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PETROPHYSICAL EVALUATION

PL 085

JURASSIC FORMATION
WELL 31/3-1

SECTION: LET-SVG, MAY 1984

ENGINEER: A. Singelstad

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Classification

CONFIDENTIAL

Requested by

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Subtitle

Co-workers

John C. Self / LET-SVG

Title

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Prepared		Approved	
May -84	Arne Singelstad	24/5-84	J. C. Self

9.03.21 A

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ENCLOSURE: Graphical log presentation (CPI/log)

GENERAL WELL DATA

Licence:	085
Well:	31/3-1
Location:	60° 46' 47.86" N
	03° 44' 03.40" E
Spud date:	17 June 1983
Rig release date:	12 October 1983
Rig used:	Deepsea Bergen
KB elevation:	23 m
Water depth:	334 m MSL
Total depth:	2374 m RKB
Objectives:	Sandstones of Upper/Middle Jurassic
Operator:	Statoil
Partners:	Norsk Hydro/Saga Petroleum
Status:	Plugged and abandoned

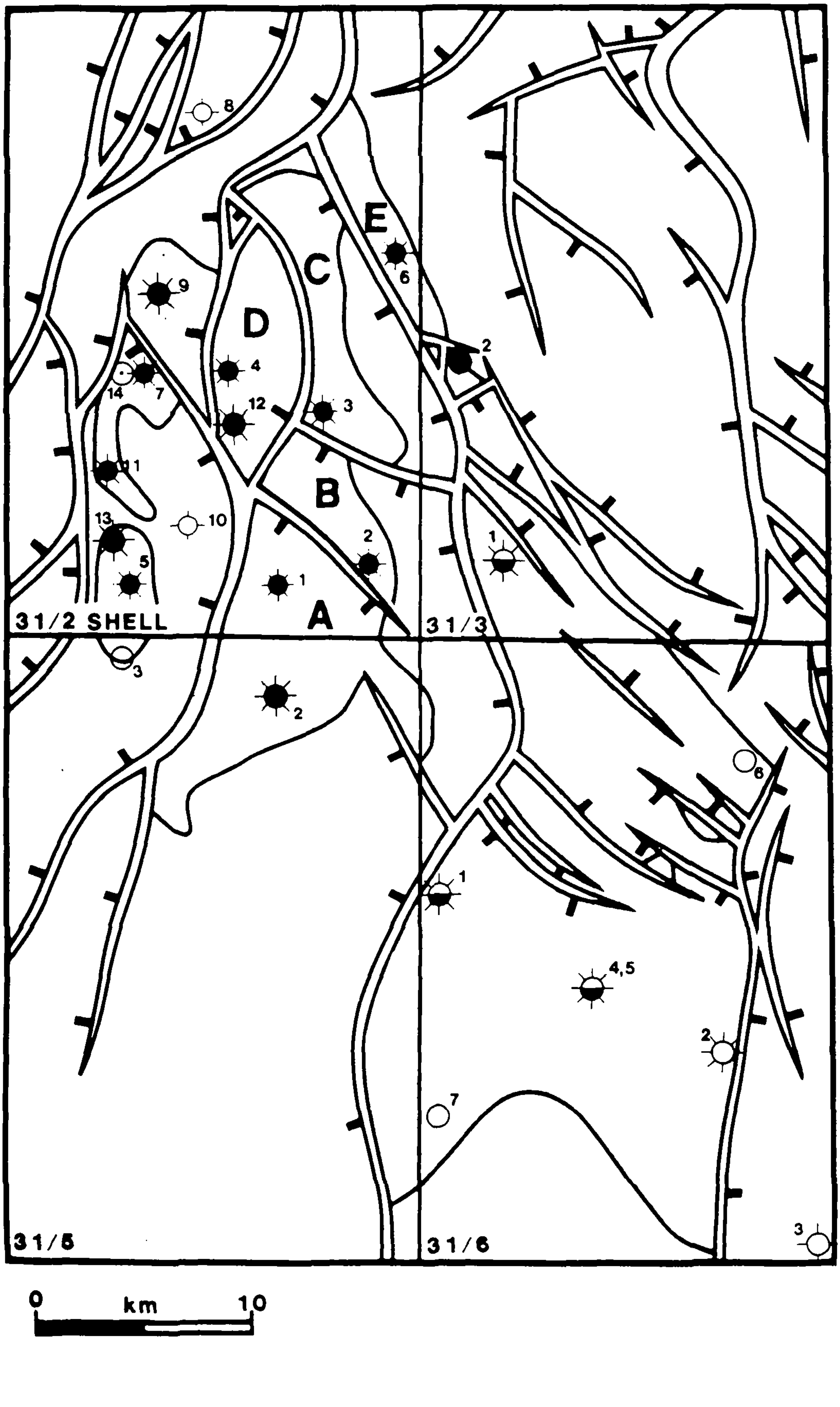
ABSTRACT

Well 31/3-1 was one of the two first wells drilled outside block 31/2 on the Troll-field. 31/3-1 was a wildcat on East-Troll, primarily designed to test possible gas and oil accumulations in sandstones of Upper to Middle Jurassic age. The secondary test was possible hydrocarbon accumulations in Middle to Lower Jurassic and Upper Triassic.

TD was reached at 2374 m RKB in formation of Triassic age.

Gas and oil was discovered in sandstones of Upper/ Middle Jurassic age, where two production tests were performed.

TROLL


8
E
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1
A
31/2 SHELL
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km
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SUMMARY

The top of the Upper Jurassic (top Draupne formation) was reached at 1320 m RKB.

Top reservoir (top Sognefjord fm.) was reached at 1351.5 m RKB.

From logs, FMT and core photos taken in ultraviolet light, the gas/oil contact is seen at 1572 m RKB, and the oil/water contact at 1576 m RKB.

Logevaluation and cores indicate good reservoir-properties.

Main results from the evaluation:

Net pay, m:	185.25
Average porosity:	.262
Average watersaturation:	.226
Average shale content:	.117

LITHOLOGY

VIKING GROUP (1320 - 1797 m RKB)

Draupne Formation (1320 - 1351.5 m RKB)

The Draupne Formation consists of carbonaceous claystone which is medium to dark grey and brownish to dark brownish grey. The claystone is moderatly hard, non to slightly calcareous, micaceous, silty in parts and occasionally fissile.

Depositional environment: open, shallow marine with somewhat restricted bottom conditions.

Sognefjord Formation (1351.5 - 1497 m RKB)

The Sognefjord Formation consists of micaceous and glauconitic sandstone and siltstone with a certain coal content.

The grainsize varies from silt to coarse sand, occasionally granules. The grains are angular to rounded. The sorting is dominantly moderate to poor. The sandstone is friable with a moderate to good porosity, pyritic and carbonate cemented in parts.

The siltstone is medium to dark grey, firm to moderatly hard and calcareous.

Depositional environment: shallow marine, shelf.

Heather Formation, unit C (1497 - 1516 m RKB)

The Unit C of the Heather Formation consists of sandstone and siltstone similar to those described for the Sognefjord Formation.

Depositional environment: shallow marine.

Fensfjord Formation (1516 - 1668 m RKB)

The Fensfjord Formation is in its upper part similar to that described for the Sognefjord and the Heather Formations except that the coal content is increased.

In the lower part the grains in the sandstone are clear to white and smoky to rose coloured. The grainsize is very fine to coarse and the grains are moderate to well sorted.

The siltstone grades from calcareous to non calcareous. In some places the siltstone becomes very shaly.

The shale content increases downwards. The shale is medium to dark grey, firm, non calcareous and silty in parts. Mica and traces of pyrite, glauconite and shell fragments are common.

Depositional environment: shallow marine.

1 PETROPHYSICAL RESULTS UPPER/MIDDLE JURASSIC

1.1 Logs run

1. DIFL/BHC ACOUSTILOG-GR
2. CDL/CNL/SPECTRALOG
3. DLL/MLL-GR
4. DIPLOG
5. FMT
6. CORGUN
7. VSP

1.2 Log analysis

The results from the log evaluation are listed below:

Top reservoir, m RKB:	1351.5	
Gas/oil contact, m RKB:	1572.0	
Oil/water contact, m RKB:	1576.0	
Interval evaluated, m RKB:	1351.5-1497	1497-1668
Net pay, m:	134.75	50.5
Net sand, m:	135.75	160.25
Av. porosity, net pay:	0.271	0.238
Av. shale content, net pay:	0.107	0.147
Av. watersaturation, net pay:	0.164	0.412
H net pay/H gross sand:	0.926	0.30
H net sand/H gross sand:	0.933	0.937
H net pay/H net sand:	0.993	0.315
Cut off values applied:	Vsh > 0.40	
	Ø < 0.10	
	Sw > 0.70	

Statistics are listed in Fig. 3.3.1 - 3.3.2.

1.3 Coring and core analysis

15 conventional cores were taken in the Jurassic. See listing below.

Core no.	Cored interval drillers depth	Corrected core depths	Recovery m	%
1	1351 - 1366	1351.5- 1367	11.3	75.5
2	1366 - 1372	1367 - 1374	5.5	92
3	1372 - 1391	1374 - 1393	18.65	100
4	1391 - 1406	1393 - 1408	14.2	95
5	1406 - 1424.3	1408 - 1425	18.1	99
6	1424.3- 1442.6	1425 - 1442	18	98
7	1442.6- 1461	1442 - 1461	18.7	100
8	1461 - 1479.5	1461 - 1481.5	19	100
9	1479.5- 1497.8	1481.5- 1499.5	18.1	99
10	1498 - 1517	1499.5- 1518	18.75	99
11	1517 - 1535.5	1518 - 1536.5	18.6	100
12	1535.5- 1554	1536.5- 1555.5	18.2	99
13	1554 - 1572.6	1555.5- 1574.5	18.6	100
14	1572.75-1591.5	1574.5- 1591.5	18.4	98
15	1590.7- 1609.8	1591.5- 1611	18.4	97

All depths are in m RKB.

Core depths are corrected from drillers depth to Dresser Atlas' log depth using Geco's Core Gamma Surface log.

A comparison of the porosity from the logs and the cores is shown in Fig. 3.5.1 - 3.5.3 and listed below.

Interval (m RKB)	Ø log	Ø core	Ø log/Ø core
1351.5-1497	0.26	0.25	1.04
1497 -1611	0.21	0.25	0.84

Routine core analysis, including horizontal and vertical air and liquid permeability, helium porosity and grain density were performed on 823 plugs.

Special core analysis were performed on 23 plugs:

- Porosity
- Grain density
- Klinkenberg corrected air permeability
- Turbulence factor
- Formation resisitivty factor
- Capillary pressure (air/water)
- Confining pressure measurements
- CEC measurements

1.4 Formation Multitester (FMT)

Six FMT-runs were made during the reservoir logging. The first FMT-run was in combination with two Flopetrol SDP/CRG gauges, the employment of which meant that sampling was not feasible.

36 out of 42 attempts to take pressure points were successful.

Pressure readings from Flopetrol gauge are listed below.

Run no. 1

Test no.	Depth (m RKB)	Formation pressure (KPA)	Comments
1	1353.5	15580	Poor permeability
2	1355.0	15609	Good permeability
3	1353.5	15552	" " " " " "
4	1362.5	15620	Very good perm.
5	1364.5	15626	" " " " "
6	1370.5	-	reading too high, leak?
7	1370.5	15630	Very good perm.
8	1374.2	15634	" " " " "
9	1377.5	15636	" " " " "
10	1382.9	15646	" " " " "
11	1390.0	15653	" " " " "
12	1406.0	-	Tool not temp. stabilized
13	1406.0	15671	Very good perm.
14	1413.0	15683	Good perm.

15	1424.0	-	Tool not temp. stabilized
16	1424.0	15696	Good perm.
17	1428.0	15702	Fair perm.
18	1445.0	15737	Very good perm.
19	1458.0	15737	" " " " "
20	1467.3	15748	Good perm.
21	1485.0	15781	Very good perm.
22	1490.2	15772	" " " " "
23	1506.0	15785	Fair perm.
24	1520.0	15802	Very good perm.
25	1532.8	15830	" " " " "
26	1541.5	15819	" " " " "
27	1541.5	15826	" " " " "
28	1555.4	-	Leaking seal
29	1555.4	15867	Very good perm.
30	1557.7	15855	Fair perm.
31	1565.5	15853	Good perm.
32	1570.0	15855	Very good perm.
33	1574.0	15886	" " " " "
34	1582.5	15966	" " " " "
35	1596.2	-	Tool not temp. stabilized
36	1596.2	16102	Very good perm.
37	1606.5	16205	" " " " "
38	1626.5	16405	" " " " "
39	1633.8	16479	" " " " "
40	1654.0	16679	" " " " "
41	1669.0	16830	" " " " "
42	1695.5	17098	Good perm.

See pressure plot Fig. 3.2.

The pressure points indicate a gas gradient of 1.208 KPA/m (SG 0.123) from top reservoir at 1351.5 m RKB down to a water contact at 1573.0 m RKB.

Below the water contact, a water gradient of 9.987 KPA/m (SG 1.02) is seen.

It is not possible to establish an oil gradient because of the thin oil zone (4 m thick).

Run no. 2

Segregated sample taken at 1370.5 m RKB.

2 3/4 gallon chamber was drained offshore.

Opening pressure:	9308 KPA
H_2S:	0 %
CO_2:	0.5 %
Gas:	0.71 Sm^3
Mudfiltrate/water:	100 cc

1 gallon chamber drained offshore.

Opening pressure:	100 KPA
H_2S:	0 %
CO_2:	0.4 %
Recovery:	Empty

Run no. 3

Segregated sample taken at 1570.0 m RKB.

2 3/4 gallon chamber drained offshore.

Opening pressure:	11720 KPA
CO_2:	0.4 %
Gas:	1.22 Sm^3
Mudfiltrate/water.	1500 ml

1 gallon chamber sent to Statoil PVT lab. for analysis.

Opening pressure offshore:	10900 KPA
Opening pressure PVT lab.:	11500 KPA
Gas:	0.22 Sm^3
Condensate:	Traces
Mudfiltrate/water:	165 ml

<u>Run no. 4</u>

Segregated sample taken at 1574.2 m RKB.

2 3/4 gallon chamber drained offshore.

Opening pressure:	8960 KPA
CO_2:	0.5 %
Gas:	0.1 Sm^3
Oil:	2500 ml
Mudfiltrate/water:	6000 ml

1 gallon chamber sent to PVT lab.

Opening pressure offshore:	9000 KPA
Opening pressure PVT lab.:	2000 KPA
Gas:	0.03 Sm^3
Oil:	1270 ml
Mudfiltrate/water:	2150 ml

<u>Run no. 5</u>

Segregated sample taken at 1579.5 m RKB.

2 3/4 gallon chamber drained offshore.

Opening pressure:	2760 KPA

CO_2:	0.4 %
Gas:	0.03 Sm^3
Cond./oil:	Traces
Mudfiltrate/water:	8000 ml

1 gallon chamber sent to PVT lab.

Opening pressure offshore:	1380 KPA
Opening pressure PVT lab.:	250 KPA
Mudfiltrate/water:	3700 ml

<u>Run no. 6</u>

Segregated sample taken at 1374.2 m RKB

2 3/4 gallon chamber drained offshore.

Opening pressure:	10860 KPA
CO_2:	0.4 %
Gas:	1.33 Sm^3
Condensate:	Traces
Mudfiltrate/water:	50 ml

1 gallon chamber sent to PVT lab.

Opening pressure offshore:	10340 KPA
Opening pressure PVT lab.:	13000 KPA
Gas:	0.41 Sm^3
Condensate:	Traces
Mudfiltrate/water:	Traces

1.5 Production testing

Two production tests were carried out in the Jurassic Formation. Gas and small amounts of condensate were produced.

Test summary

Test no.:	1	2
Perf. interval,m RKB:	1519-1529	1373-1383
Formation thickness, h:	20.75m	30.75m
Porosity, Ø:	0.243	0.294
Shale volume, Vsh:	0.13	0.067
Water saturation, Sw:	0.416	0.128
Gas rate, Sm^3/D:	709880	889000
Cond. rate, m^3/D:	14.2	17.8
Reservoir pressure, KPA:	15778 at 1524 m RKB	15610 at 1378 m RKB
Reservoir temp. ^oC:	58.2 at 1524 m RKB	55.3 at 1378 m RKB
Perm. thickness, um^2m:	12.7763	-
Permeability, um^2:	0.616	0.550 (from cores)
Skin factor:	257	14.25
Turbulence factor:	-	$6.404x10^{-5}mSm^3D^{-1}$

2 LOG ANALYSIS PROCEDURE

2.1 Water saturation

For the evaluation, a shaly sand has been applied. Water saturation was calculated using the North Sea equation.

$$1.0/\sqrt{R_t} = (V_{sh}{}^{C}/\sqrt{R_{sh}} + \varnothing^{m/2}/\sqrt{aRw})\,Sw^{n/2}$$

The various inputs to this equation, which were derived from logs, crossplots, histograms and core analysis, are discussed separately below and listed in section 3.

2.2 Data correction

The spectralog has been corrected for borehole size.

RLLD and RILD have been used to compute a correct R_t. RLLD was corrected for invasion and used as R_t in the hydrocarbon zone. RILD has bene used as R_t without any corrections in the waterzone.

The compensated neutron log was corrected for hole temperature and hydrostatic pressure.

2.3 Reservoir temperature

From test results a reservoir temperature of 57°C has been chosen. This being the average temperature over the hydrocarbon zone.

2.4 Water resistivity

Formation water resistivity is taken from test data from well 31/2-11.

This gives a value of 0.09 ohmm at 57^{o}C.

2.5 Mudfiltrate resisitivity

The mudfiltrate resistivity has been taken from the logheading and converted to reservoir temperature.
Rmf = 0.062 ohmm at 57^{o}C.

2.6 Matrix parameters

A histogram plot of the grain densities from the routine core analysis has been used to define the matrix density, Fig. 3.10.

2.7 Shale parameters

The neutron shale porosity, shale resisitivty and shale density were picked from histograms with a V_{sh} cut off. Fig. 3.8.1 - 3.8.4.

2.8 Shale volume

A borehole corrected Th-curve from the spectralog and a density-neutron crossplot have been used tc calculate the shale volume, V_{sh}. Other shale indicators studied, were VSHRT, VSHN, VSHGR, VSHDS, VSHSN and VSHQ.

2.9 Porosity

To calculate the final porosity, both compensated neutron and compensated density logs have been used. Both curves have been corrected for shale volume and a weighted average method used with a weighting of 7 for density and 2 for neutron.

The resulting porosity curve was ultimately corrected for hydrocarbons in the invaded zone with a factor of 0.1.

2.10 Formation factors/saturation exponent

Net confining measurements were performed on 23 plugs. One plug was too friable to resist the axial pressure and disintegrated.

The formation resistivity factor, FF, has been measured on 22 plugs.

A least squares method forced through FF = 1.0 and $\emptyset$ = 1.0 gave a formation factor exponent m = 1.97 and a lithology factor a = 1.0 at net confining pressure of 200 bar.

The average value of 12 saturation exponents, n, was calculated to 2.08.

2.11 Discussion

From logs, FMT and ultraviolet photos of cores it is not possible to pick exact contacts for gas/oil and oil/water.

The gas/oil contact has been taken as 1572 m RKB and the oil/water contact as 1576 m RKB for the following reasons: an FMT gas sample was taken at 1570 m RKB, oil sample at 1574.2 m RKB and a water sample at 1579.5 m RKB.

The FMT gradients indicate a hydrocarbon/water contact at 1573 m RKB. An increasing water separation between RLLD and RMLL is seen from 1572 m RKB. Ultraviolet photos do not show fluorescence below 1576 m RKB (i.e. fluorescence is seen in the waterzone between 1579.5 - 1581 m RKB, but this is probably due to residual hydrocarbons).

The logevaluation shows 100% watersaturation in the oilzone between 1573 - 1576 m RKB. The reason can be a combination of oil with high density and high water saturation giving low resisitivty readings.

PHIN, RHOB and DT vs. $F(R_t)$ crossplots give Rw-values scattering from 0.03 - 0.06 ohm m.Fig. 3.9.1 - 3.9.4, while formation water from the FMT-sample give 0.064 ohm m.

Both methods are questionable, porosity vs. resistivity crossplots because of the spread in Rw-values, and the water from the FMT-chamber was polluted with mudfiltrate and cushionwater. Therefore the formation water produced during DST no. 1 in 31/2-11 is thought to give the best available Rw for this well.

However, due to the difference in mineral composition in 31/3-1 compared to 31/2, the actual Rw in 31/3-1 may vary from that of the 31/2-area.

Kaolin, mica and potassium feldspar has been detected by XRD-analysis on cores from 31/3-1. Both potassium-feldspar and mica contain potassium, while most of the thorium is probably bound to the kaolin.

For this reason the shale volume is calculated from the thorium curve (from the spectralog) and density- neutron crossplot (VSHTH + VSHDN) only.

Based on earlier 31/2-wells (1, 2, 3, 4 and 5), the core porosities from routine core analysis were multiplied with a factor of 0.91 to convert them to reservoir-conditions.

Further analysis of laboratory results, indicate that 0.96 is a more correct conversion factor and should be used in later petrophysical evaluations. Still the measurements on unconsolidated material are limited.

3 STATISTICS, PLOTS, HISTOGRAMS ETC.

3.1 Analysis parameters

Interval, m RKB:	1325 - 1668
Formation temperature, ^{o}C:	57 at 1450 m RKB
Rw at $57^{o}C$, ohm m:	0.09
NaCl, ppm:	45000
Rmf at $57^{o}C$, ohm m:	0.062
Rsh, ohm m:	1.1
RHOBsh, g/cc:	2.19
PHINsh, frac.:	0.33
RHOma, g/cc:	2.66 (1351.5-1497)/
	2.69 (1497-1668)
PHINma, frac.:	0.03/0.02
RHOfl, g/cc:	1.0 (waterzone)
	0.8 (gaszone)
Thcorr, min:	3.6
Thcorr, max:	13.0
m:	1.97
n:	2.08
a:	1.0
Shale exponent:	1.6
Hydrocarbon corr factor:	0.1
Saturation equation:	North Sea
Vsh cut off:	> 0.40
Ø cut off:	< 0.10
Sw cut off:	> 0.70
Correction factor on PHIcore:	0.91

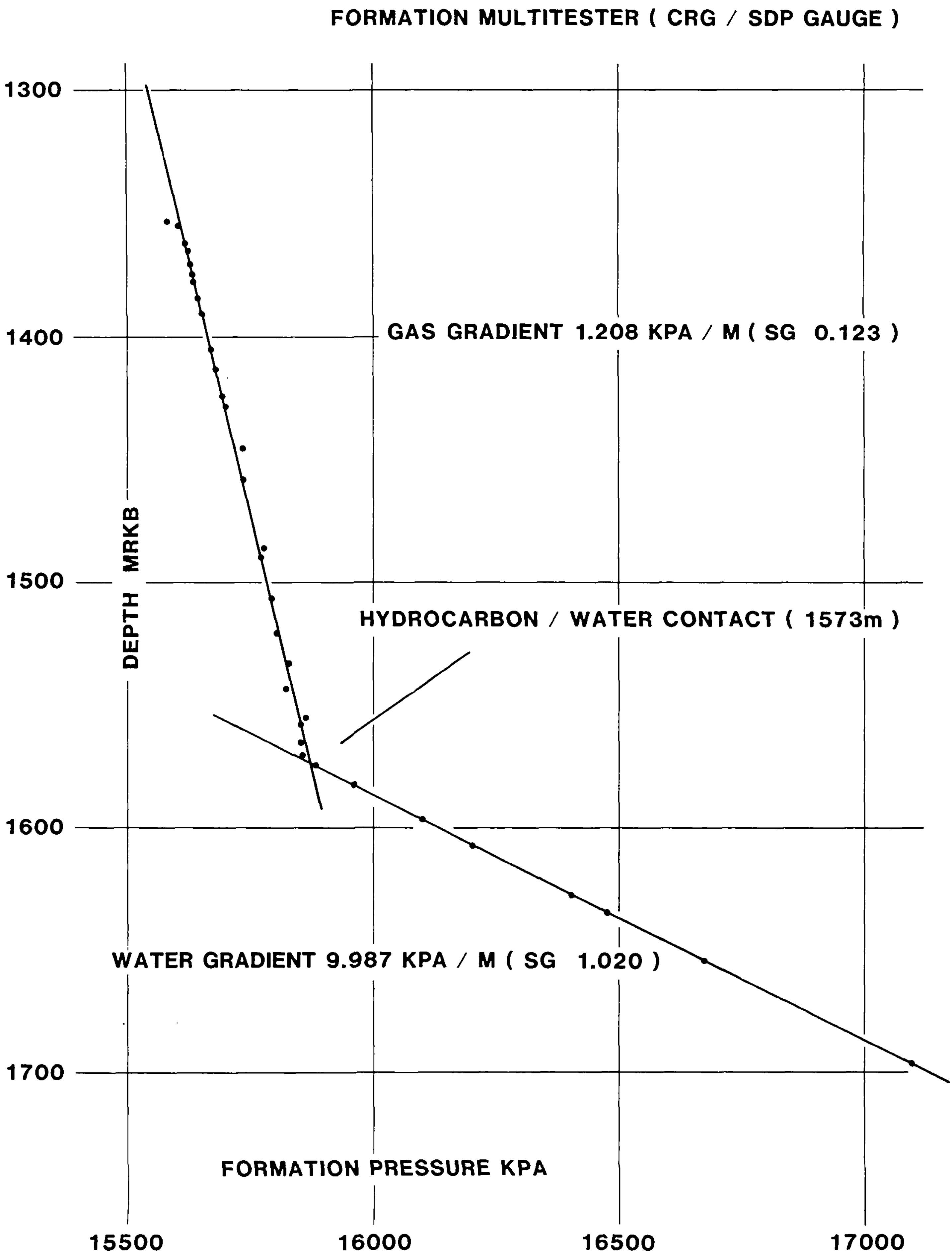
FORMATION MULTITESTER (CRG / SDP GAUGE)
1300
1400
1500
1600
1700
DEPTH MRKB
GAS GRADIENT 1.208 KPA / M (SG 0.123)
HYDROCARBON / WATER CONTACT (1573m)
WATER GRADIENT 9.987 KPA / M (SG 1.020)
FORMATION PRESSURE KPA
15500
16000
16500
17000

Fig. 3.2

```
 S T A T I S T I C S
*********************

FIELD: . . . . . . . . . . .            TROLL
WELL:  . . . . . . . . . . .           31-3-1
ENGINEER:  . . . . . . . . . ASI
DATE:  . . . . .              10. 6   28 MAY 1984

DEPTH INTERVAL:  . . .  1351.50 TO  1668.00
APPLIED CUTOFFS:
.               VSH:  GREATER THAN       0.40
.              PHIF:     LESS THAN       0.10
.                SW:  GREATER THAN       0.70

 T O T A L    D E P T H
*******************************************
THICKNESS: . . . . . . . . .      316.500
AVERAGE  . . . 'PHIF'  . . .        0.232
AVERAGE  . . . 'VSHALE'  . .        0.138
AVERAGE  . . . 'SW'  . . . .        0.533
W.AVERAGE  . . 'SW' * 'PHIF'        0.469
AVERAGE  . . . 'SH'  . . . .        0.467
VOID VOLUME: . . . ('PHIF').       73.315
HC VOID VOLUME . . ('SH'*) .       38.965
RES HC VOID VOLUME ('SHR'*).       15.420
MOV HC VOID VOLUME . . . . .       23.546
*******************************************

 N E T    P A Y
*******************************************
THICKNESS: . . . . . . . . .      185.250
AVERAGE  . . . 'PHIF'  . . .        0.262
AVERAGE  . . . 'VSHALE'  . .        0.117
AVERAGE  . . . 'SW'  . . . .        0.257
W.AVERAGE  . . 'SW' * 'PHIF'        0.226
AVERAGE  . . . 'SH'  . . . .        0.743
VOID VOLUME: . . . ('PHIF').       48.576
HC VOID VOLUME . . ('SH'*) .       37.608
RES HC VOID VOLUME ('SHR'*).       14.474
MOV HC VOID VOLUME . . . . .       23.134
*******************************************

 N E T    S A N D
*******************************************
THICKNESS: . . . . . . . . .      296.000
AVERAGE  . . . 'PHIF'  . . .        0.242
AVERAGE  . . . 'VSHALE'  . .        0.129
AVERAGE  . . . 'SW'  . . . .        0.521
W.AVERAGE  . . 'SW' * 'PHIF'        0.464
AVERAGE  . . . 'SH'  . . . .        0.479
VOID VOLUME: . . . ('PHIF').       71.485
HC VOID VOLUME . . ('SH'*) .       38.303
RES HC VOID VOLUME ('SHR'*).       15.246
MOV HC VOID VOLUME . . . . .       23.057
*******************************************

 N E T / G R O S S    R A T I O S
******************************************

HNETPAY /HGROSS SAND =  0.58531
HNETSAND/HGROSS SAND =  0.93523
HNETPAY /HNETSAND    =  0.62584
******************************************
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Fig. 3.3.1

```
S T A T I S T I C S
*********************

FIELD: . . . . . . . . . .              TROLL
WELL:  . . . . . . . . . .             31-3-1
ENGINEER: . . . . . . . . . ASI
DATE:  . . . . .             10. 8   28 MAY 1984

DEPTH INTERVAL:  . . .  1351.50 TO  1497.00
APPLIED CUTOFFS:
.              VSH:  GREATER THAN      0.40
.             PHIF:     LESS THAN      0.10
.               SW:  GREATER THAN      0.70

T O T A L    D E P T H
*******************************************
THICKNESS: . . . . . . . . .       145.500
AVERAGE  . . . 'PHIF'  . . .         0.259
AVERAGE  . . . 'VSHALE'  . .         0.118
AVERAGE  . . . 'SW'  . . . .         0.210
W.AVERAGE  . . 'SW' * 'PHIF'         0.172
AVERAGE  . . . 'SH'  . . . .         0.790
VOID VOLUME: . . . ('PHIF').        37.638
HC VOID VOLUME . . ('SH'*) .        31.162
RES HC VOID VOLUME ('SHR'*).        11.844
MOV HC VOID VOLUME . . . . .        19.318
*******************************************

N E T    P A Y
*******************************************
THICKNESS: . . . . . . . . .       134.750
AVERAGE  . . . 'PHIF'  . . .         0.271
AVERAGE  . . . 'VSHALE'  . .         0.107
AVERAGE  . . . 'SW'  . . . .         0.188
W.AVERAGE  . . 'SW' * 'PHIF'         0.164
AVERAGE  . . . 'SH'  . . . .         0.812
VOID VOLUME: . . . ('PHIF').        36.540
HC VOID VOLUME . . ('SH'*) .        30.531
RES HC VOID VOLUME ('SHR'*).        11.724
MOV HC VOID VOLUME . . . . .        18.807
*******************************************

N E T    S A N D
*******************************************
THICKNESS: . . . . . . . . .       135.750
AVERAGE  . . . 'PHIF'  . . .         0.270
AVERAGE  . . . 'VSHALE'  . .         0.106
AVERAGE  . . . 'SW'  . . . .         0.191
W.AVERAGE  . . 'SW' * 'PHIF'         0.166
AVERAGE  . . . 'SH'  . . . .         0.809
VOID VOLUME: . . . ('PHIF').        36.682
HC VOID VOLUME . . ('SH'*) .        30.591
RES HC VOID VOLUME ('SHR'*).        11.742
MOV HC VOID VOLUME . . . . .        18.849
*******************************************

N E T / G R O S S     R A T I O S
*******************************************

HNETPAY /HGROSS SAND =   0.92612
HNETSAND/HGROSS SAND =   0.93299
HNETPAY /HNETSAND    =   0.99263
*******************************************
```

```
S T A T I S T I C S
*********************

FIELD: . . . . . . . . . .              TROLL
WELL:  . . . . . . . . . .             31-3-1
ENGINEER: . . . . . . . . . ASI
DATE:  . . . . .             10.10   28 MAY 1984

DEPTH INTERVAL:  . . .  1497.00 TO  1668.00
APPLIED CUTOFFS:
.              VSH:  GREATER THAN      0.40
.             PHIF:     LESS THAN      0.10
.               SW:  GREATER THAN      0.70

T O T A L    D E P T H
*******************************************
THICKNESS: . . . . . . . . .       171.000
AVERAGE  . . . 'PHIF'  . . .         0.209
AVERAGE  . . . 'VSHALE'  . .         0.154
AVERAGE  . . . 'SW'  . . . .         0.808
W.AVERAGE  . . 'SW' * 'PHIF'         0.781
AVERAGE  . . . 'SH'  . . . .         0.192
VOID VOLUME: . . . ('PHIF').        35.677
HC VOID VOLUME . . ('SH'*) .         7.804
RES HC VOID VOLUME ('SHR'*).         3.576
MOV HC VOID VOLUME . . . . .         4.228
*******************************************

N E T    P A Y
*******************************************
THICKNESS: . . . . . . . . .        50.500
AVERAGE  . . . 'PHIF'  . . .         0.238
AVERAGE  . . . 'VSHALE'  . .         0.143
AVERAGE  . . . 'SW'  . . . .         0.439
W.AVERAGE  . . 'SW' * 'PHIF'         0.412
AVERAGE  . . . 'SH'  . . . .         0.561
VOID VOLUME: . . . ('PHIF').        12.036
HC VOID VOLUME . . ('SH'*) .         7.077
RES HC VOID VOLUME ('SHR'*).         2.750
MOV HC VOID VOLUME . . . . .         4.327
*******************************************

N E T    S A N D
*******************************************
THICKNESS: . . . . . . . . .       160.250
AVERAGE  . . . 'PHIF'  . . .         0.217
AVERAGE  . . . 'VSHALE'  . .         0.148
AVERAGE  . . . 'SW'  . . . .         0.801
W.AVERAGE  . . 'SW' * 'PHIF'         0.778
AVERAGE  . . . 'SH'  . . . .         0.199
VOID VOLUME: . . . ('PHIF').        34.804
HC VOID VOLUME . . ('SH'*) .         7.712
RES HC VOID VOLUME ('SHR'*).         3.504
MOV HC VOID VOLUME . . . . .         4.208
*******************************************

N E T / G R O S S     R A T I O S
*******************************************

HNETPAY /HGROSS SAND =   0.29532
HNETSAND/HGROSS SAND =   0.93713
HNETPAY /HNETSAND    =   0.31513
*******************************************
```

Fig. 3.3.2

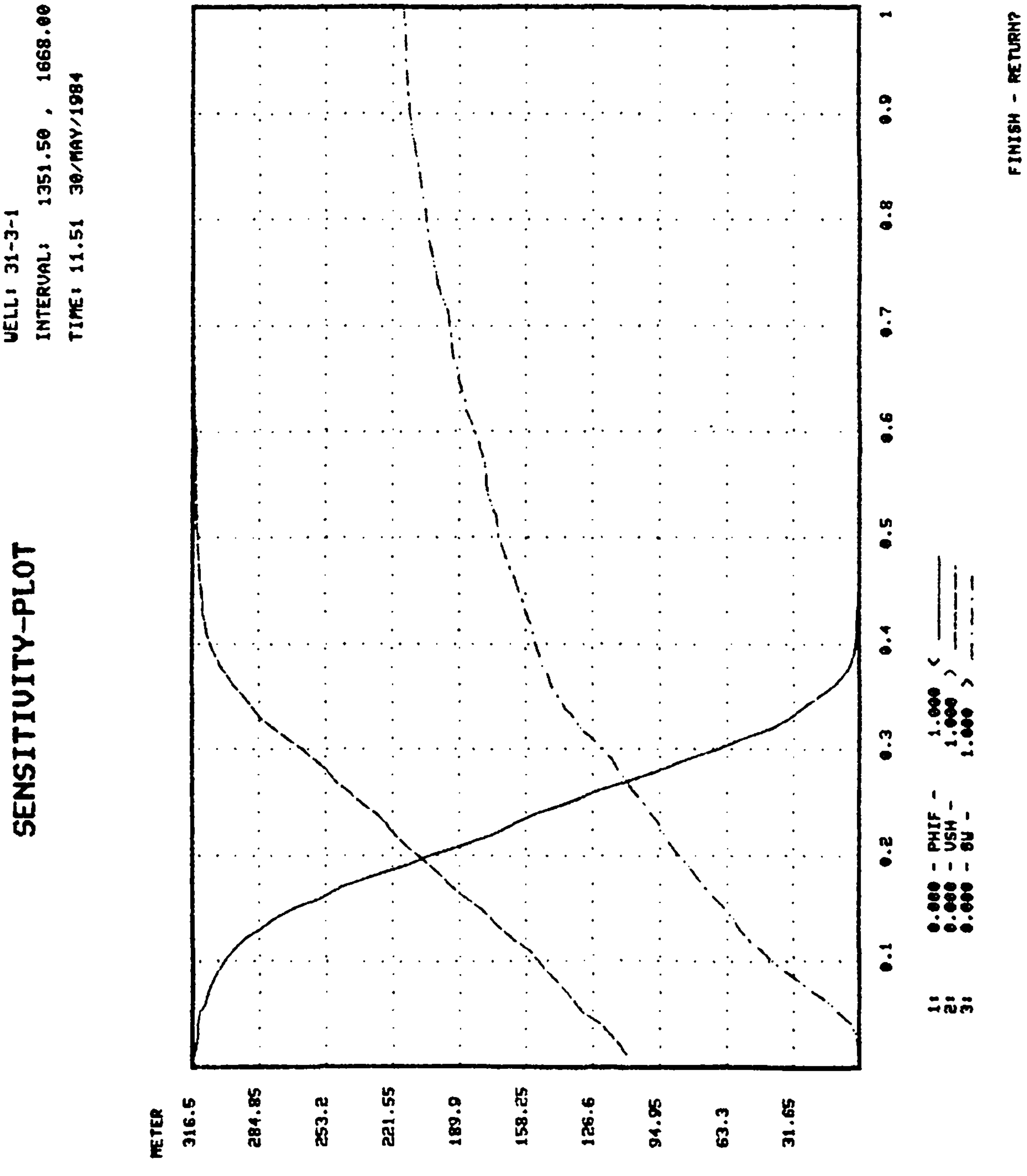

SENSITIVITY-PLOT
WELL: 31-3-1
INTERVAL: 1351.50 , 1668.00
TIME: 11.51 30/MAY/1984
METER
316.5
284.85
253.2
221.55
189.9
158.25
126.6
94.95
63.3
31.65
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1: 0.000 - PHIF - 1.000 <
2: 0.000 - VSH - 1.000 >
3: 0.000 - SW - 1.000 >
FINISH - RETURN?

Fig. 3.4.1

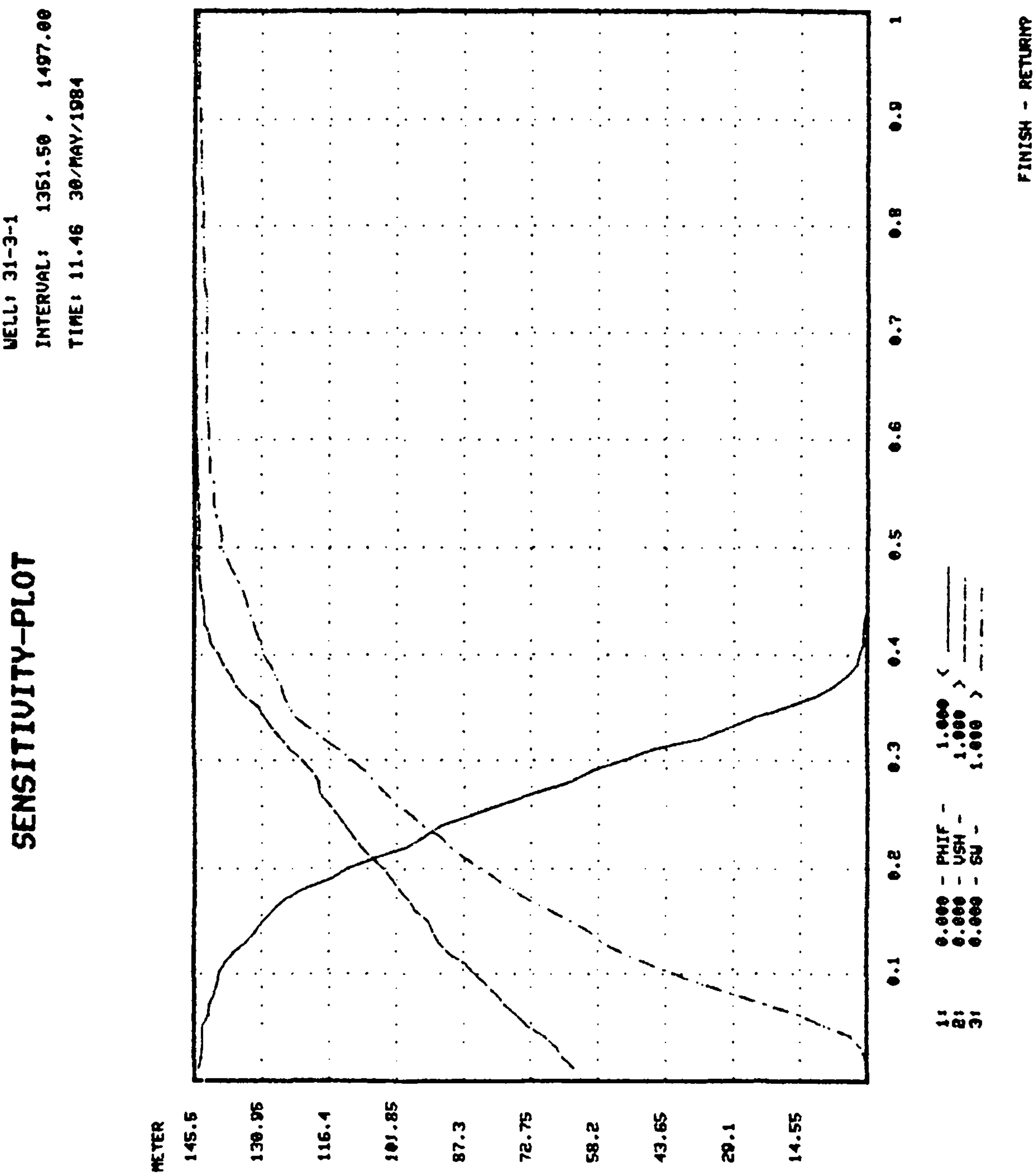

SENSITIVITY-PLOT
WELL: 31-3-1
INTERVAL: 1351.50 , 1497.00
TIME: 11.46 30/MAY/1984
METER
145.5
130.95
116.4
101.85
87.3
72.75
58.2
43.65
29.1
14.55
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1: 0.000 - PHIF - 1.000 <
2: 0.000 - VSH - 1.000 >
3: 0.000 - SW - 1.000 >
FINISH - RETURN?

Fig. 3.4.2

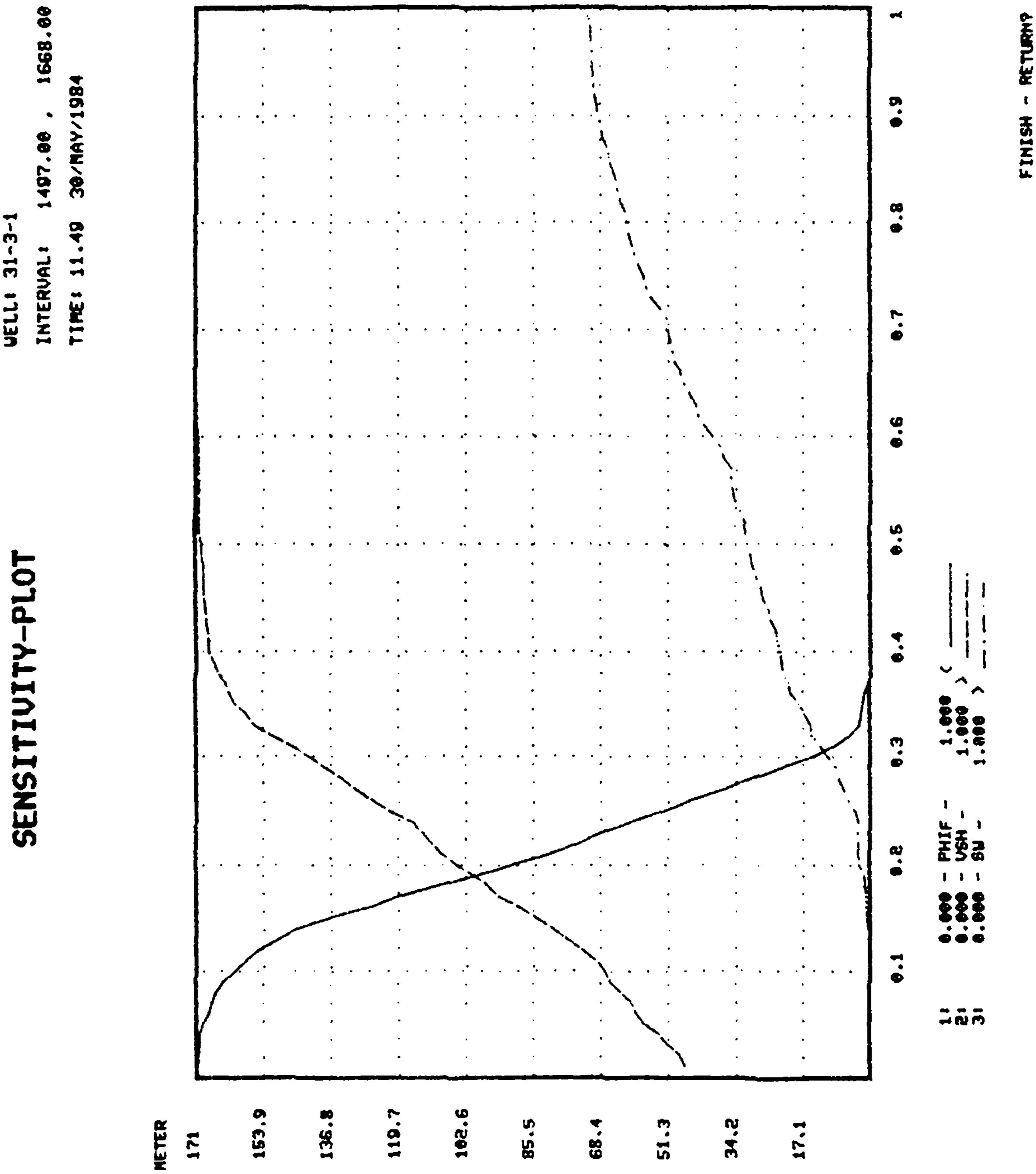

SENSITIVITY-PLOT
WELL: 31-3-1
INTERVAL: 1497.00 , 1668.00
TIME: 11.49 30/MAY/1984
METER
171
153.9
136.8
119.7
102.6
85.5
68.4
51.3
34.2
17.1
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
1: 0.000 - PHIF - 1.000 (
2: 0.000 - VSH - 1.000)
3: 0.000 - SW - 1.000)
FINISH - RETURN?

Fig. 3.4.3

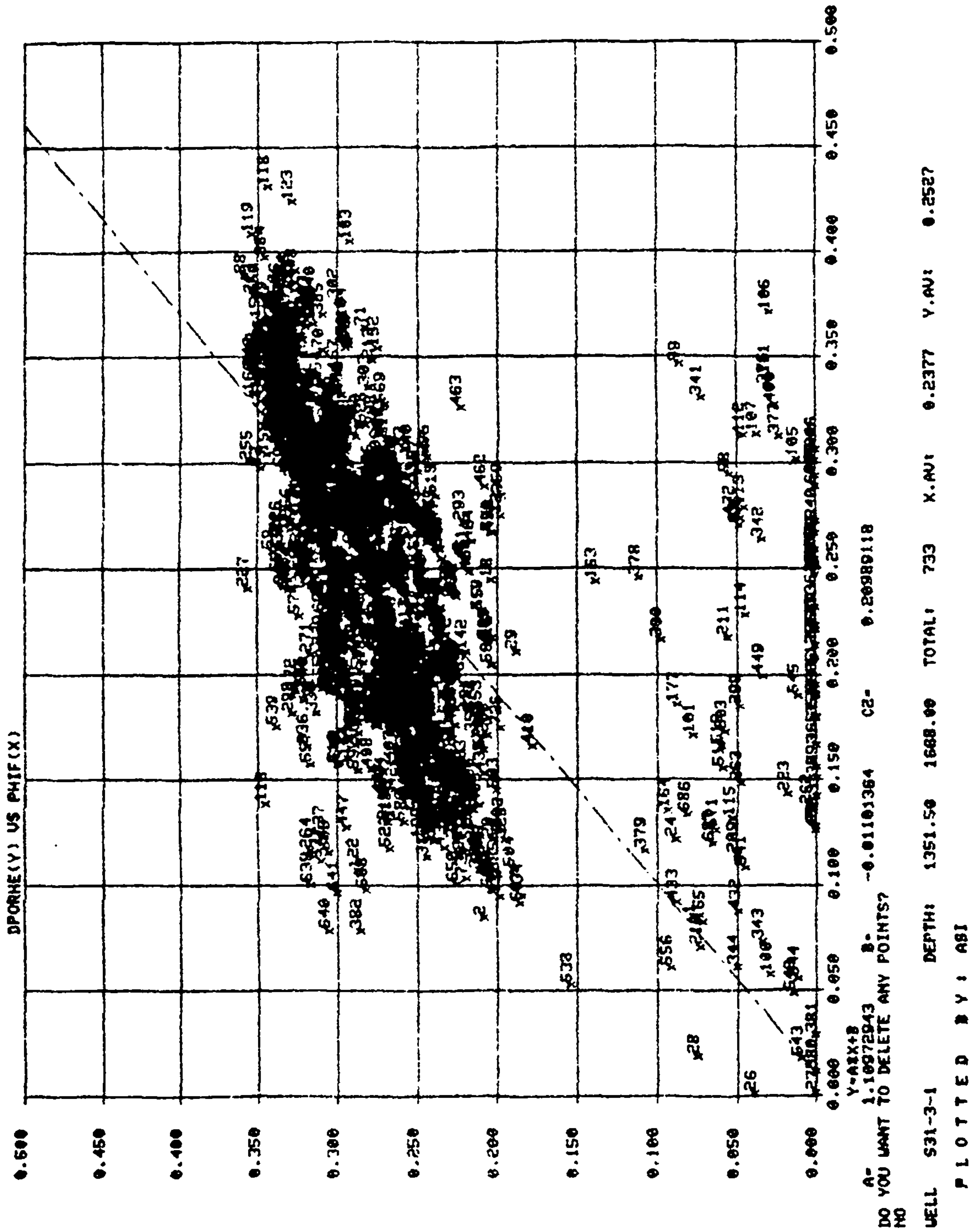

DPORHE(Y) VS PHIF(X)
Y=A*X+B
A= 1.10972943 B= -0.01101364 C2= 0.20989118
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL S31-3-1 DEPTH: 1351.50 1608.00 TOTAL: 733 X.AV: 0.2377 Y.AV: 0.2527
PLOTTED BY: ABI

Fig. 3.5.1

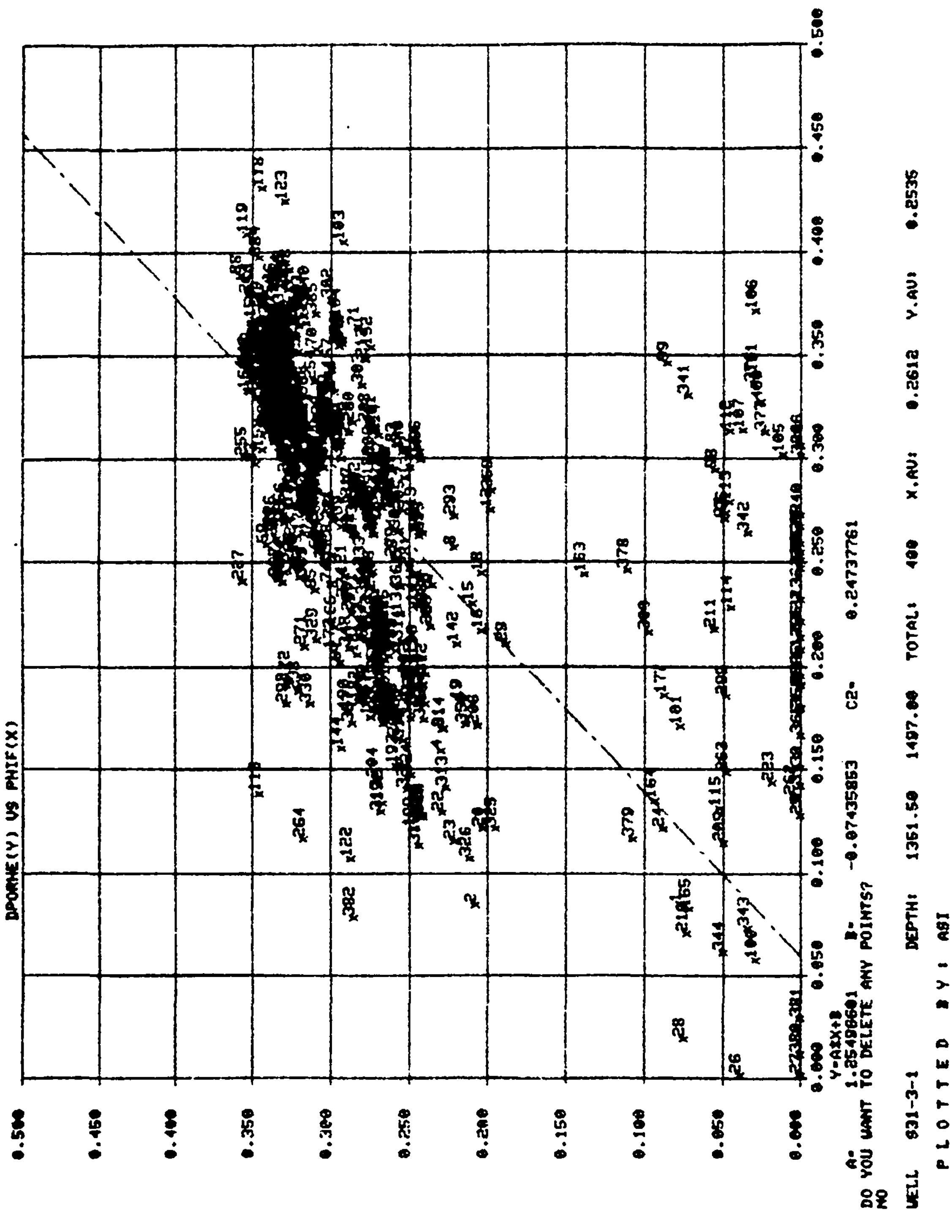

DPORNE(Y) VS PHIF(X)
Y=AXX+B
A= 1.8549601 B= -0.07435853 C2= 0.24737761
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL 031-3-1 DEPTH: 1351.50 1497.00 TOTAL: 400 X.AV: 0.2612 Y.AV: 0.2535
P L O T T E D B Y : ASI

Fig. 3.5.2

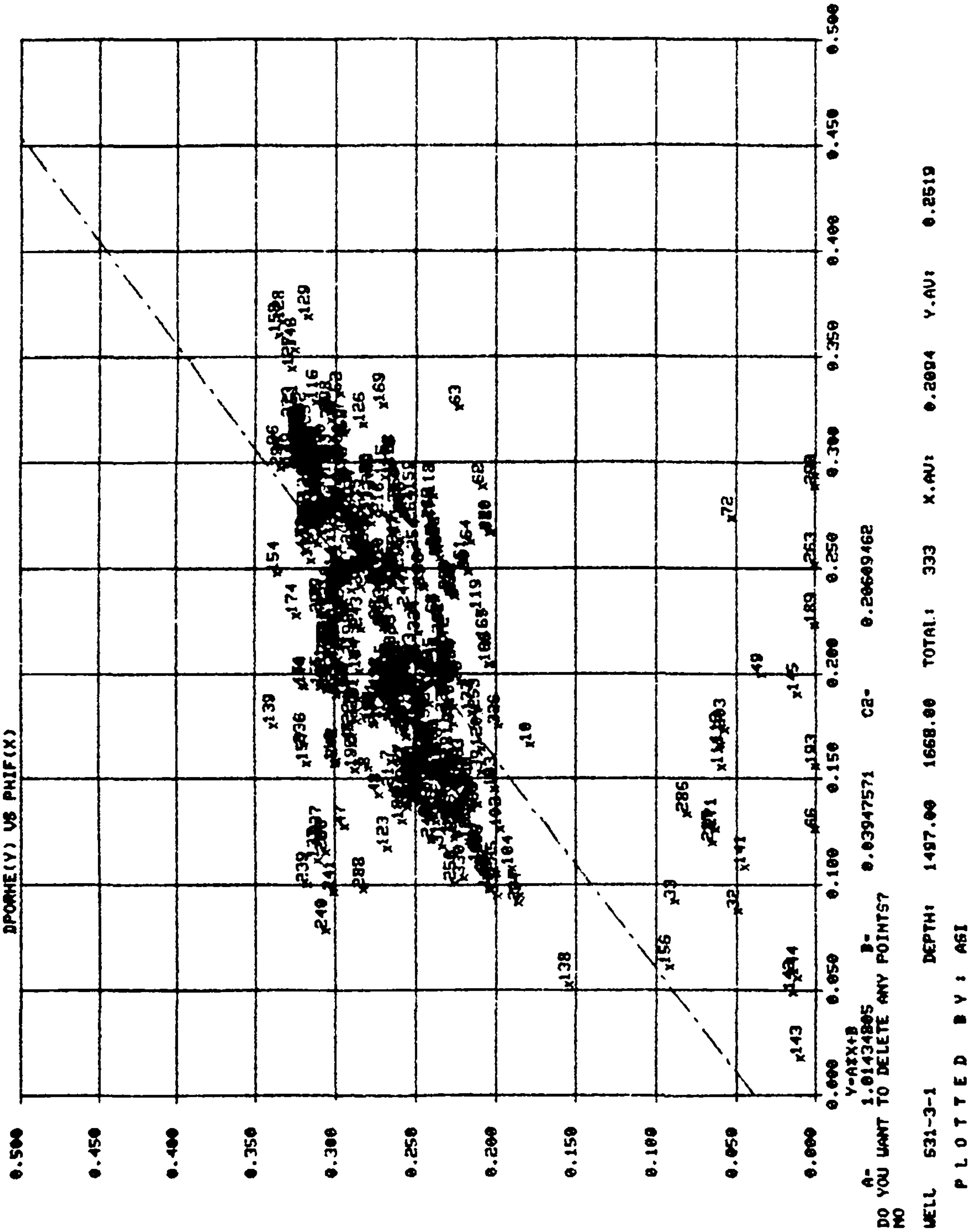

DPORHE(Y) VS PHIF(X)
Y=A*X+B
A= 1.01434805 B= 0.03947571 C2= 0.20689462
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL 531-3-1 DEPTH: 1497.00 1668.00 TOTAL: 333 X.AV: 0.2094 Y.AV: 0.2519
P L O T T E D B Y : AGI

Fig. 3.5.3

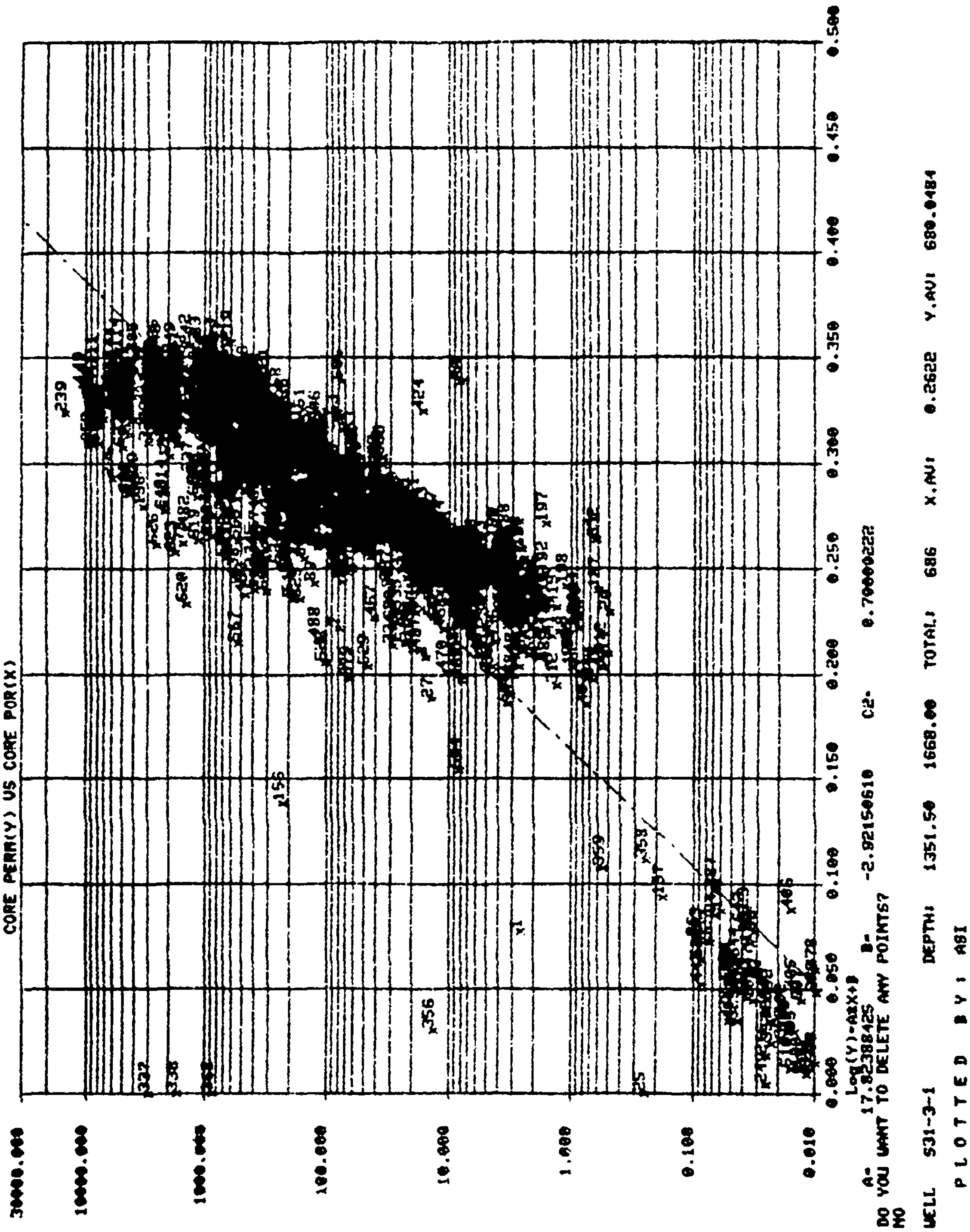

CORE PERM(Y) VS CORE POR(X)
30000.000
10000.000
1000.000
100.000
10.000
1.000
0.100
0.010
0.000
0.050
0.100
0.150
0.200
0.250
0.300
0.350
0.400
0.450
0.500
A= Log(Y)=A*X+B B=
17.82388425 -2.92150610 C2= 0.70000222
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL S31-3-1 DEPTH: 1351.50 1668.00 TOTAL: 686 X.AV: 0.2622 Y.AV: 680.0484
P L O T T E D B Y : ABI

Fig. 3.6.1

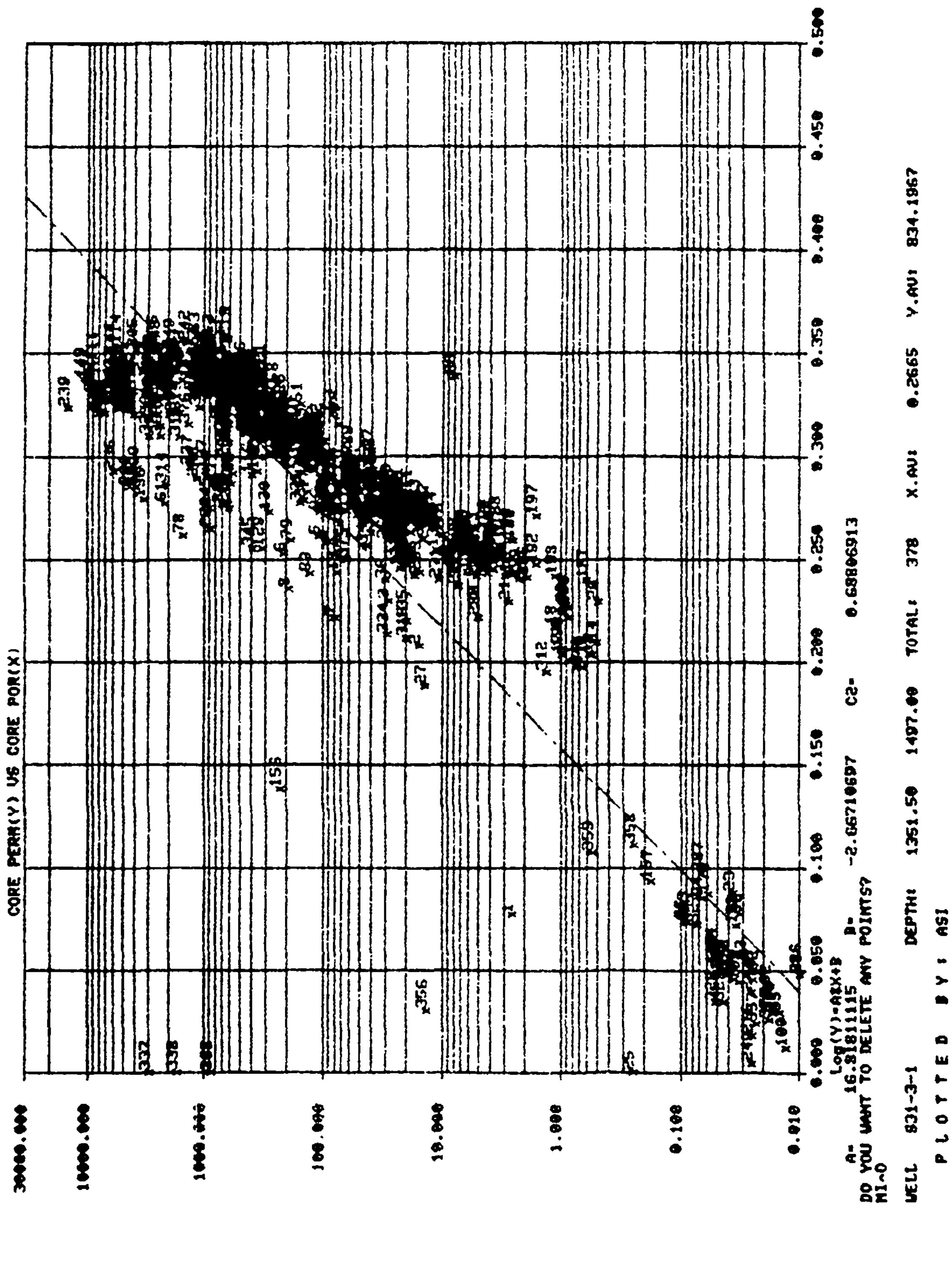
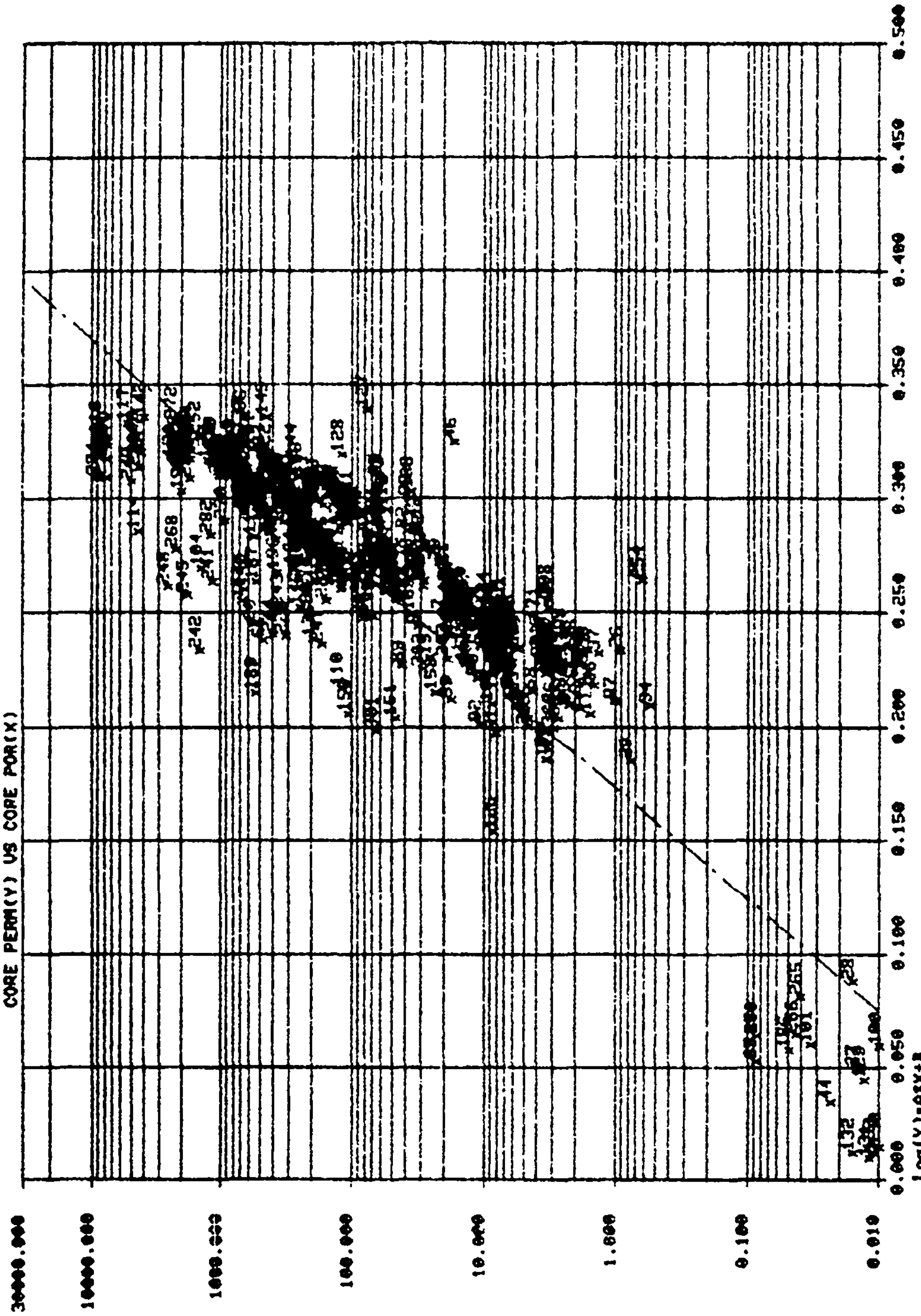

CORE PERM(Y) VS CORE POR(X)
30000.000
10000.000
1000.000
100.000
10.000
1.000
0.100
0.010
0.000
0.050
0.100
0.150
0.200
0.250
0.300
0.350
0.400
0.450
0.500
Log(Y)=A*X+B
A= 16.81811115 B= -2.66710697 C2= 0.68806913
DO YOU WANT TO DELETE ANY POINTS?
N1-0
WELL 831-3-1 DEPTH: 1351.50 1497.00 TOTAL: 378 X.AV: 0.2665 Y.AV: 834.1967
P L O T T E D B Y : ASI

Fig. 3.6.2

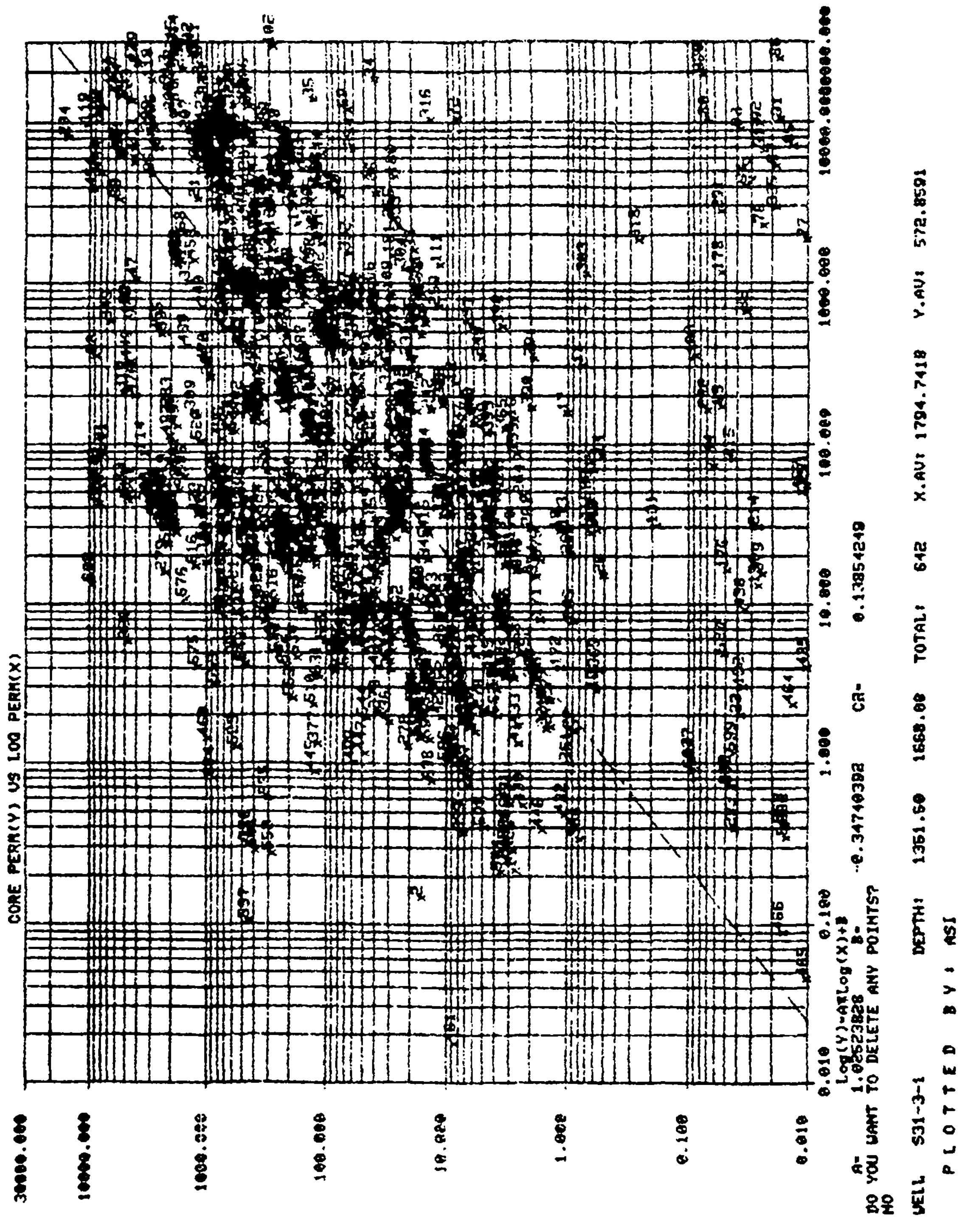


Log(Y)=A*X+B
A= 20.17097707 B= -3.50773665 C2= 0.73885350
DO YOU WANT TO DELETE ANY POINTS?
NO

WELL S31-3-1 DEPTH: 1497.00 1668.00 TOTAL: 308 X.AV: 0.2569 Y.AV: 490.8665

P L O T T E D B Y : ASI

Fig. 3.6.3



CORE PERM(Y) VS LOG PERM(X)
30000.000
10000.000
1000.000
100.000
10.000
1.000
0.100
0.010
0.010
0.100
1.000
10.000
100.000
1000.000
10000.000
Log(Y)=A*Log(X)+B
A= 1.02623828 B= -0.34740392 CR= 0.13854249
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL 531-3-1 DEPTH: 1351.50 1668.00 TOTAL: 642 X.AV: 1794.7418 Y.AV: 572.8591
P L O T T E D B Y : ASI

Fig. 3.7.1

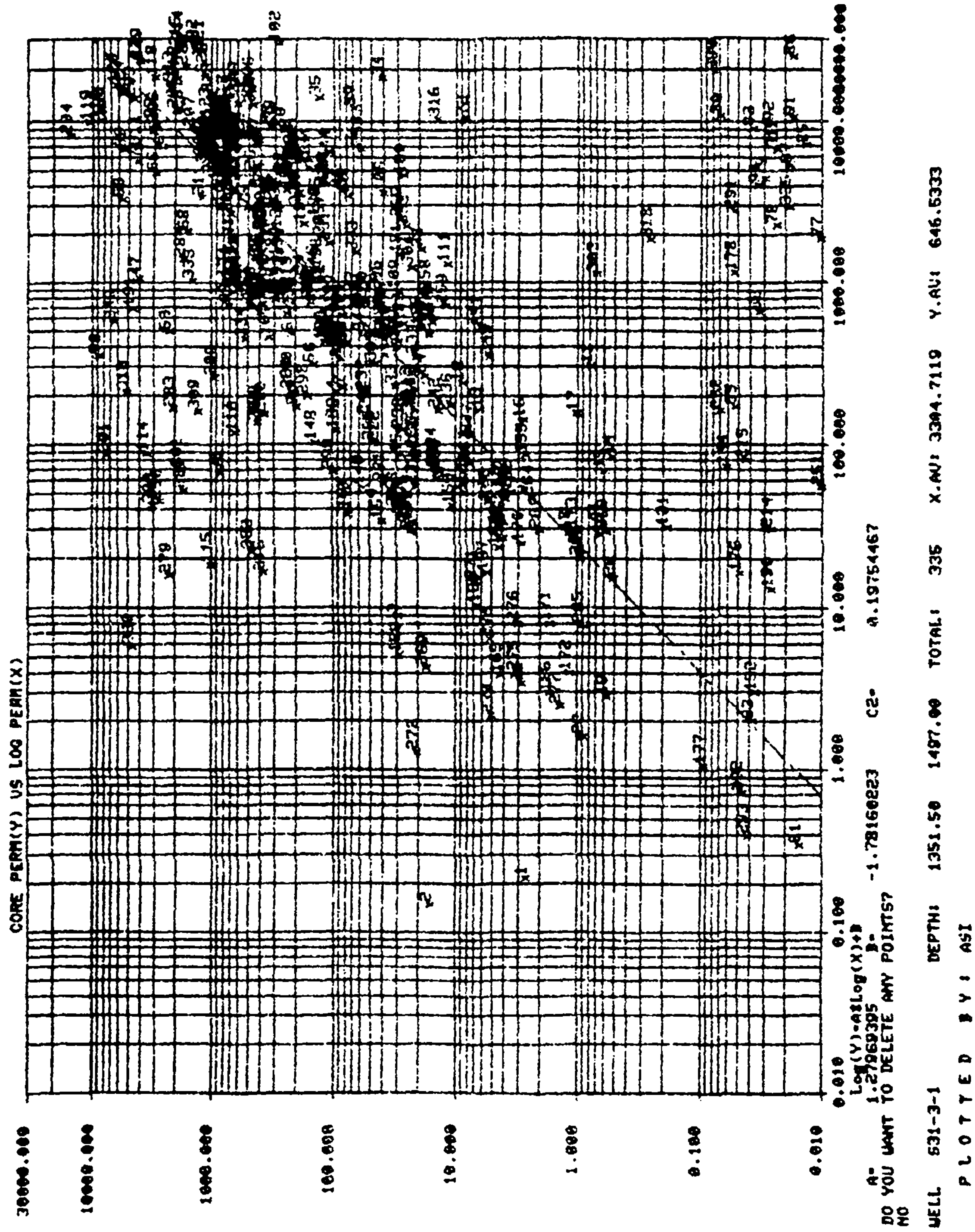

CORE PERM(Y) VS LOG PERM(X)
30000.000
10000.000
1000.000
100.000
10.000
1.000
0.100
0.010
0.010
0.100
1.000
10.000
100.000
1000.000
10000.000
100000.000
Log(Y)=A*Log(X)+B
A= 1.27969395 B= -1.78160823 C2= 0.19754467
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL 531-3-1 DEPTH: 1351.50 1497.00 TOTAL: 335 X.AV: 3304.7119 Y.AV: 646.5333
P L O T T E D B Y : ASI

Fig. 3.7.2

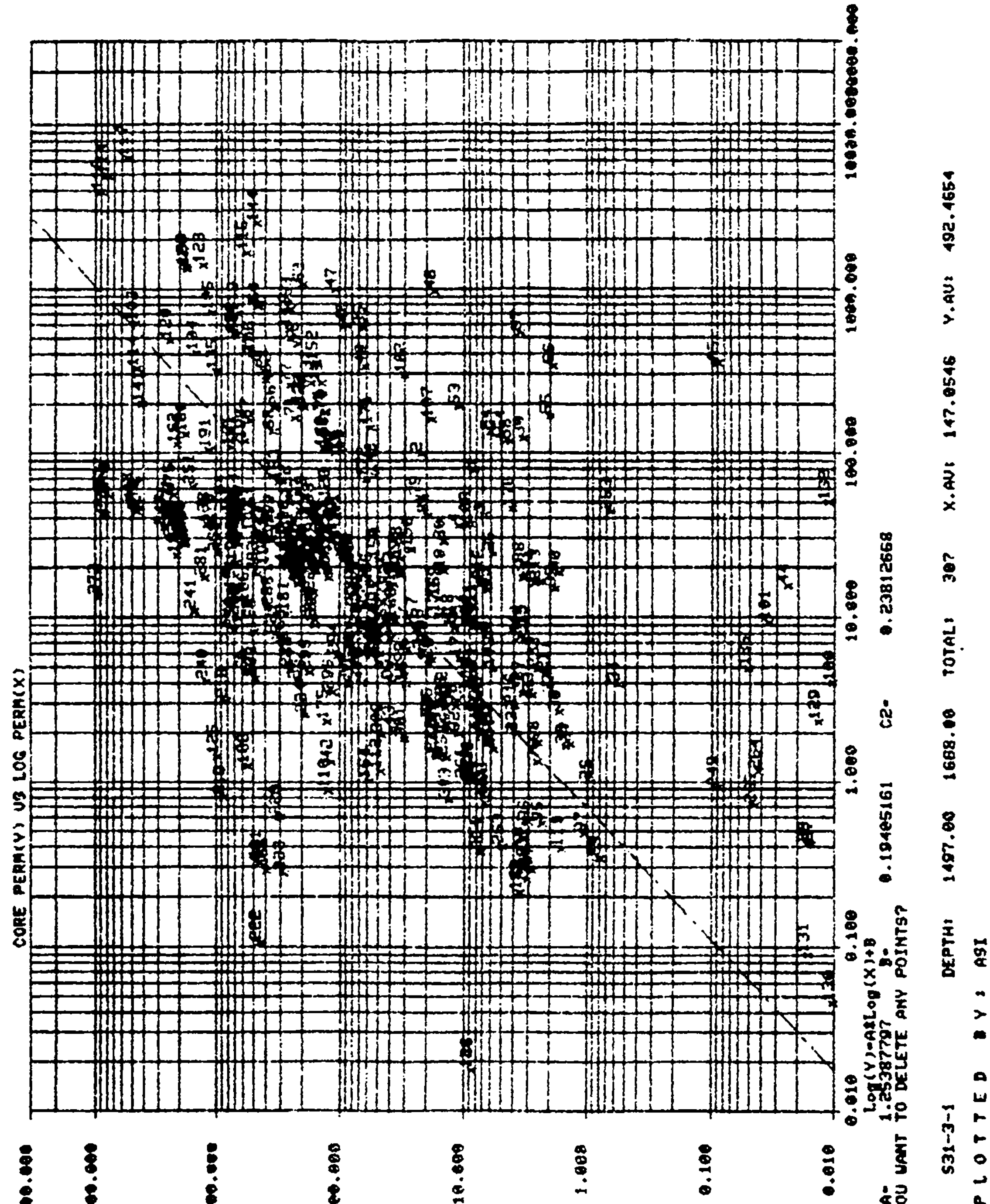
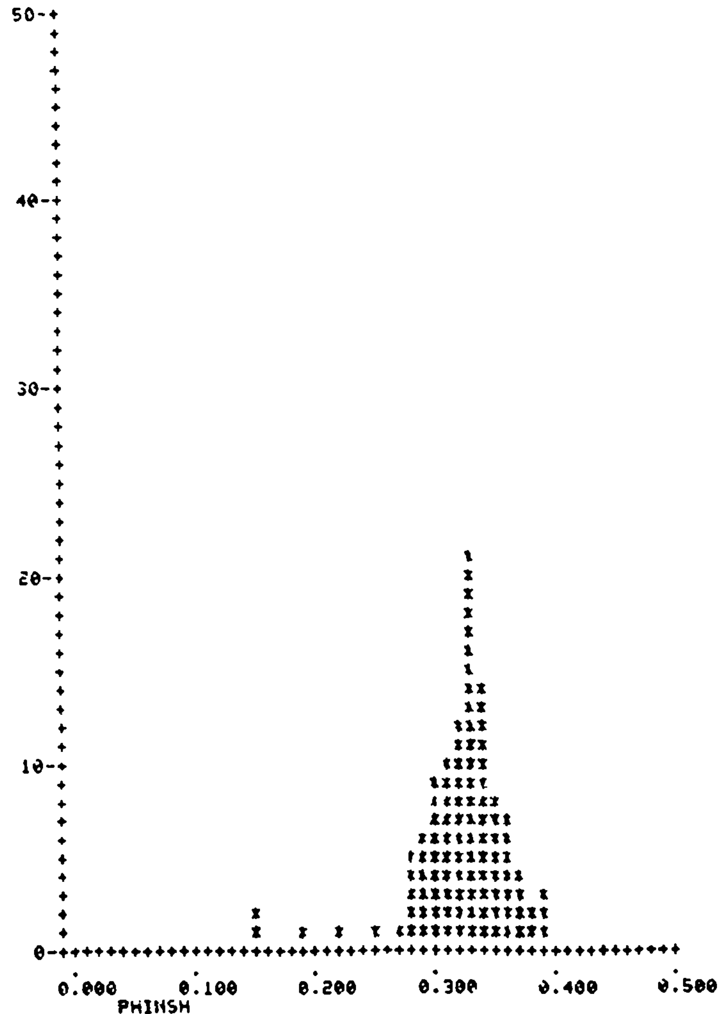

CORE PERM(Y) VS LOG PERM(X)
Log(Y)=A*Log(X)+B
A= 1.25387797 B= 0.19405161 C2= 0.23812668
DO YOU WANT TO DELETE ANY POINTS?
NO
WELL S31-3-1 DEPTH: 1497.00 1608.00 TOTAL: 307 X.AV: 147.0546 Y.AV: 492.4654
PLOTTED BY: ASI

Fig. 3.7.3

PHINSH HISTOGRAM



WELL S31-3-1 DEPTH: 1325.00 1668.00 TOTAL: 107
X.AV: 0.3267
Z - VSH , 0.75 , 1.00

P L O T T E D B Y : ASI

Fig. 3.8.1

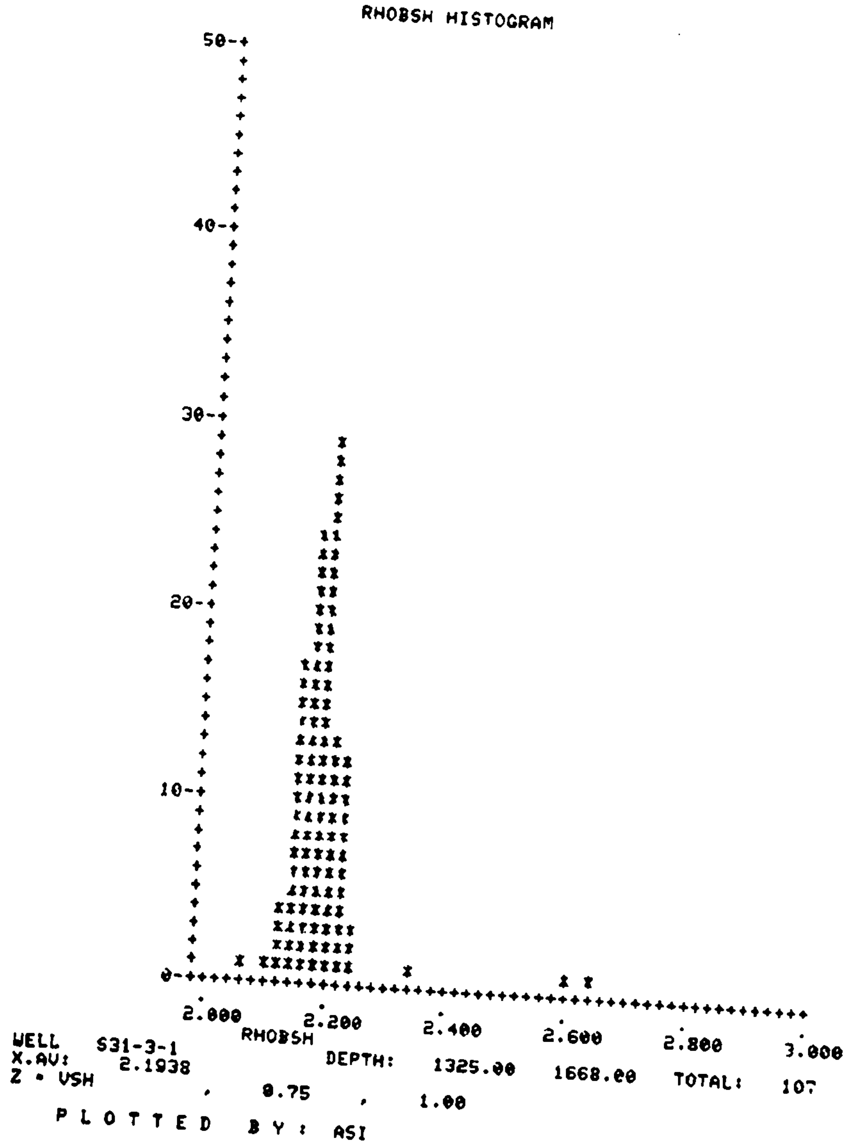
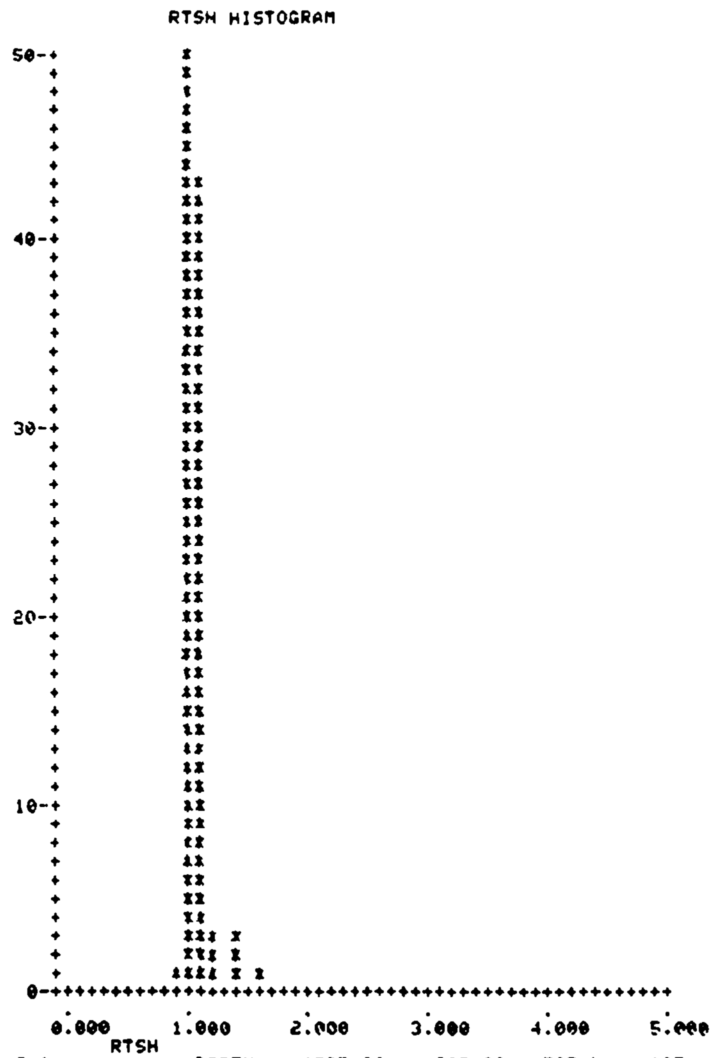

RHOBSH HISTOGRAM
50
40
30
20
10
0
2.000
2.200
2.400
2.600
2.800
3.000
RHOBSH
WELL S31-3-1
X.AV: 2.1938
Z • VSH
DEPTH: 1325.00 1668.00
TOTAL: 107
0.75
1.00
PLOTTED BY: ASI

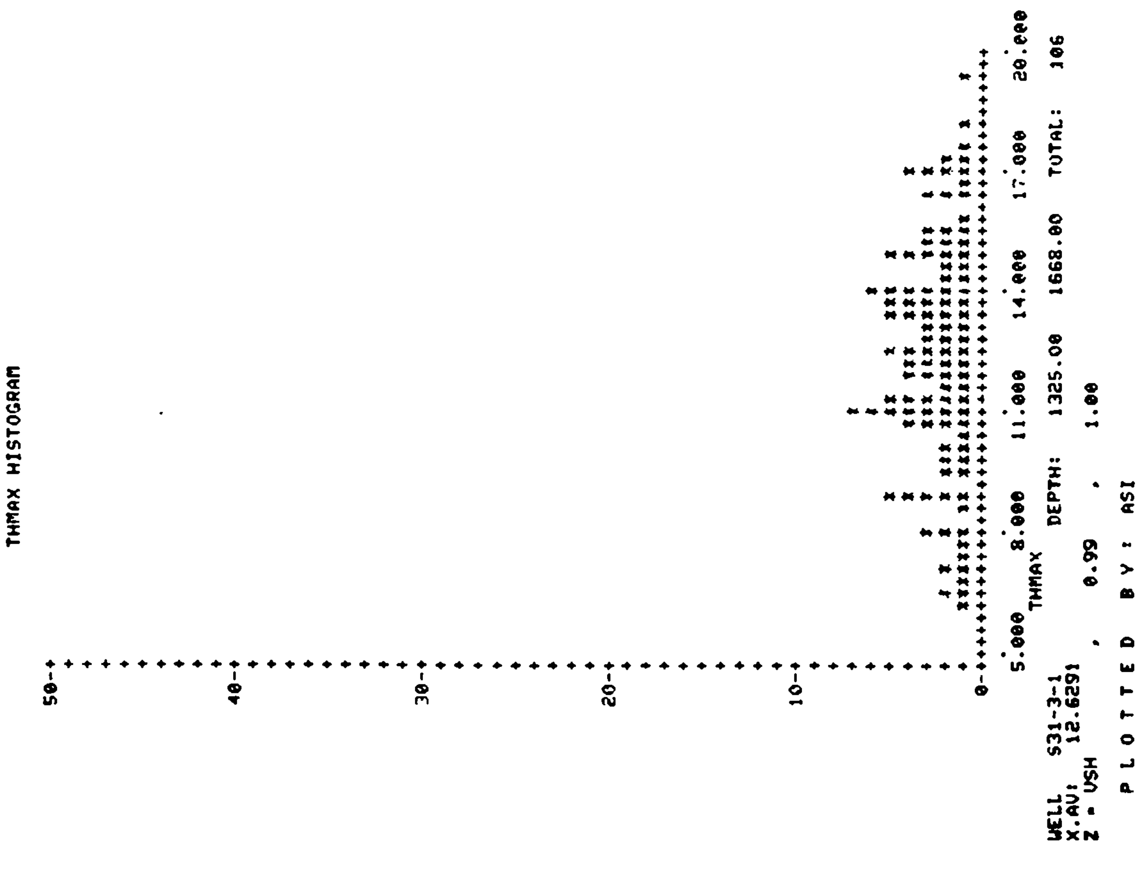
Fig. 3.8.2



WELL S31-3-1 DEPTH: 1325.00 1668.00 TOTAL: 107
X.AV: 1.1045
Z = VSH , 0.75 , 1.00

P L O T T E D B Y : ASI

Fig. 3.8.3


THMAX HISTOGRAM
WELL S31-3-1 THMAX DEPTH: 1325.00 1668.00 TOTAL: 106
X.AV: 12.6291 , 0.99 , 1.00
Z = USH
P L O T T E D B Y : A S I

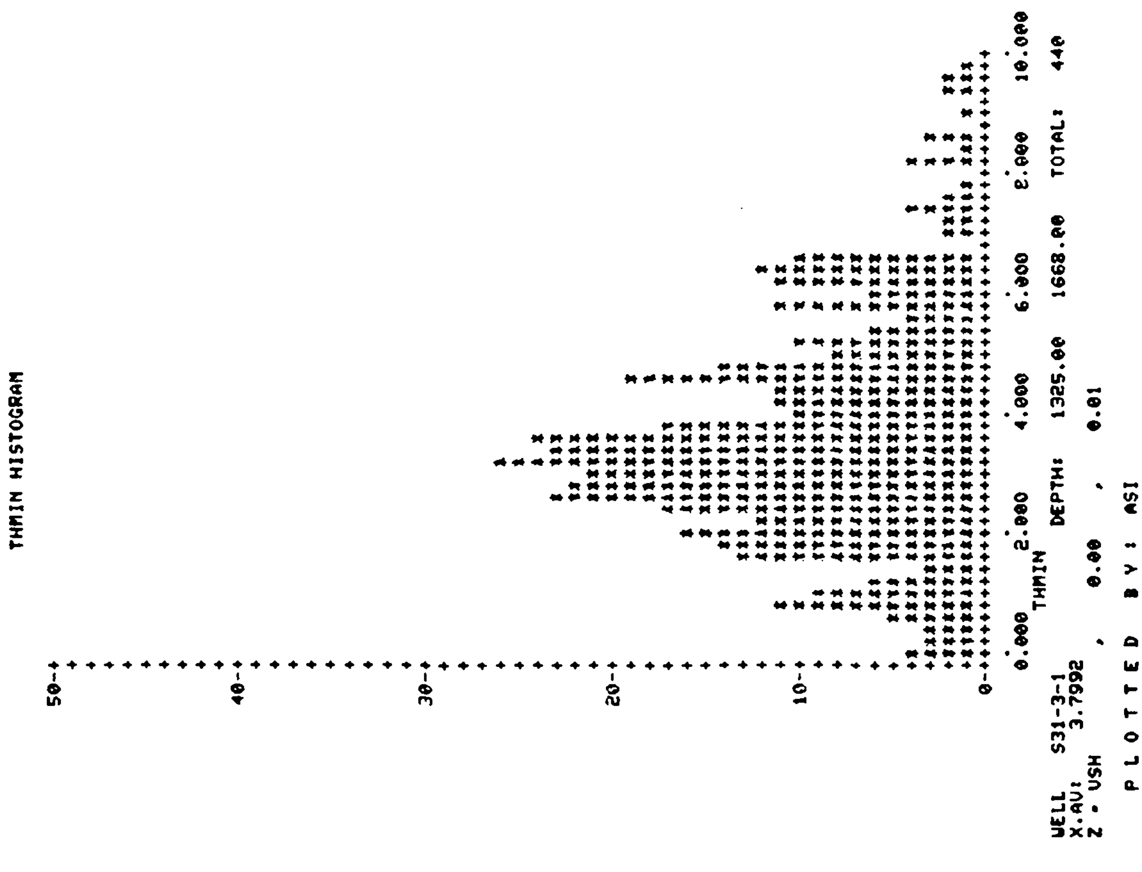
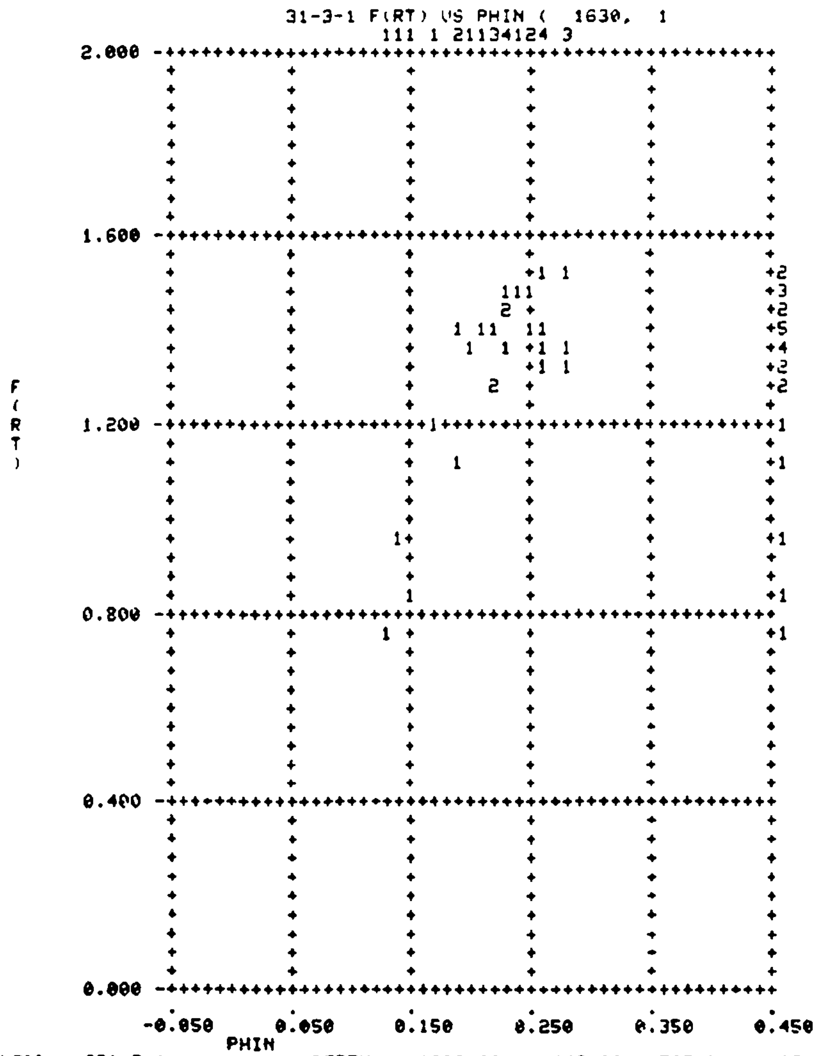

THMIN HISTOGRAM
WELL S31-3-1 THMIN DEPTH: 1325.00 1668.00 TOTAL: 440
X.AV: 3.7992 , 0.00 , 0.01
Z = USH
P L O T T E D B Y : A S I

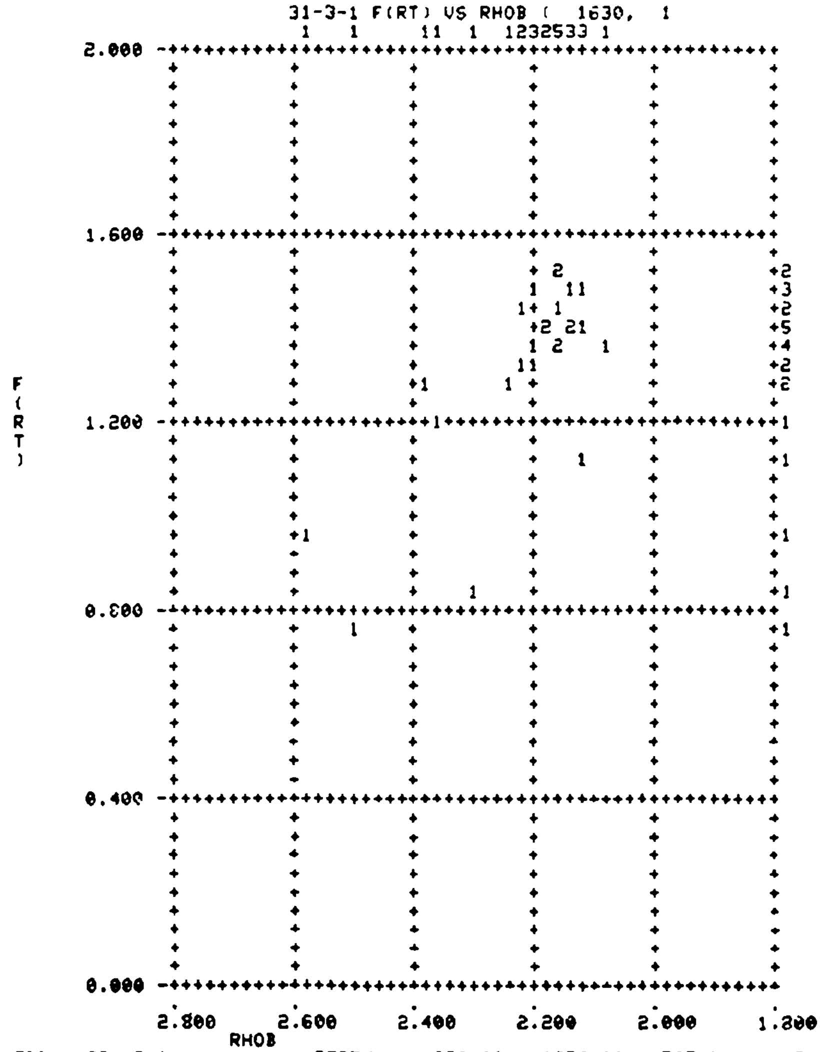
Fig. 3.8.4



WELL S31-3-1 DEPTH: 1630.00 1636.00 TOTAL: 25
X.AV: 0.2283 Y.AV: 1.3369

P L O T T E D B Y : ASI

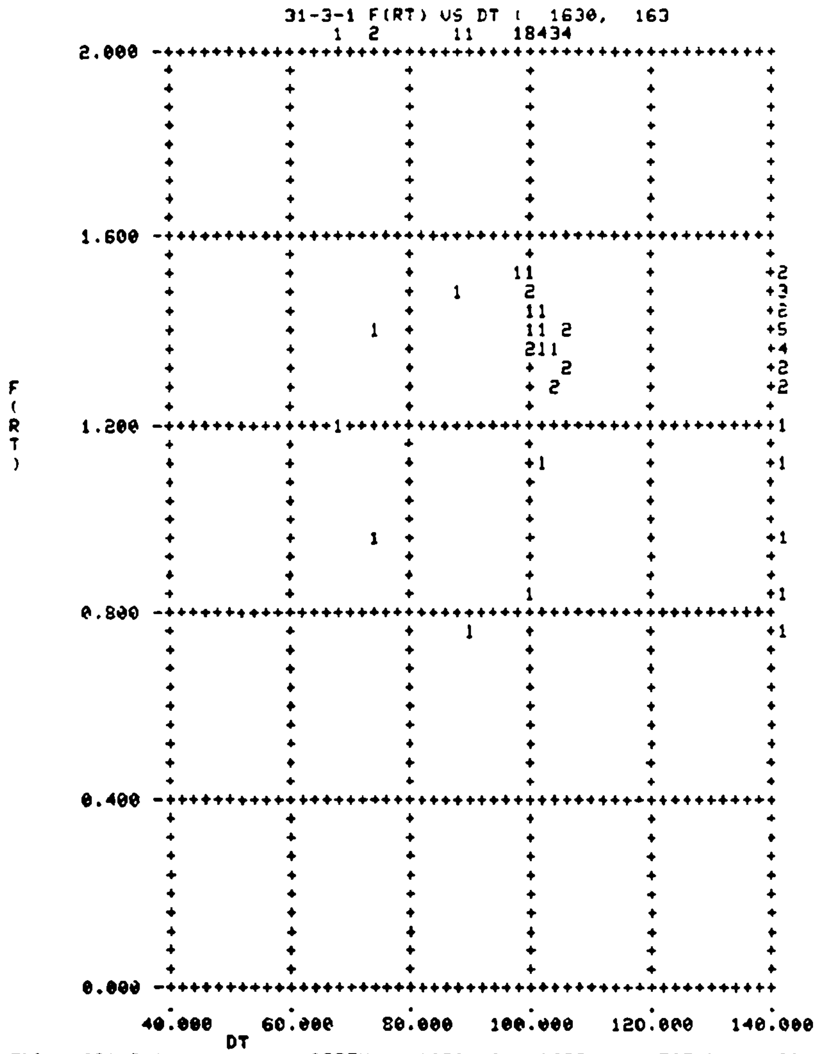
Fig. 3.9.1



WELL S31-3-1 DEPTH: 1630.00 1636.00 TOTAL: 25
X.AV: 2.2273 Y.AV: 1.3369

P L O T T E D B Y : ASI

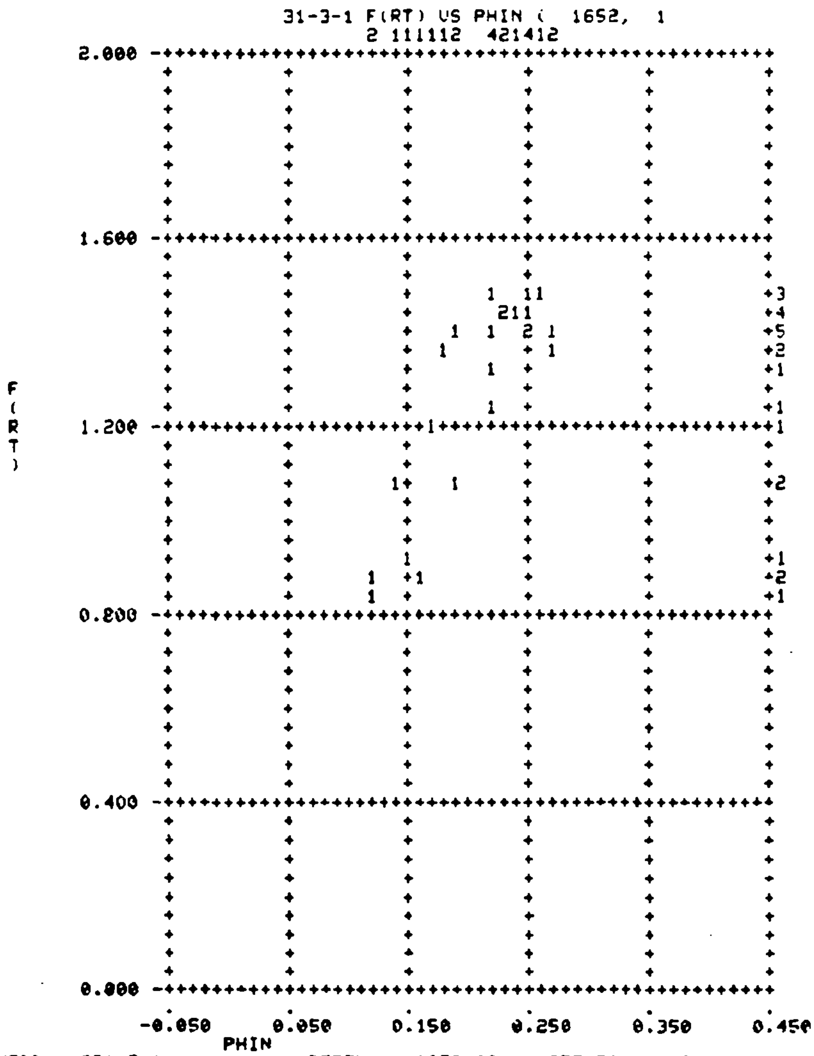
Fig. 3.9.2



WELL S31-3-1 DEPTH: 1630.00 1636.00 TOTAL: 25
X.AV: 98.3116 Y.AV: 1.3369

P L O T T E D B Y : ASI

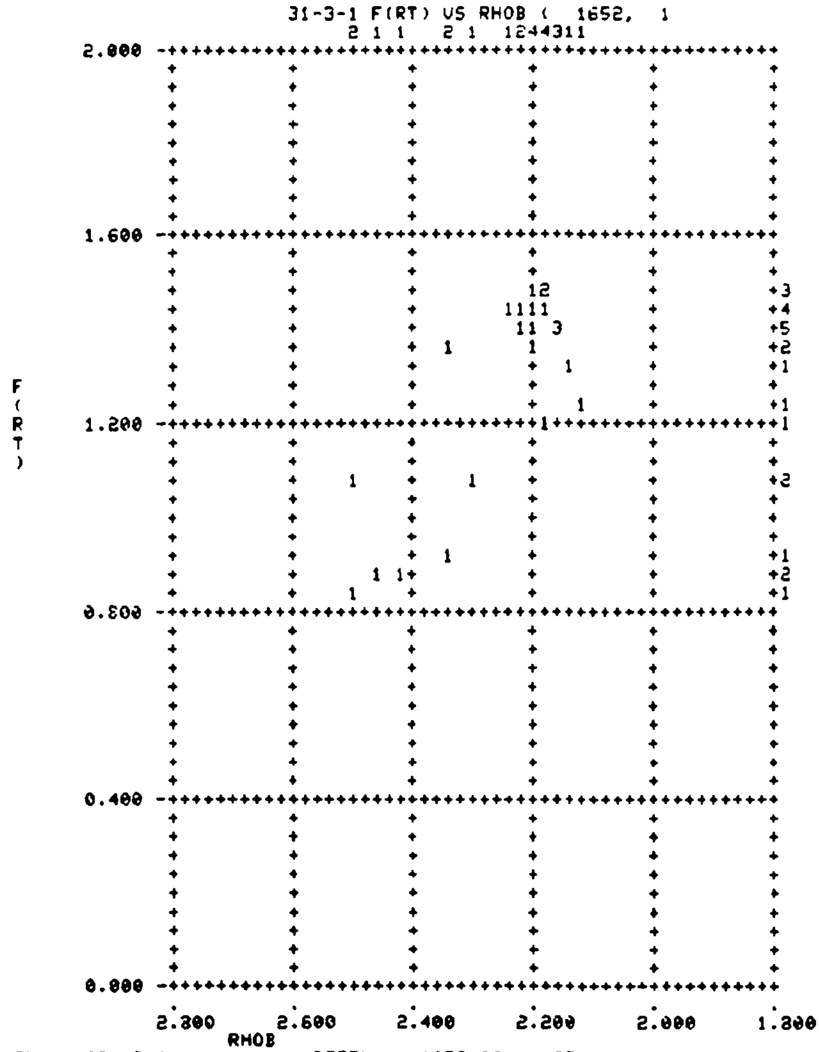
Fig. 3.9.3



WELL S31-3-1 DEPTH: 1652.00 1657.50 TOTAL: 23
X.AV: 0.2138 Y.AV: 1.2935

P L O T T E D B Y : ASI

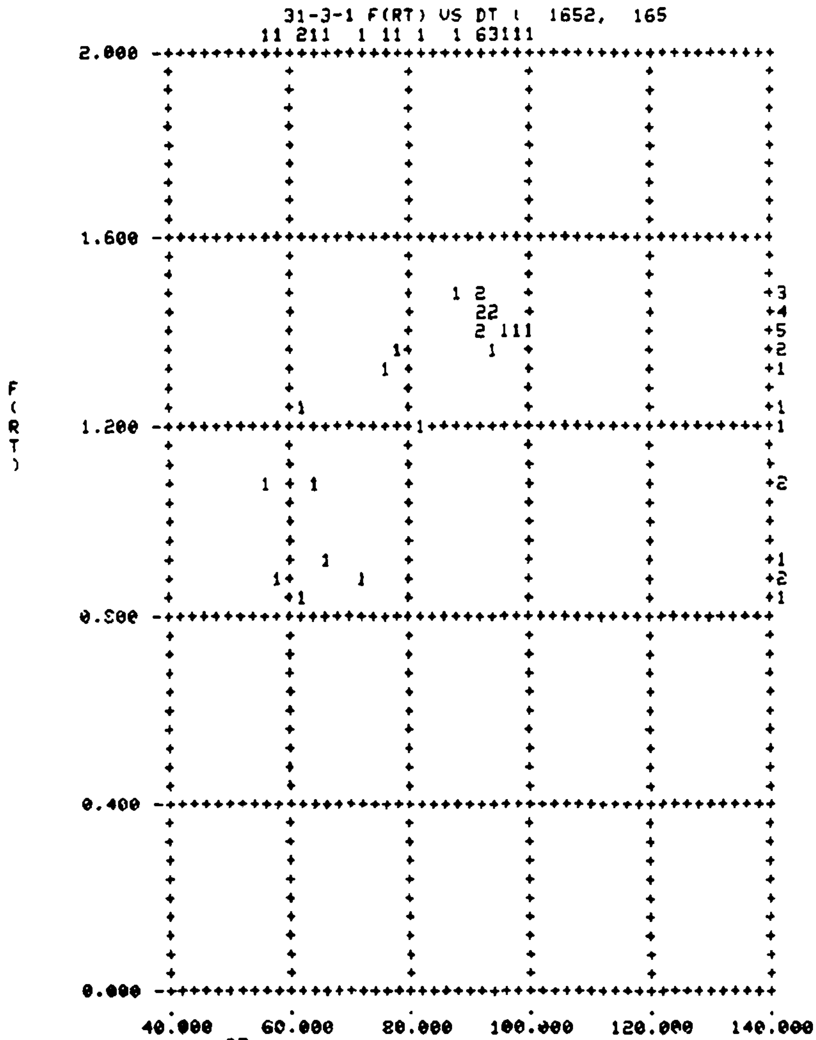
Fig. 3.9.4



WELL S31-3-1 DEPTH: 1652.00 1657.50 TOTAL: 23
X.AV: 2.2594 Y.AV: 1.2935

P L O T T E D B Y : ASI

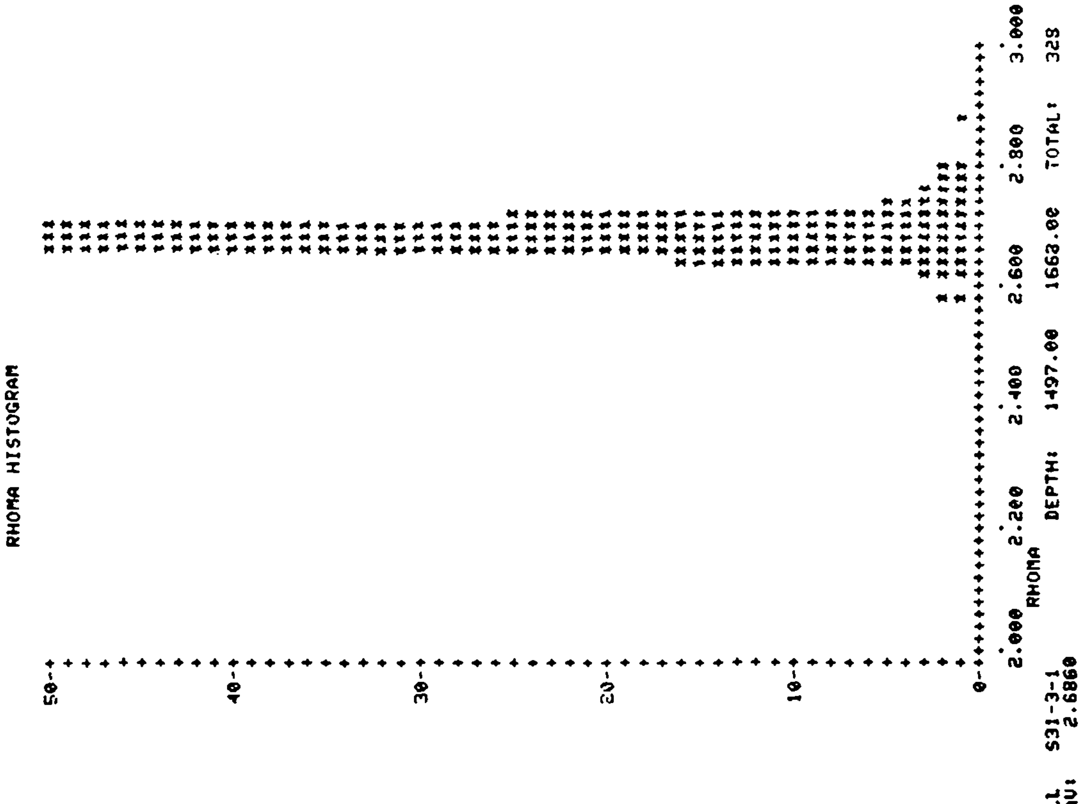
Fig. 3.9.5



WELL S31-3-1 DEPTH: 1652.00 1657.50 TOTAL: 23
X.AV: 83.0827 Y.AV: 1.2935

P L O T T E D B Y : ASI

Fig. 3.9.6


RHOMA HISTOGRAM
50
40
30
20
10
0
2.000
2.200
2.400
2.600
2.800
3.000
RHOMA
WELL S31-3-1
X.AV: 2.6860
DEPTH: 1497.00 1663.00
TOTAL: 328
P L O T T E D B Y : ASI

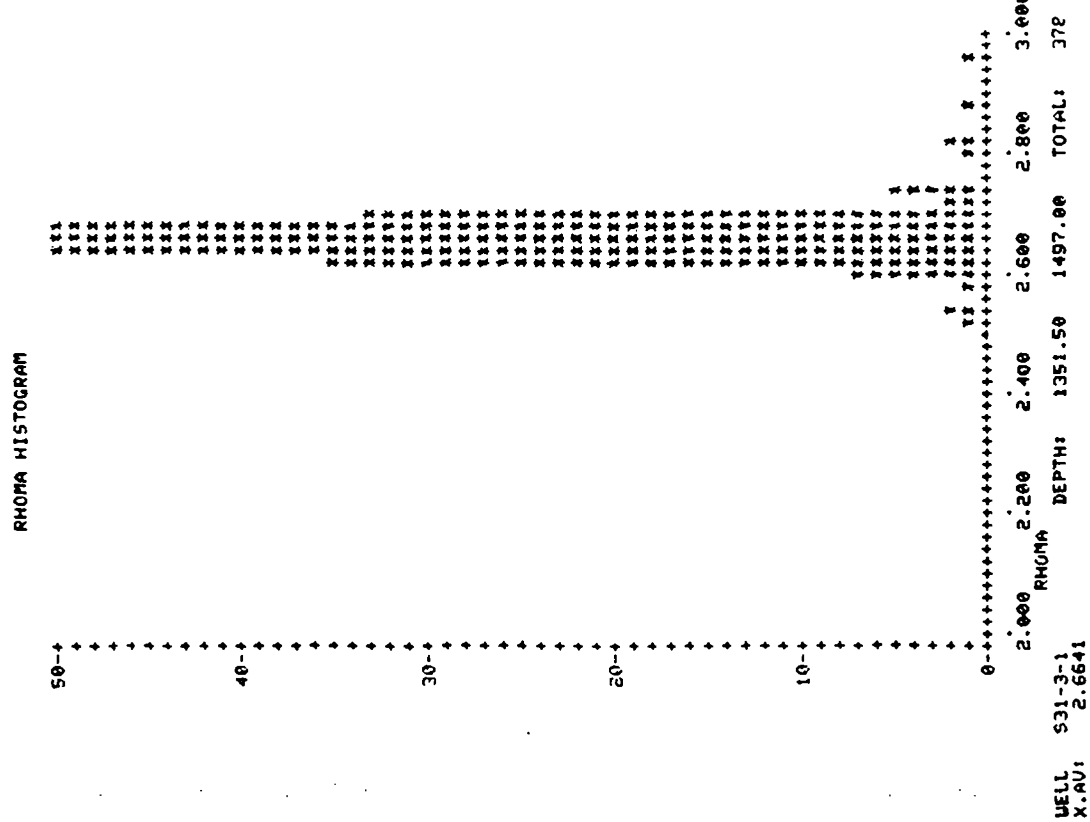

RHOMA HISTOGRAM
50
40
30
20
10
0
2.000
2.200
2.400
2.600
2.800
3.000
RHOMA
WELL S31-3-1
X.AV: 2.6641
DEPTH: 1351.50 1497.00
TOTAL: 372
P L O T T E D B Y : ASI

Fig. 3.10