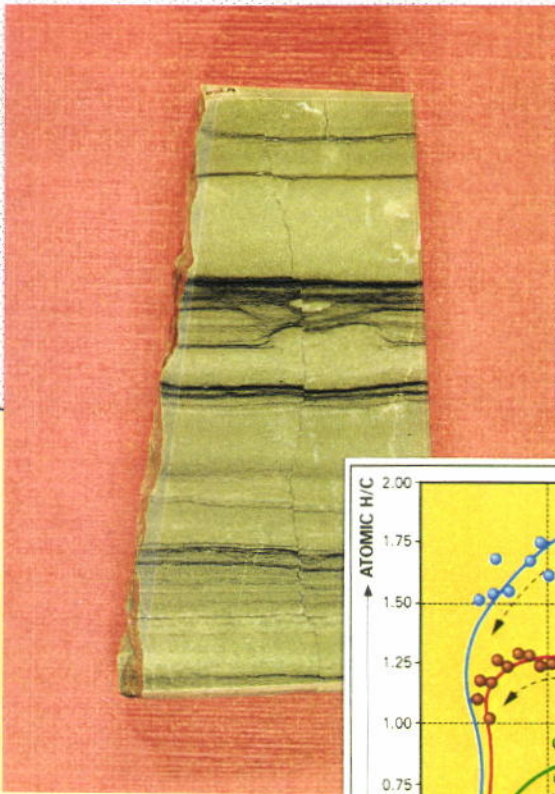
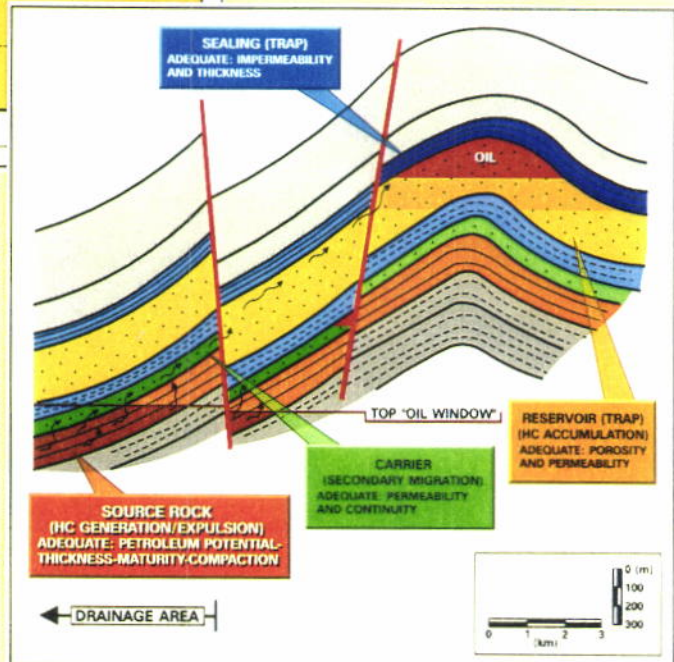
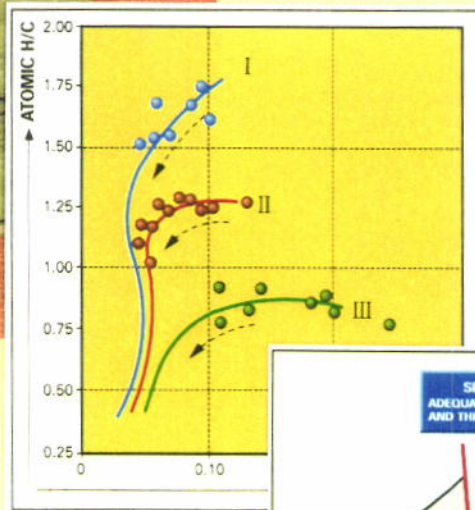




Eni Agip E&P Division



THE SOURCE ROCK: a key point for Hydrocarbon Exploration



Quaderno Tecnico n° 8

What does “Source Rock” mean?

*The intervals of sedimentary rocks having the potential capability to generate and expel hydrocarbons in important quantities, from the economic viewpoint, are defined **source rocks**.*

They are therefore sediments containing significant quantities of **organic matter** (mainly of vegetable origin) preserved against degradation phenomena and deposited in non-oxidizing environments. In extreme anoxia conditions (severely reducing environment) the maximum preservation degree is reached, and the whole organic potential, mainly consisting of carbon-hydrogen compounds, is trapped in the sediment.

In the starting phases of sediment burial, the organic matter sustains transformations with the re-organization of carbon-hydrogen bonds, with formation of an organic compound (a large macromolecule) called “**kerogen**”.

The progressive burial of the potential source rock will determine (due to the geothermal gradient) a temperature increase, thus starting the transformation reactions of the kerogen into hydrocarbons (phenomenon briefly defined “**kerogen thermal degradation**”).

To obtain the extent of said transformation different experimental parameters are measured in the source rock; they are called **maturity** parameters.

The content of *organic matter (o.m.)* in a sediment is usually measured as quantity of **organic carbon (T.O.C. = Total Organic Carbon)** expressed as percentage by weight of the rock sample.

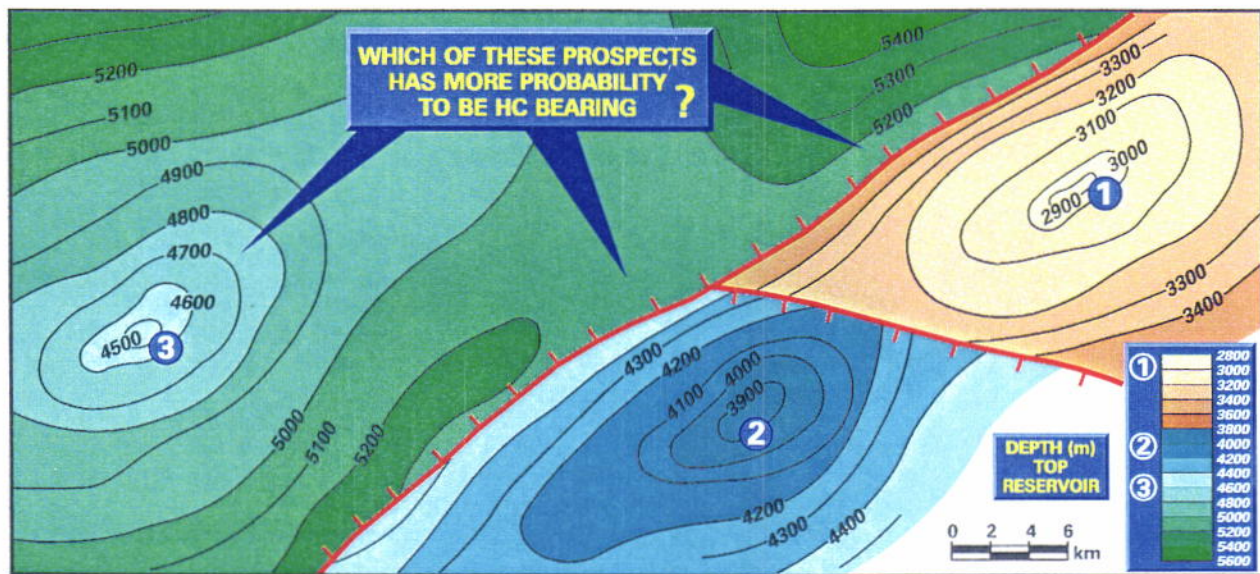
At equal T.O.C., according to the quality of the original organic matter and to its preservation degree, the kerogen can be more or less rich in hydrogen; the higher is the hydrogen content, the higher shall be the quantity of hydrocarbons that can be produced.

The higher are the above-mentioned parameters (T.O.C., o.m. quality and preservation degree), the higher shall be the quantity of hydrocarbons the source rock can generate.

Said quantity, expressed in *Kg of hydrocarbons which can be generated per ton of rock*, is defined **Petroleum Potential**. An interval of sedimentary rock can be defined **source rock** if the original **Petroleum Potential is higher than 1 Kg HC/t rock**.

Why is the study of source rocks important?

“Although every petroleum pool occurs in a trap, it does not follow that every trap contains a pool.” (Levorsen, 1954)



For an effective oil exploration in a given sedimentary basin it is necessary the study of all the phenomena concurring to the genesis of hydrocarbon accumulations.

The sole identification of traps or structures is a necessary condition, but of course not sufficient, to foresee the existence of an hydrocarbon accumulations. A prospect becomes a real industrial target when it is verified that there are good possibilities for being filled with hydrocarbons.

In fact, many factors concur to represent the **“risk in exploration”**, which can be summarized as follows:

- . trap risk (actual geometrical closing of the structure and suitable size);
- . reservoir risk (adequate porosity and permeability);
- . sealing risk (existence of a efficient seal);
- . **hydrocarbon charge risk.**

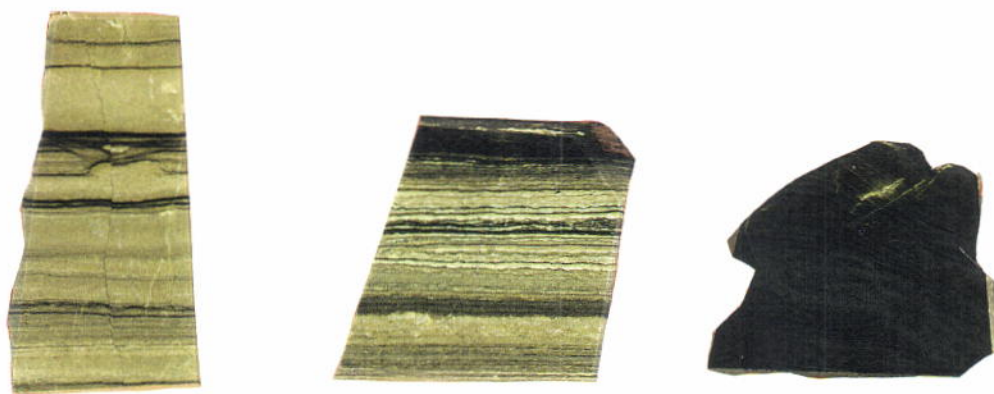
To contribute to the evaluation of the “*hydrocarbon charge risk*” it is necessary to conduct *a deeper study in the sedimentary basin* and therefore: *to identify* the potential source rocks; *to characterize* them by using a large number of samples and appropriate techniques; to consider their *maturity* level and to evaluate the relevant *Hydrocarbon Potential*.

We recall that “*kerogen or organic matter maturity*” means the extent of the kerogen thermal degradation process to give hydrocarbons; said extent can be expressed as a ratio: the “*Transformation Ratio (TR)*” (TR= generated Hydrocarbons / initial Hydrocarbon potential of the considered source).

Identification of source rocks

The identification of potential source rocks should not derive from geochemical analysis carried out in a systematic way on all the sediments of a sedimentary basin, but it shall be restricted to a selection of the formations having peculiar characteristics in terms of *lithofacies* (mineralogical composition, texture, sedimentary structures, colour), reflecting therefore *particular sedimentation environments where the organic matter had the possibility to be sedimented, concentrated and preserved* (key factors are: the sedimentation rate, the chemical – physical conditions at the time of sedimentation and type and provenience of organic matter).

Fig. 2. The three following samples belong to the “Unità a Laminiti Organiche di Rio Resartico” (Late Triassic age, outcropping in the Carnia Region). The first two samples represent dolomitic lithofacies having different lamination frequency, the third one results being dolomitic marl densely laminated and having high dark pigmentation. The T.O.C. result being higher as the lamination frequency and clay content increase.



Clays & Mica =	2 %	4 %	30 %
T.O.C. =	1.0 %	1.4 %	12.7 %

To guide the research of potential source rocks there are also *stratigraphic criteria*; in fact, during geological ages, in some period particularly advantageous conditions to the concentration/ preservation of the o.m. occurred.

Some of these events find a sedimentary expression diffused at global scale, and for this reason they are defined OAE (Oceanic Anoxic Event).

An example in this respect is the *Cenomanian-Turonian* event (95 million of years approx.), during which rich sediments in o.m. were deposited in a great part of sedimentary basins of the planet.

This event can originate thin naphthogenic levels, and therefore of no practical importance, such as for instance the well known "Livello Bonarelli" (diffused in basins of the major part of the Italy), having high petroleum potential but thickness seldom higher than one metre. Or, on the other hand, in particularly advantageous environment conditions, it can originate sedimentary units with industrial interest (adequate petroleum potentials and thickness). A true and real *source rock* is for instance the unit (more or less coeval to the Livello Bonarelli) sedimented in the Internal Apula Platform in the Southern Apennines; consisting of laminated dark limestone, these sediments (with the contribution of other cretaceous levels) are responsible for the generation of oil occurrences of the Val d'Agri.

Geochemical Analysis of samples of source rock

When a potential source rock is identified, in order to evaluate the *Petroleum Potential* and the *maturity* level reached by the kerogen, a set of geochemical analyses have to be performed, which have become routine analyses in the field of hydrocarbon exploration.

Considering the simplicity of these analyses and the need to introduce the meaning of the main geochemical parameters, they shall be briefly described below.

Determination of the Total Organic Carbon (T.O.C.)

As already said the o.m. content in a sediment is measured as the quantity of organic carbon (T.O.C.) expressed in percent on the weight of the rock sample.

Methodological remark

The analysis consists in heating a small quantity of ground sample (after carbonates chemical destruction) up to 1500C° in order to burn the o.m. contained in the same; the *organic carbon* undergoes an oxidation at CO₂ which is measured with an infrared detector. The T.O.C. % is then calculated comparing it to the rock starting weight.

Pyrolysis Rock-Eval

The sole T.O.C. determination does not enable to assess the actual *Petroleum Potential* of the sample, since this depends also on the quality of kerogen. Coals, for example, can have very high T.O.C. but a low Petroleum Potential as consequence of the low quality of the o.m. (terrestrial origin).

In nature, the generation of hydrocarbons occurs after thermal degradation of the kerogen

through geological time (generally, from some million to some tenths of millions of years), and comparatively soft heating is required (generally, with temperatures in the range of 80 - 140 °C); the higher shall be the heating, the lower shall be the time necessary to the kerogen degradation to hydrocarbons.

This phenomenon, so described, can be reproduced at laboratory scale, by using an high heating (more than 250 °C) for a very short time (some hours). This process is known as kerogen pyrolysis.

A technique, called *Rock-Eval* pyrolysis has been set up by the Institut Francais du Petrole (IFP), during the “seventies” for the study of the source rocks (determination of *Petroleum Potential, maturity* and *quality of kerogen*).

Methodological remark

The analysis is made using a small quantity of sample (100 mg of ground rock) on which the T.O.C. is generally measured in advance. The whole analytical cycle lasts 20 minutes only, with the output shown in the following figure.

In the first heating phase (3 minutes at 300 °C) volatilize *free hydrocarbons* (parameter *S1*) already present in the sample (HC already generated by the source rock and not yet expelled), represented by a first peak (with area *S1*).

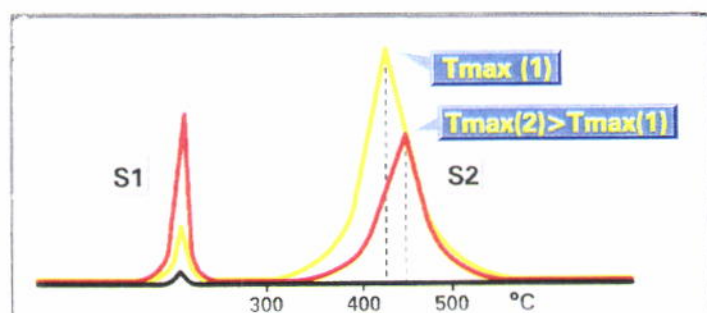
Increasing the temperature (with a heating speed equal to 25 °C per minute) up to 550 °C, the thermal cracking kerogen progressively occurs with generation of hydrocarbons not yet produced in a natural way by the sample, represented by a second peak (area *S2*), forming the *Residual Petroleum Potential* (parameter *S2*),

Fig. 3. The output of the Rock-Eval pyrolysis analysis relevant to three samples with equal initial petroleum potential, but different maturity is shown.

Immature sample: yellow curve (1)

Mature sample: red curve (2)

Overmature sample: black curve (3)



Tmax is temperature at which the maximum of *S2* peak occurs. Tmax increases in function of the maturity of kerogen.

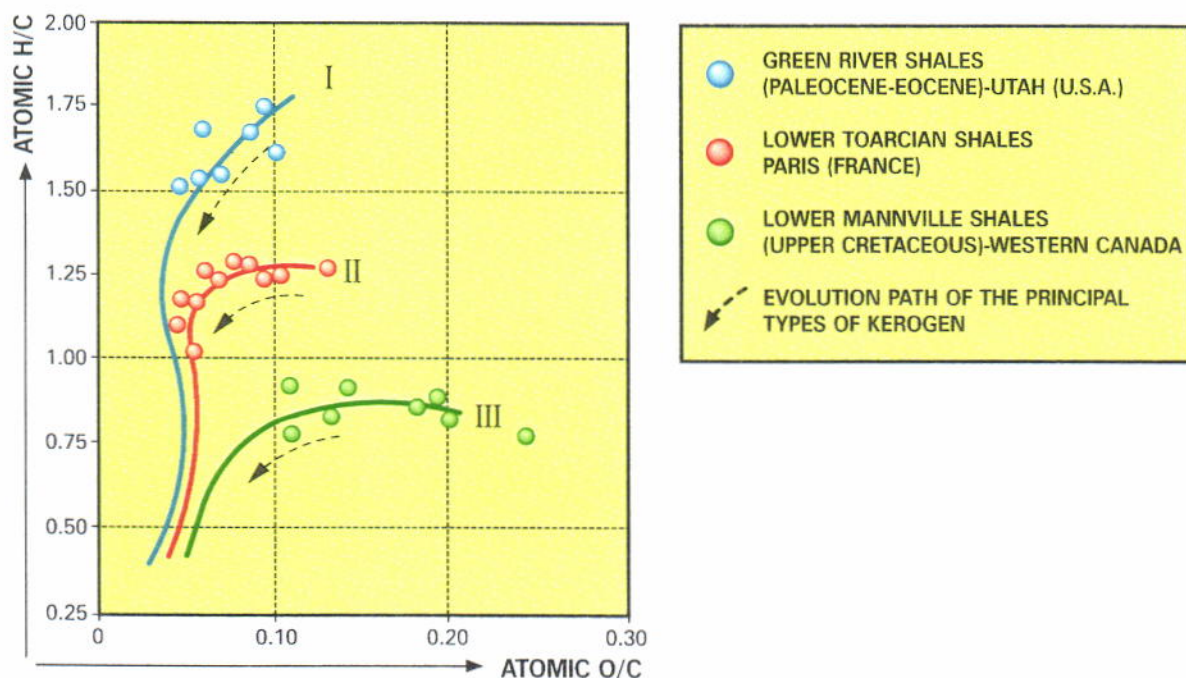
We have already pointed out that samples with equal T.O.C., according to the quality of the original o.m. and to its preservation degree (hydrogen richness of kerogen) can produce different quantities of hydrocarbons. Richness in hydrogen represents a direct indication of

the *quality of kerogen*; its direct measure can derive from the elemental analysis of the kerogen (H/C: Hydrogen/Carbon ratio).

The H/C - O/C (Oxygen/Carbon ratio) diagram (van Krevelen diagram) describes kerogen quality (see also page 10):

- Type I* very high Hydrogen/Carbon ratio (very good organic matter quality and preservation)
- Type II* high Hydrogen/Carbon ratio (good organic matter quality and preservation)
- Type III* low Hydrogen/Carbon ratio (poor organic matter quality, or fair/good o.m. quality and scarce preservation)

Fig. 4. The figure shows a van Krevelen diagram.



Richness in hydrogen can be obtained from the combination of the data resulting from the T.O.C. and Rock-Eval analysis. In fact, comparing the *Residual Petroleum Potential (S2)* with the T.O.C. we obtain a parameter directly related to the H/C ratio and called *Hydrogen Index (HI)*, expressed in mg HC/g T.O.C..

Furthermore, comparing the CO₂ quantity (from Rock-Eval analysis) with T.O.C. we obtain the OI (Oxygen Index - mg CO₂/g T.O.C.), that is related to the O/C ratio.

Therefore, HI - OI diagram gives information like van Krevelen diagram.

We reiterate that the *Hydrogen Index*, when measured on *immature kerogen* (which did not underwent a natural impoverishment process of the initial Petroleum Potential), represents the *actual quality parameter of the kerogen*, since it contemplates both the quality of the o.m. and its preservation degree.

Kerogen optical analysis

Through the kerogen optical analysis the *quality of the o.m.* and the maturity can be also assessed.

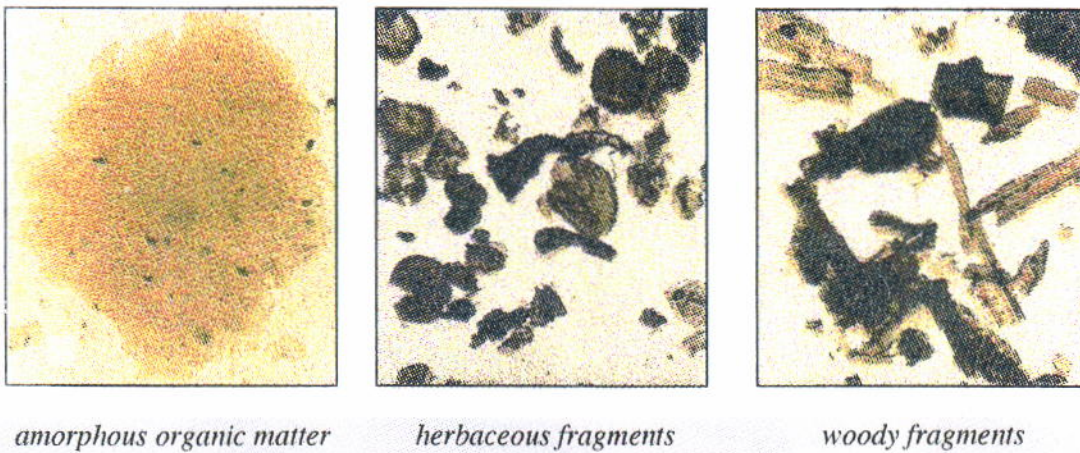
Methodological remark

The sample preparation takes place separating the kerogen from the mineral matrix and dividing it into two preparations: on slide, for the analysis in transmitted light; in plug (mixed to a resin), for the analysis in reflected light, after polishing of the specimen.

The observation of the sample at the microscope in *transmitted light (slide)* enables first to distinguish the different organic compounds divided into the following main groups:

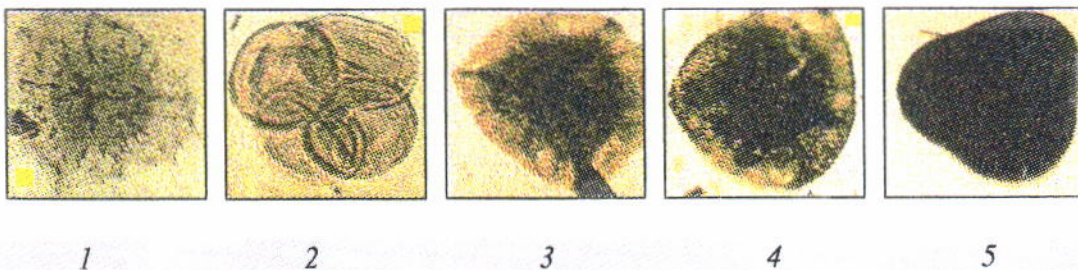
CWF	<i>Continental Woody Fragments</i>
CHF	<i>Continental Herbaceous Fragments</i>
MPH	<i>Marine Phytoplankton</i>
AOM	<i>Amorphous organic matter</i>

Fig. 5. This figure shows some typical associations of organic matter.



Always in transmitted light, observing the colour of palynomorphes (spores and pollens) it is possible to evaluate the *maturity* level of the sample. Observed colour is associated to a value of an index (**TAI - Thermal Alteration Index**) ranging from 1 to 5, covering all the maturity levels, from immature to the organic metamorphism.

Fig. 6. The figure shows some palynomorphes, at different maturity levels.



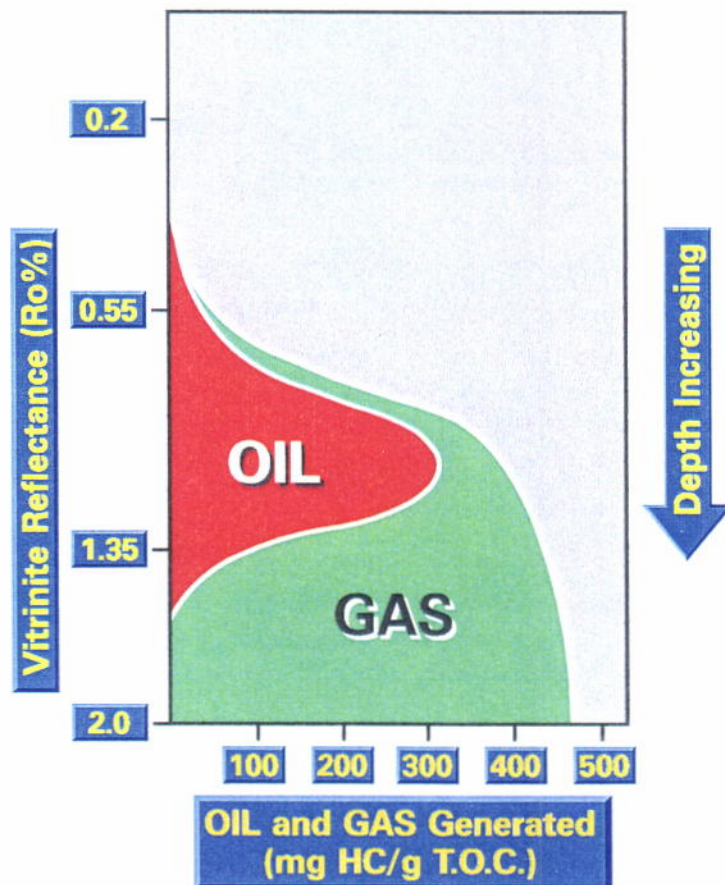
With the observation at the microscope in *reflected light (polished plug)* the *maturity level* of the sample is obtained from the **Vitrinite Reflectance (Ro%)** - the ratio between reflected and incident light, in percent). Vitrinite is a transformation product of lignin and cellulose, and can be found in kerogens rich in higher plants fragments (CWF).

As the maturity increases, a progressive ordering takes place of the vitrinite molecular structure, this determines an increase of the reflection capacity of the incident light.

The Vitrinite Reflectance represents a widespread maturity parameter. The ranges defining the different maturity levels are generally the following:

<i>Ro < 0,55%</i>	<i>(immaturity)</i>
<i>Ro 0,55 to 1,35%</i>	<i>(maturity)</i>
<i>Ro 1,35 to 2%</i>	<i>(high maturity)</i>
<i>Ro > 2%</i>	<i>(organic metamorphism)</i>

Fig. 7. In this figure it is shown a sketch of hydrocarbon generation evolution as function of Ro%.



Returning to the *quality of the kerogen*, and summarizing the information obtained mainly from the optical analysis and pyrolysis Rock-Eval, it is possible to classify kerogens in 5 main types, with characteristics, which can be summarized as follows:

Ref. in Fig. 8	Kerogen Type (according to IFP)	Principal biomass	Environment (general)	Original Hydrogen Index	Sulphur incorporation	Type of HC mainly generated and expelled
A	Type I	algae	tectonic non-marine basin	> 700	low	oils
B	Type II	marine algae	marine	400-700	moderate	oils
C	Type II S (sulphur rich)	marine algae	marine, carbonatic environment	400-700	high	oils
D	Type III "H"	spores, pollens, cuticles, resin, lignin	fluvial-lacustrine, coastal plains	300-600	low	waxy oils
E	Type III	lignin	deltaic, turbiditic	50-250	low	gas and light oils

The table has a merely indicative value; it shall not be forgotten that in the reality kerogens are the result of a mixture of different biomasses and of variable chemical-physical conditions of the sedimentation environment. As a rule we have for instance basin sediments of open sea where even important quantities of organic matter coming from the continent (mainly fragments "herbaceous" - CHF) are associated to the aquatic component (algae - MPH).

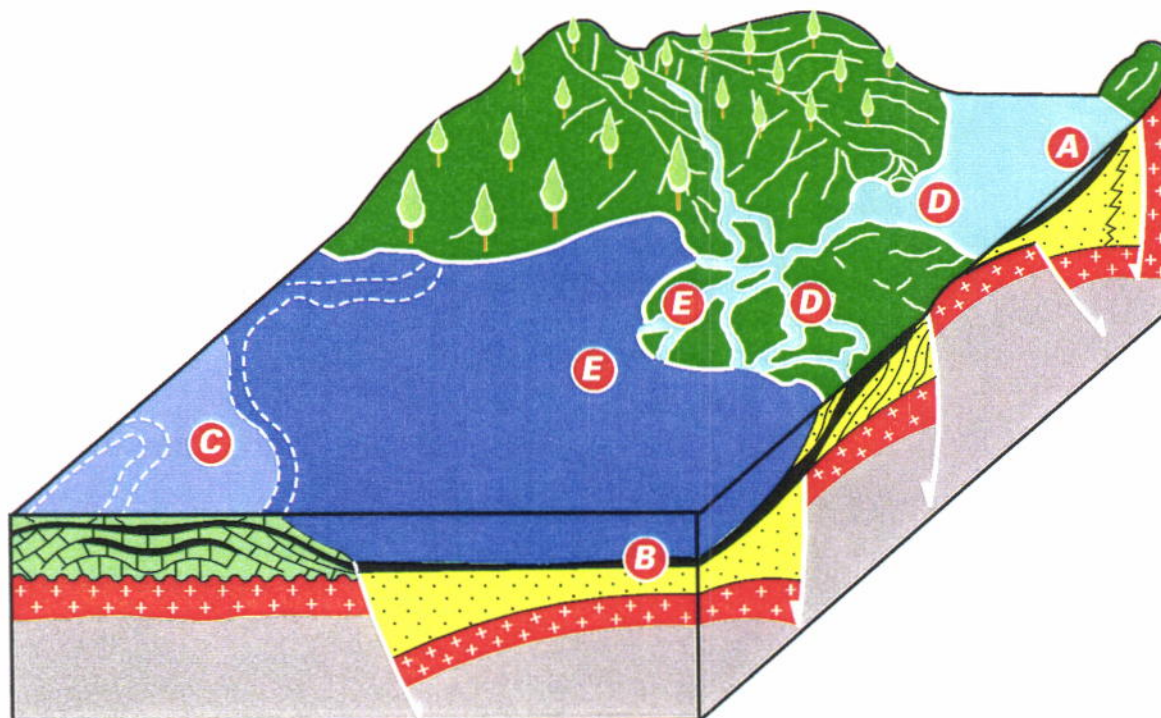


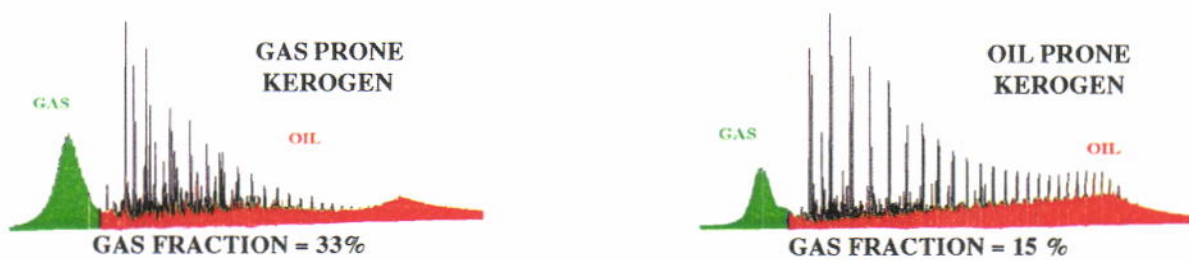
Fig. 8. In this figure a possible distribution of the organofacies in different sedimentary environments is shown.

Analysis of pyrolysis products through gas chromatography

As we have just shown, the *HC* type directly produced by the *kerogen* (oil and gas in variable ratio) depends on its *quality* and is therefore as function of the *Hydrogen index (HI)*; the higher is the HI, the higher shall be the quantity of oil which can be generated compared to the gas quantity.

The capacity of kerogen to generate more oil ("*oil proness*") or gas ("*gas proness*") is described by the index called ***Gas Fraction (GF)*** expressing the gas % over the total of HCs which can be generated directly from kerogen. The *GF* is an index obtained from a combined analysis (Rock-Eval plus gas chromatography).

Fig. 9. Two different analyses obtained through Rock-Eval plus chromatography are shown.



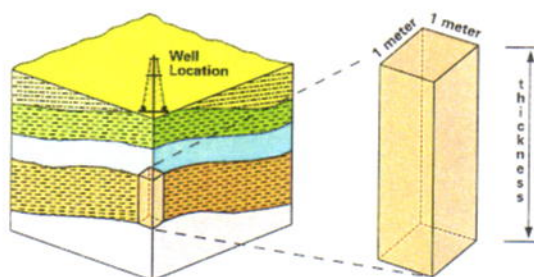
Evaluation of the Hydrocarbon Potential (Source Potential Index)

As already mentioned, in sedimentary series, naphthogenic events with no industrial interest can be often identified; in fact in presence of good petroleum potential (on the single samples), the thickness could be not adequate.

To define the actual petroleum interest of a sedimentary section it is normally used a parameter, which summarizes the average petroleum potential and rock thickness, called ***Source Potential Index (SPI)***; it defines the quantity of hydrocarbons (in metric tons) that can be generated within a column of source rock under 1 m² of surface area (t HC/m²) (Demaison & Huizinga, Chevron, 1991).

$$SPI \text{ (t HC/m}^2\text{)} = \text{Petroleum Potential (KgHC/t rock)} * \text{Thickness (m)} * \text{Rock Density (t/m}^3\text{)} / 1000$$

Fig. 10. The diagram of net source rock thickness factor (to use in the SPI equation) is shown (Demaison & Huizinga, 1994).



In the following table, some examples of SPI relevant to different Source Rocks are shown (Demaison & Huizinga, 1994).

<i>Petroleum Province</i>	<i>Source Rock Age</i>	<i>SPI (t HC/m²)</i>
Junggar (China)	Upper Permian	65
Lower Congo (Cabinda)	Lower Cretaceous	46
Offshore Santa Maria (U.S.A.)	Miocene	21
North Sea (U.K.)	Upper Jurassic - Lower Cretaceous	15
Central Arabia (Saudi Arabia)	Upper Jurassic	14
Maracaibo (Venezuela)	Middle - Upper Cretaceous	10
Paris (France)	Lower Jurassic	7
Williston (U.S.A.)	Upper Devonian - Lower Carboniferous	3
Metan (Argentina)	Upper Cretaceous	1

The *SPI value*, integrated by other data (maturity, effectiveness of primary and secondary migration), will enable to quantitatively evaluate *the “hydrocarbon charge risk”*.

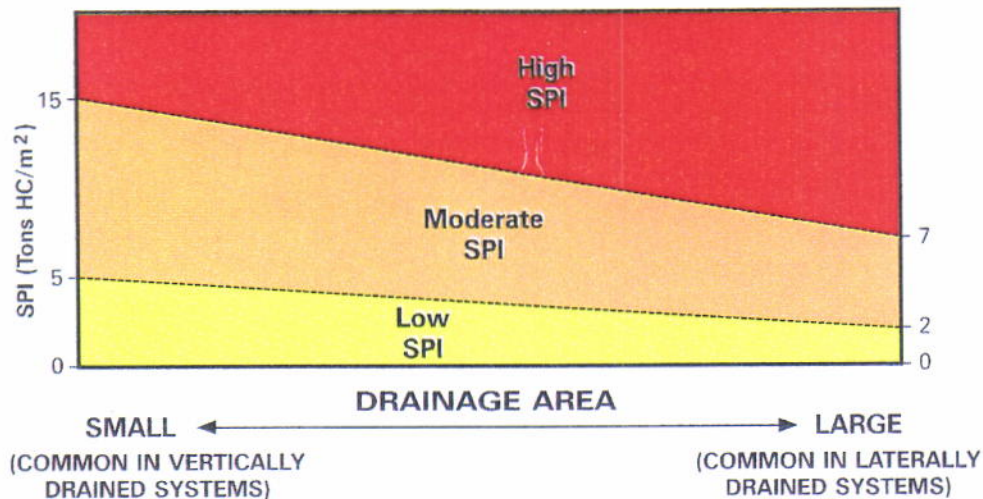
We recall that the “hydrocarbon charge risk” is one of the parameters concurring to determine the “risk in exploration”, which must be always considered for the selection of prospects to drill.

Deeply knowing the *“petroleum systems”* characterizing the sedimentary basin under study we could also evaluate the quantity of entrapped hydrocarbons.

“The *petroleum system* is a dynamic petroleum generating and concentrating physicochemical system, functioning in a geologic space and time scale. A petroleum system requires the timely convergence of certain geologic elements and events essential to the formation of petroleum deposits (e.g., mature source rock, expulsion, secondary migration, accumulation, and retention)” (Nijhuis and Baak, 1990).

The real meaning of the SPI value depends on the specific petroleum system.

Fig. 11. A preliminary SPI classification, which would have a statistical validity, is here below shown (from Demaison & Huizinga, 1994).



The SPI threshold value of minimum industrial interest is represented by the value which it can enable the formation of a significant accumulation from the industrial point of view. Obviously this value can strictly depend on the specific geological framework and the occurrence of generation/expulsion processes.

To determine a threshold value of minimum theoretical interest, the most favorable petroleum system should be considered: *high maturity*; *large drainage areas* and *efficient migration/accumulation processes* (minimum hydrocarbon losses and good seals).

The *SPI threshold value* to define a sedimentary section as "*potential source rock*", could be tentatively placed (in favorable conditions) at approximately *0,5 t HC/m²*.

Study of Generation and Expulsion phenomena of hydrocarbons from the source rock

Once ascertained the actual interest for a potential source rock (adequate SPI for the specific petroleum system), the extent of generation and expulsion of hydrocarbons shall be evaluated.

HC Generation

We have already touched upon the fact that different maturity parameters are studied which suggest the extent of naphthogenic phenomena (T_{max}, Reflectance of Vitrinite etc.) for the samples of source rock analyzed.

These experimental data usually come from wells, which are generally drilled on structural highs, where the extent of the sediment burial is less compared to the basinal areas (depocenters).

To evaluate the source rock maturity off structure in basinal areas, specific software was developed ("*hydrocarbons generation simulation*").

The use of this numerical model implied a first phase of "*calibration of thermal history*" characteristic of the study area (evolution of the heat flow through geological time).

The following *simulation of hydrocarbon generation* is performed in different key points of the basin under study, by using different methodological approaches (1D, 2D, 3D models).

An appropriate set of "*kinetic parameters*" modulates in function of the temperature the rate of *kerogen thermal degradation* to give hydrocarbons; in its turn the evolution of the source rock temperature through geological time is determined by the burial history and heat flow variations. *Kinetic parameters* are specific for each source rock and can be experimentally determined on samples of immature kerogen, representative of the potential source rock of the area; alternatively they can be selected, with minor accuracy, among standard set, relevant to the different types of kerogen previously described (Type I, II, II S, etc.).

As a final result we can obtain:

- *areal extent of generation process* (Transformation Ratio) in the source rock
- *timing of hydrocarbon generation* (to be compared with the age of trap formation)

Expulsion of HC from the source rock (primary migration)

Expulsion is a critical process in hydrocarbon charge risk. A good source rock must be able also to expel efficiently HC in order to create an oil accumulation.

The main critical parameters governing the expulsion process of hydrocarbons are:

- 1. abundance of organic matter and its distribution;*
- 2. kerogen maturity;*
- 3. compaction of the source rock (porosity reduction).*

These parameters are strictly interrelated among them.

In fact, in the hypothesis that oil relative permeability is the main factor controlling hydrocarbon expulsion, the oil saturation in the rock is deriving from the combination of the above mentioned parameters. For example rich source rocks at optimum maturity level can have high oil saturation and, consequently, good expulsion efficiency. Compaction through pore size reduction can trigger the expulsion process by means both of the oil saturation increase and pressure raise.

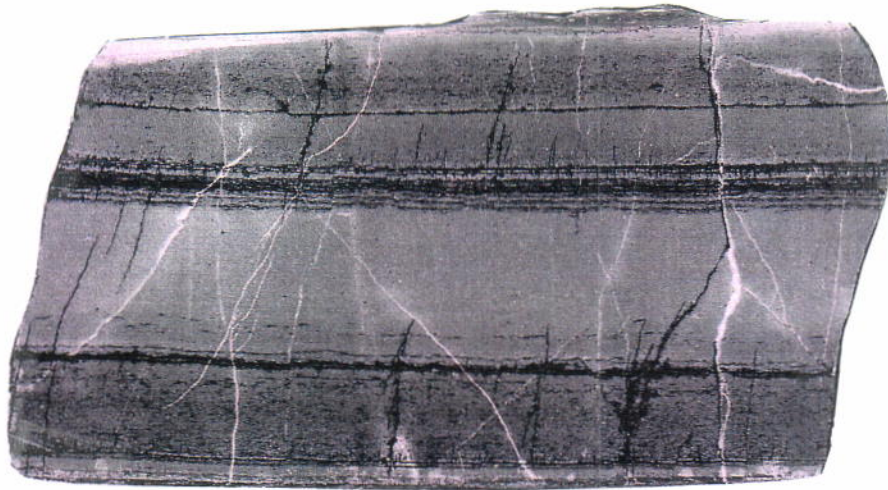


Fig. 12. In this photo the hydrocarbon expulsion process occurring in a laminated dolostone is shown. Notwithstanding the poor average original petroleum potential of the rock (around 0.5 KgHC/t rock), from the laminae rich in organic matter hydrocarbons have been expelled along microfractures orthogonal to stratification. The sample is at a high level of maturity, and the HC movement in the past is now highlighted by carbonous residuals.

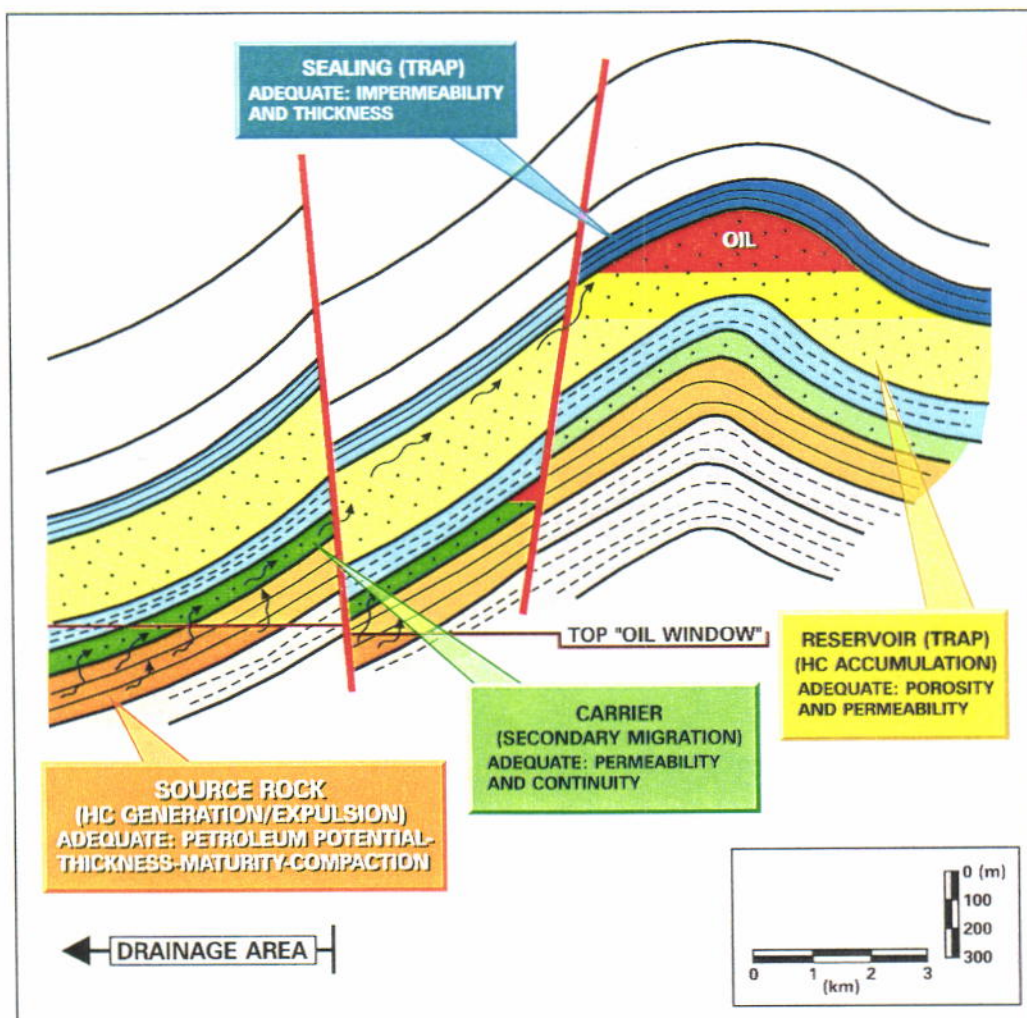
Secondary Migration

Going beyond the subject treated, we just mention that hydrocarbons, once expelled from the source rock, have to move towards the trap. This process, called *secondary migration* takes place through the rock units (*carrier*) characterized by good permeability and continuity.

The secondary migration can also occur through complex migration pathways, with the transit of the HCs in different carriers, connected among them also through faults/fractures.

To complete the definition of the *Petroleum System*, *geometry (traps)*, *reservoirs* and *sealing* shall be then considered.

Fig. 13. An elementary example of Petroleum System is shown in the figure.



Source rock studies: more frequent problems

1. What are the main outputs of a source rock evaluation study in a well?

While drilling, samples for source rock study are systematically collected, whereas geochemical analyses are performed only upon request.

It is advisable that exploration dept. ask for the geochemical study at least for wildcat wells (regardless of hydrocarbon occurrence), in order to ascertain *the maturity level reached by the whole series crossed*, and to investigate *the presence of potential source rocks*.

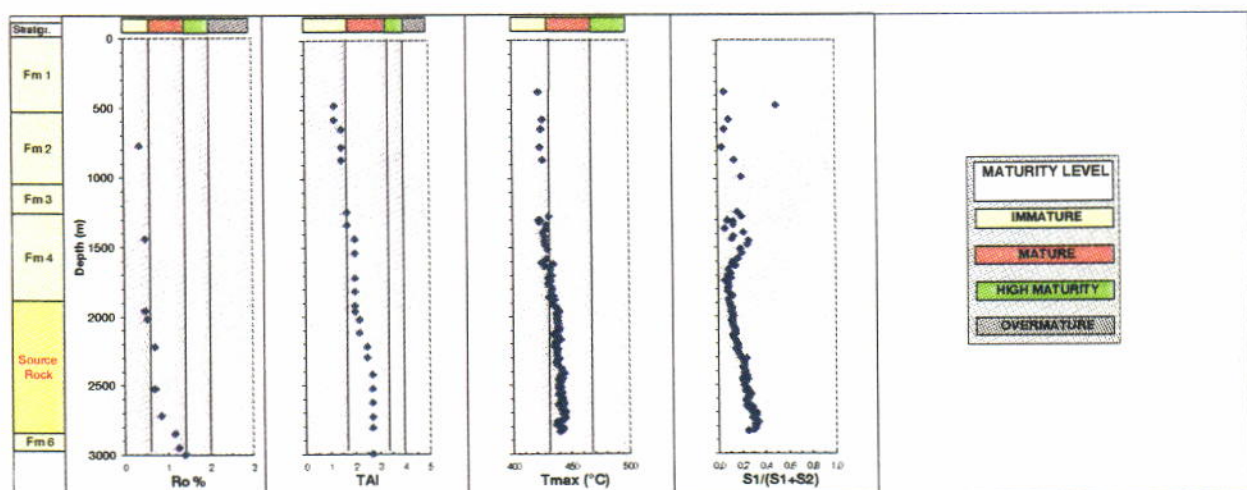
It must not be forgotten that the geochemical study includes also other analyses which, associated to those mentioned above, concur in the definition of the petroleum system; the most frequent refer to the complete characterization of oils and gas (even in traces and with different samples recovery techniques).

The *usual presentation of geochemical source rock data* includes a series of diagrams and logs where *the naphthogenic features of the potential source rocks (maturity, m.o. content, kerogen quality)* are describe allowing the evaluation of the actual original hydrocarbon potential.

Regardless of the presence of potential source rocks in a well, maturity profile definition for the whole series crossed is very important since it concurs (together with the temperatures vs. depth log) to the definition of the thermal evolution of the basin and allows (once a specific source rock has been identified or presumed) to evaluate, through geochemical modeling, the eventual timing of eventual hydrocarbon generation.

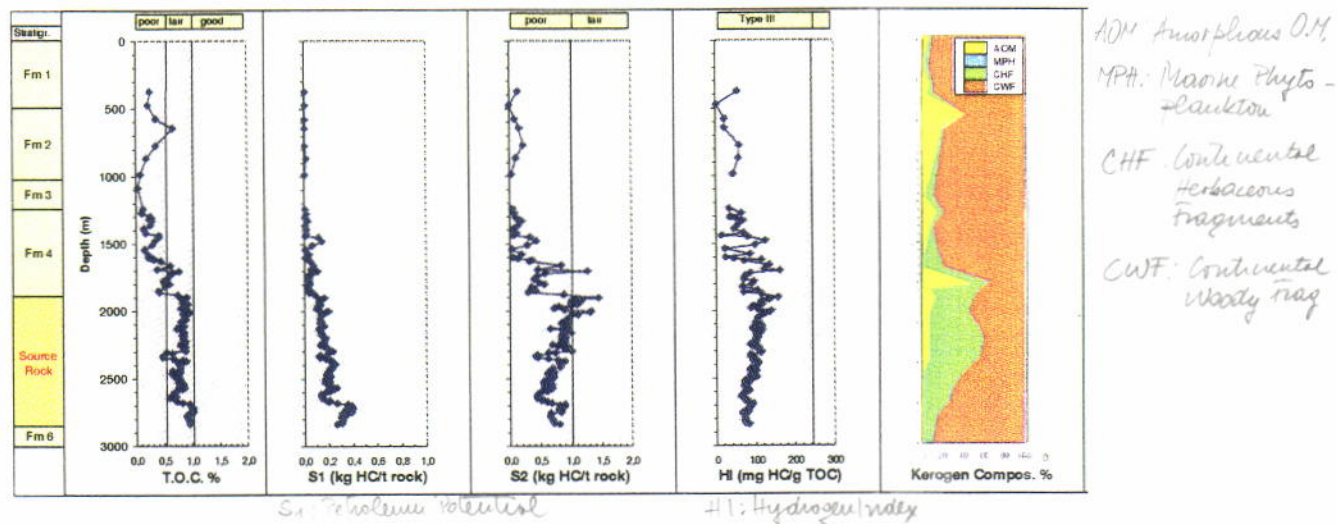
The logs of fig. 14 and 15 show the naphthogenic characteristics of a sedimentary section drilled in a wildcat well, where an interval with fair (original) source rock properties is recognizable. The upper portion has low maturity; the lower portion is more mature, and original naphthogenic properties are lowered. For the interpretation of the figures and diagrams, refer to previous pages.

Fig. 14. Logs showing kerogen maturity.



TAI: Thermal Alteration Index
Ro: Vitrimite Reflectance
S: Petroleum Potential

Fig. 15. Logs showing naphthogenic properties (kerogen quantity and quality).



Based on such naphthogenic characteristics, the *source rock potential* of a specific interval of sedimentary rocks (belonging to the same petroleum system in terms of *Source Potential Index (SPI)*) can be evaluated. As defined in the previous pages, SPI (residual or original) is evaluated combining the average petroleum potential (residual or original) of the source rock, with its thickness.

After the source rock identification, correlation can be made with eventual oil occurrences of the basin under study, by extracting from the source rock the free hydrocarbons already generated but not yet expelled. The "*oil-source rock correlation*" is made by using different types of geochemical analyses, the most frequently used being gas-chromatography (GC) combined with mass spectrometry (MS) (biomarker analyses) and carbon isotopic analysis ($\delta^{13}\text{C}$).

2. The wells are normally drilled on the structural highs and they don't often reach the source rock. In this case how is it possible to identify and to characterize the source rock?

In some sedimentary basin it is not very easy to find the source rock of oil occurrence.

This is due to the fact that the source rock facies could develop in a lateral position to the structural high where oil accumulations were found by the wells, probably charged by horizontal secondary migration; in other cases the source rock could be older (and consequently deeper) than the sediments reached at total depth in the well.

From oil geochemical analyses an "*identikit*" of the source rock (in terms of sedimentary facies) can be defined.

If outcrops exist, and if through paleogeographic reconstruction (for different geological time) a similarity between outcrops and underground series can be inferred, it will be useful

to perform surface samplings for all the naphthogenic units matching in some way the source rock identikit.

In case of positive oil-source rock correlation, using outcrop samples, the usual geochemical approach, just described, can be applied to define source rock properties.

3. How can the original hydrocarbon potential of source rock be evaluated if in the wells only very mature facies was found ?

In a basin, wells may drill the source rock in a very mature facies. The naphthogenic process has already occurred, and the source rock, having generated and expelled the hydrocarbons, has only a residual petroleum potential (which can be totally depleted at the highest maturity levels).

To reconstruct the potential of the petroleum system under study, its original naphthogenic potential (in the form of SPI), must be restored.

Kerogen quality assessment (in terms of original Hydrogen Index) is essential for this evaluation.

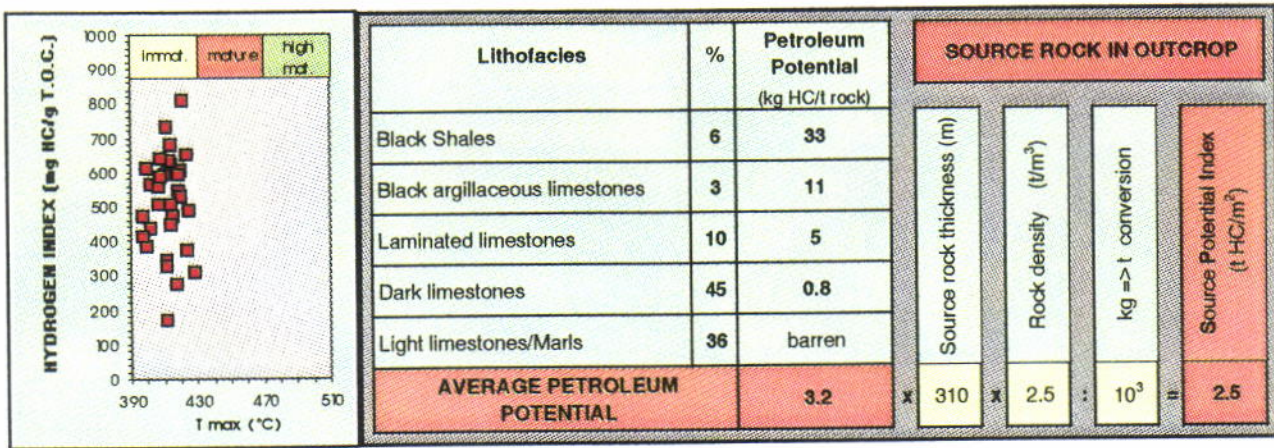
The *original Hydrogen Index* can be assumed as a specific of the type of organic matter (determined by to the kerogen optical analysis) and of the specific sedimentation environment of the source rock.

In some other cases, the source rock itself can be sampled in outcropping series; analyzing immature samples the original Hydrogen Index can be analytically determined for the different lithofacies contained in the source rock (or more simply the average Hydrogen Index).

If the source rock in the sedimentary basin shows homogeneous characteristics (with changes only in its thickness), the average petroleum potential, can be evaluated through the immature outcrops, can be used in first approximation also for the area under study; the SPI will then be modified only according to the different thickness of the source rock.

Weighted average petroleum potential of the source rock can be evaluated combining petroleum potentials of the different lithofacies and by using their relative thickness compared to whole considered section.

Fig. 16. It is shown the evaluation of the naphthogenic potential of an important source rock in Northern Italy. On the left the HI vs. Tmax diagram points out samples immaturity; on the right the approach for the computation of weighted average petroleum potential and SPI is shown.



4. If LCM (Lost Circulation Material), additives or even oil base mud have been used in a well, how can the naphthogenic potential of a source rock be evaluated ?

Over the last few years it has become harder to obtain good naphthogenic data due to the habit of packing the mud with different sorts of LCM and additives. On top of this the use of oil based mud and of PDC (Polycrystalline Diamond Compact) bits which pulverize the cuttings , have made the situation even worse.

Concerning the increase in drilling speed which these systems can guarantee, the cost/benefit advantages should be evaluated in the different cases, i.e. if it is really profitable in some cases to reduce drilling costs at the expense of a proper performance of the studies (geochemical, petrographic, stratigraphic) which could allow the understanding of the petroleum systems making exploration research more efficient (increase in the rate of success and consequently cost effective research).

For wells whose *cuttings* appear *irreparably contaminated*, analyses must be performed only on eventual bottom or side core samples. It is obvious that the survey will be restricted to a limited portion of the source rock, and it will be therefore impossible to reconstruct a continuous log of the petroleum potential through direct analysis.

It is however easy to recognize the different lithofacies characterizing the source rock from core analysis, and average petroleum potential can be measured for each lithofacies.

At this stage, through an *integration of log analysis and geochemistry*, lithofacies (in this case "*electrofacies*") distribution along the sedimentary section can be recognized and by using their average petroleum potential it is possible to obtain the weighted average petroleum potential of the source rock.