

2
SUPERVISORY BOARD
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PETROLEUM ENGINEERING
DIVISION

*To be amended & brought up
to date (Oct 5/71) by Samedan.*

**ENGINEERING REPORT
PROPOSED EAST ROUTLEDGE UNIT NO. 1
Manitoba, Canada**

**Samedan Oil Corporation
April, 1971**

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SAMEDAN OIL CORPORATION
APRIL, 1971

Prepared by: H. Leon Veeder

TABLE OF CONTENTS

	<u>PAGE NO.</u>
I. OBJECT	1
II. CONCLUSION	1
III. RECOMMENDATIONS	2
<u>DISCUSSION</u>	3
A. DEVELOPMENT HISTORY	3
B. GEOLOGY	3
C. COMPLETION PRACTICES	5
D. ROCK CHARACTERISTICS	5
E. PRIMARY PERFORMANCE	6
F. SECONDARY PERFORMANCE	7
G. DEVELOPMENT PLAN	8
1. WATER SUPPLY	8
2. PLANT SITE	9
3. PRODUCTION SYSTEM	9
H. INVESTMENT AND OPERATING EXPENSES	10
a. PRIMARY	10
b. SECONDARY	10
I. PARAMETERS	11
1. CURRENT OIL PRODUCTION	11
2. CUMULATIVE OIL PRODUCTION	11
3. ADJUSTED CUMULATIVE OIL PRODUCED	11
APPENDIX	

I. OBJECT

The purpose of this study was to investigate the feasibility of secondary recovery of oil by waterflooding the Cherty Zone in the proposed portion of the Routledge Field.

II. CONCLUSION

1. The original oil in place as determined by volumetric methods was 9,141,600 barrels. The cumulative oil produced is 1,115,896 barrels as of March 1, 1970. The remaining primary oil is estimated to be 1,286,000 barrels with a remaining life of Twelve (12) years. The ultimate primary oil recovery would be 26.27% of the oil originally in place.

2. The study indicates the Cherty Zone will respond to secondary recovery by waterflooding. It is proposed that a inverted 9-spot injection pattern be considered. This can be accomplished by converting Seven (7) wells to injection. It will not be necessary to drill any additional injection or producing wells.

3. It is estimated that waterflooding the Cherty Zone will result in the recovery of 801,400 barrels of secondary oil, and will require a project life of Ten (10) years. The project economics are as follows:

Gross Income	\$4,360,946
Operating Costs	\$1,331,942
Investment	\$ 229,155
Net Profit	\$2,799,849
Net Profit Discounted at 8%	\$1,994,879
Payout - Years	0.6
Return on Investment	13.22 to 1

4. An adequate water supply is available in the Devonian Formation underlying the proposed Unit Area.

III. RECOMMENDATIONS

1. It is recommended to unitize the area shown on Figure No. 1. The field is experiencing a decline in production, and as of March 1, 1970, had produced 46.5% of the ultimate primary oil.

2. It is recommended that secondary recovery operations by waterflooding be initiated as soon after unitization as possible.

DISCUSSION

A. DEVELOPMENT HISTORY

This portion of the Routledge Field was discovered in January, 1964, with completion of the Samedan-Routledge "A" Well No. 7-11 located at LSD 7, Section 11, Township 9 North, Range 25 West of the Principal Meridian, Manitoba Province, Canada. It was completed from the Cherty Zone at a total depth of 2,150'. On potential the well pumped at a rate of 80 barrels of oil and 21 barrels of water per day. The majority of the wells in the field were drilled in 1964. Development continued until the last well was completed in August, 1968, being the Routledge "B" Well No. 4-11. There have been a total of Forty-Seven (47) wells drilled, Seventeen (17) of which were dry holes, Three (3) were completed in the Oolitic Zone, and Twenty-Seven (27) wells are presently producing from the Cherty Zone. The field was developed on 40-acre spacing.

B. GEOLOGY

This portion of the Routledge Field lies on the northeast flank of the Williston Basin, southeast of the town of Virden, Manitoba, in Township 9, Range 25 West of the Principal Meridian. The field is a combination stratigraphic and structural trap within the Mississippian. The eastern, northern and southern margins are controlled by sharp structural lows probably caused by solution of the underlying Prairie Evaporite salt with subsequent collapse of the overlying beds.

The reservoir rocks are found within the Lodgepole Formation of Lower Mississippian age, underlain by Devonian, Silurian and Ordovician

sediments. The overlying sediments are Jurassic and Cretaceous in age, all masked by unconsolidated sands and gravels of the glacial drift. The Lodgepole Formation is further subdivided into Three (3) members: the Scallion Member; the Virden Member; and the Whitewater Lake Member, in ascending order.

The Scallion Member has a thickness of approximately 210' in the field area. The uppermost 30' to 40' is characteristically medium to coarsely crystalline buff colored bioclastic limestone, essentially Crinoidal debris, interbedded with minor thin (2') beds of very fine to microcrystalline, in part slightly argillaceous, dense limestone. The bioclastic limestone has good to excellent intercrystalline porosity, occasional very fine to medium vug porosity, with some short open fracturing. The basal 8' of this interval generally contains some inclusions of Tripolitic chert. This is the main producing zone within the field. The upper unit is underlain by fine crystalline cherty limestone, occasionally argillaceous, with a few interbeds of medium crystalline crinoidal limestone. In some areas, the basal 70' to 80' of this Member is a greenish gray calcareous shale, locally called the Routledge Shale.

The Lower Virden Member consists of interbedded oolitic limestone and argillaceous limestone, hence its common name, the Oolitic zone. There are Four (4) correlateable oolite beds in this zone, the Fourth, Third, Second and First Oolites in ascending order. Minor production is obtained from this Member in Section 2 and Section 3, Township 9, Range 25 West of the Principal Meridian.

The Upper Virden Member is a bioclastic limestone consisting of Crinoidal debris, commonly known as the "Crinoidal". No production is obtained from this zone in the field.

The overlying Whitewater Lake Member is generally dolomitized and tight within the field area and the rocks up to the top of the Lodgepole are variably argillaceous, dolomitic, anhydritic, tight and non-productive.

The Cherty Zone is identified as the interval from 2083' to 2113' which occurs in the Samedan Oil Corporation-Routledge "A" Well No. 7-11 located at LSD 7-11-9-25 WPM, Manitoba, Canada. The Cherty Zone varies in thickness from 0' to 28' as shown on the Net Isopach Map, Figure No. 3. The field limits as shown on the Structure Map, Figure No. 2 are defined by a porosity pinch out on the North, East and part of the West with the water-oil contact at a subsea depth of -680' at the South and Southwest.

C. COMPLETION PRACTICES

Common completion practice was to set 7" surface casing at approximately 400'. A production string of 4-1/2" casing was set thru the pay. Each well was selectively perforated and cleaned up with a small amount of mud acid. All wells were completed as pumping wells. Subsequent treatments of Versene have been required to maintain maximum productivity.

D. ROCK CHARACTERISTICS

Every producing well had a 6-1/8" core recovered from the producing interval. This core data consisting of 727' was grouped into Eight (8) ranges of permeability. The permeability range from 1 to 10 millidarcies contained less than Three Percent (3%) of the total permeability capacity. Therefore, a pay cut off of Ten (10) millidarcies has been used. A permeability-feet map can be seen on Figure No. 4. Flood susceptibility and capillary pressure tests were run on a select group of cores.

The average rock characteristics are as follows:

Porosity	13.53%
Geometric Mean Permeability	50.17md
Total Water Saturation	52%✓
Residual Oil Saturation	29.08%
Original Formation Volume Factor	1.05✓
Average Oil Viscosity at 82°F	5.6cp
Average Oil Gravity at 60°F	34° API

E. PRIMARY PERFORMANCE

After reviewing the capillary pressure data and the primary production history it became apparent that a partial water drive existed in this reservoir. Oil accumulation occurs in a transition zone consisting of both oil and water. All wells were completed making some water. It was also noted from the field decline curve that the water cut has a tendency to stabilize around Sixty-Three Percent (63%). Since this oil production occurs in a transition zone, the water saturation was reported as a total water saturation of Fifty-Two Percent (52%). ✓

Accumulated production from the proposed unit area is 1,115,896 barrels to March 1, 1970. The remaining primary is estimated to be 1,286,000 barrels and was determined from a field decline curve as shown in Figure No. 7. An economic analysis for the remaining primary can be seen on Table No. 1. Economic limit was based on actual operating costs which were determined to be 5 barrels of oil per day per well. The original oil in place is 9,141,600 barrels. The ultimate primary recovery will be 26.27% of the original stock tank oil in place. Production for the wells in the study area averaged 20 barrels of oil per day for the year 1970.

The original bottom hole pressure as measured by drill stem test in the discovery well located at LSD 7-11 was 978 psia. During the first week of April, 1971, a static fluid level was shot. The calculated bottom hole pressure was

436 psia. This decline in pressure supports the theory that only a partial water drive exists in this reservoir. Other fluid levels indicated the bottom hole pressure was as high as 842 psia in the vicinity of the salt water disposal well located at LSD 7-10.

F. SECONDARY PERFORMANCE

The reservoir calculations which were made pertinent to waterflooding the Cherty Zone are shown on Table No. 4. The project reserves as of March 1, 1970, were determined to be 2,087,400 barrels. Included in this figure are 1,286,000 barrels of remaining primary oil. An estimated secondary performance curve can be seen on Figure No. 7. The expected life of the project is estimated to be Ten (10) years. An economical analysis was made and the results are shown in Table No. 2. The total development costs are estimated to be \$229,155. Present worth of the net income discounted at Eight Percent (8%) was determined to be \$1,994,879. The return on investment will be 13.22 to 1.

A comparison schedule can be seen on Table No. 3 which shows the primary, project, and incremental economics.

The initial proposed system is composed of Six (6) injection wells located at LSDs 7-10, 2-11, 10-11, 12-11, 14-11 and 6-14. Two (2) additional wells located at LSDs 4-11 and 8-14 will be converted to injection in approximately One (1) year. The reason for delaying the conversion of these Two (2) wells is due solely to the current production rate which is 20 and 39 barrels of oil per day, respectively.

*7-10 not in
fluid zone*

G. DEVELOPMENT PLAN

The proposed location of the injection wells, water distribution system and waterflood plant is shown on Figure No. 5. It has been determined that the proposed Devonian Water Supply is not compatible with the formation water produced from the Cherty Zone. Therefore, it will be necessary to maintain a split injection system never commingling produced and supply water except as an interface. The plan is to utilize the Routledge "C" No. 7-10 Well as a "relief valve" for produced water. When produced water reaches the recommended injection capacity of Well No. 12-11, injection of produced water will commence in this well. The incremental produced water between this amount and the recommended rate of the next well, No. 4-11, will be put in the relief well, No. 7-10. This pattern will continue and move counter clock wise thru LSDs 4-11, 2-11, 10-11 and 14-11. According to predictions, produced water injection will never be necessary in LSDs 6-14 and 8-14. According to the injection forecast prepared, the following is anticipated:

<u>INJECTION (BWPD)</u>			
<u>Produced and Supply Water</u>	<u>Initial</u>	<u>Maximum</u>	<u>Final</u>
Produced	1,100	4,600	4,453
Supply	2,611	4,715	1,672

From the above it is apparent that flexibility must be included in the design of injection equipment at the plant site. A maximum injection pressure of 1,000 psi is anticipated.

1. Water Supply

The Devonian will be the source of supply water for injection into the Cherty Zone. A single supply well will be located as close as possible to the

plant site. With the use of an electric submergible pump it is anticipated that this well will be capable of producing in excess of the maximum requirement of 4,700 barrels of water per day. The investment costs include drilling, completing, and equipping this supply well along with a short line, which will be necessary to transport the water to the plant site.

2. Plant Site

Location of the plant site was selected because of its central location along with the large amount of useable equipment presently at this location.

3. Production System

All producing wells are presently equipped with 40,000 in.-lb. beam pumping units. When equipped with 1-3/4" tubing pumps these units have a capacity of 220 barrels per day. It is expected that the existing beam pumping units will be capable of handling Sixteen (16) of the Twenty (20) total producing wells with full flood development. Included in the investment is the anticipated cost of purchasing and installing Four (4) electric sub-mergible pumps.

All producing wells will be brought into Three (3) satellites and then thru the central plant facility as shown on Figure No. 6.

There appear to be heater-treaters available of adequate size to handle the testing which will be required at each of these satellites. The purchase of 10,650' of 2", and 5900' of 3" fiberglass flow line will be required to complete this system. Sufficient headers exist with a minimum of modifications to complete these satellites.

Due to the lack of available gas it is recommended that a chem-electric treater be purchased for use at the central plant facility. Tankage and free-water knockouts will probably be available in the field to complete the oil and water handling facility. Only a small cost of moving and re-setting along with adequate controls will be necessary.

The field is entirely electrified at present. The necessary modifications will be made by Manitoba Hydro.

H. INVESTMENT AND OPERATING EXPENSES

Table No. 5 outlines the estimated investment costs for the unit. These will be spread as shown on the Secondary Forecast Table No. 2 as follows:

1971	\$168,893
1972	\$ 3,401
1973	\$ 56,861
	<u>\$229,155</u>

The following operating expenses were used:

a. Primary

\$348.00 per producing well (includes salt water disposal expense)

b. Secondary

\$300 per producing well (10 HP)
\$360 per producing well (25 HP)
\$390 per producing well (30 HP)
\$420 per producing well (39 HP)
\$480 per producing well (67 HP)
\$150 per injection well
\$0.03 per barrel water injected

I. PARAMETERS

1. Current Oil Production

This is the actual oil produced by well from ^{MAY 1/70 - MAY 1/71} September 1, 1970 to March 1, 1971.

2. Cumulative Oil Production

This is the total oil produced by well from inception to ^{MAY 1/71} March 1, 1971.

3. Adjusted Cumulative Oil Produced

This parameter has been used in the participation formula of all the Verden-Roselea Units. The cumulative production by well has been divided by the sum of the cumulative production from all wells. This decimal cumulative oil is divided by the months which each well has produced from its inception to ^{MAY 1/71} March 1, 1971, then taken times the quantity 1 minus the average water cut by well for a ^{MAY 1/70 - MAY 1/71} six-month period from September 1, 1970 to March 1, 1971. The formula for the above is shown as follows:

$$\text{Adjusted Cumulative Oil} = \frac{\text{Cumulative Production}}{\sum \text{Cumulative Production}} \times \frac{1}{\text{Months}} \times (1 - \text{W.C.})$$

These above parameters are shown on Table No. 6.

$$\frac{\text{TRACT CUM OIL}}{\text{Months in Prod.}} \times (1 - \text{W.C. interval})$$

$$\sum \left(\frac{\text{TRACTS CUM. OIL}}{\text{Months in Prod.}} \times (1 - \text{W.C. interval}) \right)$$

$$\frac{\text{Ave. monthly Prod.} \times (1 - \text{W.C.})}{\sum \text{Ave. monthly Prod.} \times (1 - \text{W.C.})} \times 100 = \text{percent}$$

APPENDIX

A. TABLES

1. PRIMARY FORECAST
2. SECONDARY FORECAST
3. COMPARISON SCHEDULE
4. RESERVOIR CALCULATIONS
5. INVESTMENT ESTIMATE
6. PARTICIPATION PARAMETERS

B. ILLUSTRATIONS

FIGURE NO.

1. UNIT BOUNDARY MAPS
2. STRUCTURE MAP
3. NET OIL ISOPAC MAP
4. PERMEABILITY - FEET MAP
5. WATER DISTRIBUTION SYSTEM
6. OIL GATHERING SYSTEM
7. PRIMARY DECLINE AND UNITIZED FORECAST
8. PERMEABILITY VS. CUMULATIVE FREQUENCY
9. DISPLACEMENT SWEEP EFFICIENCY VS. WATER-OIL RATIO

TABLE NO. 1PRIMARY FORECAST

<u>Year</u>	<u>8/8th Barrels</u>	<u>W.I.Net Barrels</u>	<u>Gross *</u> <u>Income</u>	<u>Operating</u> <u>Costs</u>	<u>Net</u> <u>Income</u>	<u>Net Income</u> <u>Discounted</u> <u>at 8%</u>
1970 (10 Mo.)	169,000	128,265	\$351,446	\$ 94,000	\$257,446	\$247,740
1971	178,000	136,044	372,761	112,800	259,961	231,625
1972	158,000	121,550	333,047	112,800	220,247	181,704
1973	139,000	107,479	294,492	112,800	181,692	138,795
1974	122,000	95,276	261,056	112,800	148,256	104,861
1975	106,500	84,119	230,487	112,800	117,687	77,073
1976	94,000	75,110	205,801	112,800	93,001	56,396
1977	82,500	66,684	182,714	112,800	69,914	39,257
1978	72,000	58,956	161,539	112,800	48,739	25,339
1979	63,000	52,324	143,368	112,800	30,568	14,715
1980	56,000	47,163	129,227	112,800	16,427	7,322
1981 (11 Mo.)	46,000	39,272	107,605	88,000	19,605	8,091
Total	1,286,000	1,012,242	\$2,773,543	\$1,310,000	\$1,463,543	\$1,132,918

* Price per barrel \$2.74

TABLE NO. 2SECONDARY FORECAST

<u>Year</u>	<u>8/8th Barrels</u>	<u>W.I. Net Barrels</u>	<u>Gross * Income</u>	<u>Operating Costs</u>	<u>Investment</u>	<u>Net Income</u>	<u>Net Income Discounted at 8%</u>
1970 (10 Mo.)	169,000	130,013	\$356,236	\$ 94,000	-	\$262,236	\$252,350
1971	172,400	133,881	366,834	130,723	\$168,893	67,218	59,947
1972	204,000	156,884	429,862	140,544	3,401	285,917	235,881
1973	289,800	218,512	598,723	154,567	56,861	387,295	295,855
1974	336,000	251,231	688,373	154,446	-	533,927	377,647
1975	336,000	251,231	688,373	160,554	-	527,819	345,669
1976	279,400	210,519	576,822	147,110	-	429,712	260,577
1977	163,300	126,945	347,829	138,876	-	208,953	117,327
1978	94,000	75,993	208,221	129,270	-	78,951	41,047
1979 (8 Mo.)	<u>43,500</u>	<u>36,377</u>	<u>99,673</u>	<u>81,852</u>	<u>-</u>	<u>17,821</u>	<u>8,579</u>
Total	2,087,400	1,591,586	\$4,360,946	\$1,331,942	\$229,155	\$2,799,849	\$1,994,879

* Price per barrel \$2.74

TABLE NO. 3COMPARISON SCHEDULE

	<u>PRIMARY</u>	<u>SECONDARY</u>	<u>INCREMENTAL</u>
Project Life - Years	11.75	9.50	(2.25)
8/8 Reserves (3-1-70) - Barrels	1,286,000	2,087,400	801,400
Working Interest - Net Barrels	1,012,242	1,591,586	579,344
Gross Income - Dollars	\$2,773,543	\$4,360,946	\$1,587,403
Operating Costs - Dollars	\$1,310,000	\$1,331,942	\$21,942
Investment - Dollars	-0-	\$229,155	\$229,155
Net Income - Dollars	\$1,463,543	\$2,799,849	\$1,336,306
Net Income Discounted at 8% - Dollars	\$1,132,918	\$1,994,879	\$861,961
Payout - Years		0.6	3.17
Return on Investment		13.22	6.83
Average Annual Rate of Return			94.77

TABLE NO. 4

RESERVOIR CALCULATIONS

Porosity - Percent	13.53
Permeability - Geometric Mean - md	50.17
Total Water Saturation - Percent	52.0
Residual Oil Saturation - Percent	29.08
Original Formation Volume Factor	1.05
Total Reservoir Acres	1,633
Total Reservoir Acre-Feet	23,312
Average Thickness	14
Developed Acres	1,055
Developed Acre-Feet	19,053
Average Thickness	18
Floodable Acres	903

Stock Tank Oil Originally In Place

$$\frac{7758}{1.05} \times 0.1353 \times (1.0 - 0.52) = 479.8 \text{ Bbls./Acre-Foot}$$

Residual Oil

$$\frac{7758}{1.05} \times 0.1353 \times 0.2908 = 290.7 \text{ Bbls./Acre-Foot}$$

Primary Recovery (3-1-70)

Accumulated Production (3-1-70) 1,115,896 Barrels

$$\frac{1,115,896}{19,053} = 58.6 \text{ Bbls./Acre-Foot}$$

TABLE NO. 4
RESERVOIR CALCULATIONS

(Continued)

Ultimate Primary Recovery

Accumulated Production (3-1-70)	1,115,896 Barrels
Remaining Primary Reserves (3-1-70)	1,286,000 Barrels
Ultimate Primary Recovery	2,401,896 Barrels
$\frac{2,401,896}{19,053} = 126.1 \text{ Bbls./Acre-Foot}$	

Percent Recovery of Original Stock Tank Oil In Place

$$\frac{126.1}{479.8} \times 100 = 26.28\%$$

Estimated Waterflood Recovery

Areal Sweep Efficiency

$$\frac{903}{1,055} = 0.856$$

Variation (See Figure No. 8) 0.72

Displacement Sweep Efficiency (See Figure No. 9)

At a WOR = 32.33 (97% Watercut) 0.78

Stock Tank Oil Originally In Place 479.8 Bbls./Acre-Ft.

Residual Oil 290.7 Bbls./Acre-Ft.

Mobil Oil 189.1 Bbls./Acre-Ft.

Ultimate Primary Recovery 126.1 Bbls./Acre-Ft.

Mobil Oil In Place At End Of Primary 63.0 Bbls./Acre-Ft.

Waterflood Recovery

$$19,053 \times 0.856 \times 0.78 \times 63.0 = 801,400 \text{ Barrels}$$

TABLE NO. 4
RESERVOIR CALCULATIONS

(Continued)

Project Reserves (3-1-70)

Remaining Primary (3-1-70)

1,286,000 Barrels

Secondary

801,400 Barrels

Total

2,087,400 Barrels

TABLE NO. 5

INVESTMENT ESTIMATE

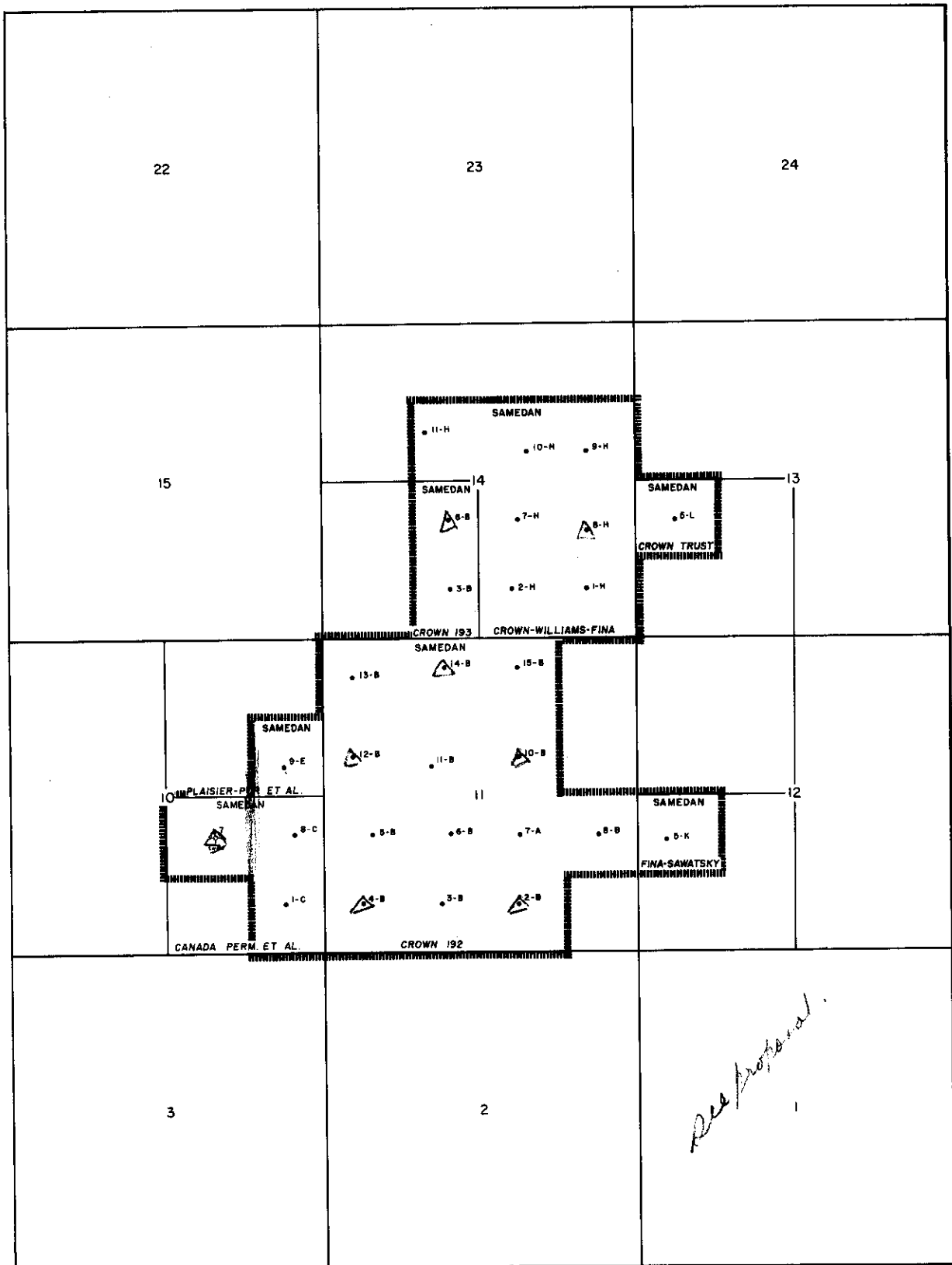
Injection Facility	\$ 29,370
Plant Producing Facility	\$ 22,370
Injection System (Plant to Wells)	\$ 28,170
Gathering System	\$ 22,985
Water Supply Well	\$ 57,500
Injection Well Conversion - 7 Total	\$ 11,900
Producing Well Equipment	<u>\$ 56,860</u>
Total	\$229,155

TABLE NO. 6

PARTICIPATION PARAMETERS

<u>Lease & Well No.</u>	<u>Oil Production From 9-1-70 to 3-1-71</u>	<u>Curr. Prod. Decimal Interest</u>	<u>Cumulative Oil From Inception to 3-1-71</u>	<u>Decimal Cumulative Oil</u>	<u>Decimal Adjusted Cum. Oil</u>
<u>Routledge "A"</u>					
Well No. 7-11	4,325	.047575	115,650	.088501	.044764
<u>Routledge "B"</u>					
Well No. 2-11	667	.007337	13,287	.010168	.002450
Well No. 3-11	2,687	.029557	43,309	.033142	.011599
Well No. 4-11	3,694	.040634	76,004	.058162	.027120
Well No. 5-11	3,865	.042515	89,096	.068181	.026303
Well No. 6-11	4,538	.049918	100,738	.077090	.035615
Well No. 8-11	3,534	.038874	33,784	.025853	.048521
Well No. 10-11	480	.005280	23,416	.017919	.007025
Well No. 11-11	1,559	.017150	35,794	.027392	.017154
Well No. 12-11	1,422	.015642	36,347	.027815	.017154
Well No. 13-11	123	.001353	15,617	.011951	.001634
Well No. 14-11	919	.010109	6,430	.004921	.001960
Well No. 15-11	6,562	.072182	51,004	.039031	.120569
Well No. 3-14	2,977	.032747	34,361	.026295	.053096
Well No. 6-14	3,249	.035739	44,073	.033727	.034635
<u>Routledge "C"</u>					
Well No. 1-10	4,422	.048642	84,254	.064476	.037249
Well No. 8-10	2,504	.027544	67,368	.051554	.042477
<u>Routledge "E"</u>					
Well No. 9-10	3,229	.035519	39,423	.030169	.008985
<u>Routledge "H"</u>					
Well No. 1-14	2,197	.024167	32,838	.025129	.015520
Well No. 2-14	4,395	.048345	42,162	.032265	.038066
Well No. 7-14	3,927	.043197	47,760	.036548	.056200
Well No. 8-14	7,593	.083523	65,928	.050452	.119098
Well No. 9-14	5,811	.063921	43,263	.033107	.062245
Well No. 10-14	6,412	.070532	57,736	.044183	.088548
Well No. 11-14	4,325	.047575	50,962	.038999	.050319
<u>Routledge "K"</u>					
Well No. 5-12	1,980	.021780	21,453	.016417	.015030
<u>Routledge "L"</u>					
Well No. 5-13	3,513	.038643	34,698	.026553	.016664
Totals	90,909	1.000000	1,306,755	1.000000	1.000000

R. 25 W.



T
9
N.

EAST ROUTLEDGE UNIT NO. 1
MANITOBA PROVINCE, CANADA

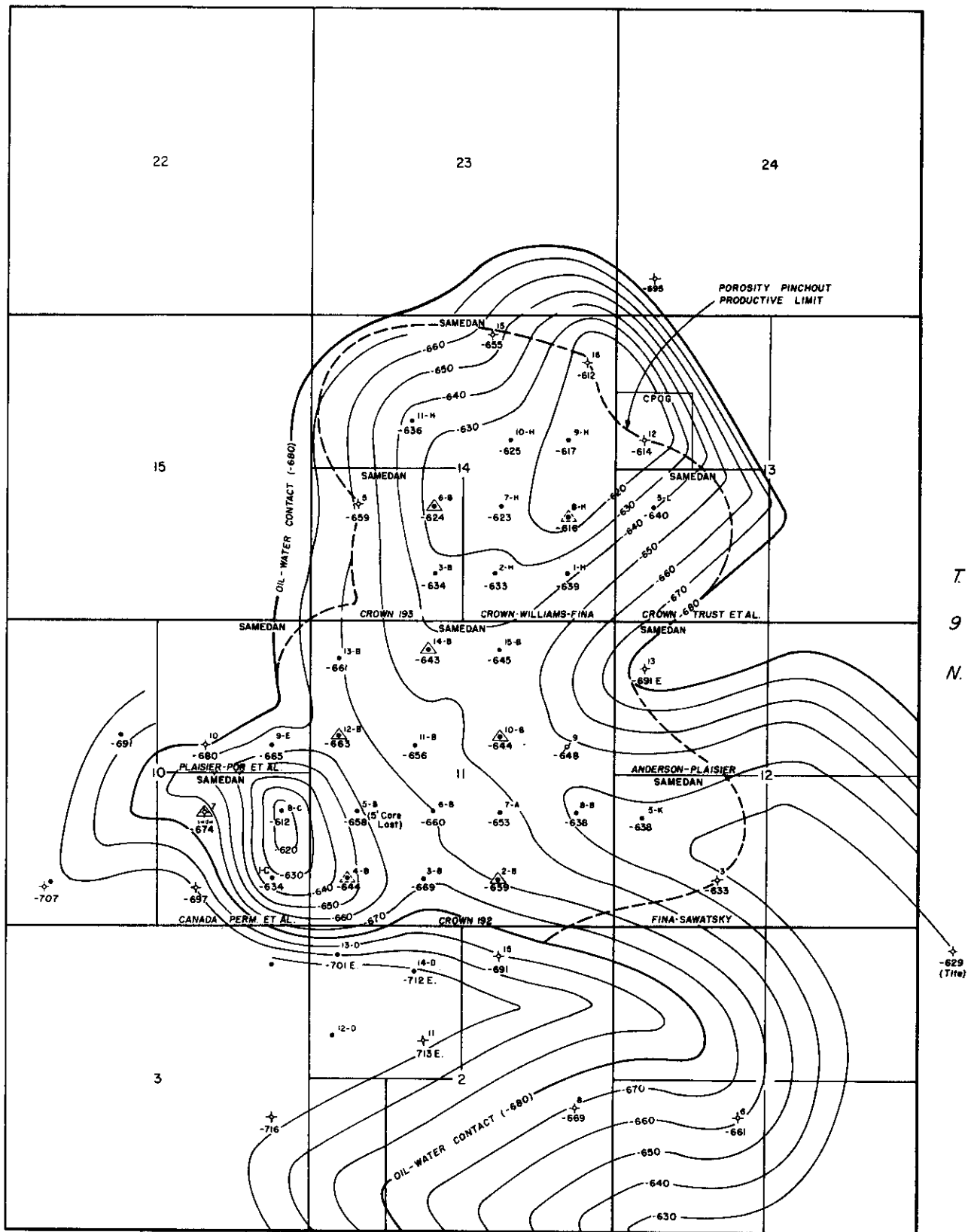
0 1000 2000 3000
scale

FIGURE NO. 1

UNIT BOUNDARY MAP

DATE: 3/1/70

R. 25 W.



- PRODUCING WELL
- ✦ DRY HOLE
- △ INJECTION WELL
- △ PROPOSED INJECTION WELL

EAST ROUTLEDGE UNIT NO.1
MANITOBA PROVINCE, CANADA

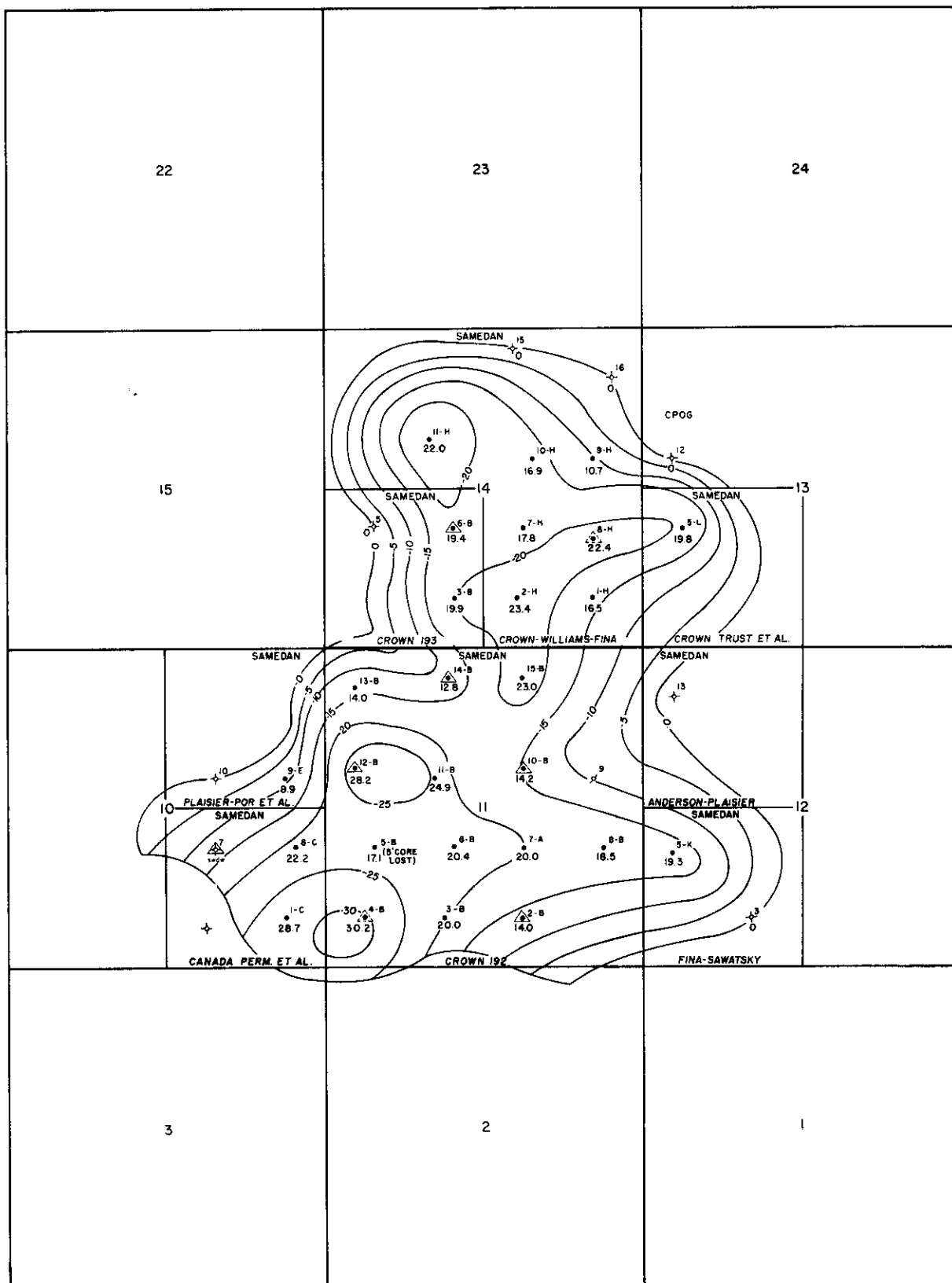
0 1000 2000 3000
scale

FIGURE NO.2
STRUCTURE MAP
TOP OF CHERTY ZONE
C.I. - 10'

GEOLOGY BY: G.J.Mc.

DATE: 3/1/70

R. 25 W.



T
9
N.

- PRODUCING WELL
- + DRY HOLE
- △ INJECTION WELL
- PROPOSED INJECTION WELL

EAST ROUTLEDGE UNIT NO. 1
MANITOBA PROVINCE, CANADA

0 1000 2000 3000
scale

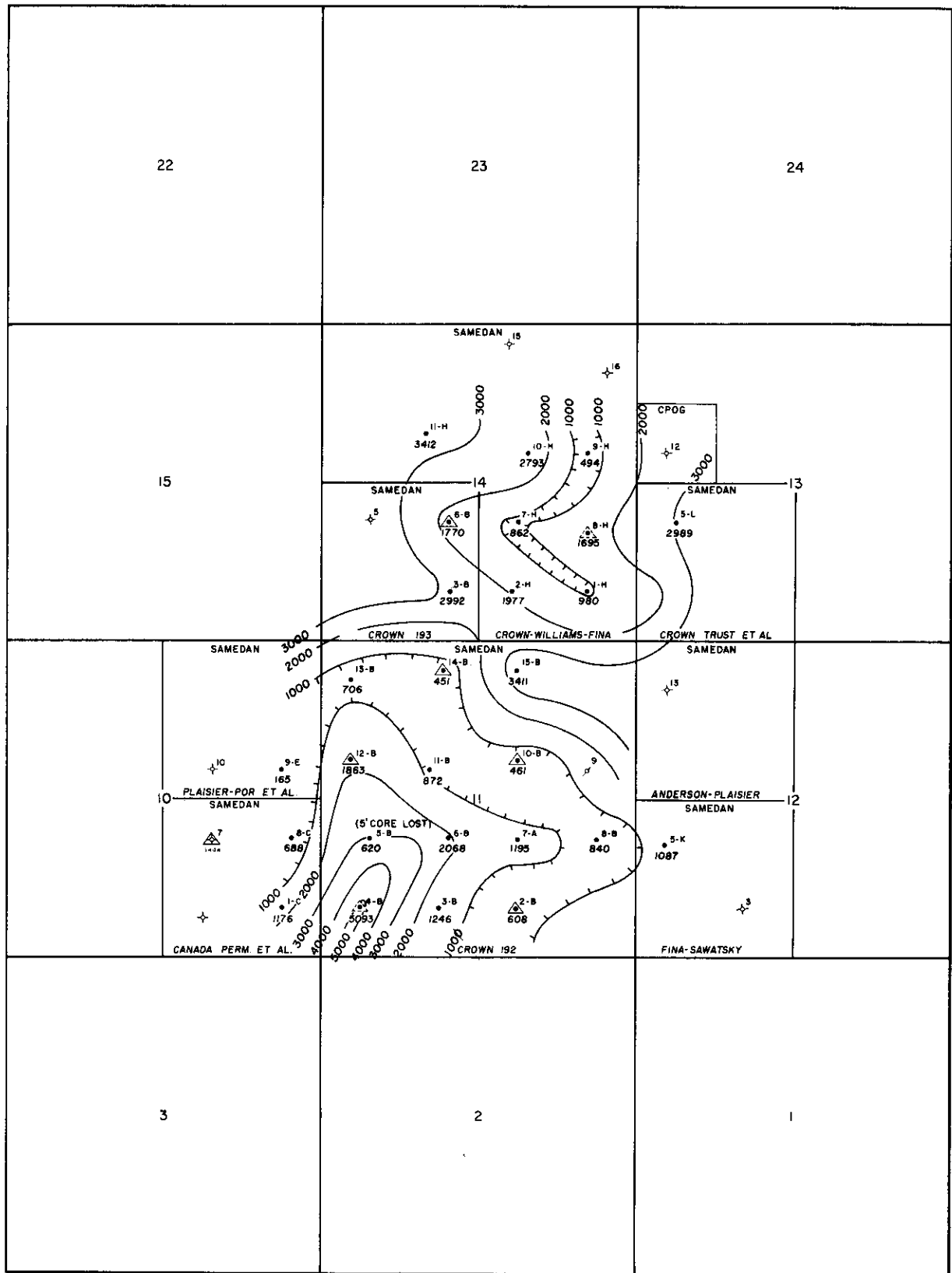
FIGURE NO. 3

NET OIL ISOPAC MAP
C.I. - 5'

GEOLOGY BY: G.J.Mc.

DATE: 3/1/70

R. 25 W.



- PRODUCING WELL
- ✦ DRY HOLE
- ▲ INJECTION WELL
- △ PROPOSED INJECTION WELL

EAST ROUTLEDGE UNIT NO.1
MANITOBA PROVINCE, CANADA

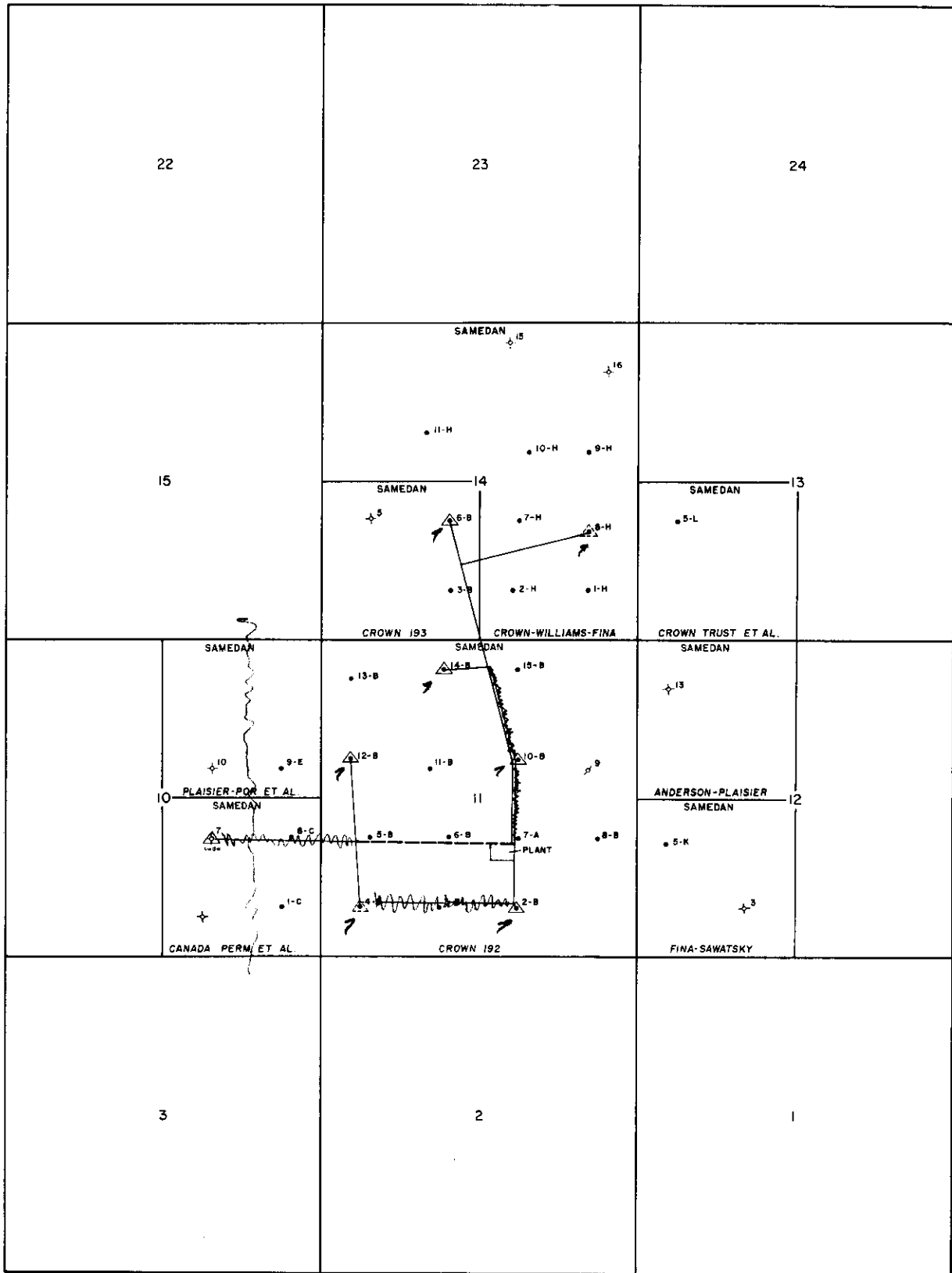
0 1000 2000 3000
Scale

FIGURE NO.4
PERMEABILITY-FEET MAP
TAKEN FROM CORE DATA
C.I. - 1,000'

GEOLOGY BY: G. J. Mc.

DATE: 3/1/70

R. 25 W.



T.
9
N.

- 2" FIBERGLASS 1200 PSI
- 3" FIBERGLASS 1200 PSI
- PRODUCING WELL
- + DRY HOLE
- △ INJECTION WELL
- △/ PROPOSED INJECTION WELL

EAST ROUTLEDGE UNIT NO. 1
MANITOBA PROVINCE, CANADA

0 1000 2000 3000
Scale

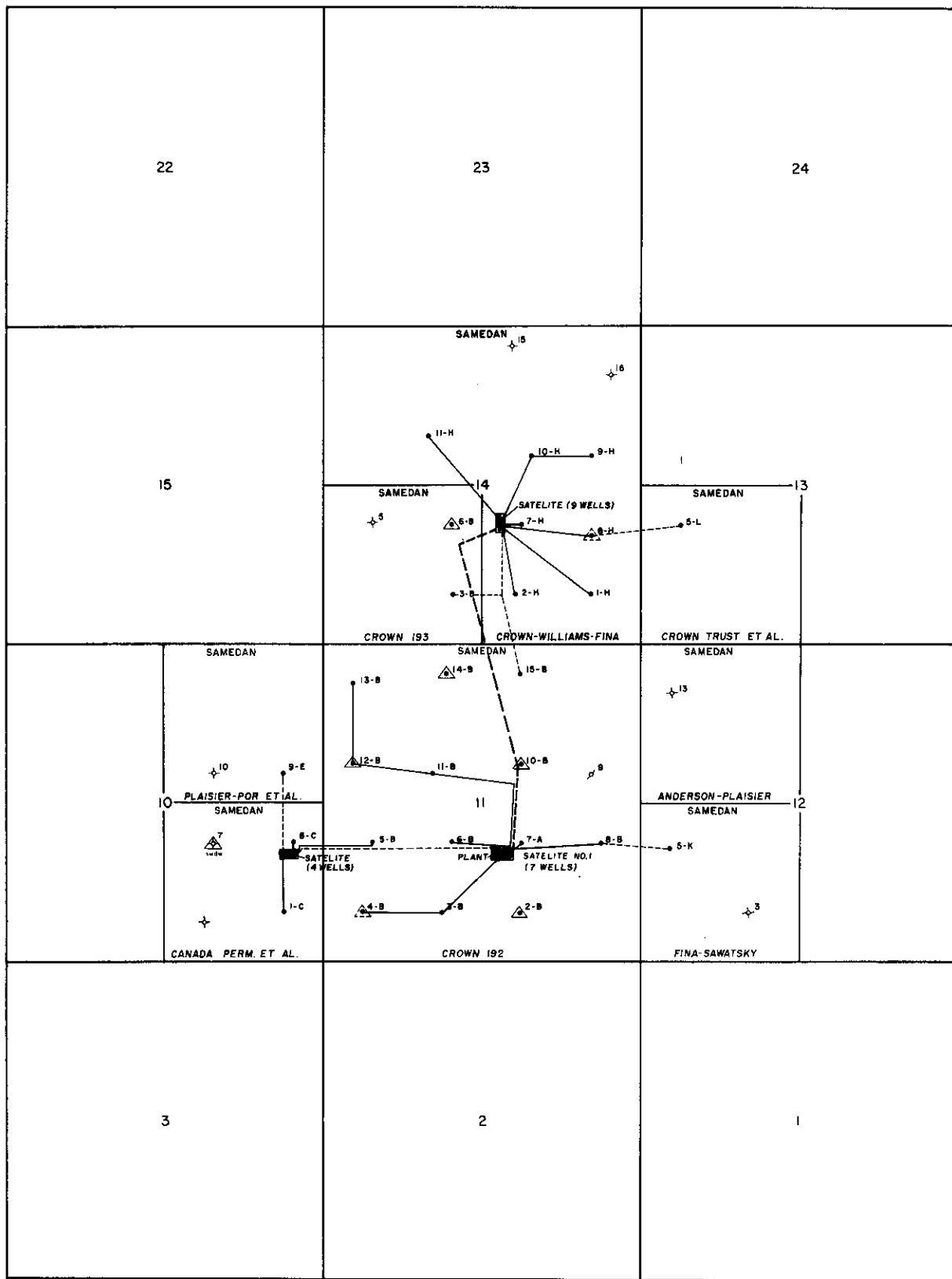
FIGURE NO. 5

WATER DISTRIBUTION
SYSTEM

LAYOUT: H.L.V.

DATE: 3/1/70

R. 25 W.



T
9
N.

EAST ROUTLEDGE UNIT NO. 1
MANITOBA PROVINCE, CANADA

0 1000 2000 3000
scale

FIGURE NO. 6

OIL GATHERING SYSTEM

LAYOUT: M.L.V.

3/1/70

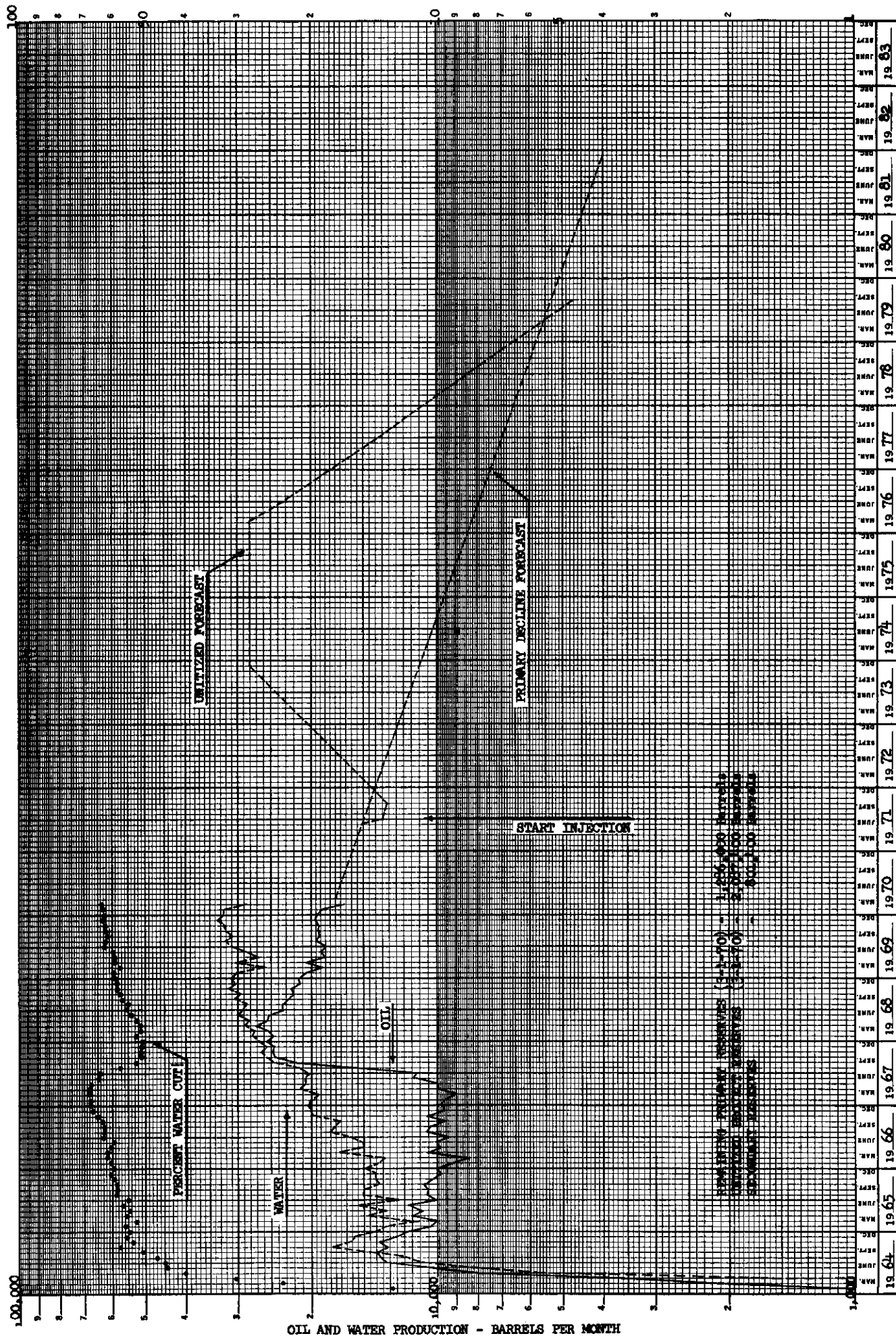


FIGURE NO. 7

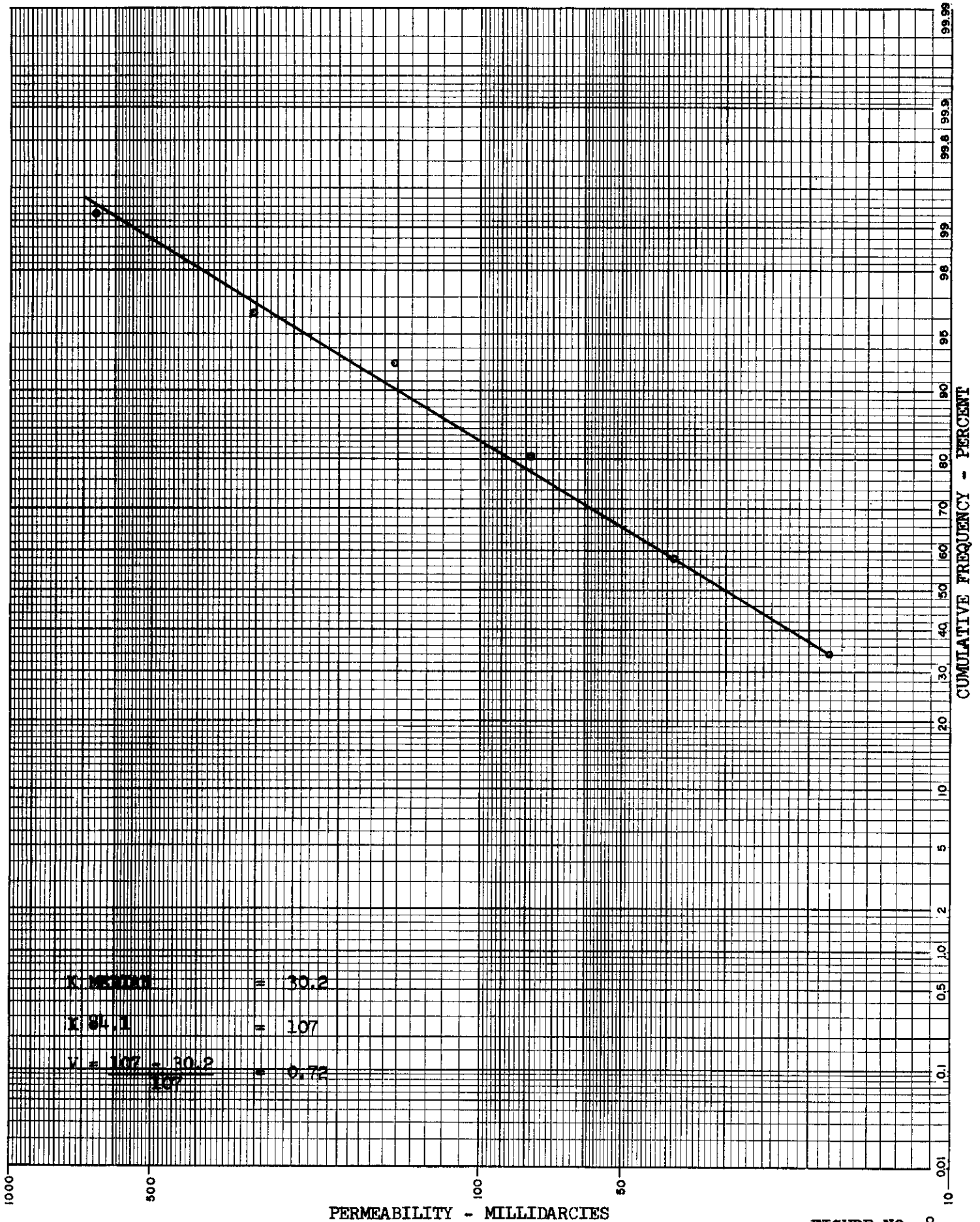
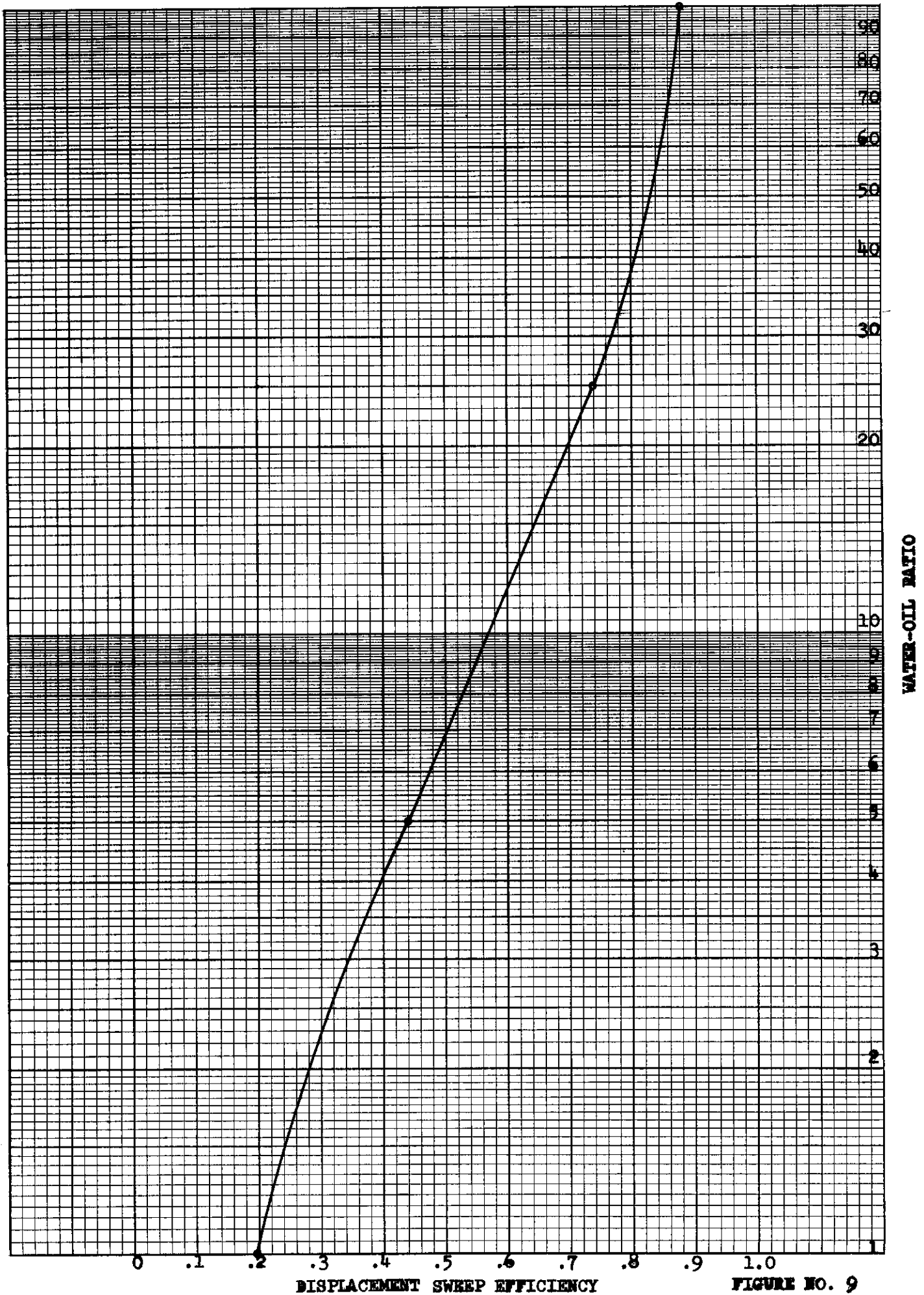


FIGURE NO. 8



DISPLACEMENT SWEEP EFFICIENCY

FIGURE NO. 9