BENSON-MONTIN-GREER DRILLING CORP.
EXHIBITS IN CASE NOS. 8946 & 8950
BEFORE THE OIL CONSERVATION DIVISION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

AUGUST 7, 1986

Exhibit 7

COMPARISON OF POROSITY AND PERMEABILITY FOR TWO SYSTEMS OF FRACTURING

IN PLATES I AND II THE FORMATION AT TWO DIFFERENT LOCATIONS IS STRESSED (TENSION) TO SAME DEGREE AND EACH HAS SAME NUMBER OF SAME SIZE FRACTURES

IN PLATES III AND IV THE FORMATIONS HAVE BEEN STRESSED AN ADDITIONAL AMOUNT SO THAT THE PERMEABILITY HAS BEEN INCREASED 100-FOLD

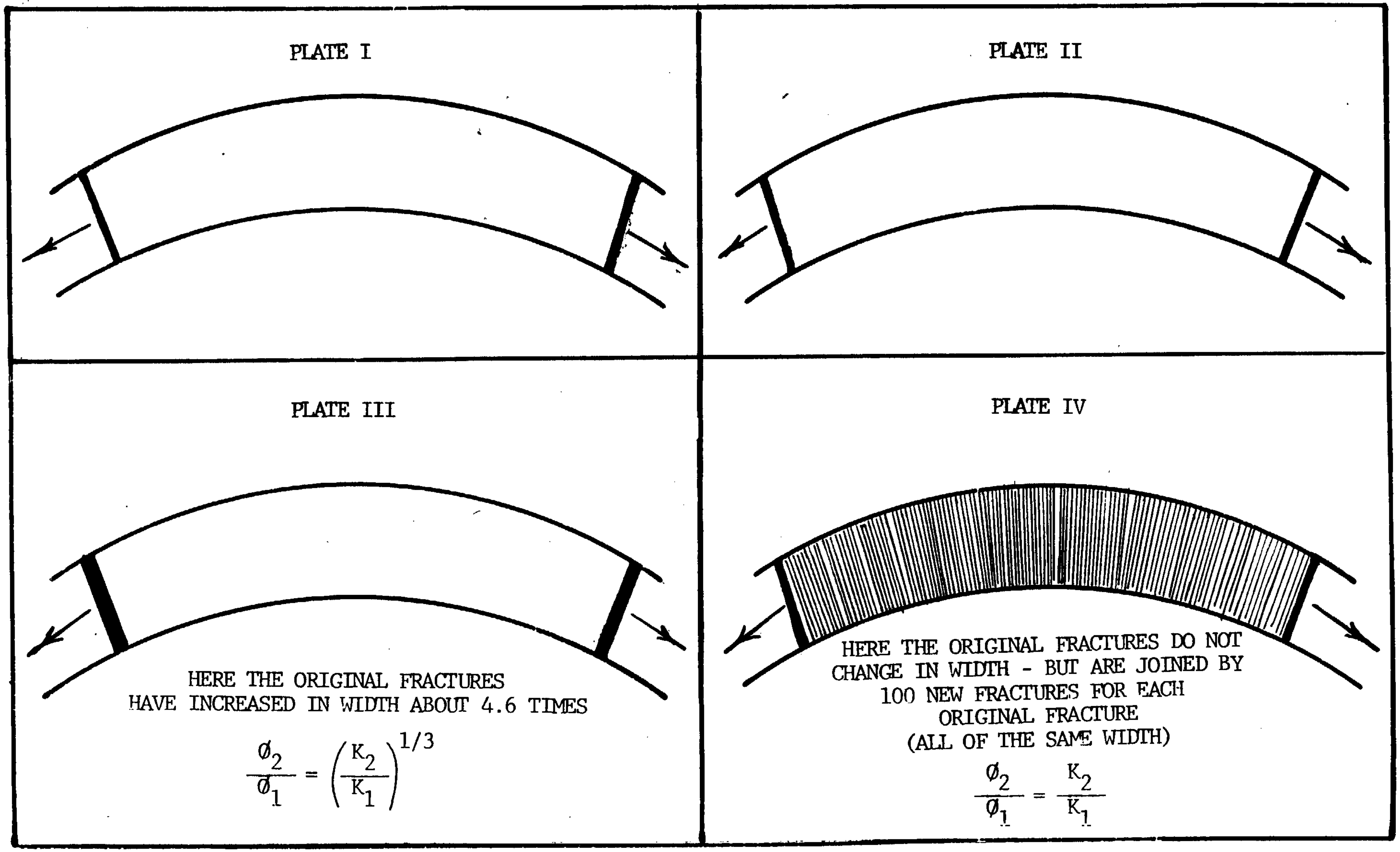

Plate III: $$\frac{\phi_2}{\phi_1} = \left(\frac{K_2}{K_1}\right)^{1/3}$$

Plate IV: $$\frac{\phi_2}{\phi_1} = \frac{K_2}{K_1}$$

DIRECT COMPARISON OF POROSITY TO PERMEABILITY RELATIONS FOR OIL WELL RECOVERIES

(Actual recoveries from any well will depend on a number of factors, including the area drained by the well, but assuming these ancillary matters to be the same, then the following shows how unlikely it is that porosity will bear a direct relation to permeability.)

Example Wells:

Compare Canada Ojitos Unit C-2 initial productivity with the Canada Ojitos Unit B-29, use the C-2 cumulative recovery and project the B-29 cumulative recovery (C-2 cumulative = 230 Mbbls):

Comparative Productivities			Cube Root of Ratio of Productivities	Projected Recovery of B-29	
C-2 (BOPD)	B-29 (BOPD)	Ratio B-29 to C-2		By Cube Root of Ratio of Productivities (Mbbls)	By Direct Ratio of Productivities (Mbbls)
56	15,000	270	6.45	1,500	62,000

VOL. 52, NO. 1 (JANUARY, 1968), PP. 57–65, 5 FIGS., 1 TABLE

QUANTITATIVE FRACTURE STUDY—SANISH POOL, McKENZIE COUNTY, NORTH DAKOTA[1]

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ABSTRACT

The Devonian Sanish pool of the Antelope field has several unusual characteristics which make it almost unique in the Williston basin. Some of these are: (1) high productivity of several wells from a nebulous, ill-defined reservoir; (2) association with the steepest dip in the central part of the basin; (3) very high initial reservoir pressure; and (4) almost complete absence of water production.

Analysis of these factors indicates that Sanish productivity is a function of tension fracturing associated with the relatively sharp Antelope structure. Fracture porosity and fracture permeability can be related mathematically to bed thickness and structural curvature (the second derivative of structure). It is found that fracture porosity varies directly as the product of bed thickness times curvature and that fracture permeability varies as the third power of this product. A map of structural curvature in the Sanish pool shows good coincidence between areas of maximum curvature and areas of best productivity.

Volumetric considerations show that the quantities of oil being produced cannot be coming from the Sanish zone. It is concluded that the overlying, very petroliferous Bakken Shale is the immediate, as well as the ultimate, source of this oil. The role of the Sanish fracture system is primarily that of a gathering system for many increments of production from the Bakken.

The extremely high initial reservoir pressure indicates that the Sanish-Bakken accumulation is in an isolated, completely oil-saturated reservoir and, hence, is independent of structure in the normal sense. Similar accumulations should be present anywhere in the Williston basin where a permeable bed, of limited areal extent, is in direct contact with either of the two Bakken shale beds.

INTRODUCTION

The Sanish pool is one of several oil accumulations in the Antelope field of McKenzie County, North Dakota. As shown in Figure 1, this field is on a relatively sharp, southeast-trending anticline on the east side of the Nesson uplift of the central Williston basin. The field discovery, the Pan American No. 1 Woodrow Starr, SW¼ SE¼, Sec. 21, T. 152 N., R. 94 W., was completed in December 1953 with an initial flow potential of 550 bbl a day from 10,526–10,566 ft in the Devonian Sanish zone. Production in the Mississippian Madison Group was established in May 1956, and production in the Devonian Nisku and Duperow Formations and in the Silurian section was found in 1960. One well, the Amerada No. 1 Nelson, SW¼ SW¼, Sec. 5, T. 152 N., R. 94 W., recently has been recompleted as a discovery well in the Mississippian Lodgepole Formation. Cumulative production as of July 1, 1966 was 7,986,141 bbl from the Madison, 7,140,448 bbl from the Sanish, 1,072,890 bbl from the Duperow, and 1,477,410 bbl from the Silurian, a total of approximately 17 million bbl.

The Madison, Nisku, Duperow, and Silurian pools generally may be considered to be conventional structural accumulations. The Sanish pool, however, has several unusual characteristics which make it almost unique in the Williston basin. To date, the only other Sanish production in the United States part of the basin has been in the one-well, subcommercial Elkhorn Ranch field in Sec. 5, T. 143 N., R. 101 W., Billings County, North Dakota. Some of the very interesting aspects of the Antelope Sanish accumulation are a very high initial reservoir pressure, the high productivity of several wells from a nebulous, ill-defined reservoir, and, in contrast to most Williston basin fields, an almost complete absence of water production.

LITHOLOGIC AND RESERVOIR CHARACTERISTICS

SANISH ZONE

As shown in Figure 2, the so-called "Sanish zone" is at the very top of the Devonian Three Forks Formation, just below the lower Bakken shale. A thin, very dolomitic sandstone at the top of this interval was termed the "Sanish Sand" during the early development of the field. It originally was believed that the limits of Sanish production would be related to the areal extent

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The writer is indebted to W. H. Somerton, Univ. California, Berkeley, for checking the mathematical treatment presented herein.

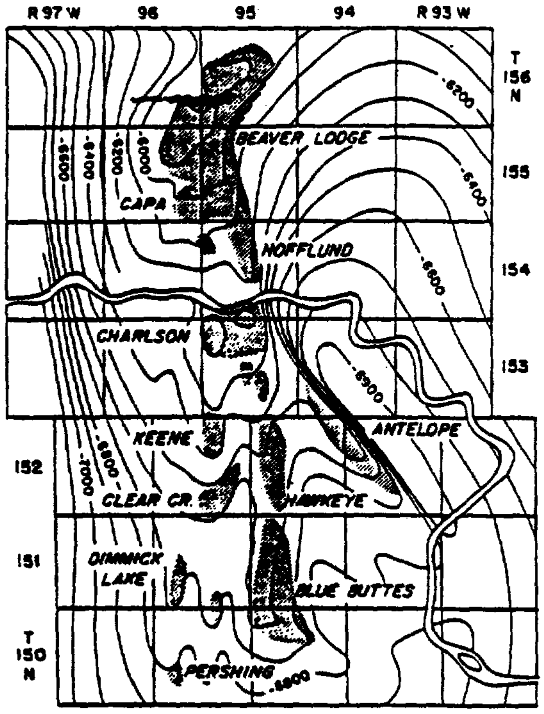

FIG. 1.—Regional structural contour map of McKenzie County area, North Dakota. Structural datum, base of lowest Charles (Mississippian) salt. Map shows location of oil pools on part of Nesson anticline. Contour interval, 100 ft. Contour datum, sea level.

and degree of development of this sandstone. However, subsequent drilling showed that this sandstone is absent in much of the field. Where the sandstone is absent, the Sanish zone consists of gray, very dense dolomite, commonly sandy, interbedded and intercalated with waxy, greenish, pyritic shale typical of the underlying Three Forks section.

Surprisingly, some of the wells with the best-developed Sanish sandstone have been among the poorest producers, whereas others with no sandstone have been among the best producers. For example, the No. 1 Reed-Norby Unit, NW¼ NE¼, Sec. 6, T. 152 N., R. 94 W., penetrated 4 ft of sandstone but has been a poor producing well. Cumulative production to July 1, 1966, was 73,876 bbl and productive capability at that time was less than 15 bbl a day. In contrast, the Carter No. 1 Norby-Melby Unit, SW¼ NE¼, Sec. 7, T. 152 N., R. 94 W., found no sandstone but has been one of the best wells in the field. Cumulative production to July 1, 1966 was 511,910 bbl and the producing rate then was approximately 270 bbl a day.

Core analyses of the Sanish section indicate poor reservoir parameters regardless of the presence or absence of sandstone development. Porosity averages between 5 and 6 percent and plug permeability almost invariably is less than 0.1 md. Despite a universal absence of initial water production, core analyses indicate wide variations in oil and water saturations among wells.

BAKKEN FORMATION

The Mississippian Bakken Formation is composed of three easily differentiated units. The most striking of these are the two shale beds at the top and bottom of the formation, respectively. These are very radioactive, black, petroliferous shale and undoubtedly are source beds throughout the central Williston basin. They invariably have shows of oil and gas in cuttings and their log characteristics also are strong evidence for their identification as source beds. Their fluid-filled pore space, as indicated by velocity and/or neutron logs, is normal or greater than normal for shale at the depth at which they are found. Their

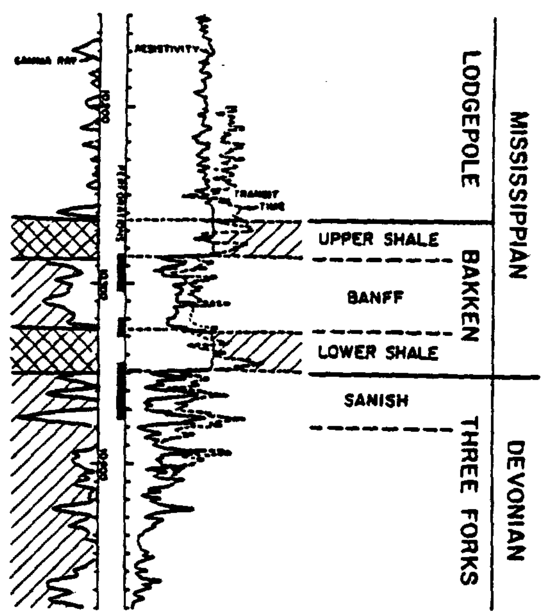

FIG. 2.—Logs from Lloyd H. Smith No. 1-A Weedeman, SE¼ SW¼, Sec. 29, T. 153 N., R. 94 W., McKenzie County, North Dakota, showing typical productive section. Curve on left is gamma ray. Solid curve on right is resistivity. Dashed curve is interval transit time. Depths (from surface) in feet.

resistivity, however, is essentially infinite. This fact, in conjunction with the visibly petroliferous character of the two shales, indicates that their pore space is hydrocarbon-saturated. The lower shale was perforated together with the Sanish section in several wells. However, no attempt has been made to separate the production by zones. Consequently, the direct contribution of the shale to the total production is unknown.

The section between the two shale zones is composed of dolomite, dolomitic siltstone, and minor quantities of shale. As might be expected, this section, called the "Banff member" by some workers, generally carries oil shows. This section also was perforated in conjunction with the Sanish zone in several wells in the field. However, as in the case of the lower shale, no attempt has been made to measure the production from the Banff independently of that from the Sanish.

LODGEPOLE FORMATION

The interbedded limestone and shale of the Mississippian lower Lodgepole Formation overlie the upper Bakken shale. This lower part of the Madison Group recently has been proved to be productive in a rework of the Amerada No. 1 Nelson, SW¼ SW¼, Sec. 5, T. 152 N., R. 94 W. Although not discussed here, this Lodgepole accumulation probably is related closely to the Bakken-Sanish pool.

Role of Fracturing in Sanish Production

THEORY

Because the productivity of individual Sanish wells appears to be unrelated to variations in reservoir lithology and because measured porosity and plug permeability are very low, it appears reasonable to assume that productivity is related to fracturing. Although core descriptions do not indicate an unusual degree of fracturing, a few fractures were noted. The data from the Carter No. 1 Norby-Melby Unit illustrate the peculiarities of the Sanish reservoir which lead to the hypothesis that fracturing is the controlling parameter. This well found no sandstone in the Sanish section—only dense dolomite and shale with some slight fracturing. Whole-core analysis shows an average porosity of approximately 5.5 percent and permeability below 1.0 md, except for a value of 27 md in a 1-ft zone and another value of 6.7 md in another 1-ft zone. Nevertheless, this well has been one of the best in the field! The writer believes that the only logical hypothesis to explain this fact is that the more than 500,000 bbl which has been produced from this well has come from fractures in the 2 ft of section with whole-core permeability values greater than 1.0 md.

The important role of fracturing also is suggested by the association of this production with the area of steepest dip in the central Williston basin. A cursory examination of the Sanish pool shows that the best wells are concentrated along the northwest-southeast line where the Antelope anticline bends abruptly from the relatively flat crest into the steep, northeast flank (Fig. 4). It is intuitively reasonable that the greatest intensity of tension fracturing would be in this position, where structural curvature (rate of change of dip, or structural second derivative) is greatest. Although this simple observation reinforces the hypothesis of a fractured reservoir, it indicates nothing about the magnitudes of fracture porosity and fracture permeability or about the minimum curvature necessary for the development of fractures.

To attempt to answer these questions, with particular reference to the Sanish pool and the individual wells in the pool, the writer has derived two mathematical relations which express fracture porosity and fracture permeability, respectively, as functions of bed thickness and structural curvature. Because the Antelope anticline is relatively elongate, the equations have been derived for a structural configuration which is infinite in the axial direction. This greatly simplifies the mathematical treatment.

Figure 3 shows a cross section of a segment of a competent bed, of thickness T feet, folded into an arc, of radius of curvature R feet. The folding is assumed to be sufficiently sharp to have caused stress greater than the ultimate tensile strength of the bed and, consequently, to have resulted in tension fractures represented by the idealized pie-shape voids. For convenience, the neutral surface (surface of no change in length, or no strain) has been taken as the base of the competent bed. The Z axis of Figure 3 is vertical; the Y axis—normal to the page—is chosen to coincide with the direction of the structural axis; and the X axis is the horizontal axis at right angles to the structure. The angle θ, measured in radians in a counter-

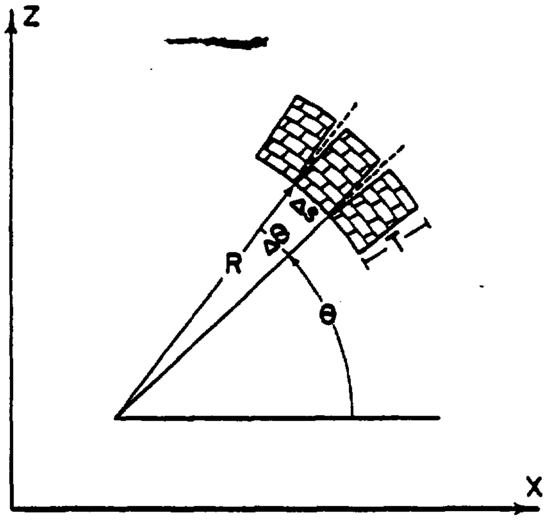

Fig. 3.—Geometry of fracture system used in deriving expressions for fracture porosity and fracture permeability.

clockwise direction from the positive X axis, is the angle made by a normal to the competent bed. The angular increment between adjacent fractures is represented by $\Delta\theta$. The corresponding increment in the surface of the fractured bed is represented by Δs.

The fractional porosity of the fracture system is determined easily from the geometry of the figure. Because the structural configuration and porosity are unchanging in the axial direction, the porosity may be calculated by considering a "slice" of the structure of unit length in the Y direction. Thus, from the expression for the area of a sector of a circle, the fractional porosity, ϕ, of that segment of the reservoir bounded by the two sides of angle $\Delta\theta$, the top and bottom of the bed, and unit length in the Y direction is given by

$$\phi = \frac{\frac{1}{2}(2RT + T^2)\Delta\theta - T\Delta s}{\frac{1}{2}(2RT + T^2)\Delta\theta}.$$

Because

$$\Delta s = R\Delta\theta,$$

this may be reduced to

$$\phi = \frac{T}{2R + T}.$$

T generally is very small in comparison with R. For example, the greatest thickness of any single competent bed, T, in the Sanish zone is on the order of 10 ft, whereas the minimum value of R for the Antelope structure is approximately 10,000 ft. Hence, the last expression may be reduced to

$$\phi = T/2R. \qquad (1)$$

It is useful to express the radius of curvature R in terms of the derivatives in the $X-Z$ coordinate system permitting the graphical evaluation of equation (1) from structural cross sections. In the usual structural situation, dz/dx, the dip measured in feet per feet is very small in comparison with unity. Hence, as is proved in most elementary calculus texts (Sherwood and Taylor, 1946), it is sufficiently accurate to take

$$R = 1 \Big/ \frac{d^2z}{dx^2}.$$

From this expression it may be observed that the curvature, which is defined as the reciprocal of the radius of curvature, is simply the second derivative of structure, d^2z/dx^2. Substitution into (1) yields the simple expression

$$\phi = \frac{1}{2}T\frac{d^2z}{dx^2} \qquad (2)$$

for fractional porosity as a function of bed thickness and structural curvature.

It should be noted that fracture porosity generally is very small. For example, use of the maximum and minimum values of T and R, respectively, for the Sanish pool gives a maximum fracture porosity of approximately 1/2,000, or 1/20 of 1 percent.

As might be expected, fracture permeability is much more significant. The basic expression used in deriving the relationship between fracture permeability, bed thickness, and structural curvature is the equation for the volume of fluid flow per unit length between two parallel plates (Lamb, 1932),

$$q_y = -\frac{h^3}{12\mu}\frac{dp}{dy}$$

where h is the separation of the plates, μ is fluid viscosity, and dp/dy is the pressure gradient in the direction of flow. The minus sign arises because the direction of flow is in the direction of decreasing pressure. Because the angular divergence of the fracture faces is very small, the total volume of flow through one of the pie-shape fractures may be approximated by

$$Q = \int_0^T q_y dt = -\frac{1}{12\mu}\frac{dp}{dy}\int_0^T h^3 dt$$

where t is the distance in the fracture above the point of zero separation, or above the base of the fractured bed. For the pie-shape fracture, $h = kt$ and

$$Q = -\frac{k^3}{12\mu}\frac{dp}{dy}\int_0^T t^3 dt = -\frac{k^3 T^4}{48\mu}\frac{dp}{dy}.$$

The average flow per unit area is the total flow per fracture divided by the average area A per fracture,

$$q = \frac{Q}{A} = -\frac{k^3 T^4}{48\mu A}\frac{dp}{dy}.$$

In order to evaluate k, it is noted that

$$\frac{\frac{1}{2}h_0 T}{A} = \phi \quad \text{and thus } k = \frac{A}{T^2}\left(T\frac{d^2z}{dx^2}\right),$$

where h_0 is fracture width at the top of the bed. Hence,

$$q = -\frac{A^2}{48T^2\mu}\left(T\frac{d^2z}{dx^2}\right)^3\frac{dp}{dy}.$$

From the last expression the permeability is seen to be given by

$$K = \frac{A^2}{48T^2}\left(T\frac{d^2z}{dx^2}\right)^3.$$

After conversion from cgs units to the more familiar millidarcy (Pirson, 1950) and evaluation of A in terms of an assumed fracture spacing of 6 in., this expression reduces to

$$K = 4.9 \times 10^{11}\left(T\frac{d^2z}{dx^2}\right)^3. \quad (3)$$

$\phi \approx 0.0006\sqrt[3]{K}$, darcys

Although the assumption of a fracture spacing of 6 in. admittedly is arbitrary, there are certain considerations leading to this as a reasonable approximation. If the fracture spacing were much greater than this it would be possible for some of the favorably located wells to have missed the fracturing altogether. There is no evidence of this in the Sanish pool. Also, assumption of wider spacing leads to unreasonably large values of calculated permeability. Finally, the writer's field experience leaves the impression that a 6-in. fracture spacing may be somewhat short, but that it is not entirely unreasonable.

Because permeability increases as the third power of $T\,d^2z/dx^2$, it becomes appreciable with relatively small values of this parameter. The tabulations in Table I give illustrative permeability values for different values of T and d^2z/dx^2.

TABLE I. EXAMPLES OF PERMEABILITY VALUES

$T = 5$ ft		$T = 10$ ft	
$\frac{d^2z}{dx^2}(\times 10^{-6})$	K (md)	$\frac{d^2z}{dx^2}(\times 10^{-6})$	K
1	0.06	1	0.49
2	0.49	2	3.92
4	3.92	4	31.20
6	13.20	6	106.00

The figures in Table I should not be taken too literally. The configuration of a natural fracture system undoubtedly varies considerably from the assumptions made in deriving the above expressions for porosity and permeability. Particularly subject to question are the assumptions that the base of the competent bed is a neutral surface and that the fracture spacing is 6-in. It also is apparent that the regular, pie-shape fracture voids are an oversimplification. In some cases the value of bed thickness is uncertain. T represents the thickness of a single competent bed unbroken by shale intercalations capable of providing slippage. In a section like the Sanish, with abundant shale intercalations, a value for T is difficult to ascertain. Despite these uncertainties, it is believed that the above expressions are important as indications of the order of magnitude of fracture porosity and fracture permeability which might be expected with a particular bed thickness and structural configuration.

It should be noted that a minimum value of the parameter $T\,d^2z/dx^2$ must be exceeded before fracturing is developed. It is easily shown that the tensile stress in the upper surface of the bed of Figure 3 is given by

$$F = ET\frac{d^2z}{dx^2}$$

where F is the stress in the upper surface and E is Young's modulus for the bed (Stephenson, 1952). If $T\,d^2z/dx^2$ is such that F exceeds the ultimate tensile strength of the bed, fractures will develop. A rough idea of this critical value may be obtained from measured values of the ultimate tensile strength and Young's modulus of building stones. Some average values (Kidder and Parker, 1935) would give a critical value of about 1.2×10^{-4} for $T\,d^2z/dx^2$ in the case of a limestone. As discussed hereafter, the empirically determined critical value of structural curvature, d^2z/dx^2, for the presence of Sanish fracturing appears to be about 2×10^{-6}. Depending on the exact value of T, this would place $T\ d^2z/dx^2$ near the above figure of 1.2×10^{-4}.

APPLICATION TO SANISH POOL

Figure 4 shows the correlation between well productivity and structural curvature in the Sanish pool. Figure 5 shows how the values of curvature on the map were obtained. At the top of Figure 5 is a structural profile of the Bakken Formation along section A-B. The central profile is a plot of dip magnitude along this line of section. This second curve has been obtained from the first by drawing tangents to the first curve, as indicated, measuring the dip in feet per hundred feet, and plotting this magnitude at the position measured. West dip has been chosen arbitrarily as positive and east dip as negative. The bottom profile of structural curvature has been obtained from the second curve just as the second was obtained from the first. Tangents are drawn on the dip-magnitude curve, their slopes measured, and the values of these slopes plotted at their respective positions.

Across the Antelope field from west to east, the curvature increases to a maximum of about 5×10^{-5}/ft where the dip is changing abruptly into the steep east flank, then returns to zero at the inflection point in the middle of the east flank, and reaches a second maximum where the beds bend sharply into the syncline on the east. As indicated in the legend in Figure 4, the dotted areas show where the curvature is between 2×10^{-6}/ft and 4×10^{-5}/ft and the dashed areas show where the curvature is greater than 4×10^{-5}/ft. As outlined above, the minimum curvature necessary for the development of tension fractures in a 10-ft bed is approximately 2×10^{-6}/ft. Hence, as a first approximation, production should be restricted to the dotted and dashed areas. This appears to be empirically correct. The few producing wells in areas where the structural curvature is less than 2×10^{-6}/ft are all subcommercial.

The matter of sign is arbitrary. Downward curvature has been taken as negative and upward curvature as positive. However, the direction and sign of the curvature in a few cases could be significant with regard to fracture geometry. The widest part of a fracture is at the top of the competent bed if the curvature is downward. If the curvature is upward, the widest parts of the fractures are at the base of the bed.

After several similar cross sections were constructed, the areas where the curvature exceeds the critical value for the development of fracture permeability (dotted) and the areas where the curvature and fracture permeability are the greatest (dashed) were mapped. As indicated in the legend in Figure 4, the well spots are keyed to their productivity. The match between actual productivity and the theoretical fairway is not perfect, as shown by the presence of some of the best wells and a few very poor wells in the dotted areas. However, if the statistical variation which is inevitable in a fracture reservoir is considered, the match between theory and experience is remarkably good.

SANISH PRODUCTION AND RESERVES

There is a wide variation in productivity of the Sanish wells. Prior to recent drilling on the north end of the field, there were 14 wells along the fairway of maximum structural curvature which had produced most of the oil from the pool. Each of these 14 wells, as of January 1, 1966, had produced more than 250,000 bbl and together had produced 74 percent of the oil recovered from the pool. The average producing rate of each well was 178 bbl a day at that time. The other 19 wells had produced the other 26 percent of the total. The 16 of these 19 poorer wells which were still producing as of the first of 1966 had an average producing rate at that time of only 17 bbl a day apiece.

The five northernmost wells in the fairway have been drilled during the past 1½ yr. Although there is some variation in the productivity of these recently completed wells, their average is as good as that of the best 14 older wells.

It is impossible to derive a meaningful reserve estimate for the Sanish from volumetric calculations. The better wells already have produced several times as much oil as could be estimated for the ultimate recovery from core analysis. For example, the discovery well, the No. 1 Woodrow Starr, SW¼ SE¼, Sec. 21, T. 152 N., R. 94 W., had a January 1, 1966, cumulative production of 607,467 bbl. (This includes production from the Starr No. 1-A which was drilled on the same 160-acre location after the casing collapsed in the original well.) The 14 best wells had a cumulative

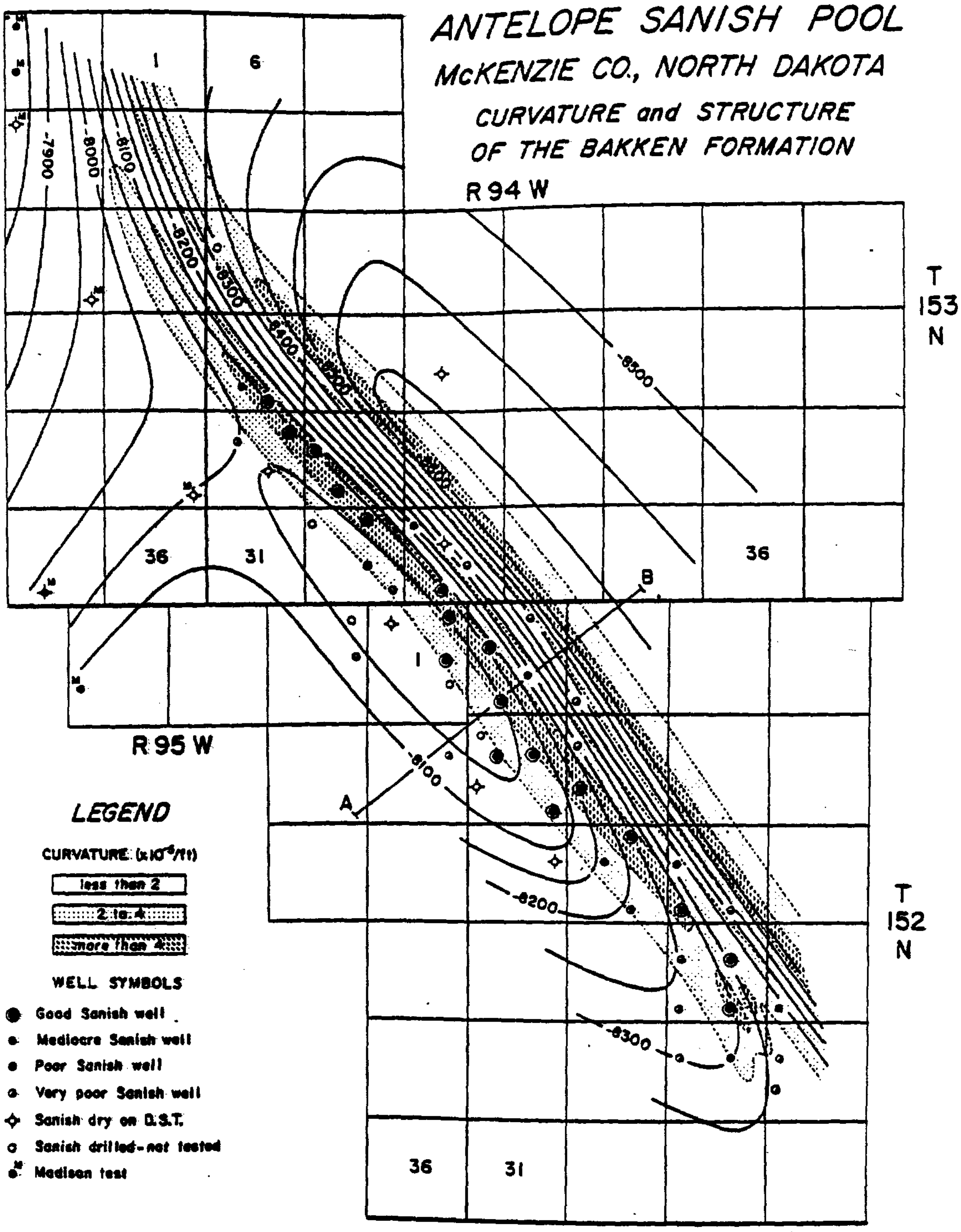

FIG. 4.—Structural contour map of Antelope Sanish pool, McKenzie County, North Dakota. Structural datum, top of Mississippian Bakken Formation. As noted on legend, well spots are keyed to their productivity and values of structural curvature are mapped by patterned areas. Contour interval, 50 ft. Contour datum, sea level. Section A-B is location of Figure 5.

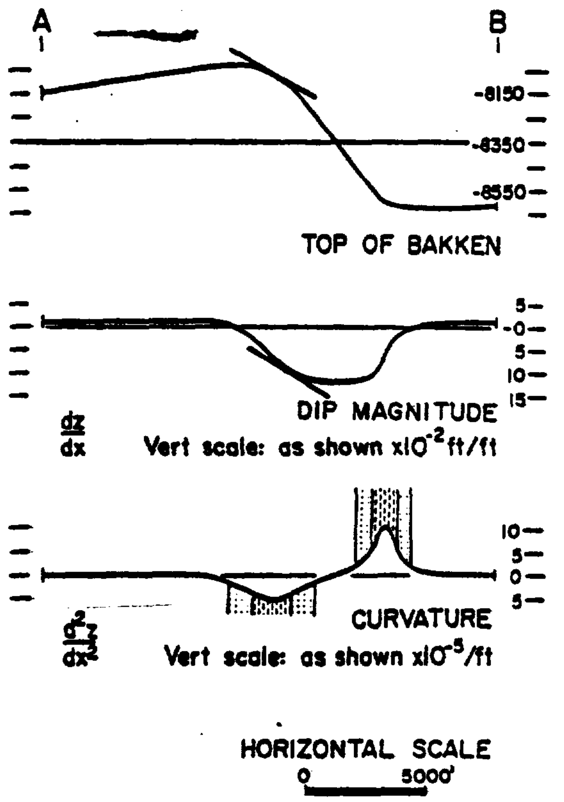

FIG. 5.—Comparison profiles of Bakken structure, dip magnitude, and structural curvature along line of section A-B of Figure 4.

production as of January 1, 1966 of 4,940,261 bbl, or an average of 2,200 bbl/acre. Average reservoir pressure at that time was 3,644 psi. Reservoir-pressure decline has been a straight-line function of barrels produced, indicating that production to date has been the result of fluid expansion.

SIGNIFICANCE OF RESERVOIR PRESSURE

The initial reservoir pressure of the Sanish pool was 7,670 psi at a datum of −8,400 ft. This is more than 2,500 psi above normal for the depth of the accumulation. For example, the original Sanish pressure was 2,150 psi greater than the original pressure in a Silurian reservoir which is about 1,500 ft deeper.

This indicates that the Sanish accumulation is in a closed, completely oil-saturated reservoir. The most important consequence of this fact is that the Sanish pool is independent of structure in the normal sense and there is no risk of penetrating a water column in the Sanish. To date, this conclusion generally has been supported by the productive history of the pool. There was essentially no water production until the reservoir pressure had declined considerably. There now are four or five wells with appreciable water cuts, but this water production is not structurally related because the wells with the largest cuts are very high on the structure. It is believed that this water may be true connate water—or "associated" water—being expelled from the Three Forks shale interbedded with the reservoir.

BAKKEN SHALE AS SOURCE OF OIL

Because the Sanish reservoir is performing much better than could be expected from volumetric calculations, it is believed that the Bakken shale beds are the immediate, as well as the ultimate, source of most of the oil. As has been outlined, the visual and log characteristics of the Bakken shale beds indicate that the pore space in the shales is oil-saturated. With approximately 30 ft of lower Bakken shale, containing 30–35 percent porosity (the pore space is oil-saturated), there is sufficient in-place oil to account for the Sanish production, provided that only a small percentage of this Bakken oil moves into the well bore. The role of the Sanish fracture system is primarily that of a gathering system for many increments of Bakken production.

These shale beds are, in a larger sense, saturated or even supersaturated oil reservoirs throughout the central basin area. If the internal pressures could be measured, they would be found to be abnormally high throughout the central basin. Indirect evidence for abnormally high internal pressures can be seen in the greater-than-normal shale porosity (as indicated by mechanical logs) of these two units. The excess porosity and internal pressure result from the difficulty of expulsion of the oil from these beds through the overlying Lodgepole and the underlying Three Forks sections. As a consequence, any restricted reservoir in direct contact with either of the two shale units should be productive anywhere in the deeper part of the basin, regardless of structural position.

CONCLUSIONS

Analysis of the Sanish pool supports the immediate [illegible]ssion that the production is from a tension-fracture system associated with the relatively sharp Antelope fold. In the local context of the Williston basin, one of the most important conclusions is the recognition that the upper and lower Bakken shale beds are supercharged oil shales and that they probably are the immediate source of most of the oil. Hence, discovery of permeability in beds adjacent to either of these two shale units—either in another fracture system or an area of matrix permeability in sandstone or carbonate rocks—would probably mean the discovery of prolific production comparable with that of the Sanish pool. Equally intriguing is the conclusion that, because the two shale beds are everywhere oil-saturated, such production is independent of structure in the normal sense and might be found in a synclinal location. Most important, it is believed that the relations between fracture porosity, fracture permeability, bed thickness, and structural curvature may prove useful in the analysis of similar problems in other geologic provinces.

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BENSON-MONTIN-GREER DRILLING CORP.
REBUTTAL TESTIMONY
RESPECTING INTERFERENCE TESTS
CANADA OJITOS UNIT

With respect to Mr. Hueni's response to the Chairman's questions about interference tests conducted in the Canada Ojitos Unit, we assume that Mr. Hueni apparently did not understand the nature of the subject interference tests, for his responses were to the effect that:

1. Interference testing can only show information about the formation between the test wells, and is complicated by fracturing.

2. The EI straight line solution does not apply to a heterogeneous reservoir.

3. The best way to determine the reservoir characteristics is from individual well pressure build up tests.

Since all three of these statements are incorrect as to the subject reservoir and tests, it is assumed that Mr. Hueni didn't have time to study them, so his failure to correctly assess the tests is understandable; however his statements are in the record, and the record needs to be set straight.

First we note that it was the heterogeneity of the formation, whose average characteristics could not be determined from well testing that made need for the interference tests. A reservoir substantially larger than the drilled area was indicated from some of the pressure testing; and the Unit Operator required more information about the reservoir so that an orderly, and informed, development plan could be implemented. One option was pressure maintenance by gas injection and a question here was the degree of anticipated gas channelling; the answer to which turned on the level of transmissibility (Kh) - not of the "tight blocks" in which the wells were completed - but of the reservoir average.

Interference testing was decided on since it was the only method - then and now - available to determine the necessary characteristics of this fractured reservoir rock.

As set out in our direct testimony, the stratified reservoir of Gavilan presents problems in interference testing (as well as for individual well pressure build up surveys), but the Canada Ojitos Unit 1965 and 1968 interference tests were of only one zone and were thus not affected by this complication.

With respect to the above-numbered items, we state:

1. Although most interference tests may be those

conducted for a relatively short period of time (ordinarily "short" because of the cost of delayed production for a long test) and are in reservoirs whose rate of diffusion of pressure transients is slow (and consequently they "sample" only a small portion of the reservoir), in contrast, in the Canada Ojitos Unit, the diffusivity constant at the time of the 1965 test ranged up to 1×10^7 and tests of 15 to 20 days reflected average quantities for distances of 2 or 3 miles beyond the locations of the test wells. This is the consequence of the fractured formation's high transmissibility coupled with its low per acre volume of oil in place.

That the EI formula can be used to fairly describe the reservoir properties beyond the test wells can be confirmed by examining the transient pressure equations for a reservoir with a "large internal radius", as, for example, an oil field in a large aquifer; and comparing this with the EI solution as described herein. What we do here is to "expand" the wellbore radius to a distance equal to that of the interference observation well, and assume that the "wellbore" has a small volume (but infinite transmissibility).

This comparison shows very clearly how interference testing "filters out" the problems of induced fractures, wellbore resistance, heterogeneous rock characteristics, etc.

The example shown here derives from Muskat's solution to this problem; but others are available, as for instance, through use of the Laplace Transformation; and clearly shows the powerful potential of interference testing to "sample" a large part of the reservoir.

2. The degree of heterogeneity that can be tolerated by an interference test and give reliable results as to the average physical properties depends strictly on the rate of diffusion of the pressure transients in the affected areas. In the Canada Ojitos Unit test area the geometry of the reservoir is that of individual "tight blocks" surrounded by a high capacity fracture system. The information following shows clearly that the rate of diffusion is high enough that valid results can be anticipated. The proof, here, of course, is that such actually happened and was measured in observation wells in the 1965 interference test.

3. Individual well test Kh's had been determined prior to the 1965 test and they showed that transmissibility varied twenty-fold, from .02 darcy feet to .45 darcy feet. (No way here to determine a reasonable "weighted average".) Moreover it appeared that the true reservoir average Kh was substantially higher than that shown for any of the wells; so any "average" of their properties would be totally incorrect. After the interference test was run, it revealed that the reservoir average Kh was on the order of 5 to 10 darcy feet - ten to twenty times higher than the highest individual well test at that time.

Here again, the proof that the interference test provided more definitive data than the individual well tests was revealed when a well drilled two years after the interference test was completed showed the high capacity system to exist; and when gas injection commenced it was possible to confirm under steady state conditions the transmissibility for a 2-1/2 mile distance to be in the same 5 to 10 darcy feet range.

Time does not permit introduction here of all the supporting data, however it is well documented in Case No. 3455 before the Oil Conservation Division in November 1966 and December 1969.

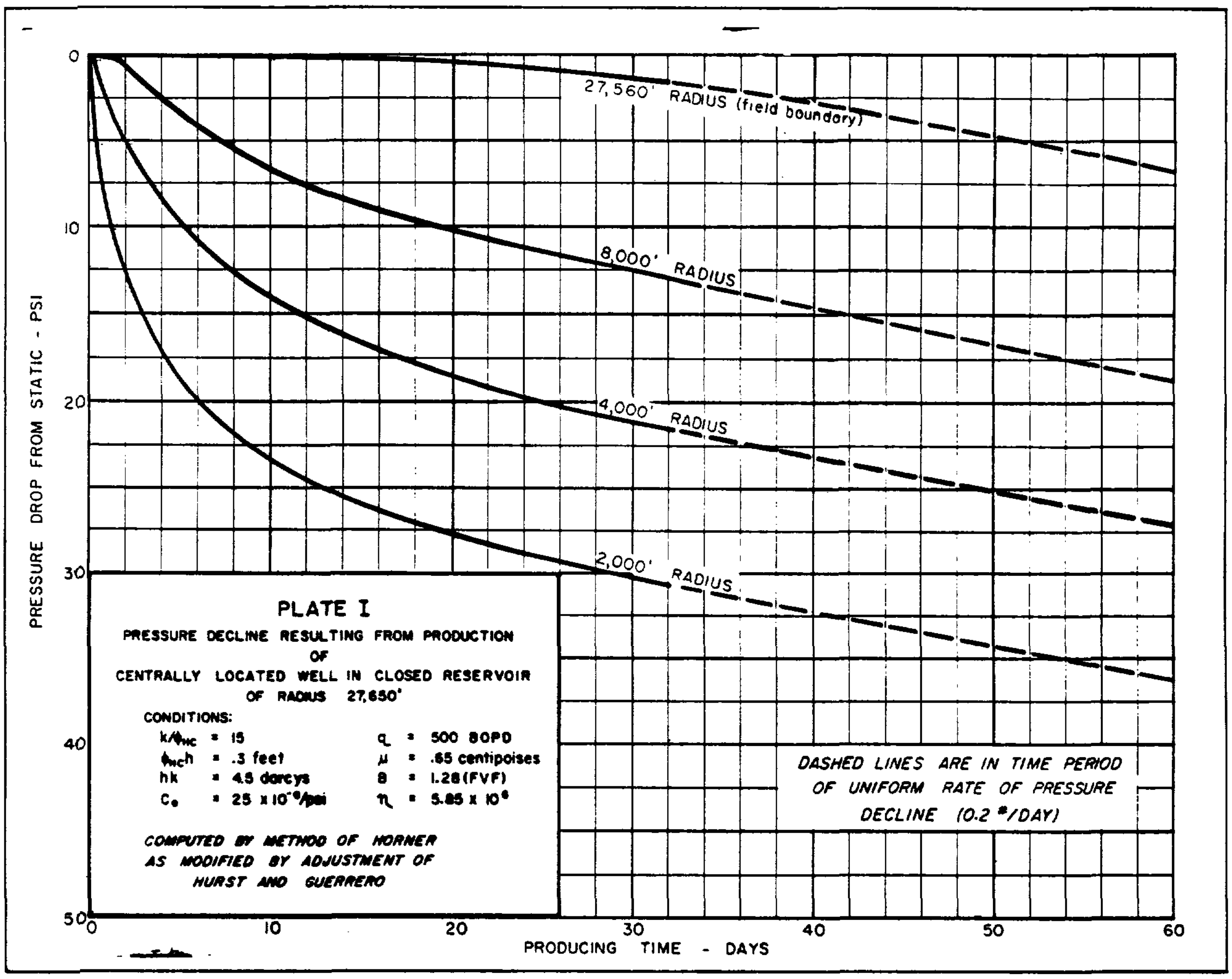


PLATE I
PRESSURE DECLINE RESULTING FROM PRODUCTION OF CENTRALLY LOCATED WELL IN CLOSED RESERVOIR OF RADIUS 27,650'
CONDITIONS:
k/ϕ_{wc} = 15
$\phi_{wc}h$ = .3 feet
hk = 4.5 darcys
C_e = 25 x 10^{-6}/psi
q = 500 BOPD
μ = .65 centipoises
B = 1.28 (FVF)
η = 5.85 x 10^{6}
COMPUTED BY METHOD OF HORNER AS MODIFIED BY ADJUSTMENT OF HURST AND GUERRERO
27,560' RADIUS (field boundary)
8,000' RADIUS
4,000' RADIUS
2,000' RADIUS
DASHED LINES ARE IN TIME PERIOD OF UNIFORM RATE OF PRESSURE DECLINE (0.2 #/DAY)
PRESSURE DROP FROM STATIC - PSI
PRODUCING TIME - DAYS
0
10
20
30
40
50
60

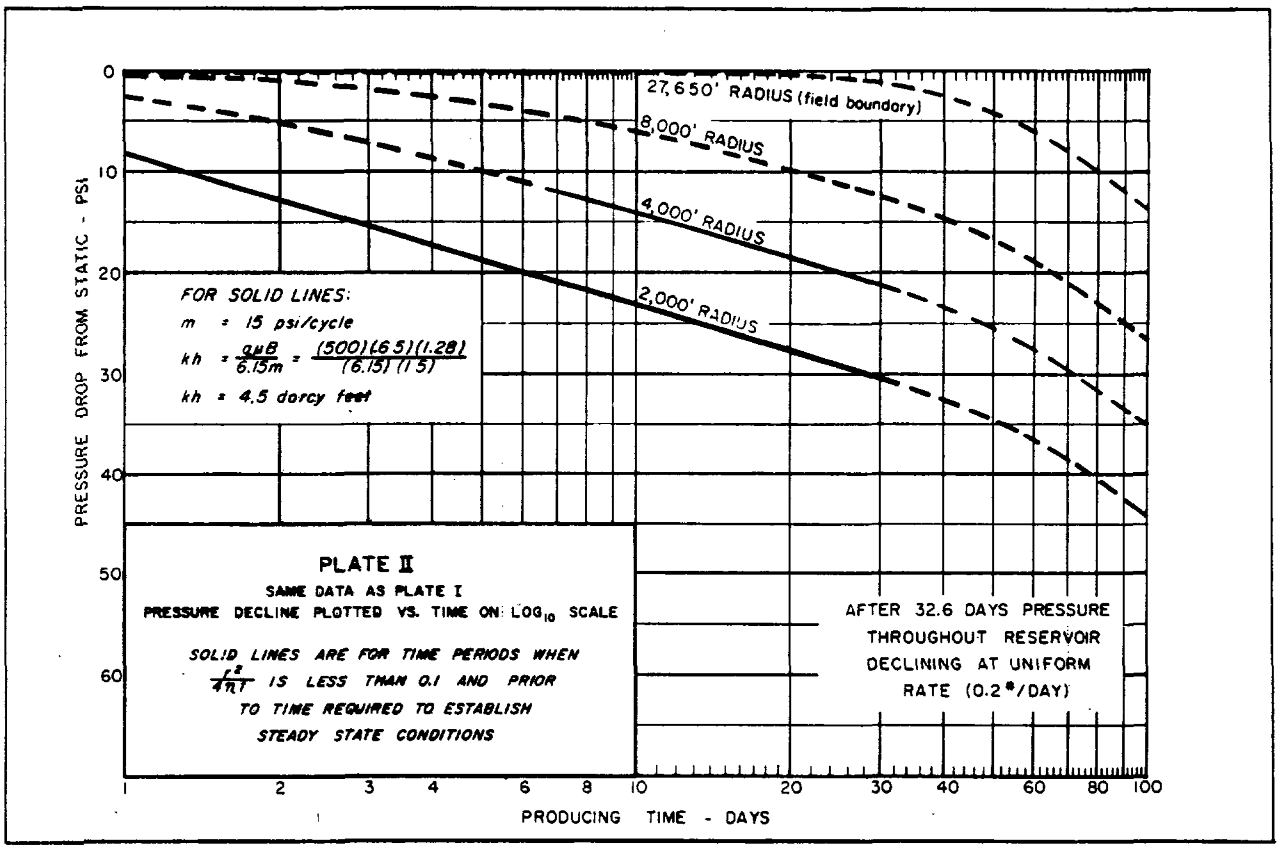
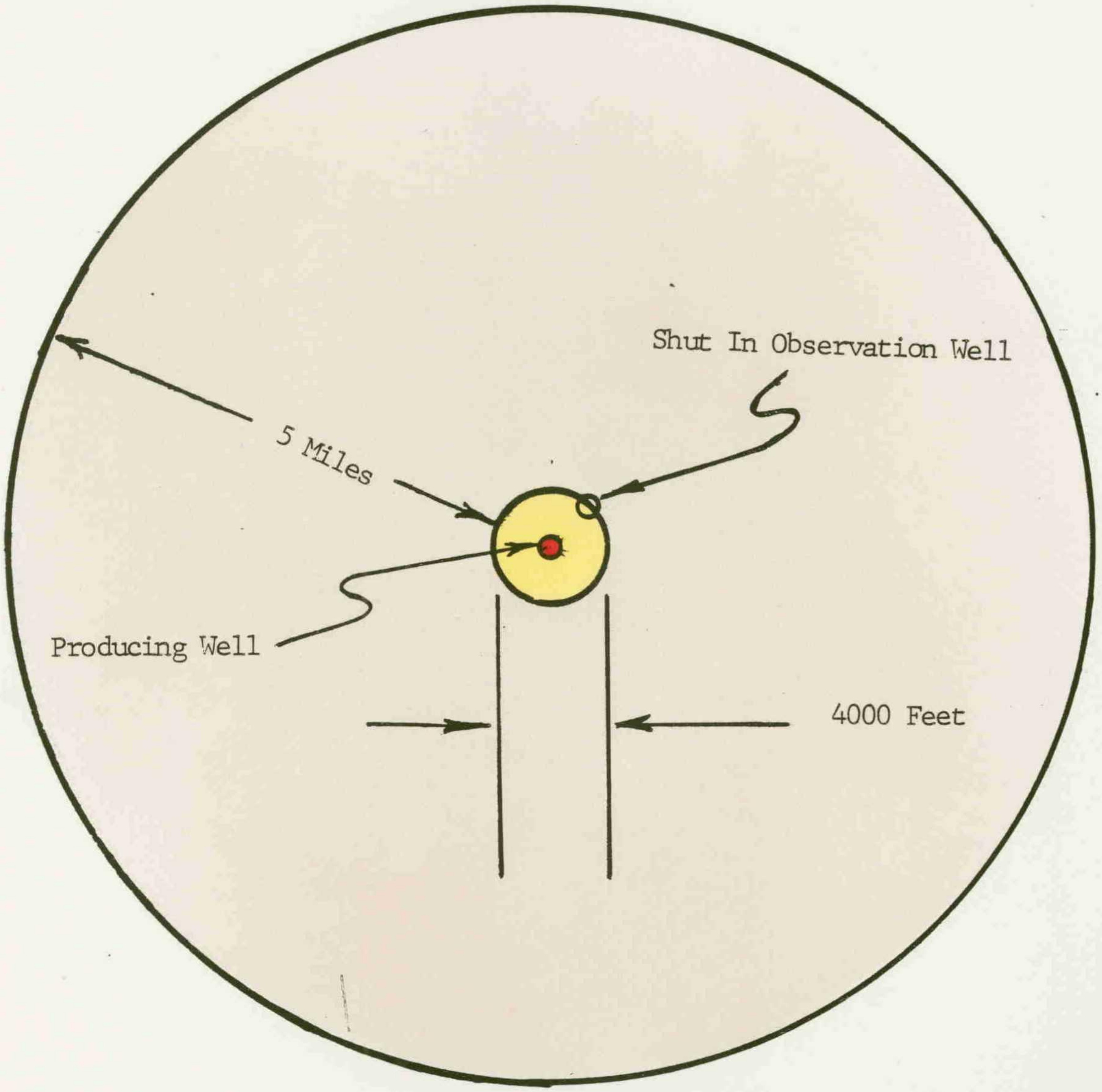


PLATE II
SAME DATA AS PLATE I
PRESSURE DECLINE PLOTTED VS. TIME ON LOG_{10} SCALE
SOLID LINES ARE FOR TIME PERIODS WHEN $\frac{r^2}{4\eta T}$ IS LESS THAN 0.1 AND PRIOR TO TIME REQUIRED TO ESTABLISH STEADY STATE CONDITIONS
FOR SOLID LINES:
m = 15 psi/cycle
$kh = \frac{q\mu B}{6.15m} = \frac{(500)(.65)(1.28)}{(6.15)(15)}$
kh = 4.5 darcy feet
27,650' RADIUS (field boundary)
8,000' RADIUS
4,000' RADIUS
2,000' RADIUS
AFTER 32.6 DAYS PRESSURE THROUGHOUT RESERVOIR DECLINING AT UNIFORM RATE (0.2 #/DAY)
PRESSURE DROP FROM STATIC - PSI
PRODUCING TIME - DAYS
1
2
3
4
6
8
10
20
30
40
60
80
100

COMPARISON OF SOLUTIONS
OF THE DIFFUSIVITY EQUATION

POINT SOURCE (EXPONENTIAL INTEGRAL)
WITH
LARGE INTERNAL RADIUS



PHYSICAL PRINCIPLES OF OIL PRODUCTION

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The specific system to be analyzed here will be defined by the initial and boundary conditions (cf. Fig. 11.3)

$$\left.\begin{aligned} t = 0 \quad &: \quad \gamma = \gamma_i(p = p_i), \\ r = r_f \quad &: \quad 2\pi r\gamma v_r = q(t), \end{aligned}\right\} \qquad (1)$$

where the radius r_f is taken as the equivalent oil-field radius, assumed circular, and p_i is the initial pressure in the water reservoir. In actual

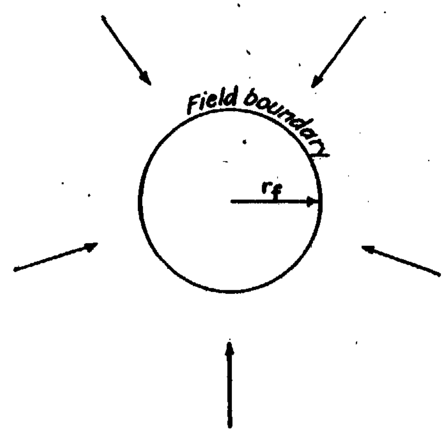


FIG. 11.3

complete-water-drive fields the mass flux $q(t)$ at the field boundary is to be considered as representing the fluid withdrawal within the field, except for that replaced by expansion of its own fluid content.

By means of the solution of Eq. 11.3(13), subject to the conditions of Eq. (1), the fluid density and pressure at $r = r_f$, or field boundary, can be determined as a function of time. This solution can be verified to be[1]

$$\gamma = \gamma_i + \frac{1}{\pi^2 f r_f}\int_0^\infty \frac{e^{-au^2t}[J_0(ur)Y_1(ur_f) - Y_0(ur)J_1(ur_f)]\,du}{J_1^2(ur_f) + Y_1^2(ur_f)}\int_0^t q(\lambda)e^{au^2\lambda}\,d\lambda. \quad (2)$$

where J_n, Y_n denote Bessel functions[2] of order n of the first and second kinds, respectively.

For the special case where $q(t)$ is a constant q_o, Eq. (2) reduces to

$$\gamma = \gamma_i + \frac{q_o}{\pi^2 a f r_f}\int_0^\infty \frac{(1 - e^{-au^2t})\,[J_0(ur)Y_1(ur_f) - Y_0(ur)J_1(ur_f)]\,du}{u^2[J_1^2(ur_f) + Y_1^2(ur_f)]}. \quad (3)$$

[1] The solution for this problem, applying to the special case of Eq. (3), has been derived by J. C. Jaeger in an unpublished manuscript.

[2] These functions are treated exhaustively by G. N. Watson, "The Theory of Bessel Functions," Cambridge University Press, 1922. Most of the properties required in developing the analysis given in this chapter are briefly outlined in M. Muskat, "The Flow of Homogeneous Fluids through Porous Media," Sec. 10.2, McGraw-Hill Book Company, Inc., 1937.

At the field boundary r_f, γ will therefore have the value

$$\gamma_f = \gamma_i - \frac{2q_o}{\pi^3 a f r_f^2}\int_0^\infty \frac{(1 - e^{-au^2t})\,du}{u^3[J_1^2(ur_f) + Y_1^2(ur_f)]}. \quad (4)$$

On translating the decline in density $\gamma_i - \gamma_f$ to the corresponding pressure drop $\Delta p = p_i - p_f$ and introducing the dimensionless time variable $\bar{t}$, Eq. (4) becomes

$$\Delta p = \frac{2Q\mu}{\pi^3 k}\int_0^\infty \frac{(1 - e^{-z^2\bar{t}})\,dz}{z^3[J_1^2(z) + Y_1^2(z)]}; \qquad \bar{t} = \frac{at}{r_f^2}, \quad (5)$$

where Q represents the volumetric outflow per unit thickness at r_f, but measured at the surface,[1] that is, q_o/γ_o. In Fig. 11.4 a graphical evaluation

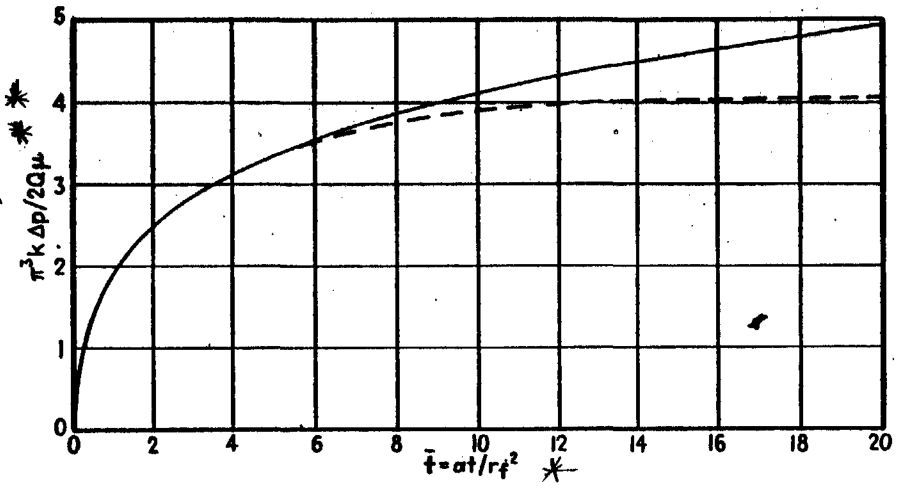


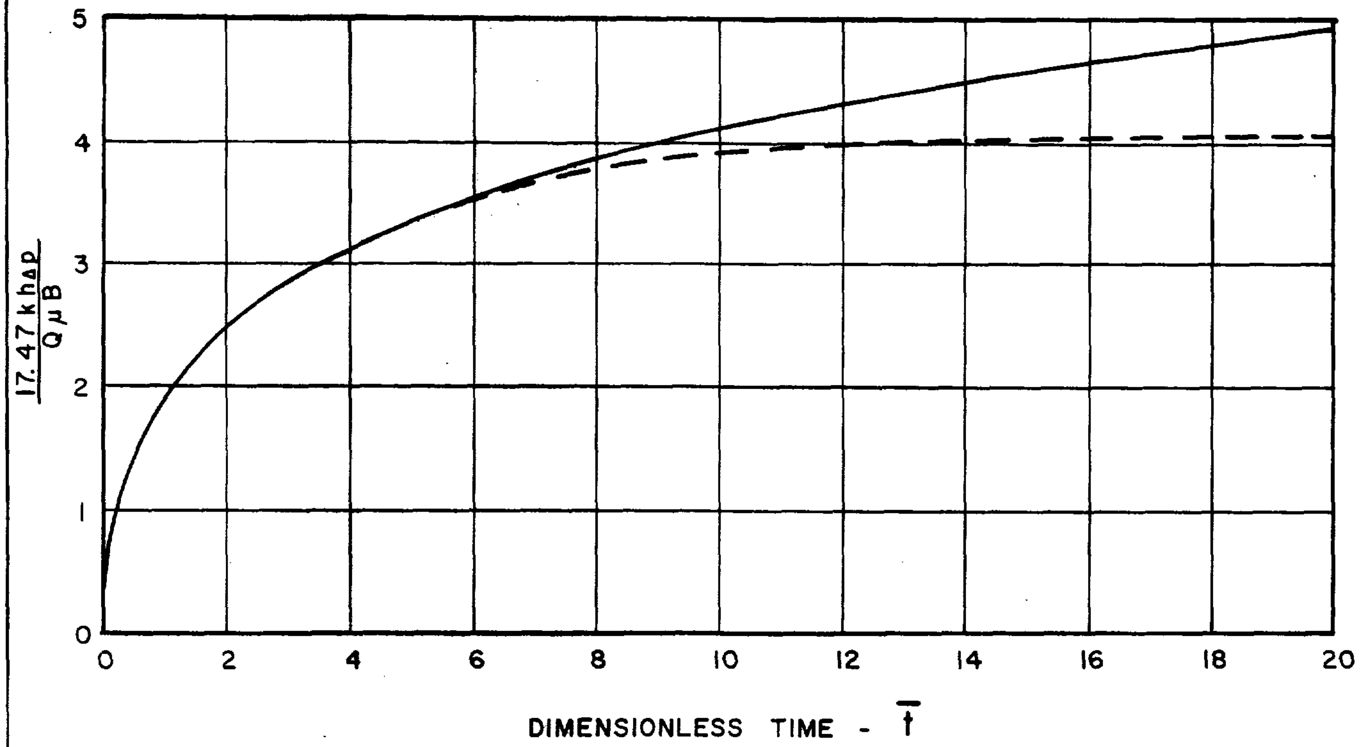
FIG. 11.4. The calculated pressure drop Δp vs. the time t plotted in dimensionless form, at the internal boundary of water reservoirs, with constant water-withdrawal rate Q per unit thickness. Internal-boundary radius = r_f; permeability of water reservoir = k; μ = viscosity of water; κ = compressibility of water; f = porosity; $a = k/f\kappa\mu$. Solid curve refers to an infinite water reservoir. Dashed curve applies to a finite water reservoir with the pressure kept fixed at an external radius that is 6.3 times r_f.

of Eq. (5) is plotted as the solid curve in dimensionless form, as $\pi^3 k\,\Delta p/2Q\mu$ vs. $\bar{t}$. As may be shown by an analysis of Eq. (5), Δp initially rises as $\sqrt{\bar{t}}$ and asymptotically assumes a logarithmic variation with $\bar{t}$. Thus in contrast to the steady-state approximation treated in the last section there

[1] To second-order terms in κ, the conversion between $\Delta\gamma$ and Δp can be made using any convenient value of γ [cf. Eq. 11.3(11)]. The values of flux represented by Q in this and the following sections refer to complete cylindrical systems. If the reservoirs are more appropriately described by sectors of angular width w, the equations relating pressure drops to flux will still remain valid provided that the values of Q used in the equations are the actual values multiplied by $2\pi/w$.

PRESSURE DECLINE AT THE INTERNAL BOUNDARY OF LARGE RESERVOIRS SUBJECT TO CONSTANT WITHDRAWAL RATE

AFTER MUSKAT, PHYSICAL PRINCIPLES OF OIL PRODUCTION, 543



$\bar{t} = \frac{6.328\, kt}{\phi c \mu\ r_f^2} = \frac{\eta t}{r_f^2}$ $\eta = \frac{6.328k}{\phi c \mu}$

where:

$\bar{t}$ = dimensionless time
k = permeability, darcys
t = producing time, days
ϕ = porosity, fraction
c = system compressibility, $\Delta v/v$/psi
μ = viscosity, centipoises
r_f = internal boundary radius, feet

Q = constant withdrawal rate, bbls/day
μ = viscosity, centipoises
B = formation volume factor, reservoir bbls per surface barrel

ΔP = pressure drop from static at time t, at internal boundary

SOLID CURVE REFERS TO AN INFINITE RESERVOIR
DASHED CURVE APPLIES TO A FINITE RESERVOIR WITH THE PRESSURE KEPT FIXED AT AN EXTERNAL RADIUS THAT IS 6.3 TIMES r_f

FIGURE NO. 22

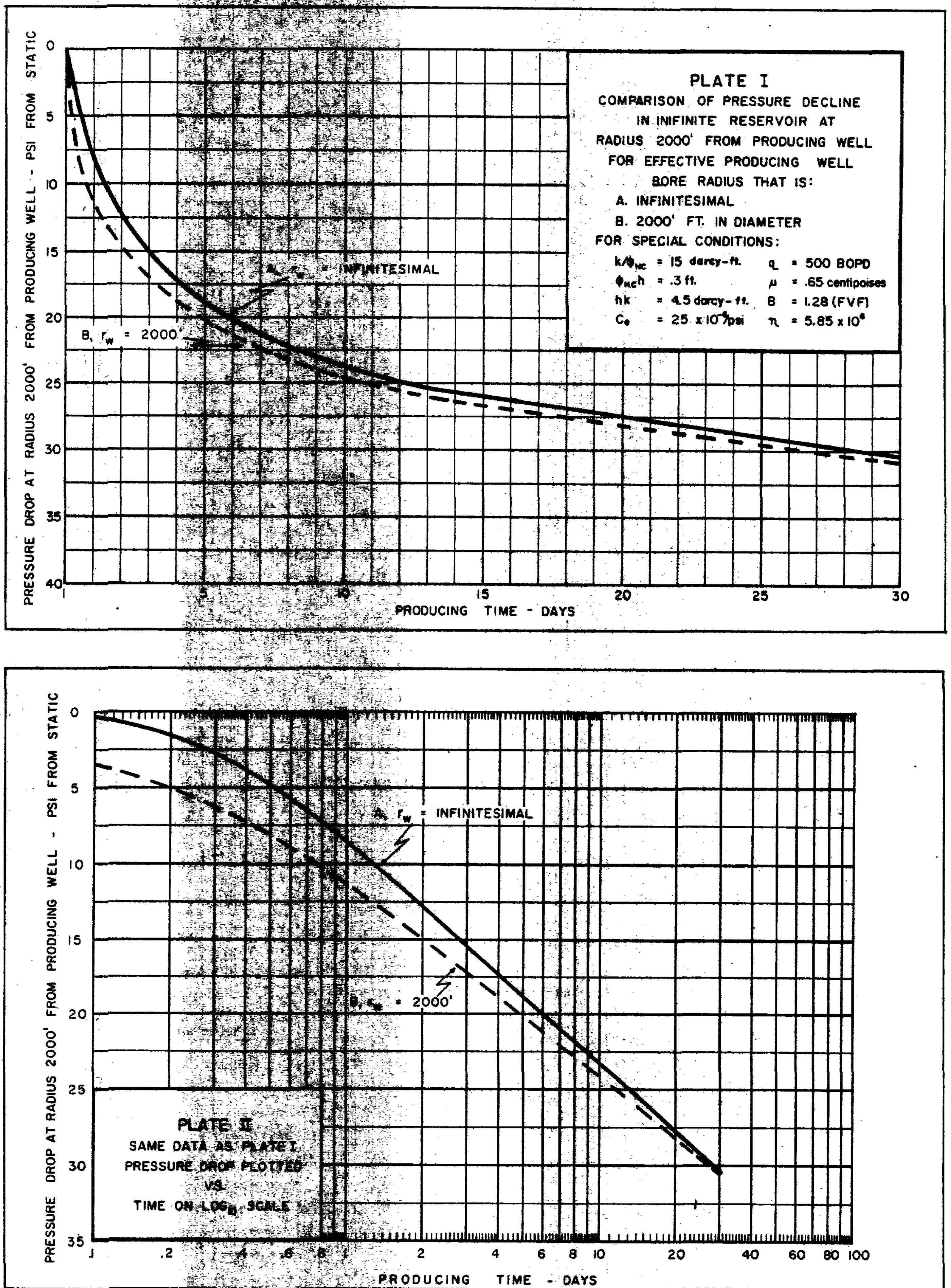
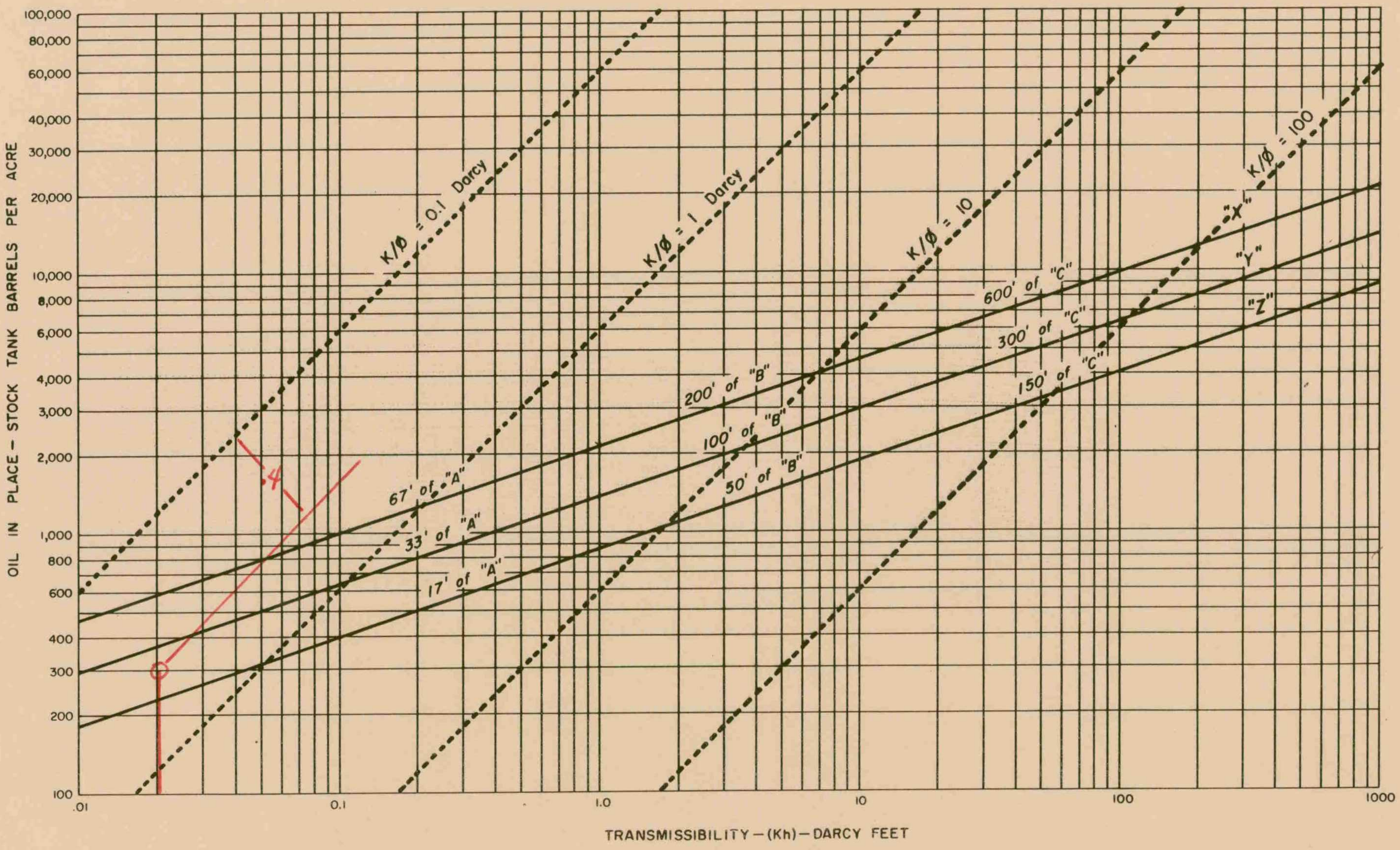


PLATE I
COMPARISON OF PRESSURE DECLINE
IN INIFINITE RESERVOIR AT
RADIUS 2000' FROM PRODUCING WELL
FOR EFFECTIVE PRODUCING WELL
BORE RADIUS THAT IS:
A. INFINITESIMAL
B. 2000' FT. IN DIAMETER
FOR SPECIAL CONDITIONS:
k/ϕNC = 15 darcy-ft.
q = 500 BOPD
ϕNCh = .3 ft.
μ = .65 centipoises
hk = 4.5 darcy-ft.
B = 1.28 (FVF)
Ce = 25 x 10-6/psi
η = 5.85 x 10^6
A. rw = INFINITESIMAL
B. rw = 2000'
PRESSURE DROP AT RADIUS 2000' FROM PRODUCING WELL - PSI FROM STATIC
0
5
10
15
20
25
30
35
40
1
5
10
15
20
25
30
PRODUCING TIME - DAYS
A. rw = INFINITESIMAL
B. rw = 2000'
PLATE II
SAME DATA AS PLATE I
PRESSURE DROP PLOTTED
VS.
TIME ON LOG10 SCALE
PRESSURE DROP AT RADIUS 2000' FROM PRODUCING WELL - PSI FROM STATIC
0
5
10
15
20
25
30
35
.1
.2
.4
.6
.8
1
2
4
6
8
10
20
40
60
80
100
PRODUCING TIME - DAYS

FIGURE NO. 23

RELATION OF OIL IN PLACE
TO
TRANSMISSIBILITY
FOR
POROSITY–PERMEABILITY RELATIONS
"A", "B" & "C"
AND FOR
RESERVOIR THICKNESSES SHOWN
F.V.F. = 1.29



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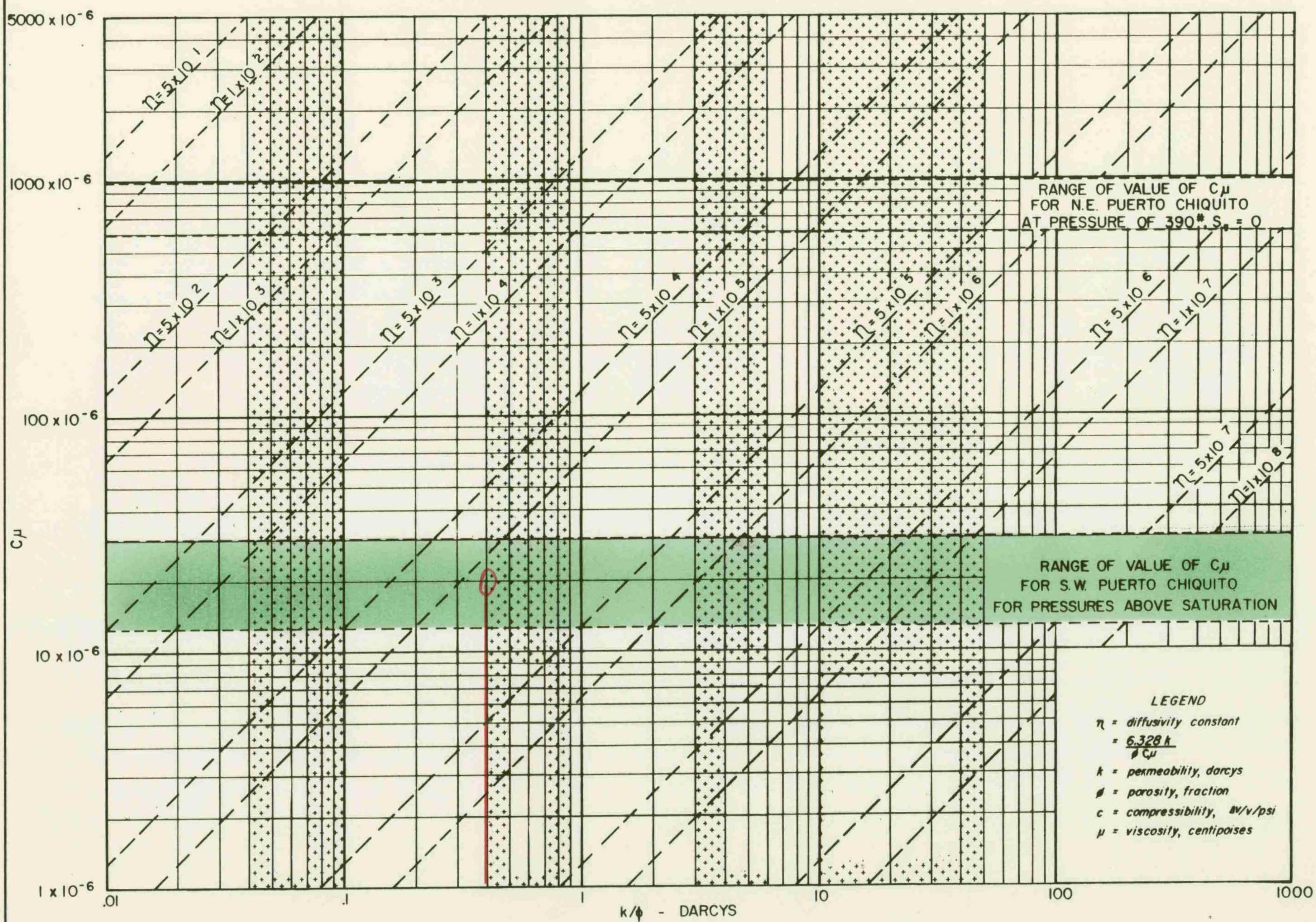
APPENDIX III FIGURE NO. III-5

Rev. 8/86

VALUE OF DIFFUSIVITY CONSTANT AS FUNCTION OF K/ϕ VS. Cμ



Rev. 8/86

FIGURE NO. 10

TIME REQUIRED TO ESTABLISH STEADY-STATE CONDITIONS FOR CIRCULAR DRAINAGE AREAS OF UNIFORM PROPERTIES