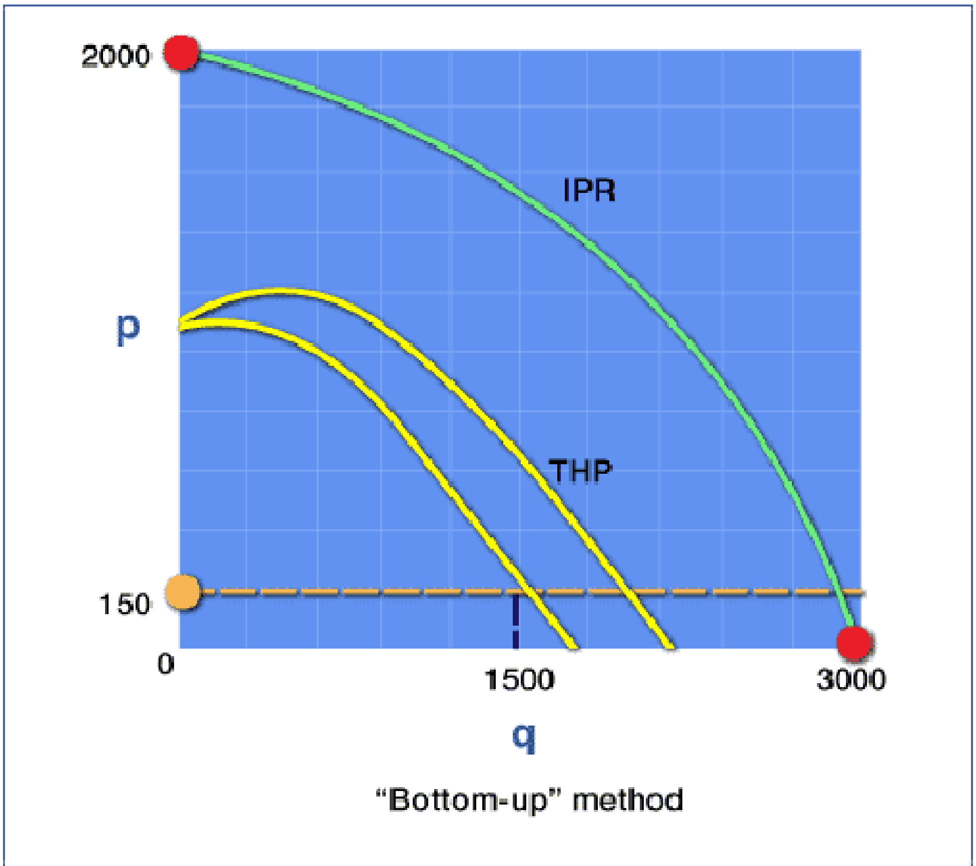


Figure 12

By changing any one variable, for example, either the separator pressure, the gathering line size, the tubing size, or the GLR, the flow rate will also change. In order to optimize the design, then, an engineer will determine the system's sensitivity to these variables and see what the most economical use of the equipment will be.

Without a choke in the line, any pressure variations on the surface will directly affect the well's ability to produce. One reason for the installation of a choke is to make it the controlling element in the system.

The installation of a choke will reduce the flow rate and increase the tubing head pressures. Effective control is achieved only when the tubing head pressure is twice the pressure at the upstream point in the gathering system. This is the critical flow requirement.

Installing a choke and using the "top-down" method, we can calculate the tubing head pressure required for criteral flow as being twice the THP that was calculated when we did not have a choke in the system.

This new curve is the pressure upstream of the choke and is the new required THP curve (Figure 13).

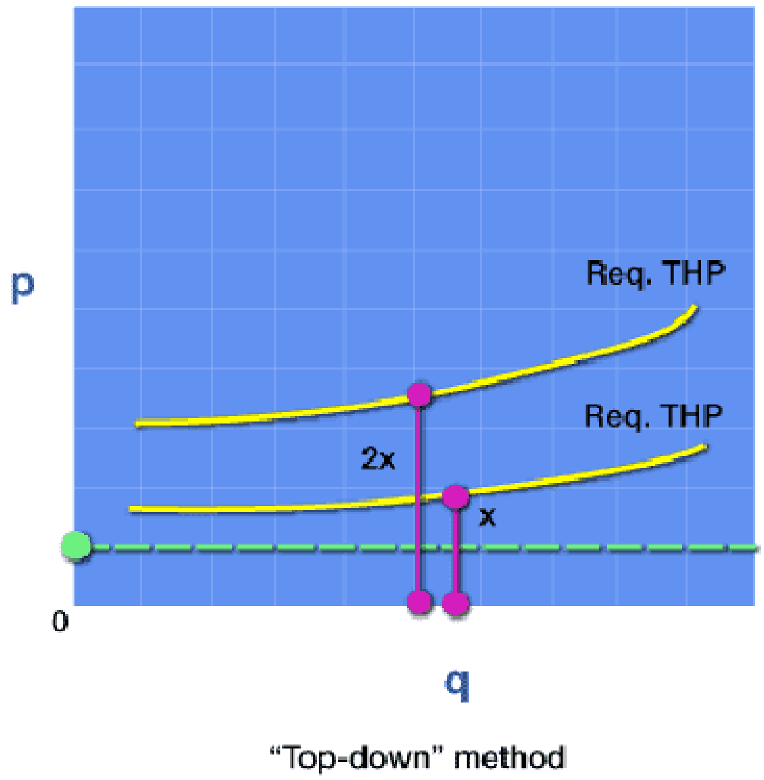


Figure 13

Now we add the vertical pressure differences in the tubing to find the required bottomhole flowing pressures. It is the intersection of this last curve with the IPR which determines the system flow rate (Figure 14).

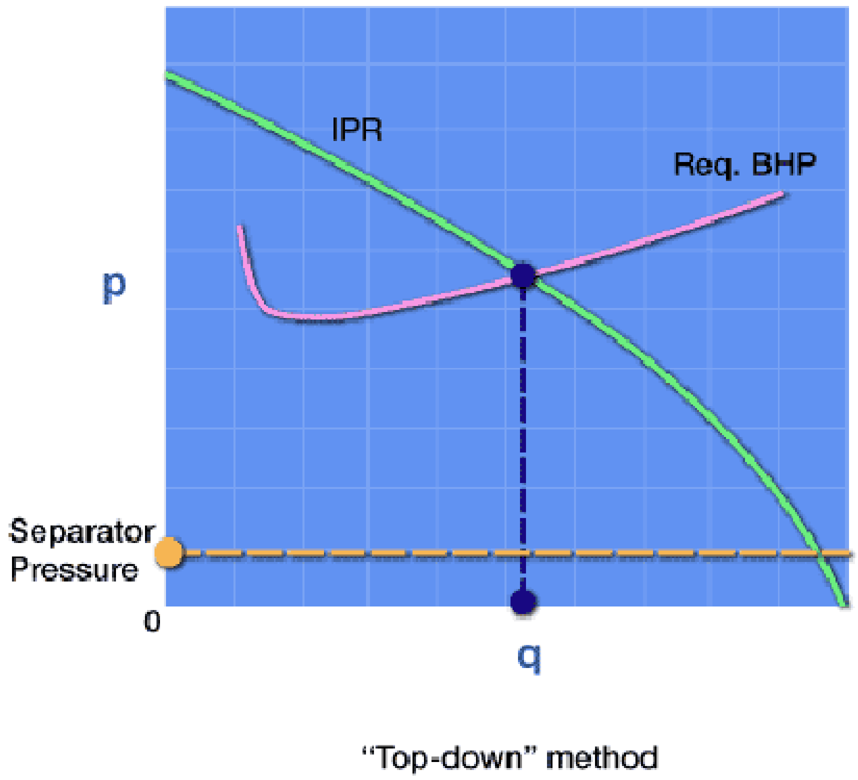


Figure 14

The choke performance can be added to the bottom-up solution we performed earlier. The IPR and THP curves do not change because we have not yet encountered the choke in our flow system. Now we add the effect of the choke which gives a curve below the THP equal to one half of the THP at each flow rate (Figure 15).

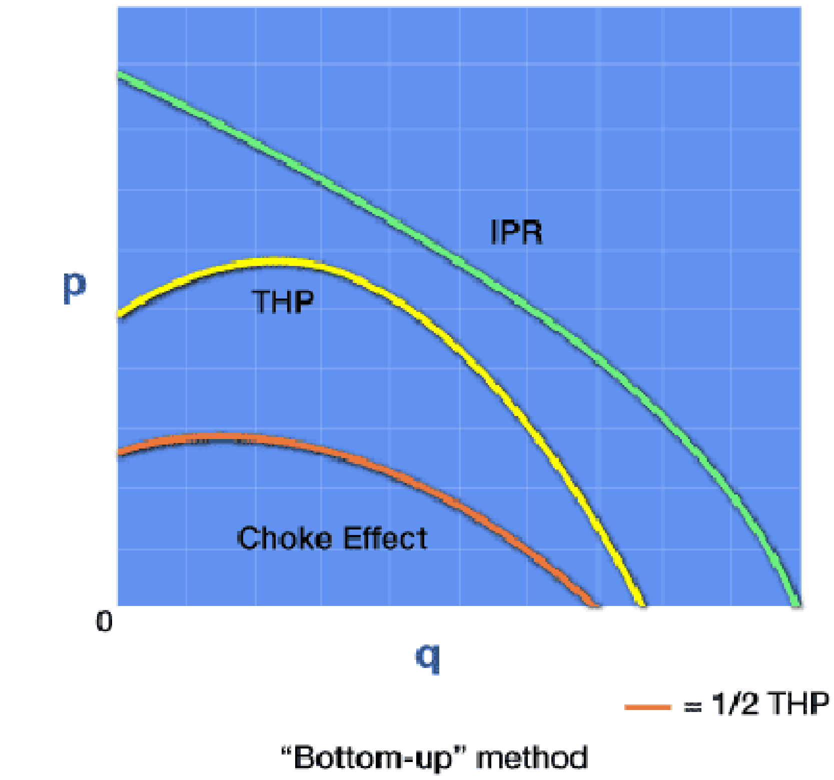


Figure 15

This difference or loss in pressure represents the pressure losses through the choke during critical flow. We add a fourth curve representing losses in the gathering line. The point of intersection of this curve with our given separator pressure value is the system production rate if the production rate is controlled by the separator (Figure 16).

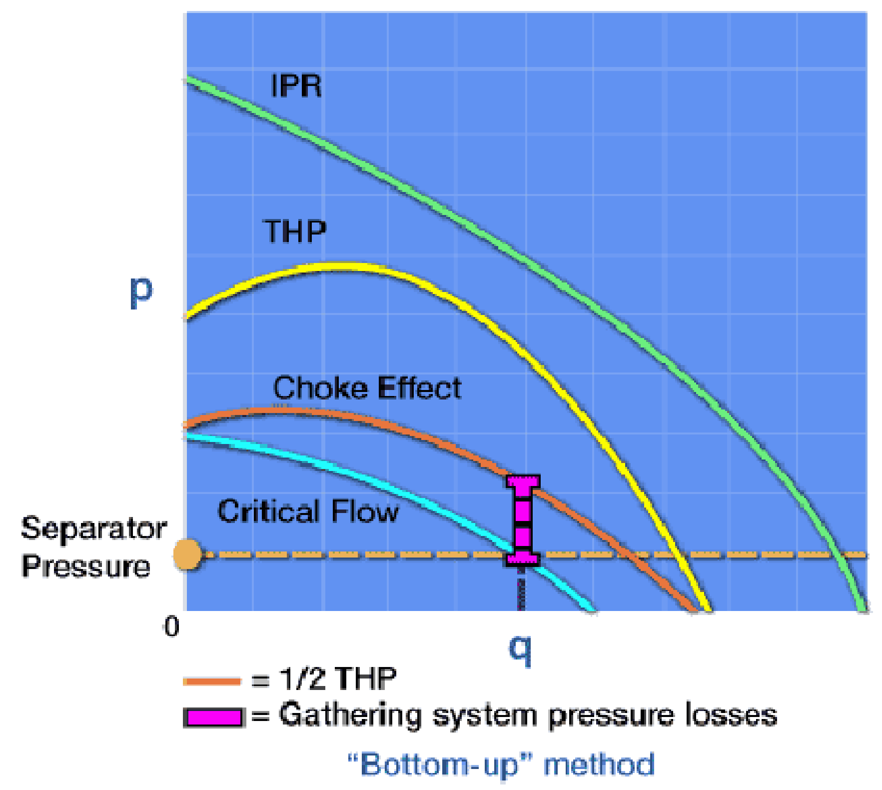


Figure 16

The choke size must be chosen to yield a rate equal to or less than this production rate in order for the choke to control the well's production. This limiting condition is shown in Figure 17.

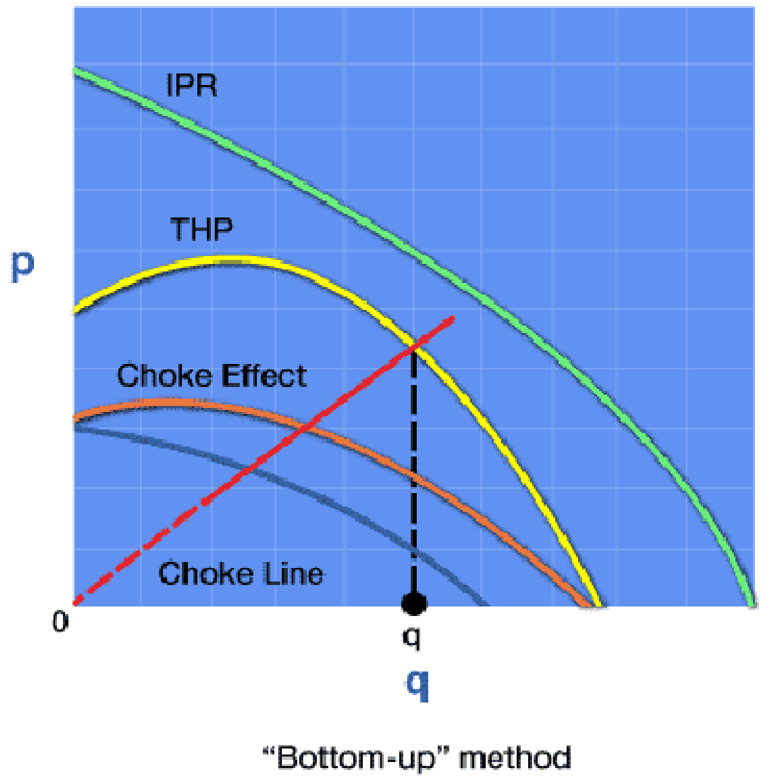


Figure 17

If the choke size selected had been larger, the choke performance line would have been lower and given a higher flow rate at its point of intersection with the THP curve q2 (Figure 18). The choke calls for a higher flow rate than the separator will allow. Under these conditions, then, the separator will control flow.

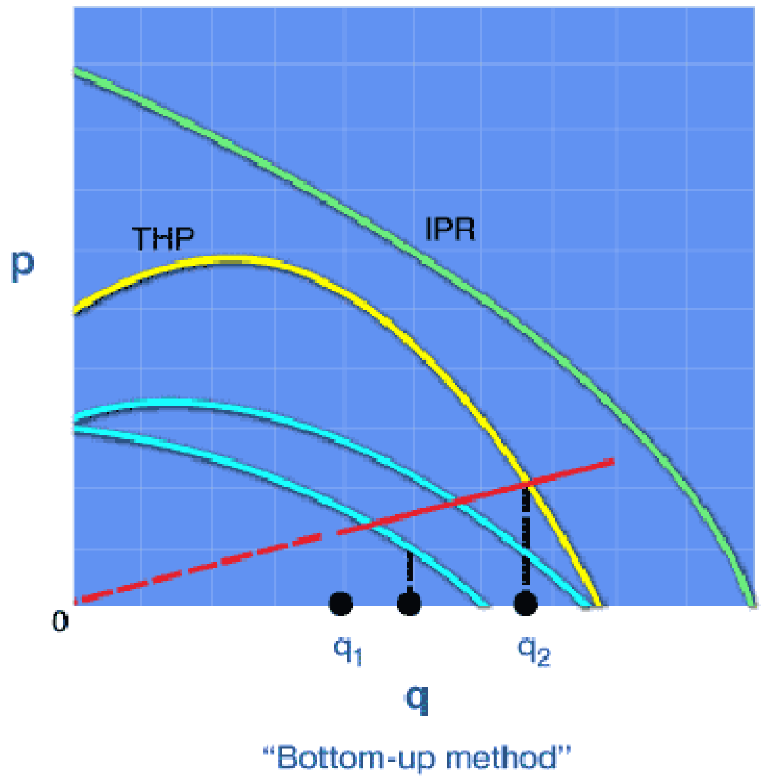


Figure 18

The rates and pressures of various choke sizes for this installation can now be calculated and an optimal choke size selected.

Stable flow occurs when fluctuations of pressure and flow rate are dampened and flow rate tends to return to a stable value. We have plotted in Figure 1 the THP and choke performance curve.

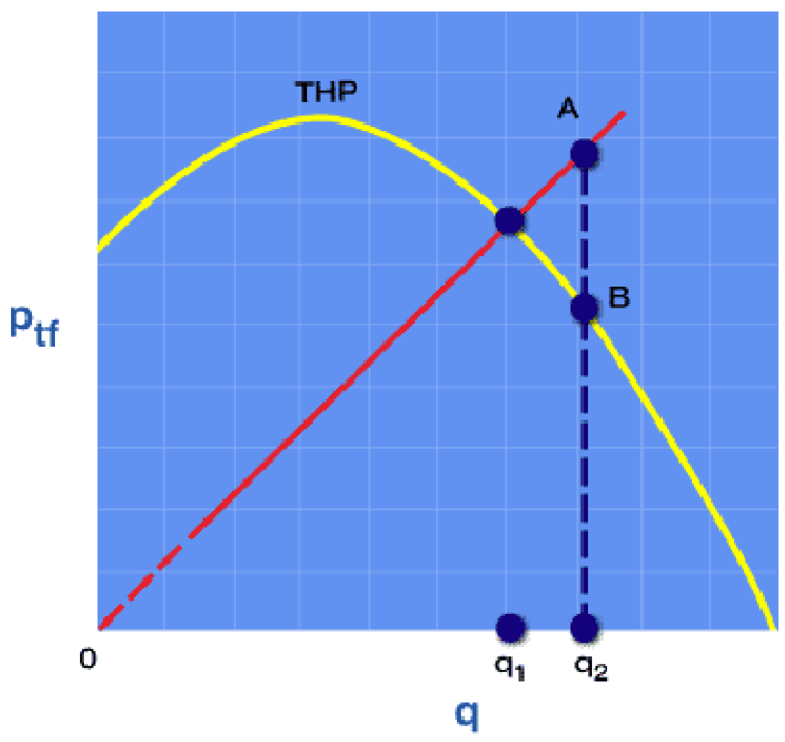


Figure 1

A flow rate at point 1, that is q1, is stable because an increase in flow rate to q2, increases bean backpressure to point "A" and reduces the tubing head pressure to point "B." In essence the pressure required by the choke to sustain this flow rate is greater than the THP available at this flow rate. Because an increase in backpressure of the amount A B is imposed on the well, the flow rate tends to decrease from q2 back to q1, the stable rate. In a similar manner a reduction in rate to q3, as shown in Figure 2 , will reduce the required THP, and therefore, reduce backpressure on the formation by the amount A’ B’.

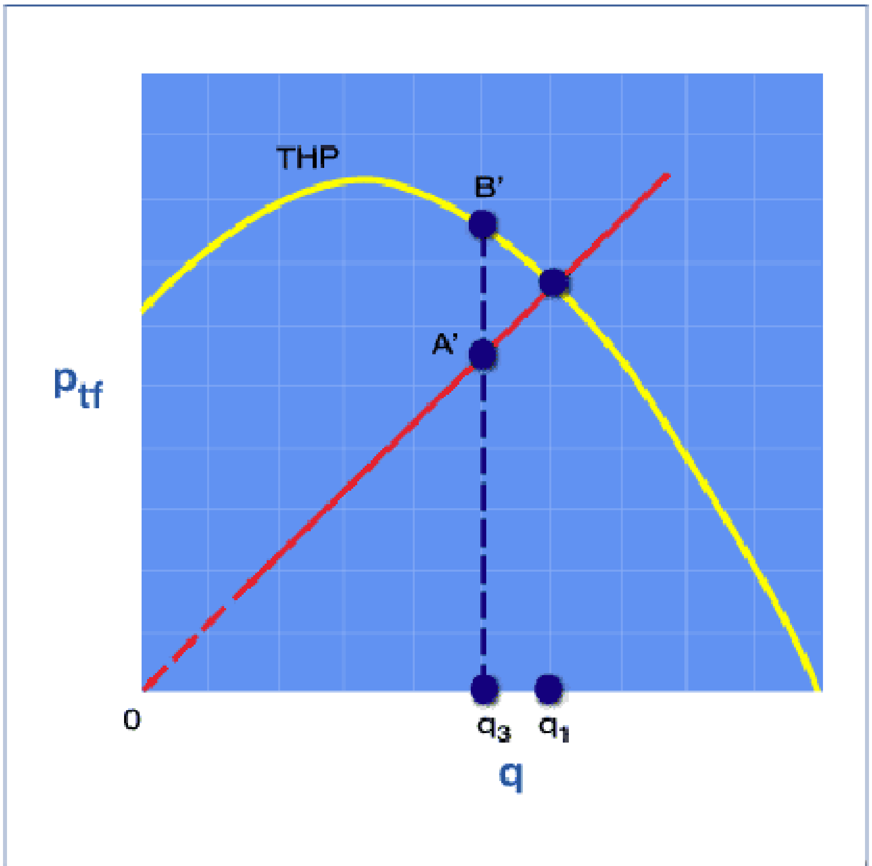


Figure 2

This will increase the flow rate back to q1 and once again the well returns to a stable flow condition.

Unstable flow is also possible. It is illustrated in Figure 3 where a slight decrease in rate below q1 reduces the tubing head pressure below that required by the choke for critical flow.

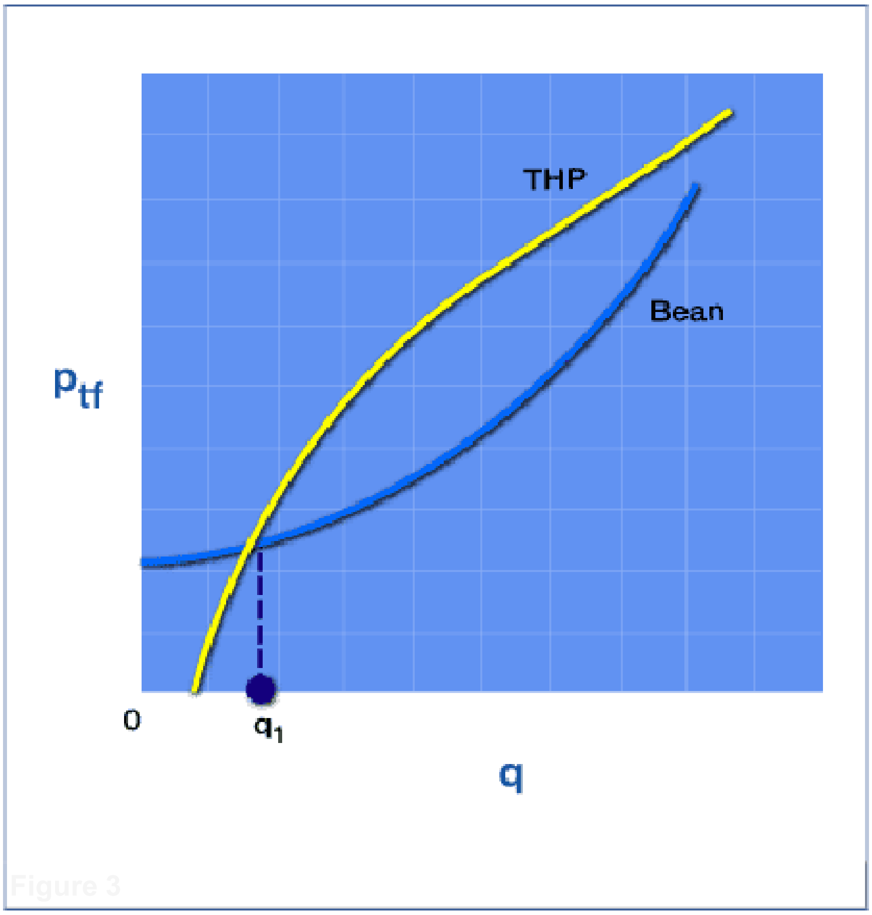


Figure 3

This causes the flow rate to decrease until the well dies. An increase in flow rate above q1 reduces the backpressure on the formation causing further rate increases until a stable flow rate is reached beyond the maximum point on the THP curve. The maximum point on the THP divides the stable flow region from the unstable region (Figure 4).

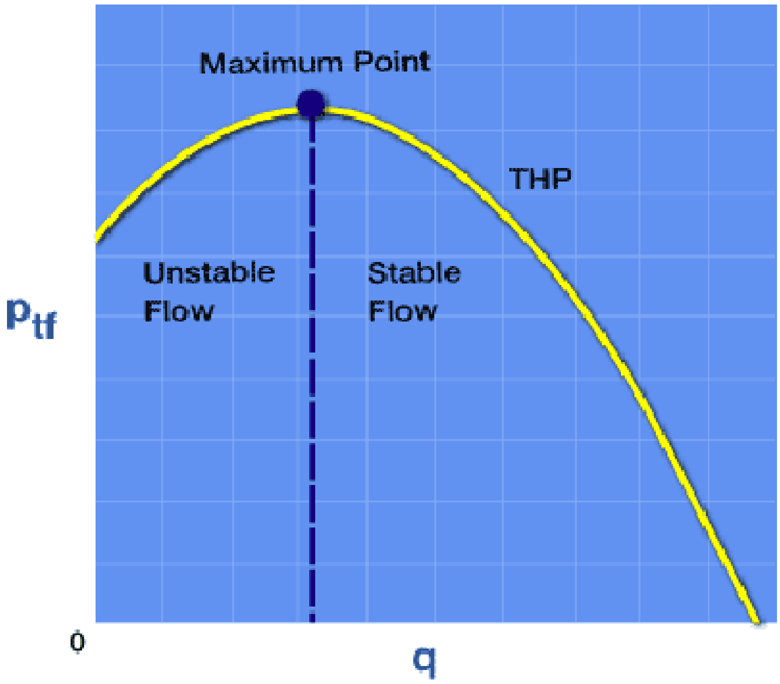


Figure 4

This becomes intuitively clear if we draw the IPR curve and then add the Vertical Pressure Loss curve, or VPL. Now we subtract the Vertical Pressure Loss from the IPR and obtain the THP curve (Figure 5).

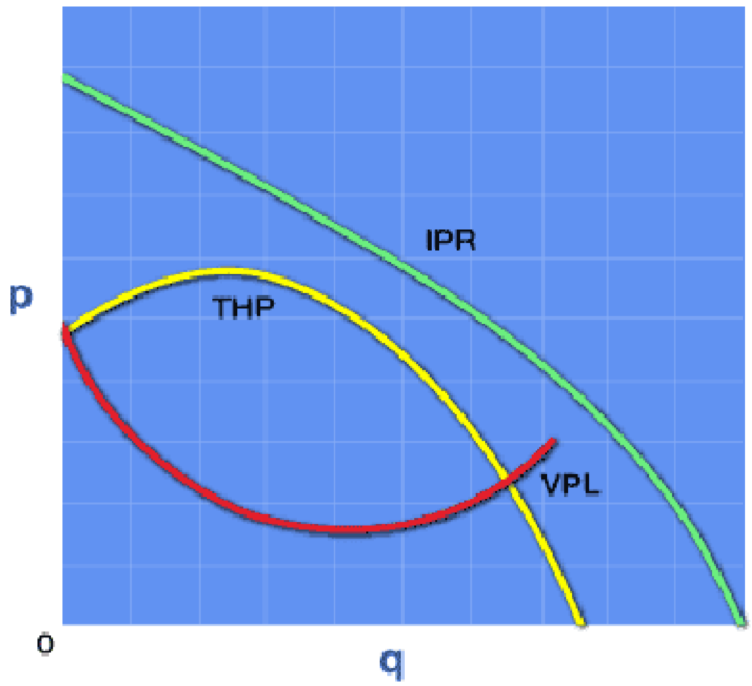


Figure 5

The THP maximum occurs where the slope of the IPR is equal in magnitude to the slope of the VPL curve (Figure 6).

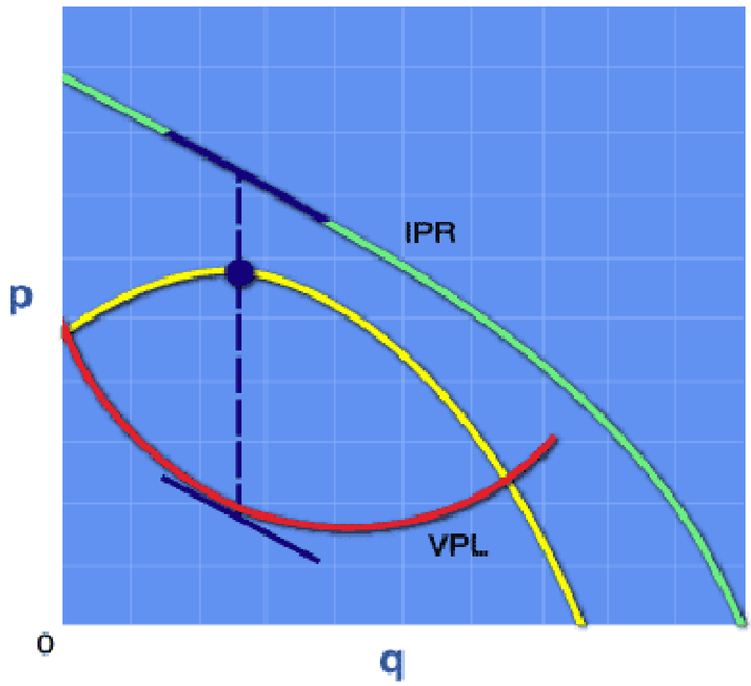


Figure 6

To the left of that point, any decrease in rate results in increased pressure losses in the tubing due to slippage. The well gradually loses sufficient bottomhole flowing pressure to support flow to surface. To the right of the maximum point, frictional losses dominate and the flow rates stabilize (Figure 7).

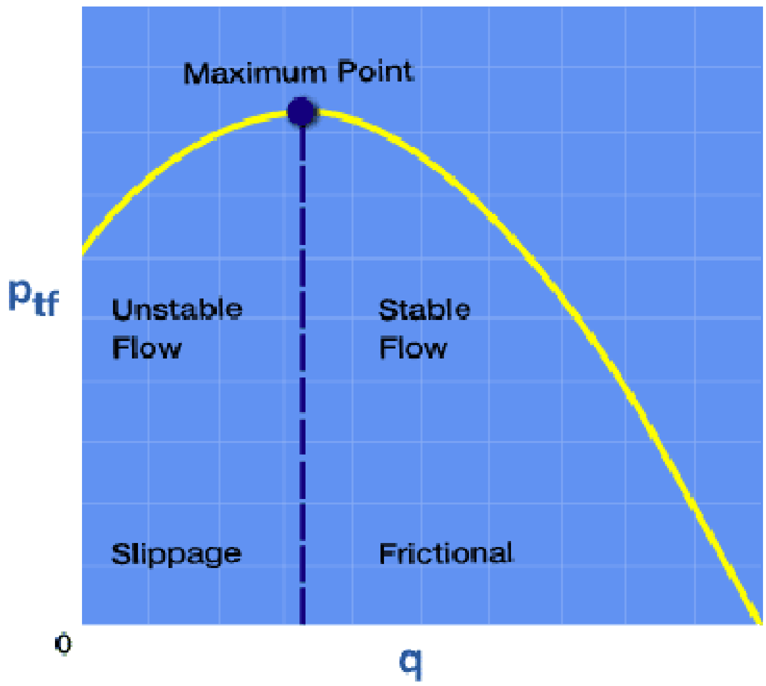


Figure 7

Integrated Performance of a Flowing Well

The inflow performance curve describes flow into the wellbore and allows us to predict q’, the pumped-off potential for a given average reservoir pressure. For any given tubing size we may calculate the vertical pressure losses in the tubing, and thus generate the THP curve.

Assuming the installation of a surface choke and that critical flow occurs, we may generate a third curve of pressure and rate downstream from the surface choke. A fourth curve might be added to show pressure losses in the gathering system and, finally, the pressure and rate performance of the separator can be added. The intersection of curves 4 and 5 in Figure 1 is the maximum practical flowing rate qmax for the system.

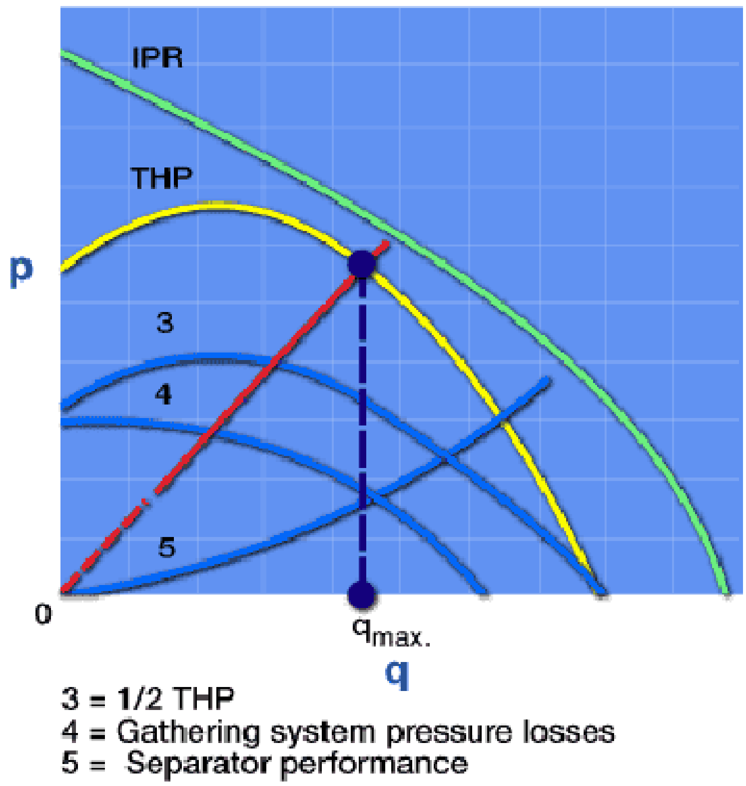


Figure 1

The choke must be chosen so as to produce at that rate or less, otherwise the separator or other downstream equipment will control production.

In Figure 2 the pressure losses throughout the system are quite apparent.

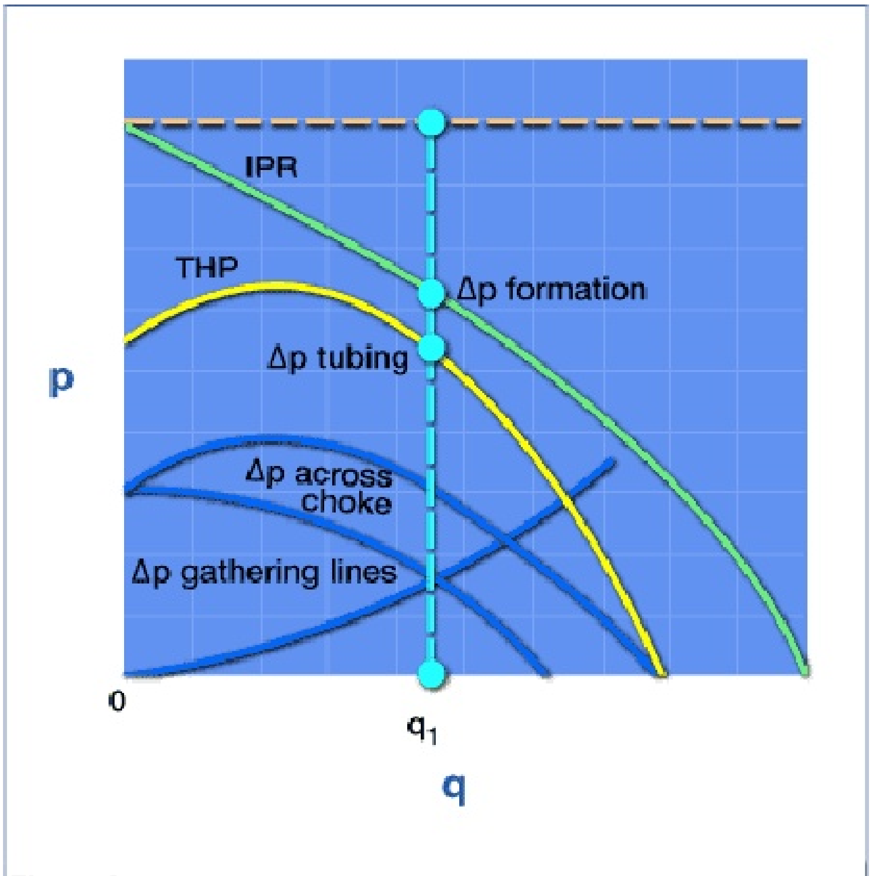


Figure 2

Starting at the average reservoir pressure and a given flow rate, q, we observe the pressure losses through the formation, through the tubing, across the surface choke and through the surface lines. In a sense the average reservoir pressure drives the whole system and is used up along the way. At each stage, however, there must be sufficient pressure to drive the subsequent systems at that flow rate otherwise flow stops at some point in the system. The component that controls or limits the flow rate determines the system capacity.

Let us now turn to the prediction of the future life of a flowing well. The efficiency of flow - that is the actual production rate divided by the formation potential, expressed as a percentage - is not constant throughout the life of a flowing well. In its earlier stages, the efficiency is high. But later on it will depend on the variations in GLR, the shape of the IPR, water cut, and the manner in which reservoir pressure decreases with cumulative production. When slug flow dominates vertical flow in the tubing, the efficiency of flow may even increase for a while. Towards the end of a well's flowing life, very sudden decreases in efficiency may occur and, of course, at the moment at which the well dies, the efficiency drops to zero.

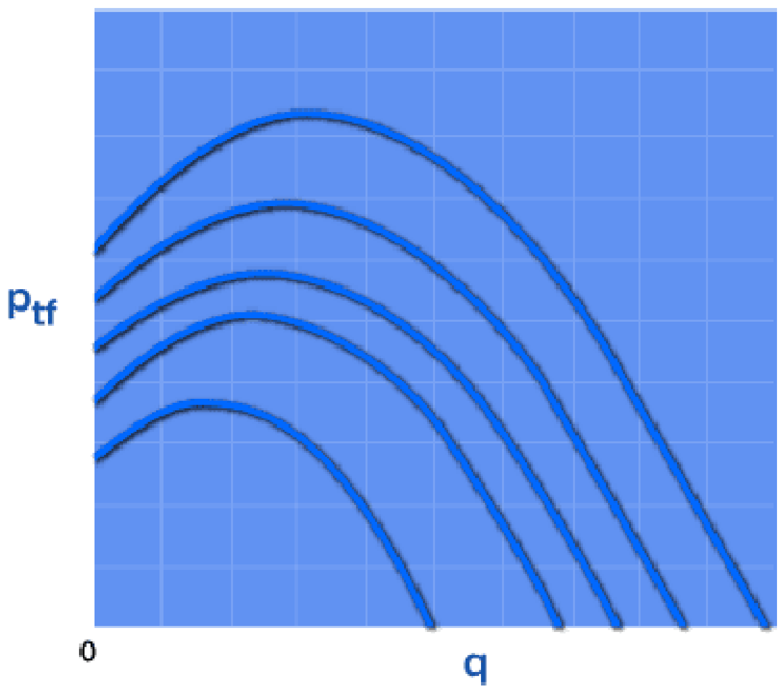
This picture is further complicated by decisions as to production policy -whether to attempt a steady rate of flow for as long as Possible by means of changes in choke size; whether to maintain a constant THP; or whether to let the well produce against a certain size of choke for Prolonged periods. Many factors are considered in determining optimal flow rates, including control of sand production, water coning, and gas depletion.

In order to predict the future performance of a flowing well, we must know how reservoir pressure, GLR, and WOR will change with cumulative production. The behavior or these variables is Predicted by using reservoir engineering methods such as those of Tarner (1944) or Muskat (1981, 1949). In addition one must have a complete knowledge of the IPR, its current and future shape.

The reservoir engineering analysis allows us to tie the average reservoir pressure with cumulative production. The IPR ties the average reservoir pressure with inflow rate. Joined together they allow us to predict the future inflow performance of a well and the field. In order to relate the performance of an individual well to the cumulative production from the pool, a production analysis of every well draining the pool is necessary. The structural position as well as other geological and formation factors must be taken into consideration for each well in order to account for differences in GLR, WOR, and so on.

Let us see how we would predict the performance of an individual flowing well. The analysis may be undertaken by either the "top-down" or the "bottom-up" method. This decision rests with the engineer in charge of the analysis in the light of the production policies to be adopted.

Let us first look at the "bottom-up" method. In this analysis, flowing gradient curves are used to determine a series of THP curves based on assumed future average reservoir pressures and values of the GLR and WOR derived from the reservoir studies. In this way future THP's are obtained, one for each assumed value of average reservoir pressure or cumulative production (Figure 1).



"Bottom-up" method

In this case, it has been decided to produce the well with a constant choke size at decreasing production rates until a certain minimum THP is reached (Figure 2).

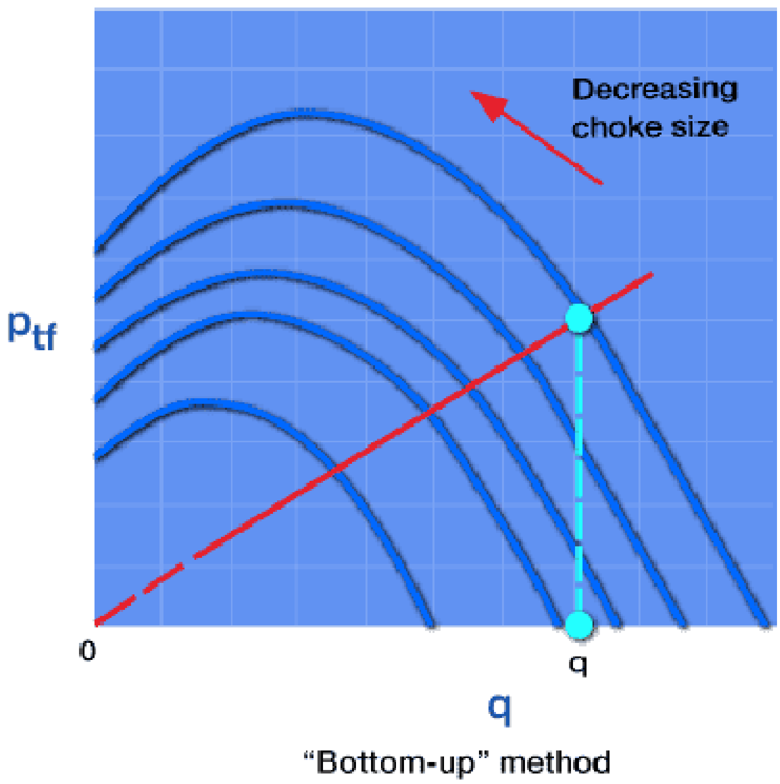


Figure 2

At that stage, the choke size is steadily decreased in an attempt to hold the THP at this level (Figure 3).

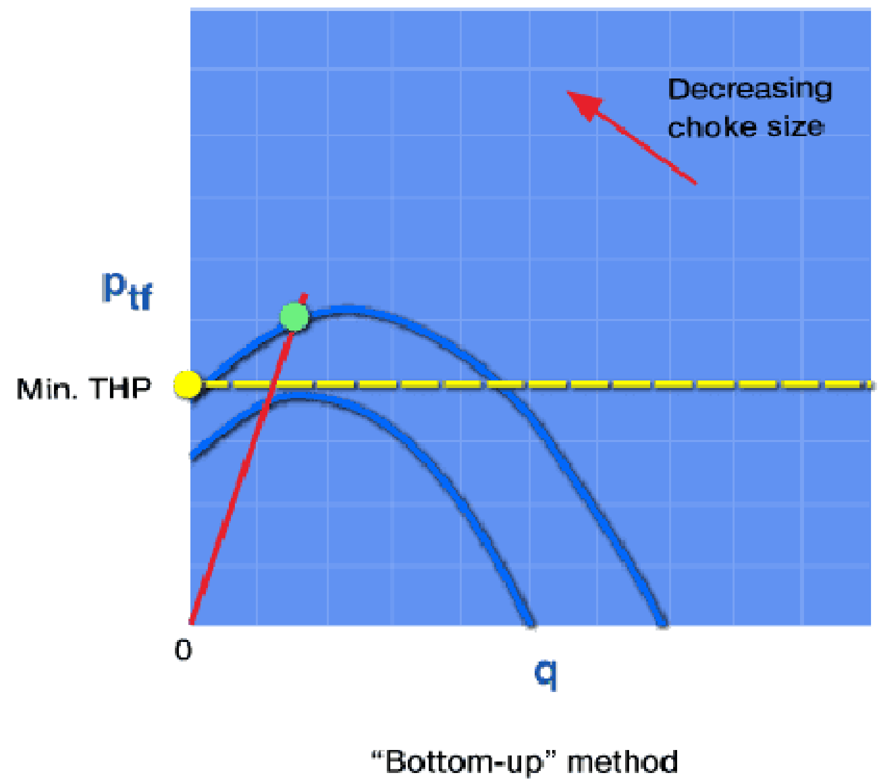


Figure 3

But now we enter the unstable flow region; the well will not flow against the minimum THP. The well dies when the THP and choke curves intersect at an unstable flow rate (Figure 4).

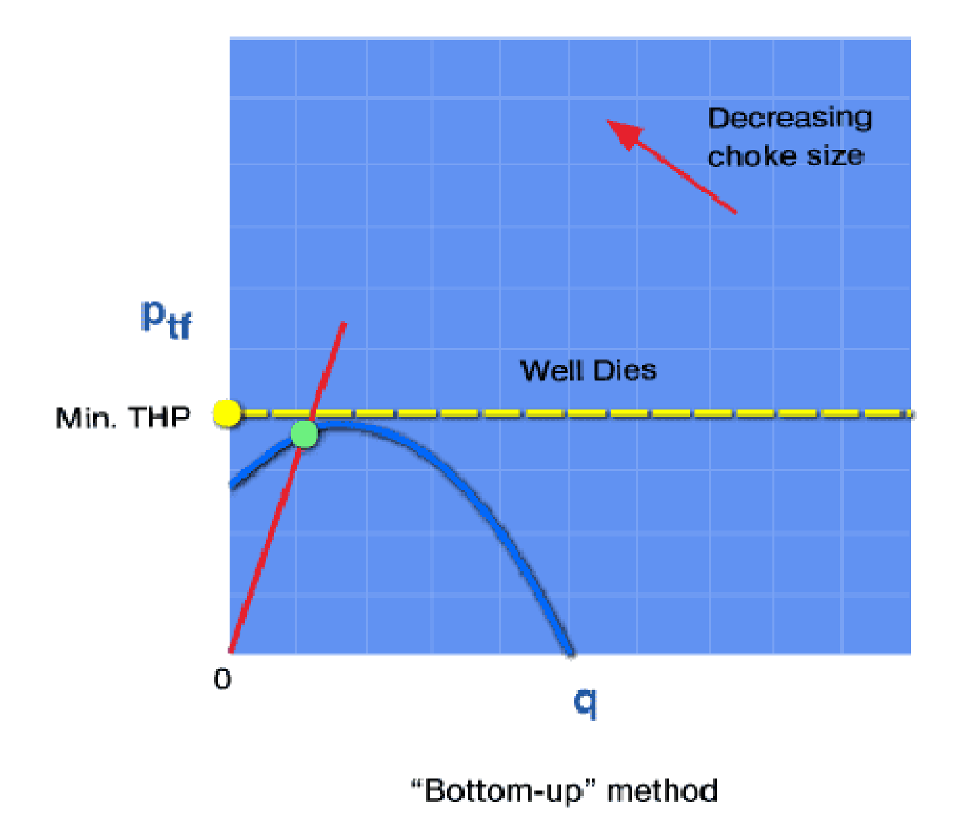


Figure 4

This analysis enables a plot to be made of the production rate from the well under study against the cumulative production from the field or pool. Similar plots are made for each producing well. It is now a simple matter to determine the time required for each cumulative production period and the contribution of each well to that cumulative production. In this way, a complete forecast for the pool, and for each well in the pool, is obtained.

The "top-down" approach is similar, and would be used, perhaps, in a situation in which the production policy was to hold the THP constant at some reasonable minimum value in an attempt to maximize the production rate. The constant THP could be used, in conjunction with the gradient curves, to generate a vertical flow performance versus rate curve. As was shown earlier, the intersection of this curve with the IPR will give the actual production rate to be expected at that THP (Figure 5).

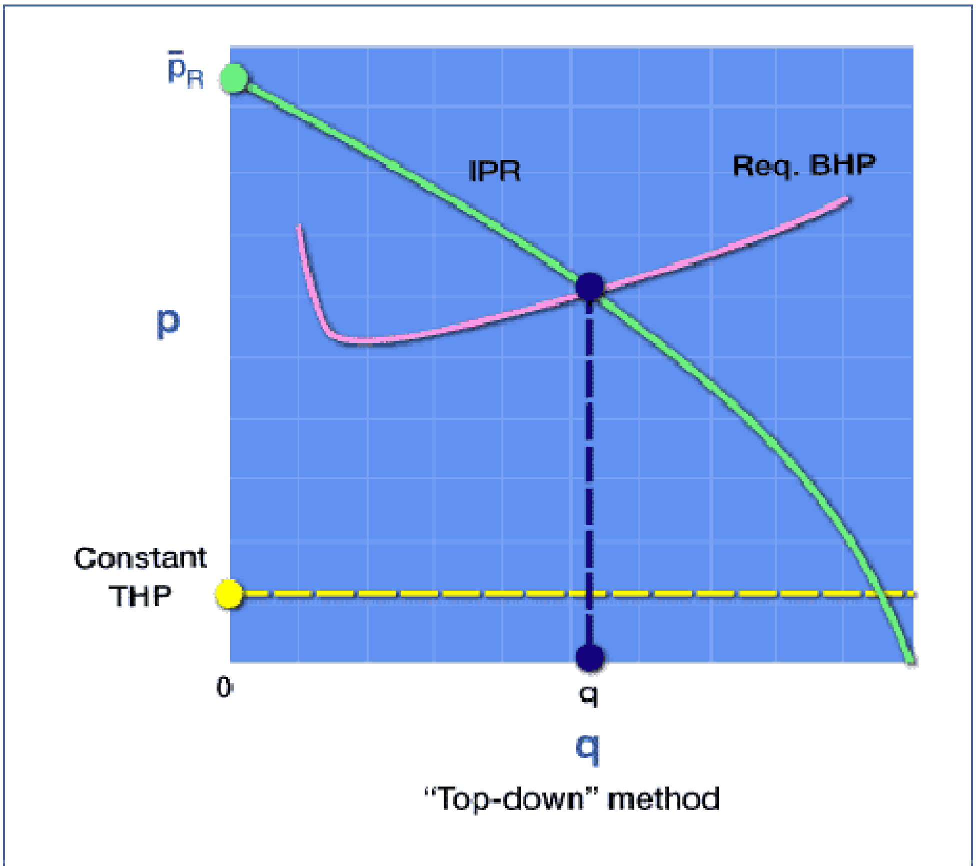
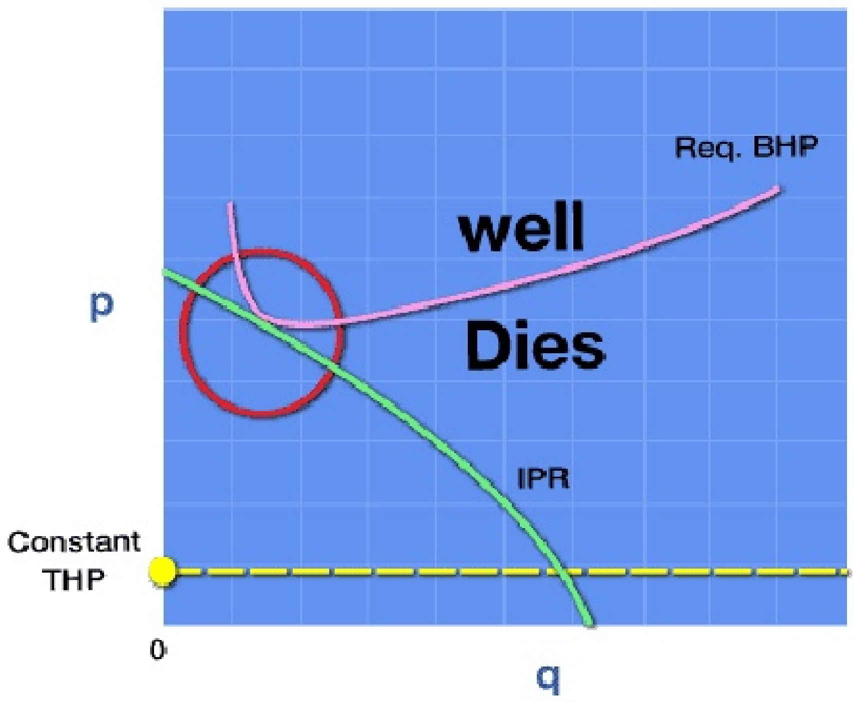


Figure 5

A new assumed value for the average reservoir pressure changes the IPR and the gradient curves used: This process would be continued until a stage was reached at which there was no point of intersection between the "top-down" vertical flow curve and the corresponding IPR. In fact, the well could be expected to die at the stage at which these two curves just touched (Figure 6).



“Top-down” method

Figure 6

The total pool performance is obtained by adding the cumulative production of the individual wells, as just described.

A predictive technique, such as the one discussed, shows the potential of the formation as well as the rate of production at each stage of the life of the flowing well. This information assists in deciding whether or not a high-rate artificial lift technique, such as gas lift, would be a profitable venture and, if so, the optimum time to install such a system. Alternatively, a well may remain on natural flow for as long as practical and then a pumping unit installed. Knowledge of the potential of the formation at the time of introducing the pumping unit will allow us to select the correct type and size and determine the power requirements.

Exo1

A certain well is completed with 7500 ft of 3 1/2-inch tubing in the hole, the tubing shoe being located just above the top perforations. The well is flowing 130 BOPD of oil with a water cut of 25 percent and a GLR of 1200 Scf/bbl.

(a) If the well's average reservoir pressure is 2800 psi and its gross PI is 0.32 B0PD/psi, estimate the size of choke in the flow line.

(b) At what oil rate would the well flow if a 1/2-inch bean were substituted for the current one?

Sol1

The value of the THP at the gross liquid rate of 173 BOPD is 640 psi. Use the following equation:

$$p_{tf} = \frac{600 \times (R^{0.5}) \times q}{S^2}$$

(a) Substituting R. q, and p_{tf}

(b) Substituting 1/2-inch for choke size in equation will give:

$$p_{tf} = \frac{600 \times (0.9)^{0.5} \times q}{\left(\frac{1/2}{1/64}\right)^2}$$

$$p_{tf} = \frac{569.2q}{(32)^2} = 0.556$$

Plotting this line, its intersection with the THP curve gives a flow rate of 450 BOPD.

Exo2

Tests have led to the conclusion that the gradient curves in the flowing wells (all completed with 2 7/8-inch tubing) in the Black Goose field are of the form:

H = 2.5 C q 1n(p/ptf) + 1.25 (p - ptf)

where:

H is the depth in feet below tubing head
q is the liquid production rate in BOPD
p is the pressure (in psi) at the depth
H ptf is the tubinghead pressure in psi

and: C varies with the GLR as illustrated in Figure 1 .

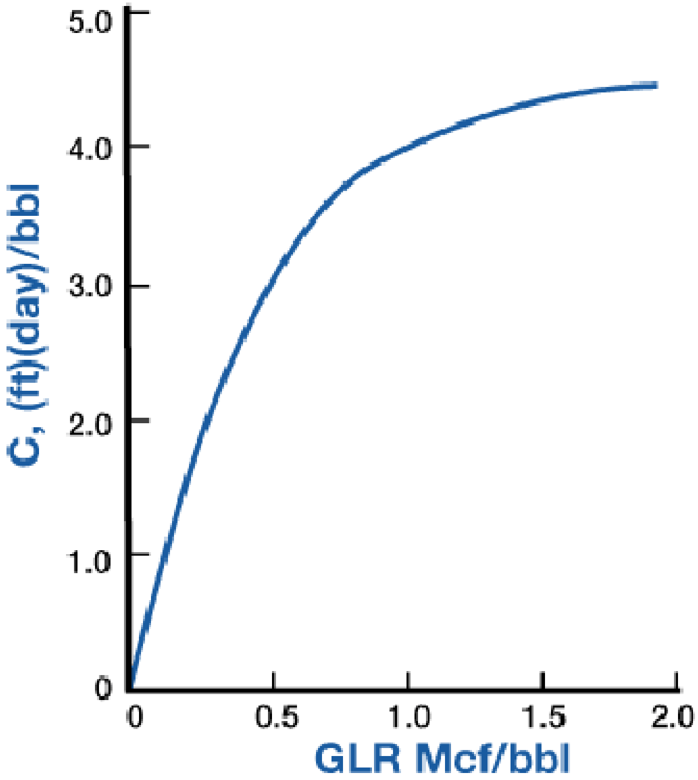


Figure 1

Well A is currently flowing at 1450 BOPD, GLR 350 Scf/bbl, through 10,000 ft of 2 7/8-inch tubing, with a THP of 400 psi. The current average reservoir pressure at 10,000 ft below tubing head is 3200 psi.

The IPR of well A is thought to be of the Fetkovich type, and reservoir analysis predicts that GLR will rise as the average reservoir pressure drops, in the manner shown in Figure 2 .

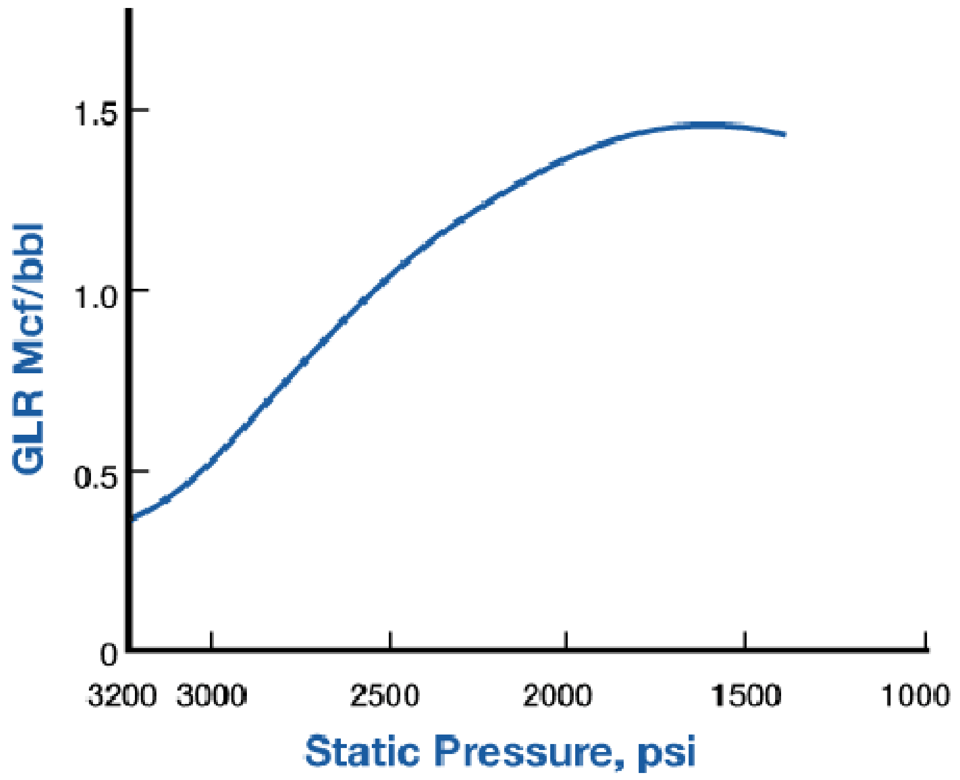


Figure 2

If it assumed that well A will be produced in such a way that the THP of 400 psi maintained throughout the flowing life, determine the future flow rate as a function of average reservoir pressure, and indicate the choke size at each stage. What will be the average reservoir pressure, the flow rate, and the formation potential when the well is on the point of dying?

Solu2

The first step is to find the value of p_{wf} which is the value of the inflow pressure at the foot of the tubing. This is most readily done by plotting gradient pressure p (psi) against depth H (ft) of the tubing, or 10,000 ft. Current values are:

q = 1450 BOPD

GLR = 0.35 Mcf/bbl

C = 2.45 (from Figure 1)

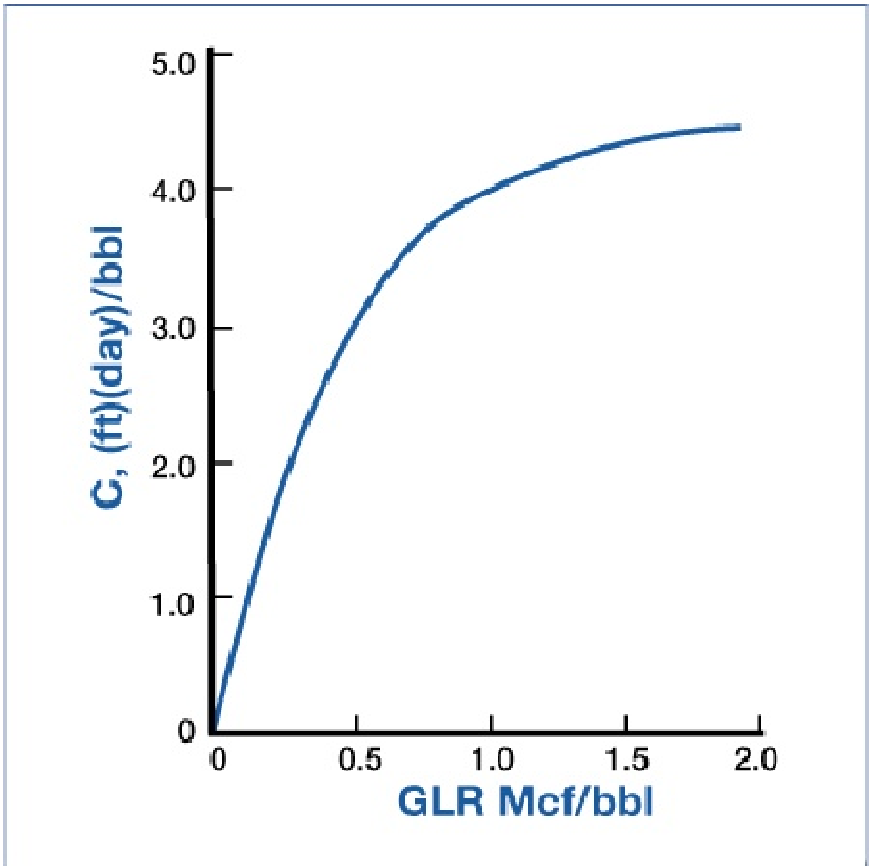


Figure 1

ptf = 400 psi

So the equation of the gradient curve is:

$$H = 2.50q \ \ln\left(\frac{p}{p_{tf}}\right) + 1.25\left(p - p_{tf}\right)$$

$$H = 2.5 \times 2.45 \times 1450 \ \ln\left(\frac{p}{400}\right) + 1.25\left(p - 400\right)$$

$$H = 8881 \ \ln\left(\frac{p}{400}\right) + 1.25\left(p - 400\right)$$

Substituting values of p in the above equation will result in Table 1.

Table 1

p	p/400	ln (p/400)	8881 ln (p/400)	1.25 (p-400)	H
600	1.5	0.405	3,601	250	3,851

800	2.0	0.693	6,156	500	6,656
1000	2.5	0.916	8,138	750	8,888
1200	3.0	1.099	9,757	1000	10,757
1400	3.5	1.253	11,126	1250	12,376
1600	4.0	1.386	12,312	1500	13,812

pwf at 10,000 ft is approximately equal to 1115 psi.

Substituting:

q = 1450 BOPD and pwf = 1115 psi in Fetkovich's equation:

$$q = J'\left(\bar{p}_R^{\,2} - p_{wf}\right)^2$$
$$J' = \frac{1450}{3200^2 - 1115^2} = 0.0001612$$
$$or\ J' = 1.612 \times 10^{-4}\ BOPD / psi^2$$

The value of J' at some future average reservoir pressure can be obtained from the following formula:

$$J'_f = \frac{J'\,\bar{p}_{R\ f}}{p_i}$$

p_i = average reservoir pressure

$$J' = 1.612 \times 10^{-4}\ \frac{\bar{p}_R}{3200}$$

The equation of future IPR is:

$$q = J'_f\left(\bar{p}_R^{\,2} - p_{wf}^{\,2}\right)$$

Substituting different values of average reservoir pressure (3000, 2800, 2700, and 2600 psi, respectively) in equation (1) will yield the following results (table 2).

Table 2

p_i	J'_f
3000	1.511 x 10-4

2800	1.411 x 10-4
2700	1.360 x 10-4
2600	1.310 x 10-4

Column (8) of Table 3 represents the values of present IPR.

Table 3a

(1)	**(2)**	**(3)**
p_{wf}	**$p_{wf}^2/10^4$**	**$(3200^2 - p_{wf})^2/10^4$**
3000	900	124
2500	625	399
2003	400	624
1530	225	799
1000	100	924
500	25	999
0	0	1024

Table 3b

(4)	**(5)**	**(6)**	**(7)**	**(8)**
$(\bar{p}_R^2 - p_{wf})^2/10^4$ at $\bar{p}_R$ =				**q (Present)**
3000	**2800**	**2700**	**2600**	**Column (3) x J'**
0	-	-	-	200
275	159	104	51	643
500	384	329	276	1006
675	559	504	451	1288
800	684	629	576	1489
875	759	704	651	1610
900	784	729	676	1651

Table 4 represents the values of future IPR.

Table 4a

Values of q at p_{wf}	p_{wf} = 3000	p_{wf} = 2800	
		J'_f = 1.511 x 10^{-4}	J'_f = 1.411 x 10^{-4}
		Column (4) x J'_f	Column (5) x J'_f
3000	0		--
2500	416		224
2000	755		542
1500	1020		789
1000	1209		965
500	1322		1071
0	1360		1106

Table 4b

Values of q at p_{wf}	p_{wf} = 2700	p_{wf} = 2600
	J'_f = 1.360 x 10^{-4}	J'_f = 1.31 x 10^{4}
	Column (6) x J'_f	Column (7) x J'_f
3000	--	--
2500	141	67
2000	447	362
1500	685	591
1000	855	853
500	957	755
0	991	886

Results from tables 2, 3, and 4 are plotted in Figure 2 .

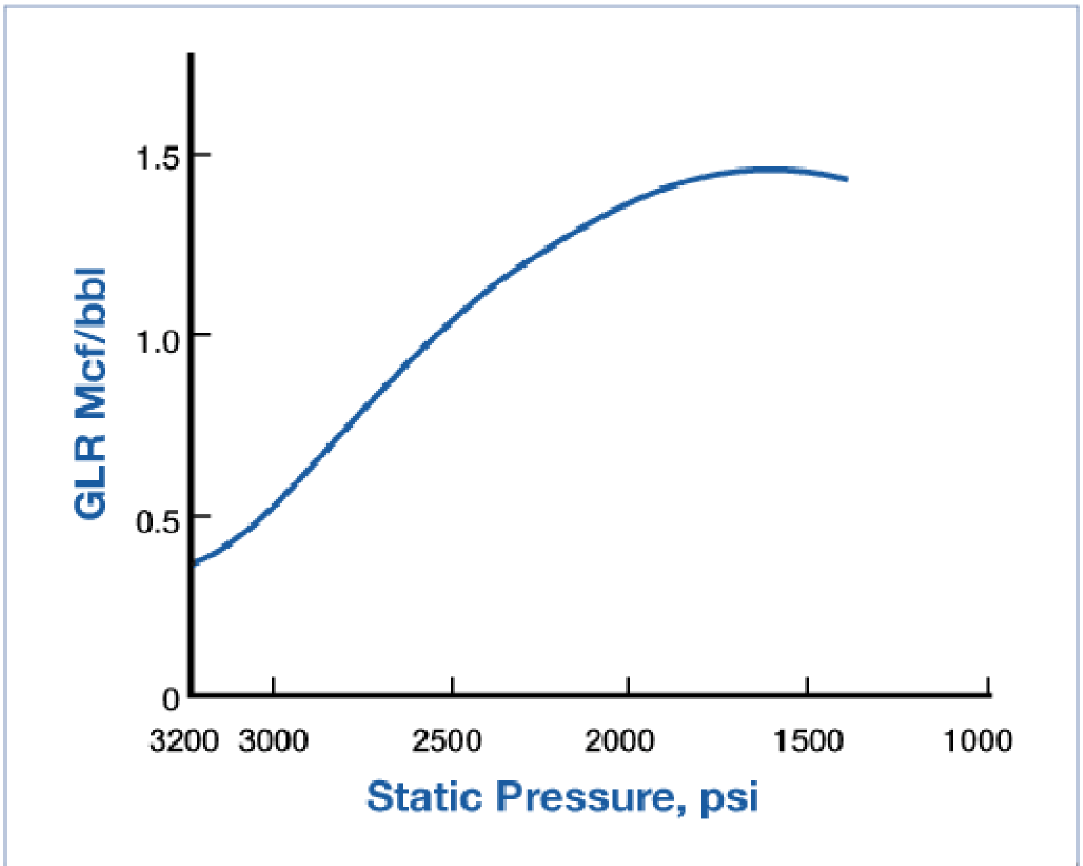


Figure 2

In order to determine the flow rates at a THP of 400 psi, we must plot the p_{wf}-q curves for vertical flow based on a THP of 400 psi at each of the assumed static pressures.

The points at which these curves intersect the corresponding IPR's are the future flowing production points.

The following equation can be used to compute q versus pressure flowing gradient:

$$H = 2.5\ C\ q\ \ln\left(\frac{p}{p_{wf}}\right) + 1.25\left(p - p_{wf}\right)$$

$$\therefore 10{,}000 = 2.5\ C\ q\ \ln\left(\frac{p}{400}\right) + 1.25(p - 400)$$

$$\therefore q = \frac{10{,}000 - 1.25\,(p - 400)}{2.5\ C\ \ln\left(\frac{p}{400}\right)} \qquad (3)$$

Tables 5 and 6 summarize the computation of q versus p_{wf}

Table 5a

p	**In p/400**	**1.25 (p-400)**	**Numerator**
3200	2.08	3500	6500
2800	1.946	3000	7000
2400	1.792	2500	7500
2000	1.609	2000	8000
1600	1.386	1500	8500
1200	1.099	1000	9000
800	0.693	500	9500

Table 5b

Denominator

p_{wf} = 3000	**p_{wf} = 2800**	**p_{wf} = 2700**	**p_{wf} = 2600**
GLR = 0.5	**GLR = 0.7**	**GLR = 0.8**	**GLR = 0.92**
C = 3.0	**C = 3.5**	**C = 3.75**	**C = 3.85**
15.60	18.20	19.50	20.02
14.60	17.03	18.24	18.73
13.44	15.68	16.80	17.25
12.07	14.08	15.08	15.49
10.40	12.13	12.99	13.34
8.24	9.62	10.30	10.58
5.20	6.06	6.50	6.67

Table 6

Production rate q at p_{wf} =

p_{wf} = 3000	**p_{wf} = 2800**	**p_{wf} = 2700**	**p_{wf} = 2600**
417	357	333	325

480	411	384	374
558	478	446	435
663	568	531	516
817	701	654	637
1090	935	871	850
1825	1560	1460	1420

From Figure 2 it is seen that the flow rates will be:

1200 BOPD at 3000 psi

910 BOPD at 2800 psi

700 BOPD at 2700 psi

Moreover, the two relevant curves barely touch at the 2700 psi, while there is no point of intersection at 2600 psi. Thus the well is on the point of dying (400 psi THP) when the average reservoir pressure has fallen to 2700 psi. At that time, the flowing production is 700 BOPD, and the formation potential at this stage is 1000 BOPD.

Finally the choke size required to maintain flow at a THP of 400 psi is given by the equation

$$P_{tf} = \frac{600R^{0.5}q}{S^2}$$

where p_{tf} is held at 400. The choke sizes are shown in table 7

Table 7

p_{wf}	q	R	$R^{0.5}$	S^2	Choke (in)
3200	1450	0.35	0.592	1290	9/16
3000	1200	0.50	0.707	1272	9/16
2800	910	0.70	0.837	1142	17/32
2700	700	0.82	0.906	951	31/64

Exo3

This is a hard and challenging problem. The student can attempt it at the instructor's discretion. A detailed solution is provided. The data shown in Table 1 .

DATA RESULTING from TESTS on WELLS A, B, C and D

Well	Cumulative Oil Production Well, bbl	Cumulative Oil Production Field, bbl	Static Pressure at Datum, psi	Oil Rate, BOPD	Flowing BHP, psi	GLR, scf/bbl	Water Cut, %
A	100,000	1,482,000	2120	630	1470	200	2.0
				460	1720	189	2.2
				380	1880	212	1.7
				460	1200	1180	0.0
B	200,000	1,482,000	2120	320	1530	1180	0.0
				235	1700	1140	0.2
				520	2720	121	10.3
C	621	621	3000	420	2820	193	8.7
				360	2882	210	4.5
				180	820	1116	0.2
C	330,000	3,426,000	1520	120	1160	1141	0.2
				90	1240	1132	0.3
				340	1190	1863	0.0
D	170,000	2,471,000	1790	200	1390	1869	0.0
				220	1470	1855	0.0
				115	650	622	0.2
D	370,000	4,600,000	1300	90	840	641	1.3
				60	960	629	0.2

Table 1

have been obtained from a series or test on four wells (A, B, C, and D) in a certain field.

By analogy with gaswell performance a reasonable assumption might be that the production rate, q, is related to the drawdown (p_R - p_{wf}) by an equation of the form:

$$q = k(p_R - p_{wf})^n$$

where *k* and *n* are constants in any particular test but may vary from test to test. It is further postulated that there is a relationship between the values of *k* and the values of *n*.

Using a log-log plot of production rate against drawdown to determine *k* and *n* values for each of the six tests, construct a graph of *log k* as a function of *n* and hence construct a regular grid on log-log paper of production rate against drawdown for values of *n* equal to 0.4, 0.5, 0.6, 0.7, and 0.8.

Table 2

Additional data on Well E (Well E was completed without a tubing-casing packer in the hole.)

Well's **Average** **CHP**

cumulative Production (bbl)	Reservoir Pressure (psi)	Oil Rate (STB/D)	GLR (SCF/bbl)	(psi)
0	3100			
150,000	440	550	1947	
160,000	300	700	1925	
200,000	2440			
260,000	350	2000	1620	

Well E is currently flowing on 2 3/8-inch tubing at 200 BOPD of clean oil, GLR 700 Scf/bbl, through a 1/4-inch choke. This well is perforated from 8003 to 8021 ft, and the tubing is hung at 8000 ft. The well's cumulative production to date is 460,000 bbl, and the current static pressure at the datum of 8000 ft is 1750 psi. The initial flowing BHP on Well E was 2910 psi at a production rate of 540 BOPD, GLR 200 Scf/bbl. Some additional data from well E are listed above in Table 2.

Plot the current IPR for Well E. What is the well's potential at the present time?

For Well E prepare a graph showing the variation in average reservoir pressure and in GLR with cumulative oil production from the well. On the same graph, plot the production rate that would have been obtained from the well if it had been produced at a constant drawdown of 100 psi. Extrapolate these three curves to higher cumulatives as well as possible, and use these extrapolated curves to answer the following questions:

1. What would have been the production rate from the well at a draw-down of 600 psi when its cumulative production was 100,000 bbl?
2. What will be the future flowing life history of this well on 2 3/8-inch tubing, assuming that the THP is maintained at 100 psi?
3. What will be the well's maximum inflow potential when it ceases to flow, and what percentage of this potential will it actually be making immediately prior to dying?
4. The problem can be solved in the following steps:
5. Use data of Table 1 to plot rate against drawdown on log-log paper.

DATA RESULTING from TESTS on WELLS A, B, C and D

Well	Cumulative Oil Production Well, bbl	Cumulative Oil Production Field, bbl	Static Pressure at Datum, psi	Oil Rate, BOPD	Flowing BHP. psi	GLR. scf/bbl	Water Cut. %
A	100,000	1,482,000	2120	630	1470	200	2.0
				460	1720	189	2.2
				380	1880	212	1.7
				460	1200	1180	0.0
B	200,000	1,482,000	2120	320	1530	1180	0.0
				235	1700	1140	0.2
				520	2720	121	10.3
C	621	621	3000	420	2820	193	8.7
				360	2882	210	4.5
				180	820	1116	0.2
C	330,000	3,426,000	1520	120	1160	1141	0.2
				90	1240	1132	0.3
				340	1190	1863	0.0
D	170,000	2,471,000	1790	200	1390	1869	0.0
				220	1470	1855	0.0
				115	650	622	0.2
D	370,000	4,600,000	1300	90	840	641	1.3
				60	960	629	0.2

Table 1

6.

Draw in the straight line that best fits the results from each well (shown in Figure 1).

ADDITIONAL DATA on WELL E*

Well's Cumulative Production, bbl	Average Reservoir Pressure, psi	Oil Rate BOPD	GLR scf/bbl	CHP psi
0	3100			
150,000		440	550	1947
160,000		300	700	1925
200,000	2440			
260,000		350	2000	1620

*WELL E was completed without a tubing-casing packer in the hole

Figure 1

7.

8. Determine the value of J and *n* as defined by the following equation:

9. $$q = k(\bar{p}_R - p_{wf})^n$$

10. Solve for simultaneous equations of different wells: log q = log k + n log

11. $$(\bar{p}_R - p_{wf})$$

12. Determine, from one of the choke-performance equations, the current THP, and hence, the flowing BHP of Well E.
13. Locate the values of Well E (production rate and BHP) on the plot of step 1, and draw in the straight line representing the IPR of Well E. Use this line to plot the IPR of Well E on a regular graph (see Figure 2). The present open flow potential of 700 BOPD may also be read off from the same figure.

Additional Data on Well E*

Well's Cumulative Production, bbl	Average Reservoir Pressure, psi	Oil Rate BOPD	GLR scf/bbl	CHP psi
0	3100			
150,000		440	550	1947
160,000		300	700	1925
200,000	2440			
260,000		350	2000	1620

*WELL E was completed without a tubing-casing packer in the hole

Figure 2

14.

15. Use given data from Table 2 and plot average reservoir pressure and GLR against the well's cumulative production.

DATA RESULTING from TESTS on WELLS A, B, C and D

Well	Cumulative Oil Production		Static Pressure at Datum, psi	Oil Rate, BOPD	Flowing BHP, psi	GLR, scf/bbl	Water Cut, %
	Well, bbl	Field, bbl					
A	100,000	1,482,000	2120	630	1470	200	2.0
				460	1720	189	2.2
				380	1880	212	1.7
				460	1200	1180	0.0
B	200,000	1,482,000	2120	320	1530	1180	0.0
				235	1700	1140	0.2
				520	2720	121	10.3
C	621	621	3000	420	2820	193	8.7
				360	2882	210	4.5
				180	820	1116	0.2
C	330,000	3,426,000	1520	120	1160	1141	0.2
				90	1240	1132	0.3
				340	1190	1863	0.0
D	170,000	2,471,000	1790	200	1390	1869	0.0
				220	1470	1855	0.0
				115	650	622	0.2
D	370,000	4,600,000	1300	90	840	641	1.3
				60	960	629	0.2

Table 2

16.

Extrapolate these curves to higher values. (see Figure 3)

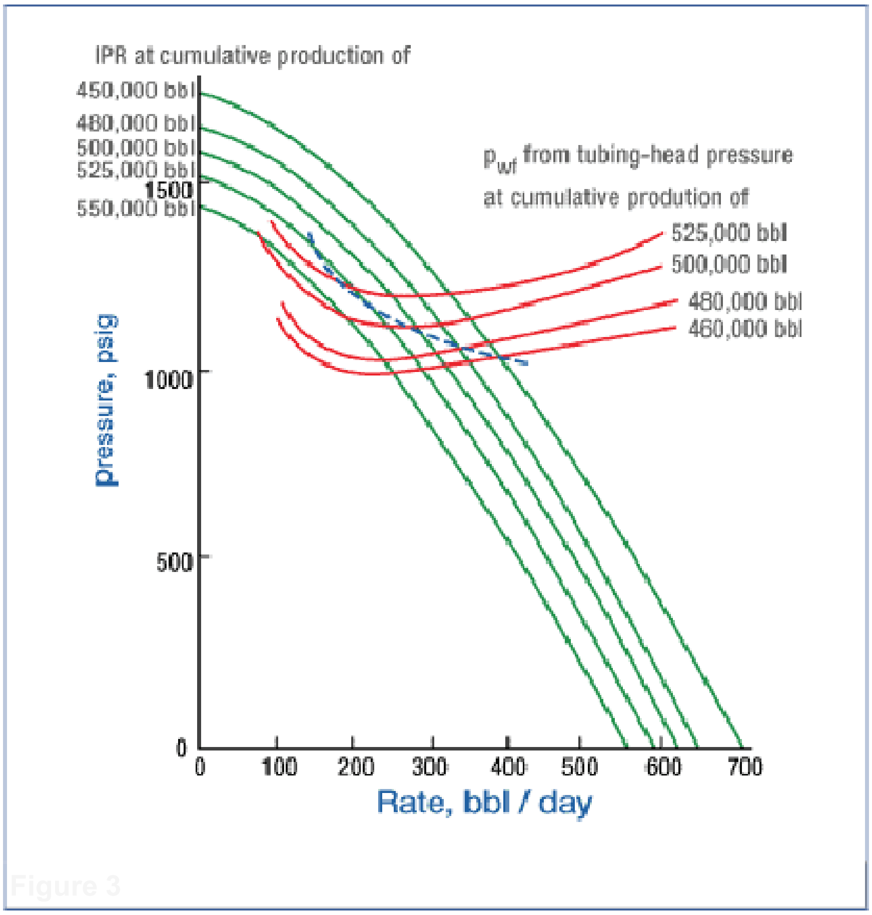


Figure 3

17.

18. Plot on Figure 3 the production rate at the reference drawdown of 100 psi against cumulative production and extrapolate the curve. These points may be obtained from the data presented at cumulatives of 0, 150,000, 160,000, and 260,000 bbl. Table 2 shows an oil rate of 300 BOPD and a value of pwf determined from the CHP through the equation:

$$P_{wf} = p_c\left(1 + \frac{D^{1.5}}{100}\right)$$

19.
20. of 2363 psi. From the average reservoir pressure line of Figure 3 , p_R at this cumulative for Well E is 2620 psi, so that the drawdown at 300 BOPD is 257 psi. Locate this point on the plot of step 1 and interpolate the corresponding IPR line. This cuts the p = 100 line at q = 180 BOPD.
21. To determine the production rate from when its cumulative production was 100,000 bbl, read off q10O at 100,000 bbl from Figure 3 ; this is 293 BOPD.
22. Go back to the q-Δp log-log plot. Draw the corresponding line and determine the value of q (660 BOPD) when p = 600 psi.
23. To determine the future flowing life, first choose some future regular cumulative production steps, for example, 480,000 bbl, 500,000 bbl, and so forth. Read off the corresponding values of q_{100} from Figure 2 . Locate the points on the plot of step 1. Read off a series of rate versus drawdown values for each line. Since the value

of $\overline{p}_R$ at each cumulative may be obtained from Figure 3 , the IPR curve at each assumed cumulative may be plotted (see Figure 2).

24. Considering now, for example, the situation at a cumulative of 460,000 bbl, the GLR may be obtained from Figure 3 , and so the curve of pressure at the tubing shoe (assuming 100 psi THP) may be plotted on Figure 2 . The intersection with the IPR gives the flowing production rate (390 BOPD).
25. This process is continued at increasingly higher assumed cumulatives until no intersection occurs. This situation is reached at a cumulative slightly in excess of 525,000 bbl (Figure 2) at which point the well dies.

Sol1