ORGANIC GEOCHEMICAL STUDIES IN THE NORTH SUMATRA BASIN

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ABSTRACT

Preliminary studies of existing organic geochemical data from the North Sumatra Basin, indicate that any one of several sedimentary formations may be responsible for the sourcing of indigenous hydrocarbon reserves. Some areas and formations are delineated as apparently having greater source potential than others but the non-availability of fresh, unoxidised, rock samples has hindered more specific conclusions being drawn. However, attempts have been made to make use of the recently installed VG Trio-2 GC/MS at Lemigas, to acquire and interpret limited geochemical data on oils, and possible source rocks, relevant to this discussion.

I. INTRODUCTION

The North Sumatra Basin (NSB), as illustrated in Figure 1 (after Tiltman, 1987), is a back-arc basin from which oil has been in continuous production, since its discovery over one hundred years ago. The geothermal gradient in the basin is one of the highest in the world (40^{O}C to 50^{O} C per kilometre), and has encouraged maturation of the residual organic matter to the extent that extremely light oil/condensate is produced from formations at relatively shallow depths.

The general geology of North Sumatra has been described in a series of maps (at 1:250000 scale) and reports arising from the co-operative project undertaken by the Geological Survey of Indonesia (now DMR/GRDC), and the Institute of Geological Sciences (now BGS), between 1975 and 1980. The stratigraphy, lithology, tectonics and structure of the NSB have been summarised by Kingstone (1978), the Tertiary structural evolution and hydrocarbon occurrences described by Davies (1984), and a more recent interpretation of part of the basin, based on seismic reflection data, has been given by Kirby et al. (1989). The major units are shown in figure 2 (Gardner and Helm, 1985), the Upper Oligocene being dominated by Bampo shales, the Lower Miocene by Belumai sands, the Middle Miocene by the Baong shales, and Upper Miocene to Pliocene by the sands of Keutapang, Seurula, and Julu Rayeu Formations, all of which rest on a Pre-Tertiary basement.

II. GEOCHEMICAL STUDIES

The geochemistry of the NSB has been discussed by Kingstone (1978), Situmeang and Davies (1988) and briefly by Robinson (1987). The Lemigas Basin Studies Group undertook a field survey in 1985, and subsequently pub-lished limited geochemical data based on the analysis of 84 outcrop samples. This present study re-examines original data obtained by commercial service organisations such as P.T. Geoservices and P.T. Robertson Research, which were contracted to provide specific geochemical reports for the Indonesian State Oil Company, PERTAMINA, and combines it with more recently acquired data.

Because the NSB data have been gathered over a number of years by several independent laboratories, having different types of specialised analytical equipment, it has not been possible to choose the same wells to show comparisons between the different parameters determined, because of batches of missing

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data. Hence, individual wells have been chosen that demonstrate a particular parameter clearly, with due regard to these wells being representative of a field or local area.

Geochemical data were made available by PERTAMINA for most of the wells drilled on its behalf in the NSB, from the middle 1970's to the present day. These data comprised total organic carbon (TOC) determinations, Rock Eval pyrolysis, maceral characterisation using vitrinite reflectance and spore coloration techniques, and limited gas choramographic (GC) analyses of headspace gases, gasoline-range hydrocarbons and solvent extracts of drill cuttings; some GC data were also available for oils. In total, geochemical data on 1501 samples were entered into a computer database to facilitate further processing.

It was unfortunate, from the geochemical research aspect, that only a few wells in the southern end of the basin have been drilled through to the Pre-Tertiary basement. In the northern area, the Middle Baong Sandstone of the Baong Formation was generally the target formation for oil exploration, and hence commercial interest dictated that very few wells penetrated beneath this depth to allow geochemical information to be obtained about possible source-rocks occurring further down the stratigraphic column; this has led to an imbalance in the reported data, biased toward the southern end of the basin.

In addition to the above, PERTAMINA UEP-1 gave permission for sub-samples of a selection of original drill cuttings and core sections to be taken for further analysis; the intention being to check some of the apparent discrepancies between TOC data derived from the different methods used for determination, but the breakdown of the LECO WR-12 TOC analyser prevented this. It is not known how reliable these checks would have been, however, as storage of sample material in anything other than ideal conditions, needs to be closely controlled to avoid oxidation of the residual organic matter; this is particularly true in a tropical environment.

Core samples were made available from a number of wells, and although these were probably originally taken as being representative of particular rock formations for geotechnical testing, they co tained sufficient shale material to make a number them inte-resting for further geochemical investig tion. Many of these cores are currently being stud by LEMIGAS trainees, in both the United Kingdo and Australia, as part of their research topics f higher degrees, and therefore more detailed geoche istry conclusions will he available in due course.

III. SOURCE ROCK CHARACTERISATION

III.1. General

A potential hydrocarbon source-rock is ch racterised by a combination of several different anal tical measurements, namely the total organic carb content, the type of organic matter from which it originates (maceral composition), the extent to which th organic matter has matured (time and temperatu dependent), the petroleum 'potential' of the organ component, and the type and amounts of hydroc bons it produces. In addition, both qualitative an quantitative determinations, and comparison, o groups of compounds by GC/MS, on oils and solve extracts of source rocks, can assist the geochemi with the interpretation of oil/source rock and oil/o correlation data. These data are useful in petroleu research studies and, in combination with other ge logical techniques, may assist with the prediction o likely locations for further oil exploration. Any on of these measurements can be indicative, but generally the determination of at least two or more of thes parameters must be undertaken before any early conclusions can be drawn about the possible hydrocarbo source potential of the samples being studied. Eve then it is ususally necessary to investigate some particular types of samples more thoroughly with othe techniques.

III.2. Drill Cutting and Core Analysis

III.2.1. Total Organic Carbon

Total organic carbon (TOC) determination one of the preliminary geochemical screening techniques carried out prior to more detailed analytic procedures. TOC contents of 0.5% for shale, or 0.3% for carbonates, are considered to be the minimum acceptable lower limits for commercial oil generation.

As there appeared to be considerable duplication of TOC data obtained from the NSB by conventional techniques, and also by Rock Eval, a single database file has been produced to rationalise the results and to allow easier computer processing. TOC obtained by Rock Eval Pyrolysis frequently gives slightly different results to those obtained by standard oxidation procedures, and this is due to the method of calculating the final result by addition of the carbon contents from each stage of the pyrolysis procedure. Generally this is not a significant problem, and to all intents and purposes can be ignored; therefore the data used here is based on the TOC obtained by either one or by both methods. Where a pronounced difference in the TOC results between the two methods was apparent neither result was used. The final TOC database file consisted of 1483 samples.

Reference to Table 1 shows that the average TOC content of all the samples is 0.65%, with only the Seurula and Keutapang Formations containing appreciably lower levels. Of the 85 samples from the Seurula Formation none has a TOC content of 0.5%. The number of samples from the Keutapang Formation was almost half the total of all the results available, with 746 pieces of data. The TOC on the Seurula and Keutapang field samples, reported by Tambunan (1985), generally supports these findings, and confirms that neither formation would be likely to generate any appreci able liquid hydrocarbons, based solely on their TOC content.

The Baong Formation is represented in all but three of the wells for which data are available, and forms the second largest group with 560 samples. The average TOC content of all the samples is 1.0%, which therefore must include the Baong Formation as one of the most likely source rocks of the North Sumatra Basin. The Lemigas Basin Studies Group collected 48 Baong outcrop samples, all but four of which contained 0.5% TOC; this therefore also confirms the well data.

The Belumai Formation is only penetrated by wells in the southern half of the basin, but all of these wells contained an average TOC content in the Belumai of 0.5%, based on data from 65 samples. This leads to the conclusion that the Belumai Formation may also be considered a possible source of hydrocarbons, but field outcrop samples from the Belumai Formation, as reported by Tambunan (1985), contradict this as they are extremely poor in TOC content; although it should be noted that representative sample material was obtained from only eight locations.

Both the Bampo Formation, and the Pre-Tertiary Basement, are represented by too few samples, all from wells at the southern end of the basin, for any reliable conclusions to be drawn.The average TOC of the three Bampo samples is slightly above the 0.5% threshold, and the eight field samples collected by LEMIGAS range from 0.01% to 1.13%. The Bampo Formation must therefore be worthy of further field and laboratory studies to determine the true nature of its organic component.

The Pre-Tertiary Basement was only penetrated by three wells; in all three wells the TOC content was 0.5%. No known comparable data is available for any field location, although these rocks do outcrop further to the west towards the Barisan Mountain chain. The Pre-Tertiary Basement must therefore also be considered as another possible hydro carbon source, based on geochemical evaluation.

III.2.2. Soluble Organic Matter (bitumen) Extraction

The amount of soluble organic material that can be extracted from a rock matrix into a suitable organic solvent (usually dichloromethane or a mixture of dichloromethane / methanol) is indicative of the source-rock richness. Up to 0.1% is considered poor to fair, from 0.1% to 0.4% good to very good, and above 0.4% excellent. It is principally the Baong Formation samples in the southern half of the NSB that indicate good to very good prospects based on their bitumen contents.

III.2.3. Rock Eval Pyrolysis

The technique of Rock Eval Pyrolysis was developed in France by Espitalié et al. (1987), and involves programmed pyrolysis of a ground rock sample in an inert atmosphere. Free hydrocarbons are released first (S_1), followed at a higher temperature by kerogen pyrolysis which generates hydrocarbon-type compounds (S_2). S_1 and S_2 peaks are detected by flame ionisation, but the effluent from the kerogen pyrolysis is split so that carbon dioxide and water are also directed through a thermal conductance cell (S).

The hydrogen index (mg hydrocarbon/g TOC) is calculated from the S_2 peak, and relates to the maturity of the hydrocarbon which is produced from the kerogen present in the sample, and is hence indicative of the type of kerogen present; TOC is calculated by summation of the carbon contents from each stage of the pyrolysis procedure. In addition, another parameter referred to as T_{max} is recorded, which corresponds to the temperature achieved at maximum hydrocarbon generation during the kerogen pyrolysis, and is also a maturation indicator. A temperature below 430°C is considered immature, 430°-465° C is indicative of oil generation and above 465° C of gas generation.

There are only ten samples from the whole of the NSB that have T_{max} values greater than 465 C, and these are concentrated in the deeper wells at the southern end of the basin - the formations intersected being the Baong and Belumai Formations and Basement. The highest temperature recorded was 472° C. In contrast, 15% (222 samples) contain oil- prone kerogen (T_{max} 430° C to 465° C), of which over 80% are from the Baong Formation (182 samples).

Kerogen maturation profiles, similar to those reported by Espitalié et al. (1987), were prepared using samples with a T_{max} value 400 C extracted from the database. Graphs of T_{ax} versus Hydrogen Index were plotted for different wells (fields) on an approximate line from the southeast corner to the northwest corner of the basin (A - A'), and also at right angles to this down at the southern end (B - B') (Figures 3 and 4). There is a marked difference between the opposite ends of the basin; wells in the north west and central areas possibly indicating sourcing from Type III kerogen, while those from south are more indica tive of Types I and II. However, this may be due solely to the fact that wells further north were generally only drilled to relatively shallow depth, and therefore only intersected sediments subjected to
proportionately lower geothermal gradient.

Although only these six wells (fields) ar
presented here, similar results were obtained fro
other wells in close proximity. Rock Eval data fro
elsewhere in the NSB indicate a generally over
lower level of maturity, which as stated above, mus
some extent be the result of a marked lack of samp
material from deeper down the stratigraphic colu
in many of the areas penetrated by exploration wel

III.2.4. Headspace-Gas Analysis

Headspace, or cuttings-gas analysis, can g
an indication of the maturity of a stratigraphic sec
by plotting the variation of the light hydroca
gases, methane, ethane, propane, normal and iso-
tanes against burial depth. Also the wet-gas co
which is the amount of C_2-C_4 component divid
the total gas content (Tissot and Welte, 1984), ca
dicate the onset of oil generation.

There is very limited data available fo
four wells in the NSB, and Figure 5 shows the
parameters plotted for data from the southern pa
the six diagrams, only the ethane content is of
use in indicating the depth at which the sta
generation might be expected to occur, a noti
break in slope on the other five diagrams bein
ent. Note the higher concentrations of methane
upper part of the column which are probably b
cally derived.

III.2.5. Gasoline-Range Hydrocarbons

The gasoline hydrocarbons are those
carbon-chain lengths fromC_4-C_7, and inclu
branched-chain and aromatic hydrocarbons
range. Crude petroleum only contains lo
ages of these constituents, but the determ
their concentration helps delineate the
generation. There are only 78 data sets on
all from the southern end of the basin, and
the whole stratigraphic column. Figure 6 s
ly indicates the approximate depth at which
ating potential begins.

III.2.6. Optical Techniques

The measurement of the reflecta

particles (typically vitrinite) by reflected-light microscopy can be used to determine the maturity of the organic matter associated with the onset of oil generation, but there are no fixed values that can applied universally. Generally a vitrinite reflectivity of 0.6% R is considered indicative of the beginning of commercial oil accumulation, with gene ration peaking at 0.8% to 1.0%. There are only about 40 samples from the whole of the North Sumatra Basin that exhibit values in excess of 0.6%, and it is in the Baong Formation that the majority of these occur. It is usual to take upwards of 30 measuremants per sample (subject to there being sufficient vitrinite particles to measure) in order to obtain reliable data, but there are very few samples that satisfy this criterium. Table 8 shows data for all of the samples having a reflectance 0.6% R .

III.2.7. Oil Analysis

The oil samples obtained from the NSB, are very light oils or condensates with API gravities ranging between 40^{0} and 56^{0}. The samples were diluted 20:1 with AR grade hexane, and whole oil gas chromatograms run on a Varian 3700 capillary GC, temperature-programming from 50^{0} to 250^{0} C at 5^{0}C per minute. A selection of these chromatograms are shown in Figure 7. The maximum carbon number observed is about C 28 to C 29 and all the oils are well matured, showing the typical tri-angular-shaped chromatogram, with Carbon Preference Index (CPI) values approaching unity. The CPI is thought to vary dependent on the level of maturity and the source type, values around 1.0 indicating marine source rocks. The isoprenoid alkanes, pristane and phytane, are lower in abundance than their parent hydrocarbons, again indicating maturity.

Data from eight wells were acquired during the course of earlier surveys. CPI values range from 0.86 to 1.48 with a mean of 1.08, but ratios of pristane and phytane to each other, and to their respective parent hydrocarbons seem to be very variable, even within individual well formation. These results may be true values, but owing to their variability may equally well be due to poor sampling and anlytical techniques.

III.2.8. Gas Chromatography/Mass Spectrometry

The technique of GC/MS involves the direct coupling of a capillary gas chromatograph to a mass spectrometer, ideally with both instruments being controlled by the same computer data system. As the components of interest elute from the GC column into the source of the MS, they are bombarded with electrons excited to a high energy state, and hence break down to form characteristic fragmentation patterns. Identification of the mass spectra of these 'fragment ions' can help to determine the type of parent molecule from which they are derived, and also its molecular weight. The commonest form of data acquisition is in the scanning mode after electron impact ionisation, but this often results in very large data files, probably containing much more infor mation than is actually required. A system can therefore be initiated that only records a few ions of specific interest, and which occupies a much smaller amount of data storage space. As the GC/MS system is recording and storing much less data in this Selected Ion Recording (SIR) mode, the technique is considerably more sensitive. As with other acquisition modes, the file can be processed to reproduce a Reconstructed Ion Chromatogram (RIC) trace of the ionic concentration against the chromatographic retention time.

Two mudstone core samples of Keutapang Formation, and one sandsatone with interbedded mudstones of Belumai Formation, were extracted into dichloromethane using a Soxhlet apparatus. The extract was concentrated into a small volume by rotary evaporation, and an aliquot taken, from which the alkane (straight-chain hydrocarbon) fraction was removed using molecular sieve absorption. This procedure isolated the branched/cyclic fraction for sub sequent GC/MS analysis. Oil samples collected from the same fields were diluted with dichloromethane and the whole-rock extracts, diluted whole-oil samples and the fractionated portions were then individually injected into the GC/MS, and data collected for each sample using both scanning and SIR modes. Moni-toring of the Total Ion Current (TIC) commenced after twenty minutes had elapsed from the moment of the sample injection, to prevent unnecessary data from the solvent and light components of the sample from being stored, thereby using up valuable disk space in the data system. Also, the fragment ions of interest being moni tored by SIR would only start appearing after the C 17 peak had eluted, and it was therefore considered unnecessary to record comparison data in scanning mode for the earlier eluting peaks. In the SIR mode, ions diagnostic of cyclic compounds (m/z 83), alkanes (m/z 85), acyclic isoprenoid hydrocarbons (m/z 183), cyclic terpanes (m/z 191) and regular steranes (m/z 217, 218) were monitored.

Figure 8 and 9 show the data obtained for whole-oil samples. Figures 10 and 11 for the extracted core samples, Figures 12 and 13 for the branched/cyclic fraction of the core samples in both scanning and SIR modes, respectively. It has not been possible, in the relatively short time that the GC/MS has been operating in LEMIGAS, to build-up sufficient experience to allow accurate interpretation of maturation data, therefore the results reported here are based on visual comparisons between individual TIC's and single ion traces only.

The whole-oil TIC's (Figure 8) are very similar to one another with no marked differences apparent at the scale of the diagram; the first major double peak in each trace being the C17/pristane peaks. However, the SIR traces of m/z 217 and m/z 218 of the same samples (Fi-gure 9) clearly indicate that these oils are very similar, while the other one is noticeably different. Owing the very low concentra tions above about C25, none of the diagnostics C27 or C29 steranes or cyclic terpanes were recovered from the oil samples.

The soluble organic matter in the three core samples all exhibit totally different TIC's in the scanning mode acquisition (Figure 10), showing particularly good recovery, with carbon numbers up to about C25. All three samples have distinctive *unresolved hump* patterns. It is obvious from the diagram that all three either contain soluble organics sourced in different environments or are possibly contaminated. This seems to be confirmed by the SIR data (Figure 11), in which the traces of the individual ions monitored are comparably different in each sample.

The branched/cyclic extracts of the core samples again show marked contrast, especially in the normal scanning acquisition mode (Figure 12). Figure 13 indicates that the cyclic terpanes and steranes observed in the extracted core sample (Figure 11) are still evident, and there now appears to be a similar concentration of these compounds in that sample. Failure to recognise these during the analysis of the unseparated sample, may be due solely to themasking effects of straight-chain compounds removed by the molecular sieving technique, and illustrates the obvious advantage of the concentration procedures prior to analysis.

IV. DISCUSSION AND CONCLUSIONS

The existing TOC data points to several formations as being possible sources for the North Sumatra Basin hydrocarbons. Of these the Baong Formation must feature as the most likely, although the larger number of samples from this formation (560) must somewhat distort the statistical results compared to say the Bampo Formation, with only three data points. The large number of samples from the Keutapang Formation probably already rule this formation out as a source rock, based on overall TOC determinations, but studies on the isolated areas where higher results have been obtained may be worthwhile. The Bampo Formation certainly merits more intensive studies.

The Baong Formation again dominates when the sovent-soluble organic matter is considered, with most of the important data being found towards the southern half of the basin. The lack of data from the non-penetrated deeper formations in the northern half distorts the overall pattern, however.

During Rock Eval pyrolysis, the Baong Formation provided the largest number of samples in which oil-prone kerogen was found, although again the results are probably distorted because of the disproportionate number of Baong Formation samples in the database. Based on Rock Eval data the Keutapang Formation is probably too shallowly buried to be a source-rock contender.

Headspace gas analysis is available for four wells in the NSB, even less data are available for the gasoline-range hydrocarbons. It is again unfortu that data are not available for the northern end of the basin, so that comparison may be drawn. Each well indicates the onset of oil generation to be at about 1600 - 1700 m depth level, which is again in the Baong Formation.

All of the oils are essentially similar in characteristics, being very light condensate-type, having maximum carbon numbers to about C 28, and of all these analysed by gas chromatography only that from the Wampu field was slightly different from the remainder. Limited GC/MS studies reveal that there appears to very little similarity between the oil samples when compared individually with the core samples taken from the same areas. However, the core samples were taken several years ago, and have since been in less than ideal storage conditions, which may have affected their organic content through oxidation etc. In addition these core samples were unlikely to have been taken specifically for geochemical analysis, but rather as being representative of particular formations for geotechnical testing, therefore it perhaps not surprising that there is little or no similarity between core and oil samples. Unfortunately no other suitable core-type material was available for analysis.

It has not been possible to undertake a fully comprehensive geochemical study of the NSB for several reasons. Much of the geochemical data supplied for the study were acquired by PERTAMINA during the 1970's and was not there fore of the same quality as would be expected at the present day, given the rapid advances that have been made in the *state-of-the-art* instrumentation over the last decade. For example geochemists can now detect, and determine, many parameters at concentrations previously considered impossible, and this has been due entirely to the introduction of new equipment and methodology. The GC/MS in LEMIGAS is an ideal example of this advancement, where the power of an ordinary desktop microcomputer is able to control all of the functions of a highly complex instrument, in addition to manipulating and storing vast quantities of analytical data.

In conclusion, however, although the geochemical study of the NSB has been restricted by the constraints described above, the overall objectives, to provide manpower and technology training, have been achieved and can be further strengthened in the future.

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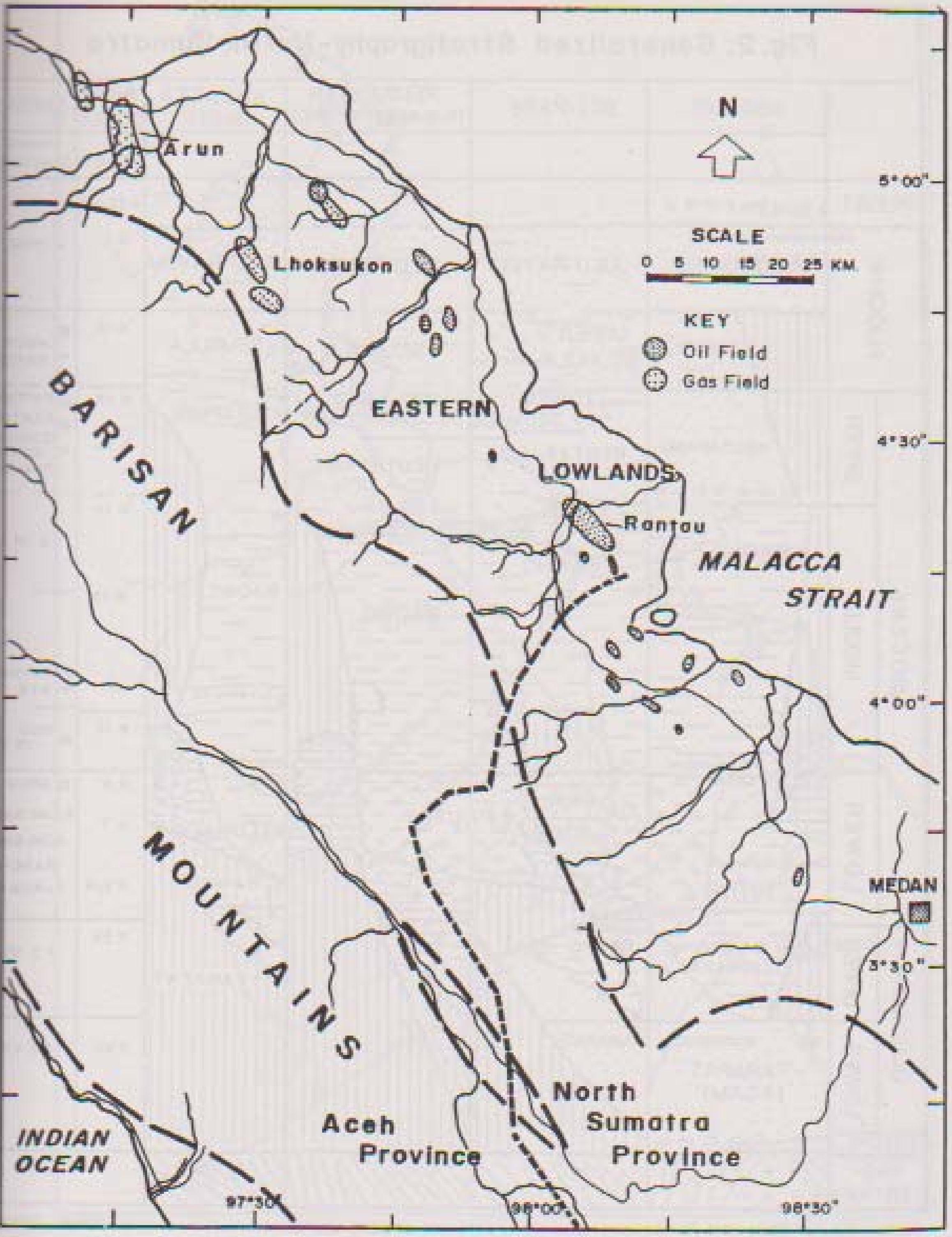
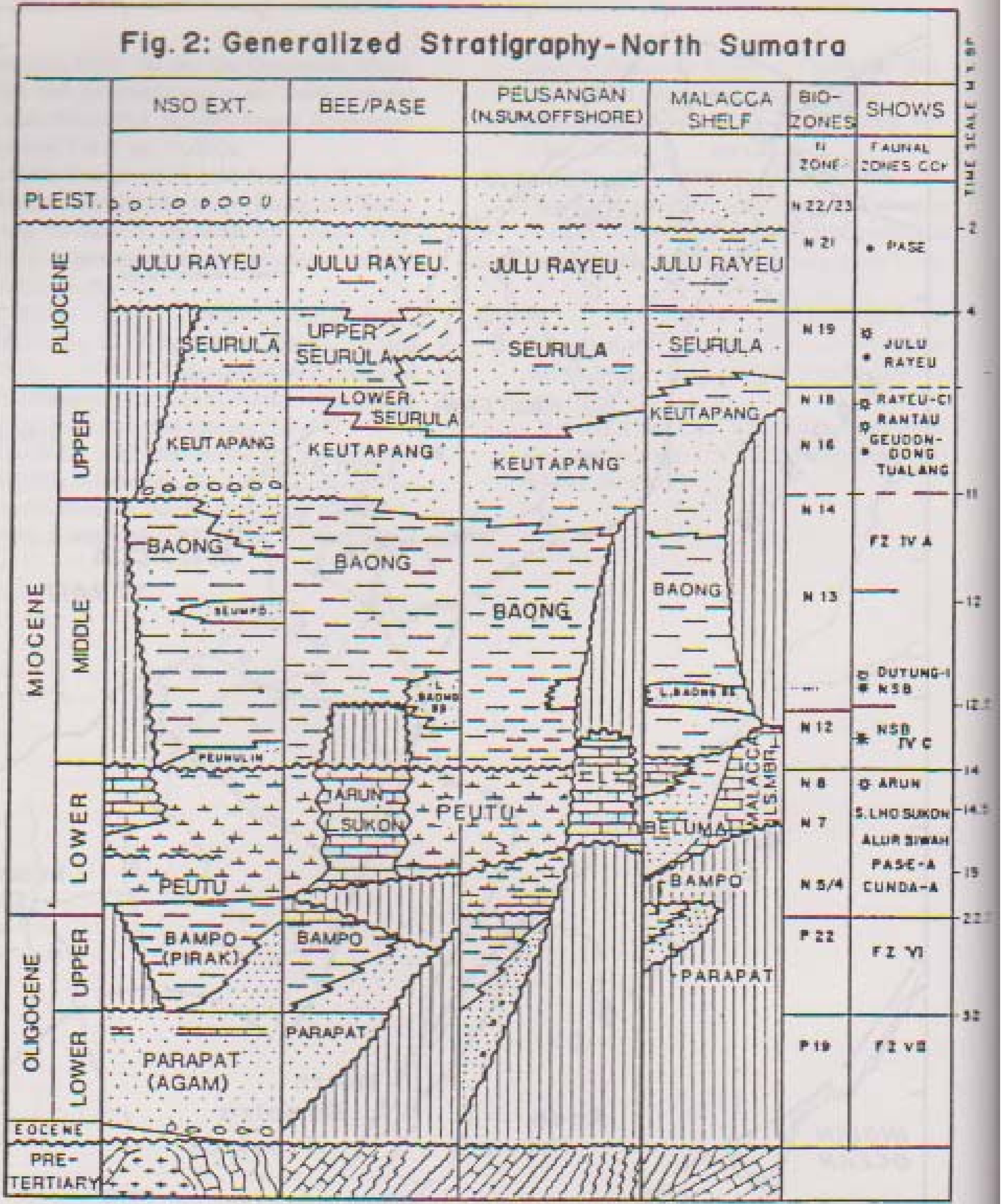


Figure 1.
Location map of North Sumatra



Note : Faunal Zone and Formational boundaries do not exactly coincide (Gardner, 1985)

Figure 2
Generalized Stratigraphy of North Sumatra (Gardner, 1985)

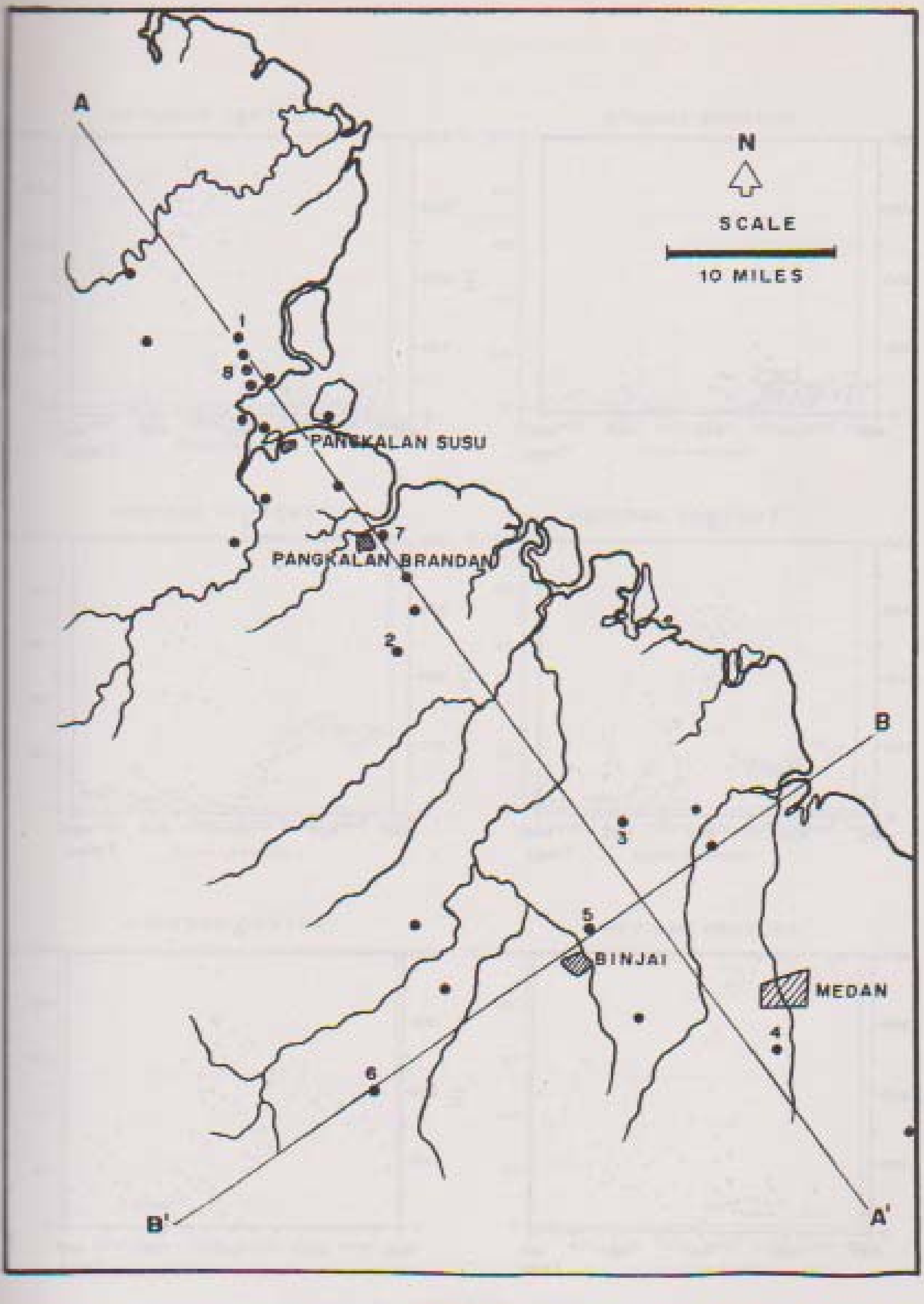


Figure 3
Kerogen Maturation Profiles

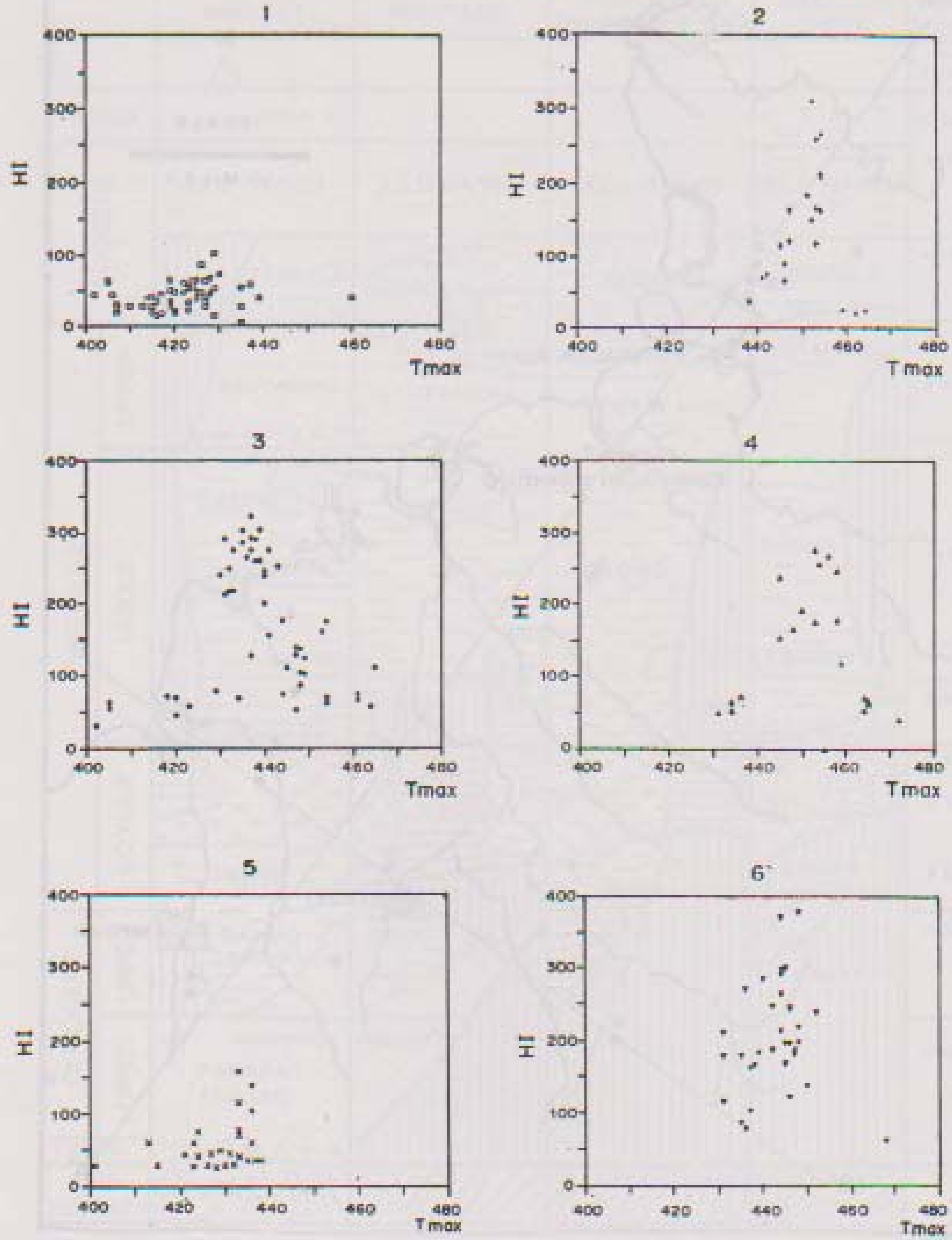


Figure 4
HI vs. Tmax

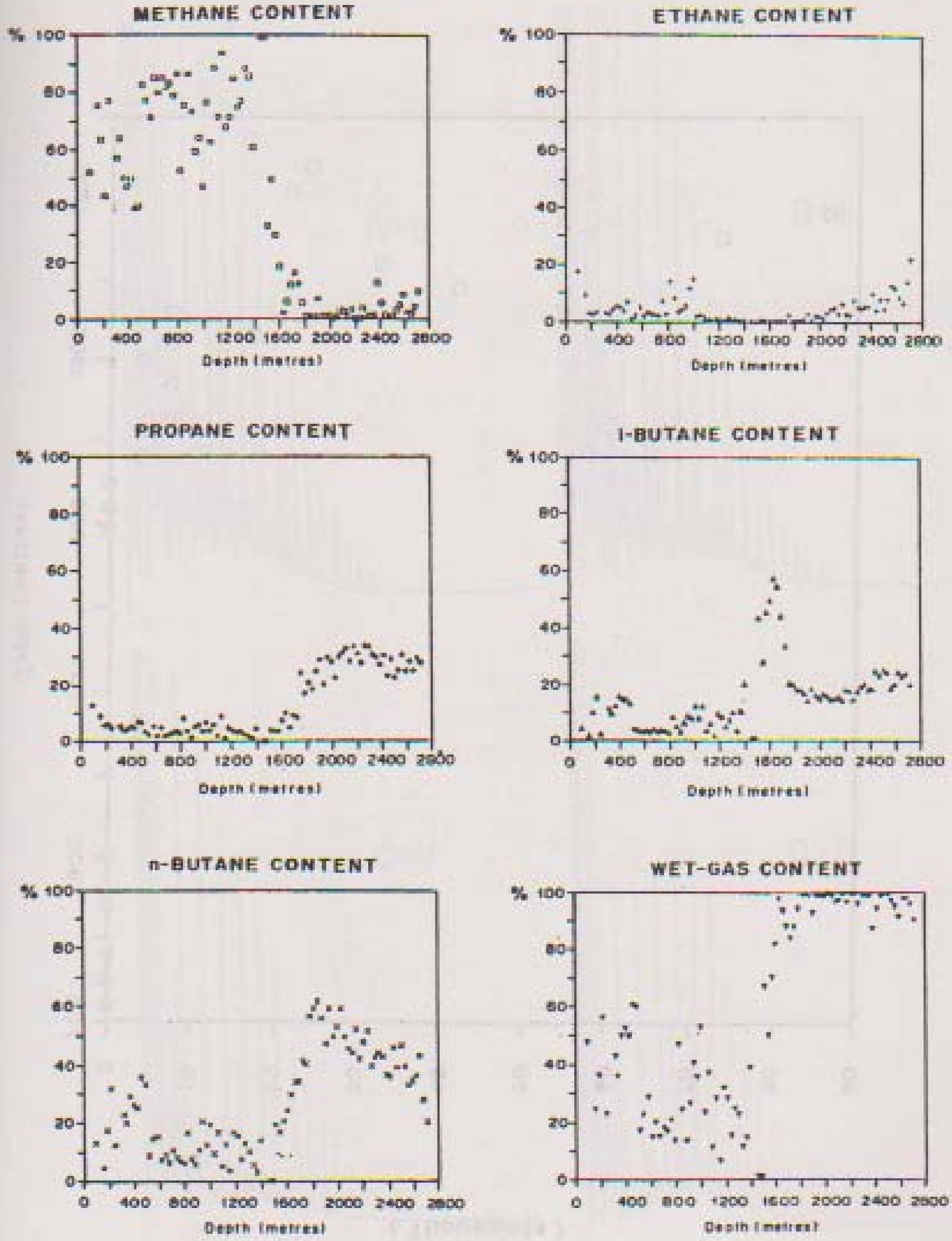


Figure 5
Hydrocarbon Composition vs. Depth

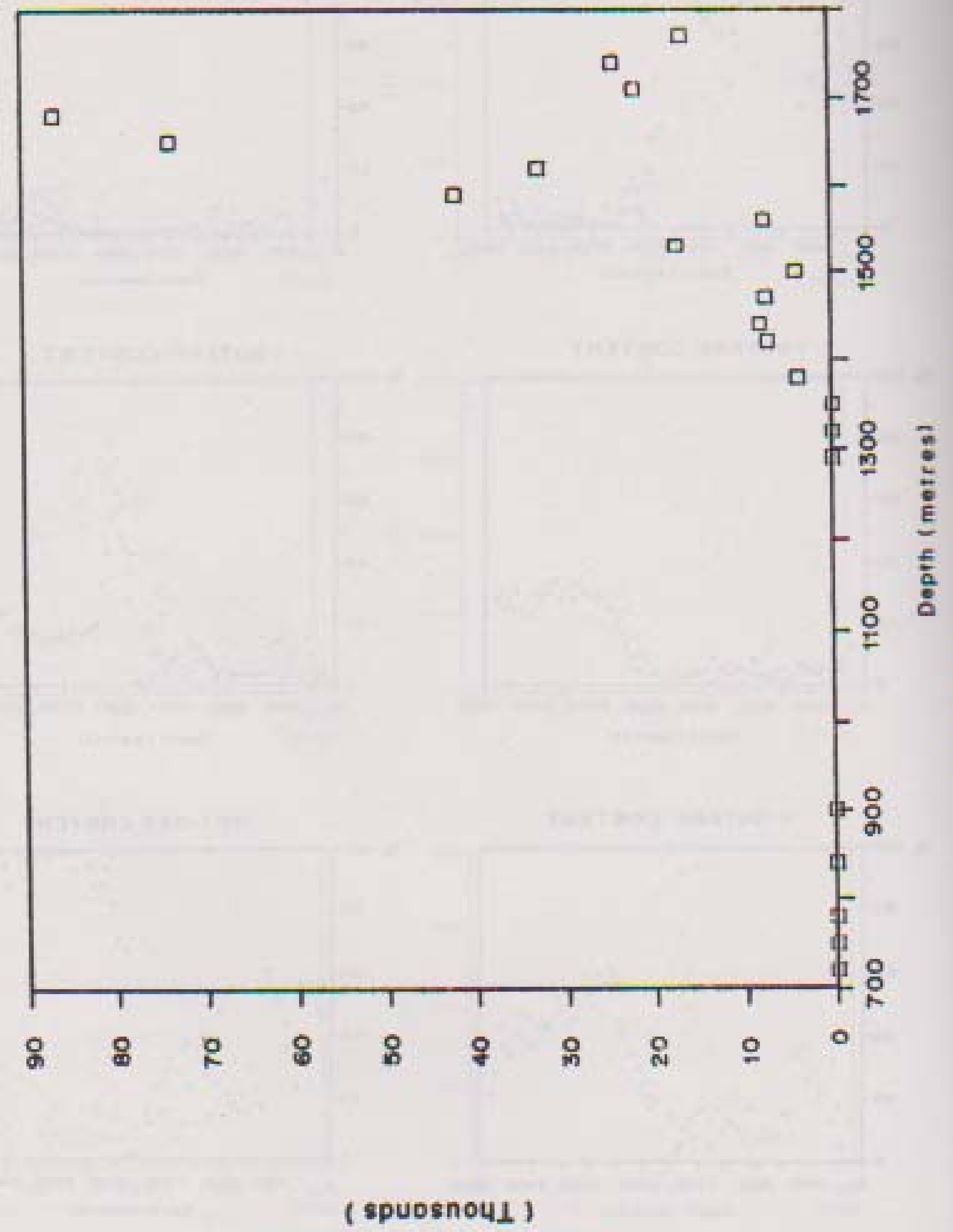


Figure 6. Gasoline Content vs Depth

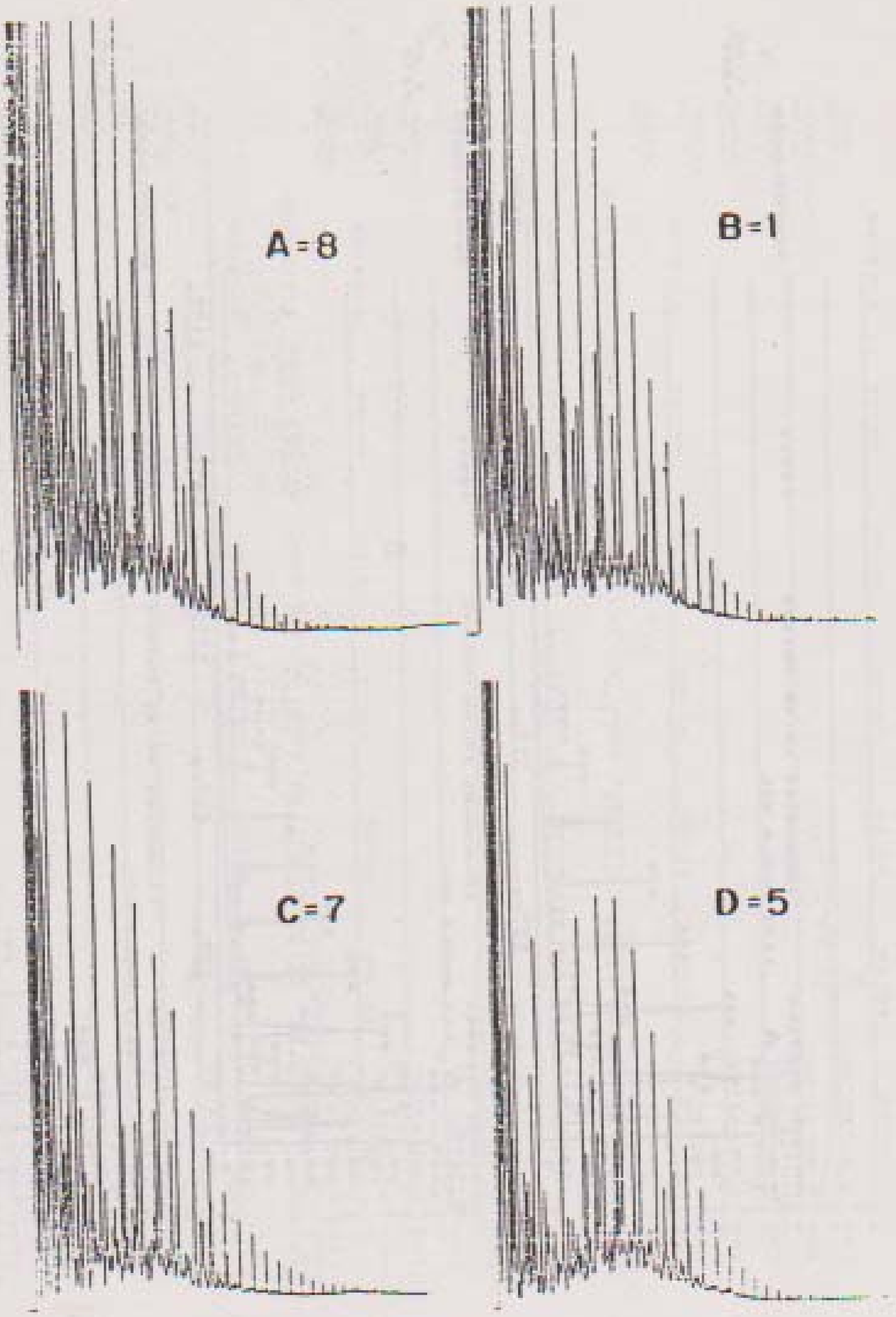


Figure 7
Oil Gas Chromatographic Profile (1, 5, 7, 8 Wells)

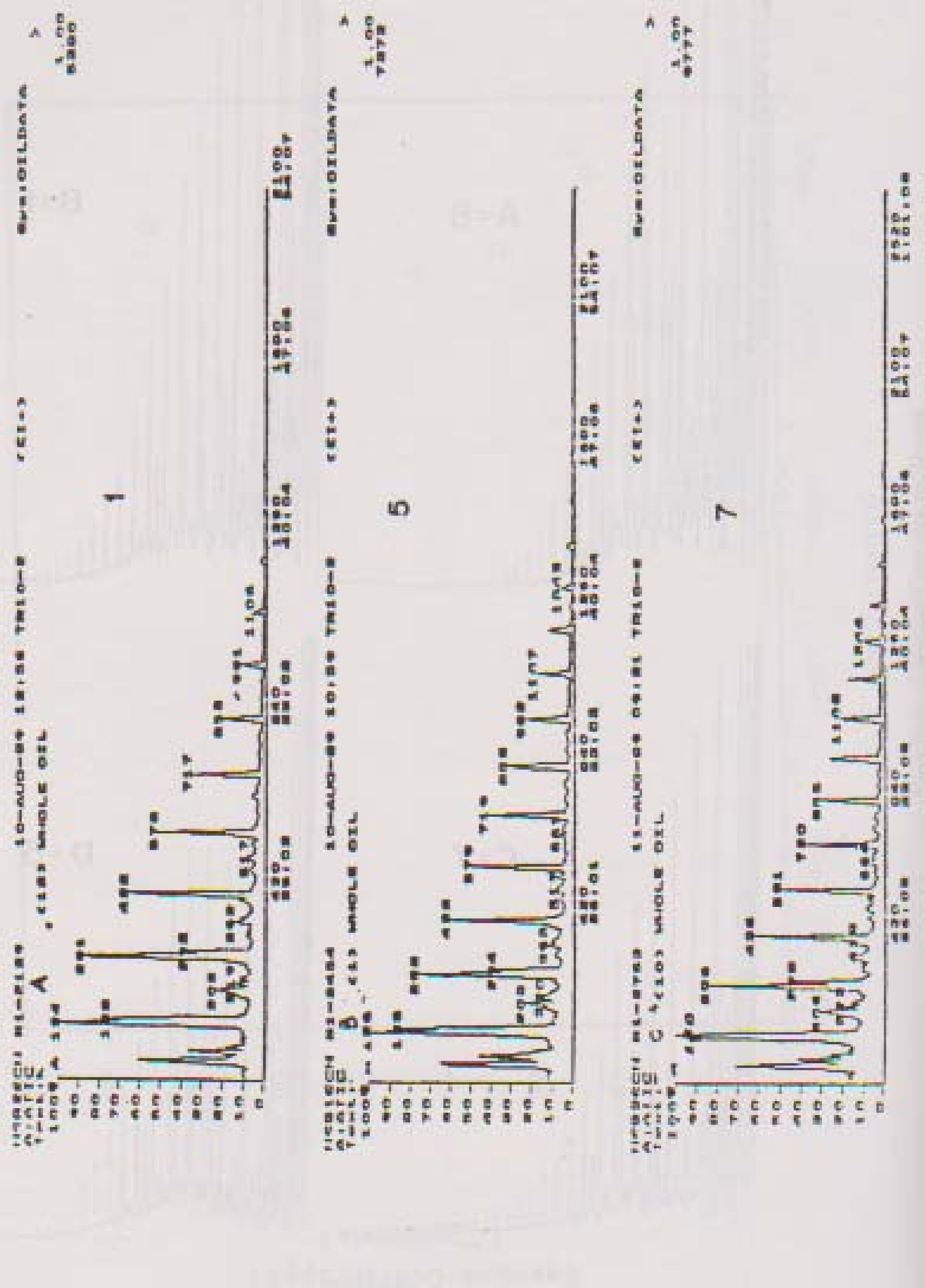


Figure 8. Full Scan of whole oil (1, 5, 7 Wells)

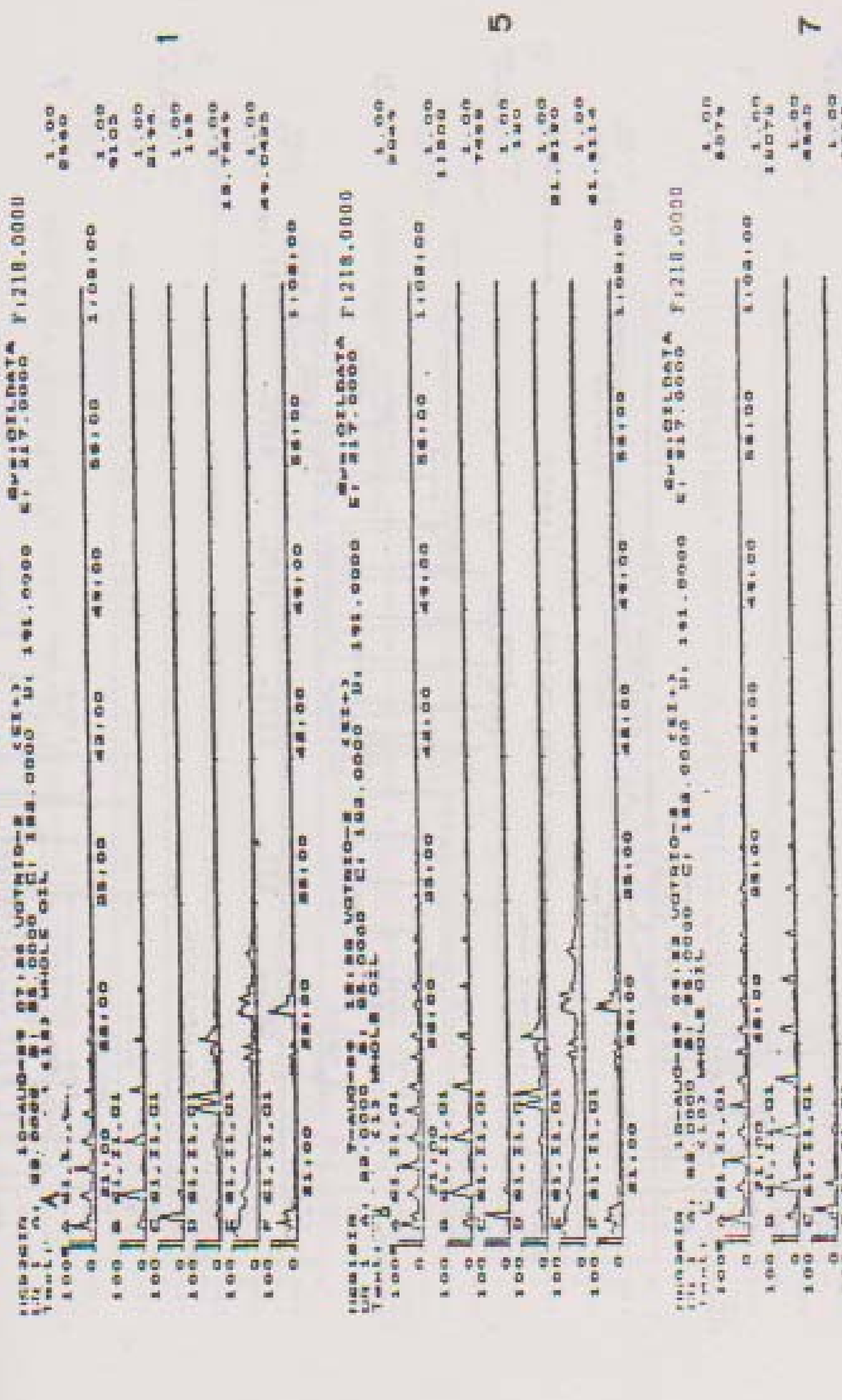


Figure 9. S.I.R. of whole oil 1, 5, 7 wells)

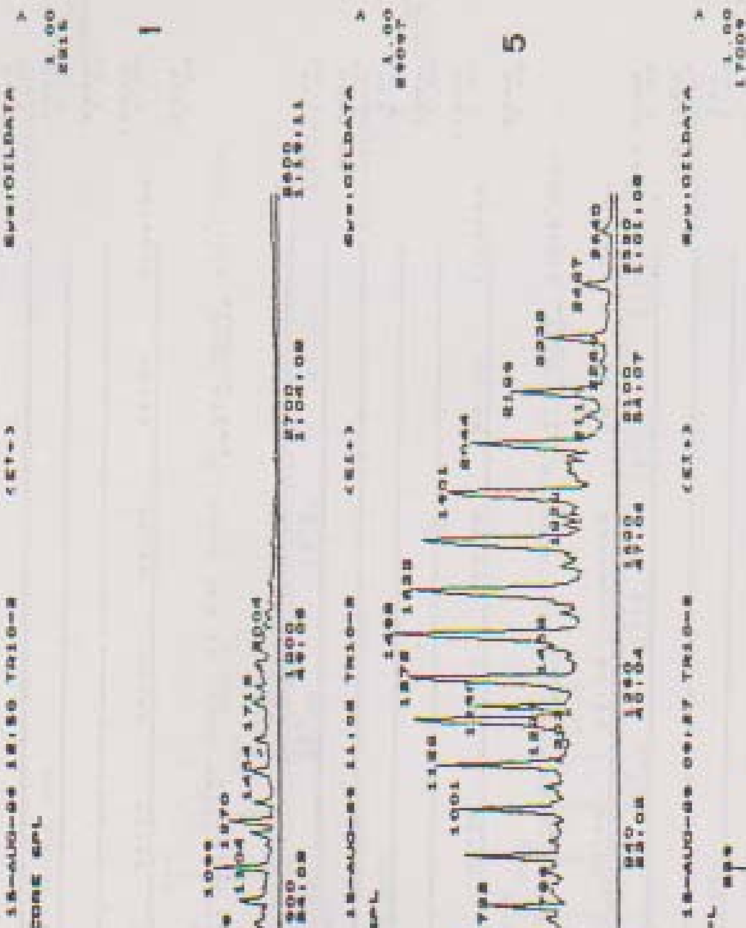


Figure 10. Full scan of core samples (1, 5, 7 wells)

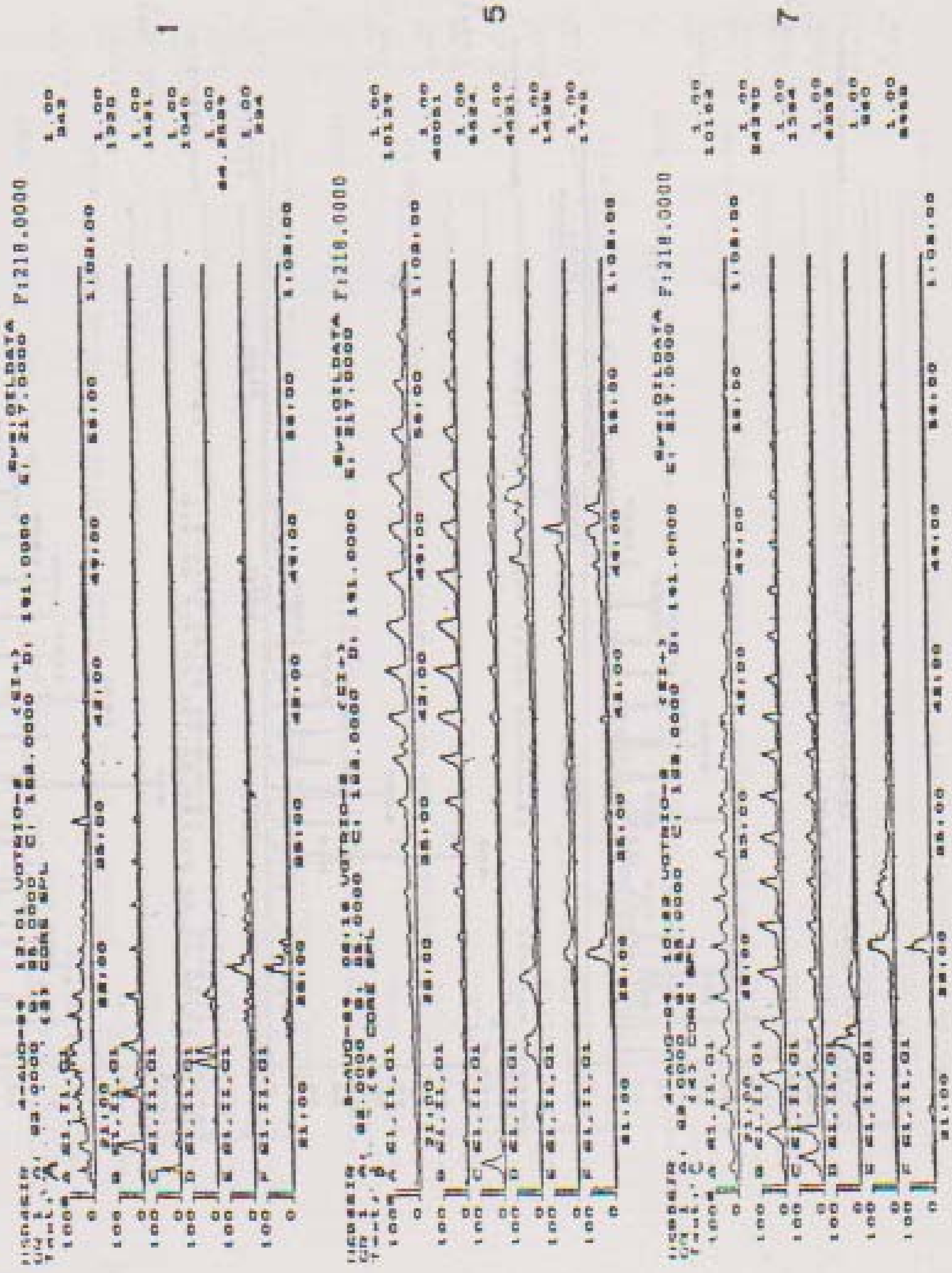


Figure 11. S.I.R. of core samples (1, 5, 7 wells)

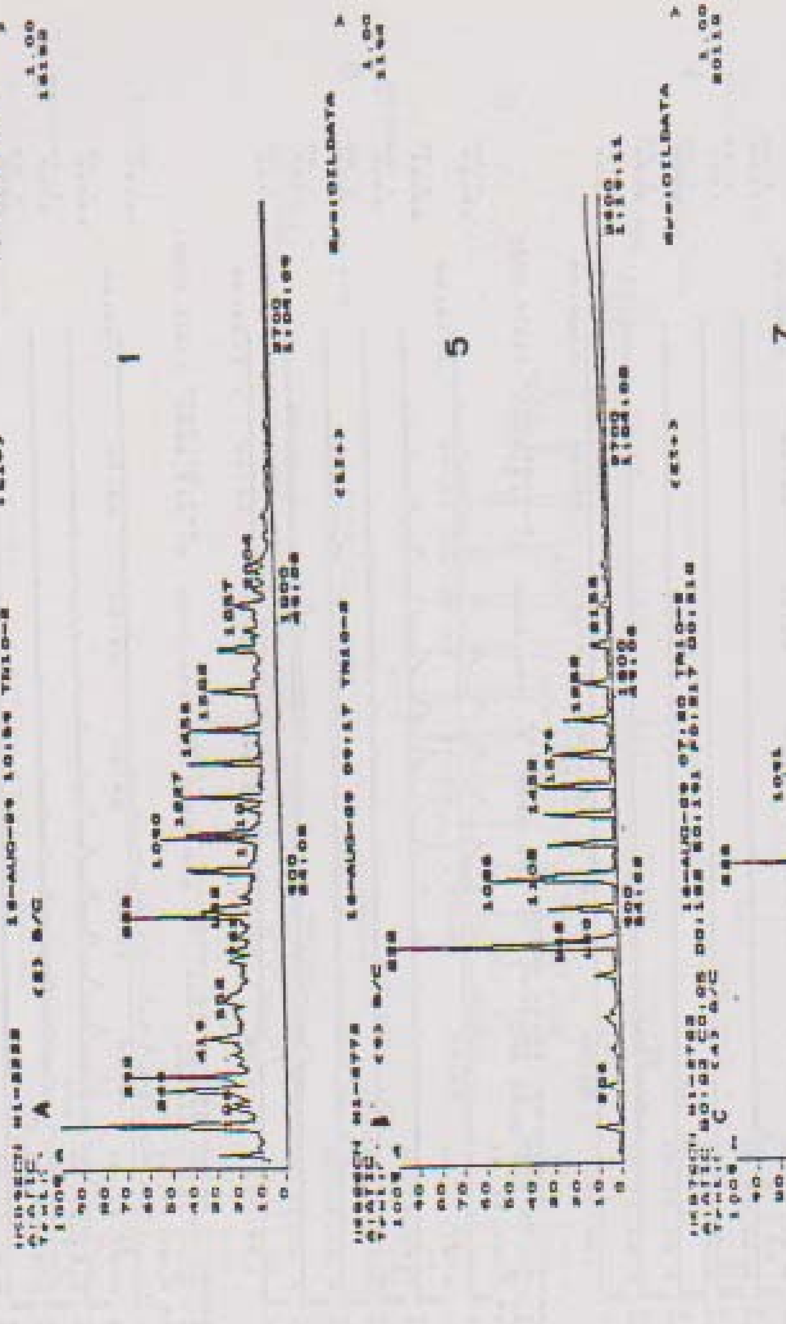


Figure 12. Full scan of branched/cyclic fraction (1, 5, 7 wells)

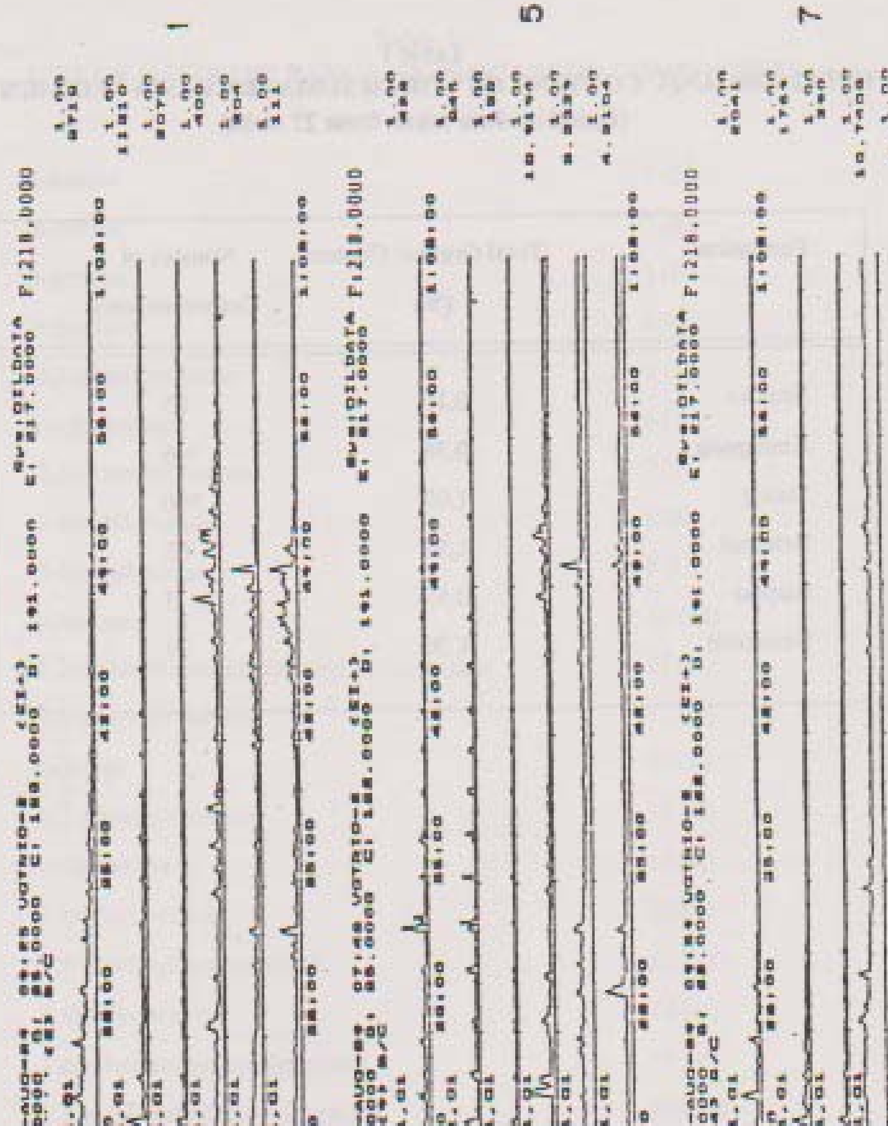


Figure 13. S.I.R of branched/cyclic fraction (1, 5, 7 wells)

Table 1
TOTAL ORGANIC CONTENT OF NORTH SUMATRA BASIN SEDIMENTS
(Based on data taken from 27 wells)

Formation	Total Organic Content (%)	Number of Determinations
Seurula	0.19	85
Keutapang	0.36	746
Baong	1.00	560
Belumai	1.36	65
Bampo	0.55	3
Basement	1.20	24

Table 2
LIST OF GASOLINE RANGE HYDROCARBON COMPONENTS

i-butane	1 (D)
n-butane	2 (E)
i-pentane	3 (F)
n-pentane	4 (G)
2,2-dimethyl butane	5 (H)
cyclopentane	6 (I)
2,3-dimethyl butane	7 (J)
2-methyl pentane	8 (K)
3-methyl pentane	9 (L)
n-hexane	10 (M)
2,2-dimethyl pentane/methyl cyclopentane	11 (N)
2,4 dimethyl pentane	12 (O)
benzene	13 (P)
3,3-dimethyl pentane	14 (Q)
cyclohexane	15 (R)
2-methyl hexane	16 (S)
1,1-dimethyl cyclopentane	17 (T)
3-methyl hexane	18 (U)
1,cis-3-dimethyl cyclopentane	19 (V)
1,trans-3-dimethyl cyclopentane	20 (W)
1,trans-2-dimethyil cyclopentane	21 (X)
3-ethyl pentane	22 (Y)
n-heptane	23 (Z)
1,cis-2-dimethyl cyclopentane/methyl cyclopentane	24 (AA)
ethyl cyclopentane	25 (AB)
toluene	26 (AC)