Analysis of oils recovered from drilling mud

Three samples of liquid hydrocarbons were collected from the drilling fluid and subsequently analysed by Gulf's research laboratory (GR&DC) at Harmarville, Pennsylvania U.S.A.

Sample 1 at 3515 From a mud sample collected on 13 September, 1980 while circulating out the kick which occurred on drilling into the Brent. This sample was shipped direct to the laboratory in a sealed can.

Sample 2 at 3518m A clear, dark brown to amber (Munsell Colour Code 3/6-4/8) low viscosity 'thin' oil of 36.5 API collected from the mud pits on 21 Sept. 1980 after reaming the cement plug set on bottom prior to running 9 5/8" casing.

Sample 3 at 3567m Clear, dark straw (Munsell colour code 3/6) low viscosity oil of 44.7 API collected from the mud pits on 27 September while circulating out kick which occurred whilst pulling core number 3.

These three oil samples (despite differences in colour and gravity of 2 and 3) are nearly identical as shows shown in the following summary and confirmed by C15 + fingerprints.

	Gravity		Content			Fractional Composition %			
Sample	API	SG	CPI	Nit	Sulph	Asph	Sat	Arom	Resin
1	-	-	1.12	-	-	4.3	69.4	20.7	5.6
2	36.5	0.8422	1.06	0.013	<0.04	0.5	74.0	21.7	3.8
3	44.7	0.8030	1.15	52ppm	<0.04	0	79.9	19.9	0.2

The difference in colour was originally thought to be due to contamination/mixing with possible oil in overlying Upper Jurassic sands but was eventually shown to be caused by preferential solution of saltex (a blown ashphalt mud additive) which gave sample 2 its dark colour. Other differences, particularly gravity are due to loss of volatiles during collection and transport.

Results of analysis of the DST fluid samples are not available at the time of writing but their general appearance suggest that they are the same as each of the three samples described above.

15. Repeat Formation Tester

Eight separate runs were made with the RFT tool as part of the last three logging runs. Depth correlation was based on the GR of the FDC/CNL log recorded during the same logging run.

RFT No	Log run	TD metres	Max BHT
1	4	3584.0	218°F
2-5	5	3789.0	247°F
6-8	6	4346.5	290°F

Each test has been given a two digit number indicating the run number and the test number, e.g. 1/2 indicates the second test taken during the first trip into the hole with the RFT tool (following Tables). Although some permeabilities were calculated the values derived were considered to be too inaccurate to be of use in reservoir evaluation. Due to the relatively high formation pressures the Schlumberger engineer suppressed the second pre-test chamber on runs 1 through 5. A 15,000 psi gauge calibrated to 10,000 psi was used on all tests. Hydrostatic values of up to 11,000 psi were recorded during runs 6 through 8. The appropriate correction for ~~temperature~~ effect for values over 10,000 psi was derived by extrapolating along the nearest temperature line on the correction chart.

All values taken through the Brent Sand appear to give reasonable results; pressures measured in the Dunlin and Statfjord sands were all anomalously high. This report will therefore discuss the results from the Brent Sands measurements separately from those at deeper horizons.

BRENT SAND INTERVAL

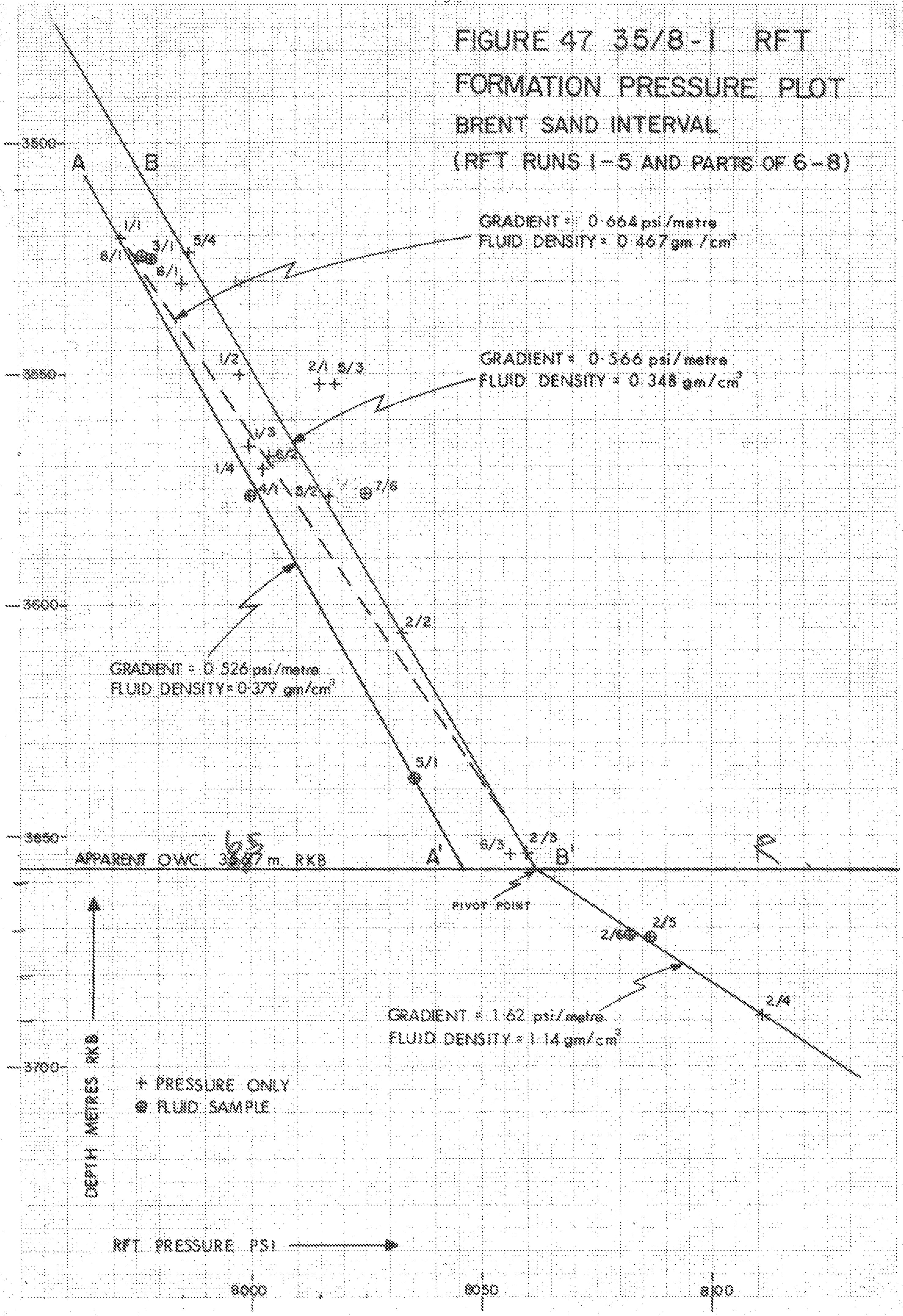
The RFT pressures measured through the Brent Sand have been plotted against depth to define a pressure gradient and formation fluid densities (Figure 47). The three values below the oil-water contact indicate an apparent formation fluid density of 1.14gm/cm^3 which is equivalent to a salt water concentration of 190,000ppm NaCl. The log derived salinity is 15,000ppm Na Cl (Rw 0.14) which equates to a fluid density of 1.008gm/cm^3. However there is no difference in slope, at the scale plotted, between these two values.

The intersection between this slope and the hydrocarbon-water contact can therefore be used as a pivot point for the slope through the hydrocarbon column.

FIGURE 47 35/8-1 RFT FORMATION PRESSURE PLOT

BRENT SAND INTERVAL

(RFT RUNS 1-5 AND PARTS OF 6-8)



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Two trends have been plotted above the oil-water contact: A-A' which connects most of the low values and B-B' connecting most of the high values. Pressures from RFT 2/1 and 5/3 are considered anomalously high due to a slight supercharge effect. The B-B' trend appears more likely to be correct than A-A' as it meets the projected water gradient at the OWC. If this assumption is valid then the fluid density, at reservoir conditions, above the hydrocarbon-water contact is 0.398gm/cm^3. This is too heavy for gas, but also very light for an oil.* An average trend from RFT 1/1 to 2/3 has been dashed in, which gives a slightly higher apparent density of 0.467gm/cm^3. There is no evidence to suggest more than one uniform hydrocarbon fluid throughout the reservoir. If the measurement at RFT 5/3 is correct then a line joining this value with RFT 2/3 would suggest a fluid density of 0.292gm/cm^3. As a check on RFT pressure values, recorded hydrostatic pressure measured before and after each test have been plotted against depth. (Figure 2). The values fall along slopes corresponding to mud weights of 1.96 (16.35 lb/gal) for RFT Number 1, 1.74 (14.5 lb/gal) for RFT number 2 and 1.67 (13.9 lb/gal) for RFT number 5. Measurement before and after the test are noticeably different for RFT's number 3/1 and 4/1 with a lower value being measured after the test in each case. This suggests that the pre-test formation pressures for these two tests might be in error. The high mud weight during RFT Number 1 is caused by a slug of heavy mud having been placed across the lower part of the hole during logging, the mud weight in the rest of the hole and in the pits being only 1.8sg (15 lb/gal).

RFT Sample Recovery

RFT 2/5 (3671.5m)

The upper chamber was opened first but it was suspected that the chamber was not filling so the tool was retracted and moved 1/2 metre upwards and the test repeated (2/6).

RFT 2/6 3671.0m

The upper chamber was opened again and then, although there was no positive indication that the chamber was full, the lower chamber was opened for a short period (2½ min) and the tool retracted. Both chambers were opened at the well site. Recovery was as follows:

Upper Chamber (2 3/4 gallon) 2 litres of mud filtrate; a grey brown cloudy liquid with sour odour and an unmeasurable trace of gas; (Rw = 0.06 at 61°F = 180,000 ppm. NaCl. Mud filtrate = 160,000 ppm).

Lower Chamber (2 3/4 gallon) 1.5 litres of mud filtrate and formation water; a light brown liquid with sour odour and trace of dissolved gas (Rw 0.075 at 61°F = 120,000 ppm NaCl.

* Compared to a reservoir fluid density of 0.29 calculated from the results of Drillstem tests.

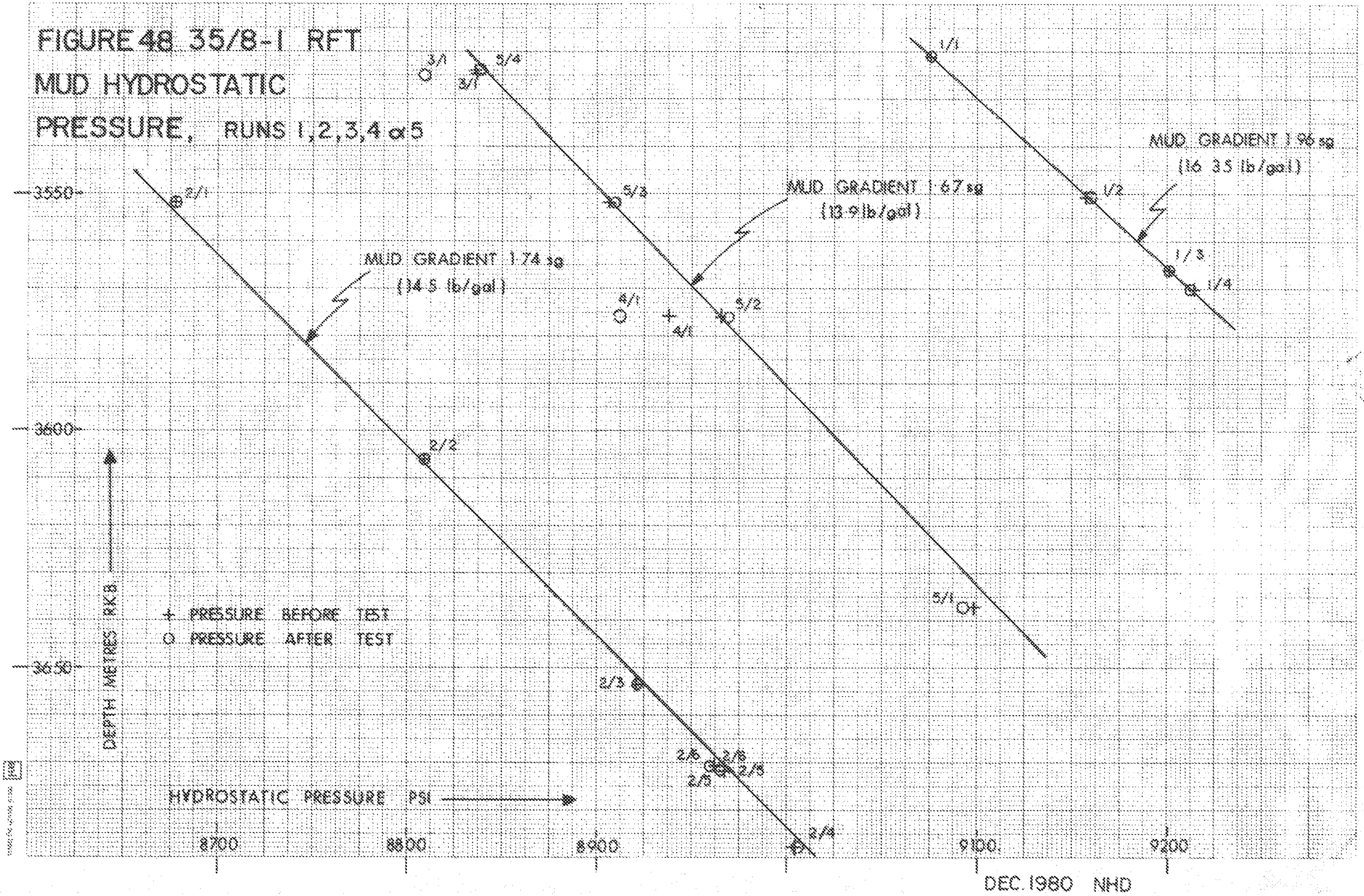

FIGURE 48 35/8-1 RFT
MUD HYDROSTATIC
PRESSURE, RUNS 1,2,3,4 & 5
MUD GRADIENT 1.96 sg
(16.35 lb/gal)
MUD GRADIENT 1.67 sg
(13.9 lb/gal)
MUD GRADIENT 1.74 sg
(14.5 lb/gal)
+ PRESSURE BEFORE TEST
O PRESSURE AFTER TEST
DEPTH METRES RKB
HYDROSTATIC PRESSURE PSI
3550
3600
3650
8700
8800
8900
9100
9200
1/1
1/2
1/3
1/4
2/1
2/2
2/3
2/4
2/5
2/6
3/1
4/1
5/1
5/2
5/3
5/4
DEC.1980 NHD

Chromatographic analysis of released gas

Methane	100 000	ppm
Ethane	80 000	ppm
Propane	60 000	ppm
Butane	50 000	ppm
Pentane	8 000	ppm

RFT 3/1 (3524.6m)

The upper chamber was inadvertently opened first and appeared to quickly reach formation pressure after 27 minutes whereupon the lower chamber was opened. This appeared to fill quickly and the test was completed after 40 minutes.

Upper Chamber (2 3/4 gallon). This chamber was vented on the rig releasing 52.75 cubic feet of gas with 2.15 litres of 39°API oil and traces of mud in suspension. (G.O.R. 3900/SCF/BBL). The oil was straw coloured in transmitted light with a slightly greenish hue and strong blue fluorescence.

Chromatographic analysis of the released gas:

Methane	greater than	520 000	ppm
Ethane		210 000	"
Propane		125 000	"
Iso butane		175 000	"
Normal butane		310 000	"
Pentanes		58 000	"

The presence of Pentane as a gas and the relatively low gravity of the oil compared to subsequent tests suggests that the chamber was opened too quickly and the dissolved gas flashed, vaporising some of the lighter liquid hydrocarbons. Also the lines and valves frosted over on this test which did not happen subsequently.

Lower Chamber (2 3/4 gallon). Although this chamber had appeared to fill in less than one minute it was shipped to Statoil's PVT laboratory in Stavanger where it was found to contain only 50ccs of filtrate, due probably to plugging of the tool.

RFT 4/1 (3576.5m)

The upper 1 gallon chamber was (again incorrectly) opened first and after 35½ minutes of plugging and intermittent flow was sealed. Formation pressure was reached after a further 1½ minutes whereupon the lower 2 3/4 gallon chamber was opened. This chamber filled very slowly with a very low flowing pressure (2900 psi) and after a further 115 minutes was closed and the test terminated.

Upper Chamber (1 gallon). This was vented on the rig releasing 12.0 cu ft of gas with 1.4 litres of mud filtrate 0.35 litres of oil. (GOR 5450 SCF/BBL). The oil was straw coloured with strong blue fluorescence and similar to that in RFT number 3/1 except for a higher gravity (43°API).

Chromatographic analysis of the released gas:

Methane	greater than	600 000 ppm
Ethane		294 000 "
Propane		424 000 "
Iso butane		211 000 "
Normal butane		364 000 "
Pentane		none detected

The sample was bled off more slowly then in 3/1: The absence of Pentanes and the higher gravity confirm that the earlier sample had been opened too quickly allowing some heavier hydrocarbon liquids to vaporise.

Lower Chamber (2 3/4 gallon). This chamber was sealed and sent to Statoil's PVT laboratory in Stavanger where it was found to contain oil and filtrate (See separate report).

RFT 5/1 (3637.5m)

The tool plugged immediately on attempting to sample and was found to be stuck. However, after freeing the tool it was re-set at the same depth. This test proved to be the first test carried out correctly (apart from the non utilisation of pre-test number 2) and successfully. The lower 2 3/4 gallon chamber was opened first and after 40 seconds had built up to a flowing pressure close to the pre-test formation pressure. The upper 1 gallon chamber was then opened, and filled in less than 10 seconds. It was not possible to differentiate from the log response this successful sampling from the unsuccessful attempt during RFT 3/1.

Lower Chamber (2 3/4 gallon). This was vented on the rig floor releasing 73.7 cu ft of gas and 3.095 litres of 43°API oil with a trace of drilling mud. (GOR 3785 SCF/BBL). The oil was light amber in colour with a bright white fluorescence.

Chromatographic analysis of the released gas:

Methane	greater than	885 600 ppm
Ethane		574 000 "
Propane		487 500 "
Iso butane		120 480 "
Normal butane		204 800 "
Pentanes		none detected

Upper Chamber (1 gallon). This was sealed and shipped to Statoil's PVT laboratory in Stavanger where it was found to be almost full of hydrocarbons (with approximately 100cc of filtrate) and to have an internal pressure of 2700 psi. (See separate report)

RFT 7/6 (3576.0m)

This sample was taken on the way out of the hole after taking pressure measurements in the underlying Statfjord sands. The formation pressure measurement recorded (8025 psi) should be used with caution due to the relatively unpredictable nature of the hysteresis effect which the RFT tool demonstrates when cooling down. The lower chamber was opened first and sealed after 14 minutes when the upper chamber was opened. Formation pressure was reached after 6-7 minutes and the test was terminated.

Lower Chamber (2 3/4 gallons): This was vented on the rig floor and contained 9.8 litres of brown mud filtrate with a trace of oil and 3cu ft of gas.

Chromatographic analysis of released gas

Methane	500 000 ppm
Ethane	130 000 ppm
Propane	44 000 ppm
Butane	trace
Pentane	none detected

Upper Chamber (2 3/4 gallon) This was sealed for delivery to Statoil's PVT laboratory in Stavanger and subsequently to Core Laboratories laboratory in Aberdeen Scotland (See separate report).

RFT 8/1 (3524.5m)

This was the last sample taken and was a repeat of RFT 3/1 in which the sample chamber had plugged. The lower chamber filled slowly and was closed after 196½ minutes and the upper chamber was opened. This also filled slowly and after 56½ minutes the test was terminated in neither case did the tool indicate a full return to the formation pressure measured during the pre-test (7977 psi). Subsequent recovery confirmed that neither chamber had filled.

Lower Chamber (2 3/4 gallon) This was vented on deck but due to a fault in the valve none of the gas went through the gas meter but was discharged suddenly into the air. Schlumberger estimate the volume to have been 50cu ft. Only 1.3 litres of straw coloured oil, with a trace of mud, were recovered. This had a bright blue fluorescence and a gravity of 45.5°API.

Chromatographic analysis of the released gas

Methane	184,000 ppm
Ethane	234,130 ppm
Propane	19,390 ppm
iso Butane	3,912 ppm
normal	10,660 ppm
Pentanes	2,290 ppm

The presence of pentanes again confirms the sudden vaporisation of the gas as occurred also in RFT 3/1.

Upper Chamber (1 gallon) This was delivered to Statoil's PVT laboratory in Stavanger and then transported to Core Laboratories in Aberdeen Scotland (See separate report).

Note The variations in measured oil gravities and in the the ratios of the various hydrocarbon gases measured at the well site reflects variations in the method of collection and subsequent storage history of the samples and are not due to significant variations in composition.

PRE-BRENT SAND FORMATIONS

The three last RFT runs were made primarily through the interval between the Brent Sand and TD. There was one unsuccessful attempt to sample the Statfjord sands at 4176m and four unsuccessful attempts in the Triassic? Cormorant sand at 4313m.

There was no attempt made to sample the Dunlin sands. A plot of formation pressure against depth is shown in figure 49. Pore pressure measurements generally indicated overpressuring in the formations rising from approximately 12.9 lbs/gal equivalent (1.55 gm/cm^3) in the Brent Sand at 3687.8m (RFT 2/4) to 13.4 lbs/gal equivalent in the ?Cormorant sands at 4313m (RFT 6/14). The interval below the Dunlin Shale comprises sands and coarse relatively clean silts which in terms of geological time could be expected to show vertical transmissability and therefore should exhibit a uniform pore pressure gradient related to the density of the pore fluid.

A plot of pore pressure against depth shows a wide scatter of data in the lower part of the well but using only values from RFT runs 6 and 7 a rough best visual fit line indicates an apparent pore pressure gradient of over 2.9 psi/m.

Such a gradient could only be achieved with a formation fluid density of 2.0 gm/cm^3 (16.7 lb/gal equivalent). There is one thin shale from 3980-3995m in this interval and although this could separate two different pressure regime the slope of the gradient above and below shows no evidence of such a change.

A theoretical salt water gradient of 1.5 psi/metre ($B-B^1$) has been drawn on Figure 49 through the value for RFT 6/5 and a similar gradient can be shown for RFT's 6/11 through 6/14 (line $C-C^1$). This salt water gradient has been used to project a theoretical pressure at any depth below RFT 6/4 (line $D-D^1$). At 4313m (RFT 6/14) the theoretical formation pressure should have been approximately 9350 psi in the order of 500 psi less than recorded.

One clue as to the cause of this anomalous gradient can be found in the differences between two separate measurements

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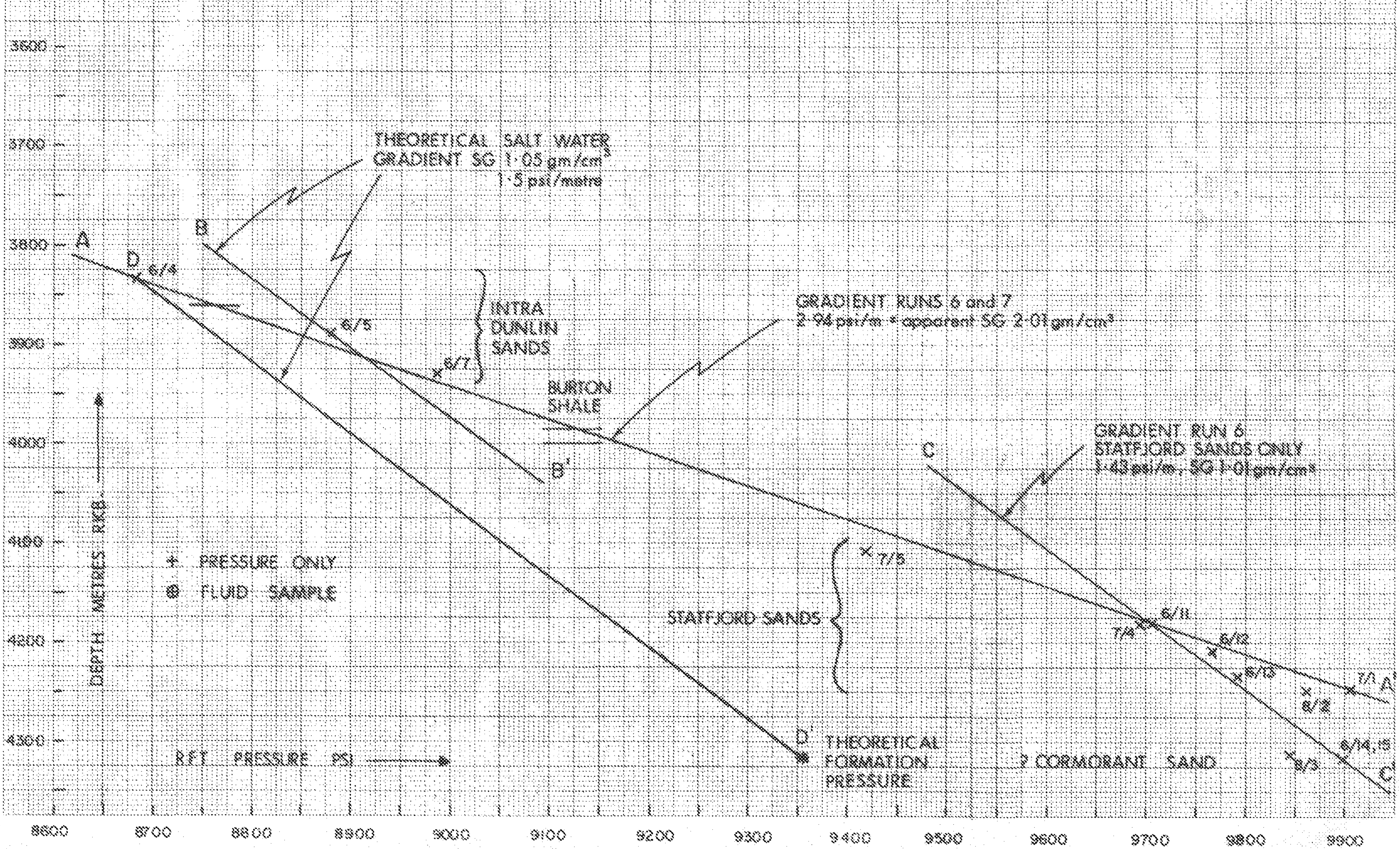
FIGURE 49 35/8 - 1 RFT FORMATION PRESSURE PLOT



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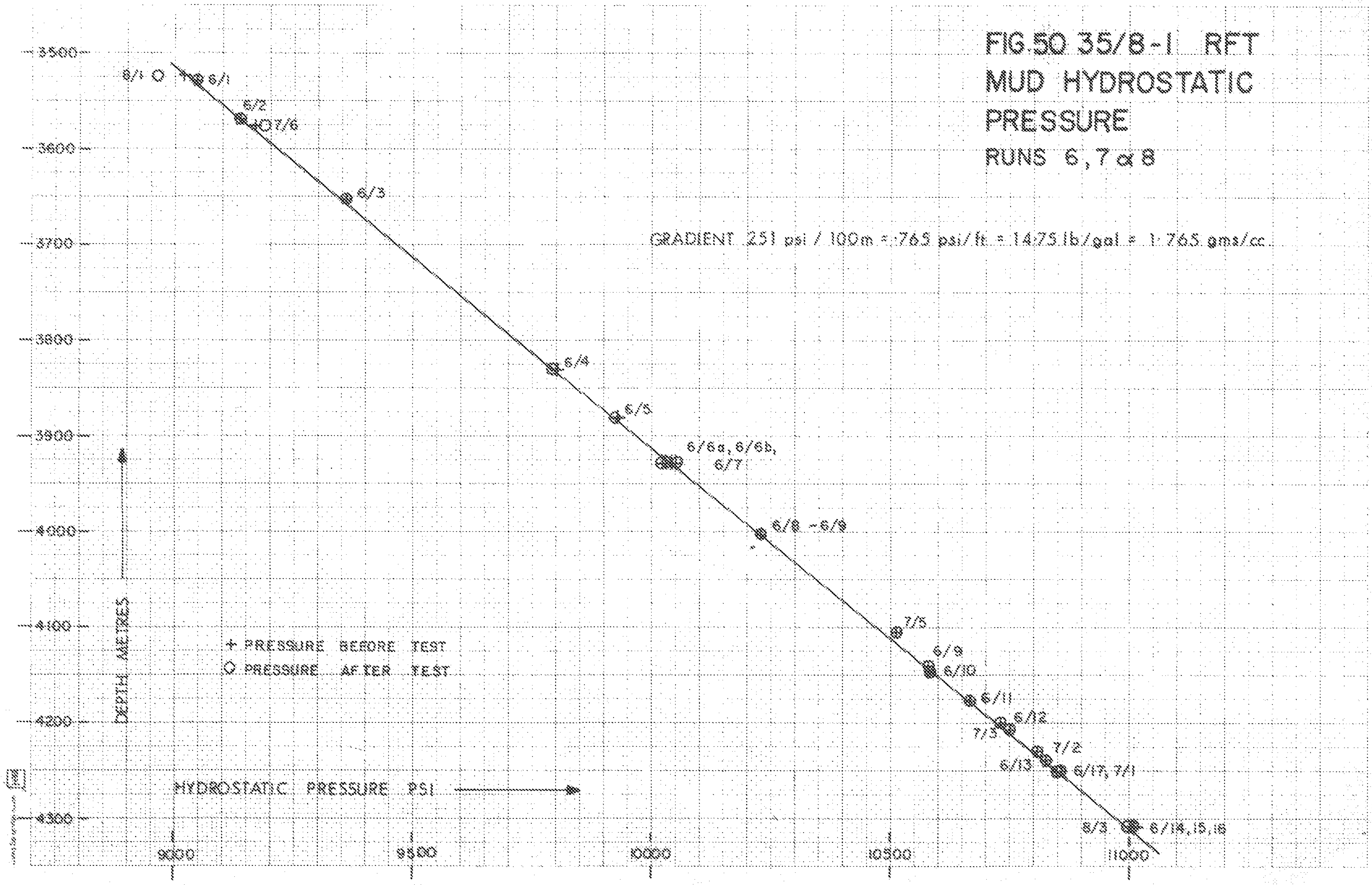
DEC. 1980 DHB



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made at identical depths.

	depth	pressure
RFT 7/1	4248m	9905 psi
RFT 8/2	"	9861 psi
RFT 6/14	4313m	9897 psi
RFT 8/3	"	9846 psi

The drop in pressure between the earlier and the later measurement at each depth (44 psi and 51 psi) suggest that the formations concerned are exhibiting an effect known as "supercharging" caused by mud filtrate invasion. Invasion or flushing of the formation only continues as long as the filter cake is permeable. If this were not so the RFT tool would never be able to measure true formation pressure. Filter cake was still in the process of forming when the RFT pressures were measured. As the first test in Run 6 was taken 48 hours after circulating either the formation permeability must be extremely low or the mud cake must be inefficient. The latter explanation is considered unlikely as measured fluid loss was only 3.1cc and there were no problems in the ovelying Brent Sand section.

To check that the tool was reading pressure consistently a plot of mud hydrostatic against depth was made (Figure 50). This shows a very consistent gradient of 2.51 psi metre or a mud density of 1.765 gm/cm^3 (14.75 lbs/gal equivalent).

It is apparent therefore that the formation pressures measured beneath the Brent Sand interval are in error and should not be used for any further calculations. As the only way of detecting this anomalous situation is to plot apparent formation pressure against depth or simply calculate a gradient it is recommended that such a procedure be adopted by the well site geologist at the well site as the pressure measurements are being taken.

Runs 1 through 5

RFT RESULTS

Run No 1 — 4 pressure measurements only, tool unable to sample.

Sample Number	Depth metres	Depth feet	Hydrostatic	Formation	Corrected Pressure (psig) Hydrostatic		Sample type
1/1	3521.0	11552	9076	7972	9076		pressure
1/2	3550.5	11649	9157	7998	9159		pressure
1/3	3565.9	11699	9201	8000	9200		pressure
1/4	3570.5	11714	9214	8003	9212		pressure
Run No 2	4 pressure tests and two partially successful attempts to obtain formation water. Recovery primarily filtrate.						
2/1	3552.2	11654	8677	8015	8677		pressure
2/2	3606.2	11831	8809	8033	8809		pressure
2/3	3653.5	11987	8922	8060	8922		pressure
2/6	3671.0	12044	8962	8082	8959	partial	sample
2/5	3671.5	12045	8967	8086	8964		sample
2/4	3687.8	12099	9004	8111	9006		pressure
Run No 3	One oil sample attempted and recovered.						
3/1	3524.6	11564	8837	7979	8806		sample
Run No 4	One oil sample attempted and recovered.						
4/1	3576.5	11734	8939	8000	8906		sample
Run No 5	One oil sample attempted and recovered. Three repeats of previous pressure measurements.						
5/1	3637.5	11934	9099	8036	9096		sample
5/2	3576.5	11734	8965	8017	8968		pressure
5/3	3552.2	11654	8906	8018	8908		pressure
5/4	3524.6	11564	8836	7987	8839		pressure

RFT RESULTS Runs 6 through 8

Run No 6 28 tool settings were attempted including four unsuccessful sampling attempts. There were 10 seal failures and most of these are not included in the following listing.

Sample Number	Depth metres	Depth feet	Corrected Pressure (psig) Hydrostatic	Formation	Hydrostatic	Sample type
6/1	3530.5	11582,97	9056	7985	9055	Pressure
6/2	3567.5	11704,36	9148	8004	9148	"
6/3	3654.0	11988,15	9371	8056	9369	"
6/4	3831.5	12570,5	9815	8680	9708	"
6/5	3881.5	12734,54	9946	8876	9938	"
6/6	3929.5	12892,02	10066	TIGHT	10036	2x "
6/7	3930.0	12893,66	10069	8984	10070	"
6/8	4001.0	13126,60	10248	No Seal	10247	2x "
6/9	4001.5	13128,24	10247	TIGHT	10249	3x "
6/10	4145.0	13599,04	10604	No Seal	10603	5x "
6/11	4175.8	13700,09	10688	9700	10685	2x "
6/12	4201.0	13782,76	10752	9769	10750	"
6/13	4238.5	13905,79	10845	9792	10844	"
6/14	4313.0	14150,22	11033	9897	11030	"
6/15	4313.0	14150,22	11031	9897	10999	fluid sample
6/16	4313.0	14150,22	11032	TIGHT	11035	Pressure
6/17	4249.0	13940,24	10868	TIGHT	10868	"

Run No 7 7 tool settings attempted including one failed and one failed and one successful segregated sample attempt.

Sample Number	Depth metres	Depth feet	Hydrostatic	Formation	Hydrostatic	Sample type
7/1	4248.0	13936,96	10872	9905	10853	Pressure
7/2	4229.0	13874,63	10825	TIGHT	10828	2x "
7/3	4210.5	13812,29	10774	No Seal	10777	"
7/4	4176.0	13700,74	10692	9698	10692	Failed Sample
7/5	4109.0	13480,93	10530	9416	10530	Pressure
7/6	3576.0	11732,24	9180	8025	9198	Sample

Run No 8 3 tool settings including one successful segregated sample.

8/1	3524.5	11563,28	9034	7977	8977	Sample
8/2	4248.0	13936,96	10863	9861	10808	Pressure
8/3	4313.0	14150,22	11037	9846	11019	"

Note that although the Schlumberger pressure gauge is rated and tested only to 10000 psi it is capable of reading up to 15000 psi. Correction values for log/gauge measurements higher than 10000 psi were obtained by extrapolating the correction curve beyond the 10000 psi value.

19. Mud Report (Anchor Drilling Fluids)

Summary of Events

36" HOLE/ 30" CASING INTERVAL

The section was drilled with seawater with high viscosity pills of spud mud (Vis: 100 ± sec/qt. yp: 60-65 lb/100 sg ft.) before connections. A 17½ pilot hole was drilled first. Spotted high viscosity Ancovis mud on bottom before running in with the 36" hole opener. On reaching TD, 1864', the hole was displaced with high viscosity mud. Made wiper trip and found tight spots at 1436' and 1940'. Hole needed to be reamed from 1840' - 1864'.

Additional polymer mud was mixed to displace the hole again. Mud wt. 9.2 ppg. Some of the mud became progressively thicker while mixing Barite and appeared to be cross linked. Pilot testing showed that this effect could be reproduced with 0.2 ppb. of cement. Although no cement was found in the Barite afterwards, it would only take a small amount to be left in the lines which had not been used since the last well, (probably for cement plugs) to cause this effect.

The hole was then displaced with 800 bbls prehydrated Bentonite, mud wt. 10.2 ppg after reaming a tight spot at 1620' - 1670' and fill from 1789'-1865'. The hole condition improved on the subsequent wiper trip, but a bridge from 1510' - 1525' required reaming on the way back in, together with the bottom section from 1845' - 1864' (possible fill).

A further 40' of hole was made to compensate for fill before displacing the hole with another 800 bbls of prehydrated Bentonite mud wt. 10.2 ppg.

The 30" casing was held up at 1648' and was washed down to 1700' and then run clean to bottom.

26" HOLE/ 20" CASING INTERVAL

This section was drilled with salt water and viscous pills of Ancovis. The returns were recirculated to allow the build up of a native mud in the 17½" pilot hole and to enable the monitoring of pit volumes. The hole was displaced with 520 bbls of unweighted Ancovis. The hole was clean on the subsequent trip, but logs were held up at 2417'.

The caliper log showed that most of the logged hole was close to gauge. The only washed out section was below the 30" shoe.

The hole was opened to 26" using salt water and viscous pills of Ancovis. At TD the hole was displaced with the remainder of Ancovis, (200 bbls), 50 bbls of salt water and 1100 bbls of prehydrated Bentonite at 10.0 ppg. The hole was clean on the wiper trip.

The 20" casing was landed at 2879' and cemented.

Cleaned out pits and sand traps. Ready to mix up new Drispac system.

17½ " HOLE/ 13 3/8" CASING INTERVAL

Mixed up the Drispac system but drilled out the shoe with sea-water before displacing the hole with Drispac mud. Lost approx. 300 bbls over shakers on bottoms up due to fine sand and polymers plugging the screens. The mud was severly cement contaminated and some of the polymers precipitated out. (pH 12, Ca ++ 1000 ppm). To maintain the volume required a mud consisting of Bentonite/CMC/ XC-Polymer was mixed and used for the rest of the section.

Light additions of Lignosulfonate were used to improve fluids loss and rheology.

Apart from a few tight spots no severe hole problems were encountered in this section. The 17½" hole was drilled to 7206' with a mud weight of 9.9 ppg. Logs were run successfully and casing landed at 7162'. The casing was cemented with partial mud returns. Lost approx. 200 bbls of mud during the displacement of the cement.

Throughout this section all the solids removal equipment was utilized to keep solids at a minimum to reduce chemical additions.

Cleaned out the mud pits and sand traps in order to mix KCL system for the 12 1/4" section.

12 1/4" HOLE/ 9 5/8" CASING INTERVAL

Mixed up the KCL - Lime- Polymer mud as per specification and commenced drilling the 12 1/4" hole.

No real mud problems were encountered in this section. The KCL content in the active system was maintained by continously adding dilution fluid containing 35 - 40 ppb (9-10 0/0) KCL and polymers, rather than adding seawater and dry KCL together with the polymers.

Mud weight was gradually increased to 11.7 ppg at 11493' and then to 13.2 ppg at 11541' due to gas cut mud. Well was flowing and mud weight eventually increased to 13.5 ppg resulting in lost circulation. A 50 bbls LMC pill was spotted at bottom and chased with 300 bbls of 17 ppg mud with no returns.

The well was finally stabilized with a mud weight of 13.4 ppg. A cement plug was set at bottom and well drilled to 11500'.

Logs were run successfully, and the 9 5/8" casing shoe landed at 11475'. Cemented same.

Mud material consumption was high in this interval due to kicks followed by lost circulation. Also mud was lost over gumbo-trap when circulating out gas cut mud.

8½" HOLE/ 7" CASING INTERVAL

Drilled out of the 9 5/8" shoe with the KCL system and performed leak off test equivalent to 16.4 ppg at 11545'.

Started to core at 11557' and cored to 11705' at which point the well started to flow on tripping out of the hole. The mud weight was increased to 15.8 ppg but had to be increased to 18.0 ppg with drill pipe at 6370 in order to kill the well. Ran in the hole to bottom and displaced hole with 15.2 ppg mud, stabilized hole: Reduced mud weight to 15.00 ppg and cored ahead to 11769 where logs were run.

Reduced mud weight to 14.5 ppg at 11809' and further to 14.2 ppg at 12267'. Mud weight was again increased to 14.5 ppg at 12429' and kept at this value to TD.

Logs were run successfully at 12429'.

Drill pipe was stuck at 11462' after several days out of the hole, but came free after spotting Ancho Pipe Free and working pipe loose.

The KCL - Polymer system worked well also in this section, but as the bottom hole temperature began to reach the temperature limitation for the KCL - Polymer system, fluid loss and rheology became increasingly difficult to control. This problem was overcome by dispersing the system with Lignite and Lignosulfonate.

The hole was drilled to 14256' and logged successfully. The 7" liner was run and the shoe landed at 14254'.

The well was then tested before plugged and abandoned.

Recommendations

36" hole 30" Casing.

On drilling this section Ancovis was used as the primary viscosifier for spud mud. Although Ancovis has frequently been used with success on top hole before, this polymer did not give the desired results under the existing hole conditions. We therefore recommend to use prehydrated Bentonite flocculated with Lime on future wells in the area. We also feel that the spud mud should be weighted up to a minimum of 9.5 ppg before running surface pipe.

When Ancovis ploymer mud was returned over shaker back to the pits, problems were experienced in polymers blinding the shaker screens with the relatively large volumes being circulated. Although the pills of Ancovis kept the hole clean, we feel that the problems with the shakers could be avoided by using pre-hydrated Bentonite, flocculated with Lime for additional viscosity if necessary.

As for this 26" hole, we would recommend to keep the mud weight at 10 ppg for future wells in the area.

17½" hole 13 3/8" Casing.

Problems were experienced with polymers (Drispac) precipitating out due to a combination of high pH and calcium content after drilling cement. This problem could have been partially re-solved by more pretreatment with Soda Ash to reduce Ca ++ levels, but the high pH alone (from cement) would still cause large amounts of Drispac to precipitate out. The level of pretreat-ment with Soda Ash is also difficult to decide (too much will leave carbonates in the mud) as the mud engineers do not know how much or how green the cement will be.

To avoid this problem we recommend for future wells, in the area, to use: Seawater - prehydrated Bentonite, CMC and after drilling cement, XC-Polymer for additional viscosity if needed.

12 1/4" hole 9 5/8" Casing.

Pilot testing of the initial KCL- Lime- Polymer mud in the pits showed it would be advantageous to reduce hardness salts in the mud. Therefore the seawater was treated with Soda Ash, and Caustic Soda was used for alkalinity control in both the 12 1/4" and 8½" section.

8½" hole 7" liner

Due to the fact that the KCL - Polymer system had to be dispersed because of high bottom hole temperature, we feel that the reservoir in future wells could be drilled with a prehydrated Bentonite - CMC - Lignosulfonate based mud. In other words the mud from the previous section could be used by letting the KCL content reduce by natural dilution.

However, this is provided geological investigations of the producing formations shows no reactive clays.

If a KCL-Polymer system is preferred the Anchopol (polyacrylamide) should be discontinued (as for this well) before drilling the reservoir to prevent possible plugging of the producing formations. We feel that the KCL/Ancopol system used on this well, proved to be a success. A couple of times, the hole was left open for days, but there was no problem getting back to bottom after these periods. The hole was indeed in a very good shape.

Anchor will therefore strongly recommend the use of a KCL/ Ancopol system for Gulf's future wells in this area.

FORMATION TESTING

Brent Sand; 11,965-11,930 ft, KB

1. DST No. 1

The testing of this interval was performed with a Baker Model "D" packer set at 11,864 feet, KB. The string was run and landed. The string was externally pressure tested at each connection to 7500 psi by use of Gator Hawk and the string was filled with a full water cushion. After the string was run it was internally pressure tested to 5800 psi. The surface lines from the control head to the choke manifold were pressure tested to 7100 psi and the lines from the choke manifold to the separator were tested to 1000 psi.

An Expro (Baker) surface tree and choke manifold with three-inch valves were used to control the well at the surface. The surface tree was equipped with a hydraulically operated valve which could be closed quickly if necessary. Two-inch chicksans connected the surface tree to the choke manifold. A combination two inch-three inch line connected the choke manifold to a Baker heater and single stage, three phase Baker separator. A single three inch line carried both gas and liquid flow from the separator to a Baker burner.

Bottomhole pressure instruments were included in the test string. Three RPG-3 pressure gauges and one recording temperature gauge were included in the bundle carrier. Also two Sperry-Sun temperature and pressure gauges were hung in the tailpipe below the packer

At 0921 hours on 25 December 1980 the annulus was pressurized and at 0923 hours there was 2670 psig on the closed choke manifold. At 0925 the well was opened on a 32/64 inch choke and at 0938 gas surfaced. The pins in the APR-A circulating valve sheared prematurely after about eleven minutes of flow and the tubing was reversed out.

2. DST No. 2

The same test string, surface equipment, water cushion, and testing procedures used for DST No. 1 were used for this test.

This test was opened at 0823 hours on 27 December 1980 against closed valves on the choke manifold. At 0824 hours the pressure at the choke manifold was 2785 psig. At 0824 hours the well was opened to flow on a 32/64 inch choke and at 0839 gas surfaced. It was closed in at the surface at 0841 due to a leak in the burner line. After other delays the well was opened for flow on a 32/64 inch variable choke at 1044 hours. At 1125 hours flow was switched through a 32/64 inch positive choke and at 1156 hours flow was passed through the separator. However, due to a failure of the hydraulic by-pass in the string above the packer the test was aborted at 1235 hours.

3. DST No. 3

Since the hydraulic bypass could not be repaired and another was not available, no hydraulic bypass was used during this test.

The surface equipment and preliminary procedures were the same as those for DST No. 1.

The annulus was pressurized at 0925 hours on 4 January 1981 to open the APR-N test valve, but the valve would not open. The tubing was pressurized to 6000 psi and the APR-N valve opened. At 1016 hours there was 1250 psig on the choke manifold, valves closed. Then the well was initially opened on a variable 28/64 inch choke; the choke was gradually increased until the well was flowing on a 40/64 inch fixed choke at 1222 hours. Flow was directed through the separator at 1245 hours and flow continued until the APR-M valve was sheared at 2120 hours and the tubing was reversed out.

Four sets of separator fluid samples were taken during the stabilized flow period. Each set consisted of one twenty liter gas bottle and one 600 cc liquid sample at separator conditions. Also, two 55-gallon drum and three five-gallon cans of atmospheric liquid samples were taken from the separator.

B. Brent Sand; 11,739-11,697 ft, KB

1. DST No. 4

For this test the Baker Model "D" packer was set at 11,620 feet, KB and the test string was run and landed in it. The surface equipment and preliminary procedures were the same as those for DST Nos. 1 through 3.

The annulus was pressurized at 0929 hours on 8 January 1981. The APR-N valve opened at 0938 hours and at 0939 hours there was 2900 psi on the closed choke manifold. At 0940 the well was opened for flow on a 14/64 inch variable choke; this choke was gradually increased to a 50/64 inch. The 50/64 inch was too large for critical flow so the well was placed on a 48/64 inch fixed choke at 1100 hours. Flow was directed through the separator at 1205 and flow was continued until the APR-M valve was sheared at 1609 hours.

The test was not flowed as long as planned for two reasons. The pressure on the control line to the valves on the subsea test tree dropped at 1303 hours. Large quantities of oil was pumped to maintain a pressure to keep the valves in the subsea test tree open. If it had been a washout in the downhole equipment, the valve might have closed at any time.* Also, the weather and the heave were approaching the maximum level for testing. Hence, as soon as the desired samples were obtained the test was reversed out. The same series of samples were collected at equilibrium separator conditions as were collected for DST No. 3.

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* After completion of the testing the subsea test tree was dismantled in Expro's shop. They found that the hydraulic control line was completely severed in several places and its valves did not close during the test because of debris plugging its hydraulic system.

ANALYTICAL METHODS

Flow rate and bottomhole pressure data collected by Expro, Halliburton, and Sperry Sun during the flow and buildup periods were analyzed to determine well and reservoir properties for each of the two intervals that were perforated. Due to the rapidity at which bottomhole pressure stabilized during the flow period no well or reservoir properties could be calculated for the drawdown data. The bottomhole pressure data obtained from the buildup periods of each of the tests were analyzed by the Horner method. Since all bottomhole pressures were above 7000 psi, both buildup plots were constructed by plotting shut-in bottomhole pressure versus log $(T + \Delta T)/\Delta T$. These buildup plots appear in Figures 58 and 59

Due to the relatively small volumes of reservoir fluids produced during all testing, the P* from the extrapolated Horner plots were taken as good estimates for static reservoir pressure.

DISCUSSION OF RESULTS

A. Brent Sand; 11,965-11,930 feet, KB; DST Nos. 1, 2, and 3

The test string was run into the hole three times before a test was obtained on this interval. For each test three RPG-3 pressure gauges were included in the bundle carrier; their sensing depth was 11,854 feet, KB. Pressure data was obtained from all three gauges for all three runs. Also, two Sperry Sun pressure gauges were run with each test; their sensing depths

DATE	TIME	SAMPLE NUMBER	BOTTLE NUMBER	VOLUME	NATURE FLUID	S.G/ API	SAMPLING POINT	OBSERVATIONS:DST NO.. PERFS. 11931'-11960'
4.1.81	1605hrs.	1	TX23-335	600cc	Oil	44.5	Sep.oil line	Companion PVT Samples
"	"	2	TX22-238	20 litres	Gas	0.654	Sep.gas line	
"	1655hrs.	3	TX23-344	600cc	Oil	44.5	Sep.oil line	Companion PVT Samples
"	"	4	TX22-240	20 litres	Gas	0.652	Sep.gas line	
"	1750hrs.	5	TX23-343	600cc	Oil	44.5	Sep. oil line	Companion PVT Samples
"	"	6	TX22-231	20 litres	Gas	0.652	Sep. gas line	
"	1835hrs.	7	TX23-217	750cc	Oil	44.5	Sep. oil line	Companion PVT Samples
"	"	8	TX22-232	20 litres	Gas	0.654	Sep. gas line	
"	1945hrs.	9		5 gals.	Oil	44.5	Sep. oil line	Bulk Sample jerry cans
"	"	10		5 gals.	Oil	44.5	Sep. oil line	
"	2010hrs.	11		50 gals.	Oil	44.5	Sep. oil line	Bulk Sample Drums
"	"	12		50 gals.	Oil	44.5	Sep. oil line	
"	2103hrs.	13		2 gals.	Oil	44.5	Sep. oil line	Plastic container

DATE	TIME	SAMPLE NUMBER	BOTTLE NUMBER	VOLUME	NATURE FLUID	S.G/°API	SAMPLING POINT	OBSERVATIONS: DST NO. 4 PERFS:11,699 ft. - 11,732 ft.
8.1.81	1335 HRS.	14	TX23-206	800cc	OIL	47.5	SEP. OIL LINE	COMPANION PVT SAMPLES
"	" "	15	TX22-290	20 litres	GAS	0.642	SEP. GAS LINE	
"	1405 HRS.	16	TX23-79	600cc	OIL	47.5	SEP. OIL LINE	COMPANION PVT SAMPLES
"	" "	17	TX22-15	20 litres	GAS	0.642	SEP. GAS LINE	
"	1435 HRS.	18	TX23-113	800cc	OIL	45.6	SEP. OIL LINE	COMPANION PVT SAMPLES
"	" "	19	TX22-230	20 litres	GAS	0.642	SEP. GAS LINE	
"	1505 HRS.	20	TX23-106	800cc	OIL	45.6	SEP. OIL LINE	COMPANION PVT SAMPLES
"	" "	21	TX22-236	20 litres	GAS	0.642	SEP. GAS LINE	
"	1540 HRS.	22		5 galls.	OIL	45.6	SEP. OIL LINE	BULK SAMPLE JERRY CANS
"	" "	23		5 galls.	OIL	45.6	SEP. OIL LINE	
"	1545 HRS.	24		2 galls.	OIL	45.6	SEP. OIL LINE	
"	1601 HRS.	25		55 galls.	OIL	45.6	SEP. OIL LINE	BULK SAMPLE DRUMS
"	" "	26		55 galls.	OIL	45.6	SEP. OIL LINE	

J. SHAND

Saga Petroleum a.s.

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Title

GEOCHEMICAL DATA REPORT FOR WELL 35/8-1

Authors(s)

IDAR HORSTAD

Abstract

Sixteen samples from the cored interval in well 35/8-1 have been analysed by Iatroscan (TLC-FID) and the saturated hydrocarbon fractions from three samples were analysed by GC-FID and GC/MS.

Key Words

35/8-1, geochemistry, GC-FID, GC/MS

Classification: ☐ Free ☒ Saga and partners ☐ Internal ☐ Confidential ☐ Strictly confidential

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1 Objectives

The objective of this study was to characterise the extractable hydrocarbons in 16 core samples from well 35/8-1.

2 General well information

The well was drilled by Gulf as operator of licence 058 from 27/7-80 to24/1-81 and reached a total depth of 4352 mRKB. The KB of the rig was 25 metres and the water depth was 377 metres.

3 Samples and analytical scheme

15 samples were picked from the cored interval in the well on the 23rd of July 1992 at NPD's store in Stavanger. All samples were analysed by Iatroscan (TLC-FID), and the saturated hydrocarbon fraction from three samples (3533.9, 3572.4 and3647 mRKB core depth) were analysed by GC-FID and GC/MS.

4 Vitrinite reflectance

No samples were analysed.

5 TOC and Rock Eval

No samples were analysed.

6 Iatroscan (TLC-FID)

15 samples were analysed, and the results are tabulated in Table 1.

7 GC-FID

The saturated hydrocarbon fractions from three samples (3533.9, 3572.4 and3647 mRKB core depth) were analysed by GC-FID.

Since the evaporative loss has affected the relative concentration of individual compounds, no ratios were calculated.

The GC-FID chromatograms are shown in figure 1.

8 GC/MS

The saturated hydrocarbon fractions from the samples were analysed by GC/MS and the mass chromatograms for m/z 191, 177, 217 and 218 are shown in figure 2.

Selected biological marker parameters are given in table 2.

9 Stable carbon isotopes

No samples were analysed.

Tab. 1

0 WELL NAME	1 NATIONALITY	2 LABORATORY	3 U.DEPTH	4 L.DEPTH	5 SAMPLE TYPE	6 LITHOLOGY	7 EOM mg/g
1 35/8-1	NOR	SAGA	3523.50	3523.50	CCP	SST	1.93
2 35/8-1	NOR	SAGA	3532.00	3532.00	CCP	SST	1.60
3 35/8-1	NOR	SAGA	3533.90	3533.90	CCP	SST	4.05
4 35/8-1	NOR	SAGA	3539.50	3539.50	CCP	SST	1.40
5 35/8-1	NOR	SAGA	3546.40	3546.40	CCP	SST	2.23
6 35/8-1	NOR	SAGA	3547.30	3547.30	CCP	SST	1.42
7 35/8-1	NOR	SAGA	3564.90	3564.90	CCP	SST	1.25
8 35/8-1	NOR	SAGA	3568.00	3568.00	CCP	SST	1.87
9 35/8-1	NOR	SAGA	3572.40	3572.40	CCP	SST	2.28
10 35/8-1	NOR	SAGA	3581.40	3581.40	CCP	SST	2.48
11 35/8-1	NOR	SAGA	3597.10	3597.10	CCP	SST	1.13
12 35/8-1	NOR	SAGA	3629.90	3629.90	CCP	SST	1.80
13 35/8-1	NOR	SAGA	3632.60	3632.60	CCP	SST	0.67
14 35/8-1	NOR	SAGA	3639.80	3639.80	CCP	SST	1.75
15 35/8-1	NOR	SAGA	3647.00	3647.00	CCP	SST	2.60
16 35/8-1	NOR	SAGA	3657.80	3657.80	CCP	SST	1.86

0 WELL NAME		8 SAT (mg/g)	9 ARO (mg/g)	10 POL (mg/g)	11 SAT %	12 ARO %	13 POLARS %	14 SAT ARO	15 METHODS
1	35/8-1	1.55	0.34	0.04	80.458225	17.429079	2.112696	4.616321	Iatroscan
2	35/8-1	1.32	0.24	0.04	82.623693	14.735139	2.641168	5.607256	Iatroscan
3	35/8-1	3.34	0.60	0.10	82.533010	14.939200	2.527791	5.524594	Iatroscan
4	35/8-1	1.17	0.16	0.07	83.877816	11.396613	4.725572	7.359890	Iatroscan
5	35/8-1	1.90	0.25	0.08	85.061917	11.149045	3.789038	7.629525	Iatroscan
6	35/8-1	1.16	0.18	0.08	81.595688	12.846956	5.557356	6.351364	Iatroscan
7	35/8-1	1.03	0.23	0.00	81.795752	18.204248	0.000000	4.493223	Iatroscan
8	35/8-1	1.52	0.28	0.08	81.048711	14.913939	4.037349	5.434427	Iatroscan
9	35/8-1	1.95	0.26	0.07	85.612401	11.438285	2.949315	7.484724	Iatroscan
10	35/8-1	1.91	0.31	0.25	77.146534	12.646678	10.206788	6.100142	Iatroscan
11	35/8-1	0.87	0.13	0.12	77.607210	11.327930	11.064861	6.850962	Iatroscan
12	35/8-1	1.55	0.24	0.00	86.477126	13.522874	0.000000	6.394878	Iatroscan
13	35/8-1	0.41	0.07	0.19	60.881553	10.187300	28.931147	5.976221	Iatroscan
14	35/8-1	1.24	0.20	0.30	71.156791	11.382839	17.460370	6.251234	Iatroscan
15	35/8-1	1.99	0.32	0.28	76.802380	12.281082	10.916537	6.253714	Iatroscan
16	35/8-1	1.40	0.25	0.20	75.738574	13.466851	10.794574	5.624075	Iatroscan

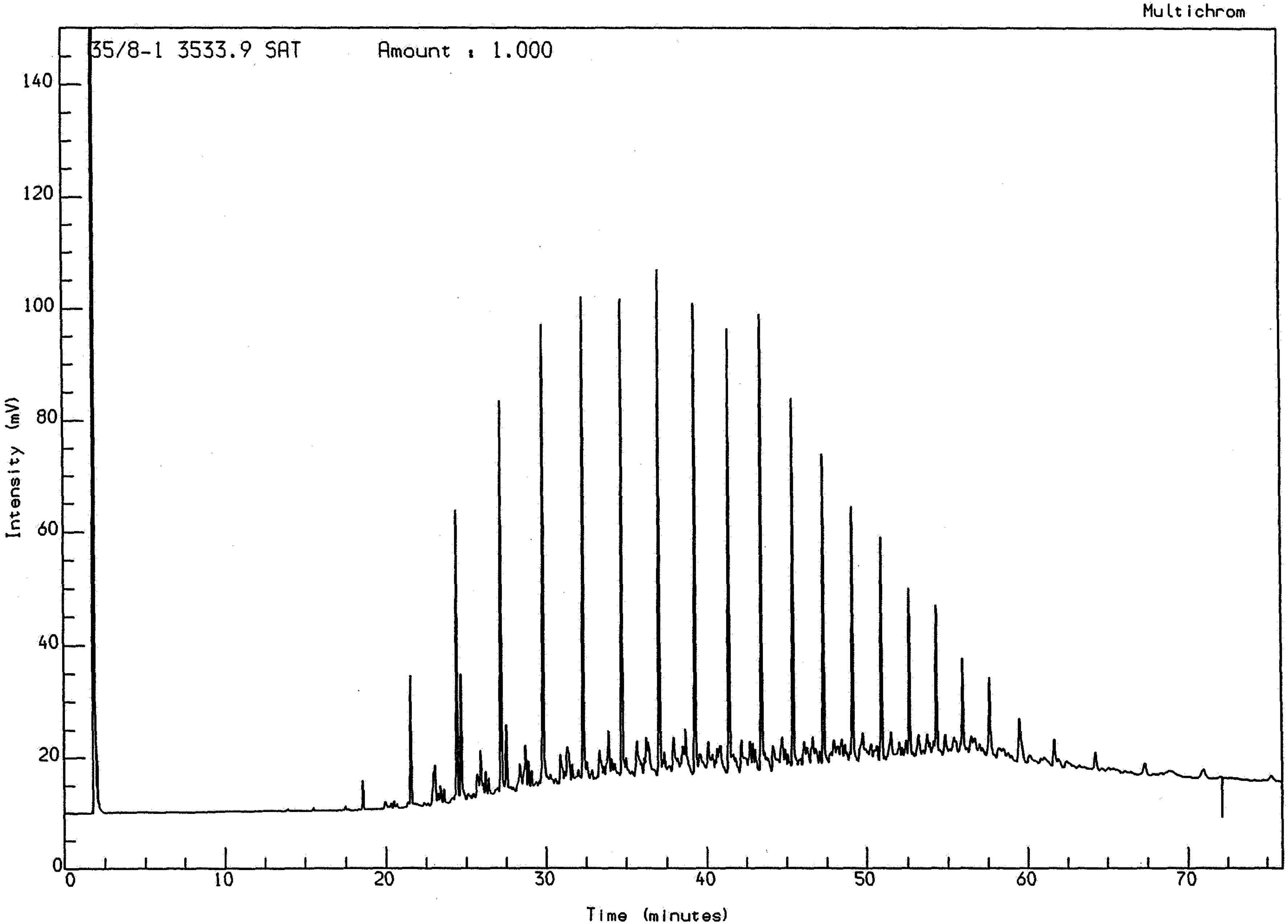
Tab. 2

0 WELL NAME	1 CONS.	2 UPPER DEPTH	3 DEPTH	4 LITH	5 SAMPLE TYPE	6 Q/E	7 Ts/Tm	8 Z/C	9 ab/ab+ba
1 35/8-1	SAGA_RR	3533.90	3533.90	SST	CCP	0.38	1.04	0.15	0.89
2 35/8-1	SAGA_RR	3572.40	3572.40	SST	CCP	0.51	1.11	0.15	0.89
3 35/8-1	SAGA_RR	3647.00	3647.00	SST	CCP	0.28	1.27	0.20	0.90

0 WELL NAME	10 %22S	11 %20S	12 %bb	13 a/a+j	14 C27st	15 C28st	16 C29st
1 35/8-1	0.58	0.56	0.60	0.90	32.44	29.08	38.48
2 35/8-1	0.58	0.55	0.60	0.89	33.49	28.98	37.53
3 35/8-1	0.58	0.56	0.60	0.90	33.26	30.75	35.99

Fig. 1

Analysis Name : [DEF⌈⌉^JECT] 3 S091,3,1.



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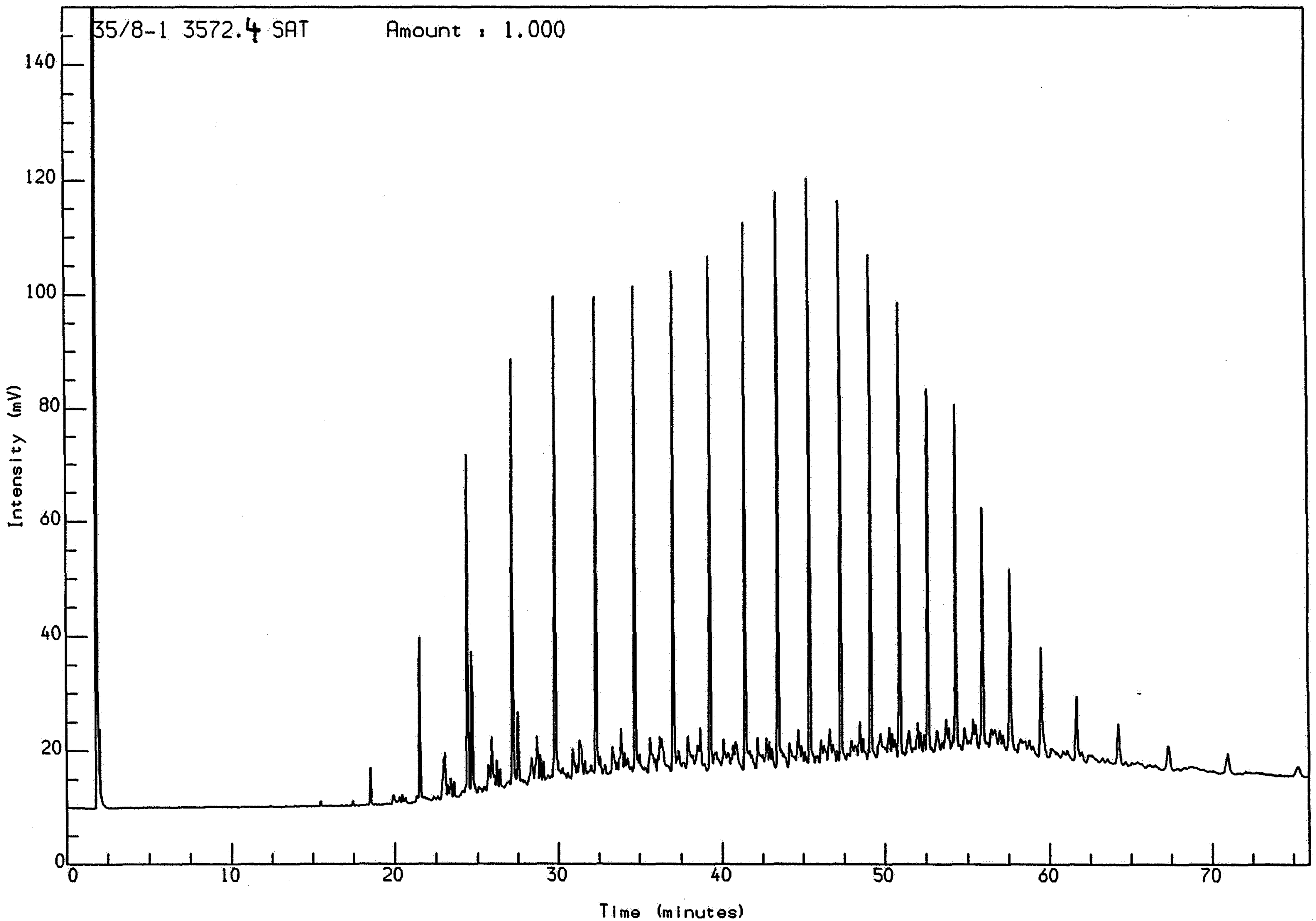
Reported on 9-SEP-1992 at 10:30

Analysis Name : [DEFF JECT] 3 S091,4,1.

Multichrom



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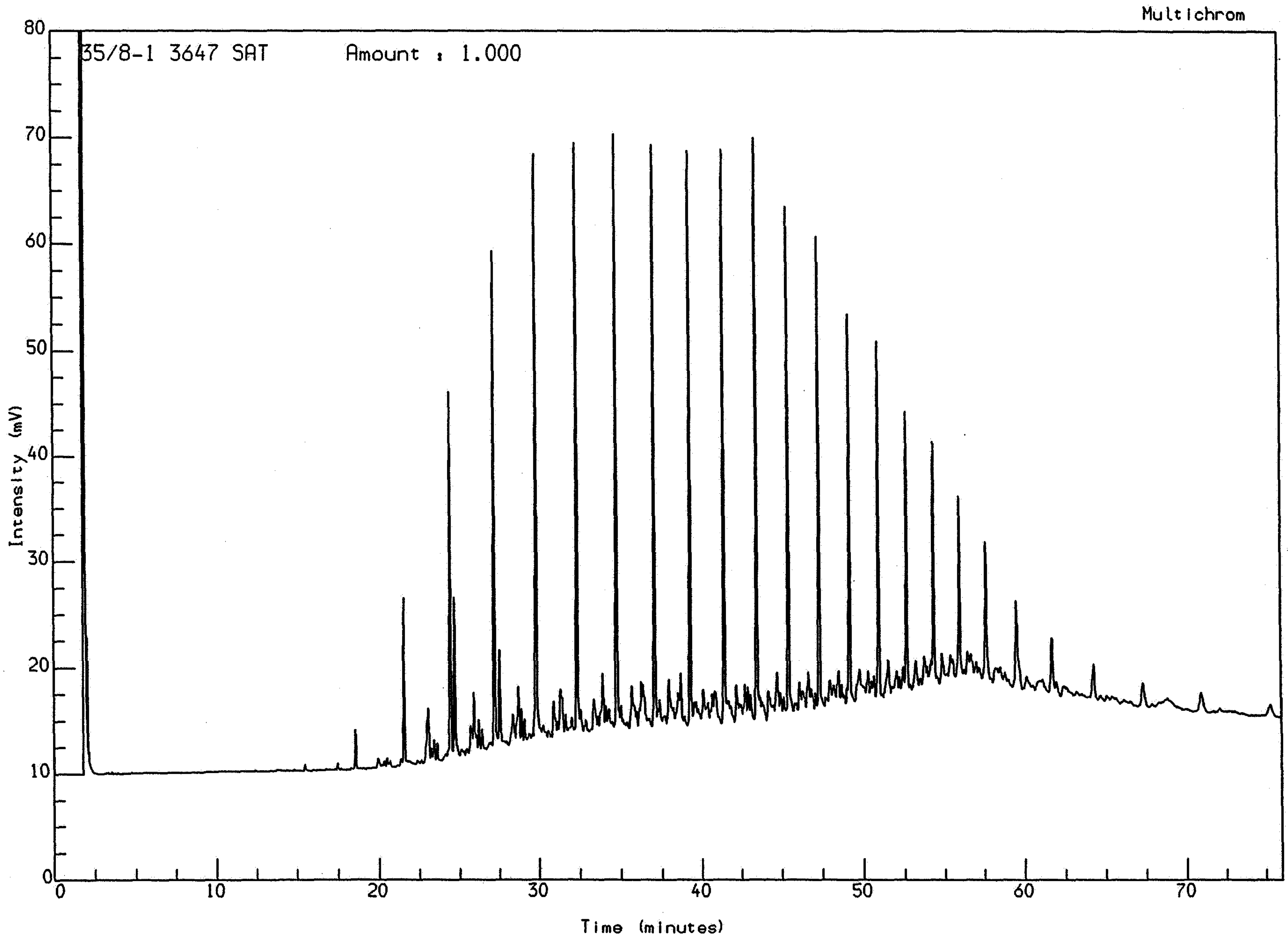
Analysis Name : [DEF``JECT] 3 S091,5,1.



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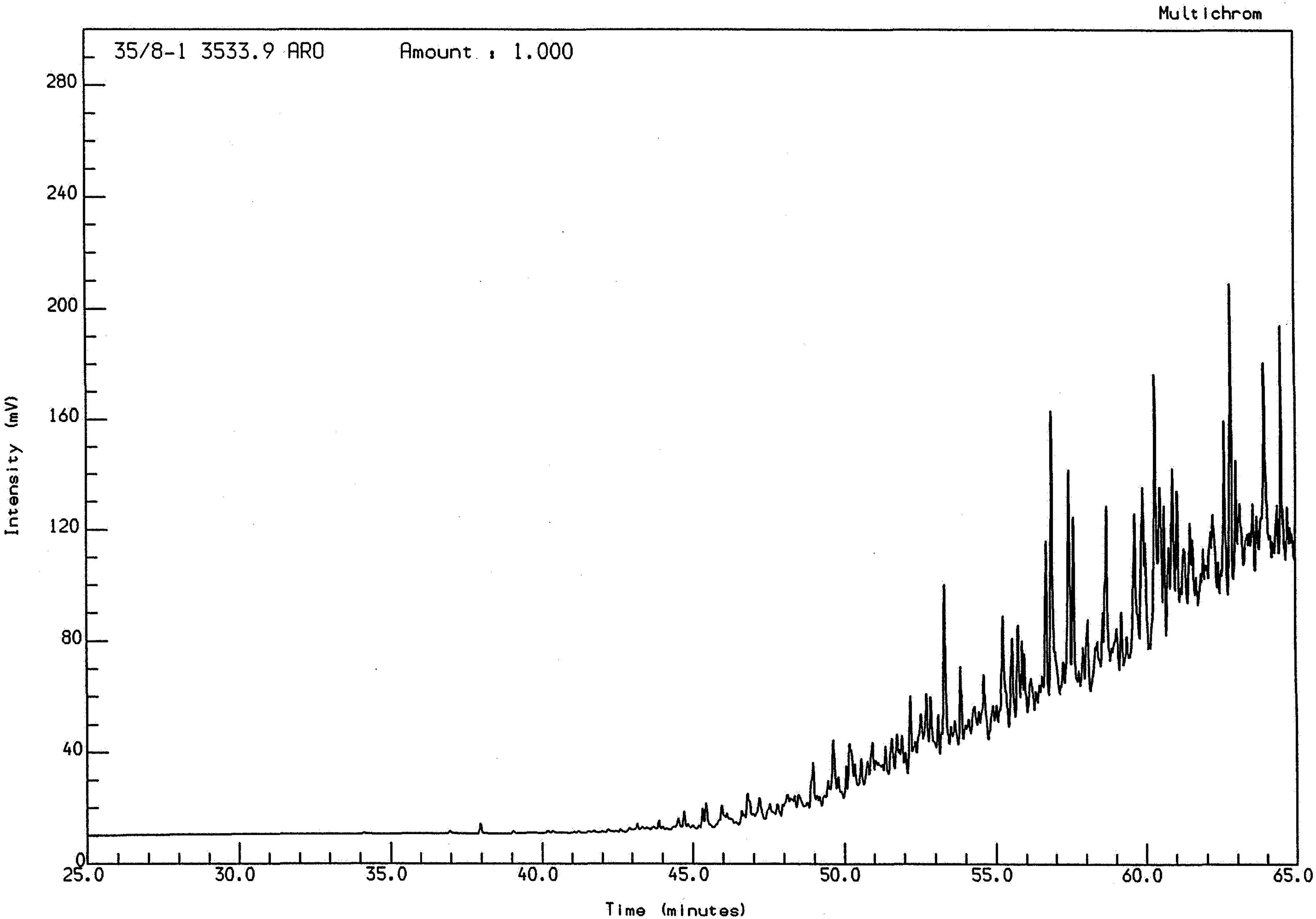

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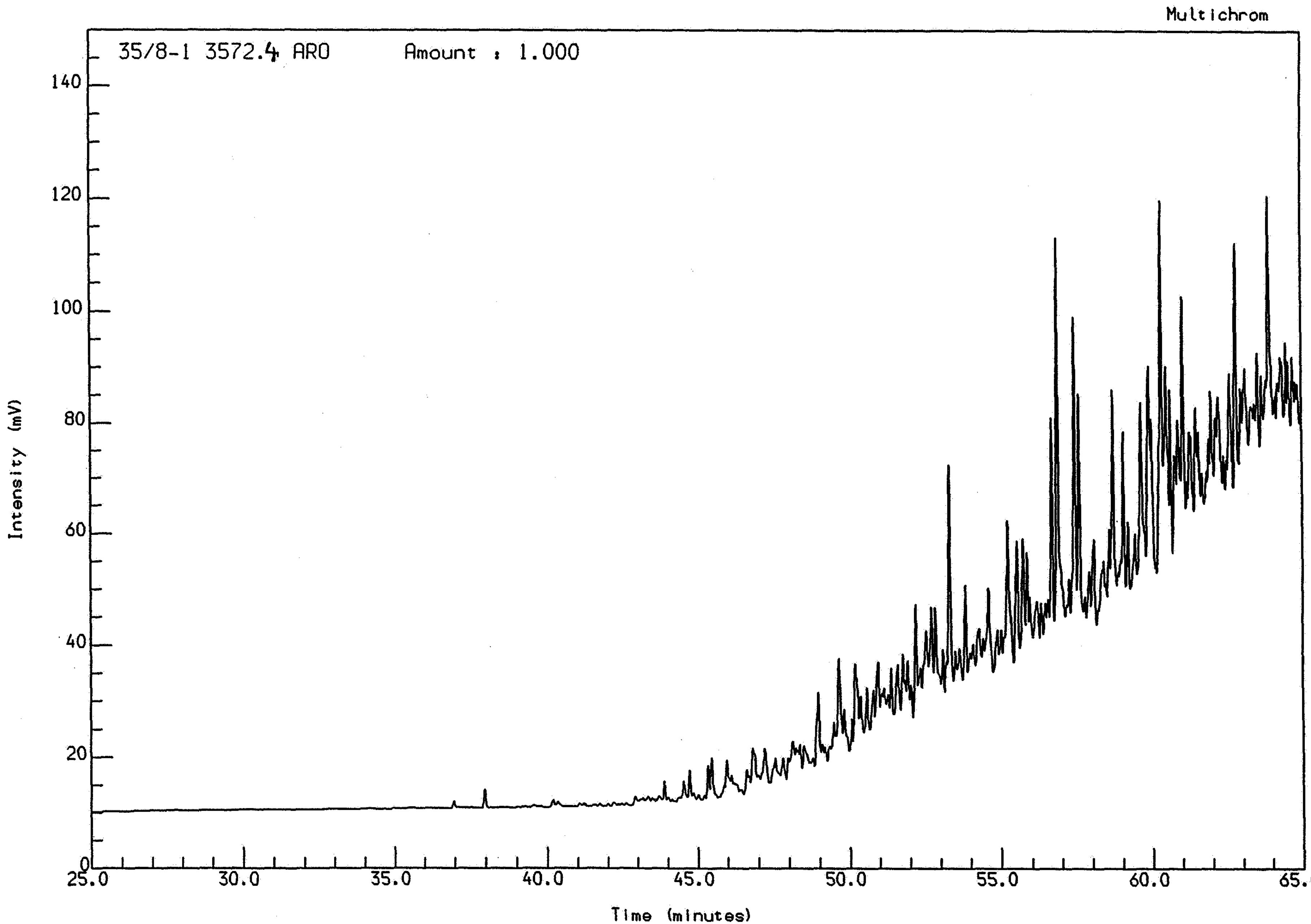
Reported on 9-SEP-1992 at 10:16

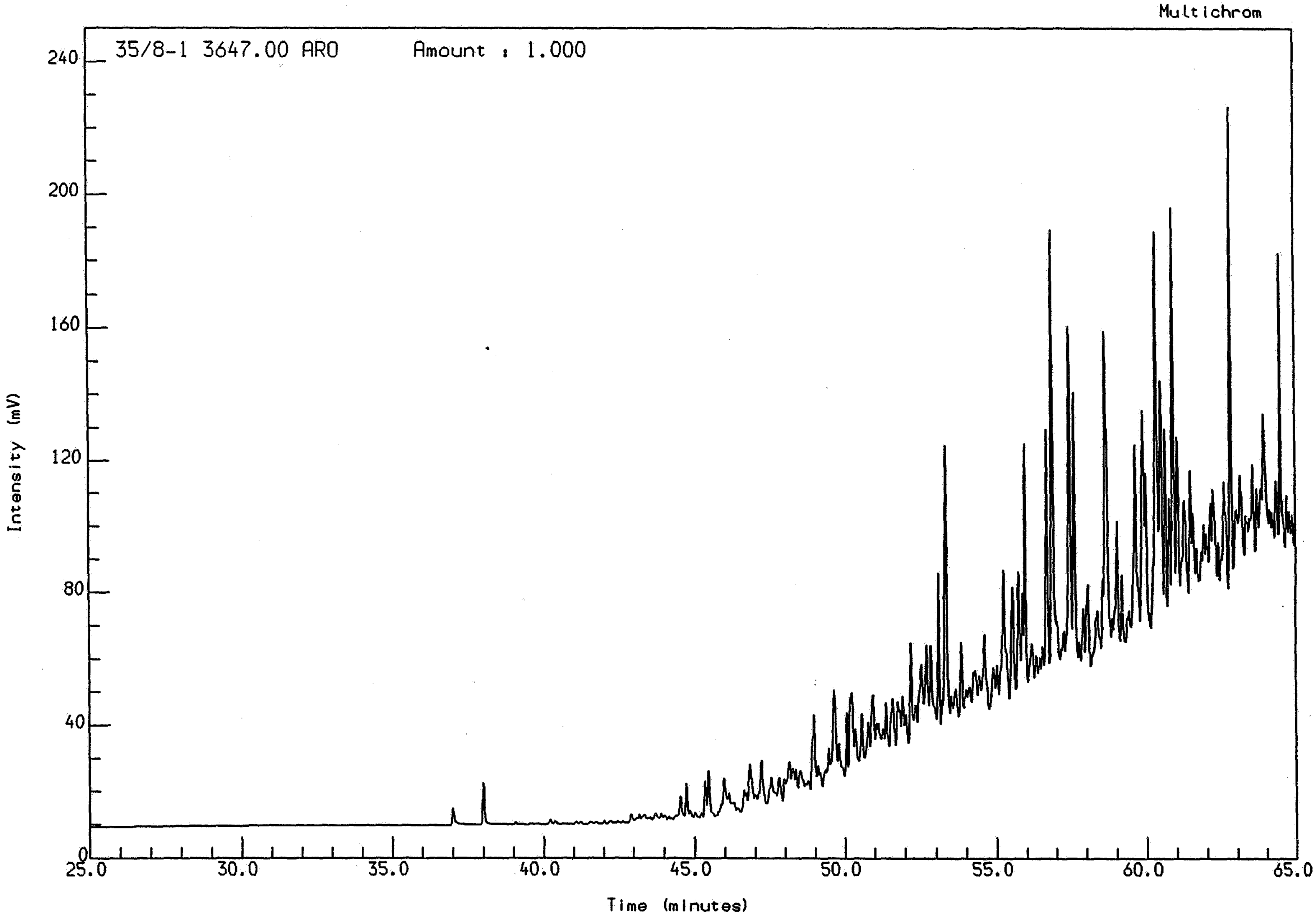
Analysis Name : [DEFF^^JECT] 1 A146,6,1.



Acquired on 4-SEP-1992 at 20:55

Reported on 9-SEP-1992 at 10:17

Analysis Name : [DEFF ^JECT] 1 A148,2,1.



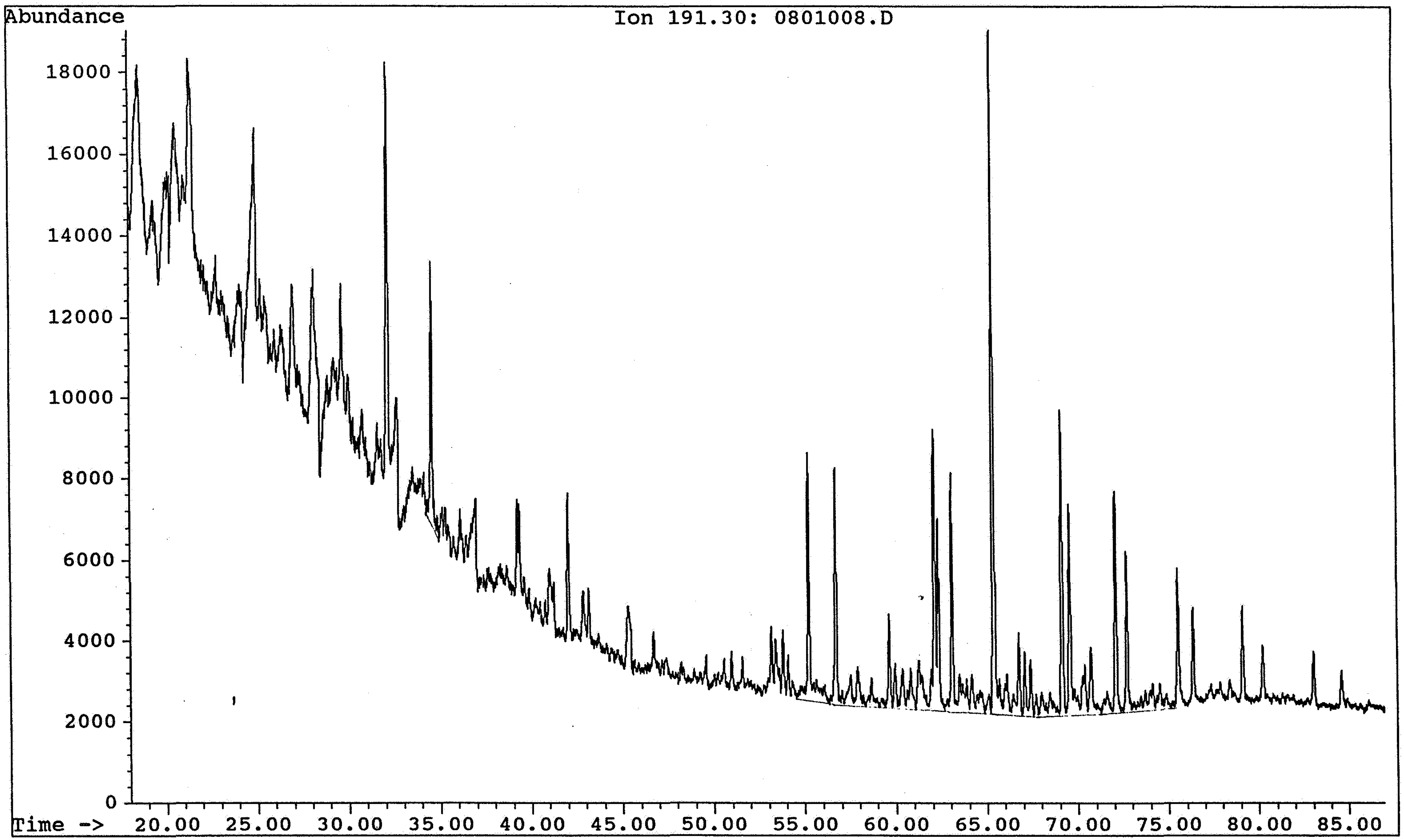
Acquired on 10-SEP-1992 at 14:10

Reported on 11-SEP-1992 at 10:07

Fig. 2

Saga Petroleum a.s. ate acquired: 18 Nov 92 10:18 pm
File: C:\CHEMPC\DATA\35CORE_R\0801008.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3533,9 SAT



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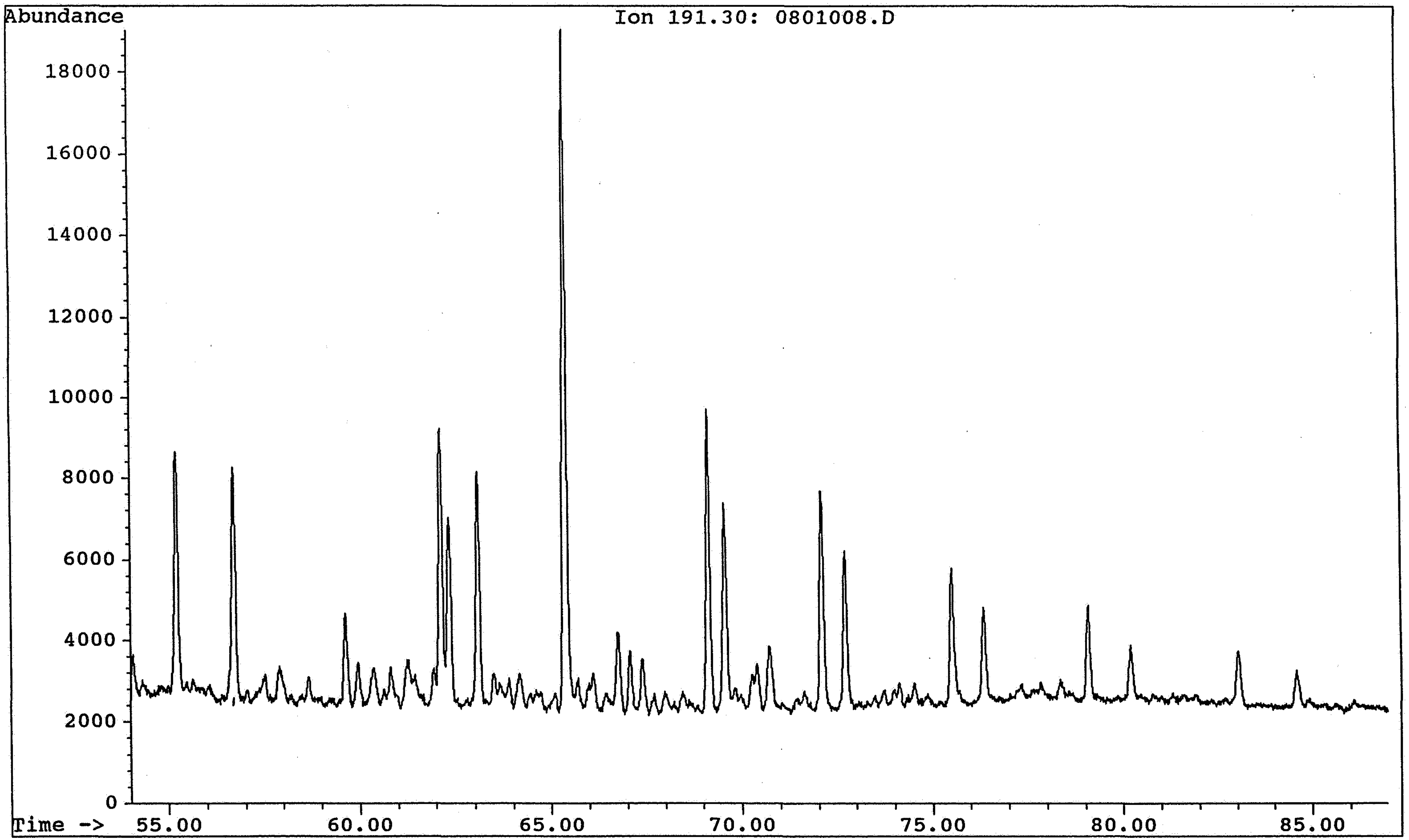
Sample name: WELL 35/8-1 3533,9 SAT



Saga Petroleum a.s. ate acquired: 18 Nov 92 10:18 pm
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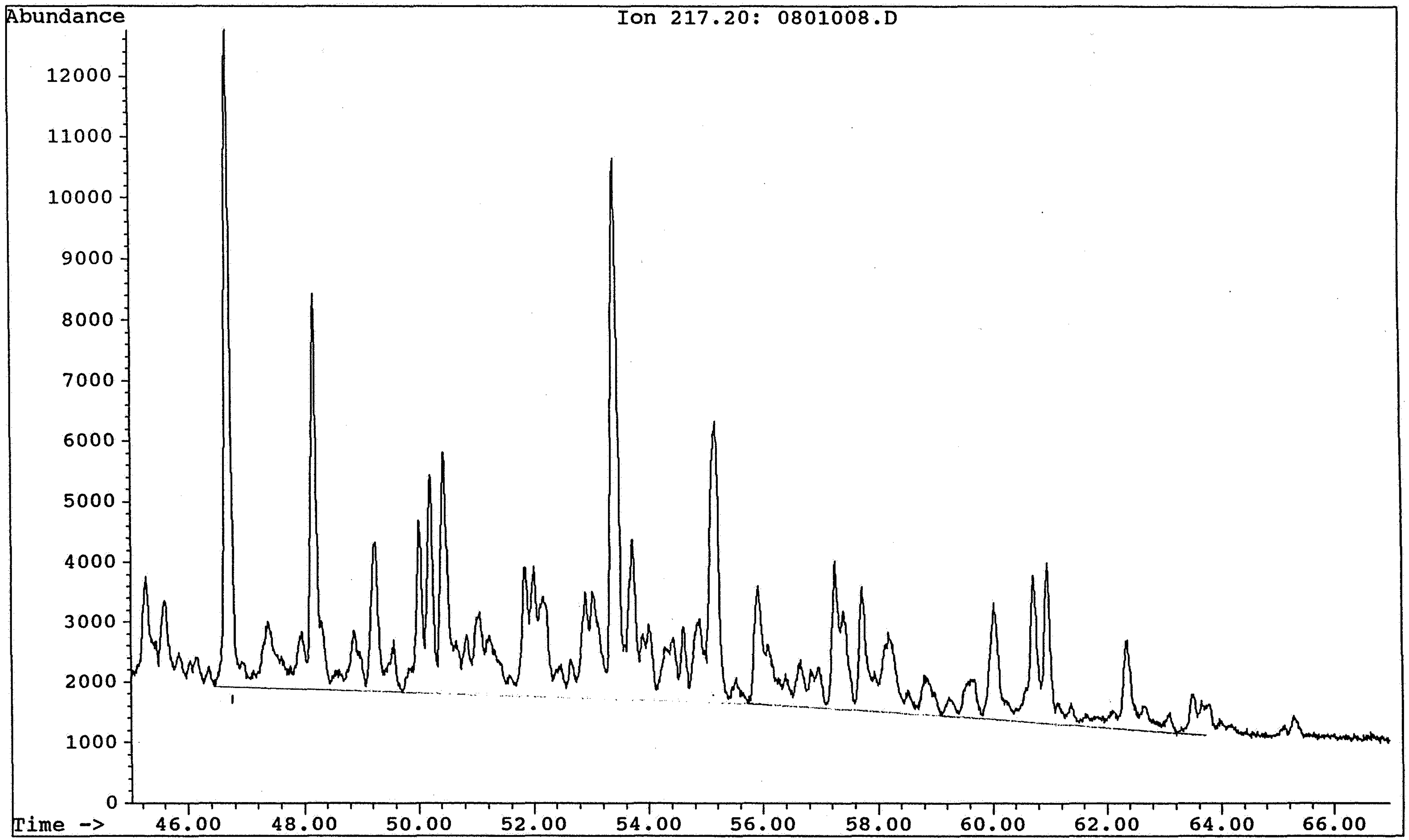
Sample name: WELL 35/8-1 3533,9 SAT



Saga Petroleum a.s. Date acquired: 18 Nov 92 10:18 pm
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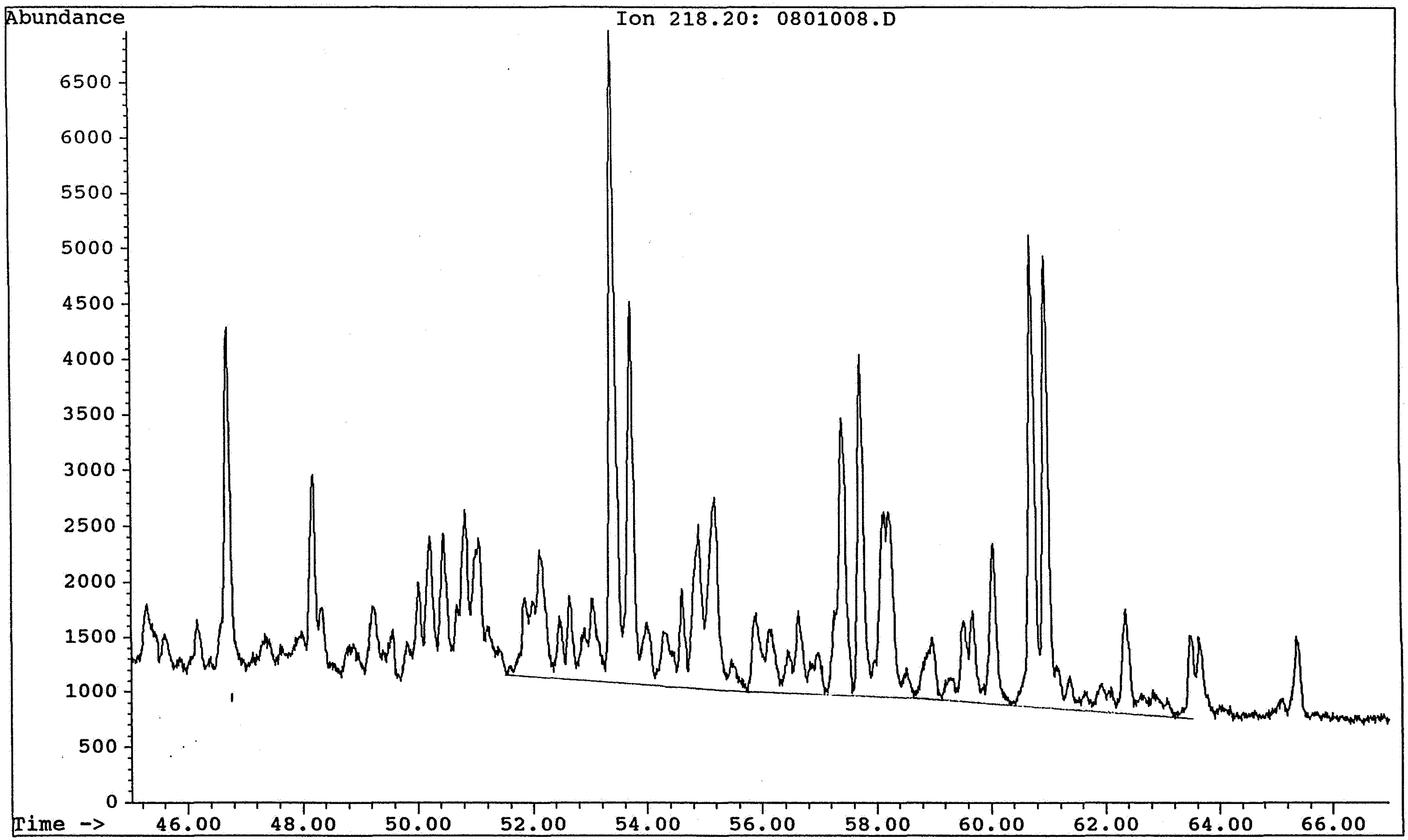
Sample name: WELL 35/8-1 3533,9 SAT



Saga Petroleum a.s. Date acquired: 18 Nov 92 10:18 pm
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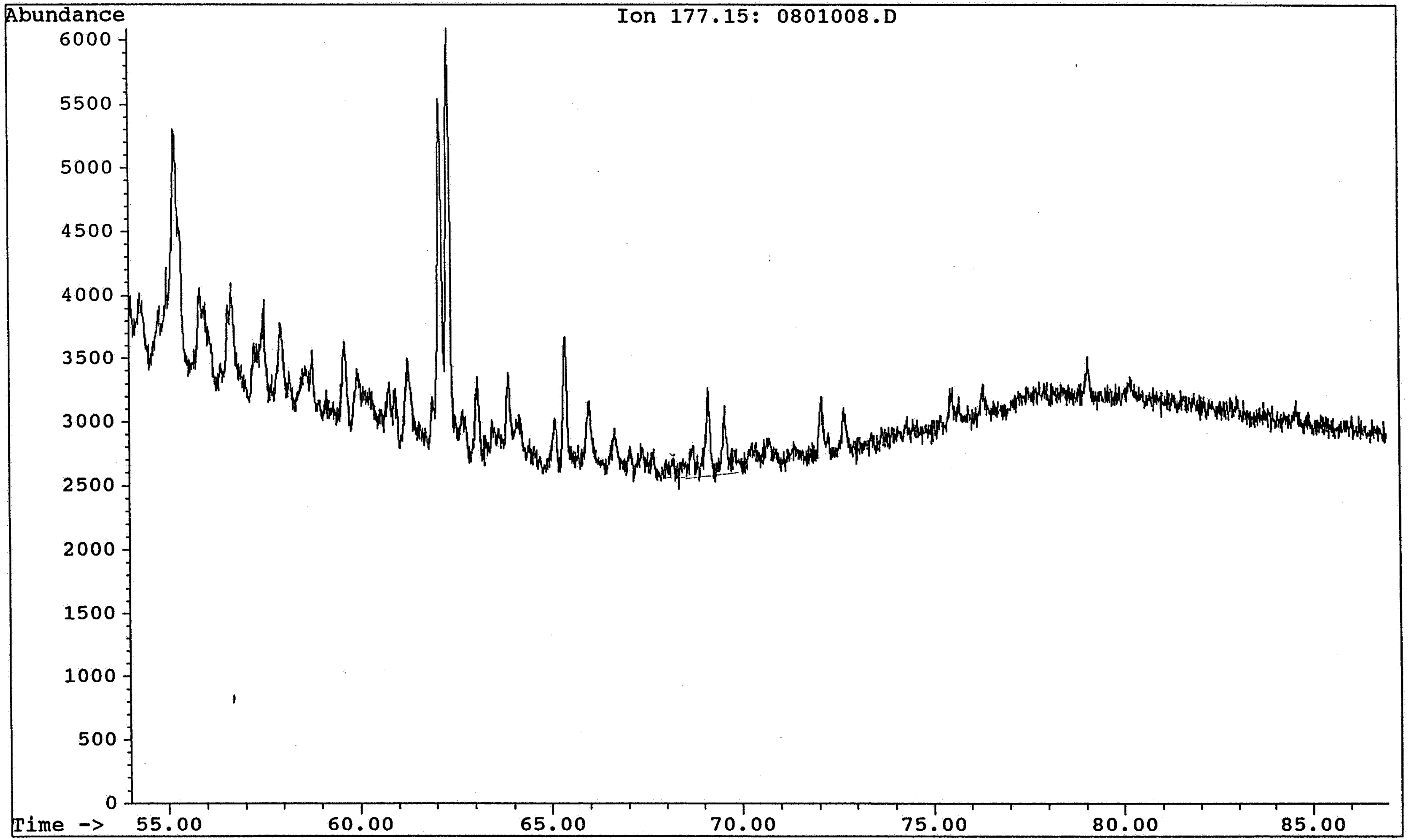
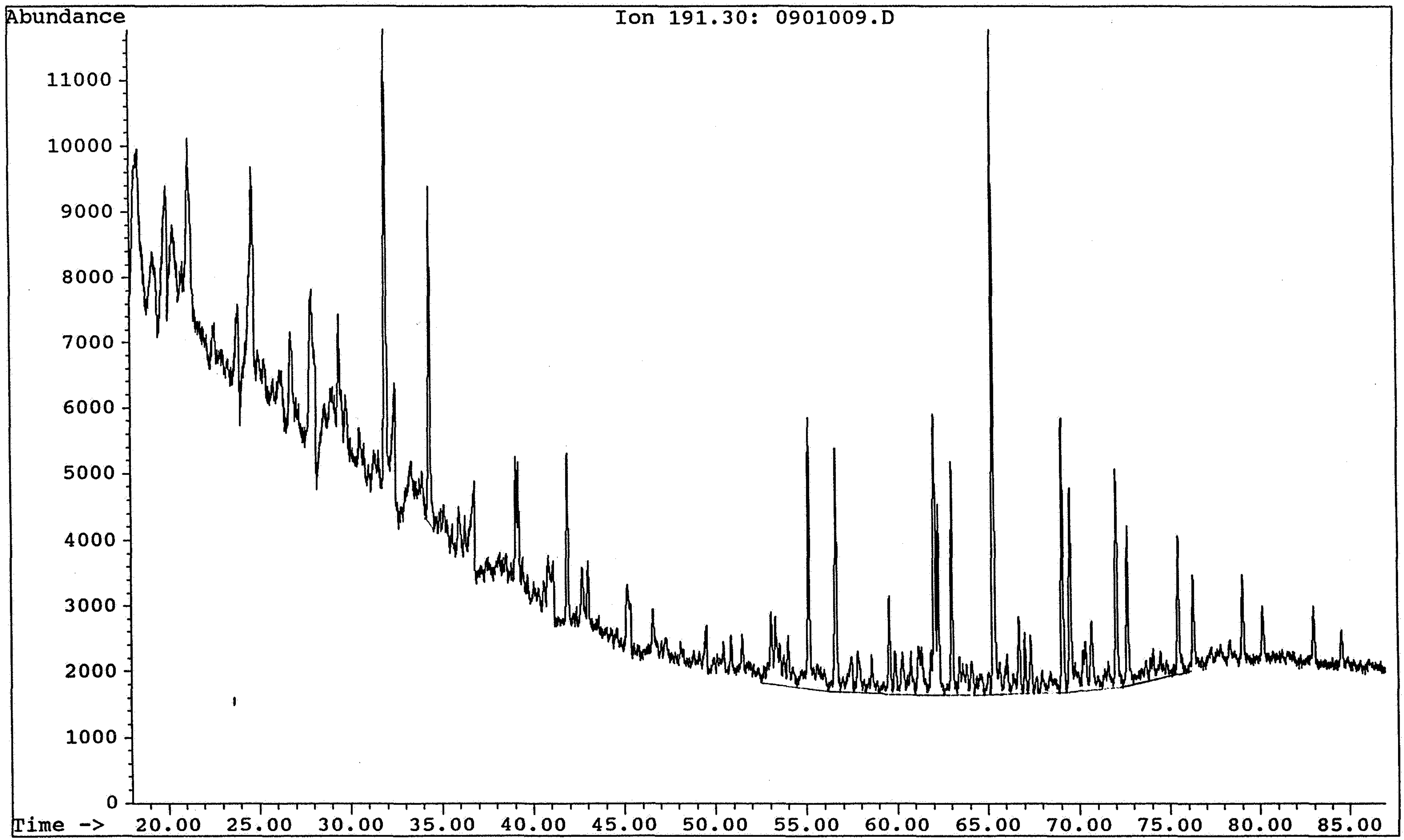
Sample name: WELL 35/8-1 3533,9 SAT



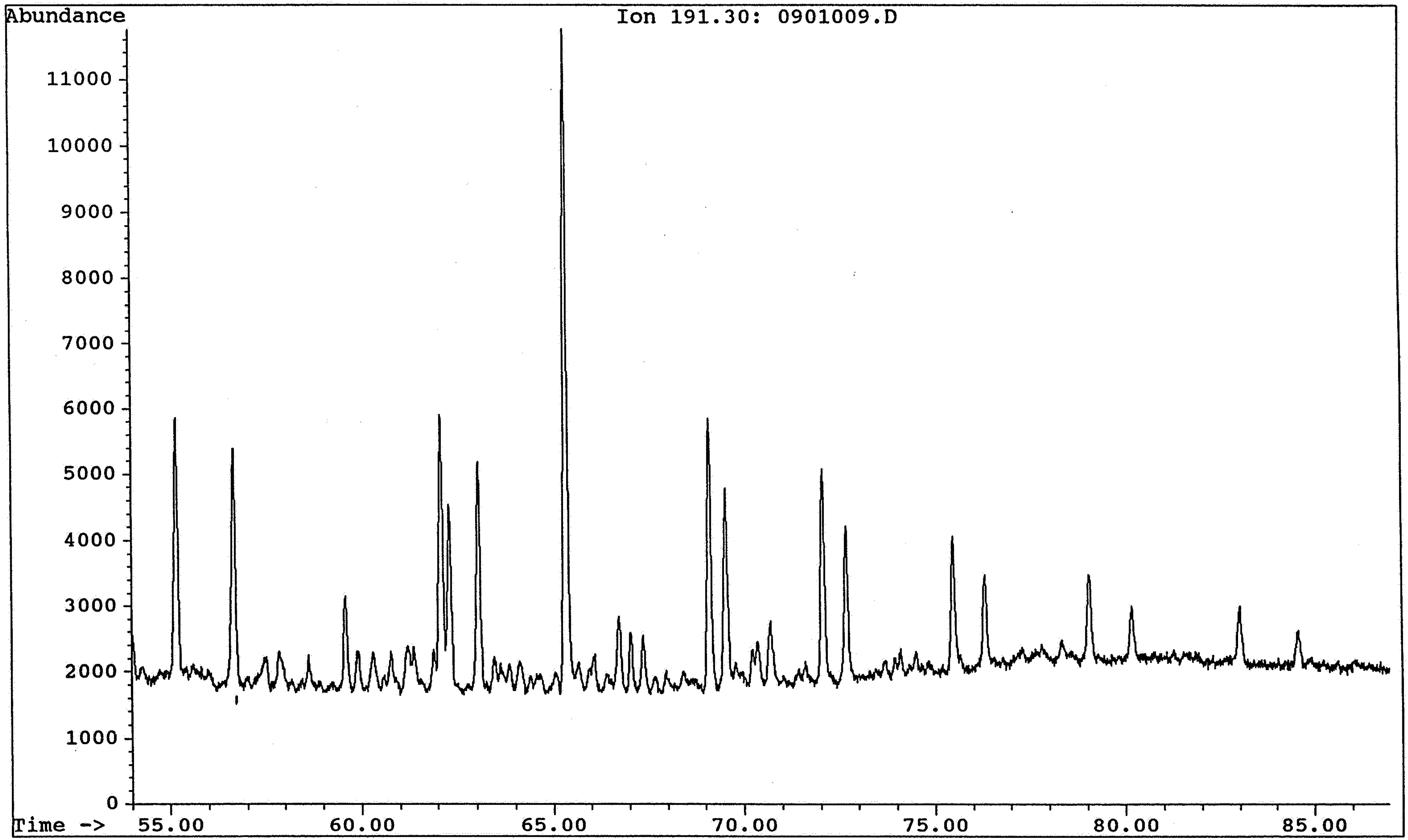
Saga Petroleum a.s. .te acquired: 19 Nov 92 0:01 am
File: C:\CHEMPC\DATA\35CORE_R\0901009.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3572,4 SAT



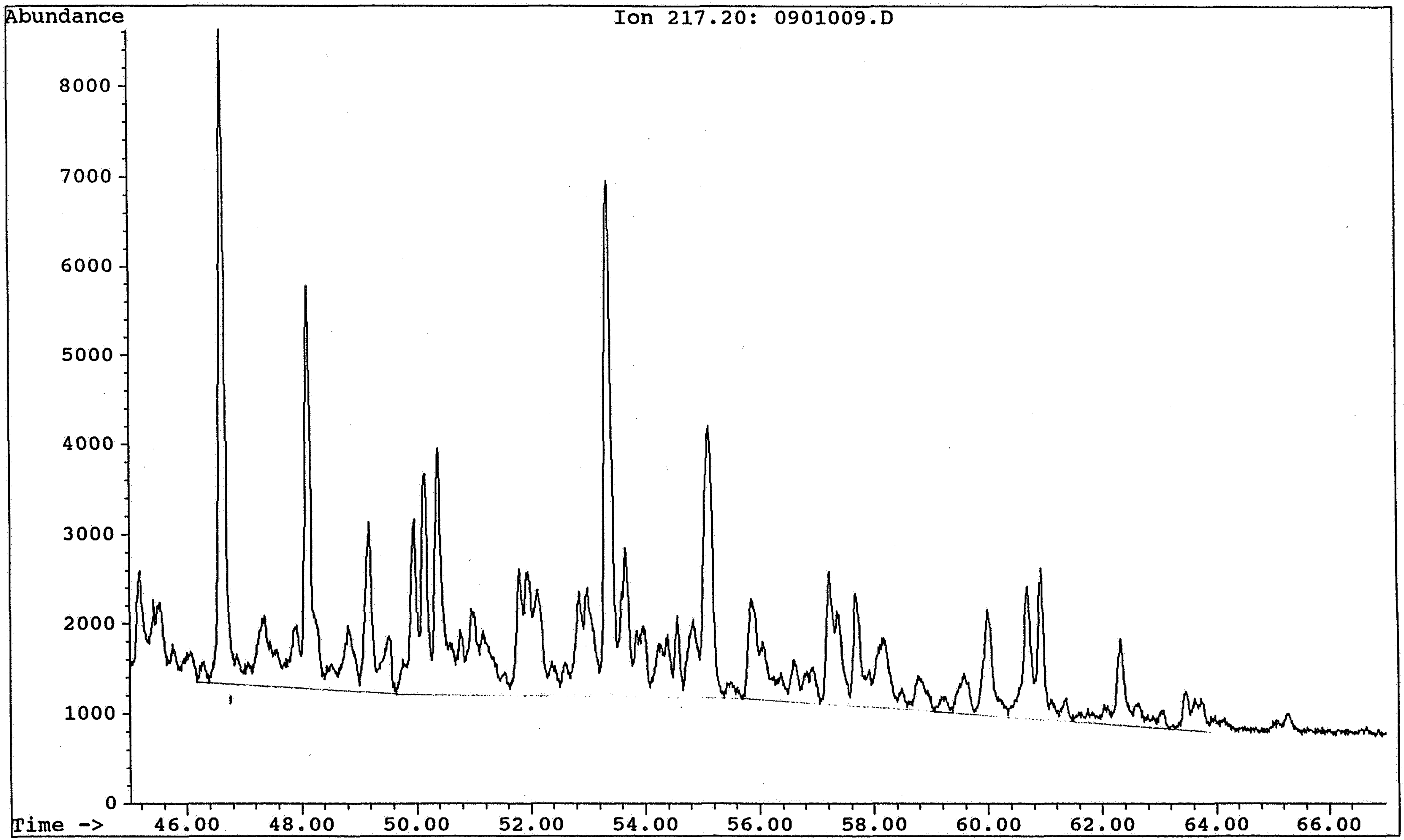
Saga Petroleum a.s. .te acquired: 19 Nov 92 0:01 am
File: C:\CHEMPC\DATA\35CORE_R\0901009.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3572,4 SAT



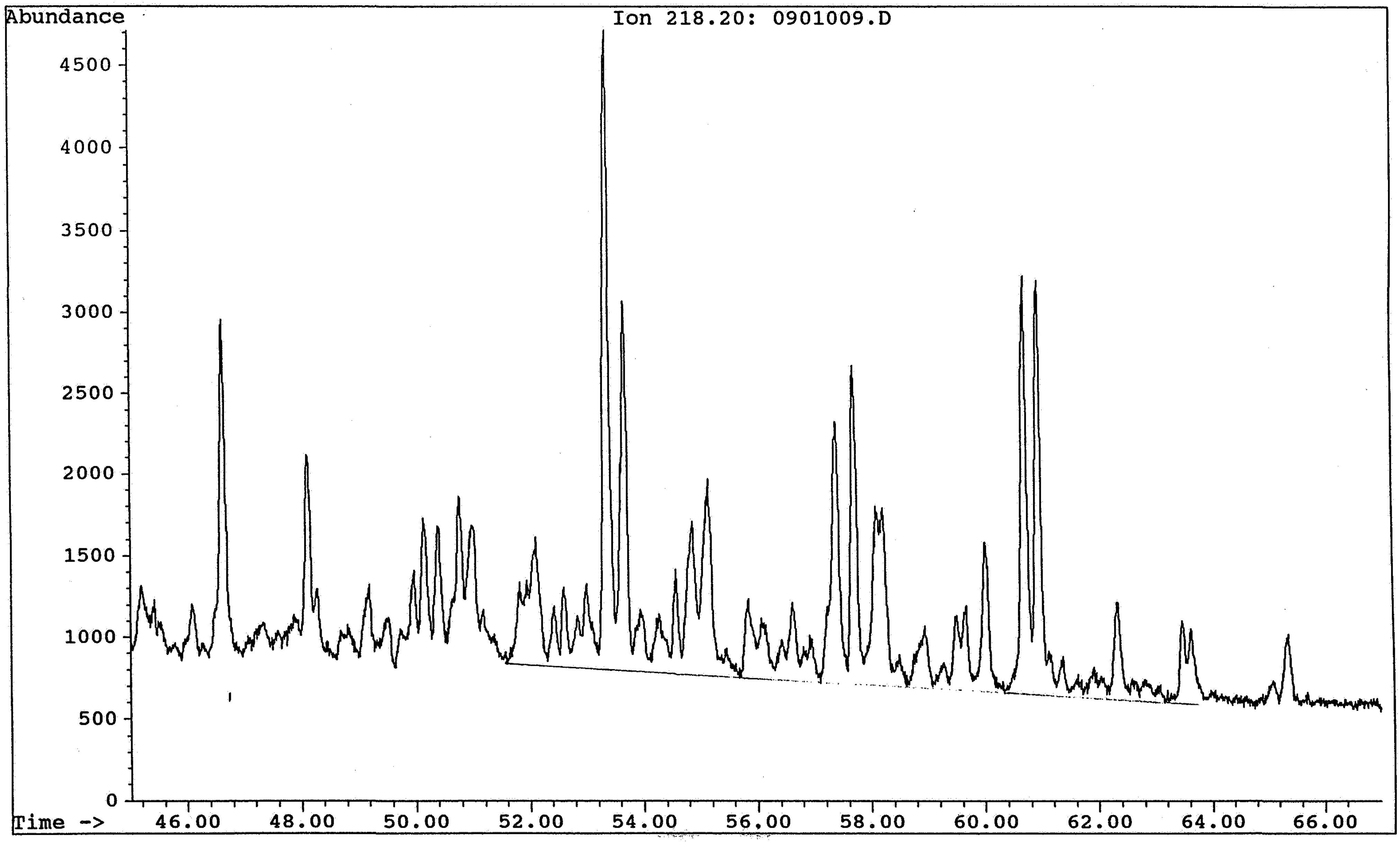
Saga Petroleum a.s. ate acquired: 19 Nov 92 0:01 am
File: C:\CHEMPC\DATA\35CORE_R\0901009.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3572,4 SAT



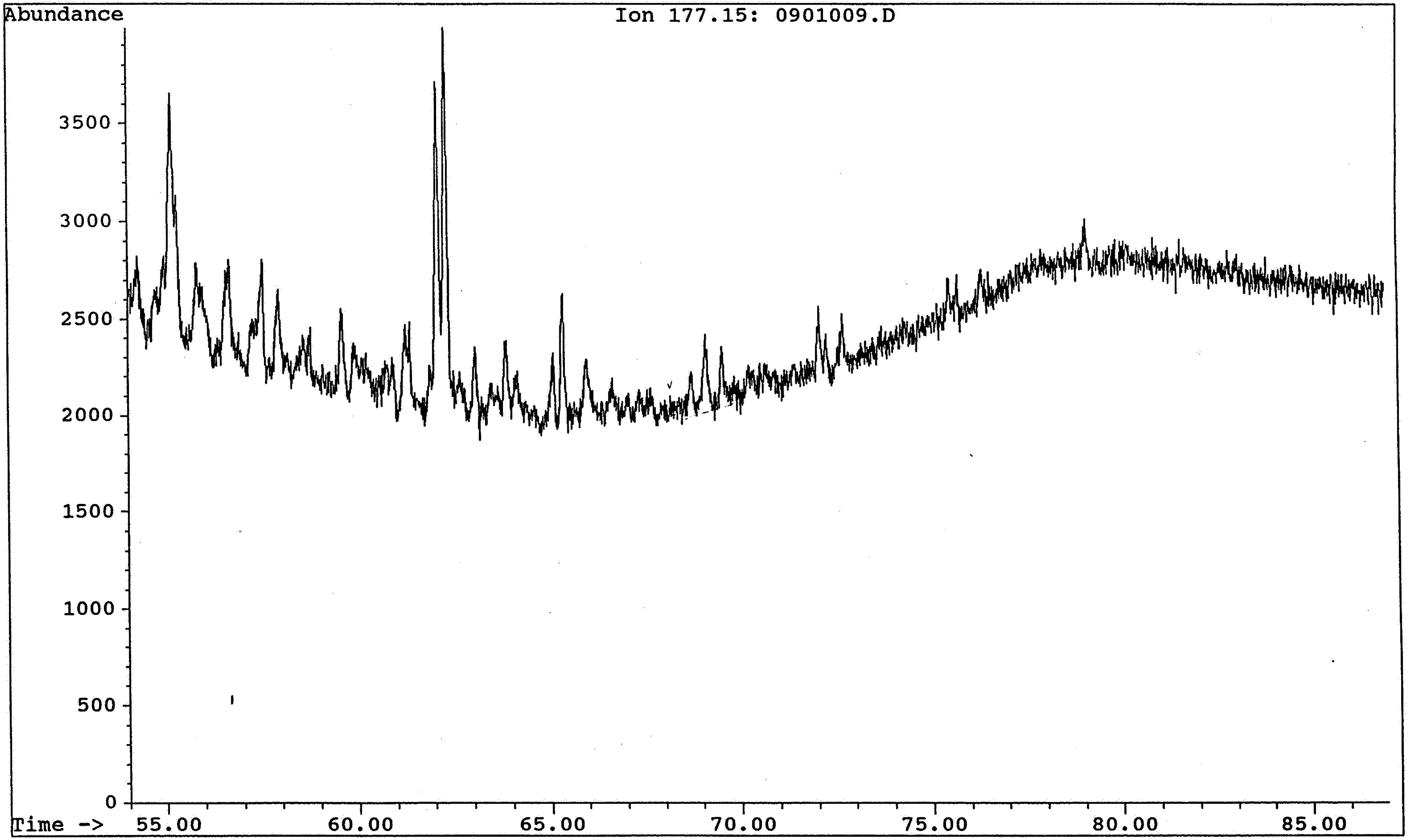
Saga Petroleum a.s. ate acquired: 19 Nov 92 0:01 am
File: C:\CHEMPC\DATA\35CORE_R\0901009.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3572,4 SAT



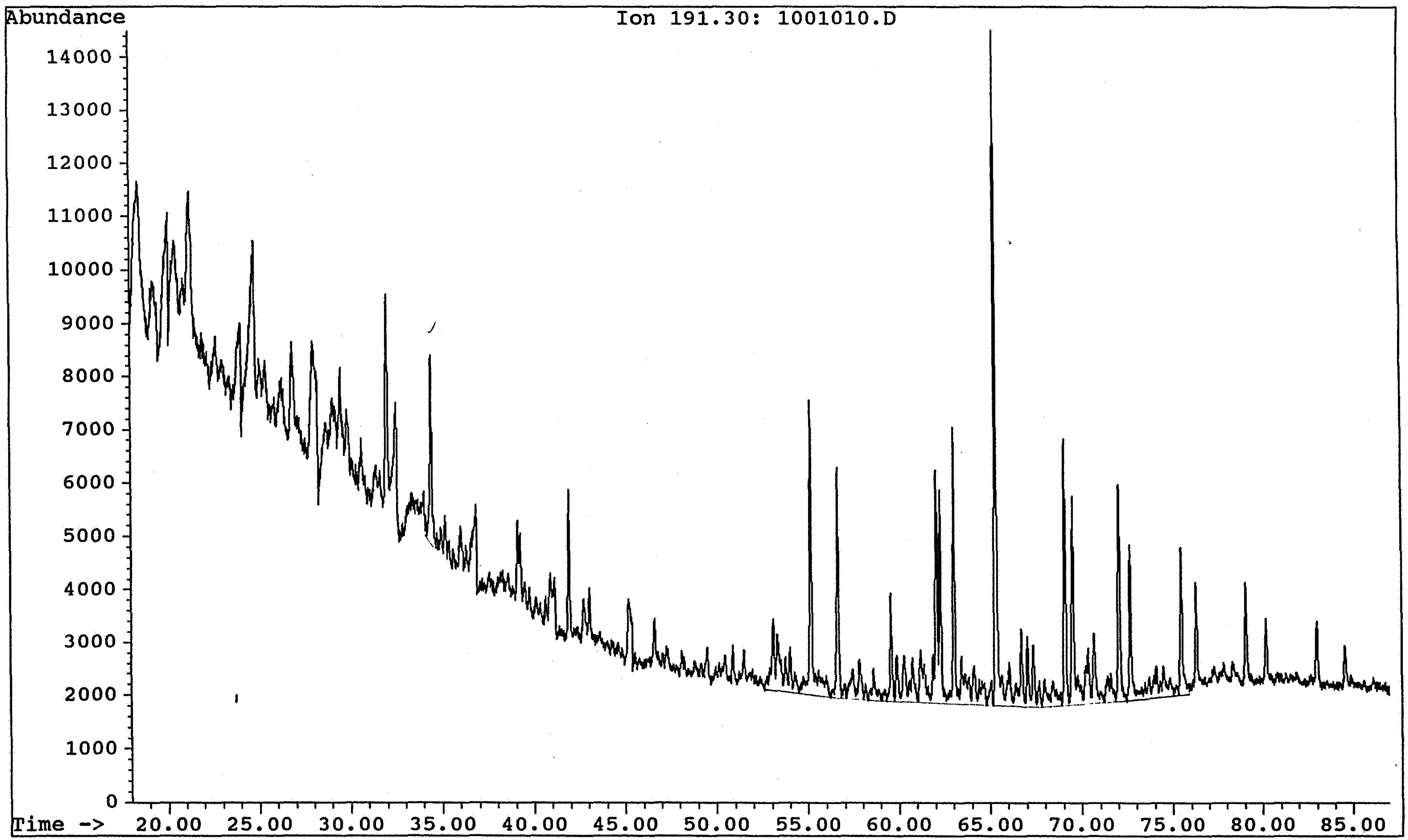
Saga Petroleum a.s. ate acquired: 19 Nov 92 0:01 am
File: C:\CHEMPC\DATA\35CORE_R\0901009.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3572,4 SAT



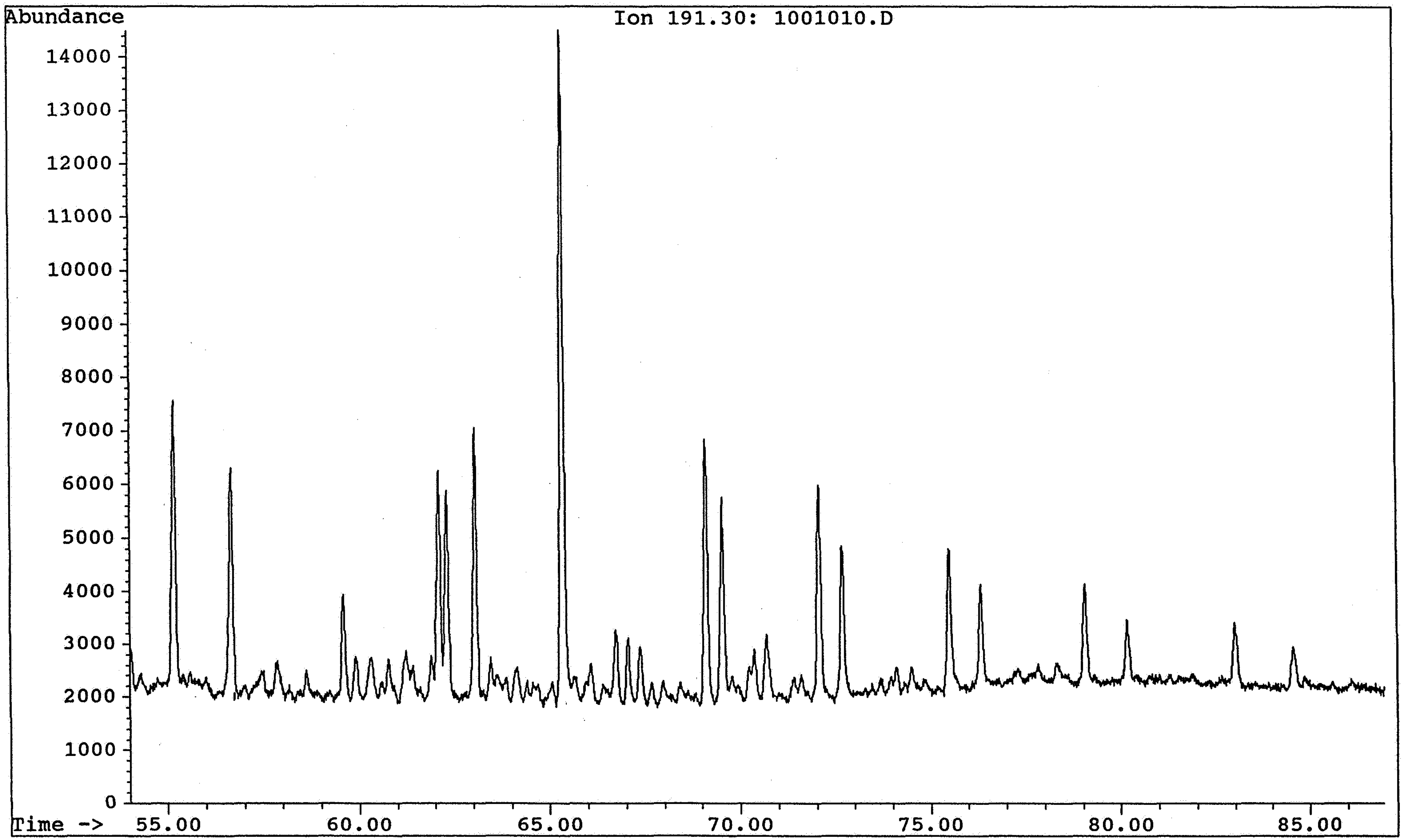
Saga Petroleum a.s. . .te acquired: 19 Nov 92 1:45 am
File: C:\CHEMPC\DATA\35CORE_R\1001010.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3647,0 SAT



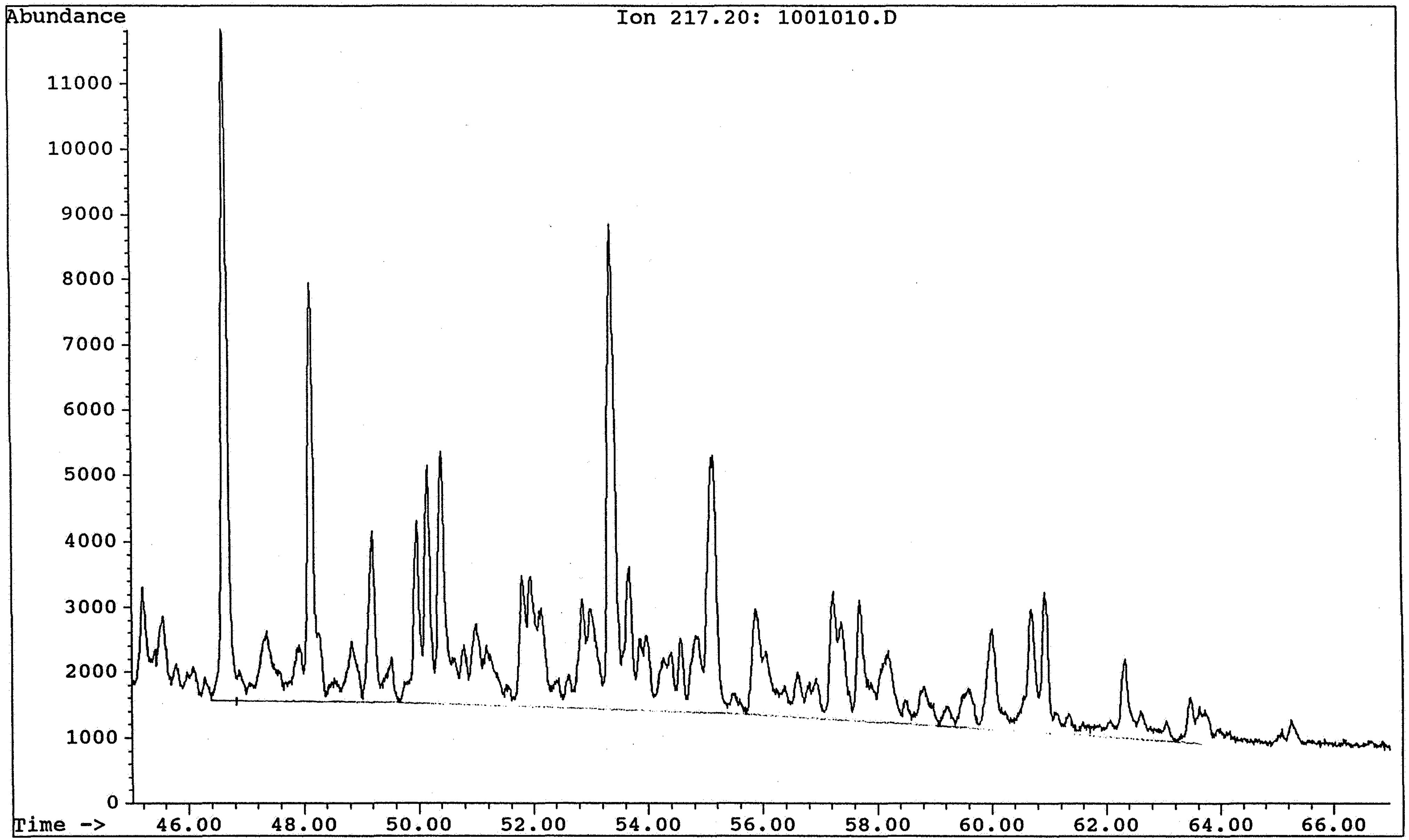
Saga Petroleum a.s. Date acquired: 19 Nov 92 1:45 am
File: C:\CHEMPC\DATA\35CORE_R\1001010.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3647,0 SAT



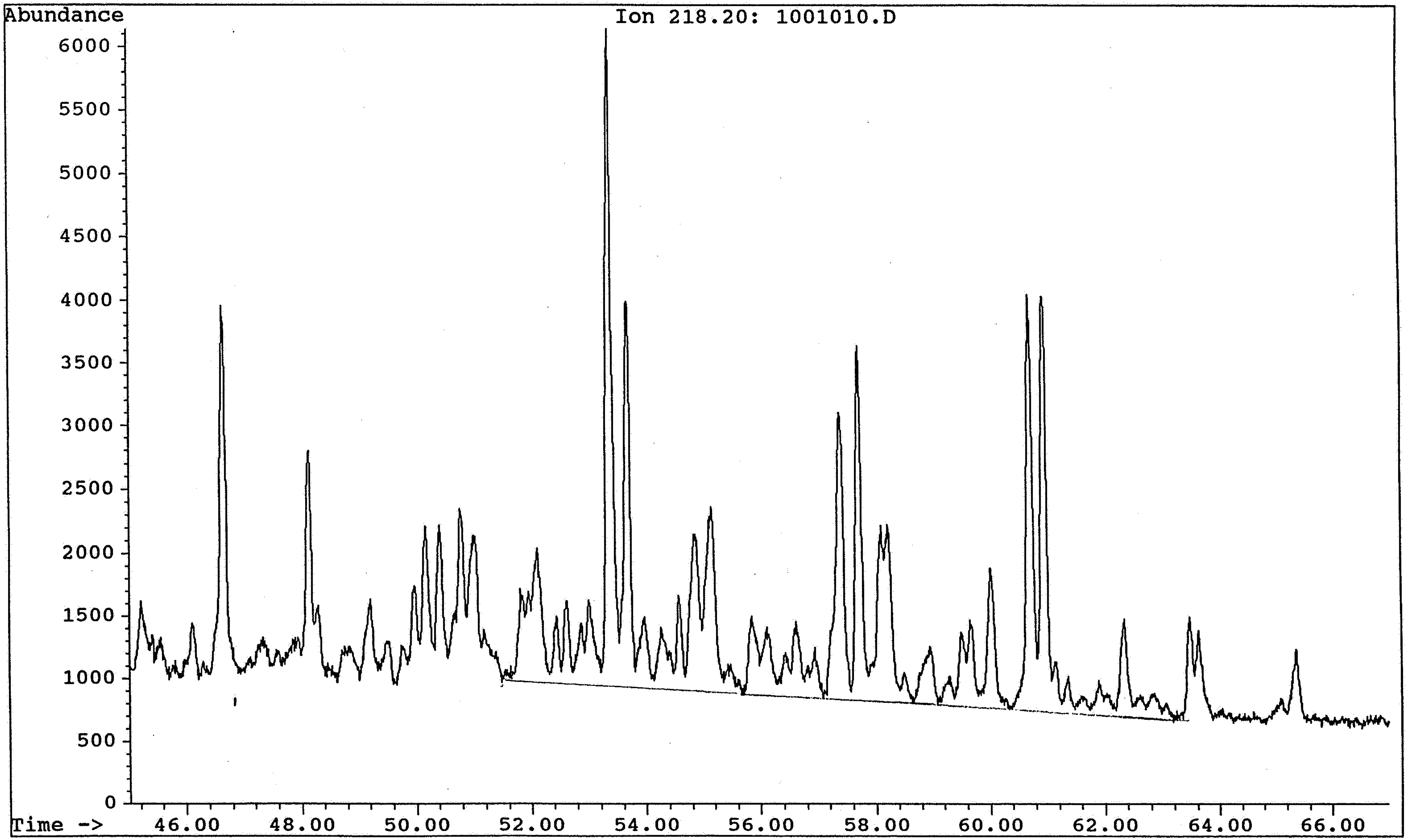
Saga Petroleum a.s. ce acquired: 19 Nov 92 1:45 am
File: C:\CHEMPC\DATA\35CORE_R\1001010.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3647,0 SAT



Saga Petroleum a.s. .te acquired: 19 Nov 92 1:45 am
File: C:\CHEMPC\DATA\35CORE_R\1001010.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3647,0 SAT



Saga Petroleum a.s. Date acquired: 19 Nov 92 1:45 am
File: C:\CHEMPC\DATA\35CORE_R\1001010.D Inst: HP5971A Inj: Split Meth: BMS.M

Sample name: WELL 35/8-1 3647,0 SAT