2.1 Definition of exploration

Exploration is the first phase of the petroleum cycle and includes all activities relating to the search for hydrocarbons. In the literature (Langenkamp, 1994; Williams and Meyers, 2003) the term exploration is defined as “the search for oil and gas […], including aerial surveys, geophysical surveys, geological studies, coring and the drilling of exploration wells”. Other classification systems include exploration under the broader heading of reservoir development. However, according to the universally accepted definition, exploration is a phase of the petroleum cycle aimed at finding hydrocarbon accumulations, which to this end makes use of various scientific disciplines. The explorationist is a geologist who uses the data obtained with various methodologies to develop a geological model of the area, and who formulates working hypotheses on the basis of all the geological and geophysical data collected, evaluated within a general context. In the United States there are two categories of explorationists: ‘generalists’ who are able to evaluate the data as a whole, and ‘specialists’, such as micropalaentologists, seismologists, log analysts, sedimentologists and geochemists, who capture and interpret specific types of data. Specialists appear on the oil scene at the end of the 1920s (before this date the geologist managed the entire process, concentrating on the fundamentals of exploration), indicating the importance of interpretative tools such as stratigraphy, sedimentology, the petrography of clastic and carbonate rocks, and log analysis.

In the context of an oil company’s activities, the role of exploration is to provide the information required to exploit the best opportunities presented in the choice of areas, and to manage research operations on the blocks acquired. Exploration is responsible for managing the risk inherent in this activity, selecting the best of a range of options in probabilistic and economic terms (see below). Risk is an inherent component of the various phases of exploration. For example, it is risky to request an exploration permit on the basis of more or less detailed data, taking on subsequent work obligations (a number of wells to be drilled, financial commitments), as is deciding to drill a given well rather than another. This element of risk cannot be eliminated entirely but it can be managed successfully. Some exploration choices are of a strategic nature, such as that between high-risk virgin areas where the probability of success is lower, and areas in mature basins where results are more easily achieved, but discoveries modest.

In the sequence of activities characterizing the petroleum cycle, exploration represents an extremely delicate initial phase. This is the start of a process on whose results (success or failure) the future economic choices of the project depend. In the case of petroleum success (discovery), a long time may be required to produce the accumulation found (from 20 to 100 years depending on the size of the reservoir discovered).

In the example in Fig. 1 the weighting of exploration within the entire oil project in terms of time and investments is shown. Exploration accounts for 14% in terms of time, and 7% in terms of investments. It is clear that exploration has an enormous impact on the profitability of an oil project, when compared to other phases of the cycle. The investment of modest risk capital may in face be connected to considerable financial returns.

2.1.2 Examining and defining available technical data

When research in a basin or in an area containing several basins begins, first the quantity and quality of
available data must be checked. In little-known areas, data on geology, stratigraphy, tectonics, the type of reserves, the production of existing fields, the layers containing hydrocarbons represent essential basic information. Sometimes the geological data are insufficient for the type of research which is intended to undertake. This was the case during the 1970s when exploration was directed towards continental shelves and in the 1980s when attention was turned towards deep offshore areas. At the time, the only available data referred to environments which could not be easily correlated with the areas under investigation. Sometimes, data are difficult to interpret or are in a non-standard format, as Western oil companies found in the early 1990s when they tackled the documentation for reservoirs in some ex-Soviet countries.

Whether we are dealing with preliminary studies of virgin basins, regional exploration or in-depth exploration of known basins, the problem of available and usable data is fundamental. It must be borne in mind that petroleum-related activities take place within the context of an extremely competitive system. Different companies exploit the same basic information on the potential of a basin, on ‘research topics’ (play, the combination of geological-stratigraphic and structural factors which may lead to the accumulation of hydrocarbons) and on the characteristics of geological formations. It is therefore important to use all available data to select the most promising areas. The mechanisms for acquiring exploration permits are so complex, the methodologies so expensive, the signature bonuses for new areas so high that it is inadvisable to run the risk of having incomplete information.

Various types of data may be available for use during the preliminary phase of petroleum exploration:

- Preliminary (scouting) data marketed by specialist companies. These might include, for example, information on operational activities in a given area, on wells being drilled, on mineral results (‘successful wells’ or ‘dry wells’, depending on whether or not they produce hydrocarbons in commercial quantities), on operating oil fields and their principal characteristics, or technical reports containing an initial processing of geological data, including maps, facies analyses, palaeogeographic reconstructions of areas and basins. These data, which are generally very expensive, may be purchased on the market, but it is obvious that only major companies with a large turnover are in a position to make systematic use of it. The reports provide preliminary information on the traits of a basin and allow us to build a geological model of the area.

---

**Fig. 1.** Activities in the petroleum cycle.
• Non-exclusive geophysical (gravimetric, magnetic, and especially seismic) surveys commissioned from service companies (contractors). These companies, in agreement with the State owning the areas, programme and carry out surveys at their own expense, on the basis of parameters suited to the basin type and the relevant mineral objective, and place these at the disposal of oil companies. Obviously, the cost is considerably higher than for the previous type of data. However, the information is more complete, since it includes original seismic data. At times, the purchaser may process these original data so as to highlight characteristics useful for the interpretation of the basin’s geology. These technical documents (packages) often contain well data, including electrical logs. These permit to assign a specific geological meaning to the seismic horizons, thus making an initial interpretative evaluation of the area possible. In this type of non-exclusive purchase, the buyer never owns the original data, which remain the property of the State with which the service company has signed the agreement.

• Photogeological and geological surveys. These, like on-site surveys or genuine geological campaigns, may be undertaken directly at relatively low cost, and may therefore also be carried out during the preliminary stage of exploration. Other types of extremely expensive survey, on the other hand, cannot be undertaken without mineral rights (e.g. an exploration permit) to protect their holder. The preliminary gathering of information about a basin may confirm the parameters required to predict the presence of hydrocarbons. At this point, it is necessary to consolidate the knowledge of the basin by developing a more sophisticated geological and geophysical model. There are two possible scenarios:

• The State has yet made no official decision regarding the granting of exploration permits for the area to be investigated. Oil companies can decide to carry out, at their own risk, seismic surveys in the area without being protected by minerary rights, as has happened in the North Sea at the beginning of the 1970s.

• The area or group of areas to be analysed form the object of a bid round announced by the competent authority (the State, directly or through the national oil company). In this case, oil companies are supplied with packages of seismic, geological and well data, enabling them to study the potential of the area and prepare the terms of their bids. The latter must contain a series of evaluations including, for example, the number of wells to be drilled, the cost of completing all necessary operations, the kilometres of seismic (set of surveys useful to understand the structure and depth of subsurface geological layers) to be acquired. These data remain the property of the State, whilst the company has the right to use them. Once the areas up for bid have been examined, and the potential for discoveries of commercial significance ascertained, the oil company which wins the bid round is assigned mineral rights. Such company can thus make investments, since it has a formal guarantee in the shape of a contract signed with the relevant authority. At this point it has the right to obtain all available data on the area (both directly from the State, and from private companies which have operated there previously), and to process them in the most appropriate way.

Some of these data may already have been supplied for the bid round. Generally, these packages do not include all existing data. Once mineral rights are obtained, it is possible to organize an archive (or database) containing all the information needed to undertake exploration in operational terms in the areas covered by the licenses. Usually, the most useful forms of data are well data and seismic data.

Well data must be evaluated with specific reference to the well’s location, effective depth and coordinates of the point of maximum depth (or total depth). It is also important to know the classification of the well before and after drilling, the depths of individual stratigraphic and productive layers, and the type of geological formations crossed, to check if these correspond to the sequences adopted for the basin model. If they differ, further analyses are needed. The stratigraphic sequence at the well must also contain any information on samples of rock (cores) and fluids taken, and the information required to find these or the analyses carried out on them.

A second set of data is seismic data. Often the documentation provided for the bid round contains only paper copies of seismic sections, which are of use only for a preliminary and very general interpretation. Once rights to the area, with specific work commitments, have been obtained, the original recordings (field data) are needed in order to carry out any necessary reprocessing. Above all, the different sets of data must be compatible with one another; surveys from different seismic campaigns must be
rendered uniform, it is also important to ensure that the acquisition parameters are sufficient to proceed with specific studies aimed at pursuing exploration objectives.

The need to obtain a set of historical data within a short space of time is often a critical aspect for many companies. The volume of data needed to prepare a project may be extremely large, and the time required to find it extremely long. These delays often result in a series of inefficiencies in the process, especially in the transition from the exploration to the development phase. Moreover, the databases belonging to individual projects are often unable to ‘talk’ to one another, and thus tend to become obsolete. Many companies have therefore felt the need to develop databases which remain stable over time, and which guarantee compatibility with individual projects on the one hand, and with regional information (supplied by the aforementioned international service companies) on the other, using a series of codified procedures to upload and manage all the information.

2.1.3 Selecting areas

The core business of an oil company is finding, producing and selling hydrocarbons and their by-products. The company’s most important activities are therefore operations which allow it to activate available reserves by managing known reservoirs, and to replace the quantity of hydrocarbons produced with new reserves. The hydrocarbon reserves (oil and gas) produced are generally replaced by a) discovering new reservoirs or broadening earlier discoveries; b) increasing the recovery of hydrocarbons from reservoirs already in production; c) acquisition of reservoirs from other oil companies.

For an oil company the percentage of reserves replaced with the three methodologies mentioned above may vary over the years (Fig. 2); the discovery of new reservoirs is usually the most effective system.

The first stage in the petroleum cycle, exploration, aims to discover new reserves, and takes place in two distinct phases: regional exploration and in-depth (or detailed) exploration.

Regional exploration has the role of examining sedimentary basins to indicate traits conducive to the generation, accumulation and preservation of hydrocarbons. In-depth exploration focuses on selected smaller areas (covered by exploration permits) where classic exploration methods can be used. These aim to make a direct study of the prospect (a potential structural or stratigraphic trap described and located using geological and geophysical data, and forming part of a given play). The study of an unexplored basin, where no data on previous discoveries are available, aims to assess the possibility that conditions conducive to the generation of hydrocarbons exist. Where available geological data do not allow us to assume that rocks capable of generating hydrocarbons are present, any future activity is compromised. Where the response is positive, it is important to attempt an evaluation of the size of accumulations in the exploration area, and thus the potential for future economic success. The explorationist can suggest the acquisition of an area only on the basis of a careful evaluation (of the nature of the basin, the number and size of possible reservoirs, the possible types of play found).

Preliminary evaluation of resources

The characteristics of a hypothetical reservoir in a basin must be predicted on a statistically reliable basis in order for the model to have any meaning. When preliminary geological data are available, the possible responses are probabilistic, in the sense that all the information inserted into the geological model is hypothetical, deriving from a series of observations generally made in different parts of the basin, often distant from one another. Without going into excessive detail, it is sufficient to know that parameters such as the thickness of a mineralized layer in an area, the porosity values of a layer, the geometrical closure of a prospect, the height of the assumed hydrocarbon column, the reserves within a basin’s reservoirs, may supply a probability or relative frequency distribution. This can be plotted on a graph, with the values of the
parameter on the x axis, and the probability or relative frequency with which the parameter assumes these values on the y axis. Probability distributions may also be represented as cumulative curves: in this case the classes of values are still represented on the x axis, with the y axis showing the probability of a given value being exceeded (Rose, 1992; Megill, 1992). This type of graph allows us to show the probability that a parameter assumes a value within a given interval compatible with available data.

When a basin is analysed, even before interpreting any seismic data which have been found, its overall potential is estimated. Some methods for estimating the resources of a basin described in the literature (White and Gehman, 1979) are, for example, geological analogy, the Delphi method, areal and volumetric yield, the number and size of fields, and the extrapolation of discovery rates.

Geological analogy. This is the most basic method, and that which historically has been most widely used. It starts from the assumption that basins with similar geological characteristics have the same hydrocarbon content. This type of evaluation makes use of an extremely complex basin classification system, based on a number of parameters used as points of comparison. In fact, geological analogy is a cognitive approach common to all evaluation methods, since it analyses the conditions for the formation of the basin, its evolution, and direct (analysed) and indirect (hypothetical) elements. Often the disappointing results obtained by applying this method are due to the failure to assess the importance of individual elements within a broader context.

The Delphi method. This method takes account of the opinion of a group of experts who examine the area and express individual opinions on the probable distribution of petroleum potential. These different evaluations come together in a final report which takes account of the different points of view. This method has been used particularly in Canada and by the United States Geological Survey.

The areal yield method. It involves multiplying the effective area (potential) of a basin by the unit production of a known productive area. The disadvantage of this method is that it fails to take into account the third dimension (depth).

The volumetric yield method. It takes into consideration the thickness of the reservoir as well as of the effective area. This approach to evaluation may be reliable on a regional scale in the early stages of exploration when little data are available, taking account of specific parameters such as the type and distribution of reservoir rock or the distribution and thickness of source rocks. However, it may be misleading if the information used is not consolidated, extending to the entire basin local situations which are not confirmed by exploration.

The geochemical evaluation approach. This volumetric model, widely used by Soviet geologists, takes account of the basin’s organic contents and its composition during the various stages of migration and preservation in order to define the postulated accumulation. The greatest difficulty lies in creating a hypothetical model without an adequate understanding of migration pathways and the quantities of hydrocarbons which actually migrated and became trapped.

The field size distribution method. It analyses the distribution of reservoirs discovered on the basis of their size. The distribution of prospects must follow the same pattern found for the reservoirs, so as to apply the same probabilistic estimation approach to them. In order to use this method satisfactorily, a large quantity of data is required.

Extrapolation of discovery rates. It has been used for forecasting with limitations due to the fact that unexplored areas, on which detailed information are not available, are difficult to insert into a probabilistic forecast.

Each of these evaluation methods has advantages and gaps, especially in the phase of comparison between different basins, where similarities are often evident, but points of divergence, far more important, are much less obvious.

Degree of exploration knowledge of a basin
From the point of view of exploration, every sedimentary basin may find itself in a different stage of ‘operational maturity’ (Royal Dutch-Shell Group of Companies, 1987); consequently, knowledge of the basin and related exploration topics may be more or less exhaustive.

Preliminary Stage. Pratt’s statement (1937; 1944) that “oil is in the minds of men” is well-suited to the preliminary stage of the exploration process, when data are scarce or barely existent, neighbouring areas of little help, the depth of water sometimes prohibitive, direct geological knowledge non-existent, and when the petroleum system can only be hypothesized on the basis of analogies. This was the case, for example, for the Angolan deep offshore in the early 1990s, or the sea off the Nile delta, where an attempt was made to build a geological model with only a few seismic lines available.

Initial Stage. Our knowledge increases when those operating in the basin attempt to formulate hypotheses on petroleum characteristics, the type of trap and the techniques most suited to our objectives. In this phase it is important to find keys to interpretation. For this reason, the first control wells are drilled, allowing us...
PETROLEUM EXPLORATION

Fig. 3. Cumulative curve of discoveries in the North Sea (Campbell, 2000).

to test the models developed. For example, the discovery of turbidite channels in the Angolan deep offshore led to a long series of exploration successes.

Mature Stage. The model has been perfected. Discovery rates and the quantities of hydrocarbons shown at each well remain constant over a certain number of years. Exploration techniques (acquisition, processing, interpretation) are consolidated. This is the mature phase of basin exploration.

Final Stage. As exploration activity intensifies, discoveries become progressively harder to make, and involve increasingly smaller and more marginal fields. Exploration activity declines (at least as far as the research topics pursued hitherto are concerned, Fig. 3).

Further exploratory approaches

When the basin has already been explored its remaining potential must be assessed, in part by evaluating the level of activities undertaken here previously. If dealing with a frontier area, and only small and sporadic quantities of data are available, geological analogy is used, adopting equivalent basins as a model, although some correction parameters are necessary. This was the path followed, for example, in evaluating the deepwater areas off West Africa, where the reference models used were Brazil or the Gulf of Mexico (though in the case of Brazil the models referred to a different geological era). On the other hand, when areas which have already been partially explored need to be evaluated, cumulative curves containing the distribution of discoveries made (for each exploration topic) may be developed in order to assess the basin’s remaining potential, the percentage of success and the size of any undiscovered fields.

These preliminary operations guarantee results on the basis of which the actual interpretation of the area can be effected, and a series of maps representing the structure of the geological horizons interpreted produced (Fig. 4). The geometry of these maps will indicate areas of interest (prospects).

2.1.4 Acquiring mineral rights

Once a regional study has been carried out using available geological, seismic and well data, a number of prospects are identified for each area (or block) studied. These represent the exploration potential of the area. The prospects shown must be technically viable; furthermore, they must meet the market conditions which, in the case of discovery, guarantee a financial return on investments. Every oil company has its own profitability criteria, on the basis of which it makes the appropriate decisions. The economic aspect of investments will be discussed later. Here we will describe the actions required to obtain new areas for petroleum exploration (new exploration initiatives).

On an international level, exploration blocks may be acquired by: a) participating in a bid round announced by the State, as owner of the acreage, either directly, or where it exists, through the national oil company. Examples are EGPC (Egyptian General Petroleum Corporation) in Egypt, NOC (National Oil Company) in Libya, Sonatrach (Société Nationale pour la Recherche, la Production, le Transport, la Transformation et la Commercialisation des Hydrocarbures) in Algeria, Pertamina (Perusahaan Pertambangan Minyak dan Gas Bumi Negara) in Indonesia, etc.; b) acquiring a quota through an agreement with the company that already holds the mineral rights; c) negotiating directly with the State.

In the case of blocks forming the object of a bid round, the technical and economic parameters of each individual block need to be defined. Blocks are evaluated on the basis of petroleum potential (number of prospects in each block, predicted value of individual prospects, type of fluids postulated) and operational aspects (the costs of any additional seismic, drilling expenses, availability of rigs, potential overpressures, field development and transport of the hydrocarbons to the market-place, the type of contract offered by the State). These factors indicate which blocks should be chosen in order to conduct industrial exploration activities.

In many international bid rounds, some contract parameters are predefined (type of contract, contractual terms), whereas others (signature bonus, financial commitments, work commitments to be undertaken) are entirely negotiable.

The second option is to obtain a participation (or the entire quota) in an exploration permit already assigned to another company. This type of acquisition is extremely common in the oil world and usually occurs when the oil company already holding the mineral rights wishes to lighten its financial burden, and offers part of its quota to others (farm out). In this case all the contract parameters are already fixed: only the cost of
entry, equivalent to the cost of programmed operations with a surcharge (signature bonus), is negotiable.

A third way of acquiring a block is by private negotiation with the relevant state institutions. In some cases this takes the form of a ‘research agreement’ which presupposes a preliminary agreement with the State (or its representative). Usually the oil company carries out a non-exclusive study (another oil company may undertake the same type of evaluation independently) on the area, using data (geological, well, seismic data, etc.) supplied by the State, which often provide the same information to several companies. The results of the study are presented, and the report becomes the public property of the State concerned. The benefit for the State lies in the availability of results based on different interpretative approaches, and its ability to evaluate better the proposals of individual competitors. For the oil company, the benefit lies in gaining knowledge of the area at relatively low cost. Even if the agreement is not finalized, the oil company can file further information about the region, the province and the basin.

An oil company may decide to acquire an exploration permit for various reasons, aside from purely economic considerations. The decision may also be influenced by factors such as, for example, a desire to increase its influence in an area where it already operates, or the potential to undertake different activities in the future.

**Definition of obligations in applications for exploration permits**

Applying for an exploration permit involves a careful appraisal of financial and work obligations, and the relevant deadlines. When participating in a bid round, the following aspects need to be carefully assessed: a) essential work required to evaluate the area; b) the cost of obligatory work; c) the contractual conditions which would allow us to recoup investments at the discount rates predicted by the oil company; d) the ability to exploit the product, in other words to sell the quota of the oil and gas found during these activities.

After assigning a technical and economic value to each block analysed, a proposal for each block detailing the work to be carried out (the amount of seismic to be acquired, the number of wells to be drilled, the signature bonus we are prepared to pay, the contractual terms acceptable to us, and those which require negotiation) needs to be presented.

For its part, the owner of the area (usually the State) has every interest in assigning exploration areas to companies with the requisite solidity and strategies to carry out a technically sound exploration programme.

Selecting and acquiring blocks is a complex process involving many of an oil company’s functions: exploration, above all, technical services and economic evaluations. Acquiring a new area entails the acquisition of obligations, risks, potential results and possible future commitments.

A successful exploration leading to the discovery of new reservoirs provides the State not only with the income deriving from oil production, but also allows it to develop a relationship with a large number of companies, and provides an increase in signature bonuses and revenues. In this context, Angola, with the first deep offshore discoveries, Norway, the Gulf of Mexico and Brazil can be mentioned. All these areas became the object of enormous interest from the international petroleum industry following initial positive results.

### 2.1.5 Programming direct and indirect surveys

After acquiring a block (or a number of blocks), the operator (the company managing the operations specified by an exploration permit, sometimes on
behalf of other companies associated in a consortium or joint venture) must honour a series of commitments set out by the contract, within a period of validity and respecting a series of predetermined deadlines (Fig. 5).

Validity period of the permit

The validity of a permit is generally broken into three periods. The first period usually lasts three or four years, and the second and third periods one or two years each. This variation in length depends on the location and logistic conditions of the block concerned, which may be in an inaccessible area, or in deep water.

The first validity period (Fig. 5 shows a permit with a first period of four years, and second and third periods of two years each) is obligatory, and for its duration the company which has obtained mineral rights takes on a number of work obligations (a given number of kilometres of seismic to be acquired and a given number of wells to be drilled). If these obligations are not met, sanctions are incurred.

At the end of each exploration period the owner must release part of the area (normally around 25-30% of the initial acreage) so as to avoid penalizing exploration in the area by others. This aspect must also be taken into consideration: the area needs to be explored as fully as possible in order to avoid releasing potential remaining reserves.

The second and third periods are optional. After analysing the results of drilling during the first period, the owner decides whether or not to ‘enter’ the second (and subsequently the third) period, thereby taking on the obligation to carry out further exploration and the resulting financial commitments.

This decision is especially difficult where exploration results are disappointing and the wells drilled turn out to be dry. In this situation it is only appropriate to continue with the next phase of exploration if there are other research interests beyond those already pursued.

Another aspect covered by the exploration permit concerns the consequences of a discovery, with the transformation of the area into a ‘development lease’. Leases have a much longer validity period (twenty or thirty years), since producing the reservoir discovered requires a series of operations (evaluation of the accumulation discovered, formulation of a development plan), often with the direct contribution of the State, which may have a participation quota in the joint venture.

During the exploration period, costs are borne entirely by the operator; if exploration is unsuccessful, they remain at the company’s expense. If there is a petroleum success, the operator and the State (the latter potentially through the national oil company) set up a mixed company to produce the field. This mixed company, which is generally non-profit, has the task of managing the reservoir discovered, producing it and selling the product on behalf of the two shareholders. In this case the operator may obtain a reimbursement of expenditure and participate in profits from operations.

The work programme is defined in the agreement, both as concerns operational activities (in particular the amount of seismic needed to delineate the areas of mineral interest), and the number of wells to be drilled. Furthermore, the minimum depth or the geological layers which must be reached by drilling are specified, in order to commit the operator to a strict work programme. This avoids the risk of keeping the area frozen during the entire exploration period, without the requisite mineral evaluations being completed.

Drafting the exploration programme is a team effort involving the participation of all the specialists working on different aspects of the project, including

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>exploration periods</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1st period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2nd period (optional)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3rd period (optional)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>work obligation</td>
<td>1,000 km 2D</td>
<td>2,000 km 3D</td>
<td>1 well</td>
<td>2 wells</td>
<td>1 well</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>minimum expenditures</td>
<td>16 million dollars</td>
<td>20 million dollars</td>
<td>10 million dollars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>signature bonus</td>
<td>2 million dollars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>relinquishment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>30% of original area</td>
<td>30% of original area</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>24-01-2000 effective date</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>23-01-2004 exp. date 1st period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>23-01-2006 exp. date 2nd period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>23-01-2008 exp. date 3rd period</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

original area: 7,000 km²

Fig. 5. Example of an exploration permit: exploration periods, work obligations and financial commitments.
the feasibility study, the geophysical survey, surveying parameters and the recording of well logs.

The sequence of activities covered by an exploration permit is fairly uniform, and involves the creation of a database, the analysis of available data, the programming of mapping, geological and photogeological surveys, seismic surveys, the interpretation of seismic data, the choice of well locations, drilling, the analysis of results and the decision as to whether or not to proceed with the application for a lease or to release the area after a complete exploration.

In mountainous areas such as the Cordillera of the Andes, the Caucasus or internal basins in China, surface geology may still play an important role. Offshore, other surveying methods, especially geophysics, are used from the outset.

Each of the activities listed takes place within a specific time-frame (for example the start date for the seismic survey or the drilling of the first exploration well) which represents an integral part of the agreement with the State. Furthermore, whilst drafting a work plan, it is important to forecast the length of time required to interpret the data, so as to act in time to find a drilling rig on the market suited to the drilling of the well, predict the costs of all the operations and ensure that sufficient funds are available to cover these.

Seismic surveys, which are the most frequently used and consolidated methodology, may have extremely variable execution times. Onshore and in impervious areas, given the high cost of field surveys, the acquisition often takes place in several phases: a regional large-scale survey followed by in-depth surveys of areas which turn out to be of interest. Offshore, seismic surveys are easier to carry out. From the mid 1980s, pioneered by Shell, the petroleum industry began to acquire three-dimensional surveys of large areas during the initial phases of exploration, so as to have at their disposal a large volume of data, also useful in case of discovery.

Each time topographic, geophysical or drilling work is assigned to a service company, this is preceded by an evaluation of the prices and of the potential quality of the service. Often, especially offshore, teams available near the survey area must be ensured, so as to avoid the high cost of mobilizing the boats needed to carry out seismic surveys.

The interpretation of seismic data is an extremely delicate phase of the exploration process. As observable in Fig. 6, the different points of the seismic horizon selected are interpreted, and their depth (with respect to a reference level of value 0) is plotted on the trace of the seismic line. Interpreting the same horizon on all the seismic lines of the survey allows us to draw a surface corresponding to the horizon’s morphology. Time values (isochrons) are then turned into depth values on the basis of the mean propagation velocity in the layers crossed. This transformation allows us to work with real subsurface geometries, and to attribute geological contents to the seismic horizons with the help of wells drilled in the vicinity, which allow us to calibrate the seismic. The subsurface geology with its structures, faults and unconformities can thus be visualized. On the basis of these models, further maps such as thematic maps, structural lineaments and other specific types of chart can be developed.

Seismic lines may provide additional information not only on structure, but also on the distribution of fluids. Some porous rocks containing gaseous hydrocarbons are characterized by a much lower velocity than the same medium impregnated with water, and may therefore return particular “seismic expressions” known as bright spots. These are extremely

![Fig. 6. Detail of seismic section (time) and A horizon depth map (meters) referred to prospect X.](image)
useful for a preliminary definition of areas of interest.

The final result of the interpretation consists of maps (isobaths) forming a geometrical expression of the different seismic horizons studied (see again Fig. 4). The presence of crests, culminations, etc. (so-called ‘structural highs’) indicates areas of probable interest (if made up of a porous nucleus and an impermeable seal, and charged with hydrocarbons generated by source rocks).

If the structural conditions shown are not supported by sufficient seismic evidence, they are known as leads. To turn a lead into a prospect, the seismic information must be completed with additional surveys.

The various prospects are listed in order of importance, on the basis of the parameters shown (volume, structural closure, vicinity to the basin where the hydrocarbons were generated).

In the example shown in Fig. 5, the first exploration period involves the obligatory drilling of one well; it is therefore needed to choose which of the different prospects shown to drill. It is worth bearing in mind that the well alone allows us to check whether the geological model developed is correct, or whether the programme requires modifications during later exploration work.

After identifying the prospect to be drilled and the coordinates where the drilling rig will be placed, some preliminary work must be carried out before drilling can start. For onshore wells, the area where the drilling rig will be installed with all its support structures is prepared. If the well is offshore, a seismic survey of the sea floor (bottom survey) in the area selected needs to be carried out. This allows us to check the morphological conditions of the sea floor where the rig is to be positioned, and to indicate the potential presence of gas in the upper layers which may represent a safety issue during drilling.

The drilling of the well presupposes a programme and the choice of a rig suited to this programme. The programme, formulated by the exploration team, sets out the predicted depths of the rock formations to be crossed, the geological characterization of seismic horizons, the mineral objectives, the overpressures. This document also provides the information upon which the drilling programme must be based (drill bits, tubing, muds, etc.). It is the task of exploration to establish the sedimentary sequences in which to take core samples, the frequency with which drill cuttings should be analysed, the type of logs and any measurement of seismic velocities in the well. On the basis of the recordings made in the wells, and any hydrocarbon shows recorded during drilling, it must be decided which layers are to be ‘sampled’ using production tests based on the direct recovery of fluids from the mineralized layer and pressure measurements.

### 2.1.6 Analysing petroleum potential

#### Evaluating the prospect before drilling the well

**Petroleum risk and geological success.** Petroleum exploration, as stressed on several occasions, has an inherent element of risk, since it operates on the basis of probabilistic scenarios. It is never certain that a well will lead to the discovery of hydrocarbons, even if the geological model contains all the parameter for this to be the case. This element of risk cannot be avoided, but it can be successfully managed to optimize results.

For each prospect shown (Fig. 7; see again Fig. 6), a number of factors allowing us to quantify the probability of success (discovery of hydrocarbons) or failure (dry well) must therefore be taken into account. In some cases, an idea of the probability of success in drilling a well in a given basin can be obtained by using historical statistics on past wells drilled in the area; however, this method is not particularly reliable.

A number of conditions are required for an accumulation to form: the presence of a source rock able to generate and release hydrocarbons; a pathway allowing the hydrocarbons to migrate; the presence of a reservoir rock, covered by an impermeable seal, to capture and preserve the hydrocarbons after migration.

If just one of these elements is lacking, the probability of finding hydrocarbons is virtually nil. The presence of each of these conditions, in the relevant geological period, is associated with a probability: the product of these probabilities gives the probability of successful hydrocarbon discovery. In a prospect where the estimated probability that a mature source rock exists is 70%, that the prospect is charged is 60% and that the trap exists in the correct geological era is 50%, the probability of geological success (in other words that the well will find hydrocarbons) is 21%.

A correct assessment of petroleum risk therefore requires us to take two aspects into account. The first is the geological model, while the second aspect is linked to the quality of the available data used to build the geological model: the volume of geological data, the quality and type of seismic and other geophysical evidence used, the number of wells analysed.

Combining all these elements allows us to check the effectiveness in a prospect of all the components of the petroleum system (generation of hydrocarbons, migration, trapping and preservation) and to estimate the probability of success.

There are numerous reasons why a well may turn out to be dry: absence of the geological structure, inadequate sealing, absence of reservoir rock, absence of porosity or permeability, failure of hydrocarbons to accumulate or generate, etc. The map of the prospect itself often contains subjective elements, and may vary
according to the different interpretative models adopted by individual specialists, who produce differing maps on the basis of identical data. The geophysical interpretation also conditions the model of migration, drainage pathways and watersheds; all elements which contribute to the description of a petroleum system. The mechanism of charging and accumulation is not a simple one: there are cases where, though hydrocarbons are generated, migration conditions are such that they are unable to fill the trap. In the field of basin geology there are a series of studies providing a numerical simulation of petroleum systems which allow us to better define the history of the maturing, release and migration of hydrocarbons and the charging phases of the various prospects. In the case of prospects with multiple objectives, the probability of achieving at least one of the goals identified increases. In any case, the probabilities cannot be summed because the elements considered are independent. The explorationist must avoid introducing secondary objectives into the programme; in other words those relating to minor accumulations present within the structure, or at greater depth, whose modest dimensions fail to justify the cost of additional work.

The oil industry uses various systems to evaluate risk. These range from the basic elements described here to far more complex systems which take account not only of the geological model, but also of the information model (in other words the type and accuracy of data used). When appropriately weighted these allow us to express risk numerically.

**Estimating the reserves in the prospect.** Hitherto the problem of petroleum success has been considered without defining what success means in terms of accumulation size. In a frontier area, in an unexplored basin, a well which finds hydrocarbons even in minimal quantities is important, since it confirms that the generation of hydrocarbons has occurred, and thus invites operators to define other evaluation parameters and continue exploration in the area. However, under normal conditions, in known basins, a show of hydrocarbons in a well cannot necessarily be described as a success. We can speak of success only when the well discovers an accumulation of hydrocarbons sufficient to be produced, and if it meets the specific commercial requirements established by SEC (Securities and Exchange Commission) regulations. As such, before investing in the drilling of one or more prospects the expected size of reserves needs to be specified.

The hydrocarbon accumulation can be easily estimated using the available elements (geological data, seismic interpretation, data on wells previously drilled in the area), and on the basis of the volume of the trap multiplied by various factors (including porosity, the thickness of porous rock, the hydrocarbon saturation, the recovery factor, etc.). However, given that none of these data are measured directly, nor checked experimentally, it is obvious that every magnitude concerned is a postulation based on a model into which available regional data are inserted. Factors such as porosity, the height of the hydrocarbon column and the size of the mineralized area are defined by a probability distribution with a minimum value, a maximum value, and a value considered most likely. Given the small amount of data generally available, a simplified distribution for each element is often used (porosity, thickness of the mineralized layer, hydrocarbon saturation, etc.). Combining these distributions using the Montecarlo method provides a probabilistic distribution with several variables for the values relating to the expected reserves.

The analysis of a number of prospects included in a drilling programme allows us to estimate the number of discoveries and the resulting additional reserves. The greater the number of prospects to drill, the more reliable the result.

**Economic evaluation.** To conclude this chapter on risk analysis and on the probabilistic distribution of postulated reserves in the prospect, it must be borne in mind that oil exploitation is an industry, and is therefore governed by the profitability of investments. It is thus obvious that the entire process described above must be considered within an economic context, and that every exploration operation must be evaluated according to this criterion. We will describe the economic aspects of exploration in detail later on. Here it is briefly outlined what is intended by the economic value of a prospect. This evaluation is carried out on the basis of a series of development scenarios (for the reserves), each associated with a risk factor. The final result is the EMV (Expected Monetary Value), which
takes account of all the geological, technical and economic variables of the project, and is expressed by a number. This value is particularly useful when it is necessary to assess and compare exploration projects of different origin, or to allocate investments appropriately in order to decide how to distribute funding for individual drilling activities.

**Post-drilling evaluation of results**

**Post-drilling analyses.** The evaluation process which follows drilling (post-drilling) is an extremely important phase in the exploration project since it allows us to use the results of exploration for industrial purposes.

The first step is the analysis of the wells drilled, which permits to test the geological model experimentally. The results obtained by drilling indicate whether the initial hypotheses on the depths of the geological horizons, their consistencies and porosities, the type of lithology and the presence of hydrocarbons in given layers were correct, or whether variations are found. The data emerging from well analysis are carefully evaluated and compared with the parameters used to generate the prospect. This type of evaluation should be carried out systematically for both mineralized and dry wells. Obviously, dry wells require more in-depth treatment. An understanding of the causes of failure and of volumetric discrepancies often leads to a new interpretation of the data which highlights the strong and weak points of the process of generating and evaluating prospects, and the associated risk.

The analysis of drilled wells may also provide important information on the distribution of the major causes of failure. The identification of systematic causes of failure may allow us to single out individual critical points in work flows, or in the application of technologies.

Furthermore, statistical analysis of results may indicate whether the methods used to assess risk are accurate. Analyses are truly valid only if made within a general operational context, and if they take into account all the exploration wells drilled over a given period.

---

**Fig. 8.** Lahee well classification.
It has been shown, using a large number of wells (over 500), that: the number of successful wells in prospects with an estimated Probability Of Success (POS) below 20% is practically nil, whilst the number of successful wells in prospects with an estimated probability of success over 20% is in line with forecasts. This means that it is important to be very careful when including prospects with an excessively low POS value in drilling programmes. If the well is successful, this represents the start of an evaluation process which is able to turn hypothetical reserves into proved reserves, followed by the development of the reservoir, or, where profitability does not meet the standards of the company, by the termination of further investments.

Well classification. Exploration wells are treated differently on the accountancy level, depending on whether or not drilling was successful. The cost of dry wells is expensed during the financial year in question, whereas that of successful wells is capitalized. It is therefore important to know the exact classification attributed to the well before drilling, with respect to the aim for which it is drilled (finding new accumulations, deeper accumulations, verifying the size of a known accumulation, or developing a field), and that assigned to it after drilling, which also takes account of results (success or failure).

Fig. 8 shows a schematic version of the Lahee classification (1944) also used by the AAPG (American Association of Petroleum Geologists) and by the API (American Petroleum Institute). To these categories (successful wells and dry wells) a third category of wells defined as suspended should be added. This category includes all those wells which, though having reached the depth specified by the programme at the end of each year, for various reasons cannot be classified (e.g. awaiting a production test).

Results of exploration and exploration reserves. The result of exploration is only partially represented by proved reserves in the year of discovery. After the first discovery well, doubts often remain as to the distribution of petrophysical parameters and the geometry of the structure drilled, with further assessments required to gain an accurate idea of the reserves.

During the pre-drilling evaluation, both the geometry of the prospect and the size of reserves are estimated probabilistically.

Once the well has been drilled, an initial evaluation of the volume of hydrocarbons in place and a rough estimate of the recovery factor are formulated. The subsequent detailed technical analysis, in accordance with the company’s development plan, permits to define three different categories of reserves: proven, probable and possible. Proven reserves are those considered reliable and for which development is defined at certain economic conditions. Probable reserves are those likely to be developed despite no precise developing project has been defined. Possible reserves are those uncertain from a technical point of view. It must also be borne in mind that, aside from the economic factors affecting the definition, only a small part of the structure – that investigated by the well – can be considered technically verified (see again Fig. 7).

To conclude, we can say that the reserves calculated during the proper exploration phase require a certain length of time to become certified and producible.

The performance of oil companies. To measure the performance of an oil company a list of regulations, which must be followed in the description of its economic results, has been created. This ensures that accounts and results are published using uniform criteria, and are therefore easy to read. A number of indicators representing the performance of oil companies have been established. These describe how companies manage their core business of exploration and production, using investments in the optimal way.

The results achieved by different oil companies on an international level can thus be compared. One important financial indicator is the ROACE (Return On Average Capital Employed), which measures the economic return on investments. Other important parameters – together with routine data such as oil and gas production and the quantity of available reserves in the various categories – for measuring technical performance are the Reserve Replacement Rate and the Finding Cost, which measures the ratio of investments in exploration and development to the proved additional reserves deriving from these activities.

Some indicators refer more specifically to exploration. An example is the Rate Of Success (ROS), which calculates the number of successful wells out of the total number of wells drilled. In recent years, Exxon-Mobil, BP (British Petroleum), Shell, Chevron-Texaco, Total and Conoco-Phillips have achieved results averaging over 50%, with peaks of 70%. This fact, extremely reassuring in statistical terms, shows that technology and greater care in allocating exploration investments have allowed companies to tackle increasingly difficult exploration conditions successfully.

Other indicators which are particularly sensitive to exploration activities are the Discovery Cost (which correlates additional proved reserves more directly with investments in exploration and the acquisition of new acreage), and the Exploration Discovery Cost, which measures proved reserves against exploration investments alone. In recent years the oil industry has
improved the overall efficiency of exploration activities, bringing the discovery cost to about 0.9 dollars per barrel, out of a total technical cost in the order of 7-8 dollars per barrel.

### 2.1.7 Economic aspects of petroleum exploration

#### Introduction

A company of any size and type must have criteria with which to evaluate its own success, generally measured by its ability to generate profits.

In the oil industry, too, the main objective is to create value for shareholders through the core business of searching for, producing and commercializing hydrocarbons. This means that these activities must not only be managed in the best possible way to reduce and control expenditure, and optimize returns, but that the company must also be able to choose between different investment opportunities to ensure the maximum yield from the capital employed. Profits also guarantee the availability of capital for further investments.

The petroleum sector has a number of distinctive features which distinguish it from other industries. In assessing the performance of an oil it must be borne in mind that profit is often associated with specific parameters (replacement of reserves produced, exploration results), which are important, but difficult to quantify in economic terms. Additionally, oil companies are exposed to mineral, geographical, political and environmental risk to a far greater extent than other businesses. For political risk, we could cite some nationalizations introduced in the past with their consequent negative impact on the operating companies.

Alongside these critical aspects, it should be considered the frequent use of short-term investments with a risk capital that can be obtained only through self-financing. The strategic choices of an oil company influence the type of exploration initiatives which can be undertaken. These may be aimed at maintenance or growth, and always have as their end goal the preservation of a balanced relationship between reserves and production. The programmes of an oil company must therefore take into account the need to operate with a given percentage of risky investments which must nevertheless not penalize its overall results.

The economic aspect of petroleum research, important in all the different phases of the production process (development, transport, commercialization), plays a particularly significant role during the exploration phase. It has a notable impact on some operational choices (the acquisition of a given permit and its conditions, the drilling of a well or the release of mineral rights to a third party). The economic aspect is crucial when it is necessary to evaluate offers to purchase petroleum properties (assets) or whole companies. These acquisitions often include known reservoirs to be produced and permits with a petroleum potential that still requires exploration.

In conclusion, the economic approach to an exploration project is important because it makes it possible to evaluate if some decision variables (the probable size of the discovery, the existence of a market, forecast sales prices, the estimate of the project's technical costs, the location of production areas) can be combined with an adequate return on the capital invested. Without this, any research activity would be unjustified.

#### Decision analysis

The concept of decision analysis is closely linked to economic aspects. This basically involves evaluating different investment opportunities, comparing them and choosing the most promising one in terms both of the guaranteed return and of the risk involved. An approach of this type confronts the exploration company with a series of questions, to which it is not sufficient to give a positive or negative response, but which must be considered in relation to the various possibilities generated by each working hypothesis.

In fact, the result of exploration activity is unknown, and its estimate depends on the evaluation of the petroleum potential of an area, a permit or a basin. As already stated, this evaluation is subject to uncertainty, both in terms of the confirmation of the exploration hypothesis (actual existence of the petroleum deposit), and in terms of the size of the discovery (extraction potential of the reserves). The economic evaluation, for sale or purchase, of an exploration permit – in contrast, for example, to a known reservoir – thus requires the formulation of scenarios concerning on the one hand the probability of success (existence of the petroleum basin), and on the other the estimate of its predicted potential (in numbers of barrels). Furthermore, if an exploration area with a given predicted potential is acquired, however many data are available, negative results (dry well) may still be obtained, or a reservoir which is smaller than forecast may be discovered; alternatively insufficient investments may have been allocated with the consequent negative financial results.

Deciding on an exploration investment thus involves trying to predict the outcomes which may result from a given choice, whilst always bearing in mind the possibility of failure. The application of decision analysis to petroleum exploration has replaced the simple ‘intuition’ of the geologist, and
provided a more correct and complete framework within which to exploit available information. This allows us to compare projects of highly diverse nature. Often those working in petroleum exploration consider these methods a pointless exercise, which does not prevent the drilling of dry wells. However, it should be borne in mind that turning the probability of an outcome and its economic consequences into a methodological approach is simply one way of exploiting available knowledge to predict and compare results. The various steps (Newendorp, 1975) characterizing a decision analysis process are as follows: a) definition of possible scenarios deriving from individual choices and their alternatives; b) definition of the advantages and disadvantages of each scenario; c) estimate of the probability that each possible outcome will occur; d) calculation of weighted average profits for each decision taken.

Terms of the problem

The main ‘asset’ of an oil company is represented by hydrocarbon reserves. In the official presentations made by oil companies to their shareholders (road shows) two aims are often stressed: the need to activate existing reserves to generate profits in the short term, and the need to invest in order to guarantee a satisfactory ratio of reserves to production in the long term. These concepts recur frequently in the strategic programmes of major companies, such as Shell, BP, Chevron-Texaco, Exxon-Mobil, TotalFinaElf and Eni. Growth requires not only replacement of the reserves produced, but also the acquisition of additional reserves; this frequently occurs through exploration which, as we have seen, is a risky activity.

Within a company context the geologist develops the initial exploration idea. The hypothesis that a given area may contain hydrocarbons must then be turned into an operational proposal involving a series of costs, both during the initial phase of acquiring the block (study of the area, acquisition of documentation), and during the permit’s validity period (detailed geological studies, geophysical surveys, drilling of wells).

The implementation of the original idea thus has a cost and, if the validity of the project is to be determined, it is essential to know if there will be a result, and whether or not this result justifies the expenditure. It is therefore important to predict all the possible outcomes of the initial hypothesis, and analyse the cost of each in operational terms. Once a discovery has been made, it must be assessed what the final economic results expected are for each scenario regarding the reserves. Even the correct allocation of exploration investments in accounting terms (Megill, 1988) represents a useful element for the development of accurate economic evaluations in the petroleum industry.

Evaluating the object of exploration

In the economic evaluation of an exploration project two factors are of particular significance:

• The petroleum risk, in other words the possibility of success. The oil industry now uses tools to evaluate geological risk which allow us to quantify the probability that a given prospect will be drilled successfully or otherwise. The probability of success is thus an extremely important parameter in evaluating exploration potential, since it allows us to calculate petroleum risk before the investment is actually made. Statistics show that companies in possession of up-to-date technologies or technical drilling capabilities which allow them to achieve their predetermined aims within the time-frame specified obtain far better results than smaller businesses which rely on service companies. In other words, initial investments in technological research (often seen as costs) have a positive impact on future operational activities;

• Commercial success. Alongside petroleum risk, it must also be taken into account potential commercial aspects, and thus establish the minimum reserves able to guarantee profitable production. It is therefore necessary to predict the quality of the discovery in terms of reserves and their distribution, expressed as a probability range bounded by maximum and minimum values, and compatible with historical data from reservoirs in the basin or the area. There is a difference between geological and commercial success in that the reserves found by a well may be wholly insufficient for development. Alternatively, the productivity of individual wells may be insufficient to support acceptable production profiles. Often, the viability of a project is determined more by the production capacities of individual wells than by reserves.

Discovery statistics show that only a small percentage of geological successes translate into economic success.

Costs

Costs in the exploration phase. The costs of the exploration phase include the payment of a signature bonus, geophysical surveys in general and seismic surveys in particular, geological and geophysical interpretations and finally the drilling of wells followed, in the case of petroleum success, by production tests. These investments are normally unavoidable in order to begin exploration in the area,
and must be included in a budget approved in the company’s plans and compatible with its strategies. Exploration costs are dealt with in different ways in the accounts. It is important, for example, to establish which costs can be expensed and are therefore deductible in the same financial year, and which are capitalized; for capitalized costs it is essential to check how long these will take to recover. Deductible expenditure is represented by salaries, geological and geophysical work, the costs of core samples, dry wells. Capitalized costs, on the other hand, include entries concerning tools, storage facilities, assets, successful wells. As a general rule, it is obviously best to expense investments as much as possible, in accordance with the regulations of the country in which operations take place.

Costs in the development phase. In the development phase other technical costs are faced. The economic evaluation of an exploration initiative does not just concern the exploration phase in the strict sense, but also that of reservoir exploitation. If the result of exploration is positive, the entire petroleum cycle is activated: development, production, commercialization and abandonment of the site used for extraction operations. It is therefore advisable, during the preliminary evaluation, to attempt to predict possible development scenarios and the operational phases required to carry them out: the accurate definition of reserves, the number of wells required to evaluate the reservoir, the number of producing wells needed to produce it according to optimal operational rules. In terms of expenditure, the project resulting from a successfully drilled prospect requires detailed planning which also includes infrastructure (for example in the case of an offshore project the construction of a production platform), and the drilling of injection wells which allow us to improve the recovery of oil and gas. The temporal distribution of investments needs to be analysed in order to maximize production without penalizing the reservoir’s production capacities in the long term. Alongside these costs, known as capex (capital expenditure), it is also important to consider operating expenditure (opex) referring to the management of production.

<table>
<thead>
<tr>
<th>YEAR</th>
<th>CASH INFLOW (thousand dollars)</th>
<th>CASH OUTFLOW (thousand dollars)</th>
<th>NET CASH FLOW (thousand dollars)</th>
<th>CUMULATIVE NET CASH FLOW (thousand dollars)</th>
<th>NET CASH FLOW (thousand dollars)</th>
<th>DISCOUNT RATE at 10%</th>
<th>DISCOUNTED NET CASH FLOW (thousand dollars)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000-03</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.000</td>
<td>0</td>
</tr>
<tr>
<td>2004</td>
<td>1 11,230</td>
<td>0</td>
<td>−11,230</td>
<td>−11,230</td>
<td>−11,230</td>
<td>1.000</td>
<td>−11,230</td>
</tr>
<tr>
<td>2005</td>
<td>2 11,505</td>
<td>0</td>
<td>−11,505</td>
<td>−22,735</td>
<td>−11,505</td>
<td>0.909</td>
<td>−10,458</td>
</tr>
<tr>
<td>2006</td>
<td>3 230</td>
<td>0</td>
<td>−230</td>
<td>−22,965</td>
<td>−230</td>
<td>0.826</td>
<td>−190</td>
</tr>
<tr>
<td>2007</td>
<td>4 64,813</td>
<td>0</td>
<td>−64,813</td>
<td>−87,778</td>
<td>−64,813</td>
<td>0.751</td>
<td>−48,675</td>
</tr>
<tr>
<td>2008</td>
<td>5 75,259</td>
<td>0</td>
<td>−75,259</td>
<td>−163,038</td>
<td>−75,259</td>
<td>0.683</td>
<td>−51,402</td>
</tr>
<tr>
<td>2009</td>
<td>6 81,661</td>
<td>0</td>
<td>−81,661</td>
<td>−244,699</td>
<td>−81,661</td>
<td>0.621</td>
<td>−50,712</td>
</tr>
<tr>
<td>2010</td>
<td>7 256,000</td>
<td>92,054</td>
<td>163,946</td>
<td>−80,753</td>
<td>163,946</td>
<td>0.564</td>
<td>92,466</td>
</tr>
<tr>
<td>2011</td>
<td>8 230,400</td>
<td>87,905</td>
<td>142,495</td>
<td>61,742</td>
<td>142,495</td>
<td>0.513</td>
<td>73,100</td>
</tr>
<tr>
<td>2012</td>
<td>9 207,360</td>
<td>95,245</td>
<td>112,115</td>
<td>173,857</td>
<td>112,115</td>
<td>0.467</td>
<td>52,358</td>
</tr>
<tr>
<td>2013</td>
<td>10 186,624</td>
<td>87,798</td>
<td>98,826</td>
<td>272,683</td>
<td>98,826</td>
<td>0.424</td>
<td>41,902</td>
</tr>
<tr>
<td>2014</td>
<td>11 167,962</td>
<td>77,278</td>
<td>90,683</td>
<td>363,367</td>
<td>90,683</td>
<td>0.386</td>
<td>35,004</td>
</tr>
<tr>
<td>2015</td>
<td>12 151,165</td>
<td>90,482</td>
<td>60,684</td>
<td>424,050</td>
<td>60,684</td>
<td>0.350</td>
<td>21,239</td>
</tr>
<tr>
<td>2016</td>
<td>13 136,049</td>
<td>81,972</td>
<td>54,077</td>
<td>478,127</td>
<td>54,077</td>
<td>0.319</td>
<td>17,250</td>
</tr>
<tr>
<td>2017</td>
<td>14 122,444</td>
<td>74,321</td>
<td>48,123</td>
<td>526,250</td>
<td>48,123</td>
<td>0.290</td>
<td>13,956</td>
</tr>
<tr>
<td>2018</td>
<td>15 110,200</td>
<td>67,540</td>
<td>42,660</td>
<td>568,910</td>
<td>42,660</td>
<td>0.263</td>
<td>11,220</td>
</tr>
<tr>
<td>2019</td>
<td>16 61,521</td>
<td>37,659</td>
<td>23,862</td>
<td>706,569</td>
<td>37,659</td>
<td>0.239</td>
<td>9,000</td>
</tr>
<tr>
<td>2020</td>
<td>17 56,114</td>
<td>33,147</td>
<td>22,967</td>
<td>739,716</td>
<td>33,147</td>
<td>0.218</td>
<td>7,226</td>
</tr>
<tr>
<td>2021</td>
<td>18 51,260</td>
<td>29,076</td>
<td>22,184</td>
<td>761,892</td>
<td>29,076</td>
<td>0.198</td>
<td>5,757</td>
</tr>
<tr>
<td>2022</td>
<td>19 46,904</td>
<td>25,398</td>
<td>21,506</td>
<td>787,388</td>
<td>25,398</td>
<td>0.180</td>
<td>4,572</td>
</tr>
<tr>
<td>2023</td>
<td>20 42,996</td>
<td>22,076</td>
<td>20,920</td>
<td>810,308</td>
<td>22,076</td>
<td>0.164</td>
<td>3,620</td>
</tr>
<tr>
<td>2024</td>
<td>21 39,494</td>
<td>19,071</td>
<td>20,423</td>
<td>839,731</td>
<td>19,071</td>
<td>0.149</td>
<td>2,842</td>
</tr>
<tr>
<td>2025</td>
<td>22 36,412</td>
<td>16,296</td>
<td>20,116</td>
<td>865,947</td>
<td>16,296</td>
<td>0.135</td>
<td>2,200</td>
</tr>
<tr>
<td>2026</td>
<td>23 33,656</td>
<td>13,781</td>
<td>19,875</td>
<td>891,822</td>
<td>13,781</td>
<td>0.123</td>
<td>1,695</td>
</tr>
<tr>
<td>2027</td>
<td>24 31,192</td>
<td>11,502</td>
<td>19,690</td>
<td>911,512</td>
<td>11,502</td>
<td>0.112</td>
<td>1,288</td>
</tr>
<tr>
<td>2028</td>
<td>25 28,815</td>
<td>9,609</td>
<td>19,206</td>
<td>930,718</td>
<td>9,609</td>
<td>0.102</td>
<td>980</td>
</tr>
<tr>
<td>Tot.</td>
<td>2,214,184</td>
<td>1,427,657</td>
<td>786,526</td>
<td>786,526</td>
<td>225,008</td>
<td></td>
<td>225,008</td>
</tr>
</tbody>
</table>
operations and the costs of abandonment, including the environmental rehabilitation of the area when production ends.

**The production profile**

Predicting the production profile is a delicate aspect because it allows us to hypothesize the actual income from the sale of the product. The reservoir’s production behaviour must therefore be stimulated in order to determine the quantity of hydrocarbons producible in any given year. The production profile is linked to the production capacities of individual wells, and to a recovery hypothesis for the oil in place. As such, an estimate of some important parameters such as full production, its duration, the rate of decline and the field’s maximum yield is fundamentally important for the economic analysis.

**Contractual and fiscal aspects**

Alongside the technical costs are others, especially those of a contractual and fiscal nature, which must be paid to the State that owns the leased acreage.

The development lease in which the operator is allowed to produce oil and gas in a given country is covered by an agreement, signed when the exploration permit is assigned. There are various types of contract. One frequent type is the participation contract, or Production Sharing Agreement, where the oil produced is divided into two parts: one part (cost oil) is assigned to the operator, allowing him to recover the costs of putting the reservoir into production. Also reimbursed are prior exploration investments which in the case of failure remain the responsibility of the operator, with no possibility of reimbursement. The remainder represents profit (profit oil), and is shared between the operator (or the joint venture on behalf of which the operator manages activities) and the State, according to different percentages linked to daily hydrocarbon production levels. There are usually also taxes on taxable income (net of costs incurred).

A second type of contract is the Concession Agreement, in which the operator has the right to exploit the hydrocarbons on the condition that royalties are paid to the State; in other words, a direct tax on production. In this case, too, taxable income is calculated net of costs incurred. There may also be further taxation affecting the profitability of an exploration project.

These commitments, together with technical costs, represent the basis for an economic evaluation of the project to be activated.

**Prices**

A fundamental element of the economic evaluation is the worth of the product. Oil prices may vary significantly. Especially in the economic evaluation of projects covering a span of 25-30 years it is important to adopt a fairly realistic price forecast. There are different models for this purpose (which at times are unfortunately affected by unpredictable external factors), which generally refer to a reference or marker oil such as Brent or Arabian Light, with specific physical and chemical properties. The reference oil in turn influences the price of all related products, such as natural gas, condensate gas, Liquid Natural Gas (LNG) and Liquid Petroleum Gas (LPG).

**The economic evaluation**

On the basis of the elements described above regarding investments, the evaluation of costs during the exploration and development phases, the production profile, prices and the fiscal regime, an economic analysis of the exploration project can be undertaken. This type of economic evaluation, however, does not include the risk factor, and does not allow us to compare alternative. Below are outlined the principles of a ‘deterministic’ economic evaluation of a petroleum exploration project. Petroleum risk will then be analysed considering the mineral risk variable.

To fully understand the methodologies used in economic evaluation, an example of a lease contract for an offshore exploration permit, containing the following obligations, can be examined:

- A first period of four years with the obligation of acquiring a three-dimensional seismic survey at a cost of 6 million dollars; in this case no well drilling is included.
- A second optional period of two years involving the drilling of two wells at a cost of 10 million dollars each.
- A third optional period of two years with the obligation of drilling another well at a predicted cost of 10 million dollars.

During the first period the seismic survey is carried out, interpretation of which will show three prospects of greatest interest:

- Prospect A: estimated reserves of 138 million barrels, 20% probability of success.
- Prospect B: estimated reserves of 109 million barrels, 16% probability of success.
- Prospect C: estimated reserves of 70 million barrels, 13% probability of success.

At this point it must be decided whether to embark in the second explorative period and drill two wells as according to the contract or whether to abandon production (the same decision will have to be taken in the future, when evaluating whether to proceed to the third period).

First of all, it must be assessed whether the hypothetical reservoirs are economically valuable as to
say that the production of oil from them justifies the investments for their exploration and development. Assuming it is decided to continue exploration, investment in the drilling of two wells during the first two years needs to be made (about 11 million dollars per well including general costs). If results are positive, the development wells drilled subsequently in the reservoir will lead to the start of production after a few years.

To construct the cash flow, which represents the basis upon which to calculate the economic evaluation, it is important to consider various factors (annual and cumulative oil production, interest rates, costs of training the work force as specified in the contract, exploration costs) for all the years during which it is predicted that investments will be made; it is also needed to specify the price forecasts, gross and net profits, cumulative costs, royalties linked to production, depreciation, taxable income and taxes.

Any economic evaluation involves, in fact, an analysis of cash flow, in other words the amount of money invested (outgoing) and recovered (incoming), calculated over the entire duration of the project (the only way of calibrating the initiative’s viability) rather than for individual years. At the beginning of the project, expenditure obviously predominates, while there is as yet no income from the sale of the product. For a complete economic evaluation of an exploration project, expenditure and income need to be considered (Table 1).

In calculating the cash flow, economic values may be expressed in nominal terms, ignoring inflation, or in real terms, with adjustments on the basis of the estimated evolution of prices and costs. The net cash flow is the annual difference between income and expenditure (investments, operating costs, fiscal and contractual payments).

If the economic evaluation of prospect A is considered, plotting the data in Table 1 referring to the cumulative cash flow in the graph shown in Fig. 9, some of the characteristic elements of the investment can be observed: the project’s Maximum Financial Exposure (MFE), the recovery (or pay out) time for the investment, and the cumulative net value.

In the specific instance shown in the diagram, the maximum financial exposure of 245 million dollars falls in year 6 (2009). In year 7 (2010) production starts, thus sparking off a cash inflow. The recovery period, equivalent to the time needed to

---

**Fig. 9.** Graph showing a cash flow.
balance income (profit) and expenditure (investments in the project) will thus fall in year 8 (2011). The net cumulative cash flow, on the other hand, represents the project’s ability to generate income to a total of 787 million dollars in year 25 (2028).

In cash flow analyses it is important to define the value of the investment in a given period. The value today (time 0) of the money which may be received after a certain number of years must be calculated. For this purpose a discount rate must always be used. The discount rate is equal to $1/(1+i)^n$ for each single year, where $i$ is the discount rate, and $n$ the number of years considered.

Table 1 shows the net cash flow values, the discount rates applied in individual years and the consequent results. The cumulative sum of net cash flows discounted at a rate of 10% gives the discounted value of the investment. As evident, after twenty-five years the equivalent discount rate is only 0.102; in other words, a dollar received in ten years time has a current value of only 10.2 cents (penultimate column in Table 1). In this particular case, then, after twenty-five years, the initiative involving the drilling of prospect A, if successful, will repay the investment made (at a discount rate of 10%) plus 225,008 million dollars (last column in Table 1). This figure, which corresponds to a parameter known as the Net Present Value (NPV), reflects the discounted cumulative difference between income and expenditure at a predetermined discount rate. This corresponds to the net increase in wealth resulting from the project, as well as that already guaranteed by the discount rate used.

The same economic evaluation procedure applied to prospects B and C (at the same discount rate of 10%) gives values for NPV of 115 and 30 million dollars respectively.

The economic evaluation may be carried out using different discount rates. Often it is used a discount rate representing the average cost of capital employed known as WACC (Weighted Average Cost of Capital). The higher the discount rate, the lower the Net Present Value (Table 2).

Expected monetary value

At this point an economic evaluation of the prospects defined on the basis of estimated reserves, which does not include petroleum, risk is available. If we want to compare different exploration projects, the parameters described above no longer suffice. It is also important to insert into this context the petroleum risk, which allows us to calculate the Expected Monetary Value (EMV) of the investment. This parameter combines the estimated profit deriving from the economic analysis and the quantitative estimate of geological risk derived from risk analysis. In fact, the EMV is the weighted average of all possible NPVs resulting from the different hypotheses: from the negative outcome represented by a dry well, to those which forecast the discovery of different reserves, each of which gives rise to a specific development project with its own costs, production profile, profitability, and probability of occurrence. The calculation of the EMV representing all possible options considered takes the form of a so-called decision tree (Fig. 10).

---

### Table 2. Economic parameters of prospect A

<table>
<thead>
<tr>
<th>Economic parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>AARR (Rate of Return)</td>
<td>29.6%</td>
</tr>
<tr>
<td>Net Present Value (NPV) million dollars</td>
<td></td>
</tr>
<tr>
<td>NPV (discount rate 20%)</td>
<td>Million dollars</td>
</tr>
<tr>
<td>NPV (discount rate 15%)</td>
<td>Million dollars</td>
</tr>
<tr>
<td>NPV (discount rate 10%)</td>
<td>Million dollars</td>
</tr>
<tr>
<td>NPV (discount rate 5%)</td>
<td>Million dollars</td>
</tr>
<tr>
<td>Top Financial Exposure</td>
<td>Million dollars</td>
</tr>
<tr>
<td>Top Financial Exposure in the year</td>
<td>2009</td>
</tr>
<tr>
<td>Pay out time</td>
<td>2011</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Selling price</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Oil</td>
<td>Brent</td>
</tr>
<tr>
<td>Differential</td>
<td>−1.00</td>
</tr>
<tr>
<td>Oil price (Dollars/Barrel)</td>
<td>20.00</td>
</tr>
</tbody>
</table>
with a series of nodes representing the various courses of action.

The branches departing from the decision nodes represent the options with their cost and probability of occurrence. The work flow of an evaluation is thus broken up into several basic steps:

- **event analysis**: the decision to drill a well may lead to one of two outcomes, a dry well or a successful well with their respective probabilities;
- **calculation of the NPV** deriving from the weighted average of different hypothetical reserves in the hypothetical reservoir;
- **calculation of the EMV**, the average of all the values considered, referred back to the origin of the process.

Basically, this procedure permits to assign a value to uncertainty (discovery or dry well) and to decision options (to drill the well or release the exploration permit).

On the basis of the same criterion dictating that development projects with a negative NPV must not be activated, prospects with a negative EMV should not be drilled.

In this way there is the opportunity of exercising an option to renounce which may, for example, involve paying a penalty to the State owning the acreage rather than drilling a high-risk well, or attempting to sell the exploration project to other companies in different operational situations (such as producing reservoirs in neighbouring areas) or with different profitability standards from those required by the current operator. This allows for decision flexibility throughout the exploration process.

It is thus clear that the Expected Monetary Value permits to choose between projects of different origin, calibrating them on the concept of risk in the decision phase. This is the only basis upon which projects in frontier areas can be compared with projects in mature basins.

To evaluate an exploration project satisfactorily, it is essential to consider other parameters alongside the EMV, which provide a complete overview of the project (the rate of return, the NPV, the ratio of NPV to investments, the relationship between EMV and exploration investments and the reserves expected from the exploration project). It is good practice to assume a scenario with fluctuations (± 20%) in prices and costs, in order to develop more flexible evaluation models.

![Fig. 10. Example of a decision tree.](image-url)
Using this reference framework, appropriate decisions can be taken in the knowledge that all those variables which, in their complexity, characterize exploration projects have been taken into account.

Bibliography


References


Pratt W.E. (1944) *Oil in the Earth*, Lawrence (KS), University of Kansas Press.


Roberto Prato
Scientific Consultant