

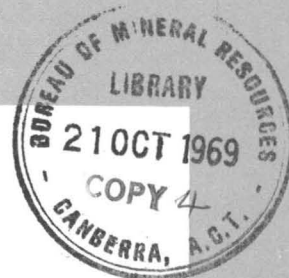
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**Bureau of Mineral Resources,
Geology and Geophysics
Mineral Resources Branch
Petroleum Technology Section**

Gage Roads No. 1

**Special Core Analysis Tests on Core
Samples from the Gage Sandstone and
Yarragadee Formation**

by

B.A. McKay

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BUREAU OF MINERAL RESOURCES, GEOLOGY AND GEOPHYSICS

MINERAL RESOURCES BRANCH

PETROLEUM TECHNOLOGY SECTION

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SPECIAL CORE ANALYSIS TESTS ON CORE
SAMPLES FROM THE GAGE SANDSTONE AND
YARRAGADEE FORMATION

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INTRODUCTION

An extensive petroleum exploration programme has been commenced by West Australian Petroleum Pty. Ltd. in their offshore titles. Using the jack-up drilling platform "Jubilee", a number of wells have been drilled and more are scheduled on their holdings over parts of the West Australian continental shelf.

Gage Roads No. 1 was the second in the series of wells programmed. It was drilled in 191 feet of water, 9 miles west-north-west of Rottnest Island (WA-14-P). The well was spudded with the "Jubilee" on November 27, 1968, and was drilled to a final depth of 12,009 feet.

Two hydrocarbon shows were encountered during drilling. One was in the Lower Cretaceous "Gage Sandstone Formation" at 5,720 feet, the other at 8,590 feet in the Upper Jurassic/Lower Cretaceous "Yarragadee Formation".

Two combined swab and flow tests were conducted in the Gage Sandstone Formation. Crude oil ranging from 37°-41° API gravity was recovered in the two tests at a maximum rate of 300 B/D, accompanied by a considerable amount of water. The show in the Yarragadee Formation between 8,590-8,680 feet was not tested, because of indications of poor reservoir characteristics.

This report deals with core analysis results comprising porosity, permeability, capillary pressure, pore size distribution, resistivity and formation damage/repair tests on 20 separate samples from the two formations mentioned above. These tests were conducted to gain better understanding of the producing potential of these two hydrocarbon bearing zones.

PROCEDURE AND APPARATUS

Three separate sets of samples were used in these tests. These comprised nineteen $\frac{1}{2}$ -inch diameter plugs for fluid imbibition tests, twenty $\frac{1}{8}$ -inch diameter plugs for porosity, permeability and formation damage tests, and twenty $\frac{3}{4}$ -inch diameter plugs for capillary pressure and pore size distribution investigations.

The core samples were preserved at the wellsite by sealing in foil and paraffin; for test purposes therefore, the imbibition plugs were selected first. These plugs were cut from the cores parallel to bedding, trimmed to approximately $\frac{1}{4}$ inches in length and then immediately immersed in refined oil to retain the indigenous wetting characteristics.

The remaining plugs were diamond drilled parallel to bedding, and trimmed with a diamond saw to $\frac{1}{4}$ - $\frac{1}{2}$ inches in length. They were subsequently extracted using toluene in a pressure extractor for 8 hours, and dried in an oven at 110°C for 48 hours.

The imbibition plugs were tested in the following manner: each sample was flushed with the equivalent of several pore volumes of oil (Soltrol-C) in a flexible rubber sleeved Hassler-cell, to ensure that residual water saturation was established in the samples. The plugs were then immediately immersed in water, and the amount of oil displaced by water (imbibition) over a seven day period was noted in each.

On completion of the imbibition tests, the same samples were used for the determination of resistivity and formation factors. They were first thoroughly extracted with toluene, and then oven dried at 110°C for 24 hours. The Gage Sandstone samples were then saturated with a 3.8% NaCl brine(*1,) while the Yarragadee samples were saturated with a 1.8% NaCl brine(*2.) Formation resistivity tests were then conducted in a Core Laboratories type core resistivity apparatus (Figure 35). This equipment consists of a dip-cell for measuring the resistivity of formation waters, and a core sample holder with spring mounted electrodes for determining core resistivity. A formation factor was calculated for each sample from the data, by expressing the core resistivity (in ohm-meters) as a fraction of the formation water resistivity. Formation factors were correlated with sample porosity; cementation factors for the zones were derived from the plotted slope of the above correlations.

The second set of samples was used for gas and liquid permeability determinations. Prior to these tests, porosity was measured in a Ruska-type mercury porosimeter, and single phase permeability to dry nitrogen in a rubber sleeved Hassler-cell.

Equivalent liquid permeability tests were then conducted on the ten samples from the Gage Sandstone formation to determine the flow capacity through these samples to a non-reactive liquid. Using nitrogen as the flowing phase, the permeability of each sample was measured at four different mean, but constant differential pressures. The four permeability values for each sample were then plotted as a function of the reciprocal mean pressure, giving the non-reactive liquid permeability (Klinkenberg).

Klinkenberg tests were not performed on the ten samples from the Yarragadee formation. The impermeable nature of these samples made flow rate and pressure control for evaluation of non-reactive liquid permeability too unreliable with the equipment available.

Separate single phase liquid permeability tests were then performed on each of the samples to determine its compatibility with various fluids. The flowing media used were a light refined oil (Soltrol-C); a 3.8% NaCl brine (Gage Sandstone); a 1.8% NaCl brine (Yarragadee Formation) and fresh water. Each of these tests was preceded by extraction and drying of the samples.

In addition the Gage Sandstone Formation samples were also subjected to permeability evaluations at increasing simulated overburden pressure in a high pressure Hassler-cell, with Soltrol-C as the flowing phase. Confining pressure around the core plugs was increased in steps, from nominal (140 p.s.i.)

(*1) - Salinity determined on water produced from drill-stem test.

(*2) - Salinity determined from electric log.

to 6,000 p.s.i., and permeability at each pressure was evaluated.

Two phase liquid flow (formation damage/repair) tests were also performed on the Gage Sandstone Formation samples. These were carried out to investigate the effects of mud filtrate invasion around the well bore during drilling and completion operations, and subsequent flushing of the invaded zone by oil during production.

For these tests, the samples were initially saturated with a 3.8% NaCl brine, and flushed to residual brine saturation with Soltrol. The samples were then subjected to a fresh water flood to residual oil saturation (invasion), and then flushed with Soltrol-C to terminal fresh water saturation (production). Permeability to each phase was determined after production of the displaced phase had ceased in the effluent.

Mercury injection capillary pressure tests were then conducted using the set of twenty $\frac{3}{4}$ -inch core plugs. These tests were carried out in a Ruska - type mercury injection apparatus using the Purcell (1) method, whereby mercury, representing the saturating non-wetting phase, is injected into the samples at increasing pressure "steps". The quantity of mercury injected at each step is recorded.

To obtain hysteresis capillary imbibition or withdrawal curves, the pressure in each sample was subsequently reduced in steps from 1,500 to 0 p.s.i. After correction for mercury surface conformance and pump expansion were made, two curves, the injection and the withdrawal, were plotted for each sample.

Pore size distribution values were calculated from the above mercury injection capillary pressure tests, using the formula $r = \frac{2\gamma \cos \theta}{\Delta P}$. Average pore "throat" radii for corresponding saturation pressure intervals were calculated using values of 480 dynes/cm for mercury surface tension (γ), and 140° as the mercury-rock contact angle (θ).

DISCUSSION

The results of the foregoing tests are tabulated as follows:

- (i) Tables 1 and 2 - single and two phase liquid flow tests.
- (ii) Table 3 - water/oil imbibition results.
- (iii) Table 4 - porosity, absolute permeability to nitrogen, and formation factors.
- (iv) Table 5 - pore throat radius for corresponding saturation pressure intervals.

Figures 1-20 present the results of the mercury injection-withdrawal capillary pressure tests; Figures 21 and 22 present the graphical correlation between porosity and formation factor for the samples; Figures 23 and 24 show the Klinkenberg test results, while Figures 25-33 present the results of the overburden pressure vs. permeability tests on the Gage Sandstone Formation. The positions of the various samples used in testing are referred to on the electrical log shown in Figure 34 and a diagram of the core resistivity apparatus is shown in Figure 35.

The single phase liquid permeability tests to brine and fresh water, shown in Figure 1, indicate that the Gage Sandstone Formation is reasonably compatible with these two fluids. Flow capacity varied from a minimum of 17% to a maximum of 77% of equivalent liquid permeability to the brine and fresh water phases; permeability disparity between the two phases in each sample was generally of a low order.

Two phase liquid flow tests simulating formation damage and resultant attempts at permeability repair, also shown in Table 1, indicated some permanent permeability damage to the Gage Sandstone Formation. The initial mud filtrate invasion (fresh water flood) of oil saturated cores, showed reductions in excess of 99% of the equivalent liquid values. Subsequent attempts at repair by flushing the fresh water invaded cores with oil were only partially successful; resultant flow capacity to oil after 24 hours attained less than one-half its value prior to performing the damage tests.

Single phase flow tests using oil, brine and fresh water in the Yarragadee Formation (Table 2) indicate a reservoir rock which is quite compatible to these fluids. No severe reductions in permeability were noted, and generally stabilized flow rates were a characteristic of these samples. Two phase flow tests as above were not attempted with these samples because of the generally low permeability, and the extremes in time and pressure required to obtain stabilized saturation conditions.

The overburden tests conducted on the Gage Sandstone Formation (Figures 25-33) did not indicate any severe reduction of permeability with increased confining pressure. At 6,000 p.s.i. confining pressure, permeability ranged from 61 to 77 per cent of the flow capacity at nominal (140 p.s.i.) confining pressure. The greatest permeability reduction occurred between 140-2,000 p.s.i. confining pressure; subsequent increases in the simulated overburden to a maximum of 6,000 p.s.i. did not cause appreciable permeability reductions. The trend at test completion was towards stabilized flow capacity with increasing overburden pressure.

Qualitative water-oil imbibition tests as shown in Table 3, indicate that all samples as received were water wet. The maximum amount of oil displaced by water during these tests was 35% of pore volume, from the more permeable samples.

The samples as used in these imbibition tests were sealed from well-site to laboratory, thus retarding weathering of the cores. The degree of wetting as determined in the laboratory should therefore approximate to the natural wetting properties of the reservoir.

The formation factor/porosity plot of both the Gage Sandstone and Yarragadee formation indicates a reasonably good correlation between these two parameters. Point scattering appears to be most severe in the Gage Sandstone Formation, partly due to the limited range of porosity (21%-29%).

The cementation factor, derived from the slope of the formation factor/porosity plots, was 1.86 for the Gage Sandstone, and 1.82 for the Yarragadee Formation. Archie's⁽²⁾ classification system places this in a moderately well cemented category, with porosities ranging up to 20%. This characterizes the lithology of the Yarragadee Formation, but is not entirely consistent with the Gage Sandstone Formation (moderately cemented, porosity ranging up to 29%).

Wyllie and Patnode⁽³⁾ have shown that the presence of clays in formations can have considerable effect on the formation factor, the latter increasing with increasing formation water salinity. This may result in a cementation factor higher than the apparent physical properties would suggest.

The lithology and two-phase liquid flow tests on the Gage Sandstone have shown this formation to contain certain clays. Therefore, a cementation factor of 1.86 would probably be normal for this type of material. In addition, variations of clay concentration in the samples have undoubtedly contributed to point scattering in the formation factor/porosity plot.

A comparison of the capillary pressure test results of the Gage Sandstone and the Yarragadee Formation reveals considerable differences. The mercury injection curves of the former are characterized by low threshold pressures and reasonably low indicated water saturations; the latter by medium to high threshold pressures and high to very high indicated water saturations. The mercury withdrawal curves, simulating the hydrocarbon producing characteristics by imbibition, show the Gage Sandstone to have an average oil recovery of 27% of pore volume, the Yarragadee Formation an average oil recovery of 19% of pore volume.

However, considering a more realistic value of (mercury) reservoir capillary pressure of 600 p.s.i.a., oil recoveries would respectively be 21% and 7% of pore volume, with one half of the Yarragadee Formation being non-productive of oil. The configuration of the capillary curves in both formations below this point indicate that water production in the Gage Sandstone Formation could be possible, and very highly probable in the Yarragadee Formation.

CONCLUSIONS

(1) Gage Sandstone

The foregoing tests revealed this zone to have generally good reservoir characteristics. Both permeability, and especially porosity throughout the cored interval were very good, while capillary pressure tests generally indicated low threshold pressures and reasonably low residual water saturations.

Single phase liquid flow tests to brine and fresh water did not show any generally marked reductions in permeability to these two phases. However, severe reduction to flow capacity was apparent in two phase flow tests, when oil saturated cores were subjected to fresh water flooding. These (invasion) tests revealed reductions of flow capacity (in 6 instances) in excess of 99% of equivalent liquid permeability. Permeability to oil was restored to about half of its former value on extensive flushing with oil (production).

(2) Yarragadee Formation

Analysis of the cored material from this formation indicates a zone with very poor reservoir characteristics. Capillary pressure tests indicate water saturations and threshold pressures of the formation to be high. Permeability is generally shown to be quite low (<0.5 md.) except in cases of porosity development.

Single phase liquid permeability tests with respect to oil, brine and fresh water indicate this zone to be quite compatible with these three fluids.

REFERENCES

- (1) PURCELL, W.R. "Capillary Pressures; their measurement using mercury and the Calculation of Permeability Therefrom". Petroleum Transactions, AIME, February, 1949.
- (2) ARCHIE, G.E. "The Electrical Resistivity Log as an aid in Determining some Reservoir Characteristics". T.P. 1422; Transactions AIME; January, 1942.
- (3) PATNODE, H.W.
WYLLIE, M.R.J. "The presence of conductive solids in Reservoir Rocks as a Factor in Electric Log Interpretation". Transactions, AIME, 1950.

TABLE 1

SAMPLE DEPTH (FEET)	POROSITY (% BULK) VOLUME	PERMEABILITY TO NITROGEN (Md.)	EQUIVALENT LIQUID PERMEABILITY (Md.)	PERMEABILITY TO FRESH WATER (% E.L.P.)	PERMEABILITY TO 3.8% NaCl BRINE (% E.L.P.*)	PERMEABILITY TO SOLTROL-C AT RESIDUAL BRINE SATU- RATION (% E.L.P.*)	FORMATION DAMAGE/REPAIR TESTS		
							PERMEABILITY TO FRESH WATER AT RE- SIDUAL OIL SATURATION (% E.L.P.*)	PERMEABILITY TO OIL AT TERMINAL FRESH WATER SATURATION (% E.L.P.*)	
								IMMEDIATE	AFTER 24 HOURS
5876	26.6	200	167	77	77	65	0.1	25	19
5878	29.3	612	577	54	69	67	7.5	29	36
5880	25.7	525	438	53	53	58	10.5	13	16
5882	27.9	137	108	17	39	19	0.08	9.3	13
5884	21.1	185	147	59	64	54	6.3	33	36
5886	27.9	1120	1055	45	79	77	8.9	19	30
5888	28.0	255	230	23	33	30	0.5	4.0	2.0
5890	26.3	177	147	54	54	52	0.8	22	18
5892	28.3	598	550	15	24	31	0.3	9.8	21
5896	28.8	325	288	17	26	24	0.3	14.3	34

* E.L.P. - EQUIVALENT LIQUID PERMEABILITY

TABLE 2

SAMPLE DEPTH (FEET)	POROSITY (% BULK) VOLUME	PERMEABILITY TO NITROGEN (Md.)	PERMEABILITY TO FRESH WATER (Md.)	PERMEABILITY TO 1.8% NaCl BRINE (Md.)	PERMEABILITY TO SOLTROL-C (Md.)
8601	11.5	0.43	0.10	0.12	0.16
8603	18.3	1.4	0.49	0.59	0.66
8605	19.3	4.2	2.4	2.6	2.6
8607	17.2	1.2	0.48	0.54	0.54
8609	17.5	1.5	0.67	0.75	0.75
8611	11.2	0.22	0.02	0.03	0.06
8613	11.2	0.22	0.03	0.04	0.07
8615	9.8	0.15	0.01	0.02	0.03
8617	10.4	0.30	0.03	0.05	0.07
8619	8.0	0.43	0.01	0.02	0.10

TABLE 3

CORE NUMBER	SAMPLE DEPTH	POROSITY (% BULK) VOLUME	PERMEABILITY TO NITROGEN (md.)	SATURATING MEDIUM	VOLUME OF WATER IMBIBED % PORE VOLUME			
					AFTER 1 DAY	AFTER 2 DAYS	AFTER 3 DAYS	AFTER 7 DAYS
6	5876	26.6	200	SOLTROL-C	27.6	29.4	31.2	34.8
6	5878	29.3	612	"	16.2	17.5	18.9	18.9
6	5880	25.7	525	"	6.4	6.4	6.8	8.1
6	5882	27.9	137	"	7.7	7.7	10.0	10.0
6	5884	21.1	185	"	10.1	13.0	13.0	15.6
6	5886	27.9	1120	UNABLE TO OBTAIN FRESH SAMPLE				
6	5888	28.0	255	"	10.5	14.1	15.2	15.2
6	5890	26.3	177	"	12.4	12.8	13.2	13.2
6	5892	28.3	598	"	14.2	15.4	15.4	15.4
6	5896	28.8	325	"	31.5	33	35.0	35.0
9	8601	11.5	0.43	"	7.9	8.9	9.5	10.0
9	8603	18.3	1.4	"	20.5	21.9	23.3	23.3
9	8605	19.3	4.2	"	10.6	10.6	10.6	10.6
9	8607	17.2	1.2	"	12.1	13.5	15.1	15.1
9	8609	17.5	1.5	"	17.6	20.5	22.0	22.0
9	8611	11.2	0.22	"	0	TR.	3.2	3.2
9	8613	11.2	0.22	"	0	0	0	TR.
9	8615	9.8	0.15	"	0	TR.	2.7	2.7
9	8617	10.4	0.30	"	4.7	7.1	7.1	7.1
9	8619	8.0	0.43	"	4.0	8.0	9.6	10.4

TABLE 4

CORE NUMBER	SAMPLE DEPTH (FEET)	PERMEABILITY TO DRY NITROGEN (Md.)	POROSITY (% BULK) VOLUME	FORMATION FACTOR
6	5876	200	26.6	15.4
6	5878	612	29.3	13.5
6	5880	525	25.7	12.5
6	5882	137	27.9	11.7
6	5884	185	21.1	17.2
6	5886	1120	27.9	10.2
6	5888	255	28.0	10.9
6	5890	177	26.3	11.9
6	5892	598	28.3	10.1
6	5896	325	28.8	15.1
9	8601	0.43	11.5	44
9	8603	1.4	18.3	24
9	8605	4.2	19.3	21
9	8607	1.2	17.2	27
9	8609	1.5	17.5	27
9	8611	0.22	11.2	52
9	8613	0.22	11.2	53
9	8615	0.15	9.8	68
9	8617	0.30	10.4	54
9	8619	0.43	8.0	74

TABLE 5

	SATURATION (% PORE VOLUME)									SAMPLE DEPTH (FEET)
	0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	80-90	
AVERAGE PORE ENTRY RADIUS (MICRONS)	7.9	7.5	6.7	4.7	2.7	1.3	0.55	0.16		5876
	8.9	5.6	3.9	2.7	1.7	1.0	0.55	0.23		5878
	16.5	13.3	8.9	6.7	4.0	1.9	0.82	0.25		5880
	14.0	9.1	7.4	5.3	3.3	1.8	0.76	0.19		5882
	10.7	8.8	6.7	4.8	3.0	1.5	0.63	0.17		5884
	21.4	18.7	15.2	11.9	7.5	3.4	1.2	0.24		5886
	13.4	11.6	9.2	6.6	3.7	1.7	0.69	0.16		5888
	7.9	6.8	5.6	4.0	2.3	1.3	0.74	0.28		5890
	16.0	15.3	13.3	11.3	8.0	4.6	2.0	0.82	0.16	5892
	18.4	17.8	16.0	13.4	7.9	3.6	1.6	0.61		5896
		0.30	0.23	0.14						8601
		1.4	1.1	0.79	0.46	0.24	0.10			8603
		1.7	1.4	1.1	0.69	0.38	0.18			8605
		1.1	0.84	0.57	0.34	0.17				8607
		1.2	0.88	0.57	0.31	0.15				8609
		0.27	0.20	0.11						8611
			0.28	0.18						8613
		0.25	0.20	0.12						8615
	0.47	0.38	0.28	0.18						8617
		0.19	0.13							8619

FIGURE 1

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5876'

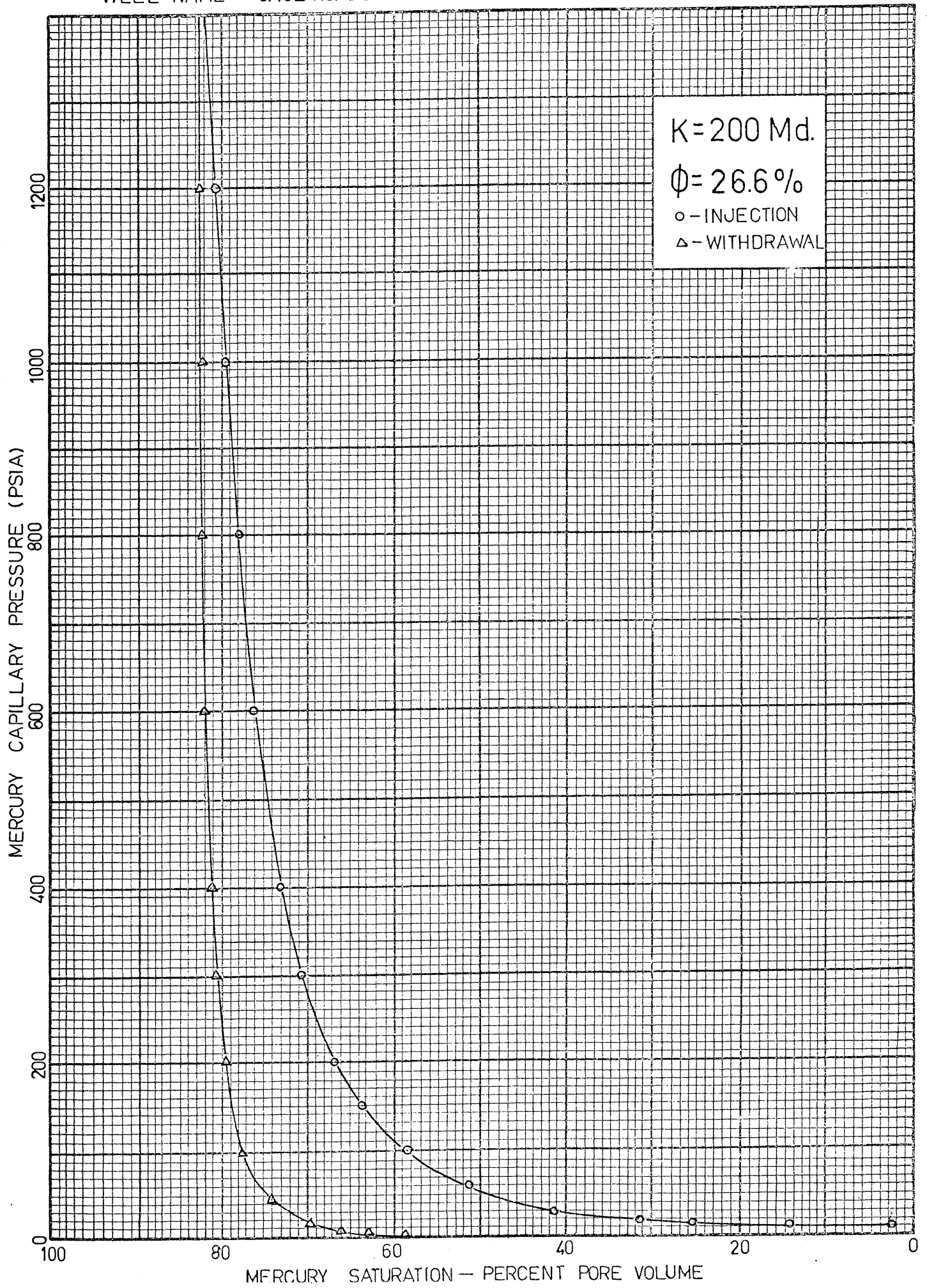


FIGURE 2

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5878'

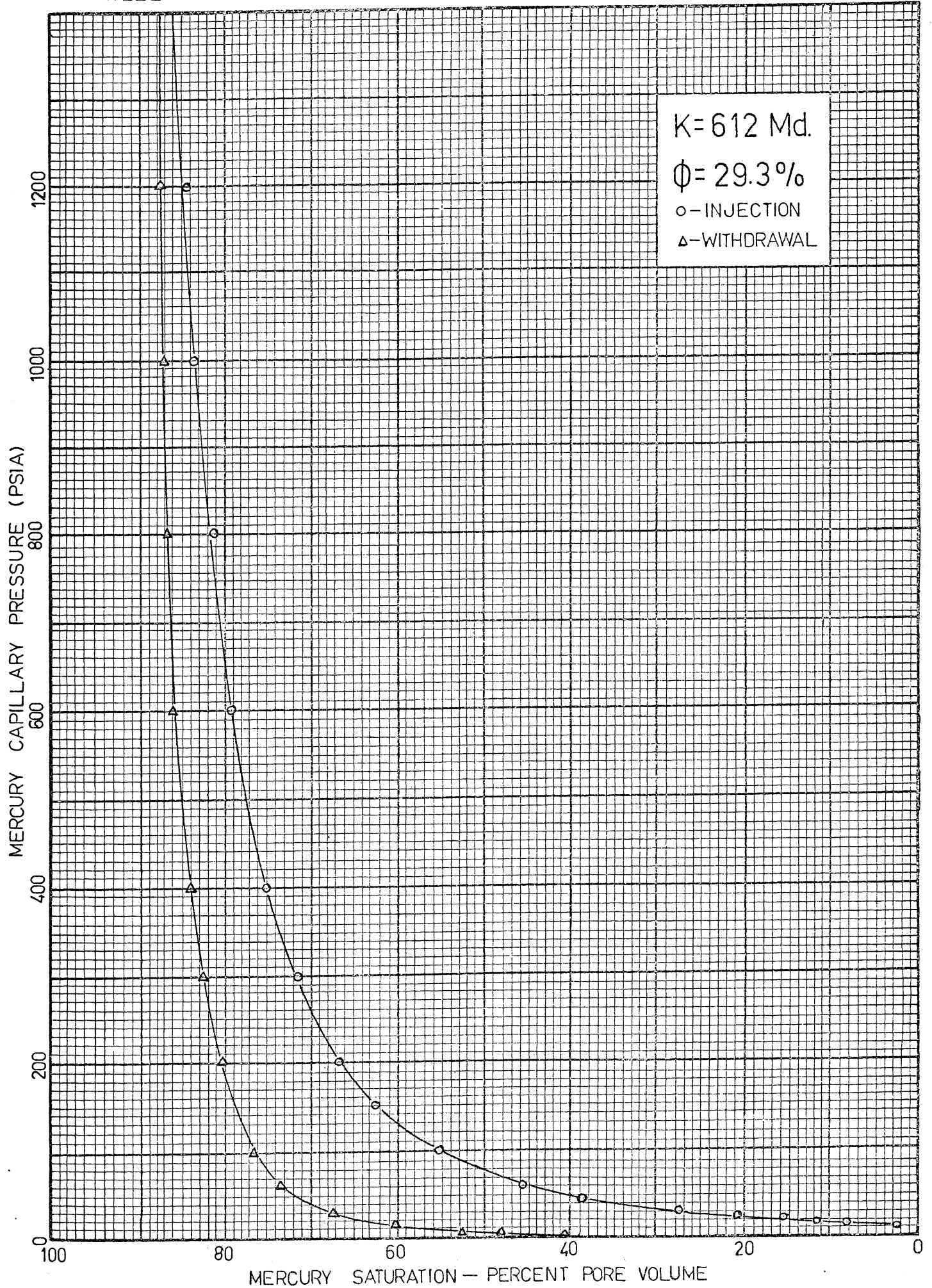


FIGURE 3

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5880'

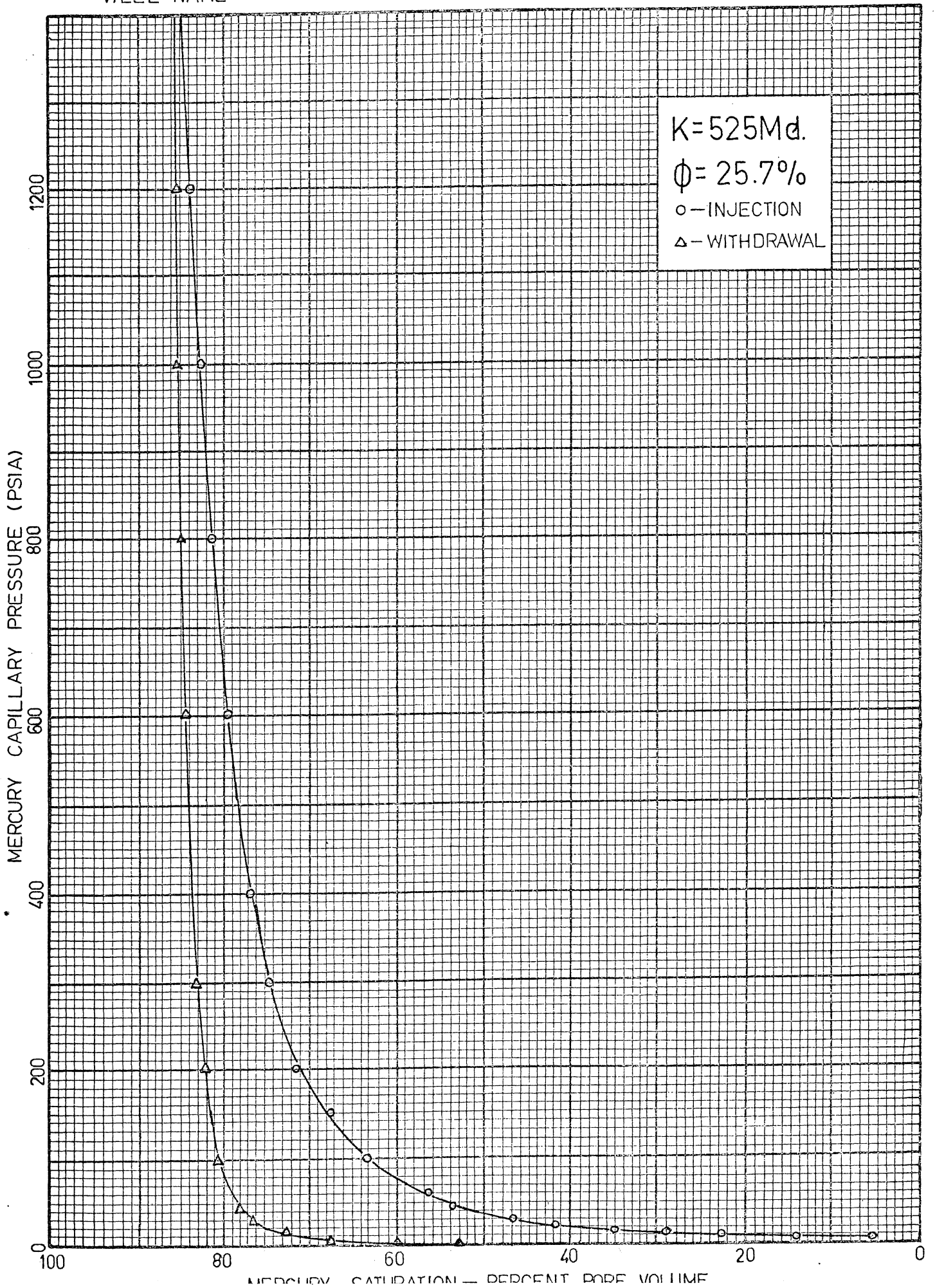


FIGURE 4

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5882

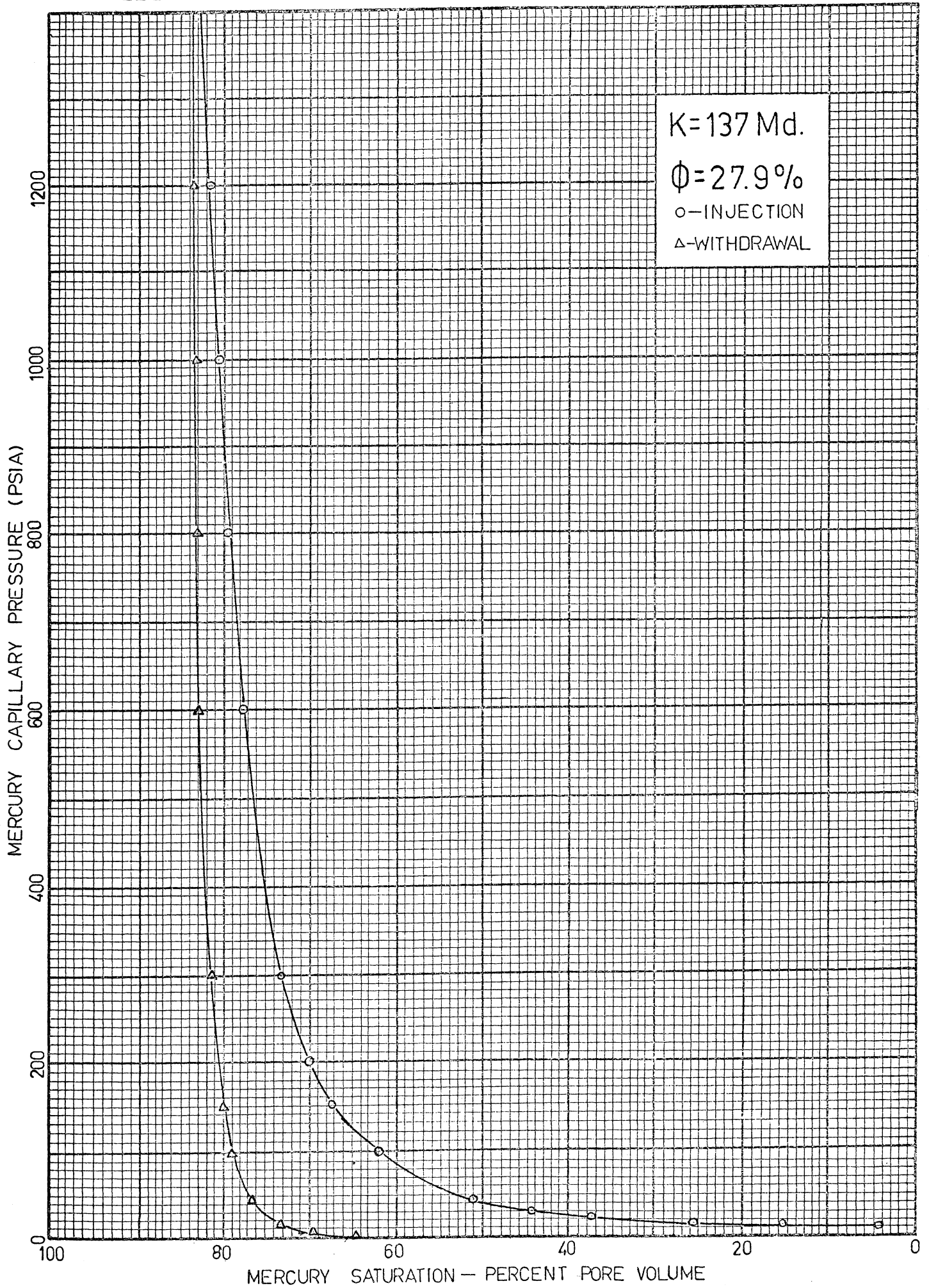


FIGURE 5

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH — 5884'

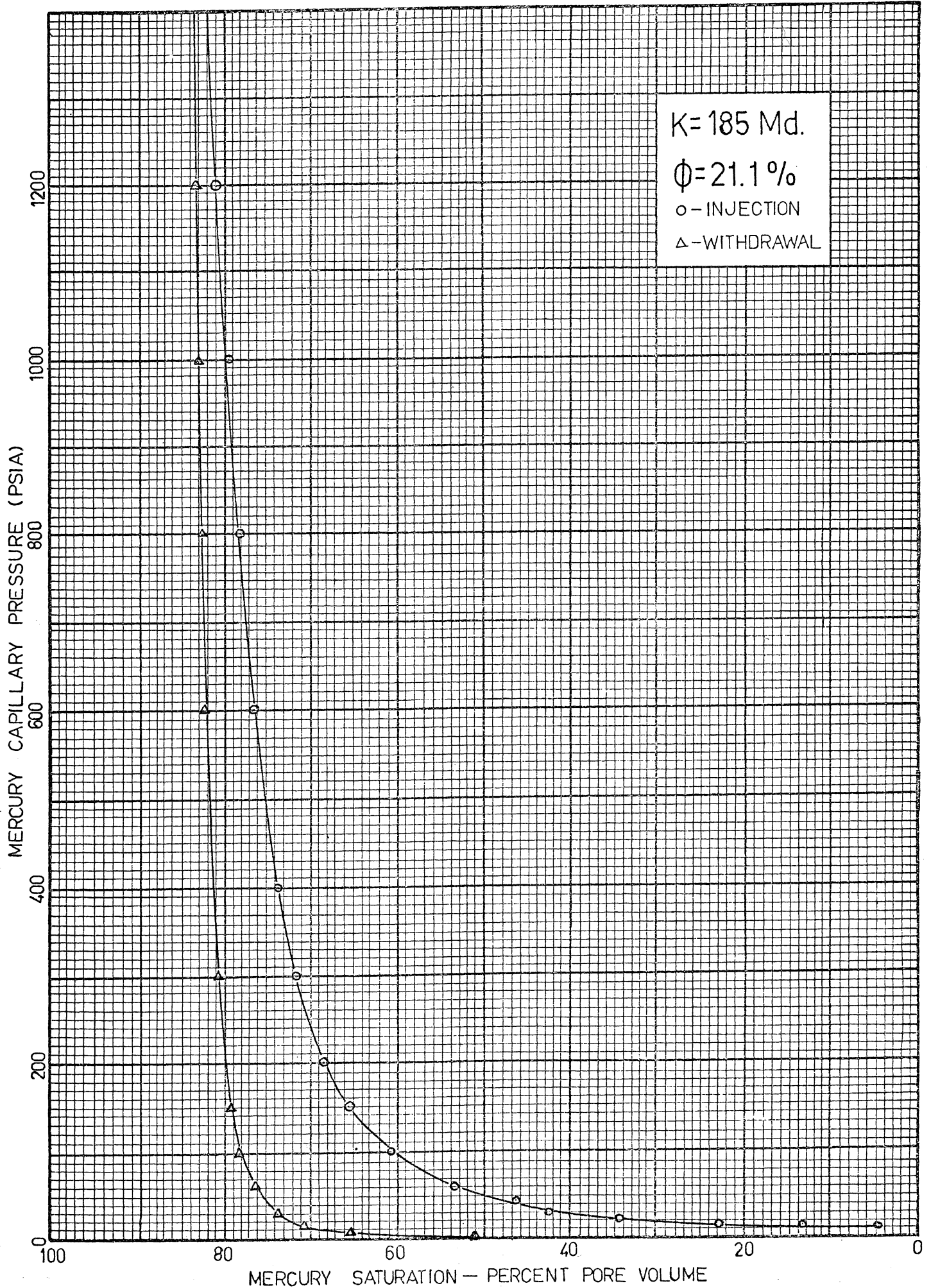


FIGURE 6

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No1

SAMPLE DEPTH — 5886'

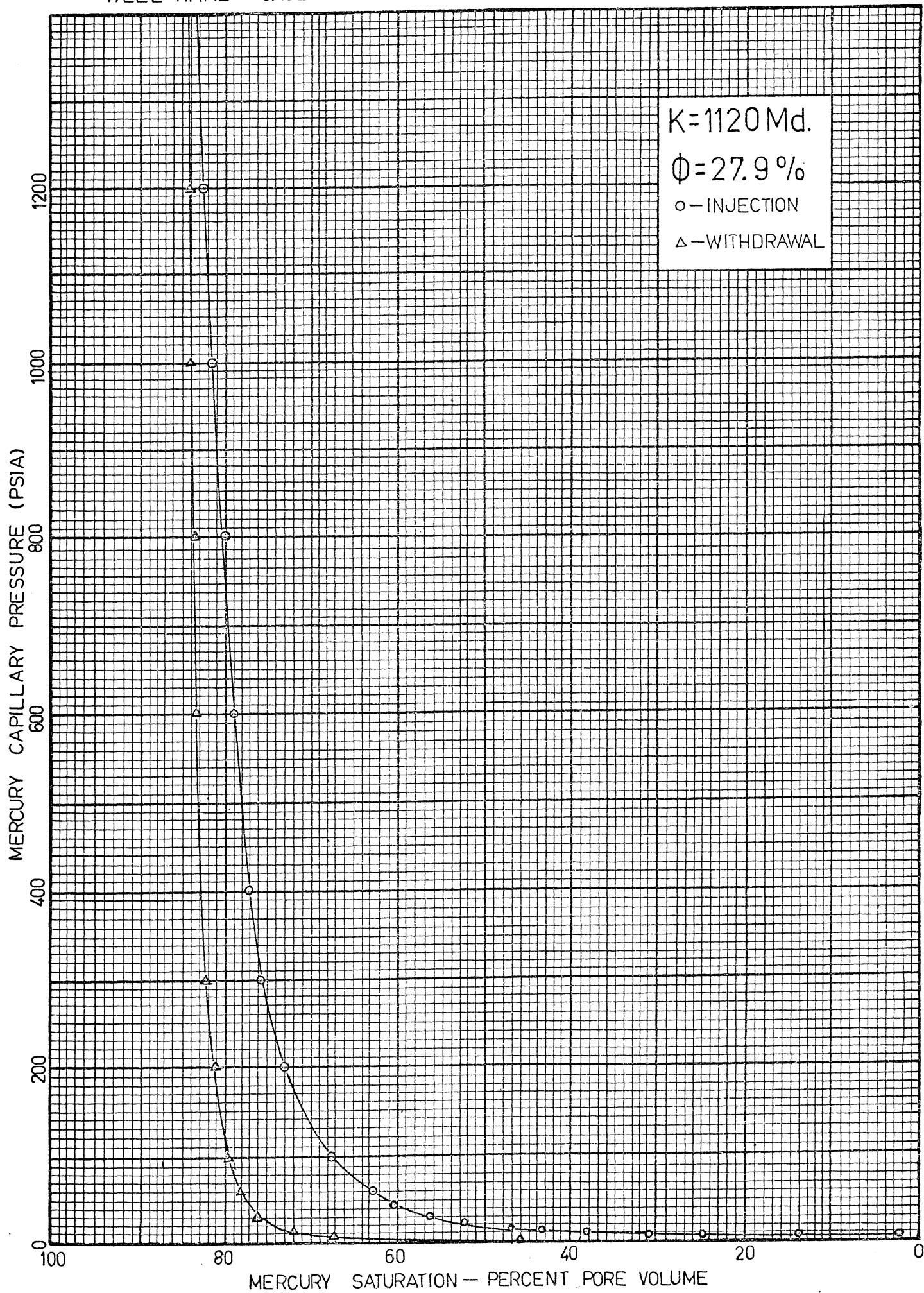


FIGURE 7

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5888'

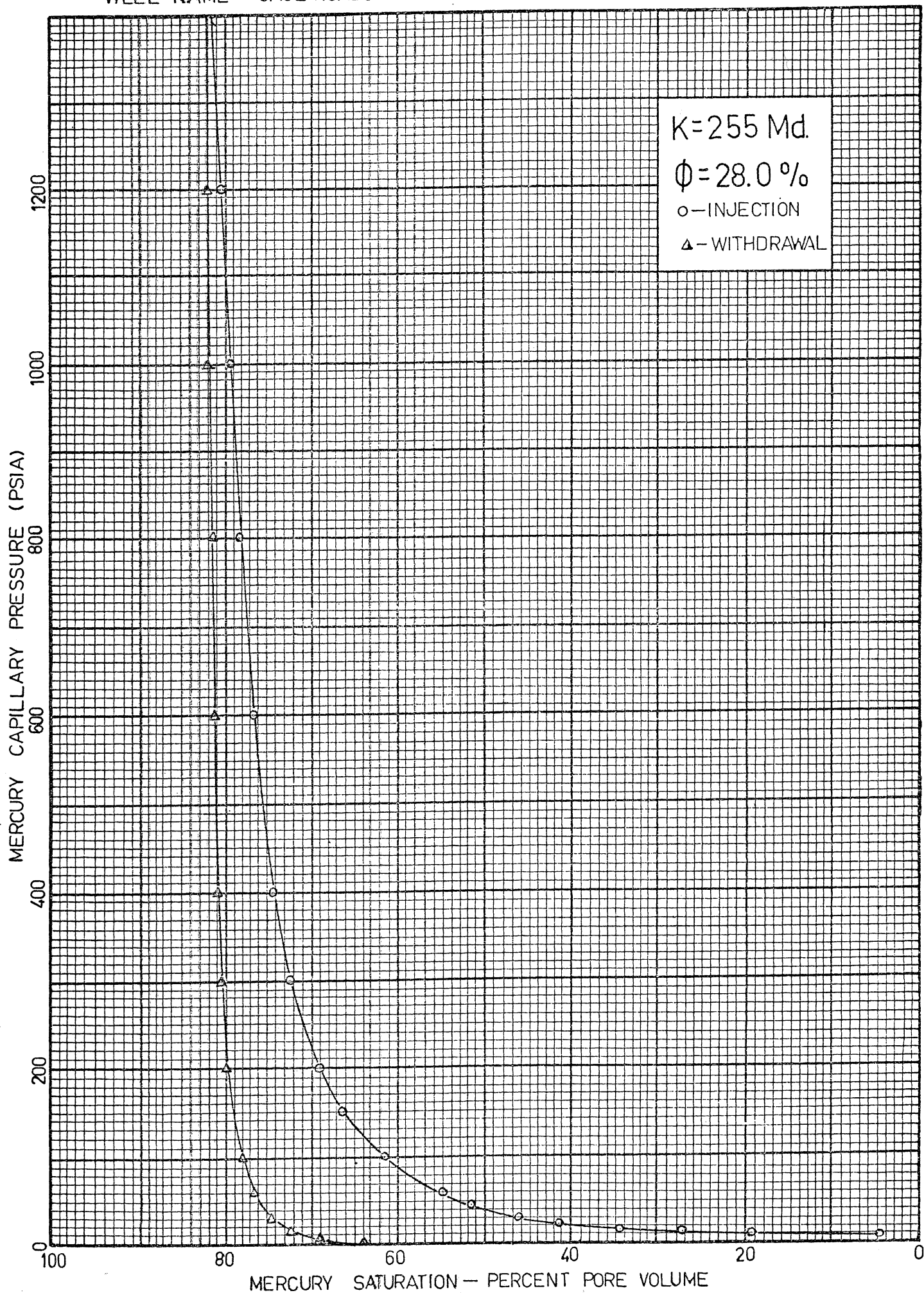


FIGURE 8

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5890'

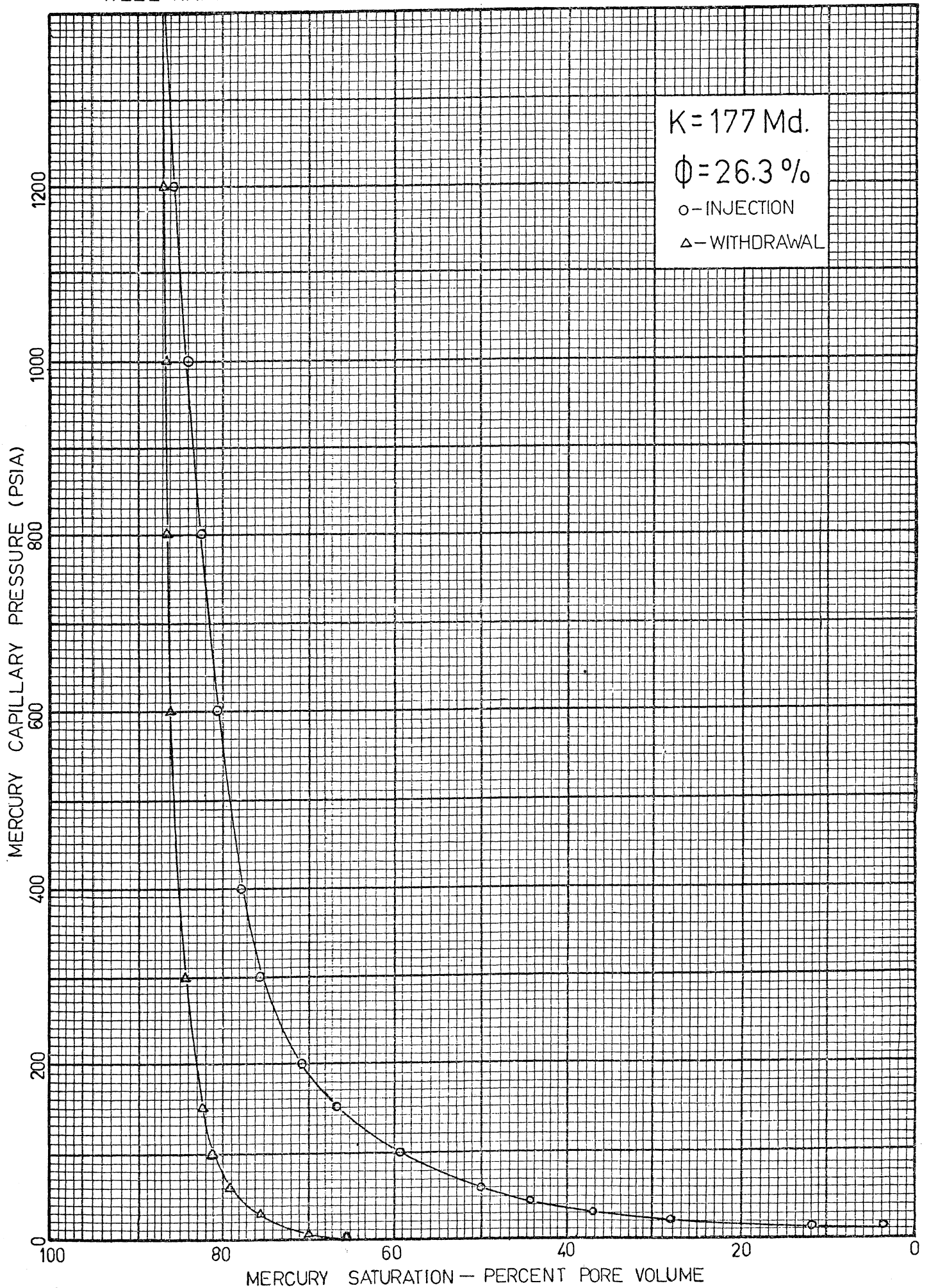


FIGURE 9

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 5892'

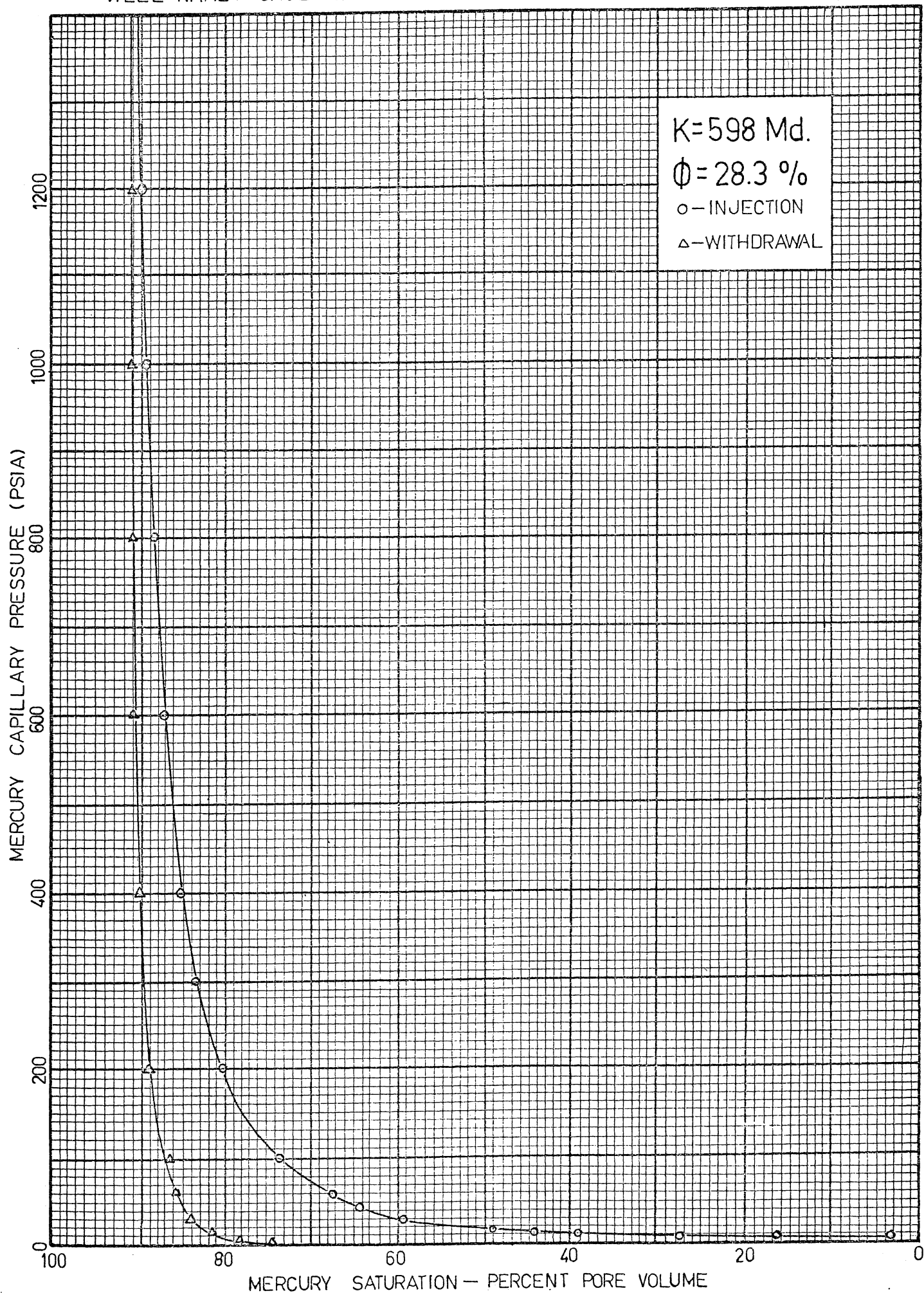


FIGURE 10

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No. 1

SAMPLE DEPTH—5896

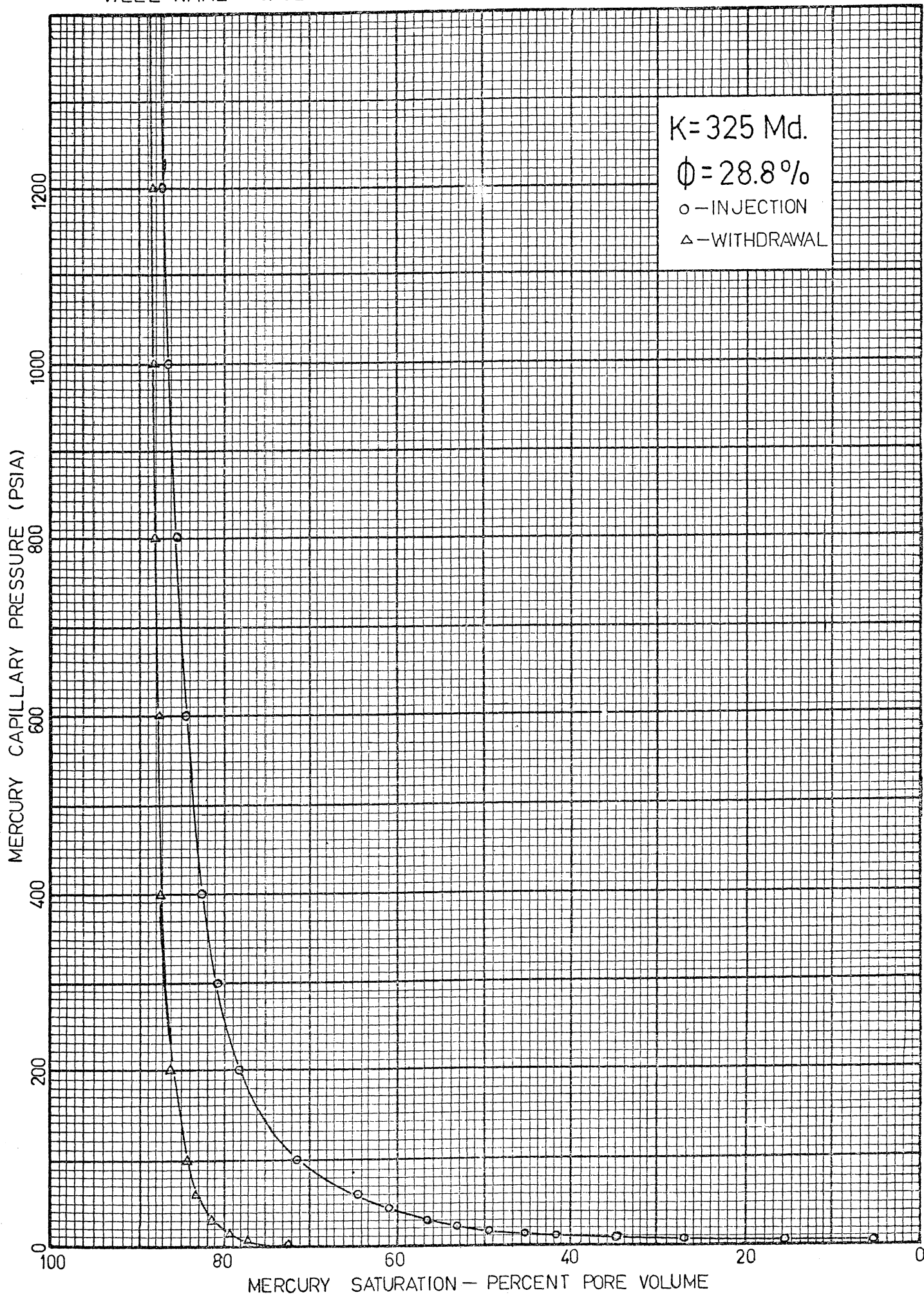


FIGURE 11

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH—8601'

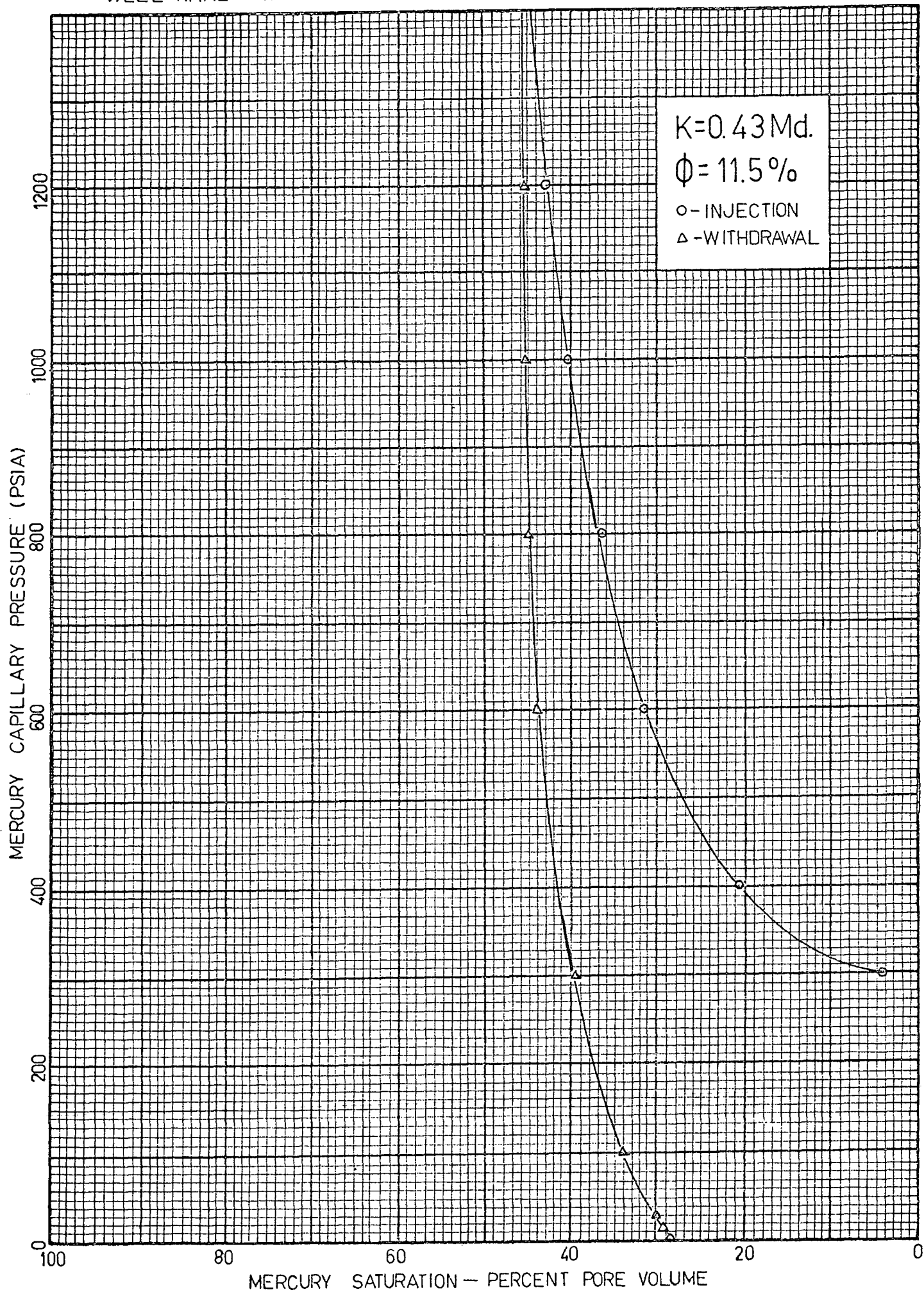


FIGURE 12

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH—8603'

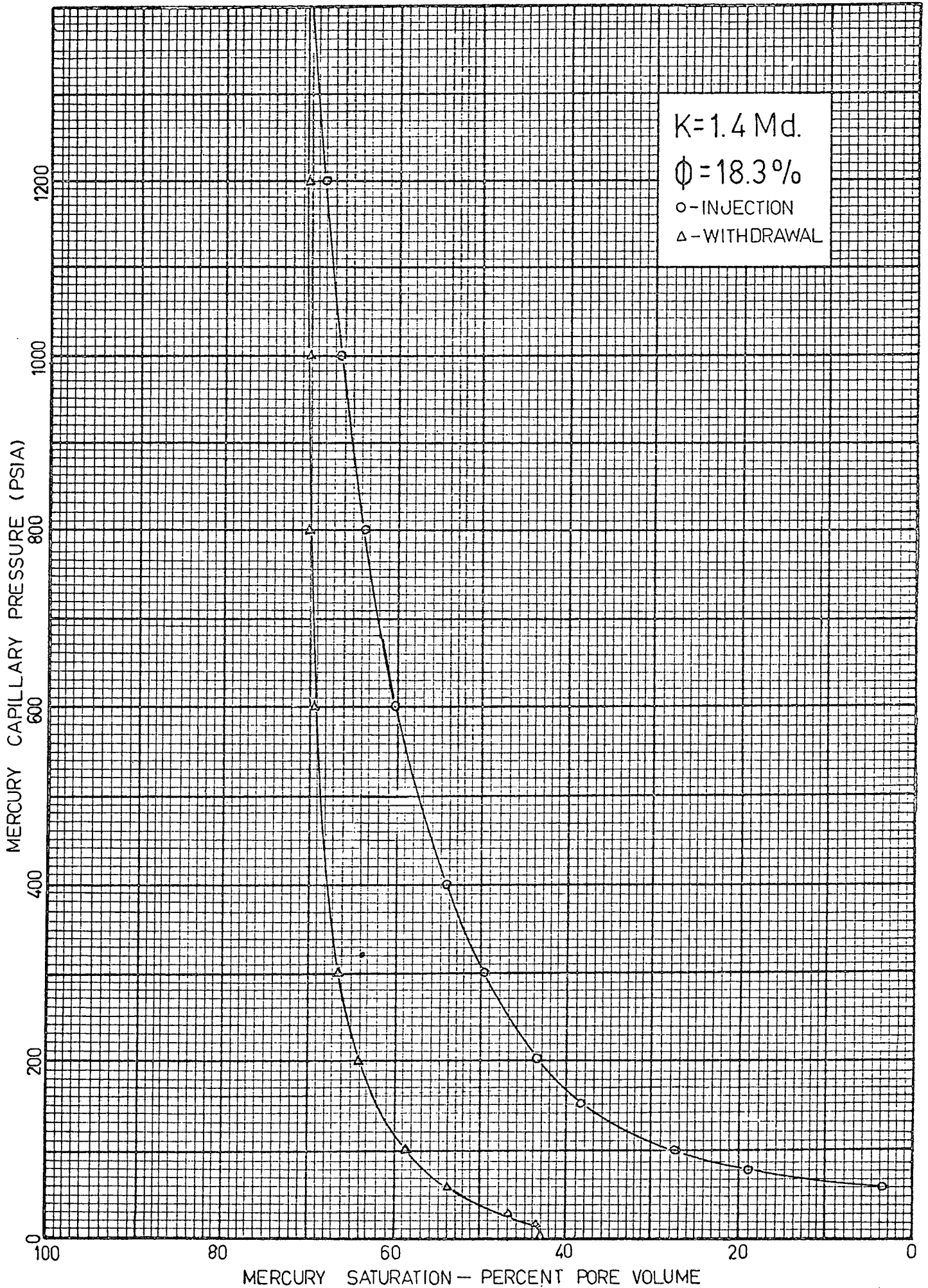


FIGURE 13

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH — 8605'

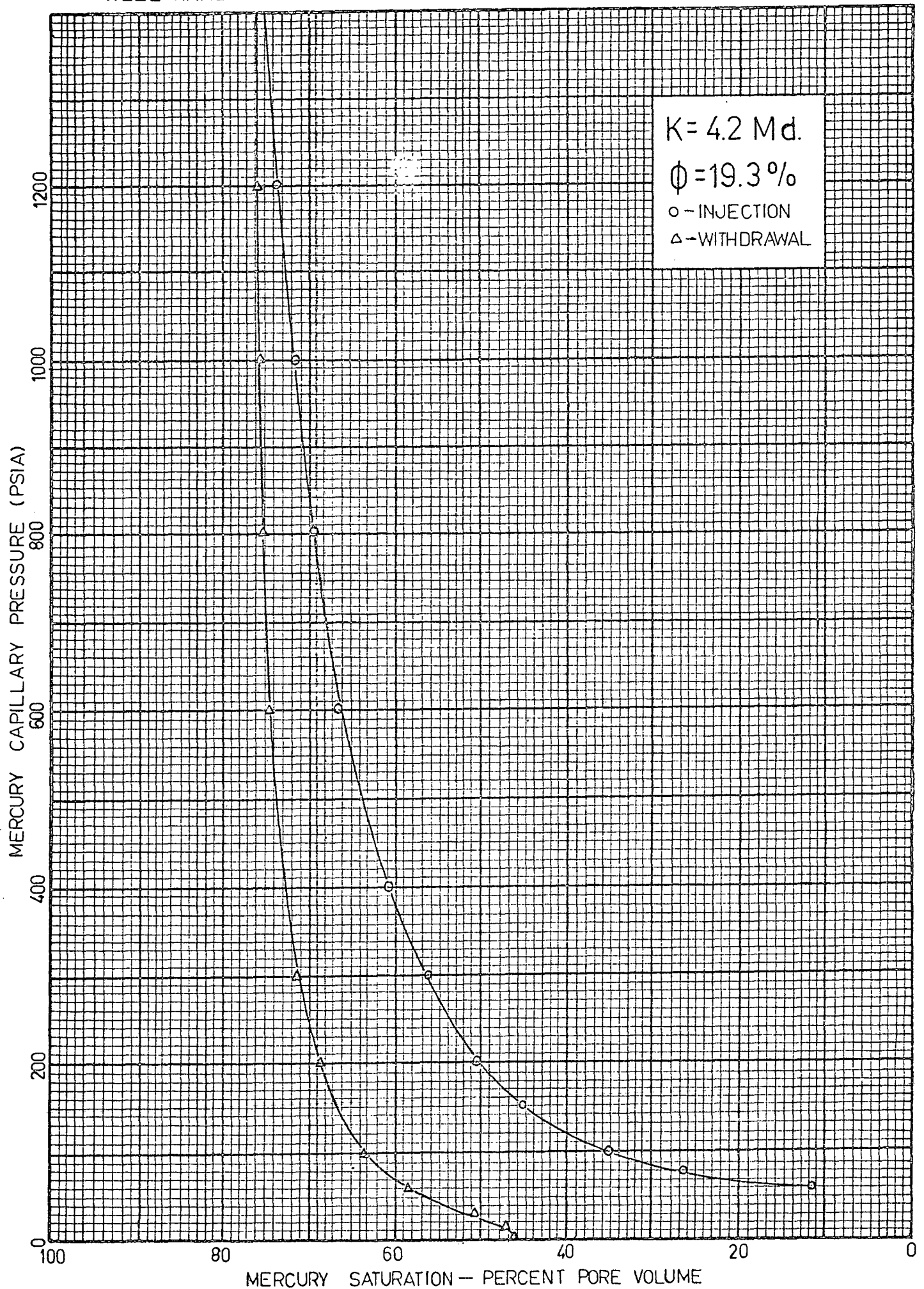


FIGURE 14

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 8607'

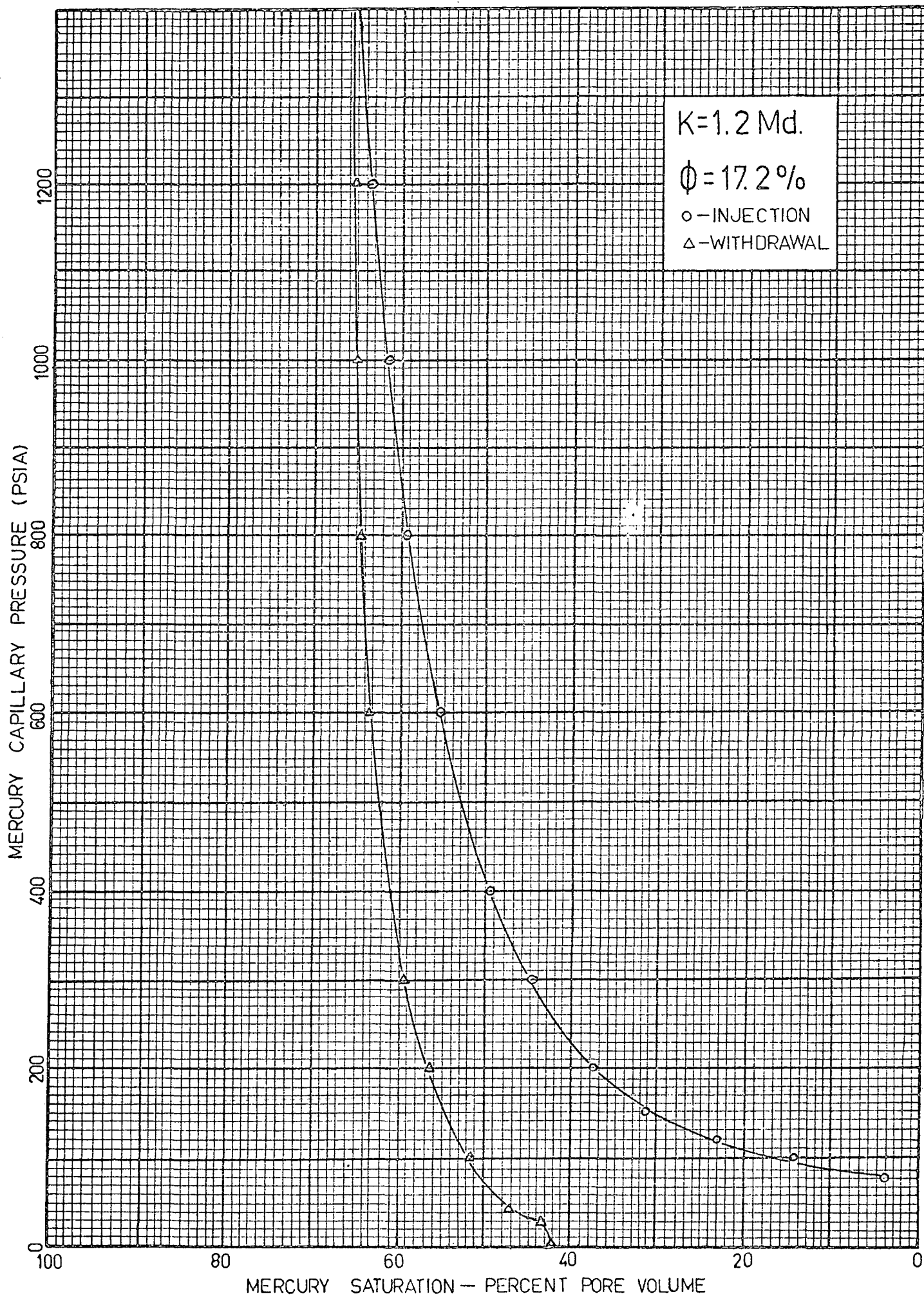


FIGURE 15

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No1

SAMPLE DEPTH — 8609'

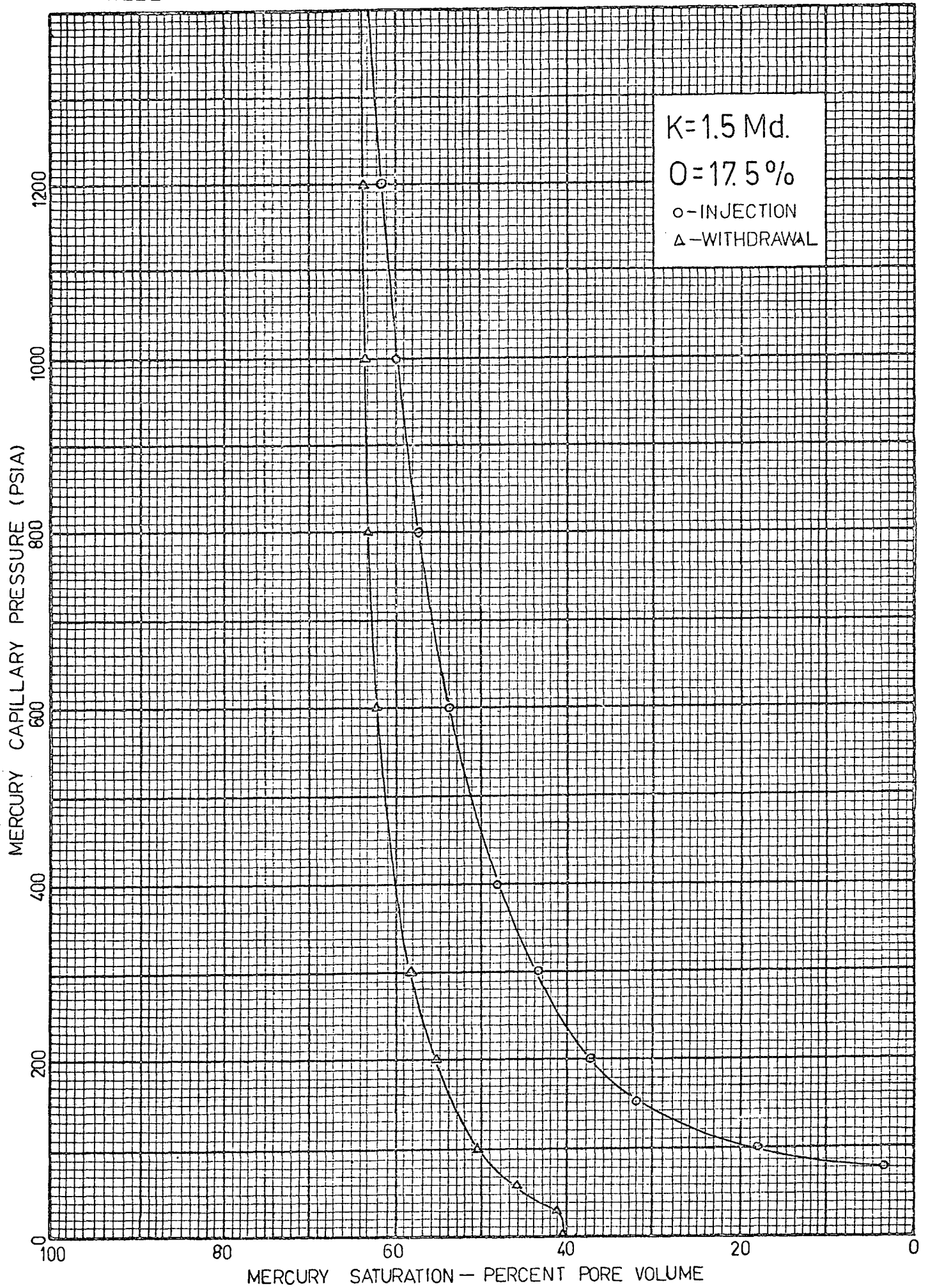


FIGURE 16

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No.1

SAMPLE DEPTH — 8611'

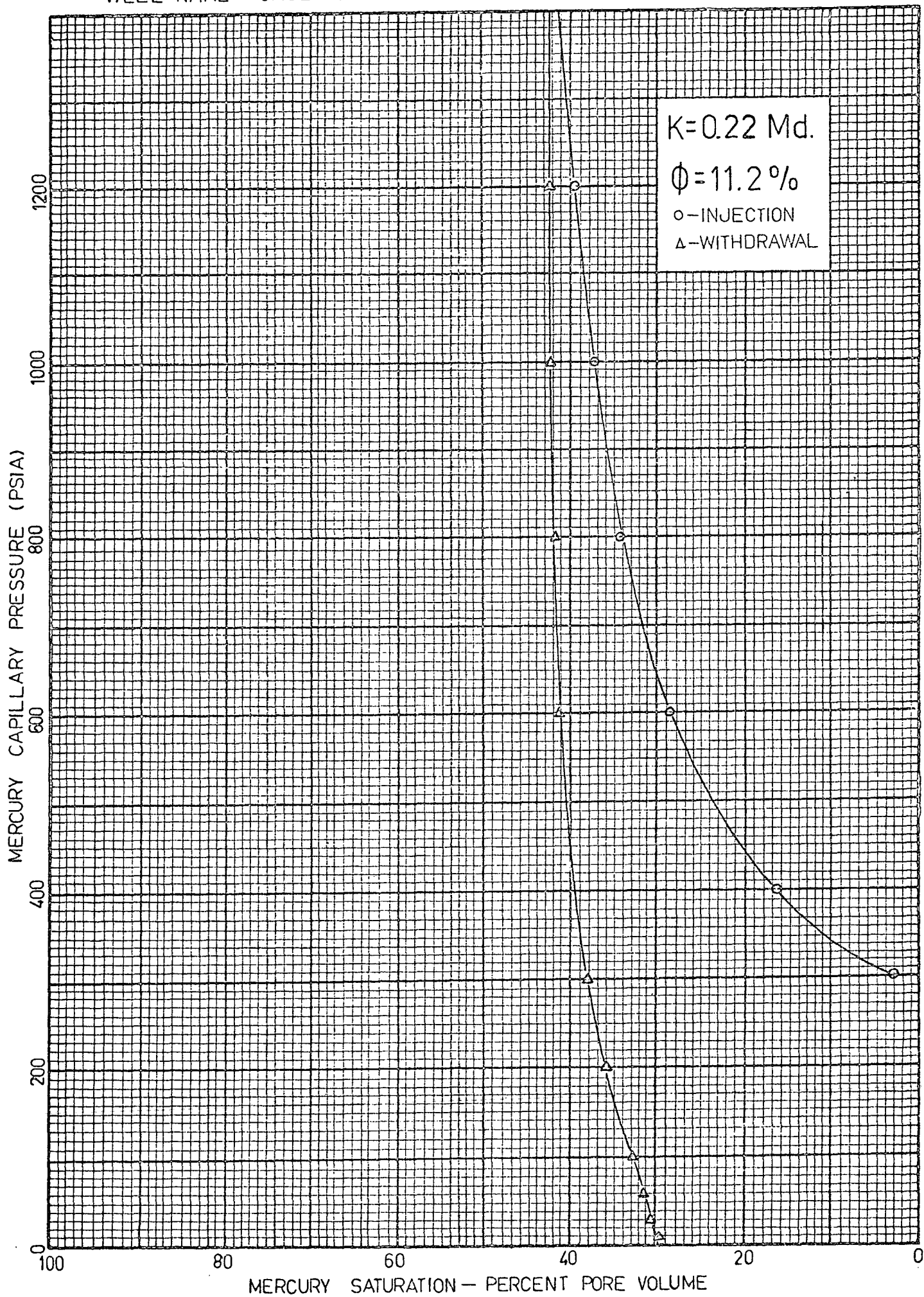


FIGURE 17

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH — 8613'

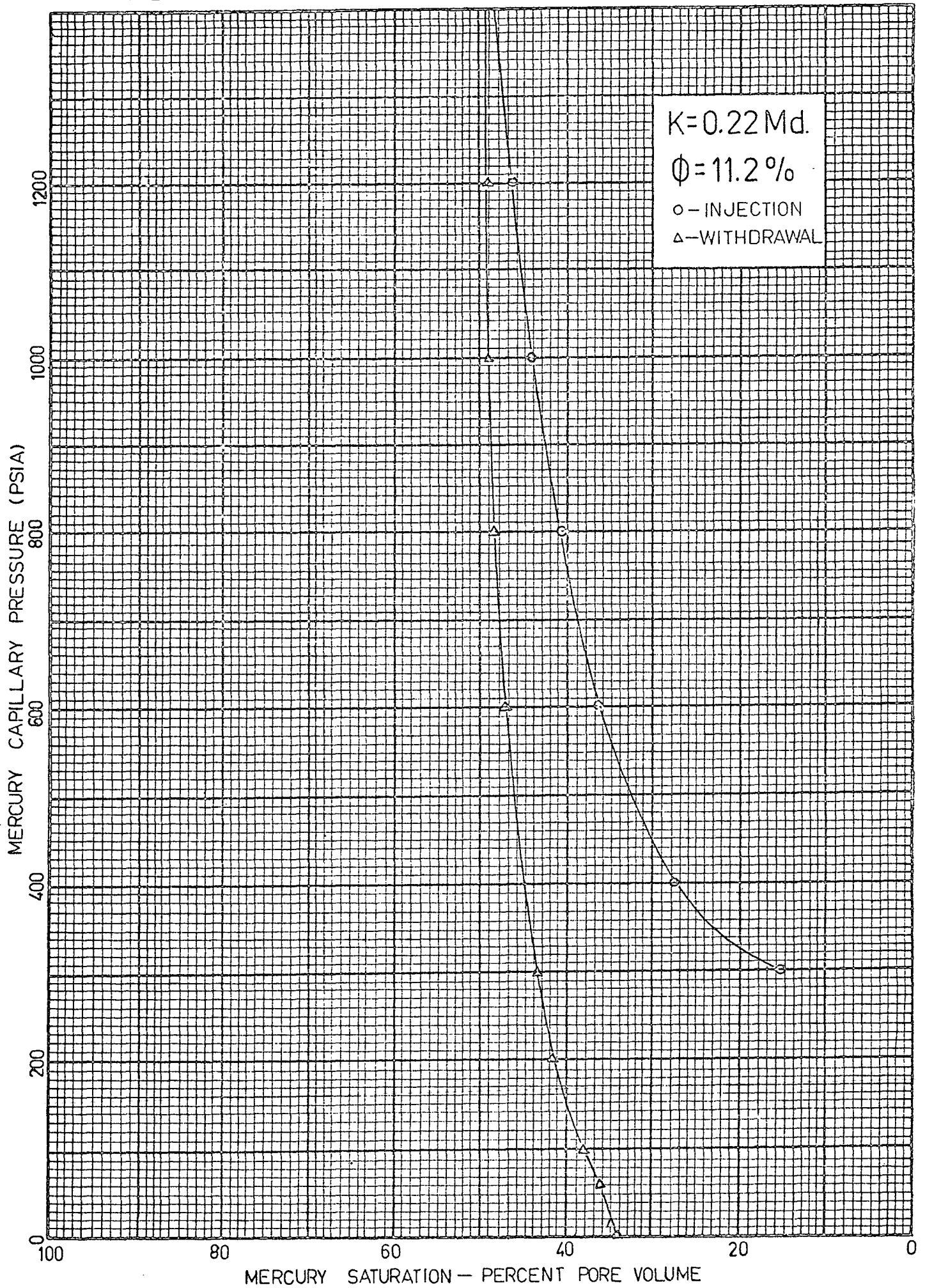


FIGURE 18

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH — 8615'

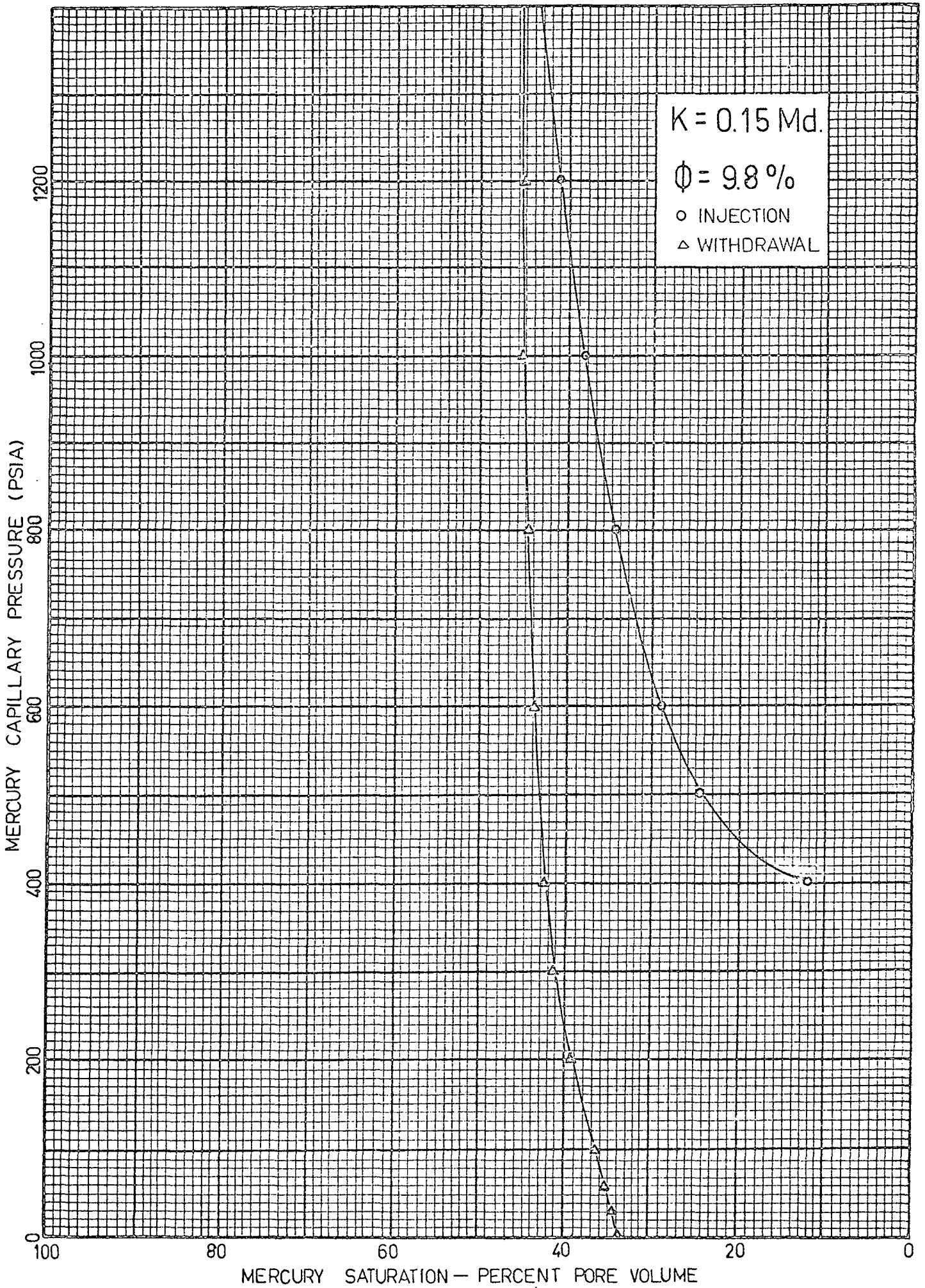


FIGURE 19

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No. 1

SAMPLE DEPTH — 8617'

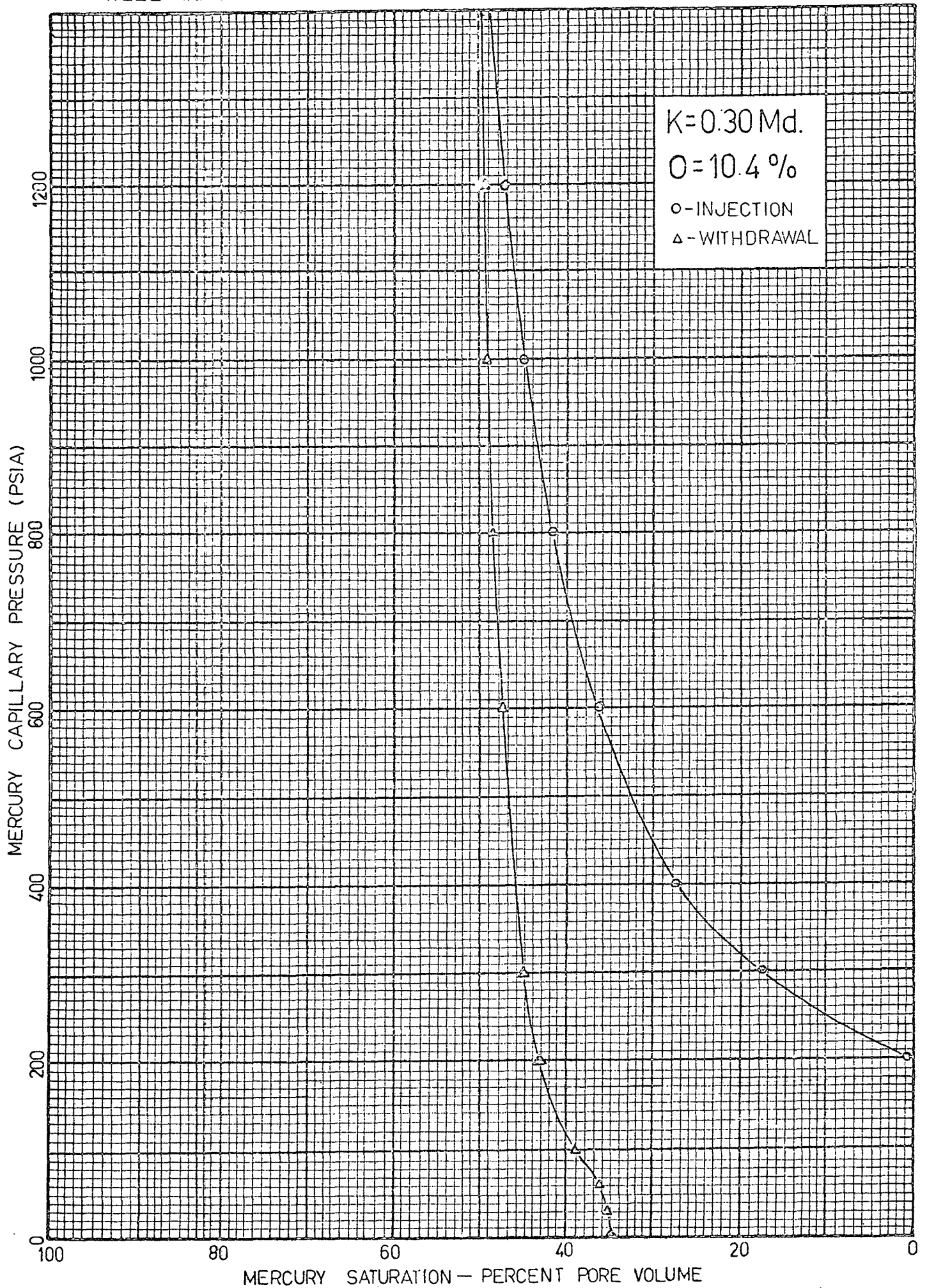


FIGURE 20

MERCURY CAPILLARY PRESSURE

WELL NAME — GAGE ROADS No 1

SAMPLE DEPTH — 8619'

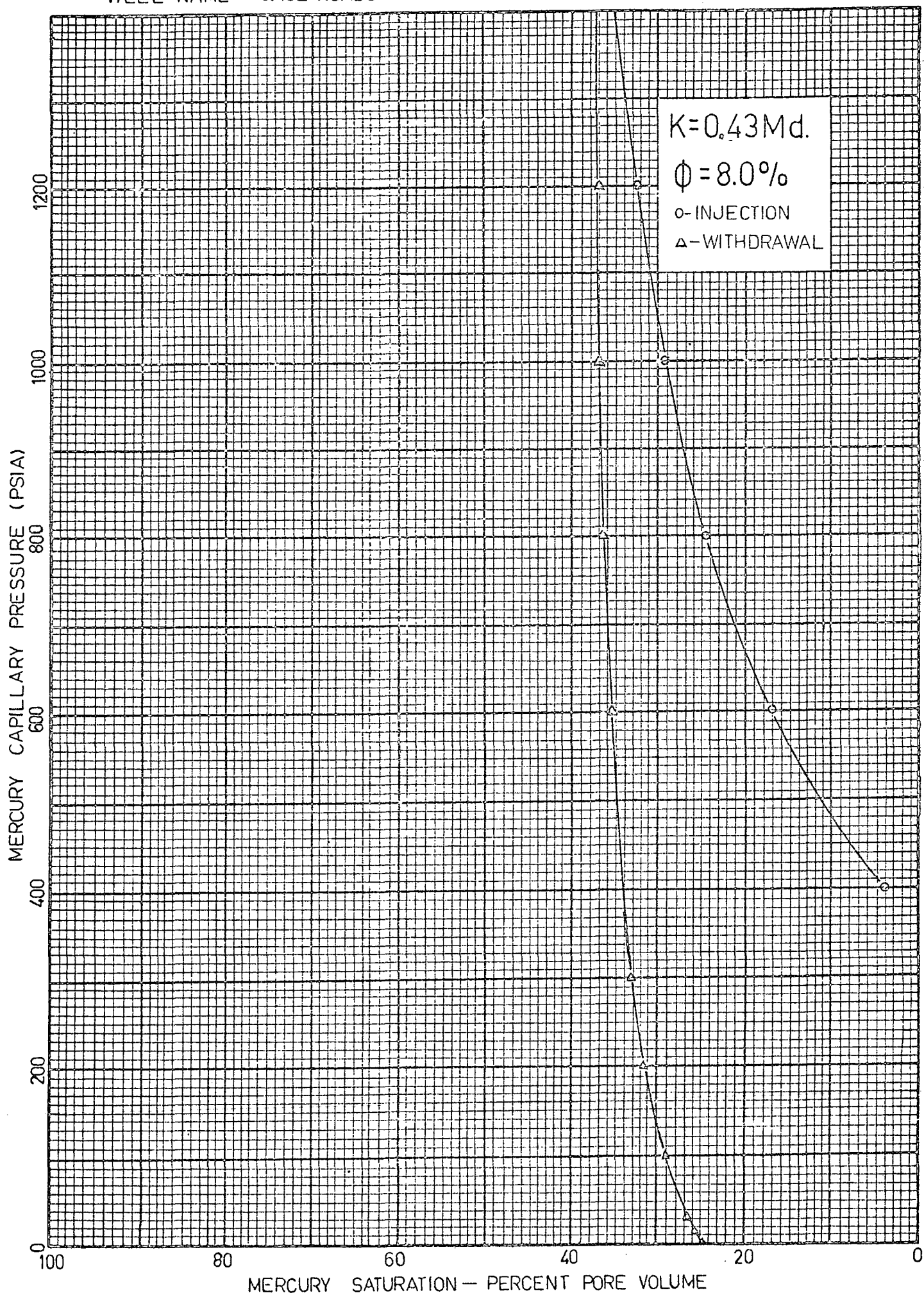


FIGURE 21

FORMATION FACTOR VS POROSITY

WELL NAME AND NUMBER - GAGE ROADS No. 1

DEPTH INTERVAL - 5876 to 5896

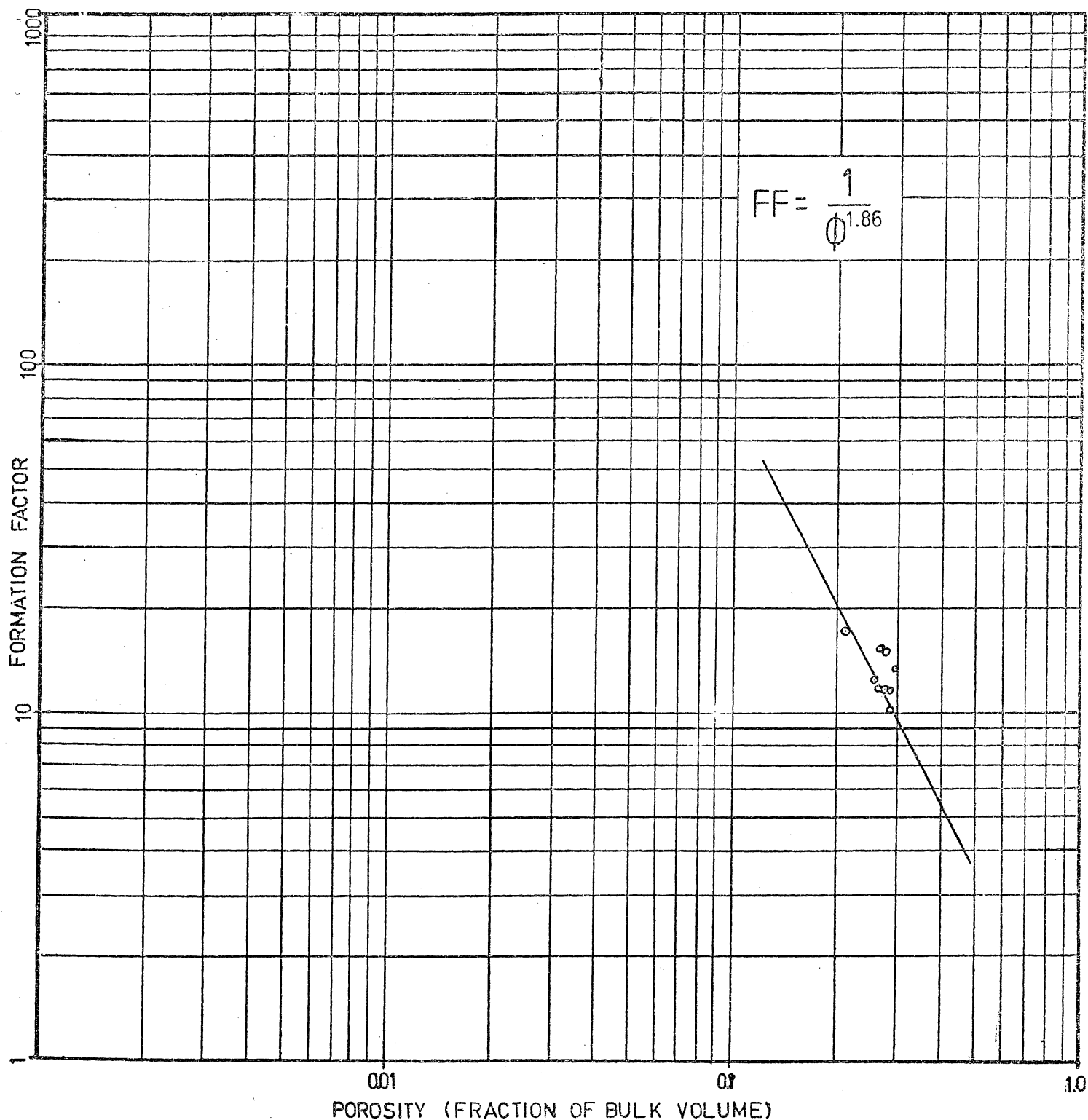


FIGURE 22

FORMATION FACTOR Vs POROSITY

WELL NAME AND NUMBER - GAGE ROADS No.1

DEPTH INTERVAL - 8601 to 8619

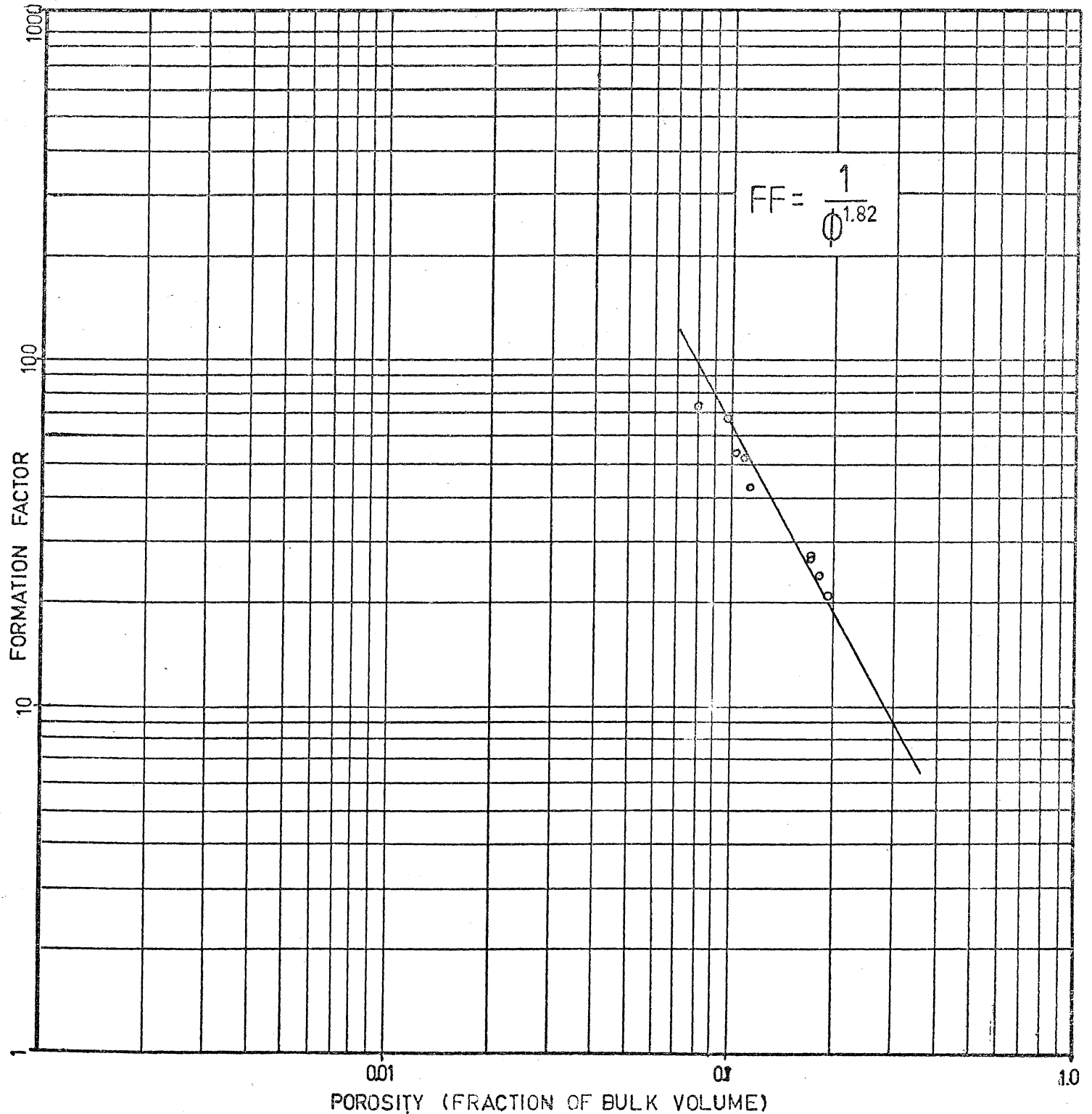


FIGURE 23

GAGE ROADS No 1
 $K \text{ vs } \frac{1}{P_m}$

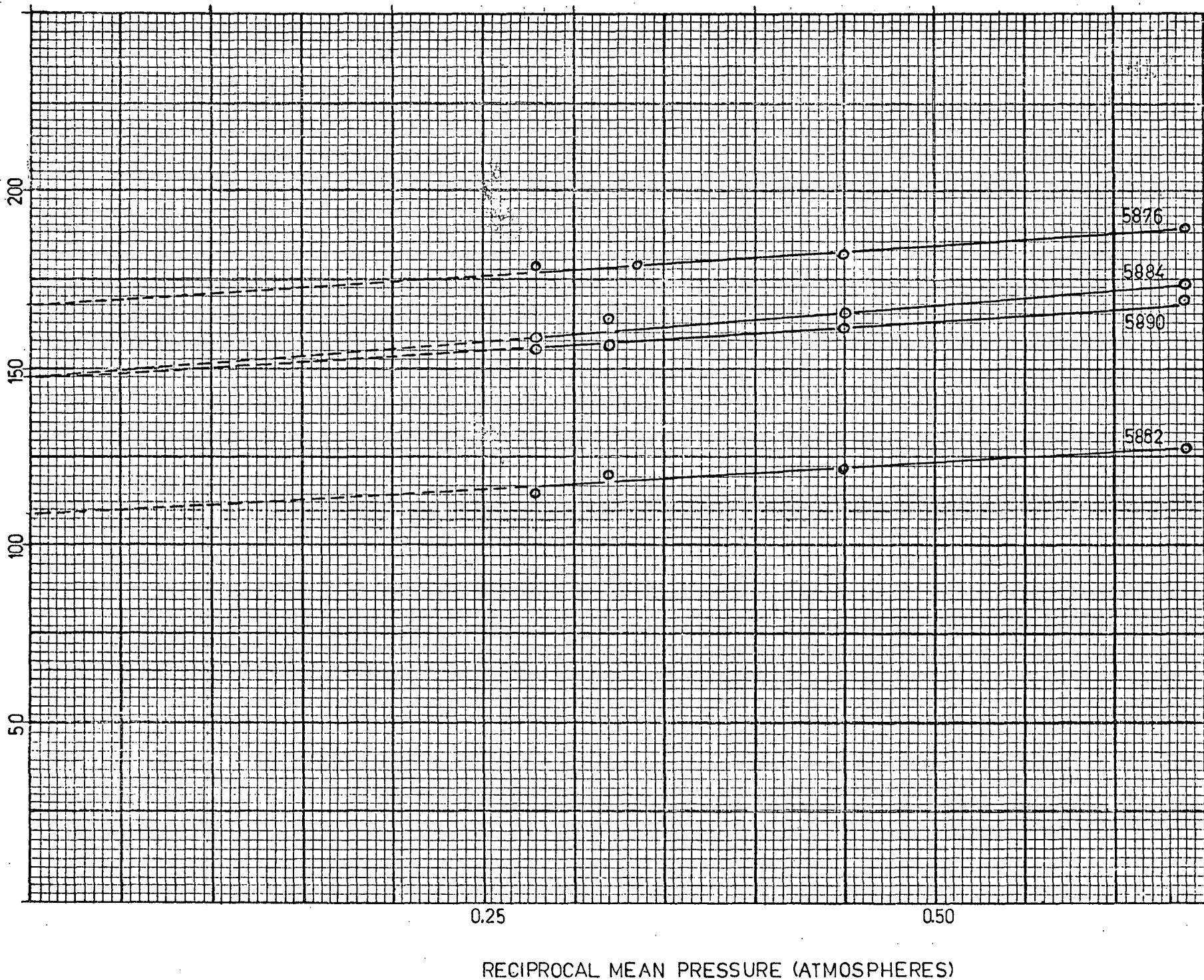


FIGURE 24

PERMEABILITY (MILLIDARCYS)

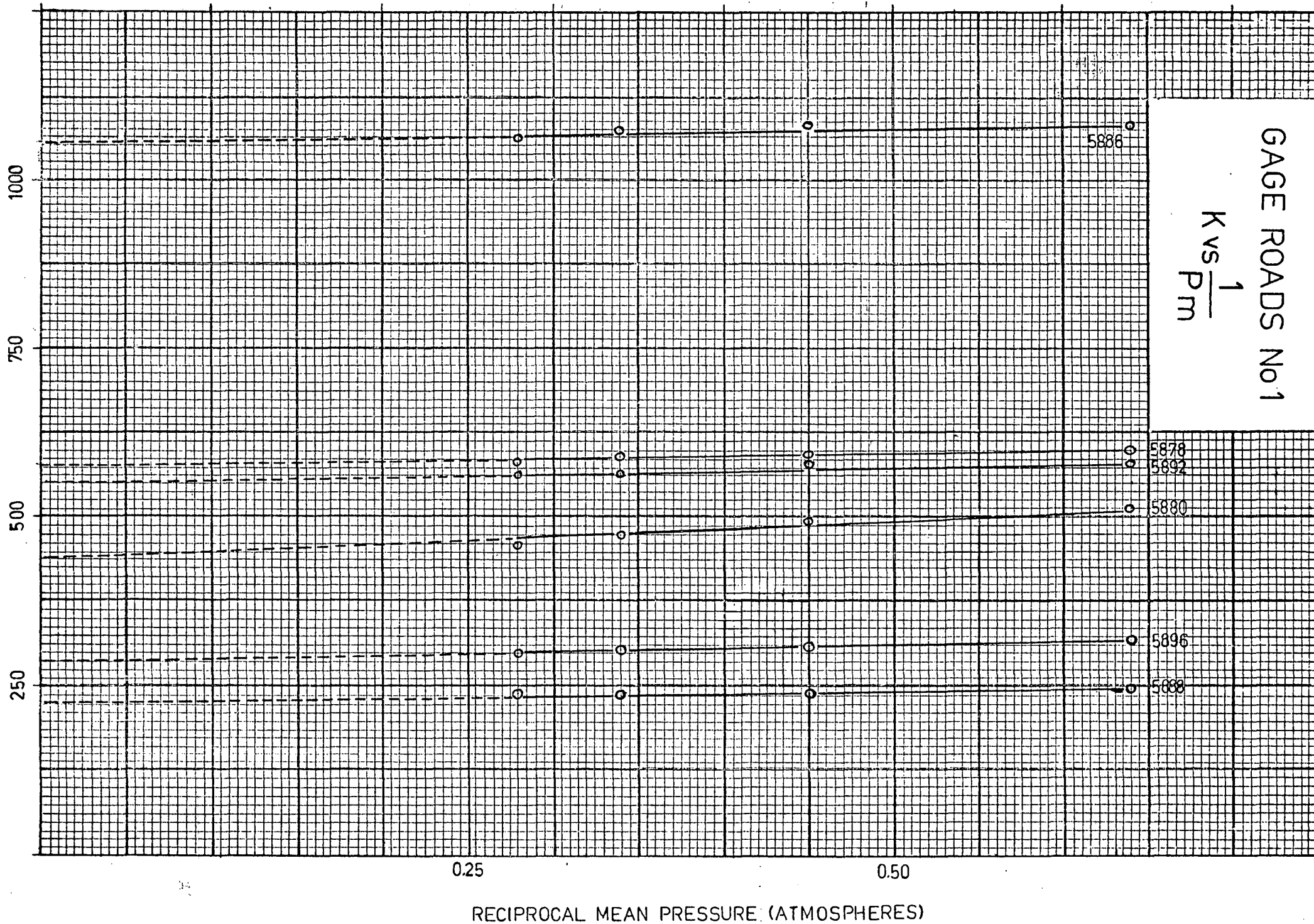


FIGURE 25

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No.1

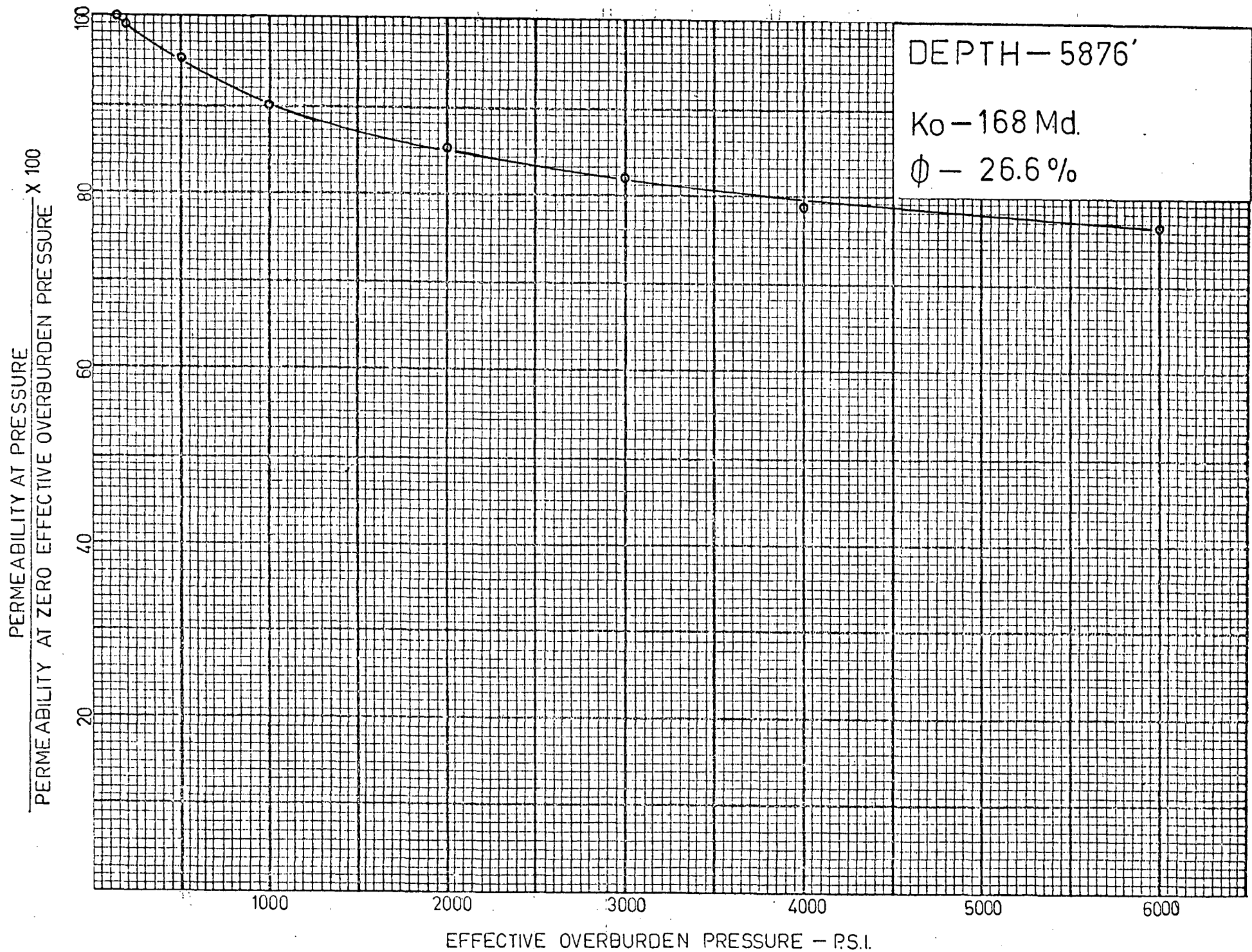


FIGURE 26

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS NO. 1

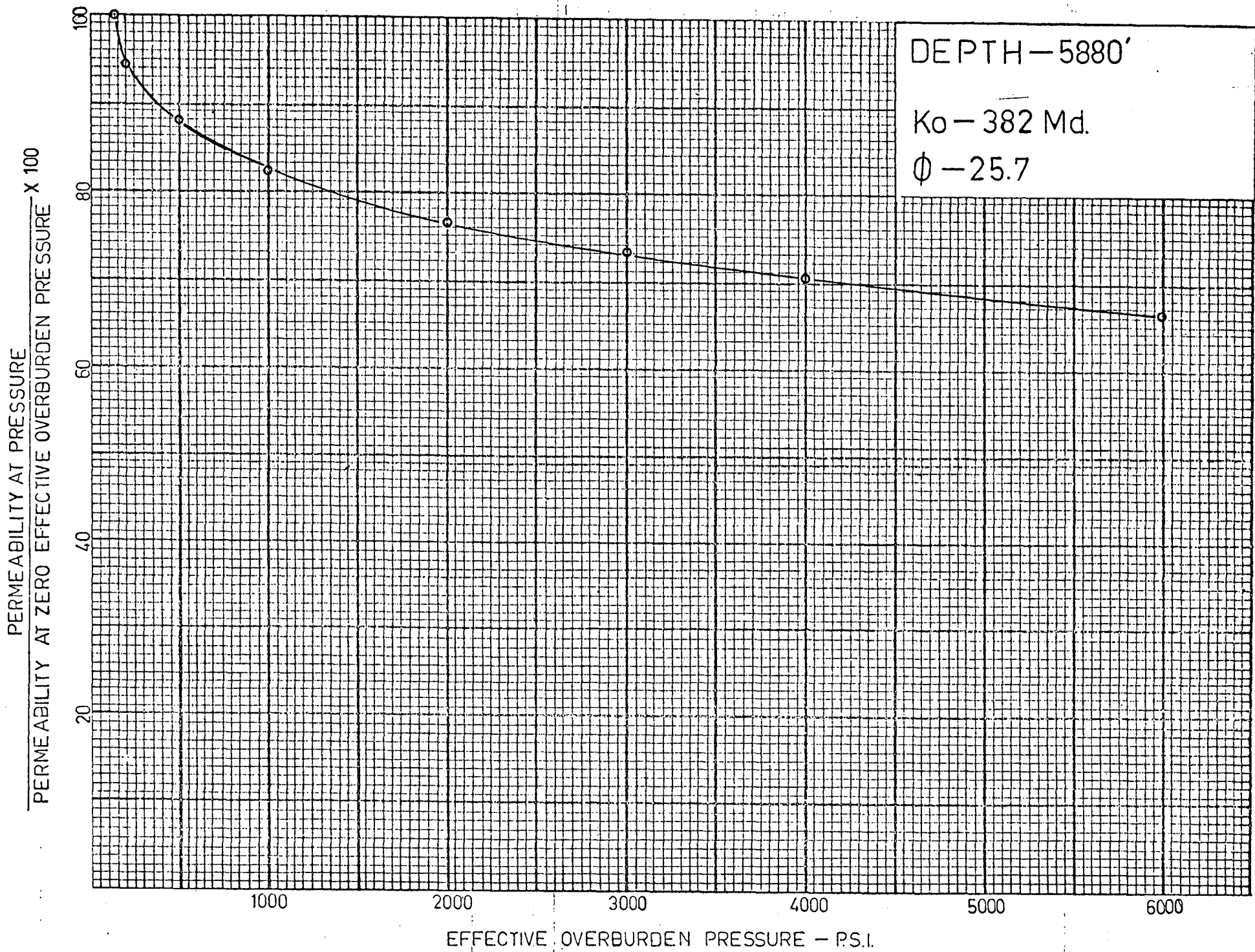


FIGURE 27

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

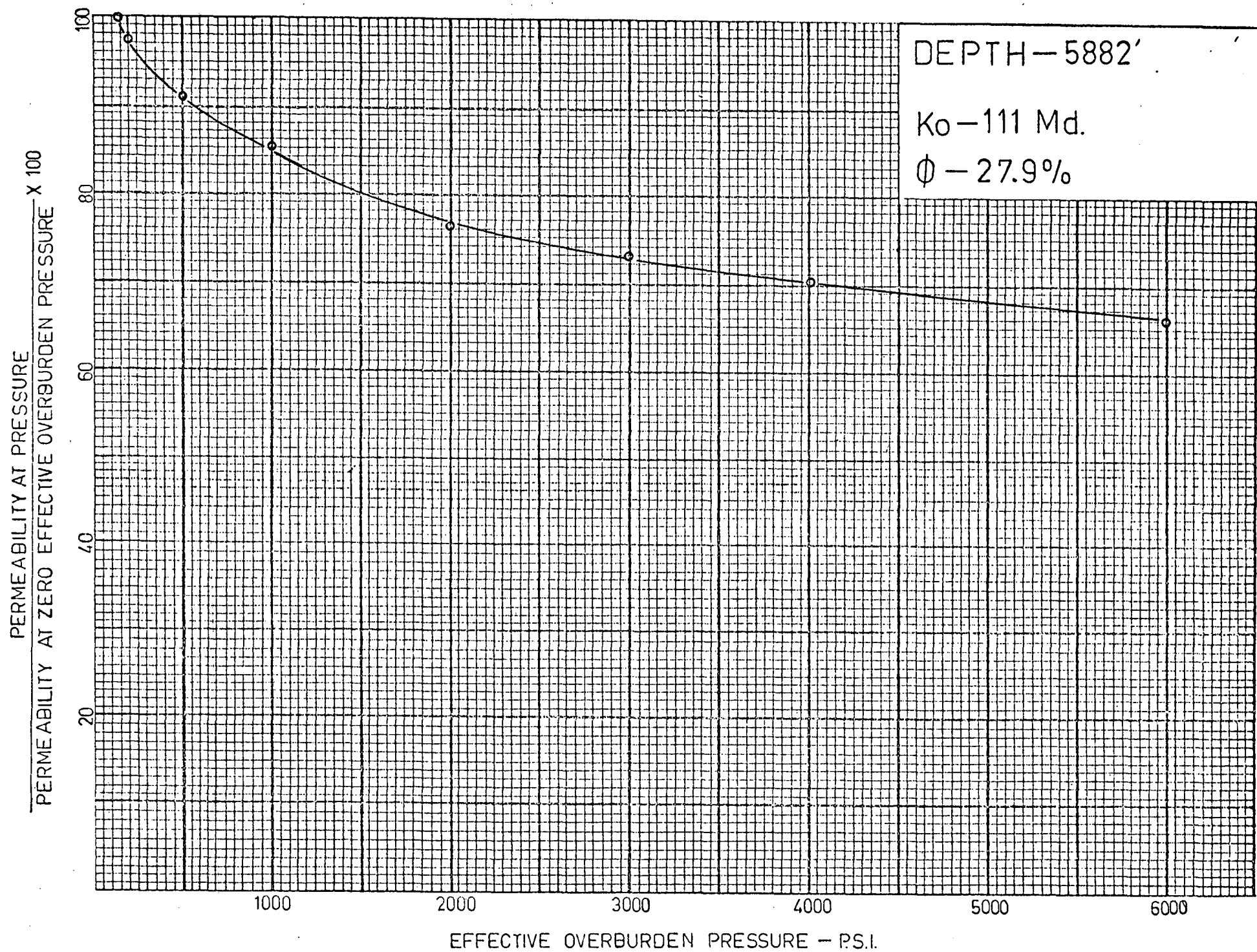


FIGURE 28

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

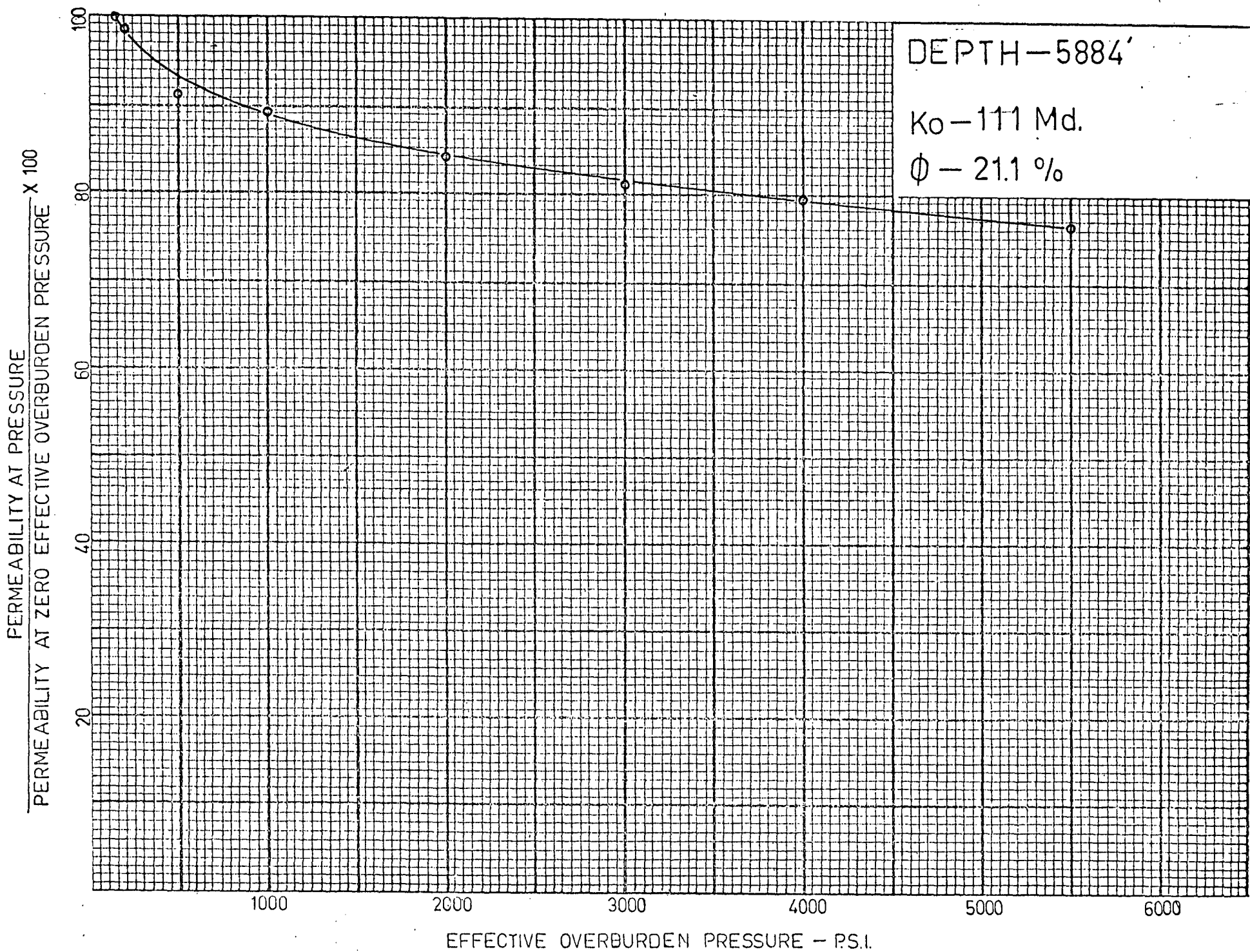


FIGURE 29

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

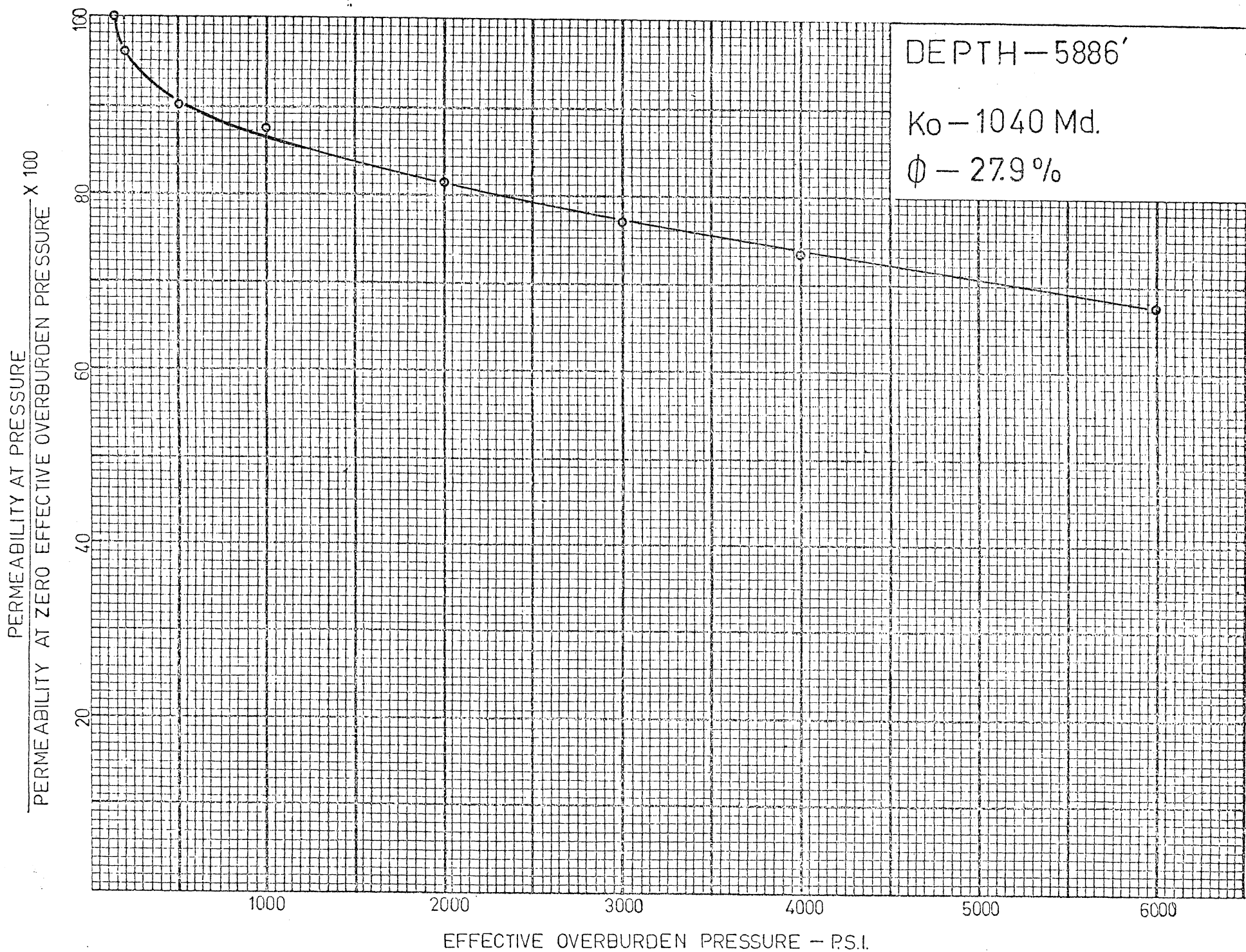
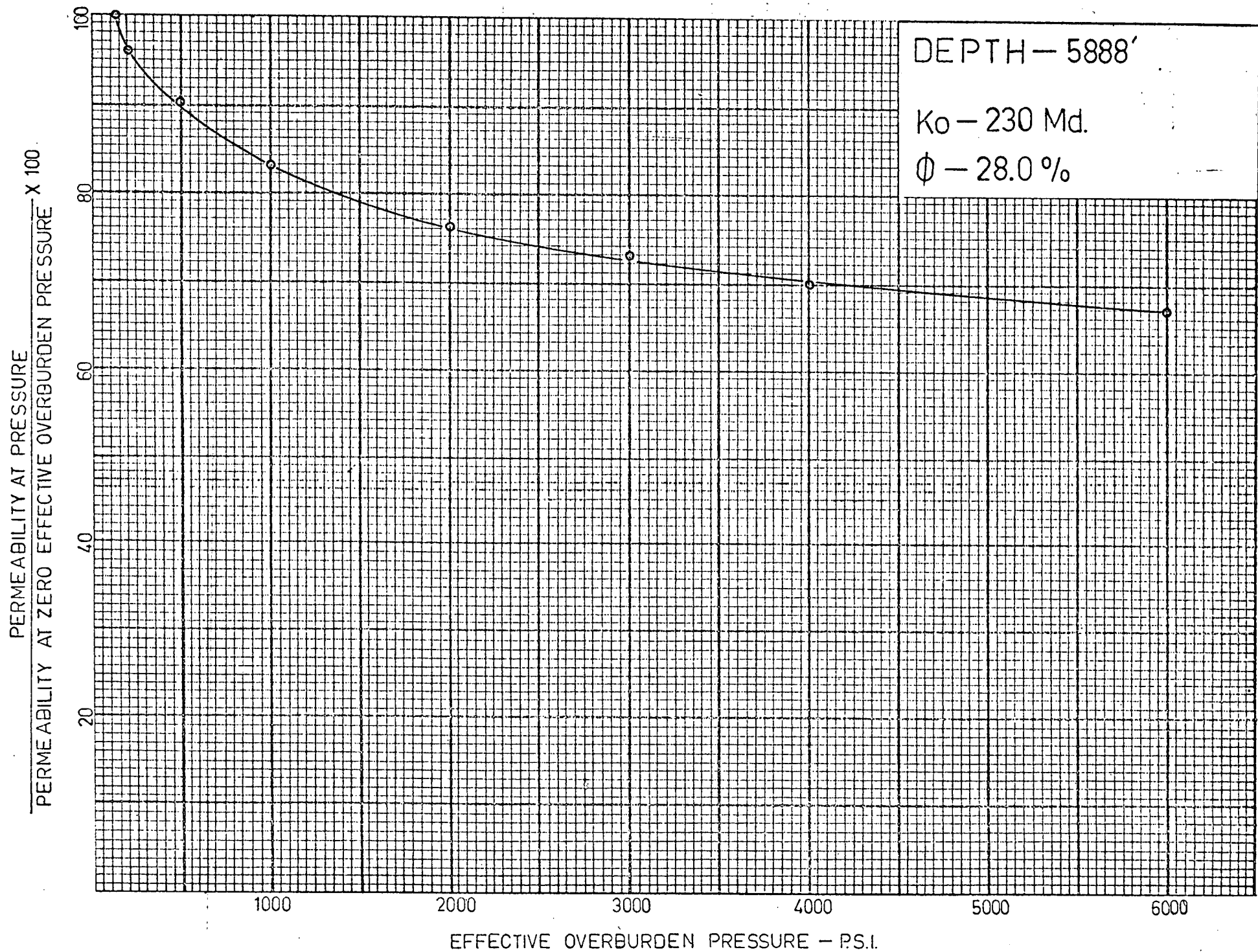
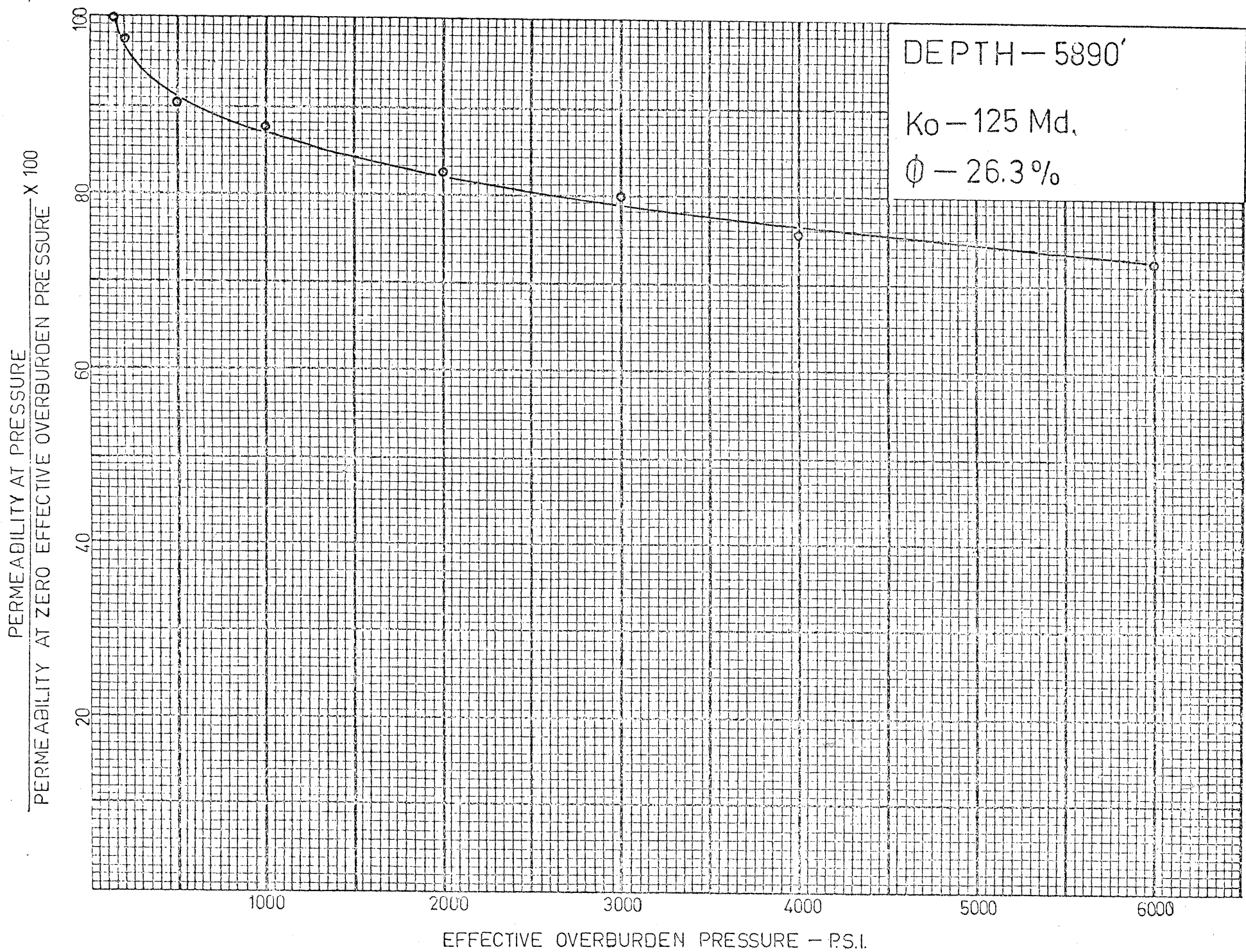
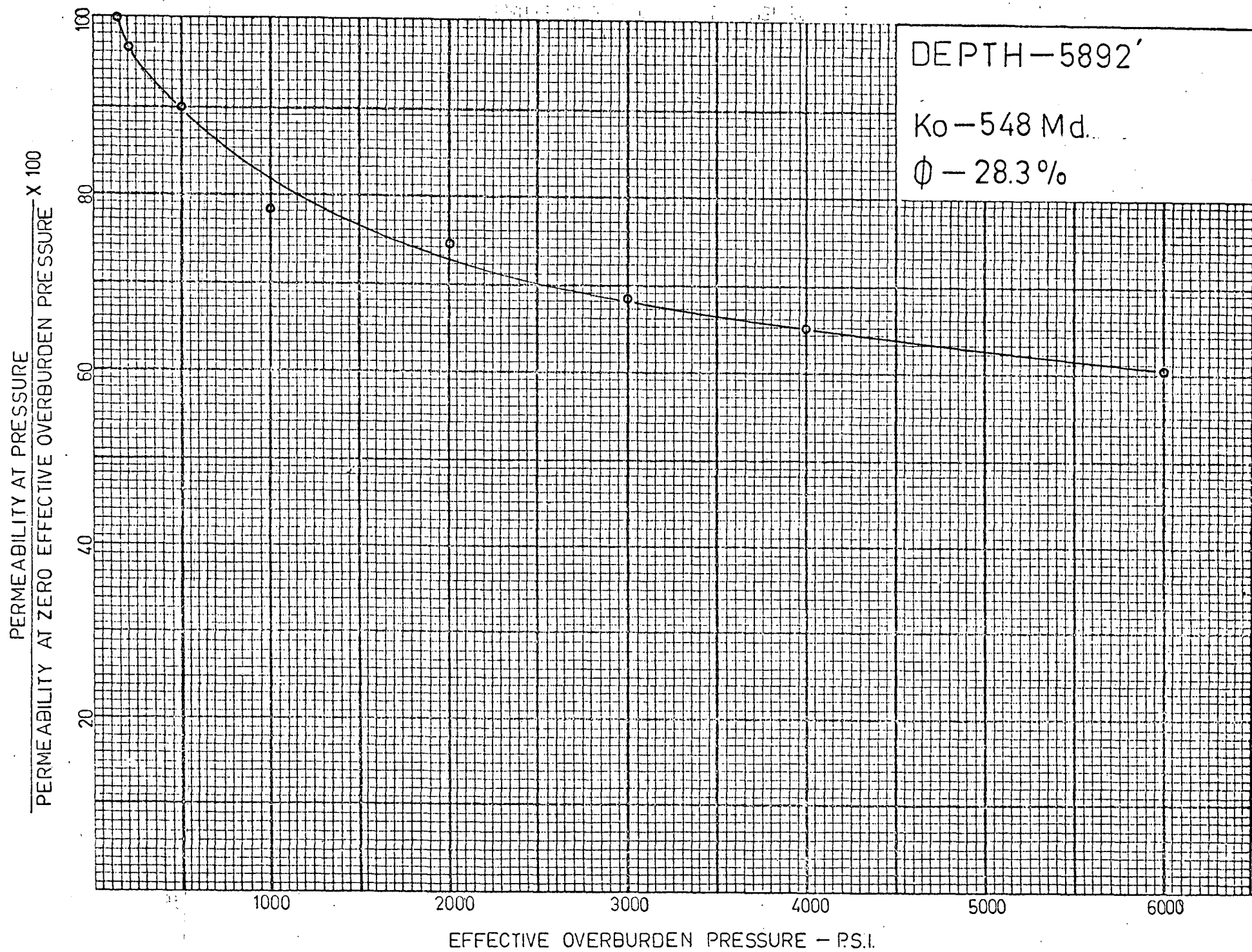


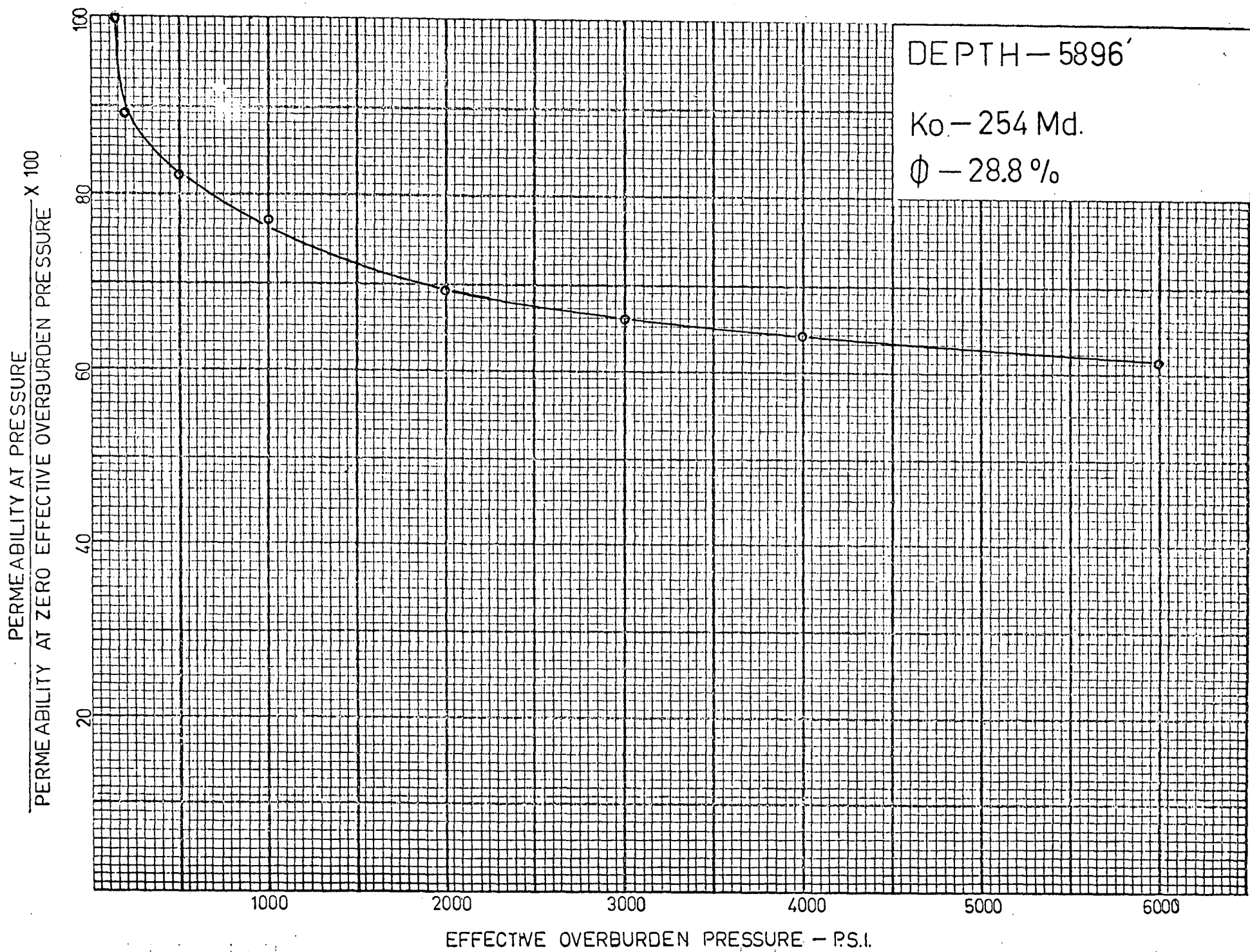
FIGURE 30

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1



OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

OVERBURDEN PRESSURE VS PERMEABILITY
GAGE ROADS No. 1

GAGE ROADS No 1 ELECTRICAL LOG

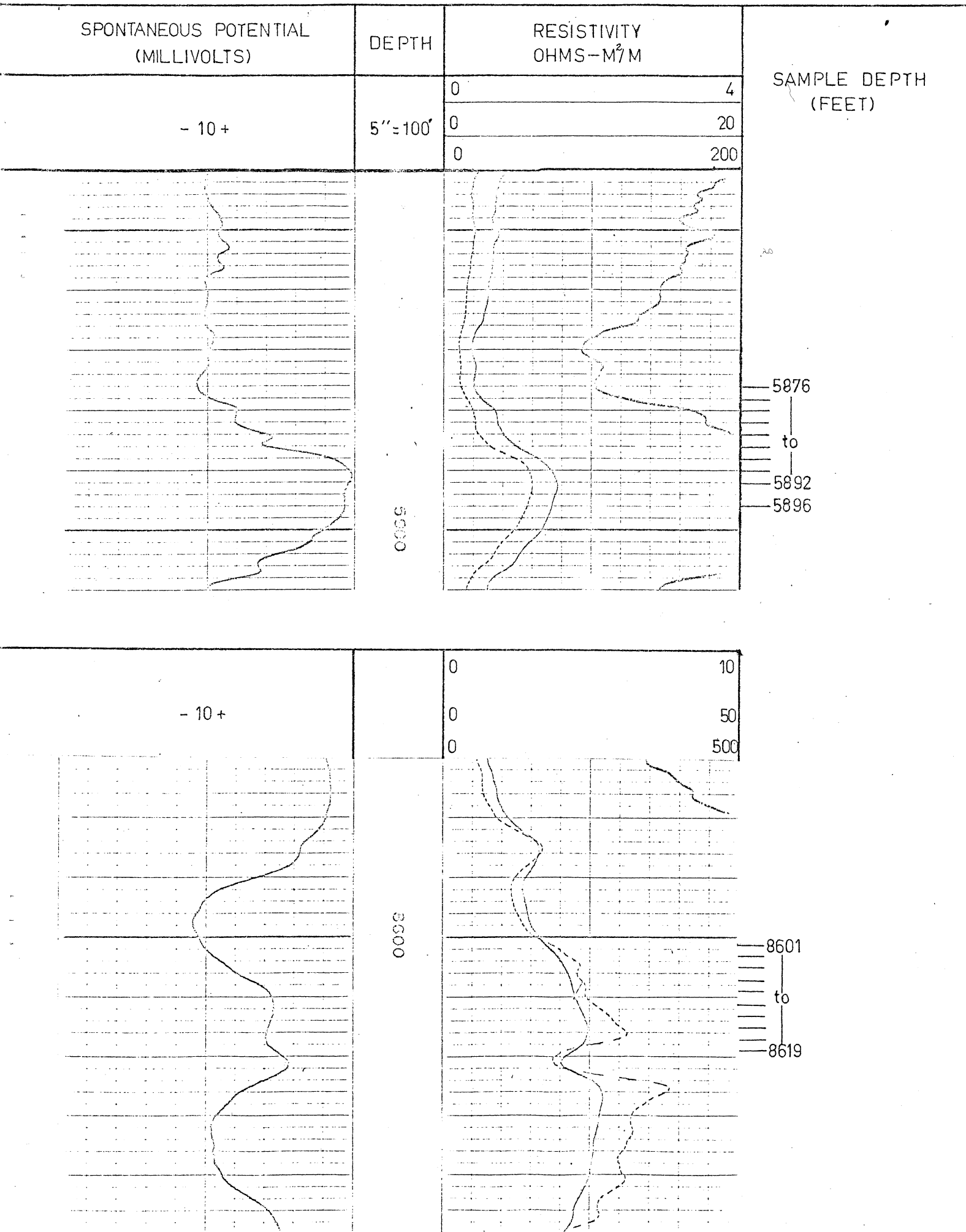


FIGURE 35

CORE LABORATORIES TYPE RESISTIVITY APPARATUS

