Optimizing Hydraulic-Fracture Length in the Spraberry Trend

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Summary. Between 1982 and 1986, more than 3,000 new wells were drilled in the Spraberry trend in west Texas. All these wells have been hydraulically fractured with ever-increasing volumes of fracturing fluids and proppant. Little work has been done to date to establish an optimum hydraulic-fracture length. A group of wells drilled in Midland County was studied with use of data from geological mapping, cores, openhole logs, postfracture pressure-transient testing, and production declines. From these data, a model was developed to predict production declines before completion. By combining this with well- and completion-cost data, an optimum fracture length can be determined with an internal rate of return (IRR) method.

Introduction

Hydraulic-fracture-treatment volumes have been increasing over the last decade in the Spraberry trend. A review of completion-card data for 77 wells completed in the Upper Spraberry, Lower Spraberry, and Dean formations in Midland County between 1975 and 1982 was conducted. Of these wells, the average fracture fluid volume was 154,420 gal [585 m^3] per well. A similar analysis of 36 wells completed in the same area in 1986 indicated the average fracture fluid volume per well was 179,500 gal [679 m^3]. This represents a 16% increase in volume. The average perforated interval decreased over this period by 16% as well. Both trends (the result of field experience) indicate a movement toward larger volumes over a smaller interval. Several practical background studies indicate a possible correlation between treatment volume and cumulative production in comparable offset wells. Bucy and Halapeska[1] found a positive correlation between treatment volumes and cumulative production in a study of 37 wells in the Ackerly Dean field. Barba[2] corroborated this in a study of 212 wells drilled in Midland County. Hoel[3] agreed in a study of 116 wells in Reagan and Upton Counties. Hoel also found a positive correlation between smaller perforated intervals and cumulative production. In a 21-well study in the Dean formation in Midland County, Barba[4] found that well performance could be improved by incorporating in-situ-stress data into the completion design, thus controlling fracture height.

These studies suggest that larger stimulation treatments are warranted in the Spraberry trend. At some point, however, the cost of increasing the treatment size exceeds the present value of the incremental revenue. An optimum length exists for each well on the basis of balancing the cash flows involved. To determine this optimum length, it is necessary to obtain a good reservoir definition with a combination of petrophysical and reservoir data. Pressure-transient analysis before and after the fracture treatment should be included in this process.[5]

The primary objective of this study is to define this critical point for a group of Midland County Dean formation wells through the use of petrophysical, transient-pressure test, production-decline forecasts, and the total well IRR. On the basis of this criterion, the optimum geometry for the Dean formation in southeastern Midland County indicated a propped length between 800 and 1,000 ft [244 and 305 m].

Methodology

To define the optimum fracture-treatment geometry for the Dean formation in southeastern Midland County, the following methodology is used.

1. The reservoir is described by the use of geological, openhole wireline, and pretreatment pressure-transient data.
2. With a fractured-reservoir production model, production declines are extrapolated for a reasonable range of reservoir parameters, fracture lengths, and fracture conductivities.
3. The extrapolated production declines and the resultant benefits are compared with the cost of obtaining the various fracture lengths and conductivities. The optimum geometry, based on an investment criterion of NPV or rate of return, is then identified.
4. The pumping schedule required to obtain this geometry is then determined with a hydraulic-fracture simulator that has predicted net pressure increases in the past. A model resembling the Perkins and Kern[6] geometry is presumed. The net pressure increase expected from this schedule is then compared with the in-situ-stress-derived pressure limits of the boundary rock. If the net pressure increase required to obtain the optimum economic geometry is higher than the rock will allow, then a return to the previous comparison step is indicated. The next-smaller alternative that still meets economic objectives is chosen. The calculation is repeated until a geometry that is both economical and practical is obtained. The results of the fracture treatment are evaluated with a pressure-transient test to determine the actual geometry in place. If necessary, the models are refined for application to future wells.

Defining the Reservoir

The Spraberry trend covers >160 sq miles [>414 km^2] of the Midland basin in west Texas (Fig. 1). It can be divided vertically into three sequences: the Dean, Lower Spraberry, and Upper Spraberry formations. Each consists of several hundred feet of interbedded shale and carbonate overlain by sandstone and siltstone. The siltstone was deposited in a submarine fan environment, with the axis of the fan system paralleling the axis of the Midland basin (Fig. 2).[7] The reservoir rock is a very fine-grained, silty sandstone with low permeability.[8,9] Productive intervals in the Dean formation are in the 4- to 10%-porosity range. Productive intervals in the Spraberry zones range from 8 to 15% porosity. Natural fissures exist in all three zones.

Given the low-permeability matrix and presence of natural fractures, an important step in optimizing the stimulation is to define the flow mechanism within the reservoir. If the fractures are the dominant flow mechanism, then removing near-wellbore skin is a valid approach. Such an approach was recommended by Dyes and Johnston[10] on the basis of their observed effective permeabilities in the 30-to-40-md range.

If the low-permeability matrix is the dominant flow mechanism, then increasing the effective wellbore radius by creating a hydraulic fracture becomes important. To help establish this, a transient-pressure test before the fracture treatment is recommended. Because the Dean formation will produce little or no fluid before stimulation, this is not practical.

An alternative approach is to compare the cumulative production of wells that lie on the submarine fan axis and the fracture-trend axis with the cumulative production of wells that lie outside. If the cumulative production is larger along the fracture trend, then the fractures are probably the dominant flow mechanism. If the production follows the axis of the sand deposition, then the low-permeability matrix is probably the dominant flow mechanism. Fig. 3 shows the distribution of the fracture trend based on waterflood pilot studies.[8,11] Fig. 3 also shows the distribution of the fracture trend based on dipmeter and electrical imaging data.[12] From this it can be seen that the fracture orientation in the Midland/southern-Martin-County area varies between northeast/southwest and east/west. Fig. 4 shows the distribution of the higher-cumulative-production wells in southern Martin County. Fig. 5 shows the distribution of the higher-cumulative-production wells in southeastern

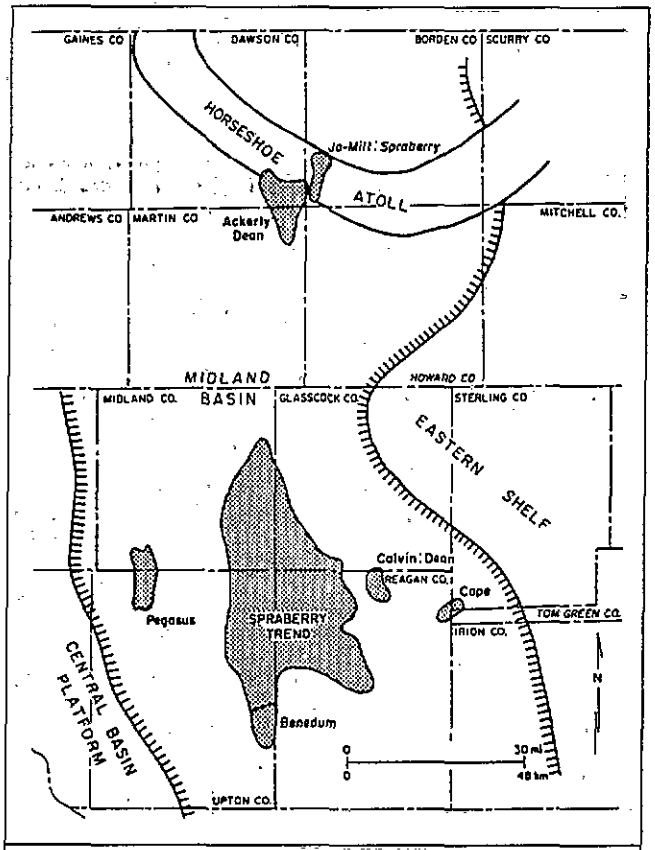

Fig. 1—The Spraberry trend (after Galloway *et al.*[8]).

Midland County.[13] This should be compared with the north-northwest/south-southeast axis of the submarine fan system shown in Fig. 2. Fig. 6 is a map of initial potentials (IP's) made in the Tex-Harvey field in 1953.[14] The orientation of the highest-IP wells is clearly along the fracture trend shown in Fig. 3. The orientation of the higher-cumulative-production wells is clearly along the axis of the submarine fan system shown in Fig. 2. This comparison supports the contention that the low-permeability matrix is the dominant flow mechanism in Spraberry-trend production. This presents a case for increasing the effective wellbore radius by creating a hydraulic fracture.

Transient Analysis of Prior Treatments

To define the mechanism within the reservoir further, an evaluation of prior field treatments is in order. The results of five post-fracture tests performed over the Dean interval are shown in Table 1. These tests were conducted after 12 to 22 months of production. The pressure buildups were observed for a minimum of 4 days and a maximum of 9 days. These numbers were derived by analyzing pumping-well buildup performance with finite-conductivity type curves and the pressure derivative.[15-17] A representative plot from the group is shown in Fig. 7. A uniqueness problem in interpretation exists because of the relatively short buildup times. To assist in obtaining a unique match, the prefracture-treatment-matrix permeability range was determined by downgrading core permeabilities by an order of magnitude. A pretreatment transient-pressure test is preferred, although in this case it is not practical. A direct measurement of bottomhole pressure (BHP) is also preferred over a pumping well test because the pumping well data often have some scatter resulting from fluid-level changes not directly related to BHP. If the permeability and fracture-conductivity measurements from the pumping well data were within reasonable limits, it was felt that the data were valid. The reasonable limits for permeability were based on core permeabilities. The range of 0.02 to 0.04 md is about an order of magnitude less than the core permeabilities to air from the same zone. This is similar to published comparisons with an effective overburden of 6,000 psi [41.4 MPa].[18,19] In addition, the fracture-conductivity measurements were close to the 100-to-200-md-ft [30-to-61-md·m] range predicted by Parker and McDaniel.[20]

The equation used to determine permeability is

$$kh=141.2\Delta qB\mu(p_D/\Delta p), \quad (1)$$

where k=permeability, h=height of permeable interval, Δq=flow-rate change, B=FVF, μ=viscosity, and $p_D/\Delta p$=pressure match from log-log plot and type curve.

The height was obtained from the openhole logs with an effective porosity cutoff of 4% and a minimum sand content of 50% from a crossplot of external boundary pressure, bulk density, and compensated-neutron-log data.[21] Comparisons with core data determined that this is a sandstone reservoir and that the carbonate stringers have virtually no contribution to reservoir storage.

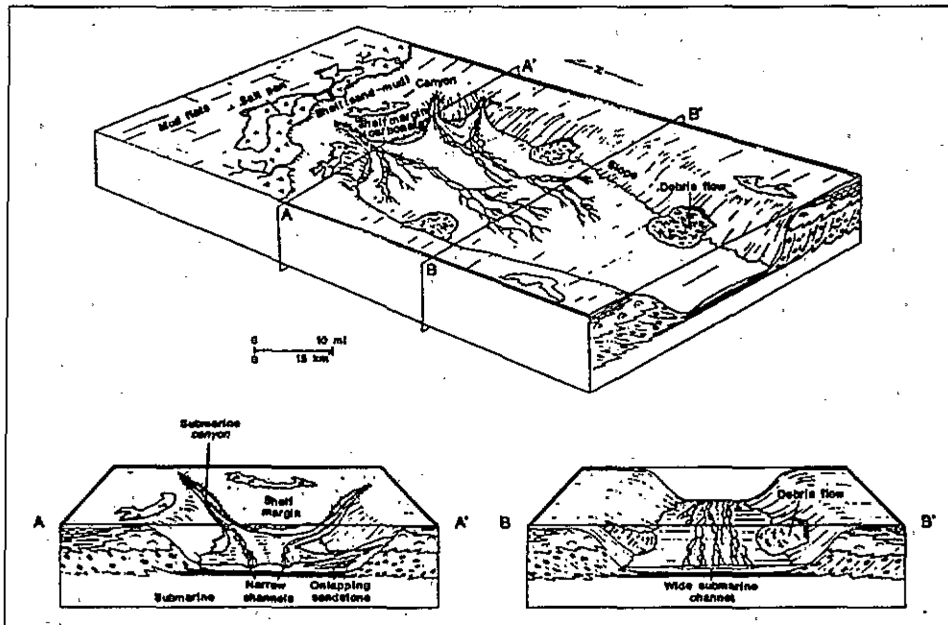

Fig. 2—Block diagram and cross sections illustrating the interpreted physiographic features and depositional environments of the Midland basin during deposition of the Spraberry/Dean submarine-fan system.

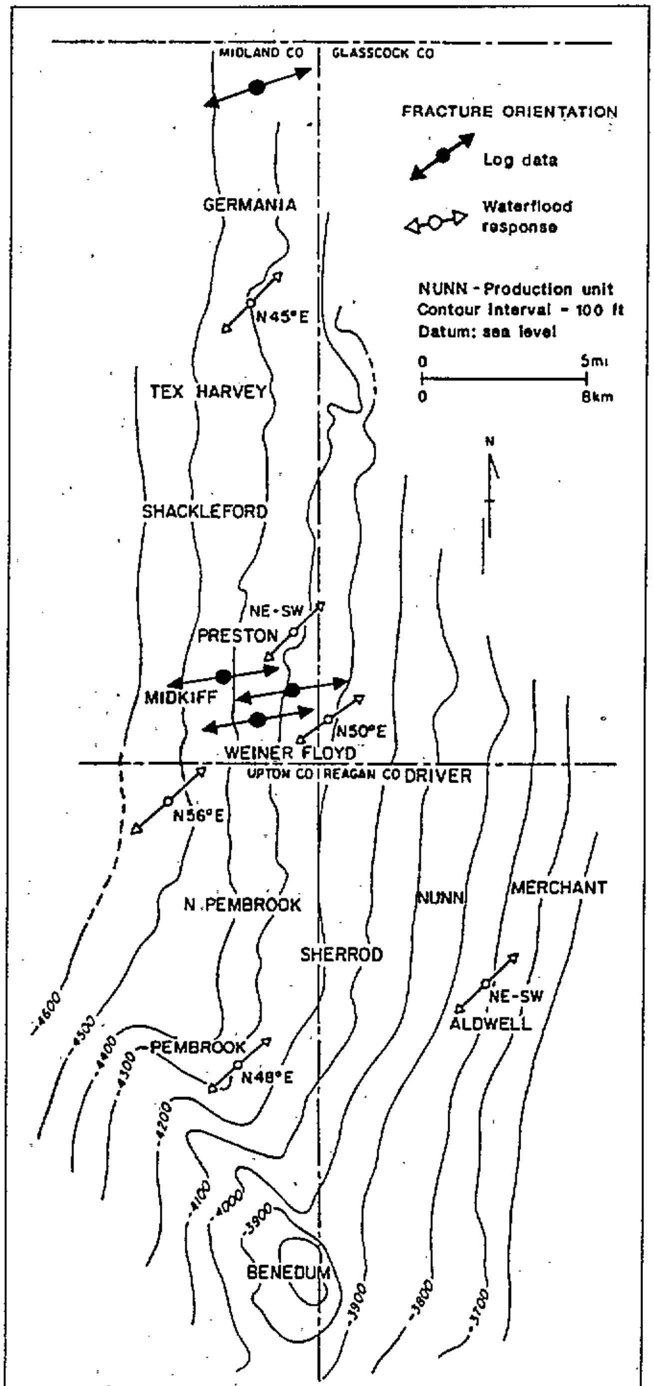

Fig. 3—Calculated fracture orientation from waterflood studies and log data.

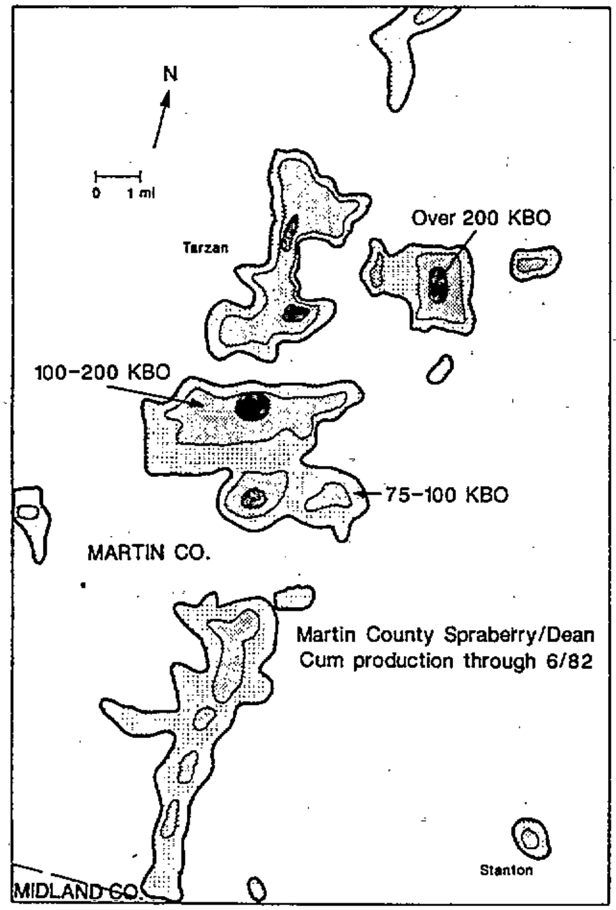

Fig. 4—Distribution of higher cumulative production wells in Martin County, TX.

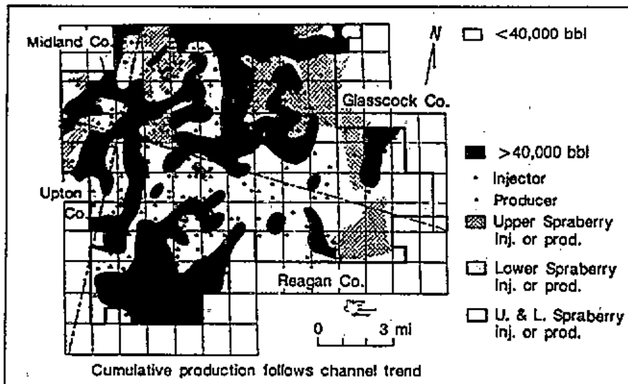

Fig. 5—Spraberry Driver unit cumulative production, Feb. 1985 (Ref. 13).

Guevara[13] reached a similar conclusion. The porosity used in the reservoir calculations was the average of all effective porosity greater than the 4% minimum pay requirement. The other reservoir parameters—e.g., gravity, water cut, GOR, compressibility, and viscosity—were determined from production data and corrected for reservoir conditions.[22] The five wells summarized in the first section of Table 1 all had reasonable pressure matches. The results of the time match are shown in Table 1. The effective fracture half-lengths for the wells range from 435 to 580 ft [133 to 177 m]. These were obtained from

$$x_f=0.0162[(k/\phi)\mu c_t](t_D/t), \quad (2)$$

where x_f=fracture half-length in the direction of x, ϕ=effective porosity, c_t=total system compressibility, and t_D/t=time match from log-log plot and type curve.

In addition to the effective fracture length, a measurement of effective fracture conductivity can also be obtained from the time match. These comparisons are also shown in Table 1. The fracture conductivities vary from 46 to 84 md-ft [14 to 26 md·m]. These were obtained from

$$k_f b=C_{fD} k x_f, \quad (3)$$

where C_{fD}=dimensionless fracture conductivity, k_f=fracture permeability, and b=width.

The lengths for Wells 1 and 3 compare reasonably with a Geertsma-de Klerk[23] hydraulic-fracture model with sonic-derived stress barriers for the fracture-height prediction (see Figs. 8 and 9).[24] In addition, the conductivities are reasonably in line with the laboratory work performed by Parker and McDaniel.[20] Wells 2 and 5 did not have measured in-situ-stress data, and it is not certain

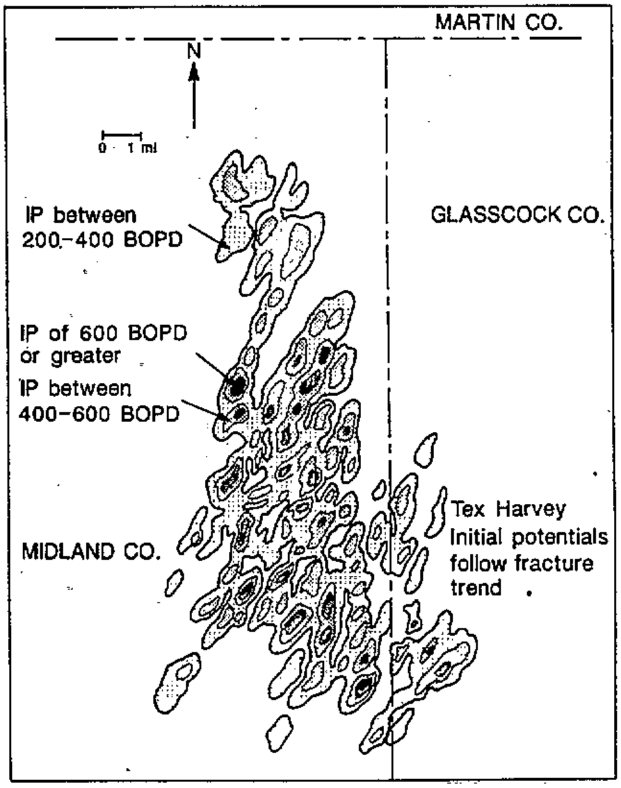

Fig. 6—Map of IP's in the Tex Harvey field in 1953 (Ref. 14).

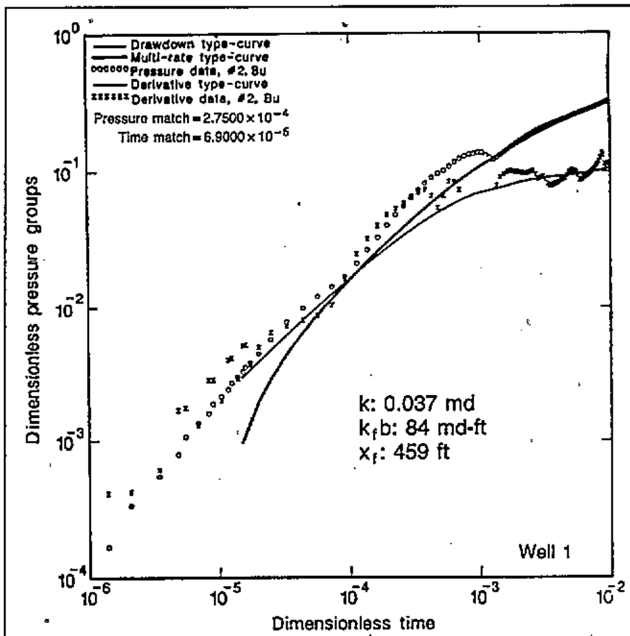

Fig. 7—Type curve for a finite-conductivity vertical fracture in an infinite reservoir.

TABLE 1—SUMMARY OF RESERVOIR AND PETROPHYSICAL DATA

	Well				
	1	2	3	4	5
Pressure-Match Data					
Flow rate at test, BOPD	65	35	18	18	13
Flow rate, BWPD	1	1	5	8	4
Initial potential data	Feb. 1986	Sept. 1985	Nov. 1985	April 1985	Aug. 1985
Cumulative oil at test, 10^3 bbl	17.5	22.4	10.4	17.7	7.4
Porosity, %	7.9	7.7	7.5	7.0	7.7
Permeable height, ft	66	58.5	63	47.5	50
Porosity-ft	5.21	4.50	3.33	4.73	3.85
Test duration, hours	143.2	114.4	231.5	189.8	141.4
Test date	Feb. 1987	Feb. 1987	Feb. 1987	Feb. 1987	Feb. 1987
$p_D/\Delta p$ match, $\times 10^{-4}$	2.75	2.77	5.77	4.0	10.56
p^*, psi	2,814	2,331	2,400	2,400	2,400
PWF, psi	486	346	481	136	80
Permeability to 0.7 cp, md	0.037	0.023	0.023	0.021	0.037
Time-Match Data					
C_{fD}	5.0	5.5		5.0	
C_{fD}, $\times 10^{-3}$	5.0	1.5		6.0	
x_f, ft	459	580		435	
$k_f b$, md-ft	84	74		46	
Fracture-Treatment Data					
400-psi Δp height, ft	450	418		460	
GD model x_f, ft	484	396		449	
GD model $k_f b$, md-ft	87.6	82.9		109	
Fluid type	PE**	XLG†		XLG	
Fluid volume, 10^3 gal	110	130		160	
Sand volume, 10^3 lbm	242	304*		374	

*179,000 lbm 20/40 Ottawa and 125,000 lbm ISP.
**Polyemulsion.
†Crosslinked gel.

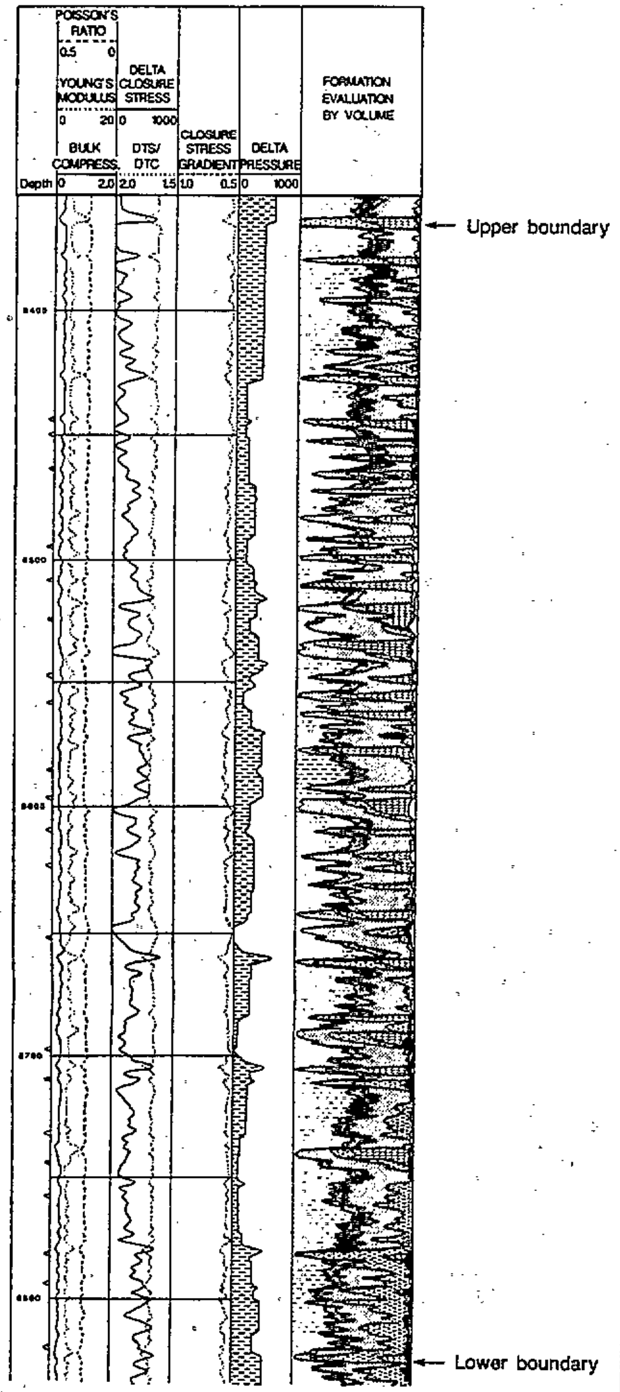

Fig. 8—Sonic-derived in-situ-stress distribution log.

where a reasonable barrier existed for the height estimate. With the prefracture reservoir and petrophysical inputs, these fracture-geometry measurements allow a reasonable production forecast to be made. From Figs. 10 and 11, it is clear that the model is indeed reasonable.

The next step in the optimization process is the simulation of production vs. fracture half-length with the reservoir data discussed in this section.[25,26] This will provide the cash-flow portion of the optimization model.[27]

Economic Comparison

The two methods used most commonly are NPV and IRR. NPV assumes a cost of capital rate and is the difference between the present value of all future cash flows and the cost of the asset. The IRR method balances the inflows and outflows, then provides the

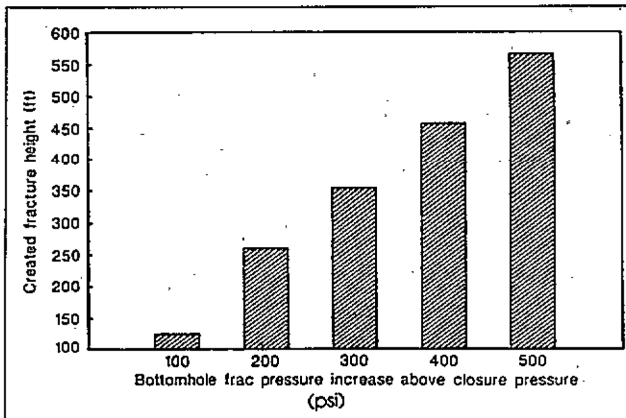

Fig. 9—Fracture height vs. delta pressure from Midland County Dean Well No. 1.

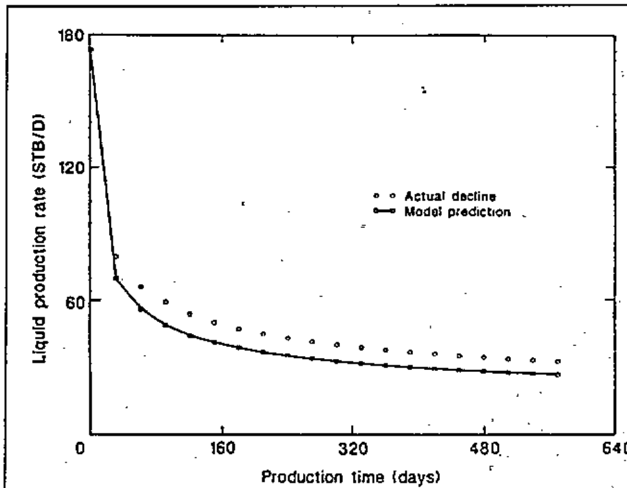

Fig. 10—Model raw output showing effect of time on production rate for fracture half-length of 460 ft.

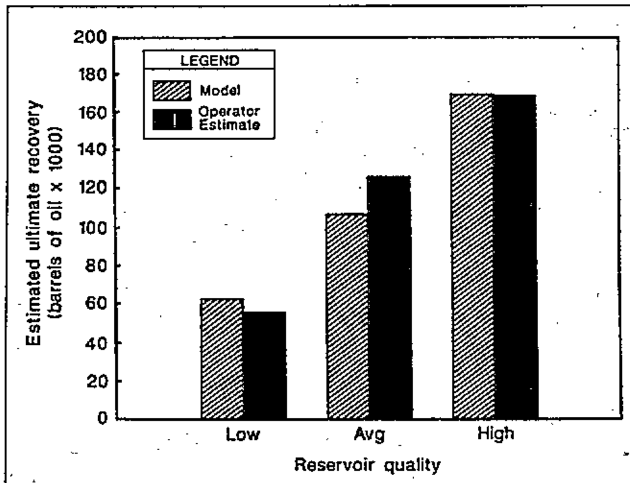

Fig. 11—Estimated ultimate recovery estimates vs. model prediction in the Midland County Dean (x_f=500 ft and k_fb=100 md-ft).

cost of capital required to obtain this balance. The IRR method allows the operator to compare the asset's performance with the performance of other assets the company has, and is thus a more universal method. To provide a representative sampling of production from the field, three scenarios for permeability and porosity

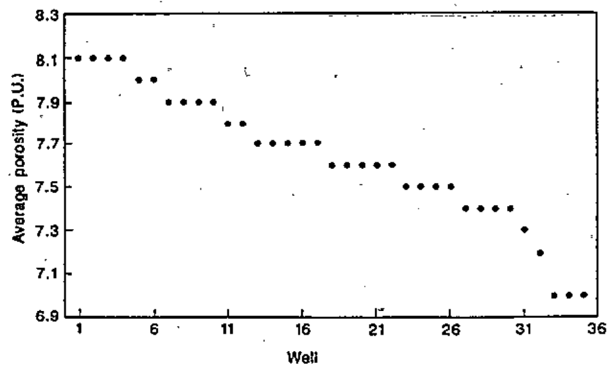

Fig. 12—Average porosity distribution for 35 wells in the Midland County Dean (average = 7.63%; median = 7.60%).

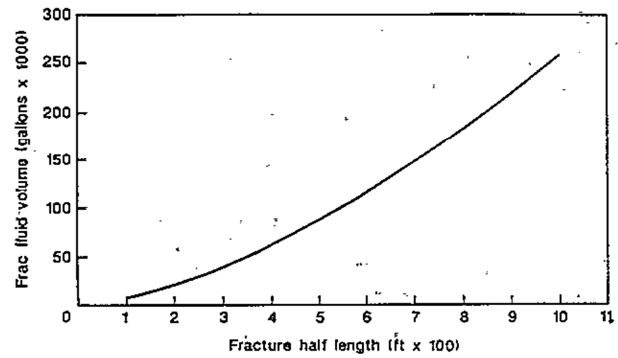

Fig. 15—Fracture volume vs. fracture length in the Midland County Dean (450-ft fracture height, 4-lbm/gal maximum sand, and 30-lbm crosslinked gel system).

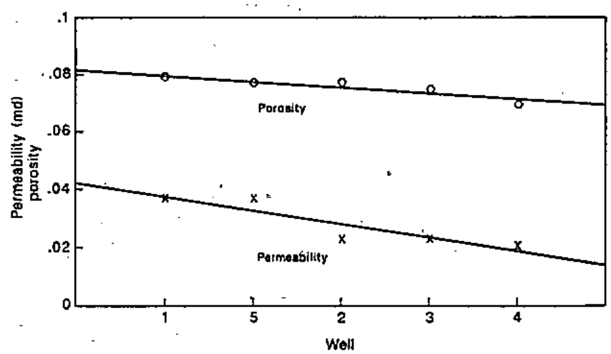

Fig. 13—Permeability vs. porosity by well in the Midland County Dean formation.

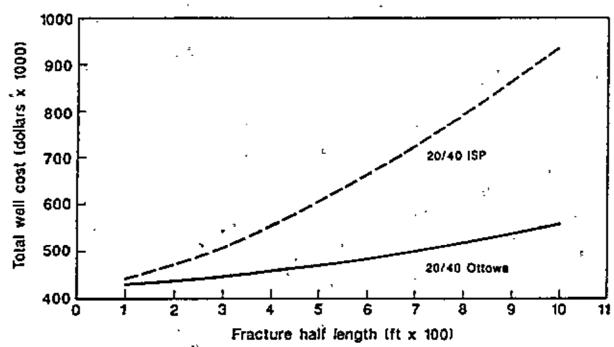

Fig. 16—Total well cost vs. fracture length in the Midland County Dean ($400,000 base cost plus fracture cost; 450-ft created fracture height).

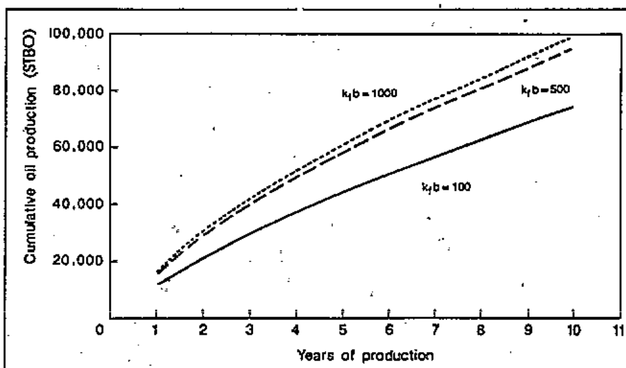

Fig. 14—Cumulative production predictions in the Midland County Dean (average reservoir with optimum x_f: 0.03 md, 0.075ϕ, 54.1h, and 800 x_f).

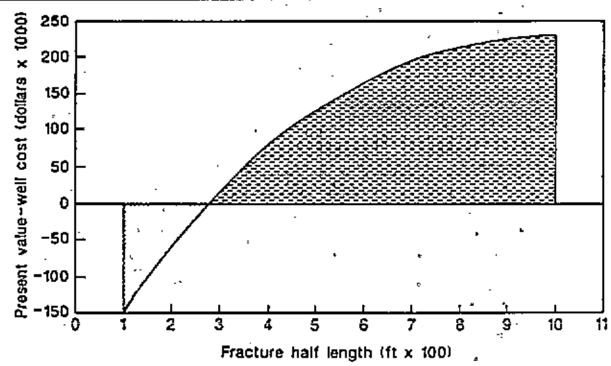

Fig. 17—Present-value minus present-cost comparison for an average-reservoir-quality well (0.03 md, 0.075 ϕ, and 54.1 h/k_fb=100) in the Midland County Dean formation: 15%-discounted-cash-flow/10-year/$18 base.

were constructed. The distribution of porosity and permeability values for the field can be seen in Figs. 12 and 13. The lowest permeability encountered was 0.021 md, and the lowest porosity encountered was 7%. At the other extreme, the highest permeability was 0.037 md and the highest porosity was 8.1%. The average and median porosity was 7.6%, based on a sample of 35 wells. From this range, low, average, and high porosity/permeability combinations were chosen. The height was varied along with the porosity and permeability values, with this parameter varying from 47.5 to 65.5 ft [14.5 to 20 m]. This allowed worst, average, and best reservoir-quality cases to be made.

The cash inflows were determined with a fractured-reservoir production model based on Agarwal's work.[17-19] The fracture geometries shown are within a reasonable range for the field. Fracture-length development within the Dean formation is limited by the relatively low in-situ-stress contrast of from 200-to-500-psi [1379-to-3447-kPa] net pressure before unacceptable height growth. In addition, two fracture-conductivity values were chosen. The maximum proppant concentration in the Dean formation is ≈1 lbm/ft^2 [≈48.8 kg/m^2], based on a maximum propped width of ≈0.10 in. [≈0.25 cm]. A wider fracture is possible; however, the rates and viscosities required to generate the width will generally result in a net pressure increase in excess of the normal in-situ-stress barriers of 200 to 600 psi [1379 to 4137 kPa]. Fig. 8 illustrates the predicted height migration from a 400-psi [2758-kPa] net pressure increase. Given the constraint of 1 lbm/ft^2 [48.8 kg/m^2],

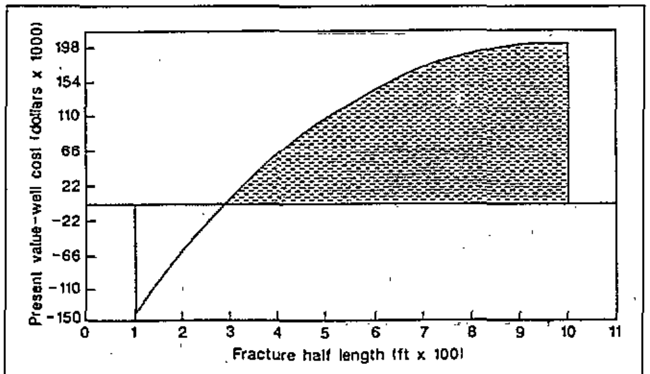

Fig. 18—Present-value minus present-cost comparison for an average-reservoir-quality well (0.03 md, 0.075ϕ, and 56.5 $h/k_fb=500$) in the Midland County Dean formation: 15%-discounted-cash-flow/10-year/$18 base.

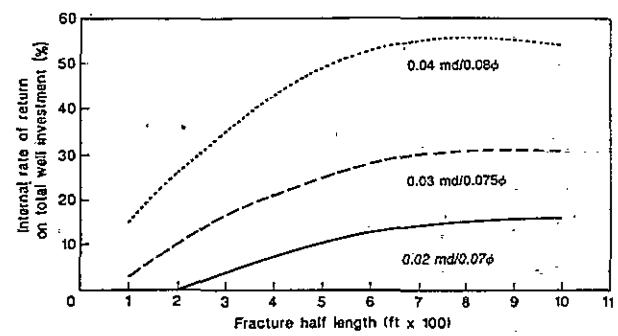

Fig. 19—IRR vs. fracture length in the Midland County Dean formation (20/40 Ottowa, 1 lbm/ft^2; and $k_fb=100$): 10-year-cash-flow/$18 base price.

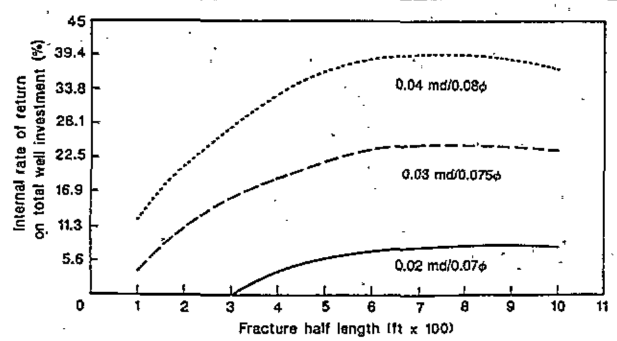

Fig. 20—IRR vs. fracture length in the Midland County Dean formation (20/40 ISP, 1 lbf/ft^2; and $k_fb=500$): 10-year-cash-flow/$18 base price.

the two options at the 5,000-psi [34.5-kPa] closure stress range are 20/40 Ottawa and 20/40 ISP. On the basis of measured data in this study and an interpolation of Parker and McDaniel's work,[19] the Ottawa sand was estimated to have a fracture conductivity of 100 md-ft [30 md·m]. The 20/40 ISP was estimated to have a fracture conductivity of 500 md-ft [152 md·m] on the basis of an interpolation of Parker and McDaniel's data.

The time duration chosen for the comparison was 10 years. Fig. 14 illustrates the cumulative production for three conductivity scenarios and an 800-ft [244-m] fracture half-length. An $18 base price for oil was chosen, with a 5% increase each year. The NPV comparison used a 15% discount rate. Gas production was assumed to offset lease operating costs. The fracture-treatment costs assumed that the in-situ-stress distribution allowed for a 450-ft [137-m] height containment, as it did in the case of Well 1. With the Ottawa sand and ISP cases, a 30-lbm [13.6-kg] crosslinked gel was the fracturing fluid. A 35-bbl/min [5.56-m^3/min] treatment rate was also assumed. The volume required to generate each length is shown in Fig. 15. The fracture costs for each length were added to a base well cost of $400,000 in Fig. 16. The cost of the well generally is not subtracted if one were to make a strict comparison of fracture incremental benefits and costs. In the Dean formation, however, wells cannot produce without fracturing. As a result, it is a reasonable assumption that fracture and well costs are lumped together and subtracted from the expected revenues. With the revenue model and cost models in hand, a present-value minus present-cost comparison can be made. These are shown for an average-reservoir-quality well in Figs. 17 and 18. The IRR comparison is then shown in Figs. 19 and 20 to summarize the data.

Conclusions

The dominant flow mechanism in the Dean formation is the matrix permeability. The natural fracture system affects the IP; however, the matrix determines the cumulative production. With a comprehensive set of reservoir and petrophysical data, the production from the reservoir can be predicted as a function of matrix permeability, thickness, porosity, and hydraulic-fracture length. The production can then be directly related to matrix parameters, stimulation parameters, or a combination of the two. There is a strong case for not completing wells that have a combination of low porosity, permeability, and thickness. The worst-case-scenario wells will provide a maximum 15% IRR, even with a 1,000-ft [305-m] hydraulic-fracture length. For wells with the field average permeability, porosity, and thickness, the IRR can be increased from a current level of 21% at a 400-ft [122-m] fracture half-length to 32% at an 800-ft [244-m] fracture half-length. In the best-case wells, the IRR can be increased from a current level of 42.5% at a 400-ft [122-m] fracture half-length to a maximum of 57% at an 800-ft [244-m] fracture half length.

Nomenclature

b = fracture width, in. [cm]
B = FVF, RB/STB [res m^3/stock-tank m^3]
c_t = total system compressibility, psi^{-1} [kPa^{-1}]
C_{fD} = dimensionless fracture conductivity
h = height of permeable interval, ft [m]
k = permeability, md
k_f = fracture permeability, md
Δp = pressure change, psi [kPa]
p_D = dimensionless pressure
Δq = flow-rate change, B/D [m^3/d]
t = time
t_D = dimensionless time
x_f = fracture half-length in the direction of x, ft [m]
μ = viscosity, cp [Pa·s]
ϕ = effective porosity, %

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	=	m^3
cp	× 1.0*	E−03	=	Pa·s
ft	× 3.048*	E−01	=	m
lbm	× 4.535 924	E−01	=	kg
lbm/gal	× 1.198 264	E+02	=	kg/m^3
miles	× 1.609 344*	E+00	=	km
psi	× 6.894 757	E+00	=	kPa
psi^{-1}	× 1.450 377	E−01	=	kPa^{-1}

*Conversion factor is exact.

SPEFE

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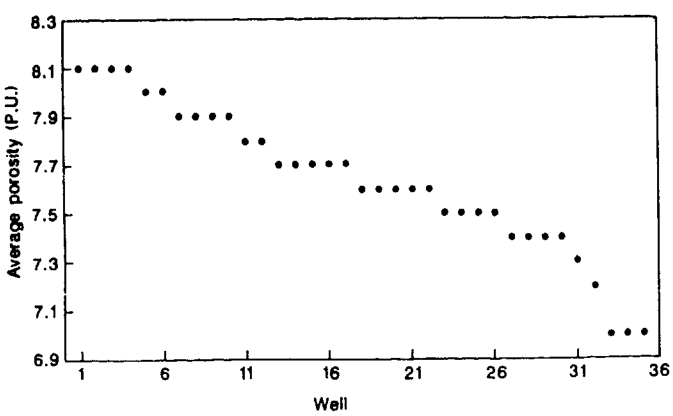

Fig. 12—Average porosity distribution for 35 wells in the Midland County Dean (Average = 7.63%/Median = 7.60%).

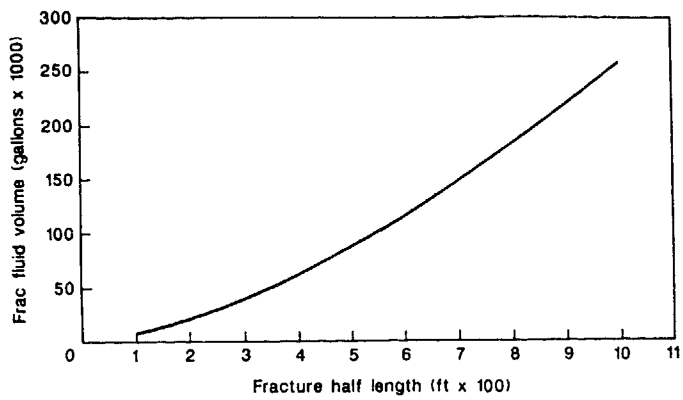

Fig. 15—Fracture volume versus fracture length in the Midland County Dean (450 ft fracture height/4 ppg max sand/30 lb cross-linked gel system).

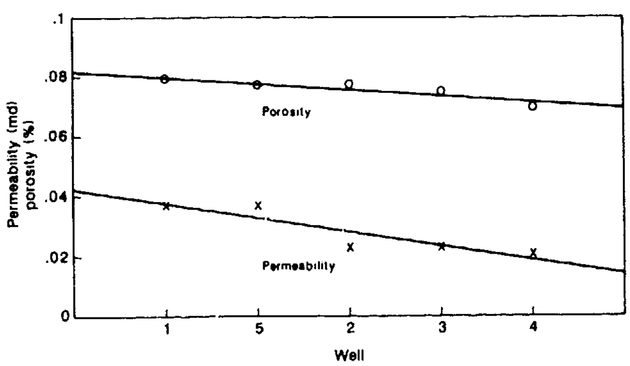

Fig. 13—Permeability versus porosity by well in the Midland County Dean formation.

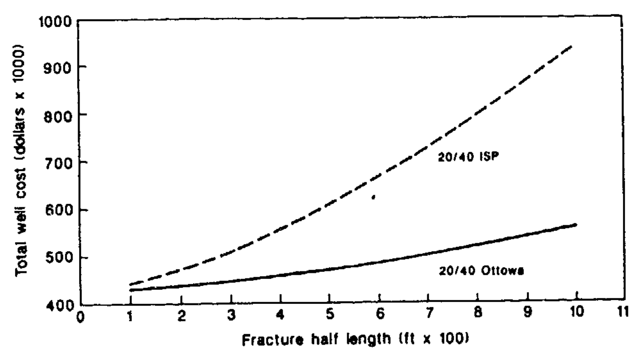

Fig. 16—Total well cost versus fracture length in the Midland County Dean ($400,000 base cost plus frac cost/450 ft created fracture height).

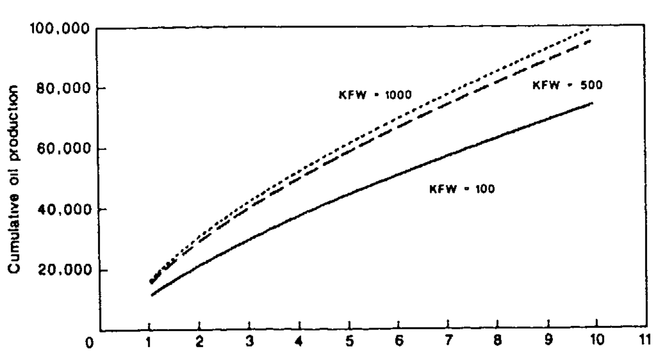

Fig. 14—Cumulative production predictions in the Midland County Dean (Average reservoir with optimum x_f: 0.03 md/0.075 phi/54.1 h/800 x_f).

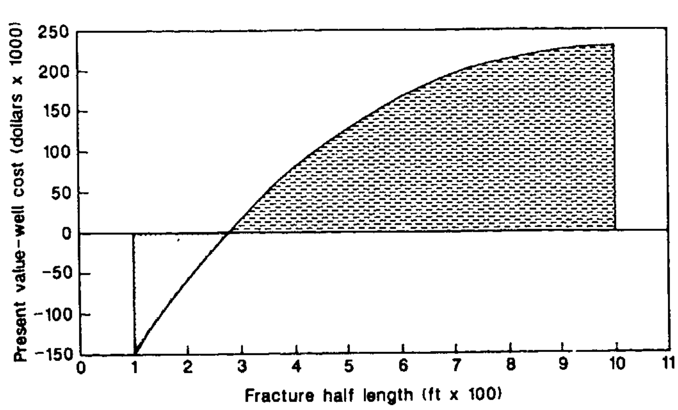

Fig. 17—Present value minus present cost comparison for an average reservoir quality well (0.03 md/0.075 Φ/54.1 h/k_fw = 100) in the Midland County Dean formation: 15% discounted CF/10 yr/$18 base.

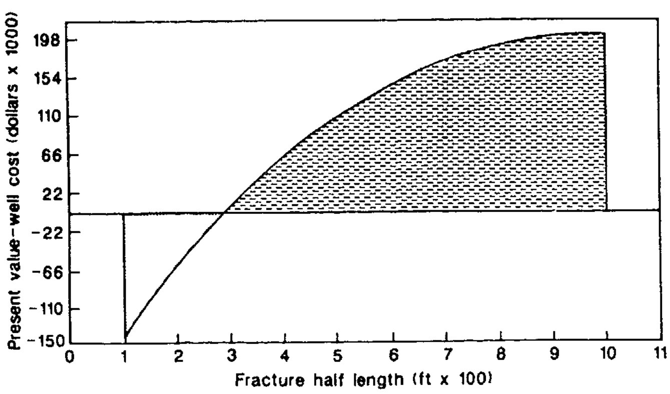

Fig. 18—Present value minus present cost comparison for an average reservoir quality well (0.03 md/0.075 Φ/56.5 $h/k_f w$ = 500) in the Midland County Dean formation: 15% discounted CF/10 yr/$18 base.

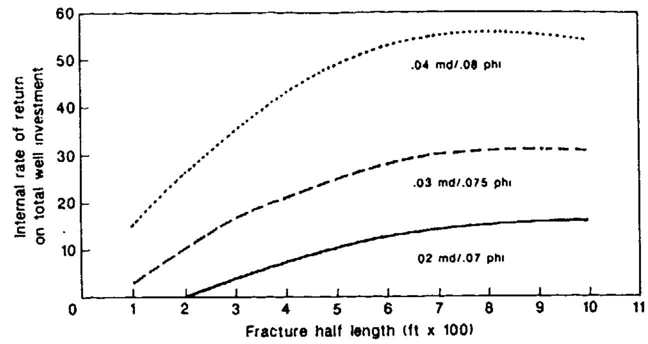

Fig. 19—Rate of return versus fracture length in the Midland County Dean formation (20/40 Ottowa; 1 lb/ft²; $k_f w$ = 100): 10 yr cash flow/$18 base price.

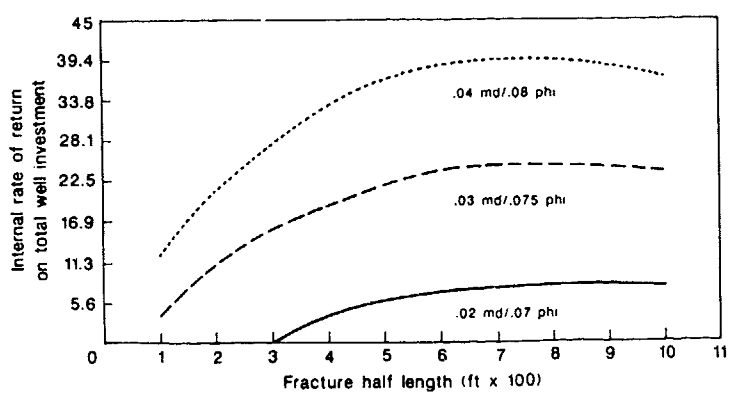

Fig. 20—Rate of return versus fracture length in the Midland County Dean formation (20/40 ISP; 1 lb/ft²; $k_f w$ = 500): 10 yr cash flow/$18 base price.