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DEPARTMENT OF NATIONAL DEVELOPMENT

BUREAU OF MINERAL RESOURCES
GEOLOGY AND GEOPHYSICS

RECORDS:

RECORD No. 1966/157

MARLIN No. A-1
(FORMERLY GIPPSLAND SHELF NO. 4)
SPECIAL CORE ANALYSIS TESTS OF SAMPLES FROM FOUR SANDSTONE RESERVOIRS

Refer to pp. 8, 5 & 6.

Work relevant to the proposed General Reservoir Engineering Course. 19-30 July. Sydney.

by

B.A. McKAY

15928/65

BUREAU OF MINERAL RESOURCES, GEOLOGY AND GEOPHYSICS

PETROLEUM TECHNOLOGY SECTION

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INTRODUCTION

The following report presents results of liquid permeability, wettability and mercury capillary pressure determinations carried out on samples of cores from oil and gas bearing zones in the Marlin No A-1 well. Additional data, comprising pore size distribution, permeability versus fluid saturation, and average capillary pressure curves for three of the zones are also presented. This study was carried out in the Petroleum Technology Laboratory of the Bureau.

PROCEDURE & APPARATUS

Four separate sets of core samples totalling 86 individual plugs were selected for the tests; 37 of these were ¾-inch diameter plugs for capillary pressure; 32 of 1⅛-inch diameter for permeability, and 17 of 1½-inch diameter for imbibition tests. All plugs were diamond-drilled parallel to bedding from slabbed cores, and where possible, trimmed with a diamond saw to a length of 1¼ inches.

The samples were then extracted with toluene in a Soxhlet-type apparatus for a period of 24 hours, then dried in an oven for 24 additional hours at 110°C. Upon cooling, the effective porosity and absolute permeability (using dry nitrogen) were determined on each of the plugs.

Capillary pressure tests on the ¾-inch diameter plugs were the first to be carried out. These were conducted in a Ruska-type mercury injection apparatus, using a method described by Purcell in Petroleum Transactions, AIME, 1949. Upon extensive evacuation, each of the samples was subjected to increasing mercury pressure, and the relative mercury volumes injected at each pressure step were measured.

The pressure/volume data obtained from tests on these 37 samples were subsequently used to compile mercury capillary pressure curves, after corrections for mercury surface conformance and pump expansion had been made.

Average capillary pressure curves for three intervals; 4575'-4643'; 5053'-5098'; and 5120'-5178' were then constructed from the capillary test results on samples from these intervals.

The method of construction (*) utilizes the relationship between capillary pressure, saturation and permeability (Figures 38, 39 & 40) of all permeable (> 10md.) samples. Data points for compiling each of the average capillary pressure curves (Figures 41, 42 & 43) were selected by reference to figures 38 to 40 using average (nitrogen) permeability values (corrected for Klinkenberg) of 670, 62 and 990 millidarcy respectively.

Pore size distribution of the samples was determined using the capillary pressure formula $r = \frac{2\gamma \cos\theta}{\Delta P}$. Values for the average pore entry radius (r) over a particular saturation/pressure interval were calculated for each sample. Values for the other two parameters, γ and θ, representing the surface tension of mercury (480 dynes/cm) and the mercury-rock contact angle (140^{o}) were taken from the relevant paper by Purcell to which reference has already been made.

Permeability tests were next performed on 32 of the $1\frac{1}{8}$-inch diameter plugs. Initially, an equivalent liquid (Klinkenberg) permeability value was derived for each of the samples. This value, representing the absolute, undamaged, permeability to a non-reactive liquid, was determined by measuring three or four gas (nitrogen) permeability values in the cores at several different mean pressures, and extrapolating to an infinite pressure.

Following this, separate permeability tests were carried out using respectively, a de-aerated and filtered kerosene, 1.65% NaCl brine, 0.825% NaCl brine and distilled water. The aqueous phases used were treated with 25 ppm mercuric chloride to prevent possible pore channel plugging by bacteria.

Each of the [redacted] flow tests was preceded by extraction and drying of the samples; [redacted] permeability measurements were made (average of three flow rates) after initial displacement of two pore volumes of fluid through the sample.

A simple test to supplement [redacted] liquid permeability investigations was also carried out. For this, an additional sample was selected adjacent

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* "PRACTICAL RESERVOIR ENGINEERING" by GUERRERO & STEWART (THE OIL & GAS JOURNAL)

to each of the permeability plugs. These samples were disaggregated, and two identical volumes (approximately 4cc) of each were selected. One of each volume was placed in a graduated cylinder in distilled water (to promote clay swelling), the other in kerosene (to suppress swelling). After standing undisturbed in the two fluids for 24 hours, the solid volumes of each pair of samples were compared to detect the presence of any swelling clays.

Imbibition tests were conducted on the final seventeen 1½-inch samples to determine their fluid wetting characteristics. This was accomplished by saturation of the samples with oil (kerosene), and immersing them in fresh water for a period of seven days. For samples in which an immediate positive result was not obtained, adjacent core material was saturated with water and immersed in oil to test for reverse (oil) wetting properties. The relative wettability was determined by noting the type and volume of liquid displaced from the samples by the immersion fluid after a seven-day period.

DISCUSSION

Capillary pressure curves, and the permeability-capillary pressure-fluid saturation combined relationship for three productive zones are shown in figures 1-43. Mercury saturation capillary pressure values are listed in table 1 to clarify the lower readings in curves shown in figures 1-37.

Equivalent liquid permeability results are presented in figures 44-50. These values were subsequently used as a basis for the results shown in tables III, IV and IVB in which permeability to kerosene, brine, and fresh water are all expressed as a percentage of the Klinkenberg values.

Finally, imbibition test results, and the calculated values for pore size distribution from the capillary pressure curves are presented in tables II and V, while the electric log of the three upper productive intervals with the relevant samples is shown in figure 51.

A comparative examination of the capillary pressure tests reveals certain similarities between the upper (4575' - 4643') gas productive sample material, and the lower oil and water productive sands (5120' - 5178').

Average capillary curves from these two zones exhibit very low initial displacement (threshold) pressures, and low (15-20%) residual water saturations. On the other hand, the average capillary curves from the gas sand at 5053' - 5098' revealed substantially higher threshold pressures and residual water saturations than the above-mentioned two zones. In addition, the shape of the average capillary pressure curve revealed that irreducible saturation had not been attained at the ultimate test pressure applied to samples from this interval.

Pore throat-size values calculated from the capillary pressure tests indicate that the largest pore throats (97 to 107 microns) occur in core material from the zone at around 4600 feet and from the oil bearing section at around 5150 feet. The gas productive sandstone at ± 5070 feet was characterized by pore throat radii up to 13 microns, whereas three samples selected from the gas producing zone at ± 7475 feet contained measured pore throats up to 5 microns in radius.

Liquid permeability tests made on each of the samples listed in tables III and IV, with respect to kerosene, brines and fresh water resulted in values generally lower than the equivalent liquid permeability (Klinkenberg). This was most pronounced in the flow tests with fresh water. Permeability to this particular phase ranged from an average of 49% down to an average of 5% of the Klinkenberg value for the four separate sandstone intervals tested. The flow tests with kerosene most closely approached equivalent liquid values; tests with this liquid varied from 64% to 99% of the Klinkenberg permeability in the four sand intervals tested.

The main reductions in permeability with respect to fresh water were apparently caused by movement of particles in the pore channels. Tests aimed at the detection of swelling clays in the samples proved negative with three exceptions, namely two samples (4575' & 4587') from the top of the upper gas sand and one impermeable sample (5117') within the oil zone. Material from these zones when placed in fresh water, was found to have respectively increased in volume 10%, 13% and 15% over duplicate volumes of material placed in kerosene. Unfortunately, none of these samples was physically suitable for liquid permeability flow tests.

Increased permeability with respect to fluid of decreasing salinity was noted in three samples (5148', 5161' and 5165'), so that final permeability to fresh water nearly equalled initial flow capacity to kerosene. This phenomenon was apparently caused by movement from the samples of mobile particles during permeability tests, as shown by very cloudy effluents. Since all three samples showed a predominance of large pore throats (up to 107 microns in radius), a displacement of mobile material causing an increase of permeability in the samples seems quite feasible.

Wetting characteristics from the imbibition tests showed all samples to be mildly to strongly water wet. Most of the oil saturated samples imbibed water readily within a short immersion time in water. Total saturation with this phase stabilized at 4% to 52% of pore volume after seven days. However, wetting forces were noticeably weaker in samples having a multitude of large pores; the resultant water saturation by imbibition in these samples was substantially lower than in core material having a larger proportion of intermediate pore openings (< 20 microns).

Low resultant water saturations were obtained from the imbibition tests on two samples (4575' and 4587'). Although a reverse (oil) wetting test proved negative, ultimate water imbibed stabilized at low values of 7.7% and 4.3% of pore volume, with no water imbibed in the first 24 hours.

"Swelling" tests carried out on these two samples previously, had indicated the presence in them of small amounts of hydrophylic clays. Therefore, pore channel blockage by clay swelling may have ~~been~~ the governing factor in water imbibition, rather than the actual wetting characteristics of the rock.

CONCLUSIONS

Special core analysis investigations comprising capillary pressure, pore size distribution, fluid permeability and imbibition tests were performed on core samples from oil and gas productive intervals in Marlin No. A-1. Material from four intervals (4575' - 4643', 5053' - 5098', 5120' - 5178' and 7474' - 7477') was studied.

Average capillary curves were compiled from data obtained on the first three intervals; insufficient core material was available for capillary pressure characterization of the lowest zone.

The following conclusions can be drawn from the results:

1. Average residual water saturations for the upper gas (4575' - 4643') and lower (oil) productive zone (5120' - 5178') were found to be 21% and 15% (at 1200 psia mercury capillary pressure) respectively. Average residual water saturation for the intermediate gas productive sandstone (5053' - 5098') was 32%.

2. Maxima pore size radii of the samples as determined from the capillary pressure tests ranged from 2.1 to 107 microns.

3. Liquid permeability tests showed that fresh water had an adverse effect on flow capacity in practically all the samples. Swelling tests indicated presence of negligible amounts of hydrophylic clays, so that main reductions in permeability were apparently caused by particle movement in the samples.

4. The samples showed moderate to strong preferential wettability by water. Oil displacement by water imbibition varied from 4% to 52% of pore volume, after seven days immersion of the samples in the aqueous phase.

TABLE I

	MERCURY SATURATION (% PORE VOLUME)							SAMPLE DEPTHS (FEET)
	5	15	25	35	45	55	65	
MERCURY CAPILLARY PRESSURE (PSIA)	4.8	8.2	13	22	44	110	370	4575
	2.0	3.0	5.0	9.2	20	58	270	4585
	6.2	10.5	19	40	127	450	1270	4587
	1.0	1.3	1.7	2.6	4.7	12.4	50	4635
	1.0	1.3	1.7	2.5	4.3	8.4	19	4639
	5.8	9.8	12.5	18.2	25.7	40.6	83	4641
	5.7	12.4	22.6	41	76	147	348	4643
	8.0	9.8	12.2	16.6	27.4	60	163	5053
	15.4	23.8	43	135	275	540	1140	5071
	28.4	34.2	45	71	175	418	950	5075
	43	58	84	158	305	590	1160	5077
	11	59	140	265	487	830	1370	5098
	9.2	13.1	18.5	25.6	40.6	89	198	5120
	7.4	8.3	9.6	11.6	16.7	31.7	88	5121
	8.6	9.5	10.8	14.3	22.5	48.5	130	5128
	7.1	7.9	9.1	11	15.5	34.4	108	5130
	6.4	7.3	8.6	10.2	13.2	25.6	75	5132
	6.2	6.8	7.8	9.5	13.3	28.4	90	5134
	2.7	3.4	4.2	5.7	9.7	28.4	116	5137
	1.9	2.1	2.5	3.3	4.6	7.6	25	5141
	1.0	2.5	5.3	11.6	38	200	1080	5144
	2.8	4.4	8.0	18	48	123	340	5146
	1.0	1.1	1.5	2.7	10.3	150	930	5148
	1.5	1.9	2.3	2.6	3.1	4.3	7.2	5161
	3.3	4.6	6.2	8.4	13.4	33	100	5165
	1.1	1.7	3.0	5.5	9.8	20	60	5169
	4.2	4.9	5.8	6.8	8.8	18.5	72	5171
	3.4	4.2	5.8	10.7	24.5	70	230	5175
	1.5	1.9	2.6	3.5	5.0	10.6	51	5178
	38	47	63	96	165	315	635	7474
	20	24.5	31	48	87	180	380	7475
	19.2	22.8	27.8	39.6	73	150	350	7477

TABLE II

AVERAGE PORE ENTRY RADIUS (MICRONS)

SATURATION (% PORE VOLUME)										SAMPLE DEPTH (FEET)
1-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	80-90		
21	13	7.7	4.5	2.1	0.79	0.24				4575
52	33	17	11	4.9	1.3	0.31				4585
18	9.6	5.3	2.3	0.67	0.21					4587
97	82	59	38	19	7.4	1.5	0.13			4635
	82	59	40	23	10	4.9	1.1	0.13		4639
18	12	8.4	5.8	4.0	1.9	1.1	0.39			4641
18	8.2	4.5	2.6	1.3	0.66	0.27				4643
13	11	8.6	6.1	3.6	1.5	0.58	0.18			5053
	0.25	0.18	0.13	0.11						5056
	0.62	0.34	0.22	0.14	0.093					5066
6.7	4.2	2.4	0.75	0.36	0.18					5071
3.7	3.0	2.7	1.3	0.53	0.24					5075
2.4	1.8	1.2	0.65	0.33	0.17					5077
2.1	1.4	0.89	0.56	0.36	0.22	0.12				5084
	0.56	0.27	0.13							5097
	1.6	0.72	0.38	0.21	0.12					5098
12	8.0	5.7	4.0	2.4	1.1	0.47	0.18			5120
14	13	11	8.9	5.9	3.0	1.0	0.32			5121
2.1	1.0	0.46	0.24	0.14						5125
12	11	9.5	7.2	4.3	1.8	0.70	0.24			5128
15	13	12	9.4	6.3	2.6	0.82	0.24			5130
17	14	12	10	7.4	3.6	1.2	0.35			5132
17	15	13	11	7.3	3.2	0.95	0.28			5134
40	31	25	18	9.4	3.1	0.77	0.21			5137
56	51	41	31	22	12	2.1	0.21			5141
82	38	19	7.6	1.8	0.40					5144
37	22	12	5.2	1.8	0.77	0.27				5146
107	89	63	32	5.4	0.48					5148
71	56	49	40	32	24	11	2.0	0.30		5161
31	27	17	12	7.0	2.7	0.89	0.25			5165
97	59	33	18	10	4.6	1.4	0.35			5169
25	22	18	15	11	4.6	1.1	0.30			5171
31	26	17	9.1	3.8	1.2	0.41	0.15			5175
71	53	41	30	20	7.6	1.2	0.15			5178
	2.2	1.6	1.1	0.59	0.31	0.14				7474
	4.3	3.2	2.1	1.1	0.54	0.25				7475
5.5	4.6	3.7	2.5	1.3	0.64	0.27				7477

TABLE III

Well Name and Number	Sample Depth (Feet)	Porosity (% B.V.)	Dry-Air Permeability (MD)	Equivalent Liquid Permeability (MD)	Permeability to Kerosene (% Equivalent Liq Permeability)	Permeability to 1.65% Brine (% Equivalent Liq Permeability)	Permeability to 0.825% Brine (% Equivalent Liq Permeability)	Permeability to Fresh Water % Equivalent Liq Permeability
Gippsland Shelf No. 4	4575	20.6	750*	UNSUITABLE	FOR	TESTING		
"	4585	30.0	640*	"	"	"		
"	4587	20.6	300*	"	"	"		
"	4635	19.1	2830	2140	100	100	81	71
"	4639	12.0	1032	875	100	100	100	84
"	4641	5.3	19	16	36	36	14	6.3
"	4643	5.7	56	45	56	42	14	11
				AVERAGES	73	69	52	43
"	5053	25.0	213	175	87	65	34	12
"	5066	16.3	2.9	2.0	50	25	25	15
"	5071	19.0	18	14	78	79	53	35
"	5075	25.3	87	73	100	100	100	25
"	5084	20.2	5.8	4.0	70	58	57	30
"	5093	13.0	13	11	31	20	22	7.3
"	5098	15.5	45	38	71	71	25	13
				AVERAGES	69	60	45	20

* Mounted in wax

TABLE IV

Well Name and Number	Sample Depth (Feet)	Porosity (% B.V.)	Dry-Air Permeability (MD)	Equivalent Liquid Permeability (MD)	Permeability to Kerosene (%Equivalent Liq Permeability)	Permeability to 1.65% Brine (%Equivalent Liq Permeability)	Permeability to 0.825% Brine (% Equivalent Liq Permeability)	Permeability to Fresh Water % Equivalent Liq Permeability
Gippsland Shelf No. 4	5120	26.0	792	682	100	43	34	26
"	5121	25.0	667	490	100	83	73	62
"	5124	18.0	35	31	84	61	61	12
"	5128	24.0	355	318	100	100	61	11
"	5130	23.1	360	283	100	69	49	16
"	5132	24.5	533	440	100	72	55	8.0
"	5134	26.0	1420	1050	100	100	95	65
"	5137	19.3	566	420	100	95	89	86
"	5141	19.8	4700	3370	100	67	48	38
"	5144	10.5	935	815	100	100	65	53
"	5146	8.0	172	155	97	66	17	8.4
"	5148	15.0	2020	1470	100	29	60	84
"	5161	25.5	4710	3100	99	91	48	100
"	5165	20.8	787	660	100	100	77	100
"	5169	18.6	3460	2750	100	96	49	38
"	5171	19.7	1100	900	100	77	83	40
"	5175	15.7	639	405	100	100	100	86
"	5178	12.4	1040	600	100	51	45	41
				AVERAGES	99%	78%	62%	49%

TABLE IV B
2.

Gippsland Shelf No. 4	7474	15.0	9.0	6.3	49	43	22	6.3
"	7475	16.9	22	19	74	58	20	6.9
"	7477	17.3	30	25	80	56	25	2.6
				AVERAGES	64%	52%	33%	5.3%

TABLE V

WELL NAME & NUMBER	CORE NUMBER	SAMPLE DEPTH	POROSITY (% B.V.)	DRY - AIR PERMEABILITY (MD)	SATURATING MEDIUM	VOLUME OF WATER IMBIBED % PORE VOLUME			
						1 DAY	2 DAYS	3 DAYS	7 DAYS
GIPPSLAND SHELF NO. 4	1	4575	20.6	750	KEROSENE	0	4.5	6.3	7.7
"	2	4587	20.6	300	"	0	2.1	3.4	4.3
"	3	4636	17.9	1950	"	20.0	24	25	28
"	3	4645	6.6	67	"	49	52	52	52
"	7	5056	15.0	0.6	"	34	41	43	45
"	7	5066	16.3	2.9	"	39	41	47	47
"	8	5084	20.2	5.8	"	39	43	45	46
"	9	5097	13.0	13.0	"	45	51	51	51
"	9	5098	15.5	45	"	42	51	51	51
"	9	5120	26.0	792	"	31	33	33	34
"	9	5128	24.0	355	"	26	27	28	30
"	10	5131	26.6	710	"	30	33	33	33
"	10	5138	12.0	214	"	30	30	30	30
"	10	5141	19.8	3370	"	8	10	11	11
"	10	5150	4.5	1.7	"	11	23	25	25
"	11	5168	15.4	760	"	21	27	27	27
"	11	5178	12.4	1040	"	38	41	43	43

FIGURE 1

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-4575'

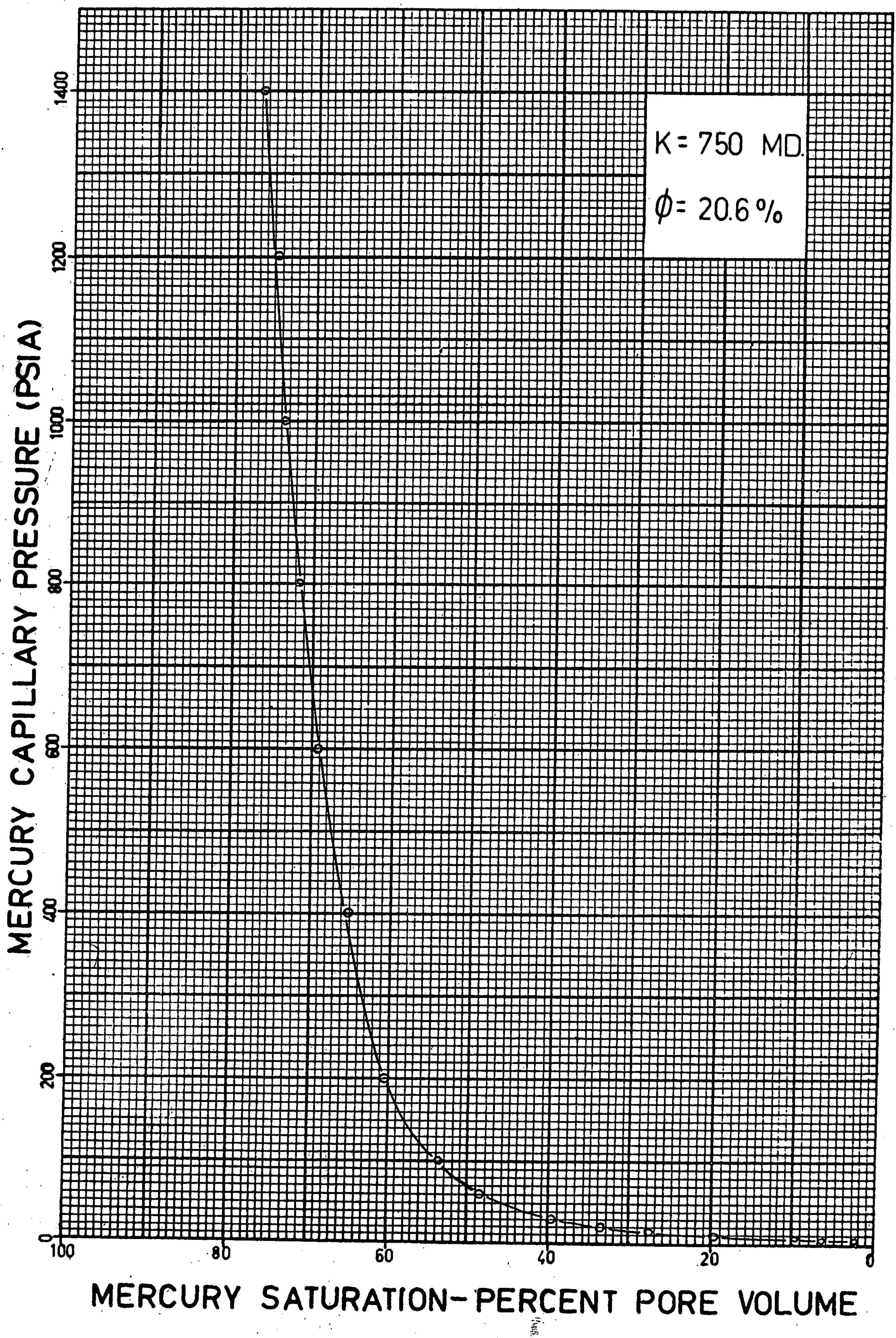


FIGURE 2

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-4585'

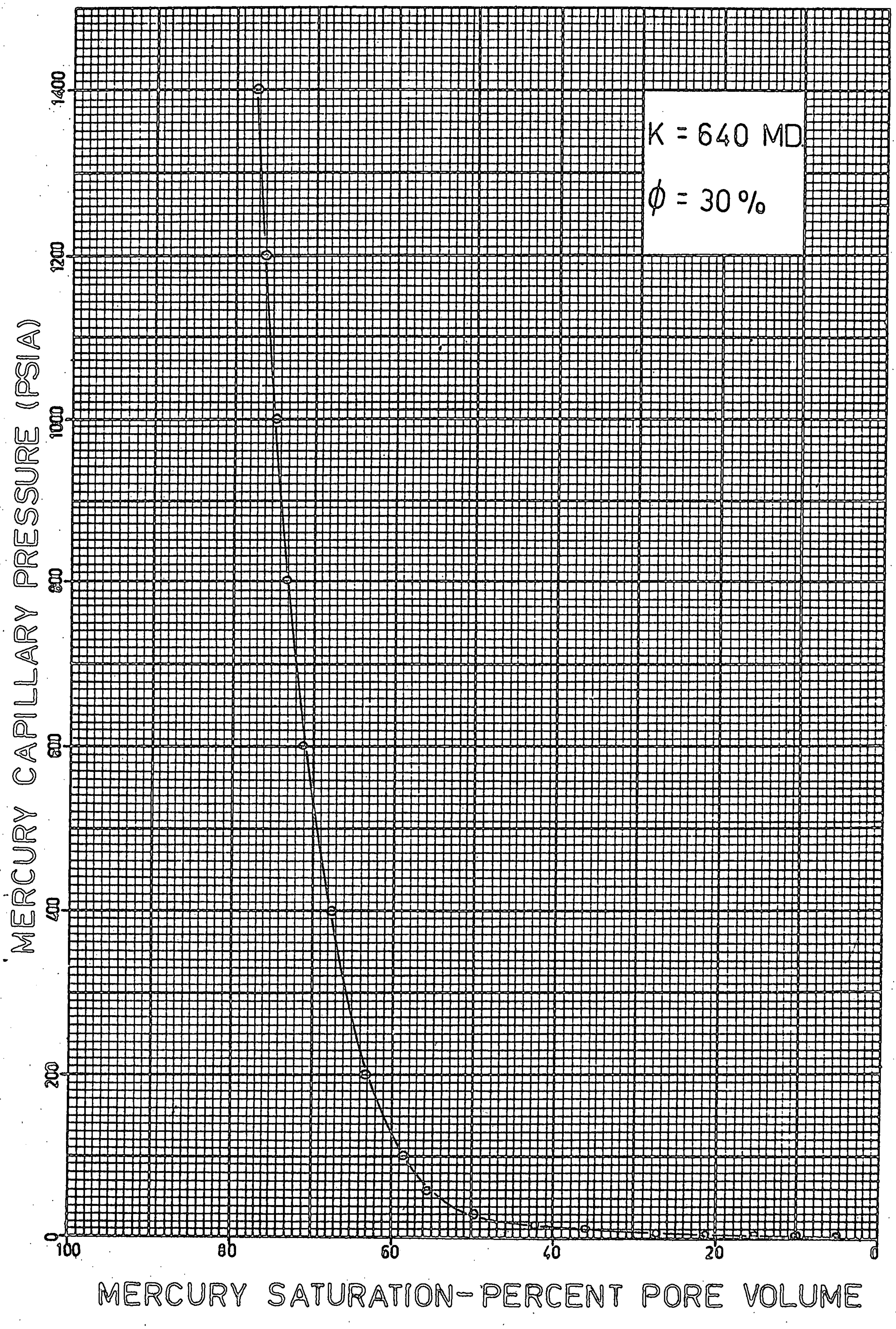


FIGURE 3

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-4587′

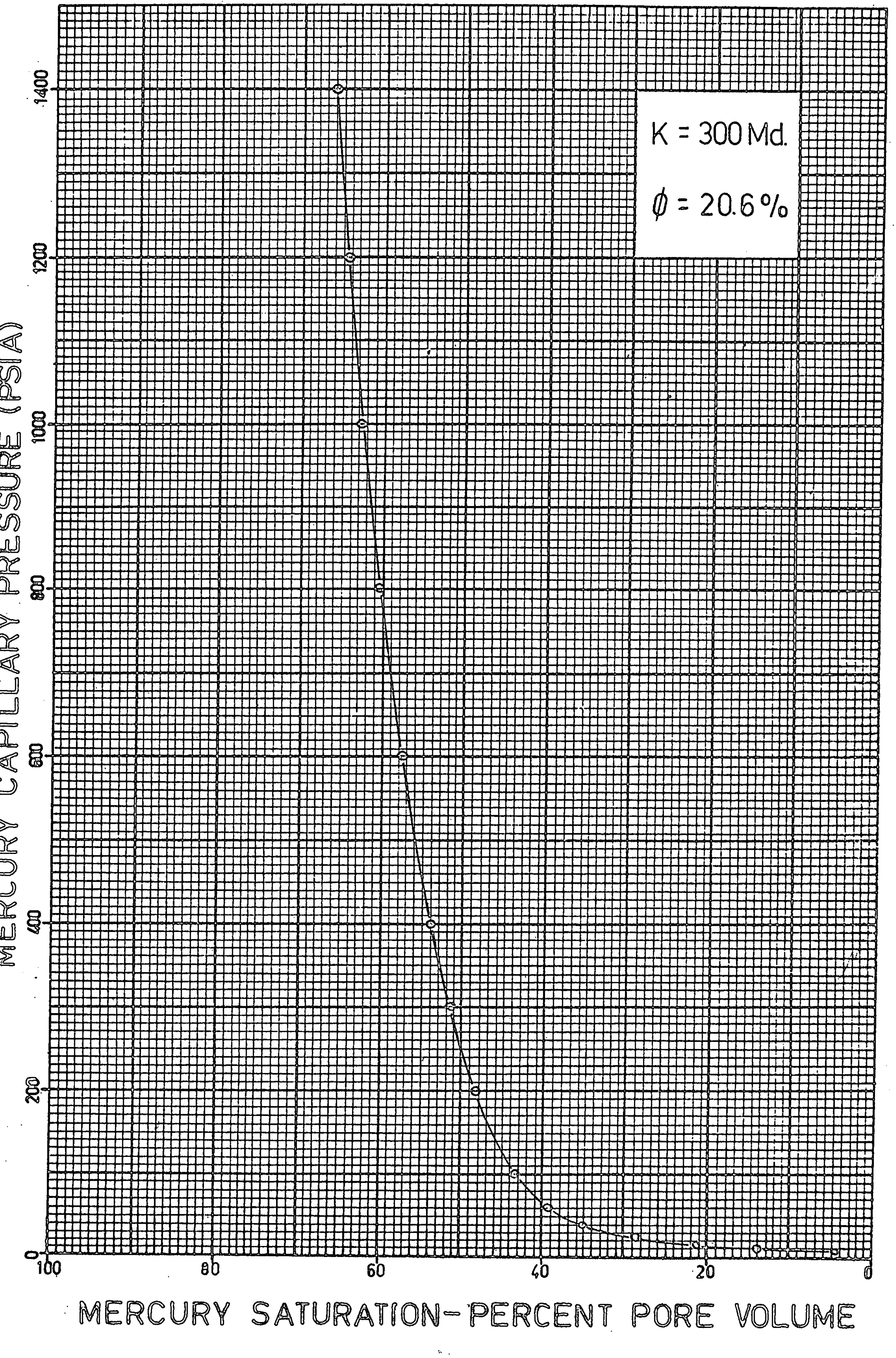


FIGURE 4

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-4635′

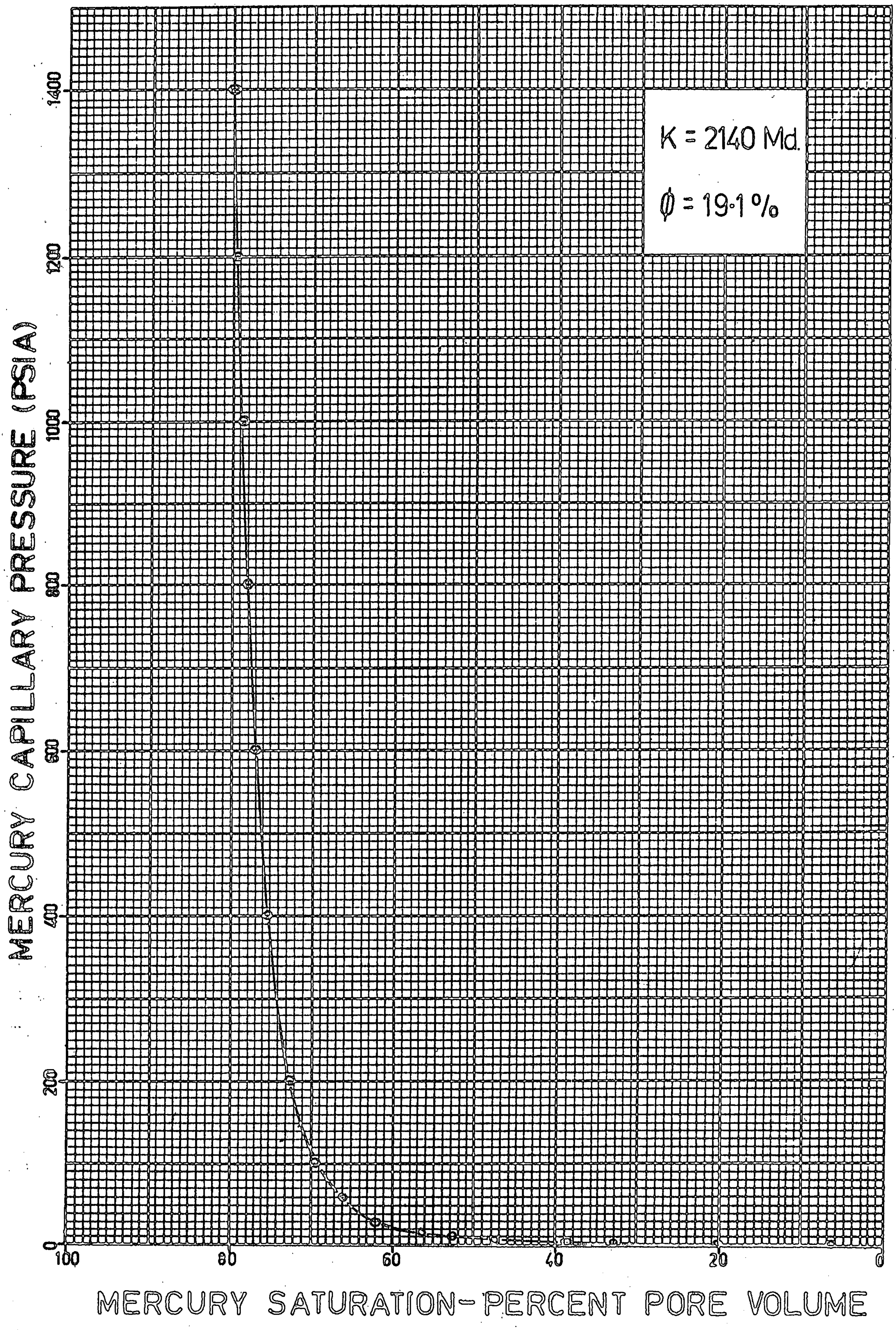


FIGURE 5

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-4639′

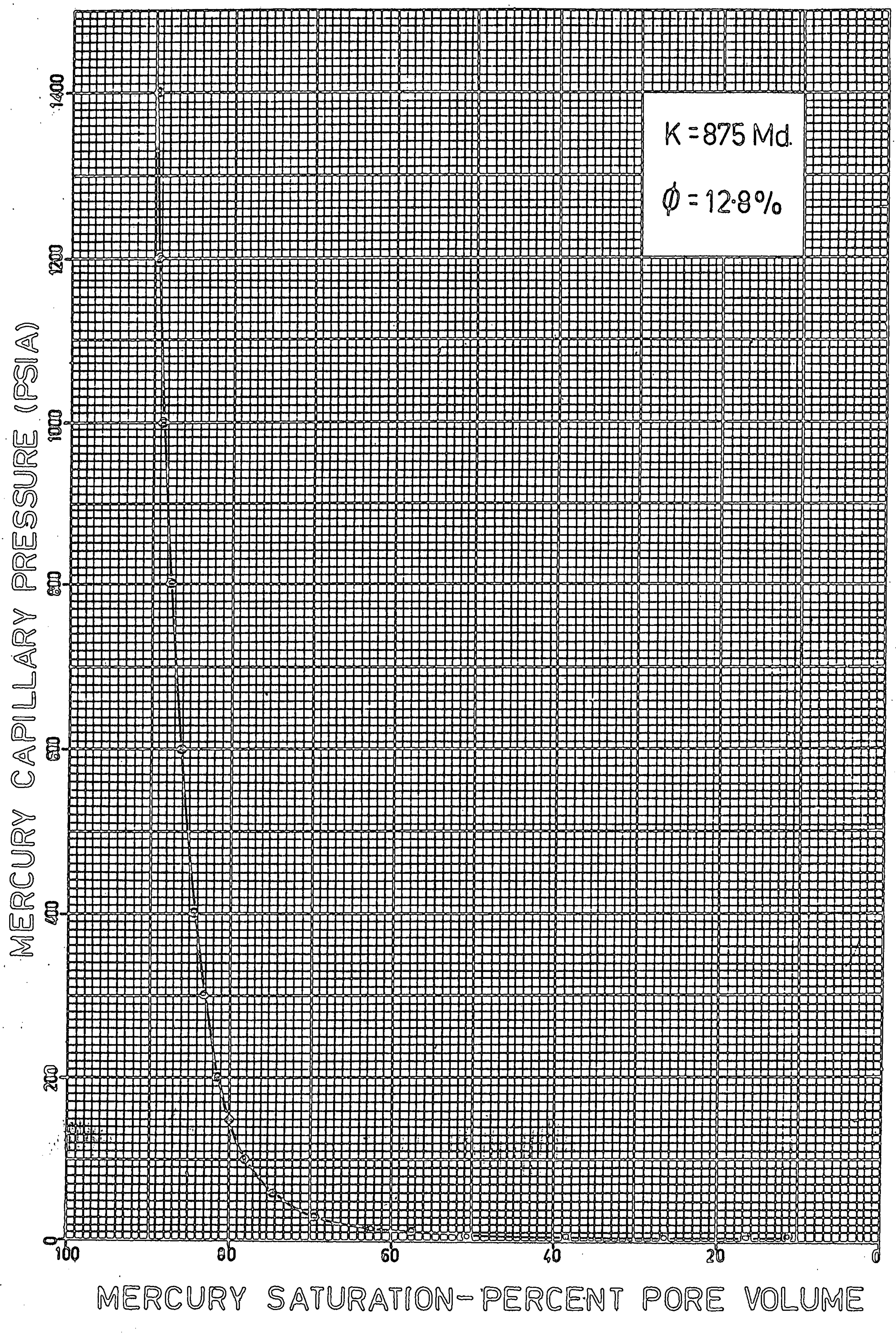


FIGURE 6

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-4641'

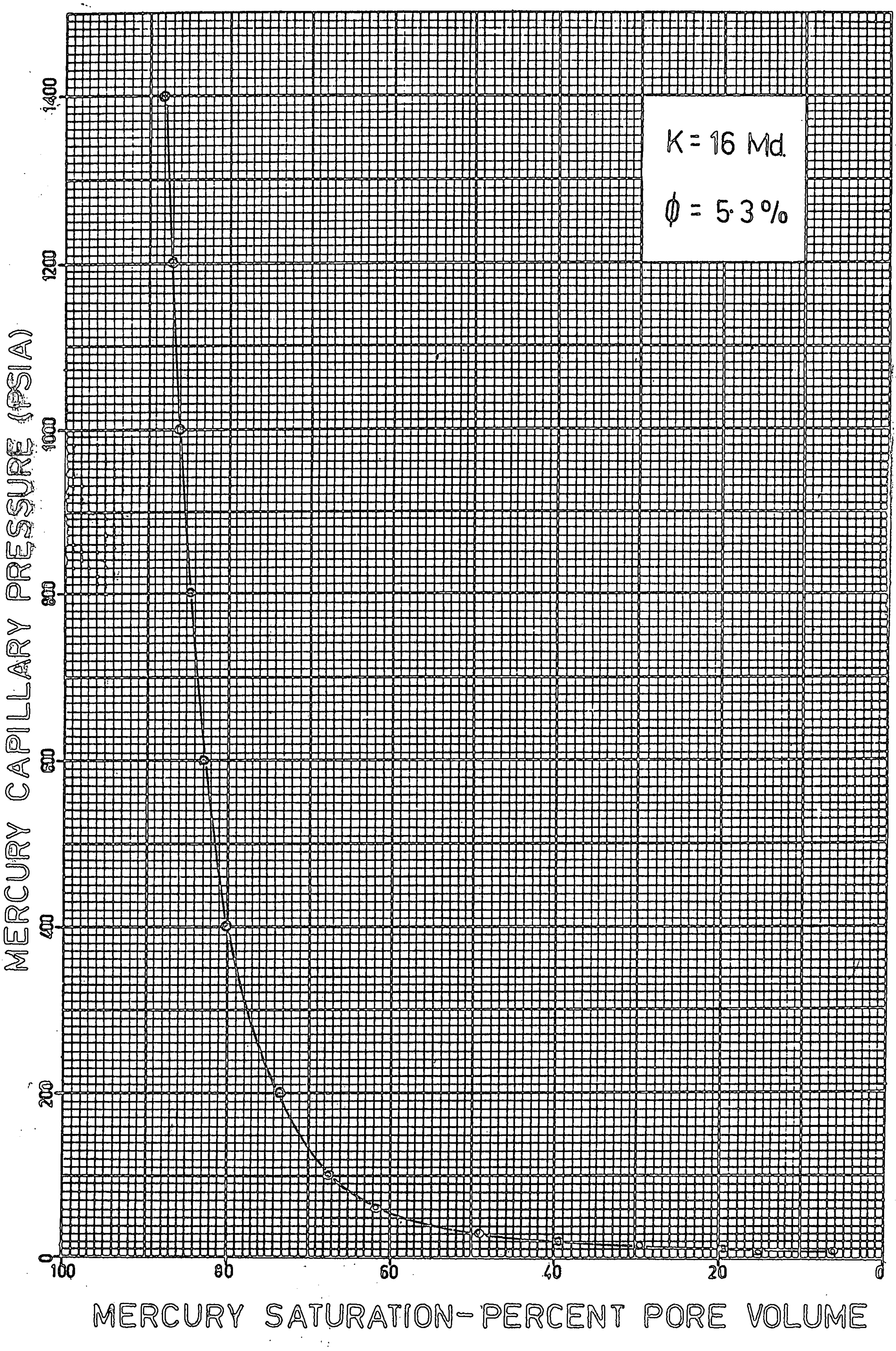


FIGURE 7

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-4643'

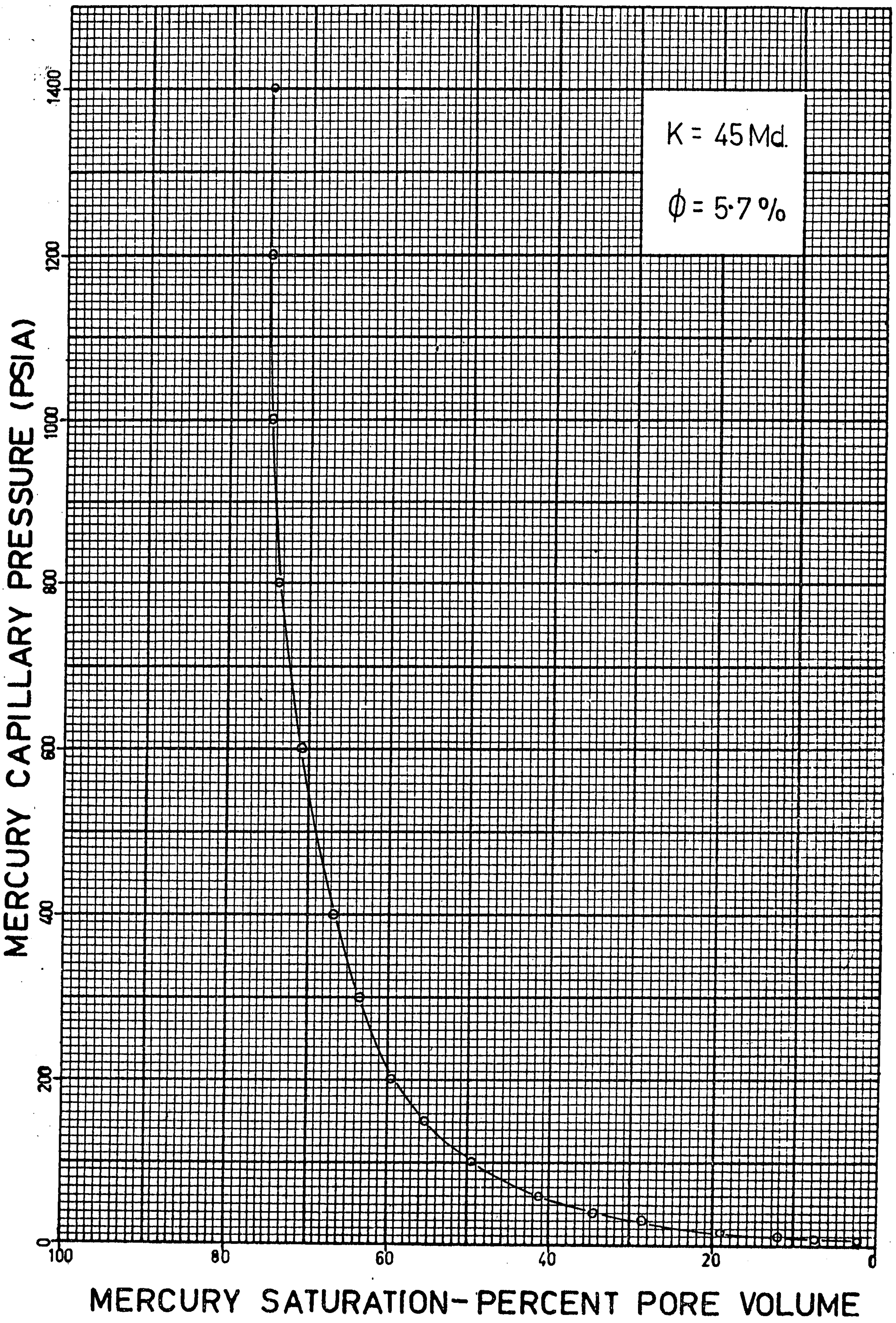


FIGURE 8

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5053′

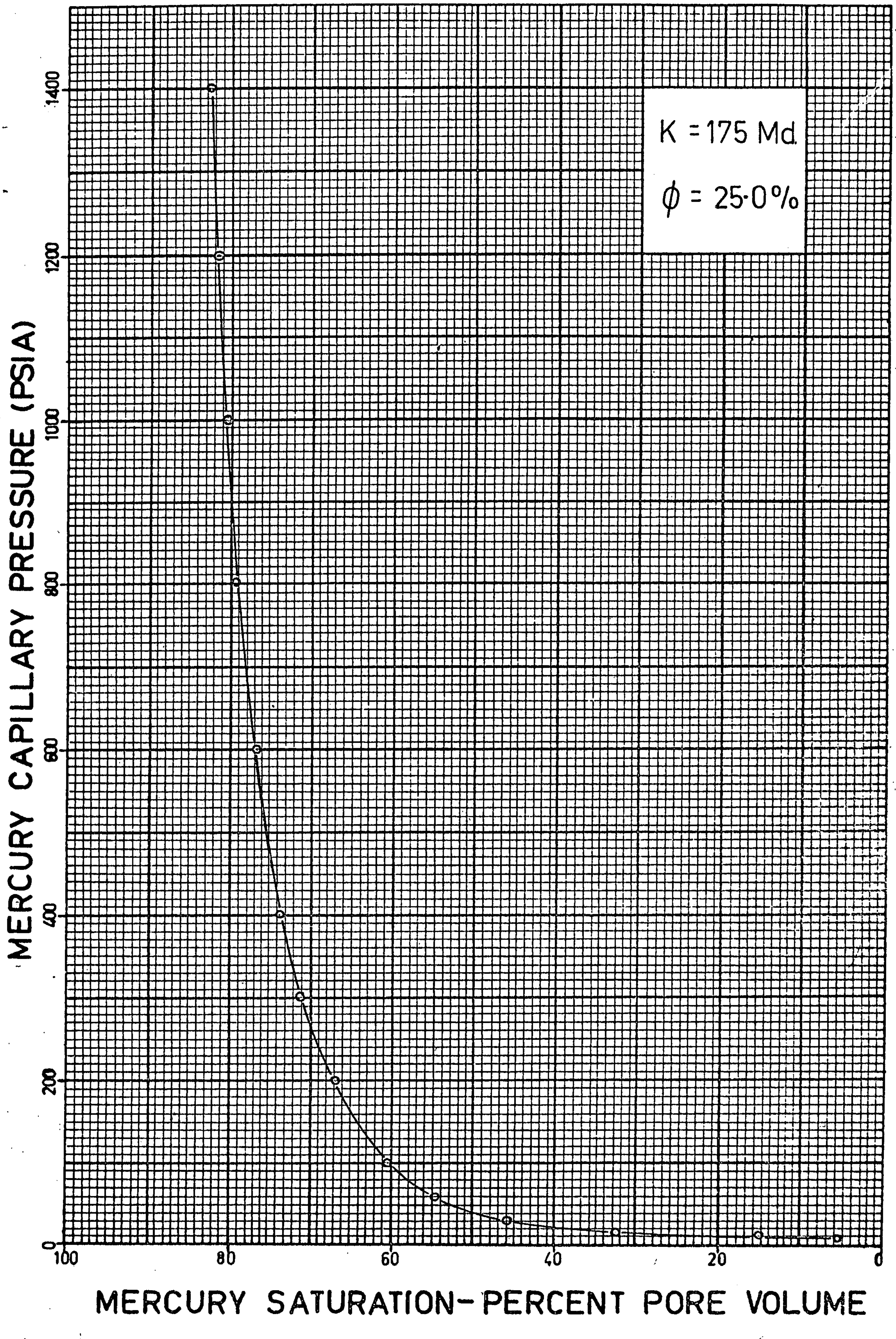


FIGURE 9

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5056′

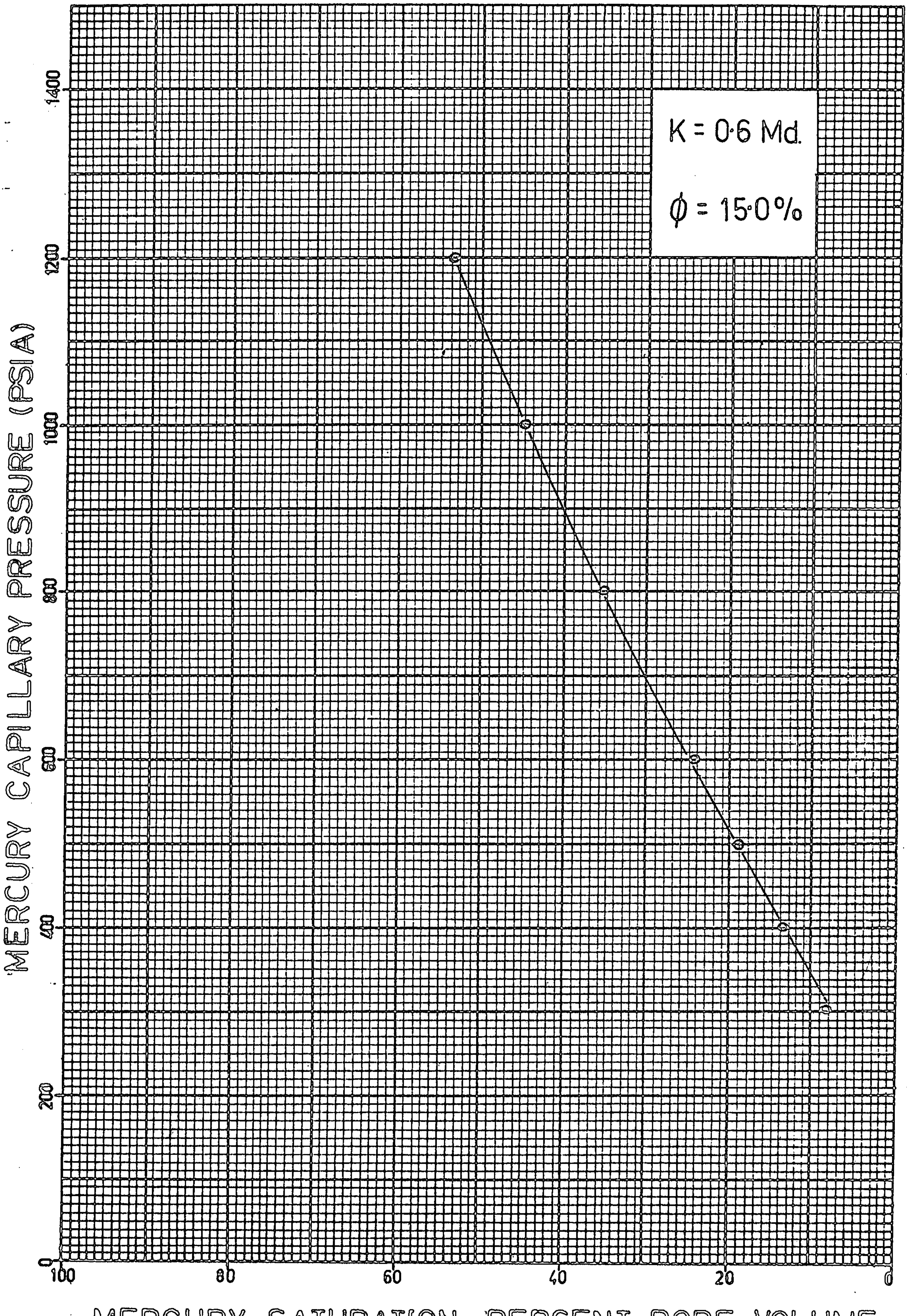
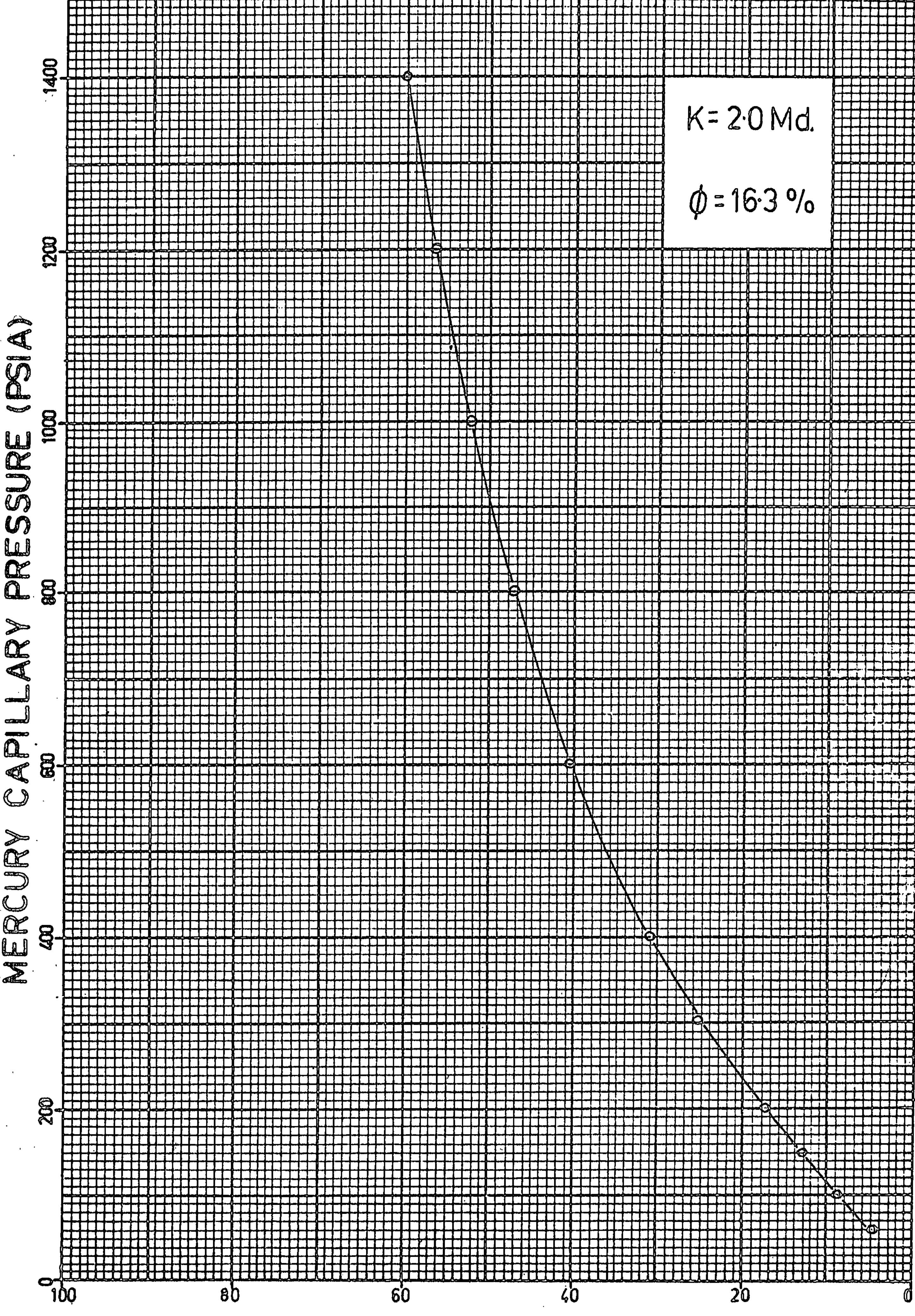


FIGURE 10

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5066′



MERCURY SATURATION-PERCENT PORE VOLUME

FIGURE 11

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-5071′

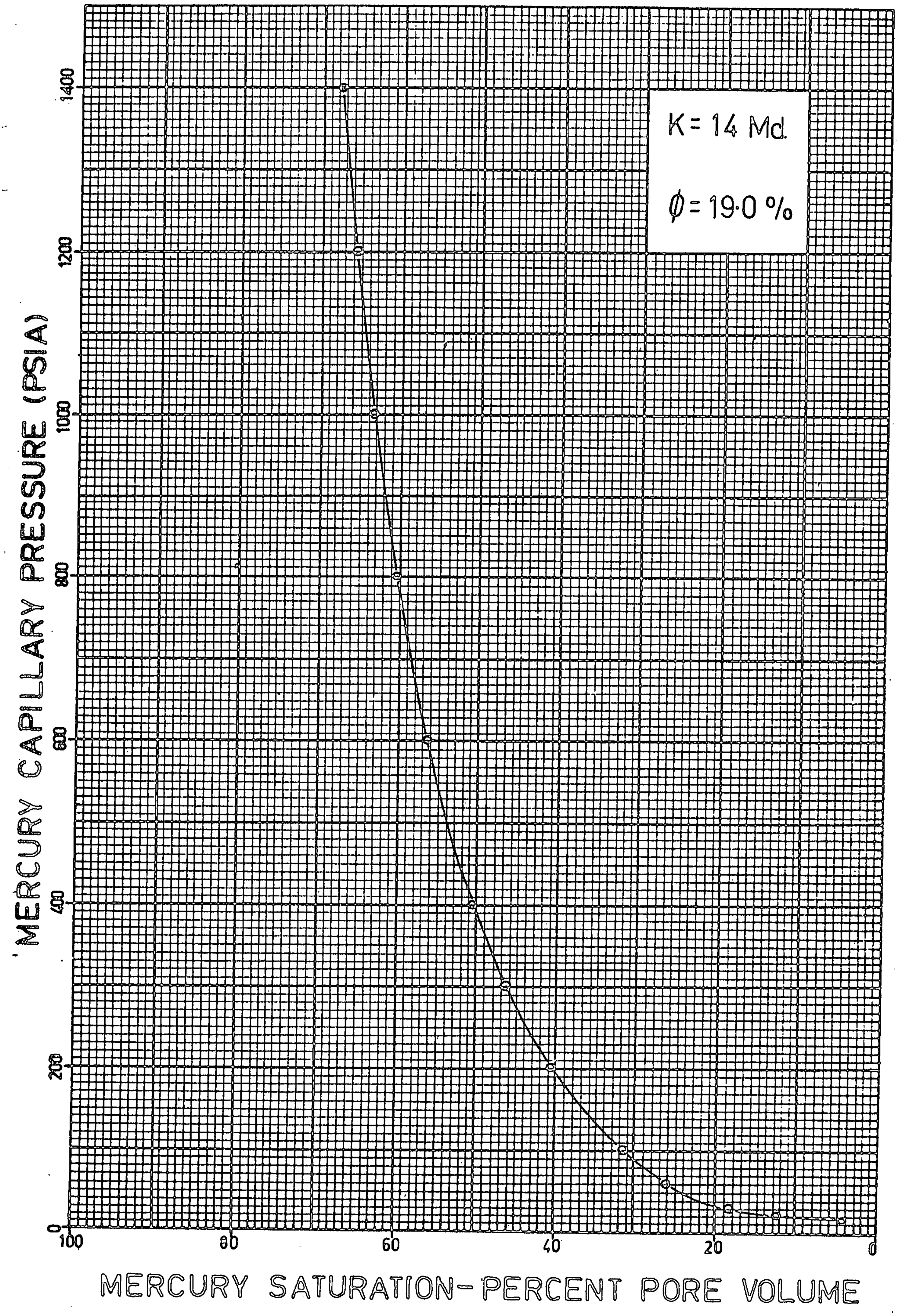


FIGURE 12

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5075′

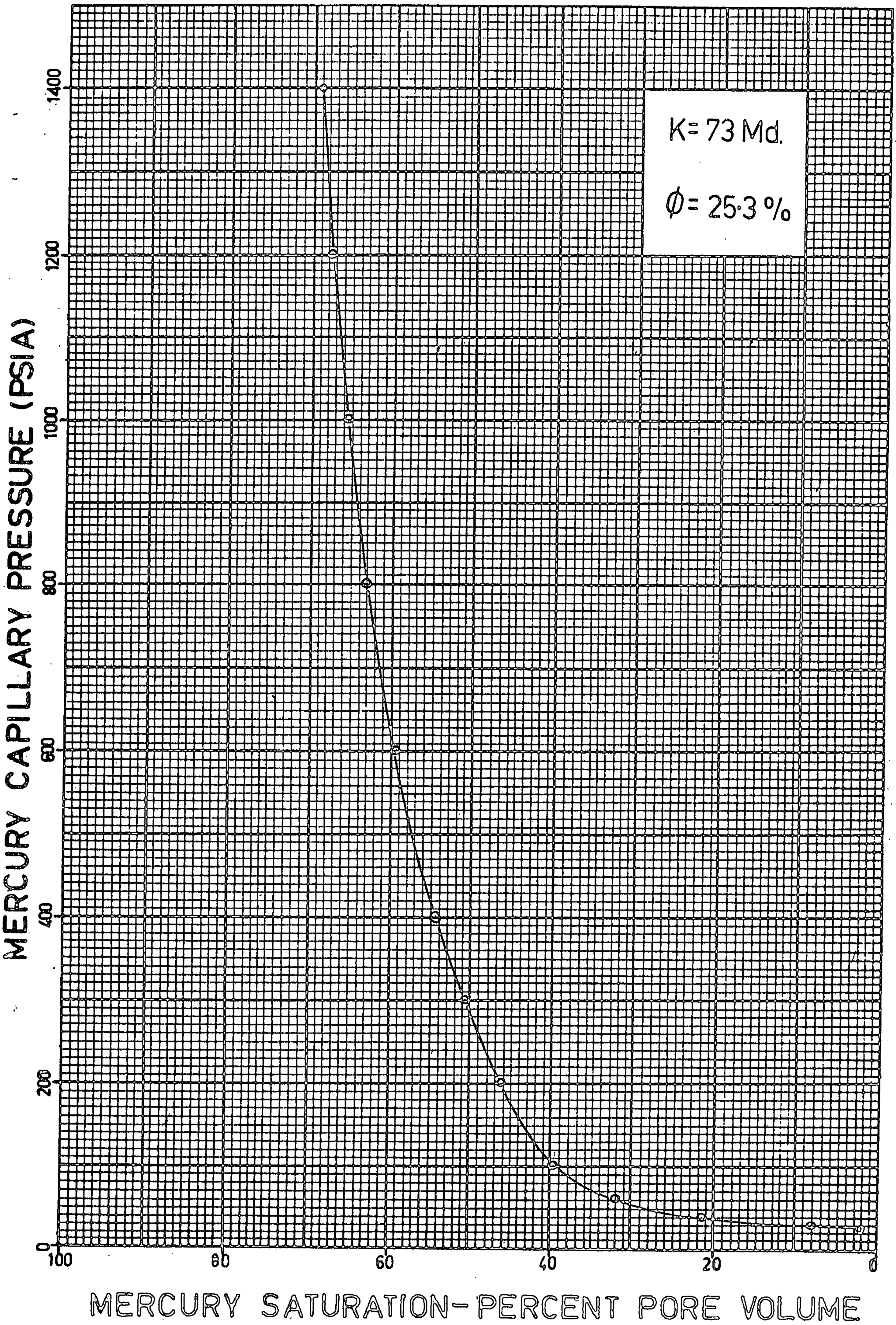
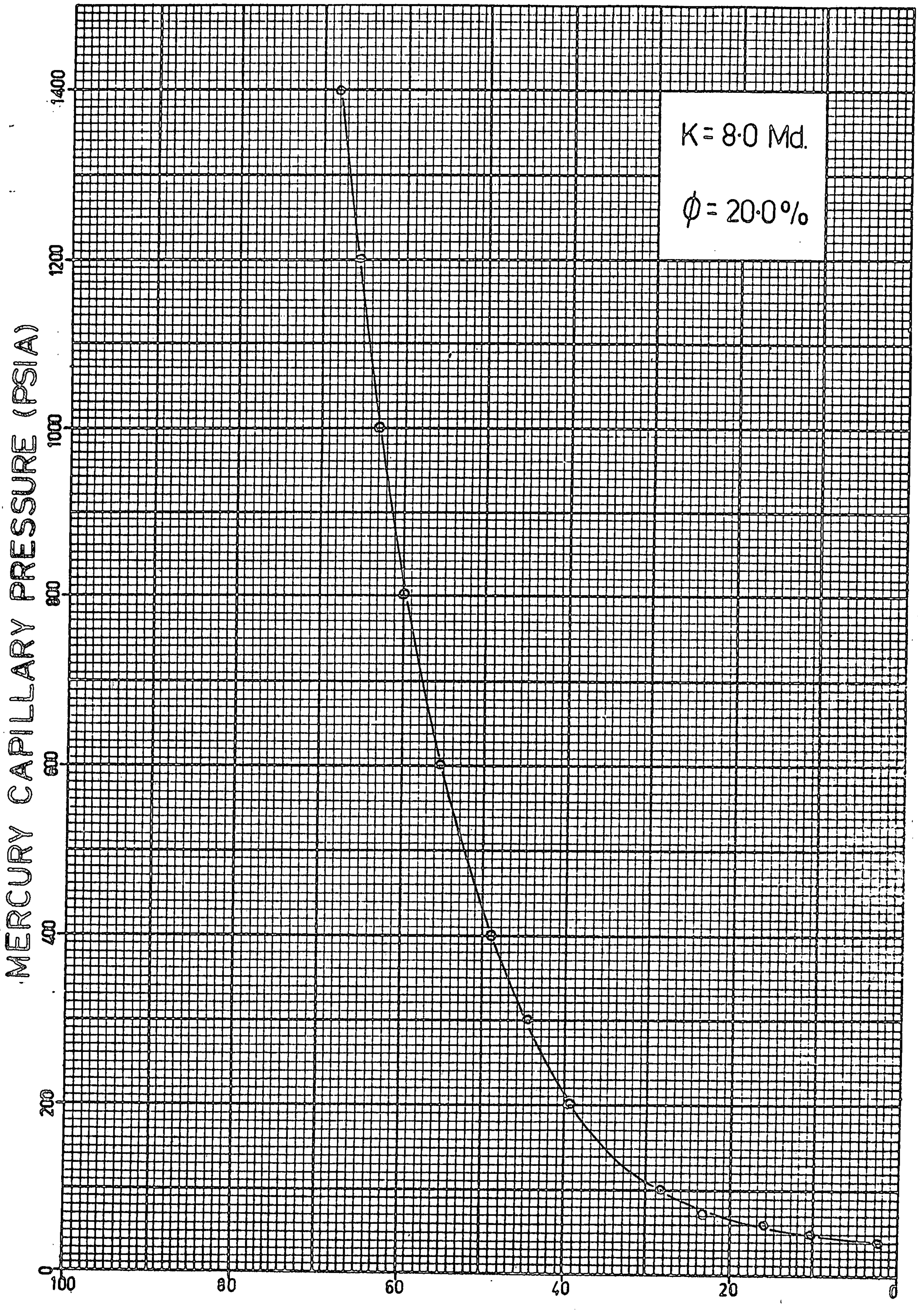


FIGURE 13

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No.4 SAMPLE DEPTH-5077'



MERCURY SATURATION-PERCENT PORE VOLUME

FIGURE 14

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5083'

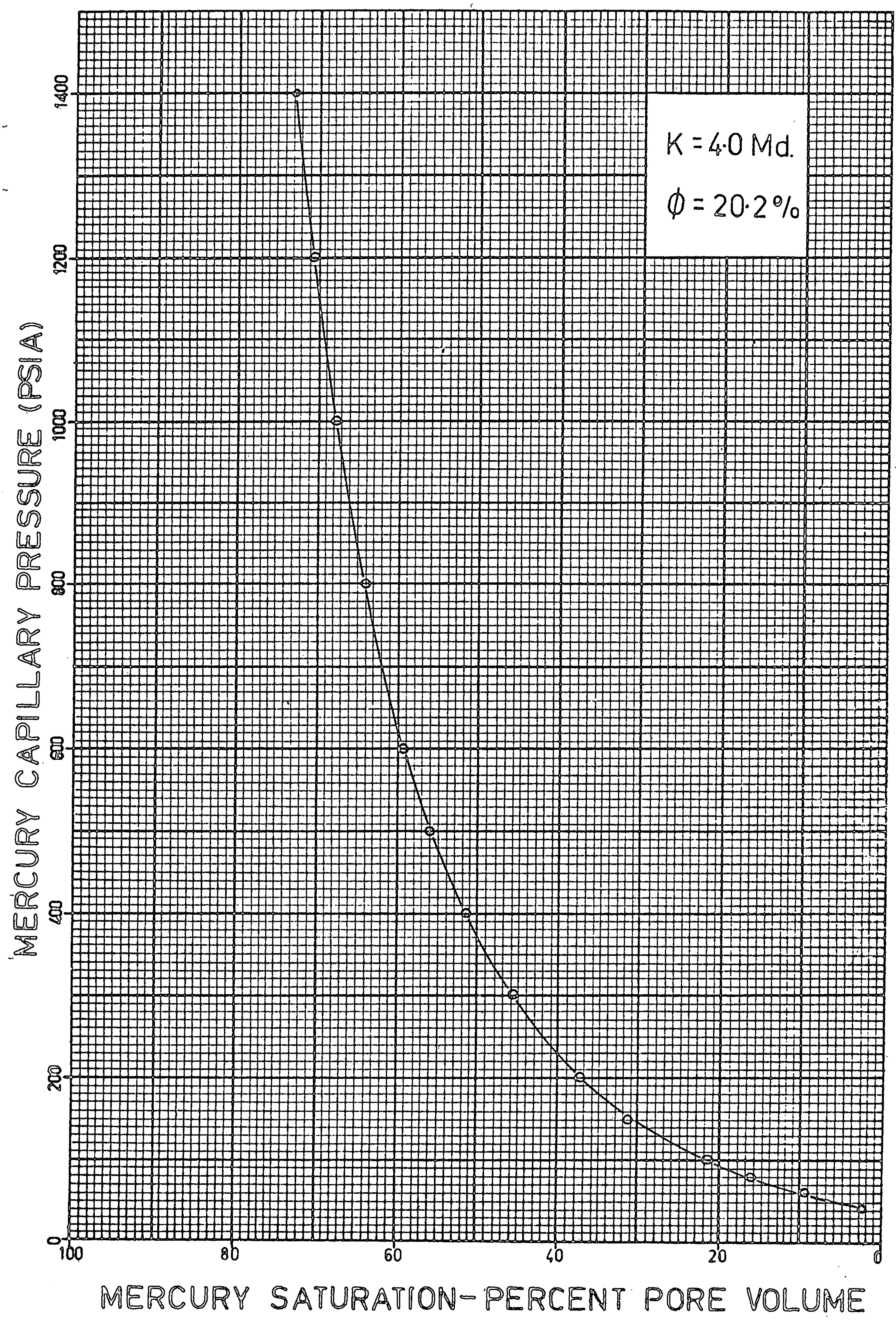


FIGURE 15

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5097′

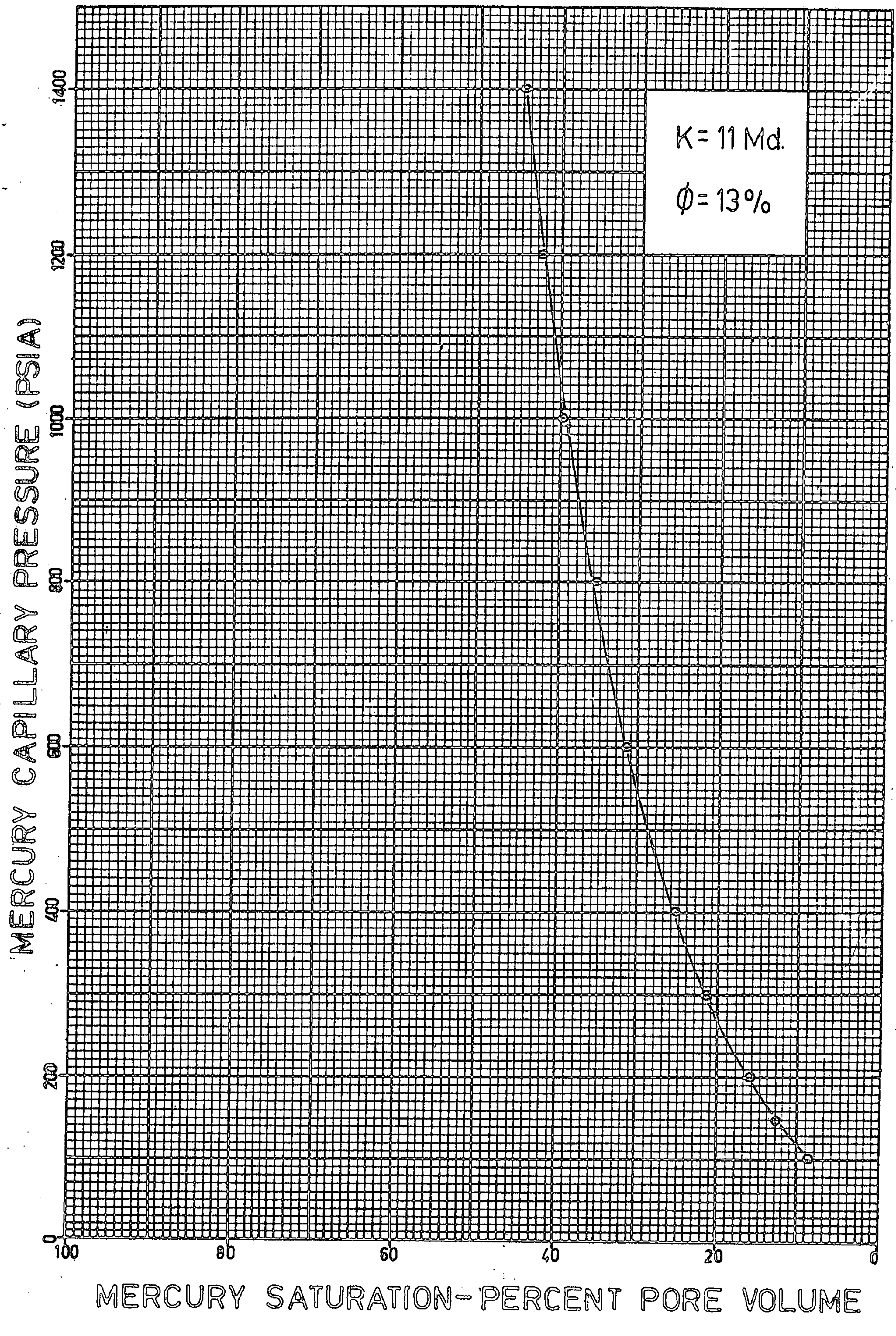


FIGURE 16

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No.4 SAMPLE DEPTH-5098'

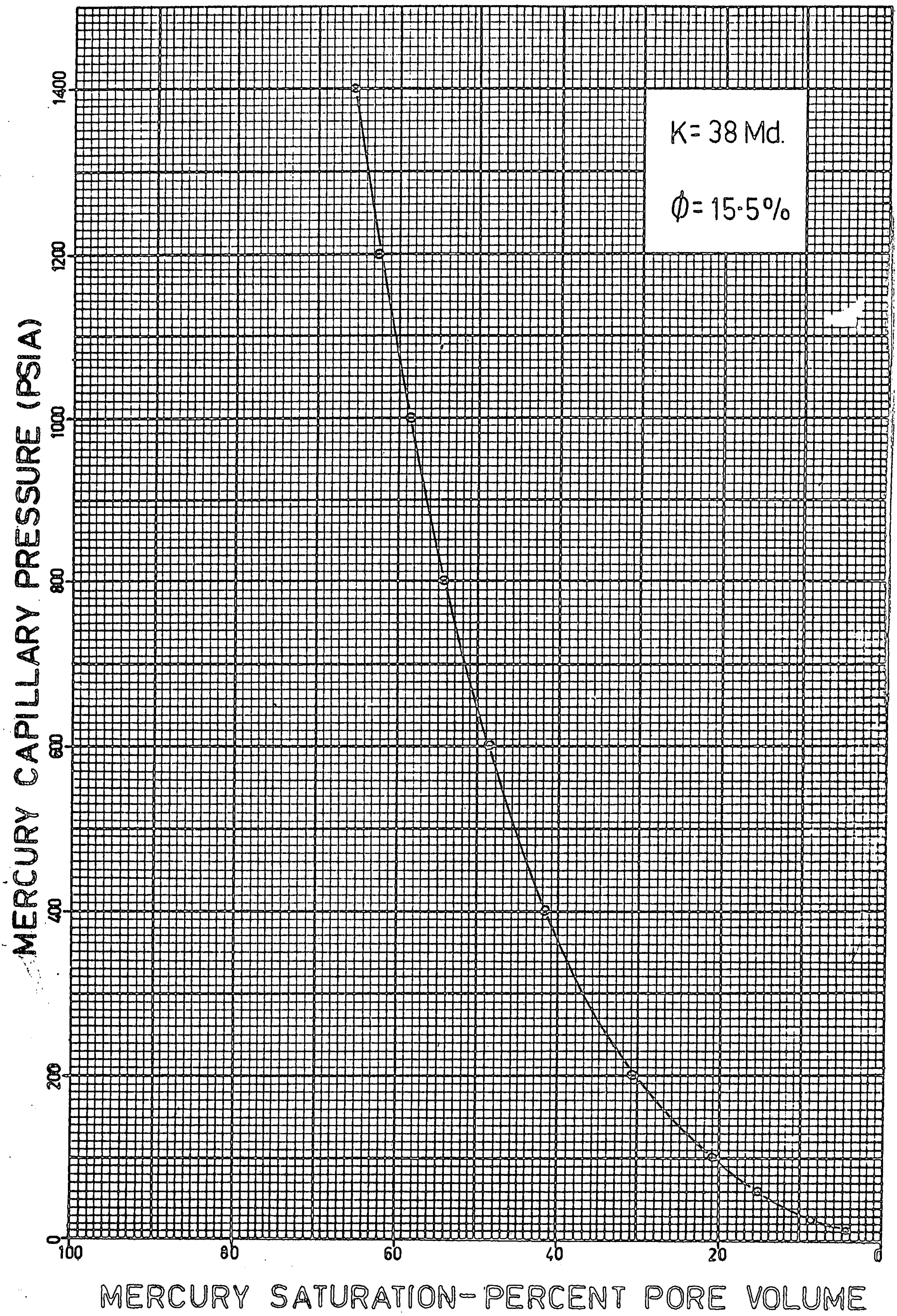


FIGURE 17

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5120'

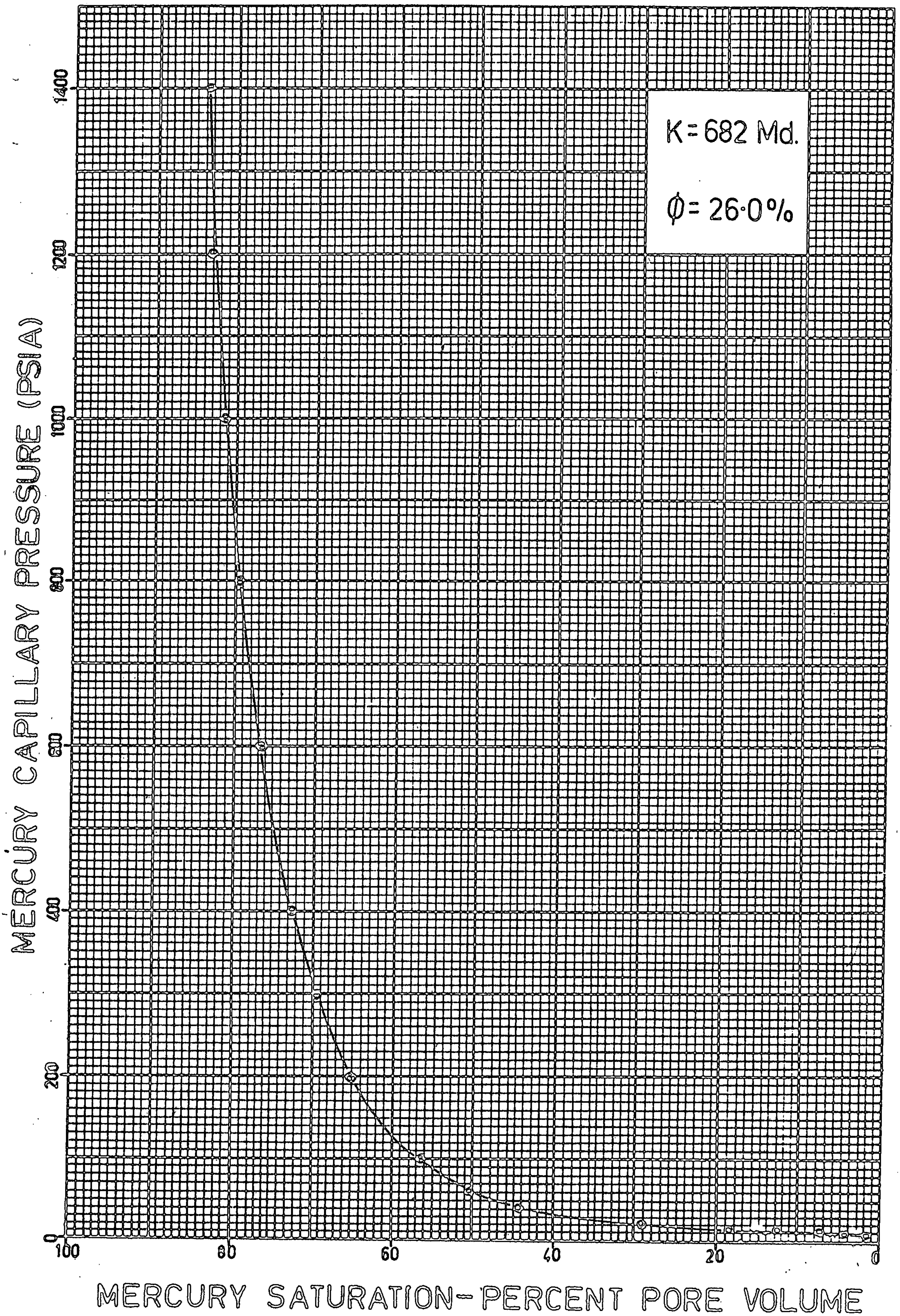
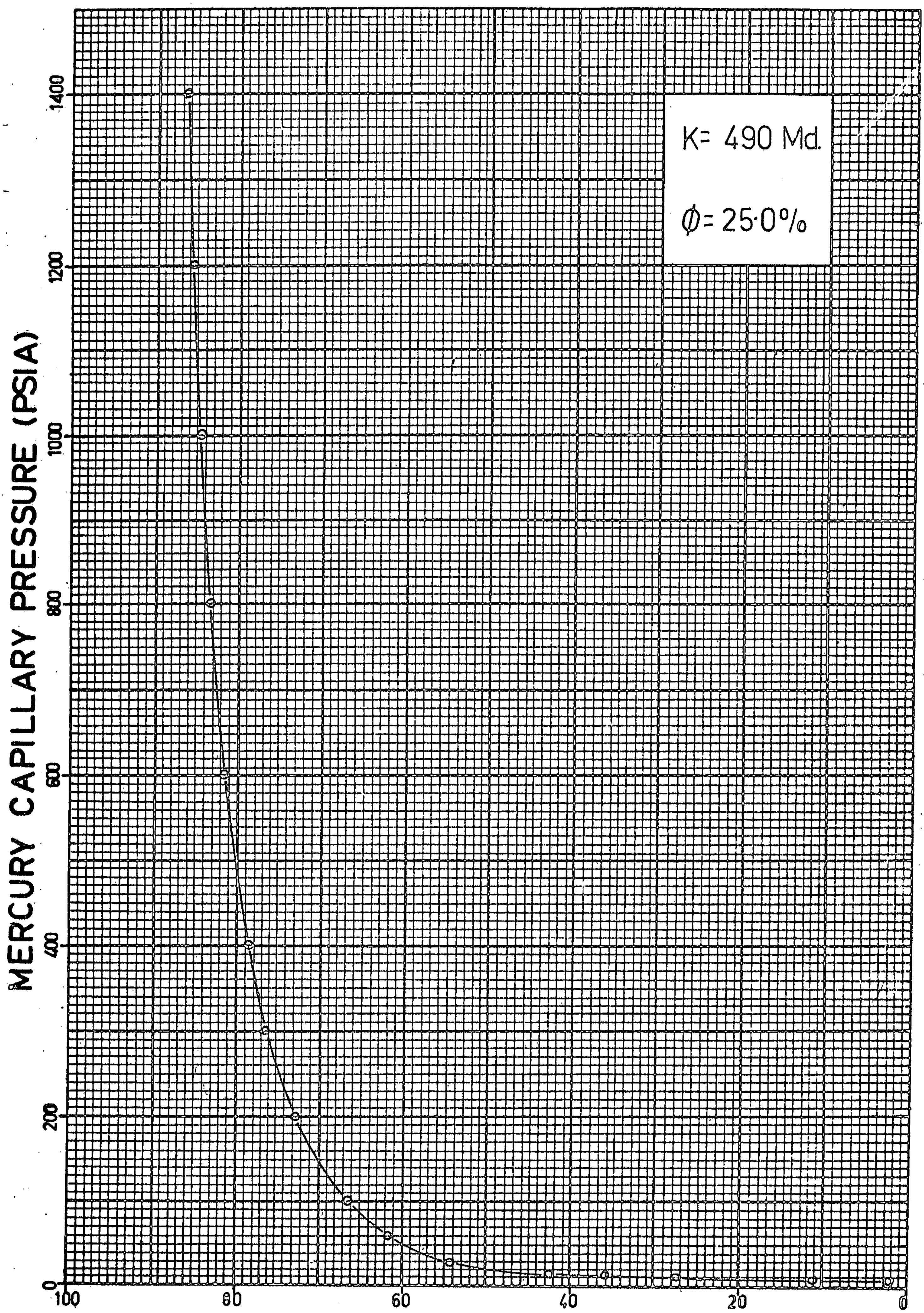


FIGURE 18

MERCURY CAPILLARY PRESSURE

WELL NAME GIPP. SHELF No. 4 SAMPLE DEPTH 5121′



MERCURY SATURATION-PERCENT PORE VOLUME

FIGURE 19

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-5125′

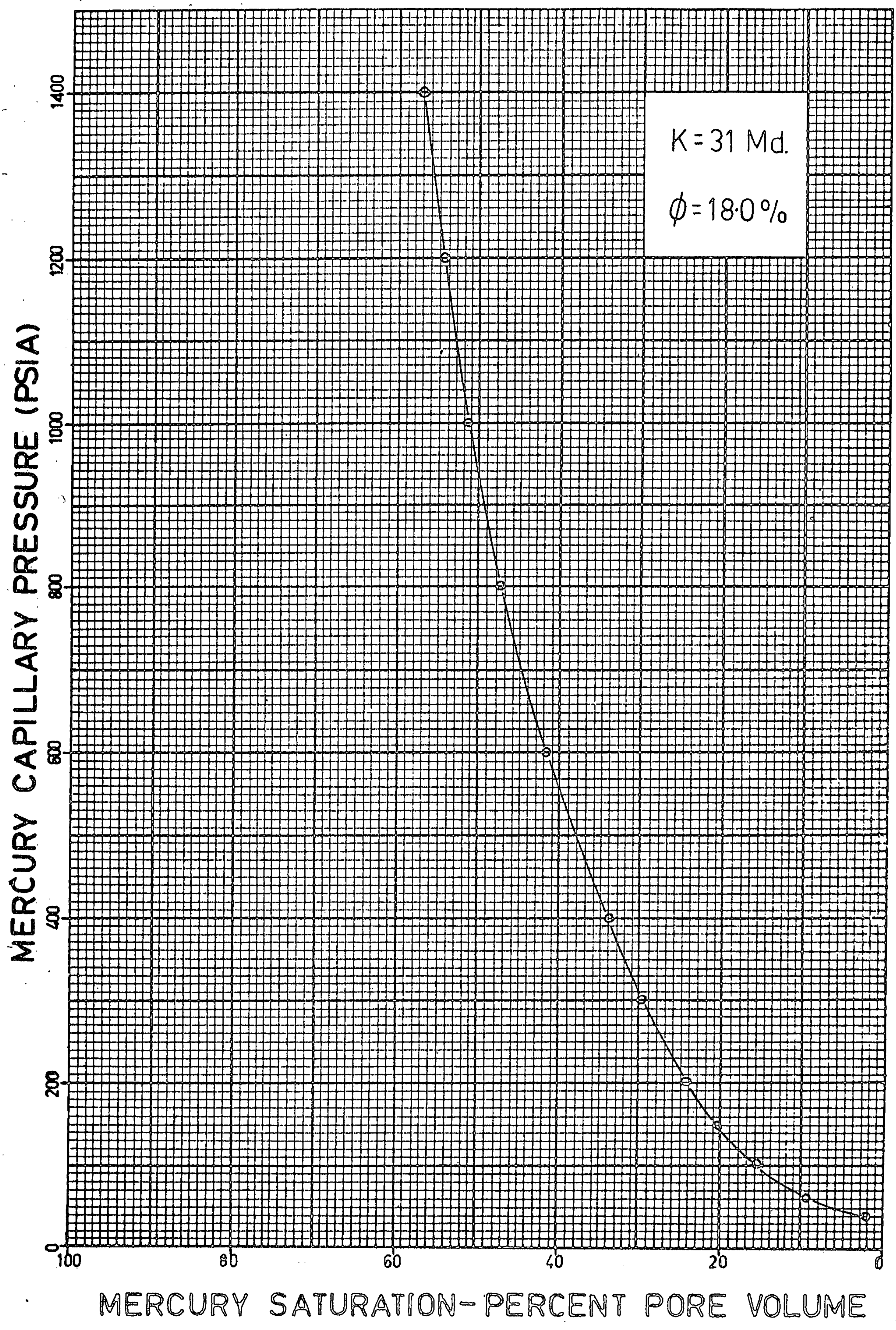


FIGURE 20

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-5128′

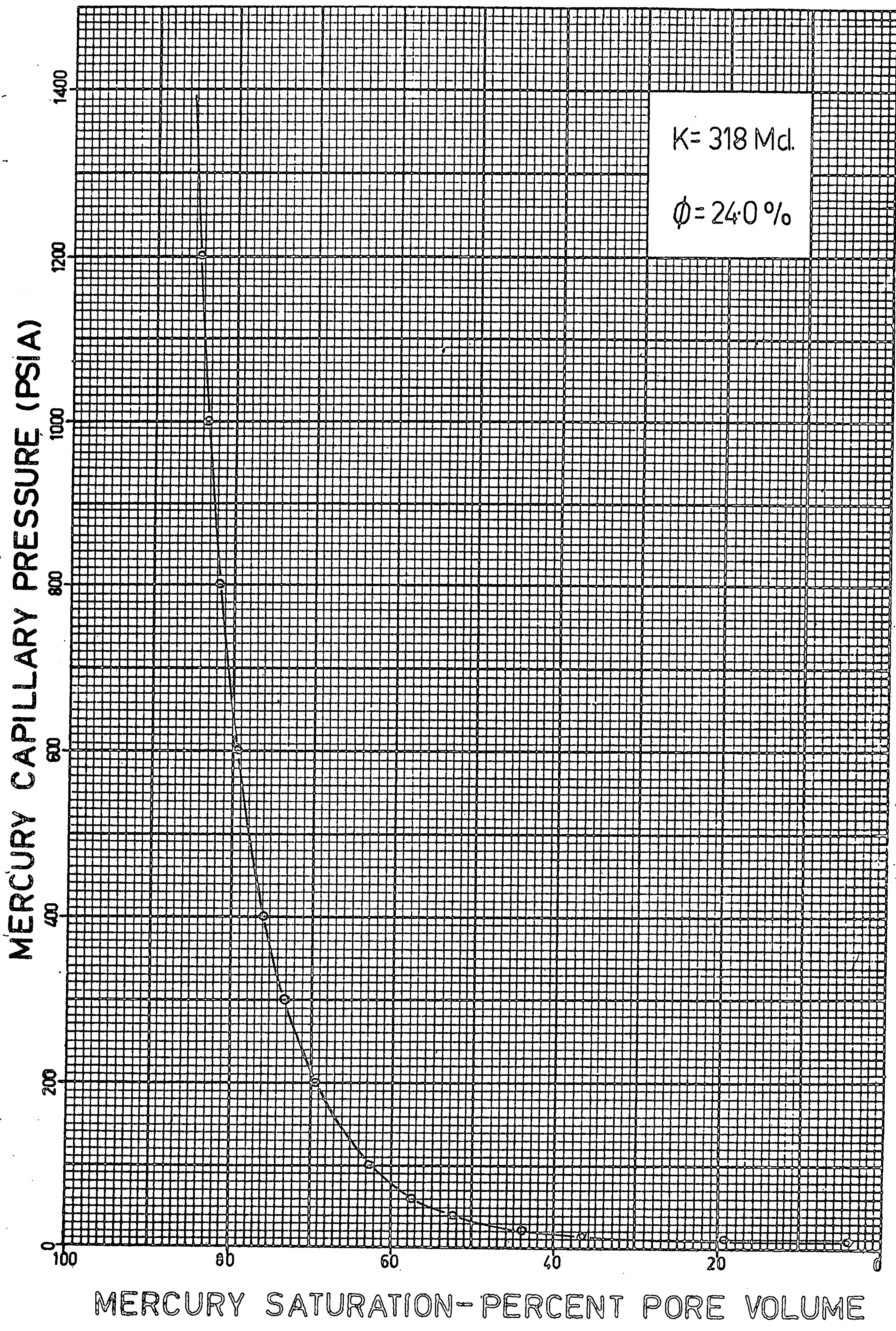


FIGURE 21

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5130′

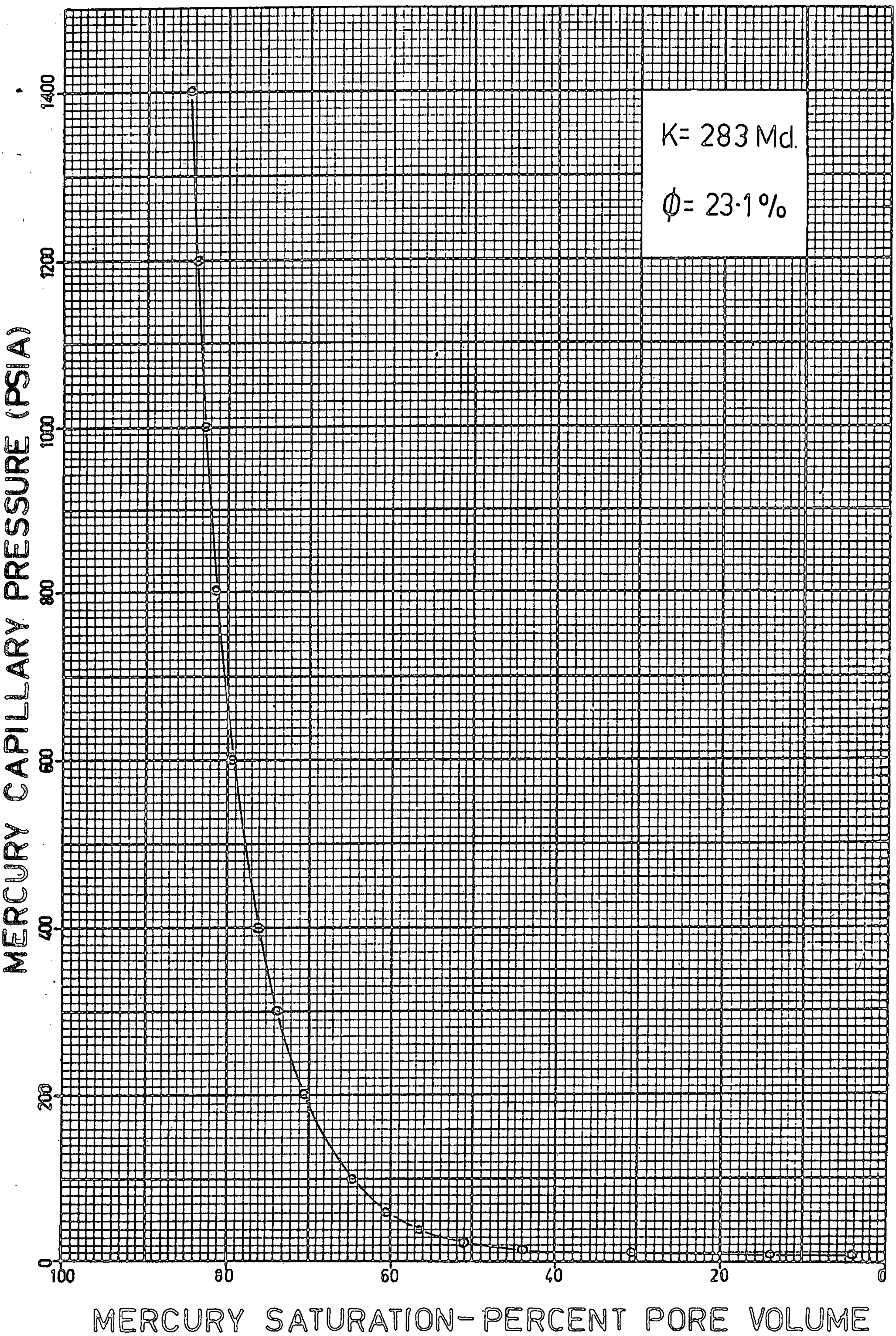


FIGURE 22

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5132'

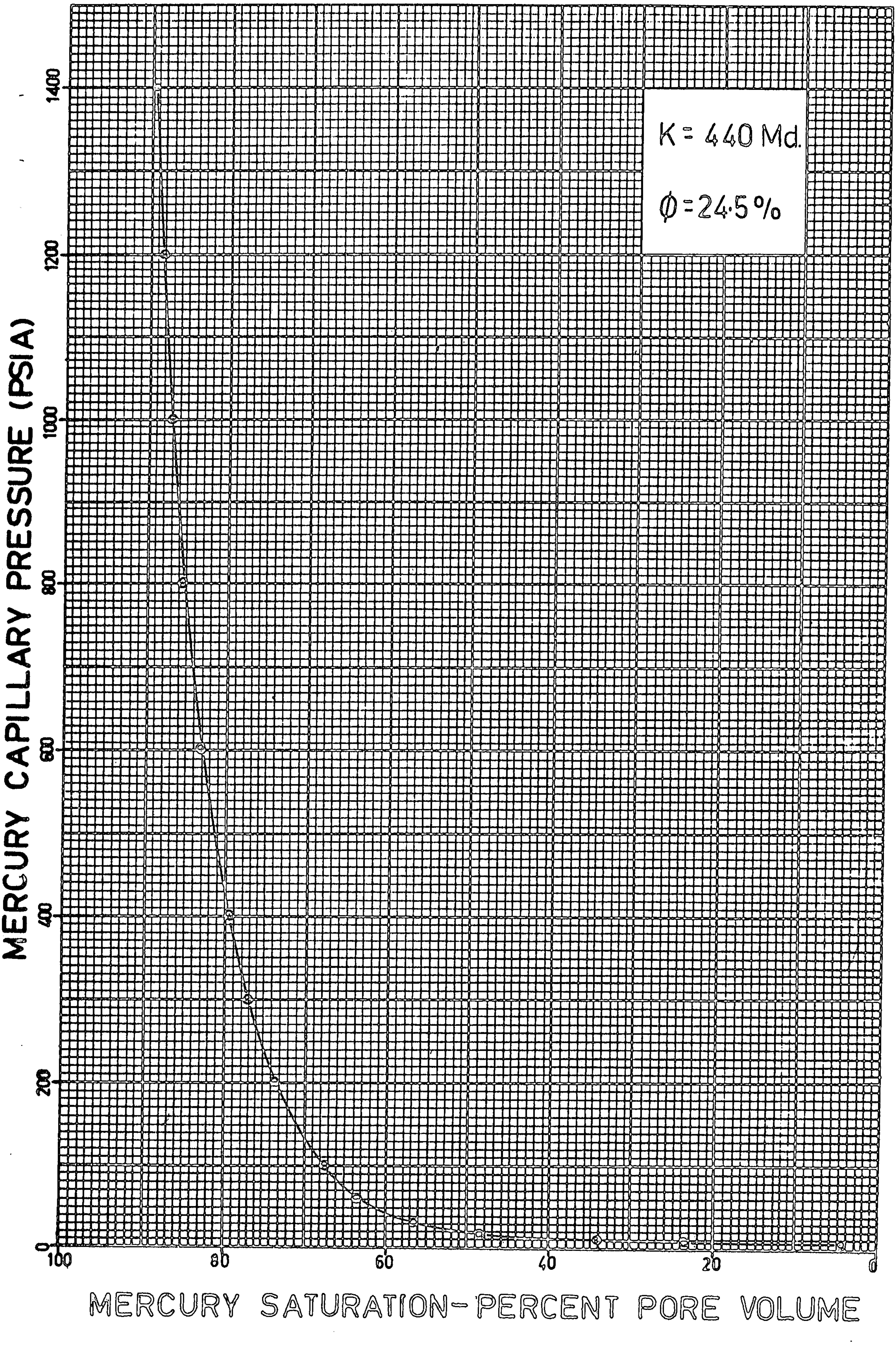


FIGURE 23

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5134'

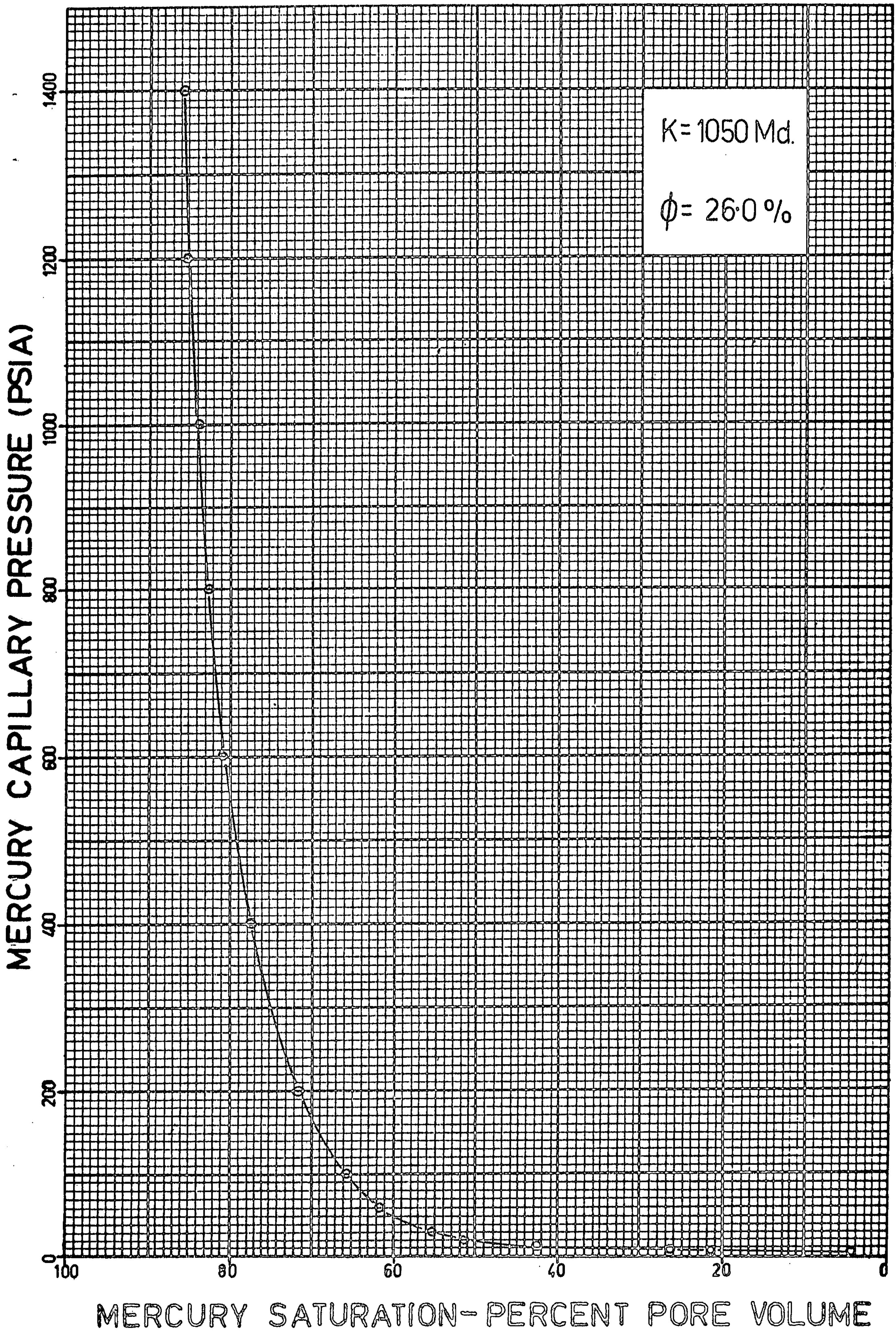


FIGURE 24

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5137'

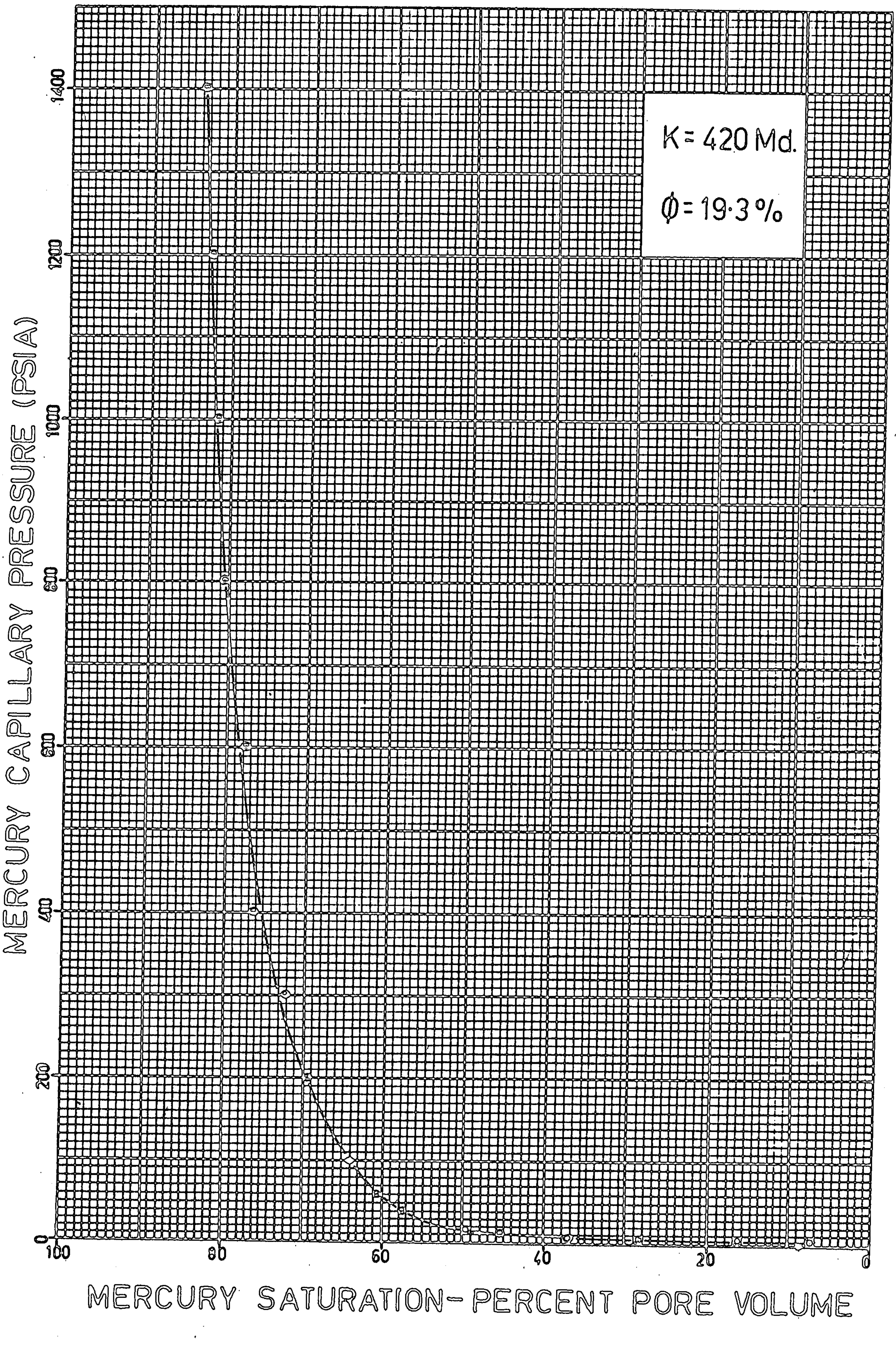


FIGURE 25

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5141′

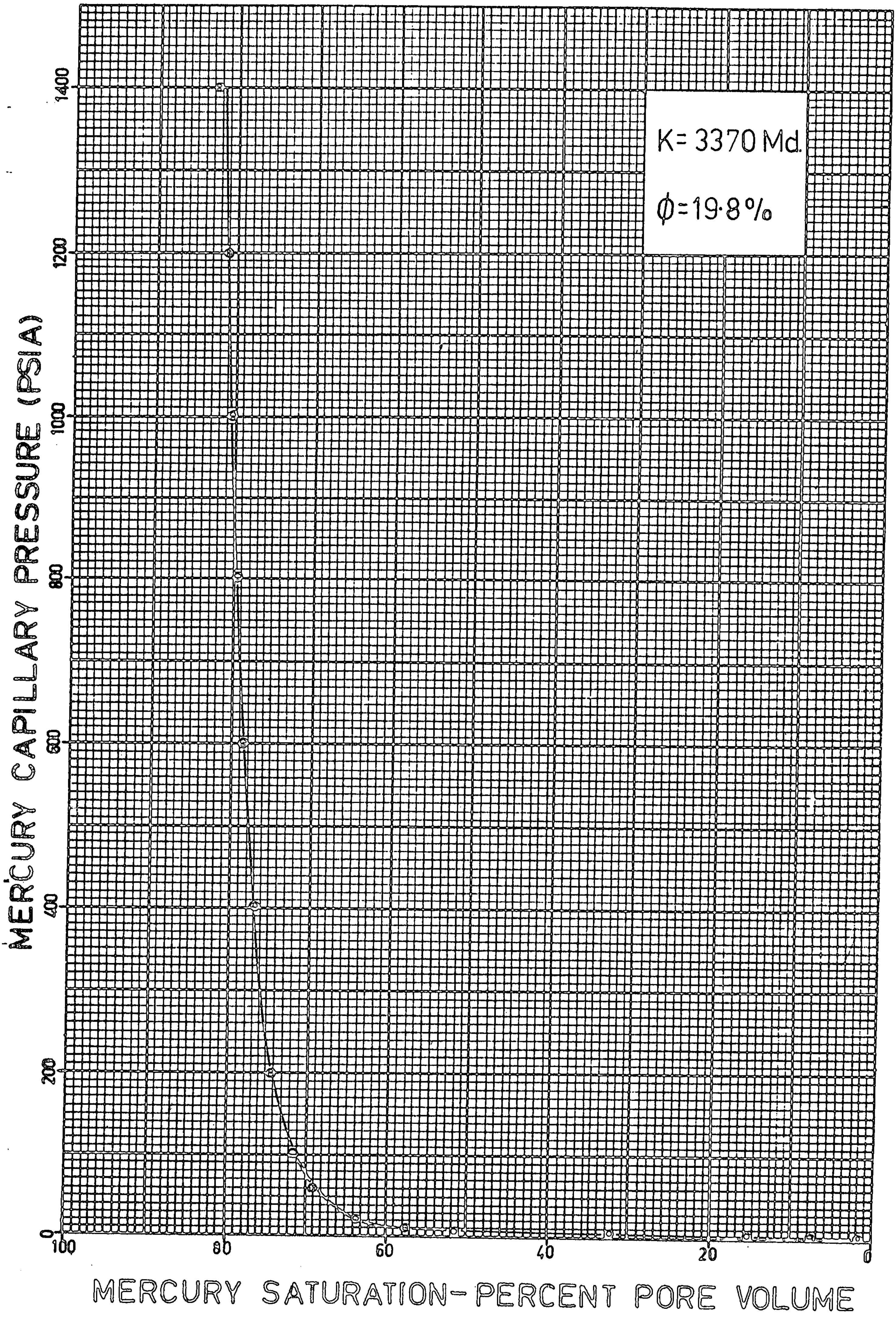


FIGURE 26

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5144′

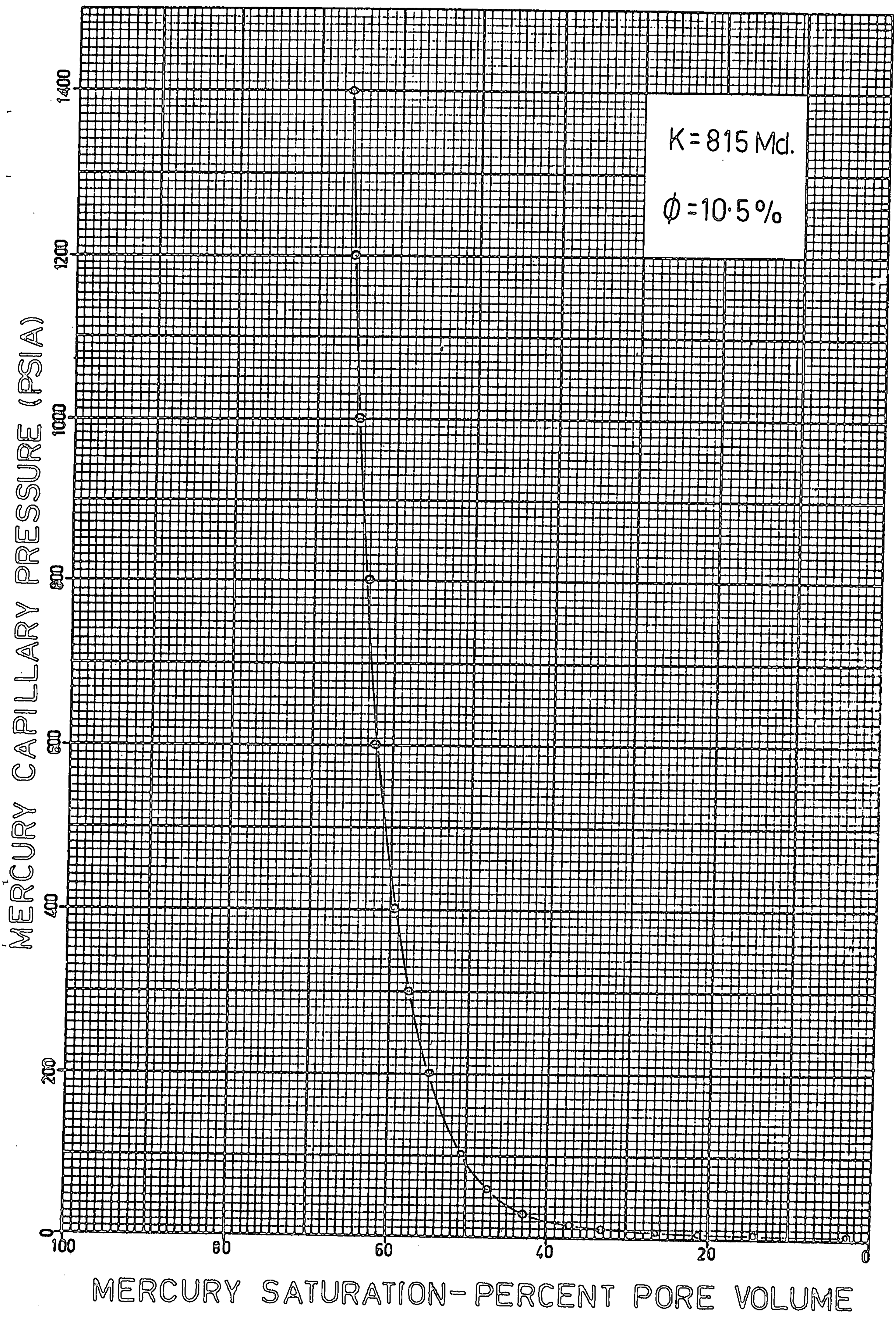


FIGURE 27

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5146′

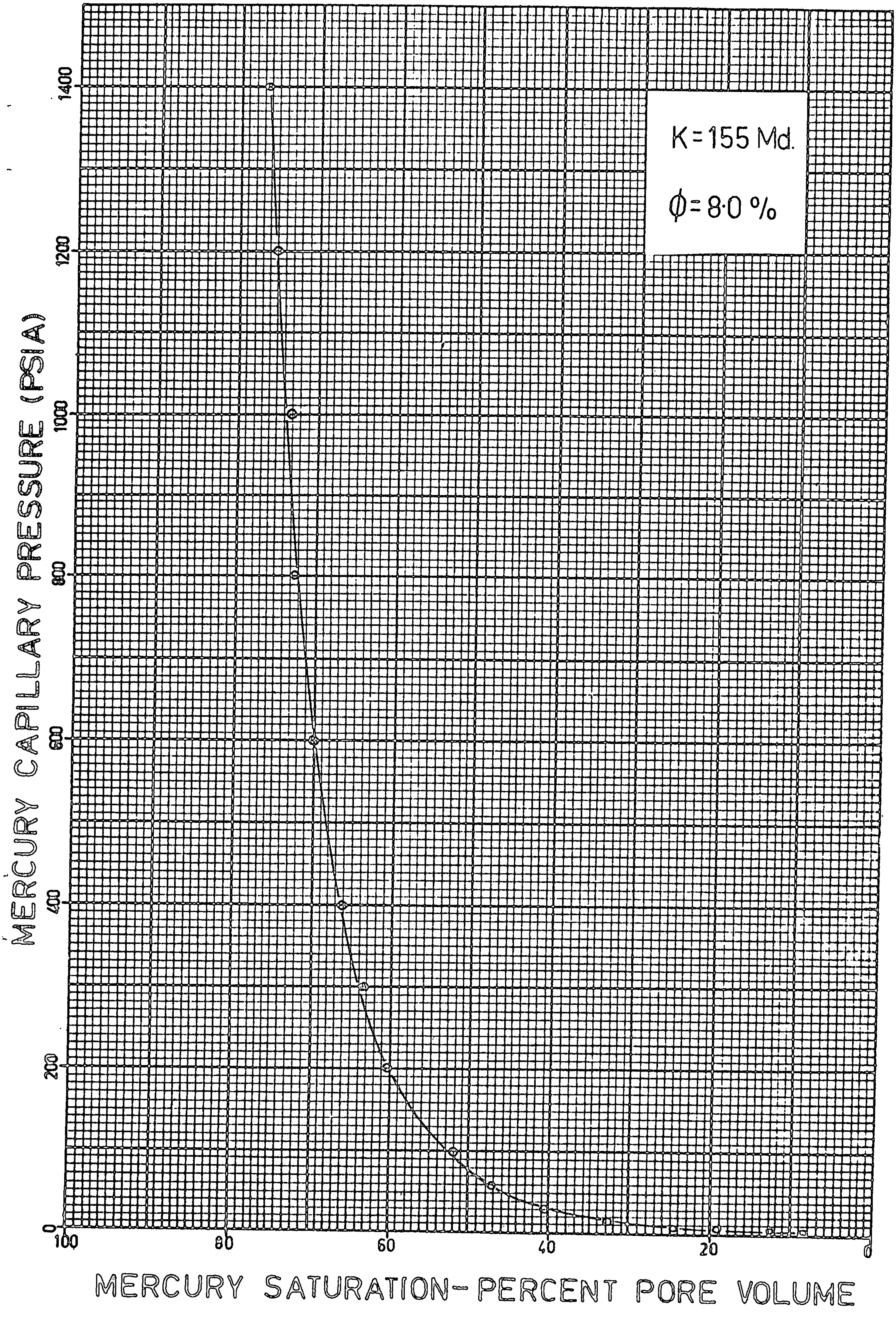


FIGURE 28

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5148'

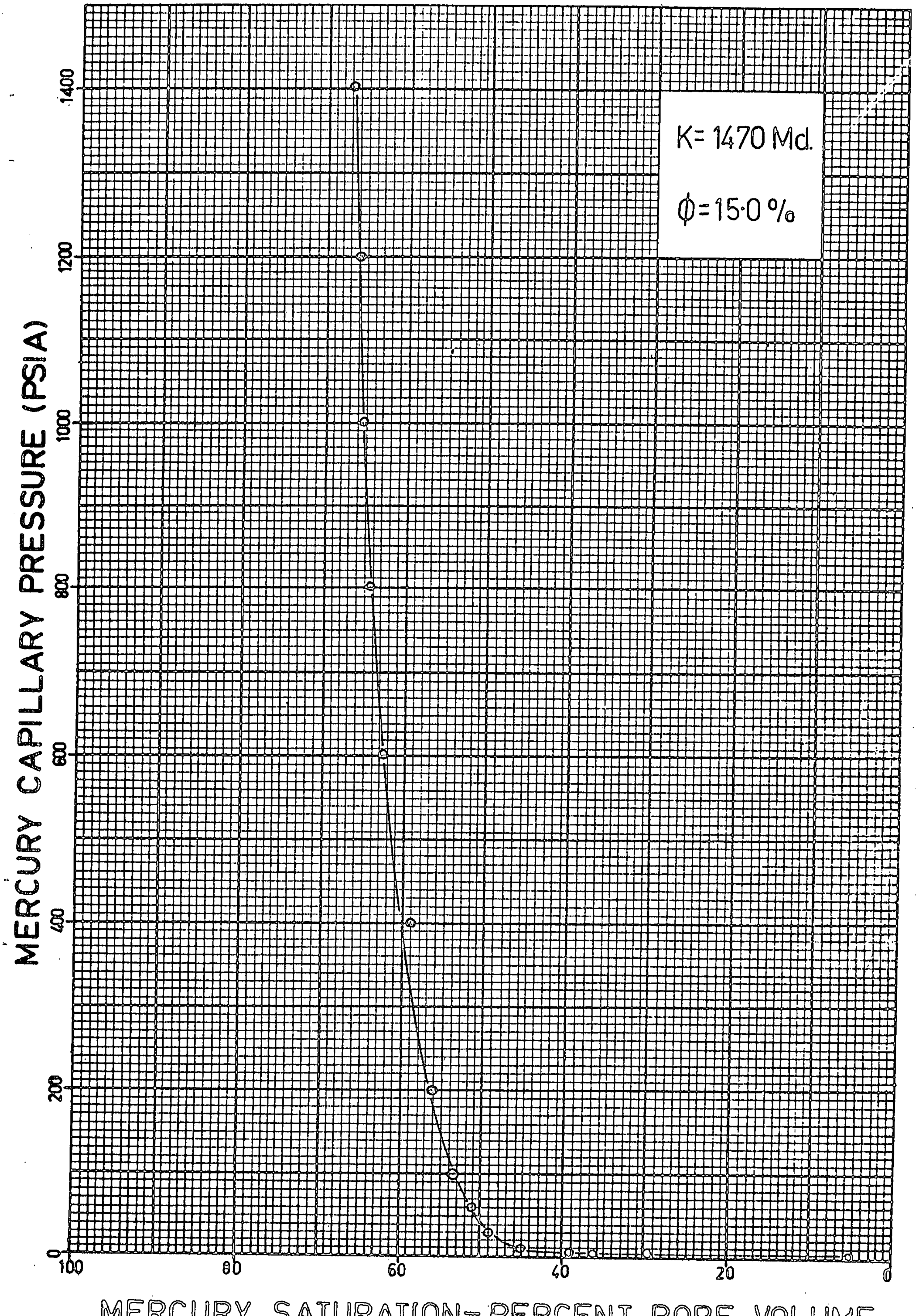


FIGURE 29

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5161′

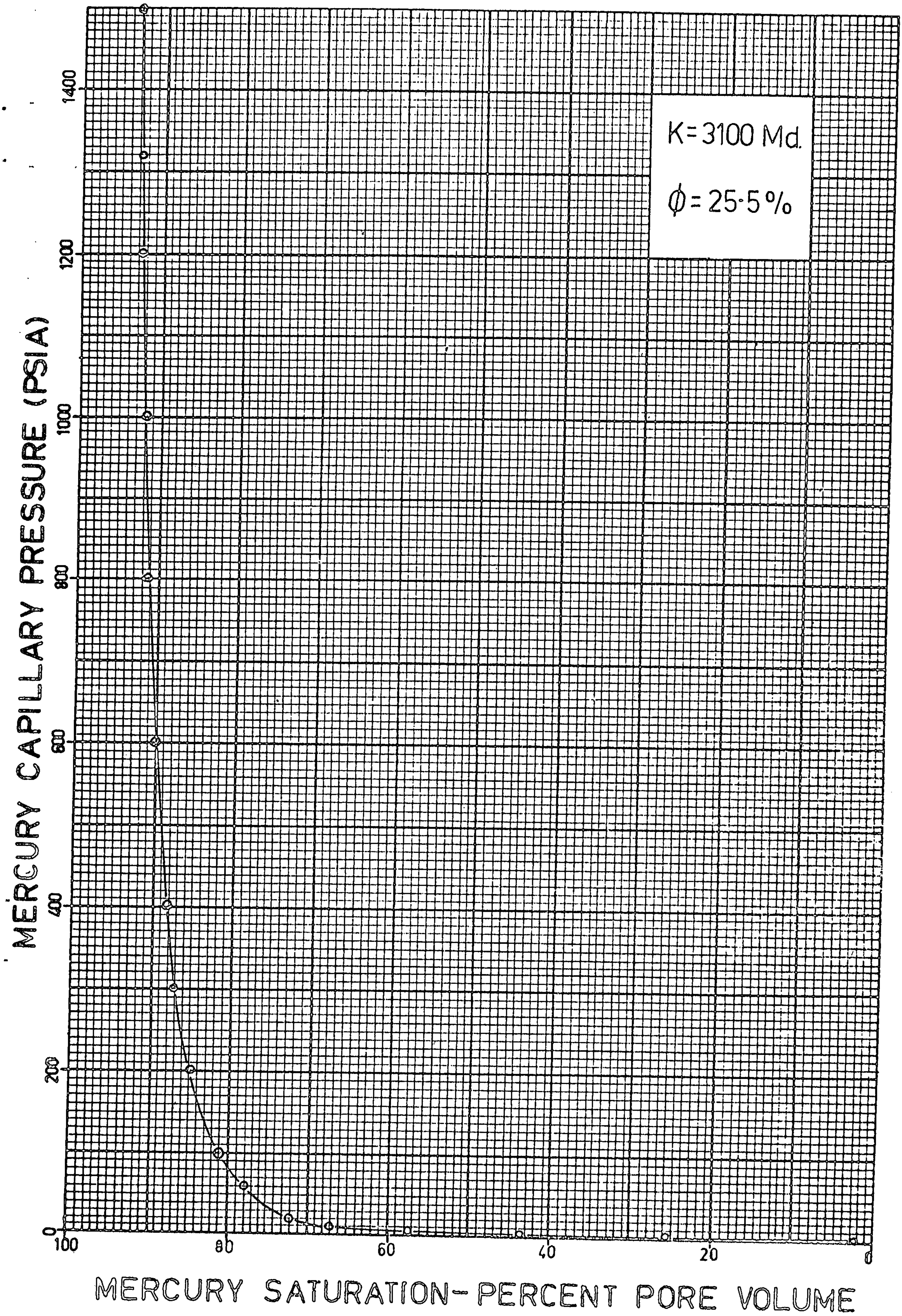


FIGURE 30

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No.4 SAMPLE DEPTH-5165'

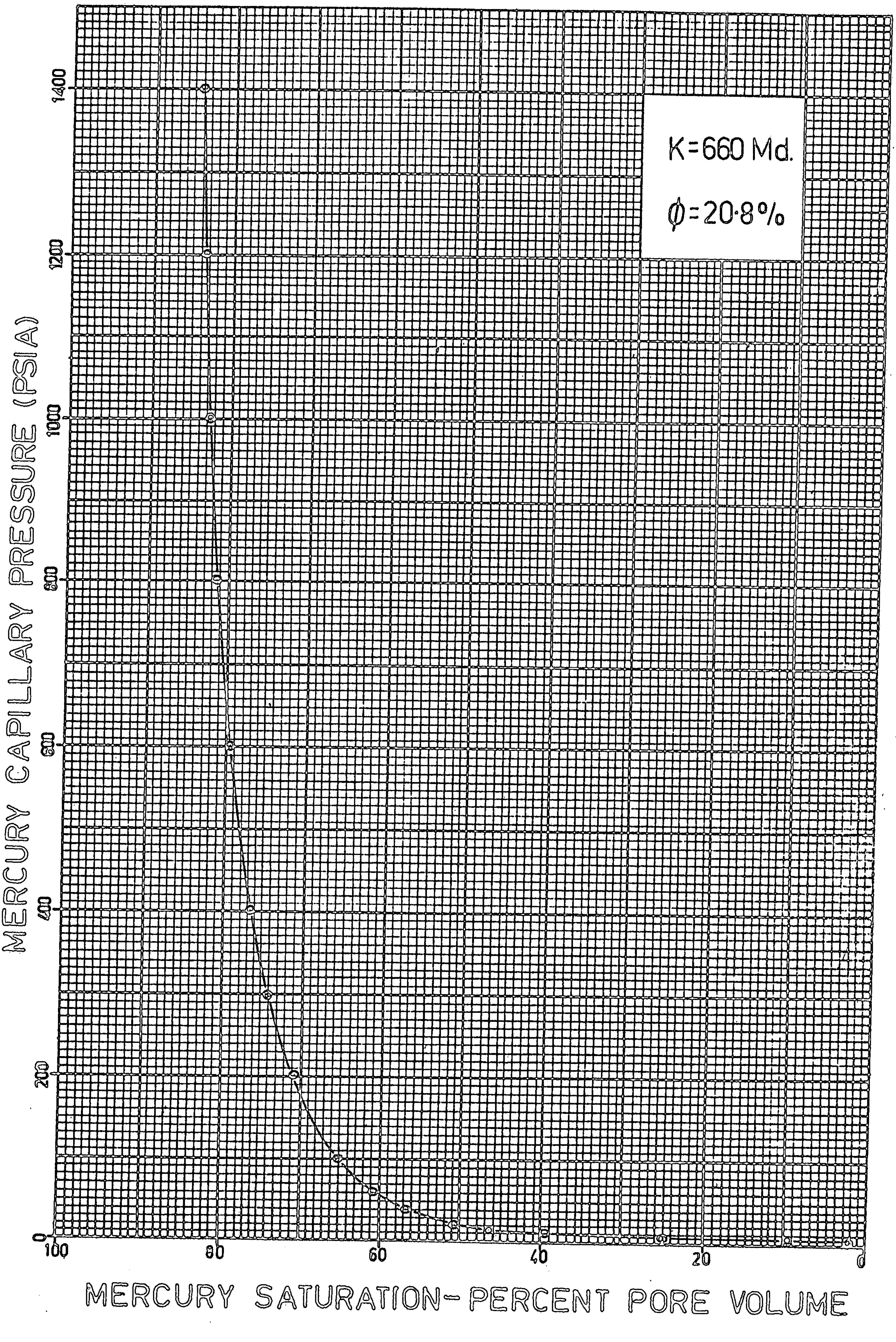


FIGURE 31

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5169'

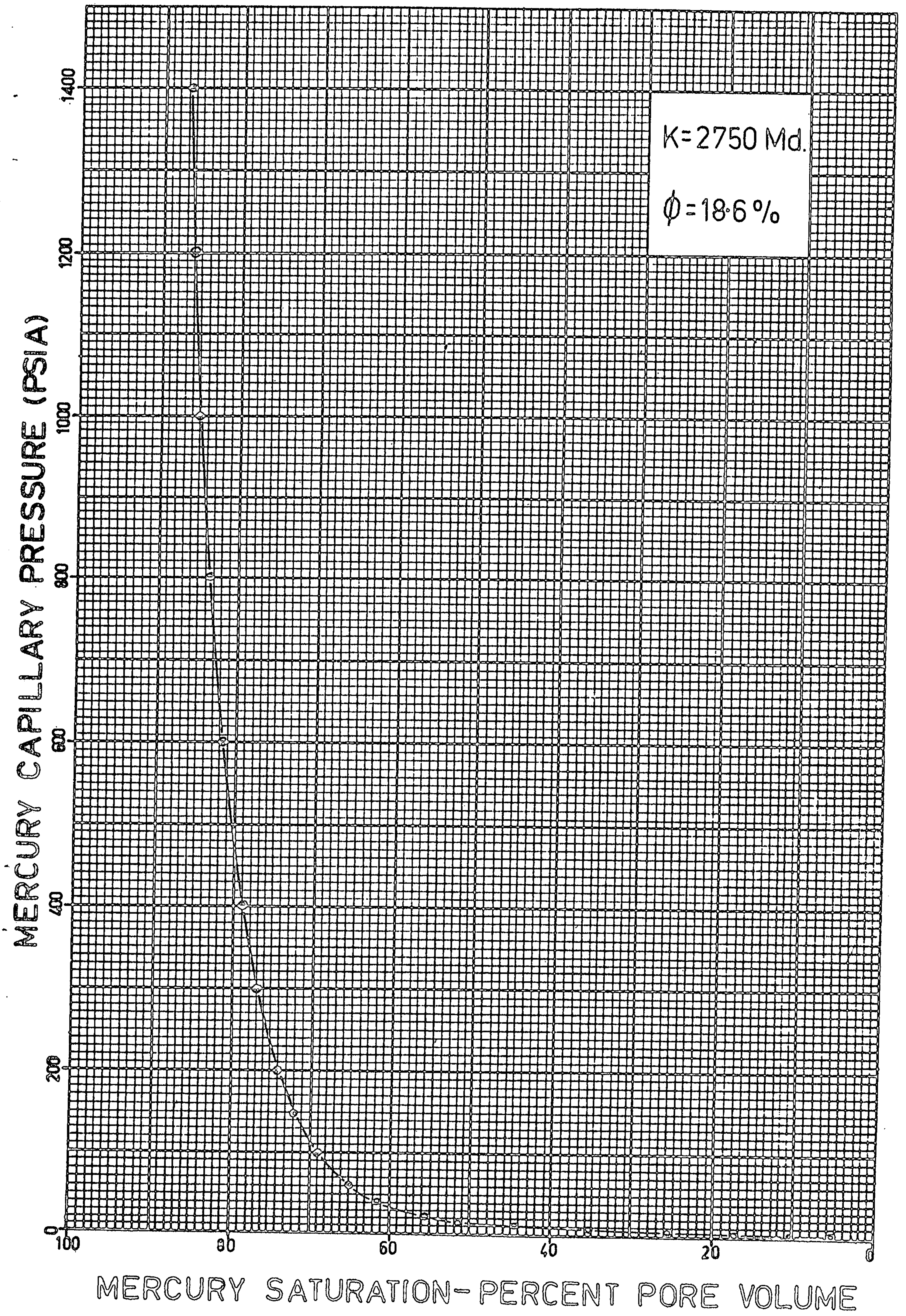


FIGURE 32

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP SHELF No. 4 SAMPLE DEPTH-5171′

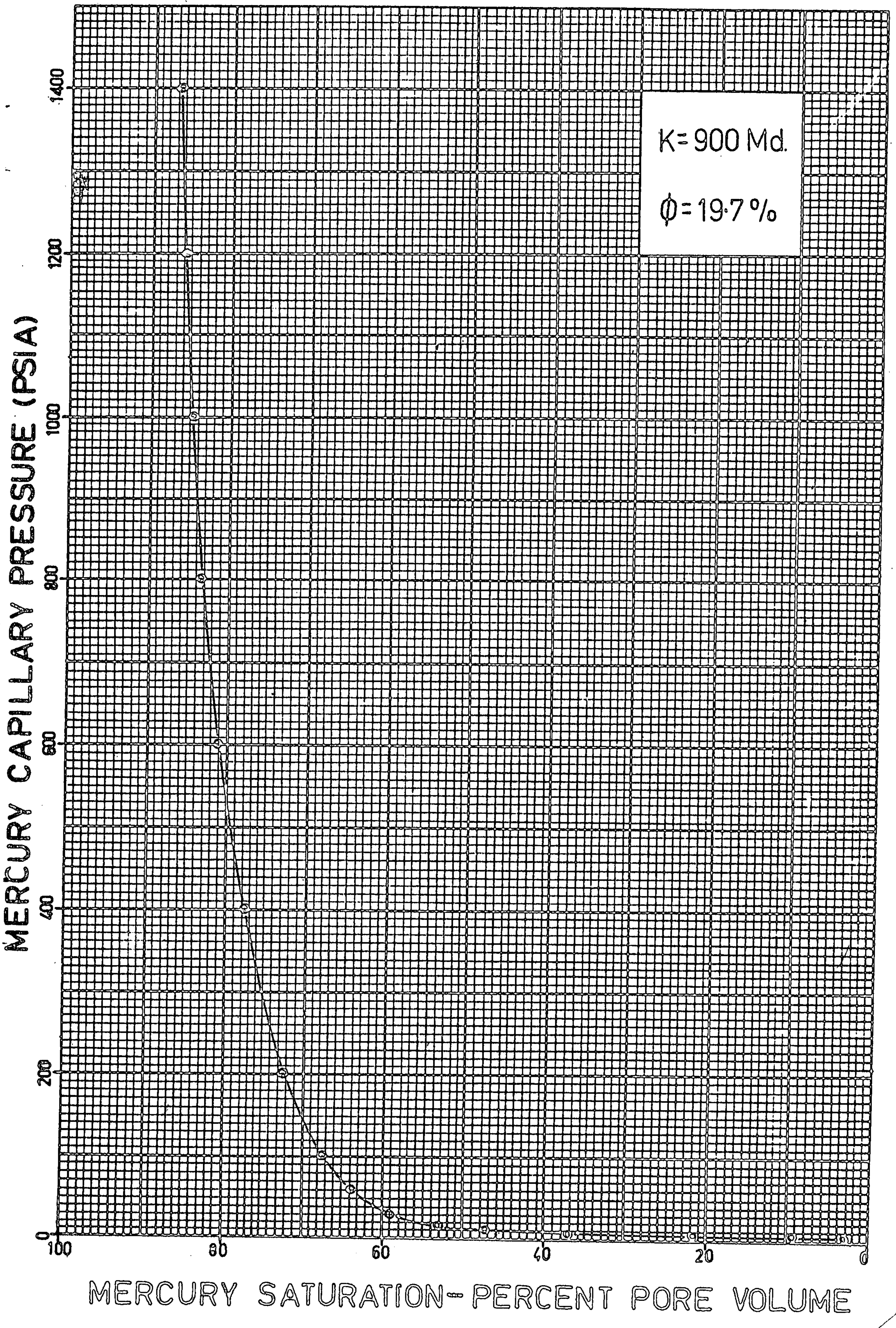
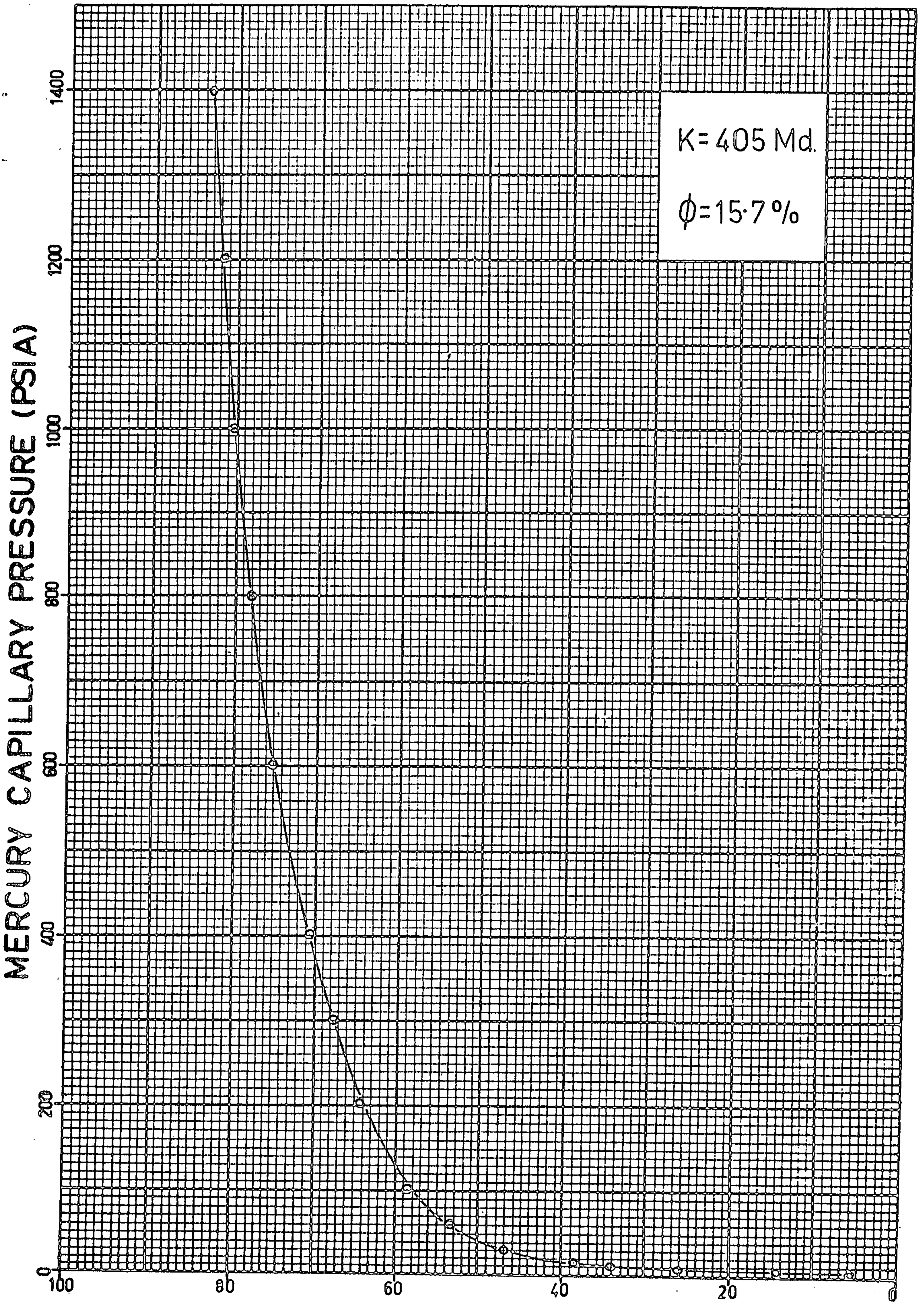


FIGURE 33

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-5175'



MERCURY SATURATION-PERCENT PORE VOLUME

FIGURE 34

MERCURY CAPILLARY PRESSURE

WELL NAME–GIPP. SHELF No. 4 SAMPLE DEPTH–5178'

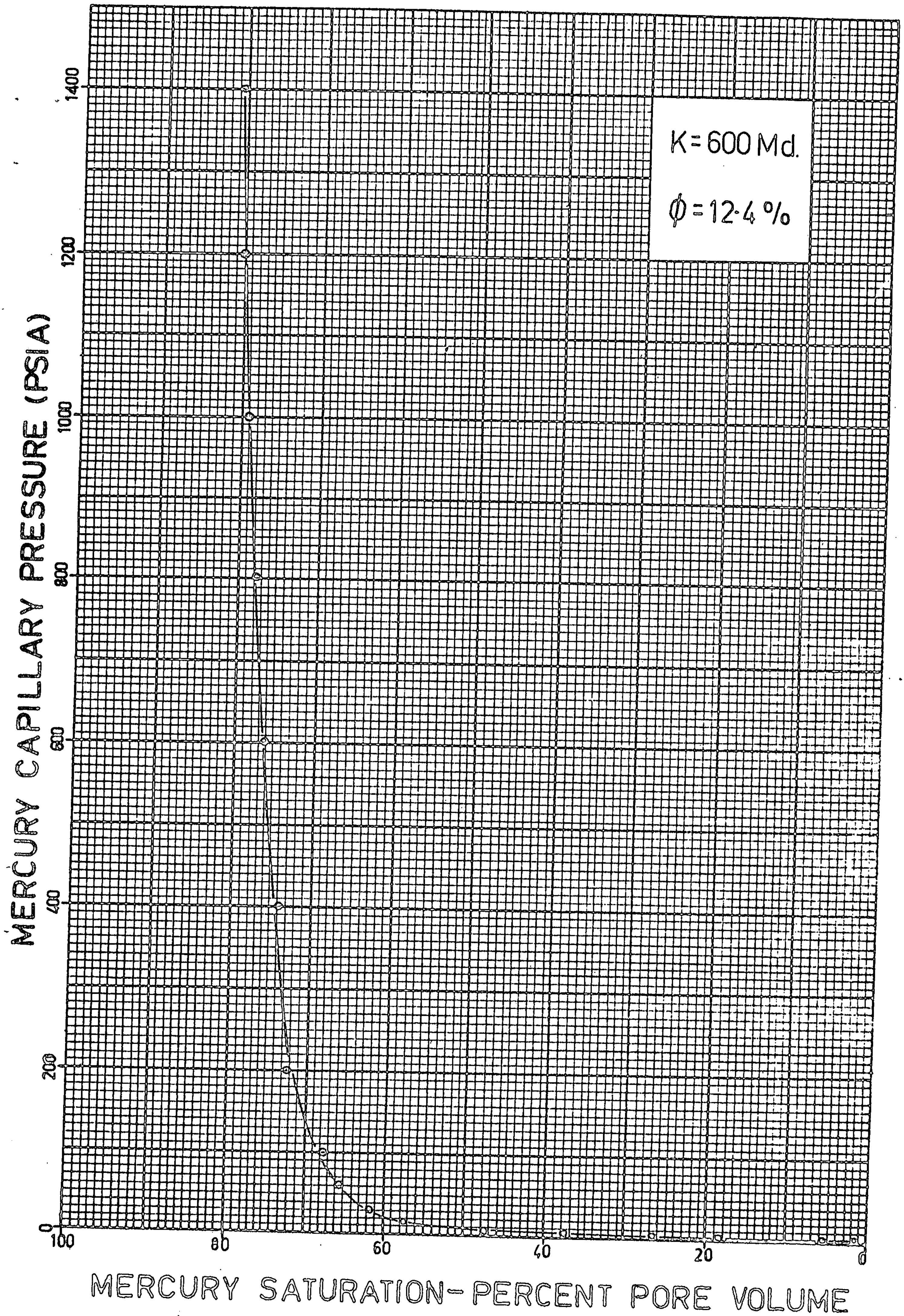
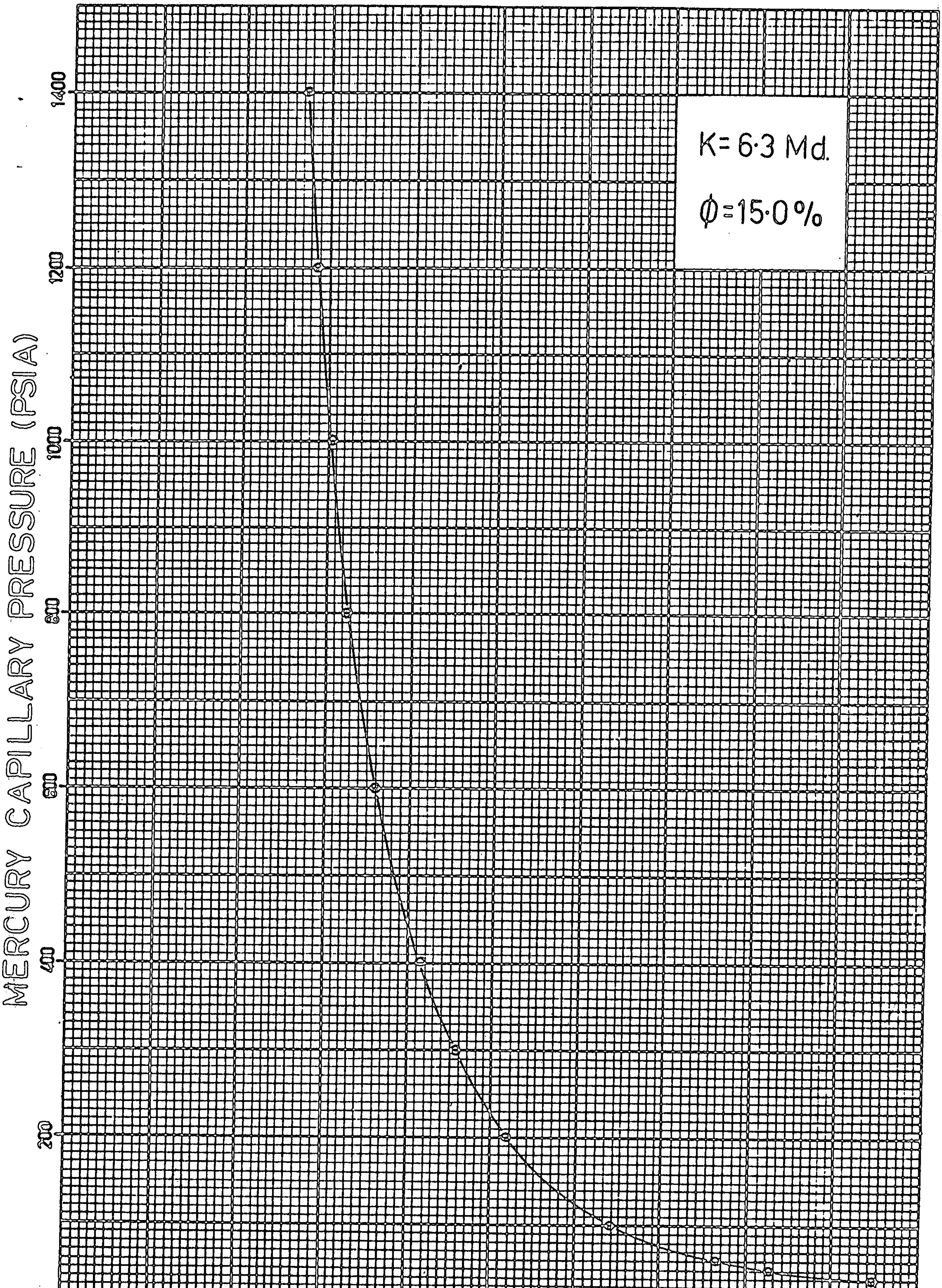


FIGURE 35

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-7474'



MERCURY SATURATION-PERCENT PORE VOLUME

FIGURE 36

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-7475'

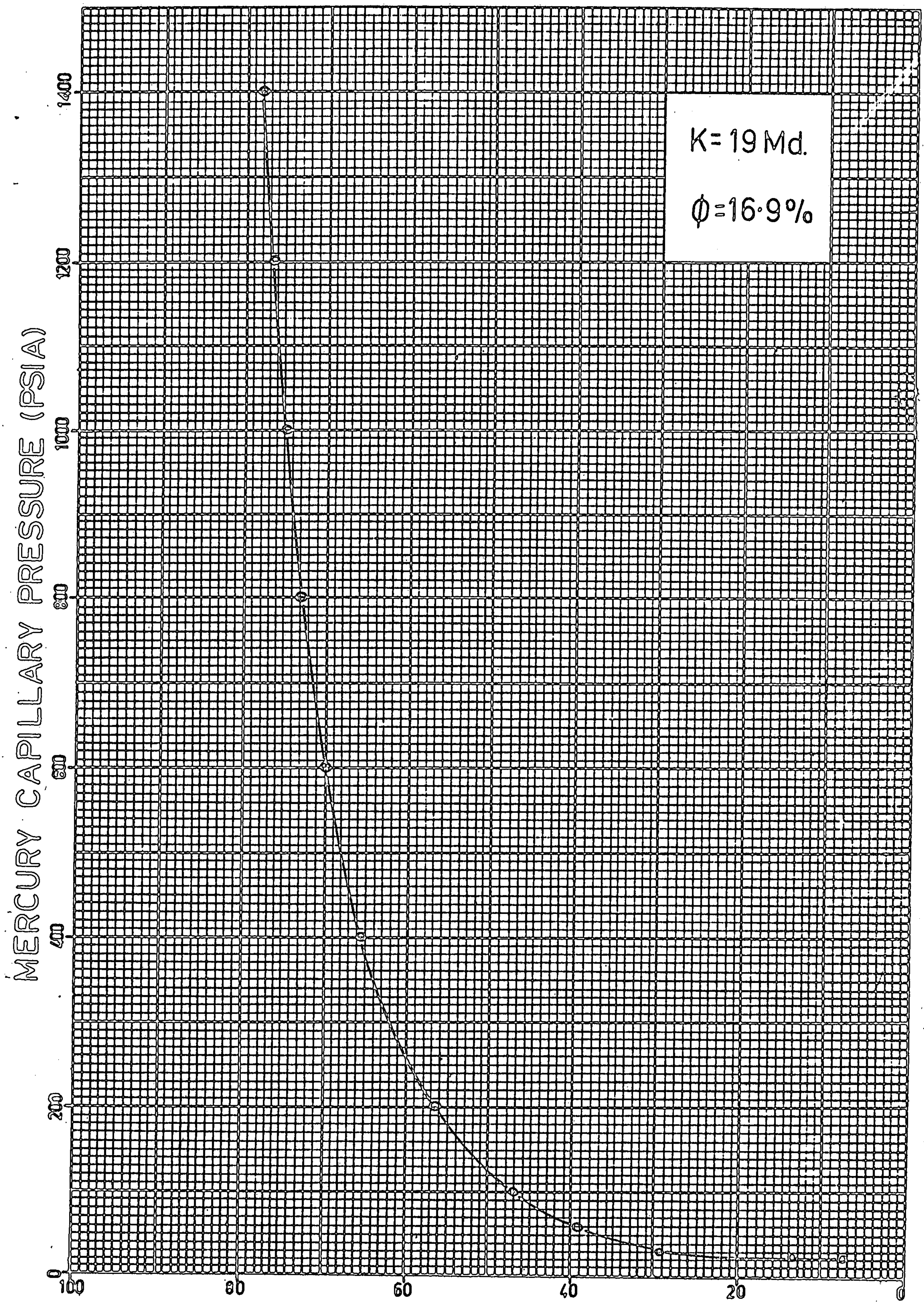


FIGURE 37

MERCURY CAPILLARY PRESSURE

WELL NAME-GIPP. SHELF No. 4 SAMPLE DEPTH-7477′

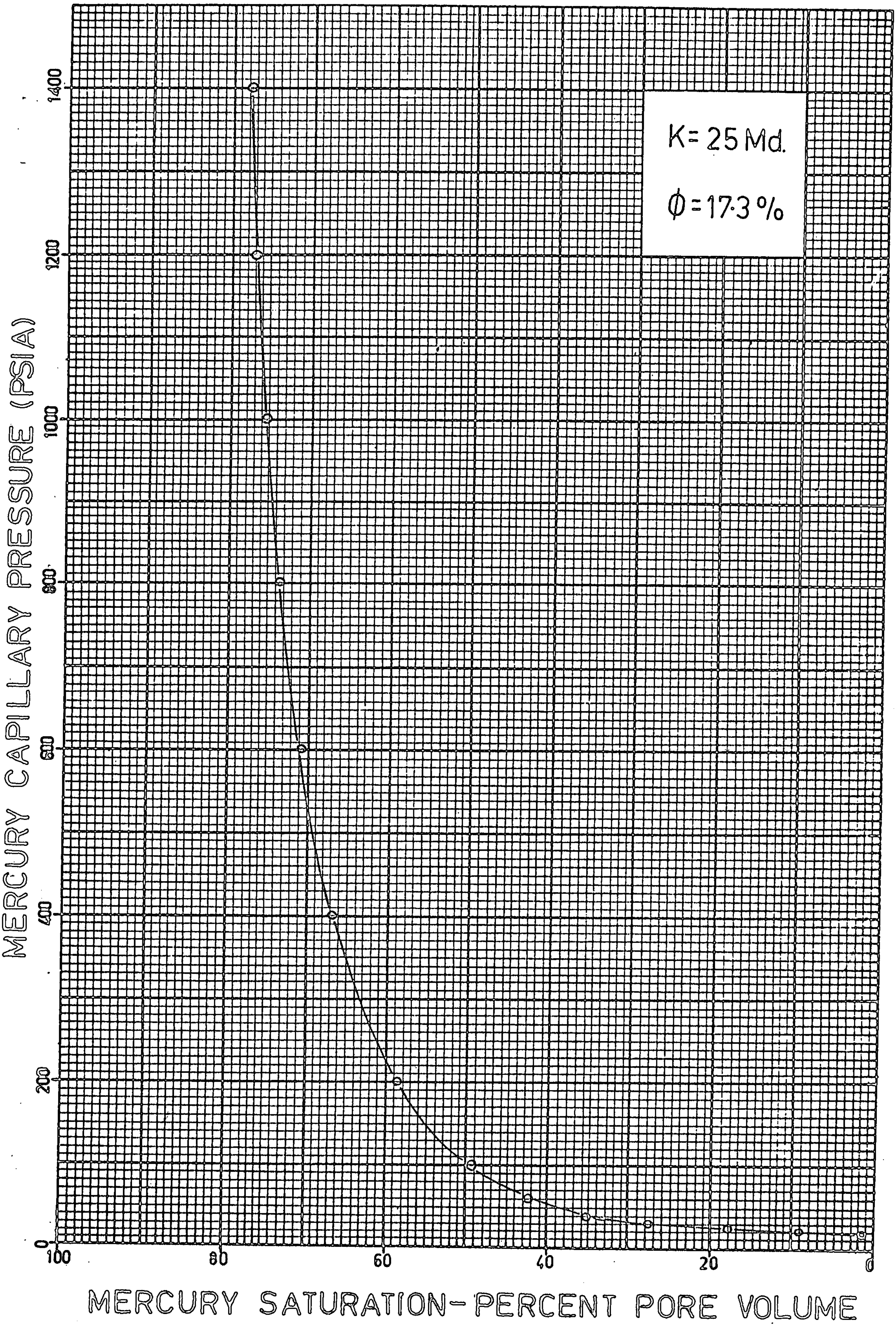


FIGURE 38

RELATION BETWEEN PERMEABILITY SATURATION AND CAPILLARY PRESSURE

GIPPSLAND SHELF No 4 4575-4643

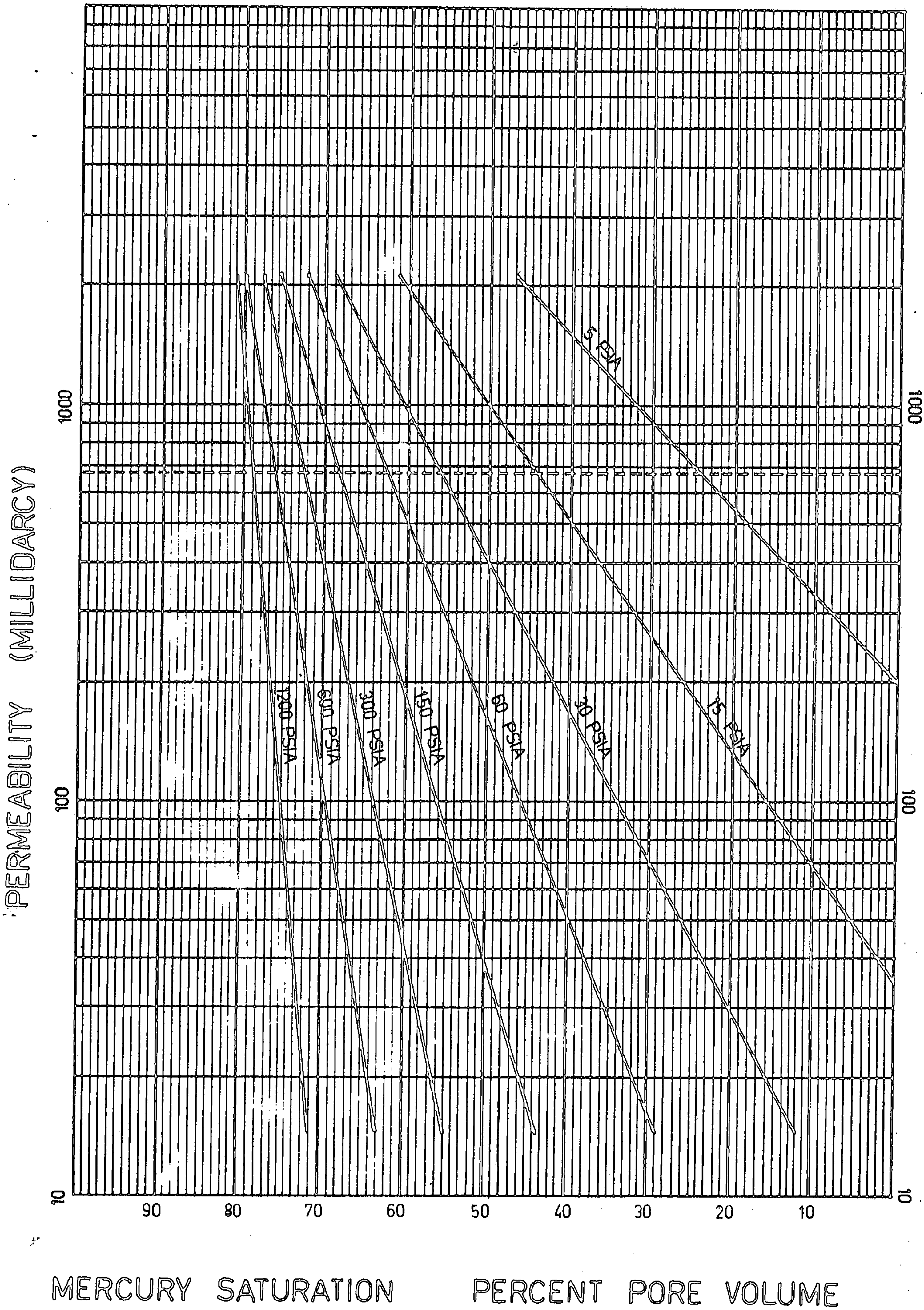
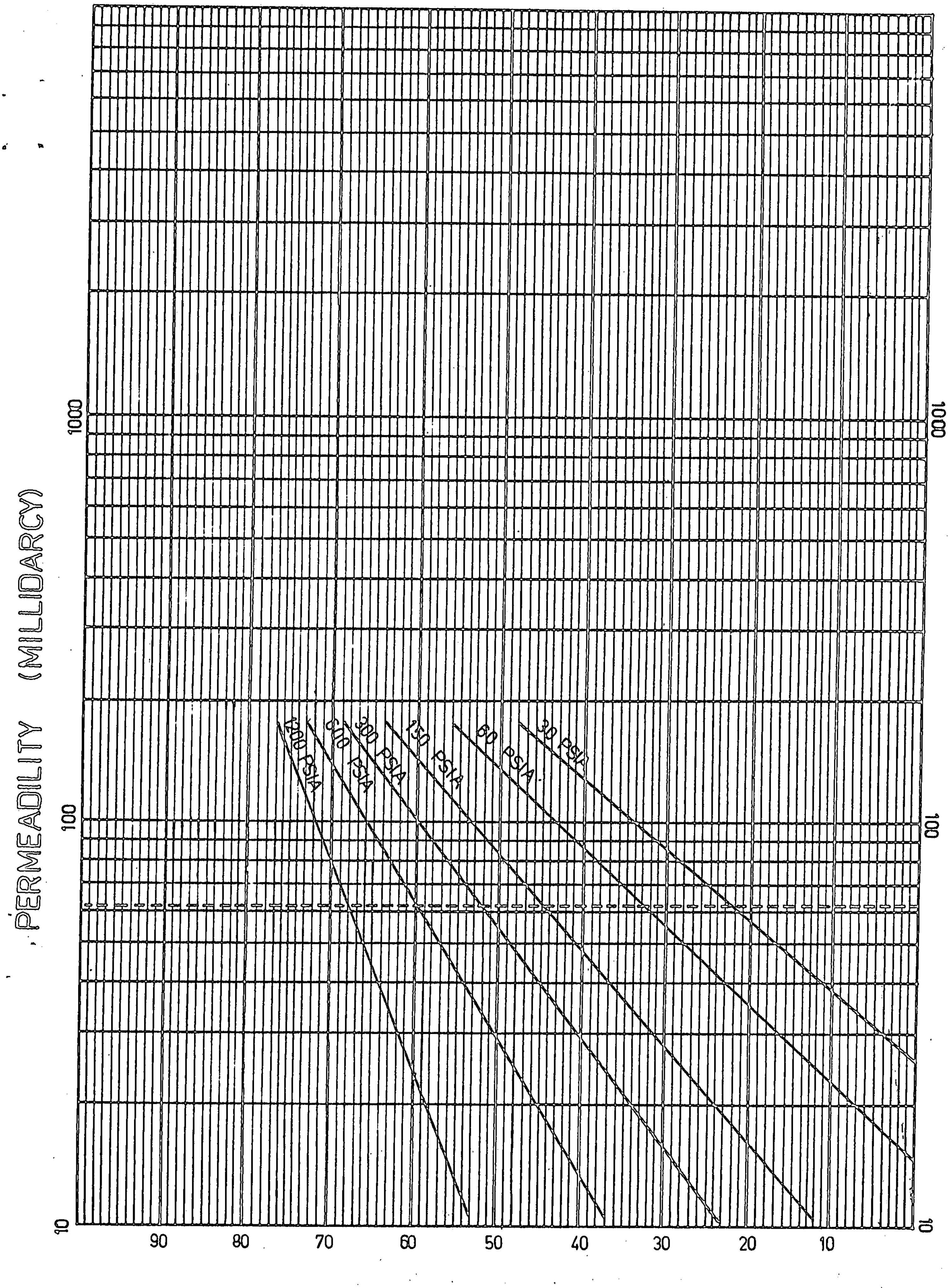


FIGURE 39

RELATION DETWEEN PERMEADILITY SATURATION AND CAPILLARY PRESSURE

GIPPSLAND SHELF No 4 5053-5098

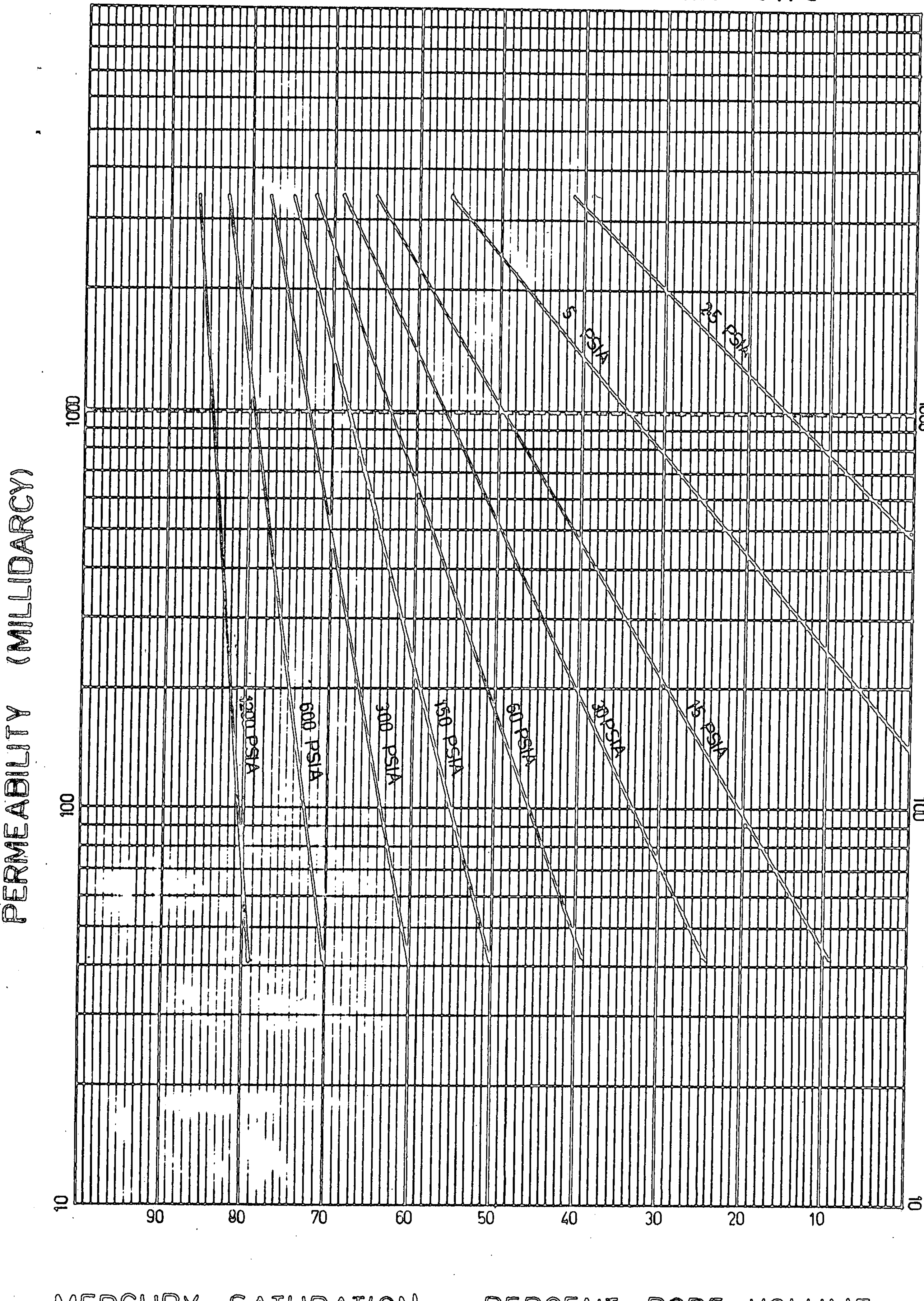


MERCURY SATURATION PERCENT PORE VOLUME

FIGURE 40

RELATION BETWEEN PERMEABILITY SATURATION AND CAPILLARY PRESSURE

GIPPSLAND SHELF No 4 5120 - 5178



MERCURY SATURATION PERCENT PORE VOLUME

AVERAGE
MERCURY CAPILLARY PRESSURE

WELL NAME GIPP. SHELF No. 4 SAMPLE DEPTH 4575 to 4643

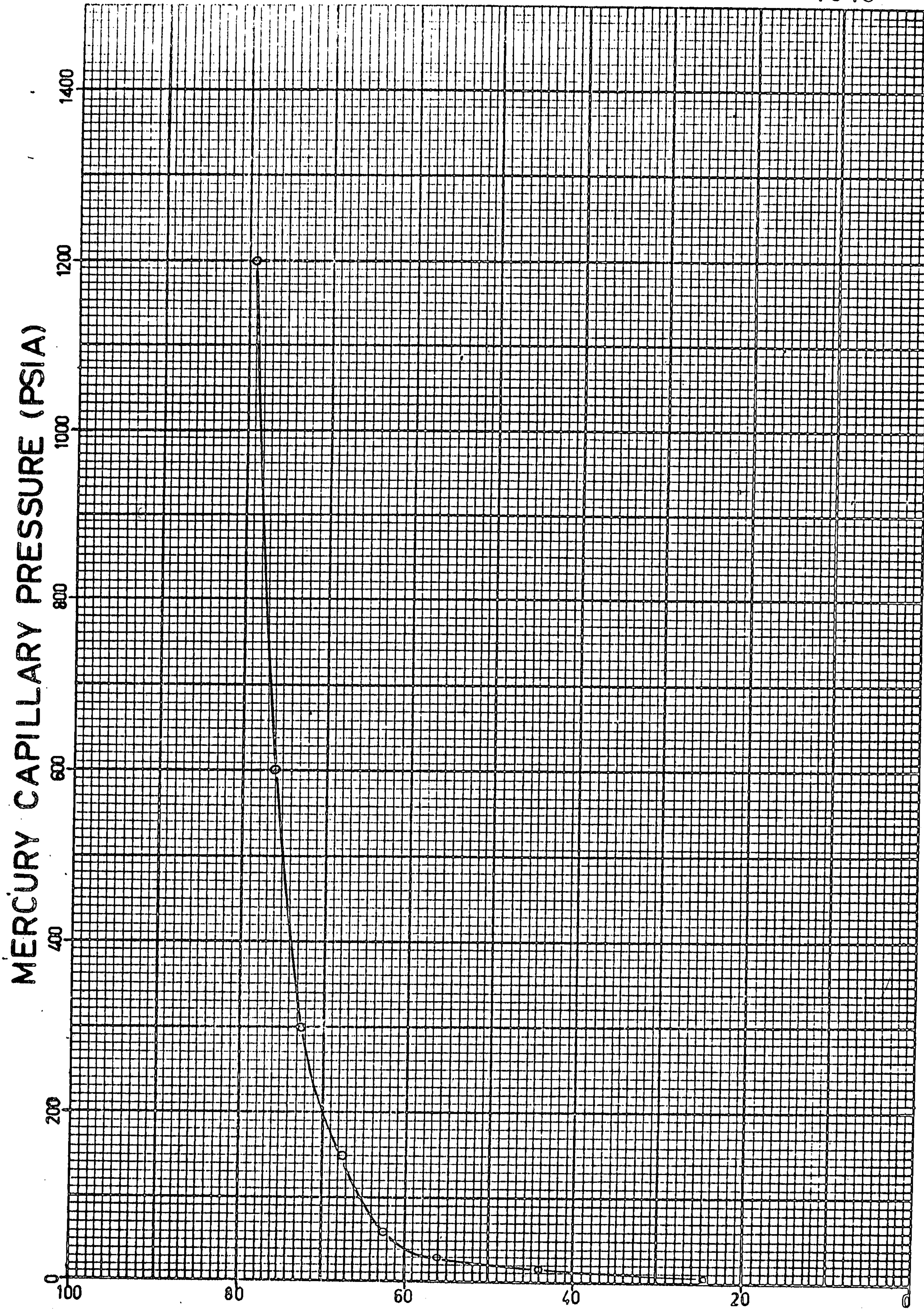
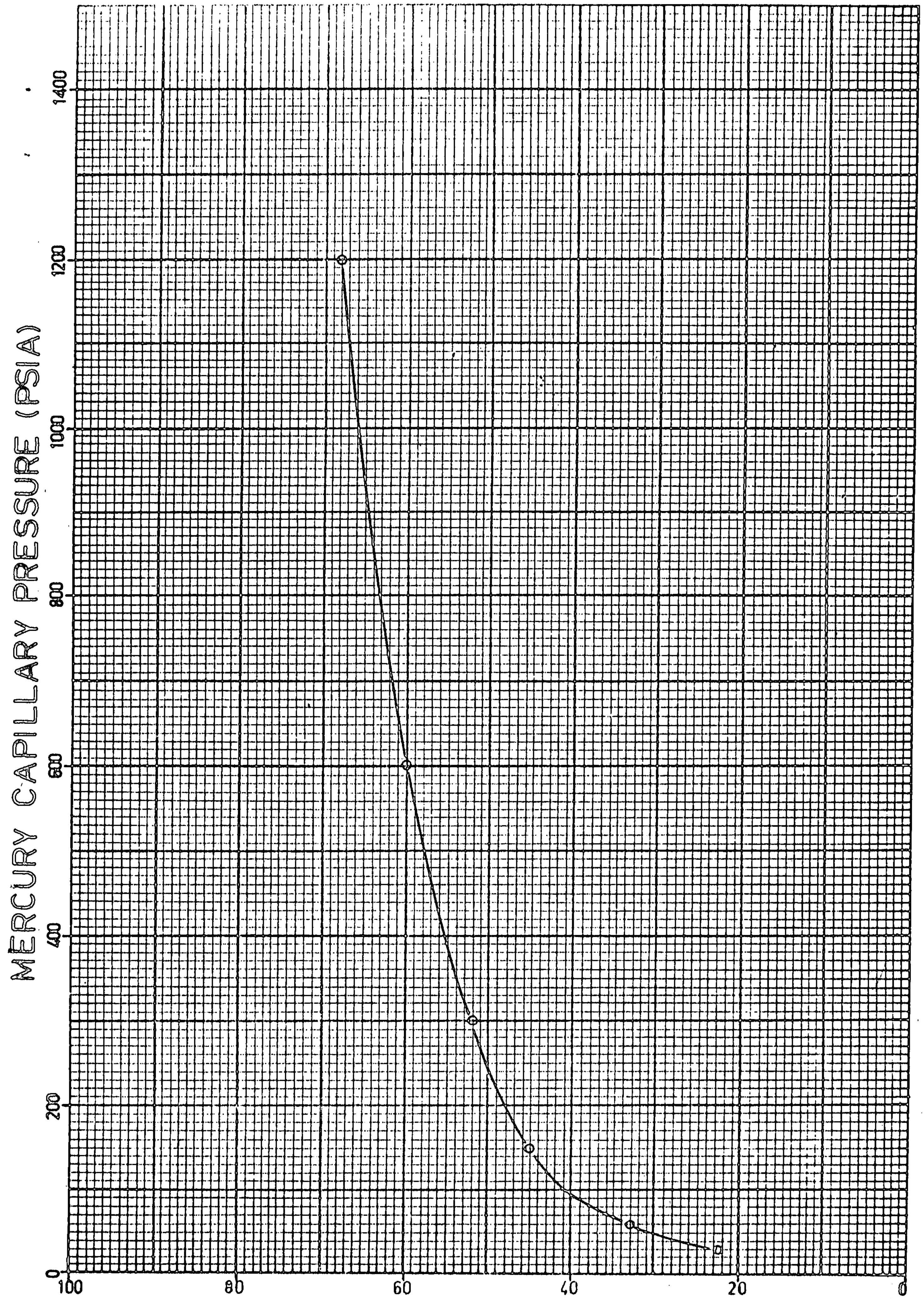


FIGURE 41

AVERAGE
MERCURY CAPILLARY PRESSURE

WELL NAME GIPP SHELF No 4 SAMPLE DEPTH 5053 to 5098



MERCURY SATURATION–PERCENT PORE VOLUME

FIGURE 42

AVERAGE
MERCURY CAPILLARY PRESSURE

WELL NAME GIPP. SHELF No.4 SAMPLE DEPTH 5120 to 5178

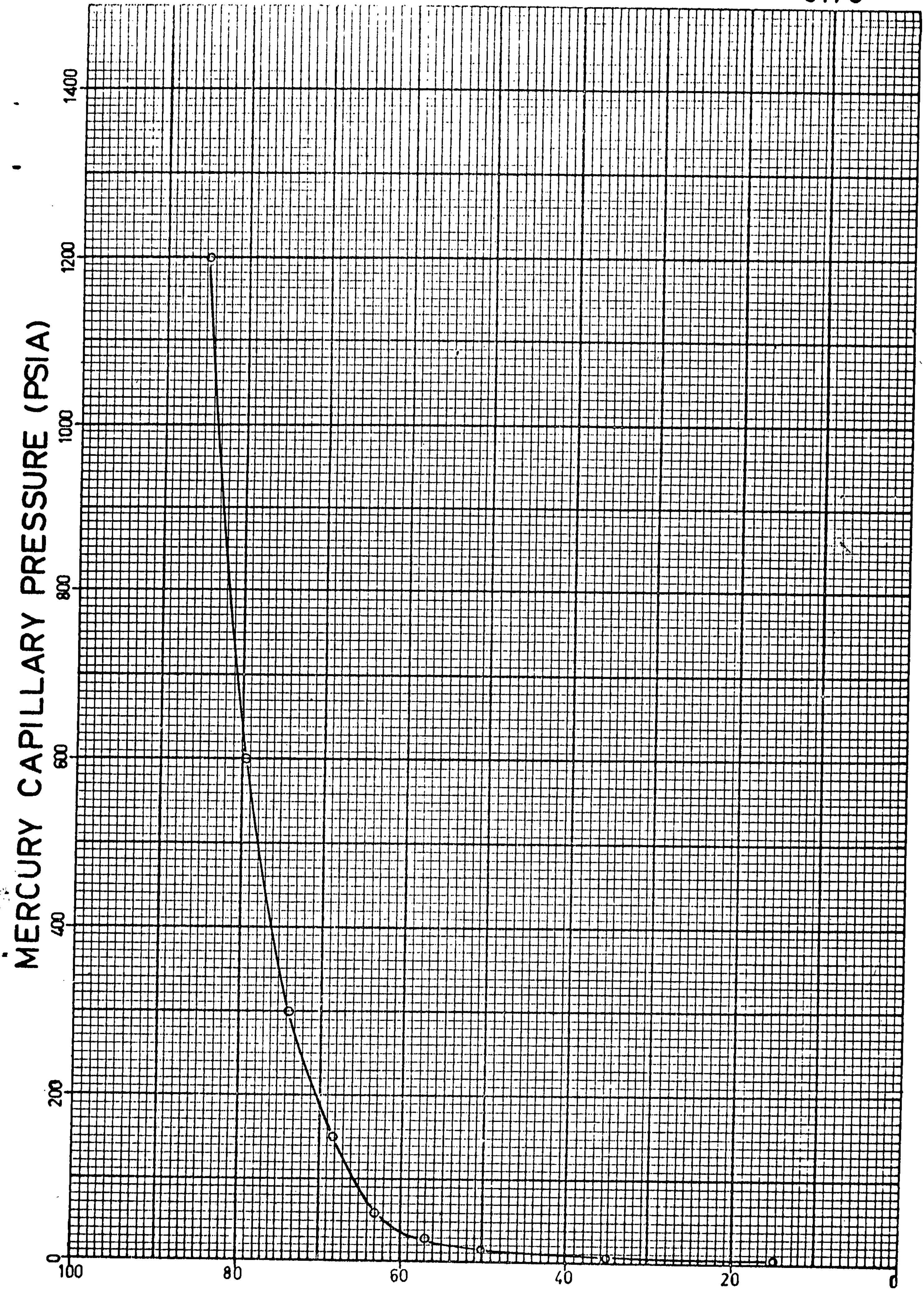


FIGURE 43

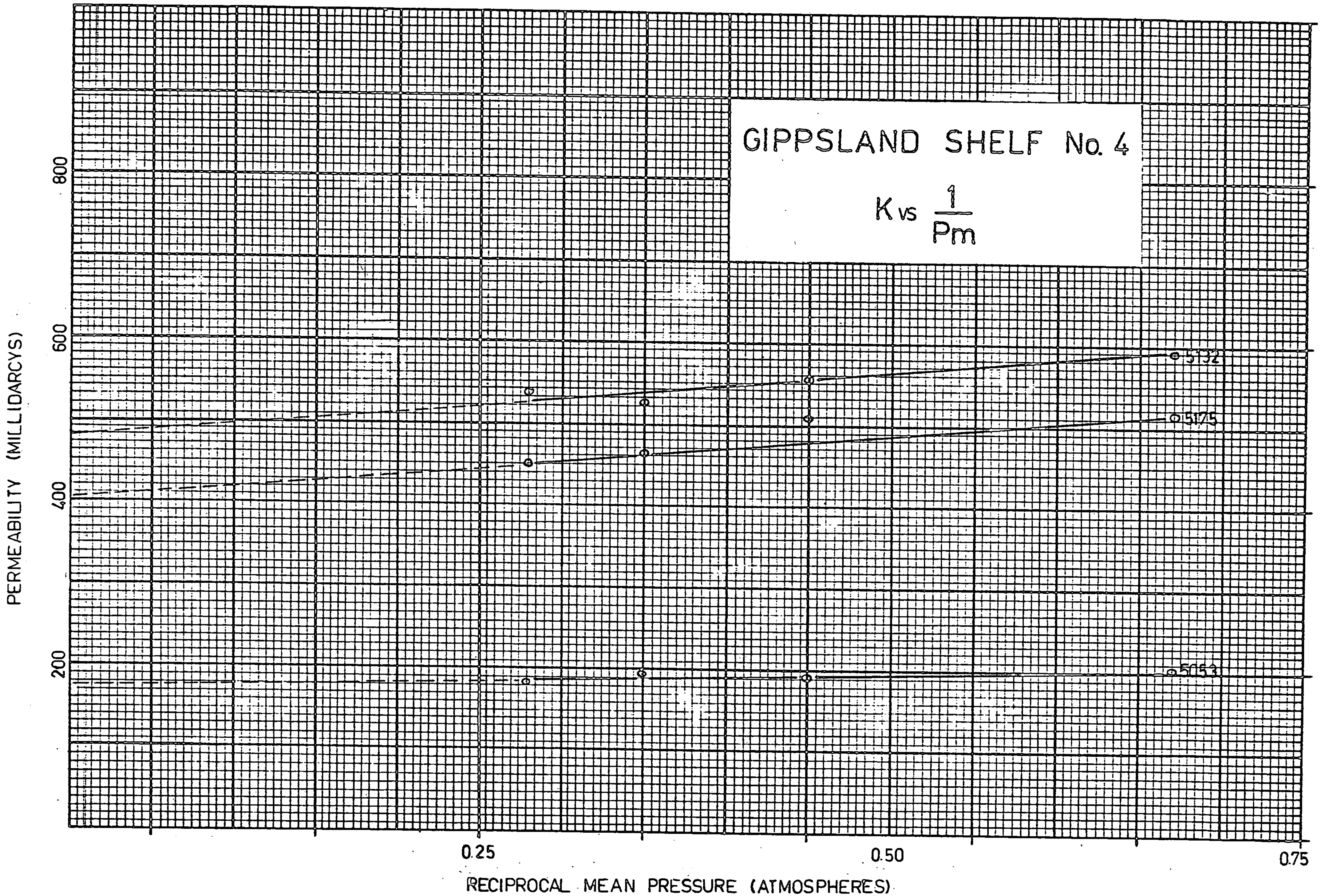

GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
800
600
400
200
5132
5175
5053
0.25
0.50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)

FIGURE 44

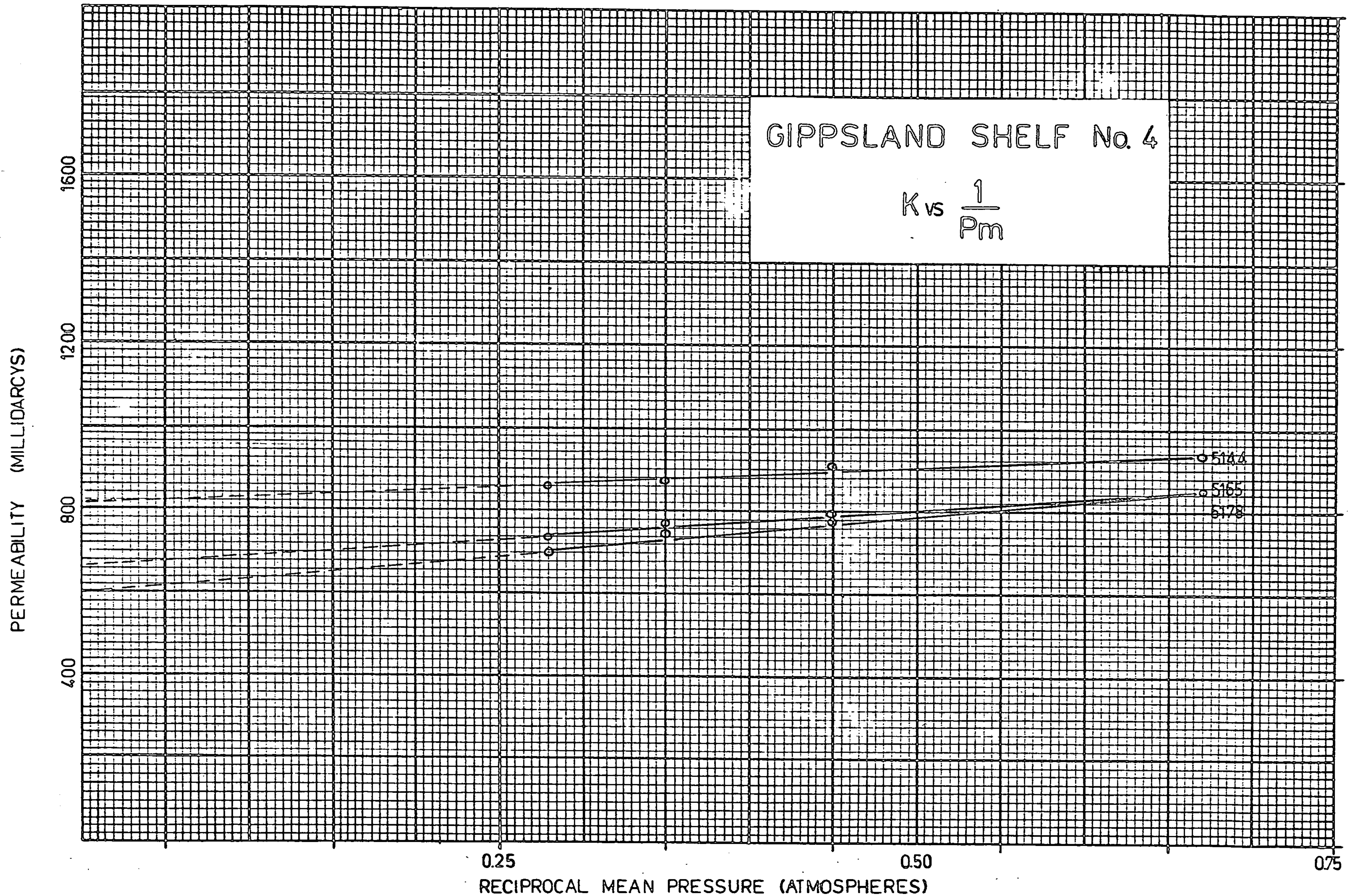
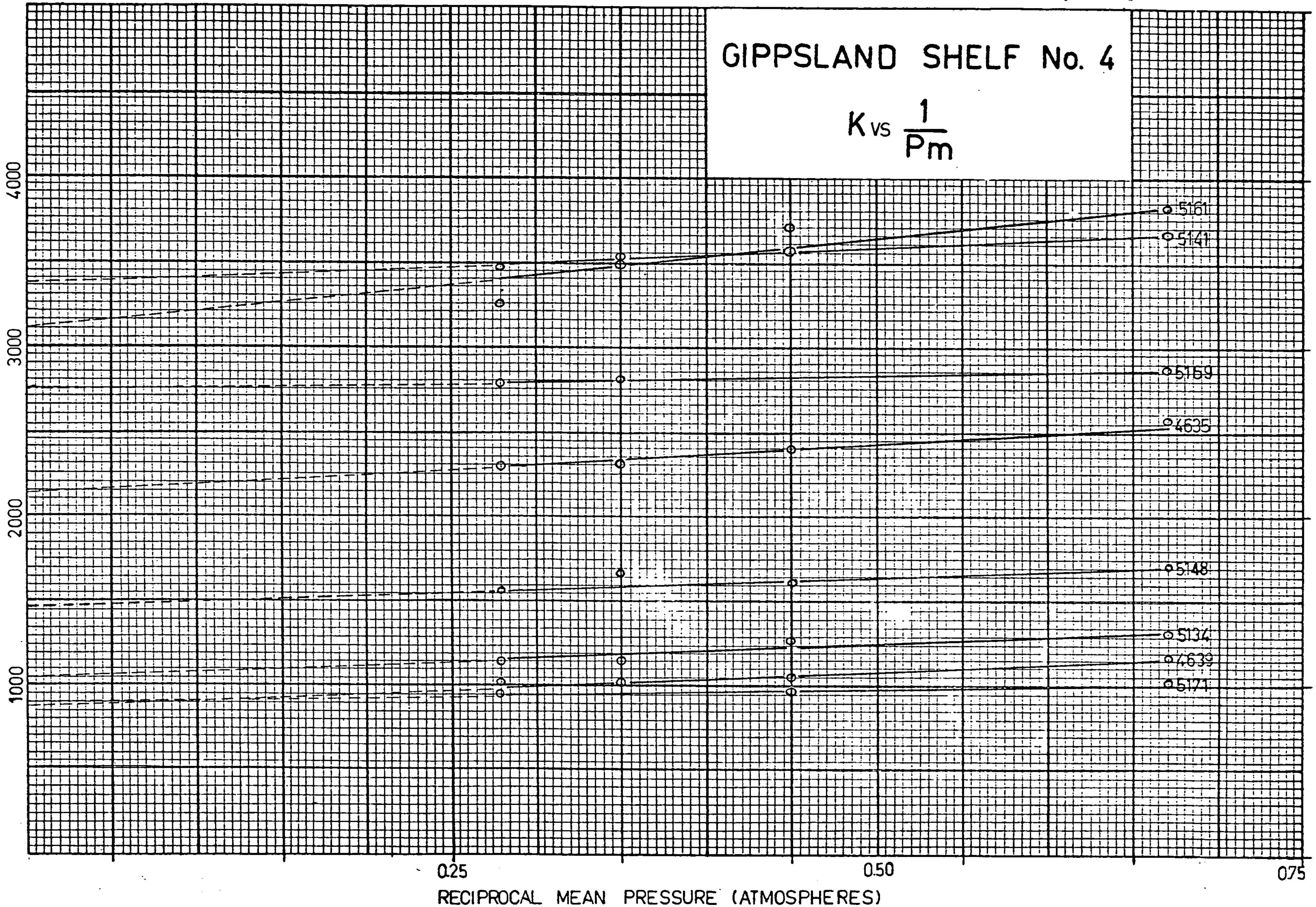

GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
1600
1200
800
400
5144
5165
5178
0.25
0.50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)

FIGURE 45



GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
1000
2000
3000
4000
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
0.25
0.50
0.75
5161
5141
5169
4635
5148
5134
4639
5171

FIGURE 46

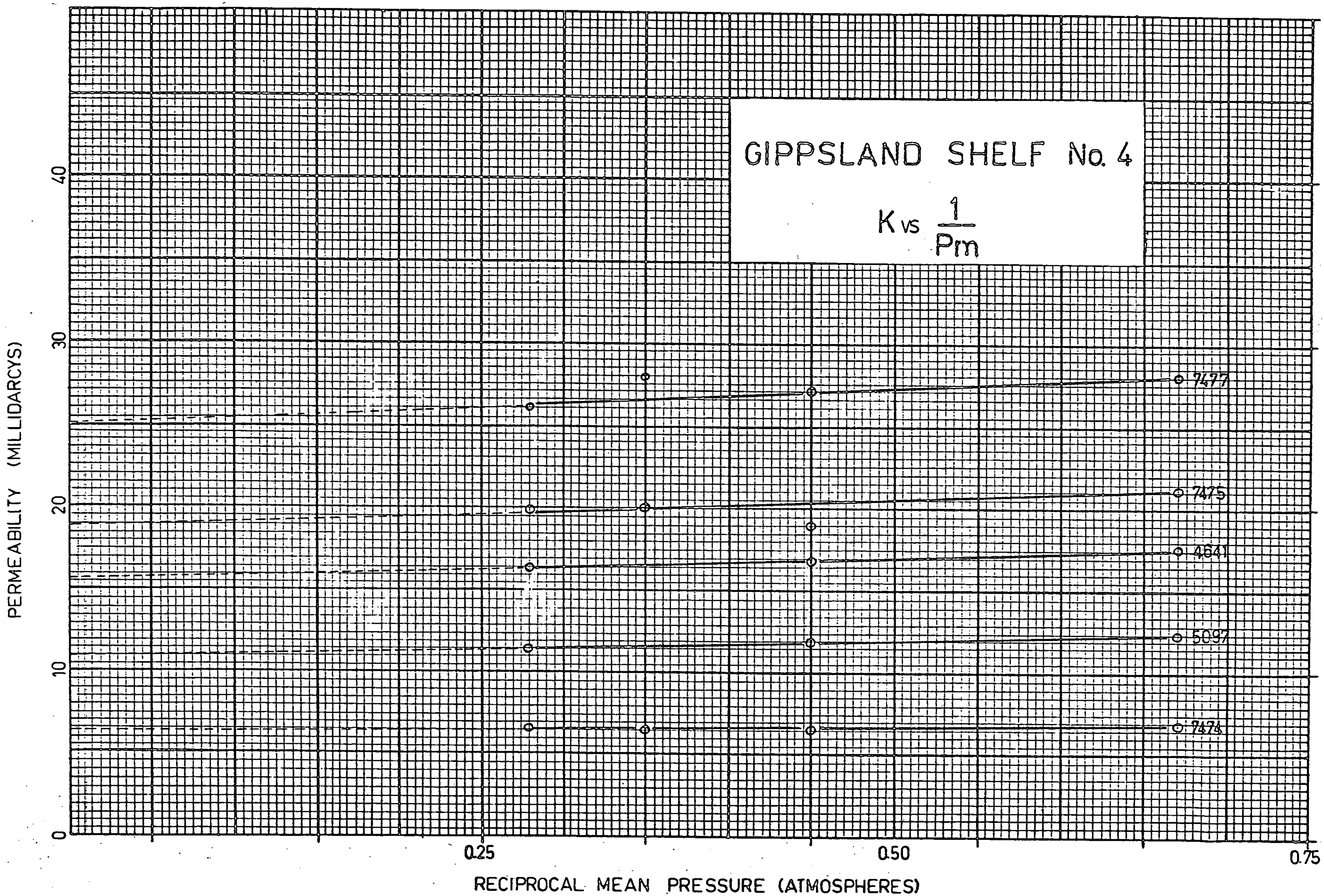

GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
0
10
20
30
40
0.25
0.50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
7477
7475
4641
5097
7474

FIGURE 47

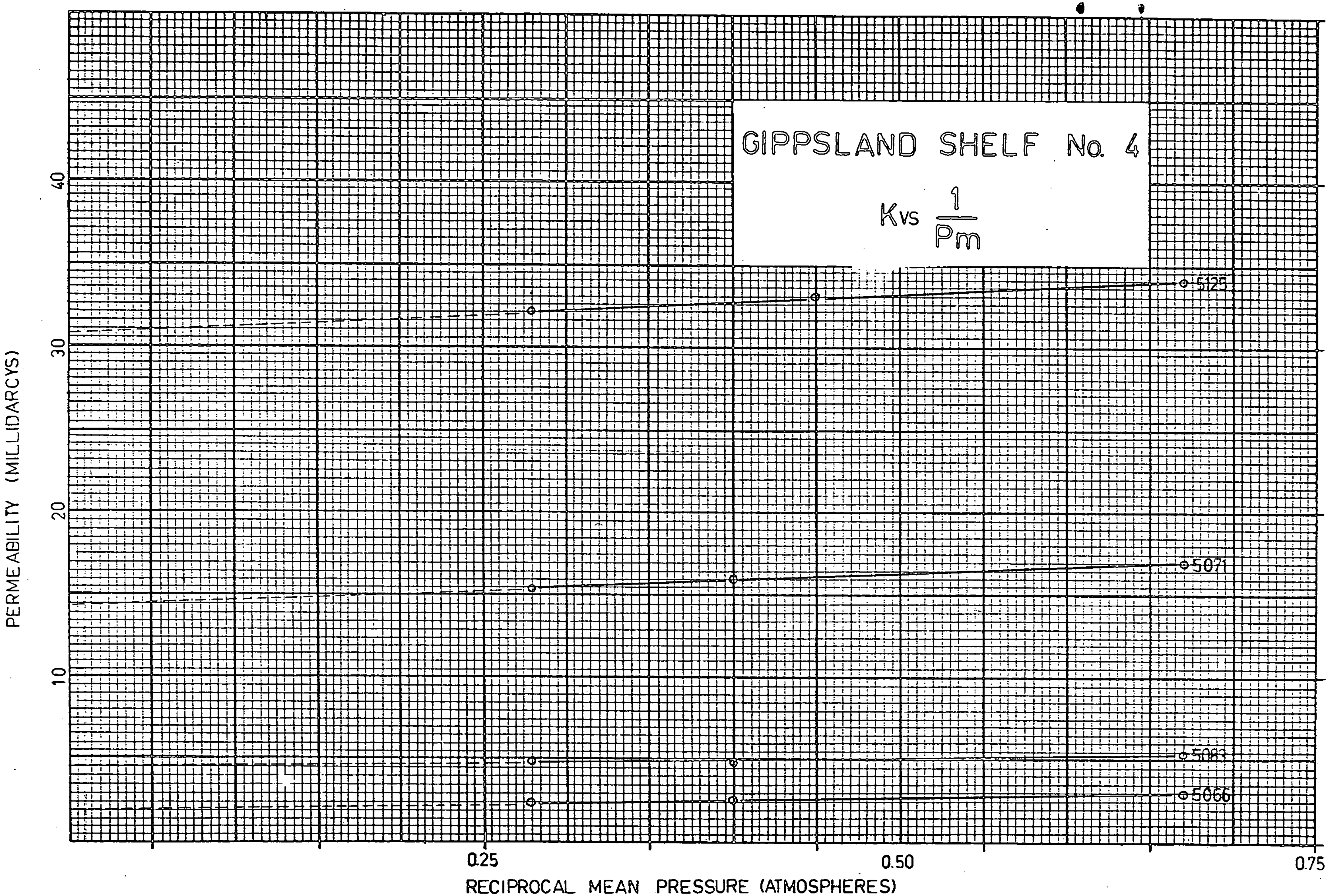
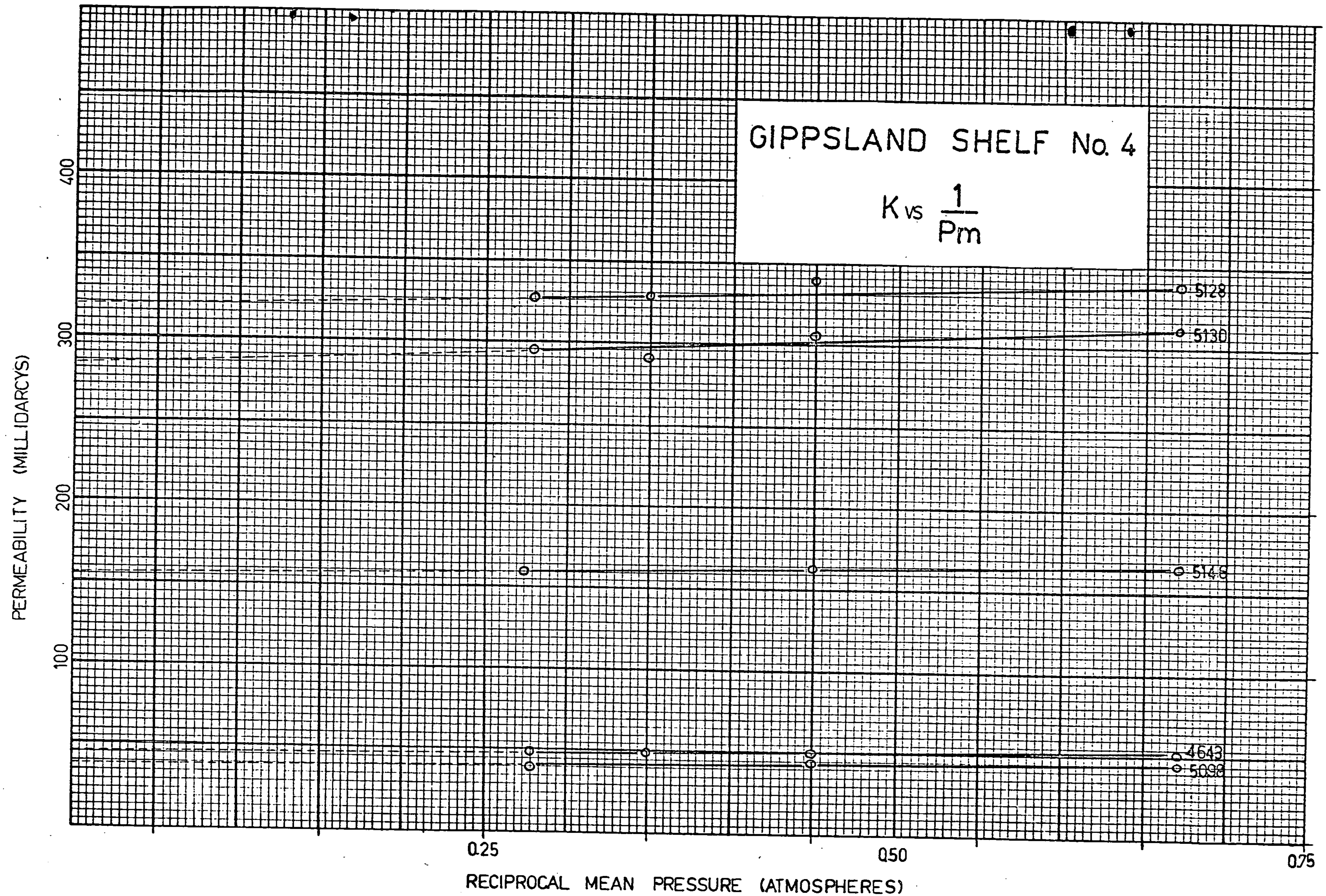

GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
10
20
30
40
0.25
0.50
0.75
5125
5071
5083
5066

FIGURE 48



GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
100
200
300
400
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
0.25
0.50
0.75
5128
5130
5148
4643
5098

FIGURE 49

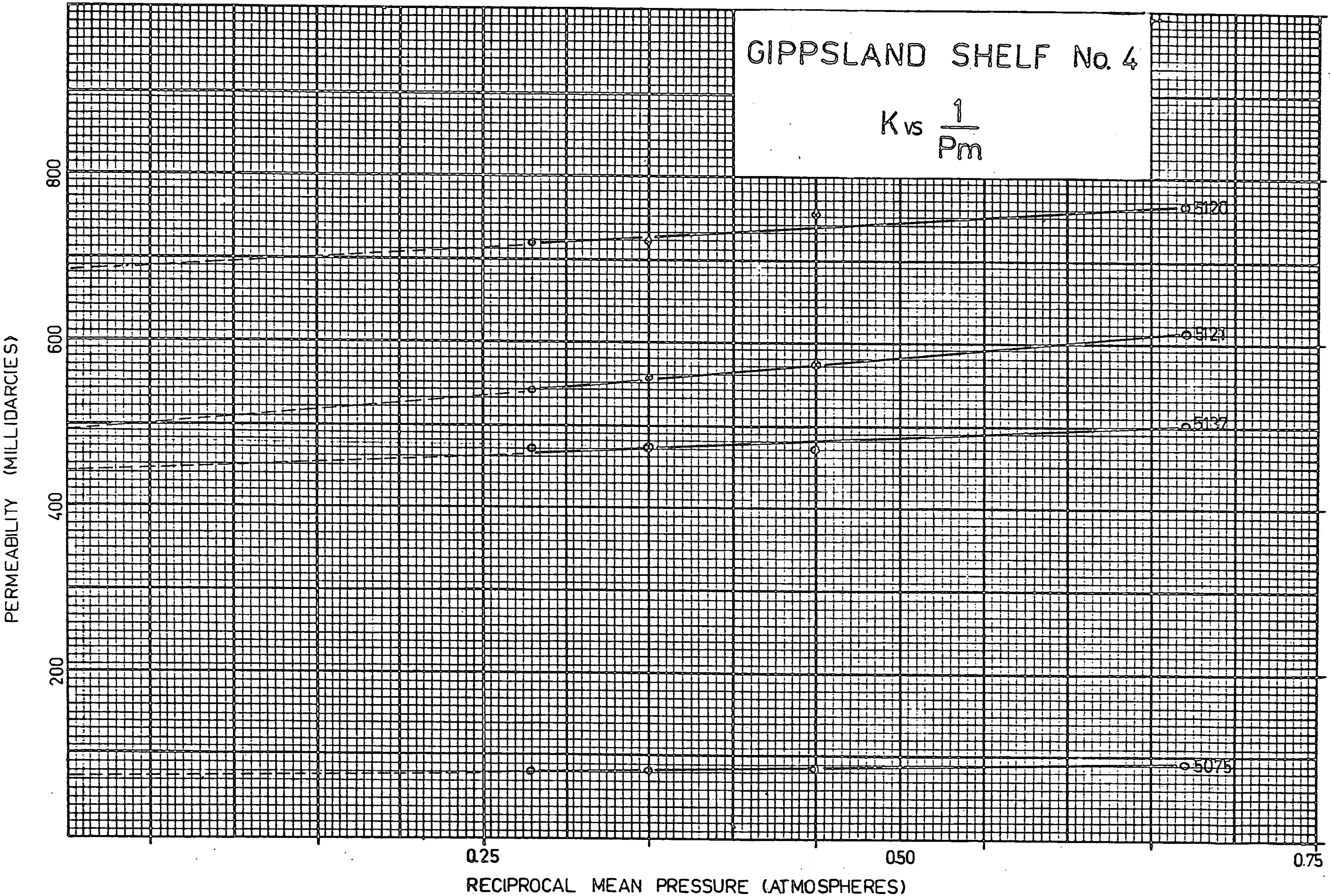

GIPPSLAND SHELF No. 4
K vs 1/Pm
PERMEABILITY (MILLIDARCIES)
800
600
400
200
0.25
0.50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
5120
5121
5137
5075

FIGURE 50

FIGURE 51

GIPPSLAND SHELF No 4 ELECTRICAL LOG