# Prediction of the Orientation and Azimuthal Direction of Induced Fractures

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## INTRODUCTION

Stanolind Oil and Gas Company (now Pan American Petroleum Corporation introduced their "Hydrafrac" process of well stimulation to the petroleum industry in 1948.[1] In the following year, the first commercial fracturing treatment was conducted, thus introducing the petroleum industry to one of the most outstanding well stimulation practices of the past two decades.[2] Since the initial fracturing treatment was executed in 1949, over 400,000 additional treatments have been performed in the free world, as well as an untold number behind the Iron Curtain.[2]

During the past 18 years, many advancements have been made in the concepts of hydraulic fracturing theory concerning the orientation and azimuthal direction of induced fractures. The purposes of this paper is not to clarify these concepts, but to present a sound technique of effectively employing the concepts. Discussion of theory will be confined to only that necessary to clarify the procedures presented in the paper.

## FRACTURE ORIENTATION

Since the initial development of the hydraulic fracturing process, one of the most controversial issues in hydraulic fracturing theory has been the orientation of induced fractures. Fracture orientation is very pertinent, since it dictates the procedure to be employed in designing fracture treatments.

In the beginning of the hydraulic fracturing process, it was generally believed when hydraulic pressure was applied in a borehole that the pressurized fluid parted the formation along bedding planes, lifted the overburden, and created horizontal fractures. This mechanism was supported by several investigators;[1,3,4] however, in actual field treatments, it was observed that many wells fractured at pressures appreciably below the overburden pressure.[5,6,7] These field results were not compatible with horizontal fracturing theory, and horizontal fracturing advocates explained the relatively low fracturing pressures with the hypothesis that the total overburden weight need not be lifted in generating horizontal fractures, but that it was only necessary to lift the weight of a partial or "effective overburden", requiring a correspondingly lower pressure. Others proposed when the relatively low fracturing pressures were encountered that the fractures produced were vertical in orientation. Among the first to propose this mechanism were Hubbert[8] in 1953, Harrison et al.[9] in 1954, and Reynolds et al.[10] in 1954, with Hubbert and Willis[11] further developing the theoretical concepts in 1957.

Hubbert and Willis[11] concluded the following:

(1) If fluid pressure is applied locally within rocks and is increased until parting of the rock occurs, the plane along which fracturing will first occur is perpendicular to the least principal regional stress. Figure 1 illustrates the triaxial loading of rocks and shows the stress element and preferred fracture plane.

(2) Horizontal fractures cannot be produced by hydraulic pressures less than the entire overburden pressure.

(3) In sedimentary rocks, a close approximation of the overburden pressure is equivalent to 1.00 psi/ft of depth.

(4) In areas of active tectonic compression (such as much of California, and portions of Canada being affected by the Rocky Mountain uplift), the least principal regional stress should be vertical and tantamount to the overburden pressure; the fractures formed should be horizontal with injection pressures equal

to or greater than the overburden pressure.

(5) For tectonically relaxed areas characterized by normal faulting (such as the Permian Basin in West Texas and New Mexico, and the Sirte Basin in Libya), the least principal regional stress should be horizontal and less than the overburden pressure; the fractures contrived should be vertical with injection pressures less than the overburden pressure.

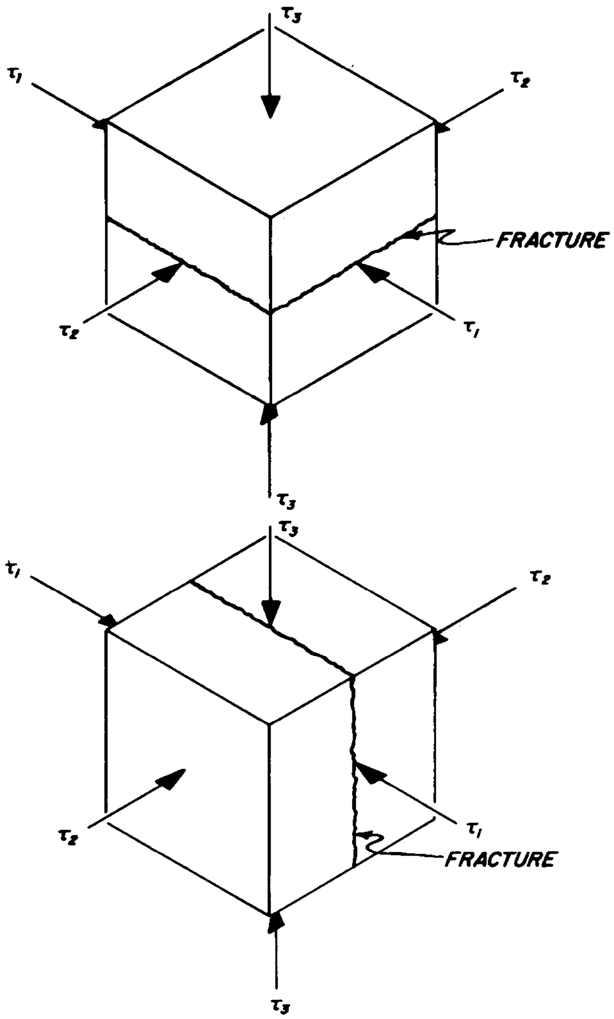



**FIG. I**

**TRIAXIAL LOADING OF ROCKS**

It is generally accepted throughout the oil industry that the fracture plane is horizontal when the fracture treating gradient is 1.00 psi/ft of depth or greater, and vertical when the fracture treating gradient is 0.70 psi/ft of depth or less.

Crittendon[12] presented a formulation for equating fracture treating pressure with fracture orientation.

$$Pt = \frac{P_{ob}}{2}\left[\left(1 + \frac{2\upsilon}{1-\upsilon}\right) + \left(1 - \frac{2\upsilon}{1-\upsilon}\right)\cos 2\theta\right] \quad (1)$$

Where: $Pt$ = bottomhole fracture treating pressure, psi

$P_{ob}$ = overburden pressure, psi

$\upsilon$ = Poisson's ratio, dimensionless

$\theta$ = angle of the fracture from the horizontal, degrees

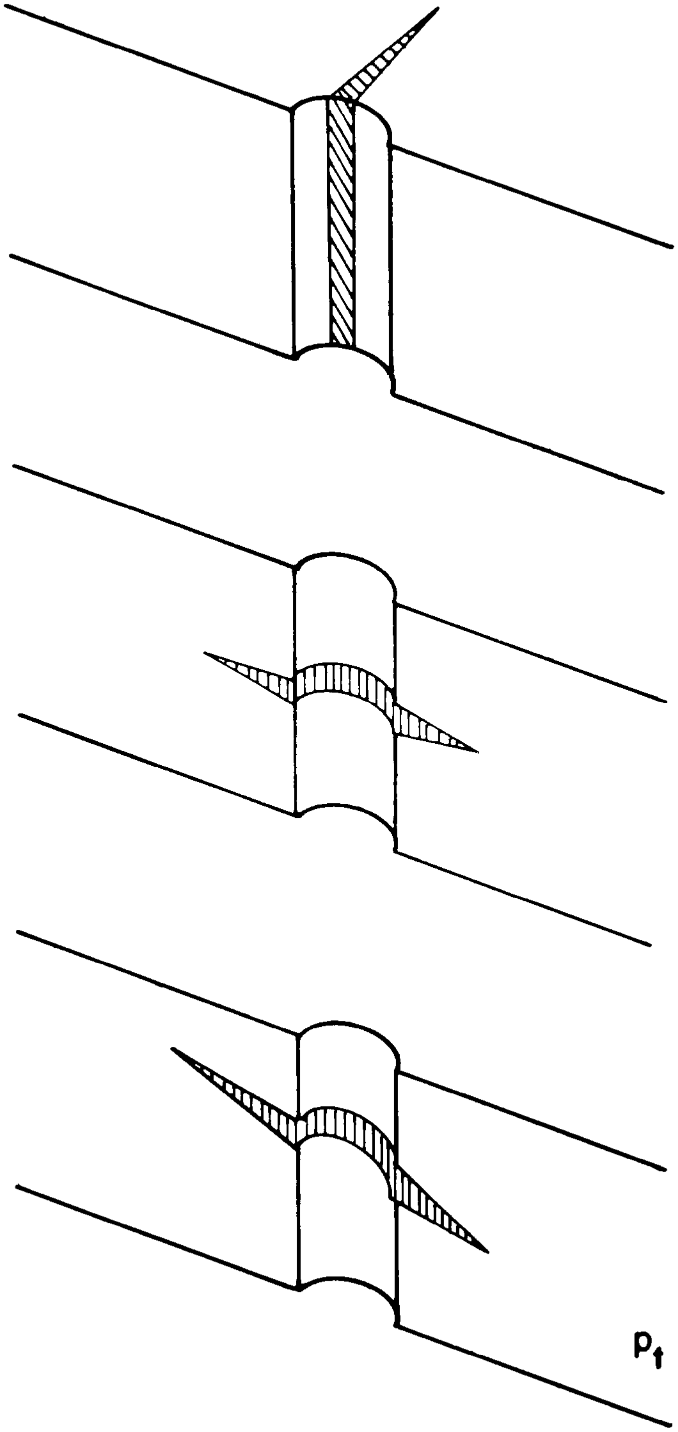
The angle of the fracture from the horizontal as described in Eq. 1 is in reality the angle of the fracture from the dip of formation bedding planes; however, the dip of most formations susceptible to fracturing treatments is usually so insignificantly small that the two angles are normally used synonymously.

Fig. 2[13] exemplifies the three types of fracture orientation that Eq. 1 indicates may be obtained, and Fig. 3[12] presents a graphic solution to Eq. 1 in terms of fracture treating gradient, Poisson's ratio, and fracture orientation. If a Poisson's ratio of 0.25 is employed in Fig. 3, the fracture treating gradient required to obtain horizontal fractures is 0.94 psi/ft of depth, and the fracture treating gradient required to obtain vertical fractures is 0.62 psi/ft of depth. These fracture treating gradients are in close agreement with the aforementioned values of 1.00 psi/ft of depth or greater for horizontal fractures and 0.70 psi/ft of depth or less for vertical fractures.

If reasonably accurate values of the fracture treating gradient and Poisson's ratio can be obtained, Fig. 3 can be utilized to predict whether a formation will fracture prevalently in a vertical or horizontal plane, thus dictating if a vertical or horizontal fracture treatment design method should be employed. The problem now resolves to one of determining the values of the variables to be used in Fig. 3.

## FRACTURE TREATING GRADIENT

Fracture treating gradient is the sum of the instantaneous shut-down pressure following a fracturing treatment and the fluid head at the time the instantaneous shut-down pressure was recorded divided by the subsurface depth of the formation. Fracture treating gradients are us-



VERTICAL FRACTURE

$$p_t = \frac{2\nu}{1-\nu} \times p_{ob}$$

HORIZONTAL FRACTURE

$$p_t = p_{ob}$$

ANGLE FRACTURE

$$p_t = \frac{p_{ob}}{2}\left[\left(1+\frac{2\nu}{1-\nu}\right)+\left(1-\frac{2\nu}{1-\nu}\right)\cos 2\theta\right]$$

FIG. 2

TYPES OF FRACTURE ORIENTATION

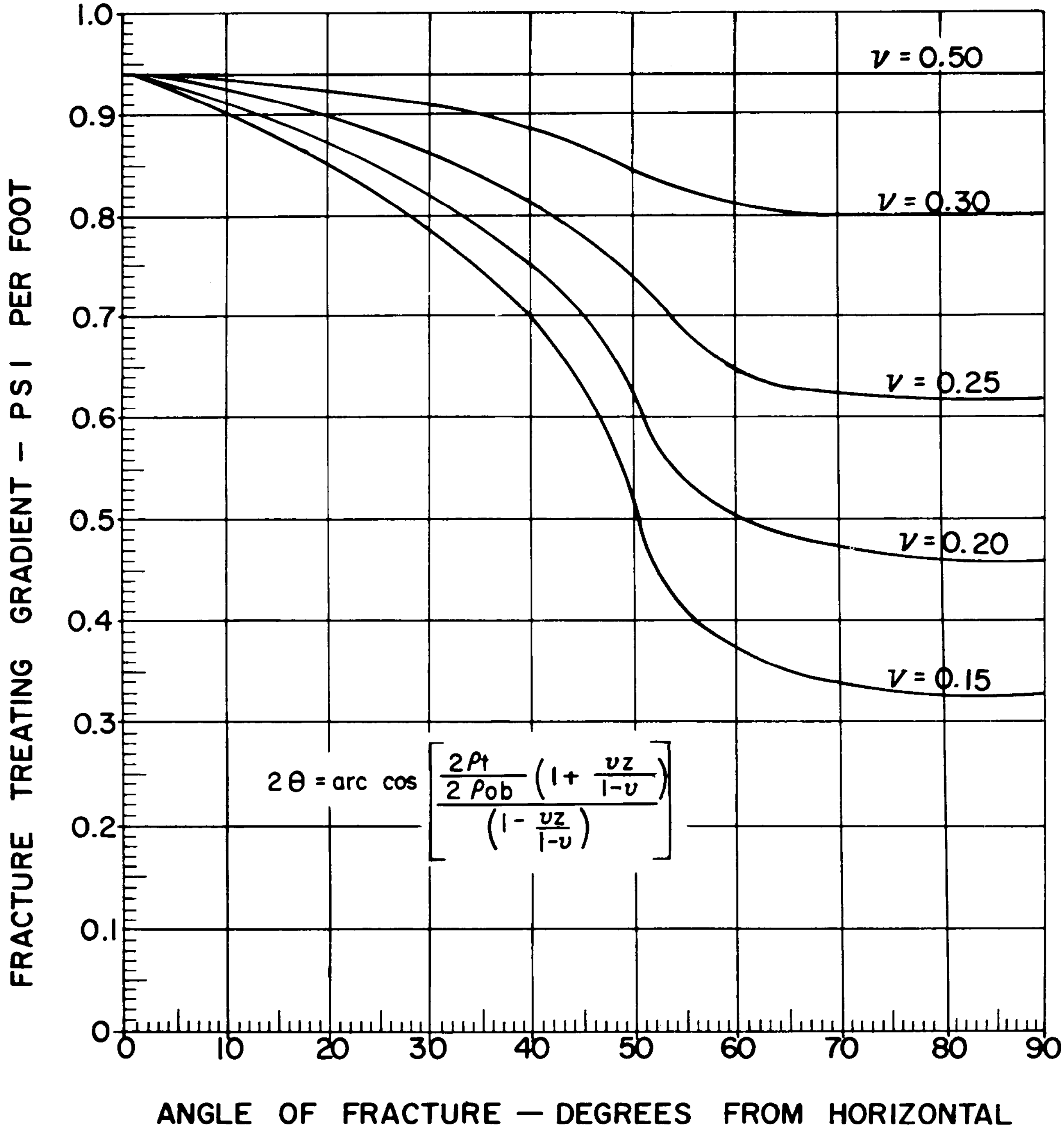



FIG. 3

CONFINING PRESSURE OF FRACTURES AT VARIOUS ANGLES ually reasonably constant for a specific formation throughout a given field, and in some instances over a large geographic area.

## POISSON'S RATIO

Poisson's ratio is a gage of a material's elasticity and can be defined as the ratio of the strain perpendicular to an applied load to the strain parallel to the applied load. Fundamentally, Poisson's ratio is a measure of the capability of a material to withstand deformation in a specific direction as the result of a force applied from a perpendicular direction. Poisson's ratios for rocks reported in the literature[14/15/16/17] range from approximately 0.05 to 0.45, with an average of about 0.25. In general, the harder the rock, the lower the value of Poisson's ratio. As a rock becomes softer and more easily deformed, Poisson's ratio approaches 0.50, which is its value for a true fluid.

There are three mutually perpendicular principal regional stresses underground (Fig. 1); the maximum principal horizontal regional stress ($\tau_1$), the minimum principal horizontal regional stress ($\tau_2$), and the principal vertical regional stress ($\tau_3$). Hubbert and Willis[11] postulated that the general underground stress condition is one in which the three principal regional stresses are unequal, since over long periods of geological time, the earth's crust has been subjected to numerous severe movements wherein the rocks have been repeatedly deformed to the limit of failure as is presently manifested by areas of folding and faulting. The three principal regional stresses in an underground formation control both the borehole pressure required to propagate induced fractures (bottomhole fracture treating pressure) and the azimuthal direction of induced vertical fractures.

Hubbert and Willis[11] also ascertained that the presence of a wellbore in a formation distorts the pre-existing stress field in the rock, and Dunlap[18] illustrated that the stress changes are confined to the immediate vicinity of the wellbore (approximately 2.5 wellbore diameters). Even though the stress changes are relatively near the wellbore, they are particularly significant, since it is the localized area around the wellbore that controls the borehole pressure required to initiate induced fractures (bottomhole breakdown pressure).

The magnitudes of the three principal regional stresses can be calculated from fracturing pressure data; Poisson's ratio, in turn, can be calculated from the values obtained for the three stresses. The theoretical relationships among fracturing pressure data, the three principal regional stresses, and Poisson's ratio have been aptly developed by Dunlap in two previous papers.[18/19] These relationships were evolved primarily for vertical fractures; however, the relationships should be reasonably correct for angular fractures and invalid only when fracture orientation nears the perfectly horizontal plane. Since the majority of formations vulnerable to fracturing operations rupture in planes approaching the vertical, the procedure presented in this paper for calculating Poisson's ratio can be used with confidence, however, not indiscriminately. If the fracture treating gradient (1.00 psi/ft of depth or greater) indicates that the fracture orientation is completely horizontal, Poisson's ratio should be assumed (usually 0.25) and not calculated as outlined herein.

The difference between the two principal horizontal regional stresses can be determined from the following expression[18]:

$$\Delta\tau = (2)(p_t) - P_{bd} - (\phi)(P_r) - (2)(P_{ff}) - S_h \quad (2)$$

Where:

$\Delta\tau$ = difference between the two principal horizontal regional stresses, psi

$P_t$ = bottomhole fracture treating pressure, psi

$P_{bd}$ = bottomhole breakdown pressure, psi

$\phi$ = formation porosity, fraction

$P_r$ = reservoir pressure, psi

$P_{ff}$ = fracture friction, psi

$S_h$ = rock horizontal tensile strength, psi

The only terms in Eq. 2 that cannot be easily secured are fracture friction and rock horizontal tensile strength.

There are only a few correlations for fracture friction available at the current state of the art, and that developed by Craft and Hawkins[20] is simple and basically as good as any available. It is as follows:

$$P_{ff} = \frac{(108 \times 10^{-6})\ (Q)\ (\mu_{fs})\ (r_f)}{(W_t^3)\ (H_f)}$$

Where:

$P_{ff}$ = fracture friction, psi

Q = injection rate, bbls/ min

$\mu_{fs}$ = fracturing slurry viscosity, cp
$r_f$ = fracture radius, ft
$W_t$ = treating fracture width, in.
$H_f$ = fracture height, ft

Fracturing slurry viscosity, fracture radius, and treating fracture width are the only terms in Eq. 3 that are not readily obtainable. The proper procedures for resolving these treatment variables have been adequately described in the literature,[21,22] and no further discussion will be attempted here for the sake of brevity.

The relative importance of the rock horizontal tensile strength term in Eq. 2 has been questioned by some investigators[11] who assert the term can be neglected, because in the extension of induced fractures, the stress concentration at the extremities of the fracture essentially eliminates rock strength as a factor affecting fracture propagation. Another investigator[18] maintains the term cannot be neglected and should be considered, because although the term is usually small as compared with most principal horizontal regional stresses, it may be large in comparison with the difference between the two principal horizontal regional stresses. For the latter reason, it is the belief of this writer that the term should be considered.

It is possible to measure rock strengths from actual formation samples such as cores and large cuttings; however, surface measurements will not give highly accurate values of in-situ rock strengths, since rock strengths normally increase with increasing confining pressure.[23,24] Rock strengths obtained from surface measurements are usually reasonably rough estimates of in-place rock strengths and are certainly superior to mere conjectures. The range of values of rock strengths reported in the literature[14,16,17] is from approximately 100 to 2500 psi, with an average of around 500 psi. No correlation, except rock strength with formation lithology, could be resolved from this data. In an effort to obtain a useable correlation of rock strength with some easily obtainable parameter, rock horizontal tensile strength was plotted versus formation subsurface depth (Fig. 4) from data[13] for formations in West Texas. Values obtained from Fig. 4 appear to be fairly reasonable in magnitude; therefore, the use of Fig. 4 to secure values of rock horizontal tensile strength for use in Eq. 2 appears justifiable.

The minimum principal horizontal regional stress can be calculated from the following expression:[18]

$$\tau_2 = P_t - P_{ff} \qquad (4)$$

Where:

$\tau_2$ = minimum principal horizontal regional stress, psi
$P_t$ = bottomhole fracture treating pressure, psi
$P_{ff}$ = fracture friction, psi

The following equation[18] can be employed to obtain the maximum principal horizontal regional stress:

$$\tau_1 = \Delta\tau + \tau_2 \qquad (5)$$

Where:

$\tau_1$ = maximum principal horizontal reqional stress, psi
$\Delta\tau$ = difference between the two principal horizontal regional stresses
$\tau_2$ = minimum principal horizontal regional stress, psi

The principal vertical regional stress can be acquired from the following expression:[18]

$$\tau_3 = (\rho_{ob})\,(Z) \qquad (6)$$

Where:

$\tau_3$ = principal vertical regional stress, psi
$\rho_{ob}$ = overburden gradient, psi/ft
$z$ = subsurface formation, depth, ft

Poisson's ratio can be computed from the following formulation:[19]

$$\upsilon = \frac{(\tau_2)(1-\upsilon)(1-2\upsilon)}{(\tau_3)(1-2\upsilon) + (\Delta\tau)(1-\upsilon)} \qquad (7)$$

Where:

$\upsilon$ = Poisson's ration, dimensionless
$\tau_2$ = minimum principal horizontal regional stress, psi
$\tau_3$ = principal vertical regional stress, psi
$\Delta\tau$ = difference between the two principal horizontal regional stresses, psi

Examination of the above expression indicates that a trial-and-error solution is required to determine Poisson's ratio. The tabulation included in the example problem, which is presented later in this paper, provides a rapid trial-and-error solution to the equation.

The results obtained from the method just described for predicting the orientation of induced fractures from hydraulic fracturing data are compared in Table I with actual field data for several West Texas fields. Examination of the table reveals that the theoretical predictions compare very favorably with the known field results.

## FRACTURE DIRECTION

The azimuthal direction of induced vertical fractures is very important, since drainage patterns, flood patterns, sweep efficiencies, etc., are

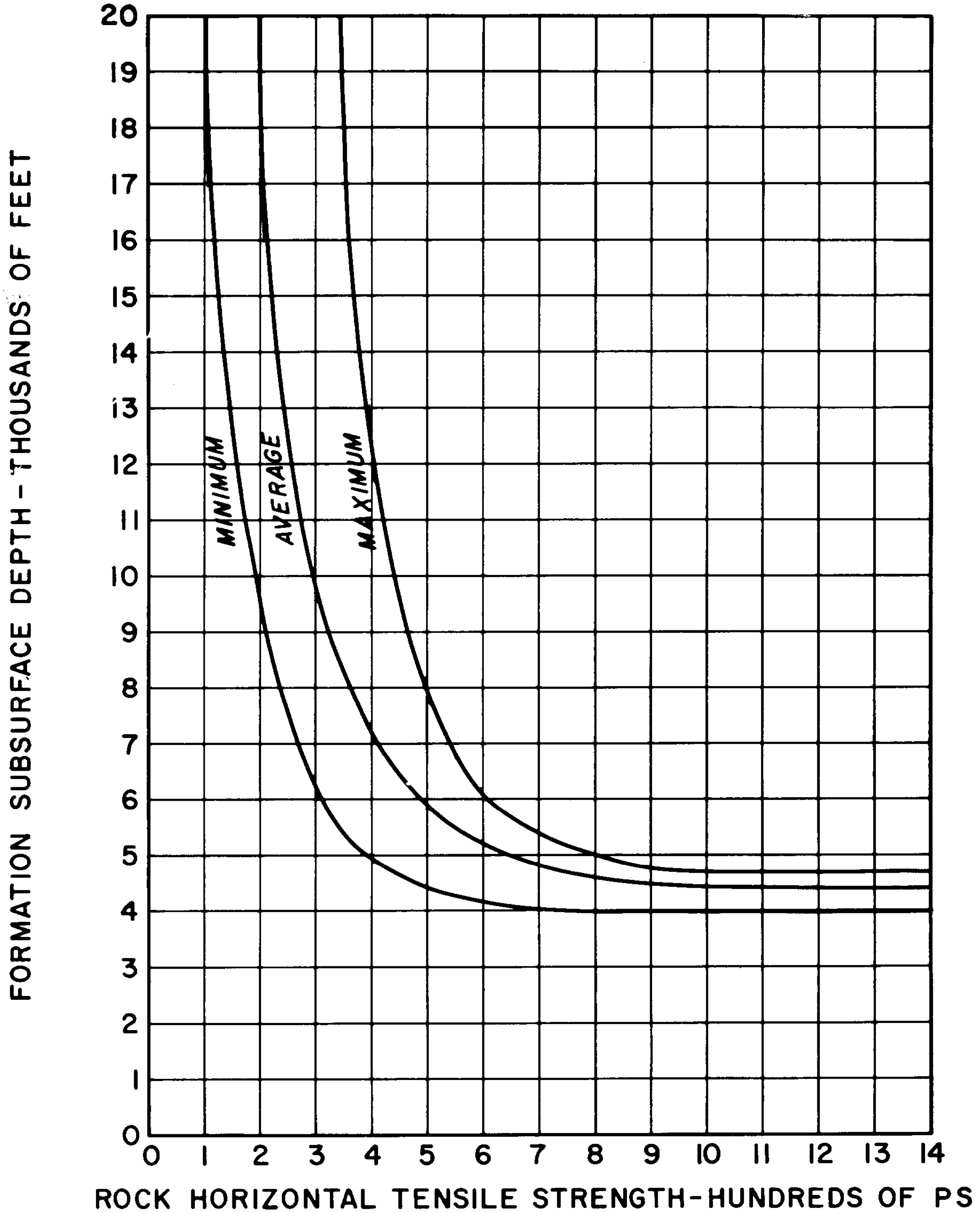



**FIG. 4**

**EFFECT OF FORMATION SUBSURFACE DEPTH ON ROCK HORIZONTAL TENSILE STRENGTH FOR WEST TEXAS FIELDS**

TABLE I

COMPARISON OF PREDICTED AND ACTUAL ORIENTATION AND AZIMUTHAL DIRECTION OF INDUCED FRACTURES FOR SEVERAL WEST TEXAS FIELDS

| Field | Formation | Depth (Ft) | Geographic Location | Geological Location | Predicted Fracture Orientation | Actual Fracture Orientation | Predicted Azimuthal Fracture Direction | Average Actual Azimuthal Fracture Direction | Remarks |
|---|---|---|---|---|---|---|---|---|---|
| Dune | San Andres | 3,300 | Crane Co. | Central Basin Platform | Vertical | Vertical | N 80° E | N 99° E | Range of Actual Values: N 99° E |
| Edwards | San Andres | 3,400 | Crane Co. | Central Basin Platform | Vertical | Vertical | N 80° E | N 99° E | Range of Actual Values: N 96° E - N 101° E |
| Howard Glasscock | Queen Sand | 1,600 | Howard Co. | Eastern Shelf | Vertical | Vertical | N 75° E | N 73° E | Range of Actual Values: N 73° E |
| Iatan, East Howard | San Andres | 2,700 | Howard & Mitchell Cos. | Eastern Shelf | Vertical | Vertical | N 99° E | N 84° E | Range of Actual Values: N 71° E - N 93° E |
| Pegasus (Spraberry) | Spraberry | 8,300 | Midland | Midland Basin | Vertical | Vertical | N 80° E | N 107° E | Range of Actual Values: N 107° E |
| Spraberry (Trend Area) | Spraberry | 8,000 | Midland & Glasscock Cos. | Midland Basin | Vertical | Vertical | N 80° E | N 94° E | Range of Actual Values: N 92° E - N 95° E |
| Welch | San Andres | 5,000 | Dawson Co. | Midland Basin | Vertical | Vertical | N 80° E | N 75° E | Range of Actual Values: N 75° E |

NOTE: The predicted and actual azimuthal fracture direction of the induced fractures reported in this table are measured from true north.

all dependent on azimuthal fracture direction. In waterflood projects, for example, alternate location of producing and injection wells along lines parallel to the azimuthal direction of induced vertical fractures will result in premature breakthrough of injection water; whereas, location of alternate rows of producing and injection wells along lines parallel to the azimuthal direction of induced vertical fractures will result in favorable flood patterns. The effect of the azimuthal direction of induced vertical fractures on waterflood sweep efficiencies is well illustrated in graphical form from laboratory-derived data in the literature.[25,26]

Since induced vertical fractures will form perpendicular to the minimum principal horizontal regional stress and propagate in the direction of the maximum principal horizontal regional stress, the azimuthal direction of induced vertical fractures can be predicted, if the azimuthal direction of either of the two principal horizontal regional stresses can be determined. As previously discussed in this paper, the magnitude of the two principal horizontal regional stresses can be calculated, as well as the magnitude of the difference between the two stresses. The value of the difference between the two stresses is very significant in determining the azimuthal direction of induced vertical fractures. Should the quantity be zero, the values of the two stresses will be identical, and azimuthal fracture direction will be random; however, for all positive values of the quantity, induced vertical fracture propagation will be in the azimuthal direction of the maximum principal horizontal regional stress. The greater the value of the difference between the two stresses, the more pronounced will be the azimuthal direction of induced vertical fractures. The problem now resolves to one of procuring the azimuthal direction of the maximum principal horizontal regional stress for acquiring the azimuthal direction of induced vertical fractures.

Based on the concept that in tectonically relaxed areas characterized by normal faulting, the maximum principal regional stress is horizontal and the induced fractures formed are predominately vertical, geological data can be engaged to predict the azimuthal direction of the induced fractures fabricated in such areas.

In tectonically relaxed areas, such as the Permian Basin in West Texas and New Mexico, the strike of the maximum principal horizontal regional stress should be approximately normal to tangents drawn to the general boundaries of the geological provinces located in the areas, as well as perpendicular to normal faults existing in the provinces. This being the case, the azimuthal direction of induced vertical fractures generated in the provinces should also be approximately normal to tangents drawn to the general boundaries of the provinces, as well as perpendicular to normal faults situated in the provinces. A degree of caution should be exercised in the construction of tangents to the general boundaries of the geological provinces, since the province boundaries are in places arbitrarily drawn as the result of the occurrence of stratigraphic features. In these places, the province boundaries are not entirely related to the principal regional tectonic features (uplifts and depressions) from which the province boundaries primarily resulted, and which actually control the azimuthal direction of the maximum principal horizontal regional stress in the provinces. Figures 5 and 6 pictorially illustrate the reasoning behind the preceding discussion, and Fig. 7[27] may be utilized to select the general boundaries of the provinces located in the Permian Basin, thus allowing the azimuthal direction of induced vertical fractures produced in the Permian Basin to be predicted with a reasonable degree of accuracy from geological data.

The results obtained from the method just described for predicting the azimuthal direction of induced vertical fractures from geological data are compared in Table I with actual field data for several West Texas fields. The predicted and actual azimuthal fracture direction of the induced vertical fractures reported in Table I are measured from true north. Examination of the table reveals that the theoretical predictions compare reasonably well with the known field results.

Two other geological approaches to predicting the azimuthal direction of induced vertical fractures are by the analogy with the strike of regional joints and by the analogy of dike emplacement. Fraser and Pettitt[28] reported that well-developed joint systems are indicative of regional stress conditions, and that northeasterly striking joints are prominent in surface exposures of Paleozoic rocks in North Central and West Central Texas. This is borne out by the fact that the Spraberry Trend Area situated in

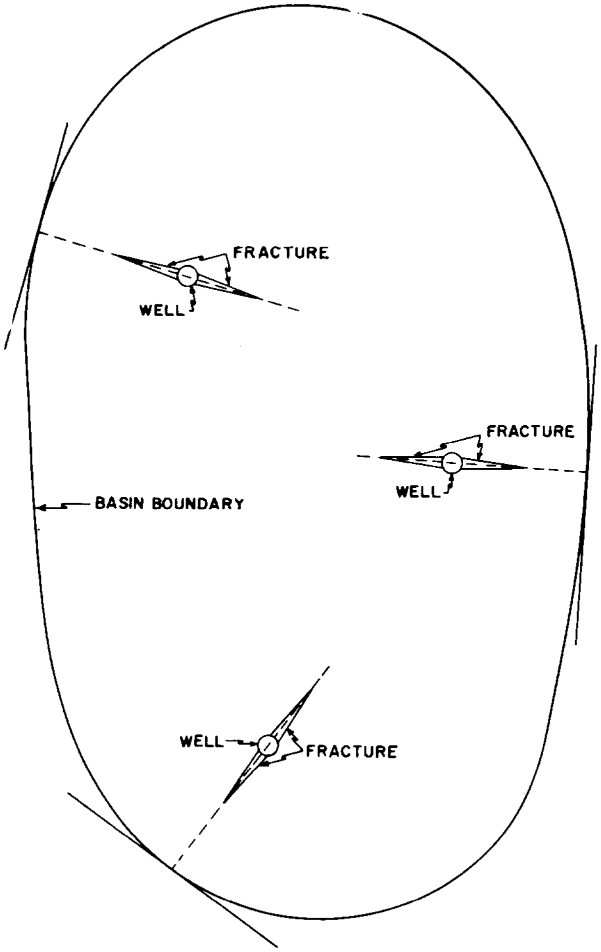



**FIG. 5**

**AZIMUTHAL FRACTURE DIRECTION**

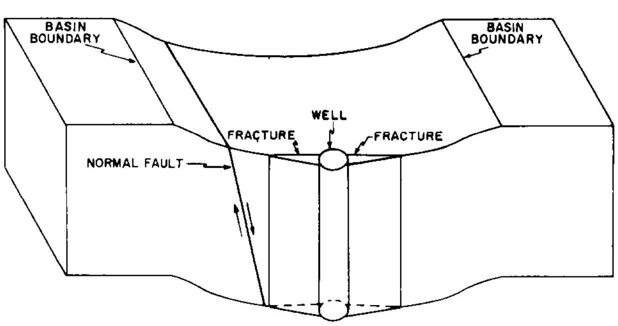



FIG. 6

AZIMUTHAL FRACTURE DIRECTION

West Texas has a northeasterly striking joint system with induced vertical fractures created in the area striking in a northeasterly direction.

Hubbert and Willis[11] deduced that a phenomenon very similar to artificial formation fracturing, but on a much larger scale, is that of dike emplacement and pointed out that igneous dikes should be injected along planes perpendicular to the axis of the least principal regional stress. They[11] cited that a good field example of their reasoning was afforded in the azimuthal direction of the igneous dikes existing in the Spanish Peaks igneous complex in Colorado.

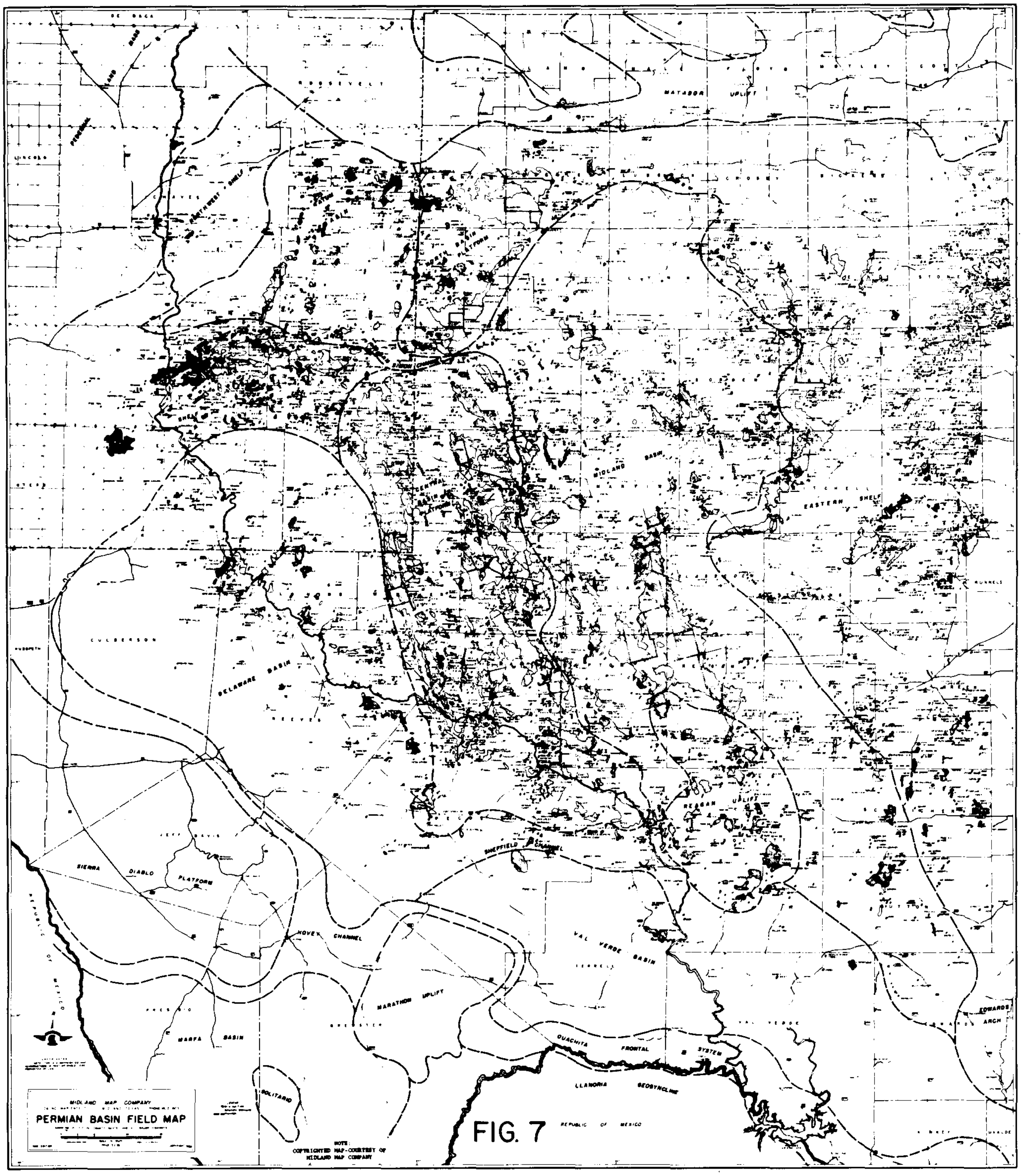
The azimuthal direction of induced vertical fractures can also be determined experimentally downhole with special packers, radioactive tracers, acoustical devices, etc. The presence of fracture impressions on inflatable formation packers was reported by Crittendon[12] in 1958, and in 1961, Fraser and Pettitt[28] used a formation packer equipped with an especially sentitive rubber cover and a directional device to obtain the azimuthal direction of induced vertical fractures in the Howard Glasscock Field located in West Texas.

## EXAMPLE PROBLEM FOR PREDICTING THE ORIENTATION OF INDUCED FRACTURES

The concepts previously discussed in this paper for predicting the orientation of induced fractures from hydraulic fracturing data can best be explained by the means of an example problem. There are six basic steps to follow in such a problem. The steps are as follows:

(1) Determine the difference between the two principal horizontal regional stresses.
(2) Determine the minimum principal horizontal regional stress.
(3) Determine the maximum principal horizontal regional stress.
(4) Determine the principal vertical regional stress.
(5) Determine Poisson's ratio.
(6) Determine the orientation of the fracture.

For this example problem, assume the following data:




MAP PRINTED THROUGH THE COURTESY OF MIDLAND MAP COMPANY

$H_f$ = fracture height = 150 ft
$P_{bd}$ = bottomhole breakdown pressure = 6400 psi
$P_r$ = reservoir pressure = 3000 psi
$P_t$ = bottomhole fracture treating pressure = 4200 psi
$Q$ = injection rate = 15 bbls/min
$r_f$ = fracture radius = 250 ft
$W_t$ = treating fracture width = 0.10 in.
$z$ = subsurface formation depth = 6300 ft
$\mu_{fs}$ = fracturing slurry viscosity = 60 cp
$\rho_{ob}$ = overburden gradient = 1.00 psi/ft
$\rho_t$ = fracture treating gradient = 0.67 psi/ft

**Step 1:** Determine the difference between the two principal horizontal regional stresses.

Acquire fracture friction from Eq. 3.

$$P_{ff} = \frac{(108 \times 10^{-6})(Q)(\mu_{fs})(r_f)}{(W_t{}^3)(H_f)}$$

$$P_{ff} = \frac{(108 \times 10^{-6})(15)(60)(250)}{(0.10^3)(150)}$$

$$P_{ff} = 162 \text{ psi}$$

From Fig. 4 for average conditions and a subsurface depth of 6300 ft, rock horizontal tensile strength is 460 psi.

Obtain the difference between the two principal horizontal regional stresses from Eq. 2.

$$\Delta\tau = (2)(P_t) - P_{bd} - (\phi)(P_r) - (2)(P_{ff}) + S_h$$

$$\Delta\tau = (2)(4200) - 6400 - (0.06)(3000) - (2)(162) + 460$$

$$\Delta\tau = 1956 \text{ psi}$$

**Step 2:** Determine the minimum principal horizontal regional stress from Eq. 4.

$$\tau_2 = P_t - P_{ff}$$
$$\tau_2 = 4200 - 162$$
$$\tau_2 = 4038 \text{ psi}$$

**Step 3:** Determine the maximum principal horizontal regional stress from Eq. 5.

$$\tau_1 = \Delta\tau + \tau_2$$
$$\tau_1 = 1956 + 4038$$
$$\tau_1 = 5994 \text{ psi}$$

**Step 4:** Determine the principal vertical regional stress from Eq. 6.

$$\tau_3 = (\rho_{ob})(z)$$
$$\tau_3 = (1.00)(6300)$$
$$\tau_3 = 6300 \text{ psi}$$

**Step 5:** Determine Poisson's ratio from Eq. 7.

$$\upsilon = \frac{(\tau_2)(1-\upsilon)(1-2\upsilon)}{(\tau_3)(1-2\upsilon) + (\Delta\tau)(1-\upsilon)}$$

A trial and error solution of Eq. 7 is required to compute Poisson's ratio. Table II provides a rapid trial-and-error solution to the equation, and from Table II, Poisson's ratio is 0.295.

**Step 6:** Determine the orientation of the fracture.

From Fig. 3 for a fracture treating gradient of 0.67 psi/ft of depth and a Poisson's ratio of 0.295, the orientation of the fracture is vertical.

In summary, the example problem just completed consists of the following:

$\tau_1$ = 5994 psi
$\tau_2$ = 4038 psi
$\tau_3$ = 6300 psi
$\Delta\tau$ = 1956 psi
$\nu$ = 0.295
$\theta$ = vertical

TABLE II

TRIAL AND ERROR SOLUTION TO EQUATION 7 FOR POISSON'S RATIO

| 1 | 2 | 3 | 4 | 2x3x4=5 | 6 | 6x4=7 | 8 | 8x3=9 | 7+9=10 | 5/10=11 |
|---|---|---|---|---|---|---|---|---|---|---|
| $\nu$ | $\tau_2$ | $1-\nu$ | $1-2\nu$ | $(\tau_2)(1-\nu)(1-2\nu)$ | $\tau_3$ | $(\tau_3)(1-2\nu)$ | $\Delta\tau$ | $(\Delta\tau)(1-\nu)$ | $(\tau_3)(1-2\nu)+(\Delta\tau)(1-\nu)$ | $\nu$ |
| 0.250 | 4,038 | 0.750 | 0.500 | 1,514 | 6,300 | 3,150 | 1,956 | 1,467 | 4,617 | 0.328 |
| 0.300 | 4,038 | 0.700 | 0.400 | 1,131 | 6,300 | 2,520 | 1,956 | 1,369 | 3,889 | 0.291 |
| 0.295 | 4,038 | 0.705 | 0.410 | 1,167 | 6,300 | 2,583 | 1,956 | 1,379 | 3,962 | 0.295 |

## SUMMARY AND CONCLUSIONS

A technique has been developed and presented in this paper which provides methods for:

(1) Predicting the orientation of induced fractures from hydraulic fracturing data, thus allowing the proper fracture treatment design procedure to be selected.

(2) Predicting the azimuthal direction of induced vertical fractures from geological data, thereby permitting the determination of recovery factors essential to the prudent production of hydrocarbons.

By no means are the predictions of fracture orientation and azimuthal fracture direction the final or only answers to well stimulation and petroleum recovery problems; however, they do offer essentially unexplored technological fields that have potentials of yielding large rewards.

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