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REPORT ON A LIGHT HYDROCARBON, VITRINITE REFLECTIVITY, MAXIMUM PALAEOTEMPERATURE, SPORE COLOURATION AND SOURCE ROCK POTENTIAL ANALYSIS OF SAMPLES FROM THE MOBIL NORWAY 33/12-2 (NORTH SEA) WELL

by

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INTRODUCTION

The interval of the Mobil Norway 33/12-2 Well from 5,500 to 13,900 feet has been analysed for light hydrocarbons, vitrinite reflectivity, maximum palaeotemperature, spore colouration and source rock potential.

Sample were analysed for light hydrocarbons, vitrinite reflectivity, maximum palaeotemperature and source rock potential at one hundred feet intervals approximately from 5,500 to 11,300 feet. In the intervals 9,200 to 9,500 and 10,600 to 11,300 feet organic carbon screening was carried out so that only samples with greater than 0.3% organic carbon were analysed for source rock potential. From 11,300 to 13,900 feet samples were analysed for source rock potential at approximately 400 feet intervals. A total of fifty-two samples was analysed for source rock potential and vitrinite reflectivity analysis was carried out on fifty-one samples.

Samples were obtained as wet ditch cuttings preserved in the drill mud so that it was possible to carry out gaseous and gasoline range hydrocarbon analyses on these cuttings. Core samples were obtained in the interval from 8,662 to 8,692 feet and were sampled for all analyses. Where several different lithologies occurred in the same sample, the individual lithologies were sampled for organic carbon determinations.

Spore colouration analysis has been carried out on the interval from 8,160 feet to Total Depth.

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SOURCE ROCK POTENTIAL ANALYSIS

1. Definition of Problem

a. Type of Hydrocarbon

Compared with their ancient counterparts, recent sediments have low hydrocarbon contents and many of the hydrocarbons which are present not only in ancient sediments, but also in crude oils, are absent. This is particularly true of the hydrocarbons with between two and fourteen carbon atoms in the molecule (Sokolov, 1959; Dunton and Hunt, 1962; Kvenvolden, 1962) which constitute about 50% of most crudes. Clearly, recent sediments cannot yield compounds which they do not contain and therefore cannot source oil (Erdman, 1961). The Russians report accumulations of biologically-generated dry gas at relatively shallow depths (age uncertain) but these occurrences are anomalous and non-predictable. With the possible exception of methane, recent sediments do not possess a present source potential for hydrocarbons.

With increasing burial, it is observed that not only are the missing hydrocarbons formed, but the total hydrocarbon abundance increases (Philippi, 1965). This process is called maturation. The hydrocarbons are generated either from kerogen (insoluble organic matter) via non-hydrocarbon intermediaries (Tissot et al., 1971) or directly from the non-hydrocarbons which were originally present. In both cases, the non-hydrocarbons are the common denominator and hence source rock evaluation must consider the total soluble extract, which is the sum of the non-hydrocarbons (future potential) and the hydrocarbons (present potential). Catalytic cracking is probably significant in hydrocarbon generation, particularly in explaining differences between argillaceous and calcareous rocks, but the preference for normal hydrocarbons rather than their branched isomers shows that thermal cracking is dominant in maturation.

Hence, in response to the greater temperatures generated by increasing depths of burial, a negligible source potential is gradually replaced by a realisable potential for hydrocarbons. The first maturation reactions to occur are those which have low activation energies, such as the thermal generation of dry gas (methane). Light liquid hydrocarbons are still absent at this level of maturation which is termed IMMATURE. Immature rocks cannot source oil and only limited amounts of dry gas should be anticipated.

At higher temperatures, light liquid hydrocarbons are formed by the thermal cracking of larger molecules (Rogers and Koons, 1971; Bailey et al., 1973a; Durand and Espitalie, 1972). The sediments are now MATURE. The initial hydrocarbon liquids which are available for migration away from mature source rocks are heavy condensates (Savvina and Velikhovskii, 1968) and young oils with gravities of approximately 20°API (Rogers, Bailey et al., 1972). Tars result from the alteration of pre-existing crude oils and are not a primary product (Bailey et al., 1973b). As thermal maturation proceeds, more and more of the lighter hydrocarbons are cracked off the heavier compounds and the source rocks yield lighter crudes which ultimately, are replaced by light condensates. Hydrocarbon liquids can only be yielded by mature source rocks and the most prolific generation probably occurs in the centre of the maturation range between approximately 175°F and 275°F (Kartsev et al., 1971; Kontorovich, 1968; Radchenko, 1968; etc.). Although gas may also be found in rocks other than those which are mature, it is within the mature and more advanced stages that the most copious production occurs (Modelevskiy et al., 1972). Some sediments are gas-prone at levels of thermal alteration equivalent to the mature stage (Staplin, 1969; see below).

At advanced levels of thermal alteration ORGANIC METAMORPHISM destroys not only the ability of source rocks to yield liquid hydrocarbons but also any liquids which had previously accumulated in reservoirs. Only dry gas, which may contain significant amounts of H_2S and CO_2 can now be generated. With progressive metamorphism, the kerogen becomes increasingly rich in carbon and a poorer gas source until eventually it is converted into graphite and loses all potential even for dry gas. The mature level is replaced by the organic metamorphic state at a temperature approximately $150^{o}F$ lower than that necessary for greenschist metamorphism (Evans and Staplin, 1971) and hence thousands of feet above the first conventional metamorphism readily visible in hand specimen.

By definition, kerogen is that fraction of the total organic matter (commonly over 90%) which is insoluble in organic solvents. It consists of the organic matter which was sedimented and survived diagenesis, modified by the products of bacterial metabolism. Kerogen varies in character as a function of the proximity of the basin of deposition to sources of land plant and algal (freshwater or marine) debris. Although source rocks are laid down sub-aqueously rather than subaerially, their organic matter may originate either within the water body or from land (Rodionova and Maximov, 1970). This in turn affects the type of hydrocarbons which the sediment will yield : woody organic matter tends to be gas-prone regardless of its level of maturation (Staplin, Bailey et al., 1973); epicuticular plant waxes are a rich source of paraffinic-base crudes (Hedberg, 1968; Biederman, 1969; Reed, 1969), and the associated plant material is a more prolific source of gas than algal debris, which is primarily a rich source of more normal crudes.

b. Source Richness

Good source rocks must contain abundant hydrocarbons which are able to migrate into the reservoir. Migration is most efficient when the source and reservoir facies are interfingered. Thick shale intervals are less suitable.

Petroleum geochemistry is concerned with the source richness aspect. Lean rocks are unable to yield commercial amounts of hydrocarbons to the reservoir. As major hydrocarbon accumulations are the exception rather than the rule it is likely that the most favourable sources are of above average richness (i.e. shales with more than 1.14% organic carbon and 96 ppm heavy hydrocarbons (Gehman, 1962)), and this is borne out by experience. Although carbonates and particularly argillaceous carbonates, can source oil, the best sources are generally shales and siltstones. Sandstones are seldom significant as their organic matter content is not only low but has been oxidised during deposition, thus largely destroying its hydrocarbon potential. The lagoonal sands described by Palacas et al. (1972) are exceptional in the quality of their organic matter but are still lean.

As the soluble fraction of organic matter (soluble extract or bitumen) is generally less than 10% of the total and of this less than one half is hydrocarbons, sediments with less than approximately 0.3% organic carbon can be ignored. The best sources have more than approximately 2% organic carbon but excessively rich rocks such as oil shales and cannel coals may not realise their anticipated potential for oil (humic coals may be prolific gas sources). This is because migration of the liquid hydrocarbons may be prevented by their adsorption upon the abundant organic matter (Erdman, 1961; Philippi, 1965). As a result, a rock with 100 ppm heavy hydrocarbons (i.e. average shale) may have some source potential for oil if it contains 0.8% organic carbon but not at 8% organic carbon when the hydrocarbon to organic carbon ratio is an order of magnitude lower.

The higher the hydrocarbon to organic carbon ratio, the better the source (Erdman, 1961; Philippi, 1965). Immature rocks may be potentially rich sources but at their present level of maturation have low hydrocarbon to organic carbon ratios. This problem of evaluating future source potential is overcome by considering the ratio of soluble extract to organic carbon.

Source richness is also a function of kerogen type. Algal debris is commonly richer than land plant debris but nevertheless the latter is a perfectly valid exploration objective.

c. Conclusions

Source rock evaluation must include consideration of both the richness of the source and the type of hydrocarbon it will yield in its present maturation state. This necessitates analytical data on the total soluble extract, the proportion of hydrocarbons within it, and the organic carbon content.

2. Analytical Techniques

The analytical laboratory of Robertson Research International Limited is supervised by a qualified chemist. High standards are maintained and blanks are run routinely. Prior to submission for analysis, the samples are washed free from drilling mud and hand picked to remove obvious cavings and particulate contamination reflecting the drilling techniques employed (lost circulation material, paint etc.). Samples are crushed to minus 60 mesh and split into two, one portion being used for organic carbon determination and the other for extraction.

Carbonate material is removed from the first split by acid attack and the organic carbon content then measured with a Leco carbon analyser in which the amount of CO_2 generated by heating is calibrated by the change in thermal conductivity.

The other sample portion is Soxhlet extracted for 12 hours with 2:1 benzene-methanol to give the total soluble extract (saturates, aromatics and resins plus asphaltenes). The extract is then redissolved in n-pentane and saturates and aromatics separated and measured by high pressure liquid chromatography using a carbon specific FID detector for quantitification. This technique is more rapid than conventional liquid chromatography and can handle smaller samples.

3. Presentation and Interpretation of Data

The geochemical interpretation includes graphical presentations to highlight the exploration significance of the data.

Three diagrams are involved in the evaluation of source rock potential. The first of these ("Type of Hydrocarbon Product from Source Rocks") deals with the type of hydrocarbon (gas, oil) which the samples can yield at the present time. The two axes are the proportion of hydrocarbons in the total soluble extract and the proportion of the total organic carbon which the soluble extract constitutes - i.e. it is a plot of maturation state (incorporating the influence of different types of organic matter) against richness. Samples which are heavily oil-stained, or contaminated with other non-indigenous hydrocarbons (e.g. pipe dope etc.) can be recognised and the remainder qualified in terms of the type of hydrocarbon for which they have present potential. This decision is a function of the proportion of hydrocarbons in the total extract; with increasing maturation, the proportion of hydrocarbons increases (Tissot et al., 1971, etc.) indicating the onset and continued enhancement of oil source potential. Naturally there are "grey" areas between fields; within the central field, oil potential increases at the expense of gas in an upwards direction. The ratio of saturated (paraffins) to aromatic hydrocarbons is also considered but does not appear in the diagram. If a sample has some oil potential, its richness can be evaluated with the next diagram.

The source richness of samples which are sufficiently mature to yield oil can be determined directly from a plot of hydrocarbon abundance against organic carbon content ("Mature Source Rock Richness"). An estimate can also be made of the potential richness of immature samples (i.e. richness if the sample were mature in a down-dip position). The plot is divided into fields which are labelled to facilitate an evaluation of the relative amounts of liquid hydrocarbons which can be anticipated from a particular sediment. Samples with less than 0.3% organic carbon and 100 ppm hydrocarbons are considered to be too lean to constitute an effective source. Oil potential is divided from gas-with-minor-oil potential by the 100 ppm hydrocarbon line up to an organic carbon content of 1% using the reasoning that an effective oil source must be richer than the average shale (96 ppm hydrocarbons, 1.14% organic carbon; Gehman, 1962). In more organically-rich sediments, natural chromatography may prevent the release of liquid hydrocarbons into the reservoir and hence the extension of the boundary follows a hydrocarbon to organic carbon ratio value of 0.01. The oil field is divided into fair (commercial oil in non-frontier areas), good (major oil, commercial in all areas) corresponding closely with Philippi's (1965) definition of a source rock, and very good (highly desirable) source rocks. If the hydrocarbon to organic carbon ratio is above 0.2, the sample is oil-stained or otherwise contaminated with non-indigenous hydrocarbons. Naturally, lesser contamination may be present in samples which apparently possess oil source potential. The recognition of such effects requires an experience factor. Samples which fall into the gas-with-oil or gas field may contain significant quantities of heavy hydrocarbons but cannot source significant oil due to natural chromatography or the inadequate generation of the lighter liquid hydrocarbons necessary for migration. The potential of mature (oil-prone) samples equivalent to the immature (gas-prone) samples which were analysed can be estimated by assuming that ultimately, approximately 50% of the total extract will be converted into hydrocarbons.

The final diagram ("Source Rock Summary Chart") integrates the lithology of the samples as analysed, with certain analytical results (organic carbon content and hydrocarbon abundance with appropriate cut-offs, and EPOC, extract percent of organic carbon, which is the percentage of the organic carbon soluble in organic solvents), and the interpretations derived above (richness and product type). Maximum palaeotemperature measurements are included for ease of reference and comparison. The data are plotted against depth and the good source intervals can be recognised at a glance. EPOC is a measure of the potential source quality of immature samples, and the required additional burial to achieve maturity can be estimated from the temperatures necessary for maturity and the palaeogeothermal gradient. Using the same reasoning, the depth to organic metamorphism (and hence dry gas potential) can be estimated. If a section is gas-prone the maximum palaeotemperature can indicate why : immaturity, metamorphism, or organic matter unfavourable for oil generation.

Following the discovery of liquid hydrocarbons, it is important for future play evaluations to recognise those intervals which have demonstrated their oil potential.

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MAXIMUM PALAEOTEMPERATURE ANALYSIS

1. Definition of Problem

Recent sediments not only have a lower total abundance of hydrocarbons than more ancient sedimentary rocks, but those hydrocarbons with between two and fourteen carbon atoms in the molecule which are present in ancient sediments and which constitute up to fifty percent of a typical crude oil, are largely absent (Sokolov, 1957; Dunton and Hunt, 1962; Kvenvolden, 1962). Hence such rocks are unable to source oil (Erdman, 1961) but may have a limited potential for dry gas. Russian authors have reported accumulations of biologically-generated (biogenic) gas from young sediments but such instances are anomalous, non-predictable and cannot form the basis of an exploration play. With burial, hydrocarbon abundance increases (Philippi, 1965; Tissot et al., 1971) and more significantly, the previously absent lighter liquid hydrocarbons appear (Rogers and Koons, 1972; Durand and Espitalie, 1973; Bailey et al., 1973). This process is called maturation. Although catalytic cracking is undoubtedly significant, particularly in explaining differences between argillaceous and calcareous source rocks, the preference displayed for straight-chain compounds rather than their branched isomers indicates that maturation is dominated by the thermal cracking of pre-existing large molecules. In other words, it is temperature dependent.

As the formation temperatures due to burial increase, but prior to the appearance of all the C_2 to C_{14} hydrocarbons, the rocks develop some, but still limited, potential for dry gas. At this level of maturation they are still described as "IMMATURE".

When a complete spectrum of hydrocarbons has been generated, the sediments possess the ability to source liquid hydrocarbons and are termed

"MATURE". The initial products are heavy condensates (Savvina and Velikhovskii, 1968), and young oils (not tars) with gravities of around 20°API (Rogers, Bailey et al., 1972). As the maturation process proceeds, lighter oils are generated until eventually the heavier molecules are largely broken down and a potential for light condensate results. Naturally, the oil-condensate boundary is transitional. Liquid hydrocarbons can only be sourced by mature sediments. The most prolific gas sources correspond either to the mature or more advanced levels of thermal alteration (Modelevsky et al., 1972). With further thermal alteration only the lightest hydrocarbon, methane, is left and the source rocks only have a potential for dry gas. This is termed the level of "ORGANIC METAMORPHISM" and again, is transitional to the mature stage. Particularly in carbonates, the gas may be sour (Kozlov, 1950). Organic metamorphism occurs at temperatures approximately 150°F lower than those corresponding to the onset of the greenschist facies of conventional metamorphism (Evans and Staplin, 1971). The organic matter in "sediments" which have suffered greenschist facies metamorphism is converted to graphite and does not retain any potential for hydrocarbons.

Gas may be sourced without oil but oil is always accompanied by gas and hence the term "oil potential" is purely relative. Some sediments which should be sufficiently mature to source oil are in fact gas-prone due to the character of the kerogen which they contain (Staplin, 1969; Staplin, Bailey et al., 1973). Woody kerogen tends to yield dominantly gas whilst non-woody land plant material and algal debris are both oil-prone if mature, although the former yields more associated gas and requires a somewhat higher temperature to become mature (Nalivkin et al., 1967; Kontorovich, 1968). The influence of organic matter type is evaluated by integrating maximum palaeotemperature with source rock potential analysis unless a palynological examination is requested.

The length of time over which a sediment is exposed to a given temperature is also important as time and temperature are to some degree exchangeable and a reaction will proceed more nearly to completion if a longer time is allowed (Lopatin, 1971; Welte, 1972). The effect of time can be gauged from the fact that a Cretaceous sediment becomes mature at a temperature approximately 10°F lower than that necessary for a comparable Miocene rock.

Although the effects of kerogen type and time must be recognised, temperature dominates the maturation process. Approximate values can be applied to the various levels of maturation discussed above : 150°F for the immature gas to mature transition (Correia, 1969; Kartsev et al., 1971; Louis and Tissot, 1967; Kontorovich, 1968), 300°F for the oil to light condensate transition (Momper, 1972) and 350°F for the condensate to metamorphosed dry gas transition (Evans and Staplin, 1971; Momper, 1972). If the temperature to which a rock has been exposed can be measured, the sediment can be fitted into the correct slot (immature, mature, metamorphosed) and predictions can be made concerning neighbouring sections with different burial histories.

2. Analytical Techniques

Samples are washed and hand-picked to remove both contamination introduced during drilling and caved material, before being described and then submitted for analysis. The inorganic material is qualitatively removed by digesting the samples with acid and the kerogen concentrate is washed with an organic solvent to remove non-indigenous hydrocarbons.

During thermal cracking, free radicals (with unpaired electrons) are generated (Duchesne et al., 1961; Retcofsky et al., 1968; Marchand et al., 1969). Those which are associated with aromatic ring structures are protected from further reaction and provide a record of the thermal history of the kerogen. Hence, the higher the maximum temperatures to which the sample is exposed, the greater the number of unpaired electrons per unit of kerogen. These unpaired electrons are studied with an electron spin resonance spectrometer which measures the absorption, by kerogen placed in a varying magnetic field, of a fixed microwave frequency. Three parameters are obtained:

a. Ng - the number of unpaired electrons per gramme of organic carbon;

b. g - the spectroscopic splitting factor;

c. W - the width of the resonance signal in gauss.

Several hundred samples which, from geological and palaeontological reasoning, are believed to be at their maximum depth of burial at this time, have been selected as standards. Their formation temperatures are known from reliable formation and drillstem tests and from E-log measurements. The three ESR parameters discussed above have been calibrated against these formation temperatures and hence the maximum palaeotemperatures of unknown samples can be established. The practical application of ESR techniques has been discussed by Pusey (1973).

Internal standards are run constantly and reproducibility is excellent (± 15 °F).

3. Presentation and Interpretation of Data

The maximum palaeotemperature values are presented in tabular form and are illustrated graphically in two diagrams to facilitate their direct correlation with other geological data.

The first diagram is a plot of maximum palaeotemperature values against present-day depth of burial. A regression line is fitted to the data points and its correlation coefficient calculated (the data may indicate several legs rather than a single regression line). Its slope gives the palaeothermal gradient and the temperature at which it intercepts the surface is also quoted. Surface intercepts significantly higher than the temperatures prevailing in the basin of deposition, and jumps within the subsurface data points, both indicate the removal of section by erosion. Igneous activity may be recognised by distortion of the data.

The relevance of maximum palaeotemperature measurements to petroleum geochemistry is illustrated by the second diagram ("Source Rock Product as a Function of Thermal Alteration") which is a plot of temperature against the age of the rock (in millions of years). Uphole samples are plotted towards the top of the diagram and those which have experienced higher temperatures occur lower down.

The diagram is divided into three major fields all of which are transitional one to the other, but within each of which there is a most likely product :

1. The immature field has a potential only for dry gas and not for oil or other liquid hydrocarbons. Indeed, except at higher temperatures, it generally has a poor potential even for gas.

2. The mature field is the only one from which liquid hydrocarbons can be sourced. At the low temperature end it is prone to yield heavy condensates and young oils with gravities around 20°API. With higher temperatures, lighter oils are sourced until eventually, the oil field phases into the light condensate field within which the probability of oil diminishes progressively and that of gas increases. Oil potential is probably maximal between 175°F and 275°F. Oil generation is always accompanied by gas.

3. The field of organic metamorphism has a potential only for dry gas- sometimes with significant non-hydrocarbon contents. In carbonates the gas may be sour. At more advanced levels of metamorphism the

kerogen becomes increasingly carbon-rich and possesses a lower potential which is effectively destroyed prior to the onset of greenschist metamorphism.

Oil may be accumulated in an immature section if the reservoir is in communication with mature source rocks downdip. In contrast, organic metamorphism destroys not only the oil potential of source rocks but also any liquid hydrocarbons which had accumulated in reservoirs and hence metamorphosed sections are always dry gas objectives.

In addition to evaluating the present maturation state of a section, maximum palaeotemperature measurements can also be used predictively. For example, if a well only penetrated immature strata, the palaeothermal gradient can be projected (assuming constancy) downwards to estimate the depths at which the temperatures necessary for the onset of maturation and also organic metamorphism are achieved, thus defining the "oil envelope". Such predictions can also be extrapolated to include potential plays in nearby areas with similar depositional histories to provide pre-drill information.

It should be noted that interpretations discussed above may not apply to over-pressured sections due to the restraints imposed upon migration in such intervals.

A simplified composite of these two diagrams is included in the Source Rock Summary Chart to facilitate the integration of the total data pertaining to source rock evaluation.

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VITRINITE REFLECTIVITY ANALYSIS

1. Definition of Problem

Recent and very immature sediments can yield biologically-generated dry gas (which is only trapped under unusual conditions such as gas hydrate formation) but cannot source either oil or condensate. In response to the higher temperatures resulting from increased depths of burial, immature rocks become mature and then, at even higher temperatures, organically metamorphosed. This is discussed in greater detail in the 'Source Rock Potential' section. As immature sediments generally have little economic significance, whereas only mature sediments can yield oil, and metamorphosed sediments have a potential only for dry gas (often in major amounts), it is important to recognise the maturation state of the source rocks in the section.

This can be achieved by measuring the reflectivity (i.e. the proportion of the light from the light source which is reflected by the polished surface) of vitrinite macerals within the total kerogen. As the level of maturation increases, so too do the vitrinite reflectivity values, which can therefore be used to estimate the maturation state of the kerogen.

2. Analytical Techniques

The rock cuttings are mounted in a one-inch block of clear plastic resin and then ground and polished using successively finer grades of alumina until a good surface is achieved.

Reflectivity determinations are carried out on a Leitz M.P.V. microphotometer using optical glasses as standards. The field of measurement is adjusted to the size of the particle but is generally in the order of 2-3 microns. All measurements are made at a wavelength of 546 nm in oil of R.I. 1.516.

Whenever possible, twenty vitrinite particles are measured in sediment samples and the results used to construct a histogram and to calculate the mean value of the sample.

Using the whole sediment sample rather than a kerogen concentrate has the following advantages :

- it is easier to distinguish vitrinite from the other kerogen macerals, the measurement of which would give incorrect results;
- reworked and caved material can be more easily recognised and avoided;
- the possibility of alteration (oxidation) of the vitrinite during concentration is eliminated;
- oxidation caused by the excessive heating inherent in incorrect sample drying techniques (e.g. infra-red lamps) at the wellsite can be recognised and avoided.

3. Presentation and Interpretation of Data

An advantage of this method is that individual macerals can be examined and only those which are truly representative (i.e. ignoring reworked, caved and artificially oxidised material) recorded. Reworked material is commonly present and is a serious disadvantage of all the methods which involve the examination and measurement of the gross kerogen rather than of its individual macerals, as maturation levels significantly too high may be indicated. If this is the case then, for example, an uninteresting immature interval may be interpreted to be a prospective mature horizon. The same would be true if an interpretation were based upon artifically oxidised material whereas the use of caved sediments would underestimate the true level of maturation.

The analytical data, a histogram of these reflectivity determinations and the mean values for each sample are presented. In some cases three mean values are quoted; one referring to those measurements which are considered to be representative of the indigenous, unoxidised vitrinite (underlined), one referring to measurements on caved material, and one referring to reworked material. In most cases only one or two values will be quoted depending on the depth in the section. In addition, the equivalent, dry-ash-free carbon content of an equivalent coal is supplied for comparison with the work of Teichmuller (1971). Two diagrams are involved in the interpretation of the results. The first is a plot of the change in vitrinite reflectivity with depth in the well section. Reflectivity determinations based upon indigenous material are distinguished from those which are judged to be caved or reworked. A line is fitted to the selected data points. The second diagram is a plot of depth in the well section against the carbon content of an equivalent coal on the dry-ash-free basis. This diagram is included to give an indication of the 'rank' gradient down the hole.

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KEROGEN DESCRIPTION

The Nature and Terminology of Phytoclasts

In describing the visible components of kerogen, we have used many terms already defined for maceral description by coal petrologists. Below we list the main diagnostic features of the phytoclast types. Many of these distinctive types originate in soils, onshore flora and shoreline deposits before being enclosed in sediments but it should be borne in mind that in the sediment a large part of the kerogen may be amorphous and fine grained and not distinctive.

The kerogen types fall into groups which reflect their chemical characteristics.

Humic Substances

Vitrinites - formed by humification of woody tissue in wet anoxic conditions change in colour, red-brown translucent to opaque, and reflectivity in response to maturation.

1. VITRINITE (Structured)

1a. TELLINITE : Tracheids and woody tissue; yellow/yellowish red. Shows transverse or longitudinal cortical sections.

2. VITRINITE (Unstructured)

2a. COLLINITE : Degraded platey or finely divided amorphous organic debris; low relief yellowish brown/brown. Fractures in response to cleat or has vitreous fracture.

Inertinites - are carbon rich, undergo no changes during diagenesis, and are derived from woody tissue by oxidative degradation; they are often structured, with straight fracture.

3. INERTINITE (Structured)

3a. FUSINITE : Opaque, brightly reflective wood fragments with preserved cellular structure, usually subangular and platey; black, high relief and reflectivity.

3b. SEMIFUSINITE : As 3a but with brown body colour or periphery.

3c. SCLEROTINITE : Fungal hyphae; colourless - dark brown.

4. INERTINITE (Unstructured)

4a. FUSINITE : As 3a but lacking structural detail.

4b. SEMIFUSINITE : As 3b but lacking structural detail.

4c. MICRINITE : Essentially non-platey granular fragments; matt black, very high relief.

Sapropelic Substances

Exinites - Waxy and resinous, usually with distinctive morphology, respond to thermal maturation by colour changes, pale yellow through red, brown to opaque.

5. EXINITE (Structured)

5a. CUTINITE : plant cuticles; colourless - pale yellow and may show leaf-edge structures and epithelial cells.

5b. SPOROPOLLENIN : spores, pollen, dinoflagellate cysts and acritarchs: colourless-black.

5c. ALGINITE : Incutae sedis algal bodies e.g. *Pila tasmanites*, *Botryococcus* etc; colourless-black.

6. EXINITE (Unstructured)

6a. RESINITE : Large irregularly curved fragments with conchoidal fractures: typically yellow.

7. BITUMINOUS SAPROPELS

7a. BITUMEN : Irregular, unstructured masses with low relief; dark-brown to black with translucency in shades of red, brown and orange. Semi liquid aggregates, droplets or smears. If hard has curved outlines.

7b. JET : Like vitrinite but has conchoidal fracture and very low reflectivity: occurs in marine shales.

Miscellaneous

8. CHITINITE : Chitinous fragments of arthropods, graptolites etc.

III

RESULTS AND INTERPRETATION

1. Lithology

The analysed interval of the well can be classified lithologically as follows :

5,500 to 7,400 feet - essentially similar lithologies consisting of olive-grey to light olive-grey to green-grey mudstone throughout the interval with minor lithologies at certain intervals.

7,500 to 7,700 feet - olive-grey shale or shaly mudstone with 10% to 60% sand.

7,800 to 8,800 feet - grey shale throughout the interval with olive to light olive-grey shaly mudstone at 7,800, 8,000, 8,300 and 8,400 feet. The core samples covering the interval 8,662 to 8,692 feet consisted of medium olive-grey, micaceous, slightly carbonaceous shale. Sand and silt were common in the cuttings in the interval and constituted 80% of the sample from 8,200 feet. Lost circulation material was fairly common in the samples from 8,000 to 8,200 feet.

8,900 to 9,300 feet - green-grey to olive-grey shaly mudstone with 10% to 70% sand or silt. The sample at 9,200 feet was 90% sand and 10% shale.

9,410 to 11,300 feet - Mottled red/grey-green mudstone dominantly red below 9,700 feet. The samples from 9,410 and 9,500 feet were 60-70% sand and at 9,600 feet the sample contained 20% of silt or siltstone.

11,700 to 13,600 feet (T.D.) -	These samples were of red-brown calcareous mudstone varying to silty mudstone and siltstone. Traces of anhydrite were noticed at 11,700 feet and grey-green siltstone at 11,700 to 12,500 feet. The samples from 13,000 to 13,600 feet contained 20% to 30% grey calcareous shale and 5% to 10% white and pink sandstone.

2. Maturity

In this well four methods of maturation assessment have been used. They are (a) gasoline and gaseous hydrocarbon analysis, (b) vitrinite reflectivity analysis (c) maximum palaeotemperature analysis and (d) spore colouration analysis. The results of these analyses are described and discussed below and an integration of the data provides a composite evaluation of the well section.

a. Light Hydrocarbon Analaysis (Table 1 and Figures 1 and 2)

Analyses of the gaseous and gasoline range (C_1 to C_4 and C_5 to C_7) hydrocarbons have been carried out to determine the amounts and relative proportions of the adsorbed hydrocarbons in the kerogens throughout the well section. A total of forty-four samples were analysed. In twenty four samples measurable quantities of most of the constituent hydrocarbons were obtained and in most cases greater than 50 parts per billion (ppb) of gasoline range hydrocarbons were measured. In eighteen of the samples below 9,000 feet very little gaseous or gasoline hydrocarbons was obtained. All of these samples contained less than 50 ppb of gasoline hydrocarbons and the results are included at the end of Table 2.

Gaseous Hydrocarbons

In the analysis for the C_1 to C_4 (Methane through n-Butane) hydrocarbons the quantities measured, being less than 1 part per million (ppm), are rather less than expected and some loss of gaseous hydrocarbons has occurred. However, the hydrocarbons will have escaped in relatively proportional amounts so that the relevance of this analysis in determining maturity is not lessened in any way. Maturity in a section is determined by measuring the proportion of methane relative to the other C_2 to C_4 hydrocarbons (Ethane through n-Butane). In an immature sediment only methane of biogenic origin is found. With increasing maturity other hydrocarbons in this range are generated and the relative proportion of methane decreases.

The results for the well are included in Table 2 and Figure 1. The samples from 5,500 to 6,100 feet contained 76% to 88% of methane in the C_1 to C_4 range. They are therefore considered to be transitional between immature and mature sediments. That is original methane of biogenic origin(?) is being complemented by the other hydrocarbons being generated by thermal cracking of kerogen.

The samples below 6,700 feet contained 12% or less of methane and are therefore considered to be mature. Sample 29 from 8,300 feet contained the highest recorded concentration of gaseous hydrocarbons of 11 ppm which may be compared with the gasoline content of 15 ppm. This sample was the richest analysed in the well section. Concentrations of hydrocarbons encountered and a summary of maturity are included in Figure 1 and Table 2.

Gasoline Hydrocarbons

Gasoline hydrocarbon analysis has been complementary to gaseous hydrocarbon analysis in determining the onset of maturity in this well. In general maturity is indicated by all constituent gasolines listed in

Table 2 being present in approximately equal amounts. Differences in percentage abundances between two components should not be greater than one order of magnitude in a mature sediment. In immature sediments some components will be present in very high percentage abundance while others will not be present in measurable quantities at all and the total quantities of gasolines present will be low and generally less than 100 ppb.

The results from this well indicate that samples 1 and 2 (5,500 to 5,600 feet) are immature. Samples 3 to 13 (5,700 to 6,700 feet) are considered to be transitional to being mature with most constituent hydrocarbons being present but, certain hydrocarbons being present in abnormally large quantities. Samples 17 to 35 (7,100 to 8,900 feet) are considered mature. Gasoline hydrocarbon abundances tend to increase, though erratically from,1,463 (sample 17) to a maximum of 14,980 ppb (sample 29). The interval from sample 28 to 34 (8,200 to 8,800 feet) is particularly rich.

The abnormal leanness below 9,100 to 13,800 feet of less than 50 ppb of gasolines and less than 1 ppm of gaseous hydrocarbons is considered to be due to the extremely oxidised nature and concomitant organic leanness of the interval.

A summary of the concentrations of gasolines measured and the maturity assessment are indicated in Figure 2 and Table 2.

b. Vitrinite Reflectivity (Figure 3)

The results of the vitrinite reflectivity analysis, present a rather confused picture due to the great abundance of reworked material present in the upper part of the well section from 5,500 to 9,000 feet. Additionally below approximately 8,000 feet caving poses problems. The results are displayed graphically in Figure 3. In some samples it has been a difficult task to attribute the values obtained to reworking or caving, on the basis of the morphology of the organic material and lithology. However, it is felt that the final results show a fairly well defined rank gradient through the well to the base of the Jurassic section.

The trend through the Triassic portion of the well is fairly well defined but at rather high reflectivities of 1.35 to 1.55%. These values are attributed to reworked material although the particles of vitrinite appeared to be contemporaneous with the sediment. A good sample of red marl, sandstone and grey shale from 13,500 feet gave twenty two measurements with average reflectivity of 1.73%. It is almost certain that the measurements on the two samples at 10,500 to 10,700 feet are on caved material on lithological similarities.

The rank gradient obtained rises steadily from 0.4% at 5,500 feet to approximately 0.5% at 7,000 feet. From 7,000 to 9,500 feet it has proved very difficult to distinguish between measurements due to caved, indigenous and reworked vitrinite. The reflectivity values in this interval have been averaged to obtain a gradient which rises from 0.5% at 7,000 feet to 0.7% at 9,500 feet. Below 9,500 feet we believe, no indigenous material was present. The stratigraphic succession shows no break between the base of the Jurassic and the lean Triassic sediments. Spore colouration measurements made on the well have shown a continuous gradient through the Jurassic-Triassic boundary. On balance we therefore suspect that the reflectivity measurements have been carried out on reworked vitrinite of high rank and that the true level of maturity is lower than that suggested by the observed reflectivity values.

Examination in Ultraviolet Light

Examination of exinite fluorescence of the samples under ultra-violet light has substantiated the result obtained by reflectivity measurements.

Good yellow fluorescence was obtained from spores in the upper section of the well in Tertiary sediments. Exinite content in the Tertiary sediments was variable with the interval 5,500 to 5,600 feet appearing moderate to rich, while the interval 5,700 to 6,100 feet were lean with only a trace, or no exinite observed.

Orange fluorescence occurs in the Cretaceous sediments indicative of greater maturity. Exinite content was again variable, being fairly abundant in the intervals 6,500, 6,700 to 7,200, 7,700 and 7,900 to 8,100 feet. The intensity of fluorescence noted was also variable.

The Jurassic section of the well contains phytoclasts with variable fluorescence. The interval from 8,300 to 8,500 feet contains dully fluorescing organic components while the sample at 8,200 feet was barren of fluorescing exinitic material. These characteristics are possibly due to oxidation related to the presence of the extensive unconformity immediately above these samples. Below 8,600 to 9,400 feet good fluorescence was noted in general. Abundance of exinitic material is variable, being high in the interval 8,400 to 8,900 feet but rare from 9,000 to 9,400 feet. A possibly significant observation under ultraviolet light is the presence of fluorescence due to hydrocarbon films in the samples from 9,000 to 9,100 feet.

The Triassic section of the well is organically very lean. Exinite was generally absent but the samples from 9,900, 10,500, 13,300, 13,500 and 13,600 feet showed a trace organic content in some cuttings, while the rest had no exinite content. It is considered very likely that the exinite observed was caved. From the results arising from what is believed to be indigenous vitrinite, the reflectivity measurements and ultraviolet examination indicate that the interval from 5,500 to approximately 7,000 feet is immature and probably incapable of sourcing significant yields of gas or oil. The interval from 7,000 to approximately 9,500 feet ranges in reflectivity from 0.5 to 0.7% and should be at a maturity level capable of sourcing low tending to medium ^{o}API gravity oil from oil-prone source rocks with increasing depth.

c. Maximum Palaeotemperature (Table 1 and Figure 4)

The quality of some of the maximum palaeotemperature data obtained for this well is unfortunately rather poor. Since the method involves analysis of the total kerogen, it is very susceptible to the effect of reworked and caved material. In situations where reworking and caving is rare, very good results and good correlations with other maturation indices can be obtained.

In the well it can be seen (figure 4) that the temperatures at the top of the section analysed appear to be at the same level as those at 8,000 to 10,000 feet. These results can be compared to the reflectivity figure which shows abundant high reflecting reworked material in this interval. On the basis of the results from the interval 8,000 to 10,000 feet, which appear perhaps reasonable; a rough palaeothermal gradient has been calculated. The temperatures rise from approximately 225^{o}F in the Middle Jurassic (8,500 feet) to approximately 300^{o}F at total depth. Our experience with analysis of kerogens from red-beds in other basins, suggests that the temperatures may be on the low side below 9,500 feet. The quality of the data in the samples from 13,300 and 13,600 feet is good and these temperatures may be fairly accurate.

A palaeotemperature of approximately 300^{o}F at the bottom of the hole is indicated.

d. Spore Colouration Analysis

The maturation of kerogen during diagenesis has been described by a number of workers of whom Correia (1967 and 1971), Staplin (1969) and Gutjahr (1966) have referred specifically to modifications of sporopollenin. One effect of maturation processes on sporopollenin is to increase the visible colour density from pale yellow, through orange and brown to black. The determinative procedures outlined by Staplin (1969) have been largely followed in this study, except that a ten-point scale of colour indices has been utilized rather than the five-point scale adopted by Staplin. A quantitative assessment of kerogens has not been attempted although dominant kerogen types are noted.

Colouration analysis has been carried out on samples from 8,160 feet to total depth. The results are described below :

Interval 8,160 Feet

The dominant kerogens are semifusinite with some collinite, tellinite and bituminous debris. Spore colouration indices are 2.5 to 3 indicative of low maturity. Unfortunately the palynofloras recorded are too sparse to allow an accurate assessment to be made, and caved assemblages predominate.

Interval 8,180 to 8,270 Feet

Semifusinite again dominates the kerogens although collinite is more abundant at 8,270 feet. Spore colouration indices are 4 to 4.5, indicative of moderate maturity.

Interval 8,290 to 8,750 Feet

Vitrinite (collinite and tellinite) and inertinite (semifusinite) dominate the kerogen contents, although sporopollenin is moderately abundant. Caving is often apparent, sometimes in abundance and the in situ palynofloras are generally corroded and poorly preserved. Spore colouration indices are 4.5 to 5, indicative of mderate maturity.

Interval 8,830 to 12,400 Feet

Assemblages recorded from this interval are composed almost entirely of caved material with little that could be positively identified as being in situ. Spore colouration indices in the upper part continue in the range 4.5 to 5. In the sidewall core at 10,903 feet, fusinite and semifusinite are the dominant kerogens and the colouration index is 6.5. In the sidewall cores at 11,196, 12,343 and 12,378 feet, semifusinite and fusinite were recorded, but no palynomorphs: in the sidewall core at 11,290 feet, fine fusinite, semifusinite and micrinite, but again no palynomorphs, were recorded. The lower samples, below 9,360 feet are virtually barren of in situ material.

Interval 12,410 to 14,240 Feet

Although cutinite and tellinite are common in the interval 12,410 to 12,580 feet, fusinite and semifusinite are the dominant kerogens. Caved material still predominates, although spore colouration indices for the presumed in situ palynofloras which range from 7 to 7.5 (12,410 to 12,910 feet), 7.5 (12,910 to 13,510 feet) and 7.5 to 8 (13,510 to 14,240 feet) enable the caved material to be readily differentiated. These colouration indices indicate a high degree of maturity at base.

e. Comparison of Maturation Indices (Figure 5)

Information on the maturation state of the well section has been obtained by means of light hydrocarbon analysis, vitrinite reflectivity, maximum palaeotemperature and spore colouration. The results are summarised in figure 5. While too much emphasis should not put on the absolute correlation values at the base of the figure it can be seen that a good degree of coincidence is obtained. Light hydrocarbon analysis has indicated the beginning of maturity at 7,100 feet. This corresponds to an interpreted reflectivity value of 0.5%. Maximum palaeotemperatures were not extended higher in the well than 7,500 feet and in any case, the interpreted values are not considered absolute. Spore colouration measurements were only begun in the Jurassic section of the well and so no results are available higher than 8,160 feet in the well. It is noted that spore colouration shows a jump in alteration from the Kimmeridgian sample to the Middle Jurassic coinciding with the observed unconformity. The colouration index increases from 2.5 to 3 in the Kimmeridgian to 4 to 4.5 in the Middle Jurassic immediately below. Thereafter close parallelism exists between the spore colouration index and maximum palaeotemperature to the base of the well.

The whole of the well section below 7,100 feet is mature and is still mature (not metamorphosed) at total depth. Organically rich sediments below total depth could still be prospective for condensate. In this context, attention is drawn to the occurrence of quite rich hydrocarbon contents in the samples below 10,100 feet.

3. Source Rock Potential (Table 1 and Figures 6, 7 and 8)

On the basis of the geochemical analysis results, the interval of the well examined falls into four groups :

a. Samples 1 to 25 (5,500 to 7,900 feet)

This interval of the well is thermally immature or marginally mature. The organic content of this group of olive-grey shales and mudstones is poor ranging from 0.17% to 0.72% with the majority of samples in the 0.4% to 0.5% range. Shales on average are reported to contain between 1% and 2% organic carbon and on this basis these samples are lean to very lean. The extractability of the organic matter in solvent, varies from 3.9% to 21.8% with most samples in the 10% to 15% range and such values are perhaps a little high for immature sediments. The abundances of hydrocarbons are low, varying from 25 to 130 ppm.

The likely product from these samples (figure 6) is gas, apart from samples 1, 5, 7, 11, 15 and 18 which could source gas-with-minor oil and samples 10 and 12 which might source gas-with-oil. Generally speaking the interval is immature gas-prone on the basis of the percentage of hydrocarbons in the extract. The richness of the samples as oil-sources (figure 7) is generally poor, apart from samples 11, 12, 14, 15, 16, 18 and 19 which are rated as fair oil sources. The abundances of hydrocarbons are still low and non-prospective in this area.

b. Samples 26 to 32 (8,000 to 8,600 feet)

The organic content of this small group of shale samples is good and ranges from 2.11% to 4.44%. There was insufficient material after washing for analysis of the rich sample (4.44% organic carbon) from 8,200 feet. The extractability of the organic matter is very variable between 3.0% and 14.2%. These samples have values of 3.0% to 5.1% which are very low. The abundance of hydrocarbons ranges from 130 to 700 ppm which in considering the maturity and organic richness of these samples is rather low.

The likely product from these samples (figure 5) is usually gas except for samples 30 and 31 which should source oil-with-gas and gas-with-oil respectively. The richness of the samples as oil-sources (figure 6) is fair - samples 27, 29, 31 and 32, good - sample 30, while sample 26 should source gas. To be a good gas source rock a sample requires to have an organic content of 2% or more. On this basis all samples should source good quantities of gas or gas-with-oil.

c. Samples 33 to 41 (8,662 to 9,100 feet)

This interval of Lower Jurassic shales and sandstone has variable organic content between 0.43% and 1.40%; values varying from lean to about average. The core sample from 8,662 to 8,692 feet which was sampled every ten feet has organic content of 0.92% to 1.40%. The extractability values for the core were fairly constant and the abundance of hydrocarbons is 100 to 120 ppm which is rather low for shales with average carbon content at this level of maturity.

The extractability of the samples was higher than the overlying group of samples and ranged from 6.1% to 13.4%. Hydrocarbon abundances of 40 to 90 ppm, excluding the core sample, are low.

The likely product from these source rocks is gas (figure 5) and with the exception of the shale in the core which has a fair rating in richness terms (figure 6), the rest of the samples are lean.

d. Samples 42 to 71 (9,200 to 13,900 feet)

These samples are mature on the basis of maximum palaeotemperatures and spore colouration. The organic content is very poor throughout this interval and with one exception (0.48%) less than 0.20% organic carbon. In view of the red and oxidised nature and the organic content of these rocks there can be no source potential. The general leanness of the section is reflected in the hydrocarbon abundances except that from 10,100 feet to total depth some quite high concentrations were measured - 80 to 460 ppm. These samples, it is believed, are contaminated by migrant oil possibly from a deeper prospect, since the overlying red-beds are virtually barren.

IV

CONCLUSIONS

As a result of the present study of the Mobil 33/12-2 Well for maturity and source rock potential, the following conclusions are drawn :

5,500 to 7,000 feet - Thermally immature - source rocks lean and non-prospective.

7,100 to 7,900 feet - Thermally mature - source rocks lean and non-prospective.

8,000 to 8,600 feet - Thermally mature - the interval is organically rich but dominated by gas-prone organic matter. The interval at 8,400 feet is a good source for oil-with-gas and at 8,500 feet a fair source for gas-with-oil. The oil products will be dominantly heavy to medium gravity oil.

8,700 to 9,100 feet - Thermally mature - source rocks are in general, lean and non-prospective. The organic matter is largely gas-prone and at best could source minor oil.

9,200 to 13,600 feet - Thermally mature - source rocks are very lean. Hydrocarbon abundances in the interval 9,600 to 10,000 feet are very low. From 10,100 to 13,600 feet oil-stain is apparent possibly derived from greater depth where gas condensate may be expected from oil-prone sediments.

APPENDIX I

ABBREVIATIONS USED IN ANALYTICAL DATA SHEETS

-	-	Sample not analysed			
*	-	No results obtained			
C.M.T.	-	Cement	L.C.M.	-	Lost circulation material
Cht	-	Chert	Qtz	-	Quartz
Snd	-	Sand	Sst	-	Sandstone
Slt	-	Silt	Sltst	-	Siltstone
Cgl	-	Conglomerate	Mdst	-	Mudstone
Clyst	-	Claystone	Cly	-	Clay
Sh	-	Shale	Dol	-	Dolomite
Lstn	-	Limestone	Chk	-	Chalk
Lig	-	Lignite	Musc	-	Muscovite
Sndy	-	Sandy	Slty	-	Silty
Shly	-	Shaly	Arg	-	Argillaceous
Aren	-	Arenaceous	Carb	-	Carbonaceous
Calc	-	Calcareous	Mic	-	Micaceous
Ool	-	Oolitic	Sil	-	Siliceous
Fer	-	Ferruginous	Lam	-	Laminae/laminated
Frags	-	Fragments	Pp	-	Purple
Brn	-	Brown	Yel	-	Yellow
Gy	-	Grey	Gn	-	Green
Ol	-	Olive	Blk	-	Black
Wht	-	White	Bl	-	Blue
Mtl	-	Mottled	Vgt	-	Variegated
Sft	-	Soft	Hd	-	Hard
Tr	-	Trace	Occ	-	Occasional
Sl	-	Slightly	V	-	Very
Lt	-	Light	Dk	-	Dark
Med	-	Medium	Crs	-	Coarse
Mnr	-	Minor ($<$ 10%)	Pyr	-	Pyrite/pyritic
Gy-gn	-	Greyish green	Gn-gy	-	Greenish grey
Gn/gy	-	Green and/to grey			

TABLE 1

MAXIMUM PALAEOTEMPERATURE AND SOURCE ROCK POTENTIAL (C_{15+} FRACTION) DATA

CLIENT MOBIL (NORWAY) WELL 33/12-2 LOCATION NORTH SEA

SAMPLE NUMBER	DEPTH (FEET)	TYPE OF SAMPLE	LITHOLOGY	MAXIMUM PALAEO-TEMP (°F)	ORGANIC CARBON % OF ROCK	TOTAL EXTRACT P.P.M. OF ROCK	EXTRACT % OF ORGANIC CARBON	HYDRO-CARBONS P.P.M. OF ROCK	HYDRO-CARBONS % OF EXTRACT	SATURATES* % OF HYDRO-CARBON	REMARKS
1.	5500	Cuttings	Lt ol-gy mdst + mnr red mdst	237	0.17	370	21.8	70	19	57	
2.	5600	"	Ol-gy/lt ol-gy mdst + mnr dk gy sst (?basalt)	232	0.27	390	14.4	30	8	32	
3.	5700	"	Ditto + mnr ditto	228	0.37	470	12.7	80	17	35	
4.	5800	"	Ditto	241	0.39	600	15.4	80	14	40	
5.	5900	"	Lt ol-gy mdst	250	0.34	390	11.5	75	19	53	
6.	6000	"	Ditto, occ slty (tr diesel)	255	0.40	570	14.3	25	4	35	
7.	6100	"	Ditto, occ gy-gn	257	0.47	430	9.1	85	20	61	
8.	6200	"	Ditto, occ gy-gn	271	0.50	500	10.0	55	11	41	
9.	6300	"	Ditto, occ gy-gn (tr diesel)	247	0.41	450	11.0	60	13	51	
10.	6400	"	Ditto, occ gy-gn (tr diesel)	258	0.38	150	3.9	35	23	31	
11.	6500	"	Ditto, occ gy-gn	247	0.42	510	12.1	100	19	46	
12.	6600	"	Lt ol-gy/gn-gy mdst	244	0.38	580	15.3	130	23	36	
13.	6700	"	Ditto	265	0.43	440	10.2	65	15	45	
14.	6800	"	Ditto	256	0.43	680	15.8	110	16	34	
15.	6900	"	Ditto, occ slty	271	0.48	480	10.0	100	21	32	
16.	7000	"	Ditto + tr red-brn mdst	265	0.52	610	11.7	90	15	37	
17.	7100	"	Ditto	253	0.51	450	8.8	65	14	34	

* SATURATES = Sum of naphthenes normal and iso-paraffins

TABLE 1 Cont'd

MAXIMUM PALAEOTEMPERATURE AND SOURCE ROCK POTENTIAL (C_{15+} FRACTION) DATA

CLIENT MOBIL (NORWAY) WELL 33/12-2 LOCATION NORTH SEA

SAMPLE NUMBER	DEPTH (FEET)	TYPE OF SAMPLE	LITHOLOGY	MAXIMUM PALAEO-TEMP (°F)	ORGANIC CARBON % OF ROCK	TOTAL EXTRACT P.P.M. OF ROCK	EXTRACT % OF ORGANIC CARBON	HYDRO-CARBONS P.P.M. OF ROCK	HYDRO-CARBONS % OF EXTRACT	SATURATES* % OF HYDRO-CARBON	REMARKS
18.	7200	Cuttings	Ditto + tr red-brn mdst	265	0.59	450	7.6	80	18	33	
19.	7300	"	Gy-gn mdst, occ lt ol-gy	259	0.53	530	10.0	85	16	40	
20.	7400	"	Ditto + tr slt/sst	269	0.72	510	7.1	65	13	46	
21.	7500	"	Ol-gy sh/shly mdst + 10% snd	231	0.46	480	10.4	60	13	42	
22.	7600	"	Ditto + 60% snd	233	0.39	-	-	-	-	-	
23.	7700	"	Ditto + 60% snd	*	0.38	-	-	-	-	-	
24.	7800	"	Gy sh + ol-gy sh/shly mdst + 20% snd	272	0.48	480	10.0	75	16	42	
25.	7900	"	Ditto + mud + slt	263	0.58	-	-	-	-	-	
26.	8000	"	Ditto + ol-gy sh/shly mdst + mnr snd + LCM	222	4.20	1270	3.0	130	10	56	
27.	8100	"	Ditto + mnr snd + LCM	222	2.12	3000	14.2	260	9	39	
28.	8200	"	Ditto + 80% slt + mnr mica	225	4.44	-	-	-	-	-	
29.	8300	"	Ditto + 20% lt ol-gy mdst + 30% slt	253	2.11	2650	12.6	340	13	57	
30.	8400	"	Ditto + 20% ditto	243	2.19	2170	9.9	700	32	42	
31.	8500	"	Ditto + 20% slt	225	3.88	1580	4.1	360	23	57	
32.	8600	"	Ditto + 20% slt	250	2.84	1440	5.1	220	15	55	

***SATURATES** = Sum of naphthenes normal and iso-paraffins

TABLE 1 Cont'd

MAXIMUM PALAEOTEMPERATURE AND SOURCE ROCK POTENTIAL (C_{15+} FRACTION) DATA

CLIENT MOBIL (NORWAY) WELL 33/12-2 LOCATION NORTH SEA

SAMPLE NUMBER	DEPTH (FEET)	TYPE OF SAMPLE	LITHOLOGY	MAXIMUM PALAEO-TEMP (°F)	ORGANIC CARBON % OF ROCK	TOTAL EXTRACT P.P.M. OF ROCK	EXTRACT % OF ORGANIC CARBON	HYDRO-CARBONS P.P.M. OF ROCK	HYDRO-CARBONS % OF EXTRACT	SATURATES* % OF HYDRO-CARBON	REMARKS
33.	8662	Core	Med ol-gy mic sl carb sh	256	0.92	710	7.7	110	15	38	
34.	8672	"	Ditto	255	0.92	750	8.2	110	15	34	
35.	8682	"	Ditto	270	1.40	940	6.7	120	13	41	
36.	8692	"	Ditto	275	1.20	730	6.1	100	14	42	
37.	8700	Cuttings	Ditto + 20% slt	240	1.13	-	-	-	-	-	
38.	8800	"	Gy/ol-gy sh (occ slt lam) + 20% slt + mnr pyr	252	1.19	970	8.2	70	7	68	
39.	8900	"	Ol-gy shly mdst + 10% gn sh + 20% snd/slt + mnr lstn	223	0.72	780	10.8	90	12	40	
40.	9000	"	Gy-gn shly mdst + 40% crs snd	251	0.73	980	13.4	90	9	50	
41.	9100	"	Ditto + 50% snd	253	0.43	550	12.8	40	7	52	
42.	9200	"	Med gy snd + 10% sh	*	0.11	-	-	-	-	-	
43.	9300	"	Gn shly mdst + 70% med gy snd	*	0.14	-	-	-	-	-	
44.	9410	"	Mtl red/gy-gn mdst + 10% gn shly mdst + 60% snd	240	0.20	-	-	-	-	-	
45.	9500	"	Ditto + 10% gy/gy-gn shly mdst + 70% snd	244	0.13	-	-	-	-	-	
46.	9600	"	Ditto + 20% slt/slt-st	212	0.48	370	7.7	85	23	71	
47.	9700	"	Ditto (mainly red)	229	0.10	330	33.0	55	17	75	

* SATURATES = Sum of naphthenes normal and iso-paraffins

TABLE 1 Cont'd

MAXIMUM PALAEOTEMPERATURE AND SOURCE ROCK POTENTIAL (C_{15+} FRACTION) DATA

CLIENT MOBIL (NORWAY) WELL 33/12-2 LOCATION NORTH SEA

SAMPLE NUMBER	DEPTH (FEET)	TYPE OF SAMPLE	LITHOLOGY	MAXIMUM PALAEO-TEMP (°F)	ORGANIC CARBON % OF ROCK	TOTAL EXTRACT P.P.M. OF ROCK	EXTRACT % OF ORGANIC CARBON	HYDRO-CARBONS P.P.M. OF ROCK	HYDRO-CARBONS % OF EXTRACT	SATURATES* % OF HYDRO-CARBON	REMARKS
48.	9820	Cuttings	Ditto, (some yel-brn)	295	0.14	430	30.7	55	13	72	
49.	9900		Ditto (some yel-brn)	248	0.07	240	34.3	40	17	78	
50.	10000	"	Ditto	242	0.08	220	27.5	40	18	84	
51.	10100	"	Ditto	*	0.07	240	750%	460	9	64	
52.	10200	"	Ditto	222	0.08	170	21.3	160	94	63	
53.	10300	"	Ditto	245	0.09	790	87.8	130	16	63	
54.	10400	"	Ditto	*	0.09	1290	143%	240	19	58	
55.	10500	"	Ditto,	212	0.13	170	13.1	100	59	42	
56.	10610	"	Ditto	-	0.10	-	-	-	-	-	
57.	10700	"	Ditto	-	0.11	-	-	-	-	-	
58.	10800	"	Ditto	-	0.16	-	-	-	-	-	
59.	10890	"	Ditto	-	0.14	-	-	-	-	-	
60.	11000	"	Ditto	-	0.11	-	-	-	-	-	
61.	11100	"	Ditto	-	0.10	-	-	-	-	-	
62.	11200	"	Ditto	215	0.12	470	39.2	180	39	31	
63.	11300	"	Ditto	-	0.12	-	-	-	-	-	
64.	11700	"	Red-brn calc mdst/slty mdst/sltst + tr anhy+ gy-gn sltst	245	0.08	480	60.0	80	17	41	
65.	12100	"	Ditto (occ banded gy-gn)	233	0.09	270	30.0	130	48	40	
66.	12500	"	Ditto	257	0.18	210	11.7	100	48	42	

*SATURATES = Sum of naphthenes normal and iso-paraffins

TABLE 1 Cont'd

MAXIMUM PALAEOTEMPERATURE AND SOURCE ROCK POTENTIAL (C_{15+} FRACTION) DATA

CLIENT MOBIL (NORWAY) WELL 33/12-2 LOCATION NORTH SEA

SAMPLE NUMBER	DEPTH (FEET)	TYPE OF SAMPLE	LITHOLOGY	MAXIMUM PALAEO-TEMP (°F)	ORGANIC CARBON % OF ROCK	TOTAL EXTRACT P.P.M. OF ROCK	EXTRACT % OF ORGANIC CARBON	HYDRO-CARBONS P.P.M. OF ROCK	HYDRO-CARBONS % OF EXTRACT	SATURATES* % OF HYDRO-CARBON	REMARKS
67.	13000	Cuttings	Ditto + 20% gy calc sh + 5% wht sst	-	0.17	-	-	-	-	-	
68.	13300	"	Ditto + 20% ditto + 10% pink sst	296	0.19	560	29.5	140	25	37	
69.	13500	"	Ditto + 30% ditto + 5% ditto	-	0.25	-	-	-	-	-	
70.	13600	"	Ditto + 30% ditto + 5% ditto	288	0.27	300	11.1	100	33	50	
			ORGANIC CARBONS								
21.	7500	"	Gy sh		0.76						
32.	8400	"	Ditto		0.82						
39.	8900	"	Ol-gy shly mdst		1.30						
39.	8900	"	Gn sh		0.11						
43.	9300	"	Gn shly mdst		0.16						
66.	12500	"	Red-brn calc mdst		0.16						
71.	13800-900	"	Red sh		0.12						
71.	13800-900	"	Gy sh		0.66						

*SATURATES = Sum of naphthenes normal and iso-paraffins

TABLE 2

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY
WELL 33/12-2
LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	1		2		3		4	
DEPTH (FEET)	5500		5600		5700		5800	
	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$
C_1	*	80	*	*	*	79.0	*	76
C_2	*	3.5	*	*	*	7.5	*	6.5
C_3	*	7.5	*	*	*	6.0	*	8
iC_4	*	4.4	*	*	*	3.5	*	4
nC_4	*	4.4	*	*	*	3.5	*	5.5
TOTAL	<1	99.8	< 1	*	< 1	100	<1	100

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	1		2		3		4	
DEPTH(FEET)	5500		5600		5700		5800	
	P. P. B.	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$	P. P. B	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$
ISO-PENTANE	*	*	*	*	2	1	6	2
N-PENTANE	14	82	18	100	28	16	48	14
CYCLOPENTANE	*	*	*	*	1	<1	1	<1
2-ME. PENTANE	*	*	*	*	8	5	22	6
3-ME. PENTANE	*	*	*	*	4	2	9	3
N-HEXANE	*	*	*	*	9	5	28	8
ME. CYCLOPENTANE	*	*	*	*	1	<1	3	1
CYCLOHEXANE	1	6	*	*	70	40	94	28
2-ME. HEXANE	*	*	*	*	tc	*	tc	*
3-ME. HEXANE	*	*	*	*	14	8	28	8
3-ETHYLPENTANE	*	*	*	*	7	4	16	5
N-HEPTANE	*	*	*	*	13	7	30	9
BENZENE	2	12	*	*	6	3	23	7
DI-ME PENTANE	*	*	*	*	2	1	5	1
ME. CYCLOHEXANE	*	*	*	*	10	6	26	8
TOTAL	17	100	18	100	175	100	339	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY WELL 33/12-2 LOCATION NORTH SEA

GAS (C_1 - C_4)

SAMPLE NO.	5		6		7		8	
DEPTH (FEET)	5900		6000		6100		6200	
	P.P.M.	%C_1 - C_4	P.P.M.	%C_1 - C_4	P.P.M.	%C_1 - C_4	P.P.M.	%C_1 - C_4
C_1	*	78	tc	*	*	88	*	65
C_2	*	3	tc	*	*	3	*	3
C_3	*	12	*	*	*	6	*	6
iC_4	*	7	*	*	*	1.5	*	13
nC_4	*	*	*	*	*	1.5	*	13
TOTAL	<1	100	<1	100	<1	100	<1	100

GASOLINE RANGE (C_5 - C_7)

SAMPLE NO.	5		6		7		8	
DEPTH (FEET)	5900		6000		6100		6200	
	P.P.B.	%C_5 - C_7	P.P.B.	%C_5 - C_7	P.P.B	%C_5 - C_7	P.P.B.	%C_5 - C_7
ISO-PENTANE	9	1	tc	*	28	3	18	2
N-PENTANE	76	12	*	*	76	8	48	5
CYCLOPENTANE	2	<1	*	*	5	<1	3	<1
2-ME. PENTANE	52	8	*	*	100	10	90	9
3-ME. PENTANE	24	4	*	*	46	5	52	5
N-HEXANE	64	10	*	*	108	11	104	11
ME. CYCLOPENTANE	9	1	*	*	27	3	28	3
CYCLOHEXANE	72	11	*	*	124	12	80	8
2-ME. HEXANE	tc	*	*	*	tc	*	tc	*
3-ME. HEXANE	90	14	*	*	120	12	106	11
3-ETHYLPENTANE	48	7	*	*	78	8	88	9
N-HEPTANE	76	12	*	*	96	10	116	12
BENZENE	15	2	*	*	20	2	33	3
DI ME PENTANE	16	2	*	*	21	2	20	2
ME. CYCLOHEXANE	92	14	tc	*	144	15	184	19
TOTAL	645	100	< 50	100	993	100	970	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY
WELL 33/12-2
LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	9		10		13		17	
DEPTH (FEET)	6300		6400		6700		7100	
	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$
C_1	tc	*	tc	*	*	12	*	*
C_2	*	*	tc	*	*	2	*	*
C_3	*	*	tc	*	*	4	*	*
iC_4	*	*	*	*	*	27	*	*
nC_4	*	*	*	*	*	55	*	*
TOTAL	tc	*	<1	*	0.01	100	< 1	100

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	9		10		13		17	
DEPTH (FEET)	6300		6400		6700		7100	
	P. P. B.	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$	P. P. B	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$
ISO-PENTANE	11	2	3	1	80	50	23	2
N-PENTANE	188	29	48	24	5	3	184	13
CYCLOPENTANE	tc	*	*	*	4	3	5	<1
2-ME. PENTANE	32	5	9	4	14	9	84	6
3-ME. PENTANE	14	2	4	2	4	3	52	4
N-HEXANE	42	6	10	5	5	3	140	10
ME. CYCLOPENTANE	7	1	4	2	4	3	40	3
CYCLOHEXANE	38	6	60	30	9	6	68	5
2-ME. HEXANE	40	6	9	4	*	*	92	6
3-ME. HEXANE	60	9	13	6	7	4	136	9
3-ETHYLPENTANE	34	5	7	3	*	*	96	7
N-HEPTANE	66	10	11	5	5	3	200	14
BENZENE	5	<1	*	*	9	6	5	<1
DI ME PENTANE	7	1	4	2	*	*	8	1
ME. CYCLOHEXANE	104	16	21	10	14	9	320	22
TOTAL	648	100	203	100	160	100	1463	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY WELL 33/12-2 LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	18		19		20		24	
DEPTH (FEET)	7200		7300		7400		7800	
	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$
C_1	.027	9	*	*	*	*	.001	1
C_2	.066	22	*	*	*	*	*	*
C_3	.035	12	*	*	*	*	.005	6
iC_4	.160	54	*	*	*	*	.016	19
nC_4	.010	3	*	*	*	*	.064	74
TOTAL	0.3	100	< 1	100	< 1	100	0.09	100

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	18		19		20		24	
DEPTH (FEET)	7200		7300		7400		7800	
	P.P.B.	$\%C_5 - C_7$	P.P.B.	$\%C_5 - C_7$	P.P.B	$\%C_5 - C_7$	P.P.B.	$\%C_5 - C_7$
ISO-PENTANE	144	3	68	4	*	*	16	5
N-PENTANE	480	11	232	14	*	*	33	11
CYCLOPENTANE	26	> 1	9	< 1	*	*	4	1
2-ME. PENTANE	44	1	144	8	*	*	22	7
3-ME. PENTANE	216	5	66	4	*	*	13	4
N-HEXANE	540	13	184	11	*	*	32	11
ME. CYCLOPENTANE	160	4	42	2	*	*	17	6
CYCLOHEXANE	264	6	66	4	*	*	20	7
2-ME. HEXANE	332	8	108	6	*	*	13	4
3-ME. HEXANE	540	13	172	10	*	*	24	8
3-ETHYLPENTANE	320	7	112	7	*	*	19	6
N-HEPTANE	640	15	215	13	*	*	34	11
BENZENE	160	4	4	< 1	*	*	3	1
DI. ME. PENTANE	80	2	28	2	*	*	*	*
ME. CYCLOHEXANE	360	8	255	15	*	*	50	17
TOTAL	4306	100	1705	100	< 25	*	300	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY WELL 33/12-2 LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	25		27		28		29	
DEPTH (FEET)	7900		8100		8200		8300	
	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$	P.P.M.	$\%C_1 - C_4$
C_1	.02	5	.013	1	tc	*	.06	<1
C_2	.002	<1	.002	<1	tc	*	.03	<1
C_3	.08	20	0.150	16.5	*	*	2.4	22
iC_4	.14	35	0.150	16.5	*	*	2.2	20
nC_4	.16	40	0.58	65	*	*	6.2	57
TOTAL	0.4	100	0.9	100	<1	100	11	100

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	25		27		28		29	
DEPTH (FEET)	7900		8100		8200		8300	
	P.P.B.	$\%C_5 - C_7$	P.P.B.	$\%C_5 - C_7$	P.P.B	$\%C_5 - C_7$	P.P.B.	$\%C_5 - C_7$
ISO-PENTANE	22	2	17	1.5	400	5	800	5
N-PENTANE	135	13	563	51	2000	25	3200	21
CYCLOPENTANE	5	<1	6	<1	60	<1	120	<1
2-ME. PENTANE	52	5	28	3	400	5	700	5
3-ME. PENTANE	36	3	22	2	160	2	440	3
N-HEXANE	80	8	50	5	960	12	160	14
ME. CYCLOPENTANE	30	3	28	3	260	3	440	3
CYCLOHEXANE	50	5	56	5	328	4	620	4
2-ME. HEXANE	65	6	66	6	288	4	880	6
3-ME. HEXANE	105	10	94	9	344	4	840	6
3-ETHYLPENTANE	75	7	29	3	240	3	560	4
N-HEPTANE	135	13	10	1	1320	17	2160	14
BENZENE	85	8	*	*	240	3	*	*
DI ME PENTANE	9	<1	*	*	29	<1	60	<1
ME. CYCLOHEXANE	170	16	125	11	840	11	2000	13
TOTAL	1054	100	1100	100	7869	100	14980	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY WELL 33/12-2 LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	30		31		32		33	
DEPTH (FEET)	8400		8500		8600		8700	
	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$
C_1	.064	2	.018	1	.059	2	0.42	11
C_2	.006	<1	.005	<1	.01	<1	0.02	<1
C_3	.53	14	.53	26	.94	27	0.86	23
iC_4	.85	23	.26	13	.56	16	0.64	17
nC_4	2.32	62	1.23	60	1.88	55	1.76	48
TOTAL	3.8	100	2.0	100	3.4	100	3.7	100

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	30		31		32		33	
DEPTH (FEET)	8400		8500		8600		8700	
	P. P. B.	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$	P. P. B	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$
ISO-PENTANE	640	5	540	5	940	8	680	8
N-PENTANE	2880	22	1600	16	3530	30	2160	25
CYCLOPENTANE	108	<1	54	<1	135	1	52	<1
2-ME. PENTANE	720	6	460	5	620	5	332	4
3-ME. PENTANE	400	3	280	3	280	2	216	3
N-HEXANE	2160	17	1440	14	1120	10	776	9
ME. CYCLOPENTANE	460	4	500	5	550	5	340	4
CYCLOHEXANE	650	5	520	5	735	6	460	5
2-ME. HEXANE	1080	8	440	4	480	4	420	5
3-ME. HEXANE	880	7	560	6	590	5	500	6
3-ETHYLPENTANE	500	4	460	5	320	3	400	5
N-HEPTANE	2320	18	1440	14	880	7	860	10
BENZENE	*	*	340	4	340	3	208	2
DI ME PENTANE	108	<1	37	<1	40	<1	38	<1
ME. CYCLOHEXANE	200	2	1440	14	1180	10	1060	12
TOTAL	12906	100	10111	100	11740	100	8502	100

TABLE 2 CONT'D

GASEOUS AND GASOLINE RANGE HYDROCARBONS

CLIENT MOBIL NORWAY WELL 33/12-2 LOCATION NORTH SEA

GAS ($C_1 - C_4$)

SAMPLE NO.	34		35		37-70			
DEPTH (FEET)	8800		8900		9100 - 13,600			
	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$	P. P. M.	$\%C_1 - C_4$
C_1	.064	3	.074	4	tc	100		
C_2	.011	< 1	.016	< 1	*	*		
C_3	.51	23	.46	24	*	*		
iC_4	.35	16	.24	13	*	*		
nC_4	1.28	58	1.12	59	*	*		
TOTAL	2.22	100	1.91	100	tc	100		

GASOLINE RANGE ($C_5 - C_7$)

SAMPLE NO.	34		35		37-70			
DEPTH (FEET)	8800		8900		9100 - 13,600			
	P. P. B.	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$	P. P. B	$\%C_5 - C_7$	P. P. B.	$\%C_5 - C_7$
ISO-PENTANE	380	6	124	3				
N-PENTANE	1600	27	640	18				
CYCLOPENTANE	37	< 1	17	< 1				
2-ME. PENTANE	276	5	140	4				
3-ME. PENTANE	172	3	92	3				
N-HEXANE	580	10	332	9				
ME. CYCLOPENTANE	240	4	132	4				
CYCLOHEXANE	330	6	256	7				
2-ME. HEXANE	216	4	280	8				
3-ME. HEXANE	240	4	340	9				
3-ETHYLPENTANE	140	2	184	5				
N-HEPTANE	720	12	480	13				
BENZENE	208	3	120	3				
DI ME-PENTANE	37	< 1	52	2				
ME. CYCLOHEXANE	800	13	400	11				
TOTAL	5976	100	3591	100	< 50	100		

FIGURE I

GASEOUS ($C_1 - C_4$) HYDROCARBONS

COMPANY : MOBIL NORWAY WELL : 33/12-2 LOCATION : NORTH SEA

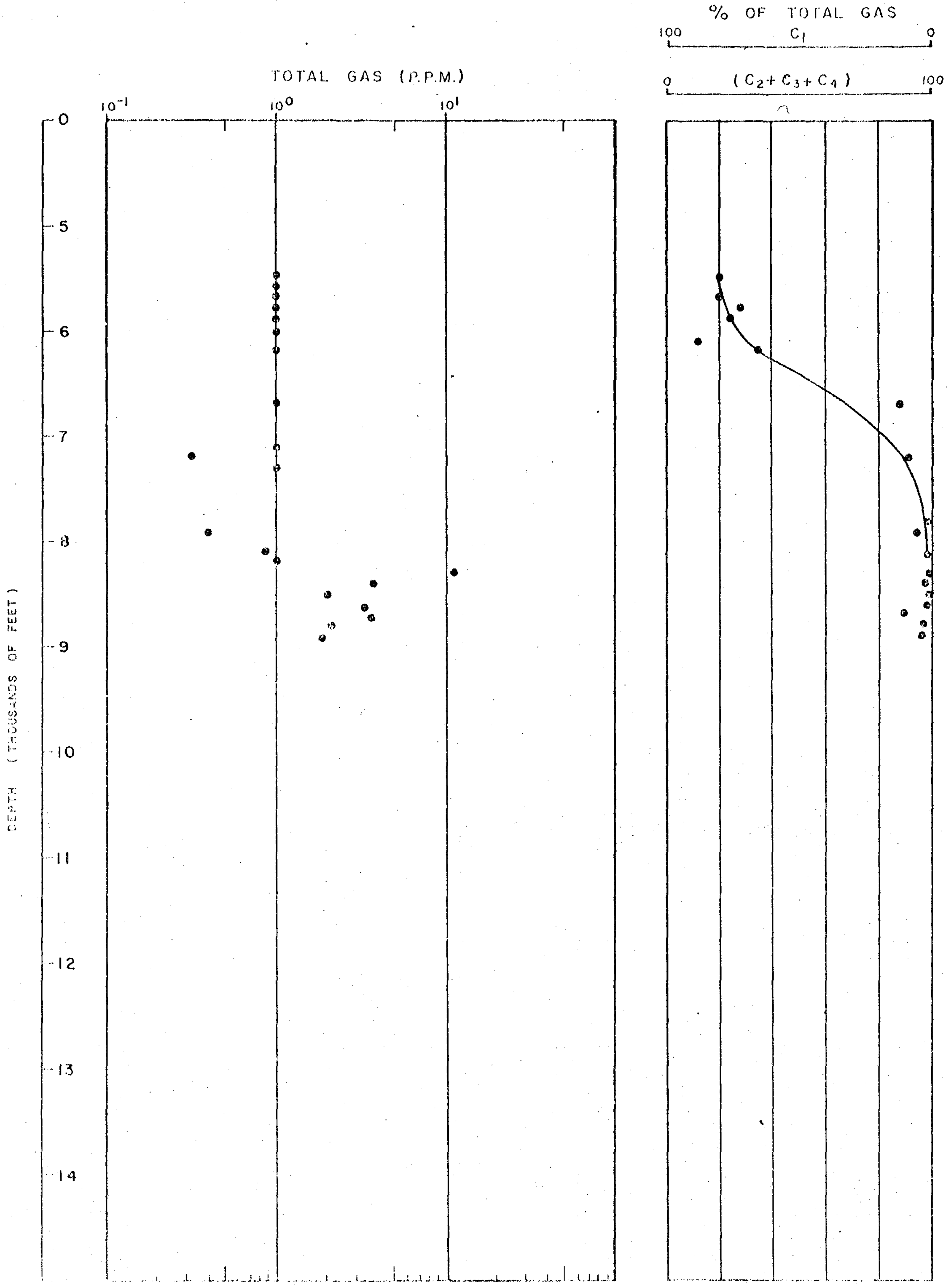
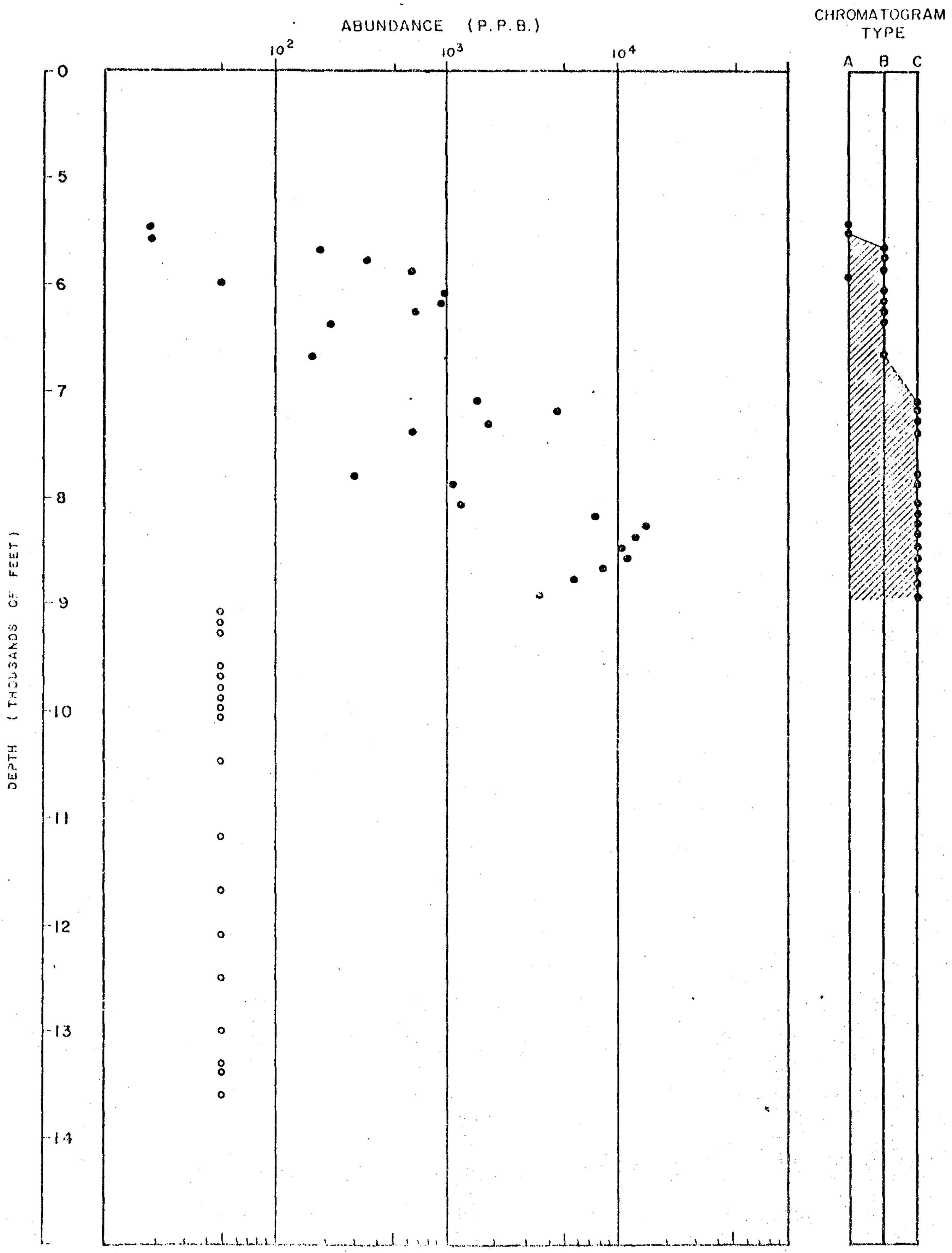


FIGURE 2

GASOLINE RANGE (C_5-C_7) HYDROCARBONS

COMPANY : **MOBIL NORWAY** WELL : **33/12-2** LOCATION : **NORTH SEA**



A, IMMATURE; B, TRANSITIONAL; C, OIL-LIKE

FIGURE 3

VITRINITE REFLECTIVITY AGAINST DEPTH

COMPANY : **MOBIL NORWAY** WELL : **33/12-2** LOCATION : **NORTH SEA**

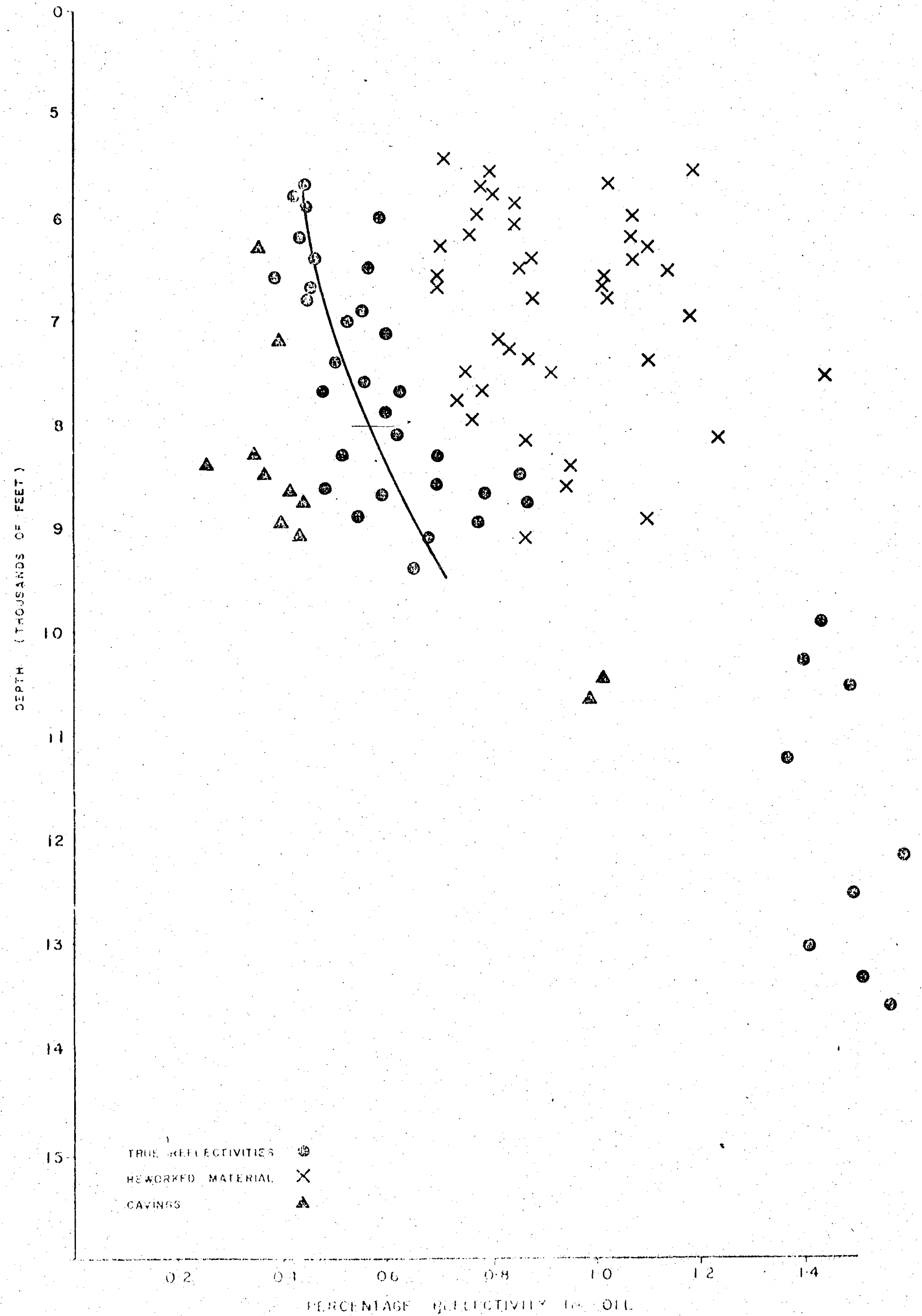


FIGURE 4

MAXIMUM PALAEOTEMPERATURE AGAINST PRESENT DEPTH OF BURIAL

COMPANY : MOBIL NORWAY   WELL : 33/12-2   LOCATION : NORTH SEA

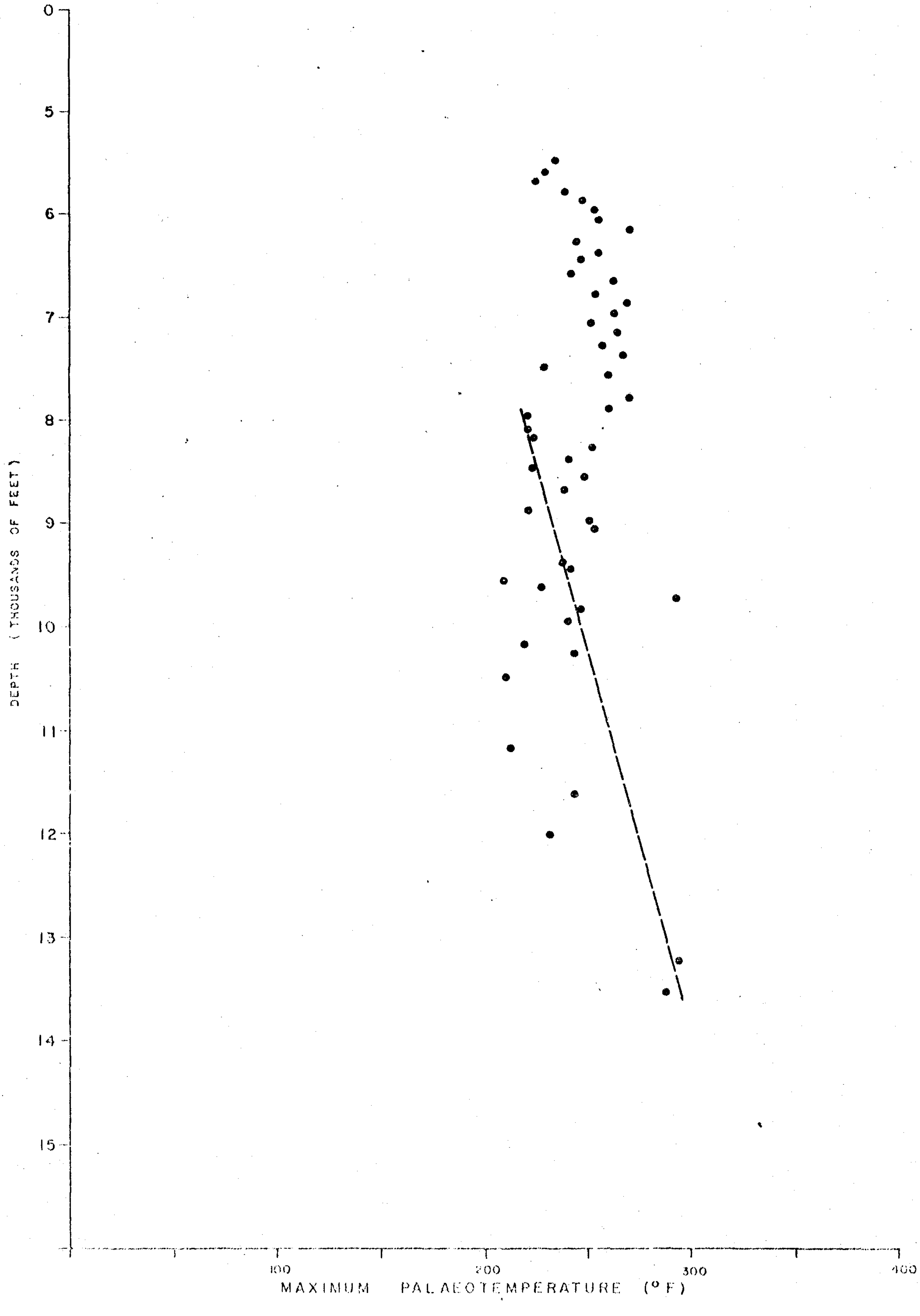


FIGURE 5

COMPARISON OF MATURATION INDICES

CLIENT : MOBIL NORWAY WELL : 33/12-2 LOCATION : NORTH SEA.

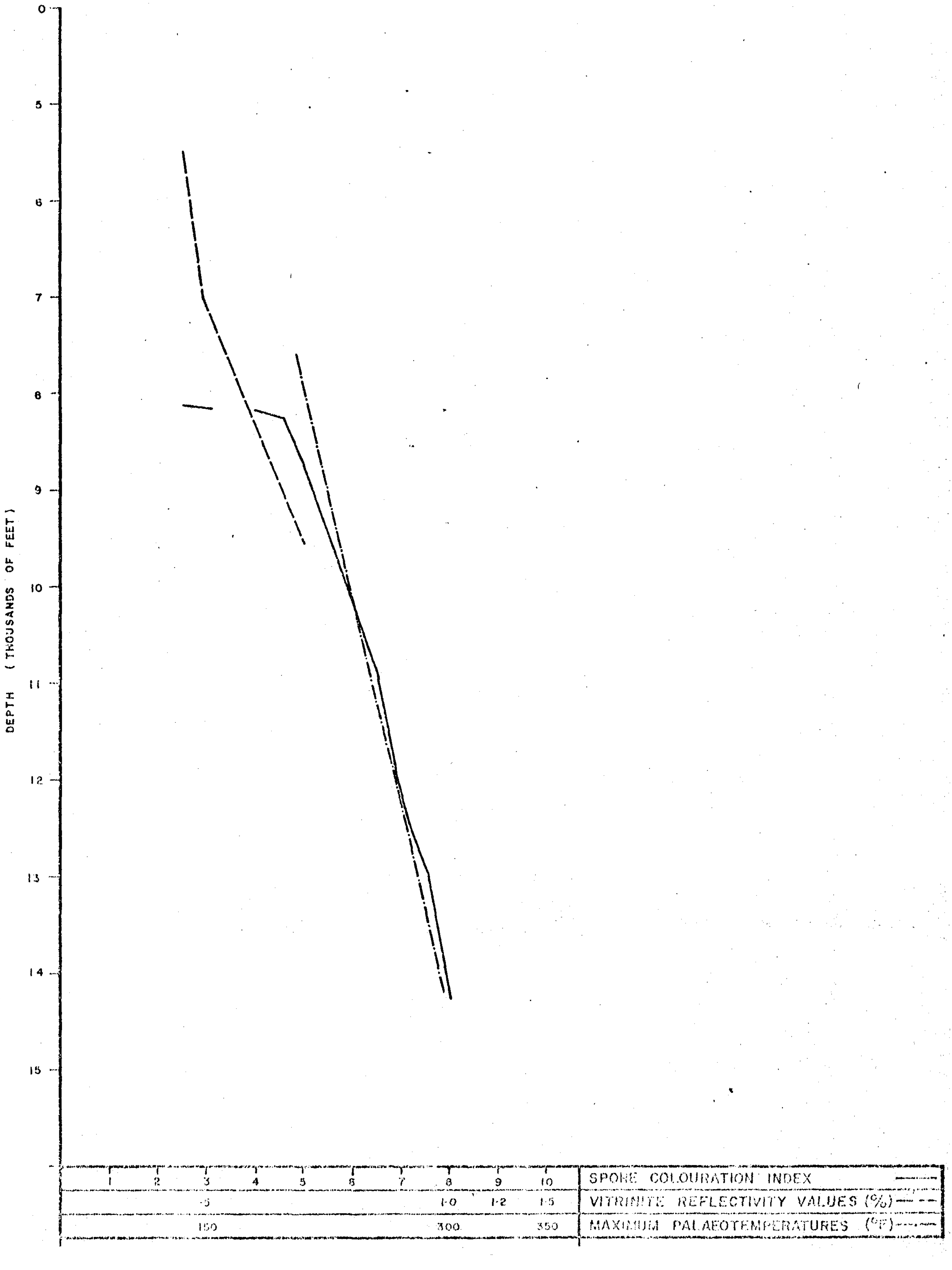


FIGURE 6

TYPE OF HYDROCARBON PRODUCT FROM SOURCE ROCKS

COMPANY : MOBIL NORWAY WELL : 33/12-2 LOCATION : NORTH SEA

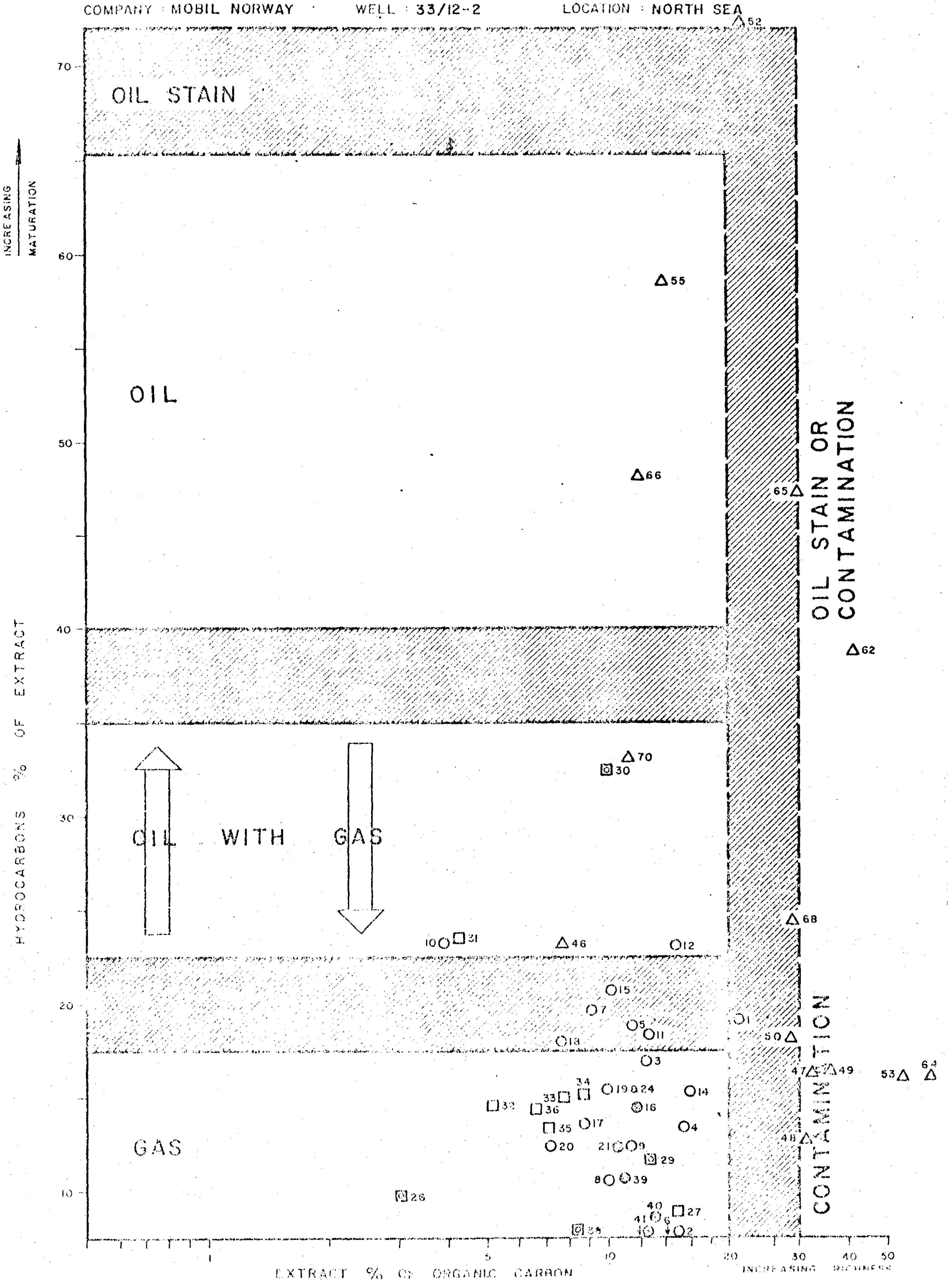
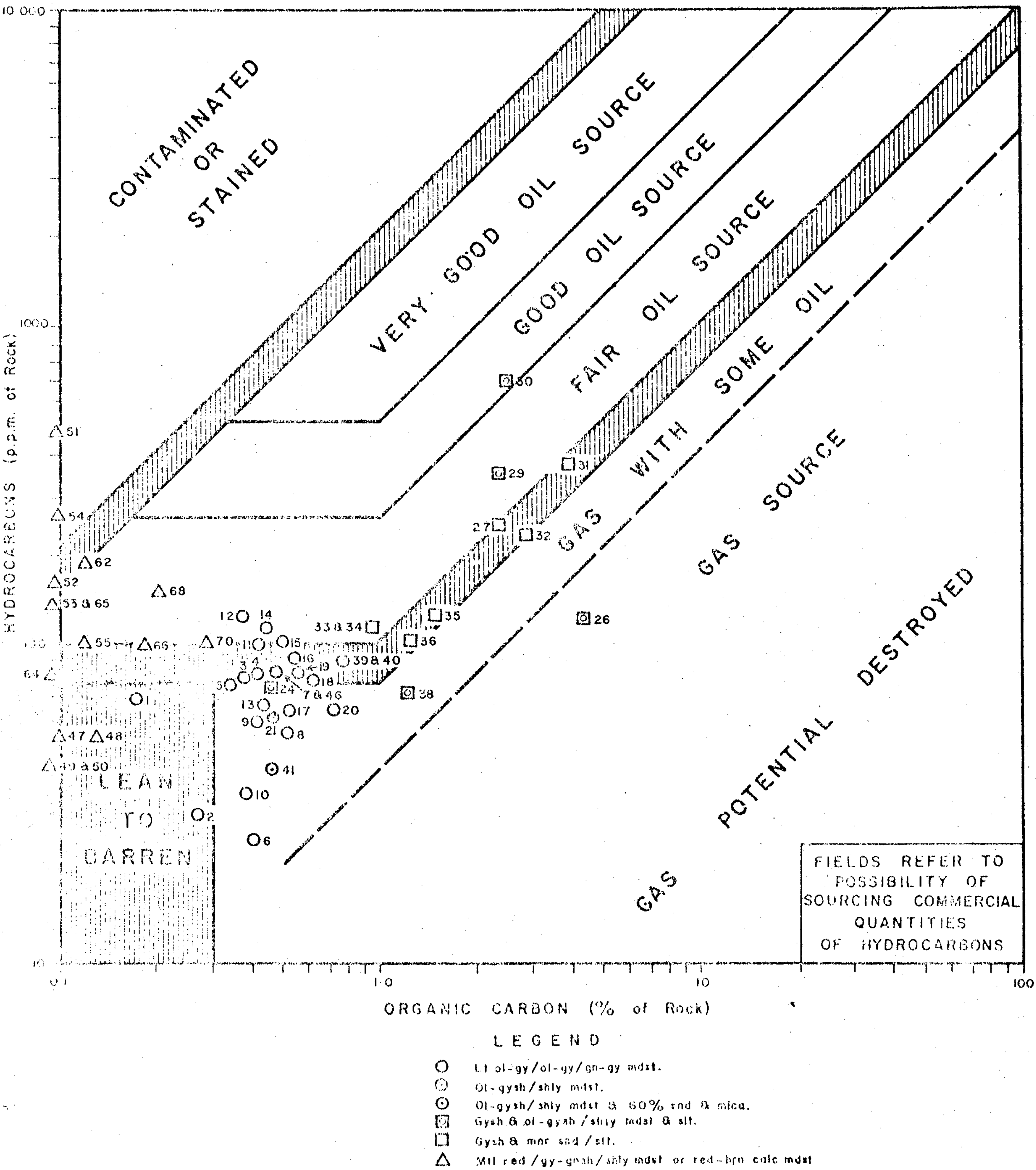


FIGURE 7

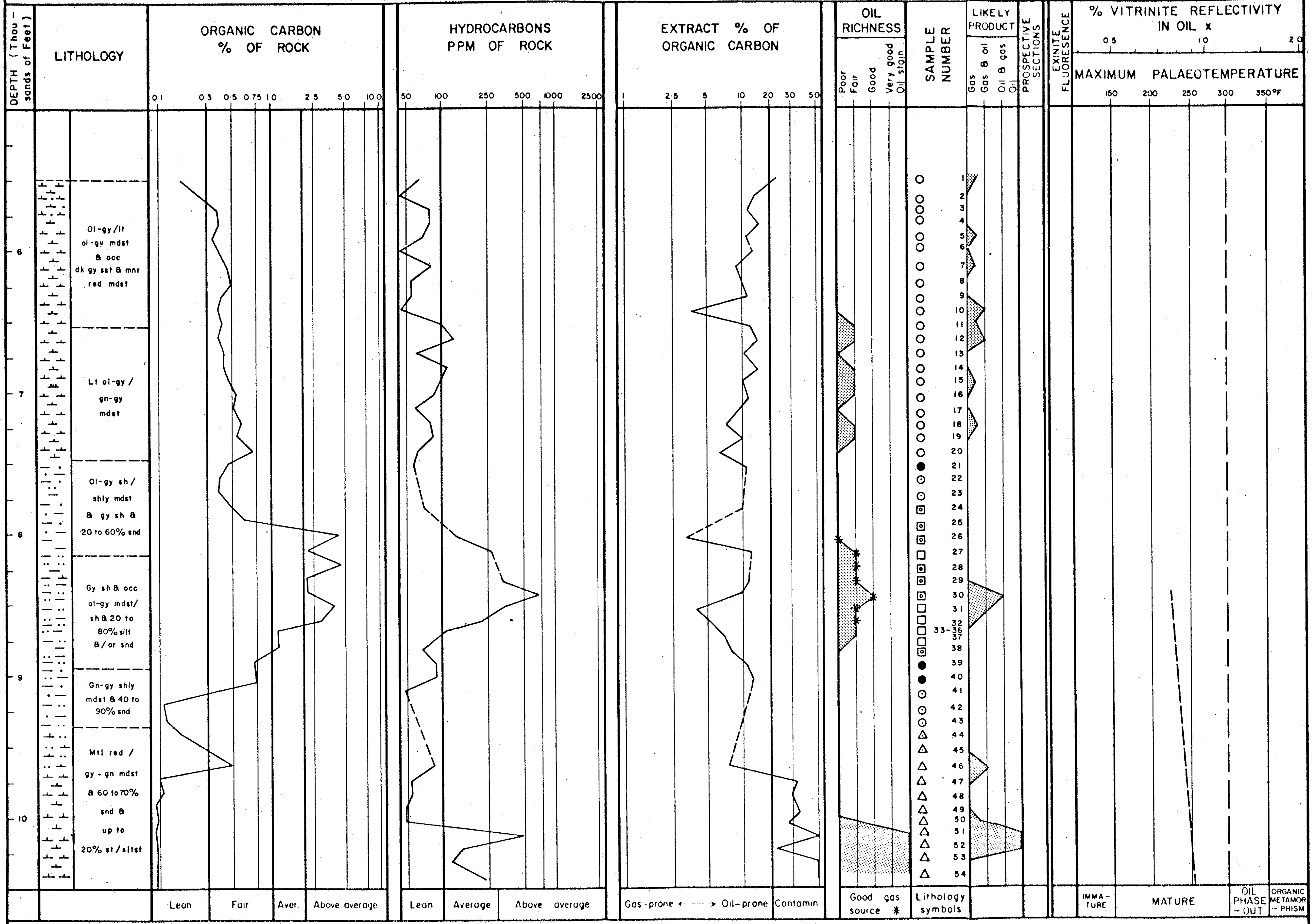
MATURE SOURCE ROCK RICHNESS

COMPANY : MOBIL NORWAY   WELL : 33/12-2   LOCATION : NORTH SEA



SOURCE ROCK SUMMARY CHART

COMPANY MOBIL NORWAY WELL : 33/12-2 LOCATION : NORTH SEA

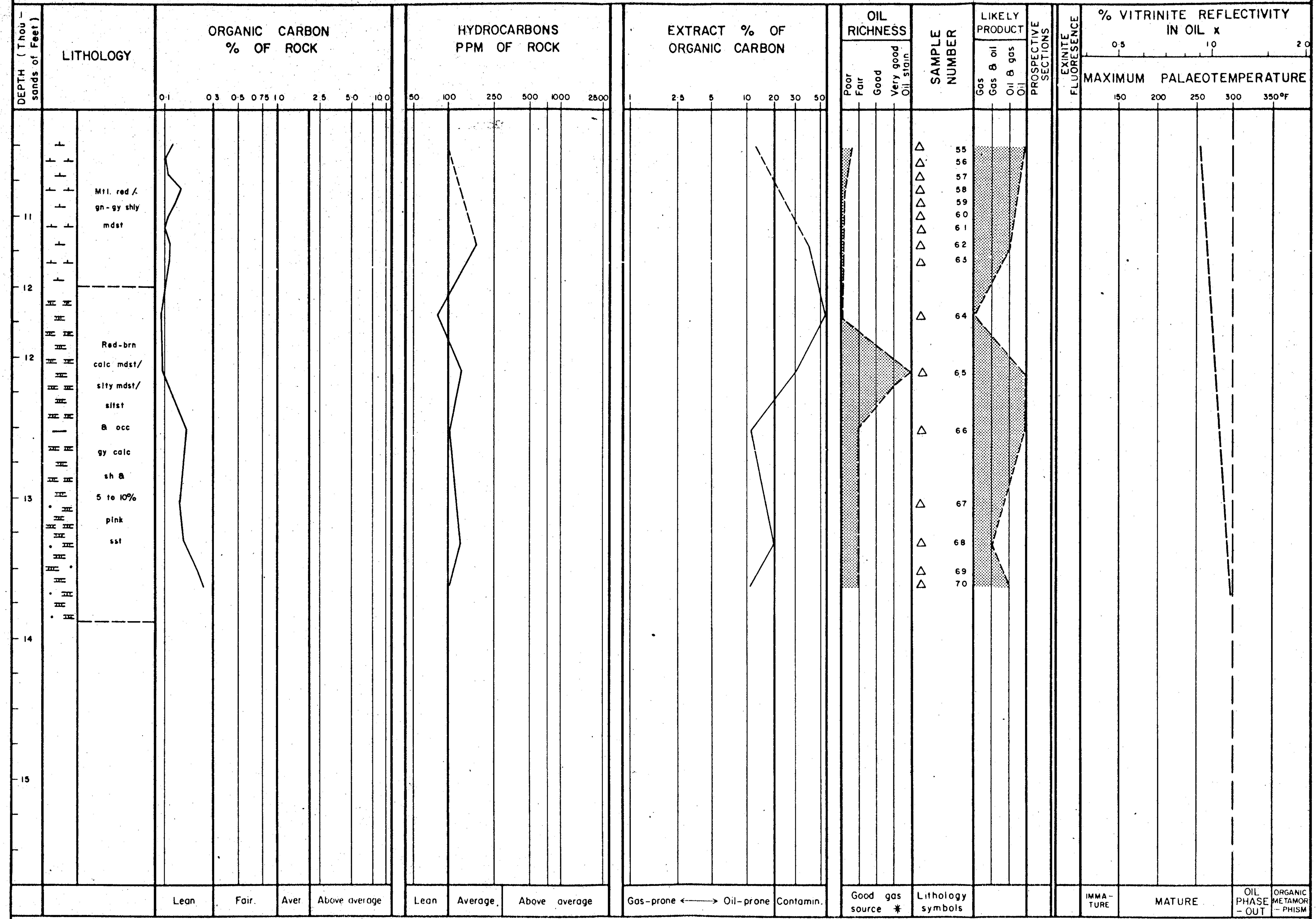


Drawing No. 741/2100/2666

FIGURE 8(i)

SOURCE ROCK SUMMARY CHART

COMPANY MOBIL NORWAY WELL : 33/12-2 LOCATION : NORTH SEA



Drawing No. 741/2100/2666

FIGURE 8(ii)