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

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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 intiation 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 (4½-in.) were shot with a typical 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-

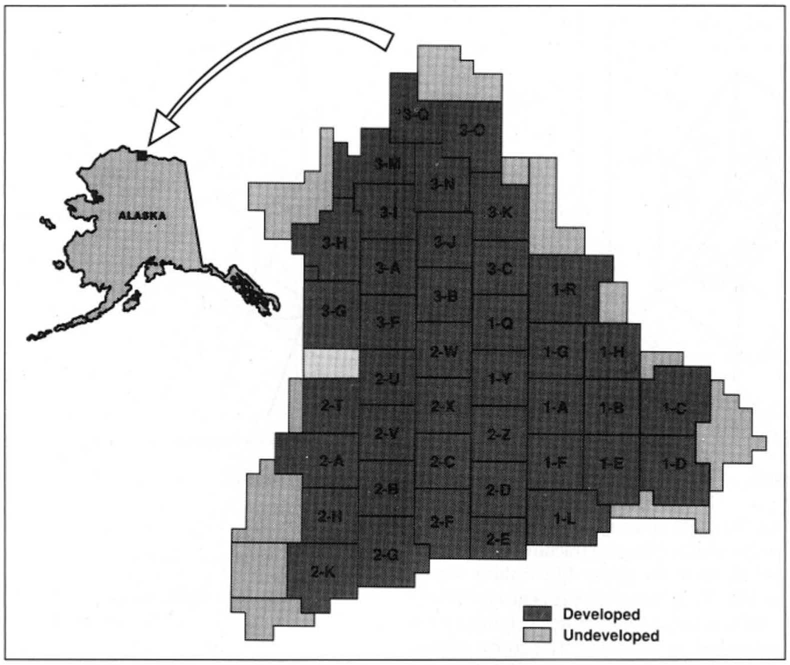

Fig. 1—Kuparuk River field.

"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."

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 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 by[6]

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

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

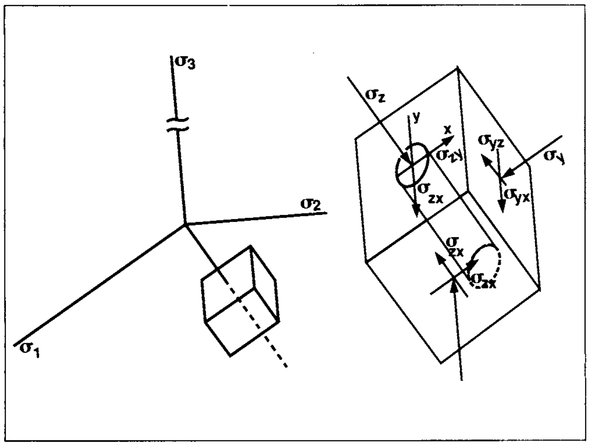

Fig. 2—State of stress around a deviated well.

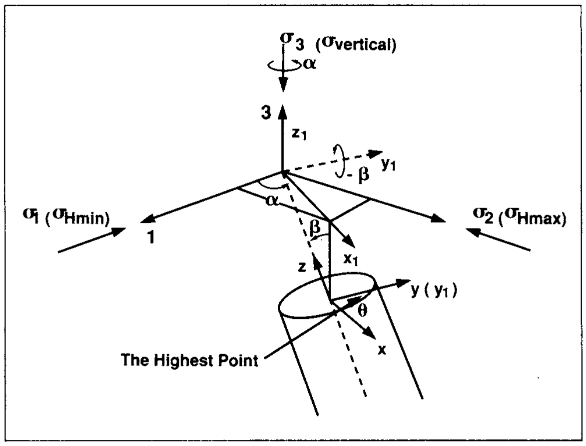

Fig. 3—Deviated coordinate system.

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 interact. 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. . . ."

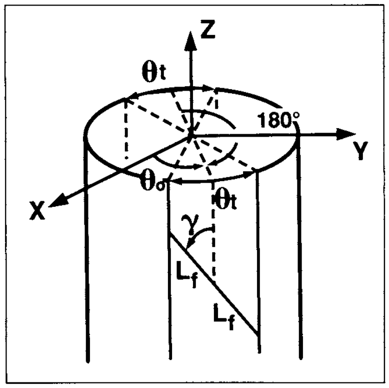

Fig. 4—Deviated openhole minifracture orientation.

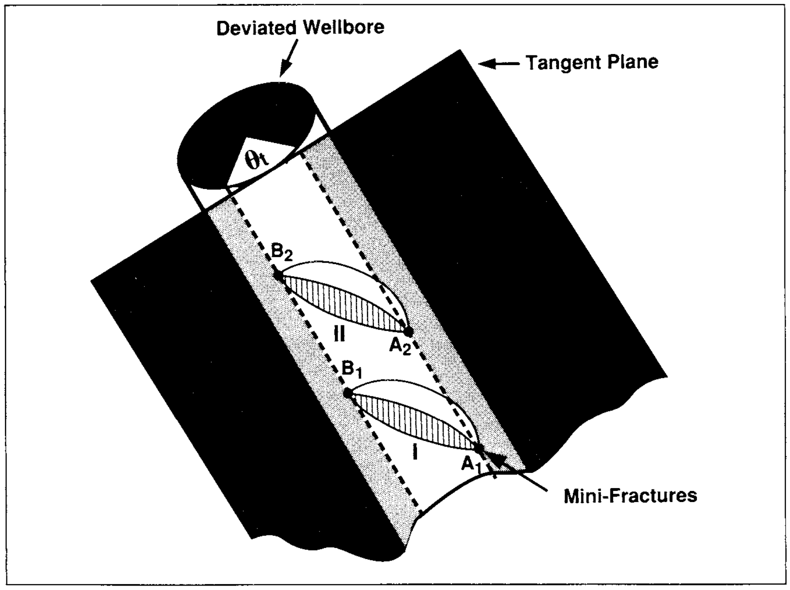

Fig. 5—Multiple minifractures on an open deviated wellbore.

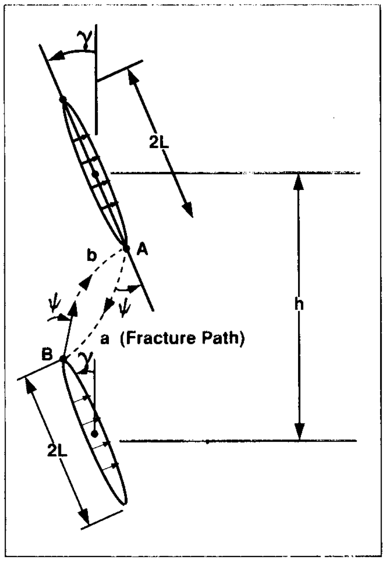

Fig. 6—Link-up between two inclined minifractures.

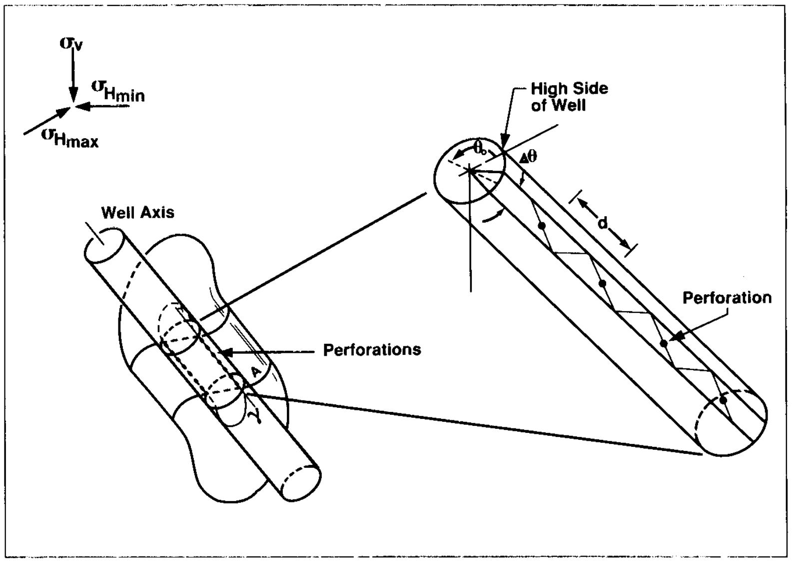

Fig. 7—Perforation link-up.

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 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 required spacing. It is based on fracture initiation from a deviated open wellbore, as described above. Previous analyses[6] that investigated the effects of casing and cement found little difference in the location of θ_0

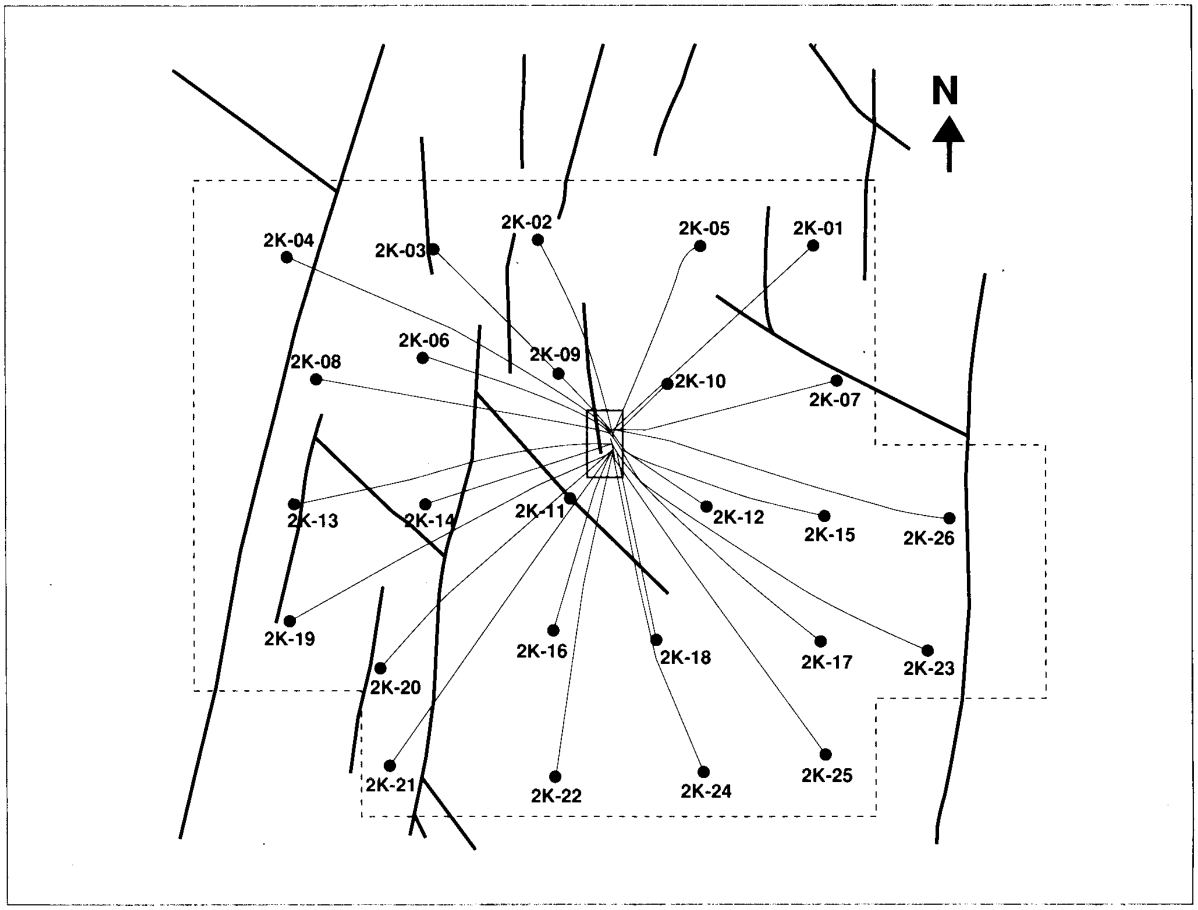

Fig. 8—Drillsite 2K fault/spider map.

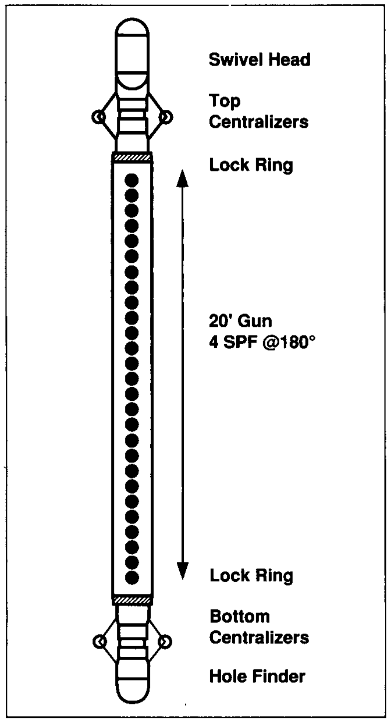

Fig. 9—Oriented perforating gun schematic.

TABLE 1—PERFORATION DESIGN INFORMATION

$E=2\times10^6$ 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) α	β	Breakdown Pressure, p_b (psi)	Angular Position of Fracture, θ_0 (degrees)	Fracture Plane Deviation Angle, γ (degrees)	Maximum Perforation Spacing, d* (in.)
	15	8,498	90	7.68	22.18
0	30	9,240	90	14.08	16.1
	60	10,575	0	0.0	—
	15	8,415	57.79	6.58	24.95
30	30	8,850	49.9	11.5	16.45
	60	9,426	17.61	10.62	16.62
	15	8,260	27.96	3.73	40.97
60	30	8,261	22.56	6.34	23.78
	60	8,070	9.59	7.63	17.13
	15	8,187	0	0	—
90	30	8,017	0	0	—
	60	7,552	0	0	—
	15	8,260	152.04	3.73	40.97
120	30	8,261	157.44	6.34	23.78
	60	8,070	170.41	7.63	17.13
	15	8,415	122.21	6.58	24.95
150	30	8,850	130.1	11.5	16.45
	60	9,426	162.39	10.62	16.62
	15	8,498	90	7.68	22.18
180	30	9,240	90	14.08	16.1
	60	10,575	0	0	—

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 remainder 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

"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.

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