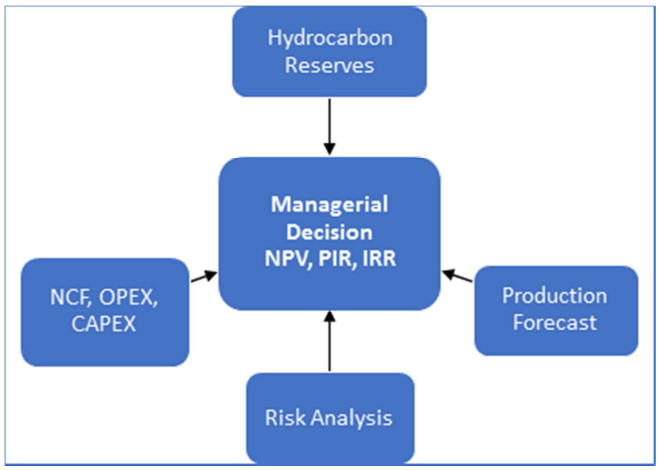
CHAPTER 5 SOURCES OF UNCERTAINTY AND RISK

Engineering Economics Topics in Hydrocarbon Subsurface _ a Bibliographical Review Handbook



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Chapter 5 Sources of Uncertainty and Risk

Learning Objectives Chapter 5 Sources of Uncertainty and Risk

Having worked through this chapter the reader will be able to:

- Introduction
  - Explain the difference between uncertainty and risk, in the context of investment
  - Describe a simple system of classification for factors giving rise to investment risk
- Risk in a hydrocarbon business
  - Describe the different sources of risk in the context of hydrocarbon projects
- Geology
  - Explain the concept of exploration success
  - Describe three methods of analyzing success
  - List and describe the issues pertinent to appraisal
  - Explain the relationship between appraisal time and field size
  - Describe some examples of reservoir model inaccuracy, leading to development and production discrepancies
- Facilities
  - List facilities problems resulting from contained fluids
  - Describe the type of facilities problems encountered in the subsurface
  - Describe the type of facilities problems encountered at the surface
  - List some important environmental issues pertaining to oilfield development
  - Describe an example of human failure
- Government
  - Describe some of the ways in which a government might impose change on a project
  - Describe an example of such a process
  - Explain the relationship between taxation policy and investment decisions
- Economics
  - Explain the basis of the world market for oil
  - Describe three important reasons why concurrent oil prices may differ
  - Explain the concept and implications of demand elasticity
  - Describe in broad terms OPEC influence on the oil market 1970 onwards
  - Describe the function of SPOT markets and marker crudes
  - List and explain the factors contributing to current oil price uncertainty
  - Explain why the market for gas is not global
  - Describe important elements of a gas sales contract
  - Describe the main issues with respect to gas pricing
  - Explain why exchange rate variation might influence project economics
  - Explain the risk associated with borrowing money
  - Explain the possible impact of changing rate of inflation
- Partners
  - List and explain the factors, which might compromise partnership
- Accounting for Risk
  - Describe the options for risk assessment and risk evaluation

Introduction

The hydrocarbon industry is typically a risky business. Historically, the uncertainty associated with exploration drilling has characterized the industry and oil prices volatility has added more risk. The terms “uncertainty” and “risk” are commonly used interchangeably; but:

- Uncertainty relates to the imperfect knowledge of the future
- Risk suggests that this uncertainty has financial or material implications

Risk is the unpredicted deviation of cash flows from the expected values for a capital-intensive project. The relative risk associated with hydrocarbon investment proposals is a factor not directly economic in its nature, but which affects investment decisions.

Sometimes uncertainty and risk are directly related. In some cases, uncertainty carries no material risk. For example, uncertainty associated with the drilling of an exploratory well gives rise to a material risk due to possibly having expenditure without return.

The expected profitability from an investment in a hydrocarbon-related project has several areas where the expected results are uncertain. The hydrocarbon industry projects are generally risky undertakings and all investments have some uncertainty because they are subject to risks related to:

- Financial
- Political
- Equipment risks
- Cost estimates
- Capital and operating costs
- Sales
- Drilling and completion problems
- Natural disasters
- Oil market price
- Technology
- Geological
- Properties of the reservoirs
- Reserves
- Oil production rate
- And others

The economic assessment of a project must be based on profitability calculations, which in turn are derived from “estimates or forecasts of the expected variations” of the most significant factors that can have an impact on profitability. Risk analysis takes into account the range of such possible variations, as well as the likelihood or probability of the change occurring.

Risk and investment decisions go hand in hand, and risk must be considered in the context of discounting future cash flows. If for instance, two projects generate the same return, but with different levels of risk, the first choice is to select the project with lower risk.

The riskier investment is only attractive if it offers a better return. The relationship between "better return" and "riskier" is the typical decision for top management to make. The term risk is used to describe an investment project whose cash flow is not known in advance with absolute certainty, but for which an array of alternative outcomes and their probabilities can be estimated.

Another term used is ***project risk***, which refers to the estimated variability in a project's expected NPV. A higher project's risk means that there is an increased expected variability in the project's NPV.

As a result of the aforementioned "risks" or "project risks" the forecasting of the corresponding cash flows is subject to some degree of uncertainty. Therefore, management can reasonably expect to prepare estimates for the range of possible future costs and benefits, and the relative chances of achieving a certain return on the investment. Usually, the approach is to have "best estimates" for each of the uncertain factors, and then prepare estimates of profitability indicators such as NPV or rate of return for the entire project.

The recommendation is to evaluate risk rather than using its qualitative description. However, risk has many forms and sources and is difficult to estimate with precision. To overcome this situation analysis can range from simplistic adjustment of interest rates to sophisticated mathematical simulation such as the Monte Carlo Method that can be used to calculate probability weighted outcomes.

Another typical method for describing a project´s risk is using different scenarios analysis. It considers the sensitivity of NPW to:

- Changes in key variables
- Range of likely values for those variables

For example, the decision maker may consider a "worst-case" scenario (low oil rate, low oil prices, high variable costs, etc.) and "best-case" scenario. The NPV estimates under the worst and best conditions are then calculated and compared to the "expected, more likely or Base Case, NPV".

Usually, on petroleum investments the primary concern is the impact of uncertainty, because the potential investment is based on a specific dataset. If something changes, the financial outcome of the investment may be negative or positive:

- Risk is normally assumed to be a negative factor, "downside risk"
- If some parameters, such as oil price or reserves are better than expected, this is called "upside potential"

The factors, which could change are "sources of uncertainty" in a general sense; however, in the context that these changes may have an impact on some previous investment, they are also "sources of risk".

Risks Related to International Aspects of Capital Budgeting

Hydrocarbon companies usually invest abroad to exploit opportunities that exist around the world, and to keep technical research and knowledge secret to retain competitive advantage. For example, foreign subsidiaries are preferred to licensing arrangements or join ventures.

The basic principles of international investments can be grouped into:

- Effects and expected cash flows
- Project risk
- Selecting an appropriate discount rate

The evaluation of a project may vary depending on whose point of view analysts take:

- That of the multinational parent company
- That of a local subsidiary

Conceptually, any analysis should be done from the point of view of the main headquarter whose shareholders ultimately own any new venture. In practice, however, managers may take a more local perspective, if their own rewards are tied to success at the local level. This potential conflict between local interest and those of a multinational company may be accentuated when investments are arranged in the form of an alliance between companies with local participation (joint ventures).

Factors affecting expected cash flows may include special economic incentives provided at the local level. For example, reductions in tax rates and changes in regulations, and restrictions on the free flow of funds for repatriation of profits that reduce economic value of cash flows.

Description of Some Risks in a Hydrocarbon Business Investment

The risk of doing business must include all the possible “negative” elements, despite their low probability of occurrence. The hydrocarbon industry has many uncertain factors that can generate risk. Some of these risk factors for convenience and ease of description can be classified as:

- Subsurface
- Surface
- Investment
- Cost
- Hydrocarbon Prices
- International Business
- Political
- Incomplete Input Data
- Inflation
- Project
- Discount Rate
- Others

Subsurface Risk:

Decisions concerning exploration and field development are necessarily based on incomplete datasets that come from subsurface information and consequently subject to uncertainty and associated risk.

Reserves of oil and gas occur subsurface and most petroleum engineering activity must therefore take place subsurface, in some cases at depths greater than 10000 feet. Such activity is remote from direct observation and is dependent on data derived from various remote-sensing technologies. Decisions concerning exploration and field development are necessarily based on incomplete datasets and consequently subject to uncertainty and associated risk.

Resources Risk

In terms of resources, there are two main categories of hydrocarbon accumulations: conventional and unconventional.

Conventional Resources

They exist as discrete hydrocarbon accumulations, usually present in specific and localized sites, in a geological structural or stratigraphic setting. In general, each accumulation is bounded by a down-dip contact with an aquifer, and such hydrocarbon accumulations are significantly affected by the hydrodynamic effects based on not only the specific gravity differences between oil and water, but also by the hydraulic effect of aquifer response to the pressure changes in the hydrocarbon-bearing zone. The production from these reservoirs usually requires lower risk investments.

Unconventional Resources

These types of hydrocarbon accumulations usually extend throughout a large area, and are generally not significantly affected by hydrodynamic forces. Further, their exploitation is usually associated to high-risk investment plans.

The exploration and production of unconventional resources, such as shale gas, is usually more complex and riskier when compared to the production methods used in the production plans for conventional resources. Their production plan requires a multidisciplinary approach to achieve, for example, an adequate understanding of a shale gas basin and the formations present to estimate reserves and forecast a reliable future production profile.

The volume of recoverable gas has two components that are complex to evaluate: a free gas component and an adsorbed gas component. The gas present in shale formations is usually a combination of free gas and adsorbed gas, where the free gas is normally located in the porous part of the formation, whereas the adsorbed gas is spread throughout the organic material-rich formation.

In addition, the production profile forecast needs to consider the issues of horizontal drilling and hydraulic fracturing. Fracking is needed to overcome the low permeability, around 10-100nD (10-

6mD). Inducing fractures will allow the gas to be produced in commercial volumes. Horizontal drilling is required to yield wellbores with a very high degree of contact surface with the formation, and this leads to higher drilling costs. Horizontal drilling and fracking procedures are two crucial risky processes, normally required to produce unconventional resources in an economically viable scenario.

Reserves Risk

One of the critical calculations in reservoir engineering is to quantify the original volume of hydrocarbons in place in any reservoir targeted for exploitation. An inadequate estimate of Original Hydrocarbon in Place (OHIP) and the subsequent estimation of producible reserves, may lead to unreliable development plans and inadequate or simply wrong decisions by operators and investors. The evaluation of any hydrocarbon producing property is typically divided into three estimates:

- The remaining reserves
- The production schedules
- The cash flow schedule

Reserves are those volumes of hydrocarbons in the reservoirs remaining to be produced. This definition implies that three conditions are met:

- The hydrocarbon must be physically present
- Oil and/or Gas will be economically producible with existing technology
- The valuation must be under current governmental regulations

Therefore, the prevailing economic and operating conditions imply, in turn, that prices and costs as of the date of the estimate are to be prepared or acquired. In other words, it is required to specify the economic conditions used in the evaluation such as: discount rate or any other economic parameters that are accepted as being reasonable to forecast.

The ***"original reserves"*** are those volumes estimated to exist at the discovery date. In general, reserves are estimates and not "measured" quantities. The hydrocarbon volumes which have been already produced, up to the effective date of their study or assessment, are generally identified as Cumulative Recovery (**CUM**). This real value (cumulative production already occurred or CUM) plus the Estimated Remaining Reserves (**ERR**) are the value for Estimated Ultimate Recovery (**EUR**).

$$EUR = CUM + ERR$$

Not all the hydrocarbon volume originally in place is recoverable. Thus, the value of EUR is related to the Original Oil (N) or Gas in Place (G) multiplied by the Recovery Factor (RF):

$$EUR\ Oil = N * RF$$

or

*EUR Gas = G * RF*

The main issue is that only the "CUM" term is measurable. All other values are estimates and are part of the risk involved in such estimates.

A significant number of parameters must be estimated or calculated when using any method to "determine" recoverable volumes of hydrocarbons. These include:

- The area or volume of the reservoir
- Fluid properties
- Rock properties

A number of these parameters are used in more than one stage of the calculation process. There are also some parameters whose estimation, although supported by technical and geological knowledge, is necessarily subjective. The expected ultimate recovery factor is also a source of uncertainty. It reflects the estimated proportion of (risked) originally hydrocarbon in place that is technically recoverable. There are independent methods of estimating EUR, N and RF which allow minimizing the uncertainty.

- Static calculations use petrophysical, fluid and geological data
- Dynamic methods use petrophysical, fluid, and real time production data

Considering the importance of this topic it will be treated in a forthcoming separate section.

Surface Risk

Hydrocarbon production systems usually extend from several feet subsurface, through several hundreds of miles of marine salt water or desert sand. Produced fluids may be at high temperature and pressure, of corrosive nature and highly flammable.

Complex production systems must survive the attack of hazardous fluids from:

- The inside of the equipment
- The geological environment subsurface
- The surface environment
- The human environment on the outside

The production system must resist these attacks for the duration of the project, usually more than two to three decades. This topic will be expanded in latter sections.

Investment Risk

In term of investment in resources, an unconventional field has different development requirements when compared to a conventional hydrocarbon field. The cash flow profile in both cases is different. For example:

- Conventional gas reservoirs have a high level of initial investment with significant profit for years
- Shale gas (unconventional) usually requires lower initial investments with lower profits over the period of production

The duration of licenses required for shale gas is thus longer than the licenses required for conventional gas. Should this not be the case, the shale-gas production becomes unattractive.

Because of production decline and reduced revenues, the hydrocarbon industry often reacts by:

- Reducing investment in marginal, hostile, and environmentally challenging areas
- Tends to invest only in lucrative, “easy ventures”

Producing from new discoveries in frontier or hostile areas will require higher investment. Since the cost of materials, equipment, and labor varies from one project to another, investment is a source of risk.

Costs Risk

Project cost estimates require the assessment of as many as possible of the physical factors affecting cost components, including surface and subsurface variables. The typical cost behavior analysis will separate **variable costs and fixed costs**.

- Variable costs increase with an increase in activity
- Fixed costs remain relatively stable for a given level of activity

Operating costs (OPEX) should be treated on a total cost basis rather than on per unit (STB or MCF) basis. This is because “unit costs” can be very misleading and such “average” value is heavily dependent on sample-size. In addition, skewed data becomes averaged-out and yields unrealistic values. It is recommended to identify, in as much detail as possible, all the available historical cost data as this information becomes the basis for developing improved forecasted cost estimates.

Cost estimates are intended to assist management in making appropriate decisions about potential project feasibility. Management must provide guidance with respect to how much time and money should be authorized for “cost estimation” and how accurate the results of the feasibility study should be at any given stage of the project investigation.

OPEX vary due to:

- Project location
- Seasonal impact
- Inflation
- Equipment

- Labor intensity
- Recovery methods
- Gas treatment
- Water management
- etc.

There is always a significant number of project variables involved in estimating operating costs. Thus, to offset the risk ingredient in any project's evaluation, it is usually included in the estimates a contingency provision to account for the unforeseeable elements of costs, all within the project scope.

Preliminary operating costs are generally more difficult to estimate than capital costs for most hydrocarbon projects. The relative uniqueness of each project operation makes the estimation of operating costs most difficult.

Project cost estimates are only as accurate as the input data used, and their "accuracy" should be consistent with the purpose of the study.

Cost estimates are just that: simply estimates of what project capital and operating costs may be, based on numerous engineering and other variables.

There is no estimating cost technique which yields a "correct answer," so this is the reason for considering costs as a source of risk.

Hydrocarbon Supply, Demand, and Price Risk

There are four variables in the evaluation of hydrocarbon properties or in the determination of the value of oil or gas wells:

1. The estimation of reserves
2. The forecasting of production
3. Oil or gas prices
4. The "market" price predictions

Usually, the assumptions related to oil business have fluctuated from:

- Expectations of rising supply and demand (with flat prices)
- Rising prices and limited supply
- Oil prices will increase due to shortage of supply and that oil producers will be "holding oil in the ground", where it will "retain its value better than other investments"

One reason for the poor forecasting performance has been that prices are mostly independent of supply and demand in the short or medium term, because of the influence of the producer oil countries. The failure to predict prices should not be attributed to the shortcomings of economic analysis, but rather to an inability to accurately perceive major players intentions and power.

Investors must adapt their plans to the situation of changing prices and future financial requirements of the business. Ingenuity and creativity will be required to align policies with the economic environment, to handle properly the challenges that have developed during decades.

The principal risks to an economic analysis lie in the traditional concerns about implementing major energy and other projects during a period of notably high real interest rates. A sustained, major break in world oil prices, or major real cost overruns in constructing and operating the plants, would minimize the real net income benefits for investors. Other events or views can severely affect worldwide consumption (a pandemic incident, global warming concerns, and others for example).

Price derives from the interaction between supply and demand, and anything that changes the behavior of producers or consumers may disturb the equilibrium of the market.

Demand in the future will change because of factors such as:

- Levels of economic activity in developed countries
- Growth of less developed economies
- Availability of alternative energy technologies
- Price in relation to alternative technologies
- Weather and climatic change

Supply in the future will change because of factors such as:

- OPEC and non-OPEC market share
- OPEC policy
- UN policy on some countries
- Growth of non-OPEC production. e.g., Russia, Caspian
- Evolution of production technology
- Political discontinuity

OPEC remains as a force in the market. Its policy for some periods has been to try to maintain a price band for their products by adjusting quotas, whenever the price remained outside that band for more than 20 days quota adjustments have been made. For the future, it seems likely that OPEC market share and power can only increase, unless there are significant discoveries of petroleum elsewhere, or a change in energy technology occurs. OPEC holds 78% of world recorded oil reserves and has reserves to production ratio of 74.3 years. In contrast, non-OPEC countries have a ratio of only 14.3 years.

Additional hydrocarbon Prices Affecting Factors

Oil prices are tied to the API gravity and sulfur content of the oil. The price of natural gas, besides federal regulations, is determined by the quality of such gas and the terms for delivery established by the gas contracts. The gas contracts will usually specify the minimum acceptable heating value for the gas which is usually measured in terms of British Thermal Units (BTU's) per cubic foot of gas. The acceptance of the gas by the purchaser is often subject to stipulations concerning the

oxygen, carbon dioxide (CO_2), hydrogen sulfide (H_2S), water vapor and total sulfur content of the delivered gas.

Price variability also affects the minimum gas price needed to support production in different shale-gas areas. For example, a gas shale price of $X/MCF would support production in one area, while a price of $Y/MCF would be required in other areas.

Despite new environmentally friendly sources of energies, the world economies will continue to rely on hydrocarbons as a major energy source. Oil and gas will remain as principal sources of energy for the future. Long term hydrocarbon shortages (though often predicted) are unlikely; although, prices are expected to remain flat, this has not always been true. There were oil prices shocks in 1973-74 and in 2020, due to the exceptional conditions prevailing at the time.

However, oil is a complex global market in which more than 100 million barrels typically move around the world every day with remarkable fluidity. But when the market is tight, it is highly vulnerable to disruption. New interruptions could come from a variety of sources—from a widening of the war beyond Ukraine to a cyberattack on natural-gas pipelines, a hurricane knocking U.S. refineries temporarily out of operation or a variety of other "unexpected" events.

Risks Associated to International Business

The economic evaluation of an international hydrocarbon project is more complex due to the impact of several sources of risk or uncertainties:

- Financing arrangements made with the host country
- Policies
- Regulations
- Fluctuating currency exchange rate
- Taxation
- Royalties
- Market accessibility

Political Risk

This is a risk that is often overlooked. Political risk is most dramatically illustrated by outright expropriations, particularly in Latin American countries. Hydrocarbon-related companies contemplating any new venture must assess the political risks to ensure that the added financial exposure is warranted. The petroleum industry attracts much attention from governments around the globe. Companies negotiate production rights, live within a regulatory framework and pay a substantial proportion of cash flow to taxation. Changes to the contracts, to the rules or to the numbers can have significant impact on project profitability.

Incomplete Input Data Risk

A complete set of certified input data is the key to improve the conclusions of an engineering-economic evaluation of a hydrocarbon project. Usually, the information is incomplete or unavailable with the corresponding risk of overlooking variables which may change the project´s viability. It is advisable to prepare a list (as comprehensive as possible) of all the factors that will be considered for the feasibility studies on a hydrocarbon property or project.

Inflation Risk

As a reminder, the prices of most goods and services change over time. Inflation, relates to rising prices and deflation, or negative inflation, refers to falling prices. ***Inflation*** is a general rise in average prices, which is not accompanied by an equivalent rise in productivity. Therefore, the same dollar amount buys less of an item over time.

Under conditions of high inflation, the increasing prices of inputs may not be covered from sales, which would require further calls of working capital. These continuous needs for working capital can ruin a capital project such as a new hydrocarbon venture. In the capital-intensive hydrocarbon industry where developments for new projects are long-time propositions, inflation is a factor of importance in investment analysis. If inflation is ignored, hydrocarbon projects tend to be overvalued. Inflation must be included in the evaluation process in a quantitative manner.

Handling inflation in an economic evaluation is a complex task. Consequently, the form in which final evaluation results are presented is determined by the needs of the decision maker. For presentation to top management, both constant-dollar and inflation-adjusted data and results are helpful.

The constant-dollar analysis provides technical understanding of the project and allows management to study separately

- The sensitivity of project profitability
- The sources of risk
    - The technical risk
    - The economic risk

Project Risk

As stated earlier, important factors affecting the risk of international projects are political uncertainty and changes in foreign-exchange rates. Political instability over the life of the investment can affect future cash flows and is a major consideration in international capital-budgeting decisions.

Locally earned cash flows ultimately must be converted into multinational company's home currency at exchange rates that could have large variability.

If foreign investments are viewed as significantly more risky than domestic ones, adjustments for the added risk will have to be made at the evaluation stage.

Despite above issues, a company may find that international diversification reduces the risk of being dependent on a single market, even if the foreign investment, viewed in isolation, is risky.

Origins of Project Risk

A project's economic assessment must be based on profitability calculations, which are derived from estimates of variation in the significant factors that can impact on profitability. Risk analysis considers the range of variation as well as the likelihood of the change. Therefore, the term ***risk*** describes:

- An investment project whose cash flow is not known in advance with absolute certainty, but for which an array of alternative outcomes and their probabilities are known
- ***Project risk*** refers to the variability of a project's NPV. A greater project risk means that there is a greater variability in the project's NPV.

Cash flows are difficult to estimate accurately, so project managers frequently consider a range of possible values for cash flow elements. If there is a range of possible values for individual cash flow, then there is a range of possible values for the NPV of a given project. The issue is to determine:

- The probability and reliability of each individual cash flow
- The level of certainty about overall project worth

Discount Rate Risk

In international business markets the capital is globally mobile and the cost of financing a project is generally independent of the location. Not all financial markets, however, are globally fully integrated, and host governments usually offer favorable financing which is tied to specific investment decisions.

Economic Risk

"Economic" here means market prices and the economic system at large. Oil and gas markets are volatile and any enterprise, which invests long-term and operates internationally must expect problems arising from inflation and exchange rate fluctuation.

Other Risks

Sound commercial arrangements for the supply, procurement of materials and services, infrastructure support, transportation requirements, market factors, price determinants, competitive forces and regulatory, legislative and fiscal terms are essential elements when considering a hydrocarbon-industry related risk investment. Additional risk elements considered in the hydrocarbon-industry are:

- Construction costs
- Technology
- Environmental
- Management
- Commodity price
- Commercial arrangements for
    - The supply
    - Procurement of materials
    - Services
- Infrastructure support
- Transportation requirements
- Market risk
    - Market factors
    - Price determinants
    - Competitive forces
- The risks inherent to obtaining regulatory approval
    - Legislative
    - Fiscal terms

Risk Reduction

There are methods to achieve risk reduction in the hydrocarbon business. The most common procedure is to emphasize data gathering and validation:

Collect Information

As specified earlier, uncertainty and risk generally result from incomplete information. In some cases, this missing information may be acquired at a cost because usually for each prospect, a complete reservoir data set exists and can be obtained. However, this requires sufficient expenditure of time and effort. O the other hand, economic consideration sets a limit on this cost and requires geoscientists to balance costs and benefits obtained. If reservoir uncertainty precludes investment a group of actions can be taken, such as:

- Running new seismic surveys to improve reservoir volume and structure appraisal and definition
- Drilling additional wells to determine petrophysical properties and layer continuity in poorly defined areas
- Running further well tests to confirm reservoir continuity and well productivity
- Initiating geological studies of a sedimentological or diagenetic nature, to improve confidence in extrapolation and interpolation from existing wells
- Building more detailed reservoir simulation models to investigate behavior and to identify areas of critical uncertainty

If after new data acquisition uncertainties still exist the analysts must advise management. If the reserves potential does not warrant further expenditure the investment plan should be dropped and abandoned.

Usually, corporate experience and knowledge of previous developments is a critical input. It is advisable that relevant data and ideas are preserved in a format such that they can be passed-on and used in the future as data base or as an analog source.

Accounting for Risk

Sound judgement in any capital investment decision is a must; therefore, the decision maker should minimize the associated uncertainty by quantifying the risks. Some of the common traditional methods to take risk into account are as follows:

Risk Adjusted Payout Period

It uses a shorter payout period to compensate for risk. This option is not recommended for capital projects

Establish Risk Classes

Another approach for handling risk and inflation is to establish risk classes for projects having increasing levels of risk and then assign additional increments to the cost of capital, which will be used to evaluate projects in these various risk classes. The increment above the interest used in the respective discount rates represents the firm's perceived risk of projects in that class, and is intended to compensate for such risk. The question to define or answer to handle the risk involved is "what is an appropriate discount rate to use in conjunction with each of the approaches to financial analysis?"

Risk Adjusted Discount Rate

It is a way to require "risky" projects to have higher rates of return on investment than "safer" ones. The major drawback of this method is the use of subjective hurdle values. There is no method for assigning acceptable risk-adjusted rates of return

Risk Adjusted Input Parameters

Basically, it is the use of conservative values for input parameters. The drawback is that being excessively conservative can lead to all projects being unduly rejected

Probability Distribution

It is a method to quantify or estimate the magnitude of the risk by quantifying the “chances of achieving a given level of profitability” in a specific project. This is a common or standard analysis used by management to evaluate possible trade-offs between risk and expected profits. This topic will be presented in Chapter 7.

Spread Risk with Participation

Companies normally form partnerships at the exploration stage, to spread risk over a larger number of opportunities. Such partnerships are particularly common in expensive and high-risk areas. As a result, many licenses are shared by two or more companies.

The partner with the largest equity shares normally acts as Operator of the license and in this capacity performs an important role, both for the partners and for government.

Occasionally two partners share the role. The Operator acts on behalf of the Joint Operating Committee (representing the partner companies) and is responsible for the technical program, for budgets and for maintaining a flow of information. The Operator as presented in Figure 29 is also responsible to government for submitting appropriate documentation and maintaining technical standards.

FIGURE 29 OPERATOR RELATIONSHIPS

The Operator of an Asset Responsibilities to Mitigate Risk

The operator of an asset is the entity which is responsible for the day-to-day management activities. Operators get approvals for their activities and are reimbursed for their costs by the non-operators.

An operator must be designated to carry out the terms and obligations of the lease for the parties. The operator's specific activities and limitations should be clearly specified in an ***Operating Agreement (OA)***. This limits the amount that the operator can spend on a single project before prior approval is required from all parties. Any major operation requires the consent of all parties subject to certain non-consent clauses

The operator is required to conduct the operations in a professional manner. Any operation done must be undertaken on a competitive basis; even if the operations are performed using equipment owned by the operator, the charges must be competitive.

License participants are usually screened by government, with respect to financial capacity, technical competence and ultimate ownership. The Operator, will face technical scrutiny. Foreign companies may be required to establish a local subsidiary, as a basis for communication and taxation.

Additional Considerations on Subsurface Uncertainty and Risk

Uncertainty and consequential risk are originated because oil and gas reservoirs are at the subsurface. Discovery, collecting information and building models is therefore dependent on the interpretation of remotely collected data. Three distinct stages can be recognized:

- Exploration
- Appraisal
- Field development

Exploration Risk

Exploration is traditionally the activity that has characterized the hydrocarbon industry as high risk. It is common to spend more than MMUS$ 100, on a single investment, knowing there is 80% chance of complete failure and zero return.

The cost of a single exploration well depends on its geographical location and may range from less than MMUS$ 1 in an onshore location, to more than MMUS$ 100 in a remote location. In the absence of a technology to identify hydrocarbons from the surface, success is dependent on a decision to drill in the "right place". Therefore, the probability of success is less than 1.0.

In exploration "***Success***" does not have a singular definition and could have the following interpretations:

- Evidence of hydrocarbons in the well
- A well is tested and flowing at a minimum economic rate
- Discovery of oil and or gas, which was sufficient to justify further investigation
- Sufficient hydrocarbon delineated to justify commercial development

"Success" should have the sense that something of value has been found, but confirmation of commercial success may take another 5 or 20 plus years to determine. Consequently, use of a geoscientifical definition of success may be necessary, in the short term. Geoscientifical success depends on several factors including:

- Nature and complexity of the geological basin
- Trap mechanism and size
- Recognition of an exploration "play"
- Geophysical technology available
- Experience and competence of explorationist

Over time, technology has improved and knowledge and experience have accumulated and the larger and more obvious traps have been mapped and drilled, so the task of finding the next becomes more difficult. Exploration success may be analyzed at various levels of detail:

Regional Statistics

For some applications it may be sufficient to recognize that in year 2000, the industry drilled 2000 exploration wells and that 500 of these were successful, a success rate of 0.25 or 25% is therefore indicated.

There is an element of subjective judgement in deciding whether a well is exploratory, or step out from an existing discovery. There can be no precise metric, since much depends on subsurface complexity and perception. In the absence of other statistics, a company might assume:

- ± 25% as the probability of initial exploration success
- Probability of eventual, commercial development more like 15%
- Over time, targets diminish, knowledge increases, technology improves

In many cases, the statistics of success are determined by economic or political issues on the surface, rather than geoscience in the subsurface.

- A small accumulation might become part of an existing field, if it can be tied into existing facilities
- It might be considered as a new field, if the Operator sets a case for geological separation

On the other hand, if a discovery happens to be offshore and remote from existing infrastructure, probably it will be classified as a commercial failure. Interpretation of these considerations must be done carefully.

Exploration Play

The accumulation of commercial volumes of oil and gas require the combination of several factors in space and time. These include generation, migration and entrapment and together they constitute a specific exploration play.

Once a play has been recognized, it is expected early discovery of the larger targets. The development of the play over time will depend on:

- The size distribution and complexity of the reservoirs
- The physical signature of the trapping mechanism
- The evolution of exploration technology
- The skill and commitment of the explorationists

Specific Targets

Each exploration well must be justified based on the geology, the economics and the uncertainty, which are specific to its location. The historical evolution of an appropriate exploration play or regional statistics are a guide, but the most reliable indicators should derive from a holistic consideration.

The existence of an accumulation of hydrocarbon is dependent of the co-existence of several factors, including:

- Generation and migration of hydrocarbons
- Existence of a reservoir (porous/permeable) lithology
- Existence of a sealing mechanism (low permeability barrier)
- Existence of a trapping geometry
- Suitable timing of geological events (seal and trap predate migration)

If one factor is missing, the project is a failure. Based on knowledge gathered from adjacent wells and regional trends, Geoscientists will generate probabilities for each of these factors, such that:

$$P_{(success)} = P_{(fluid)} * P_{(lithology)} * P_{(seal)} * P_{(trap)} * P_{(timing)}$$

Even if the assumed probability for each factor is high (0.75), the probability of all five occurring together is low ($0.75^5 = 0.24$). Doubt about the existence of any one of the factors will therefore classify a prospect unattractive.

Appraisal

Appraisal is the process of converting geological success into commercial success. Appraisal of a property involves the assembly of sufficient information to choose between making a commercial investment or abandon. These decisions are fundamental to the long-term performance of the company. Appraisal is an important process, involving detailed consideration of a range of issues:

- Existing dataset
  - The discovery may have tested at 10,000 or 1000 stbpd. The more interesting the data, the more likely that appraisal expenditure will be authorized
- Geological complexity
  - The more complex the basin and the trapping structure are, the more difficult it will be to build a coherent model, the more expensive the program is likely to be and the greater the risk that the production model will be incorrect
- Drilling program and cost
  - Drilling wells is a reliable method of proving the presence of hydrocarbon in the subsurface
  - The more complex and variable the subsurface, the more wells required
  - The deeper the target and the more complex the geological environment, the more expensive the individual wells.
- Data collection and cost
  - In addition to drilling, an appraisal program could include:
    - Logging
    - Coring
    - Fluid sampling
    - Well testing
    - Detailed seismic
  - Additional measurements add significantly to knowledge of the reservoir, but also to cost. Justification of such expenditure is based on linking the nature of the data to the perceived uncertainty

- Development economics
    - Appraisal is to demonstrate commercial viability. It is the step to build the geological model, with an appropriate technical development plan and speculative economics. This stage will provide guidance as to what additional information is required and whether the reservoir under investigation justifies further expenditure
- Tax incentives
    - In different countries, pre-development expenditure is treated in different ways from a tax point of view. If such expenditure may only be reclaimed against future revenue, the explorationist carries all the risk
    - If the marginal rate of tax is high and such expenditure may be claimed against existing production, the risk associated with appraisal is partly assumed by Government
- License relinquishment
    - Many licensing systems include a relinquishment clause, which limits the time available to the licensee to make an assessment of the block. This is a considerable incentive for appraisal activity to progress quickly and efficiently, particularly if reserve potential is great
- Corporate view
    - Companies have differing investment criteria, differing tax positions and differing attitudes towards risk
    - These will influence the information and therefore the expenditure required, before a decision is taken to develop
- Reserve potential
    - Optimistic interpretation of early data can provide an indication of the maximum likely volume, which is an indication of commercial limits
    - The greater the potential, the more likely that expenditure will continue

Hydrocarbon Reserves Estimates Risk

As a reminder Reserves are those volumes of hydrocarbons in the reservoirs remaining to be produced. One of the critical calculations in reservoir engineering is reserve estimation. An incorrect estimate of Original Hydrocarbon in Place (OHIP) and reserves will produce erroneous development plans and wrong decisions by operators and investors.

Reserve estimates presented as probabilities are frequently reported as corresponding to three levels of confidence:

- Proved reserves (1P)
- Proved and probable reserves (2P)
- Proved, probable and possible reserves (3P)

These Reserve Estimates are commonly expressed as P90, P50 and P10, respectively.

- **P90 (1P)** estimates are then interpreted as the volume of hydrocarbon production that is estimated to have a 90% probability of being exceeded by the time production ceases

- **P50 (2P)** estimates refer to volumes of hydrocarbon production that are estimated to have a 50% probability of being exceeded
- **P10 (3P)** estimates are the volumes of hydrocarbon production that are estimated to have a 10% probability of being exceeded

Under this interpretation, 2P (P50) is equivalent to a "median" estimate of reserves. For investment analysis, proved reserves or P90 (1P) are the main objective of the evaluations.

In general, reserves are estimates and not "measured" quantities; therefore, the risk associated is related to the methodologies used.

Summary of the Typical Reserve Estimation Methodologies

Method	Requirements	Advantages	Disadvantages	Risk
Analogy	A field or well which is expected to perform similarly. Need to indicate why certain analogues have been chosen for areas. Better if a range of analogues is used to indicate the **uncertainty** in the estimates obtained	Fast, economical, can be done **before** drilling and used where there is no sufficient history. Analogs are selected by features and characteristics such as depth, pressure, temperature, reserves, drive mechanism, original fluid content, reservoir fluid gravity, reservoir size, gross thickness, pay, etc.	Depends on the selection of the analogs. It could result in low accuracy	High
Probabilistic Approaches	A field or well which is expected to perform similarly	Can be used to leverage incomplete data sets. Key parameters can be modeled with mathematical distribution and combined in Monte Carlo type simulations for volumetric analysis and EUR distribution	Only provides a range of recovery efficiencies and EUR	High
Volumetric	Wells, logs, cores, estimate of drainage area, recovery factor, and fluid properties	Minimal information. Can be done early in the life of reservoirs. Relatively fast	Requires assumptions (area, recovery factor) which may not be accurate. May have gross errors	High

Method	Requirements	Advantages	Disadvantages	Risk
Decline Curves	Production History	No assumptions are required about size, recovery factor, type of rock or other properties, even reservoir fluid properties Fast and low cost. Very accurate under certain circumstances. Results in production versus time prediction	Well or reservoir must be producing under stable conditions. Need at least six months to a year of production history. Does not necessarily give a single unique answer. Not applicable to all reservoirs. Assumed functional form for the production decline curve	Medium
Material Balance	Pressures, production history, fluid properties, and rock properties	Does not necessarily need areal extent or thickness. Low sensitivity to porosity or water saturation. Can be used to calculate hydrocarbon in place, recovery factor, water influx, and gas cap size	Pressures usually not available. Predictions are very sensitive to relative permeability values. Requires more information than previous methods in this table	Medium
Reservoir Simulation	For each cell: rock properties, fluid properties, capillary pressures. For each well: location, producing interval, production rates and pressures. In general reservoir description, faults, pitchouts, aquifers, layering.	Once history match is obtained, production from individual wells can be predicted, allows to study effects of different production schemes. Input data requirements force close analysis of the reservoir.	Costly. Requires time to perform the study. Large requirement of input data, non-unique match. The assumptions made to get a match may not apply for the prediction runs.	Medium

TABLE 113 Summary of Methodologies for Reserves Estimates

Considerations on the Typical Reserve Estimation Methodologies

Analogs

The use of analogy by extrapolation of production experience relies upon careful analysis of the production experience in “analog reservoirs or wells” For which there is:

- A sufficiently long history of production
- The reservoirs are in basins with similar geological characteristics

Then, the method proceeds to extrapolate these results to either undeveloped areas of the same field or to a new “similar or analog reservoir”.

The key to the success of this procedure is to conclude beforehand what may be considered an appropriate analog. Therefore, its selection is a source of risk.

Volumetric

The volumetric approach or volumetric method uses geological and reservoir engineering knowledge of the extent and characteristics of the reservoir to estimate the volume of hydrocarbon that is originally present. A recovery factor is then applied to this “originally in place volume” to produce an estimate of the “technically recoverable (or ultimately recoverable) resources”.

The risk in this procedure is the inherent potential uncertainty in selecting the ultimate recovery factor.

Dynamic

Unconventional reservoirs have more risk than conventional reservoirs when using volumetric estimates or material balance estimates to determine hydrocarbon in place and reserves. Reservoir simulation estimates need a significant amount of high-quality data.

The longer the production history, the more reliable will be the forecasted results and the quality of the results will only be as good as the quality of the input data.

Reserve Methodologies Summary

Each of above-described methods requires different data and goes about estimating reserves in different ways. For example, if the material balance and decline curves indicate that there are reserves higher than the volumetric estimates, then there are probably undrilled areas that can be accessed.

Crossover between these approaches is common; with several options using and combining more than one approach. Each method has its own strengths, weaknesses, and assumptions. Thus, comparing results obtained using different approaches, is a sensible way to reduce risk.

The forecast of hydrocarbon production and a consistent description of the reservoir are among the most important items in a hydrocarbon investment evaluation and in its economic evaluation.

Overstatement of reserves and ‘write-downs’ are not unusual in the exploration and production (E&P) business, but they have significant implications including destruction in shareholder value, costly litigation and loss of confidence in the market. Analysts suggest that downgrading of reserves can erase 30% of a company's share price.

Production Operations and Human Factor Risks

These risks are related to the equipment installed from subsurface to surface. The system enables reservoirs fluids to flow, with suitable control, to the processing and to selling points at the surface. Engineers plan their operations and design facilities to suit the conditions and to be fit for purpose. Production Operation Best Practices implies that a company is following approved procedures. If facilities are not completed on schedule, or do not perform as expected, this will impact directly on the investment, through increased capital expenditure, increased operating expenditure and/or project delay.

Hydrocarbon production is a complex process, which takes place wherever the resource happens to be found. Some sources of risk associated to production are:

- Produced fluids
- Subsurface interaction
- Surface Facilities
- Environmental Issues
- Human Involvement
- Government regulation, particularly with respect to health and safety
    - Ownership and Licensing Risk
    - Health and Safety
    - Environmental Standards
    - Taxation

Produced Fluids Risk

The first task of the systems is to handle the produced fluids, which may be at high temperature and pressure, may contain toxic or corrosive components and are inevitably highly flammable and damaging to the environment.

Gas has a low-pressure gradient, so high-pressure gas at depth becomes high pressure gas at the surface. Entrained sand or silt particles, travelling at speed, can cause significant erosion of exposed metallic surfaces.

At low temperature, in the presence of water, solid gas hydrates may form and reduce pipeline capacity or interfere with valve operation.

Heavy oils and waxy, paraffinic oils have reduced mobility, particularly at low temperature. Viscosity management is required to maintain throughput and to prevent systems from becoming blocked.

Subsurface fluids may contain, or be associated with, problematic non-organic components. Hydrogen Sulphide is a threat to humans and to equipment. It must be identified and properly contained. This is expensive, but the outcome of not caring is more expensive. Carbon dioxide gas and salt from connate water have corrosive tendencies, which must also be properly treated and disposed.

Subsurface Interaction Risk

Engineering operations in the subsurface are exposed to increasing temperature, pressure and stress with depth. Drilling, is subject to uncertainty as the bit is always penetrating the formations. The next layer may be soluble salt, or sloughing shale or high permeability reef or a sand lens containing high pressure gas.

The skill of the driller is to achieve total depth (***TD***) in good time, while avoiding stuck pipe and anticipating conditions, which might lead to lost control and a blowout. The more wells drilled in a specific area, the more relevant data becomes available and the more predictable the progress of the bit is expected to be.

Production tubing and completion systems are designed to deliver reliably over the life of the field and to resist the conditions of the specific location and reservoir fluids. Deterioration of the fabric of the system or changes to reservoir/production strategy would result in unscheduled workover operations and in repairs or additional work for changing the string and installing a new completion. In a remote or subsea situation, such activity can be very expensive.

Surface Facilities Risk

Surface facilities include well control, fluid separation and export, plus appropriate power generation, accommodation, transportation of staff and materials etc. Offshore, support above sea level, or protection forms an essential element of the system.

Some of these installations are to be found in the world's hostile environments, Arctic permafrost, desert, tropical rainforest and offshore deep water. Systems are designed appropriately to survive extremes of temperature, salt water, ocean storms. Stress fatigue and corrosion are problems encountered by many of the longer-term projects, some of which have been on production for more than fifty years.

In April 2010 eleven men on the Deepwater Horizon were incinerated when the BP/Transocean oil rig blew out and exploded. The explosion caused the deaths of 11 crew members, injuring 38. For two whole days, the coast guard fought the inextinguishable fire at the end, Deepwater Horizon sank, leaving the oil rig's well pouring oil across the Mexican Gulf seabed, inevitably leading to the largest ever oil spill in U.S. waters.

Environmental Issues Risk

Wherever the industry operates, there are environmental issues to consider, including:

- Seismic impact on marine mammals
- Disposal of drilling fluids and cuttings
- Disposal of oily water
- Flaring of surplus or un-economic gas
- Leaks from valves and pipelines
- Disposal of general industrial and human detritus

A burning flare stack is no longer seen as a suitable icon for an energy corporation. Hydrocarbon fluids do not integrate easily with the biological environment. When oil escapes from containment, it makes a highly visible mess, it is physically inconvenient and biologically damaging. The image of a dead seabird coated in oil is very powerful in terms of audience reaction. Consequently, damaged tankers and leaking pipelines become high profile news stories. Exxon Valdez spilled 230,000 barrels of oil and cost the company $3 billion in clean-up costs and compensation.

The environment is increasingly a political issue. Shell discovered that legal disposal of Brent Spar (a large concrete storage vessel) would not satisfy public opinion, bolstered by a boycott of Shell products. Companies must therefore ensure that the environment becomes a design parameter for investment and operational expenditure.

Human Involvement Risk

Petroleum systems are designed, constructed and maintained. These are activities, which require human talent and carry the risk of human error. “Error” may be the direct consequence of lack of knowledge or inattention on the part of a single employee or the cumulative effect of corporate ignorance, mismanagement and greed, or anything in between. Investment in training and project management should improve employee skills and performance, and provide them with a better framework within which to function.

Learning from experience is an important mechanism for moving forward. With access to unlimited funds, engineers can readily design and build to last. Optimization, however, requires minimum lifetime cost, consistent with being fit for purpose. High-speed computers facilitate simulation of complex systems and new composite materials and “intelligent” components provide wider scope for creating reliable and cost-effective systems. Cost efficiency gains from standardization of design and sharing of ideas.

The challenge of installation depends substantially on geography. When the industry moved into exposed offshore locations, traditional methods of installation were inefficient and expensive. Many of the early projects suffered long delays and cost overruns. The solution lay in building integrated modules onshore and installing complete systems in one or a few lifts. Larger, more stable lifting gear made that possible and installation is now faster, safer and more predictable.

Maintenance is the most difficult process to control. An inexpert technician or an inadequate administrative system can undermine the best of equipment and of intentions.

Successful maintenance is: meticulous records, work ethics, and technical competence. For completeness, a review of human involvement should include the possibility of sabotage. The industry operates in a wide range of difficult terrain, “difficult” in the sense of politics as well as geography. Pipelines, for example carry valuable commodity through areas of extreme poverty and instability. They can become a convenient target for theft, extortion or terrorist attack.

Another example of a disaster is the Piper Alpha. In July 1988, the Piper Alpha oil platform experienced a series of catastrophic explosions and fires. This North Sea platform had 226 people on board at the time of the event, 165 of whom were killed. In addition, two emergency response

personnel died during a rescue attempt. The platform was destroyed and led to damages of around 3.4 billion USD.

The Piper Alpha disaster, the one of the worst offshore petroleum accidents in history is attributed to human failure, both in terms of system design and of working practice.

- Routine maintenance of a backup condensate pump was incomplete
- The reporting system failed to prevent the pump from being used
- Fluid leaked at high pressure and ignited
- An inadequate security system was destroyed permitting the fire to spread
- The water deluge system had been switched off
- The fire weakened and destroyed two large diameter gas risers
- These contained no safety cut-off system and gas continued to flow for an hour

167 people died and many others were injured. The billion-dollar platform was destroyed. Production from Piper and from five linked fields was suspended.

- More than 300,000 stbpd were lost for six months
- It was 12 months before neighbor fields were fully operational again
- More than four years before Piper was back onstream

Projects, which benefit from access to shared facilities are exposed to risk resulting not only from malfunction of the communal equipment, but also from problems generated by the other linked fields.

Government Regulation Risk

The oil and gas industry must operate under the government legal framework. Any changes, which might be applied to this framework after an investment decision, constitutes a risk. Areas of Government interest include the following:

- Ownership and Licensing
- Health and Safety
- Environmental standards
- Taxation

Ownership and Licensing Risk

Licensing affords the licensee the right to produce hydrocarbon from a designated area, for a defined period, subject to certain technological and financial conditions.

Licensing is a formally contracted legal process and stable democratic governments normally acknowledge the right of companies to operate under the terms of their licenses without interference. Uncertainty might arise, however in a situation where the property in question was subject to dispute in international law or where the country in question was prone to political change or upheaval. In such circumstances, the company might lose its production rights completely or find that a new set of rules had been introduced.

Health and Safety Risks

To some extent, the industry is self-regulating. Accidents cost time and money and reduce profits. Staff who are well protected are more likely to be motivated and productive. Regulations about health and safety reflect current perception and experience. The more onerous the regulation, the higher the cost. It is not an investment risk if it is prior knowledge. The risk is when changes are imposed retrospectively in standards or in working practices.

Fundamental changes in design criteria for new projects and modifications to safety equipment and procedure can cost billions of US$ on these safety related issues, such as:

- Improvement to permit to work management systems
- Installation and relocation of platform and subsea shutdown systems
- Smoke hazard mitigation
- Provision of temporary safe refuge
- Improvement to evacuation systems
- Introduction of formal safety assessment reporting

Environmental Standards

At all stages, from early exploration, through production to field abandonment, Government may regulate company activity for the protection of the natural environment. Many of these constraints are in place prior to an investment decision and do not constitute a material risk. However, standards may change because of knowledge or experience gained, or political change or international agreement. For example, consent for flaring of gas might be withdrawn because of deliberations on global warming. This would clearly have cost implications in relation to re-injection or transportation technology.

Taxation Risk

Most taxation regimes afford the opportunity for change. This creates an important source of uncertainty, since taxation normally represents one of the significant cash flows of a project. Changing tax structure and rate can convert a profitable project uneconomic or vice versa.

Taxation is an important and necessary source of income to government and normally government has the power to decide what the tax should be. It is, however a power which should be used wisely.

A project which is economic before the application of tax, must still be economic after the tax is applied. Otherwise, the project is a nonstarter and the tax take is zero, whatever the rate. Companies taking investment risk must be offered the opportunity to make a reasonable profit, otherwise they will choose to invest elsewhere. Companies likewise crave stability.

Increasing tax take is often associated with rising oil price, when government assumes or assesses that the industry is earning excess profit. Alternatively, it may be that government requires increased income to fund increased expenditure or failure elsewhere in the economy. The first

reason is more sustainable than the second. Reduced tax take is normally used as an incentive to increase exploration and development.

The Decision-Making Flow Process. Technical, Economic, and Managerial Considerations

Taking the typical Production Development Project as a sample-case for the valuation of an investment opportunity in the hydrocarbon industry, Figure 30 depicts the basic activities required to be followed:

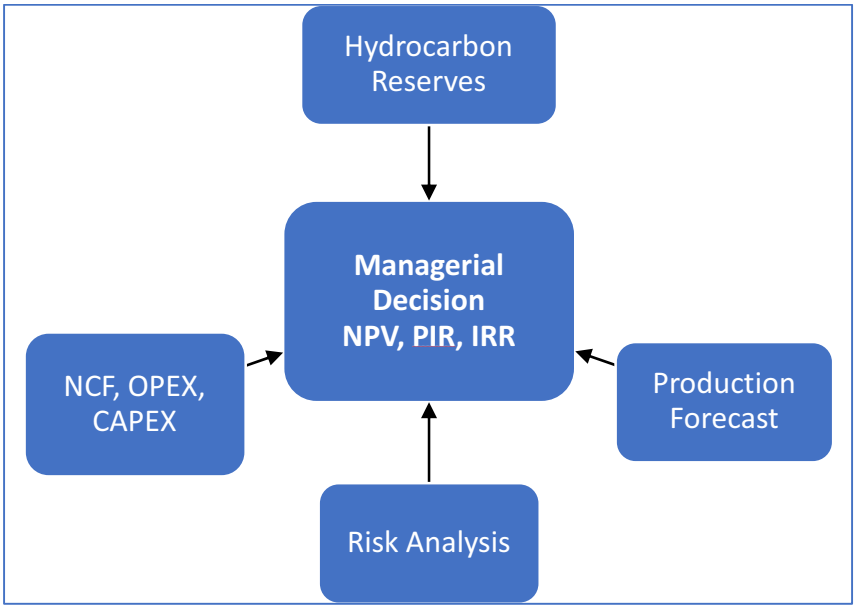

FIGURE 30 BASIC ELEMENTS REQUIRED TO VALUATE A HYDROCARBON OPPORTUNITY INVESTMENT

The main issue is the managerial decision to be made after reviewing the economic yardsticks (NPV, PIR, IRR or any combination thereof) linked with the rest of the activities. Before any economic indicators are generated, some previous conditions must be met and the associated activities and work must be done.

The fact that the hydrocarbons are in place, does not make them automatically "producible." The only fraction of the original hydrocarbons in place that can qualify as "proved reserves" are those volumes that have been adequately certified as such, following rigorous API procedures. As a reminder for investment analysis, proved reserves or P90 (1P) are the main objective of the evaluation.

Then, proved reserves become "producible" once the wells are drilled, mechanically connected to producing facilities, and in the required condition to allow a continuous steady production stream (rate-time). This forecasted production rate over a period is in fact the "revenue generating production stream."

In reviewing Figure 30, the assessment of the "reserves to be produced" must be confirmed by engineering means. Further, that level of reserves will have to be produced over a given period.

The Project must have a “reliable rate-time prognosis” (a production forecast). Its delivery and sale provide the cash inflows (after the investments required are made to have the wells and facilities available on time).

The left box in Figure 30 relates to CAPEX and the producing “operating costs” (OPEX). They become project cash-outflows. When both cash streams (inflow-outflow) are taken together over the project life a Net Cash Flow (NCF) forecast is obtained. Only when these NCF are subjected to the financial and risk evaluation tools described herein, will the financial indicators (supporting the investment decision) be obtained, and the central issue in Figure 30 will be resolved.

As a general statement, it must be observed that the proper and systematic method for evaluating a capital investment is to compare the present cash requirements with the anticipated positive net cash flows which will accrue from the project in the future. In making this comparison, it is essential that the timing of the various stages and cash flows be recognized using an appropriate interest rate to compare different money streams on a fair basis.

Having recognized that the main income stream for this typical investment scenario will come from the future production, in Chapter 9 there is a description of the basic techniques used for this purpose. The production forecast is beside the financial evaluation of the typical project; but done long before a go-no go decision is made on the investment attractiveness.

The Decision Cycle

As stated above, usually hydrocarbon projects begin with a data gathering process, followed by a screening phase, a managerial decision to go or no go to the next step, then combine economics and production forecast to reach a final decision.

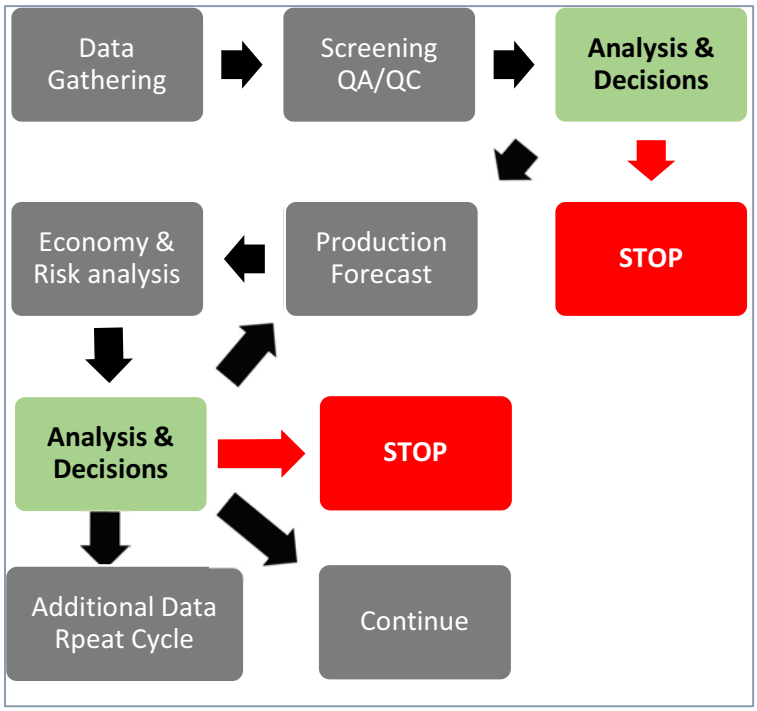

FIGURE 31 THE DECISION CYCLE

The ***screening phase*** can be constrained by the amount of data and/or the time span allocated to this step. Part of this stage is the evaluation of soft issues or those nontechnical conditions that generate restrictions (geographical, legal, environmental, political, or others).

The ***economic calculations and production forecasts*** can be run in specific software applications and it is just necessary to develop the required interfaces, so the decision-making team can make the proper decision with all the information at hand. It is advisable to run production forecasts under different scenarios for example: varying well spacing with infill drilling, fracturing schemes, injection pressures, production methods, EOR technologies, etc.

Different well spacing refers, for example, that naturally fractured reservoirs usually require larger spacing than non-fractured reservoirs. Under conditions of acceleration, the optimum number of wells for a given reservoir can be determined using combinations of economic hurdles. The common procedure is:

- First predict the performance of the reservoir under various spacing schemes
- Proceed to carry out economic evaluations to estimate reserves and NPV
- Plot recovery vs. NPV and number of wells vs. NPV using oil price as a variable to determine the optimum case

If a project is discarded because it is not profitable under the conditions evaluated, the project can be reexamined in the future under new economic conditions, changes in reservoir conditions, new technologies, changes in tax regulations, among others.

Depending on the circumstances it is possible to use optimistic production forecast profiles to test the economics under different cases of cost and prices. If projects do not offer economic merits using these production profiles, most certainly the project economics will be less attractive when more realistic parameters are used. In these cases, the projects can be discarded or postponed.

Appraisal Time and Data Gathering

Time is an indicator of challenge and of cost. Analysis of time indicates appraisal ranging from 3 months to 1-10 years. Appraisal here is the period between discovery and development consent by Government. Some of this time is spent in drilling, collecting and analyzing data, waiting for investment conditions or technology to improve. This is the time for the official review and approval process.

There is a relationship between appraisal time, reservoir size, and hydrocarbon reserves. Usually, larger fields are likely to have shorter appraisal programs. For example:

- Fields larger than 1000 million barrels could take less than one year
- Fields larger than 500 million could take less than 5 years
- Fields larger than 100 million could take less than 10 years

However, Appraisal Time is not a straight forward activity as some inconvenient usually appears. For example:

- The reservoir might contain waxy oil which gives rise to production problems
- A project could be subject of argument with Government regarding the unification of a field or reservoir status to a neighbor area
- A complex reservoir, could be subject to phased development approval
- A reservoir could have changes of project parameters during the appraisal period
    - Appraisal of a reservoir's subsurface attributes must proceed in an environment where important project parameters are subject to change
- Economic reserves are a moving target, even after the project comes onstream

Appraisal time reflects the degree of difficulty in:

- Reaching an investment decision
- Planning how the reservoir should be developed, to optimize hydrocarbon recovery and financial return

Large reservoirs are normally profitable across a wide range of assumptions. Data is therefore required to fine-tune the development plan, rather than to justify investment.

Usually, appraisal drilling might continue after the development decision is taken, to confirm reserves and to assist in planning the distribution of production wells.

Smaller reserves normally occupy a smaller gross volume of rock and therefore a smaller volume of the subsurface to be investigated. However, this does not correlate with appraisal effort. Some very small fields have very short appraisal programs. They tend to be single well investigations recompleted and tied back to an existing facility.

The poorer the prospect and the more marginal the economics, the more data is desired by the investor to minimize downside risk. A smaller reservoir implies less revenue, a constraint for both appraisal and development. Errors during the appraisal period might bring the use of secondary or enhanced recovery not included in the original economic estimation.

Production Forecast and Field Development

A successful appraisal program produces a geological model of the reservoir to be developed. This should include details of static architecture and volume, dynamic properties and fluid distribution. From this model are derived: estimates of recoverable reserves, production profiles, and plans for well distribution and reservoir management.

Errors in the model will lead to errors in reserve estimates and production profiles and possibly aspects of reservoir engineering, such as well locations or pressure maintenance strategy. These in turn may lead to inappropriate or sub-optimal asset development and depletion plan. In some cases, errors might imply a reduction of reserves or increasing the field productive life to extra years of operating expenditure.

However; uncertainty could be on the positive side, the reservoir could perform better than the original pre-production estimates. External elements such as tariff income or changes in the tax regime could allow production to continue beyond a normal economic end point.

Reservoir Development and Reserves Production Plan

These are the strategies that cover from the exploration and appraisal-well drilling phase to the abandonment phase of the asset. The plan is regularly reevaluated to optimize field production performance so that it maximizes the asset value over the full life-cycle of the field/reservoir.

External Risk Factors that Affect Project Economic Decisions

Oil and gas investment takes place in economic systems, where crucial parameters are subject to change over time. Many of these parameters usually are outside the control of the investor:

- Oil demand and price
- Market for Gas
- Exchange rates
- Financial debt
- Cash Flows Uncertainty
- Partners
- Others

- Price inflation
- Cost of system components
- Policies

Oil Demand and Price _ Oil Classification and Markers

The price of oil and gas and their variation over time has become one of the dominant features of the hydrocarbon business and uncertainty over its future direction constitutes considerable investment risk.

The market for oil is international, involving almost every country as consumer and more than 40 as significant producers. Transportation is cheap and flexible and infrastructure for processing and marketing are very widespread, leading to the idea of a world market, where prices are similar and interrelated across the globe.

Over time, prices of oils from different parts of the world behave in a similar fashion; even though, price differences may exist. These so-called differentials, result from several factors, including:

- Location of market and source
- Hydrocarbon composition
  - Inorganic impurities
- Demand and Security of supply
- Pricing strategy

Location of Market and Source

Crude oils compete for market share at the refinery and each must be price competitive on delivery. The greater the distance between market and source, the lower the price must be at source, to allow for cost of transportation.

Producers cannot price to be competitive in every market. Those who are closer to consumers do have a price advantage over those who are remote. Similarly, if faced with more than one market, producers are likely to favor that which is closer, because they would reasonably be expected to get a better price.

One of the most important concerns regarding geographic locations is transportation. Crude that is recovered far away from refineries and oil markets and without good access to pipelines will be much more expensive to transport than crude that is located within proximity to a pipeline network.

Hydrocarbon Composition and Types of Crude Oil

Crude oil is recovered in several different physical and molecular states. It exists as light, medium, or heavy crude, and it may be dubbed “sweet” or “sour.” These various classifications affect all aspects of the crude oil’s recovery, delivery and final use from its origin upstream, transportation through the midstream phase, and to the end user downstream. Different types of crude oil have

different end usage, require various refinery techniques, and ultimately yield different quality products.

Classification Systems for Crude Oil

The petroleum industry typically classifies crude oil based on the following three ways:

1. Geographic Location
    a. The geographic location of the oil field where the oil is recovered is commonly used to classify it. Thus, crude oil might be called West Texas Intermediate, Brent Blend, or Dubai-Oman
    b. The crude oil's geographic location will affect the drilling and recovery efforts in the upstream sector because the geology of the rock or shale will vary based on the region.
2. API Gravity
    a. API gravity refers to a density scale developed and used by the American Petroleum Institute (API). API Gravity is an inverse measure of the density of petroleum and the density of water. If the crude oil has an API greater than 10 it will float on water and is thus lighter than water. If the crude oil has an API lower than 10 it will sink in water because the oil is heavier
    °API = (141.5/(sp. gr. 60° F)) -131.5
    b. The crude's API gravity will impact its value as well as the quality of its yield. Light crude is more desirable than heavy crude because it produces a better yield and does not require as intensive refining to produce a range of high value petroleum products
    c. When crude oil is classified based on its API gravity it is divided into one of the following four classifications:
        i. Light
            - Light crude oil has an API gravity of 31.1 °API or higher
        ii. Medium
            - Medium crude oil has an API gravity that ranges between 22.3 °API and 31.1 °API
        iii. Heavy
            - Heavy crude oil has an API gravity that ranges between 22.2 °API and 10 °API
        iv. Extra Heavy
            - Extra heavy crude oil has an API gravity that is lower than 10 °API
                a. Extra heavy crude oil is sometimes erroneously called "bitumen"
                b. Natural Bitumen has a viscosity greater than 10,000 centipoises measured at original temperature in the reservoir and atmospheric pressure, on a gas free basis
3. Sulfur Content
    a. If the crude contains relatively little sulfur, then it is called "sweet." If it contains a large amount of sulfur then it is called "sour"

i. Sweet
   - Sweet crude oil has a sulfur volume lower than 0.42%

ii. Sour
   - Sour crude oil has a sulfur volume higher than 0.50%.

b. Crude oil with a lower sulfur content (sweet crude) is more desirable than high sulfur (sour crude) because the lower sulfur content means that the oil has less environmental impurities to remove and thus requires less refining. The allowable sulfur content is also typically regulated and thus high sulfur crude requires a larger investment to meet acceptable levels

c. The terms "sweet" and "sour" originated from the practice of nineteenth century prospectors who would literally taste or smell the crude to determine its quality. The lower sulfur content in sweet crude gave it a mildly sweet taste and a more pleasant smell. By contrast the high concentration of sulfur in sour crude caused it to smell like rotten eggs

Oil Demand

Price reflects the interaction between supply and demand. Demand for crude oil is based on a demand for the refined products, which in turn is based on demand for the goods and services, which require petroleum products. Oil dependency is a characteristic of the developed economies, being essential for transportation, lubricants, and important for heat and electricity generation and other specialized applications. Over time, demand reflects demography, economic activity, changes in technology and weather patterns as well as cost comparison with alternatives. The USA consumes more than 25% of the world total, with a population of less than 5%.

An important characteristic of demand is its elasticity. This is a measure of the response of the market to changing price. Numerically, it is proportional change in quantity divided by proportional change in price.

- If price changes by 10% and quantity changes by more than 10%, it is called that the commodity is price ***elastic*** (ratio greater than one)
- If the quantity change is less than the price change, it is said that the commodity is price ***inelastic*** (ratio less than one)
- The importance of elasticity relates to revenue, the product of price and volume

Price	Quantity	Case	Revenue	Delta Price	Delta Quantity	Error
2	5	Inelastic	10			
4	3		12	100%	40%	40%
2	5	Elastic	10			
3	2		6	50%	60%	120%

TABLE 114 Elastic Inelastic Demand Example

- If the proportional change in quantity is less than the proportional change in Price, the demand is inelastic and revenue generated has increased
- If the proportional change in quantity is more, the demand is elastic and revenue is reduced

Example of the behavior of oil demand: during the 1970's the price of oil increased by more than 500% at the beginning of the decade and by 275% at the end of the decade. On both occasions, the volume consumed was reduced. It is difficult in such circumstances to separate out specific cause and effect and to take into account time factors and market manipulation. However, the proportional change in quantity was much less, confirming that ***oil is a price inelastic commodity***. This is supported by the evidence that revenue generated by the market was increased at the higher price and then reduced when the price fell.

Price inelasticity is associated with commodities for which there is no obvious substitute and where reduced consumption would lead to perceived reduction in standard of living.

Oil Supply, Price Evolution, and markers

Pre-1974, oil was in surplus because of large discoveries in the Middle East, North Africa and elsewhere. Low and falling prices during the 1960's encouraged a rapid switch from solid fuel and a rapid increase in the mobility of the world population. At this time, much of the supply was controlled by international companies, which managed the fields and set the prices. Over an 8-year period, (1965-1973), OPEC producers doubled their output to capture 55% of the total market and a much higher proportion of export trade.

The period 1973/74 changed everything. Argument over prices, between companies and producing governments, and political and military conflict, lead to a massive transfer of control from company to government, a deliberate reduction in the supply of oil and a rapid increase in price from less than $3 to more than $10 per barrel. OPEC reduced production by only 260,000 barrels per day in 1974 and then maintained a level output for the remainder of the 1970's. This was a significant deviation from the previous decade when OPEC output was increasing at 10% per year.

During 1979/80 almost 6 million barrels per day were lost from Iran and Iraq because of political change. To some extent, this was compensated from other OPEC sources, but the market reacted to falling supply and to expectation and prices increased rapidly towards $40 per barrel. The years, which followed, were an exercise in market control by OPEC and, by Saudi Arabia. Production was progressively cut back over a five-year period to maintain a high price. The cartel was defeated from within and from without. Control of market supply will only work successfully if members of the cartel are disciplined and honest. If one member cheats, trust may be lost. In this case the group relied very heavily on the determination of Saudi Arabia with output cut back by almost 70%. A danger of artificially high price is that new supply will be attracted to the market. In the short term that means increased supply from non-OPEC sources. In the longer term, it could encourage investment in non-petroleum-based energy technology.

Between 1980 and 1985, non-OPEC production increased by 5 million barrels per day and has continued to increase at the expense of OPEC market share. In 2001, OPEC share of the market was 40%, down from 55% in 1974.

In 1986, Saudi Arabia abandoned its role as residual or "swing producer" and increased production by 1.6 million barrels per day. World supply increased by 3 million barrels per day that year and price collapsed from $28 towards $10 per barrel.

Since 1986, the market changed and oil behaved as many other "commodities" or primary products. The market was in surplus and price varies with market fundamentals. In other words, price is influenced by factors, which impact on market supply or demand and no organization has sufficient market share to have control.

Until March 28, 2000 when OPEC adopted the $22-$28 price band for the OPEC basket of crude, real oil prices only exceeded $30.00 per barrel in response to war or conflict in the Middle East. With limited spare production capacity, OPEC abandoned its price band in 2005 and was powerless to stem a surge in oil prices, which was reminiscent of the late 1970s.

Following an OPEC cut of 4.2 million b/d in January 2009 prices rose steadily in the supported by rising demand in Asia. In late February 2011, prices jumped because of the loss of Libyan exports in the face of the Libyan civil war. Concern about additional interruptions from unrest in other Middle East and North African producers continues to support the price while as of Mid-October 400,000 barrels per day of Libyan production was restored.

In 2015, new U.S. production of shale oil increased the global oil supply. By Jan. 20, 2016, the addition to supply had driven global oil prices down to a 13-year low of around $26/b. By November, OPEC had had enough. It cut production to revive prices. By April 2019, global prices topped $71/b. They remained above $55/b until February 2020; by March 2020, when Covid-19 affected the entire global economy, oil prices began falling more rapidly, soon reaching record lows.

In 2022 crude prices rose with the global benchmark price crossing $100 a barrel for the first time in years, in part because of the Russia-Ukraine conflict.

Price has become highly volatile with time and as a direct consequence, market trade has moved significantly from term contract to ***SPOT***. The ***SPOT*** market is where financial instruments, such as commodities, currencies, and securities, are traded for immediate delivery. Delivery is the exchange of cash for the financial instrument. A futures contract, on the other hand, is based on the delivery of the underlying asset at a future date.

SPOT trade is like the Rotterdam, where there exists an important infrastructure of refineries, storage and transportation, where there is access to consumers and where there is a critical mass of oil companies, traders and brokers.

Others include Singapore and the Gulf Coast, USA. A SPOT contract is one where contracts are short term, based on a current price. Price relates to market conditions, using a ***marker crude***. Three major markers used in pricing of crude oil across the globe are:

- **WTI** (Western Texas Intermediate) for the American markets

- **Brent** for the European/West African Markets
- **Dubai** or OD (Oman/Dubai) crude oil grades used for Persian Gulf and the Asian markets

Country	Marker	°API	Location	Market
USA	West Texas Intermediate (WTI)	39,60	Cushing OK	NY MEX Nueva York
United Kingdom	Brent / Forties	38,06	Sulton Voe	IPE London
Middle East	Dubai OD (Oman/Dubai)	31,00	Fateh Dubai	SIMEX Singapore

TABLE 115 Crude Oil Markers

A marker is a crude that is representative of a market. A successful marker requires to have some important attributes:

- Stable chemical characteristics
- Available in sizeable quantity to ensure that there is meaningful trade
- Readily available with no physical or political interference
- Traded openly in a recognized market such that price is transparent

Benchmark crude (oil marker) is the oil that serves as a pricing reference for other types of oil and oil-based securities. The benchmark makes it easier for traders, investors, analysts, and others to determine the prices of multitudes of grades of crude oil varieties and blends. Using benchmarks makes referencing types of oil easier for sellers and buyers.

Crude oil benchmarks or oil markers are reference points for the various types of oil in the market. Crude oil markers were introduced in the 1980s, for establishing a standard for the world's most actively-traded product. There are several oil markers representing crude oil from a particular part of the globe. The price of most of them are attached to one of the following three primary benchmarks: Brent, WTI or OD. Roughly two-thirds of all crude contracts around the world reference Brent Blend, making it the most widely used marker of all.

- **Brent blend** is a light (38.06° API), sweet crude (0.37% sulfur by weight). Some 15 U.K. fields in the Brent area in the northern North Sea contribute to the blend, although very little production comes from the once-prolific Brent field, after which the stream was named.
- **WTI**, known also as Texas Light Sweet crude, is referred to as the oil extracted from oil fields and wells in the U.S. and is landlocked. The crude is transported via pipelines and hence one of the drawbacks as it is expensive to distribute and sell to other parts of the globe. This crude is light and "very sweet" (API gravity 39.6°, sulfur content 0.4-0.5 % by weight). WTI is pumped to Cushing hub in Oklahoma and is a benchmark for crude mainly in the United States.

There is always a spread between WTI, Brent and other blends due to the relative volatility (high API gravity is more valuable), sweetness/sourness (low sulfur is more valuable) and transportation cost – the price that controls world oil market price.

Historically, price differences between Brent and other index crudes have been based on physical differences in crude oil specifications and short-term variations in supply and demand. Prior to September 2010, there existed a typical price difference per barrel of between ±3 USD/bbl compared to WTI and OPEC Basket; however, since the autumn of 2010 Brent has been priced much higher than WTI, reaching a difference of more than $11/b a barrel by the end of February 2011 (WTI: 104 USD/bbl). In February 2011 the divergence reached $16/b during a supply glut, record stockpiles, at Cushing, Oklahoma before peaking at above $23/b in August 2012. It has since (September 2012) decreased significantly to around $18/b after refinery maintenance settled down and supply issues eased. In 2018, on the average, this price premium in relation to WTI stood at over US$6.1/b.

Other well-known oil markers include the OPEC Reference Basket used by OPEC, Tapis Crude which is traded in Singapore, Bonny Light used in Nigeria, Urals oil used in Russia and Mexico's Isthmus as well as Canada's Western Canadian Select (WCS) and Edmonton Par crude.

- **Dubai/Oman** OD refers to the crude oil produced in Middle Eastern countries and is lower grade than Brent or WTI. It has high sulfur content and is procured in Dubai, Oman and Abu Dhabi. This is the benchmark for the Persian Gulf production and is mainly sent to Asia.
- **Tapis Crude**: It is the benchmark for light sweet Malaysian crude. The sulfur content is as low as 0.03% and the API gravity is around 45.5. Although this oil marker is not as widely traded as WTI, it is used as a benchmark in Asia.
- **Bonny Light**: It is a benchmark for high grade Nigerian crude, with an API of around 36°. Due to its very low sulfur content, generally, it does not corrode the refinery infrastructure.
- **Isthmus**: This is the crude oil benchmark for light crude produced in Mexico. The sulfur content is around 1.45% and the gravity is 33.74° API.
- **The OPEC Reference Basket (ORB)**, also referred to as the OPEC Basket, was introduced in 1987 and was originally the pricing data formed by collecting seven crude oils from the OPEC nations (except Mexico). These included, on an arithmetic basis, the SPOT prices of Saudi Arabia's Arab Light, Algeria's Saharan Blend, Indonesia's Minas, Nigeria's Bonny Light, Venezuela's Tia Juana Light, Dubai's Fateh and Mexico's Isthmus. This information was used by OPEC to monitor the global conditions of the oil market. Since 2005, the OPEC Reference Basket of Crudes (ORB) was the production-weighted average of 14 crudes. Since 2018 it composed of 15 crudes: Saharan Blend (Algeria), Girassol (Angola), Djeno (Republic of Congo), Oriente (Ecuador), Zafiro (Equatorial Guinea), Rabi Light (Gabon), Iran Heavy (Islamic Republic of Iran), Basra Light (Iraq), Kuwait Export (Kuwait), Es Sider (Libya), Bonny Light (Nigeria), Qatar Marine (Qatar), Arab Light (Saudi Arabia), Murban (UAE) and Merey (Venezuela). As of June 2005, ORB's API gravity was 32.7° and its sulfur content – 1.77% by weight.
- **Edmonton Par and Western Canadian Select (WCS)** are benchmarks crude oils for the Canadian market. Both Edmonton Par and West Texas Intermediate are high-quality low-

sulfur crude oils with API gravity of around 40°.
Par crude, delivered at Edmonton, Alberta, has 40.02° API gravity and 0.3% sulfur.
In contrast, WCS, blended at a storage terminal in Hardisty, Alberta, is a heavy and sour crude oil with an API gravity of 20.5 to 21.5° (925 to 935 kg/m³) and sulfur content of 3.0 to 3.5% by weight.
Western Canadian Select (WCS) trades at a considerable discount to WTI (up to US$30/b at the end of 2017). But the gap started to widen in 2018 as U.S. refinery capacity was rising.
For Edmonton Light, the discount jumped to U.S. $7.32 per barrel in January, after averaging U.S. $3.93 in Q4 2017, and this discount was expected to narrow to around US$3.50 by 2019.

- The **Canadian Crude Index (CCI)** serves as a benchmark for oil produced in Canada. It allows investors to track the price, risk and volatility of the Canadian commodity. The CCI provides a fixed price reference for Canadian crude oil and provides an accessible and transparent index to serve as a benchmark to build investable products upon, and could ultimately increase its demand to global markets. The CCI was launched by Auspice Capital Advisors in 2014 and can be used to identify opportunities to speculate outright on the price of Canadian crude oil or in conjunction with WTI to put on a spread trade which could represent the differential between the two. Currently, Canadian oil trades at a discount to WTI. The landlocked location and transportation constraints of crude oil in Western Canadian provinces contribute to this discount.
- Also, until 1986, **Arab Light** (or shortly **AL**) price (32. 8° API (0, 8612 gr/cm^3; OPEC sources insist on 34° API; sulfur content – 1. 97 %) was a leading oil marker and a technical reference, to which all OPEC's other oil prices were linked. In early 1986 Saudi Arabia adopted net-back pricing and **AL** price was replaced as the world oil czar by Brent blend SPOT prices.

Oil Pricing Strategy

The petroleum industry is continually innovating and advancing. New technology has allowed for the recovery of crude oil in geographic regions where it was once impossible. Likewise advances in the midstream phase of distribution are making transport safer, more efficient, and more reliable as refineries increase their capacity and capabilities. Hydrocarbons and its various types will continue to be an important source of energy.

Crude oil is a complex mixture of hydrocarbon molecules with low value in its natural state. When the oil is processed there are important applications with demand and value. The value of the barrel is derived directly from the market price of the products, which the refiner can generate from the barrel.

Refinery techno-economics is very complex and the split depends on the blend and the process. For example, some butane can be added and catalytic conversion will increase the proportion of lighter products. The heavier oil can be hydro-treated to remove sulphur.

The lighter products normally have higher price and the heavier products, a lower price. This implies that crude oils, which generate a higher proportion of lighter products will normally have a

higher price. The price of each product in the marketplace depends on supply and demand that at the same time are affected by competition and season. For example, there is a tendency to travel more in summer months (gasoline and jet fuel) and to require more heating fuels in winter.

Sulphur corrodes, and interferes with the refinery process. It is also an undesirable component of any product to be used as a fuel. Increased cost is therefore incurred to remove sulphur and crudes containing the element are inevitably less valuable. Other elements, such as vanadium are undesirable because they can poison catalysts and render them ineffective.

These are the most important reasons for price differentials, based on oil characteristics. Other issues, which are mainly concerned with politics, are non-systematic and intermittently significant.

The price of a barrel of oil is highly dependent on its API gravity, sulfur content and location and usually, it is tied to a marker crude oil grade that is quoted via a pricing agency. The Energy Information Administration (EIA) uses several sources to generate a world oil price. This does not mean that there is a unique oil price.

Before refining crude, oil has less value than the final oil products that consumers request and these products also depend on the specific gravity of the oil (°API) and its sulfur content (sour). For example, heavy crude oils with low proportion of light hydrocarbons require more complex refining process than lighter oils to produce similar amounts of the more valuable products such as gasoline, kerosene, and fuel oil.

As removing sulfur content requires additional investment, lighter oils that produce a higher share of the more valuable final refined products and require simpler refining processes are more valuable than heavy sour oil crudes.

The price of light oil marker crudes might double the price of heavy crudes. However, differences in quality are one component of the price difference and these differences vary with time. Volatile crude oil price differentials are influenced among other parameters by:

- Changes in the prices of different petroleum products
- Seasonal patterns. The Brent and WTI oil prices tend to record positive returns during the months of March, April and August and negative returns during the months of October and November. Crude oil prices tend to rise in August due to the summer driving season, which results in a rise in gasoline demand. in the event of a cold winter when heating oil supply is low, the price for the residential heating oil to the consumer may increase despite a decrease in the current SPOT price for crude oil
- Factors outside the oil sector. Natural and manufactured disasters can impact oil prices if they are dramatic enough. A war or a pandemic event can distort oil prices

The world heavy oil resources are more than double than the lighter oil. However, the heavy oils are usually sold at a discount to lighter oils due to the increase refining costs. Larger discounts allure heavy oils to refineries, which respond by increasing their import on heavy oil and increasing the production of refined oil products to meet the rise in demand. This way, the incremental demand for light oil products, such as gasoline, can be met importing more economical heavier oils. However, the use of more heavy oil instead of light oi may be difficult for many refineries to process the increased amounts of sour crudes. This the reason some refineries have been

upgraded to handle more heavy oil crudes. It is a balance between costs and profits from the reservoir to the markets.

Market for Gas

The market for hydrocarbon gas is different from that of oil. Gas occupies one thousand times the volume of oil, per unit energy content, at ambient conditions. It must be compressed or liquefied for transportation, storage and distribution and this can cost ten times as much per unit energy content, as for oil. The implication is that gas produced in one region is at a distinct disadvantage, when competing for markets in another. Consequently, there are regional, rather than global markets for gas.

Units for gas are usually cubic meters, cubic feet, normally specified as standard cubic feet (**scf**) or million BTU's. A variety of units is used in this document, to familiarize the reader with these units and the conversion from one to another. When cubic feet are used, the following abbreviations may appear: Mcf (10^3), MMcf (10^6), MMMcf or Bcf (10^9), Tcf (10^{12}).

Most gas travels from reservoir to processing to customer by a system of pipelines and compressors and storage vessels. Historically, most gas distributors would purchase the contents of a whole reservoir to guarantee future supply for its customers. This encouraged negotiation of long term or whole field (depletion) contracts. Usually with more highly developed networks, in regions, such as USA and Europe, it is feasible to introduce competition for supply and for customers to switch from one distributor to another, within a common network. Shorter term and even SPOT trade becomes possible.

The Sales contract is an important element of gas trade and becomes a focal point in relation to market risk. Such contracts will normally include reference to issues of time, quantity, specification and price.

Contract Term Time

Gas is normally sold long term or SPOT. Long term may be for a defined time, such as 10 or 20 years or may be for the life of a producing field. Such a field may be either associated to oil or non-associated gas (free gas). For a field depletion contract, it is important to define the end point and this is normally related to economics, e.g., relationship between revenue and avoidable cost. The longer the distance and the more expensive the transportation infrastructure, the more likely that the contract relates to multiple or non-specific supply and that the contract is for a fixed time. This will enable the supplier to amortize its debt.

Quantity

Gas supply is normally defined as an Annual or Daily Contract Quantity (ACQ or DCQ). For a depletion contract, this must be forecasted over time to handle the anticipated performance of the reservoir. Therefore, the plateau height and length would be defined and periodic negotiation will follow. A "Take or Pay" clause provides the buyer with some flexibility while protecting the

cash flow of the producer. 80% take or pay implies that the buyer must pay at least 80% of the value of the ACQ, regardless of the amount taken. Provision may be included to permit under-deliveries to be taken later.

Demand for gas as a source of heat is seasonal, and unlike oil, gas is not easily or cheaply stored. Variation in demand is normally satisfied by varying the rate, at which gas is supplied from the reservoir.

The production from some field is presented as monthly production, divided by average monthly production. A value of 100% indicates that in that month, production was the monthly average for the year, i.e., annual total divided by 12.

Peak output in winter could be four times the demand in summer, this is called the ***swing factor***. For those field that are gas associated with oil it is more difficult to vary the rate of gas production. If they are also more remote from market the cost of installing increased export capacity could be prohibitive. The cost of extra production / export capacity is reflected in the price paid for the gas.

The inverse of ***swing factor*** is called ***load factor***. Thus, a swing factor of 233% equates with a load factor of 100 / 233 equals 0.429. This implies that in an average month, the system produced 0.429 or 42.9% of capacity.

Gas Specification

Gas specification relates to chemistry and physical properties. As with oil, gas is seldom simple in terms of its composition. For example:

- Sulphur content concerns human safety and environmental pollution
- Wobbe Index
    - It indicates the interchange ability of a fuel gas and is the best indicator of similarity between natural gas and a specific propane-air mixture
    - The Wobbe index relates heating characteristics of blended fuel gases. It can be used to obtain constant heat flows from gases of varying compositions
    - It does not relate flame temperatures, heat transfer coefficients or temperature gradients
    - The Wobbe Index is a measure of the interchangeability of fuel gases and their relative ability to deliver energy
    - It gives an indication of whether a turbine or burner will be able to run on an alternative fuel source without tuning or physical modifications
- Dew point. For water and hydrocarbons, dew point relates to liquid accumulation in pipelines. For air the dew point is the temperature at which air is saturated with water vapor, which is the gaseous state of water. Below the dew point, liquid water will begin to condense on solid surfaces (such as blades of grass) or around solid particles in the atmosphere (such as dust or salt), forming clouds or fog

Gas Price

There is limited global trade in gas. Consequently, gas price has evolved on a regional basis. There is a contrast between oil and gas development.

- Reserves of gas and oil are similar; however, gas reserves are usually less well developed than oil
- Gas trade is much less developed than for oil, representing just over 20% in terms of energy equivalents

Oil Market	Gas Market
Oil has an International Market and is easily saleable	Local or regional market. Greater infrastructure is required for international gas commercialization
It has an international price	It does not have an international price. It depends on the consumption and its final use
Oil transportation is economical	Transportation is expensive about 5 times greater than crude oil
The price of crude oil represents a high percentage of the selling price (approximately 70%)	Gas price tends to be a small part of the final selling price (20%). Transportation, distribution and marketing costs represent a high component of the final gas price
It is vertically integrated throughout the value chain	Regulators separate activities and restrict vertical integration

TABLE 116 Oil Market Compared to Gas Market

The international trade in methane is in two forms:

- Gaseous methane by pipeline
- Liquefied methane, LNG, by tanker

The main markets for gas by pipeline are

- The USA (from Canada)
- Europe (from other European states, Russia and Algeria)

The primary markets for LNG are:

- Japan
- Indonesia
- South Korea
- other Far Eastern states

Each regional market has its own, unique supply / demand conditions and each can therefore sustain a different price regime for gas.

In some sense gas prices are related to oil prices, although not in a direct manner. Japanese, imported LNG, for example seems to have a price which is generally higher than the oil

reference, and that is because this price premium reflects the perception that gas has a better environmental profile. In other regions, the price of gas is generally less than that of oil.

For the protection of buyer and seller, long term gas prices are normally correlated to Inflation and other commodity prices. Since gas is normally competing directly with electricity and energy products such as fuel oil and gasoil, these are commodities, which are commonly used. The following is an example of a price escalation formula:

$$P_n = P_0 * \left(0{,}3\frac{GO_n}{GO_0} + 0{,}2\frac{FO_n}{FO_0} + 0{,}4\frac{RPI_n}{RPI_0} + 0{,}1\frac{E_n}{E_0}\right)$$

Terminology:

Subindex n: means at time n

Subindex 0: means at current or initial time

P_n: Price of gas at time n, related to P_0

P_0: Initial price and of proportional changes to the prices of:

Gasoil (*GO*)

Fuel oil (*FO*)

Retail Price index (*RPI*)

Electricity (*E*)

For this formula to operate equitably, the method of defining prices and indices must be explicit and agreed. If, for example, the buyer and seller were based in different currency environments, they would either choose one as basis for RPI, or agree to a compromise. By this mechanism, the contract price would move, in line with market prices, thus keeping both parties equally exposed to any changes. The formula principle does not protect buyer or seller from market changes. It only prevents parties from gaining at the direct expense of the other.

Within each regional zone, there could be several sectors or isolated markets for gas and this can produce a wide range of contractual conditions and prices. As transportation networks expand and evolve, relationships can change.

Within the countries there are distinct markets. Such as, domestic heat, industrial and commercial heat, and power generation. Also, the SPOT international market provides indication of day-to-day market conditions. On a cold winter's day, a sudden growth in consumer demand can cause an increase in the price profile.

Exchange Rate Risk

The hydrocarbon industry is international and must therefore buy and sell, borrow and invest in different countries, with different currencies. If the exchange rate between some of these

currencies should change, after a contract has been taken, the outcome may be worse, or better than expected.

The value of a specific currency is set by international currency markets. Demand for dollars, for example relates to the purchase of USA exports and the desire to invest in the USA. Supply of pounds originates from USA imports and the desire of USA based companies and individuals to invest abroad. A country with a surplus of imports over exports will experience downward pressure on the value of its currency, thus rendering its exports more competitive and imports more expensive in principle, therefore, a floating rate of exchange helps to create a balance in international trade.

Where countries are closely related with respect to trade, or for reasons of stability, exchange rates may be fixed, either with respect to a standard or to another currency.

Holding a rate constant, or within a predetermined range of values, requires the intervention of government to buy or sell currency to or from reserves.

if one country, e.g., UK, experiences a higher rate of inflation than another, e.g., USA, there is likely to be a downward pressure on the exchange rate. It is unlikely to be a perfect relationship, as it is only one of several factors. Companies may prefer to define a contract in terms of a stable currency, such as dollars, if they perceive political uncertainty.

Two of the areas, where exchange rate risk is commonly encountered are the sale of oil and debt finance.

Sale of Oil

The price of oil is normally defined in terms of US Dollars, consequently, a company with a tax base in another currency faces uncertainty and risk with respect to the relevant exchange rate.

Overseas Debt

Large companies borrow from a wide range of institutions, spread across a range of currencies and for varying time periods. Each debt contract in a foreign currency exposes the borrower to exchange rate risk, when the interest is paid and the capital is repaid.

Debt Finance Risk

Equity financing is when managers sell some of their company's ownership to an investor in exchange for capital to help them grow their business. Debt financing is when managers borrow money to expand their business operations, but must pay it back with interest. A company can get debt financing through a bank or an investor, which is different from equity financing where an investor receives a percentage ownership. If companies get into debt financing, it is important to try to maintain a low debt-to-equity ratio so they can get money from creditors when these companies need more cash

Types of Debt Financing

There are several types of debt financing available to small business owners. They include:

- **Personal loans**: If you must use your own assets or if your company is brand new, you may need to secure a personal loan to get started
- **Small Business Administration (SBA) loans**: You can also secure financing with this federal agency, which is dedicated to assisting small business owners with the financing and resources they need to make their business a success. Although the SBA doesn't directly provide loans to business owners, they do have many loan programs to choose from in collaboration with lenders
- **Line of credit**: A line of credit is when you have direct access to certain funds that you can use when you need them. Your lender will only provide the maximum you are approved for, so there is not a danger of borrowing more than what they allow. Even though the funds are available, you only pay interest on the money you use
- **Credit cards**: Just like personal credit cards, you can apply for and receive approval for a business credit card. These credit cards are also subject to some of the same terms as personal credit cards, including repayment schedule and interest rate
- **Conventional loans**: With conventional loans, you usually receive the lump sum of money you need and you must pay back the money, with interest, in a predetermined amount of time
- **Cash flow loans**: This is another type of debt financing that involves you receiving a certain amount of money based on your current revenue

Characteristics of Debt and Equity

Investment capital is a blend of **Equity** (the shareholders' part) and **Debt** (the borrowed part). Oil companies approach banks and other financial institutions to borrow, either for a specific project or as a contribution to general corporate funding. In assessing a potential borrower, a lending institution will consider several factors, including:

- The risk nature of the business activity
- The record of accomplishment of the company in generating profit and repaying debt
- The proportion of company finance already provided by debt

The Risk Nature of The Business Activity

$10 million invested in an exploration well provides no security for the investor, if the project is unsuccessful. It is unusual, therefore that a banker would lend at a fixed rate of interest for such a project, without requiring other security guarantees. The more highly focused a company in high-risk areas of business, the less likely that debt will be available to them. A large integrated multinational can raise debt, and perhaps use some as a contribution to exploration activity, because security is provided by the other parts of the business. In the absence of such security,

the lender may negotiate a form of equity involvement, as is found in certain forms of project financial arrangement.

The Record of Accomplishment of The Company in Generating Profit and Repaying Debt

Debt interest is met from corporate profit, before the payment of taxes. Institutions use the Times Interest Earned Ratio to assess the security provided by corporate cash flow. The closer the ratio falls towards unity, the higher the risk of inability to pay.

The Proportion of Company Finance Already Provided by Debt

The debt-to-equity (D/E) ratio is used to evaluate a company's financial leverage and is calculated by dividing a company's total liabilities by its shareholder equity. The D/E ratio is an important metric used in corporate finance. It is a measure of the degree to which a company is financing its operations through debt versus wholly owned funds.

The proportion of debt is commonly known as the debt ratio for the company. A debt ratio of 0.5 or 50% implies that half the company's capital is provided by shareholders and half is borrowed.

- The higher is the proportion of debt, the higher the risk of failure to pay, leading perhaps to bankruptcy

Such a situation might arise, because of cash flow problems, related to poor sales performance, unexpected expenditure or poor planning. It might also arise because interest schedules were affected by fluctuating interest or exchange rates.

The process of borrowing to invest is sometimes called gearing or leverage (USA), in the sense that the shareholders have more money to invest than they provide themselves, and that they can use it to generate higher profits for themselves.

The higher the debt ratio, the higher the return on equity, if profit is higher than cost of debt. However, if profit is less than the cost of capital, the higher the debt ratio, the poorer the return on equity.

There is the likelihood that profit earned will be insufficient to meet the interest commitment. At low debt ratios, the spread of return on equity is minimal. This spread increases with increasing debt ratio. This increase in spread between good performance and poor performance is a quantitative measure of financial risk.

Debt ratio is one of the important factors in determining whether an institution will provide debt finance, and how much it will cost. As a rule, the higher the perceived risk, the higher the rate of interest. It is also likely that a debt contract will include a clause to limit new borrowing, since additional debt undermines the security of all prior debt. Where debt ratio is high, cost of borrowing is inevitably high, and debt contracts are sometimes called junk bonds. Institutions active in this market must spread their interests to manage risk.

Lease Finance

Lease financing is one of the important sources of medium- and long-term financing where the owner of an asset gives another person, the right to use that asset against periodical payments. The owner of the asset is known as lessor and the user is called lessee.

It is the lease where the lessor transfers substantially all the risks and rewards of ownership of assets to the lessee for lease rentals. In other words, it puts the lessees in the same condition as they would have been if they had purchased the asset. Finance lease has two phases: The first one is called primary period. This is non-cancellable period and, in this period, the lessor recovers his total investment through lease rental. The primary period may last for indefinite period. The lease rental for the secondary period is much smaller than that of primary period.

The periodical payment made by the lessee to the lessor is known as lease rental. Under lease financing, lessee is given the right to use the asset but the ownership lies with the lessor and at the end of the lease contract, the asset is returned to the lessor or an option is given to the lessee either to purchase the asset or to renew the lease agreement.

In other words, lease finance is a form of debt, whereby the ownership of relevant assets remains with the financier. This implies that the lessor (**the bank**) is responsible for expenditure, up front and that the lessee (**the oil company**) makes regular payments for the use of the equipment. These payments may be uniform over the contract period or variable, to track anticipated cash flow. Leasing has potential tax advantages for both parties and in the event of lessee bankruptcy, it is generally easier for the lessor to recover value. There are various forms of lease contract, which have differing risk, taxation and accountancy implications. These include:

- Financial Lease
- Sale and Leaseback
- Hire Purchase
- Operating Lease

A **Financial lease** is a contract, by which the cost of leased equipment is fully amortized and is non-cancellable. This means that the lessee undertakes to make a series of payments, which will fully reimburse the lessor for investment, interest and profit. From an accounting point of view, a financial lease is one by which the risk and reward of ownership is substantially transferred. A difference between a financial lease and conventional debt is that the lessee can charge lease payments as operating expenses, therefore gaining a tax advantage.

Sale and Leaseback can be very similar to a Financial Lease, the principal difference being that the lessee already owns the assets and sells them to the lessor, simultaneously entering a contract to pay for its use.

An **Operating Lease** differs with respect to commitment. In some countries, accountancy standards suggest that if committed payments represent less than 90% of asset value, the lease is operating, the implication being that the asset is not capitalized in the accounts. The risk associated with such arrangements depends very much on the life and detail of the contract.

One final issue on leasing relates to field abandonment. Since lease charges are part of the annual operating expenditure, they contribute to the field abandonment calculation and can lead to an earlier abandonment decision, with reduced recovery.

Long Stream of Cash Flows Generates Uncertainty

Since business is always carried out in an environment of changing prices, investment calculations normally include a projection over the relevant time. Risk results from rates of change, which were not anticipated. The further into the future, or the longer the specific stream of cash flows, the greater the uncertainty. For example:

- Fixed price contracts
    - This form of contract is no longer popular, because of inflationary problems. Some form of indexation is commonly applied to protect both parties
- Taxation
    - Since taxation is calculated in money of the day terms, allowances carried forward, diminish in real value. Higher inflation often implies higher incidence of tax. There is no fixed relationship, it depends on the specific details of the calculation
- Rate divergence
    - Retail Price Index is the mathematical link between money of the day and real terms cash flows and return on capital. If all forms of cash flow are subject to the same increases, there is less of a problem. If some cash flows are not subject to the average rate of inflation, distortion can arise. Oil price, for example is independent of RPI; however, a shift in the rate of inflation usually implies a shift in the real price of oil. Given that oil sales continue throughout the life of the project, this is potentially a significant issue

Partners Risk

Despite being amongst the world's largest enterprises, petroleum companies commonly create joint ventures for exploration and field development. This results in corporate mergers on a grand scale. The concept of partner may also be extended to include contractors from the service sector, which have formed close working alliances with operators. Such relationships can generate significant benefit, when they work. Working together can bring economies of scale and shared ideas. It can also create conflicts of interest and of personality.

As said before, gas and oil companies are often found themselves working in partnership with others. By choice, most companies enter partnerships as a means of spreading risk during exploration. These relationships extrapolate into field development and production. If discoveries are found to extend into neighboring license-blocks, partnerships are faced with unplanned cooperation.

Increasingly, operator companies are also entering into forms of partnership with oilfield service providers to drill wells, operate production services etc.

When two or more organizations come together in partnership, to work on project design and to make investment and operational decisions, it is inevitable that there will be differences of opinion. If the partners fail to work effectively together, the operation may be less than optimum. For example:

- Technical preference
    - Each company will have existing contracts and arrangements with other organizations, to provide technical services. Each has its own preferences with respect to equipment, software and procedures. These will be supported by training and experience, and by familiarity and trust. It is difficult to abandon such investment of time and effort
- Conflict of interest
    - One of the companies may have part ownership of a pipeline or other facility or service, which might be useful to the partnership. It is difficult to be fully objective in such circumstances
- Analysis and perception
    - Company engineers, scientists and economists may have differing views as to the quality of an investment opportunity. This may relate to subsurface issues, such as: reserves or well productivity, to issues of design concept or details of surface facilities, or to perception of the future with respect to oil price or demand for gas
- Corporate Issues
    - The perception of a project is partly influenced by issues of corporate status and policy. An investment opportunity may look attractive to one partner and economically marginal, at best, to another. Such issues include taxation, corporate investment opportunity, attitude to risk and strategic planning. Companies may, for example, use differing discount rates
- Human relationships
    - Partnership requires staff to cooperate and to work together, at various levels. If the senior managers are unable to trust one another, it is unlikely that the relationship will survive. In some cases, there are corporate mergers that create a requirement for a more radical and intimate mixing of two or more organizations and the inevitable shedding of staff to justify the cost of the merger. Successful merger is about holding on to the best staff and objectively selecting the best of everything from each organization

Summary of Chapter 5 Source of Risk

Risk describes a situation, in which there is a chance of loss or danger, so it can be measured. **Uncertainty** refers to a condition where people are not sure about the future outcomes; therefore, it cannot be measured.

The main activities relating to risk are:

- Risk assessment
  - It is concerned with estimating the amount of risk inherent in an investment
- Risk evaluation
  - This is where the analyst adjusts the economic value of the project to reflect the risk that investors consider
- Management of risk
  - There are various ways to limit or control risk. This is called **risk management**, and applicable techniques range from gathering additionally information to buying insurance

Risk Assessment

The first step in dealing with risk is to estimate exposure. Risk can be measured at various levels. It can be estimated for an individual project by the variability of its NPV. Some corporations use single points estimates for cash flows and adjust for risk on a purely intuitive basis; however, the common procedure is to obtain a range of possible figures that typically reflect a most-likely, an optimistic, and a pessimistic scenario.

The optimistic and pessimistic forecasts are often defined as estimates that only have a 10 percent probability of being exceeded on the positive or negative side. Using statistics, a standard probability distribution can be fitted to these ranges of estimates, thereby providing a reasonably good picture of the inherent uncertainties. To reduce the subjectivity associated with such forecasts, corporations may require consensus estimates derived through discussions from a multidisciplinary team.

One of the techniques using for risk assessment is a sensitivity analysis, it determines how vulnerable is the project economic assessment when there are changes in forecasted values.

Risk Assessment Example

An investment in a new pump costs MUS$ 100, and net cash inflows of MUS$ 30 per year are anticipated over the next five years. The applicable discount rate is 12 percent. Management is interested in knowing by how much the inflows could be reduced before the project NPV becomes negative.

	Cash Flow Economic Analysis					Option 1				
Input						Use as equivalent rate:	12,00%	i = i'+f+i'*f		
Example Sensitivity		Clear Input				Option 2				
Project Life (N, yrs)	5	*Max 40 Yrs*				12,0% is corrected to				
Initial Investment (P_{oINF}, $)	100000					To be added to i				
Interest (I)	12,0%	inflation (f)	0,0%	r corected by f =		12,00%	r = (i - f)/(1 + f)			
Fill Rows 8 & 10		Yr	0	1	2	3	4	5		
Annty Outflow (C, $ per year)		Ci		0,0	0,0	0,0	0,0	0,0		
Annty Inflow (A, $ per year)		Ai		30000	30000,0	30000,0	30000,0	30000,0		
Sunk Cost @ N (S, $)	0									
Salvage Value @ N (Sv, $)	0									
Results										
Net Cash Flow Prsnt. Val. (NCFP,$)	108143,29	Without Salvage Value or Sunk Cost								
Profit to Investment Ratio (PIR)	0,081	NPW/Po								
Discounted Payout (Payback yrs)	4,49									
NPVI	0,081	NPV (@i) / MCO (@i)								
Net Future Worth (FW_{PC}, $)	14351	$F_1 = P (1 + i)^n$		$F_2 = \Sigma(A_x (1 + i)^{(n-x)})$		$F_3 = \Sigma(C_x (1 + i)^{(n-x)})$		$F = - F_1 + F_2 - F_3 - S + Sv$		
Net Present Value (NPV, $)	8143	$P = F / (1 + i)^n$		$P = A * \{[(1 + i)^n - 1]/(i (1 + i)^n)\}$						
Benefit/Cost Ratio (PI)	1,081	ΣPV of net cash inflows/ΣPV of net cash outflows						Net Operating Income to Investment Ratio		
Internal Rate of Return (IRR,%)	12,00%	Click Calc IRR Setting D26=0 Varying B24								

TABLE 117 Risk Assessment Example

The investment's NPV is US$ 8143 suggesting that the project is acceptable: however, how sensitive is the evaluation when the cash flow is reduced?

Running this case varying the inflow it is obtained the following results

Reduction	A (US$)	NPV (US$)
0.00%	30000	8143
6.67%	28000	934
7.53%	27741	0
13.33%	26000	-6276
20.00%	24000	-13485

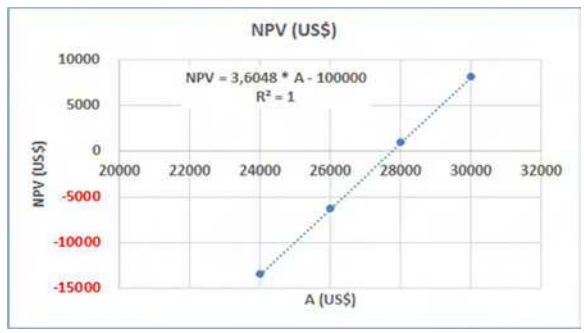

FIGURE 32 NPV SENSITIVITY

Using the regression indicated obtained in Figure 32 or by interpolation the project just breaks even with annual cash inflow of US$ 27741, implying that a reduction of more than some 8% from the original inflow forecast will make the investment unattractive. Hence, the acceptability of the project is sensitive to forecasting errors.

Such sensitivity analysis and determination of break-even values can be carried out for a variety of factors influencing a project's cash flows. For example, when analyzing a new project, analysts may determine how sensitive its NPV is about oil rate, useful life, OPEX, and other forecasted variables.

The information provides analysts with insights into the main determination of risk in a particular situation. It allows management to concentrate on those variables that are the most critical to the ultimate success of the project, and to evaluate the corporation's projected financial performance to changes in the forecast.

Risk Evaluation

After obtaining a reasonable assessment of risk, analyst moves to the project evaluation and to estimate risk's probable cost because investors and managers avoid uncertainty as risk reduces project's economic value. This section presents basic techniques that allow analysts to adjust NPV to reflect project risk. Chapter 7 will expand the techniques for risk evaluation and management.

Risk-Adjusted Discounting

The expected future cash flows may be discounted at the company's average after tax cost of capital. This is valid if the company's investments are roughly of the same risk that shareholders perceive for the overall corporation.

The new investments will not alter the terms under which the company can obtain new financing. As usual hydrocarbon companies are engaged in diverse projects and operate in several business areas or countries, each subject to different risks. Even within any one of these entities, investment projects may range from high-risk exploration and development to relatively low-risk workovers.

Under above situations it would not be appropriate to apply a single corporate wide discount rate across projects and organizations. Such an averaging approach can cause serious economic distortions, and implies a cross-subsidization by which low-risk projects are penalized (discounted at too high a rate) while high-risk ventures are subsidized (discounted at too low a rate).

Where projects differ considerably from the average risk of the company, individual risk adjustment should be applied in investment evaluations. One of the most common solutions is using **risk adjusted discount rates**. This implies that analysts vary the discount rate applied to a project's expected cash flows based on perceived risk. Typically, investments are grouped into several risk classes, and a separate discount rate is applied to each class of CAPEXs, with higher rates used for more risky investments.

Risk Adjusted Discount Rates Example 1

A company may use the following classification for the previous example (Table 117). An initial investment of US$ 100000, with cash inflows of US$ 30000 per year expected for 5 years. In this case the project's NPV become:

P (US$) =	100000
n (years) =	5
A (US$) =	30000

Project Class Risk	Discount Rate	NPV (US$)	Formula
Low	12.0%	8143	**NPV = (A ((1 - (1 + i)$^{-n}$)/i)) - P**
Normal Business	15.0%	565	
Speculative	18.0%	-6185	

TABLE 118 Project Class Risk and Discount Rate

Although the project would be acceptable in the low-risk category, and marginally acceptable given the normal business risk, it would be rejected if it is classified as higher than usual risks.

Shareholders provide the funds the company invests in its various projects. They receive the returns those projects generate and bear the risks involved. Hence, adjustment made to the discount rate have to reflect shareholders' preferences as revealed in financial markets.

Risk Adjusted Discount Rates Example 2

Consider the drilling of an oil well costing (P) MUS$ 500 that may result either in a dry hole (probability (p_f) of 85%) or in a discovery (probability (p_s)of 15%). In the latter case, a gain (V) of MUS$ 5000 is anticipated from a sale of the well.

The results from the drilling will be known in 1 year.

The ***expected cash inflow*** at the end of the year becomes

$EV = p_s * V$

$EV = 0.15*5000*10^3$

EV = US$ 750000

Even if the discount rate is raised because of the high risk, to 25%, the effect of such an increase is low. As discounting is limited to 1 year, the expected benefits are reduced only by a factor of

$Reduction\ NPV = 1/(1 + i)^n$

$Reduction\ NPV = 1/(1 + 0.25)^1$

Reduction NPV = 0.8

The project NPV remains positive at:

NPV = P + EV * Reduction NPV

NPV = -500000 + 750000 * 0.8

NPV = US$ 100000

The use of risk-adjusted discount rate implies that the risk inherent in a project's cash flow increases as we move further into the future.

However, risk and time may not be related. For instance, the initial construction costs of a new pipeline typically are subject to much greater uncertainty than the subsequent revenues once the pipeline is in place.

Risk-adjusted discount rate represents one of the most common and useful practical approaches to handling the problem of risk, and are often a good compromise between what is operationally workable and what may be conceptually desirable. Question is that there is no method for assigning acceptable risk-adjusted discount rate.

Handling the Problem of Risk Example 3

Assume expected after-tax cash inflows of US$ 100 a year for 20 years from two projects.

Project B is riskier than Project A.

Assume that the first inflow is in year 0.

Project A corresponds to the company's usual investments at discount rate of 10%.

The risk adjusted discount rate for Project B is 15%, raised from the usual 10% applied to normal projects.

Questions

a) Derive the ratio present values for the annual net cash flows of projects A and B
b) Derive PV (cash flow from A)/ PV (cash flow from B)
c) What is inferred about the riskiness of cash flows from Project B relative to cash flows of Project A over time?
d) Graph the present value of annual cash flows from each project as a function of their year of occurrence

Solution

Project A		
A_o	=	100
A	=	100
i	=	10,0%
n	=	20
NPV	=	951,36

Project B		
A_o	=	100
A	=	100
i	=	15,0%
n	=	20
NPV	=	725,93

$NPV = A\,((1 - (1 + i)^{-n})/i) + A_o$

	i =	10.0%		i_R =	15.0%	
	Project A			Project B		
	(I)	(II) = (I)/(1+i)^n	(III) = Sum (II)	(IV) = (I)/(1+i_R)^n	(V) = Sum (IV)	(VI) = (II)/(IV)
Year (n)	A (US$)	NPV A	Cum NPV (US$)	NPV B	Cum NPV (US$)	NPV A/NPV B
0	100	100.00	100.00	100.00	100.00	1.00
1	100	90.91	190.91	86.96	186.96	1.05
2	100	82.64	273.55	75.61	262.57	1.09
3	100	75.13	348.69	65.75	328.32	1.14
4	100	68.30	416.99	57.18	385.50	1.19
5	100	62.09	479.08	49.72	435.22	1.25
6	100	56.45	535.53	43.23	478.45	1.31
7	100	51.32	586.84	37.59	516.04	1.37
8	100	46.65	633.49	32.69	548.73	1.43
9	100	42.41	675.90	28.43	577.16	1.49
10	100	38.55	714.46	24.72	601.88	1.56
11	100	35.05	749.51	21.49	623.37	1.63
12	100	31.86	781.37	18.69	642.06	1.70
13	100	28.97	810.34	16.25	658.31	1.78
14	100	26.33	836.67	14.13	672.45	1.86
15	100	23.94	860.61	12.29	684.74	1.95
16	100	21.76	882.37	10.69	695.42	2.04
17	100	19.78	902.16	9.29	704.72	2.13
18	100	17.99	920.14	8.08	712.80	2.23
19	100	16.35	936.49	7.03	719.82	2.33
20	100	14.86	951.36	6.11	725.93	2.43

TABLE 119 Comparing NPV Project A and Project B

The present value of cash flows derived result in the following graph.

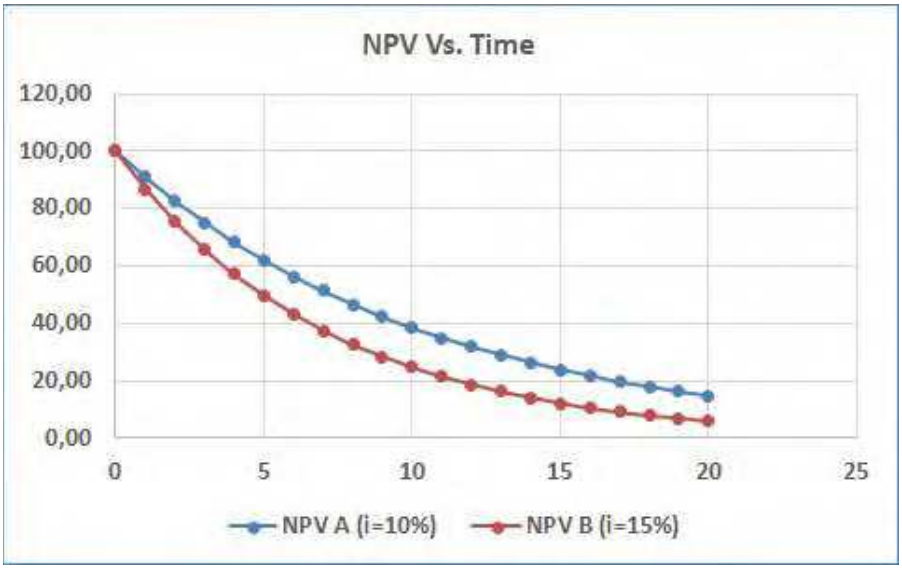

FIGURE 33 COMPARING NPV VS. YEARS PROJECT A AND PROJECT B

Figure 33 illustrates the risk assessment implied when using risk adjusted discount rates. Through discounting, later cash flows are affected more severely by an increase in the discount rate.

The numbers derived in this example imply that the riskiness of cash flows for Project B relative to the flows for Project A in period 20 is almost the double that for period 5 (2.43/1.25 = 1.95). Even if the relative risk of Project B increases over time, it would be unlikely that such increases in perceived risk would parallel the relationship implied by the ratio (NPV A)/(NPV B) in Table 119.

Risk Management

Risk is not entirely outside the control of the companies. Risk is normally determined by a combination of factors external to the corporation and factors over which the company has influence.

Examples of external factors:

- General economic conditions that affect hydrocarbon demand
- Price-level changes that may impact production

Internal factors may include:

- The ability to control initial investment expenditures
- Control ongoing operating costs

Companies have some control over sources of uncertainty, so certain aspects of business risk can and should be managed.

Even about internal or external factors a company may be able to shift risk through:

- Insurance-type arrangements

- Reducing risk through internal actions
    - Improved forecasting
    - Planning
    - Implementation

Projects that at first look promising later fail because of weak initial forecasting and/or poor controls during implementation.

Even if a company cannot eliminate risks, it can attempt to understand the source of the potential risks and avoid mistakes. Internal risks cannot be completely avoided but they must be managed. For example:

- Collect additional information may improve forecasting
    - Added information could come from internal sources or from external advisors
- Do not extrapolate past trends disregarding underlying economic factors or even economic common sense
- Lower break-even point through reduction of fixed costs
- Design flexibility into the production schemes
- Subcontract or lease assets rather than owning them
- Use insurance-type arrangements
- Diversification
    - This is one of the most effective ways to manage and reduce risk and might include moving into unrelated business

Some of above topics will be expanded in Chapter 7 Risk Management. Though, as intermediate introduction it can be said that a company can enhance its ability to bear risk. This generally involves having some flexibility in its financial resources including:

- Cash
- Lines of credit
- Assets that can be sold quickly without loss

Certain risks are difficult to avoid despite how complex the company's risk management techniques are. Other risks can be avoided, but doing so is simply too expensive. Through effective management, some risks can be reduced or even eliminated, and this may make projects viable that would otherwise have been too risky to accept.

Managers are always confronted with the difficult but constant trade-off between efficiency and flexibility, or between expected return and risk.