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An Economic Model for Assessing the Feasibility of Multilateral Wells

Abdel-Alim H. El-Sayed, M. N. J. Al-Awad, M. S. Al-Blehed and M. A. Al-Saddiqui
Pete. Eng. Dept., King Saud Univ., P.O. Box 800, Riyadh 11421
Saudi Arabia

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Abstract. This paper presents an economic model developed for assessing the feasibility of drilling multilateral wells for exploiting oil reservoirs. Detailed equations are derived for calculating the cost, return on investment and discounted net present value over the production life of the oil reservoir. Equations for calculating production rate and predicting the future production performance of multilateral wells have been introduced. A comparison between horizontal well and multilateral wells is also included. A computer program has been written to perform production forecasting and economical evaluation of oil reservoirs for any given reservoir characteristics developed by multilateral wells. The model is used for choosing the best technique needed to develop oil reservoirs taking into consideration the maximum profit of the investment.

Nomenclatures

R_F = recovery factor
CC = cumulative production costs, dollars
CSR = cumulative sales revenue, dollars
CGP = cumulative gross profit, dollars
ROI = return on investment, dimensionless
Q = total hydrocarbon production rate, STB/day
SP = oil sales price, dollars/STB
LC = lifting costs, dollars /STB
LGC = logistics costs, dollars
DC = drilling costs, dollars
PWF = present worth factor, dimensionless
T = cumulative production time, days
t = time, days
NPV = discounted net present value, dollars

GP_i	=	gross profit evaluated at present time from i-th time step, dollars
SP_i	=	oil sale price at the i-th time step, dollars/STB
LC_i	=	lifting costs at the i-th time step, dollars/STB
r	=	interest rate per annum compounded continuously, dimensionless
SP_p	=	oil sale price at the time, dollars/STB
LC_P	=	lifting costs at present time, dollars/STB
q	=	annual inflation rate, dimensionless
N_t	=	T/Δ, total number of time steps
i	=	number of time steps elapsed

Introduction

During the last decade, significant advances in drilling technology have made it possible to drill horizontally. Due to the major developments in drilling equipment, reservoir monitoring, and survey techniques, drilling and completion of horizontal wells is now an easy task. However, for a successful field operation, a drilling method should be chosen based upon reservoir considerations [1].

Horizontal wells are normally new wells, 1000 to 3000 ft long, which are drilled from the surface. Lateral holes are generally drilled from the existing vertical wells and are 100 to 700 ft long. One can drill either a single lateral hole or multiple lateral holes through a single vertical well. In this work the term horizontal well refers to new horizontal well, and lateral hole refers to holes drilled from existing vertical well [1].

In general, horizontal wells are found effective in thin reservoirs, some naturally fractured reservoirs, tight reservoirs, and in reservoirs with gas and water coning problems. Horizontal wells highlighted the requirement for better reservoir description, to both understand well performance, and to improve well placement. In general however, most completion issues concerned what type of liner to run and how best to clean-up the well. Multilateral wells add an additional level of complexity, in that well branch interactions now also need to be taken into account. These are functions of branch inflow performance, and completion performance between the sandface and well junction points, and both factors need to be considered when designing the well, particularly in low pressure heavy oil environments [3].

Lateral holes possess popularity these days where the advanced technology help drilling these lateral holes without successive problems. The desire within the petroleum industry to improve profitability through cost reduction and the advent of advanced drilling and completion technology have combined to raise the awareness of Multilateral technology. Multilateral wells are defined as wells having one or more branches (laterals) tied back to a mother wellbore which conveys fluid to or from surface. The technology is not new; the first wells were drilled in the former Soviet Union in the 1950's. These, however, encompassed simplistic completions unlike the complex completion configurations on other conventional wells at the present time. In some cases the completion system is able to offer full hydraulic isolation at the junction point coupled with selective re-entry capability for each individual lateral [4,5].

Horizontal wells and lateral holes represent wells with limited fracture height, where fracture height is equal to the wellbore diameter. A properly designed horizontal well would be equivalent to a vertical well with a fully penetrating fracture. A horizontal well represents a long, controlled vertical fracture. In most fracture jobs it is difficult to obtain infinite conductivity and, moreover fracture conductivity decreases over time. In contrast, a horizontal wellbore offers an almost permanent infinite conductivity fluid flow path. Additionally, in reservoirs where the bottom water or top gas cap renders fracturing difficult, a horizontal well offers an alternative to obtain high production rates without gas and water coning. A horizontal well offers a viable completion option and will compete fracturing operations [2].

Multilateral wells offer innovative and economical ways to produce hydrocarbons. Economic analysis on Forties field, North Sea fields, shows that for in-fill drilling, the cost to drill and complete a dual lateral well is less than the cost to re-drill two wells and becomes particularly attractive on platforms where the number of available well slots is limited. Until recently, however, the application of wells was limited to wells that did not require through tubing reservoir access for stimulation or water, scale and sand management [6].

Recent successes in the USA, Western Canada and the North Sea have provided increased publicity for multilateral technology with an increasing number of companies offering a wide variety of drilling and completion systems. The current enthusiasm of multilateral wells is often based on perception of the associated benefits and not on a rigorous evaluation. The decision to drill a lateral well must, like any other project, make good economic sense. The analysis preceding this decision must incorporate robust cost models, accurate prediction of well performance, and a realistic risk assessment evaluation [6,7].

To help arrive at the drilling decision, a certain process must be followed. Asset screening should first occur to assess the applicability of well types for the particular project in question. Performance prediction must be evaluated and can be done via an integration of numerical and analytical techniques. Risk assessment should be carried out, in terms of both reservoir risk and completion risk. Finally the economics of the project must be studied in order to quantify the viability of wells [4].

The study of the feasibility of such lateral holes is scare in the literature. In this work a feasibility study of multilateral wells in comparison to horizontal well will be emphasized. Also, an economical model based on production rate and production forecasting of horizontal well and multilateral wells is developed. This model will help decide the selection of multilateral wells or horizontal well to develop oil reservoirs.

Mathematical Background

Productivity from horizontal well and multilateral wells

Figure 1 shows a schematic diagram of a horizontal well and lateral holes. Giger [8], Borisove [9] and Murkulov [10] have reported mathematical analyses of the horizontal well problem. Since then, several papers have reported single-phase flow results for steady state and transient (well testing) conditions. For steady state, single-phase flow in an infinite reservoir with constant pressure at the wellbore and lateralage radius, the following equation is used to calculate oil production from a horizontal well [8].

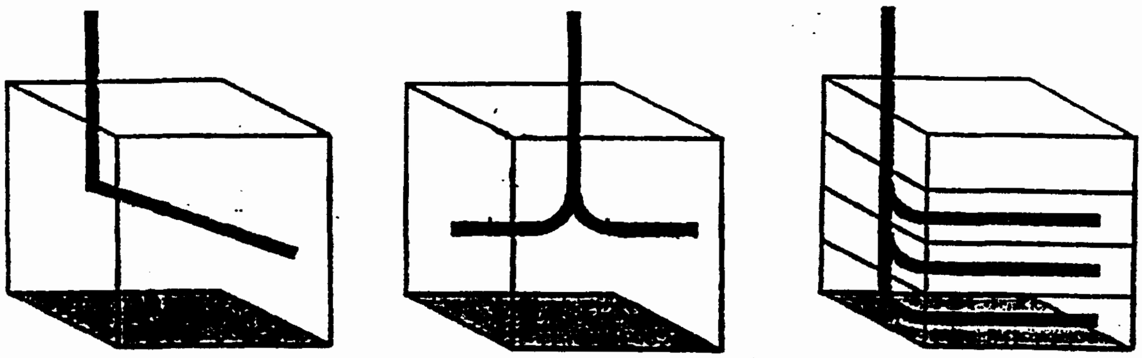

Fig. 1. Horizontal and multilateral well types currently in use.

$$Q_H = \frac{0.00707k\beta h\Delta p/(\mu B_o)}{\ell n\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right]+\frac{\beta h}{L}\ell n\left[\frac{(\beta h/2)^2+\beta^2\delta^2}{\beta h r_w/2}\right]} \qquad (1)$$

for $L > \beta h$, $\delta < h/2$ and $L < 0.9\ r_{eh}$

In the above equation, $\beta = \sqrt{k_v/k_h}$ and δ represents the vertical distance of a horizontal well from the reservoir mid-height. The units in Eq. (1) are standard oil field units with Q_H in STB/day; k is oil permeability in mdarcy; h reservoir thickness in ft, a factor given by the following equation, r_w well radius in ft, and δ height of well from reservoir midpoint in ft, μ is oil viscosity in centipoise; and B is in RB/STB.

Moreover, a is defined as:

$$a = 0.5L\left[0.5 + \sqrt{0.25 + \left(2r_{eh} / L\right)^4}\right]^{0.5} \tag{2}$$

Slight variations of Eq. (1) are available in the literature.

An effective wellbore radius represents a wellbore radius of a vertical well, which produces at the same rate as a single horizontal well. Comparing Eq. (1) with the standard unstimulated vertical well equation, we can show that for a horizontal well located at the reservoir mid-hight,

$$r_{w,eff} = \frac{0.5r_{eh}L / a}{\left[1 + \sqrt{1 - \left(0.5L / a\right)^2}\right]\left[0.5\beta h / r_w\right]^{\beta h / L}} \tag{3}$$

The effective wellbore radius can be used to calculate ratios of productivities of horizontal and unstimulated vertical wells and skin factors S_h:

$$J_h / J_v = \ell n(r_{eh} / r_{w,eff}) \tag{4}$$

and

$$S_h = -\ell n(r_{w,eff} / r_w) \tag{5}$$

Assuming the same lateralage radius for horizontal and vertical wells, productivity improvement ratio can be calculated using Eq. (4).

In practice, several horizontal wells can be drilled like the spokes of a wheel from a single spudding location. Such a configuration is more likely in offshore development. When horizontal wells originate from a single point, Borisov [9] has suggested the following equation to calculate oil production from multilateral wells:

$$Q_{LP} = \frac{0.00707kh\Delta P / (\mu B)}{\ell n\left(F\frac{r_e}{L}\right) + \frac{h}{nL}\ell n\left(\frac{h}{2\pi r_w}\right)} \tag{6}$$

where n represents the number of spokes (laterals) and F=4, 2, 1.86 and 1.78 for n=1, 2, 3 and 4, respectively. In actual drilling operations, all horizontal wells will not originate from a single point as assumed in the above analysis. Depending upon the drilling method employed and its turning radius, there will be some distance between the spudding point and a point at which the well enters the reservoir. This distance will give a smaller interference effect than that indicated by Eq. (6). Borisove [9] and Clonts and Ramey [12] have solved this problem. If m represents the number of levels or elevations at which lateral holes are drilled and if H represents reservoir thickness lateraled by each lateral hole, then total reservoir height $h=Hm$. Equation (6) can be modified to account for stacked lateral holes as:

$$Q_{LS} = \frac{0.00707kh\Delta P/(\mu B)}{\ell n \frac{r_e F}{L} + \frac{h}{Lmn} \ell n[\frac{h}{2\pi m r_w}]} \tag{7}$$

where F is calculated from values given below Eq. (6).

In field operations, if the total horizontally drilled footage, i.e., product Lmn, is constant, then to produce the reservoir, one can use different combinations of well lengths, number of lateral hole levels, and number of lateral holes at each level. It can be shown mathematically that if $L>h$, then maximum productivity in a given reservoir is obtained by drilling the single (or two diametrically opposite) longest possible horizontal well or lateral hole [6].

Production forecasting of horizontal wells and multilateral wells

In many reservoirs very little is known about reservoir properties. In these types of reservoirs, a simple production forecasting method is needed. Equations (1, 6 and 7) allow us to calculate the production rate based upon pressure drop between the well bore and the reservoir lateral boundary. Over time, as the reservoir starts depleting, the initial pressure drop starts reducing. The law of conservation of mass indicates that the pressure drop should be proportional to the amount of fluid withdrawn from the reservoir. Thus, the available pressure drop in the reservoir has to be proportional to cumulative oil production. Therefore, the production rate can be calculated as [13]

$$Q_H = \frac{[0.00707k_h h\Delta p/(\mu B_0)]\left[1 - \frac{N_P}{NR_F}\right]}{\ell n\left[\frac{a + \sqrt{a^2 - (l/2)^2}}{L/2}\right] + \frac{\beta^2 h}{L} \ell n\left[\frac{h}{2r_w}\right]} \tag{8}$$

where N_P represents cumulative production in barrels at time t, N represents original oil in place, and R_F represents recovery factor. In the above equation N is calculated as:

$$N = \pi re_h^2 h\, \phi\, [1 - S_w] \tag{9}$$

For planar laterals drilled in an oil reservoir the following equation is to be used to predict the production rate as a function of pressure drop and the cumulative production.

$$Q_{LP} = \frac{0.00707kh\Delta P/(\mu B)[1-\frac{Np}{NR_F}]}{\ell n\left(F\frac{r_e}{L}\right)+\frac{h}{nL}\ell n\left(\frac{h}{2\pi r_w}\right)} \tag{10}$$

For stacked laterals the following equations is to be used for production forecasting:

$$Q_{LS} = \frac{0.00707kh\Delta P/(\mu B)[1-\frac{Np}{NR_F}]}{\ell n\{\frac{r_{eh}F}{L}\}+\frac{h}{Lmn}\ell n[\frac{h}{2\pi m r_w}]} \tag{11}$$

The recovery factor R_F is based upon the local experience with vertical wells. The table prepared by Arps and Roberts [14] and Kurtz [15] (see Tables 1 and 2) can be used to estimate the recovery factor. Although the table is prepared assuming the economic limit to be 19% of the bubble point pressure, it could be used for recovery factor estimation under the present single phase flow assumption.

To be obtaining a production forecast, equations (8-10 and 11) can be solved iteratively by assuming a fixed flow rate for a limited time interval (15-30 days). The reservoir pressure is calculated using the decline curve methods based on material balance equation. The following equation is used to predict the reservoir pressure in relationship to the cumulative produced oil [16]:

$$P_r = P_{ri} - [P_{ri}/N_{pi}]\, N_p \tag{12}$$

In the above procedure, the initial production rate is almost constant. This initial constant production is happen during the transient time, i.e., up to a point in time where the well pressure disturbance reaches the lateral boundary.

Economic Evaluation of Horizontal Well and Multilateral Wells

Objective functions

The objective of any economic analysis is to minimize the cost and/or maximize the profit of an industrial operation. In the petroleum industry, the cumulative production costs, cumulative sales revenue, cumulative gross profit, return on investment, and cumulative net profit may be expressed as follows when evaluated at present time [15, 17].

$$CC = \int_{O}^{T} Q\ (LC)\ (PWF)\, dt \tag{13}$$

$$CSR = \int_{O}^{T} Q\ (SP)\ (PWF)\, dt \tag{14}$$

$$CGP = \int_{O}^{T} Q\ (SP - LC)\ (PWF)\, dt \tag{15}$$

$$ROI = \frac{\int_{O}^{T} Q(SP-LC)(PWF)dt}{LGC+DC} \tag{16}$$

$$\begin{aligned} NPV &= \int_{O}^{T} Q\ (SP - LC)\ (PWF)\, dt - (LGC + DC) \\ &= (ROI - 1) \times (LGC + DC) \end{aligned} \tag{17}$$

For a given reservoir and a given drilling plan, the logistics and drilling costs can be considered as a fixed amount of capital invested. The oil production rate Q from reservoir is a function of time. Its profile can be generated in the process of a production forecasting. The crude oil sale price SP and the lifting costs LC are also functions of time since they are affected by inflation rate, implementation of new technology, as well as political and economic situations. In addition, the law of diminishing returns indicates that the lifting costs tend to increase with time as reservoir is depleted. However, the functional representation of these variables is usually difficult to obtain analytically. As a result, the objective functions given by equations (13 to 16) cannot be optimized using standard calculus techniques. In the discussion below, a unique approach, compatible with the production forecasting analyses discussed earlier, is taken to obtain detailed economic evaluation equations [17]

A detailed economic evaluation model

It is assured in the development of the production-forecasting model that the production of a reservoir can be approximated by a succession of pseudo-steady states. Hence, Q, SP, and LC may be treated as constants within each pseudo-steady state, i.e. a time step Δt. Further assume that profit received at any time is immediately reinvested at an interest rate of r per annum compounded continuously. As a result, the cash flow during i-th time step constitutes a uniform series of payments. The periodic is Q_1 [SP_1 - LC_1], and the number of payments has the same numerical value as Δt. Hence the gross profit during the i-th time step, when evaluated at present time, is given as [17]:

$$GP_l = \frac{Q_l\left[SP_l - LC_l\right]}{e^{\left(\frac{i\Delta tk}{365}\right)}}\left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1}\right] \tag{18}$$

The oil sales price SP is fluctuating with time. Any crude price predictions cannot be made without uncertainties. However, in a stable economic and political environment, one may assume that oil sale price and lifting costs are only functions of inflation rate. Furthermore, the inflation rate is assumed to remain constant during the producing life of a reservoir. Therefore, the values of SP_l and LC_l in equation (18) can be evaluated as [17]:

$$SP_l = SP_p e^{\left(\frac{i\Delta tq}{365}\right)} \tag{19}$$

$$LC_l = LC_p e^{\left(\frac{i\Delta tq}{365}\right)} \tag{20}$$

substituting equations (19) and (20) into equation (18), one obtains:

$$GP_l = \frac{Q_l\left[SP_P - LC_P\right]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}}\left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1}\right] \tag{21}$$

Therefore, the cumulative gross profit from the production of a reservoir as given by equation (20) can be approximated as:

$$CGP = \int_0^r Q[SP - LC](PWF)dt = \sum_{r-1}^{N_2} \frac{Q_l\left[SP_p - LC_p\right]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}}\left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1}\right] \tag{22}$$

Similarly, one can easily show that the cumulative production costs and cumulative sales revenue as given by equations (13) and (14) can be approximated respectively as:

$$CC = \int_0^r Q[LC](PWF)dt = \sum_{r-1}^{N_2} \frac{Q_1[LC_p]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}} \left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1} \right] \tag{23}$$

$$CSR = \int_0^r Q[SP](PWF)dt = \sum_{r-1}^{N_2} \frac{Q_1[SP_p]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}} \left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1} \right] \tag{24}$$

Substituting equation (21) into equation (15),one can obtain the detailed expression for the return on investment as:

$$ROI = N \int_0^r Q[SP-LC](PWF)dt = \frac{\displaystyle\sum_{r-1}^{N_2} \frac{Q_1[SP_p-LC_p]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}} \left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1} \right]}{LGC+DC} \tag{25}$$

The corresponding expression for the discounted net present value can be obtained by substituting equation (21) into equation (16) as:

$$NPV = \sum_{r-1}^{N_2} \frac{Q_1[SP_p-LC_p]}{e^{\left(\frac{i\Delta t(r-q)}{365}\right)}} \left[\frac{e^{\left(\frac{\Delta tr}{365}\right)}-1}{e^{\left(\frac{r}{365}\right)}-1} \right] \tag{26}$$

Equations (23), (25) and (26) can be used to generate profiles of cumulative production costs, return on investment, and discounted net present value for the production of a hydrocarbon reservoir when the total function of time is given from a production forecasting analysis. The selection of an optimal drilling scheme for a new reservoir can be made by a comparative economic evaluation of the reservoir performance under various drilling scenarios. The optimal drilling scheme, which results in the most attractive economic results, can be easily identified from the profiles of cumulative production costs, return on investment, and/or discounted net present value for the different drilling alternatives [17]

Once the optimal drilling plan is selected, optimization process can be further used to obtain the optimum schemes in production planning and reservoir management. Identifying the optimal points on the profiles corresponding to the optimal drilling scheme can do this.

In some cases involving relatively simple production processes, analytical optimization may be performed if some of the variables inside the integration terms in equation (13) through (15) can be approximated by analytical functions.

Results and Discussion

Productivity of multilateral wells

The productivity of lateral wells has been calculated using equations (6 and 7). Equation (6) is used to calculate the production rate from planar laterals (laterals drilled at the same depth) whereas equation (7) is used for stacked laterals (laterals drilled at different depths). The results of these two equations are compared with the values obtained for a horizontal well calculated by equation (1). It was found that there are many factors affecting the ratio of multilateral production rate to production rate of a horizontal well. These factors are number of laterals, formation thickness, drainage area, and permeability factor. The effects of these factors are illustrated in Figures 1 to 4 and will be discussed below.

Figures 2 and 3 show the production ratio in relationship to formation thickness and number of laterals for planar and stacked laterals. Figure 2 is for planar laterals at same area, same permeability ratio and same horizontal length. The length of the lateral is assumed to be half the horizontal well length. It shows that increasing the number of laterals to two highly affect the production ratio of the multilateral wells while increasing the number to three or four laterals has slight increase on the production ratio. This can be contributed to the interference in the drainage area of laterals by increasing their number. Also, two laterals can be considered as optimum and three laterals as maximum to be drilled from a well.

Figure 4 shows nearly the same results for stacked laterals. The only exception to be noted is that the production ratio of the stacked lateral is lower than that of planar laterals for thin formation and higher for thick formation. It is to be noted that the stacked laterals are drilled in the same reservoir. For thin formation the stacked laterals will be shifted from the midpoint of the formation to the top or to the bottom which allows non-uniformity in the drainage area and brings low production rate. However in thick formation this effect can be neglected and the stacked lateral reduces the interference in the drainage areas. It can be concluded also that two laterals are optimum numbers to be drilled from a well and three are maximum numbers to be drilled from a well. Stacked laterals are more effective in thick reservoirs.

Reservoir drainage area plays an important role in selecting lateral techniques. It greatly affects the lateral length to be drilled. Figure 5 shows the effect of the drainage area for both planar and stacked laterals. It shows that increasing the drainage area does not increase the production ratio. Also, there is sharp drop in production ratio with the stacked lateral in comparison to the planar laterals. This can be contributed to the results obtained before in a previous publication [18]. It showed that increasing the horizontal length after certain value does not affect the production rate. Also, increasing the length will affect the pressure drop due to friction in the well and reduces the production rate.

This pressure drop in the stacked laterals can be higher than that in the planar laterals. Therefore, it can be concluded that increasing the drainage area will tend to increase the lateral length that will tend to increase the pressure loss in the well and reduces the production rate.

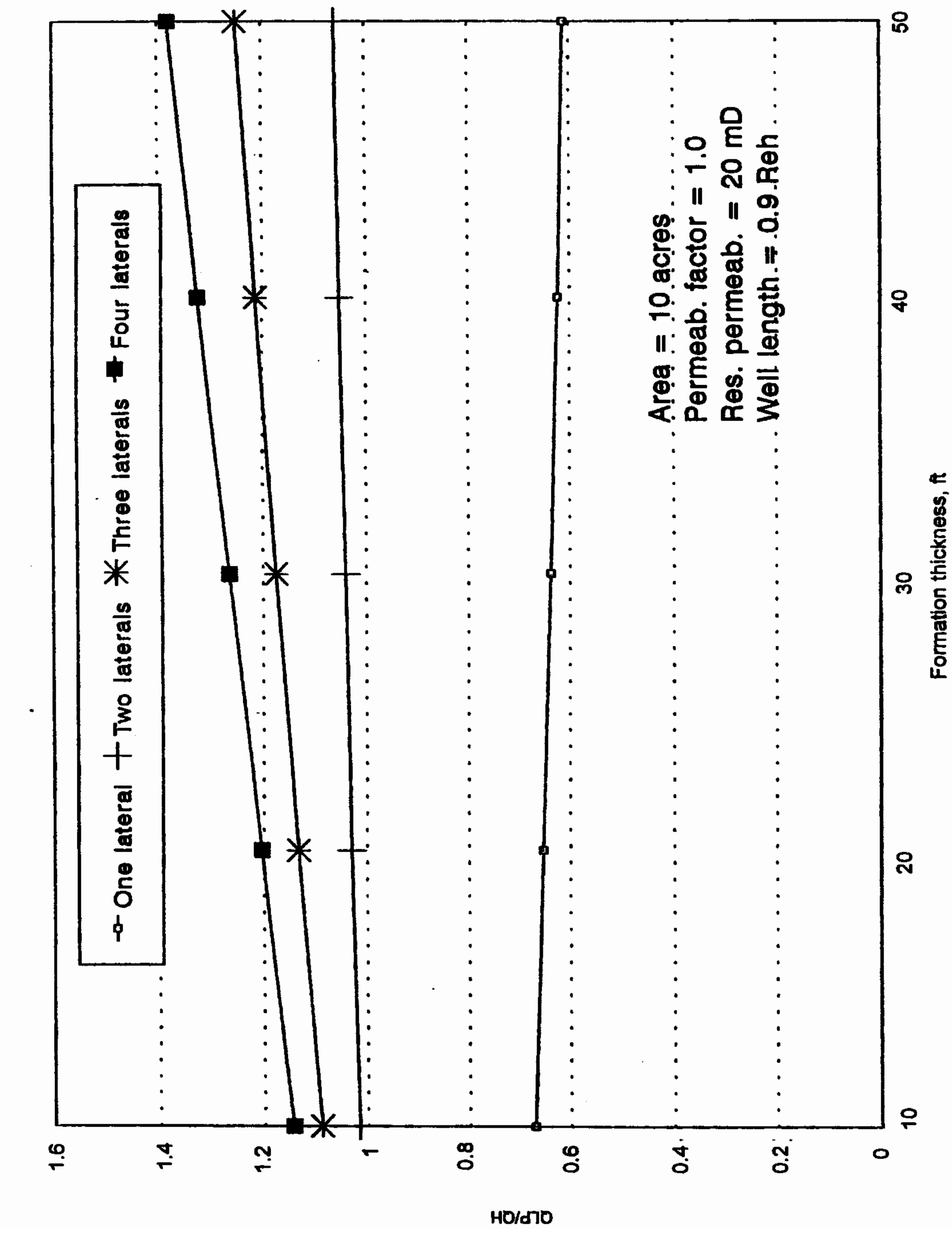

Fig. 2. Effect of number of laterals on the productivity of planar laterals and horizontal well.

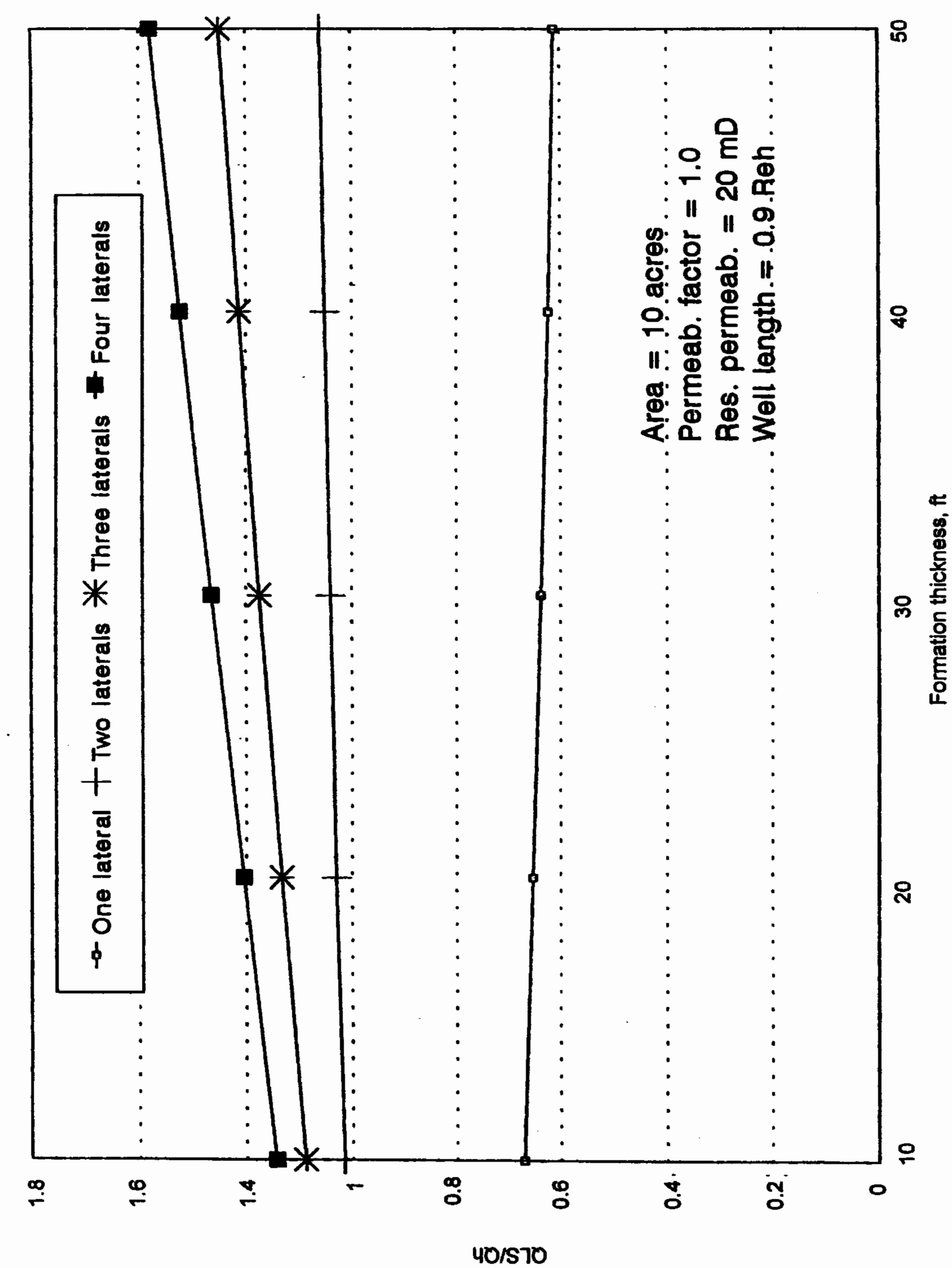

Fig. 3. Effect of number of laterals on the productivity of stacked laterals and horizontal well.

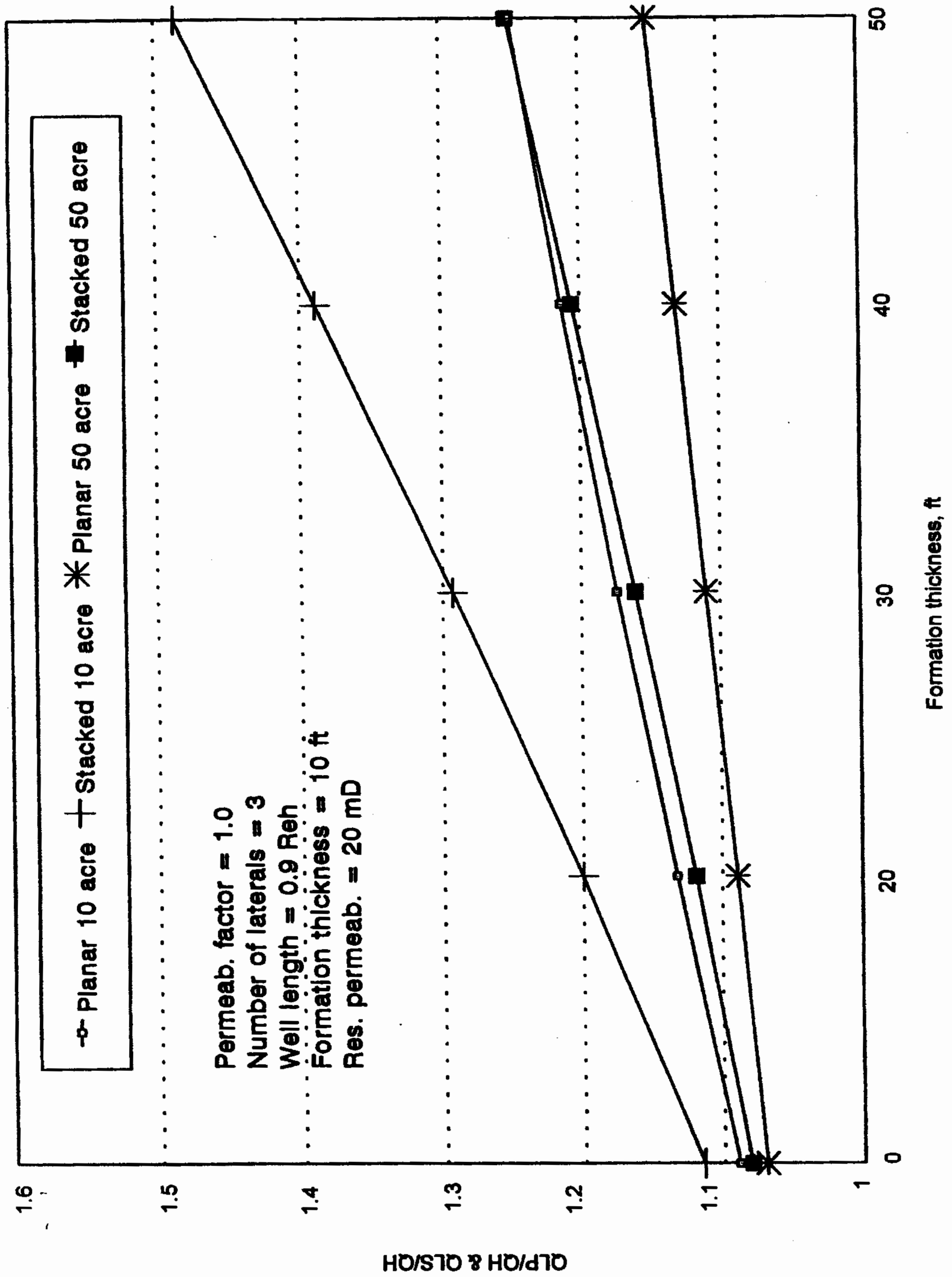

Fig. 4. Effect of area on the productivity of multilateral and horizontal well.

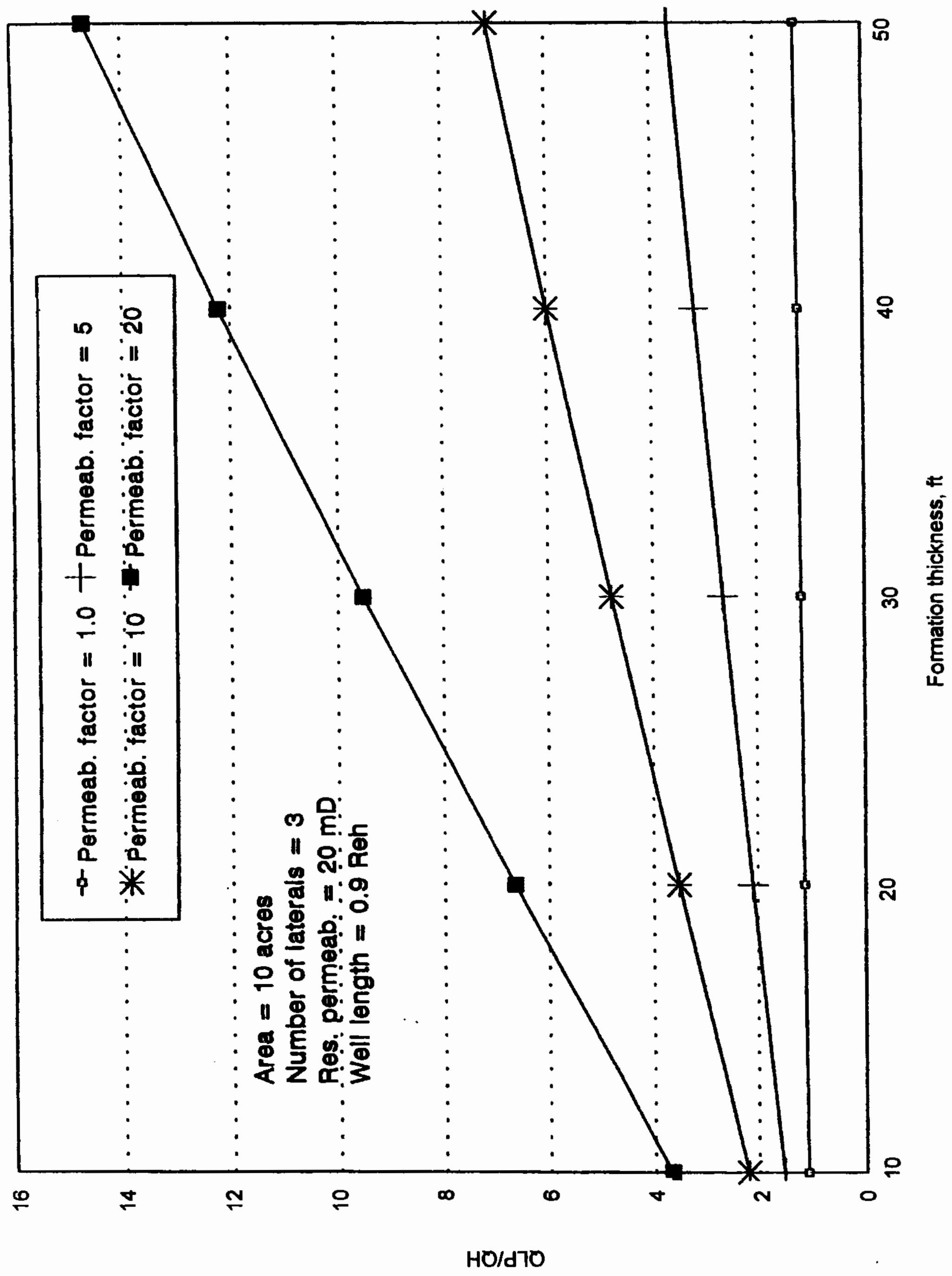

Fig. 5. Effect of permeability factor on the productivity of planarl and horizontal well.

Permeability factor is a property of reservoir anisotropy. It is defined as the square root of the vertical permeability to the horizontal permeability. It has a great effect on the production ratio of the laterals. This effect is shown in Figure 6 for the planar laterals. It can be seen that increasing the permeability factor highly increases the production ratio of the planar laterals. This vertical permeability allows high flow rate to the laterals and brings high production rate. The same results are obtained for stacked laterals, Fig. 5, except that

Production forecasting of horizontal well and multilateral wells

Based on equations (8 to 12), the production forecasting for horizontal well and planar and stacked laterals has been calculated. The reservoir data used in these calculations is given in Table 3. The pressure drop is assumed to be 500 psi. The recovery factor is selected based on the on the data given in Tables 1 and 2. It is assumed that the reservoir pressure declines continuously. The reservoir pressure decline is calculated using equation 12. The results of the calculations for the proposed reservoir data are plotted in Figs. 7 and 8.

Table 1. Primary recovery factors for depletion-type reservoirs [15,17]

Oil solution GOS	Oil gravity API	Sand or sandstone			Limestone, dolomite or chert		
		Max.	Average	Min.	Max.	Average	Min.
60	15	12.8	8.6	2.6	28.0	4.4	0.6
	30	21.3	15.2	8.7	32.8	9.9	2.9
	50	34.2	24.8	16.9	39.0	18.6	8.0
200	15	13.3	8.8	3.3	27.5	4.5	0.9
	30	22.2	15.2	8.4	32.3	9.8	2.6
	50	37.4	26.4	17.6	39.8	19.3	7.4
600	15	18.0	11.3	6.0	26.6	6.9	1.6
	30	24.3	15.1	8.4	30.0	9.6	2.5
	50	35.6	23.0	13.8	36.1	15.1	4.3
1000	15	......	......	......	......	......	......
	30	34.4	21.2	12.6	32.6	13.2	4.0
	50	33.7	20.2	11.6	31.8	12.0	3.1
2000	15	......	......	......	......	......	......
	30	......	......	......	......	......	......
	50	40.7	24.8	15.6	32.8	14.5	5.0

Table 2. Ultimate recoveries of oil for different drive mechanisms [15,17]

Reservoir type	Sand and sandstone			Sand and sandstone		
	Min.	Med.	Max.	Min.	Med.	Max.
Water drive reservoir						
BAF, bbl/AF	155	571	1,641	6	172	1,422
Rf, %	27.8	51.1	86.7	6.3	43.6	80.5
Sg, Fraction	0.114	0.327	0.635	0.247	0.421	0.908
Solution gas drive without supplement drive						
BAF, bbl/AF	47	154	534	20	88	187
Rf, %	9.5	21.3	46.0	15.5	17.6	20.7
Sg, Fraction	0.130	0.229	0.382	0.169	0.267	0.447
Solution gas drive with supplement drive						
BAF, bbl/AF	109	227	820	32	120	464

Table 2. (Contd.)

Reservoir type	Sand and sandstone			Sand and sandstone		
	Min.	Med.	Max.	Min.	Med.	Max.
Rf, %	13.1	28.4	57.9	9.0	21.8	48.1
Sg, Fraction	0.077	0.225	0.435	0.112	0.260	0.426
Gas cap drive						
BAF, bbl/AF	68	289	864	Combined with sand and sandstone		
Rf, %	15.8	32.5	67.0			
Sg, Fraction	0.223	0.271	0.571			
Gravity lateralge						
BAF, bbl/AF	290	696	1,124	Data are not available		
Rf, %	16	57.2	63.8			
Sg, Fraction	0.151	0.377	0.654			

Table 3. Proposed reservoir data for production rate and cumulative production calculations

Property	Value
Initial reservoir pressure	2000
Prorosity	25%
Permeability	20 md
Area	20 acres
Horizontal well length	475
Lateral length	237
Number of laterals	3
Permeability factor	5
Well radius	4 in
Water saturation	30%
Recover factor	30%

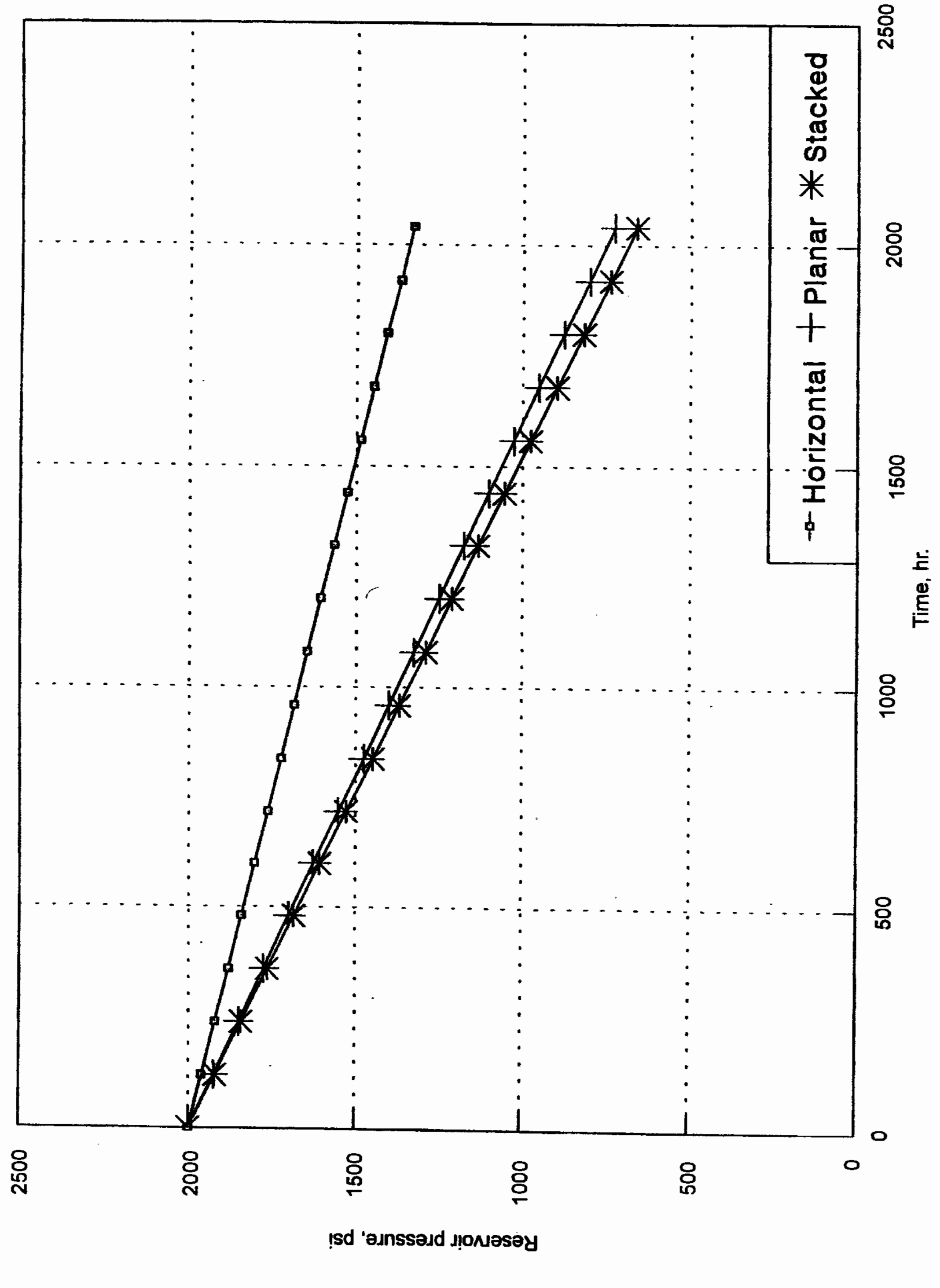

Fig. 7. Reservoir pressure decline with time.

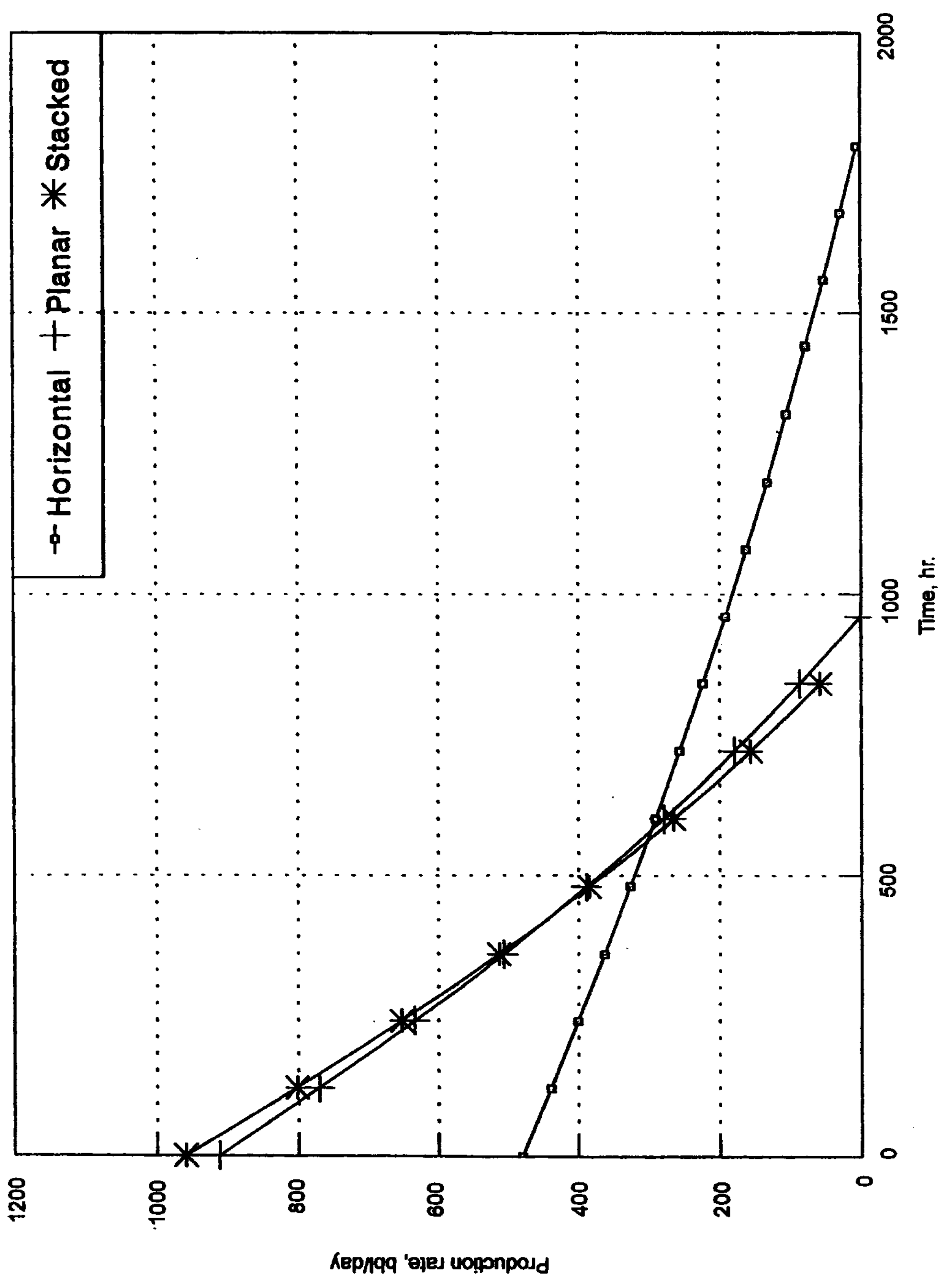

Fig. 8. Production decline with time.

Figure 6 gives the reservoir pressure decline with time. It shows that the stacked and planar lateral causes higher decline in the reservoir pressure than the horizontal well. This is due to the larger production rate of the laterals than the horizontal. In Fig. 8 the production rate versus time is plotted. Figure 8 shows that the planar laterals or the stacked laterals produce oil rate at about twice the production rate of the horizontal well. Therefore, the life of the horizontal well is larger than that of the laterals drilled in the same area.

To give a complete comparison, the cumulative production rate of the three types is plotted in Fig. 9. It is clear that stacked laterals produces the largest cumulative oil among them for the proposed area. The planar laterals produce higher oil in the early life of the well than the horizontal well and proceeded by the horizontal well in the late life of the well. This means that stacked laterals are to be recommended in the proposed area.

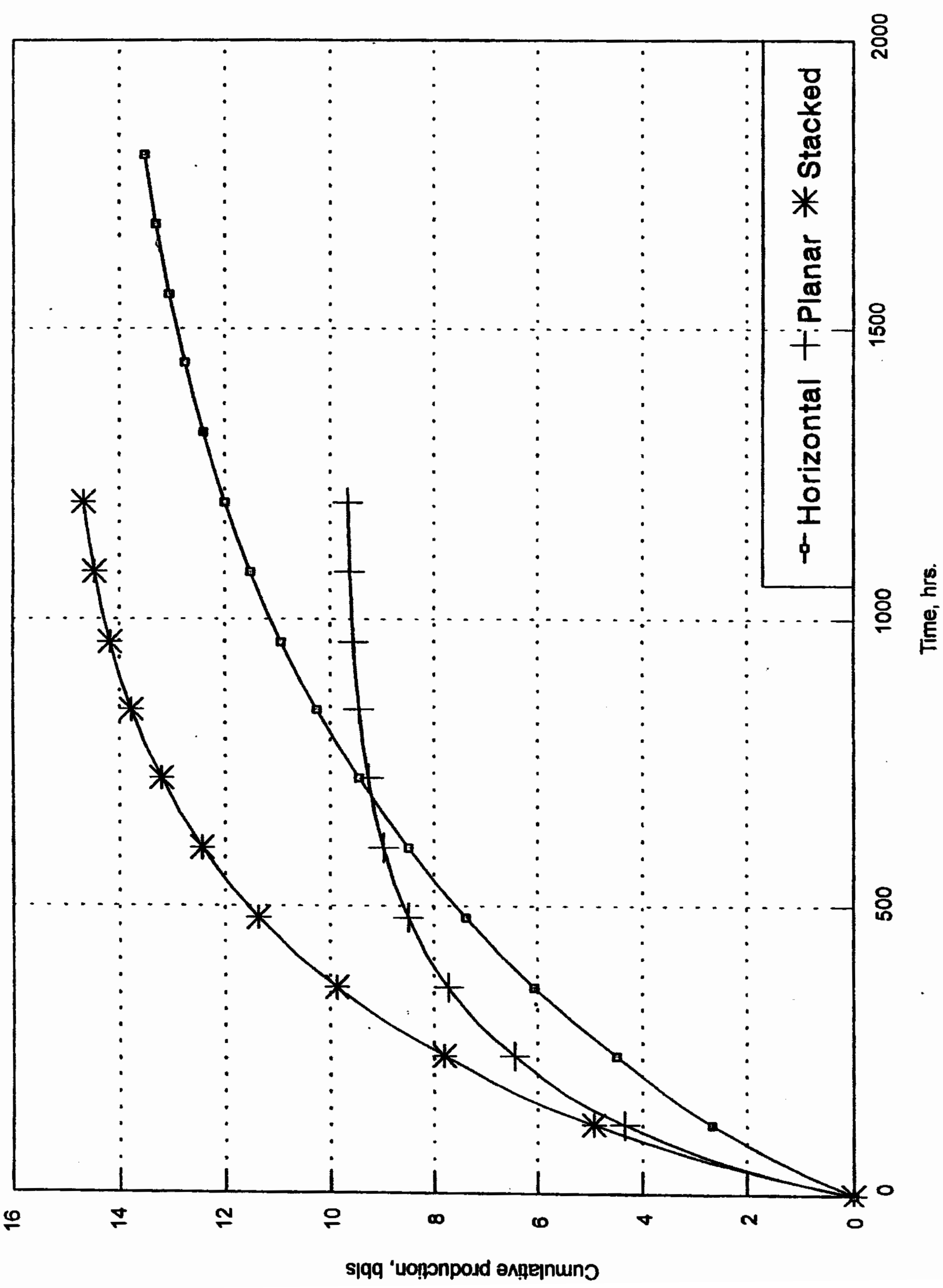

Fig. 9. Cumulative production with time.

Economical evaluation of horizontal well and multilateral wells

Based on the details given for the economical model, equation 25 is used to calculate the return on investment of the project using the cumulative production data of the area proposed in the previous section. Oil price is taken as \$20/bbl. Other data for the economical model is given in Table 4. The results are plotted in Fig. 10. The figure shows that the stacked laterals bring the highest return on investment for the proposed reservoir.

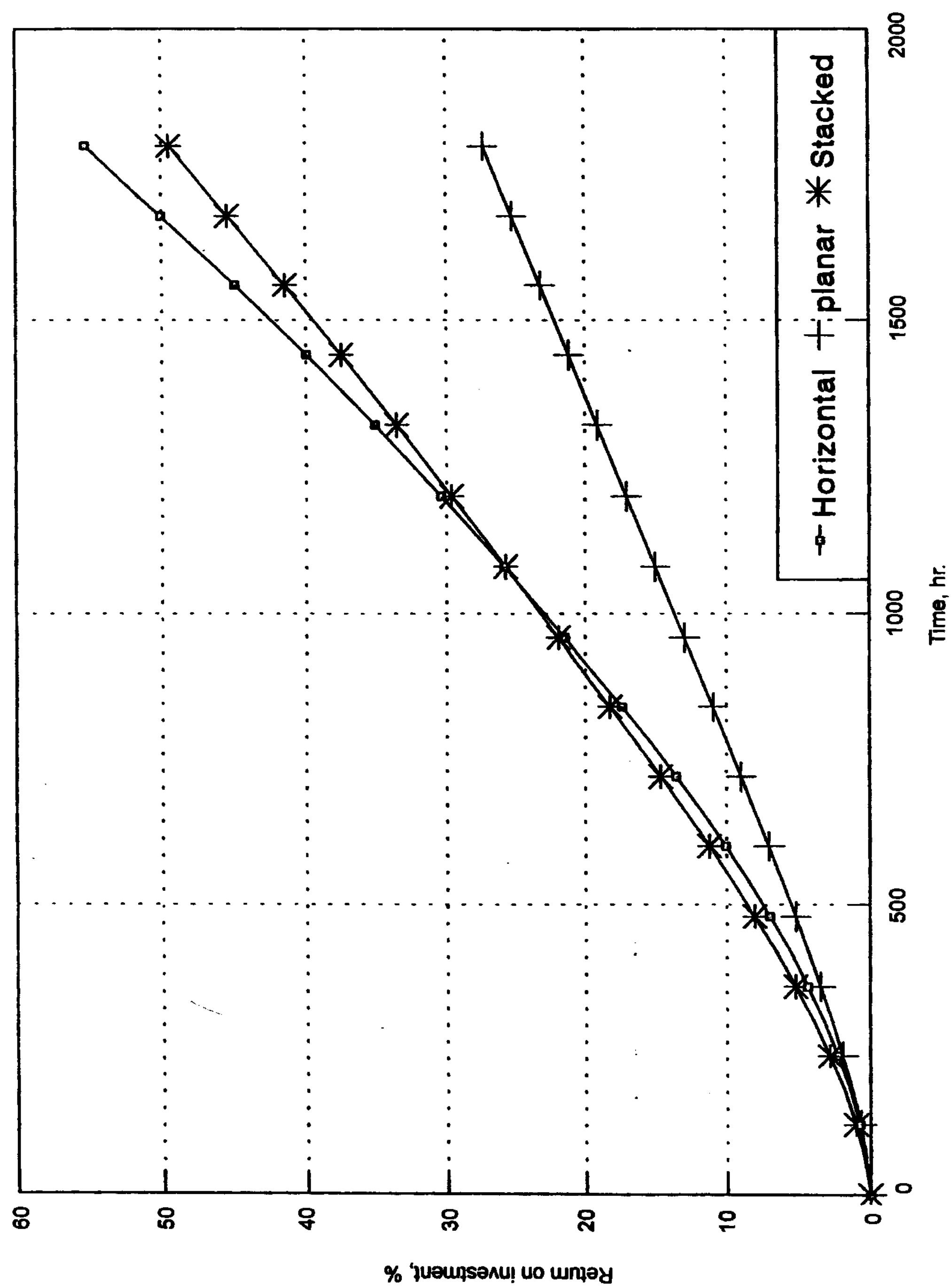

Fig. 10. Return on investment for the horizontal, planar and stacked wells.

Table. 4 Proposed costs used for the economical calculations

Property	Value
Oil price	$20
Annual interest rate	10%
Annual inflation rate	3%
Drilling cost of horizontal well	$1,000,000
Drlling cost of one lateral	$250,000
Logestic costs	$500,000
Fixed costs	$500,000
Production costs	$2/bbl

Conclusions

Based on the results obtained from the proposed equations and the calculations of production rate, production forecasting and return on investment, it can be concluded that:

1. Formation thickness, drainage area, number of laterals and formation anisotropy affects production rate of multilateral wells.

2. Planar lateral is more effective than stacked lateral at small drainage area and thin formation and vice versa.

3. The optimum number for the lateral to be drilled is two laterals while the maximum to be recommended is three laterals.

4. Laterals are very effective in anisotropy formations than horizontal, specially stacked laterals.

5. For the proposed field data stacked lateral are to be recommended for highest cumulative production and highest return on investment.

6. The calculation model can be used to compare the three drilling techniques and can help decide which technique is used for exploiting oil reservoir.

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أنموذج اقتصادي لتثمين إمكانية تطبيق الآبار المتشعبة

عبدالعليم هاشم السيد، مساعد ناصر العواد، محمد سعود البليهد
و محمد عبدالرحيم الصديقي
قسم هندسة النفط ، كلية الهندسة ، جامعة الملك سعود، ص ب ٨٠٠،
الرياض ١١٤٢١ ، المملكة العربية السعودية

(قدّم للنشر في ١٩٩٩/٠٣/٠١ ، وقبل للنشر في ١٩٩٩/١٢/٠٥)

ملخص البحث. تقدم هذه الورقة أنموذج اقتصادي طُوّر لتثمين إمكانية تطبيق الآبار المتشعبة في استغلال مكامن النفط. اشتقت معادلات تفصيلية لحساب التكاليف والعائد علي الاستثمار والقيمة الحالية الكلية علي مدار زمن إنتاج مكمن النفط ، قدّمت الورقة معادلات لحساب معدل الإنتاج وتوقع التصرف والإنتاج المستقبلي للبئر الأفقي والآبار المتشعبة ، كما تحتوي علي مقارنة بين البئر الأفقي والآبار المتشعبة ، وأعد برنامج حاسوب لإجراء حساب توقعات الإنتاج والتقويم الاقتصادي لخصائص أي مكمن ينمى باستخدام الآبار المتشعبة ، وهذا الأنموذج يمكن أن يستخدم لاختيار أحسن التقنيات لتنمية مكامن النفط مع الأخذ في الاعتبار أكبر عائد علي الاستثمار.