

Results of Stress-Oriented and Aligned Perforating in Fracturing Deviated Wells

C.M. Pearson, SPE, A.J. Bond, SPE, M.E. Eck, SPE,
and J.H. Schmidt, SPE, Arco Alaska Inc.

Summary. This paper reports the first results of stress-oriented and aligned perforating of deviated wells at the Kuparuk River field, Alaska. Preferred perforation alignment and spacing are calculated for each well so the fractures from individual perforations link to produce a single "zipper" fracture plane along the deviated wellbore. Results of the first application of this technique are presented from the 26-well development of Drillsite 2K. The results from use of three different oriented-casing-gun systems and pertinent data from Drillsite 2K fracture stimulation treatments are discussed. Comparisons to drillsites where nonaligned perforating strategies were used show a significant reduction in perforation friction, enabling the placement of larger, more productive fracture treatments. Application of this technique to deviated and vertical wells and its use at Kuparuk on developments after Drillsite 2K are discussed.

Introduction

Perforation design for a well that will be hydraulically fractured is usually controlled by the requirements to place the stimulation treatment.¹ Key parameters are the number, size, orientation, and phasing of perforations. Typically, the objective is either to minimize or, in the case of limited-entry treatments, to control the amount of perforation friction during the stimulation treatment. No uniform criteria exist within the industry for defining perforation phasing or shot density. Different operators use different techniques. However, the pumping of a fluid stage to break down the well and to calculate the perforation friction loss is routine to verify that sufficient communication exists between the wellbore and the formation to place the fracture treatment. Often, a ballout treatment is pumped before the main stimulation to force additional perforations to break down. Although it is generally acknowledged that the optimal placement of perforations in a vertical well is 180° phasing in the fracture plane, which is perpendicular to the far-field minimum stress, there are, to the best of our knowledge, no reported efforts of routinely practicing such a technique. Laboratory investigations into fracture initiation from deviated wells showed the importance of perforation placement on the length of wellbore intersecting the fracture.^{2,3}

During the past 7 years, more than 600 new development wells have been fracture-stimulated in the Kuparuk River field. The large number of treatments has provided the opportunity for significant advances in the technical and operational aspects of hydraulically fracturing deviated wells that are not aligned colinear to a direction of principal stress. The success of this stimulation program was documented in Refs. 4 and 5.

Perforation strategy during the initial development consisted primarily of perforating the net pay intervals in the Kuparuk A Sand. Depending on the drillsite, this would result in the perforating of two or three separate zones. Before the wellbore tubulars and completion equipment were run, casing guns (4 1/2-in.) were shot with a typi-

cal shot density of 4 shots/ft and a phasing of either 90° or 120°. We often used large-hole shots every fifth hole. Most initial fracture treatments pumped in wells where this strategy was used had relatively high perforation friction drops ranging from 500 to 1,500 psi. Post-treatment temperature and tracer logging often showed fluid entry into a few discreet points along the perforated interval, with the lowest zone of the A Sand often showing no evidence of fracture stimulation. The poor communication at the wellbore is thought to have caused many treatment screenouts in the field.

The first change in perforating strategy was to use limited perforating (1 shot/ft) of the upper A Sand intervals to divert more of the stimulation to the lower, less productive intervals. This strategy was used in 1986 at Drillsites 3N and 3K (Fig. 1). Postfracture reperforating of the upper A Sand lobes provided rate improvements of 0 to 400 BOPD. The second change occurred in 1987 and 1988 at Drillsites 3Q, 3M, 3H, and 3O. In these wells, the perforating interval was limited to the net pay interval of the thickest sand member (less than 20 ft), typically with 4 shots/ft at a variety of different phasings (0°, 45°, 90°, or 120°). Postfracture perforating of the upper A Sand lobes was then carried out for additional rate improvement.

The completions at Drillsite 2K during 1989-90 incorporated perforation of a single interval up to 40 ft long with the aligned and oriented perforating technique for fracture initiation from a deviated well.⁶ The technique consists of perforating at 180° phasing and at a specific orientation so that fracture initiation from the individual perforations occurs in the tension zone around the wellbore and a zipper-type fracture is formed from the coalescence of the individual fractures. The required alignment typically is measured as the counterclockwise angle from the top of the well looking down. Three types of eccentric casing guns were used until a satisfactory system was developed. This type of system has since become the standard perforation technique for deviated wells that are to be fracture-stimulated. It has been used for intervals up to 54 ft long in later developments at Drillsites 1A, 1L, and 3G. Additional postfrac-

Copyright 1992 Society of Petroleum Engineers

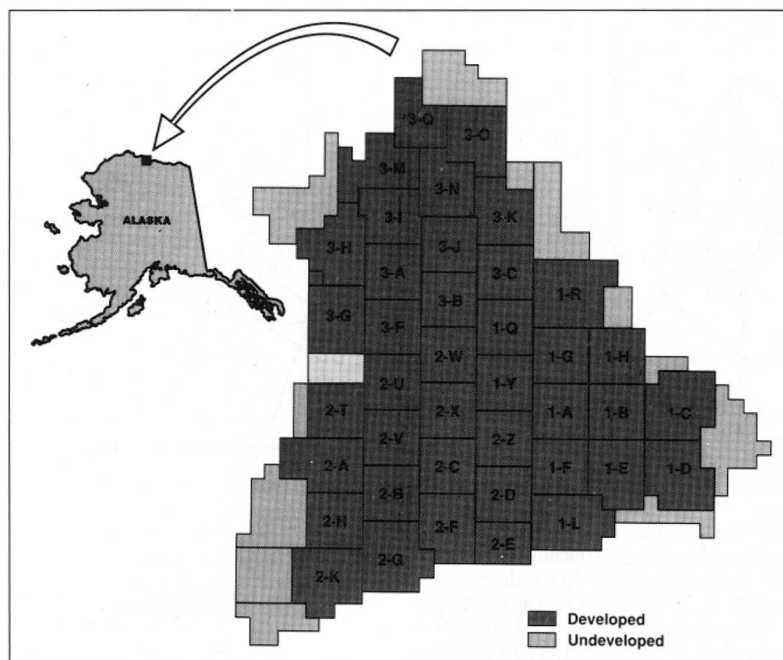


Fig. 1—Kuparuk River field.

ture perforating was carried out at Drillsite 2K in the few wells with additional A Sand lobes. In specific cases in later drillsite developments, this practice has been modified to include aligned perforating of multiple zones before fracturing.

Kuparuk Field Development

The Kuparuk River field, one of the largest oil fields in the U.S., is located in the Alaskan Arctic and covers about 115,000 acres. Fig. 1 shows the field location and the development drillsite pads from which the deviated wells are drilled. Initial development is on 160-acre well spacing with some 80-acre infill locations. The Kuparuk reservoir is a sandstone whose primary production mechanism is solution-gas drive. Most of the field is under secondary recovery, receiving pressure support through a combination of waterflood and water-alternating-immiscible-gas injection.

Production occurs from two horizons within the Kuparuk sandstone. An upper sandstone interval, the C Sand, consists of very-coarse to very-fine-grained siderite and sandstone. Net pay ranges up to 80 ft with an average permeability of 150 md. The lower producing zone, the A Sand, is present throughout the field. Although the A Sand typically averages less than 30 ft thick, with permeability ranging from 20 to 80 md, it contains 65% of the total reserves in the Kuparuk field. It is a fine- to very-fine-grained sandstone interbedded with shale and varying amounts of ankerite. The B Unit, made up of sands, siltstones, and shales, ranges in gross thickness from 0 to 150 ft. This high-shale-content zone provides an impermeable barrier to flow between the two producing zones and benefits

oil recovery by allowing the two zones of distinctly different producing characteristics to be waterflooded separately. In addition, it provides the stress barrier to isolate and treat the A Sand by hydraulic fracturing.

Kuparuk wells with departures up to 10,000 ft are drilled from centrally located gravel pads to minimize the environmental impact on the arctic tundra. Most wells are drilled at an angle through the Kuparuk to minimize drilling costs. No attempt is made to align the wellbore with the fracture orientation, and the typical hole angle across the formation is 35° to 65° from vertical. A single, nonselective completion is used for wells with minimal C Sand development, and the A Sand is generally stimulated before the C Sand is perforated.

The moderate-permeability A Sand has low initial rates. Unstimulated, it would be uneconomic in the high-cost arctic environment. Prefracture flow efficiencies average 55% (flow efficiency is the ratio of the well's actual PI to its PI if it is undamaged and unstimulated). Matrix stimulation treatments are unsuccessful because of the highly laminated nature of the A Sand, preventing effective communication between the perforations and all the sand intervals. Fracture treatments are used to overcome the near-wellbore damage caused by drilling and completion operations and to provide high-flow-capacity conduits to maximize withdrawals. The hydraulic fracture program allows the successful development of the reservoir and significantly expands the economic acreage of the Kuparuk River field.

Theory

The state of stress within the Earth's crust usually is such that one of the principal stress

"The first change in perforating strategy was to use limited perforating . . . of the upper A Sand intervals to divert more of the stimulation to the lower, less productive intervals."

directions is vertical. This guarantees that the other two principal stress directions are perpendicular to the axis of a vertical wellbore. As a result, hydraulic fractures initiated from a vertical well will extend along the wellbore axis. On the other hand, in a deviated well, the wellbore is not aligned with any of the principal in-situ stresses. This results in shear stresses at the wellbore surface, as shown in Fig. 2. The shear stresses cause a fracture to turn as it propagates into the direction mostly perpendicular to the minimum principal stress. To describe the fracture initiation, the in-situ stresses are first resolved into the components shown in Fig. 3. This transformation resolves the stresses to a coordinate system relative to the high side the wellbore. It is given by⁶

$$\bar{\sigma}_{ij} = \alpha_{ip} \alpha_{jq} \bar{\sigma}_{pq},$$

where the coordinate transformation is given by

$$\alpha_{ij} =$$

$$\begin{bmatrix} \cos(\alpha)\cos(\beta) & \sin(\alpha)\cos(\beta) & \sin(\beta) \\ -\sin(\alpha) & \cos(\alpha) & 0 \\ -\cos(\alpha)\sin(\beta) & -\sin(\alpha)\sin(\beta) & \cos(\beta) \end{bmatrix}.$$

Superposing solutions to the infinite cylindrical hole in an infinite medium loaded with internal pressure, normal stresses (σ_x , σ_y , σ_z), and shear stresses (σ_{xy} , σ_{yz} , σ_{xz}) describes the state of stress anywhere around the deviated wellbore.^{7,8} In particular, the state of stress is known at the wellbore surface. Therefore, the maximum tensile stress

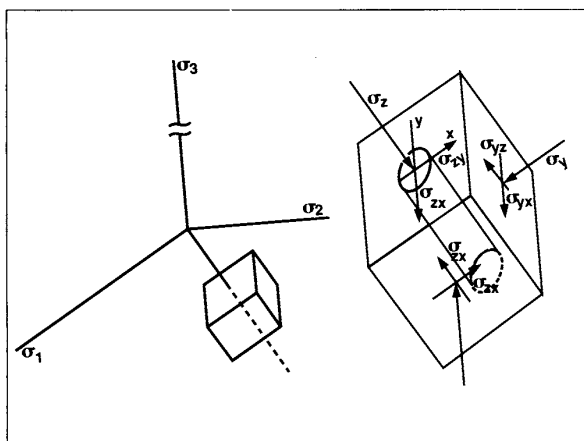


Fig. 2—State of stress around a deviated well.

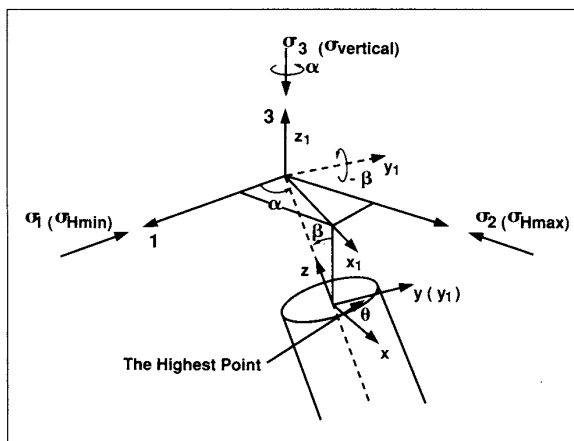


Fig. 3—Deviated coordinate system.

can be found at the wellbore surface as a function of θ , the counterclockwise rotation from the high side of the wellbore, looking top to bottom, and the internal wellbore pressure, p . In addition to the maximum tensile stress, the oblique angle that the small minifracture makes with the wellbore, γ , may also be calculated (Fig. 4).⁷ With the maximum tensile stress as the criterion for fracture breakdown, a tensile zone symmetric to the point of maximum tensile stress at the wellbore surface is located at θ_0 (Fig. 4).

Fig. 5 shows the location of two minifractures induced at different locations in the tension zone on the deviated-wellbore surface. The propagations of the fracture tips are determined by looking at the influence of the tail of Fracture 2, A_2 , on the head of Fracture 1, B_1 , and vice versa as a function of the fracture spacing, h .⁹ The fracture growth at Tip A follows Path a, while that at Tip B follows Path b (Fig. 6). When h is large, the two minifractures do not inter-

act. At close spacings, however, the interaction between the two fractures causes them to link up in the zipper-like fashion shown in Fig. 7, as reported previously.^{10,11}

In practice, minifractures originate from individual perforations. The above criteria enable a maximum perforation spacing to be calculated for a given in-situ stress field and wellbore geometry. Successive minifractures link to form a single zipper fracture along the wellbore surface. As pumping continues, the single fracture propagates into the rock medium and the fracture tip turns under the influence of shear and normal stresses. The turning rate of the fracture tip is calculated by treating the zipper fracture as an elliptic fracture, with a major axis equal to the link-up distance along the wellbore and the perforation length as the minor axis. A turning angle is then calculated from the criterion of minimum strain energy density.^{12,13} Computed results show that the fracture turns within tens of feet, aligning itself in a direction mostly perpendicular to

“The second change . . . the perforated interval was limited to the net pay interval of the thickest sand member . . .”

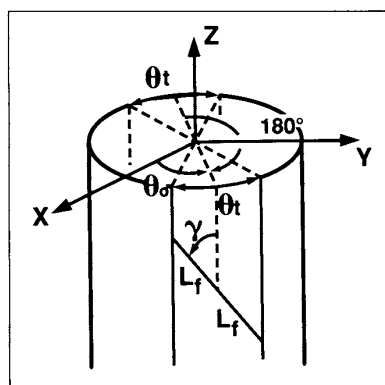


Fig. 4—Deviated openhole minifracture orientation.

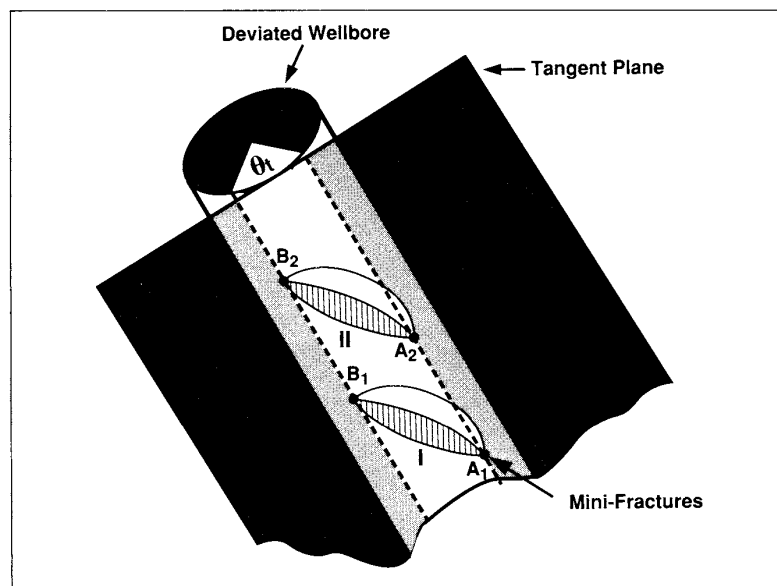


Fig. 5—Multiple minifractures on an open deviated wellbore.

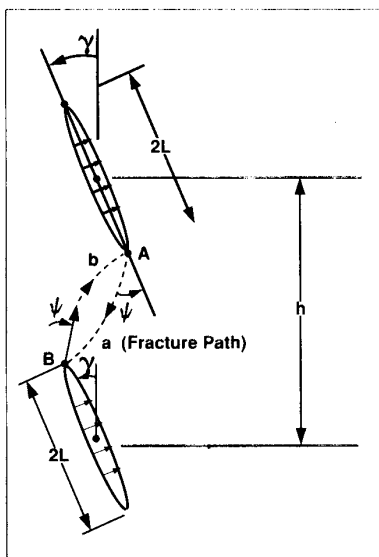


Fig. 6—Link-up between two inclined minifractures.

the minimum in-situ stress. The top and bottom fracture edges turn vertically, while the leading fracture edge remains cocked to the vertical at an angle equal to the wellbore deviation. Additionally, calculations show

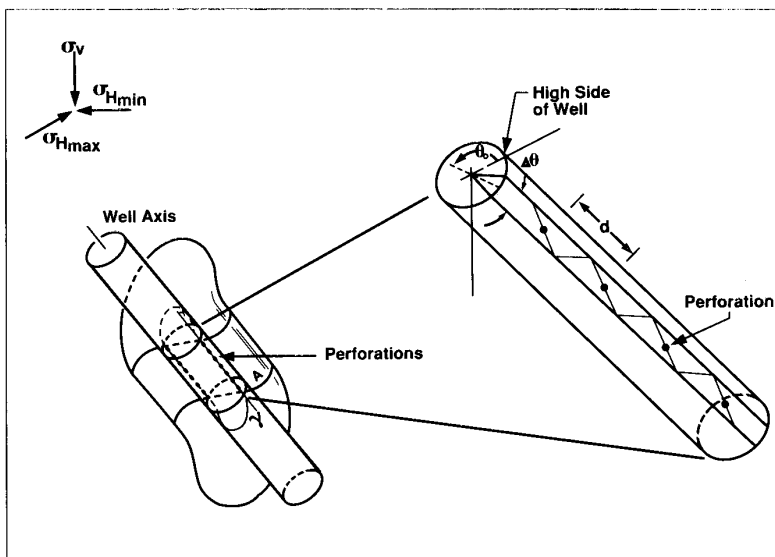


Fig. 7—Perforation link-up.

that the radius of curvature is larger with higher pumping pressures.

The Preferred Orientation Placement Program was used in this study to determine the perforation orientation and minimum re-

quired spacing. It is based on fracture initiation from a deviated open wellbore, as described above. Previous analyses⁶ that investigated the effects of casing and cement found little difference in the location of θ_0

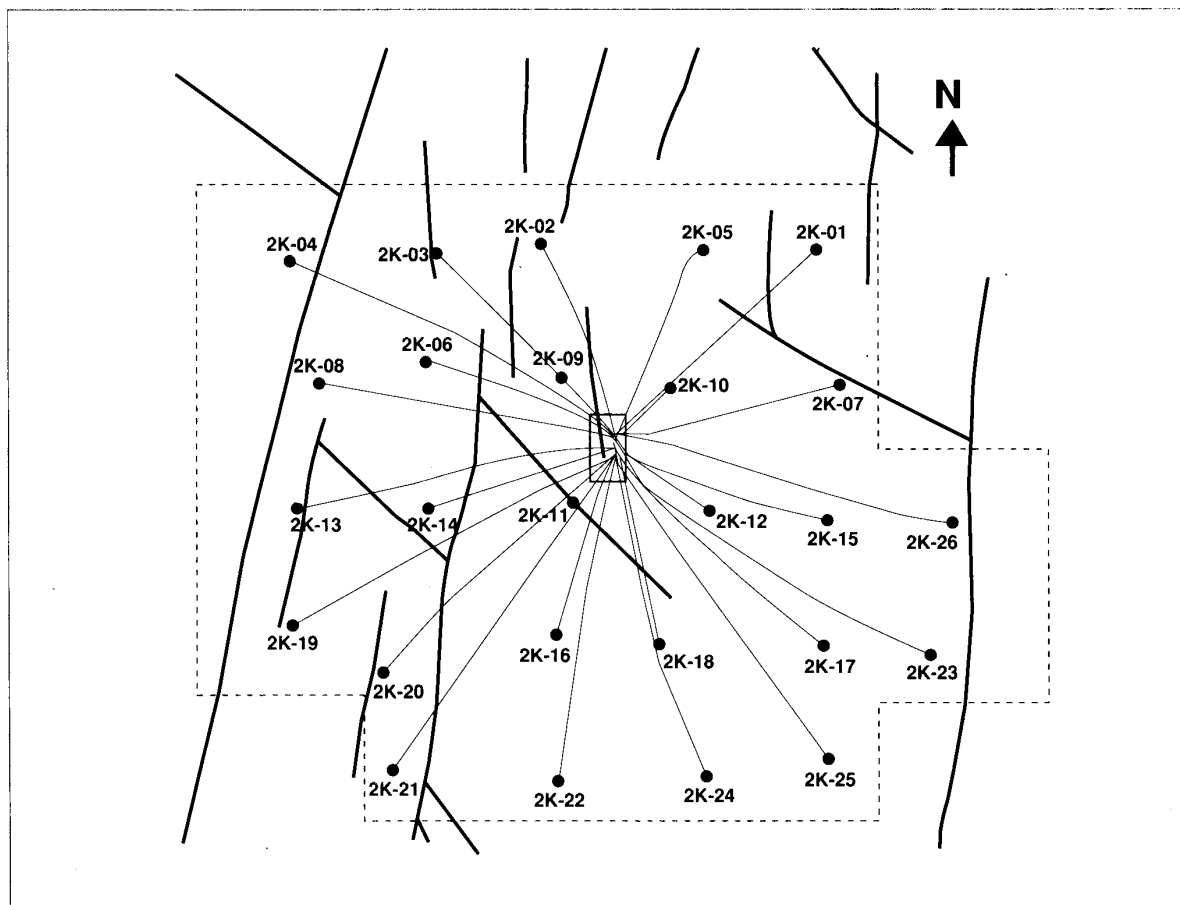


Fig. 8—Drillsite 2K fault/spider map.

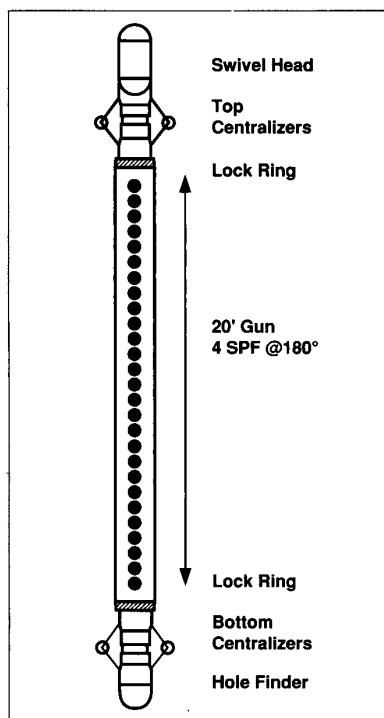


Fig. 9—Oriented perforating gun schematic.

compared with an openhole analysis. Yew *et al.*⁶ also showed that the effect of individual perforation tunnels was to change the breakdown pressure, not the location of θ_0 . Finally, the effects of inertia are neglected because hydraulic fracture growth is slow compared with wave speeds in rock.

Drillsite 2K Completions

Fig. 8 shows a spider map of the Drillsite 2K development and the principal faults. These wells were drilled in the latter half of 1989 and early 1990. The completions were carried out in two distinct phases because of space limitations at the drillsite: an initial nine wells in late 1989 and the re-

mainder of the wells in early 1990. Table 1 shows the calculated perforation requirements (minimum spacing and orientation) for a series of different well orientations and deviations at Drillsite 2K. Input data were obtained from either laboratory or field measurements. The minimum stress direction had previously been found to be perpendicular to the younger set of north-south faults (Fig. 8). In practice, actual survey data were taken at each well to calculate a specific perforation alignment, with a 4-shots/ft shot density being typical.

In the first series of completions, two different 4½-in. casing gun systems were used. System A used a bowspring to orient

TABLE 1—PERFORATION DESIGN INFORMATION

$E = 2 \times 10^6$ psi, $\mu = 0.2$, $r_w = 3.5$ in., $\sigma_t = 500$ psi, $\sigma_1 = \sigma_{Hmin} = -4,340$ psi, $\sigma_2 = \sigma_{Hmax} = -5,270$ psi, $\sigma_3 = \sigma_v = -6,200$ psi					
Deviation Angles (degrees)	Breakdown Pressure, p_b (psi)	Angular Position of Fracture, θ_0 (degrees)	Fracture Plane Deviation Angle, γ (degrees)	Maximum Perforation Spacing, d^* (in.)	
α	β				
0	15	8,498	90	7.68	22.18
	30	9,240	90	14.08	16.1
	60	10,575	0	0.0	—
30	15	8,415	57.79	6.58	24.95
	30	8,850	49.9	11.5	16.45
	60	9,426	17.61	10.62	16.62
60	15	8,260	27.96	3.73	40.97
	30	8,261	22.56	6.34	23.78
	60	8,070	9.59	7.63	17.13
90	15	8,187	0	0	—
	30	8,017	0	0	—
	60	7,552	0	0	—
120	15	8,260	152.04	3.73	40.97
	30	8,261	157.44	6.34	23.78
	60	8,070	170.41	7.63	17.13
150	15	8,415	122.21	6.58	24.95
	30	8,850	130.1	11.5	16.45
	60	9,426	162.39	10.62	16.62
180	15	8,498	90	7.68	22.18
	30	9,240	90	14.08	16.1
	60	10,575	0	0	—

“A method of preferred perforation alignment and orientation was successfully applied for the first time.”

TABLE 2—DRILLSITE 2K ORIENTED PERFORATING RESULTS, FALL 1989

Well	Wellbore Azimuth (degrees)	Wellbore Deviation (degrees from vertical)	Designed Perforation Orientation, Counterclockwise From High Side (degrees)	Gun 1 Actual Orientation (degrees)	Gun 2 Actual Orientation (degrees)	Average Difference (degrees)
System A						
2K-03	314	48	148	151	161	8
2K-04	297	65	168	189	186	23
2K-06	291	35	112	243	*	131
2K-07	79	41	48	52	67	12
				Average Difference		31
System B						
2K-02	332	38	160	166	176	11
2K-05	44	33	35	46	62	19
2K-08	287	58	163	183	192	25
2K-11	201	7	30	8	19	17
2K-12	126	26	128	197	151	46
				Average Difference		23

*The orienting equipment broke while running downhole and could not be repaired in time for the second gun run.

*The orienting equipment broke while running downhole and could not be repaired in time for the second gun run.

TABLE 3—DRILLSITE 2K ORIENTED PERFORATING RESULTS, SPRING 1990

Well	Wellbore Azimuth (degrees)	Wellbore Deviation (degrees from vertical)	Designed Perforation Orientation, Counterclockwise From High Side (degrees)	Gun 1 Actual Orientation (degrees)	Difference (degrees)	Gun 2 Actual Orientation (degrees)	Difference (degrees)
2K-01	57	37	45	47	2	44	1
2K-09	321	21	137	139	2	*	—
2K-10	27	2	26	16	10	25	1
2K-13	260	49	35	33	2	34	1
2K-14	259	38	54	60	6	56	2
2K-15	104	42	124	128	4	122	2
2K-16	198	37	12	16	4	15	3
2K-17	127	49	154	*	—	*	—
2K-18	174	37	171	163	8	168	3
2K-19	240	53	25	31	6	35	10
2K-20	217	50	17	24	7	17	0
2K-21	219	58	12	13	1	12	0
2K-22	195	65	4	18	14	2	2
2K-23	121	48	147	151	4	150	3
2K-24	162	48	171	171	0	177	6
2K-25	144	52	164	165	1	163	1
2K-26	105	54	158	155	3	166	8
Average Difference					5		3

*Navigation tool failed.

the guns to the low side of the wellbore; System B used a weighted half-cylinder attached below the gun. In both cases, the actual orientation angle was measured by a magnetic survey tool attached to the bottom of each gun. Results are shown in Table 2, which lists the designed orientation angle in degrees counterclockwise from the high side of the well and the measured angle as recorded by the survey tool. The average errors were 31° and 23° for Systems A and B, respectively. Neither of these conventional orientation systems operated satisfactorily, and both failed to meet the required tolerance of a $\pm 10^\circ$ maximum error.

Perforation gun designs considered for the second phase of completions at Drillsite 2K included the use of a downhole orientation motor. However, a nonpowered system was selected after design and successful field testing of a new bearing-mounted, eccentric system incorporating a real-time surface readout of gun orientation. Fig. 9 shows a schematic of the tool. The orientation is set with a lock ring on surface, and the gun is suspended between two rollers to allow the gun body to rotate freely to the low side of the well. The surface readout navigation package is hard-connected to the guns through the top roller assembly to provide real-time measurement of gun orientation. Table 3 gives the results of the second phase of completions, with a total of 17 wells and 34 separate gun runs with average errors of 5° and 3° for the two runs made per well.

Stimulation Treatments

Table 4 shows the stimulation treatment design for Well 2K-07, a typical treatment for most of the Drillsite 2K wells where there was only A Sand development. Earlier work³ showing the productivity benefit of larger, more conductive fractures necessitated significantly larger treatments to be placed than in previous developments that

never averaged more than 57,000 lbm of proppant per well.

Fracturing pressure data from Drillsite 2K were analyzed to provide a direct measurement of the aligned and oriented perforating technique. Any increase in the wellbore-to-fracture intersection was reasoned to reduce the near-wellbore/perforation-friction loss measured during stimulation treatments. Table 5 gives the perforation friction pressure measured from surface pressure data and calculated with field-measured tubing friction data. In all cases, the data were obtained after pumping of the treatment prep and following displacement of the tubing volume with either slick diesel or slick water (depending on the ambient temperature at the wellsite). The appropriate tubing friction, verified on a number of occasions with downhole pressure gauges, was

subtracted from the difference in the treating pressure and the instantaneous shut-in pressure to obtain the values reported in Table 5. An average 292-psi pressure loss was measured, although the median was 0 psi. High pressures were measured at Wells 2K-05 and 2K-13. At Well 2K-05, the stimulation treatment was placed as planned despite the high perforation friction attributed to poorly gelled diesel that caused high tubing friction while flushing and freeze-protecting the wellbore. Well 2K-13 was reperforated before a fracture treatment could be placed.

Table 5 also compares perforation friction pressures measured at Drillsite 2K and the previous three development drillsites (Drillsites 3H, 3M, and 3O). A variety of non-oriented techniques had been used, and the measured perforation friction was significantly higher. Drillsite 2K was the first de-

TABLE 4—GELLED-WATER TREATMENT DESIGN: WELL 2K-07

Stage	Description	Pump Rate (bbl/min)	Clean Volume (bbl)	Proppant Mesh	Proppant Concentration* (lbm/gal added)	Proppant Mass (lbm)
1	Prepad, GW**	25	335	—	—	—
2	Flush	25	75	—	—	—
3	Pad, GW	25	1,100	—	—	—
4	GW	25	92	16/20	2	7,720
5	GW	25	94	16/20	4	15,710
6	GW	25	103	16/20	6	25,910
7	GW	25	118	16/20	8	39,750
8	GW	25	63	12/18	10	26,240
9	GW	25	40	12/18	12	19,780
10	Flush	20	73	—	—	—
Total: GW, bbl						1,044
Slick diesel, bbl						148
Clean diesel, bbl						81
16/20-mesh low density ceramic proppant, lbm						89,090
12/18-mesh low density ceramic proppant, lbm						46,020
Total low density ceramic proppant, lbm						135,110

*Proppant concentration ramped through the job.

**Gelled water (GW) fluids are 40 lbm/1,000 gal hydroxypropyl guar with borate crosslinker. 40 lbm/1,000 gal silica flour and 6% clean diesel in the prepad and pad stages only.

TABLE 5—PERFORATION FRICTION (psi) ON DEVELOPMENT DRILL SITES

Well	Drillsite 2K	Drillsite 3H	Drillsite 3M	Drillsite 3O
1	0	574	292	0
2	314	0	0	1,127
3	0	314	376	427
4	0	1,363	0	1,167
5	1,611	472	2,335	125
6	80	820	670	0
7	0	1,050	139	316
8	206	609	72	754
9	472	1,268	270	435
10	0	190	0	1,150
11	0	570	158	277
12	0	524	2,060	1,248
13	2,026	15	479	485
14	490	506	51	566
15	0	260	0	1,346
16	0	928	0	0
17	0	761	1,105	384
18	0	1,389	0	795
19	0	0	450	—
20	211	490	393	—
21	—	1,923	1,473	—
22	736	86	665	—
23	498	—	—	—
24	660	—	—	—
25	0	—	—	—
26	0	—	—	—
Average	292	641	499	589
Median	0	557	281	460

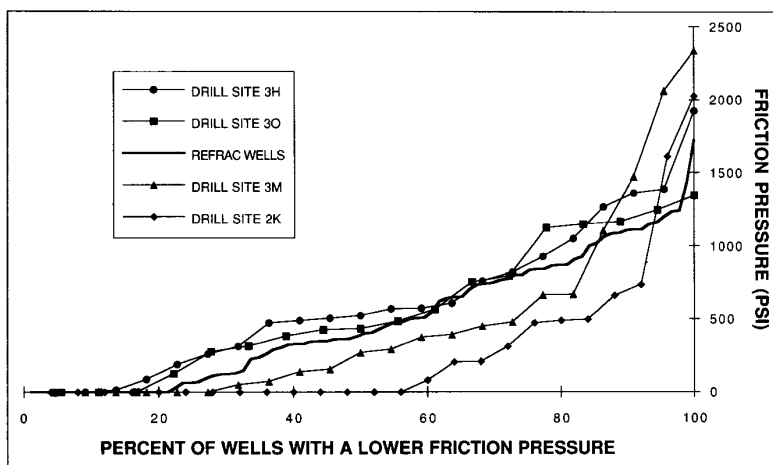


Fig. 10—Comparison of perforation frictions.

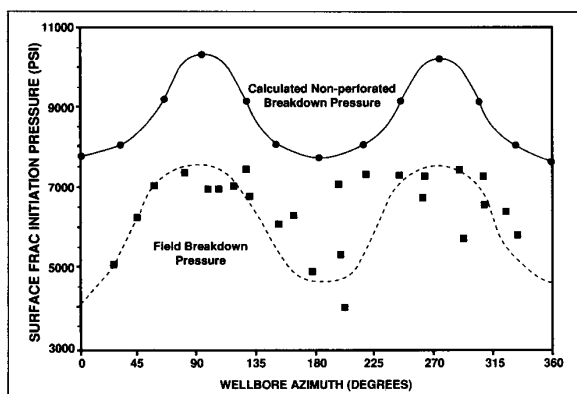


Fig. 11—Drillsite 2K fracture initiation pressures.

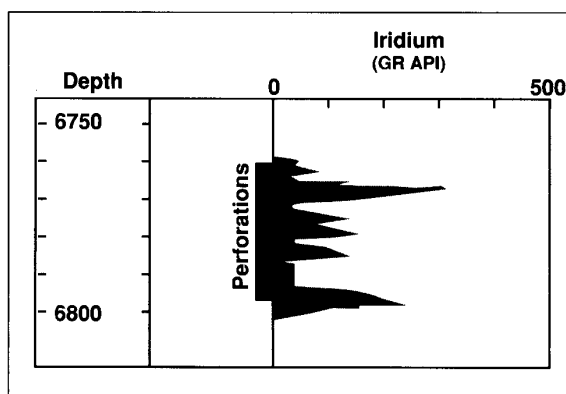


Fig. 12—Well 2K-12 post-treatment gamma log.

velopment in a number of years to use gelled-water fracturing fluids and slick water as the prepad flush fluid. Therefore, the tubing friction data used to calculate the perforation drop were different from data from the previous drillsites where only diesel-based fluids were used. Table 6 compares Drillsite 2K and wells that were refractured over the past 2 years with similar gelled-water fluids. These wells had been producing oil for a number of years with no water production from the A Sand, which would enlarge the perforations and reduce the friction. However, they have an average friction loss of 492 psi, 200 psi higher than the Drillsite 2K wells. Of particular note is that 19 of these 89 wells had 0-psi measured perforation friction. These wells typically were perforated with either 90° or 120° phasing. Thus, a 1 in 5 random chance of placing a line of perforations in the tension zone would imply a tension zone arc of 20° where the perforations should be placed. The data from Tables 5 and 6 are plotted in Fig. 10, which, for a given friction pressure, shows the percentage of wells in each group that had a friction pressure lower than the referenced value.

Fig. 11 plots surface fracture initiation pressure vs. wellbore azimuth. The upper line illustrates the calculated value of fracture initiation pressure for an unperforated wellbore. The perforation breakdown pressures are significantly lower; however, the sinusoidal nature of the data is evident from the field measurements. The minimum breakdown pressure at about 0° and 180° validates the previous field measurements that the minimum stress plane runs north-south and parallels the fault structure.

Postfracture temperature and radioactive logging measurements are not routinely carried out on the fractured deviated wells at Kuparuk because height growth occurs away from the wellbore. However, tracers were run at Wells 2K-10, 2K-11, and 2K-12. Fig. 12 is a post-treatment log from Well 2K-12, which has the highest deviation of these three wells. It shows that proppant was placed across the entire 32-ft perforated interval. Successful fracture stimulation of Drillsite 2K resulted in an average of more

TABLE 6—PERFORATION FRICTION MEASURED ON GELLED-WATER REFRRACTURED WELLS

Well	Date	Wellbore Azimuth (degrees)	Wellbore Deviation (degrees)	Perforation Friction (psi)	Well	Date	Wellbore Azimuth (degrees)	Wellbore Deviation (degrees)	Perforation Friction (psi)
2D-13	May 31, 1989	202	45	430	2T-14	Aug. 8, 1990	204	44	326
2G-13	June 13, 1989	203	39	0	2T-17	Aug. 8, 1990	124	37	1,439
2G-15	June 14, 1989	224	46	1,240	2U-13	Aug. 11, 1990	39	44	648
2X-15	June 28, 1989	122	44	1,086	3O-13	Aug. 21, 1990	170	35	93
2U-09	July 4, 1989	265	48	650	2W-01	Aug. 25, 1990	85	45	290
2G-08	July 10, 1989	76	49	844	2W-13	Aug. 29, 1990	40	49	455
3A-12	July 19, 1989	71	35	0	3I-09	Sept. 2, 1990	317	54	380
2F-10	July 30, 1989	105	44	510	2T-14	Sept. 5, 1990	199	44	0
2F-11	Aug. 3, 1989	132	45	0	1A-06	Sept. 10, 1990	170	43	505
3N-07	Aug. 11, 1989	324	42	400	2W-11	Sept. 10, 1990	338	60	0
2T-08	Aug. 15, 1989	63	40	330	2C-16	Sept. 12, 1990	340	41	545
2T-03	Aug. 18, 1989	329	42	870	3A-13	Sept. 19, 1990	352	35	733
2F-07	Sept. 14, 1989	80	47	1,201	2H-12	Sept. 25, 1990	1	44	121
2F-08	Sept. 17, 1989	43	19	227	1Y-30	Sept. 27, 1990	323	43	0
3K-10	Sept. 22, 1989	280	35	1,066	1A-10	Oct. 3, 1990	228	39	1,113
2H-05	Sept. 25, 1989	68	40	1,090	3B-14	Oct. 6, 1990	236	7	479
2H-07	Sept. 29, 1989	111	46	1,235	2A-10	Oct. 7, 1990	212	38	702
2G-04	Oct. 13, 1989	334	39	360	3H-14	Oct. 9, 1990	40	45	1,111
2G-11	Oct. 28, 1989	129	45	0	3B-11	Oct. 10, 1990	144	38	261
2W-06	Nov. 6, 1989	194	38	1,149	2A-09	Oct. 16, 1990	198	48	1,021
2B-03	Nov. 11, 1989	187	50	0	2A-10	Oct. 16, 1990	212	38	925
2H-11	April 8, 1990	216	33	872	2B-13	Oct. 17, 1990	344	30	0
3Q-11	May 1, 1990	217	31	774	2U-01	Oct. 31, 1990	116	40	29
2W-15	May 3, 1990	55	44	0	3N-16	Nov. 3, 1990	114	38	364
2B-02	May 8, 1990	198	32	130	2U-12	Nov. 14, 1990	333	43	0
3F-11	May 11, 1990	219	46	834	1R-01	Nov. 16, 1990	105	39	348
3C-03	May 16, 1990	301	42	746	3A-01	Nov. 18, 1990	132	44	1,723
1G-08	May 19, 1990	324	42	237	1A-08	Nov. 23, 1990	—	0	407
2X-10	May 21, 1990	198	35	148	1F-07	Dec. 4, 1990	107	34	0
2X-11	May 23, 1990	281	24	622	1F-12	March 3, 1991	328	24	0
2H-09	May 27, 1990	357	51	330	2U-02	April 16, 1991	151	47	0
2V-12	May 30, 1990	148	49	739	2U-08	April 21, 1991	228	33	124
2V-09	June 3, 1990	54	40	0	1E-11	April 30, 1991	318	52	0
3A-07	June 8, 1990	138	39	68	2T-10	April 30, 1991	246	46	798
2C-09	June 15, 1990	39	42	0	1Y-16	May 3, 1991	323	47	500
2W-03	June 23, 1990	123	43	348	3I-01	May 4, 1991	84	43	306
2A-14	July 1, 1990	101	36	764	2T-13	May 7, 1991	101	44	474
2A-15	July 1, 1990	142	40	1,160	3K-06	May 15, 1991	327	38	362
2C-13	July 10, 1990	211	29	908	3J-03	May 18, 1991	200	46	865
2C-15	July 17, 1990	333	38	0	2T-12	May 21, 1991	227	27	1,109
2D-03	July 18, 1990	357	43	0	3J-14	May 22, 1991	308	42	1,001
2U-15	July 25, 1990	80	33	62	3O-11	May 25, 1991	259	33	110
1A-03	July 29, 1990	48	33	800	2U-06	May 28, 1991	206	47	62
2U-13	July 29, 1990	39	44	643	3O-15	May 29, 1991	240	49	842
2G-09	Aug. 8, 1990	104	40	345					
								Average	492
								Median	400

than 94,000 lbm of proppant being placed in each well, which is significantly more than was placed at any previous development drillsite.

Conclusions

A method of preferred perforation alignment and orientation was successfully applied for the first time. Results from a 26-well development at Drillsite 2K in the Kuparuk River field showed conventional gun orientation systems to be unsatisfactory in their performance, with a 27° average error in gun alignment. A modified eccentric gun system incorporating a real-time navigational package was successfully used for the last 17 wells and 34 gun runs, with an average alignment error of 4°.

Successful perforation alignment significantly reduced the perforation friction loss measured during hydraulic fracturing compared with other drillsites where a non-

aligned perforation technique was used. The lower perforation friction was one factor that enabled significantly larger fracture treatments to be placed.

Work continues to verify the maximum extent of perforated intervals that can be stimulated successfully as a single interval in a deviated well. This work should further define the productivity benefits of this technology and refine application of the alignment theory for near-horizontal wells and wells aligned in the direction of the minimum principal stress direction.

The benefits realized at Drillsite 2K suggest that the aligned perforating technique should be applied in all hydraulic fracturing treatments where near-wellbore friction needs to be minimized. The use of a down-hole orientation motor in conjunction with the real-time navigation tool would enable aligned perforating of vertical wells.

Nomenclature

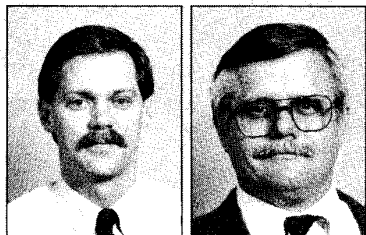
- d^* = minimum perforation spacing, in.
- E = Young's modulus, psi
- L_f = fracture half-length, in.
- p = fluid pressure, psi
- p_b = breakdown fluid pressure, psi
- r_w = wellbore radius, in.
- x, y, z = Cartesian coordinates
- α, β = deviation angles of well axis
- γ = orientation of initial fracture
- θ, r, z^+ = cylindrical coordinates
- θ_t = angle span of tension zone
- θ_0 = position of initial fracture
- μ = Poisson's ratio of rock medium
- σ_{Hmax} = in-situ maximum principal horizontal stress, psi
- σ_{Hmin} = in-situ minimum principal horizontal stress, psi
- σ_i = in-situ stress ($i=1,2,3$), psi

Authors



Pearson

Bond



Eck

Schmidt

Mark Pearson is a senior staff engineer in the Kuparuk Engineering Dept. at Arco Alaska Inc. in Anchorage. His specialties include well completion and stimulation. Pearson currently is an Alaska Section director and was program chairman for the 1991 SPE International Arctic Technology Symposium. He holds BS and PhD degrees in mining engineering from the Camborne School of Mines, U.K. **Andrew J. Bond** is a production foreman for Arco Alaska based at the Kuparuk River field. Previously, he was the operations engineer for Drillsite 2K during initial development. Bond holds a BS degree in petroleum engineering from the Colorado School of Mines. **Mark Eck** has held several engineering assignments with Arco in both the Lower 48 and Alaska. He most recently was a senior area engineer for the Kuparuk River Unit, with special emphasis in completion and stimulation practices. A 1991 member of the SPE Speakers Bureau, Eck holds a BS degree in mechanical engineering from the U. of Missouri, Rolla. **Joe Schmidt** is a staff engineer in the Prudhoe Bay Workover/Stimulation Group for Arco Alaska. He previously was a principal research engineer at Arco's Research Center in Plano, TX, where his work included horizontal drilling, ice mechanics, and hydraulic fracturing. Schmidt holds a BS degree in marine engineering, and BS, MS, and PhD degrees in mechanical engineering, all from Texas A&M U.

$\bar{\sigma}_{ij}$ = stress tensor, psi
 σ_t = tensile strength, psi
 σ_v = in-situ vertical stress, psi

Acknowledgments

We thank the management of Arco Alaska Inc. and the owners of the Kuparuk River field for support and permission to publish this paper. Numerous personnel have been involved in the field development activities detailed in this paper. Particular recognition is due the contributions of Arco Alaska Inc.'s drilling, operations, and on-site engineering personnel.

References

1. Gidley, J.L. *et al.*: *Recent Advances in Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (1989) 12, Chap. 12, 249-51.
2. Hallam, S.D. and Last, N.C.: "Geometry of Hydraulic Fractures From Modestly Deviated Wellbores," *JPT* (June 1991) 742-48.
3. Behrmann, L.A. and Elbel, J.L.: "Effect of Perforations on Fracture Initiation," *JPT* (May 1991) 608-15; *Trans.*, AIME, 291.
4. Niemeyer, B.L. and Reinart, M.R.: "Hydraulic Fracturing of a Moderate-Permeability Reservoir, Kuparuk River Unit," paper SPE 15507 presented at the 1986 SPE Annual Technical Conference and Exhibition, New Orleans, Oct. 5-8.
5. Pearson, C.M. *et al.*: "Optimal Fracture Stimulation of a Moderate Permeability Reservoir—Kuparuk River Unit," paper SPE 20707 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 23-26.
6. Yew, C.H., Schmidt, J.H., and Li, Y.: "On Fracture Design of Deviated Wells," paper SPE 19722 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, Oct. 8-11.
7. Timoshenko, S. and Goodier, J.N.: *Theory of Elasticity*, McGraw Hill Book Co. Inc., New York City (1951).
8. Hashin, Z. and Rosen, B.W.: "The Elastic Moduli of Fiber Reinforced Materials," *J. Applied Mech.* (June 1964) 223-32.
9. Lu, C.K. and Yew, C.H.: "Bonded Half-Planes Containing Two Arbitrarily Oriented Cracks: A Study of Containment of Hydraulically Induced Fractures," *SPEJ* (Feb. 1985) 55-66.
10. El Rabaa, W.: "Experimental Study of Hydraulic Fracture Geometry Initiated From Horizontal Wells," paper SPE 19720 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, Oct. 8-11.
11. Economides, M.J. and Nolte, K.G.: *Reservoir Stimulation*, Prentice-Hall Inc., Englewood Cliffs, NJ (1989) Chap. 19, 17.
12. Sih, G.C. and Cha, B.C.K.: "A Fracture Criterion for Three-Dimensional Crack Problems," *Eng. Frac. Mech.* (1974) 6, 699-723.
13. Sih, G.C. and MacDonald, B.: "Fracture Mechanics Applied to Engineering Problems—Strain Energy Density Fracture Criterion," *Eng. Frac. Mech.* (1974) 6, 361-386.

SI Metric Conversion Factors

acres	× 4.046 873	E-01 = ha
bbl	× 1.589 873	E-01 = m ³
ft	× 3.048*	E-01 = m
gal	× 3.785 412	E-03 = m ³
in.	× 2.54*	E+00 = cm
lbm	× 4.535 924	E-01 = kg
md	× 9.869 233	E-04 = μm ²
psi	× 6.894 757	E+00 = kPa

*Conversion factor is exact.

Provenance

Original SPE manuscript, **Results of Stress Oriented and Aligned Perforating in Fracturing Deviated Wells**, received for review Oct. 6, 1991. Revised manuscript received Nov. 4, 1991. Paper accepted for publication Nov. 7, 1991. Paper (SPE 22836) first presented at the 1991 SPE Annual Technical Conference and Exhibition held in Dallas, Oct. 6-9.

JPT