APPLICATION FOR IMPLEMENTATION OF ENHANCED RECOVERY PROPOSED WHITEWATER UNIT NO. 1

The applicant proposes to unitize the six capable oil wells of the Whitewater field (see Figure 1). The primary purpose of unitizing is to facilitate the operation of an enhanced recovery scheme in the subject area. An engineering report entitled "Feasibility of Enhanced Recovery - Whitewater Field" and dated August 1970 has been included in support of this submission.

The estimated original oil-in-place from volumetric calculations is 2,605,000 barrels. The indicated ultimate primary recovery from the proposed Unit area is 477,000 barrels. By comparison, waterflood calculations indicate an estimated ultimate primary plus secondary recovery of 756,000 barrels or an incremental 279,000 barrels of secondary oil from the same area. From a preliminary and cursory examination of a newly developed "polymer" flooding technique, there is an indication that oil recovery from the proposed Unit area may be increased by the institution of this type of flooding as compared to conventional waterflooding.

A study is presently being conducted by the Dow Chemical Company to confirm the feasibility of using polymer as an injection water additive in the prospective enhanced recovery scheme.

Appendix I contains a summary of the investigation of the feasibility of waterflooding. Due to the limited proposed project area (240 acres), the recommended flood pattern is essentially a line drive. A detailed outline of the proposed waterflood program is presented in Appendix II.

Unitization of the area under application would enable all royalty interest in the area to be merged so that the productive portion of the reservoir may be operated as a single property. Maximum recovery efficiency and reduced production costs may be attained under Unit operation.

Two of the six wells in the proposed waterflood scheme are required for conversion to water injection. The royalty owners must be ensured of a continued income from currently producing wells, including those that would be converted to water injection. Additional production will be obtained from the waterflood project and the Unit must provide a fair and equitable basis for sharing of this benefit. The applicant submits that the proposed participation formula provides a fair and equitable basis for sharing the unitized production.

All the capable oil wells on 40-acre spacing in the Whitewater field have been included in the proposed Unit area. The productive acreage has been substantially delineated by dry and abandoned wells (Figure 1). If future development indicates that any lands currently excluded from the proposed Unit area should be included, the Board may at any time, under Section 77 of the Mines Act, hold a further hearing to consider the admission of these or any other lands to the Unit area. Therefore, should any outside acreage be subsequently developed and proven productive, it could enter and participate in the Unit by order of the Board.

APPENDIX I

INVESTIGATION OF THE FEASIBILITY OF WATERFLOODING

The wells in the proposed Whitewater Unit No. 1 were drilled from 1953 to 1955. Initial production rates of the wells declined rapidly, indicating limited reservoir energy and/or aquifer support. Geological and reservoir studies were therefore initiated to study the feasibility of enhanced recovery in the field.

Waterflood susceptibility tests were not conducted on core samples from the Whitewater reservoir. A comparison of core samples from North Virden Scallion, on which waterflood tests have been conducted, and core analyses available from the Whitewater field showed that a reasonable similarity in lithology, permeability and porosity existed. Therefore, the results of these tests, with slight modification, are representative of the Whitewater reservoir and indicate substantial oil recoverable by waterflooding.

The report "Feasibility of Enhanced Recovery, Whitewater Field" dated August 1970 may be briefly summarized as follows:

(1) The size and structure of the reservoir and the properties of the reservoir rock and fluid were determined to obtain an estimated original oil-in-place of 2,605,000 barrels.

(b) An estimate of the ultimate primary oil reserves as a percentage of the estimated original oil-in-place was determined from a pool decline curve to be 18.3% (477,000 barrels).

(c) An ultimate recovery by waterflood of 756,000 barrels at a terminal W.O.R. of 25 was calculated using the laboratory waterflood test data with consideration given to displacement, vertical and areal sweep efficiencies.

(d) A preliminary estimate of oil recoverable by polymer flooding was derived from a cursory examination utilizing assumed parameters to calculate displacement, vertical and areal sweep efficiencies.

SUMMARY

PRIMARY RESERVES ESTIMATE

Surface Area	240 acres
Rock Volume	4,800 acre feet
Average Pay Thickness	20 feet
Footage Weighted Porosity	11.3%
Average Initial Water Saturation	35%
Initial Formation Volume Factor	1.05 Res.Bbls./STB
Original Oil-in-Place	543 Bbls./acre foot
Original Oil-in-Place	2,605,000 barrels
Primary Recovery	477,000 barrels
Primary Recovery	18.3%

WATERFLOOD RESERVES ESTIMATE

Initial Water Saturation	35%
Residual Oil Saturation	33%
Footage Weighted Permeability to Air	111 md.
Median Permeability to Air	35.5 md.
Mobility Ratio	1.54
Waterflood Efficiency	.192
Estimated Recovery Following Commencement of Injection	439,000 barrels
Ultimate Recovery	756,000 barrels
Incremental Secondary Oil	279,000 barrels

POLYMER FLOOD RESERVES ESTIMATE

Polymer Flood Efficiency	.260
Estimated Recovery Following Commencement of Injection	595,000 barrels
Ultimate Recovery	912,000 barrels
Incremental Secondary Oil	435,000 barrels
Incremental Secondary Oil Attributable to Polymer	156,000 barrels

APPENDIX II

DETAILS OF OPERATION TO BE CONDUCTED IN PROPOSED UNIT AREA

The basic objective of the enhanced recovery proposal is to recover the greatest amount of oil economically. Conversion to injection is proposed for two wells centrally located in the thickest section of the Upper Whitewater Lake Member of the Mississippian Formation. The wells, located on Lsd's 13-16-3-21 WPM and 9-17-3-21 WPM, should provide maximum vertical and areal sweep efficiencies in addition to adequate injection rates. Injectivity calculations indicate that the injection fluid will be accepted by these wells at a minimum rate of 300 BWPD.

A. SOURCE OF WATER FOR INJECTION

The Swan River Sand is proposed as a potential source of water supply for the injection system. It is tentatively proposed that a water supply well be drilled on Lsd. 13-16-3-21 WPM to test the Swan River formation, at a depth of 1,700', for sufficient productivity. If this water source proves inadequate after testing, the well will be deepened to test the Lodgepole aquifer (if present) or the Devonian formation if necessary to provide an adequate water supply for the scheme.

B. INJECTION PLANT

It is tentatively proposed that the water injection plant be located on Lsd. 13-16-3-21 WPM (Figure 1). The plant will consist of water storage facilities and a reciprocating injection pump. If polymer flooding appears feasible, additional mixing and storage facilities will also be required. It is anticipated that produced Mississippian water will be limited and therefore disposed of until the produced water volume will adequately supply a complete segment of the injection requirements, at which time the injection system will be converted to accommodate the produced Mississippian water.

C. HIGH PRESSURE INJECTION SYSTEM

It is proposed that the injection lines be 2-3/8" cement-lined, nominal sized, Grade A line pipe, coated and wrapped and tested to a pressure greater than the anticipated injection pressure. Figure 1 shows the proposed Whitewater Unit No. 1 injection system.

D. CONVERSION OF WELLS TO WATER INJECTION

It is the applicant's intention to flood the oil-bearing Upper Whitewater Lake Member of the Lodgepole Formation. A schematic diagram of a typical injection well is shown in Figure 2. The following procedure outlines the program to be carried out in converting the wells to water injection:

(a) Pull rods, pump and tubing.

(b) Run casing scraper.

(c) (i) Well 13-16 - run in with drill bit, deepen well approximately 20'.

(ii) Well 9-17 - run in with open-end tubing and reverse circulate well bore to total depth. Reperforate entire Upper Whitewater zone.

(d) Acidize well bore and perform water injection test at maximum surface pressure of 1,000 psi.

(e) Pull tubing and place well on injection down casing until such time as well is pressured up.

(f) Run 2-3/8" cement-lined tubing for injection string.

(g) Fill annulus with oil.

(h) Place well back on injection.

Additional remedial rework such as restimulation, addition of diverting agents, etc., may be required at a later date to rectify difficulties which cannot be presently anticipated.

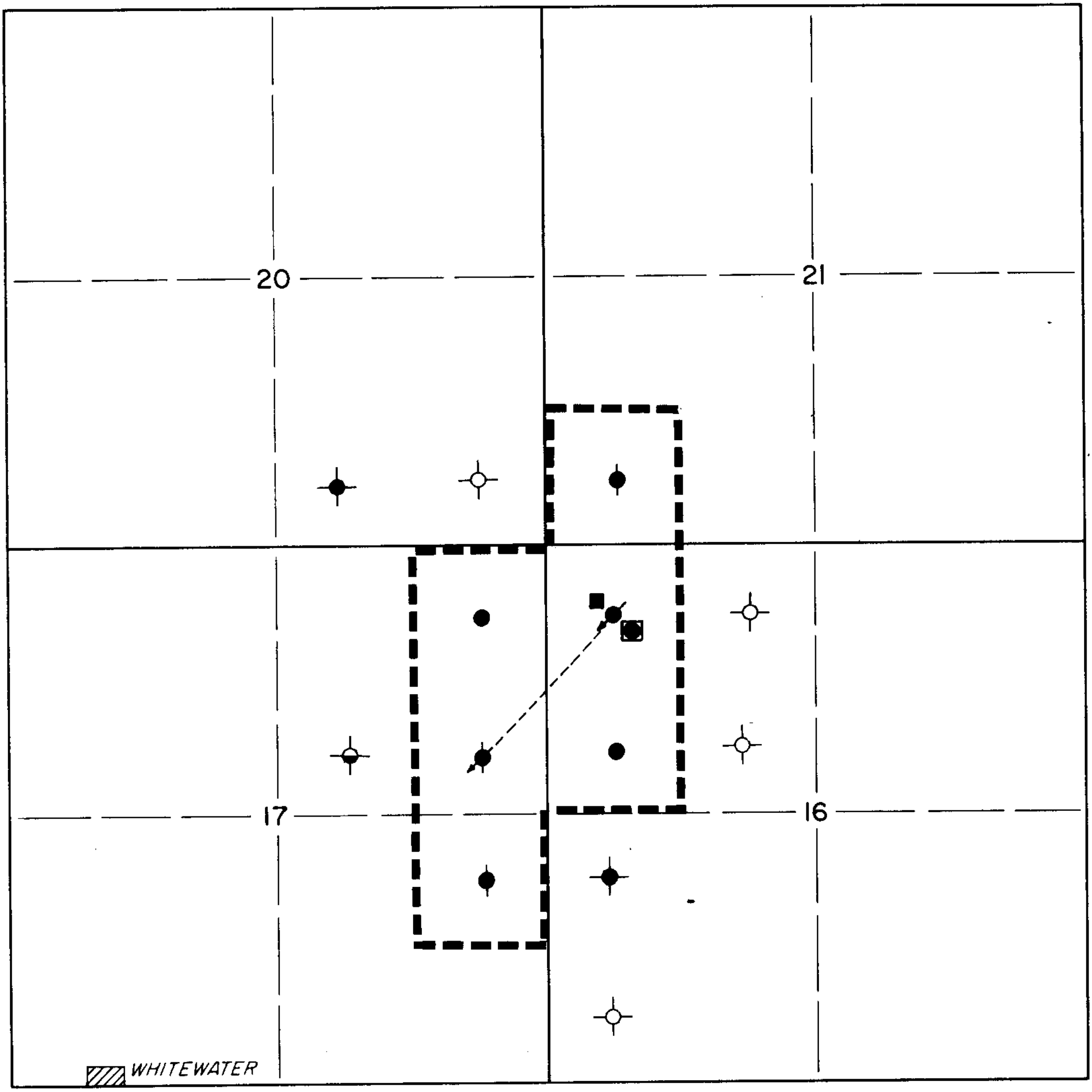
E. <u>BATTERY CONSOLIDATION</u>

Production will be handled by a central battery located on Lsd. 13-16-3-21 WPM. Separate production facilities presently located at each remaining producer in the field will be combined at the central site. If necessary, separate facilities for the disposal of produced water will be made available.

F. <u>PROJECT COST ESTIMATES</u>

The following is an estimate of the expenditures for the waterflood project:

Water Supply Well and Equipment	$36,100
Injection Plant and Equipment	8,600
Injection System	8,600
Injection Well Conversions	9,000
Battery Consolidation (Misc.)	15,500
	$77,800



TWP 3 RGE 21 WPM

INJECTION WELL

WATER SUPPLY WELL

INJECTION PLANT

FIGURE I

CHEVRON STANDARD LIMITED

PROPOSED
WHITEWATER UNIT No.I
INJECTION SYSTEM

SCALE
4" = 1 MILE

A-7971

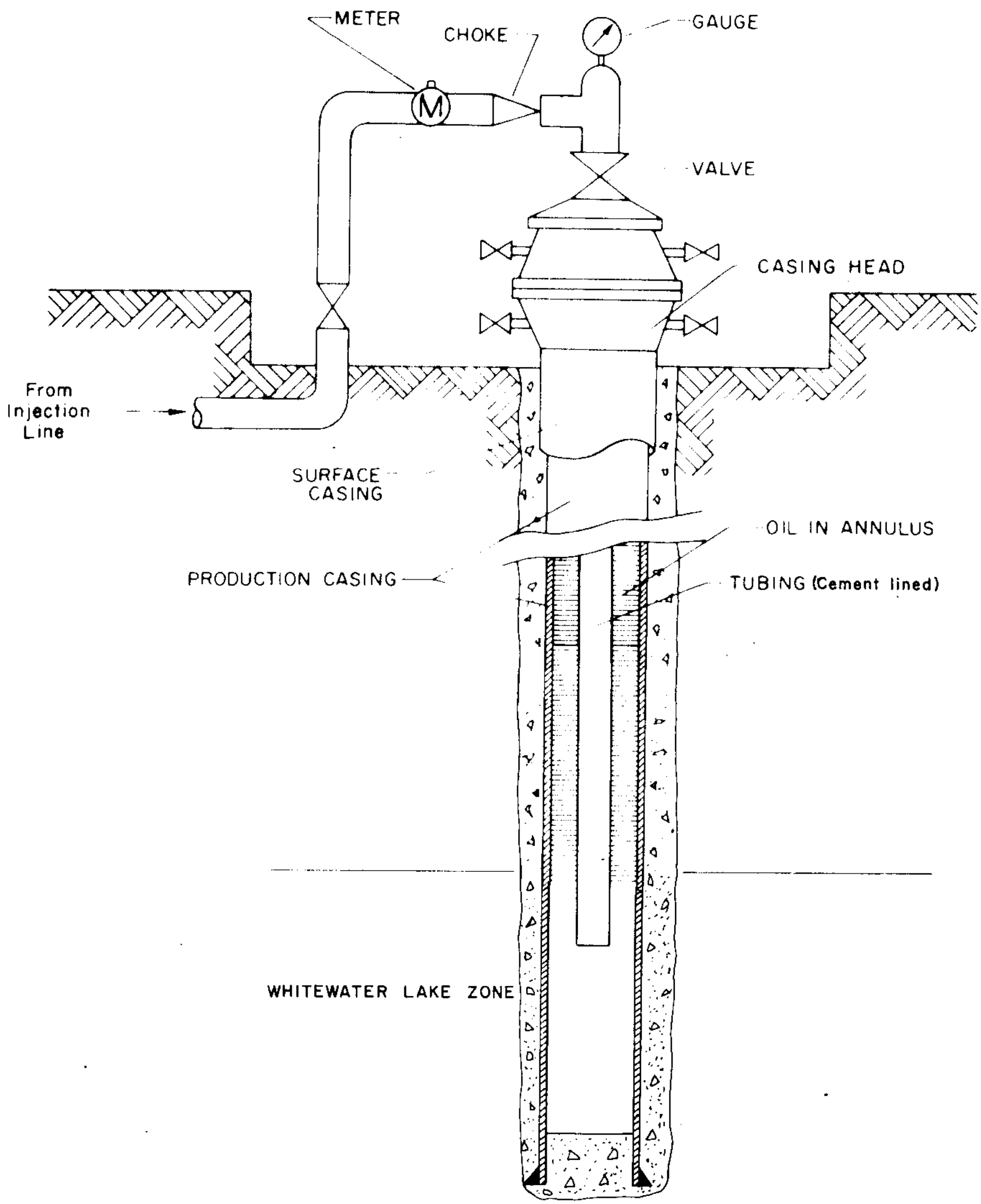


FIGURE 2

PROPOSED WHITEWATER UNIT No. 1
TYPICAL INJECTION WELL

APPLICATION FOR A UNIT MAXIMUM PERMISSIBLE RATE OF PRODUCTION PROPOSED WHITEWATER UNIT NO. 1

The applicant proposes that a degree of production flexibility, which is consistent with good engineering practice, be provided for Whitewater Unit No. 1.

It is possible that, with the implementation of the enhanced recovery scheme, some wells will be capable of producing oil at rates in excess of the current allowable producing rate.

Since the Whitewater wells have been produced at capacity for the life of the field with no evident reservoir damage, there is no reason to believe that unrestricted production at these wells when their capabilities increase would cause reservoir damage.

It is the applicant's contention that all Unit wells should be allowed to produce at unrestricted rates in order to fulfill the basic objective of the enhanced recovery scheme, which is to recover the greatest amount of oil economically. There is no reason to believe that reservoir damage within the Unit area would result by producing these wells at capacity, nor is there any reason to believe that non-Unit oil would be produced within the Unit, since the Unit well capacities would increase only as a direct result of the unitized waterflood and, therefore, the increased production would be made up of oil from within the Unit area only. There is also no reason to believe that reservoir damage outside the Unit area would result or that the production at any future offsetting non-Unit wells would be in any way affected by the production of Unit boundary wells at unrestricted rates.

The applicant respectfully requests that, on and after the first day that Whitewater Unit No. 1 becomes effective, the Unit be excluded from any provisions governing the limitations of oil production.

DISCUSSION OF THE UNITIZATION AND PARTICIPATION FORMULAE
PROPOSED WHITEWATER UNIT NO. 1

To facilitate the installation of an enhanced recovery scheme in the Whitewater field comprised of six capable wells on 40-acre spacing, it will be necessary to unitize, since the field has various royalty ownerships. The working interest in the entire area is held by Chevron Standard Limited.

During the course of unitizing several oil production units in Manitoba, the most equitable basis for participation was found to be the production history. Porosity, permeability and effective oil saturation are all factors which contribute to well performance. Where porosity, permeability and oil saturation are high, they should generally be reflected by a good producing rate and low water cut. These conditions will generally reflect a high effective reserve. Conversely, low producing rates and high water cut would be indicative of a lower effective reserve.

The first consideration in determining participation is to provide a fair basis for sharing the remaining primary reserves. There is a certain amount of month-to-month variation in production from the wells, so a six-month test period was used to arrive at a representative current production rate for each well. This has been expressed as a current production factor (C.P.) which represents the current worth of each well and can be thought of as the basis for allocation of the primary depletion oil that is recoverable under primary depletion operations.

A further consideration in determining participation is to provide a fair basis for sharing the additional oil which will be recovered as a result of the enhanced recovery operations. Production history is a measure of the effective reserves for each well, with the wells having higher effective reserves displaying a better production history. Inasmuch as it is desirable to allocate the additional reserves in proportion to the effective reserves, it is reasonable to make the allocation on the basis of production history. The relative worth of a well, based on production history, must recognize, as measures of effective reserves, cumulative oil production, current water cut and the length of time the well has been on production. A factor which is readily calculable and recognizes these parameters is a cumulative average monthly producing rate to which has been applied a water production penalty. This factor is referred to as the penalized average monthly oil production factor (P.A.M.).

The current production period chosen was June 1, 1969 to November 30, 1969. Of the six capable wells remaining in the pool, three had current production. The water cut penalty applied to the monthly production factor was based on the average water cut for the current production period of the three producers and the average water cut for the six months prior to suspension of the three former producers. A detailed description of the method followed in arriving at the C.P. and P.A.M. factors is outlined in the "Plan for Unit Operations."

A further consideration then becomes the relative weighting to give to each factor in providing a participation formula. It is apparent that greater emphasis must be placed on reserves recoverable under primary operations as compared to additional reserves recoverable under enhanced recovery operations.

By applying the discounted present worth concept to recoverable reserves under primary and secondary operations, the ratio of the present value of additional crude recoverable under waterflood compared to the present value of primary recoverable crude was calculated to be approximately 7:3. A summary of tract factors based 70% on the P.A.M. factor and 30% on the C.P. factor is as follows:

Tract	Tract Factor
12-16	25.68730
13-16	31.89932
8-17	4.12793
9-17	1.00141
16-17	35.33119
4-21	1.95285

This in summary outlines the development of the participation formula which is being presented and the reasoning behind the recommendation that it is an equitable basis for unitization.

Whitewater
UNIT #1

5

CHEVRON STANDARD LIMITED

PRODUCING DEPARTMENT

CALGARY DIVISION

FEASIBILITY OF ENHANCED RECOVERY

WHITEWATER FIELD

AUGUST 1970

B. N. McLEAN

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LIST OF FIGURES

SUMMARY

1. Purpose

The purpose of this study was to review the primary depletion and confirm the enhanced recovery potential of the Whitewater field.

2. Conclusions

The following is based on the enhanced recovery project area:

(1) Original oil-in-place is estimated to be 2,605,000 STB.

(2) Primary depletion would recover an estimated 477,000 STB or 18.3% of the original oil-in-place.

(3) A conventional waterflood would realize an ultimate recovery of 756,000 STBO or 29.0% of the original oil-in-place at a terminal WOR of 25.

(4) Indications from a cursory examination are that Polymer flooding will increase the ultimate recovery of oil.

(5) Ultimate recovery can be substantially increased by instituting an enhanced recovery scheme in the Whitewater field.

3. Recommendation

It is recommended that an enhanced recovery scheme, consisting of two injection wells, one water supply well and four producers, be instituted while the feasibility of a viscous water injection scheme is being confirmed.

FIELD DEVELOPMENT

1. History

The Whitewater pool is located northeast of the Village of Whitewater, in the Province of Manitoba, comprised of portions of sections 16, 17, 20 and 21, Township 3, Range 21, West of the Prime Meridian. (Fig. 1)

The discovery well in the pool was California Standard Whitewater 12-16-3-21 which was spudded on September 8, 1953. The well encountered what was subsequently called the Whitewater Member of the Mississippian formation at 2,508 feet. The well was deepened to a total depth of 2,539 feet, completed open hole and yielded an initial production of 90 BOPD declining to 50 BOPD after one month. On October 24, 1955 the final successful well was completed. As of December 31, 1969 there were three producing oil wells and three suspended oil wells in the field.

2. Geology

The Whitewater field produces from the limestones of the Upper Whitewater Lake member of the Lodgepole Formation of Mississippian age. This is underlain by shales of the Lower Whitewater Lake member of the Lodgepole, and overlain unconformably by shales of the Watrous Red Beds of Jurassic age. The Upper Whitewater Lake member varies from 10 to 40 feet in thickness. At the top there is a tight cap of dolomite and anhydrite of varying thickness, this is underlain by a skeletal, oolitic limestone in which the porosity is best at the top as a result of downward leaching, and decreases in quality with depth.

RESERVOIR ROCK AND FLUID PROPERTIES

1. Permeability and Porosity

Four of the wells in the six-well pool were cored and analyzed. The total pay from the core analyzed was 97.3'. Using a permeability cutoff of 1 md. (kmax. air), the footage weighted average permeability and porosity was 111 md. and 11.3%, respectively.

By plotting permeability versus cumulative pore volumes, a median permeability of 35.5 md. was determined (see Fig. 2). From this permeability distribution, the permeability variation was calculated to be 0.867.

2. Net Pay

An isopach of the net pay is shown on Figure 3. Pay thickness figures were derived from core analysis, core description and logs. The extrapolated undrilled pay thickness was determined from a cross sectional interpretation of the pool.

A rock volume of 4,800 acre-feet for the project area was established by planimetering the net pay isopach.

3. Initial Water Saturation

Initial water saturation could not be determined by either log or core analyses. The assumed initial water saturation of 35% was obtained from a Province of Manitoba publication[11]. A water saturation of 39% was derived from a porosity versus water saturation plot for the Cherty zone of the North Virden Scallion Field[4]. From the same report a water saturation of 30% was derived from an air permeability versus water saturation plot for the Cherty-Crinoidal zones. This correlation of the Whitewater formation, with the lithologically similar North Virden Scallion formations, supports the water saturation of 35%.

4. Fluid Properties

The original bottom-hole pressure was determined from drillstem test data to be 1,050 psig. The reservoir temperature is 84° F.

PVT analyses were not conducted on Whitewater fluid samples. It was assumed that tests conducted on NVS fluid samples were, with some adjustments, applicable.

A formation volume factor of 1.057 reservoir barrels/stock tank barrel was derived from a correlation chart prepared by the California Research Corporation[3] for the bubble point fluid. Correlation parameters used were:

Gas - oil ratio = 100

Specific gravity of gas = 1.47

Crude oil °API = 32.5

Bubble Point Pressure = 200 psi

The oil formation volume factor at the original reservoir conditions is estimated to be 1.050 based on the North Virden correlation.

From viscosity measurements[5] performed on a surface gathered sample from well 12-16-3-21 WPM, the viscosity of the crude at 0 psig and 84° F was calculated to be 8.85 centipoise. The viscosity at average reservoir conditions of 600 psig and 84° F is estimated to be 7.09 centipoise based on the North Virden correlation.

A water viscosity of 0.33 centipoise was derived from tables[6] for the average reservoir conditions.

ORIGINAL OIL-IN-PLACE

Pool parameters are:

Porosity	-	11.3%
Initial Water Saturation	-	35%
Formation Volume Factor	-	1.05

Based on the above parameters and the proposed project area rock volume of 4,800 acre-feet (Figure 3):

Original Oil-In-Place	=	2,605,000 STB
Average Pay Thickness	=	20.0 feet

PRIMARY PERFORMANCE

The field production rate declined from a maximum rate of 105 BOPD during December 1954 to an average of 53 BOPD during 1961. A gradual decline of approximately 2 BOPD/year resulted in an average production rate of 37 BOPD during 1969. Cumulative production to August 31, 1970 was 313,563 STB of oil and 15,174 barrels of water.

A rate (BOPD) versus time plot on semi-log paper yields a reasonable estimate of the remaining reserves under primary depletion mechanisms for the pool (see Fig. 4). This plot shows that, as of January 1, 1970, approximately 172,000 barrels of primary oil remain to be recovered for an ultimate primary recovery of 477,000 or 18.3% of the estimated project area's O.O.I.P. (2,605,000 STB). An economic limit of 4 BOPD per well was assumed.

ENHANCED RECOVERY

The Whitewater pool is a dome shaped stratigraphic trap. The pool drive mechanism is primarily liquid expansion with a suspected partial water drive from the southwest. In view of the essentially volumetric nature of the reservoir and since waterflood schemes have been successfully initiated in several lithologically similar Manitoba fields, waterflooding is considered the most feasible enhanced recovery scheme for the pool.

1. Waterflood Susceptibility

No waterflood susceptibility tests were conducted on core samples from the Whitewater reservoir. The California Research Corporation conducted waterflood tests on 12 cores from the North Virden Scallion field[2] in 1958. A comparison of the 12 core samples tested and the core analyses available from Whitewater showed that a reasonable similarity in lithology, permeability and porosity existed. A residual oil saturation (Sor) was determined in the CRC report for each of the 12 cores analysed. In order to determine an average Sor for Whitewater, seven of the 12 cores analysed were selected to adequately represent the range of porosity and permeability over the length of Whitewater core. The resultant average Sor for Whitewater is 33% (see Appendix I).

The relative permeability of water to oil versus water saturation (Kw/Ko vs. Sw), the fresh water permeability at end of flood versus air permeability (Krw vs. Ka) and the oil permeability at initial water saturation versus air permeability (Kro vs. Ka) plots used in the North Virden Scallion Waterflood study[2] were adjusted to reflect the Whitewater reservoir. The plots derived are as follows:

Figure 6 - Krw versus Ka

Figure 7 - Kro versus Ka

Figure 8 - Kw/Ko versus Sw

Figure 8 represents the average of the 12 core plugs tested, normalized to a water saturation of 35% and a residual oil saturation of 33%.

2. Pattern and Injectivity

The proposed injectors for the waterflood project are 13-16-3-21 WPM and 9-17-3-21 WPM. These locations were chosen because they directly offset producing wells and are offset in the boundary direction of the pool by abandoned wells. (Refer to Fig. 3.) Injectivity calculations utilized data from Fig. 6. Due to the limited size of the pool there is no clearly defined flood pattern. The average injection rate should be between the 380 BWPD/Well as calculated for a five spot pattern and the 700 BWPD/Well as calculated for radial flow. An average of the two injection rates is 540 BWPD/Well. A conservative injection rate of 400 BWPD/Well was assumed for the study. (See Appendix II for Injectivity Calculations.)

3. Water Supply and Quality

The Swan River sand is developed over all of the Whitewater field area and is a potential source of water for the flood scheme. The top of the sand is at approximately 1,700 feet and the average thickness is 130 feet. A drill stem test on the formation at Lsd. 12-16-3-21 WPM, yielded 1,530 feet of slightly salty water (3,000 PPM chlorine) in one hour. Shut-in pressures on the test are not available. From the limited data available (cuttings, logs) the sand is described as poorly sorted with poor to fair intergranular porosity. The sand is not uniform, shale breaks and limited porosity are evident at locations 11-16 and 16-17. It is proposed that the water supply well be drilled at location 13-16-3-21 WPM where the drillstem test appeared favorable and the sand well developed. An alternate location is 2-20-3-21 WPM where logs indicate a well developed sand with an average porosity of 18%. If the Swan River water source proved inadequate after testing, the well could be deepened, with additional cost to test the Mississippian aquifer (if present) or the Devonian formation. No significant problems are anticipated with water quality control or compatibility if the Swan River or Mississippian source is utilized. If the Devonian source is required, some water treatment may be necessary.

4. Conventional Waterflood Prediction

The waterflood prediction was determined by combining the displacement efficiency, Ed, the vertical coverage efficiency, Ev, and the areal sweep efficiency, Ea. It was assumed that the terminal water-oil ratio would be 25:1.

The vertical coverage efficiency, Ev, was determined from the standard Dykstra-Parsons method[9] using a mobility ratio of 1.54 derived from the relationship, $M.R. = \frac{Krw\ \mu o}{Kro\ \mu w}$ for the median permeability of 35.5 md.

Permeability distribution data was derived from Figure 2. The vertical coverage curve shown on Figure 9 indicates that, at a water-oil ratio of 25:1, the Ev is 57%.

The displacement efficiency, Ed, was determined by the Buckley-Leverett method[1]. The normalized Kw/Ko versus Sw curve required is shown on Figure 8. The displacement efficiency at breakthrough was calculated to be 14% of the oil-in-place at the start of waterflooding. After breakthrough Ed increased to 37.5% at a water-oil ratio of 25:1 (See Figure 9).

The areal sweep efficiency, Ea, was determined by inspection (Fig. 10). An attempt to correlate the areal sweep with prescribed methods of Dyes, Caudle and Erickson was not successful, due to the limited size of the pool. The Ea used for this study was 90%.

The conventional waterflood recovery in the study area was determined from the efficiencies as established above at a terminal water-oil ratio of 25:1.

Waterflood Efficiency	=	Ev x Ed x Ea .57 x .375 x .90 = .192
Estimated Original Oil-In-Place	=	2,605,000 STB
Estimated Cumulative Production to January 1, 1971	=	317,000 STB
Oil-In-Place at Commencement of Injection, January 1, 1971	=	2,288,000 STB
Estimated Recovery Following Commencement of Injection	=	.192 x 2,288,000 = 439,000 STB
Ultimate Recovery from Pool	=	756,000 STB or 29.0% of OOIP
Projected Primary Production	=	477,000 STB or 18.3% of OOIP
Incremental Secondary Oil	=	279,000 STB or 10.7% of OOIP

A conventional waterflood projection based on the Buckley-Leverett and Dykstra-Parsons calculations and a maximum pool capability of 190 BOPD is shown on Figure 5. The relatively early breakthrough indicated for the pool under waterflooding is attributable to the permeability heterogeneity of the formation. This is illustrated by the capacity-pore volume distribution curve (Figure. 11). The curve shows that 90% of the total wellbore capacity is derived from only 26% of the total cored footage and the pore volume represented by this footage comprises only 37% of the total porosity-feet. Relatively rapid movement of the flood through the higher capacity layers could be expected with resulting poor displacement efficiency in the large portion of the reservoir represented by the low capacity fraction.

5. Polymer Flood Prediction

As explained above, the vertical conformance of the pool is adverse for an efficient conventional waterflood scheme. The addition of a polymer to the injection water will adjust the mobility and consequently the rate at which the water moves through the high permeability zones[8].

The ultimate pool recovery would be increased through this improvement in the vertical coverage. A study is presently being conducted by the Dow Chemical Company to confirm the feasibility of using polymer as an injection water additive in the prospective enhanced recovery scheme.

An approximate polymer flooding efficiency and ultimate recovery was calculated as follows:

The vertical coverage efficiency, Ev, was calculated using a technique adapted for the use of reduced mobility fluids[10]. Since insufficient data was available on the Whitewater reservoir for this technique, data from a recent study for the Taber Mannville D polymer flood[7] was utilized. Using a slug size of 20% pore volume, a relative speed factor of 0.8, and a mobility improvement factor of 6.0, the Ev at a terminal water-oil ratio of 25:1 was calculated to be 74% (see Fig. 9) as compared to 57% for a conventional waterflood.

Assuming continuous polymer injection and utilizing the Buckley-Leverett prediction technique, a displacement efficiency, Ed, at a terminal water-oil ratio of 25 was calculated to be 42%. This value would be regarded as an upper limit of Ed. It is estimated that for the 20% slug size the Ed would be improved from the conventional waterflood efficiency of 37.5% to approximately 39% (see Fig. 9).

The areal sweep efficiency, Ea, was assumed to be 90%. This is the same as that used for conventional waterflooding. The Ea would be increased as a result of the mobility improvement, but the effect would be small due to the limited injection pattern in Whitewater.

The polymer flood recovery in the study area was determined from the efficiencies as established above at a terminal water-oil ratio of 25:1.

Polymer Flood Efficiency	= Ev x Ed x Ea = .74 x .39 x .90 = .260
Estimated Recovery Following Commencement of Injection	= .260 x 2,288,000 = 595,000 STB
Ultimate Recovery from Pool	= 912,000 STB or 35.0% OOIP
Incremental Secondary Oil	= 435,000 STB or 16.7% OOIP

From the preceeding calculations it is estimated that an additional 156,000 barrels of oil may be recovered by the increase in sweep efficiencies attributable to the use of a polymer slug.

APPENDIX I

Weighting Sor for Whitewater

North Virden Scallion Core Plug Analysed			Feet of Core with Similar Ø and K From Whitewater Analyses
Plug No.	K	Ø	
28	61	16.5	13.6
43	11.9	13.3	12.1
47	23.7	15.3	9.8
57	98	16.6	10.7
58	192	15.2	20.5
10	3.2	11.0	16.2
36	16.1	13.0	12.3
			95.2 = Total Footage Represented

A weighting can be applied to the North Virden Scallion core to represent Whitewater by the following:

Core Plug No.	Sor (%)	F (Weighting Factor)	Sor x F
28	33	13.6	448.8
43	39	12.1	471.9
47	37	9.8	362.6
57	37	10.7	395.9
58	36	20.5	738.0
10	30	16.2	486.0
36	19	12.3	233.7
Totals		95.2	3,136.9

$$\text{Weighted Whitewater Sor} = \frac{3,136.9}{95.2} = 32.95\%$$

APPENDIX II

INJECTIVITY CALCULATIONS

Radial Injectivity

The injectivity rate formulae is derived from Darcy's differential flow equation for a horizontal, steady-state, single-phase, imcompressible, unit mobility ratio, radial, fluid system[12].

$$Q_r = \frac{.00707 \quad Kwh \quad \Delta P}{\mu \beta \; (LN \frac{Re}{Rw})}$$

5-Spot Injectivity

The injectivity rate formulae was derived by M. Muskat[12] for a horizontal, steady-state, single-phase, incompressible, unit mobility ratio, 5-spot fluid system.

$$Q_5 = \frac{.003541 \quad Kwh \quad \Delta P}{\mu \beta \; (LN \frac{d}{Rw} - 0.6190)}$$

APPENDIX II (continued)

Parameters

Symbol	Value	Units	Remarks
Q	Calculated	BWPD	Injectivity Rate
Krw	16.3	Millidarcies	Reservoir permeability to water derived from Figure 6 for footage weighted. Air Permeability = 110 millidarcies.
h	26	Feet	Average of the net pay of the two proposed injectors. (30 + 22)/2.
ΔP	1590	Psi	Pressure differential assumed: (1,100 psi injection press) + (1090 hydrostatic press) - (600 psi avg. res. press)
μ	.830	Centipoise	Viscosity of injection water.
β	1.000	-	Formation volume factor of injection fluid.
Re & d	1,320	Feet	Radius of injection extension or distance between injector and producer.
Rw	0.375	Feet	Effective wellbore radius. (No fracturing assumed.)

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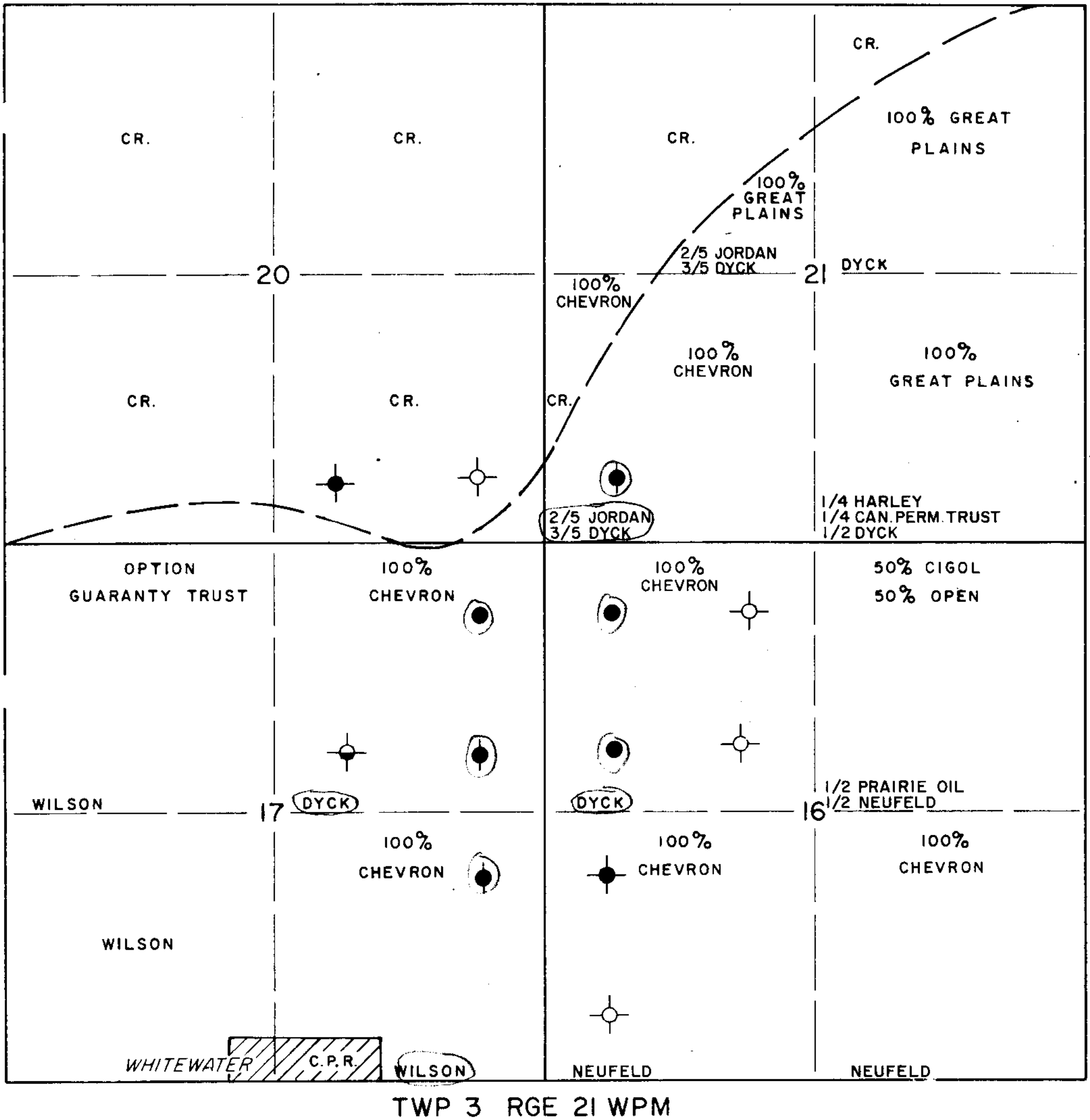


FIGURE 1

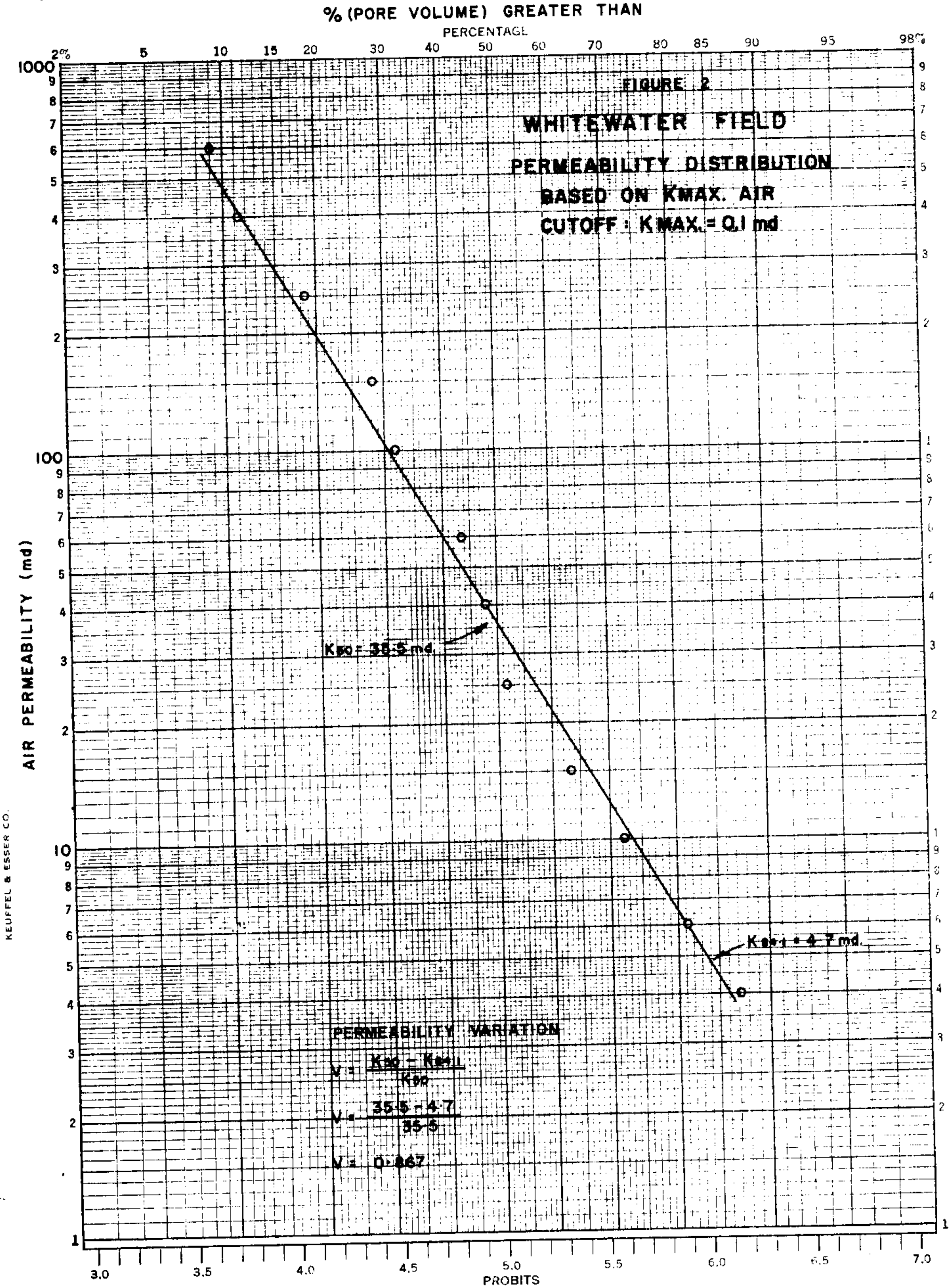
CHEVRON STANDARD LIMITED

WHITEWATER FIELD

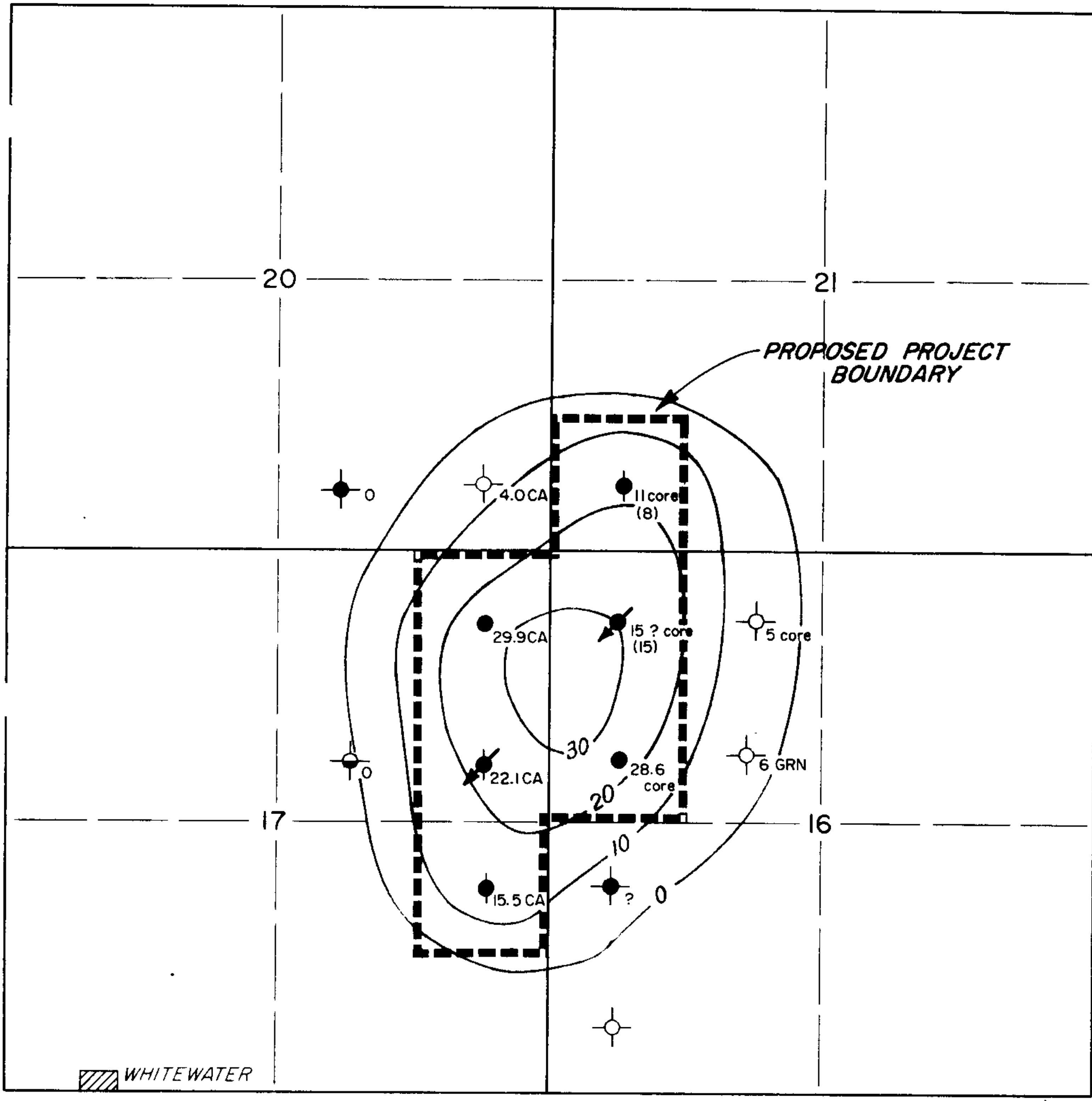
LAND & ROYALTY OWNERSHIP

SCALE
4" = 1 MILE

A-7971-1



% (PORE VOLUME) GREATER THAN
PERCENTAGE
FIGURE 2
WHITEWATER FIELD
PERMEABILITY DISTRIBUTION
BASED ON KMAX. AIR
CUTOFF : KMAX. = 0.1 md
AIR PERMEABILITY (md)
K50 = 35.5 md
K84.1 = 4.7 md
PERMEABILITY VARIATION
V = (K50 - K84.1) / K50
V = (35.5 - 4.7) / 35.5
V = 0.867
PROBITS



TWP 3 RGE 21 WPM

C.I. = 10'

28.6 PAY THICKNESS

(15) EXTRAPOLATED UNDRILLED PAY THICKNESS

PROPOSED INJECTION WELL

FIGURE 3

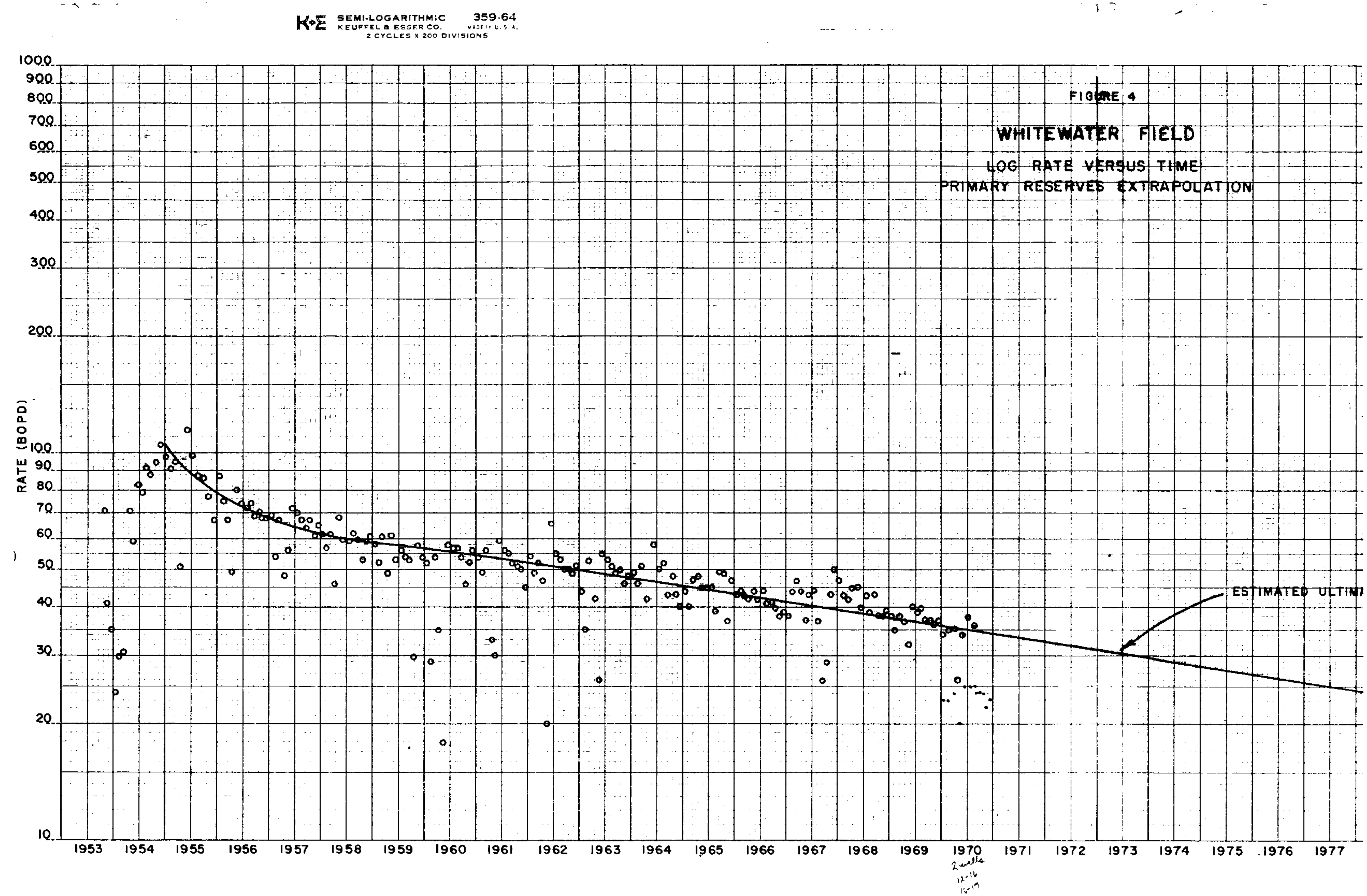
CHEVRON STANDARD LIMITED

WHITEWATER FIELD

ISOPACH OF NET PAY

SCALE 4" = 1 MILE

A-7971-2


K•E SEMI-LOGARITHMIC 359-64
KEUFFEL & ESSER CO.
2 CYCLES X 200 DIVISIONS
FIGURE 4
WHITEWATER FIELD
LOG RATE VERSUS TIME
PRIMARY RESERVES EXTRAPOLATION
ESTIMATED ULTIM
RATE (BOPD)
1000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
10
1953
1954
1955
1956
1957
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977

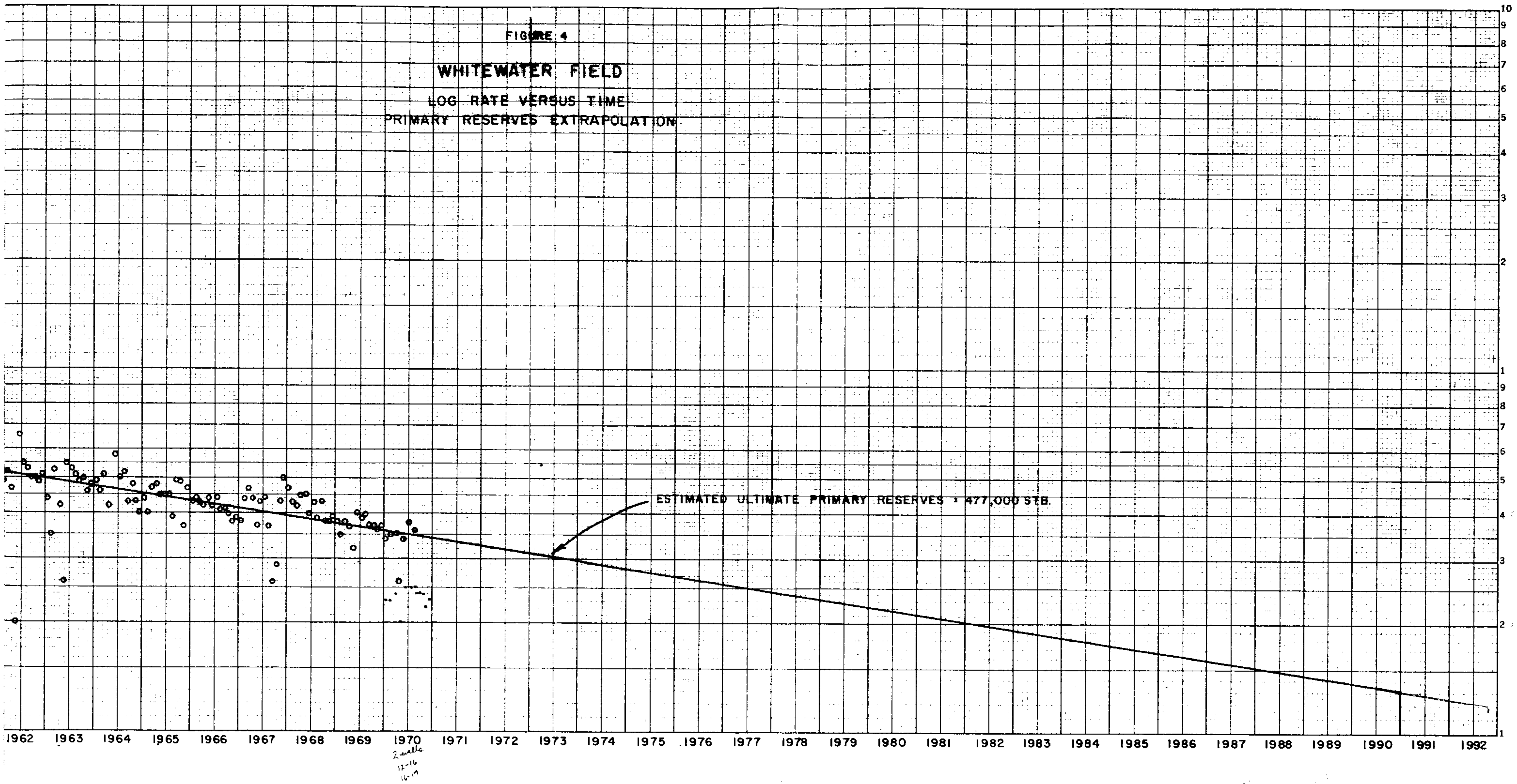


FIGURE 4

WHITEWATER FIELD

LOG RATE VERSUS TIME

PRIMARY RESERVES EXTRAPOLATION

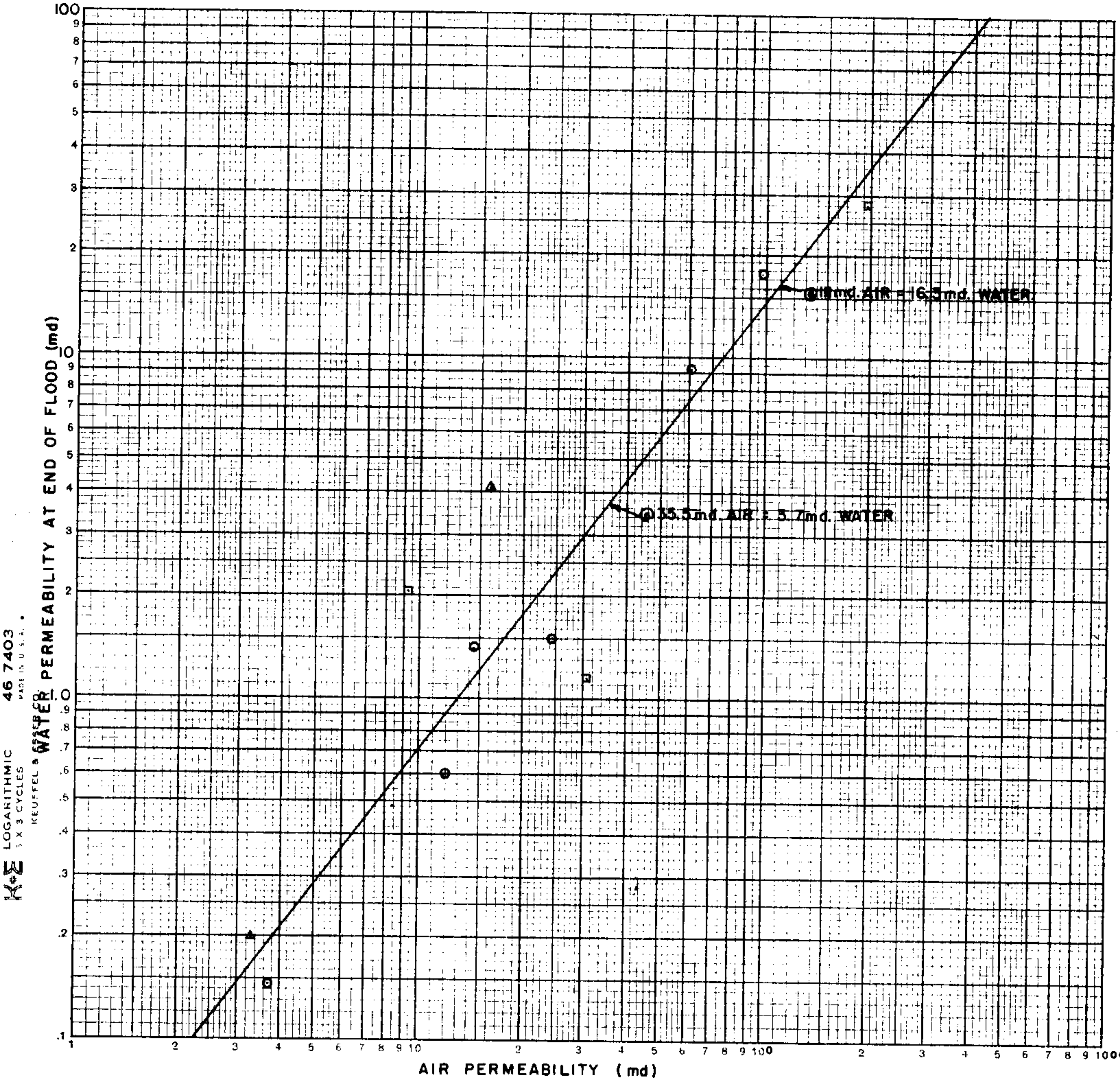


FIGURE 6

O CHERTY
△ OOLITIC
□ CRINOIDAL

WHITEWATER FIELD
FRESH WATER PERMEABILITY
AT END OF FLOOD (KRW)
VS
AIR PERMEABILITY (KA)

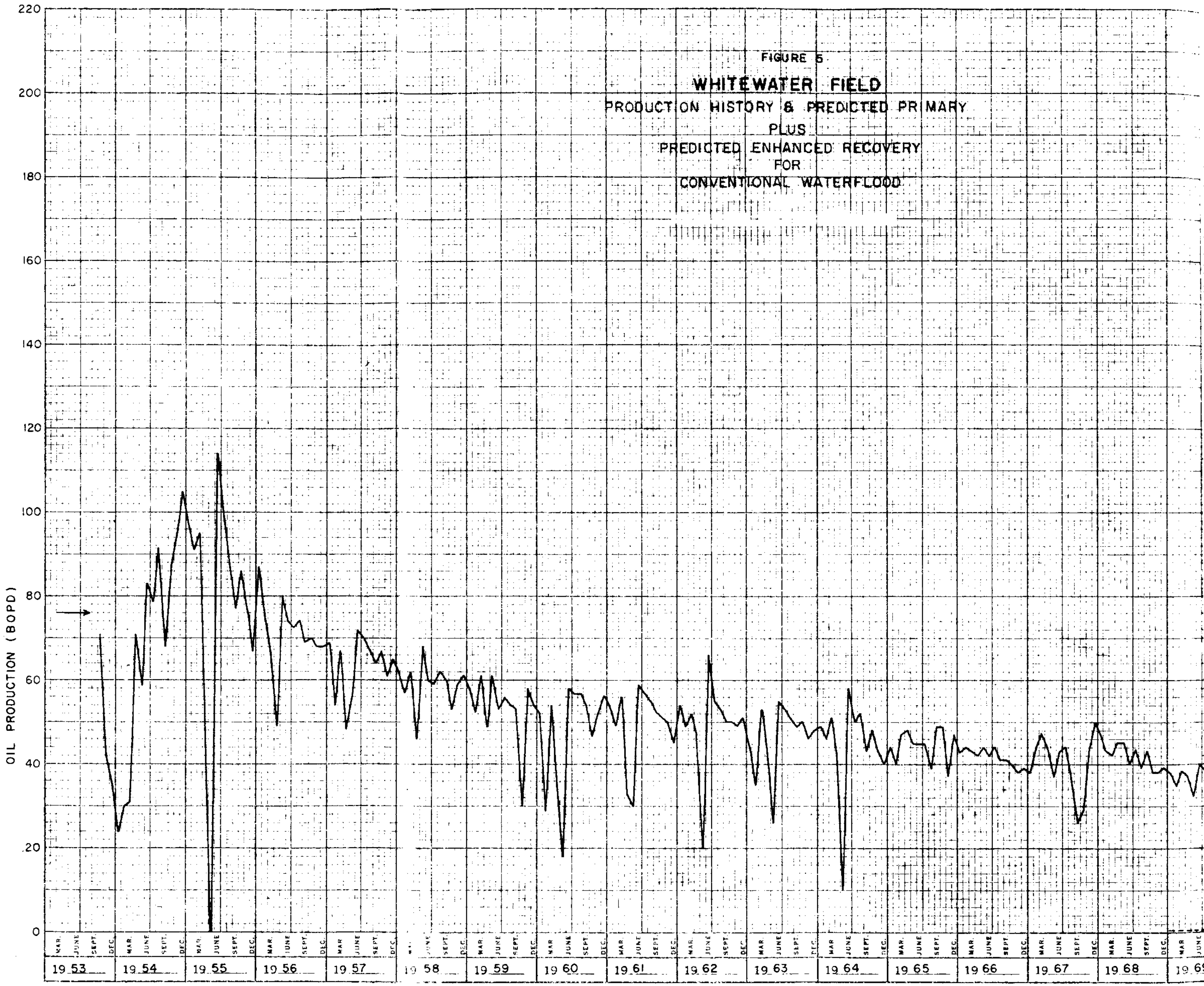
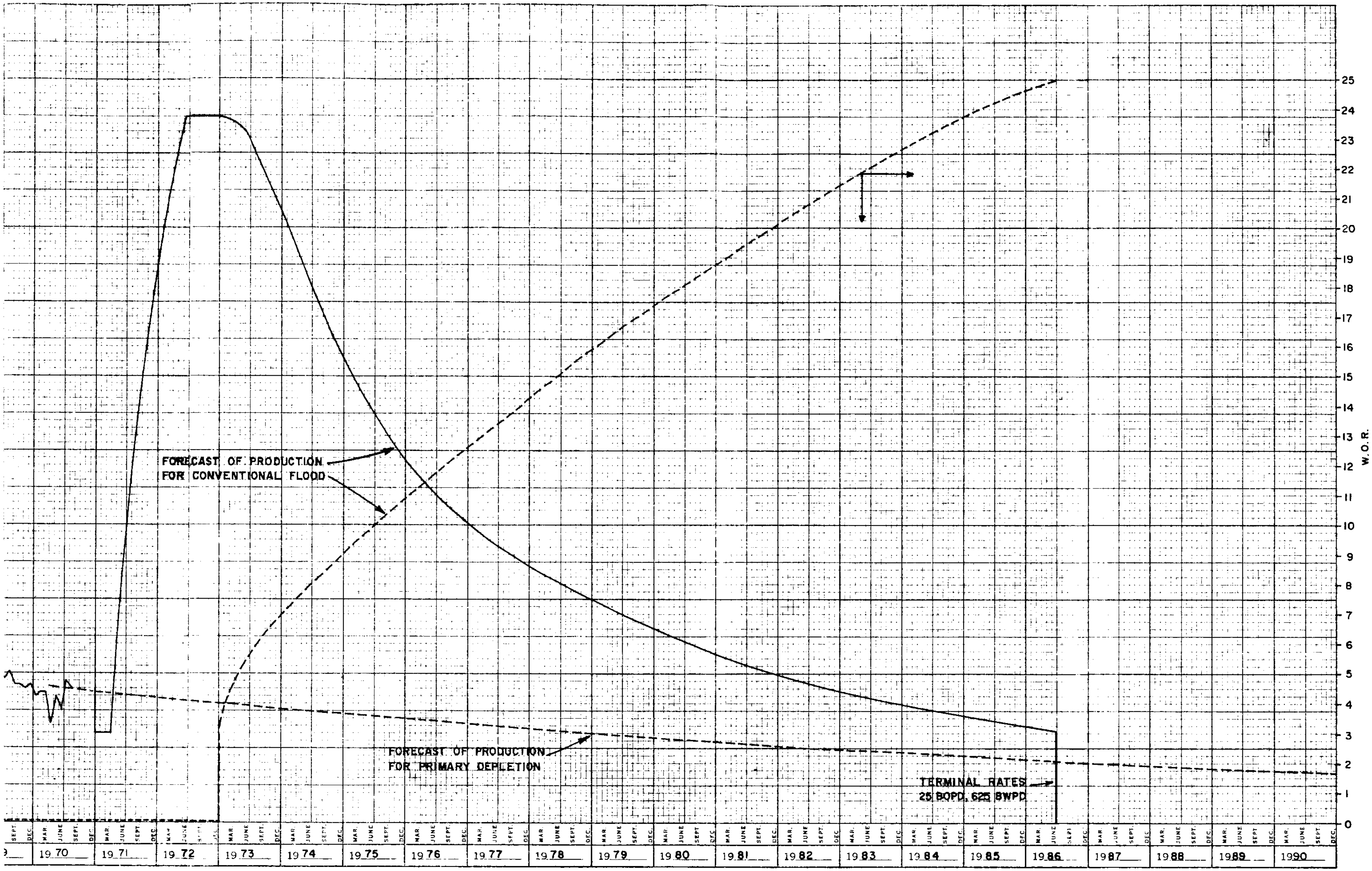


FIGURE 5
WHITEWATER FIELD
PRODUCTION HISTORY & PREDICTED PRIMARY
PLUS
PREDICTED ENHANCED RECOVERY
FOR
CONVENTIONAL WATERFLOOD



W.O.R.
FORECAST OF PRODUCTION
FOR CONVENTIONAL FLOOD
FORECAST OF PRODUCTION
FOR PRIMARY DEPLETION
TERMINAL RATES
25 BOPD, 625 BWPD
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79
19 80
19 81
19 82
19 83
19 84
19 85
19 86
19 87
19 88
19 89
19 90

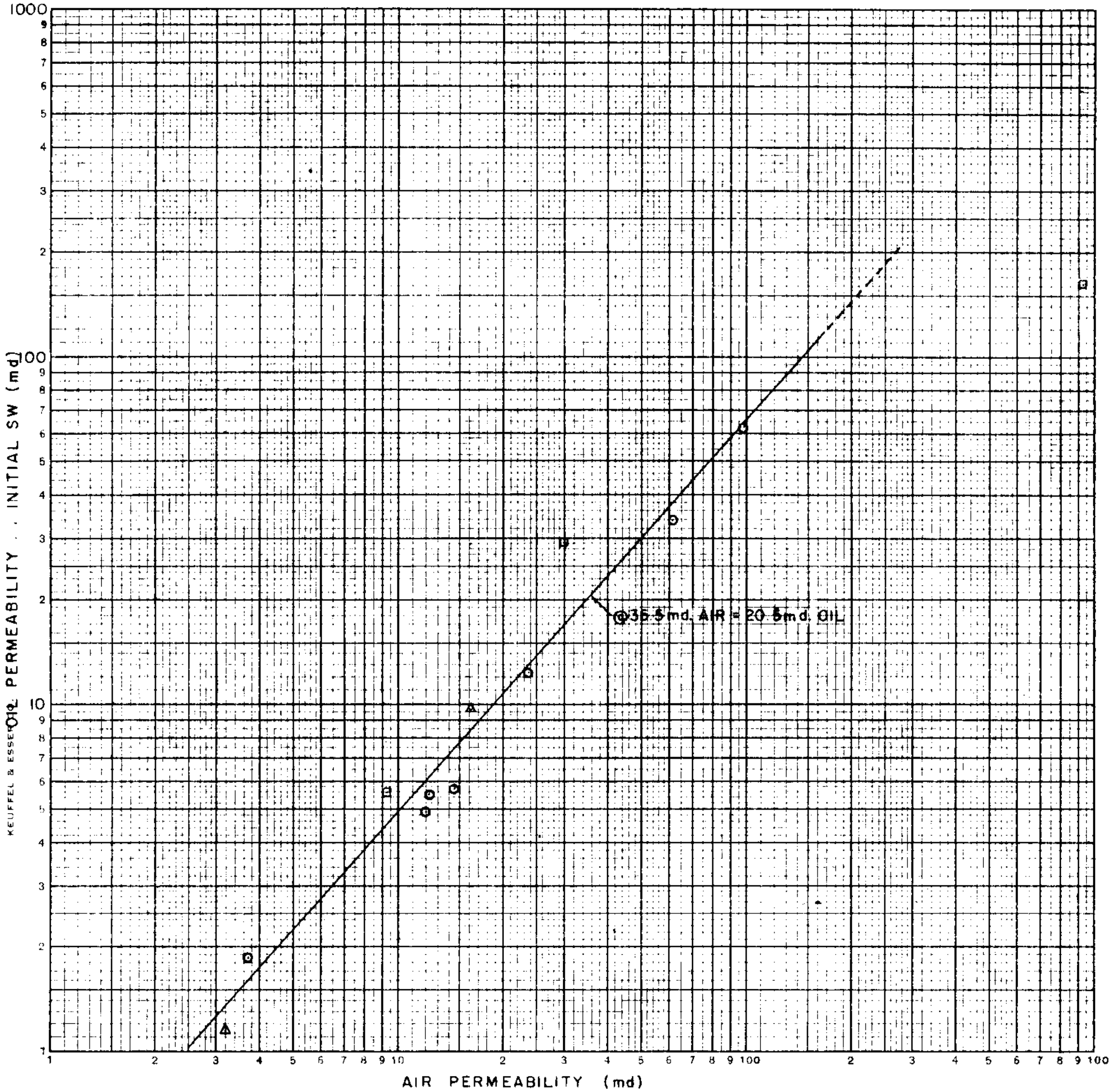


FIGURE 7

O CHERTY
△ OOLITIC
□ CRINOIDAL

WHITEWATER FIELD

OIL PERMEABILITY
AT INITIAL SW (KRD)
VS
AIR PERMEABILITY (KA)

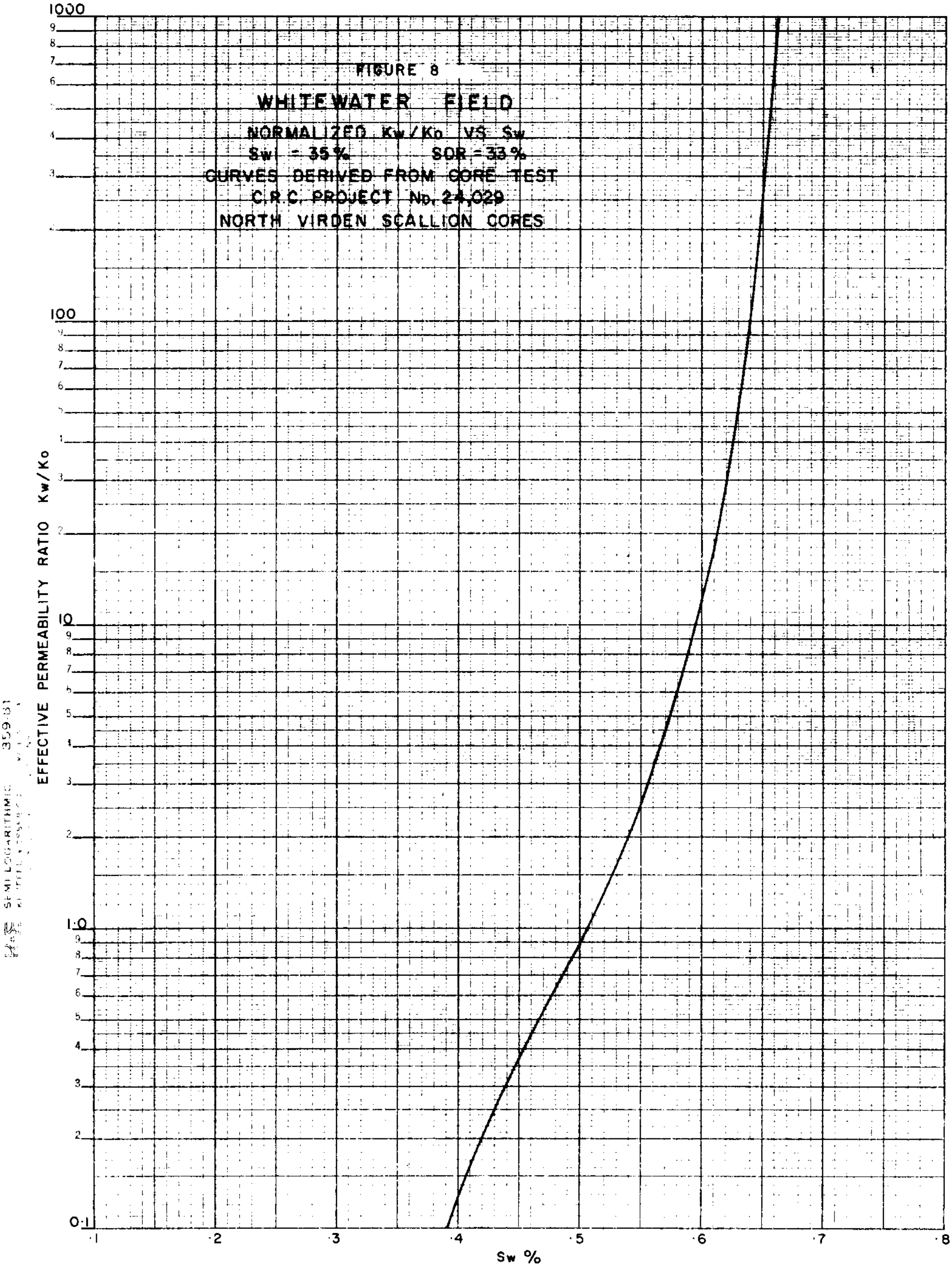
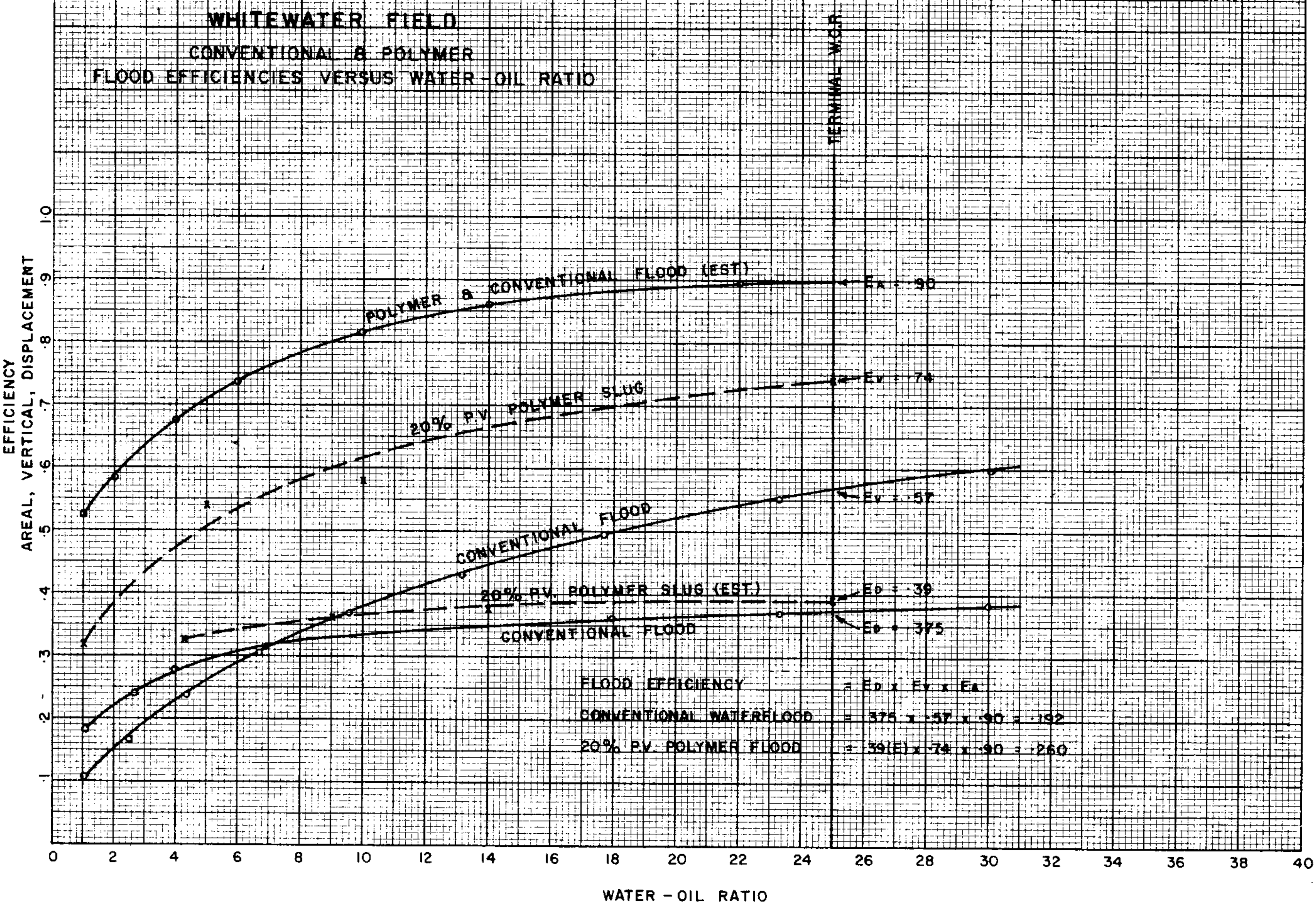
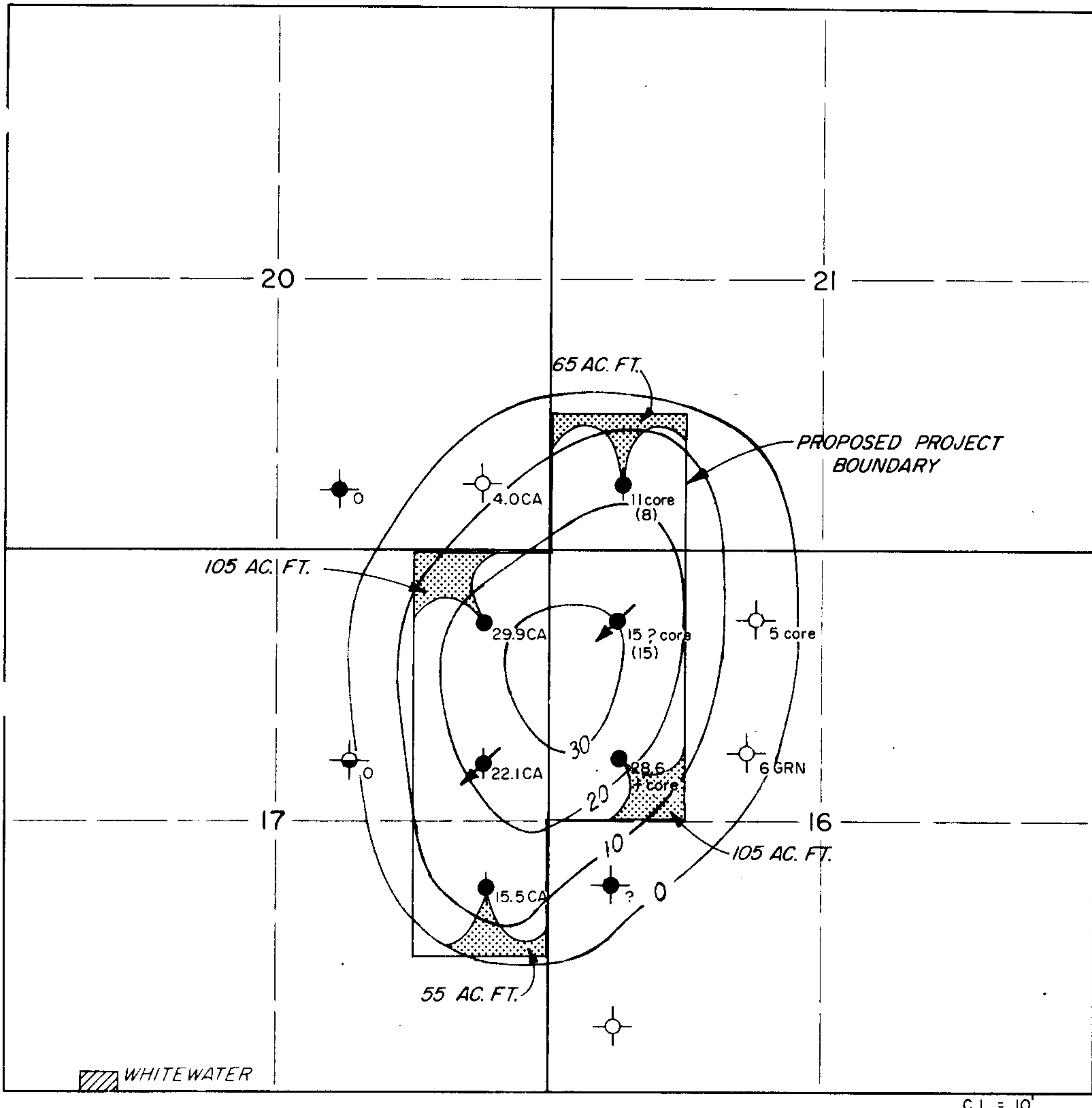


FIGURE 8
WHITEWATER FIELD
NORMALIZED Kw/Ko VS Sw
Swi = 35% SOR = 33%
CURVES DERIVED FROM CORE TEST
C.R.C. PROJECT No. 24,029
NORTH VIRDEN SCALLION CORES
EFFECTIVE PERMEABILITY RATIO Kw/Ko
Sw %
1000
100
10
1.0
0.1
·1
·2
·3
·4
·5
·6
·7
·8
SEMI-LOGARITHMIC 359-81

FIGURE 9


WHITEWATER FIELD
CONVENTIONAL & POLYMER
FLOOD EFFICIENCIES VERSUS WATER-OIL RATIO
TERMINAL W.O.R.
POLYMER & CONVENTIONAL FLOOD (EST.)
Ea = .90
20% P.V. POLYMER SLUG
Ev = .74
CONVENTIONAL FLOOD
Ev = .57
20% P.V. POLYMER SLUG (EST.)
Ed = .39
CONVENTIONAL FLOOD
Ed = .375
FLOOD EFFICIENCY = Ed x Ev x Ea
CONVENTIONAL WATERFLOOD = .375 x .57 x .90 = .192
20% P.V. POLYMER FLOOD = .39(E) x .74 x .90 = .260
EFFICIENCY
AREAL, VERTICAL, DISPLACEMENT
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30
32
34
36
38
40
WATER - OIL RATIO



TWP 3 RGE 21 WPM

AREA NOT SWEPT BY WATERFLOOD

SWEEP EFFICIENCY $(E_A) = \frac{\text{ROCK VOLUME SWEPT}}{\text{RESERVOIR ROCK VOLUME}} \times 100$

ROCK VOLUME NOT SWEPT = 330 AC. FT.

$\therefore E_A = \frac{4800 - 330}{4800} \times 100 = 93.1\%$

PROPOSED INJECTION WELL

FIGURE 10

CHEVRON STANDARD LIMITED

WHITEWATER FIELD

AREAL SWEEP EFFICIENCY CALCULATION

SCALE
4" = 1 MILE

A-7971-3

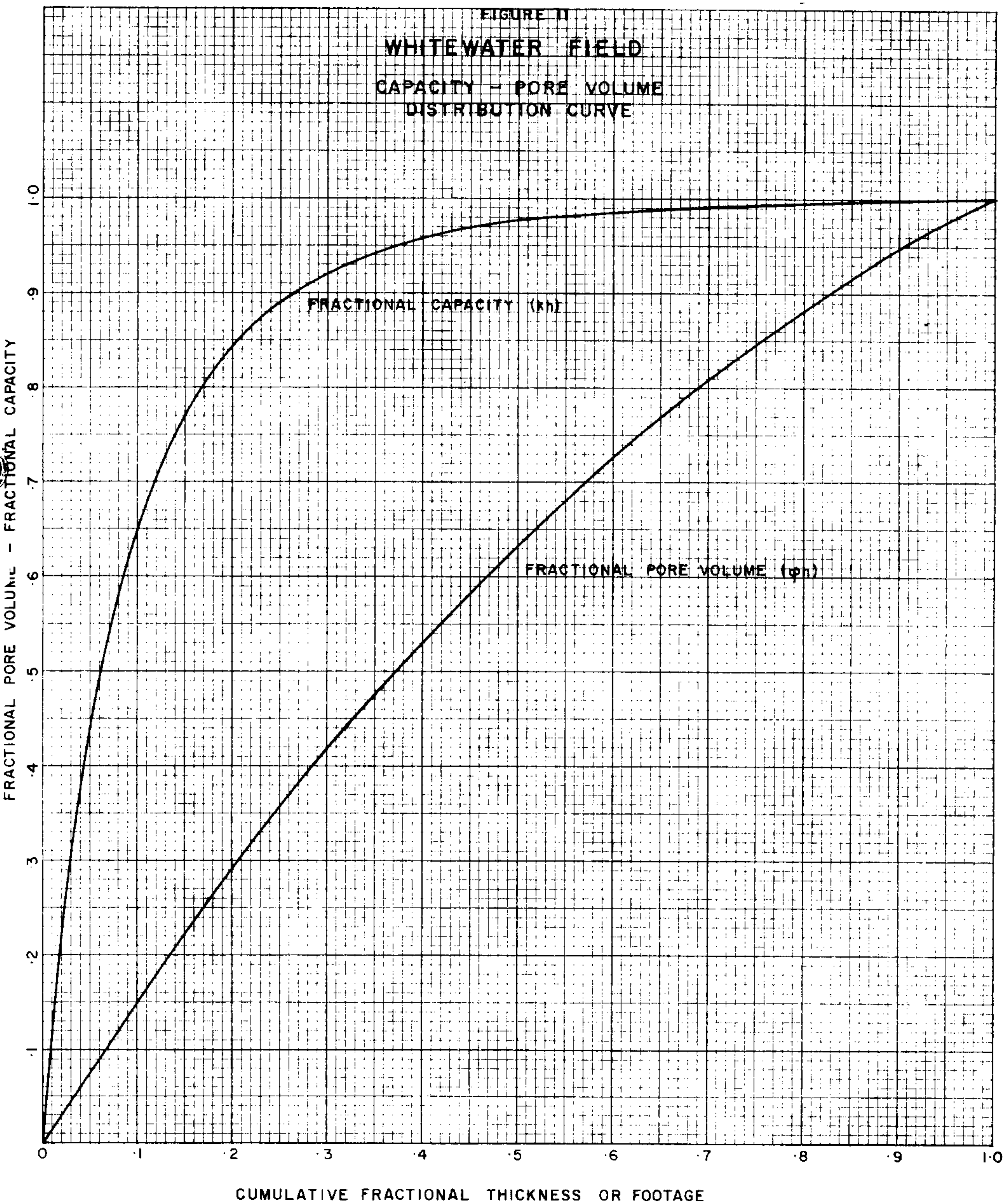


FIGURE 11
WHITEWATER FIELD
CAPACITY - PORE VOLUME
DISTRIBUTION CURVE
FRACTIONAL CAPACITY (kh)
FRACTIONAL PORE VOLUME (φh)
FRACTIONAL PORE VOLUME - FRACTIONAL CAPACITY
CUMULATIVE FRACTIONAL THICKNESS OR FOOTAGE
0
·1
·2
·3
·4
·5
·6
·7
·8
·9
1·0