DINGO GAS FIELD REVIEW
OP 175, AMADEUS BASIN, NORTHERN TERRITORY

Prepared for

PANCONTINENTAL PETROLEUM LIMITED

Project No. 85.5126

December 1985

[EN]ERGY RESOURCE CONSULTANTS (AUSTRALIA) PTY LIMITED

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ONSHORE

Project No. 85.5126

December 1985

by
ERC ENERGY RESOURCE CONSULTANTS (AUSTRALIA) PTY LIMITED

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19th December 1985

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N.S.W. 2000.

Attention: Mr. Wayne Schnick

Dear Mr. Schnick,

We are pleased to present our report entitled "Dingo Gas Field Review".

Thank you for the opportunity to assist in the evaluation of your Australian interests.

Yours sincerely,
ERC ENERGY RESOURCE CONSULTANTS (AUSTRALIA) PTY LIMITED

Elaine M. Prior

E. M. Prior
Staff Reservoir Engineer

Encl:

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1. INTRODUCTION

ERC Energy Resource Consultants (Australia) Pty Limited ("ERC") has been requested by Pancontinental Petroleum Limited ("Pancontinental") to provide an update of our previous evaluation of the Dingo gas discovery, OP175, Amadeus Basin, Northern Territory (Dingo Gas Field Study, August 1984), following the hydraulic fracture stimulation and subsequent testing of the Dingo-2 well in mid-1985. In particular, ERC was asked to review the estimates of recoverable sales gas reserves in the Dingo structure, to assess the Dingo-2 well deliverability and, in the light of post stimulation testing of Dingo-2, to consider the likely potential deliverability of other wells which may be drilled into the structure if subjected to a revised stimulation program.

For this update we have reviewed the data on the hydraulic fracture stimulation of Dingo-2 and have carried out analysis of the production testing performed after the fracture program. We have considered the implications this new data has on the likely productivity of other wells which may be drilled on the structure.

We repeat in this report, in summarised form, the results of the petrophysical and well test analyses presented in detail in our previous report.

This review has been carried out for the sole use of Pancontinental and its Joint Venture Parties. It may also be made available to the N.T. Department of Mines and Energy. It may not be used by any other party for any purpose without the prior written approval of Pancontinental and ERC, such approval to be signed by a Director of ERC.

2. SUMMARY

The Dingo discovery is located approximately 60 kilometres south of Alice Springs in OP175, Amadeus Basin, Northern Territory (see Figure 1).

The Dingo-1 discovery well, drilled in 1981, and the Dingo-2 appraisal well, drilled 2.4 kilometres west of Dingo-1 in 1984, both flowed gas at rates of approximately 1.5 million cubic feet per day on drillstem test. Dingo-2 flowed a similar amount on production test after completion. In January 1985 a series of injection tests were performed on Dingo-2 to determine parameters to be used in the design of a fracture stimulation treatment. The results suggested such a treatment was not practicable. However, a subsequent production test indicated that these tests had reduced the skin damage and increased productivity. A redesigned fracture treatment was therefore carried out in April 1985, but subsequent production testing in May 1985 indicated that little further gain in productivity had been achieved. We estimate that the open flow potential of the well increased from 2.74 MMscf/day before fracturing to 3.28 MMscf/day after the fracture operation.

Reserves

Production at both wells was from the Arumbera-1 unit of late Proterozoic age. The productive sands correlate extremely well between the two wells and can reasonably be assumed to be areally extensive over the entire Dingo structure, although our analyses of the flow tests carried out at Dingo-1 and Dingo-2 indicate that well productivity might be expected to vary significantly.

The Dingo structure is a simple unfaulted domal feature which can be mapped accurately and with a high degree of confidence at the reservoir level. It is not possible to estimate from the available data the depth to a gas water contact but it is not unreasonable to expect the structure to be gas-filled to spill point.

We interpret 65 feet of net gas pay at Dingo-1, only 36 feet of which were included in the test interval when the well was drillstem tested. Average porosity is interpreted as 12 percent. At Dingo-2 we interpret 55 feet of pay, averaging 11 percent porosity. This pay reduction is due mainly to a poorer quality basal sand at Dingo-2.

We have made volumetric estimates of the gas in place in the Arumbera-1 at Dingo and then applied a range of recovery factors derived from our study of well performance to estimate recoverable sales gas reserves. Dingo gas contains insignificant quantities of extractable liquids and has a Gross Heating Value of approximately 950 Btu/ft^3. At the

confidence levels defined in Section 9 of this report our estimates are as follows:-

	Proven	Proven+ Probable	Proven+ Probable+ Possible
Gas in Place, Bcf	112	344	538
Sales Gas Reserves, Bcf	79	254	398

The reserves quoted are Technical Reserves as defined in Section 9. Further drilling and testing are required on this large structure if some of the Probable and Possible gas is to be included within the Proven category.

Well Productivity

The main parameters derived from the analysis of the flow tests on Dingo-1 and Dingo-2 are as follows:-

	Flow Capacity, kh md ft	Skin Factor	AOFP MMcfd
Dingo-1 DST No.6	70	70*	
Dingo-2 DST No.1	18	10*	
Dingo-2 Production Test July 1984	26	14*	1.66
Dingo-2 Pre Fracturing April 1985	23	-1.6	2.74
Dingo-2 Post Fracturing May 1985	22	-4.9	3.28

(* Includes rate dependent component)

It is clear that, although Dingo-2 encountered reservoir sands of poorer quality than at Dingo-1, the well suffered only relatively minor damage, which allowed test flowrates of the two wells to be comparable.

Productivity of future wells to be drilled on the structure obviously depends on the sand quality encountered and on the degree of success of stimulation. Estimation of rates which may be achieved after stimulation depends on accurate assessment of the rate dependent portion of the skin factor. Data from the most recent series of tests on Dingo-2 suggests that this component is greater than originally estimated so that there may be limited scope for productivity improvement. This applies even to a Dingo-1 type well, for which an AOFP of some 7 MMscfd is estimated assuming a good fracture stimulation.

3. RESERVOIR FLUID PROPERTIES

3.1 Composition

3.1.1 Arumbera-1 Unit

The main reservoir sands at Dingo are in the Arumbera-1 unit and are gas-bearing.

Four wellhead gas samples were obtained during DST No.6 (Arumbera-1 main sand unit) at Dingo-1 and two wellhead gas samples were obtained during DST No.1 (Arumbera-1 main sand unit plus other potentially productive Arumbera-1 sands) at Dingo-2.

All six samples are in close compositional agreement and an arithmetic average composition has been used in the present report. Sample compositions and the average composition are shown in Table 1. The gas is a sweet, dry gas with a gravity of 0.614 relative to air.

3.1.2 Julie Formation

A wellhead sample of gas flowing from the Julie Formation was obtained during DST No.2 at Dingo-2. The composition of the sample is shown in Table 2. The main differences between this and the Arumbera-1 samples are the decrease in nitrogen content and increase in methane and ethane content, resulting in a lighter gas (gravity is 0.600 relative to air) with a higher calorific value.

3.2 Temperature

Schlumberger maximum recording thermometers measured temperatures of 162^{o}F, 165^{o}F and 167^{o}F in three successive logging runs to a depth of 10120 ft RKB at Dingo-2 during a 24 hour period following stopping of circulation. The bottom-hole temperature was fairly stable at 167^{o}F during most of the final shut-in period of DST No.1. This temperature was measured at a depth of 9680 ft RKB. As the average Arumbera-1 gas reservoir depth is somewhat below this depth we have used a reservoir temperature of 170^{o}F to calculate gas PVT properties.

3.3 Gas PVT Properties

We have calculated gas PVT properties at a reservoir temperature of 170^{o}F for a range of pressures from 400 to 6800 psia using the average gas composition derived from the six Arumbera-1 samples. These properties, together with the derived Real Gas Potential (RGP) of the gas using a base pressure of 0 psia, are shown in Table 3. The RGP is plotted against pressure in Figure 2, as is the straight line approximation to it used for the analyses.

We have not calculated PVT properties for the gas in the Julie Formation. Given the nature of the log analysis and flow test results for the Julie Formation it was felt that a separate analysis of gas PVT properties was unwarranted. The gas is sufficiently similar to the Arumbera-1 gas to render insignificant any differences in the properties when other potential sources of interpretative error are taken into account.

4. LOG AND CORE ANALYSIS FOR ARUMBERA-1 FORMATION

4.1 Dingo-1

We have carried out an evaluation of the Dingo-1 well logs using parameters obtained from our evaluation of the Dingo-2 well logs (see Section 4.2), which logs had the benefit of some core cut over part of the pay interval to allow correlation and calibration.

The table below summarises our results. These are based on a water resistivity value, Rw, of 0.02 ohm-m at bottom-hole conditions and a 7 percent porosity cutoff. Zones of porosity less than this cutoff are not expected to contribute significantly to production.

Interval (ft. RKB)	Net Pay (ft)	Porosity (percent)	Sg (percent)	Net HC - ft
9720-9734	13	9	45	.53
9748-9764	16	13	46	.96
9813-9850	36	12	52	2.25
Total Dingo-1	65	12	48	3.74

In our intrepretation we have used the Sonic Log for porosity estimation in the upper sands. However, use of the Sonic Log for porosity determination in the basal sand results in anomalously low porosities and consequently very high water saturations. As the hole condition opposite the basal sand is quite good we have used a density/neutron porosity for this interval. This increases porosity from 9 to 12 percent and reduces water saturation from 64 to 48 percent. These large variations indicate how tentative the analysis is.

It could be inferred from our interpretation that had the upper sands been open to the drillpipe on DST Nos. 2 and 6 at Dingo-1 (which tested only the basal sands), then significantly higher flowrates might have been observed.

The high connate water saturation values of around 50 percent derived from log analysis are to be expected in low porosity, low permeability sands such as those in question. Core analysis indicated water saturations of 42 percent and 48 percent on two Arumbera-1 samples at a depth of 9797 ft RKB at Dingo-2, but these values cannot be accepted as reliable indicators of the status in the reservoir.

Although no reliable Rw value is available, it is unlikely that it will be very different from the 0.02 ohm-m used in our analysis and consequently the water saturation values derived may be treated with some confidence.

4.2 Dingo-2

Dingo-2 was cored in the Arumbera-1 from 9796 to 9823 ft RKB (driller's depth), i.e. a major part of the gas productive basal sand. A correlation of core porosity and Sonic Log readings is given in Figure 3 and of core porosity and core permeability in Figure 4.

Schlumberger ran a conventional logging suite over the interval 9300 to 10090 ft RKB in Dingo-2, which interval includes the Arumbera-1 unit, the Julie Formation and the top section of the Pertatataka Formation, i.e. all the potentially gas-bearing intervals in the well. The logging suite comprised DLL/MSFL/GR, NGT/BHC, LDT/CNL/GR and HDT.

Although Dingo-2 drilled through the Arumbera only slightly overweight (9.3 ppg mud), high pressure gas lower in the well (in the Julie Formation) required an increase in mud weight to 11.3 ppg. It is considered that the serious hole caving throughout much of the Arumbera was caused by a combination of a lengthy period of circulation to build mud weight and a fishing exercise for a jammed core barrel just below the basal Arumbera sands. The Caliper shows the hole to be most severely oversize (offscale at more than 18 inches compared to nominal hole size of 8.5 inches) opposite those sand intervals interpreted to be the best porous gas-bearing intervals.

4.2.1 Porosity Calculation

The extremely poor hole conditions render Density and Neutron Logs(LDL/CNL) of no use for porosity calculations. We have therefore used the Sonic Log for porosity estimations, and used the core-measured porosity for calibration over the interval 9794 - 9820 ft RKB. Reasonable Sonic Log calibration is given with a mean dtma (matrix interval transit time) of 52, dtfl (fluid interval transit time) of 185 and a compaction factor of 0.8.

The correlation between Sonic Log readings and core porosity is shown on Figure 3. The calibration of the Sonic Log from core data lends confidence to the analysis, although having to use a compaction factor of 0.8 is not consistent with expectations of a low porosity sand of this age at this depth.

The very high resistivity readings in the non-pay sections of the sands in both Dingo-1 and Dingo-2 show these sections to be extremely tight, and ordinarily it might be concluded that the gas resides in fractured sections of the sand body. This would make the log analysis more uncertain, since the Sonic Log might be under-reading porosity and the "a", "m" and "n" factors used in the Archie equation would be open to severe doubt. Arguing against this possibility of fractures is the excellent correlation between Dingo-1 and Dingo-2 and the lack of observed fractures in the cored section. We have ignored the possibility of fracture porosity existing in the Arumbera-1 at Dingo.

Despite the high Gamma Ray readings over the net pay sands, the Sonic and LDL/CNL do not indicate significant shale, and neither does the core description. The Gamma Ray is reading potassium in the formation (feldspar) and also in the KCl mud in those sections of the hole significantly overgauge. It appears from the Schlumberger "Lithog" that the thorium series may be a useful shale indicator. However, we no not believe that the reservoir sands contain significant amounts of shale (confirmed by the core description) and have not made any shale corrections to our porosity estimates in the reservoir sands.

4.2.2 Water Saturation Calculation

As for Dingo-1 the main problem with water saturation calculation is the lack of a reliable water resistivity value, Rw. As for our analysis of Dingo-1 we have used an Rw value of 0.02 ohm-m at bottom-hole conditions.

4.2.3 Results

As for Dingo-1, the porosity cutoff for determining net pay was taken as 7 percent. From Figure 4, which gives a plot of core porosity versus logarithm of core permeability, this cutoff corresponds to a core permeability of approximately 0.3 md.

The table below gives our interpretation of the net porous intervals at Dingo-2. We report our results using a water resistivity of 0.02 ohm-m at bottom-hole conditions and a porosity cutoff of 7 percent.

Interval (ft. RKB)	Net Pay (ft)	Porosity (percent)	Sg (percent)	Net HC - ft
9666-9671	5.6	8	28	.13
9676-9681	4.6	7	35	.11
9694-9704	9.8	12	54	.64
9712-9731	19.7	10	50	.99
9784-9790	5.9	8	49	.23
9793-9808	15.1	12	60	1.09
9817-9822	4.9	9	50	.22
Total Dingo-2*	55.4	11	52	3.17

Footnote:-

* Total excludes top two intervals in table, since these were air-drilled without gas indication on the Blooey line.

All of the interpreted net sands at Dingo-2, and given in the table, are in the Arumbera-1. Some minor sands in the Julie Formation exhibit a Sonic Log character indicating lower porosity than in the top two Arumbera sands given in the table above, neither of which gave any indication of gas flows while being air-drilled. While there may be some minor gas in place in the Julie Formation an examination of the logs and DST results indicates that there is minimal potential for commercial production from this interval at the Dingo-2 well. This was also the case at Dingo-1.

4.3 Comparison of Dingo-1 and Dingo-2

It can be seen from the previous sections that overall net pay, porosity and gas saturations have remained very similar between Dingo-1 and Dingo-2. In fact the individual interpreted gas sands correlate extremely well between the wells on the Sonic and Gamma Ray Logs. However, quantitatively, while the upper sands have remained very similar in characteristics (29 feet, 11% porosity, 47% gas saturation at Dingo-1; 29 feet, 11% porosity, 52% gas saturation at Dingo-2) the basal sand at Dingo-2 is of markedly reduced net thickness, being split into three separate intervals and of generally poorer quality (36 feet, 12% porosity 52% gas saturation at Dingo-1; 26 feet, 10.5% porosity 56% gas saturation at Dingo-2).

This comparison of the basal sands is not strictly valid since the Sonic Log gave anomalously low porosities and high water saturations at Dingo-1 and consequently, as the hole condition was reasonable, a density/ neutron porosity was used.

5. DRILL STEM TEST ANALYSIS

5.1 Dingo-1

5.1.1 Overview

All the mechanically successful Dingo-1 DST's were analysed in a detailed report by S.K. Engineering Limited ("the S.K. Report"). DST Nos. 2 and 6 are interpreted as having flowed gas from the same interval at the base of the Arumbera-1 and our review of the results has been confined to these tests.

The S.K. Report presented comprehensive analyses of the Dingo-1 drillstem tests. We consider there to be potential sources of error in the gas flowrates used in the analyses, but that these errors would probably be small. We agree with the S.K. Report conclusion of flow capacity of approximately 70 md ft from DST No.6, all of which is in the Arumbera-1, and that the well is highly damaged. The tested interval, and therefore also the derived flow capacity, did not include any of the upper sands in the Arumbera-1, only the basal sand section.

The AOFP's calculated in the S.K. Report are consistent with the estimates of permeability and other rock and fluid properties. The use of a skin factor of zero for a "good completion" and a skin factor of -4 for a "best possible completion" are reasonable.

5.1.2 DST No.2

This test interval (9811 - 10023 ft RKB) included the bulk of the sand interpreted at the base of the Arumbera-1, the entire Julie Formation and some 80 feet at the top of the Pertatataka.

The main potential source of error in the interpretation of the results of this test is in the flowrate during the test. Apart from the variability of flowrate during the test there is some question about the final flowing rate. We consider a value in the range 1.0 to 1.2 MMcfd to be a reasonable best estimate, compared with 1.38 MMcfd estimated in the S.K. Report.

In essence, the flowrate used in any analysis of this test is subject to significant potential errors. The derived flow capacity (kh-product) is directly proportional to the flowrate used in the analysis and we therefore consider it likely that the true value is somewhat less than the 85 md ft calculated in the S.K. Report, probably, say, 60 to 70 md ft.

The S.K. Report used a log-derived pay thickness of 43 feet to calculate permeability from flow capacity, whereas in fact this test did not include a 6 ft section at the top of the main Arumbera-1 sand interval, so a figure of 37 ft might have been more appropriate.

5.1.3 DST No.6

This test interval (9799 - 9881 ft RKB) was basically the same as for DST No.2 except that an extra 6 ft of interpreted Arumbera-1 pay was added and the non-productive Pertatataka and most of the Julie were excluded.

Once again, the main potential source of error in the analysis in the S.K. Report is in the selection of a flowrate. Although stable wellhead conditions were reported for the last hour of the 3.5 hour flow, the gas was flowing with a water mist which could introduce errors. Bottom-hole pressure was again falling for the last hour of the flow period, but that could have been the water cushion unloading. Without reliable comments on the amount of water production at surface throughout the flow periods it is not possible to be sure about the explanation of flowing pressure behaviour on either of DST No.2 or DST No.6

The calculated flow capacity of 70 md ft on DST No.6 tallies well with the flow capacity of 60 to 70 md ft we estimate as being appropriate for DST No.2.

5.2 Dingo-2

5.2.1 DST No.1

DST No.1 open-hole tested almost all of the Arumbera-1 unit and flowed gas to surface at a rate of just under 1.5 MMcfd and surface pressure of 200 psig. An analysis of the test results indicates that despite the use of a downhole Hydrospring valve to control the flow periods, wellbore storage effects were signficant in the early part of the shut-in periods.

We have estimated a formation flow capacity of 17.6 md ft for the tested interval, which gives an average permeability to gas of 0.32 md using the log-derived value of 55 ft for the net pay interval. A reliable interpretation of what is pay in the tested interval would only be possible by carrying out separate tests on each of the interpreted sands or by full coring. The former is obviously not practical and the latter not now possible, but the resulting use of a single pay thickness value to include all sands could lead to errors in interpretation of rock properties.

A conventional Horner analysis has been used as the main tool in analysing the final shut-in period of DST No. 1. No attempt at analysing the flowing period has been made due to the erratic flowing conditions.

The well was moderately damaged, with an apparent skin factor of 9.7, or a maximum damage ratio at the test flow rate of 2.8.

5.2.3 DST No. 2

DST No.2 tested the entire Julie Formation and flowed gas to surface at a rate estimated as 0.04 MMcfd and 3 psi surface pressure. An analysis of the test data indicates that both shut-in periods were dominated by wellbore storage effects, despite the use of a downhole shut-in tool.

An initial reservoir pressure of very approximately 6500 psia has been estimated at 10000 ft RKB, establishing that the Julie is not in communication with the Arumbera in the gas zone at Dingo.

The nature of the pressure build-up indicates a damaged and very tight formation. We consider from a combination of log analysis and DST results that the Julie Formation at Dingo-2 has minimal production potential, though it does appear to be slightly better than at Dingo-1. The formation is too tight for sufficient character to have appeared on the pressure build-up plots to allow a conventional interpretation. Interpretations based on wellbore storage dominated data would be extremely unreliable in the light of major uncertainties in estimating net pay thickness, porosity, gas saturation and flowrate. We do not consider the Julie Formation to have any commercial significance at this stage.

5.3 Initial Reservoir Pressure

Based on Dingo-2, DST No. 1 results, an average Arumbera-1 reservoir pressure of 4600 psia is derived at the datum depth of 8250 ft below mean sea level.

6. PRODUCTION TEST ANALYSES - DINGO-2

6.1 Post Completion Tests - July 1984 and January 1985

The Arumbera-1 at Dingo-2 was production tested after completion and perforation of the gas-bearing intervals from logs and shown to be gas productive on DST No.1. The well was perforated using tubing-conveyed guns over the intervals 9692 to 9705, 9715 to 9731, 9781 to 9805 and 9805 to 9846 ft RKB.

On 19th July 1984 Dingo-2 was opened for clean-up flow. After 3 days the well was shut-in for build-up prior to commencing the production test. Final flowing rate was 1.3 MMcfd with a flowing wellhead pressure of 570 psig.

After 5 days shut-in, on 28th July, a static gradient survey was run and the well opened for the production test. After a flow period of just over 2 days the well was shut-in for build-up. The last 27 hours of flow were at a constant rate of 1.65 MMcfd and a constant flowing wellhead pressure of 270 psig.

At the time of analysis (8th August 1984) the well was still shut-in and bottom-hole pressure gauges monitoring the build-up of pressure. Bottom-hole pressure data were available for the final flowing period and for the final shut-in period as far as 1030 hours on 5th August, or 138 hours of shut-in. We consider the available data to be adequate for test analysis.

Our analysis results in an estimated flow capacity of some 26 md. ft, 50 percent greater than estimated from DST No.1. As this test was flowed to relatively stable conditions it is likely that the interpretation is more reliable. A slightly increased skin factor of 14 and damage ratio of 3.0 were also calculated.

The extrapolated pressure of 4614 psia at datum (8250 ft BMSL) is in reasonably close agreement with the estimated reservoir pressure at datum from DST No.1 of 4600 psia and of 4604 psia from the static gradient survey run after the January 1985 flow test.

No other results are available from the January test as the well would not flow for more than one minute, despite repeated attempts.

6.2 Pre-Fracture Test Analysis - April 1985

Before the fracture operation was carried out, a series of flow and build up tests was performed in order to compare parameters calculated before and after the fracture program. The test comprised four short flow periods, each followed by a four hour build up, and a final extended flow period of 30 hours followed by a 52 hour build up.

The final flowrate was 2.66 MMscf/day on a 33/64 inch choke with a wellhead pressure of 443 psig.

Data from the final build up period was analysed. As with the later May tests, afterflow was significant, and only in the extended build up has the straight line slope developed adequately for analysis. The afterflow and superposed time function plots are shown in Figures 5 and 6. This gives a permeability thickness product of 22.5 md feet. The extrapolated pressure of 4560 psia at the lower gauge depth of 9679 feet RKB agrees well with the estimated initial pressure of 4567 psia calculated from the reservoir pressure of 4600 psia at datum. (Note also that the upper gauge, which ceased working before the final build up, was recording values 7 to 10 psi higher).

These results have been used, together with the final flowing pressure of each flow period, to calculate the dependence of skin factor on the rate, assuming transient conditions. Our results are summarised in Table 5. Skin factor has been plotted as a function of flowrate in Figure 17 for both pre- and post-fracture tests. In isolation, this data is inconclusive for the pre-fracture testing due to the large scatter of data points, which do not exhibit the expected trend of increasing skin factor with increasing rate. Rather, the skin factor appears to have been decreasing with time, indicating perhaps that the well was still cleaning up after the January injectivity tests, as suggested by fluids production during the flow periods. However, the trend for skin factor, which is indicative of turbulence effects, seems clear for the post-fracture test. The turbulence depends only on reservoir and fluid properties and should be largely independent of the near-wellbore zone and any well treatment, for a fully perforated pay zone. Accordingly, we have assumed the same turbulence factor, and therefore slope, for the pre-fracture test as that obtained from the post-fracture tests.

We have also plotted the data from these tests on Figure 18 and estimate an open flow potential prior to the fracture operation of 2.74 MMscf/day.

6.3 Fracture Program and Post Fracture Test Analysis - May 1985

After the April 1985 flow and build up tests the well was killed. The perforations were subjected to hydrojetting to ensure satisfactory communication between the wellbore and formation prior to the fracture operation. Fracture stimulation was carried out on April 26th 1985. Subsequent laboratory tests showed that a proportion of the sand, used together with bauxite as a proppant, may have been crushed after the fracturing. It is also possible that the fracture propogated out of the pay zone, reducing the effectiveness of the treatment over the productive interval. (Refer "Hydraulic Fracturing Evaluation Dingo No.2 Arumbera", Marschang, August 1985).

A testing program was carried out during May to evaluate the success of the fracture treatment. An extended clean up flow period was followed by an 84.5 hour build up and then a four rate isochronal test in which each rate was sustained for 5 hours and followed by a 5 hour build up, except the final build up which was for 10 hours. We have analysed all five build up periods together with the flow data to estimate permeability thickness product and skin factor. Rock and fluid properties used for analysis are given in Table 4. The final flowrate was 3.21 Mmscf/day on a 32/64 inch choke with a wellhead pressure of 520 psig.

Flow data for the initial clean up flow period was limited. For our initial analyses of all tests we assumed a 96 hour flow at 2450 Mscf/day and then we reanalysed the first build up assuming a 50.5 hour flow period. As can be seen from Table 6 the results are not significantly different.

Interpretation of the 5 hour isochronal build ups was complicated by the relatively long periods of afterflow, which meant that in most cases only the last few points of each superposed time function plot appeared to fall on the transient flow semi-log straight line. However, as the initial pressure of 4567 psia at gauge depth appears reliable the extrapolated pessures were used as a means of checking the consistency of the semi-log lines. Figures 7 to 16 show the afterflow and build up plot for each of the five shut-in periods. Test analysis results are summarised in Table 6.

Skin factors are plotted as a function of rate in Figure 17. Extrapolation of the fitted straight line gives a mechanical skin factor of -4.9, indicating a successful fracture stimulation. The relatively large rate-dependent factor for skin of 2.47 per MMscf/day suggests that the limited improvement to well productivity with the fracture stimulation is primarily the result of factors outside operational control.

We have estimated the Absolute Open Flow Potential of Dingo-2 as 3.28 MMscf/day after the fracture stimulation from the AOFP plot, shown in Figure 18.

The main results of our analyses are listed below:

Permeability thickness product (md. feet)	22.0
Extrapolated pressure (psia)	4565
at gauge depth (feet RKB)	9679
Skin factor - rate independent term	-4.90
Skin factor - rate dependent term (per MMscf/day)	2.47

6.4 Conclusions and Recommendations

Our analysis shows that a significant improvement in productivity of Dingo-2 was achieved after the January injection tests with a smaller increase in productivity due to the fracture operation. This is illustrated on Figure 18. Final flowrates and wellhead pressures for the various tests are given below:

	Rate MMscf/day	Wellhead Pressure (psig)	AOFP MMscf/day
Post completion test - July 1984	1.65	270	1.66
Pre-fracture test - April 1985	2.66	443	2.74
Post-fracture test - May 1985	3.21	520	3.28

The small improvement in AOFP with the fracture treatment suggests that there is limited scope for improving well productivity by this means due to the large effect of turbulence on inflow performance. This applies even to a well of the Dingo-1 type for which an AOFP of around 7 MMscf/day is estimated, assuming a similar fracture treatment to that at Dingo-2 and taking into account the reduced effects of turbulence due to improved permeability.

7. WELL PERFORMANCE

To assess well productivity throughout field life we have carried out a simple depletion-type study of the Dingo discovery assuming no aquifer drive.

"Typical" well parameters of 10,000 ft depth, 500 psia minimum wellhead pressure, 2.441 in I.D. tubing and average temperature in the tubing of 125°F were used to calculate pressure losses in the tubing string.

For a given well inflow performance equation, a single curve describes the change in potential rate with average reservoir pressure. This is not true of transient flow but in assessing performance throughout field life we assume stabilised or semi-steady state production conditions. We have estimated the average reservoir pressure at which Dingo-2, in its current state, would no longer be able to meet a wellhead pressure of 500 psi at a minimum rate of 0.2 MMscf/day. This is 1550 psia and equates to a recovery factor of approximately 63 percent of gas initially in place.

In our previous study we estimated the likely recovery factors which might be achieved by a Dingo-1 type well if subjected to a successful stimulation program, down to the same abandonment conditions. This gave recovery factors in the order of 80 percent. However, insufficient data was available for calculation of the rate dependent portion of the skin factor and subsequent calculations of well productivity are therefore open to some uncertainty. Our analysis of the post fracture tests on Dingo-2 suggests that this well experiences significant reduction in productivity due to turbulence effects, though this turbulence coefficient varies inversely with permeability and is expected to be lower in better productivity wells, as discussed in Section 6.4.

We therefore estimate a recovery factor of 75 percent as the most likely value achievable by a successfully stimulated well of similar characteristics to Dingo-1.

8. GAS IN PLACE AND RECOVERABLE GAS RESERVES

8.1 Overview

We have estimated ranges of values for gas in place and recoverable gas reserves at Dingo. Gas in place is estimated volumetrically since the size of the structure and small offtake to date (test gas only) make any estimate by material balance impossible.

Each parameter contributing towards the gas in place and recoverable gas reserves estimations has been assigned a range of values and a Monte Carlo simulator used to combine these parameter values probabilistically to determine a range of gas in place values and a range of recoverable Technical Reserves values corresponding to the Proven, Proven+Probable and Proven+ Probable+Possible categories defined in Section 9.

Our estimates are:-

	Proven	Proven+ Probable	Proven+ Probable+ Possible
Gas in Place, Bcf	112	344	538
Gas Reserves, Bcf	79	254	398

The various input parameters are discussed below.

8.2 Structure

We have reviewed the seismic sections (1980 survey), Dingo-1 Time-Depth curve and Sonic Log, and the time, velocity and depth maps on the Top Arumbera-2A prepared by Pancontinental.

Seismic reflectors near the depths of interest (Base Chandler/ Top Todd River Equivalent and Top Arumbera-2A) were identified from the Time-Depth curve. The green seismic event on the seismic sections identified as Top Arumbera-2A is probably closer to the gas sands, judging by the time pips on the Sonic Log.

The Base Chandler can also be readily tied into Orange-1. The Chandler is a marked low velocity zone on the Sonic Log and Time-Depth curve, giving rise to a black seismic peak at the top and a white peak at the base. These events are readily identifiable on the seismic sections and can easily be mapped over the Dingo area.

The green event on the seismic sections is obviously the most important as it lies closest to the gas sands. This event, although weaker than the previous two is also readily mapped over the Dingo structure.

The time structure map on Top Arumbera-2A (see Figure 20) shows that the Dingo structure is a simple unfaulted domal feature. The seismic data show that the structure has been produced by halokinesis of pre-Cambrian salt.

The dome is elongated in a northwesterly direction and is about 11 kilometres long by 6 kilometres wide. Maximum closure is defined by a narrow saddle to the southeast of the structure.

The time structure map can be accepted with confidence because of the good quality of the data and the simplicity of the structure.

The depth structure map on Top Arumbera-1 (see Figure 19) is constructed by converting the time structure map on Top Arumbera-2A to depth and dropping the resulting map to tie in with the Arumbera-1 at Dingo-1 and -2.

The check shot survey run in Dingo-1 gave good results and the derived Time-Depth curve can be treated with confidence. Results in Dingo-2 indicated no velocity gradient between the wells. Time values were converted to depth using a single time-depth function. There is a rim syncline developed in the shallow part of the section by salt movement and also there is salt mobilisation in the Chandler Formation. In view of this it is felt that depth conversion using interval velocities would be more accurate. However, in view of the fairly steep dip closures all round, this will not cause significant changes in areal closure.

The depth map is very similar to the time map with the closing contour displaced slightly to the southeast.

We conclude that the Dingo structure is a simple unfaulted domal feature which can be mapped accurately with a high degree of confidence. The lowest closing contour shown on Figure 19 is as chosen by Pancontinental and can be considered a minimum.

8.3 Gas Water Contact

No gas water contact has been observed in the Arumbera in either of the Dingo wells. An initial reservoir pressure of 4600 psia at a datum depth of 8250 ft BMSL (10040 ft RKB at Dingo-2) is above hydrostatic gradient. The Arumbera outcrops some 20 kilometres to the south of Dingo at a ground elevation slightly lower than at the Dingo location.

Assuming the same ground level for the outcrop results in a calculated gas water contact, using a fresh-water gradient, of approximately 10705 ft RKB at Dingo-1, or 8915 ft BMSL, i.e. below the lowest closing contour at Dingo. Using a slightly salty water gradient of 0.44 psi/ ft gives a contact at 10510 ft RKB (8720 ft BMSL), i.e. above the lowest closing contour.

It appears reasonable to expect the gas water contact to be at the lowest closing contour, 8750 ft BMSL.

8.4 Areal Extent of Reservoir

In determining the range of areal extent to use in calculating gas in place we have used the following method.

For the low value of area we have used the area within two 1 mile (1.6 kilometre) radius circles drawn round each well and joined tangentially to form an oval shape - this area is 3270 acres.

For the middle value of area we have used the area at the 8250 ft BMSL contour - this area is 10670 acres.

For the high value of area we have used the area at the 8500 ft BMSL contour - this area is 13685 acres.

In choosing these areas we have recognised potential for facies changes which might eliminate the productive sands at some distance away from the control points (wells) and the possibility of the gas water contact, if it exists, being above the closing contour. We also recognise that in a tight low-porosity sand such as this there is likely to be a significant gas water transition zone above the free water level where gas saturation and productivity will be reduced below crestal values.

8.5 Gas Saturation

Our range of low, middle and high values for gas saturation reflects the results of our log interpretation and a consideration of the type of rock and its porosity and permeability. The values are 45, 50 and 55 percent respectively.

8.6. Porosity

Our range of low, middle and high values for porosity is determined from a consideration of the log and core data from Dingo-1 and Dingo-2 and of how the values might be expected to change away from the wells. The values are 9.5, 11 and 12 percent respectively.

8.7 Net Pay Thickness

Our range of low, middle and high values for net pay thickness is determined from a consideration of the logs from Dingo-1 and Dingo-2, of DST data on both wells and of how the estimated values at the wells might vary across the field area. The values are 50, 60 and 65 ft respectively.

8.8 Gas Formation Volume Factor

As there are good gas samples available we have used a single value for gas FVF at assumed initial conditions (4600 psia, 170°F) of 0.00387 vol/vol.

8.9 Recovery Factor

Our range of recovery factors is derived from a consideration of the results of calculations discussed in Section 7 and of how an average producing well might be expected to perform. It also assumes that the field will not be developed without new wells of higher productivity than Dingo-2. The low, middle and high values are 70, 75 and 80 percent respectively.

8.10 Results

The table below gives the complete input data (except the constant gas FVF) and results of the Monte Carlo simulation. The absolute minima and maxima for the values are chosen on a similar basis to that described above, but are not as significant in the calculations as the three intermediate values.

	Probability of Exceeding Given Value, %				
	100	90	50	10	0
Area, (acres)	1960	3270	10670	13685	17340
Gas saturation,(percent)	40	45	50	55	60
Porosity, (percent)	8	9.5	11	12	13
Thickness, (feet)	40	50	60	65	70
Recovery factor, (percent)	60	70	75	80	83
Gas in Place, Bcf	44.3	112.5	344.3	537.5	982.7
Gas Reserves, Bcf	33.2	79.2	254.0	397.6	585.3

The statistically derived Expected Value of gas in place is 337.0 Bcf. The statistically derived Expected Value of gas reserves is 247.0 Bcf.

We would point out that there are fairly severe constraints placed on our confidence levels by the sheer size of the structure and the fact that only two wells have been drilled to date.

We would also emphasise that the recoverable gas reserves are Technical Reserves as defined in Section 9. That is, the commercial nature of the reserves has not yet been demonstrated. The cutoff production rate of 0.2 MMcfd used in deriving recovery factors should allow covering of operating costs but we have not and can not comment at this stage on whether production would give an adequate return on the capital investment necessary to develop the field.

9. RESERVES DEFINITIONS

In this report:-

Proven, in relation to quantities of petroleum means the amount thereof which geophysical, geological and engineering data indicate to be in place or recoverable (as the case may be) to a high degree of certainty. For the purposes of this definition, there is a 90 percent chance that the actual quantity will be more than the amount estimated as Proven and a 10 percent chance that it will be less.

Probable, in relation to quantities of petroleum, means the amount thereof which geophysical, geological and engineering data indicate to be in place or recoverable (as the case may be) but with a greater element of risk than in the case of Proven. For the purposes of this definition, there is a 50 percent chance that the actual quantity will be more than the amount estimated as Proven+Probable and a 50 percent chance that it will be less.

Possible, in relation to quantities of petroleum, means the amount thereof which geophysical, geological and engineering data indicate may be in place or recoverable (as the case may be) but to which a substantial element of risk must be attached. For the purposes of this definition, there is a 10 percent chance that the actual quantity will be more than the amount estimated as Proven+Probable+Possible and a 90 percent chance that it will be less.

Technical Reserves are those quantities of petroleum which we consider on the basis of information currently available and present economic conditions, to be recoverable by present or presently anticipated producing methods, so that production of such reserves would be expected to cover operating costs at all times but would not necessarily provide a commercial return on development costs.

10. GLOSSARY AND ABBREVIATIONS

Sw	-	Water Saturation in percent
Sg	-	Gas Saturation in percent
HCPV	-	Hydrocarbon Pore Volume
BH	-	Bottom Hole
Rw	-	Water resistivity
Por	-	Porosity
RKB	-	Relative to Kelly Bushing
TVDSS	-	Time Vertical Depth Subsea
DLL	-	Dual Laterlog
MSFL	-	Microspherically focussed log
GR	-	gamma ray
NGT/BHC	-	Natural gamma ray tool/borehole compensated sonic
LDT	-	Lithodensity tool
CNL	-	Compensated neutron log
HDT	-	High resolution dipmeter tool
ppg	-	part per gallon
dtma	-	matrix interval transit time
dtfl	-	fluid transit
"a"		exponents
"m"	-	used in
"n"		log analysis
KCl	-	Potassium chloride
p	-	pressure
z	-	gas supercompressibility factor
u	-	viscosity
cg	-	gas compressibility
Bg	-	gas formation volume factor
m(p)	-	gas pseudo pressure function
md	-	measured depth
Bcf	-	Billions of cubic feet
DST	-	Drill Stem Test
AOFP	-	Absolute Open Flow Potential
ft	-	feet
MMcfd	-	Millions of cubic feet per day
psig	-	pounds per square inch gauge
psi	-	pounds per square inch
psia	-	pounds per square inch absolute
I.D.	-	inside diameter
BMSL	-	below mean sea level
cp	-	centipoise
^oR	-	degrees Rankine

Table 1

Dingo Gas Field Review

Arumbera-1 Gas Composition

Sample:-	Mole Percent 1	2	3	4	5	6	Average
Component							
Methane, CH_4	87.15	87.15	87.07	86.35	87.31	87.48	87.08
Ethane, C_2H_6	3.10	3.08	3.08	3.06	2.85	2.95	3.02
Propane, C_3H_8	.34	.34	.34	.34	.31	.34	.34
i - Butane, iC_4H_{10}	.04	.03	.03	.04	.05	.05	.04
n - Butane, iC_4H_{10}	.06	.06	.03	.05	.06	.06	.05
i - Pentane, nC_4H_{10}	.05	.04	.01	.05	.02	.02	.03
n - Pentane, iC_5H_{12}	.01	.01	.01	.01	.03	.03	.02
Hexanes, C_6H_{14}	.02	.02	.01	.02	.02	.02	.02
Heptanes+, C_7H_{16}+	.03	.02	0.02	.03	.00	.00	.02
Nitrogen, N_2	9.20	9.25	9.40	10.05	9.35	9.05	9.38
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00

Gas properties from average composition:-

Gas Gravity	= 0.614 (Air=1)
Pseudo-critical Temperature	= 340.4 ^{o}R
Pseudo-critical Pressure	= 652.0 psia
Gross Heating Value	= 948 Btu/scf
Net Heating Value	= 855 Btu/scf

Source: Samples 1-4 taken during DST No.6, Dingo-1
Samples 5 & 6 taken during DST No.1, Dingo-2

Table 2

Dingo Gas Field Review

Julie Formation Gas Analysis

Component	Mole Percent Sample 1
Methane, CH_4	90.84
Ethane, C_2H_6	5.10
Propane, C_3H_8	.47
i - Butane, iC_4H_{10}	.03
n - Butane, iC_4H_{10}	.08
i - Pentane, nC_4H_{10}	.02
n - Pentane, iC_5H_{12}	.02
Hexanes, C_6H_{14}	.00
Heptanes+, C_7H_{16}+	.00
Nitrogen, N_2	3.30
Carbon Dioxide, CO_2	.14
Total	100.00

Gas properties from average composition:-

Gas Gravity	= 0.600 (Air=1)
Pseudo-critical Temperature	= 352.2^{O}R
Pseudo-critical Pressure	= 664.2 psia
Gross Heating Value	= 1024 Btu/scf
Net Heating Value	= 924 Btu/scf

Source: Sample taken during DST No.2, Dingo-2

Table 3

Dingo Gas Field Review

Arumbera-1 Reservoir Fluid PVT Properties
(from average composition of Table 1)

Reservoir Temperature = 630 ^{o}R
Standard Pressure = 14.7 psia
Standard Temperature = 520 ^{o}R

Pressure (p) psia	Compressibility Factor (z)	Viscosity (u) cp	Compressibility (cg) psi^{-1}	Formation Volume Factor (Bg) vol/vol	Real Gas Potential (m(p)) $10^6 psia^2/cp$
0	-	-	-	-	.00
400	.9711	.0134	.00257	.04324	12.30
800	.9465	.0139	.00131	.02107	48.97
1000	.9361	.0142	.00110	.01670	76.21
1200	.9271	.0145	.00088	.01376	109.10
1400	.9198	.0149	.00075	.01170	147.37
1600	.9141	.0153	.00065	.01018	190.67
1800	.9101	.0157	.00057	.00901	238.70
2000	.9079	.0162	.00051	.00809	291.07
2200	.9073	.0167	.00045	.00735	347.38
2400	.9084	.0172	.00041	.00674	407.25
2600	.9111	.0177	.00037	.00624	470.30
2800	.9152	.0182	.00033	.00582	536.15
3000	.9207	.0188	.00030	.00547	604.47
3200	.9274	.0193	.00027	.00516	673.80
3400	.9352	.0199	.00025	.00490	746.13
3600	.9440	.0204	.00023	.00467	820.07
3800	.9538	.0210	.00021	.00447	895.37
4000	.9643	.0215	.00019	.00429	971.88
4200	.9756	.0221	.00018	.00414	1049.28
4400	.9875	.0227	.00016	.00400	1127.54
4600	1.0000	.0232	.00015	.00387	1206.47
4800	1.0130	.0238	.00014	.00376	1285.96
5200	1.0402	.0248	.00012	.00356	1446.23
5600	1.0689	.0259	.00011	.00340	1607.77
6000	1.0988	.0269	.00010	.00326	1769.88
6400	1.1296	.0280	.00009	.00314	1931.73
6800	1.1611	.0289	.00008	.00304	2093.73

Table 4

Dingo Gas Field Review

Dingo-2, Rock and Fluid Properties for Test Analysis

Net pay	=	55 ft
Porosity	=	.11
Gas saturation	=	.52
Water saturation	=	.48
Gas compressibility (1)	=	$160 \times 10^{-6} psi^{-1}$
Water compressibility (2)	=	$2 \times 10^{-6} psi^{-1}$
Rock pore volume compressibility (3)	=	$5 \times 10^{-6} psi^{-1}$
Total compressibility	=	$89 \times 10^{-6} psi^{-1}$
Wellbore radius	=	.35 ft
Gas viscosity (1)	=	.023 cp
Gas deviation factor (Z) (1)	=	.994
Reservoir temperature	=	630 °R
Gas gravity relative to air	=	.614

Footnotes:-

(1) At assumed average shut-in conditions of 4500 psia.
(2) Long & Chierici data.
(3) Hall correlation.

Table 5

Dingo Gas Field Review

April 1986 - Pre Fracture Test Analysis

Permeability thickness product	:	22.5 md ft
Extrapolated pressure	:	4560 psia
at gauge depth	:	9679 feet RKB

Rate (Mscf/day)	Skin Factor
1740	2.68
1950	5.74
2310	5.74
2530	5.27
2660	4.20

Table 6

Dingo Gas Field Review

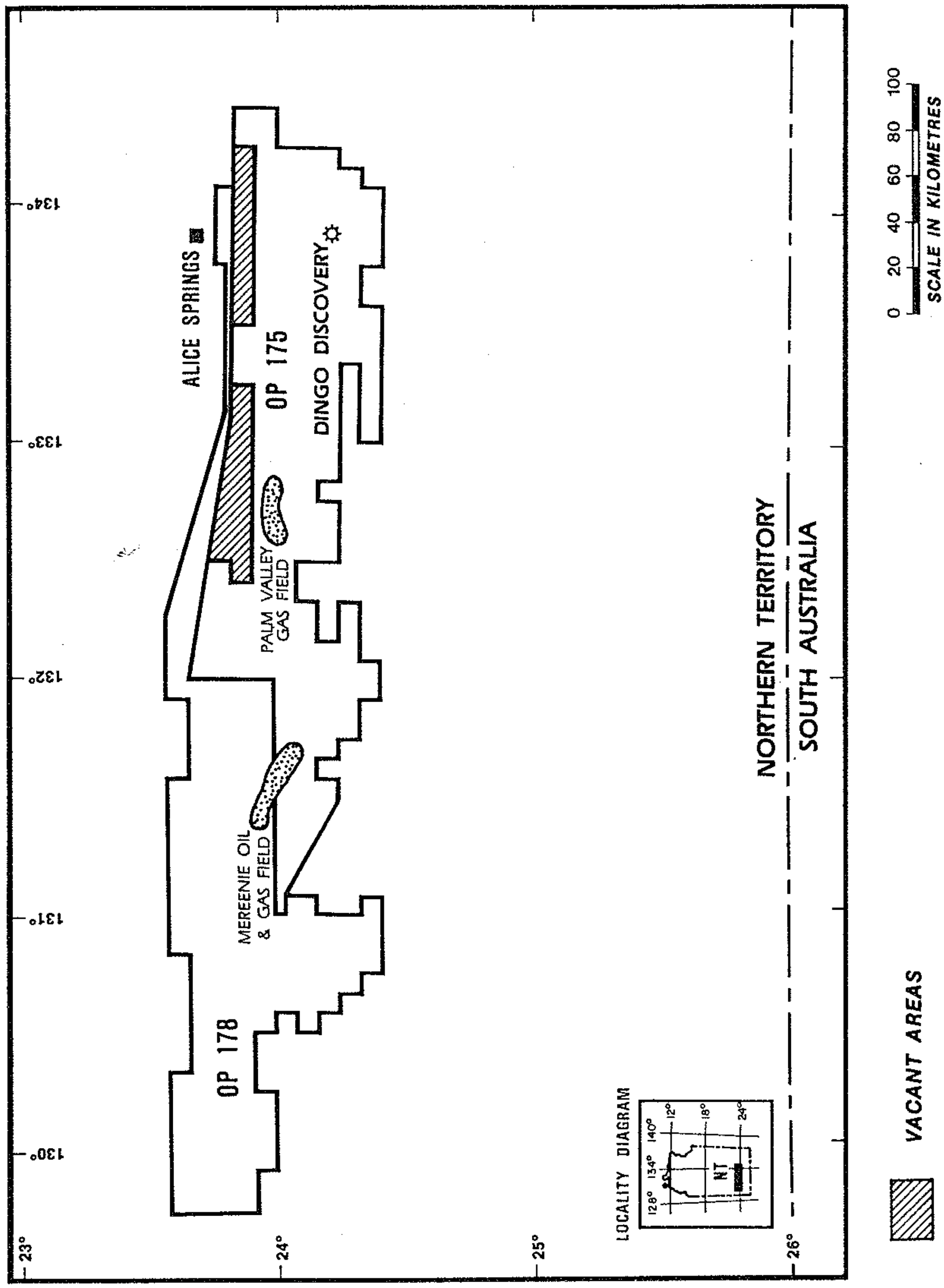
May 1985 Post Fracture Test Analysis

Build Up Number	Last Rate (Mscf/Day)	Permeability Thickness Product (md-ft)	Permeability (md)	Skin Factor	Extrapolated Pressure (3) (psia)
1 (1)	2450	18.2	0.33	1.59	4550
(2)		19.1	0.35	1.84	4550
2 (2)	2090	25.5	0.46	0.21	4560
3 (2)	2550	21.1	0.40	0.65	4565
4 (2)	2860	21.3	0.39	2.34	4565
5 (2)	3210	23.2	0.42	2.79	4565
Average		22.0	0.40		

Footnotes:-

(1) Assuming 50.5 hour initial flow period.
(2) Assuming 96 hour initial flow period.
(3) At gauge depth, 9679 feet RKB.

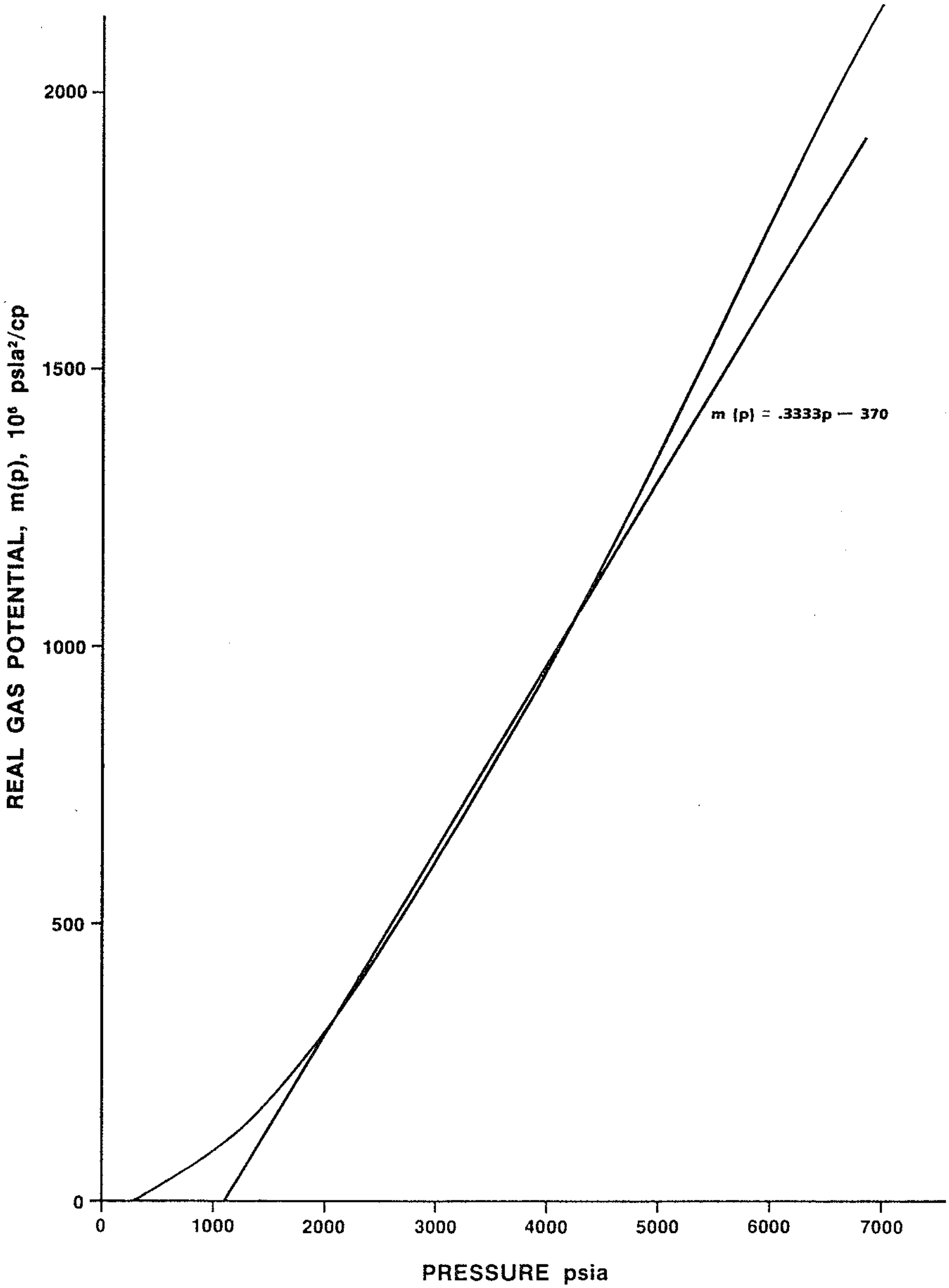
DINGO DISCOVERY - LOCATION MAP



DINGO GAS FIELD STUDY

FIGURE 1

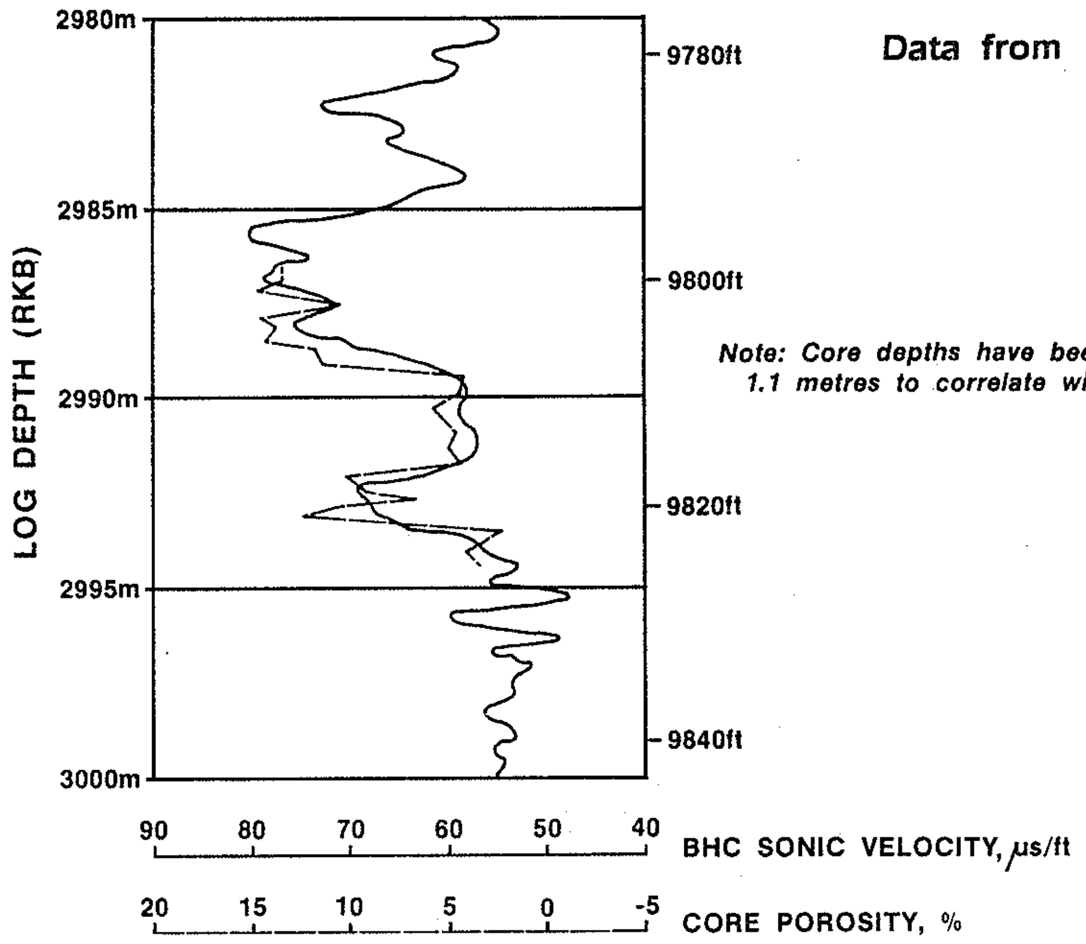
DINGO GAS FIELD STUDY
REAL GAS POTENTIAL, m(p) vs PRESSURE
ARUMBERA-1 GAS SAMPLE

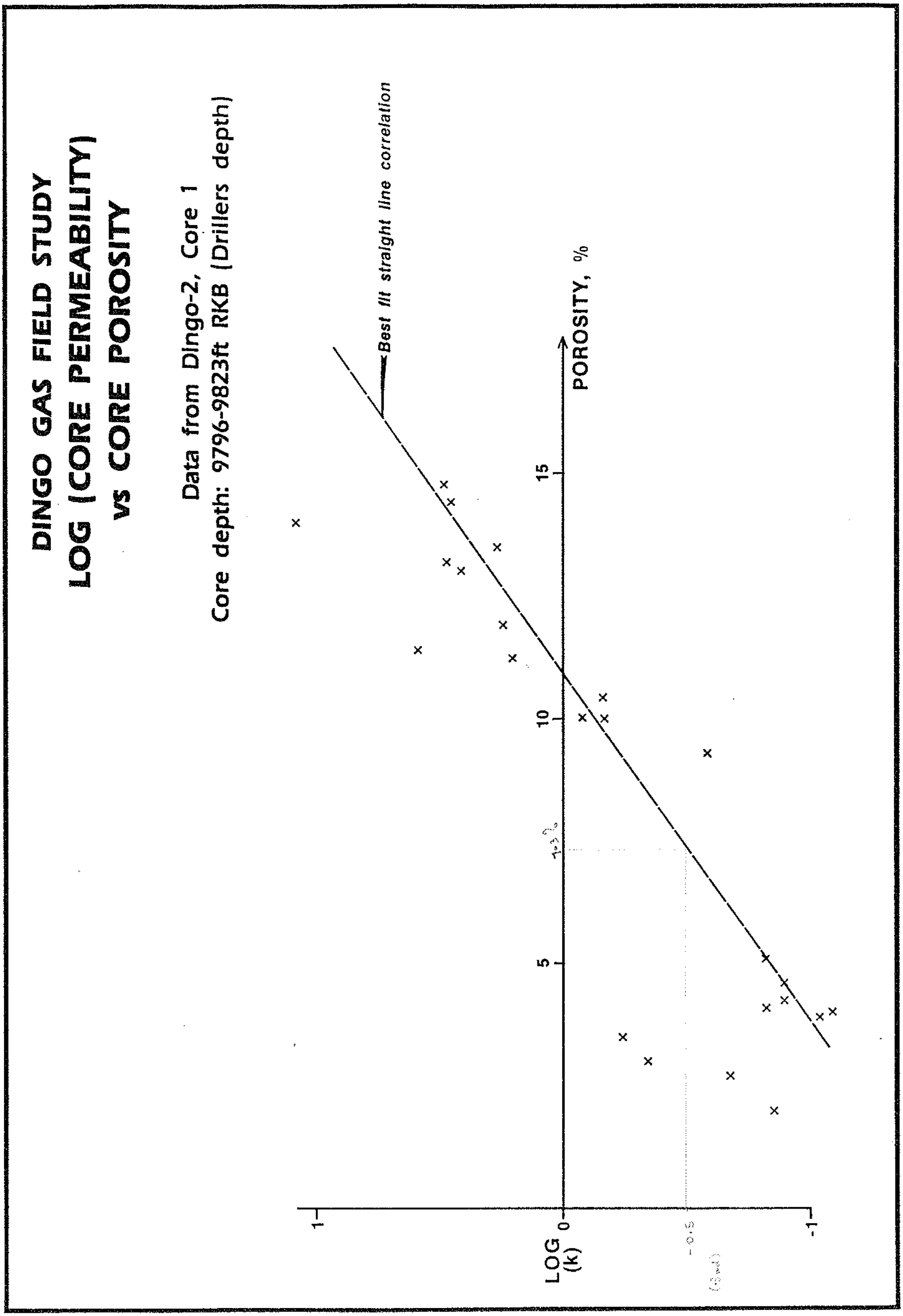


DINGO GAS FIELD STUDY
DINGO-2, ARUMBERA-1
LOG / CORE CORRELATION

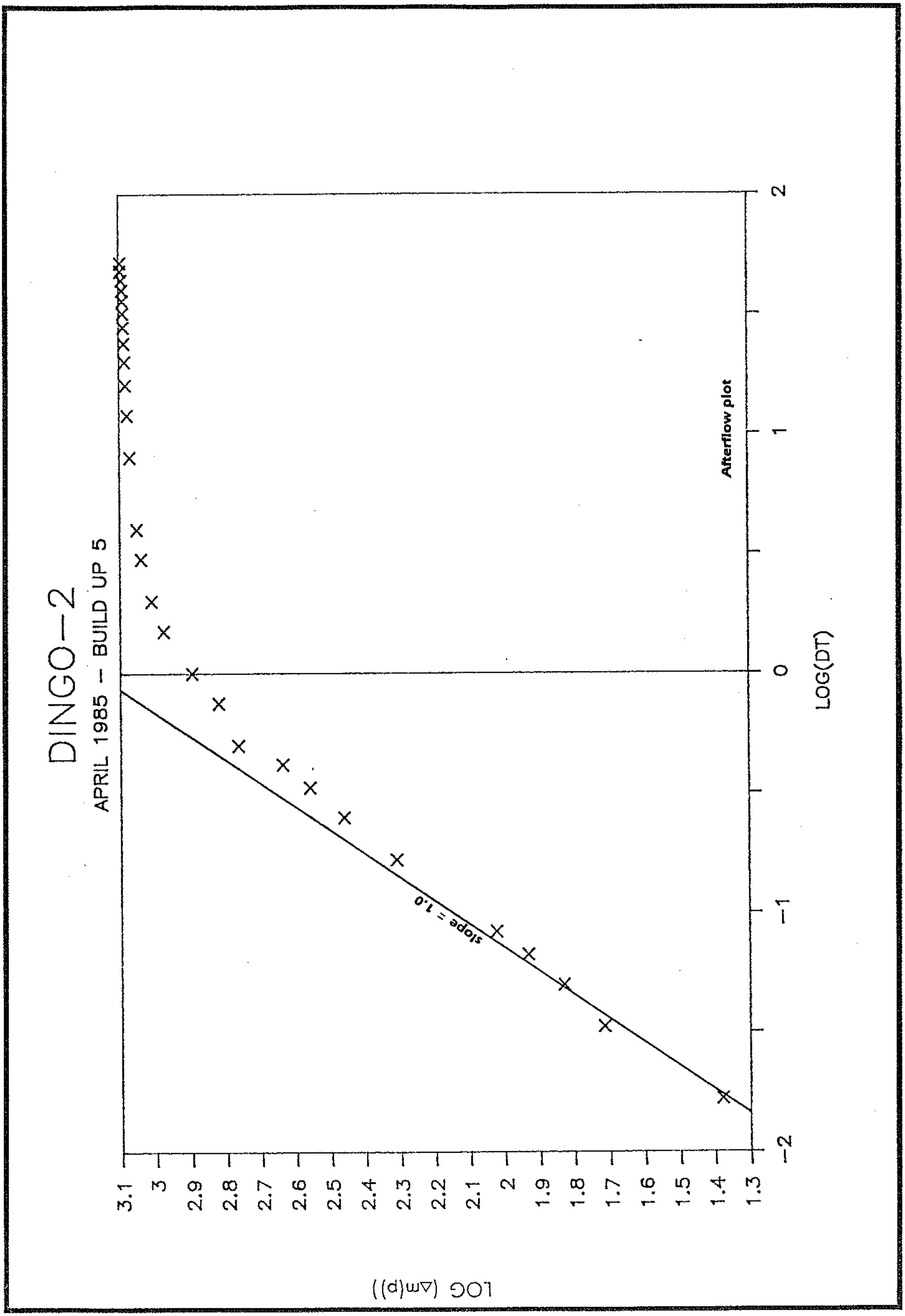
Data from BHC Sonic Log and Core 1

Note: Core depths have been increased by 1.1 metres to correlate with log depths



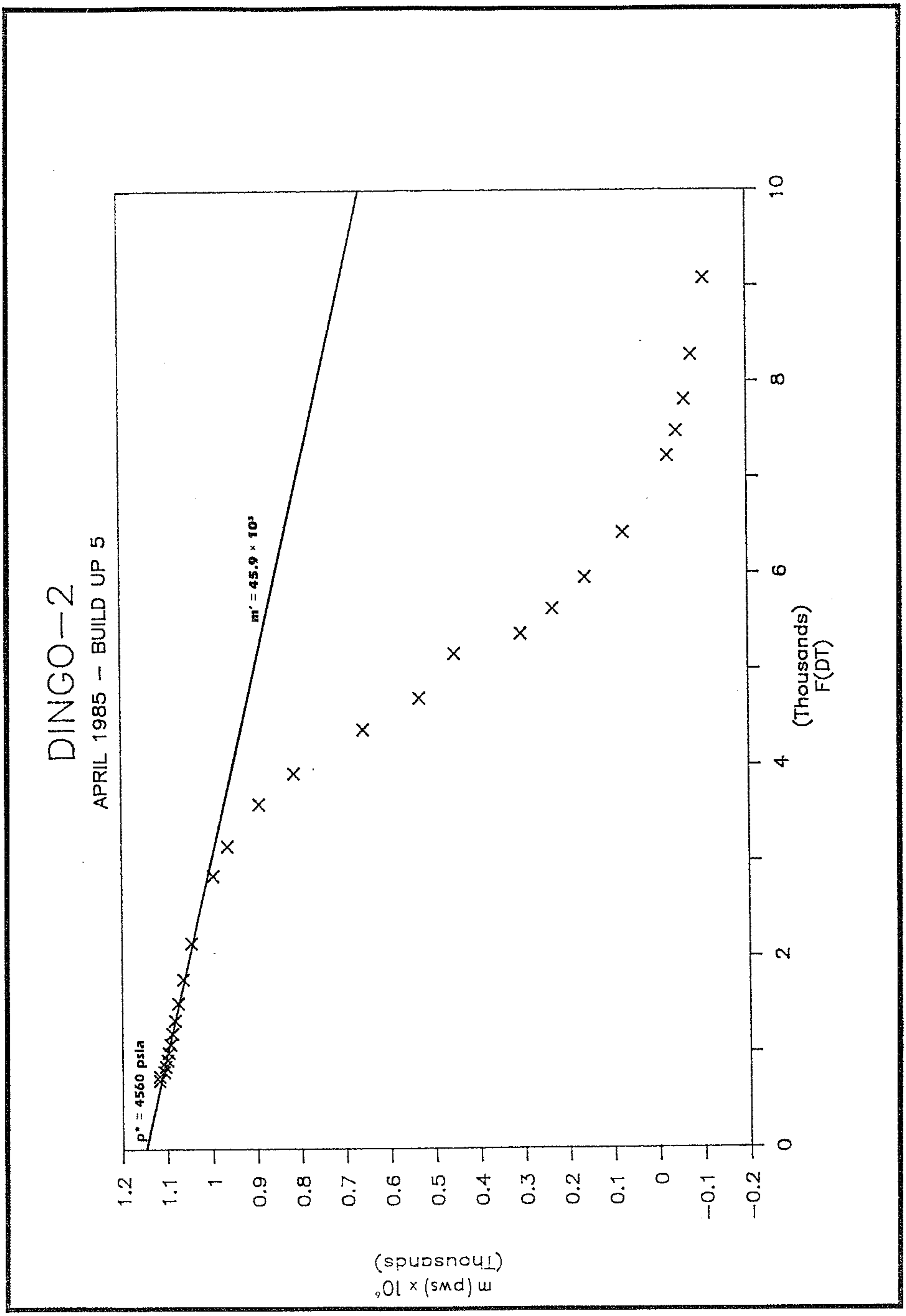


DINGO GAS FIELD STUDY
LOG (CORE PERMEABILITY)
VS CORE POROSITY
Data from Dingo-2, Core 1
Core depth: 9796-9823ft RKB (Drillers depth)
Best fit straight line correlation
POROSITY, %
LOG (k)
1
0
-1
5
10
15



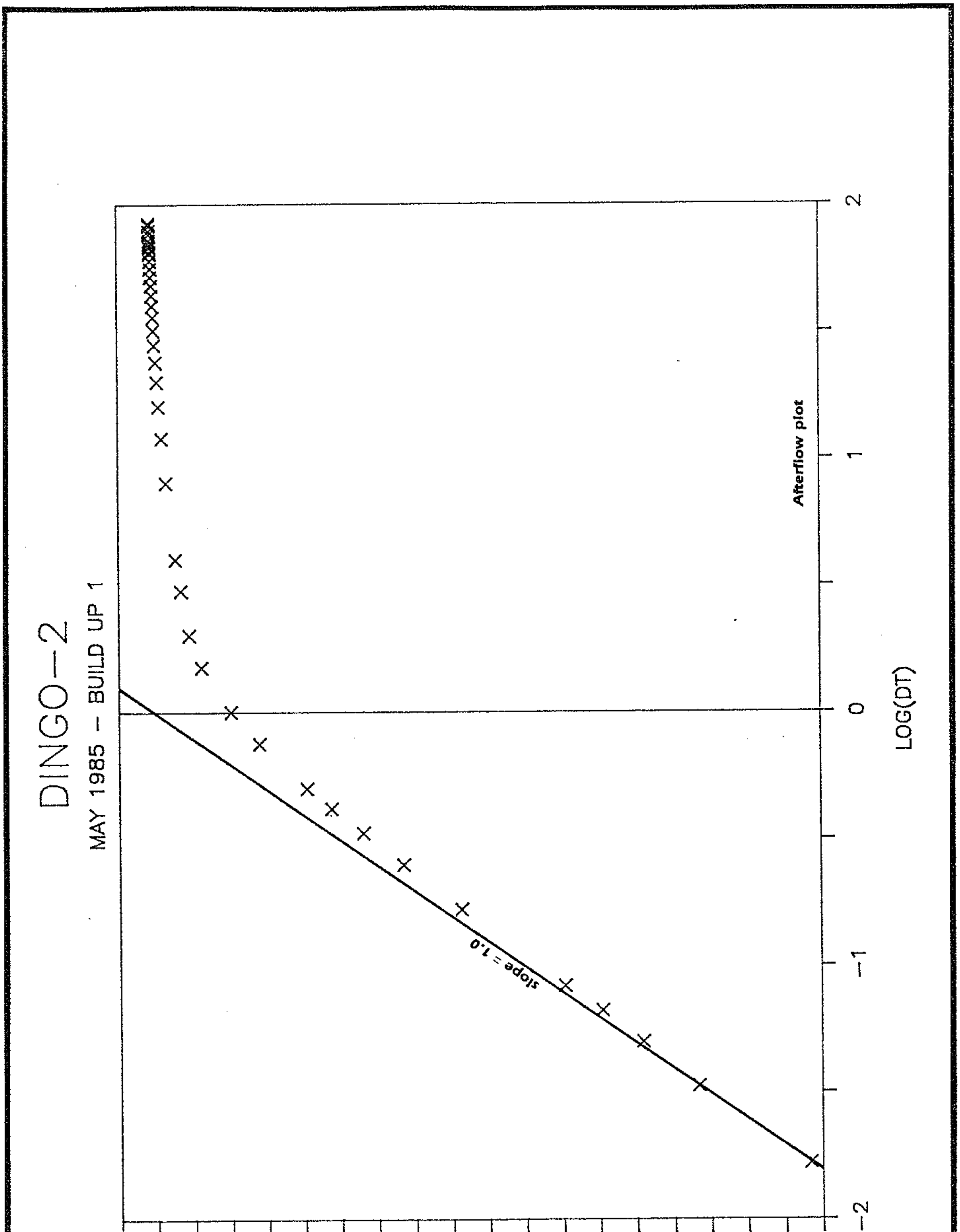
DINGO GAS FIELD STUDY

FIGURE 5



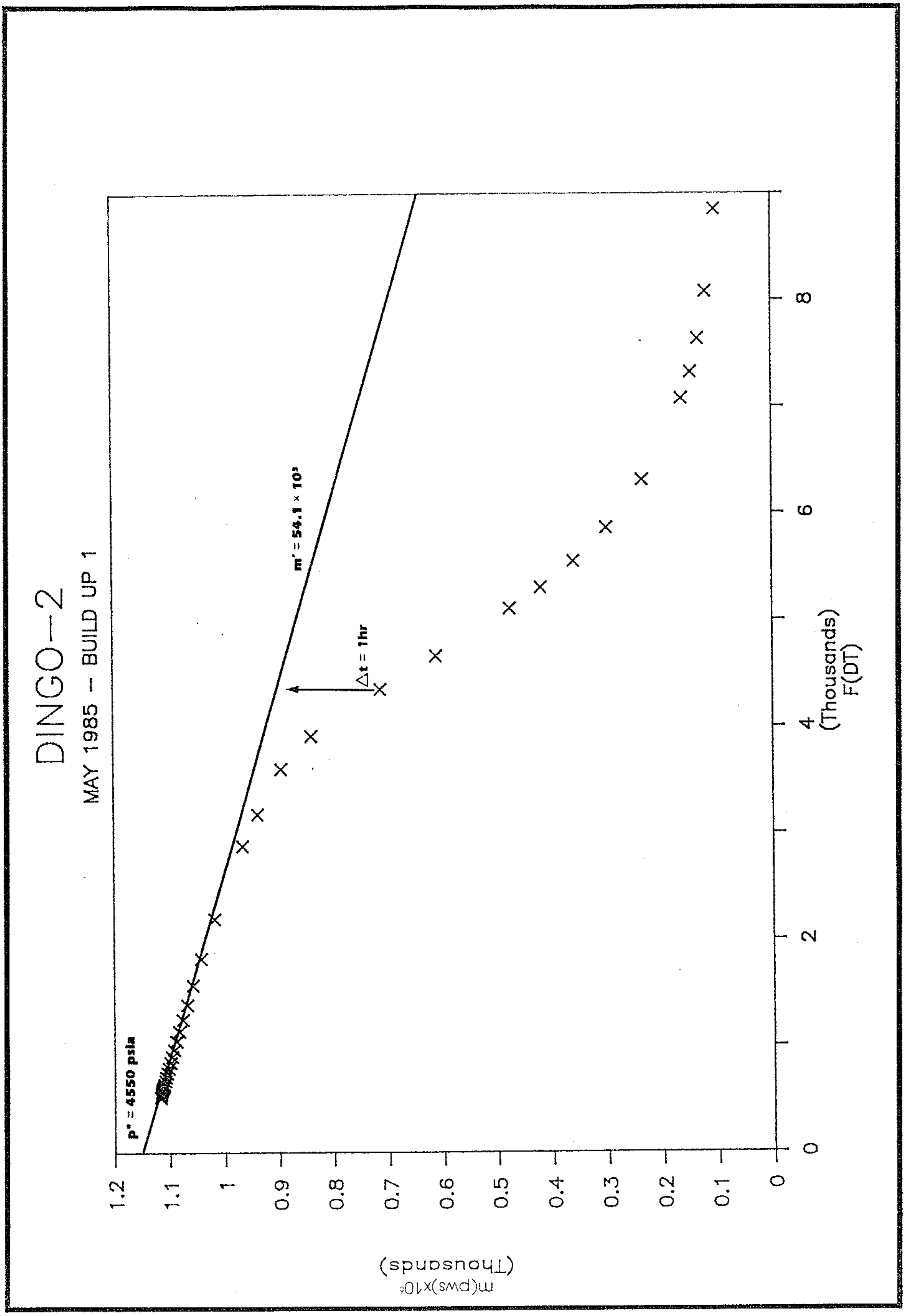
DINGO GAS FIELD STUDY

FIGURE 6



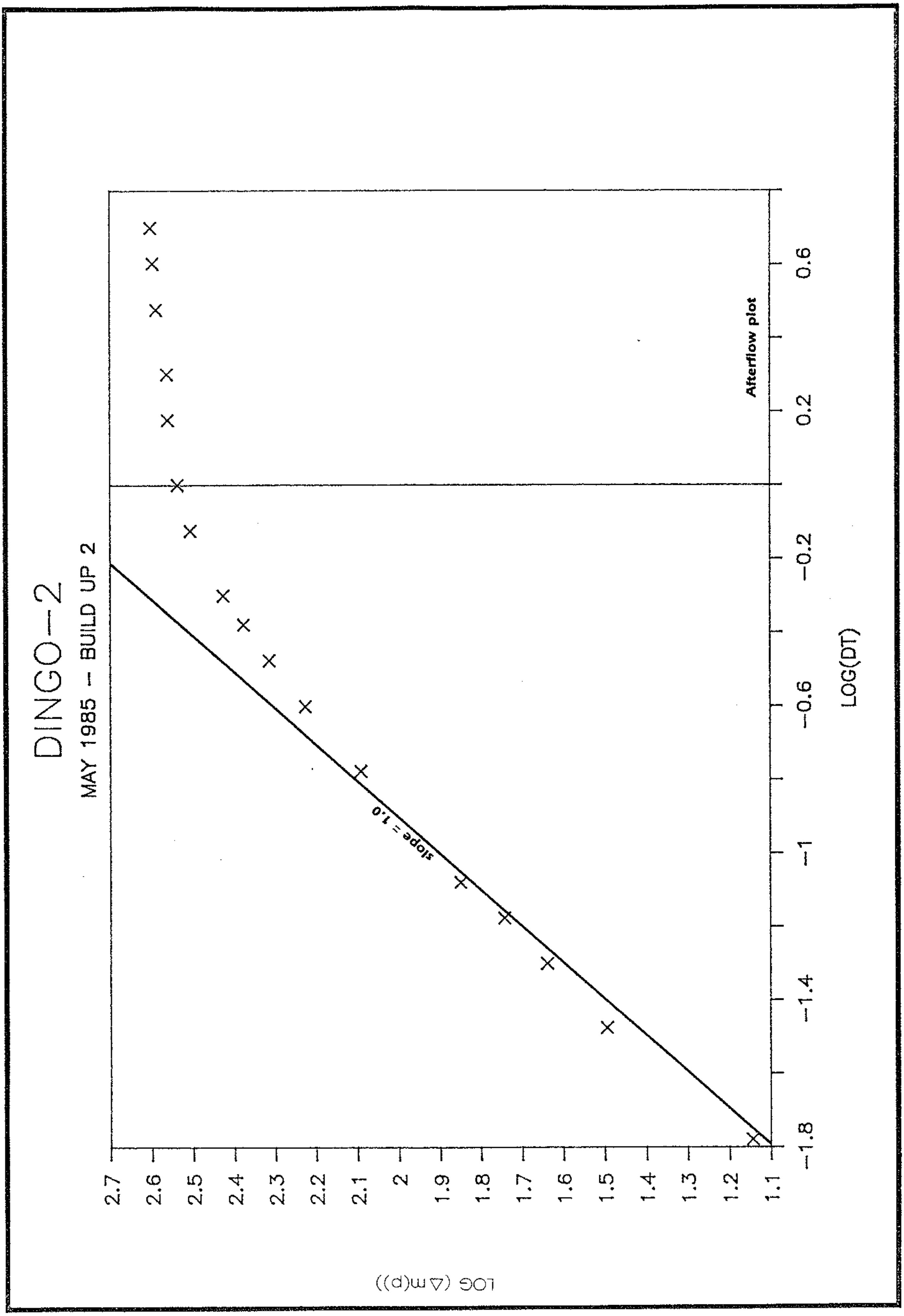
DINGO GAS FIELD STUDY

FIGURE 7



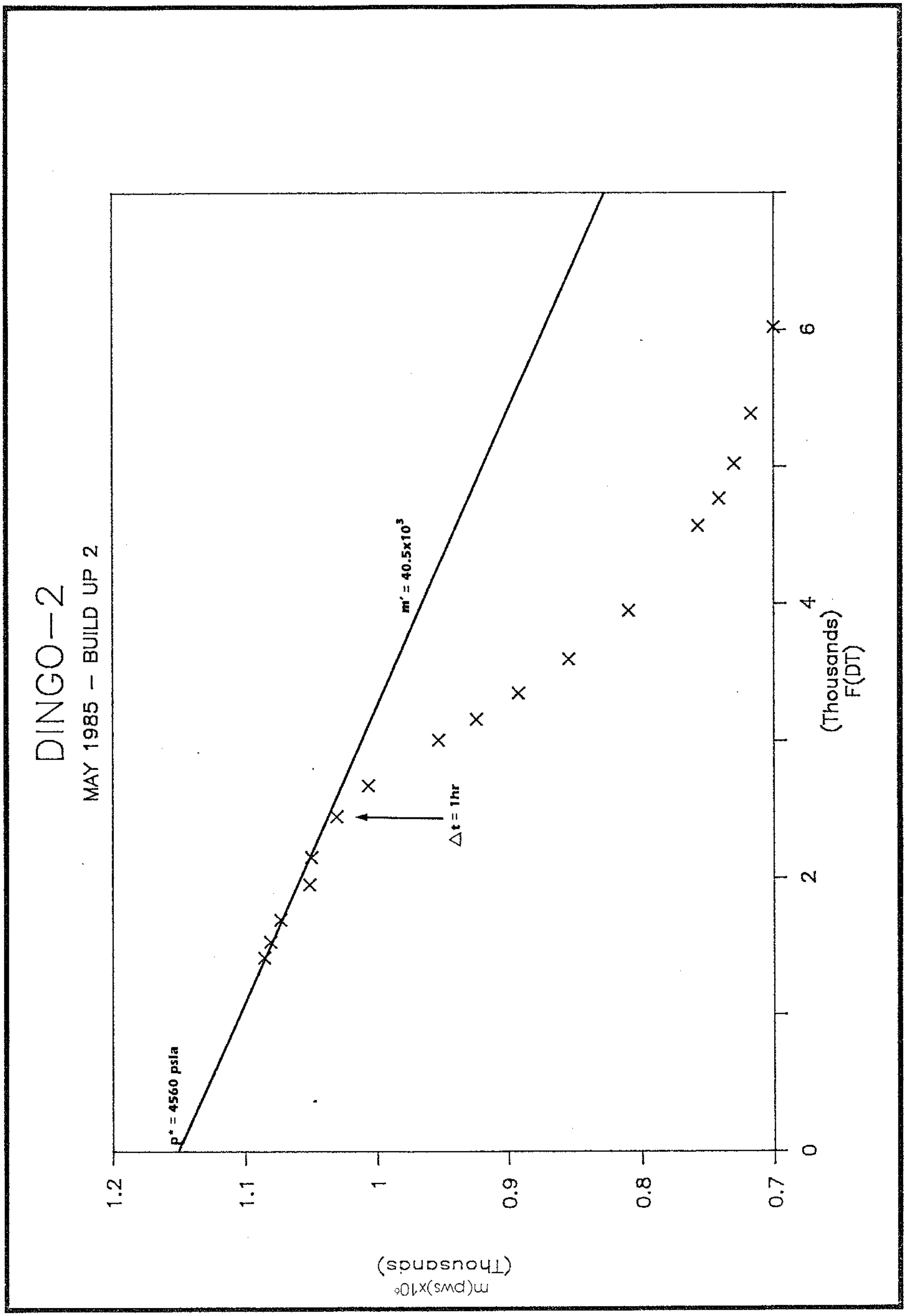
DINGO GAS FIELD STUDY

FIGURE 8



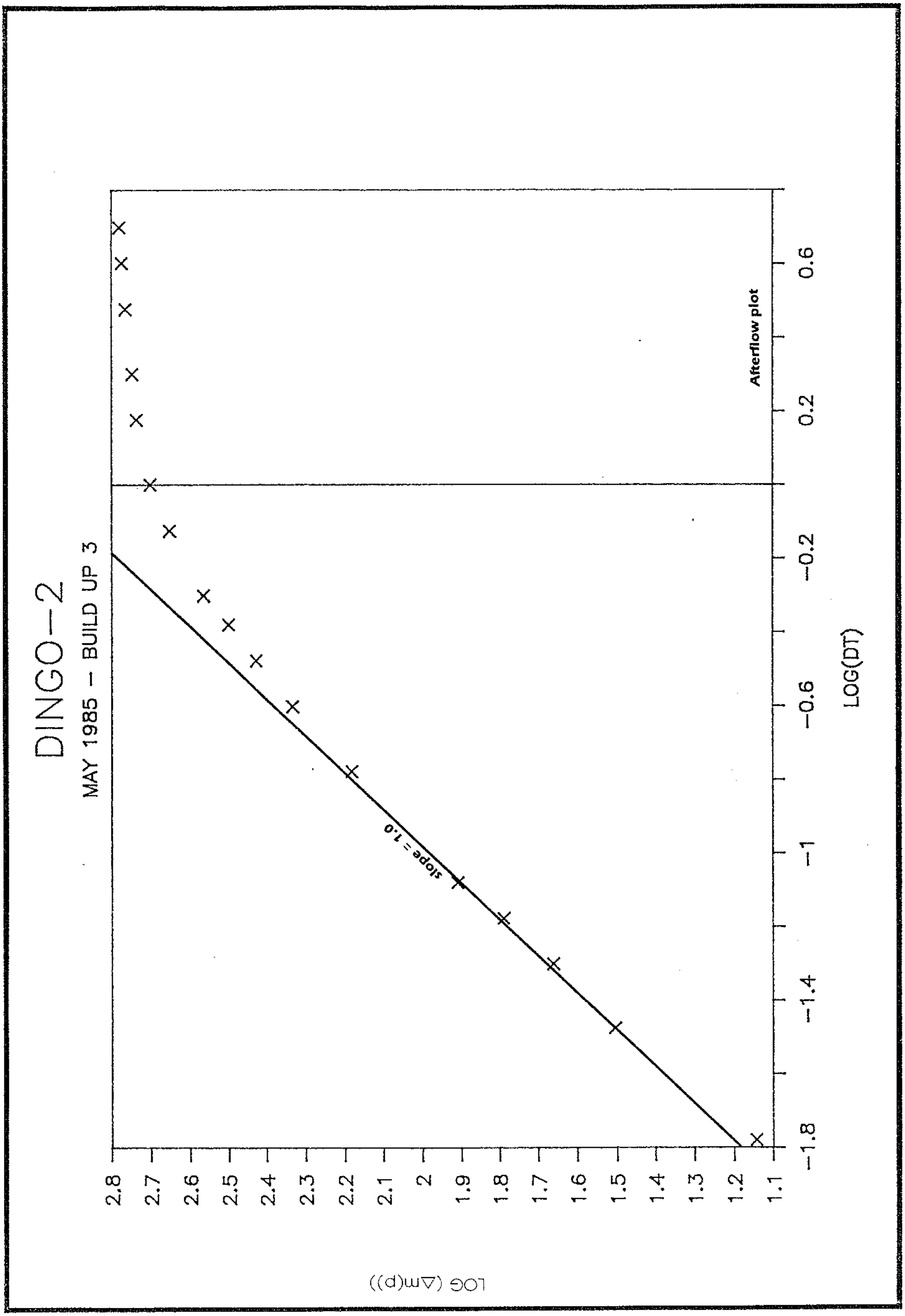
DINGO GAS FIELD STUDY

FIGURE 9



DINGO GAS FIELD STUDY

FIGURE 10



DINGO GAS FIELD STUDY

FIGURE 11

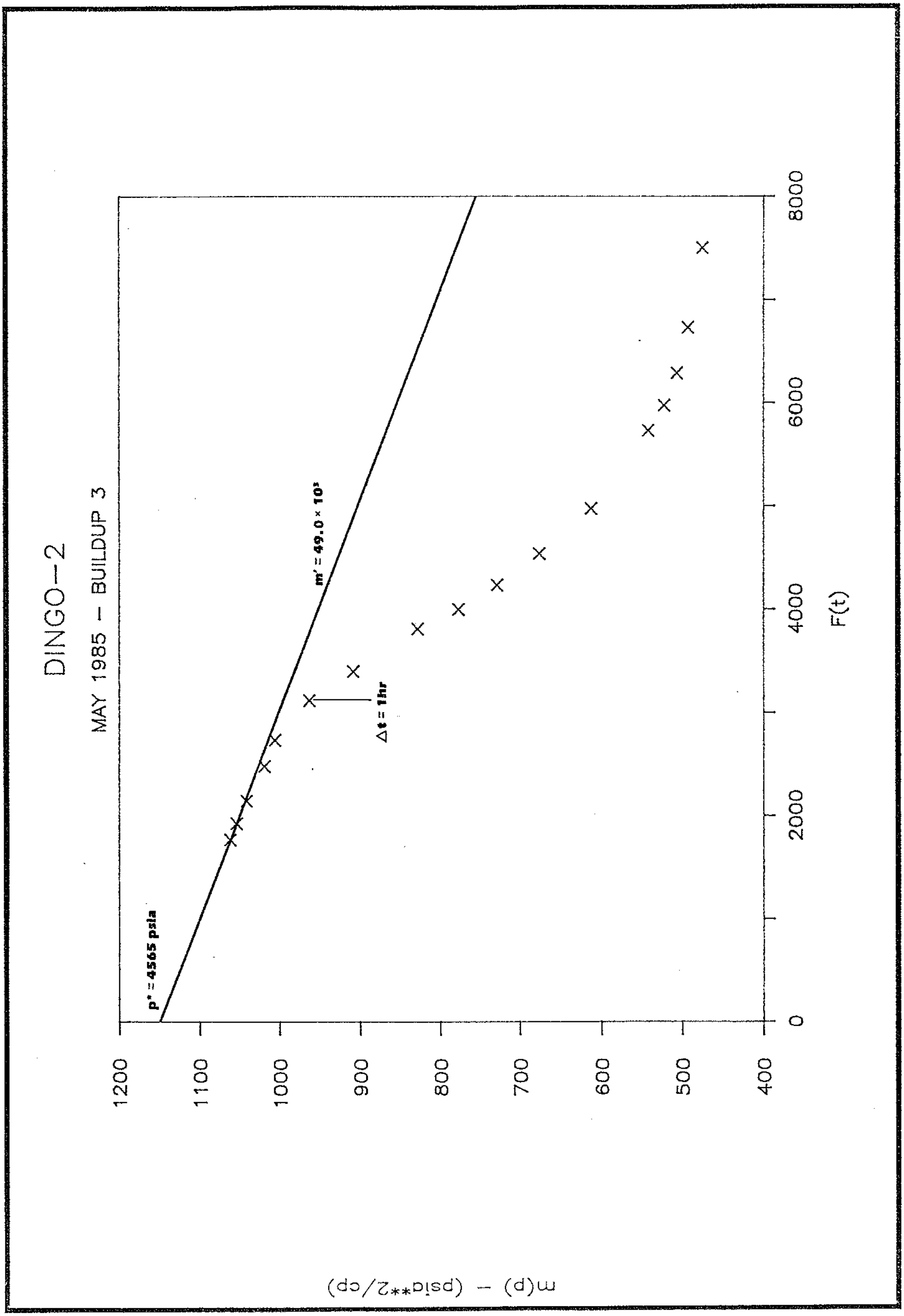
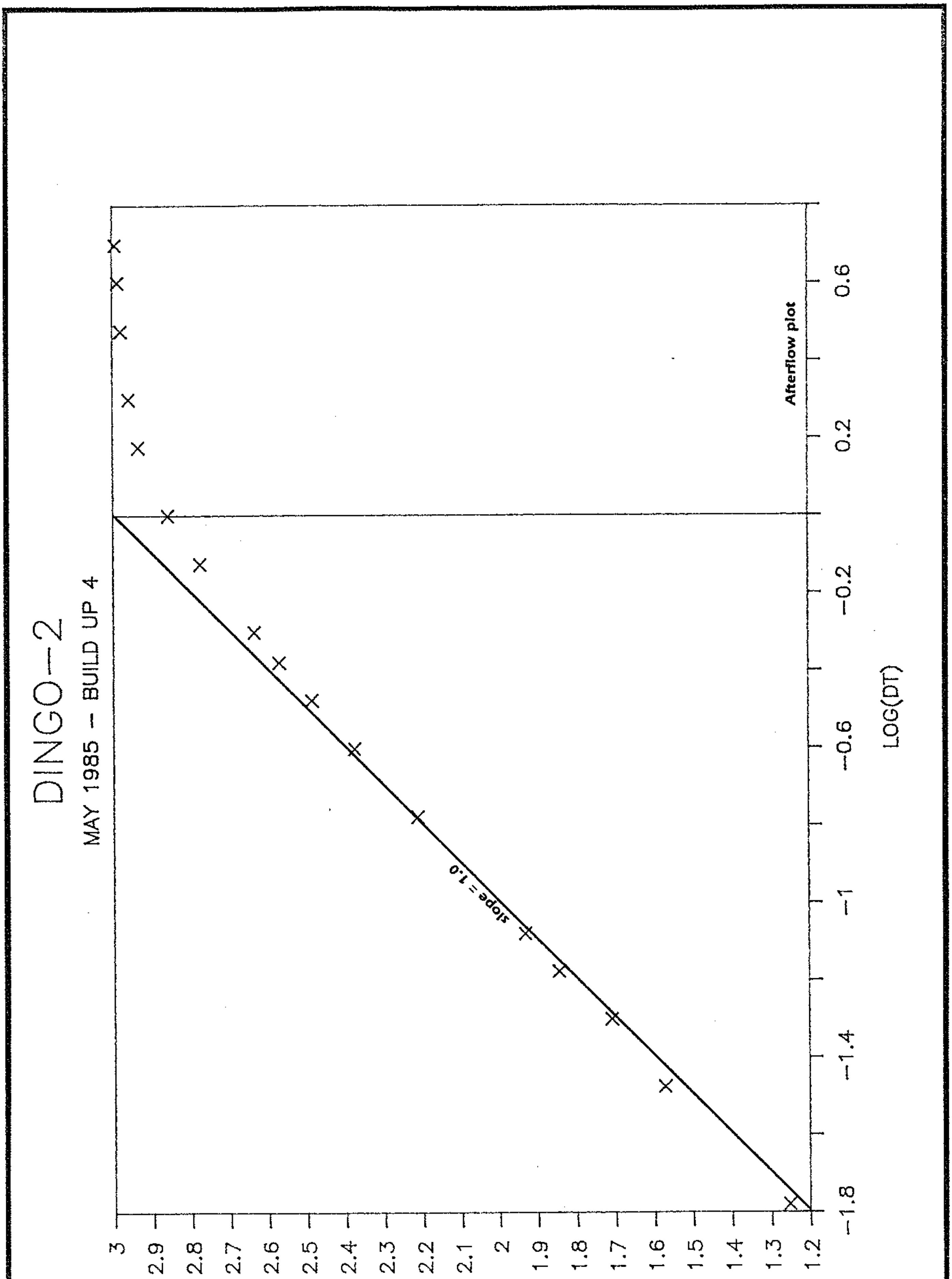
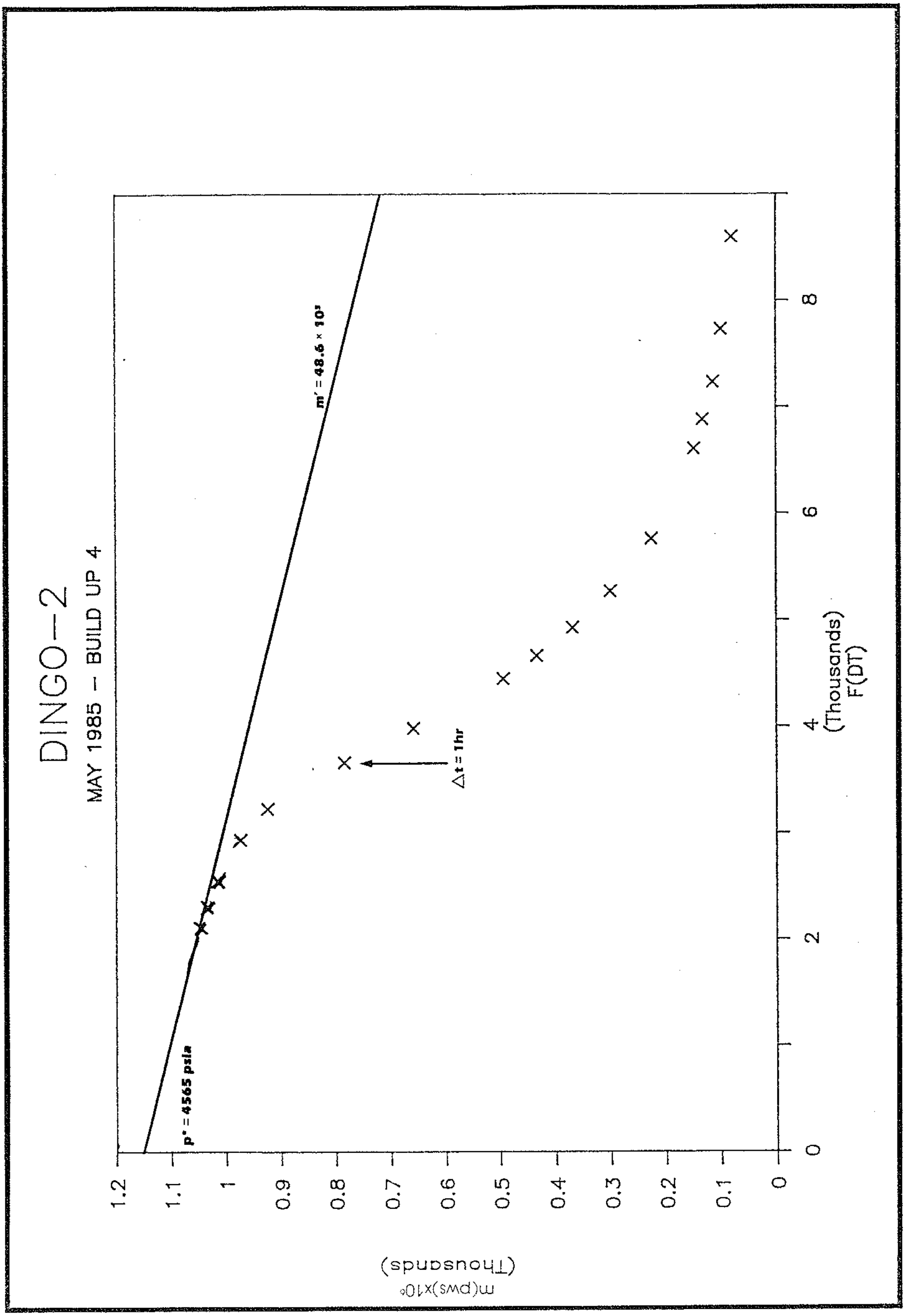


FIGURE 12
85.5126



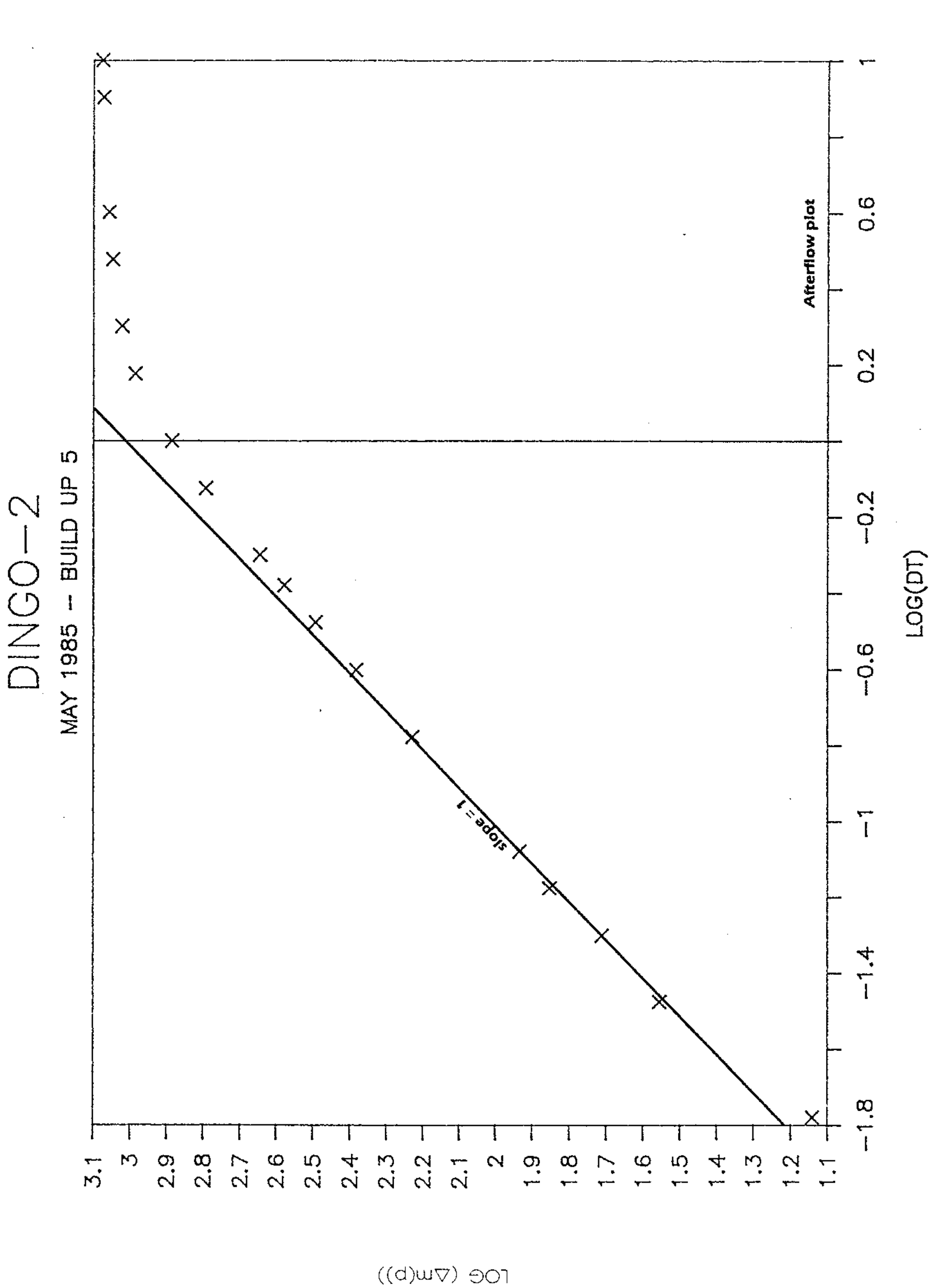
DINGO GAS FIELD STUDY

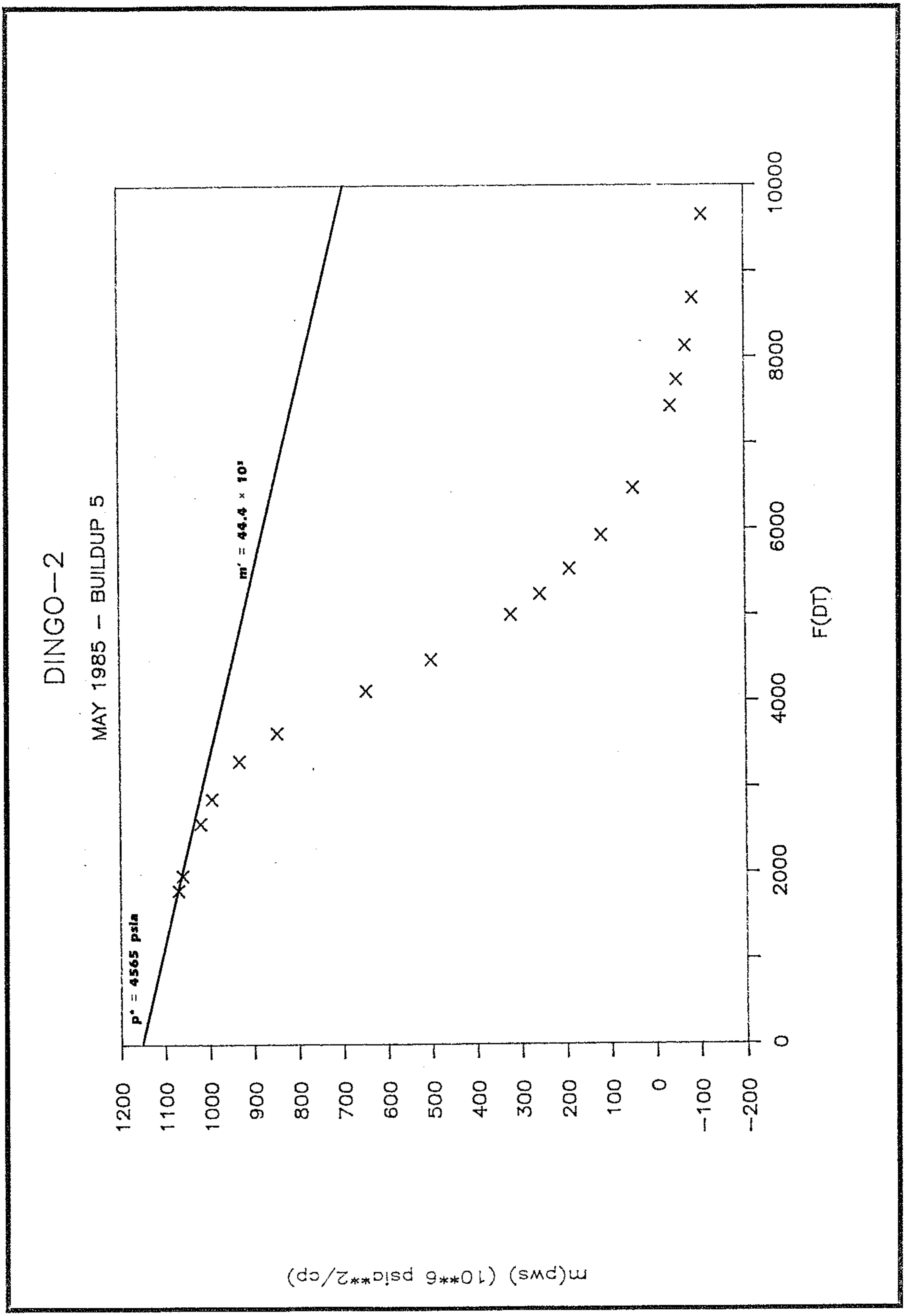
FIGURE 13

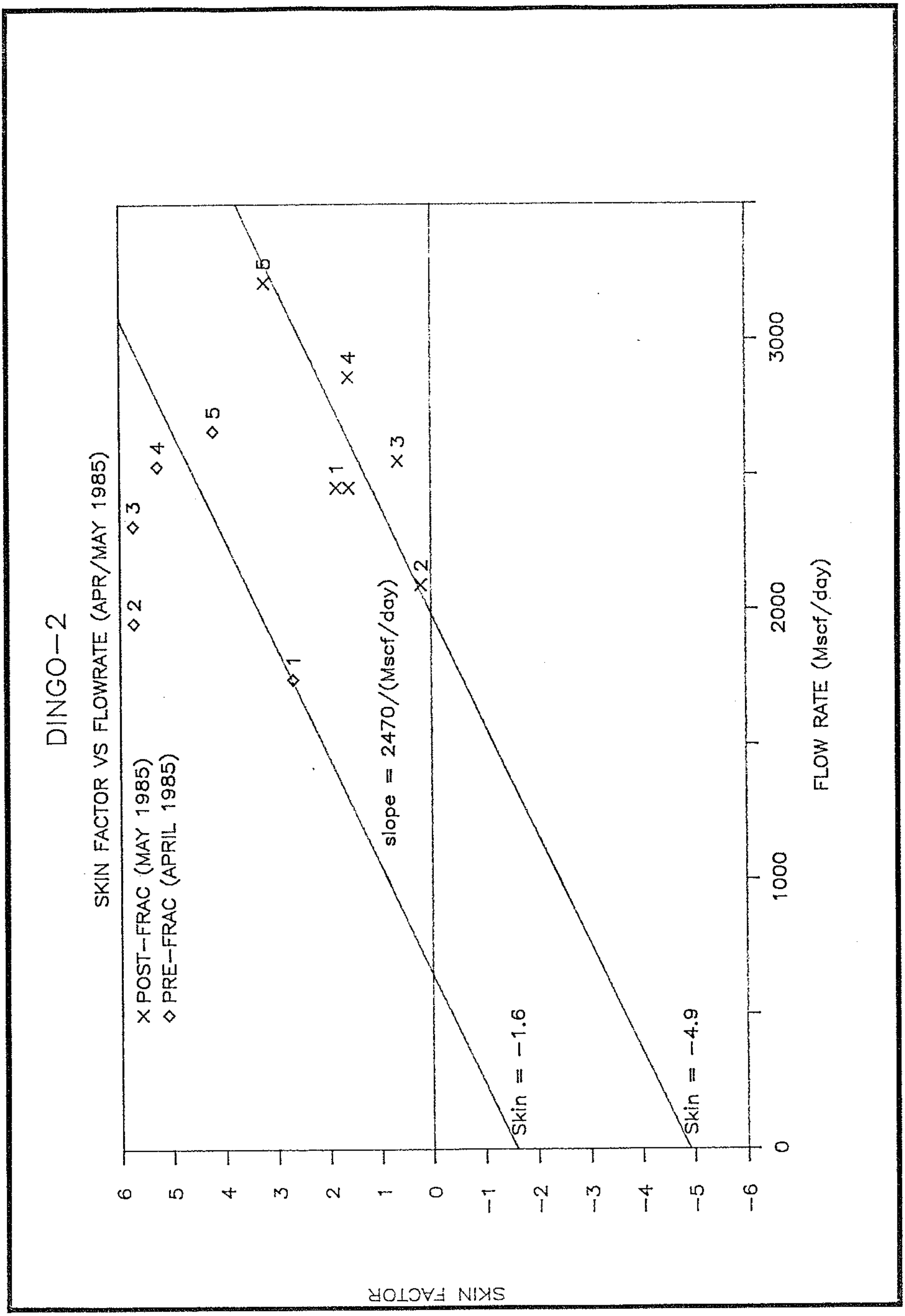


DINGO GAS FIELD STUDY

FIGURE 14

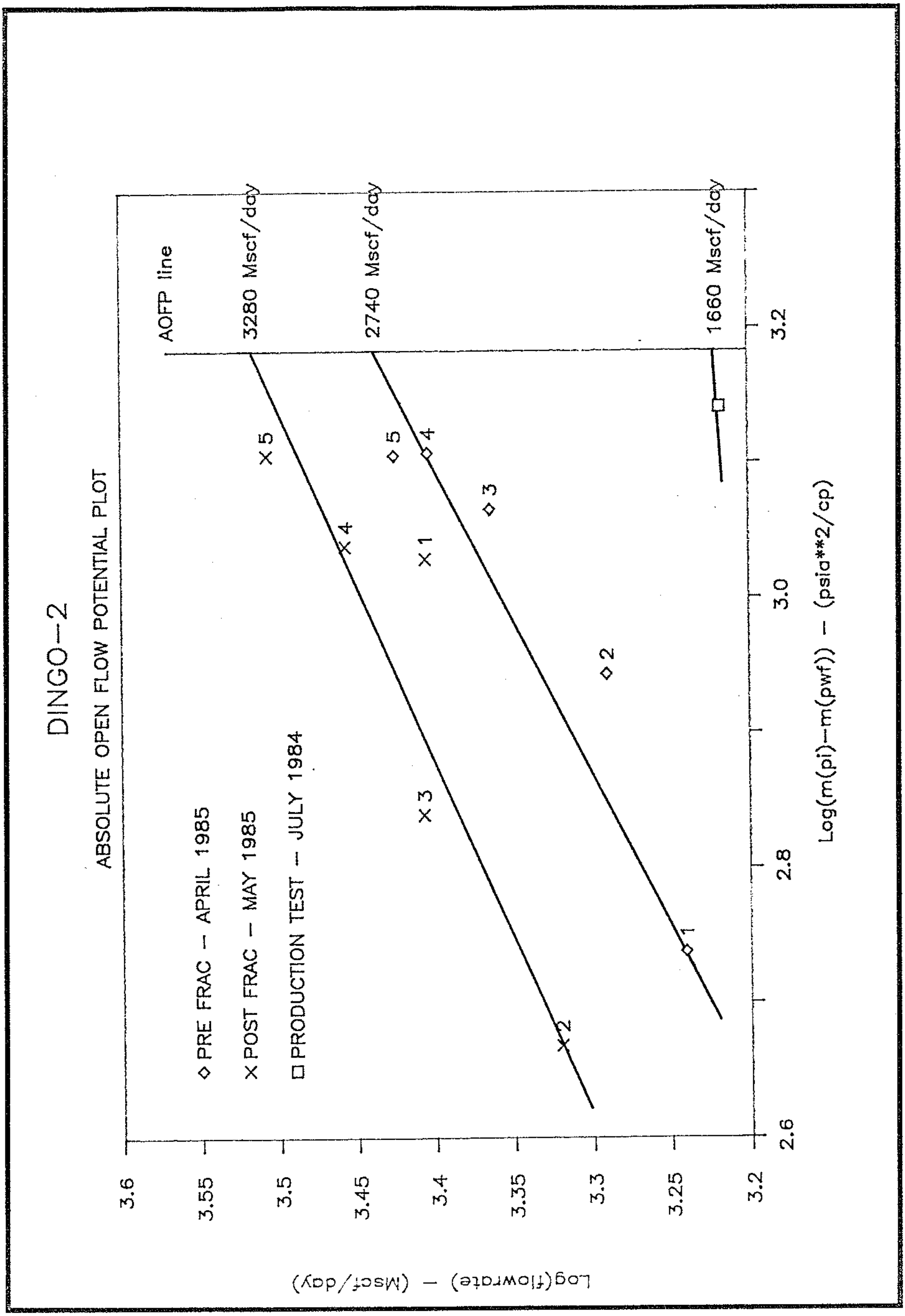

DINGO—2
MAY 1985 — BUILD UP 5
slope = 1
Afterflow plot
LOG(DT)
LOG (Δm(p))
-1.8
-1.4
-1
-0.6
-0.2
0.2
0.6
1
3.1
3
2.9
2.8
2.7
2.6
2.5
2.4
2.3
2.2
2.1
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1


DINGO–2
MAY 1985 – BUILDUP 5
p* = 4565 psia
m' = 44.4 × 10³
F(DT)
m(pws) (10**6 psia**2/cp)
0
2000
4000
6000
8000
10000
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
–100
–200



DINGO GAS FIELD STUDY

FIGURE 17



DINGO GAS FIELD STUDY

FIGURE 18

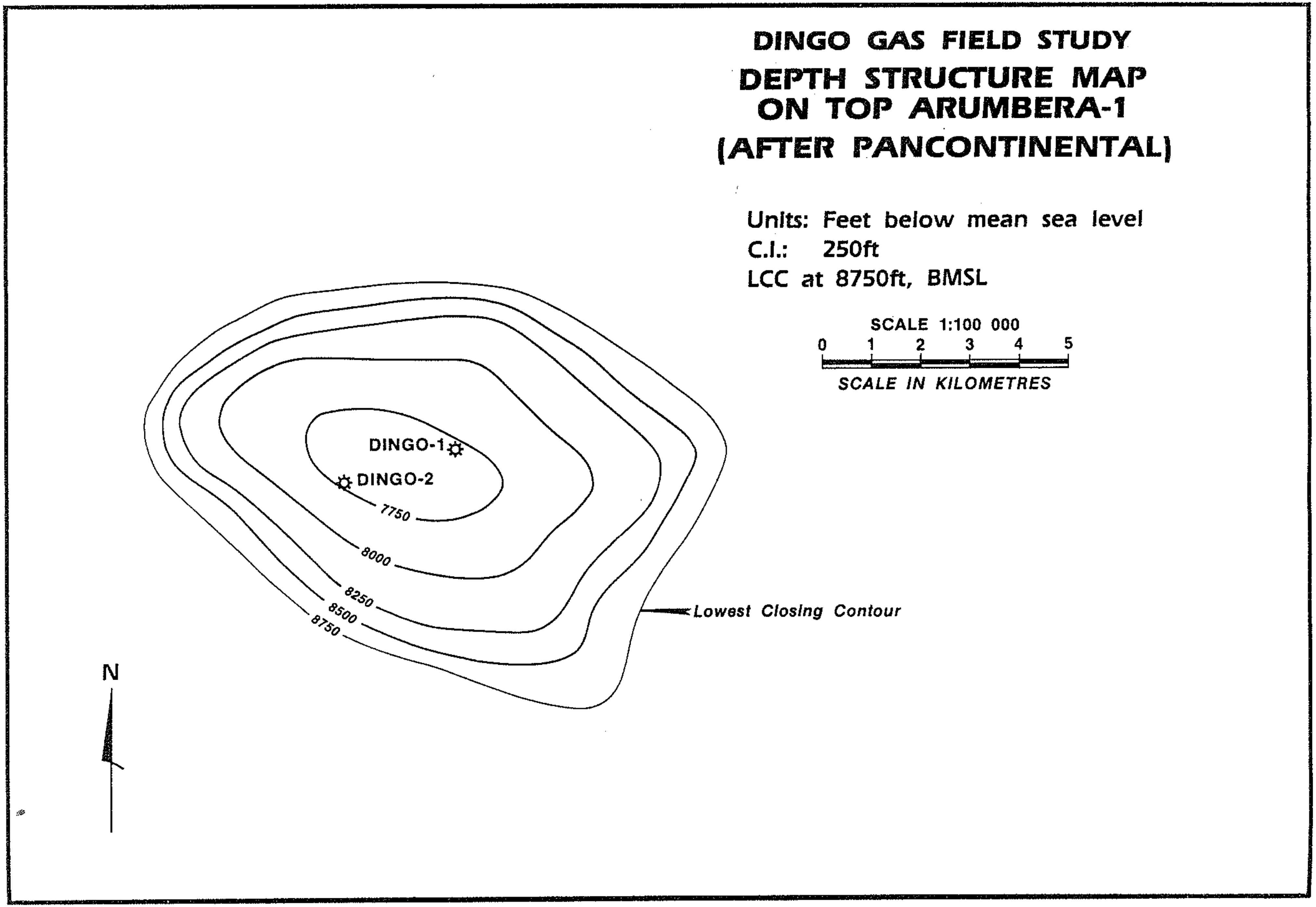
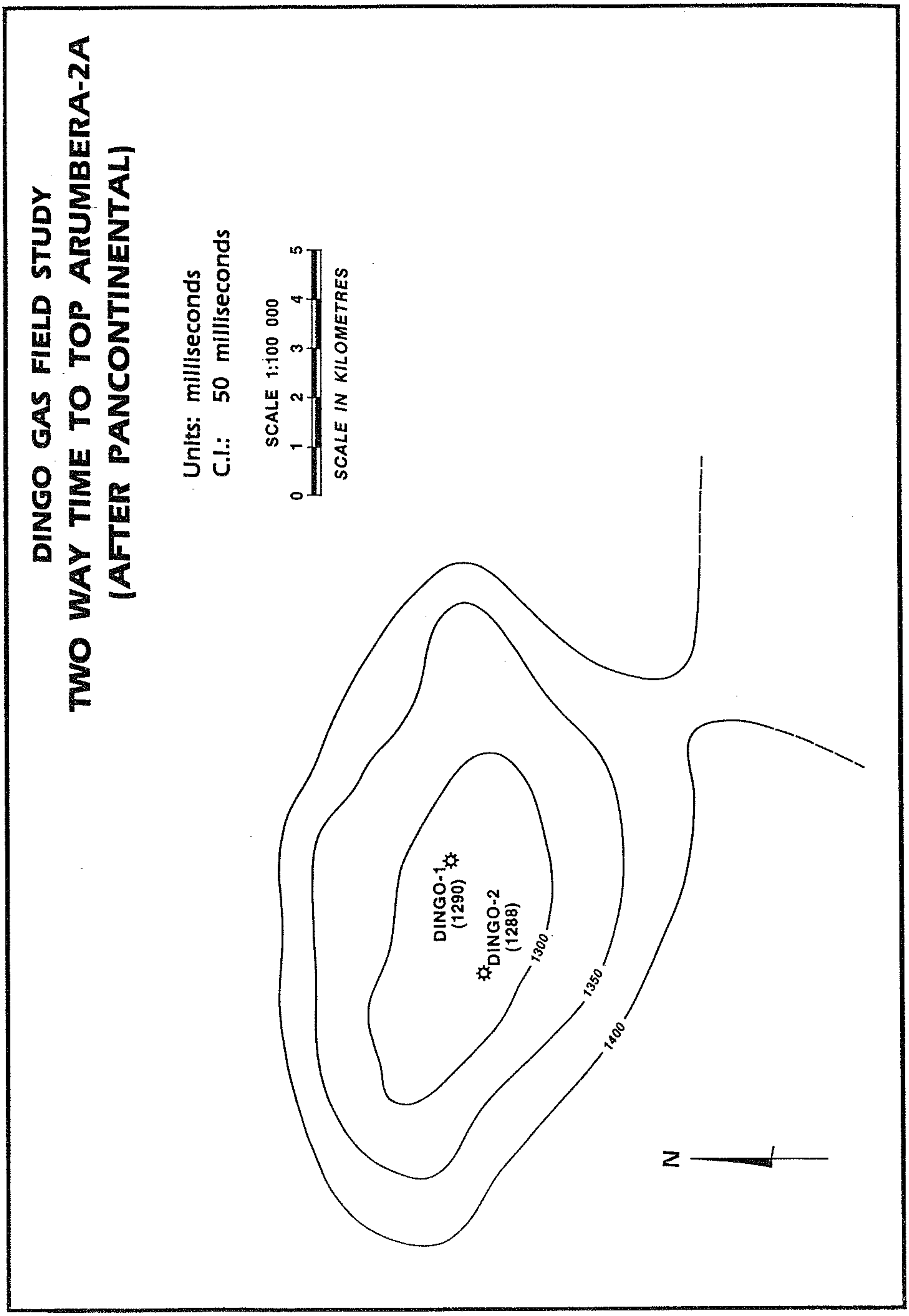

DINGO GAS FIELD STUDY
DEPTH STRUCTURE MAP
ON TOP ARUMBERA-1
(AFTER PANCONTINENTAL)
Units: Feet below mean sea level
C.I.: 250ft
LCC at 8750ft, BMSL
SCALE 1:100 000
0 1 2 3 4 5
SCALE IN KILOMETRES
DINGO-1
DINGO-2
7750
8000
8250
8500
8750
Lowest Closing Contour
N

FIGURE 19


DINGO GAS FIELD STUDY
TWO WAY TIME TO TOP ARUMBERA-2A
(AFTER PANCONTINENTAL)
Units: milliseconds
C.I.: 50 milliseconds
SCALE 1:100 000
0 1 2 3 4 5
SCALE IN KILOMETRES
DINGO-1
(1290)
DINGO-2
(1288)
1300
1350
1400
N