POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

Probabilistic Evaluation of the Net Present Value of an Oil and Gas project through Monte Carlo simulation

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Abstract

Economic and business opportunity evaluation of the oil and gas projects, in terms of Net Present Value (NPV), represents a critical stage in the Upstream sector of the petroleum industry. Risks related to a project are still difficult to assess and to model, because of the presence of a high number of uncertainties and variability affecting the project. Therefore, the approximated or the wrong estimation of the economics of a project can lead to possibilities of increasing the financial exposure of an oil and gas company, as well as a rejection of good business opportunities.

Nowadays, the deterministic approach is still a base approach of economic evaluation of a project because it is fast and easy to understand. However, the associated results are not accurate because this approach does not consider the uncertainties and their influence on the variables used in the estimation of the NPV.

In the last years, the probabilistic approach is also involved in the economic evaluation process of a project. Definition of ranges of variability and probability distributions, able to estimate the trend of the uncertainties, allows more accurate evaluations with additional information related to the probability of profits occurrences.

The developed model on MATLAB and Excel is able to evaluate, from the probabilistic definition of a group of variables, the probabilistic NPV related to a project. In the model, variables from different classes, connected to the project, are defined by a range and a distribution curve which are imposed based on the evaluation of the uncertainty affecting each variable. Then, through Monte Carlo's method, generation of an imposed number of random values, for each element of the model, allows the calculation of the costs and revenues associated to the project and its probabilistic NPV.

The interpretation of the probabilistic result of the NPV, allow a more detailed economic and financial risk evaluation of a project. In addition, different project development concepts can be tested to help decision investment and to maximize the potential of the project.

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AAPG	American Association of Petroleum Geologists
B$	Billion dollars
CAPEX	Capital Expenditures
CPI	Consumer Price Index
E & P	Exploration and Production
EIA	Energy Information Administration
FDP	Field Development Plan and design
FPSO	Floating production storage and offloading
GRV	Gross Rock Volume
IOC	International Oil Company/ies
IRR	Internal Rate of Return
JOA	Joint operating agreement
M$	Million dollars
NCF	Net Cash Flow
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Co-operation and Development
OGDE	Oil and Gas Development Estimating
OHIP	Original Hydrocarbon In Place
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operating Expenditures
P10	10% Probability
P90	90% Probability
PDF	Probability Density Factor
PIIP	Petroleum Initially In Place

PRMS	Petroleum Resource Management System
PSC	Production – Sharing Contract
PV Ratio	Present Value Ratio
RE	Recovery Efficiency
RF	Recovery Factor
SPAR	Single Point Anchor Reservoir
SPE	Society of Petroleum Engineers
STB	Stock Tank Barrel
TLP	Tension Leg Platform
UKCS	United Kingdom Continental Shelf
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure
WPC	World Petroleum Council

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Chapter 1 Introduction

1.1 Background of Thesis

The main target of the Petroleum Industry is to supply a high number of products to the markets. All the products derive from the extraction, transportation and processing of raw materials naturally occurring in the subsurface as deposits of oil and gas. The variety of these products belongs mainly to two categories: fuels and petrochemicals. The category of fuels includes products from both crude oil and gas. Main products of fuels' category derive from refining processes of the crude oil and are mainly used in the automotive industry. Instead, a small percentage of oil products and the ones deriving from natural gas, are used for heating and producing electricity. The category of petrochemicals includes all the low-value products of the refining processes that have almost no use in the fuel sector. Technology and chemical processes transform these low-value raw materials into more valuable ones. Products as plastics, synthetic rubber, solvents, adhesives, are used in many important sectors (automotive, clothing, medical equipment, etc.). The increase in demand for petrochemicals products influence also the value of the raw materials and stimulate the innovation of a better technology able to process a higher variety of raw materials.

A large supply of fuels and petrochemicals requires a larger amount of crude oil, which implies an optimization of all the operations from the reservoir arriving to the market. Harsh environmental conditions of extraction and transportation make the petroleum industry a challenging industry where effective – efficient organization of industrial activities and assessment of business risks are key factors to meet goal profit horizon (Clews, 2011).

According to R.J. Clews (Project Finance for the International Petroleum Industry, 2011), the value chain of the petroleum industry is classified into three major sectors:

- Upstream
- Midstream
- Downstream

The Upstream, or Exploration and Production (E&P), sector includes all the activities regarding the searching and extracting underground hydrocarbons (oil and natural gas) to the surface. Difficult environment, that often characterizes the drilling and production of deep hydrocarbons, involve a high proportional amount of capital investments.

The Midstream sector is related to the storage and transport systems, where the crude oil and natural gas are collected from the wellhead, treated if necessary and then delivered to the Downstream sector. The transport of the raw materials to the refineries is fundamental because only products of processed oil and gas can be used by the consumers.

The Downstream sector refers to the refining, selling and distributing processes of the crude oil and natural gas. It primarily consists of refineries and distribution companies. Limited usage of the crude hydrocarbons requires refining processes that add value to the final products.

The Upstream is divided into three interconnected macro phases: Exploration, Development, and Production. During the first macro phase, geophysical methods and exploration wells are implemented to investigate – estimate the reservoir's size and characteristics in order to prove that the reservoir is economically producible. Resulting data from exploration studies have vital importance for field development project design and planning that helps in determining the potentials – benefits of a successful discovery of a reservoir and its production. The Field Development Plan and design (FDP) includes all the exploration data (geology, reservoir, drilling), production engineering, field facilities, environmental data, project risks and project economics. Information such as depth and characteristics of the reservoir, as well as the surface location climate, characteristics and conditions influence the complexity of a project Field Development Plan.

The determination of the reservoir potential is directly related to the estimation of the Net Present Value indicator which represents the difference between possible future revenues, relative to the selling of the produced hydrocarbon, and future costs, relative to the field development – production. The Net Present Value represents then the base indicator that helps in the decision – making process where only high remunerative field development projects are considered for the successive physical field development phase where different contractors are involved.

In this dissertation, the focus is addressed on the Development phase in which variables of field development project and the relative Net Present Value estimation take place.

A development project is subject to many uncertainties related to subsurface/geological variables, surface/facilities variables, and economic variables. These uncertainties lead to a more complex and difficult determination of the economic indicators, related to the field development, that are crucial for the management section. Wrong approximation of the development project's variables can lead to possible overruns in cost and delays, as well as to rejections of valuable projects or the opposite effect, with the general result of a loss in opportunities and investments.

1.2 Problem Description

Since August 2014, the Oil and Gas industry is facing a very difficult situation due to the oil price collapse from almost \$ 101 per barrel to \$ 30 per barrel in January 2016 to reach almost \$ 60 per barrel in December 2017 (MacroTrends, n.d.). Although the oil price increased from its minimum, many projects became marginal because of their non-feasibility in terms of the production costs that overcome possible revenues.

Only a few places on earth can still be found and developed to provide supply at the current oil price and this defines somehow the end of 'cheap' oil era. Saudi Arabia is one of the countries that represent fully the 'cheap' oil concept. "According to data from energy consultant Rystad Energy, on average it costs Saudi Arabia less than \$ 9 to produce a barrel of oil last year. That's the cheapest in the world, though fellow OPEC countries Iran and Iraq can produce for around \$ 10 per barrel as well, which is well below rival nations." (DiLallo, 2017).

Future perspective of increase in oil and gas demand leads to a need of discovering and developing new reserves that are of vital importance in maintaining the present and future equilibrium between production and consumption.

Highly volatile oil and gas prices that affect the possible revenues with the high and long-term investments in field development and production represent the major constraints for the oil and gas industry. In order to deal with these constraints and to forecast field development risks, Economic Evaluation of a field development project is considered the main instrument able to analyse the range of possible profit relative to a future field production. The Economic Evaluation does not include only profit indicators; it regards as well the maximum financial exposure in terms of costs of the field development – production for the oil company. Harsh competition in the petroleum industry forces oil companies to manage carefully and efficiently the investments related to the development phase in order to survive.

Nowadays, almost all of the petroleum companies base their investment decisions on own economic models prepared by internal economists or external experts that use the available information given by company's internal sources of information (geophysicist, geologist, reservoir engineer etc.). The lack of a robust base in assessing the uncertainties of these available information can be considered as the principal element of a large and wrong estimation of results in the Economic Evaluation model. Failure to achieve completion because of inadequate management of the project's risks and uncertainties can lead to severe problems as delays in the field development, cost overrun and shortfall performance. Additional time to complete the field development project means more servicing debts and a higher possibility of bankruptcy.

The deterministic approach has been used for determining economic models over the last few decades. A deterministic approach is a fast and approximate calculation that does not account for the uncertainty which exists, consequently, it cannot show the risk related to each possible scenario. On the other hand, the probabilistic approach, which is relatively recent, outruns its previous by integrating uncertainty information and determining more significant results. However, it is very dependent on the probability judgment of the analyst regarding the definition of the uncertainties related to the variables.

The assignment of a probability distribution is based on the expertise of the analyst that is subjective and in case of wrong interpretation, the ambiguities of the problem may increase (Aven, 2015). Approximated probability judgment, in fact, will mislead the management perspective of the risk related to each scenario and so will decrease the capability of choosing the best one, creating in this way possible overrun costs and other negative consequences as well as the lower exploitation of the initial resources that can lead to a potential financial loss.

1.3 Objectives

The objective of this dissertation is to define, through a probabilistic method, the Net Present Value (NPV) of an oil and gas project during its first evaluation of profitability, using a mathematical model, and compare the result to the one defined by a deterministic approach.

The model, involved in the probabilistic definition of the NPV, performs combinations of variables, responsible of cash flow variation in terms of costs and revenues, and integrates project-related risks and uncertainties expected during field development – production phases, that can be connected to the model's considered variables.

The dissertation focuses especially on the main variables, starting from their theoretical definition and expert advises and guidance to the trial of a better understanding of the uncertainties affecting them. The tentative is to characterize some of the variables with a probabilistic distribution able to improve the accuracy of the final results.

The intention of defining probability distributions and more accurate ranges of values relative to them, of the variables, derives from the necessity of a better risk management able to predict and overcome the probability of possible negative scenarios that can lead to unfavourable financial positions of the petroleum company.

Another objective of the thesis is to assess and assign the right amount of resources on the most uncertain variables in order to maintain or to meet established goals in terms of revenues. The distributions are then combined with fixed economic data in a model to estimate the Net Present Value distribution of the possible scenarios. The final interpretation of the Net Present Value distribution indicates the probability of achieving a pre-established profit from a petroleum field.

Additionally, investigation of the profits generated by the same project developed in two different durations is performed to allow evaluation of alternative concept able to rise the opportunity of reducing development's costs. The same type of investigation is performed in relation to different development concepts of the same project.

The probabilistic and deterministic approach, applied to NPV definition, is performed on a number of case studies related to different types of fields. The objective consists in comparing the results, from the different approaches and determine the additional value of information and advantages provided by the probabilistic method and analysis.

1.4 Methodology

The Net Present Value is an economic indicator used to evaluate the profit opportunity related to a project by analysing the initial cost with respect to the possible future revenues generated by the investment. Its calculation is defined by the difference of projected cashflows (in and out) evaluated at the present value of the money over a period of time. The level of revenues indicated by the NPV estimation is of fundamental importance during the initial phases of Evaluation, Selection and

Definition of the project concept because it allows identifying, among different alternatives, the most profitable concepts. For example, reservoir development related to a SPAR or a TLP platform implies a different amount of investments because of different costs of construction, transportation, and installation. Another example of concept evaluation can be related to the comparison between construction or renting of an FPSO. While the construction scenario characterizes a large amount of Capital Expenditures, the renting one determines lower CAPEX but additional and periodical costs for the leasing of the vessel during the whole project lifecycle. NPV evaluation of these scenarios allows the management to choose in which development concept to invest.

In addition to the concept evaluation, many other variables influence the cash flows related to a project. These variables do not regard only reservoir characteristics which define the field production, but also the duration time of all the activities involved in the project, the cost of abandoning the field, the discount rate considered by the company and, one of the most important, the price of oil and gas.

A model based on the probabilistic approach and Monte Carlo's method is used to perform a more significative evaluation of NPV. Many variables and relative uncertainties, from different classes such as Production, Financial, Temporal and Economic, are used in the model to estimate projections of future cash flows in terms of costs and revenues during the entire lifecycle of the project.

The variables, however, are characterized each one by different uncertainties which determine a particular range of variability. Implementation of this variance is then necessary for the model and it is done by applying specific ranges and probability distributions that describe better the variables' behaviour. There are five main probability distributions used in the Oil and Gas Industry (in order of importance): Gaussian or Normal, Triangular, Uniform, Lognormal and Exponential (discussion with Ing. De Ghetto). For thesis purpose, however, the model integrates only Gaussian, Uniform, and Triangular distributions.

All the variables can be divided mainly into two categories. One related to the generation of revenues and one related to the generation of costs. The category of revenues contains the following classes and variables:

- ❖ **Production**
  - Rate of oil production per well
  - Number of wells
  - Yearly decline in production
  - Gas production from the oil estimated through the gas – oil ratio (Rs)
- ❖ **Economic**
  - Oil and Gas price
  - Inflation
- ❖ **Temporal**
  - Total years of production
  - Years of production at the maximum rate (plateau rate)

- Starting year of the decline in production

Most of the variables present in the Production and Temporal classes depend on the evaluated characteristics of a discovered reservoir. Its quantification and properties evaluation, investigated through exploration techniques such as seismic and drilling, help in determining reasonable ranges for the production rate and relative percentage of decline, number of wells and production of the expanded gas from the oil. Total years of production and plateau are assumed fixed in this model because based on the production rate evaluation. The range of the variables and the applied distribution here are determined by the applied technique of evaluation, the expected accuracy of the data, the interpretation of the experts and eventually by the probabilistic approach. In case of poor quality of the data, derived from the acquisition phase, a bigger range of data is set and several probability distributions are employed in order to improve the final evaluation.

The Oil and Gas price estimation instead, is based on the different benchmark indices and adjusted by the projections performed by the production countries and/or Institutions such as NYMEX (New York Mercantile Exchange), EIA (Energy Information Administration) and OECD (Organization for Economic Co-operation and Development).

The first step of Revenues estimation of a project is shown in *Figure 1.1*.

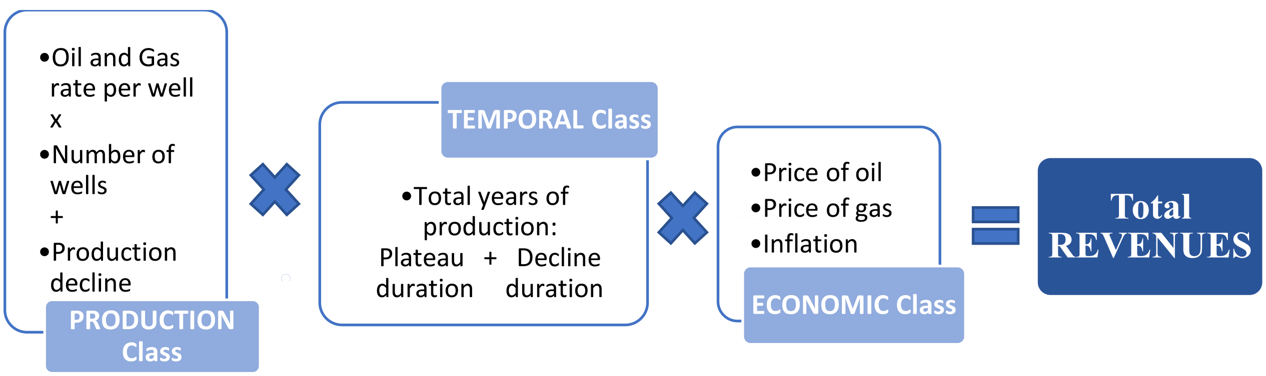


Figure 1.1 Combination of the revenue category's classes for the calculation of the Total Revenues expected from the project
**Probabilistic definition, with range and distribution curve, of most of the variables*
***Inflation influence the Revenues values relative to different years*

On the other hand, the cost category consists of the following classes:

- **Economic**
  - Capital and Operating Expenditures (CAPEX & OPEX)
  - Annual rent of the surface occupied and used for production operations
  - Abandonment costs
  - Cost faced during the delay of the completion
  - Cost of expected Workover
- **Financial**
  - Inflation

- Government take or Taxes

- ❖ **Temporal**
  - Duration of the development and completion of the production field
  - Delay of the field completion

The variables inside the Financial class and the annual surface rent expenditure, are defined as fixed because small or no variability is assumed to affect them as they are normally established in the contract relative to the hydrocarbon production between the Government and the Oil and Gas company.

The Capital Expenditures (CAPEX) is a class of costs related to the acquisition, transportation, and installation of all the elements necessary to enable the productivity of a field based on its type. It represents the initial and highest investment faced by a company. Offshore fields are characterized by more cost elements than onshore ones due to the complexity of the transportation and installation of the structure and equipment. The same considerations are valid also for the drilling operations, which costs are also accounted for in this class. Based on the influence of each element on the total cost of the class, it is possible to define a range of values and impose a probability distribution, which typically is triangular (discussion with Ing. De Ghetto). The Operating Expenditures (OPEX), which instead is related to the class of costs related to the hydrocarbon production activities, is defined based on the same logic applied to the Capital Expenditures.

The duration related to the field development and the delay related to it are normally defined based on the experience of experts (companies and contractors in the oil and gas industry) and past similar projects. Accurate evaluation of both durations is hard to be achieved because of the occurrence of unpredictable events during the project lifecycle. These time variables, however, are integrated inside the mathematical model in an independent way and are defined, based on the data available from previous projects combined with experts' knowledge, within a range in years for the project development and a range in months for the delay. For these variables, the characterizing distribution can be chosen based on the expected occurrences of the changes affecting both the time development and the delay.

The relationship between the Capital Expenditures and the time is also considered independent. In order to decrease the complexity that they can generate if the dependency is allowed, the CAPEX is divided by the defined duration for the field development and completion and accounted monthly. The monthly cost of the delay, instead, is accounted as a percentage of the monthly CAPEX based on the expected additional costs and it is imposed by the user in the model.

The time of the project development and delay are also independent with respect to the production time. In fact, the fixed value of production years, defined in the model, does not change with respect to probability distribution applied to the variability of the delay and field development time.

Visual representation of the total costs estimation is represented in *Figure 1.2*.

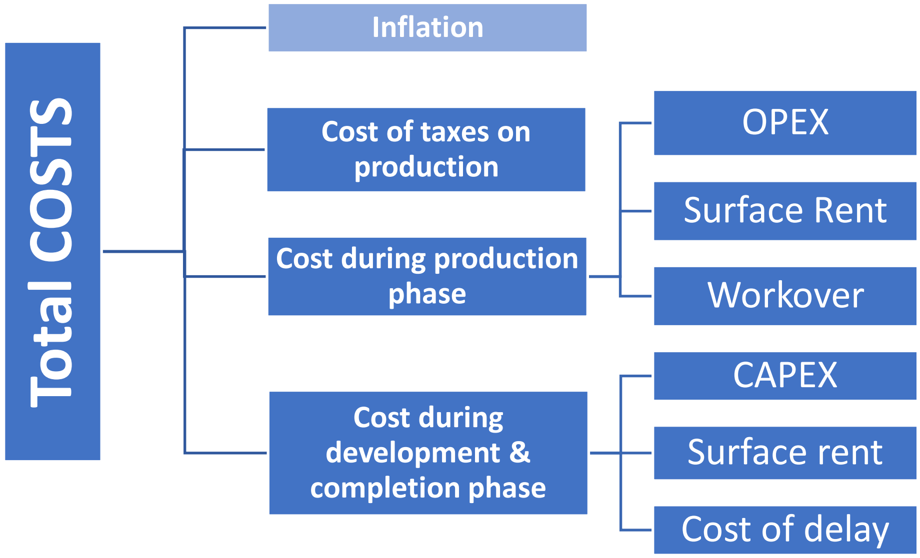


Figure 1.2 Total Costs expected from the project, relative to the different classes of cost
**Probabilistic definition, with range and distribution curve, of most of the variables*
***Inflation influence the cost values relative to different years*

The Net Cash Flow (NCF) determined by the difference between revenues and costs, for each year in the imposed time characterizing the project lifecycle, is discounted based on a percentage declared by the user in the model. The discounting process is necessary for the valuation of the projected cash flow to the present value of the money in order to estimate the real value of the profits with respect to the faced investments in the first phases of the project development. *Figure 1.3* shows the final steps necessary for the probabilistic NPV estimation.

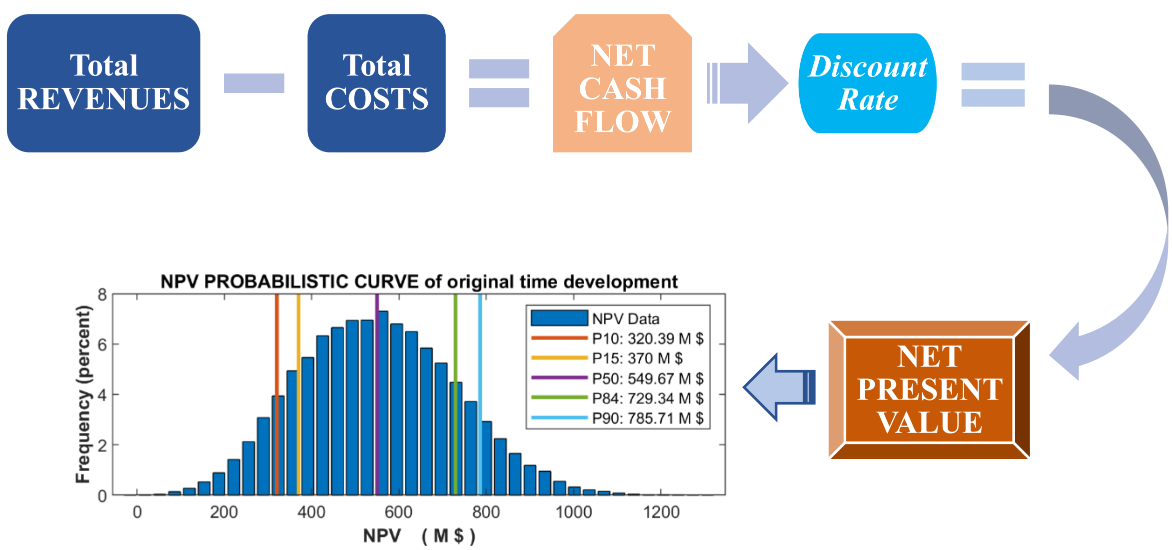


Figure 1.3 Final determination of the Net Present Value as a probabilistic curve

The model performs an additional simulation for the NPV estimation relative to a longer period of development. The imposed variables do not change in this new simulation, except for the duration of the development time, which is increased of one year. The results, therefore, are necessary for the comparison of the profits, generated by the project, related to two different periods of development. These results allow the consideration of alternative project concepts which, despite the longer time, the development phase can cost less.

This dissertation will not discuss the natural environment, Health and Safety, management and social uncertainties that are related to a petroleum field development project planning because their consideration should be taught after the achievement of a robust model and valid approach able to evaluate the potentiality and benefits of an upstream field development project design. Once the project's main variables are well defined in terms of uncertainty, these additional elements and their respective uncertainty have to be considered and implemented in the overall project's perspective.

1.5 Literature review and Limitations

A high number of theory books and published works are available regarding the risk analysis for field development project evaluation as well as on the optimization approaches applicable in the oil and gas field. However, only a limited number of publications focuses on uncertainty and relative distribution estimation. A reason related to this problem is the unavailability of data related to the projects' elements cost, which are protected by confidentiality, and the different methodology applied for the classification, evaluation, and estimation of the different variables involved in a petroleum project by the companies of the oil and gas industry. Of course, many companies, like Eni, started years ago the implementation of the probabilistic approach to the evaluation of variables such as economics and reserves quantification through complex models which are not shared.

Starting from the theoretical sources treating most of the variables connected to a petroleum project that I considered in my dissertation, it was possible to move on to research papers which analysed them more in detail. The result of many works and papers which investigated single variables or group of them, however, did not help for their characterization in terms of probability distribution necessary for the objective of my thesis. For this reason, assumptions based on the advice of a petroleum industry expert combined with the available information found from the sources were done for some variables like in case of the CAPEX, Economic indicators, and production timing variables. For some other variables instead, researches applying probabilistic approach were very helpful like in case of the Reserves quantification, duration, and delay of the field development.

A careful selection of these papers, combined with the advice of supervisor prof. Carpignano, prof. Gerboni and field experience of the co-supervisor engineer Giambattista De Ghetto, was done in order to localize the most meaningful information necessary to meet the thesis' objectives of probabilistic characterization of the variables and probabilistic evaluation of a project's profitability.

1.6 Structure of the report

In the current thesis, there are several chapters. Chapter 2 relates to the Framework of Petroleum Industry where theoretical information about the Petroleum Upstream sector is given. The Framework is analysed in its part of Project Management, Lifecycle of Petroleum Project, Petroleum Contracts and Negotiations.

Chapter 3 outlines the Key Business Indicators and the main Economic variables concerning NPV. They are defined, at first, from a theoretical point of view and then specific analysis is done to estimate better their uncertainty and relative distribution curve. A starting point of this specific analysis is based on the gathered data of the main petroleum companies found on papers and internet. The main variables that are taken into account are Project and Production Costs, Production Rates, Petroleum Price and Project development Duration.

Chapter 4 regards the Probabilistic approach used for the NPV estimation through the application of Monte Carlo's method. Theory and application of this method to a structural equation system are discussed as well as the assumptions used for this approach. The chapter also concerns about the MATLAB software used for designing an interface and simulation program able to estimate the NPV distribution curve from input data inserted by a user. Results of tests are discussed to show the sensitivity and robustness of the own written algorithm. In Chapter 5 several Case Studies are described and relative results are analysed. The data is analysed and set inside the simulation program following evaluation of uncertainties and distribution curves criteria, discussed in Chapter 3, to perform NPV distribution curves. Results of different scenarios are compared between them and with the real result. Final discussion determines the positive or negative achievement of this dissertation's objective. Conclusion on the work and final remarks on the study and results are present in Chapter 6.

Chapter 2 Framework of Petroleum Industry

The objective of this chapter consists of providing a general overview of the Petroleum Industry and its framework regarding the Project Lifecycle. Additional description was addressed of the Upstream sector, and specifically, in its phases of Project Management, Petroleum Contract and Negotiations. These elements help in understanding the relationship and dynamics between the Country, in which the resources are present, and the interested petroleum company. Description of the project characterization and evaluation processes allow understanding the effort faced by the companies in choosing and developing the right concept relative to the following project development.

2.1. Life Cycle of Oil and Gas Project

The Life Cycle of a Petroleum project consists in well-defined phases which interact between them and where a different set of activities take place in an interval of time. Each of these stages has fundamental importance to meet the ultimate objective of every company: make profits. According to (Tordo, Fiscal Systems of Hydrocarbons: Design Issues. , 2007), Petroleum project consists of the following main stages and can be described as in *Figure 2.1*:

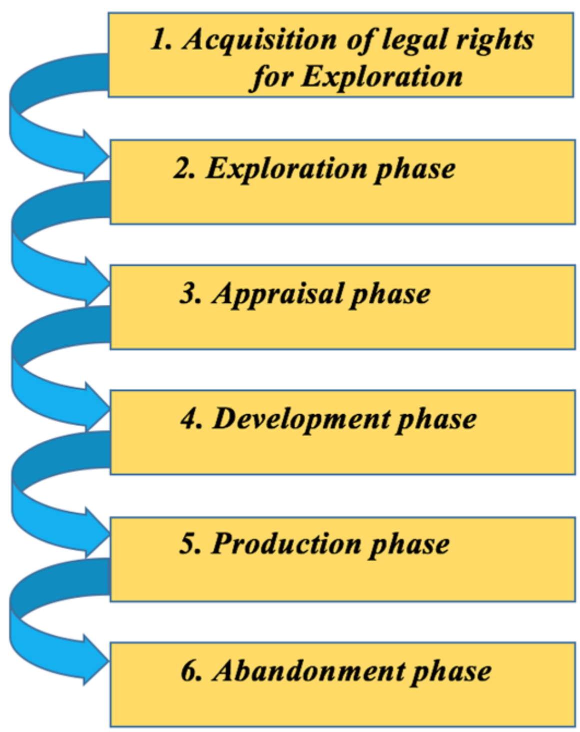


Figure 2.1 Life Cycle of petroleum projects

- ***Acquisition of legal rights and Exploration.***

Before any type of survey in the interested area, the licensing phase takes place as the first step. After the firm acquires the legal rights for exploration from the host government, it can proceed with geophysical – geological surveys to locate oil and gas reserves. Exploration wells are also drilled in the area to collect important sample cores needed to evaluate rock and fluids properties. All these data, gathered from seismic surveys and core samples, are fundamental to prove the existence of a reservoir and to estimate the amount of hydrocarbon that can be produced and with which mechanism. The only reservoirs that are economically viable can justify further investments to collect more data needed also for the next stage.

- ***Appraisal.***

Additional wells are drilled to gather more information about the reservoir and the field. This information is necessary to decrease the uncertainty and exclude possible scenarios that can lead later to financial losses. Furthermore, studies of field development planning are done to estimate the total development cost needed for the next phase. Appraisal phase can last for many years and have a high cost, but it is necessary to answer the important question about the financial exposure of the company and its later reward in terms of profits.

- ***Development.***

Once a selected development plan is approved, contractors are contacted for the bid. The designated contractors have then the task of developing the field by drilling the production wells and constructing the surface facilities. Based on the complexity of the project and the time needed to complete it, the development phase represents the most critical stage among the others. Construction of facilities and drilling operation of the production wells are the major and highest cost faced by a petroleum company. Delay or safety issues during this phase can cause severe financial problems and lead to bankruptcy.

- ***Production.***

The hydrocarbons are produced from the wells and activities of monitoring – interventions are done periodically to maintain continuous production. Depending on the field and reservoir size, production activity can extend up to 40 years. Performance of the reservoir is continuously assessed to perform the best production trend which typically is represented by the curve in the *Figure 2.2*. Factors as oil price, technology, political and others, can modify the trend of the curve in the *Figure 2.2*. Same reasoning regards the plateau rate which can change in time and is closely related to the reservoir properties as well as to the capacity of the field production facilities. All the petroleum fields at a certain point will start to have decline in production, till when the economic limit is reached and abandonment phase takes place (Höök, Davidsson, Johansson, & Tang, 2013).

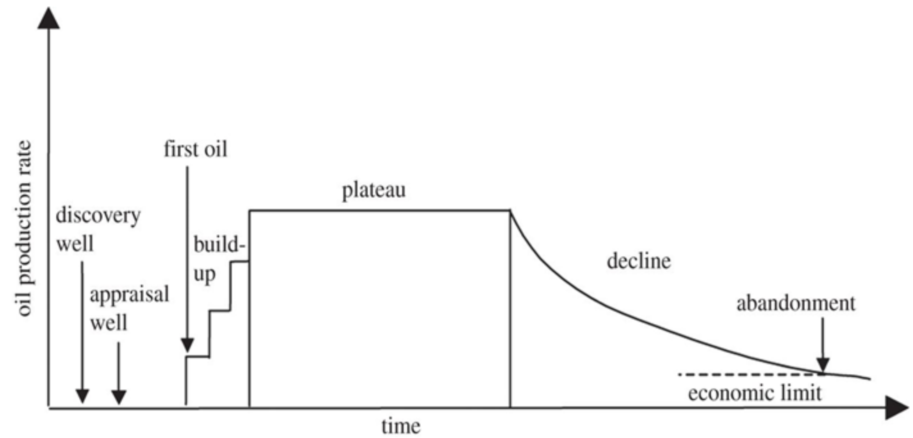


Figure 2.2 Representation of theoretical production rates during life cycle of an oil and gas (Höök, Söderbergh, & Jakobsson, 2009) field

- ***Abandonment.***

When the field production decrease at low levels, profits follows the same trend. Once the economic limit is reached, which means that revenues get closer to the production costs, abandonment decision is considered. During this phase, the production facilities are removed and wells are sealed to meet the environment safety criteria imposed by the government.

2.2. Petroleum Exploration and Production Investment Rights

Although the Government, in most of the cases, represents a powerful authority related to the oil industry, ownership regimes can be still classified in four main categories (Bret-Rouzaut, Favennec, & al., 2011):

- Ownership by accession
- Ownership by occupation
- State discretion
- State ownership

In the case of Ownership by accession regime, the legal right on the property of the owner is extended from the surface to the subsurface which includes also the presence of mineral resources as hydrocarbons. However, this kind of regime is regulated by the State which has the duty to guarantee security and resource preservation. This reality is present only in the United States.

Ownership by occupation, instead, regards the situation in which legal right on a land and relative resources is exerted by a new occupant. Nowadays, this characteristic does not apply anymore for hydrocarbons.

The next two regime categories of State discretization and State ownership, have in common the characteristic of direct ownership by the State of all-natural resources but differ in the types of contract and agreements that are made between the Government and a private company.

Following and summarizing the previous classification of ownership regimes, except for the United States of America, governments is the only authority which has jurisdiction over petroleum resources present inside the own country. To produce the national petroleum resource, the government has four possibilities (Tordo, 2010):

- develop resources themselves
- pay an oil company to develop and produce the resource for a fee
- sell legal rights to develop and produce to an oil company
- use a combination of the previous possibilities

Developing the resources by themselves, investments for exploration and development rely entirely on the government. Normally almost all the countries have their national oil company which has the duty to search and to develop the petroleum resources. Due to high risk, high investments required, lack in technology and qualified personnel, most of the times governments make agreements with oil companies which carry all or the major part of the exploration and development costs.

According to Tordo (2010), there are two main categories of the petroleum exploration and production rights allocation. The systems can be:

- *open-door*, where International Oil Companies can express interest in a specific area and negotiations about can be done anytime.
- *procedures licensing and auctions*, which are defined by the government through a procedure of bidding where the highest bidder acquire the legal right for exploration and development of an area defined previously by the host country.

Every country has its own petroleum law of which principles are set inside the country's national legislation or, in rare cases, constitution. The main purpose of these principles is to regulate and define the policy adopted by the government, as well as characterize the terms regarding contracts and fiscal tools between the government and private companies. Petroleum law represents the instrument used by the government to gain the right reward regarding the production of its own natural resource (Bret-Rouzaut, Favennec, & al., 2011). For a more detailed analysis on the Licencing policy that is adopted by different countries, see Fiscal Systems of Hydrocarbons: Design Issues (2007) and Petroleum Exploration and Production Rights (2010) written by Silvana Tordo.

Before the Exploration phase, negotiation between contractors and government takes place, based on the country's petroleum law. When an agreement between the contractor and government exist, a contract is signed. The contractor can represent one single company or a group of companies. If the contractor is a single company, then a contract is established only between the government and the petroleum company. Otherwise, additionally to the contract, joint operating agreement (JOA) exists between the petroleum companies that are involved in the exploration, development, production phases and which determine them as a joint venture. Decisions and influence of each firm, in the case of joint venture, depends on the stake in partnership determined by the JOA. Additional information about Government, IOCs, NOCs and their relationship in the petroleum business, see the book The Global Oil And Gas Industry Management, Strategy & Finance written by Andrew Inkpen and Michael H. Moffett.

2.3. Contract Types of Petroleum Exploration and Production

According to Johnston (2003), all the contract types can be divided basically into two main groups: concessionary system and contractual system. The major difference between these two systems consists of the legal ownership of the minerals that in this case regards subsurface hydrocarbons. There are cases in which production – sharing contracts (PSCs) are identical to the concessionary system but because of the ownership status of the hydrocarbon source, terminology changes. In the

Figure 2.3 of the next page shows the general classification and division of the Petroleum Fiscal Regimes.

The concessionary system indicates that the petroleum company owns legally the oil and gas that produces and the production installations. This implicates that only the oil company deals with the risks and costs related to the project from its first phase of exploration to the last one of abandonment. In this case, the government uses fiscal tools present in the country's law to gain profit from its hydrocarbon concession through taxes on profits, surface fees, bonuses and royalties on production.

Contractual system, on the other hand, relates the ownership of the petroleum resources to the host government which also contributes to the project's risks and costs. The contractor, which has to produce the resource, is paid with the share of the produced oil or with the profit deriving from production or with cash and can recover proportionally part of the costs related to the exploration and field development project based on the limits established in the contract. The differentiation between the Service Agreement and the Production Sharing Contracts (PSCs) is based on the type of compensation from the host government. Remuneration in cash normally is related to a flat fee that defines the work done by service companies. Specific attention regards the Risk Service, which differs from PSCs and is included in the Service Agreements group because in this case the oil – service company is not paid in a share of produced oil but in a share of the profits. PSCs instead, regards all that contracts involving remuneration in terms of shared produced oil or shared oil profits. All the contracts include also taxes related to all kind of revenues that companies earn from the project (Bret-Rouzaut, Favennec, & al., 2011). For more details and analysis of contract types and fiscal regulation see Oil and Gas Exploration and Production Reserves, costs, contracts by Nadine Bret-Rouzaut (2011), International Exploration Economics, Risk, and Contract Analysis by Daniel Johnston (2003) and Petroleum Exploration and Production Rights (2010) by Silvana Tordo.

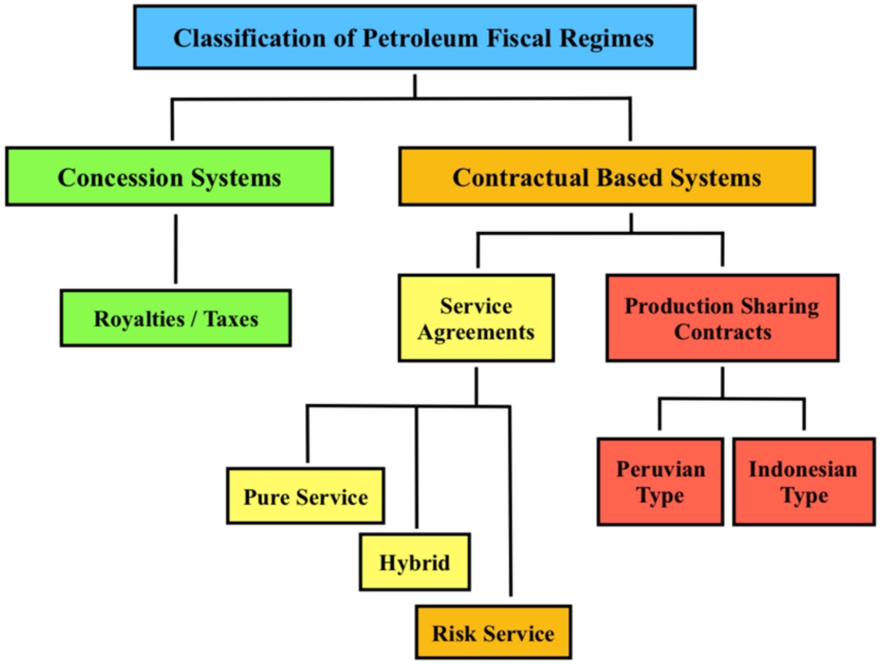


Figure 2.3 Classification of Petroleum Fiscal Regimes (modified after Johnston, 2003)

2.4. Project Management in Upstream sector

Nowadays, project management is of primary importance in the petroleum industry. Complex projects are determined by a high number of variables of which uncertainty impacts the related development process and its relative time. According to (El-Reedy, 2016), project management can be defined as the sum of all processes of controlling, organization and planning of all the resources involved in the development, in a specific period, needed to meet established business targets. Thereafter, this sum of processes involves interaction and cooperation between specialists of different disciplines.

After the agreement between oil firm and host government which results in the acquisition of legal rights for exploration, search for a petroleum reservoir is done through geological and geophysical studies of the interested area by the oil company. During the exploratory phase, all the gathered data, from seismic survey to core samples, is analysed to find proves of a hydrocarbon reservoir that has a high commercial potential. The role of the geological stage is fundamental in defining the probability of a positive discovery and the relative development costs. In case of a discovery, reference to geological scenarios combined with analogies of existing fields helps to define, approximatively, possible field designs and the relative capital and operating costs needed. The reliability of these analogies and the premature definition of the development characteristics such as costs and capital depend on the completeness and availability of a reliable database used for comparison. When all these initial studies indicate a high potential of the discovery and good perspectives of profits, concept definition of a petroleum project starts (Bret-Rouzaut, Favennec, & al., 2011). The following *Figure 2.4* shows the phases of the development concept of a project life cycle.

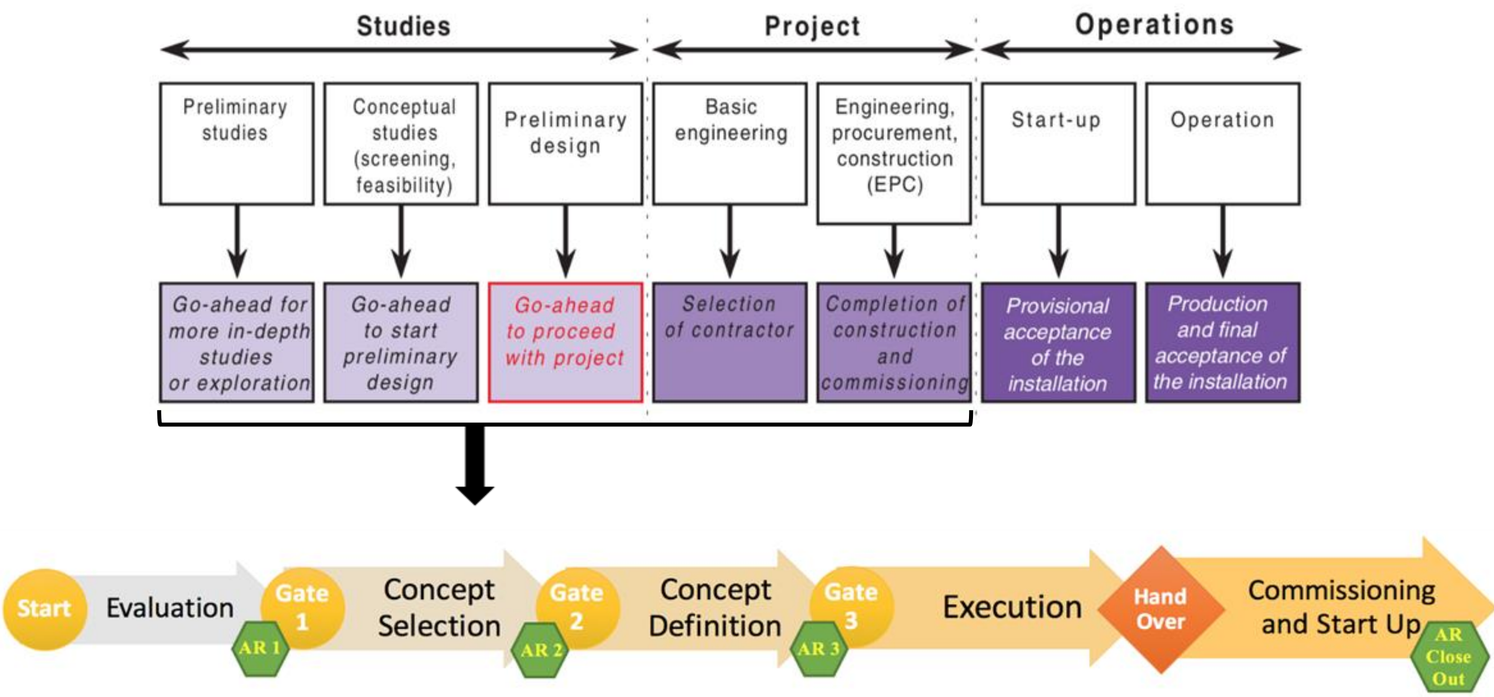


Figure 2.4 Development phases of a project (Bret-Rouzaut, Favennec, & al., 2011) and Stage and Gate Process of Oil and Gas Development Project (Workshop Oil and gas Development, Giambattista De Ghetto, 2017)

As we see in *Figure 2.4*, the Project Life Cycle is composed by many stages and the first ones comprised in the studies' part can be expanded in a more detailed process of stage and gate. Only important projects go through all the stages while small projects are characterised by fewer phases and gates. Each advancing phase of an upstream projects takes additional time to be accomplished due to the necessity to enhance the economic value of the project itself by considering and reducing the uncertainties of the uncertainties involved. The summation of all the durations characterizing the phases involved in the upstream project, from the official start to first oil, is on average seven years. This total duration can change based on the category of the project.

Categorization of a project anticipates the real starting of a project and is based on two main characteristics: total cost equity and level of complexity. The level of complexity is determined by analysing many technical, economic and environmental aspects related to the project. Meanwhile, the variable of the total cost of equity and the economic threshold change from company to company. These combined characteristics define four classes of projects (in ascendant importance):

- Marginal
- Routine
- Significant
- Strategic

Based on the category of the project, additional resources to the invested ones are dedicated. The four classes are classification is shown in the following *Table 2-1*.

Table 2-1 Categorization of different project classes (Workshop Oil and gas Development, Giambattista De Ghetto, 2017)

CAPEX – Economic Threshold	Level of Complexity		
Million ($)	**Low**	**Medium**	**High**
> 300 - 500	**Significant**	**Strategic**	**Strategic**
> 100 - 150	**Routine**	**Significant**	**Strategic**
> 50	**Marginal**	**Routine**	**Significant**
< 50	**Marginal**	**Marginal**	**Routine**

During the Evaluation or Preliminary studies phase, available data and contractor's experience is used to perform preliminary reservoir scenarios, economic evaluations and define initial development concepts. The main objective is to define the capital costs within an accuracy of 40%. In this way, the value of opportunity and its alignment with the business strategy is assessed, helping management section in the decisional process of further development concept definition or abandonment. In this phase normally, many marginal projects are stopped.

In the following phase of the Concept Selection, exhaustive studies are done to increase the accuracy of capital costs evaluation to 20%. Alternative development concepts with possible technical variants are considered, along with the relative costs, risk analysis, economics and realization difficulty, in order to find and select the 'final concept' which better fits with the business strategy.

Concept Definition phase has the purpose to define the selected development concept in more details and produce an associate project execution plan. Better definition in this phase will result in a decrease of the capital cost evaluation error in a range of 15%. This is a key phase which allows the investors, previous a careful analysis and understanding of all operational areas, to decide either to authorize the execution of the development project or reject it because the uncertainty doesn't meet the imposed and acceptable level. Another important characteristic of the Concept Definition phase is that being the last stage before Execution one represents the last possibility of any kind of major changing of the selected concept. Therefore, before any conclusion and decision, all the operational areas of a project are assessed to be coherent and characterized by validated technical considerations (Bret-Rouzaut, Favennec, & al., 2011).

These initial phases of evaluation, selection, and definition of development concepts are fundamental in the project life cycle because represent the time where there is a high potential to enhance projects' value. Following phases of Preliminary design and Execution offer low perspectives of increasing accuracy and reducing risk evaluation in costs, which means the low potential to increase value. The trend of the accuracy of costs estimation during the project lifecycle is shown in *Figure 2.5*.

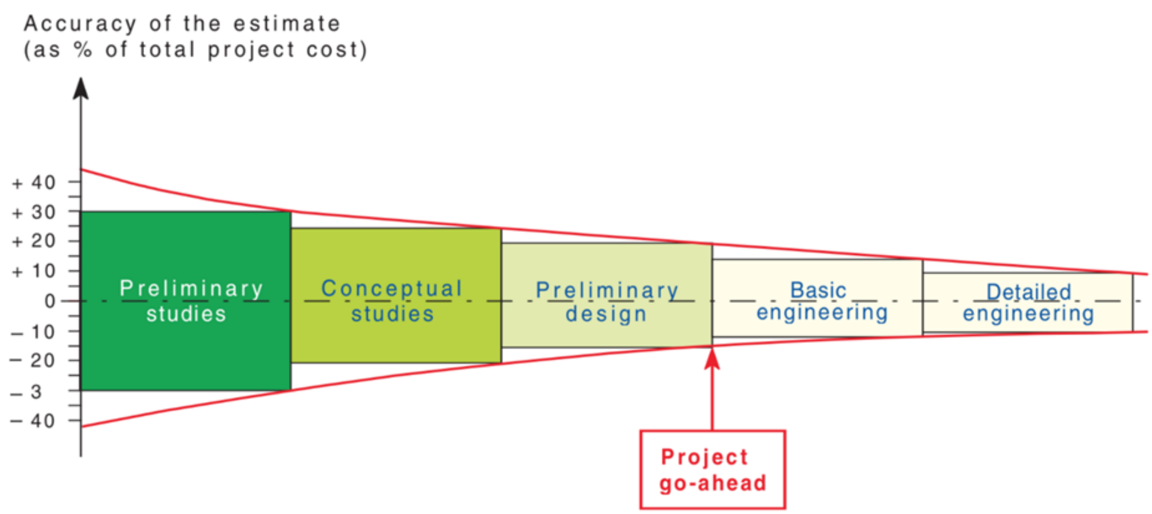


Figure 2.5 Trend of accuracy of costs estimation during Project Lifecycle (Bret-Rouzaut, Favennec, & al., 2011)

The Execution phase regards all that characteristics and information about Engineering, Construction, and Installation that are needed to be evaluated to achieve a fully operating system inside the established limits of time, costs and quality targets. Only when the asset is ready for production, Hand Over takes place and Project Start-Up begins. According to (Bret-Rouzaut, Favennec, & al., 2011), the Hand Over is an important step in the transition to the next project phase and represents the agreement between the team responsible of the project conception, the future team that will be in charge of the project and contractors. Positive agreement between these parties determines the higher chance of a successful project because involves the interaction of the parties among project choices, technical details, and optimization considerations.

Another important characteristic, related to the Project Life Cycle, is the presence of Gates and Assurance Review Team in a stage – gate project management process as shown in *Figure 2.5*. The Gates represent the final assessment at the end of each phase where the investors (project management section) perform the decisional process by applying precise rules to ensure uniformity of evaluation of various projects. At the end of the project's concept evaluation, following decisions can occur:

- to proceed: the project meets the approval criteria, so proceed to the next phase.
- to rework: additional work and revision must be done to meet the imposed requirements.
- to hold: the project is hold for future development because not immediately attractive.
- to change: a change of the level of project's scope can increase its attractiveness.
- to kill: the project does not meet the approval requirements and will not in the future.

Most of the times, an additional independent team, identified as Assurance Review Team, is an integrated part of the Gate's task by performing an additional formal verification of the project at each phase. The purpose of this team, which does not take part in the development concept, is to identify possible weaknesses of the results presented at the end of each stage and propose improvements. An additional perspective on the development concept, made by high qualified and multidisciplinary team, supports a better evaluation process which improves the resulting accuracy.

For more detailed information about characteristics of oil and gas projects, see Project Management for the Oil and Gas Industry: A World System Approach (2013) written by Adedeji B. Badiru, Samuel O. Osisanya.

Chapter 3 Petroleum Project – Conceptual Stage: Economic Evaluation and Uncertainty

As mentioned in Chapter 2, the Conceptual Stage of a Petroleum Project comprises the Evaluation and Preliminary studies where proposals of project development along with the respective feasibility studies allow to perform a rough evaluation of the possible incomes and costs. Further studies perform reduction in uncertainties, consider alternative proposals and try to anticipate – resolve possible future problems related to the Petroleum Project Lifecycle.

3.1. Economic Evaluation – Key Indicators

The main purpose of the Economic Evaluation is to help the decisional process by identifying the best development option. Technical expertise and data from different sources, along with assumptions, are used with modern software to calculate indicators that allow to compare and evaluate proposals in profit terms. Economic indicators are classified into two categories based on the consideration of the time value of money. Indicators such as Net Present Value (NPV), Internal Rate of Return (IRR) and Profit to Investment Ratio follow the discounted method while Break-even Analysis, Sensitivity Analysis, and Exposure Point are not discounted (Yas, 2010).

The NPV depends mainly on the net cash flows and the discount rate. However, the only information available for an investor at the appraisal moment is the present net cash flow. Subsequently, the main responsibilities of investors during the estimation of the NPV consist in the estimation of:

- the future net cash flows
- an appropriate discount rates

In order to assess the profitability of a new oil and gas project, after assessing its relative costs and revenues, estimation of the cash flow in the different periods of the project's life has to be analyzed in order to compare future revenues to their present value. To convert the projected cash flows to a present value, a discount factor is used in the equation:

$$Present\ Value = \frac{Future\ Value\ (t)}{(1 + Discount\ Factor)^t}$$

Equation 3-1

The optimal discount rate adopted for the NPV calculation is the weighted average cost of capital (WACC) since it accounts for the average risk and the total capital of the firm (Vernimmen, 2005).

The WACC is adopted by firms having capital components with versified risks, it is obtained by weighting each component of the capital to its corresponding weight and calculating their average. It is a function of the costs and market values of both debts and equities and the tax rate.

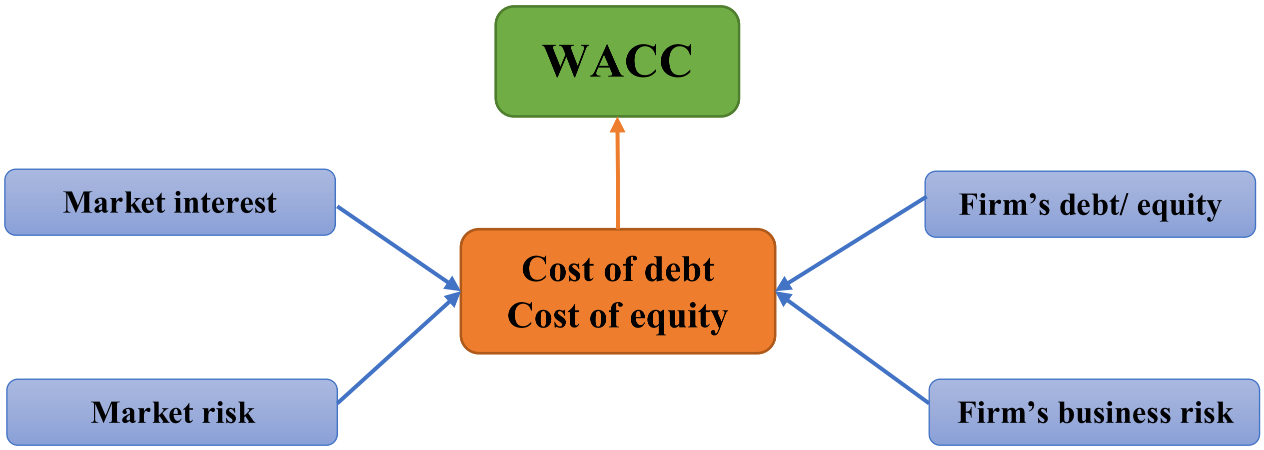


Figure 3.1 Flow chart representing the parameters behind the estimation of the weighted average cost of capital.

On another side, the fact that the NPV is a function of future projected values makes its estimation subject to uncertainty, whereas the decision making becomes highly flexible for companies on whether to sell, to invest and wait and see or to stop the project (Walters & Giles, 2000).

It can be also noted from *Equation 3-1* that a high value of discount rates implies a poor NPV, and vice versa. For this reason, companies tend to increase the discount rate to account for uncertainties. (De Ghetto, Workshop Oil and Gas Field Development, 2017).

The base element of the investigation of any cited indicator is the cash flow that is generated by the costs and revenues during the Petroleum Project Lifecycle. Especially for the discounted indicators, the time has an important effect on the monetary value which is affected by many factors related to a specific period. Different periods may imply different conditions and degree of influence. This dependence between monetary value and time imply research for a better evaluation of the current and future expected occurrences, to use more reliable and realistic assumptions that will produce better results. Some of the variables which more impact the economic indicators from a monetary value and time point of view are:

- Costs (Exploration, CAPEX, OPEX, Taxes)
- Reserves estimation and Productivity (Flow Rate)
- Project Planning
- Oil and Gas Price

In the following subchapters, each of these variables will be defined and decomposed in their basic elements. All the components and their relative uncertainty will be analyzed in detail to define a better estimation of the variable. This operation is necessary to build and characterize the variables' distribution curve which will be implemented in a model to estimate economic indicators with more accuracy.

3.2. Cost Definition

Production costs in the Oil and Gas industry may be categorized in different ways. The most general characterization follows the different phases of the project. According to Inkpen and Moffett (2011), all the costs are divided according to the stage of the petroleum project lifecycle.

Exploration and appraisal drilling constitute the so-called pre-development costs. These costs are based on fixed annual budget and are a function of the geographical and environmental conditions which characterize high-risk uncertainty; for example, unsuccessful explorations may cause dramatical economical losses from $5 to $20 million per site.

However, the production, development, and abandonment costs are classified between capital and operating costs. The capital expenditure, or CAPEX, extends over the first years and the last year of the project. The operating costs or OPEX, on the other side, include the cost of all the operations leading to production. In the following, a detailed explanation of both CAPEX and OPEX is given.

Successful exploration and positive decisions of the company to proceed further in the project lead to the development stage that includes all the costs related to the installation and construction operations needed to produce and transport the discovered resource. These costs are classified in the accounting as capital expenditure (CAPEX). Similarly, to the previous stage, the annual budget is defined for each project but in this case, it is not a fixed amount.

The real spending can vary from the budgeted one because of the dependency of the costs on the project's characteristics such as size, field location, operational difficulties, etc. Especially factors like availability of materials, design changes and quality of the service companies' interventions impact heavily the real costs but since the production of the first oil in time is a critical requirement, strict limits on developing budget are avoided.

The last main and important factor of costs related to a project is related to the Government Take under forms of taxes, royalties, fees, etc. An amount or percentage of the profits in terms of money or production, based on a defined contract, is taken by the Government. Different countries are characterized by different imposed tax percentages (Inkpen & Moffett, 2011).

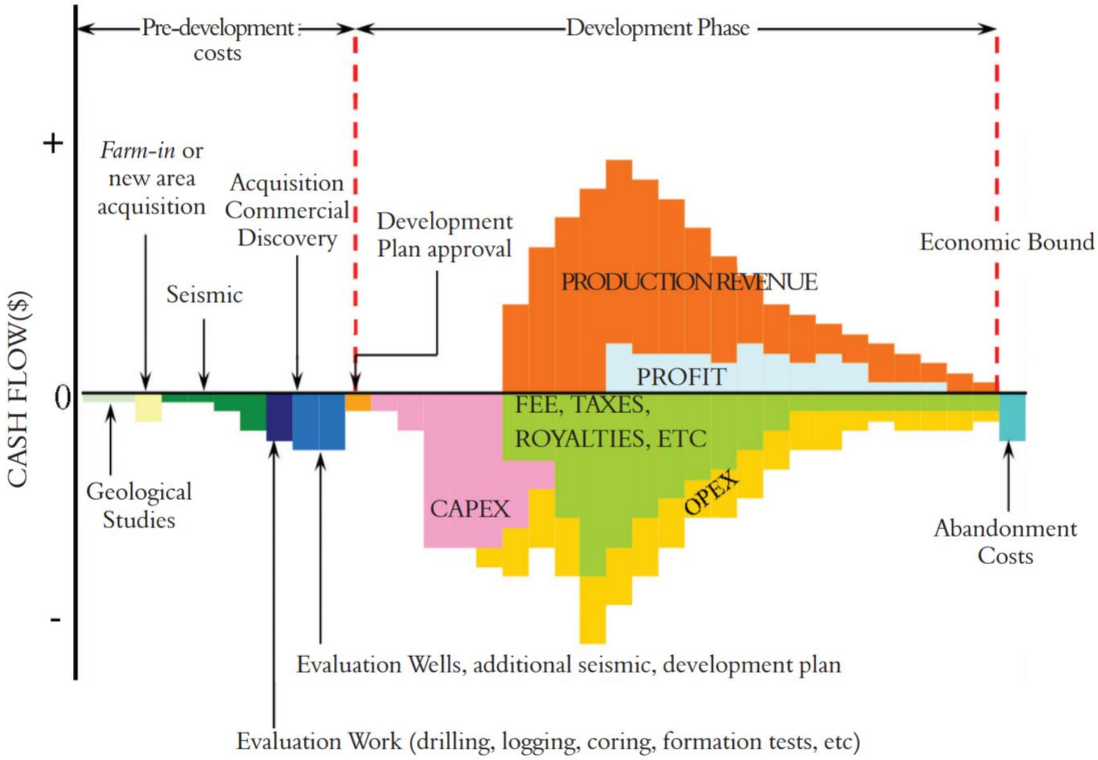


Figure 3.2 Example of a typical cash-flow of a project based on the Brazilian Fiscal System (Suslick, Schiozer, & Rodriguez, 2009).

Figure 3.2 is a general illustration of the cash flows of an oil and gas project; production costs are highlighted in pink (for CAPEX), yellow (for OPEX), and green (for Government take) (Suslick, Schiozer, & Rodriguez, 2009).

3.2.1. Capital Expenditures (CAPEX)

According to the definition found on the Business Dictionary, Capital expenditures are "*an amount spent to acquire or upgrade productive assets (such as buildings, machinery and equipment, vehicles) in order to increase the capacity or efficiency of a company for more than one accounting period*" (BusinessDictionary, n.d.).

Companies from different industries are not characterized by the same amount of CAPEX. In specific, oil and gas companies belong to one of the most capital-intensive industries. The reason is related to the size and executive phases of a project in the Upstream Oil Industry that can require billions of dollars of investments.

In the last five years, the fall of oil and gas prices influenced negatively the investments plans for the new projects which led to a partial cut of CAPEX by the global International Oil Companies (IOC) in order to avoid financial losses. The recent recovery of the hydrocarbon prices allowing considerations of opportunities in project development did not improve the future expectations of the industry which prefer to be cautious and conservative (Biscardini, Morrison, Branson, & Del

Maestro, 2017). *Figure 3.3* shows the trend of the worldwide oil industry capital expenditures from 2010 to 2017.

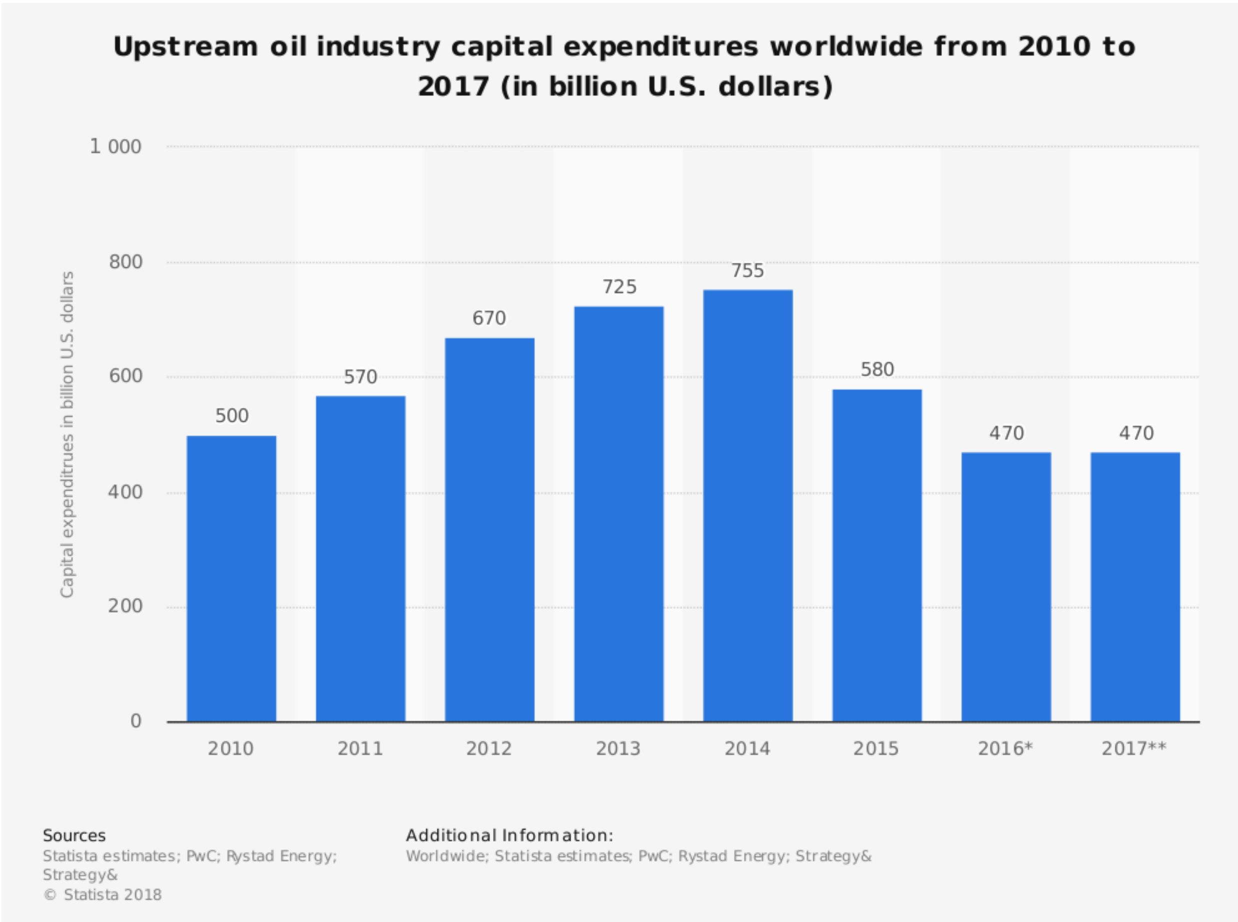


Figure 3.3 Trend of CAPEX in Upstream oil industry from 2010 to 2017 (Statista, 2018)
**2016 CAPEX estimation for the year 2016*
*** Projection of CAPEX to the year 2017*

3.2.1.1. Elements of CAPEX: Definition and Analysis

There are many elements that can be classified as capital expenditure in a project. The cash flow generated by the CAPEX along with the one caused by the Operational costs and the predicted Income are of fundamental importance for the net present value estimation. Generally, the CAPEX is defined as a unique value which is the result of the summation of all the identified elements of the category. The methods used to estimate elements of the capital expenditure and their "weights" are usually performed by an internal department of a company and can differ between companies (Emhjellena & Emhjellenb, 2001).

In general, CAPEX consists of development and facility costs and site restoration costs. Development costs are exposed once it is decided to develop the field while the restoration costs regard the last phase of well abandonment of a project. According to the general identification of the critical costs elements by Rashed (2013), they are divided in:

- Cost of the appraisal phase including drilling and testing.
- Cost of completion and equipment of production wells
- Cost of facilities such as equipment of separator, treater, storage and waste disposal system
- If predicted, also costs regarding the equipment for the enhanced reservoir recovery are considered
- Costs regarding the well abandonment and site restoration

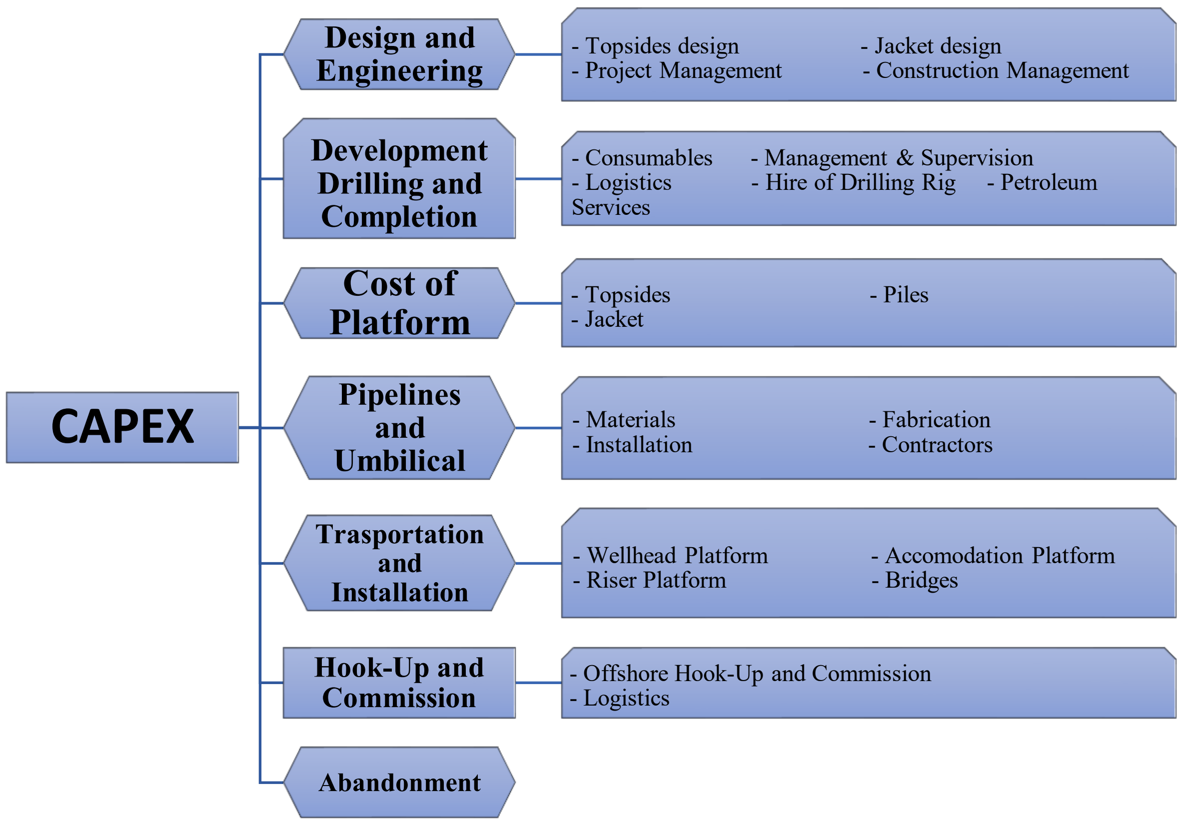


Figure 3.4 Subdivision of the Capital Expenditures in its Subclasses and Elements of costs relative to an offshore development

Analyzing more in detail the CAPEX relative to a project, it can be subdivided into many groups which account for specific elements of costs performed during the project execution. A visual representation of this subdivision is shown in *Figure 3.4*. According to the purpose of the thesis, an investigation, inside the CAPEX's sub-classes, of the cost components that mainly influence the final capital expenditure estimation is performed on the available data found on the literature and internet sources.

- **Design and Engineering Costs**

The costs associated with the design and engineering of a project can account for an average of ten percent of the CAPEX. Especially drafts and design stages have valued an average of fifty-eight percent of the engineering cost (El-Reedy, 2016). In *Table 3-1*, engineering costs are identified by the involved activities inside the phase.

Activity	**Percentage of the engineering cost**
Design and drafting	57 %
Proposal	1%
Project Management	19%
Procurement	12%
Structural engineering	4%
Project Control, Estimating and Planning	7%

Table 3-1 Example of elements inside the Design and Engineer Cost Class and their cost in percentage compared to the total cost of the class (El-Reedy, 2016).

In the Estimate Report Example (3rd Quarter of 2013) – *Table 3-2*, the available data regarding the Design and Engineering group are closely aligned with the general estimation of the percentage of engineering cost's elements present in the previous *Table 3-1* (OECD, 2018).

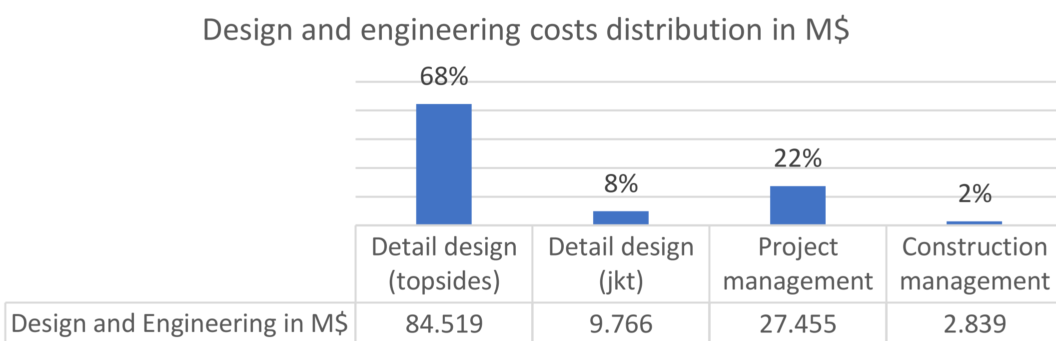


Table 3-2 Example of elements and their cost (in million dollars and in percentage) respect the total cost of the Design and Engineering category (OGDE, 2013)

Investigation and estimation of costs, regarding the Design and Engineering category, have to focus especially on the cost characterization of the Project Management and Project design activities that account both for an overall 80-90% of the total Engineering costs.

- **Development Drilling Costs**

Among the many categories of costs inside the capital expenditures, the Development Drilling represents the most important one because of the high portion of investments necessary during this phase. The elements characterizing the operations of drilling, and the related costs, are many and vary based on the location (onshore or offshore), target depth, duration of the phase, type of well, equipment costs and operational risk associated to the type of fluid present in the reservoir. Of course, additional costs must be accounted in case of mechanical problems which can stop the drilling operation to perform workovers. An example of cost breakdown relative to an offshore development well completed in 55 days (South-East Asia, water depth 70 meters) are shown in *Table 3-3* (Bret-Rouzaut, Favennec, & al., 2011).

Table 3-3 Cost Breakdown example of an offshore development well in the South-East Asia (Bret-Rouzaut, Favennec, & al., 2011)

Phase	% of total cost
Consumables Wellhead, piping, drilling bits and core barrels, mud and cement products, accessories, energy, water	34
Logistics Fixed price (trucks, aircraft, removal of drilling rig…)	8
Management and supervision Studies and project management, supervisory arrangements, geology and reservoir.	3
Hire of drilling rig Drilling contract, mobilization / demobilization of drilling rig.	41
Petroleum services Mud, cement, casing, tubing, supervision, electric logging, mudlogging, miscellaneous services, miscellaneous completion, diving team and ROV, insurance, miscellaneous equipment hire	14
Total cost	100
% of total cost	100
Duration (days)	55

The items present in *Table 3-3* are mainly dependent on two factors: time and depth. While some items' costs are closely related to the target depth to be drilled and others more related to the duration, items inside Consumables group, like wellhead, are considered as fixed costs. The Petroleum services' costs, however, even if are determined by contracts, can be considered dependent on both time and depth factors (OilScams, 2014).

Analyzing *Table 3-3*, it is evident that the total drilling cost relies mainly on two elements: Consumables and Hire of the drilling rig. To estimate the drilling costs, more detailed investigation is performed on these variables and on Completion phase.

Availability of numerical data about drilling costs, on the internet, is very limited. For this reason, additionally to the data found, some *confidential* data about Upstream costs present in the thesis of Spera (2016) have been consulted, thanks to the availability of prof. De Ghetto and Ing. Spera. The data used and analyzed in this chapter are real, but to conserve the confidentiality status, no specification of the area, contractors and company is provided.

According to the analysis of the data, conducted by Spera (2016), the cost of the drilling operations is determined based on the drilled target depth. The analysis of the costs used the following the geographical area, actualization factor, average water depth, wells and completion as inputs.

For a better investigation of the cost variable, two different categories of rig are considered: jack-up rig and floating rig. The functional difference between the considered type of rigs shown different trends of the defined cost curves. The jack-up rig, which operativity is limited to a maximum of 150 meters of water depth, determined lower drilling cost respect to the floating rig that can operate to higher water depths. In *Figure 3.5*, the data allow estimating the relative drilling costs based on the different cost curves, starting from the target drilling depth and average water depth input. The curves are defined based on the regression of the available data.

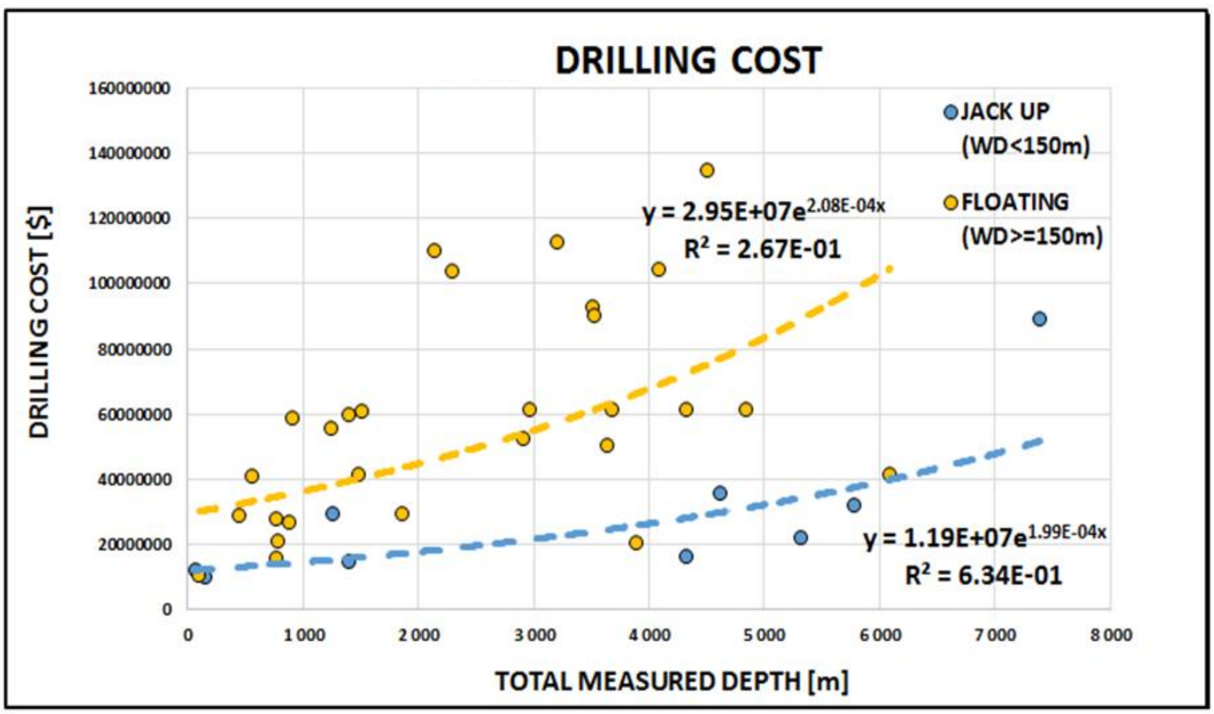


Figure 3.5 Estimation of the Drilling cost regression curve (in dollars) based on the available data of the Jack-up rig and Floating rig (Spera, 2016)

However, it is possible to apply a probabilistic approach on the data in *Figure 3.6*. Two additional curves that contain the scattered data, regarding each of the rig typologies can be defined. Between these two curves, which represent from a statistical point of view P90 and P10, a distribution curve can be applied to perform statistical estimation of the drilling costs. A triangular distribution is assumed in the following case. However, a normal or uniform distribution can be adopted as well.

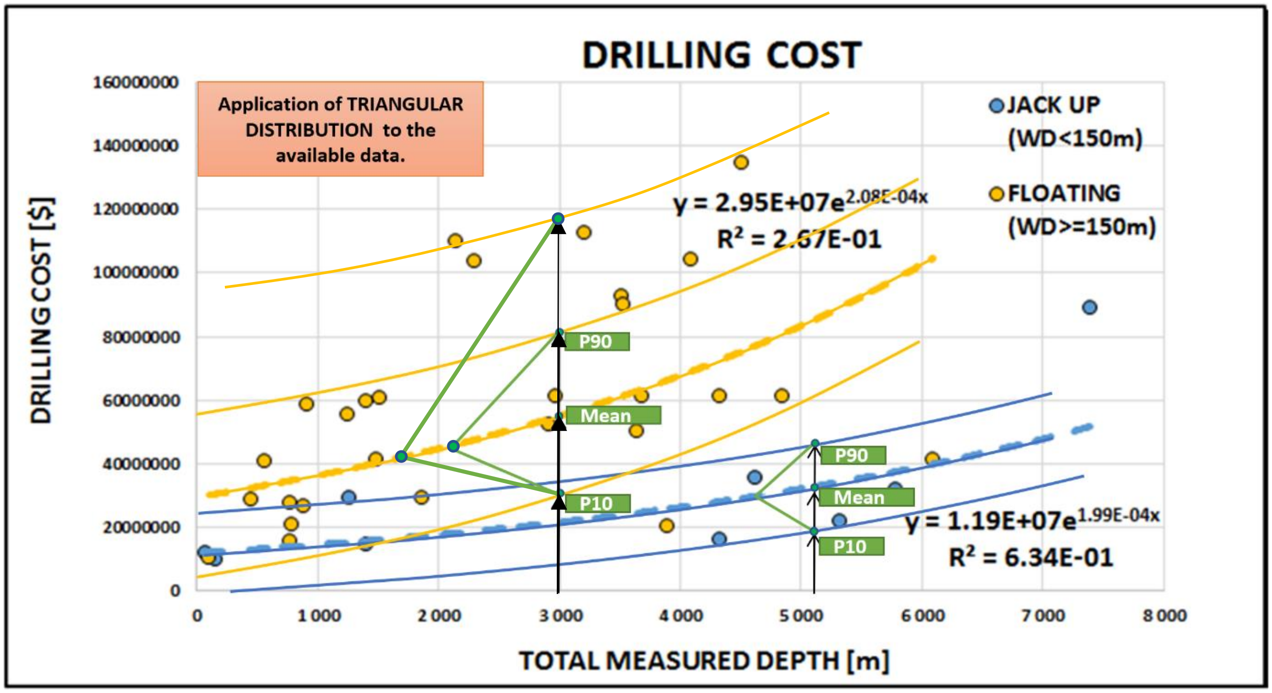


Figure 3.6 Example of application of the triangular distribution to the data in the Figure 3.5. (modified after Spera, 2016)

Completion costs associated to each of the production wells is another variable that is to be considered. Spera (2016), analyzed these costs based on the time necessary to complete a single well, and as for the drilling costs, two different trends are identified based on the previous selection of rigs. In the *Figure 3.6*, the trends are defined by regression of the data.

Here again, as for the scattered data of the drilling costs, a probabilistic approach can be applied to determine a range of values following a specific distribution curve to used then in a model to simulate the final costs of total development drilling costs.

Drilling and Completion cost, for an offshore platform, can be derived from the analysis of data cost regarding previous projects. From the cost curves relative to the water depth, type of rig, consumables used and total time necessary for the completion. An example of Drilling and Completion cost estimation based on the curves present in *Figure 3.6* and *Figure 3.7* can be of 100 Million dollars for a single well assuming:

- Floating rig
- The total depth equal to three km
- Duration related to the Completion of a single well of 40 days

The estimated cost, however, can be determined through a probabilistic approach like shown in *Figure 3.6* and *Figure 3.7*.

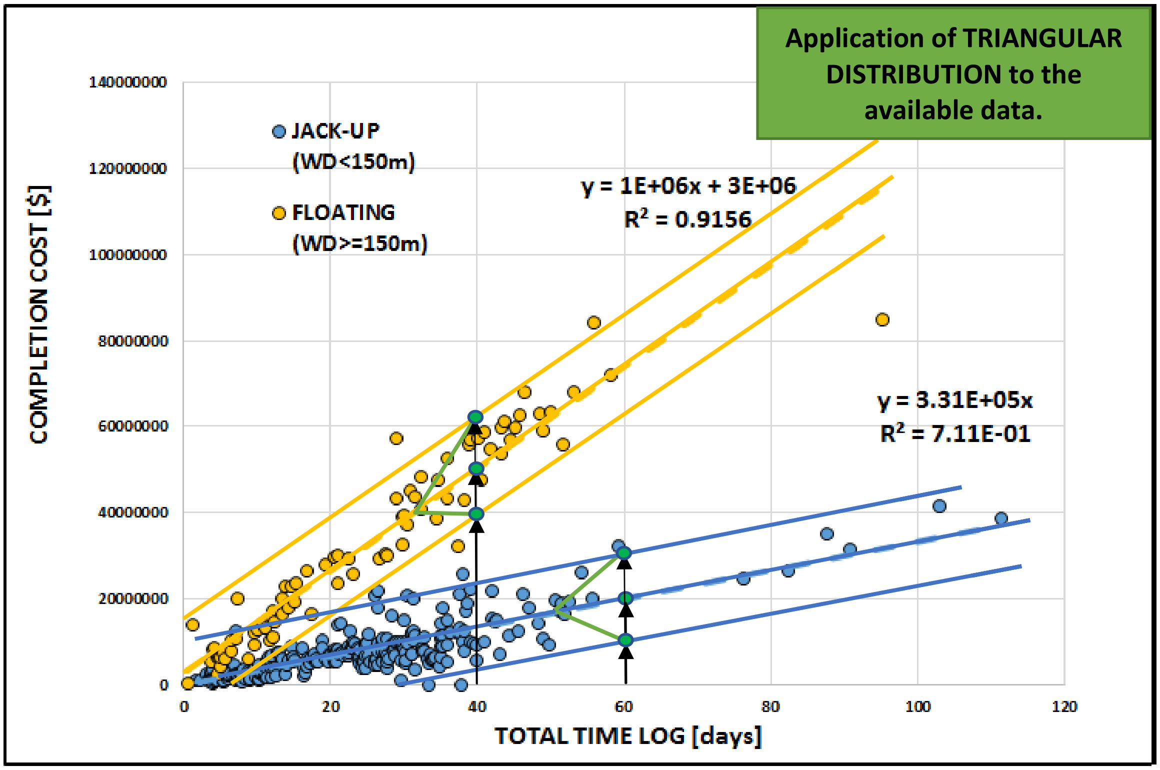


Figure 3.7 Example of application of the triangular distribution to the available data related to the curve of the completion cost (modified after Spera, 2016)

- **Platform Costs**

Platform costs are determined generally by three structural elements: Topside, Jacket, Piles. The cost of each of these elements is based on their weight. The Topside weight is correlated to the maximum production rate of hydrocarbon defined during the reservoir estimation phase and the trend is different based on the type of Topside. The weight of the Jacket, which influences the one related to the Piles, depends on: weight of the Topside and water depth. Total platform costs regarding the Topside and the substructure are equal to the summation of the costs of the each considered elements (Spera, 2016).

Topsides are divided between equipment, bulk materials, and onshore fabrication. The costs distribution of the elements inside the topside category is summarized in the histogram and data table shown in *Figure 3.8*. The bulk materials appear to have the highest weight on topsides costs (OGDE, 2013).

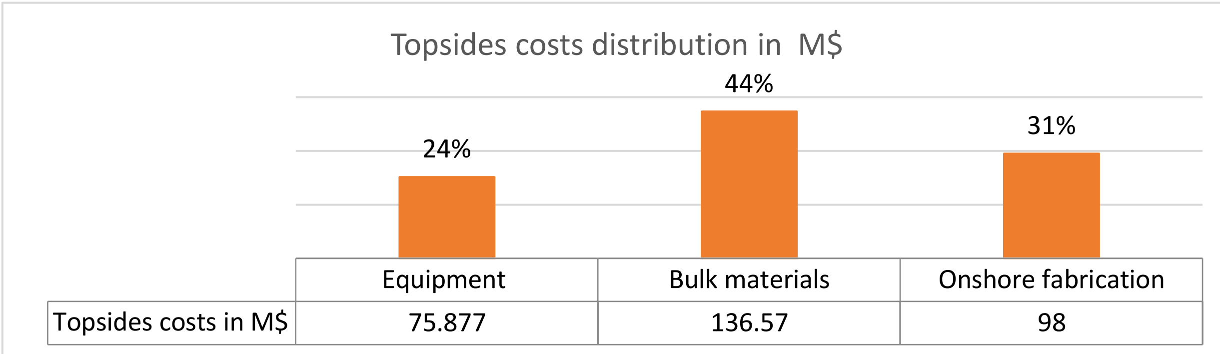


Figure 3.8. Comparison of the elements' cost (in million dollars and in percentage) relative to the total cost of the Topside category (OGDE, 2013)

Sub-structure costs in off-shore projects instead are evenly distributed between materials and fab-jackets as shown in *Figure 3.9*.

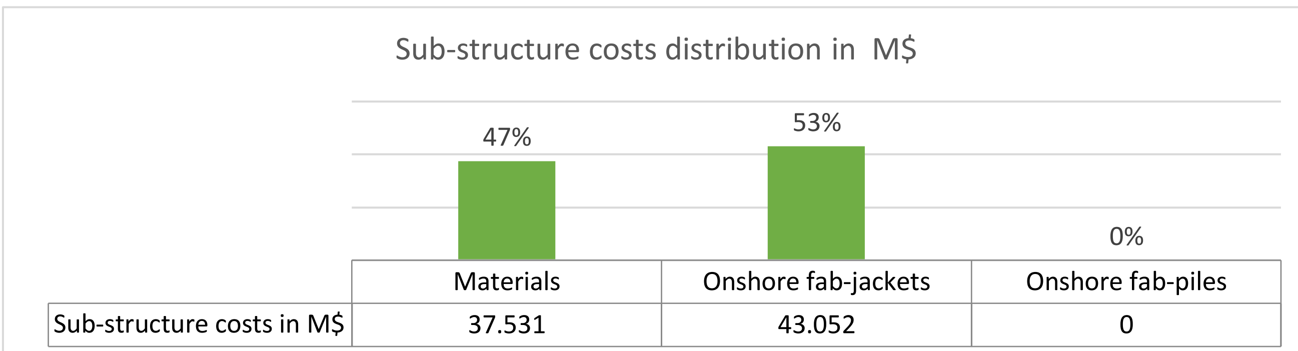


Figure 3.9. Example of costs (in million dollars and percentage) respect the total cost of the Sub-structure category (OGDE, 2013)

The analysis and determination of costs conducted by Spera (2016) regarding the Topside, Jacket and Piles take in account data of hydrocarbon production, weights of the considered elements and their correlation based on historical data.

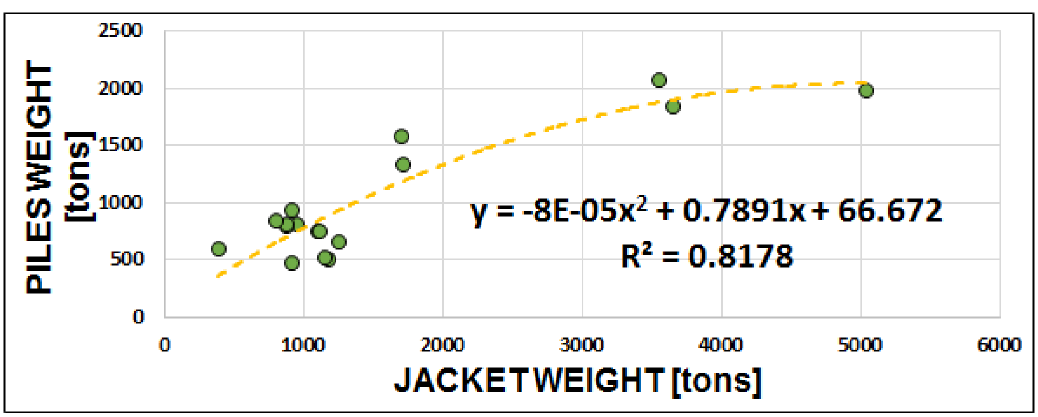


Figure 3.10 Example of the Piles weight (tons) determination of an offshore platform from the Jacket weight (tons) (Spera, 2016).

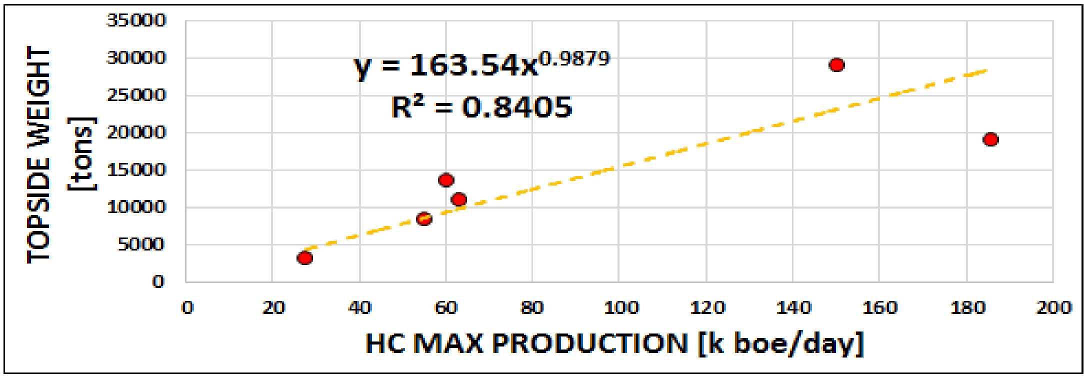


Figure 3.11. Trend of the Topside weight based on the maximum production of hydrocarbon (thousands of bbl per day) (Spera, 2016).

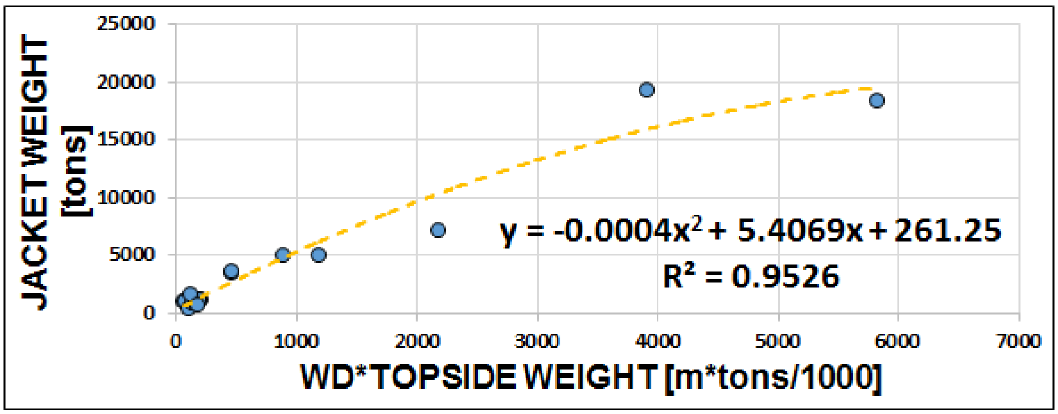


*Figure 3.12 Example of the Jacket weight (tons) determination of an offshore platform from the water depth and Topside weight (meters * tons /100) (Spera, 2016).*

Figure 3.10, *Figure 3.11* and *Figure 3.12* illustrate the weight determination of the platform elements. Once the weight trend of each of the structures are defined, cost trend based on the weight can be characterized. The Probabilistic approach used on the previous drilling cost estimation can be used also here on both weight and cost analysis of the considered platform.

To perform platform costs analysis, the available historical data of the hydrocarbon fields in an important petroleum basin are used, with the adjustments of the costs to the 4th quarter of 2015.

The costs related to the Transportation and Installation, Hook-up and Commissioning are included in each of the estimated cost of Topside, Jacket and Piles.

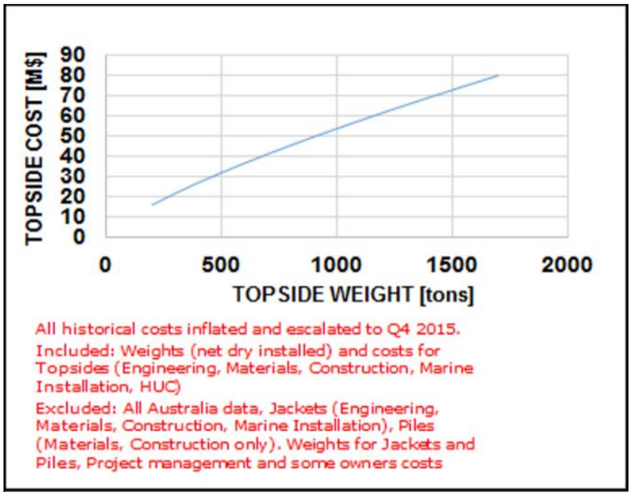


Figure 3.15 Example of Topside cost determination (in millions of dollar) from the Topside weight (tons) (Spera, 2016)

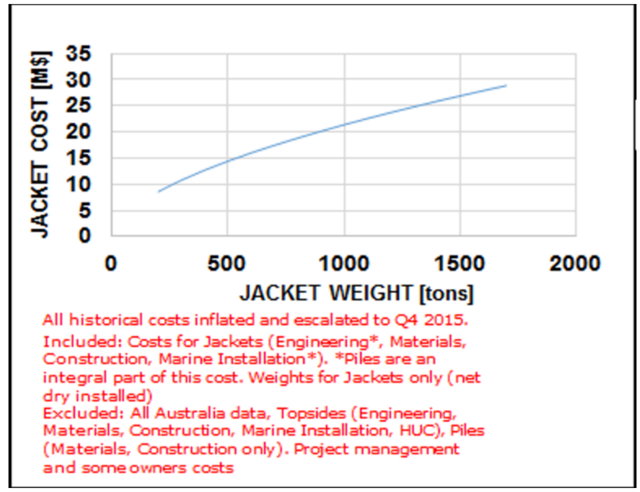


Figure 3.13 Example of Jacket cost determination (in millions of dollar) from the Jacket weight (tons) (Spera, 2016)

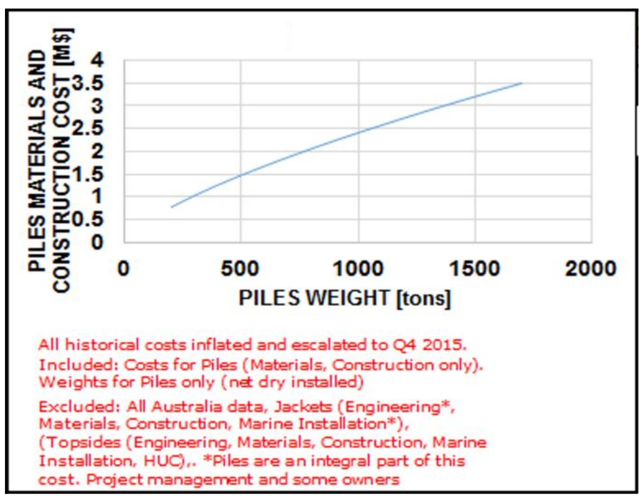


Figure 3.14 Example of Piles cost determination (in millions of dollar) from the Piles weight (tons) (Spera, 2016)

Figure 3.13, *Figure 3.14* and *Figure 3.15* are the results of the cost analysis of each element of the platform structure. The data considered for the definition of these curves regards a generic production platform. Data cost related to specifics platforms like SPAR, FPSO and TLP, which have different building design and so different building elements, can be more difficult to estimate because of possible unavailability of data.

The cost of Surface facilities depends mainly on the characteristics of the Topside and Substructure components such as weight, equipment, bulk materials, fabrication, etc. Cost curves of the Topside, Jacket and Pillars components in the *Figure 3.13*, *Figure 3.14* and *Figure 3.15*, can be used to estimate the Platform total cost. The considered curves account also for the Construction, Installation and Commissioning costs. For example, an estimation of 85 Million dollars total cost of a general Production Platform can be made assuming the following weight characteristics:

- Topside of 1000 tons weight
- Jacket of 1500 tons weight
- Pillar of 1000 tons of weight

Analysis of 24 offshore projects relative to SPAR and TLP platforms in the Gulf of Mexico, done by Jablonowski and Strachan (2008), allowed to build functions of cost for both categories of platforms. The Gulf of Mexico area was taken into account for the historical data available about the completed projects. However, the authors admitted the limited access to empirical data regarding the offshore platforms which are characterized by confidentiality status. Statistic results of costs relative to the topside weight, facility cost, hydrocarbon production and reserve estimation of SPAR and TLP projects are shown in *Table 3.4* and *Table 3.5*. The defined costs in the table are adjusted by the authors to the reference value in US dollars of the year 2006 (Jablonowski & Strachan, 2008).

Table 3-4. Example of statistical data regarding SPAR – The costs are referred to 2008 (Boschee, 2012)

TABLE 1—SUMMARY OF SPAR DATA (11 PROJECTS)

Variable	Units	Type	Max	Min	Mean	Standard Deviation
Total cost	2006 USD Value	Continuous	1175.6	411.5	694.2	280.0
Facility cost	2006 USD Value	Continuous	918.5	190.3	408.9	236.0
Water depth	Meters	Continuous	1646.3	588.4	1105.2	348.9
Oil rate	MBOPD	Continuous	113.0	35.0	59.8	26.0
Gas rate	MMCFPD	Continuous	325.0	60.0	154.1	80.3
Slot count	Slots	Continuous	20.0	6.0	11.5	5.1
Rig type		Binary	1.0	0	0.27	
Spar type		Binary	1.0	0	0.27	
Reserves	MMBOE	Continuous	320.0	75.0	160.0	81.8
Topside weight	Metric Tons	Continuous	15766.0	2903.0	7529.1	4836.8

Table 3-5 *Example of statistical data regarding TLP – the costs are referred to the 2008 (Boschee, 2012)*

TABLE 2—SUMMARY OF TENSION LEG PLATFORM DATA (13 PROJECTS)						
Variable	Units	Type	Max	Min	Mean	Standard Deviation
Total cost	2006 USD Value	Continuous	1612.7	296.7	806.5	459.4
Facility cost	2006 USD Value	Continuous	1068.5	158.3	468.4	313.1
Water depth	Meters	Continuous	1424.6	448.6	865.1	275.0
Oil rate	MBOPD	Continuous	200.0	33.0	75.6	53.80
Gas rate	MMCFPD	Continuous	420.0	45.0	180.8	130.4
Slot count	Slots	Continuous	32.0	0	12.7	10.80
Rig type		Binary	1.0	0	0.31	
Reserves	MMBOE	Continuous	500.0	6.0	161.0	164.4
Topside weight	Metric Tons	Continuous	21772.0	1950.0	10132.8	7977.7

The available max, min and mean data, allow appliance of a distribution curve and definition of the statistical cost based on the platform type and its designed characteristics.

- **Pipelines and Umbilicals Costs**

For pipelines and umbilicals, the largest costs are spent on both materials and installations as illustrated in *Figure 3.16*.

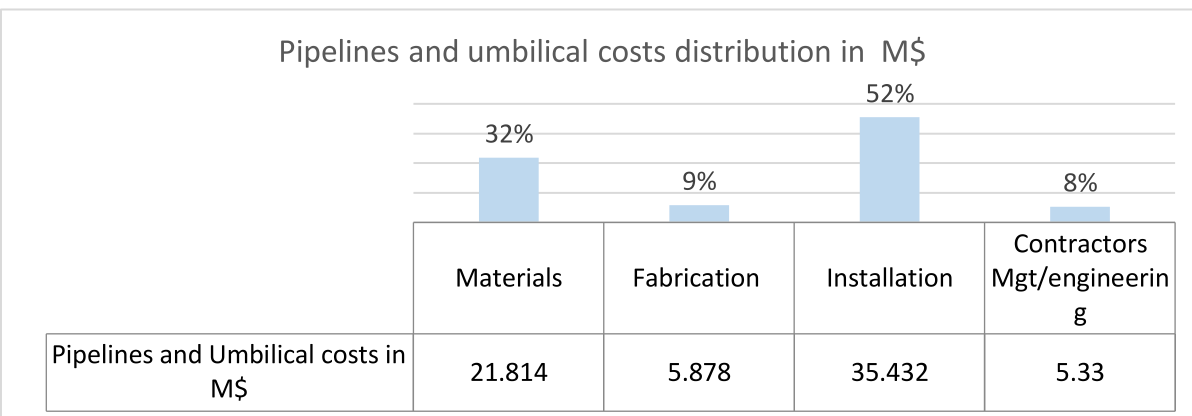


Figure 3.16 Example of costs (in million dollars and percentage) respect the total cost of the Pipelines and Umbilicals category (OGDE, 2013)

The pipelines and umbilicals are typical of subsea production which can be at shallow or deep depth. Estimation of the costs related to the elements in this class is based on a reliable Online Benchmarking of a closed Forum related to the Oil and Gas industry from which only overall costs data were found. The overall cost includes the costs of the manifolds, well system, flowlines, and umbilicals. The area related to the costs assumption is confidential. The equation derived from the data allowed to build the curve in the *Figure 3.17* where the overall cost (in million dollars) is associated with the maximum production of the field. For the Subsea production in deepwater, the same source and estimation procedure were performed (Spera, 2016).

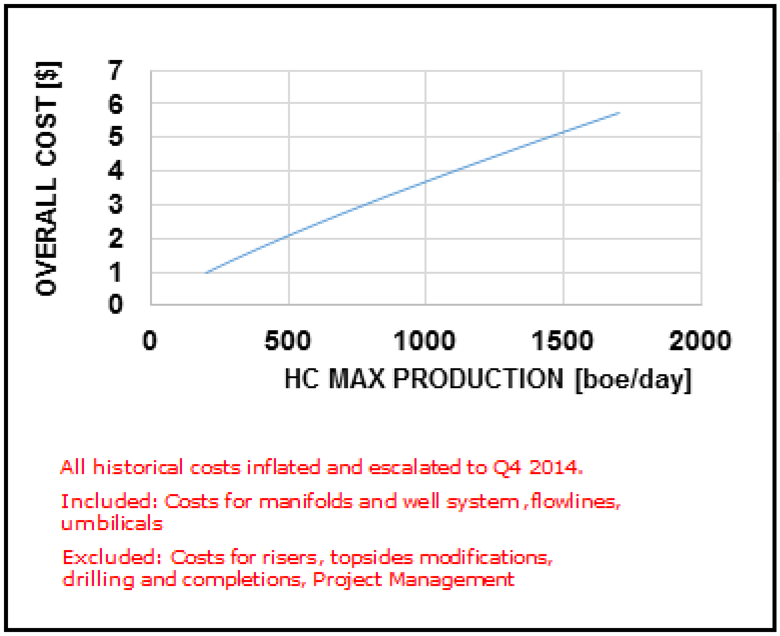
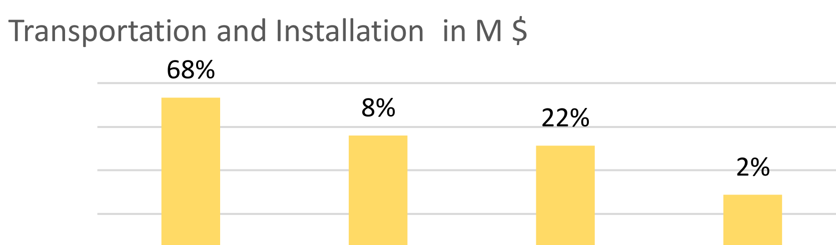


Figure 3.17 Example of Overall cost determination (in millions of dollar) with respect to the maximum production (boe/day) (Spera, 2016)

- **Transportation and Installation Costs**

Even though these costs are included in each of the previous estimation of the Topside, Jacket and Piles costs, the following *Figure 3.18* shows the elements and their impact on the total cost of this category.



	Wellhead Platform	Accomodation Platform	Riser Platform	Bridges
Transportation and Installation in M $	18.4	14.0	12.9	7.2

Figure 3.18 Example of costs (in percentage) respect the total cost of the Transport and Installation category (OGDE, 2013)

- **Hook-Up and Commission**

The same considerations regarding the Transportation and Installation class of costs are done also for the class of Hook-Up and Commission. *Figure 3.19* shows that the element which mainly affects the total cost related to this class, in this OGDE estimate cost report example, is related to the logistics.

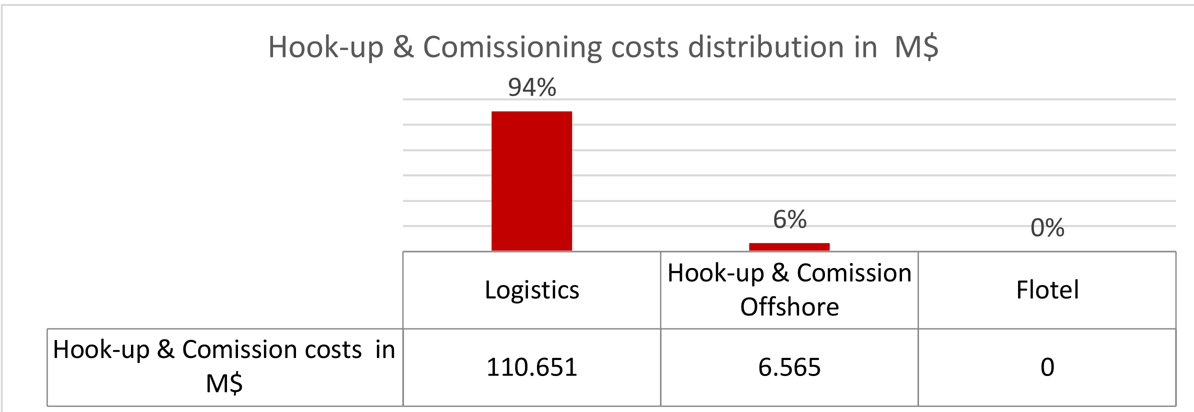


Figure 3.19 Example of costs (in million dollars and percentage) respect the total cost of the Hook-up and Commissioning category (OGDE, 2013)

- **Abandonment cost**

According to the Oilfield Glossary of Schlumberger, the abandonment cost is "the cost associated with abandoning a well or a production facility", which implies not only the well plugging, dismantle of production facilities and the linked equipment, but also the remediation of the occupied surface (Schlumberger, n.d.).

The decision to plug and abandon a well is considered when the revenues from production are equal to or lower than the production cost reaching the so-called economic limit of the production field (see *Figure 2.2*). Before reaching the field economic limit, three options related to the well are available (Aarlott, 2016):

- Slot recovery which involves the plug of the original well and production from new wells
- Temporarily plug the well for a future production or final abandonment
- Permanently plug the well

Based on the type of the project, field and complexity, abandonment process can involve one or more phases which define then a specific number of elements of the Work Breakdown Structure (WBS) that participate to the total expenditure. The Abandonment cost can regard the plug and abandonment (P&A) of a single well as well as the involved cost for all the operations needed to dismantle a complex project. *Figure 3.20* shows the components of the WBS relative to all the projects of the United Kingdom Continental Shelf (UKCS) and their costs compared to the total cost.

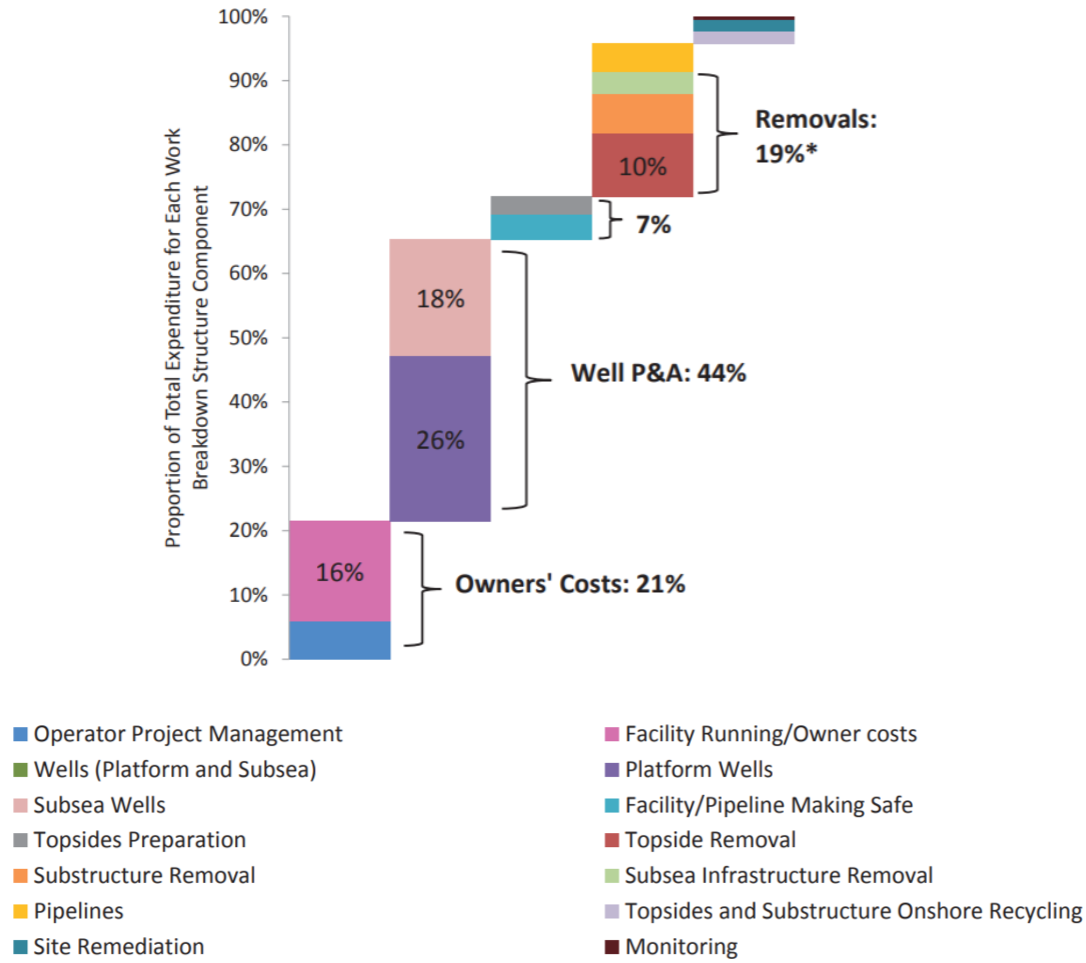


Figure 3.20 Components of WBS relative to all projects in UKCS and their impact on the total Abandonment cost (Decommissioning_Insight, 2014)

However, three main categories are identified and used to estimate the annual total Abandonment cost, relative to the oil and gas fields of the UKCS, in the Decommissioning Insight (2014). The categories and their relative estimated costs are present in *Figure 3.21* and *Table 3-7* (Decommissioning_Insight, 2014).

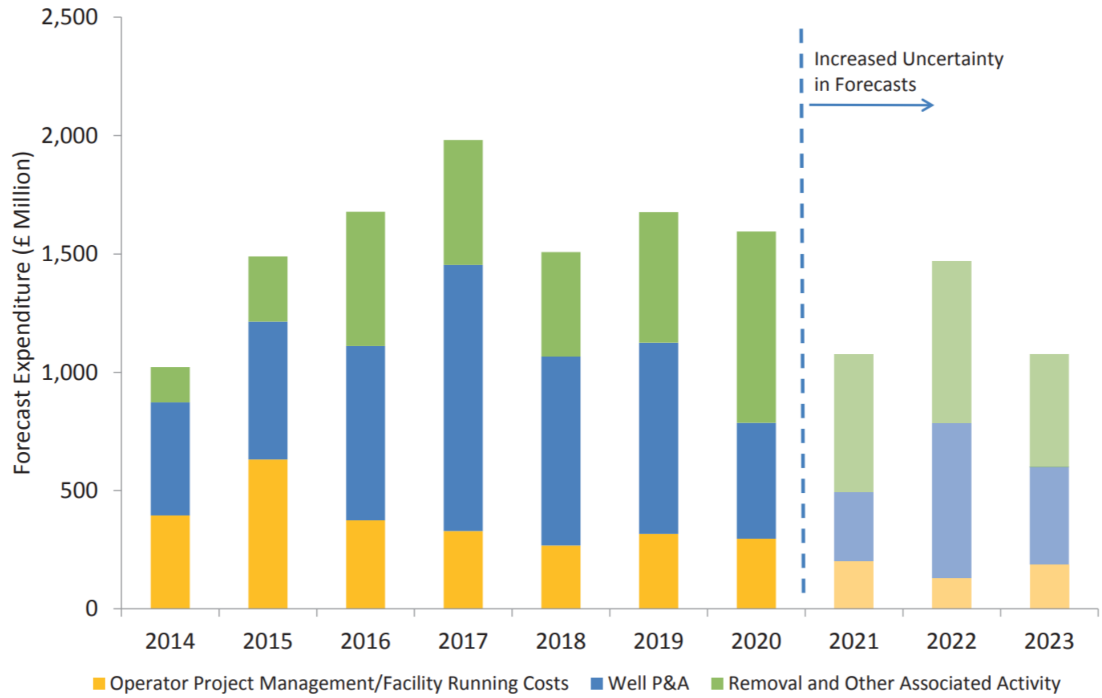


Figure 3.21 Forecast of the total abandonment cost based on the main categories involved in the estimation from 2014 to 2023 (Decommissioning_Insight, 2014)

Table 3-7 Forecast of the total abandonment cost (in Millions of pounds) of the main categories from 2014 to 2023 (Decommissioning_Insight, 2014)

	Expenditure 2014 to 2023
Operator project management/facility running costs	£3.1 billion
Well P&A	£6.4 billion
Removal and other associated activity	£5.1 billion

According to David Palmerton, not all the factors contributing to the abandonment cost are always accounted for the total cost estimation. These factors' cost that regards for example permits, access to the location, engineering and supervision, waste management, have to be additionally accounted to the cost of the main operations which involves Service rig, wireline and cementing services, facilities deconstruction and disposal. However, the main element responsible for a high increase in plugging operations regards downhole problems related to the extraction of the present equipment and tools, which can require a longer time to complete the abandonment operation and can double the total cost. Therefore, as stated by David Palmerton, "the cost related to plug a single vertical well, of 2,400 feet, can cost more than 150,000 dollars if severe downhole problems occur". Instead, "for a directional well of 7,000 feet, the cost of plugging can be higher than 100,000 dollars if no workover is needed, and double if downhole problems arise" (Palmerton, 2017).

3.2.2.2 Conclusions on the CAPEX estimation

According to (Bret-Rouzaut, Favennec, & al., 2011), the total capital expenditure regarding the development phase of an offshore platform can be identified in four classes: Drilling and Completion, Surface installations, Subsea installations, Gas export pipeline. The *Figure 3.22* shows the classes and their percentage of impact on the total development cost.

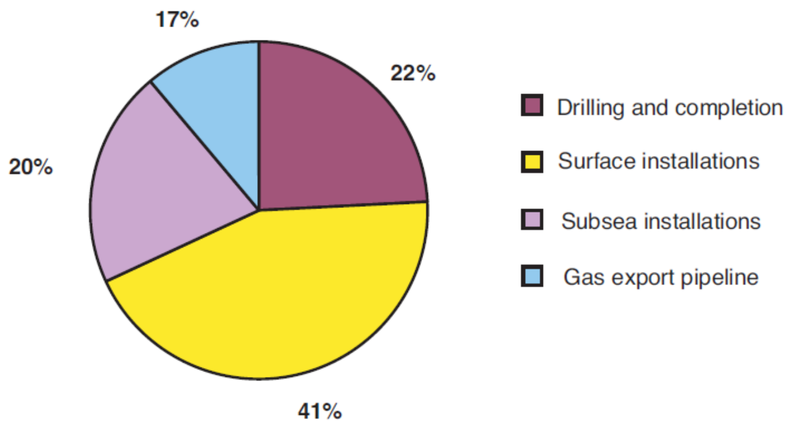


Figure 3.22 Example of the cost breakdown for an offshore development (North Sea, water depth 300 m) (Bret-Rouzaut, Favennec, & al., 2011).

Summation of the cost data regarding the Platform structure, Pipelines & Umbilicals and the costs of the Transportation, Installation and Commissioning of both, determine the base value that can be used to perform a probabilistic analysis. *Table 3-8* is an example of the determination of the Capital Expenditure regarding the facilities.

Table 3-8 Example of Cost summary related to the CAPEX of an oil and gas project (Spera, 2016)
**Costs of the elements that are accounted by other ones are equal to zero*

COMPUTE	COSTS SUMMARY
Intrafield elements and Sealines	**Total Cost [M $]**
Flowlines	16.499
Risers	0.000
Umbilicals	0.000
SPS	41.454
Sealines	12.641
Installation	1.890
Structure	**Total Cost [M $]**
Production Platform	334.250
Transfer Platform	0.000
VHPs	**Total Cost [M $]**
	67.058

To perform the estimation of the total CAPEX, the costs of the Project Management, Well Drilling & Completion, Contingency and Owner Costs must be added. Normally the Owner Cost and Contingency are assumed as a percentage of the total Platform facilities cost or can be defined independently by the experts (Spera, 2016), (De Ghetto, oral discussion).
The *Table 3-9* is another example of the total CAPEX definition.

Table 3-9 Example of the total CAPEX calculation (Spera, 2016)

CLEAR

COSTS CALCULATION

COMPUTE

	AUTOMATIC INSERTION	MANUAL INSERTION	
	Total Cost [M $]	Total Cost [M $]	Total Cost [M $]
Contingency cost	128.361		128.361
Owner cost	12.836		12.836
PM cost	192.542		192.542
CAPEX facilities	807.532		807.532
ABEX	128.361		128.361

CALCULATION FOR SENSITIVITY ANALYSIS

	AUTOMATIC INSERTION
	Total Cost [M $]
CAPEX facilities -10%	726.779
CAPEX facilities +10%	888.285

The overall CAPEX value or the Surface installations, which have a greater influence inside the Cost calculation of the CAPEX, can be then used as a base data to build the considered variable as a probabilistic one. Based on the uncertainties related to the variables, involved in the cost calculation, a max, min and most likely value can be defined for each of them and a distribution curve assigned. Normally the distribution curve assigned to the CAPEX is Triangular or Uniform because they better represent the statistical trend of the overall cost involved in the oil and gas industry (De Ghetto, oral discussion). Additionally, according to Akins et al (2005), the assumption of uniform and triangular distributions is considered standard for model building in well time and cost estimation.

3.2.2 Operating Expenditures (OPEX)

The Operating Expenditures, called OPEX, are all the costs related to the production activity of the oil and gas platform. According to Humphreys & Katell (1981), OPEX can be defined by five categories:

- Direct costs relative to elements which costs are proportional to the production. These elements regard the operations of: maintenance of the well and the production equipment, surface and downhole production, management of the platform, security.
- Indirect costs instead are not related to the productivity and account for fixed costs such as taxes on property, depreciation and other expenses associated to the management office, technical assistance, the salary of the company's staff (DiLallo, 2017).
- Distribution or Transport costs regards the cost of all the operations necessary to manufacture the hydrocarbon and transport it to the market.
- Contingencies is an additional amount which accounts for the unexpected costs, the variation of the estimate in time or wrong estimation.

Figure 3.23 shows an example of the elements and their cost weight inside the total estimated OPEX (Bret-Rouzaut, Favennec, & al., 2011).

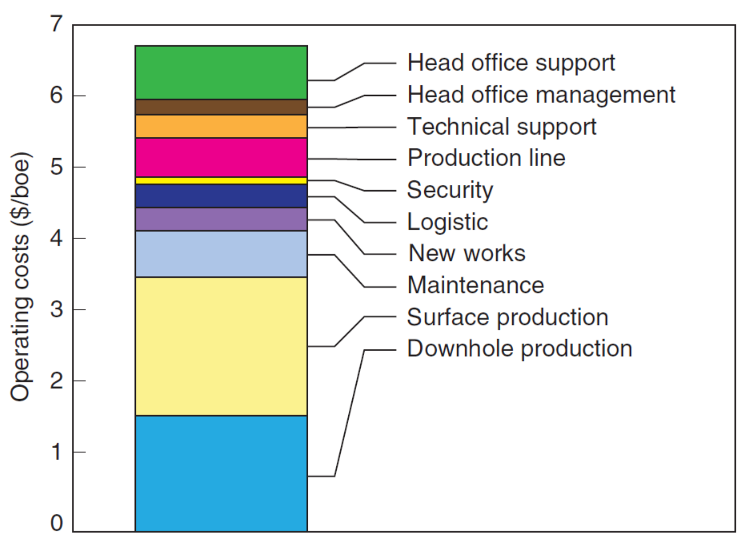


Figure 3.23 Example of elements and their cost inside the Operational cost category (Bret-Rouzaut, Favennec, & al., 2011)

According to Steube & Albaugh (1999), the estimation of the cost related to each element related to OPEX is a complex and difficult task because the categories and costs involved may be different between oil and gas companies. Therefore, to perform an accurate estimation of the Operating cost, research and investigation of the petroleum field characteristics must be done (Steube & Albaugh, 1999).

However, Operating cost can be assumed from the analysis of data costs regarding countries. The *Figure 3.24* shows the average cost of a barrel of oil or equivalent oil in some countries based on production cost data from March 2016 (Rystad Energy UCube, 2016), (WSJ, 2016). The values are adjusted to the Brent crude price benchmark relative to June 2018.

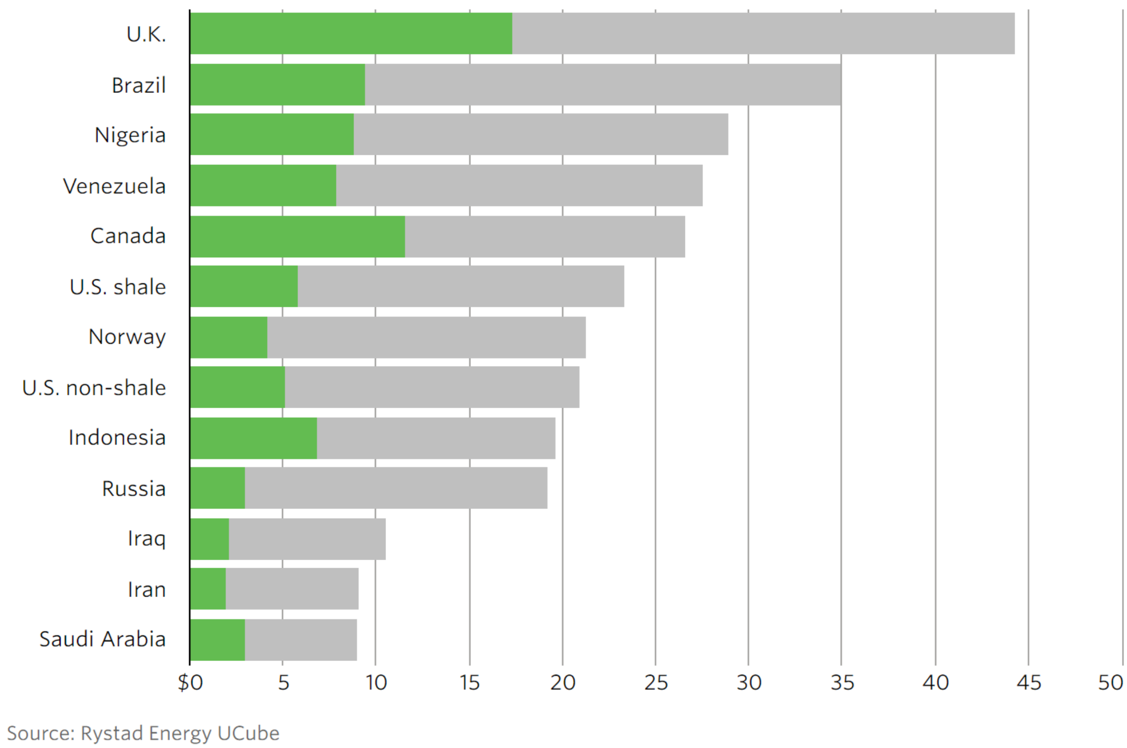


Figure 3.24 Example of Production cost (green) respect to the total Operating cost (grey) for different countries) (WSJ, 2016)
** Production data reference to 2016*
*** Values are adjusted to the Brent crude price benchmark of 18 June 2018 and refers to the cost per produced barrel of oil*

Analyzing more specifically the OPEX of the countries in the *Figure 3.24*, the categories of cost change based on the geographical location which characterize the type of reservoirs and the quality of oil and gas that can be found. Shale oil, complex reservoir and heavy oil quality present in countries like the United Kingdom, Canada, South America make production and capital spending categories to increase. Transportation costs instead tend to be on average the same if comparing it between the considered countries. The Gross Taxes have also a great impact on the OPEX of some countries like Russia, Venezuela or Brazil that account respectively the 43.9%, 37.9% and 19% of their total Operating costs, while on other countries like Saudi Arabia, UK and Iran there are not any. In *Figure 3.25*, examples of categories' cost related to Indonesia is shown (WSJ, 2016).

■	Gross taxes	$6.66	19.0%
■	Capital spending	$16.09	46.0%
■	Production costs	$9.45	27.0%
■	Admin/transport	$2.80	8.0%
	Total	$34.99	

Figure 3.25 Example of the main classes of cost of that define the total Operational Costs in Indonesia (WSJ, 2016)

Operating cost is normally assumed by the experts based on the complexity and other characteristics of the project and experience and/or data relative to previous projects that can be used for comparison purposes (Inkpen & Moffett, 2011).

Based on the OPEX estimation by country and on the main cost elements influencing it, a probabilistic estimation can be applied to it. As for the CAPEX, a triangular or uniform distribution can be applied to a base value estimated because these distributions, that have imposed limits on the minimum and maximum value, better represent the expected variability of this class of costs.

3.2.3 Fiscal Costs – Taxes on Revenue and Inflation

- **Taxes on Revenue**

The production taxes, defined by the type of contract between the IOC and government, represent the percentage of revenues in terms of cash or resources which the government takes as royalties, fees, taxes and other fiscal levies on profits. Although this type of cost impacts heavily companies' profit, it is a constant cost defined by the contract and does not affect the initial profit evaluation of the project due to its low level of risk. The calculation of the Government (GOV) Take, which result is expressed as the percentage of the pretax of the Net Cash Flow (NCF), is obtain by the formula (Agalliu, 2011):

$$Government\ Take = \left(1 - \frac{Company\ after\ tax\ Cash\ FLow}{Gross\ Project\ Revenue - OPEX - CAPEX}\right) * 100$$

Equation 3-2

The percentage of the GOV take is defined by many elements that can be based on production or profit or a combination of them to share the exploration risk and reward the investor. Each country is characterized by a different percentage of the take. In the following *Figure 3.26*, several countries are ranked by their imposed percentage of taxes on production (Agalliu, 2011):

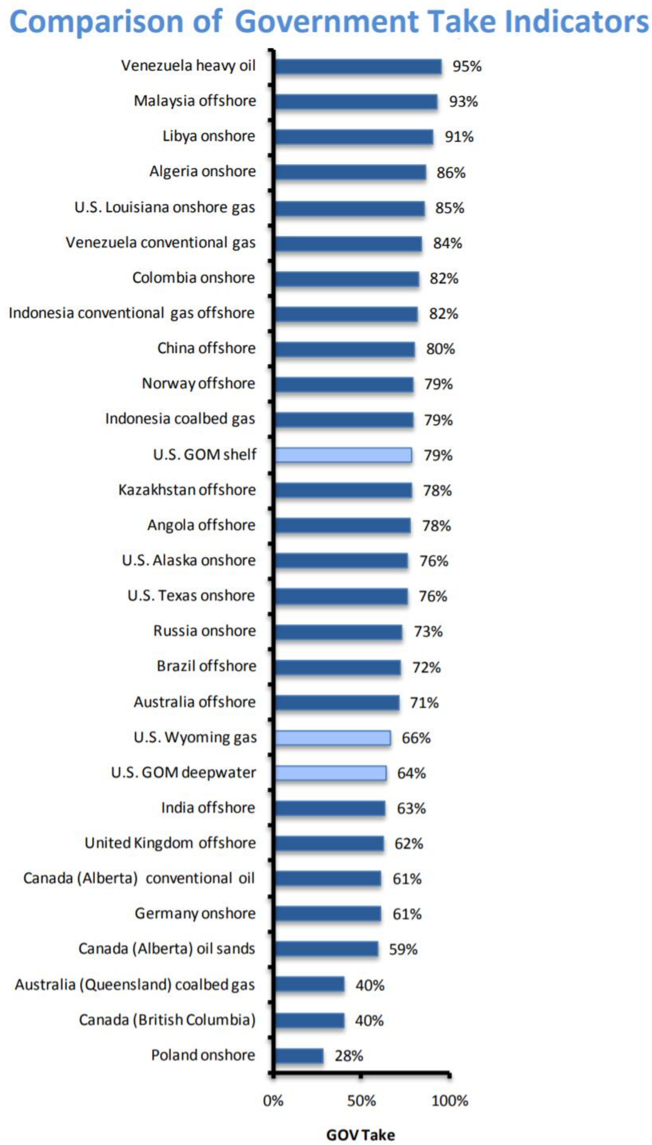


Figure 3.26 Comparison of the Government take taxes (in percentage) in different oil and gas producing countries (adjustment from (Agalliu, 2011)

Therefore, according to Iván Martén et al (2015), the taxes on the upstream revenues generated in the Upstream sector are driven mainly by two factors: the hydrocarbon price and by the competitiveness of the country in attracting IOC investments in exploration. From 2000 to 2014, the increase in oil prices justified a quick increase in the percentage of taxes imposed by the countries on the generated profits. Although, the following contraction of the oil price characterized a slower action by the Governments in reducing the fiscal pressure. On the other hand, a participation of the country to the exploration investments can stimulate more bids and attract higher exploration and development of the internal reserves.

- **Inflation rate**

The Inflation rate is an index describing the trend assumed by the Consumer Price Index (CPI) during years. Increase or decrease of the CPI depends on the weighted average price of the goods inside a bundle, which are commonly consumed by the population of a specific country and can be different between countries. Comparison of the CPI to the one of the previous year describe the annual inflation of a country. In *Table 3-10*, Inflation data about a few countries in the last 5 years are shown according to (Focus-Economics, 2017):

Table 3-10 Example of Inflation rate of a sample of countries between 2013 and 2017 (Focus-Economics, 2017)

Country	2013	2014	2015	2016	2017
Australia	2.4	2.5	1.5	1.3	1.9
Canada	0.9	1.9	1.1	1.4	1.6
Russia	6.8	7.8	15.5	7.1	3.7
Saudi Arabia	3.5	2.2	1.2	2.1	-0.8
USA	1.5	1.3	0.1	1.3	2.1
Norway	2.1	2.0	0.0	3.6	1.9
Brazil	6.2	6.3	9.0	8.7	3.4
Venezuela	40.6	62.2	122	-	-
Ghana	8.3	15.5	17.2	17.5	12.4

Based on the analysis of the country economy and the one of the world, combined with expert interpretation and economic models, the forecast of future inflation can be defined (OECD, 2018). Stable economies of many countries like Norway, USA, and Canada, characterize small variation and more predictable future inflation rates. In opposite, countries like Brazil, Venezuela and Ghana, have a higher fluctuation of the inflation due to the economic and political instability, which result in a more difficult definition of the future inflation index.

3.3 Resources, Reserves and prediction of Production Rate

Different definitions of Resources and Reserves were used in the past by experts to describe minerals accumulations. Lack of a precise and wide accepted terminology was the fundamental problem related to the description and comparison of the data regarding mineral classification.

The investigation of the national mineral resources of U.S. Bureau of Mines and U.S. Geological Survey during World War II represents the first effort to define a standard terminology (McKelvey & Kleppe, Mineral Resource Perspectives 1975 - USGS Publications Warehouse , 1975).

Important discussion on the differentiation between reserves and resource definition and terminology was addressed successively by McKelvey (1972) and Brobst and Pratt (1973). Their definition of hydrocarbon reserves considers also the economic and technologic variables of a period of time (McKelvey, 1972).

Meanwhile collaboration between many Organizations and Societies of experts involved in the Petroleum sector, as is described in the next chapter, allowed to establish a more precise and complete definition in time of the hydrocarbon reserves and resources.

As general definition adopted also by (Bret-Rouzaut, Favennec, & al., 2011), the difference between Reserves and Resources is:

- Reserves are related to the volumes of hydrocarbons which, based on their physical and economic accessibility, can be produced now or in the future, while
- Resources refer to the physical quantity of hydrocarbons present in a reservoir without any consideration for their accessibility and it is equivalent to the Hydrocarbon in Place concept.

Production forecasting instead is related to the Reserves estimation. Parameters as Plateau rates and rates during production decline are calculated as a percentage of the estimated reserves (Doré & Sinding-Larsen, 1996) or by models based on the available seismic data.

3.3.1 Reserves Classification

Organizations as the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG) and the World Petroleum Council (WPC) developed a system (PRMS – Petroleum Resource Management System) able to provide the fundamentals for classifying and categorizing the oil and gas reserves and resources. The dependency of physical oil recovery on the available technology and other variables such as associated costs of oil extraction and its market price, determine the real quantity that is economically convenient to produce. To account this implication, PRMS is based on project characteristics as a chance of commerciality and level of production (related to the number of accumulations produced recovered), but also on the range of uncertainty related to the production forecast after the project's development stage. Accounting these specifics, a project can also be considered as investment opportunity due to the investment costs and expected outcome analysis, needed for portfolio management and decision process. As we can see in *Figure 3.27*, three main classes are used to classify a project: Reserves, Contingent Resources, Prospective Resources.

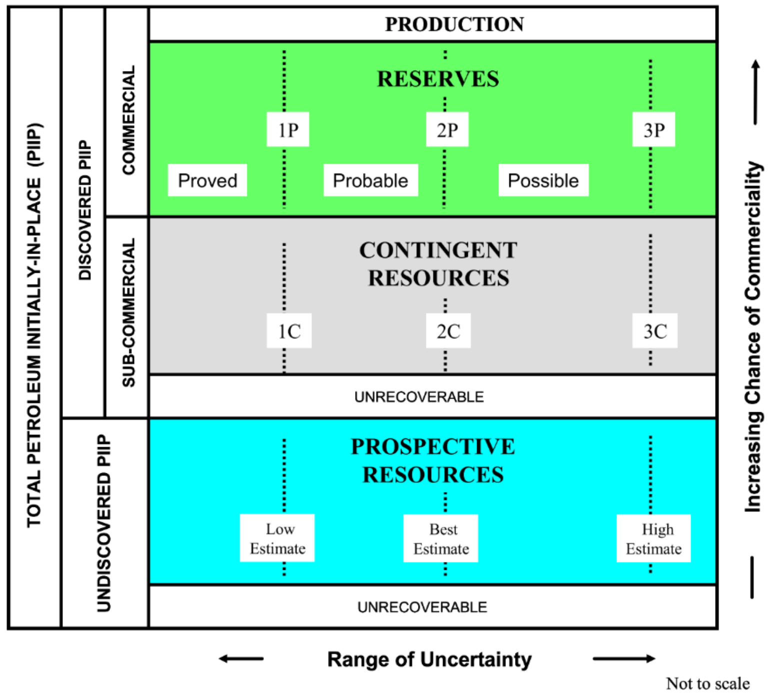


Figure 3.27 Framework of Resource Classification based on the uncertainty and commerciality related to the PIIP (Ross, 2011)

The classification – identification of the reserves has also an important role in maintaining visible in time investment opportunities which can be developed in the future. PRMS also provides a perspective focused on the recovery maximization, which means that all possible combinations are evaluated and only the best are considered for an improved generation of profits.

From the point of view of "uncertainty", reserves are classified as: Proved, Probable and Possible. Estimates of many variables involved in the calculation of reserve quantities in place as well as production performance and commerciality are affected by uncertainties on a different level, based on the method used to assess these uncertainties. This kind of classification reflects specific scenarios with three estimates from the project. There are two main methods used to determine these estimates: deterministic and probabilistic method (Ross, 2011).

3.3.2 Resource estimation: Deterministic Approach

For reserves estimation purpose with a deterministic approach, an additional distinction must be made between the deterministic "incremental" approach and deterministic "scenario" approach.

In the first type of approach, estimation of discrete volumes is closely related to the experience and highly skilled judgments of professionals. Instead for the second type of approach, sensitivity analysis is a requirement to define a range of the estimates by changing to different values of the main variables in the model and different scenarios can be assessed and considered. Of course, the selection of a proper method and type of the approach for hydrocarbon volume estimation and its accuracy depends on several factors like:

- Available data and their characteristics (type, quality, quantity) for technical and commercial analyses
- Reservoir characteristics such as geological complexity, production mechanism, maturity of the field, and stage of the development project

During exploration and initial development phases, prediction of reserves quantity can be estimated by using volumetric methods which calculate the total volume of the considered reservoir. The production rates, associated to the estimated volume, can be based on analogue projects or can be defined by analytical methods. However, the correlation between Reservoir volume and maximum production rate exists. In the model used in this dissertation, in fact, these elements are defined according to a correlation curve based on real production rates and Reservoir Volume data present in the dissertation of Spera (2016). Thanks to the curve, definition of the maximum production rate helps the estimation of the total recoverable volume of hydrocarbon and vice versa. The correlation curve is shown in *Figure 3.28.*

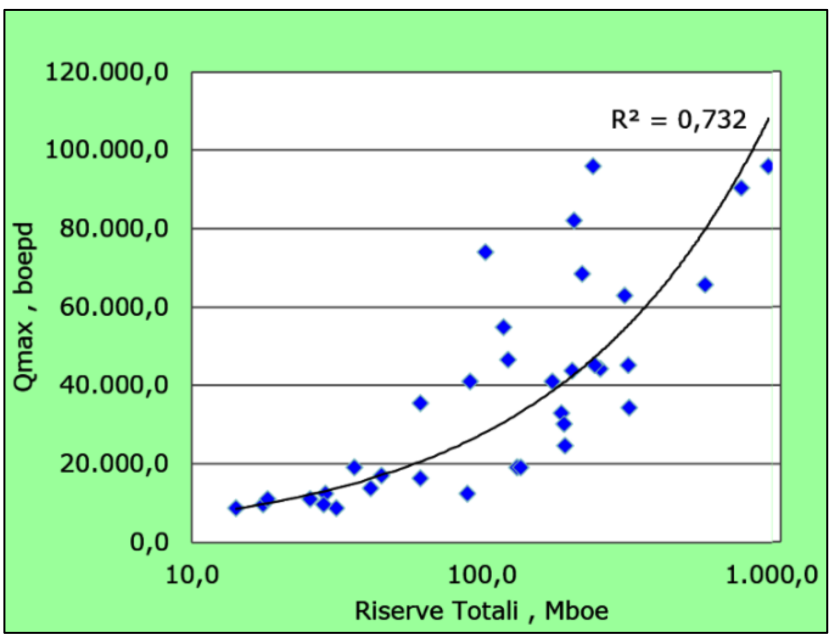


Figure 3.28 Correlation curve related to production and Reserve Volume (Spera, 2016)

Successive phases where production data is available, estimation of the total volume and recovery efficiency is based on the analysis of the production performance method (Senturk, 2011). The *Figure 3.29* describes the appropriate deterministic approach related to a specific phase of a petroleum project life cycle during its timeline.

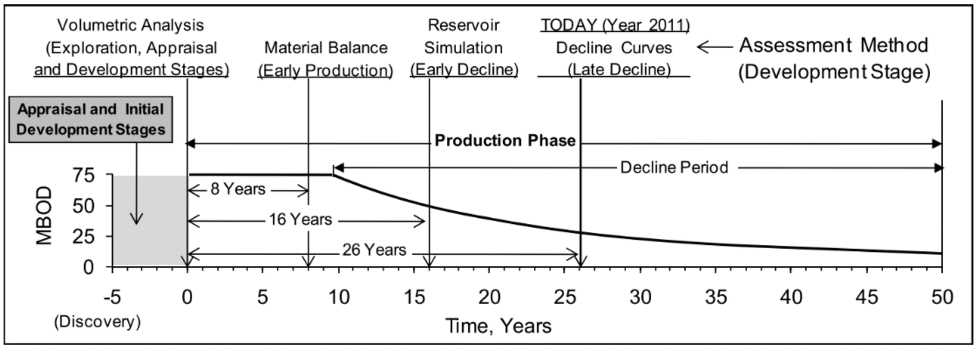


Figure 3.29 Timeline for example oil project maturity stages and assessment methods used (Senturk, 2011)

According to the objectives of the thesis, only methods regarding reserves estimation and recovery efficiency related to the Appraisal and Initial Development phases will be discussed in the following chapters. In specific, Volumetric methods and Analogous methods will be taken into account. Volume and Recovery Efficiency (RE) estimating methods that account for data gathered from production, like Material Balance methods and Performance-based methods, are not discussed in this chapter.

3.3.2.1 Deterministic methods: Volumetric and Analogous

Volumetric and Analogous methods are considered "indirect methods" because the Reserves cannot be derived directly. The Resource Volume or Original Hydrocarbon in Place (OHIP) is estimated through Volumetric methods based on available data while the RE, related to the OHIP, is defined based on similar projects or analytical results. The volume of the Resource and Reserve are defined as Stock Tank Barrels (STB) or standard cubic feet (scf). The estimations made for both Resource Volume and RE, which is assumed as a percentage of the Resource volume, are independent. The relationship between these two results can be defined by this general expression (Senturk, 2011):

- $Reserve\,Volume \;=\; Resource\,Volume\;x\;RE$

Equation 3-3

Resource volume estimation is a function of variables related to the reservoir properties and conditions under the following equation:

- $Resource\,Volume(oil\;or\;gas) \;=\; A\;h\;\varphi\;(1 - \;S_{wi})\;/\;B_{hi}$

Equation 3-4

where A is the reservoir area, h is the Net Pay, φ is the porosity, S_{wi} is the Initial Water Saturation and B_{hi} is the hydrocarbon formation factor which has different units based on the reservoir fluid and its physical condition at the reservoir pressure and temperature.

While the OHIP is determined by an equation of values which are estimated from a seismic investigation, the Recovery Efficiency estimation can be:

- chosen from similar past projects, with similar Resource and Reserves information
- derived through analytical methods
- based on published empirical correlations (to use only if other methods are not available or are not applicable)

Additionally, an available computational power of nowadays computers allows the building of simulations models able to improve prediction estimation of the listed methods. Improvement of the prediction results is also due to model accountancy of the data relative to positive drilling and completion operation as well as technology considered in development and production operation that can optimize the flow system.

Example of prediction methods applied to a project in its early phases, with tables, graphs and references to other papers, can be assessed in the paper "Guidelines for Application of the Petroleum Resources Management System" in Chapter 4 (Senturk, 2011).

3.3.3 Probabilistic method of Resource Estimation

All the variables involved in the estimation process of the amount of hydrocarbon in place and the one that can be produced are affected by uncertainty due to data investigation type, the complexity of the subsurface reality and accuracy level of the acquisition instruments. Assessment of this uncertainty is of fundamental importance in the oil and gas industry, especially in the Exploration and Appraisal phases. The range of possible results, deriving from the uncertainty accounted by the Probabilistic method, not only helps in the decisional process of management but also allows possibilities to handle different scenarios by defining a more flexible development plan, measure the level of risk related to every stage of the project, etc. The use of this method is increasing in the industry and regulatory bodies.

3.3.3.1 Parameters of Resource Estimation

- ***Gross Rock Volume (GRV).*** Many factors contribute to the uncertainty of this parameter which affects majorly the final estimation of the reservoir volume. Some factors depend on the seismic acquisition limits as lack of definition of the reservoir boundaries, time to depth conversion of the data, etc. Instead, others are connected to the complex subsurface structure which takes into account the geometrical structure and features of the hydrocarbon trap, position and transmissivity of possible faults present in the formation. The importance of uncertainty related to each factor, and thus to each parameter, is case dependent.

According to (Swinkels, 2011), the GRV "depends critically on the height of the hydrocarbon column" because of the proportional dependency between the reservoir anticline volume and the cube of the column. Integration of this kind of sensitivities in the rock volume estimation can be made based on the availability and reliability of the data acquired during the seismic acquisition phase or on many reports regarding Reserves and Resources classification which propose rules able to account for these integrations.

- ***Rock Properties (Net to Gross and Porosity).*** In addition to the trap geometry evaluation and interpretation, seismic data can also be used for prediction of reservoir properties such as porosity, pressure and rock characteristics. Of course, this kind of forecasting must be supported by data acquired from appraisal well tests and analysis and measurements performed in the laboratory which however may describe only a part of the formation condition. The variability in the rock in the formation represents the main uncertainty affecting the reservoir properties.

Geologic understanding can be also used for correlation between the depositional system and porosity to predict reasonable ranges of porosity that can be applied to the considered reservoir. Another type of correlation instead can be considered between a log scale seismic attribute and a reservoir specific property. The correlation, in this case, is highly dependent on the demonstration of the following conditions:

  - the quality of the seismic data
  - the relationship between resolution and assumed geometry of the trap
  - good match between real seismic data and modeled seismic system where logs data are used

- ***Fluids Contact and Properties.*** Prediction of fluid properties inside the pores can be done through 3D seismic analysis and well samples from the appraisal phase. Fluids presence in a reservoir normally features lower seismic velocity and a different impedance contrast respective to the surrounding shales. Different seismic velocity and impedance depend on the type of fluid. These characteristics determine an increase in reflectivity and produce an event of amplitude anomaly, unless particular geological and fluid properties are present, which can reduce reflectivity or change polarity. Water – Hydrocarbon reflection can be identified on the seismic investigation as an event called "flat – spot".

Predictions of fluid properties and contact thickness anyway cannot rely only on the seismic investigation. Additional analysis of well samples, reservoir properties, the geometry of the trap and other data sources are necessary to support consistency between data and expectations. The uncertainty related to the estimation of the fluids properties depends both on the data sampling and data analysis. While sampling accuracy relies on the acquisition methodology, additional factors like initial gradients in fluid composition or change in fluid phase during production can influence uncertainty estimation. These conditions can lead to misinterpretations and wrong analysis (Swinkels, 2011).

- ***Recovery Factor (RF).*** Reservoir properties and characteristics are the main elements that define Recovery Factor parameter. The uncertainty here is affected the most by the shape, internal geometry, transmissibility of faults, fluid contents, reservoir porosity and water strength if an aquifer is present.

Detailed data regarding elements which define the reservoir characteristics, allow the possibility to build numerical models able to simulate the RF in different scenarios based on their variability and uncertainty but also considering effects of the well, pressure depletion, fluid displacement, etc.

Otherwise, poor definition of these elements implies estimation of RFs based on Material Balance calculations or Analog methods (Swinkels, 2011).

According to Swinkels (2011), limited data and narrow range are usually approximated with triangular distribution while uniform one is used when it is difficult to determine a distribution. Especially in this last case of poorly defined data, common error done during PDF (Probability Density Function) selection and definition regards underestimation of the uncertainty range. To improve results then, as a general principle, there must be a good fit for the distribution and selection of range that reflects the uncertainty level of the parameter. Data regarding reservoir parameters acquired from the well and analyzed in the laboratory, as well as seismic data, represent the starting point of the distribution fitting and uncertainty range definition.

Another common error is connected to the usage of data regarding specific inputs to describe a parameter. Defined distribution for a specific reservoir zone cannot describe the entire reservoir. All the available data must contribute to the characterization of the parameter-averaged-value distribution as a starting point for the PDF definition. Example of a type of error consists in using porosity distribution of a formation as the average porosity of the reservoir. The error is illustrated in *Figure 3.30***.**

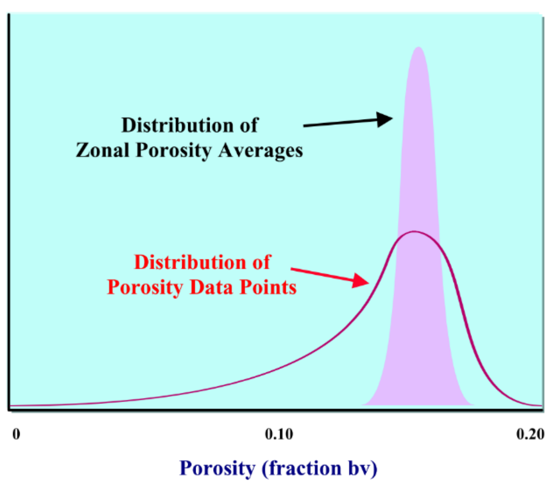


Figure 3.30 Difference between average zonal porosity and overall average porosity distributions (Swinkels, 2011)

The *Table 3-11* from the Guidelines for Application of the Petroleum Resources Management System of Swinkels (2011), page 86, provides typical intervals of uncertainty regarding common reservoir parameters.

Table 3-11 Typical ranges of uncertainty and data source of some reservoir parameters (Swinkels, 2011)
**The ranges percentage refers to the measurements of the parameters*
**The data in the table refers to typical ranges and are not intended to be used as default values.*

	Range	Source
GRV	+/– 30%	3D Seismic
		2D Seismic
Net-to-Gross	+/– 20%	Well logs
Porosity from logs	+/– 15%	Logs
Porosity from cores	+/– 10%	Cores
Hydrocarbon saturation	+/– 20%	Well logs
Dip	+/– 10%	Dipmeter
	+/– 30%	Seismic
Formation volume factor (B_o or B_g)	+/– 5%	PVT test

3.3.3.2 Case studies examples of Reservoir Characterization using Probabilistic approach and Monte Carlo

Example of the probabilistic approach aimed to perform better results regarding the reservoir hydrocarbon quantification is present in the research of Lashin & Mousa (2015) where it is discussed the investigation of petrophysical parameters of the hydrocarbon-bearing reservoir. The data used as input in the stochastic method are results of PDFs definition, statistical and other analysis of the information gathered from the well logs. All these probabilistic variables are then used in a Monte Carlo simulation and estimate petrophysical parameters.

To simulate petrophysical properties of the gas-bearing reservoir in the case study of Off-shore Nile Delta, considering the presence of zones with different shale contents, different PDFs are defined for each zone from the data acquired in the considered wells. Example of the resultant distributions regarding the well Darfeel-7 are shown in *Figure 3.31*.

Improved estimation of the petrophysical parameters enable a more accurate estimation of the resource volume and prediction of the RF.

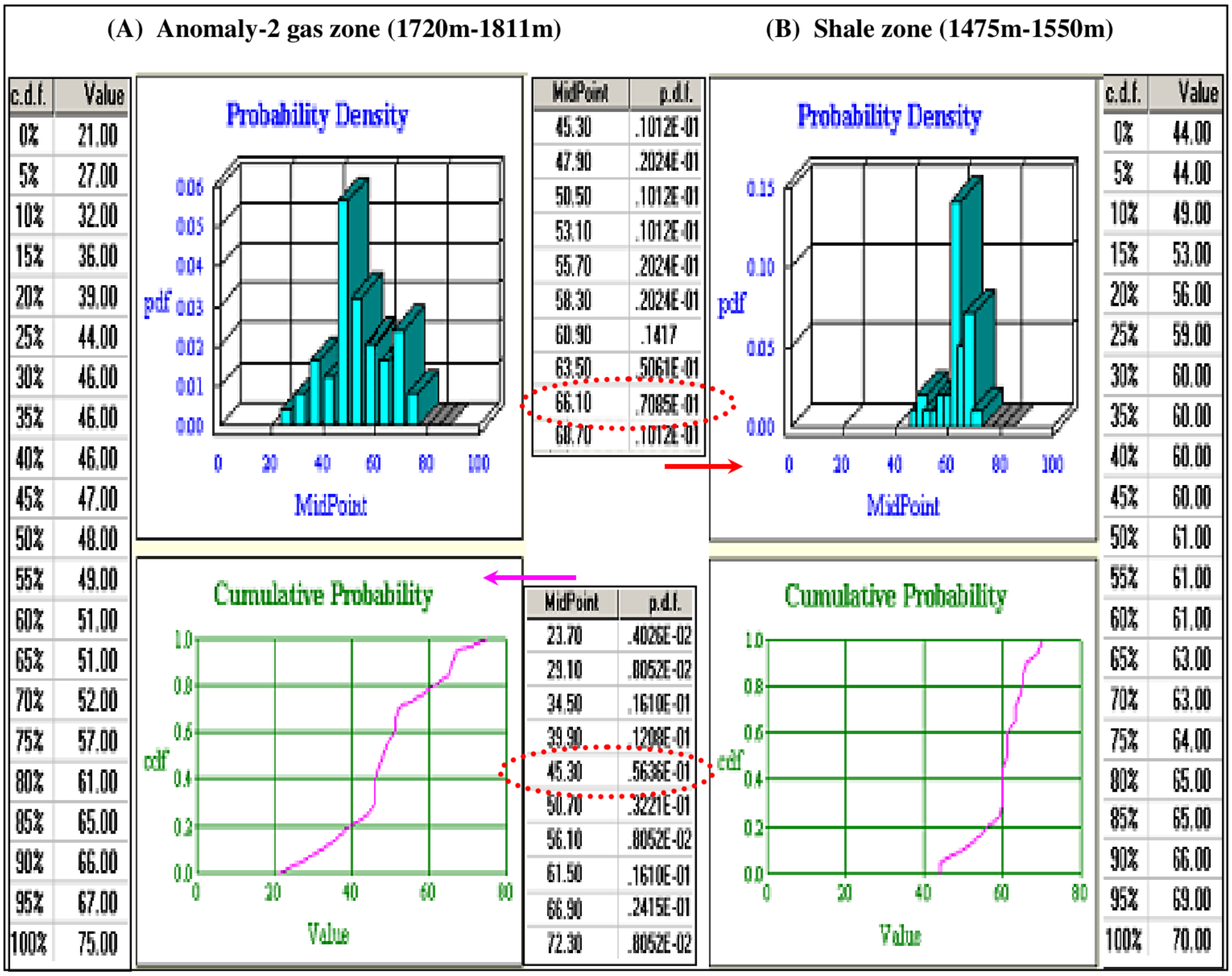


Figure 3.31 Example of distribution definition of the gamma ray data of the gas and shale zones of the well Darfell-7 (Lashin & Mousa, 2015)

3.4 Project planning – Prediction, Strategies and Performance

As discussed in Chapter 2.4, successful exploration discovery of a reservoir lead to the concept definition of a petroleum project. Through the "*stage and gate"* process, concept design and its relative costs and development time associated to the project are defined and analyzed to increase the accuracy of the estimations and help the decisional process. Depending on the complexity of the project and the uncertainty affecting the variables involved in the development concept, the accuracy of the capital cost estimation can achieve an error of 15% - 20 %.

Project complexity, however, does not affect only the capital cost estimation, but extends also to the development time variable which represents the time necessary to the platform and facilities to be finished and operative. Tools as Gant Chart or S-curve timetable are used to represent and control the project phases and related expenditures in time. Analysis of the start of the project's phases, their duration and expenditure, allow then marginal improvement of the project's concept (Bret-Rouzaut, Favennec, & al., 2011).

According to Stare (2010), literature about management of project changes during execution is poorly covered, instead of the changes considered and proposed during project design and planning definition. Experience and past finished projects can help in considering the possible occurrence of changes and their associated risk, already in the initial stages of development concept definition (Kerzner, 2006). However, this approach cannot predict all the future events responsible for project changes and there is not a model able to do it (Geraldi, Liz Lee-Kelley, & Kutsch, 2010).

Adjustments and/or changes normally occur in a development project as a necessity of adaptation to the scenario and reality in which operations take place. One of the reasons that justify this occurrence is related to the substitution of missing data or incomplete information with assumptions needed to make decisions in design and planning (Coreworx, 2010). However, these assumptions do not represent all the possible scenarios that can develop during the different phases of the project lifecycle. Successful projects depend also on the effective management of these changes (Hao, Shen, Neelamkavil, & Thomas, 2008).

Important mention about another typical problem that perform delays and cost overruns is done in the introduction of the Oracle White Paper (2009): "Construction contracts differ from most legal agreements in that they expect and plan for changes". This observation regards the issues that can arise when a change in a project "can originate with the owner, contractor or subcontractor". After the initial agreement between parties, any kind of shift from the original terms of the contract can lead to issues as conflicts, errors, unanticipated requirements, etc., that will affect project execution time and expenditures.

As an example, in the following *Table 3-12* and *Table 3-13*, projects from different continents and then specifically from Canada (Alberta), are analyzed in terms of cost and time overruns. From the present numbers is evident how an increasing number of projects and average project value, the probability that the average cost overruns in percentage increase. Instead of small projects which have low value, are characterized by lower time and cost overruns.

The trend of increasing value of a project is strictly related to its complexity and consequently to the increasing probability in overruns.

Table 3-12 Costs overruns of Oil and Gas megaprojects (Olaniran, Love, Edwards, Olatunji, & Matthews, 2015)

Geographical Location (Continent)	Number of Projects	Average Project Value (US$ million)	Total Project Value (US$ million)	Average Cost Overruns (%)
Africa	22	1,390.41	30,589	50.42
Asia	13	10,981.77	142,763	92
Europe	16	2,712.69	43,403	90.75
North America	11	3,703.09	40,734	83
Oceania	2	691	1,382	32.5
South America	**5**	**1,236**	**6,180**	**58.6**
(Adapted from Mackenzie, 2011).				

Table 3-13 Cost and time overruns on Alberta Oil and Gas Projects (Halari, 2010)

Project	**Company**	**Original Estimate CAD$ billion**	**Final Cost CAD$ billion**	**% Cost over run**	**Original Finish Date**	**Actual Finish Date**
Original GCOS Plant	Suncor	0.25	0.25	0%	1967	1967
Mildred Lake	Syncrude	1.0	2.0	100%	1977	1978
Millennium	Suncor	1.9	3.4	94%	2000	2001
AOSD – Phase 1	Shell	3.5	5.7	63%	2002	2003
UE-1	Syncrude	3.5	7.5	114%	2004	2006

3.4.1 Literature of projects overruns

According to the available literature, there is not a single project that has been executed through its lifecycle as initially designed and planned. In the following are presented two examples of studies concerning cost and time overruns in the civil and mechanical construction fields:

- Vandenberg (1996) performed a study on data gathered under two groups, impacted and not impacted by changes. He developed a model that correlates the effect of changes on the workers' efficiency. The variables considered for his model includes: total actual project hours, total estimated change hours, impact classification, the timing of change. The conclusion of the study highlighted a linear trend between the decrease in labor efficiency and the delay in time of change occurrence during the project execution (Vandenberg, 1996).
- Awad (2001) study on the construction change orders of the combined sewer overflow construction projects concluded that the major contributors of cost escalation and time overrun were the additional work, design revisions and differing site conditions caused by

the engineer and owner party. Time overrun was estimated at 30% of the planned duration while costs increased an average of 7% more than the original project costs (Awad, 2001).
- In the study performed by Motawa (2004), occurrences estimation of the project changes and their impact on the initially defined project parameters are used to define a proactive management of the changes by the project parties. The process of estimation and prediction of the changes are done through a fuzzy system implemented with the Dynamic Planning and Control Methodology.

3.4.2 Factors of Project Change

Motawa (2004) highlighted the relationship between changes and "stability" of the primary target of the project. Their study evaluates how the estimation of the stability affects the decision making to reduce the implications of change. The causes of change may be related to business drivers, technology changes, bad communication, lack of information, uncertainties, limited experience or even poor planning. (Ibbs, Wong, & Kwak, 2001).

According to Ezenta (2015), which research identified the most frequent and potential causes of changes in the Oil and Gas projects of the Alberta region (Canada), from literature and professionals experience, may be associated to:

- *Scope and design change*: since bid rounds are performed before the completion of the engineering design which at the time can be characterized by poor information in some parts of the project, following execution phase will lead to changes responsible for the cost and time overruns.
- *Site conditions*: more specifically the location and surroundings, weather conditions, salaries and wages, availability of supplies and materials.
- *Regulations*: if the legal permits and policies change throughout the execution of the project, this may lead to an extension of both the estimated duration and costs.
- *Technological changes*: reference to the evolution of the technology able to simplify the present oil and gas procedures, that may cause changes in the original plan designed by the initiation of the bid.
- *Market condition*: for example, the oil and gas price.
- *Environmental and political conditions*: like extreme weather conditions, wars, sabotage and terrorist acts.
- *Materials and equipment*: including changes in requirements of the power, size, and type of pumps, motors, pipes and other equipment.
- *Fast track*: when managers are in hurry for a fast delivery to the market, projects are launched with little engineering design.

The main consequences of change are the extension of the duration of completion, increase in expenditures, reduction of the expected quality, need for reworking to correct errors, deterioration of productivity and creation of litigation and dispute due to the disagreement between the contractor and the owner.

Horine (2005) proposed management principles for change control, including the plan for changes, the specification of a control system, training of stakeholders and use of the system, reduction of scope changes and finally improvement of the communication level. Project change management can be represented as the flowchart in *Figure 3.32* (Ezenta, 2015).

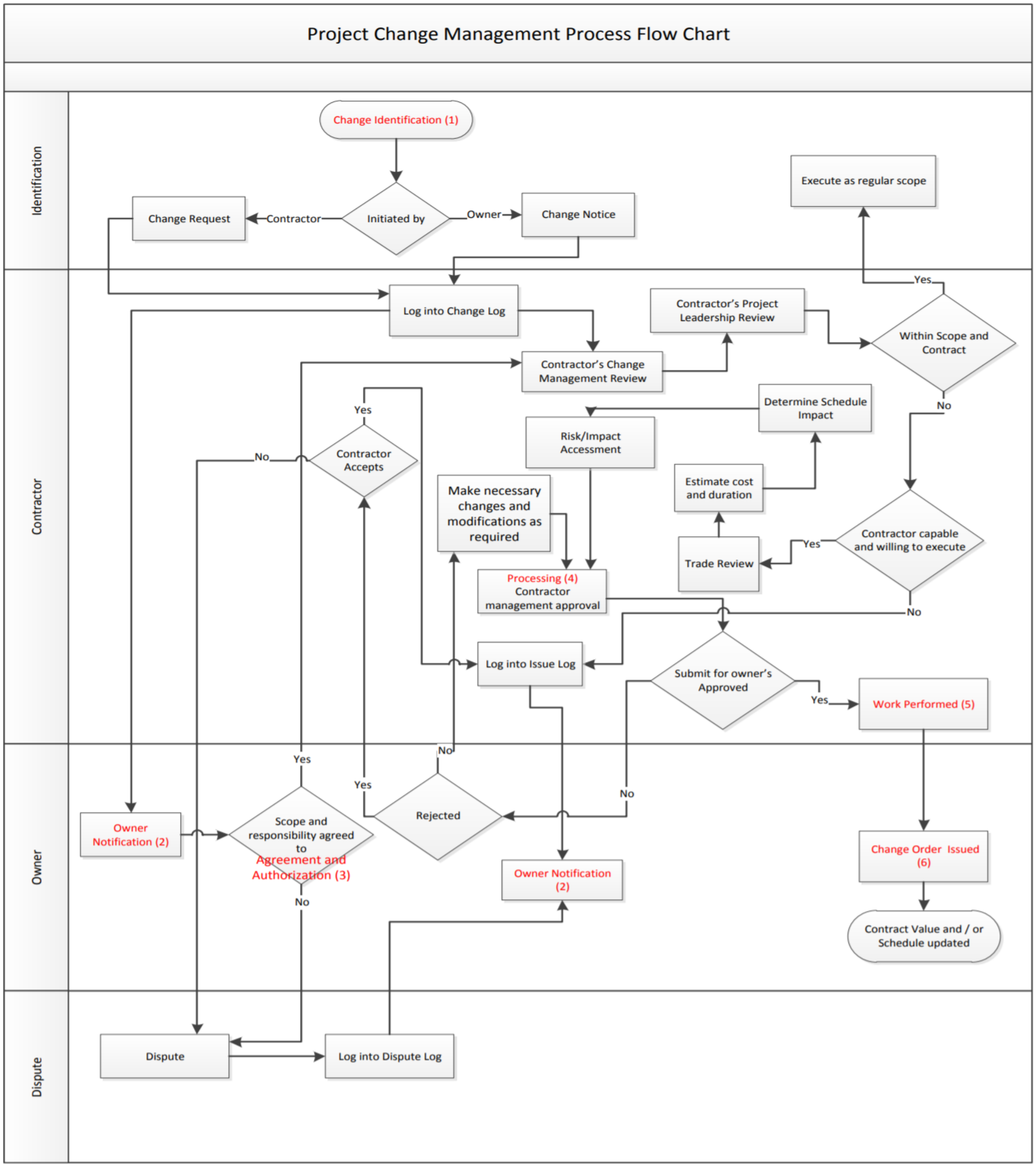


Figure 3.32- Process Flow chart of project-change management (Ezenta, 2015)

3.4.3 Impact of changes on projects: Analysis and Results from Literature

In the research done by Ezenta (2015), analysis of the project-changes and their impact are based on data collected from two different sources. One derives from questionnaires, interviews of professionals involved in the oil and gas projects developed in Alberta (Canada), while the other one is a database of the projects executed in the region from 2004 to 2012.

Statistical analysis of the questionnaires and the database was done to perform a more detailed research and classification of the data and their correlation. The projects were classified based on the initial estimated costs in three categories: large, medium and small (in reference to the estimated costs in dollars) and based on projects' duration in three other categories: long, medium and short (in reference to duration in years). Then, each category was analyzed during the four-stage of a project's execution phase: bid, preconstruction, construction and commissioning phases.

Table 3-14 summarizes the statistical analysis performed on the questionnaires data for the identification of principal causes of cost and time overruns in the different phases of a project.

Table 3-14 Statistical results from Questionnaires investigation of the causes relative to the cost and time overruns during the project (Ezenta, 2015)
**Part 1*

Phases	Causes	Cost		Schedule	
		N	Percent	N	Percent
Bid Phase	Design Changes	129	**35.5%**	83	**24.5%**
	Site Condition	4	1.1%	13	3.8%
	Scope Change	112	**30.9%**	104	**30.7%**
	Changes in Regulations	3	0.8%	9	2.7%
	Change in Technology	4	1.1%	11	3.2%
	Market Conditions	13	3.6%	9	2.7%
	Management Decisions	87	**24.0%**	69	**20.4%**
	Environmental	2	0.6%	5	1.5%
	Materials and Equipment	4	1.1%	34	**10.0%**
	Fast Tracking	1	0.3%	2	0.6%
	Others: Specify	4	1.1%	-	-
	Total	363	100.0%	339	100.0%
Preconstruction Phase	Design Changes	123	**23.9%**	99	**29.4%**
	Site Condition	89	**17.3%**	53	**15.7%**
	Scope Change	130	**25.3%**	105	**31.2%**
	Regulations	1	0.2%	3	0.9%
	Change in Technology	1	0.2%	4	1.2%
	Market Conditions	11	2.1%	12	3.6%
	Management Decisions	102	**19.8%**	49	**14.5%**
	Environmental	47	9.1%	2	0.6%
	Materials and Equipment	5	1.0%	5	1.5%
	Fast Tracking	1	0.2%	1	0.3%
	Others: Specify	4	0.8%	4	1.2%
	Total	514	100.0%	337	100.0%

Table 3-15 Statistical results from Questionnaires investigation of the causes relative to the cost and time overruns during the project (Ezenta, 2015)
**Part 2*

Phases	**Causes**	**Cost**		**Schedule**	
		N	**Percent**	**N**	**Percent**
Construction Phase	Design Changes	73	**11.7%**	58	**12.5%**
	Site Condition	143	**23.0%**	89	**19.2%**
	Scope Change	104	**16.7%**	78	**16.8%**
	Regulations	4	0.6%	4	0.9%
	Change in Technology	-	-	-	-
	Market Conditions	2	0.3%	5	1.1%
	Management Decisions	81	**13.0%**	72	**15.5%**
	Environmental	77	**12.4%**	59	**12.7%**
	Materials and Equipment	117	**18.8%**	88	**19.0%**
	Fast Tracking	16	2.6%	6	1.3%
	Others: Specify	5	0.8%	5	1.1%
	Total	622	100.0%	464	100.0%
Commissioning Phase	Design Changes	10	3.3%	27	6.6%
	Site Condition	13	4.2%	39	9.5%
	Scope Change	38	**12.4%**	57	**13.8%**
	Regulations	3	1.0%	4	1.0%
	Change in Technology	4	1.3%	2	0.5%
	Market Conditions	10	3.3%	9	2.2%
	Management Decisions	75	**24.5%**	59	**14.3%**
	Environmental	7	2.3%	53	**12.9%**
	Materials and Equipment	127	**41.5%**	147	**35.7%**
	Fast Tracking	9	2.9%	5	1.2%
	Others: Specify	10	3.3%	10	2.4%
	Total	306	100.0%	412	100.0%

Meanwhile, data from surveys and interviews are mainly classified based on the experience of the participants, their role in the company and the role of the company in the project.

For a better understanding of the data acquisition and classification, see Chapter 3 and Chapter 4 of the research taken as reference (Ezenta, 2015).

Further analysis of the research done by Ezenta (2015) on the changes in cost during the different project's phases highlights a trend of high-cost increase in the Construction Phase for all project categories. *Figure 3.33* illustrates an example of the Medium Project category only.

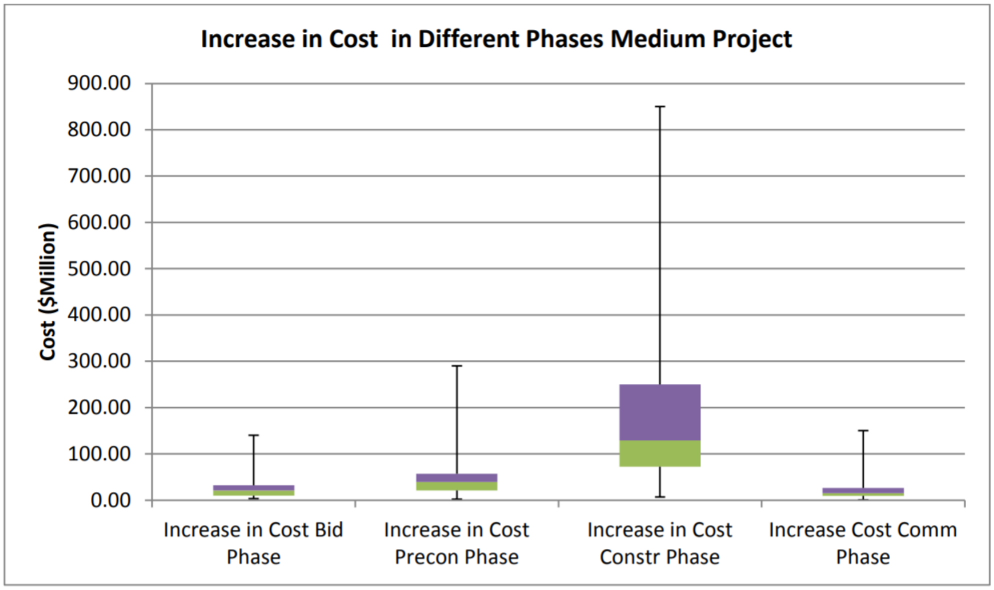


Figure 3.33 Example of the cost overrun analysis at different project stages of a Medium Project (Ezenta, 2015)
**Initial costs estimation are represented by the green part while violet part indicated the change in cost*

The analysis of project duration and its change during project lifecycle shows, similarly to the analysis of cost changes, a significant increase in duration in the Construction Phase, while the first two phases present both the same degree of duration change. Ezenta (2015) remarks on the fact that cost and duration are "*not linearly related*". The *Figure 3.34* shows the additional duration estimated in the different phases of a Long Project category.

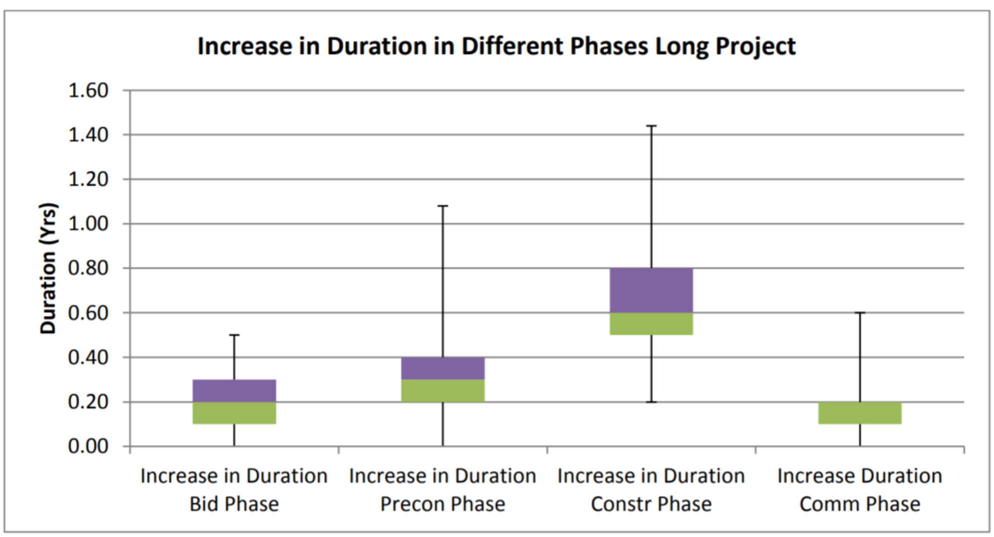


Figure 3.34 Example of the duration overrun analysis at different project stages of a Long Project (Ezenta, 2015)
**Initial costs estimation are represented by the green part while violet part indicated the change in cost*

To find a system able to predict the project-changes during the execution phase and its degree of impact, additional analysis of the base data regarding the executed projects in Alberta (Canada) and data from questionnaires was done. The objective of this analysis is to find correlations able to validate or refuse initial hypothesis proposed by the researcher (Ezenta, 2015).

The statistical analysis validated the following hypothesis in the research:

- "*Low percentage in engineering project definition is responsible for changes in project costs*", but with a low fit of the data in the model.
- The variable of projects-changes is highly correlated to the increase in project costs.
- Longer project duration is determined by project-change; however, the correlation exists between the project duration and final costs.
- Project-change influence both costs and duration during the execution phase. This indicates a "*strong linear relationship between total cost and the change in cost in different phases of the project"*. The same statement is true in considering project duration and change in cost variables.

The model proposed by the researcher allow to define, for each of the phases, the changes related to the costs and duration from the initial estimations of these variables and the level of completion of the engineering design. The results can be plotted and analyzed as in *Figure 3.35.*

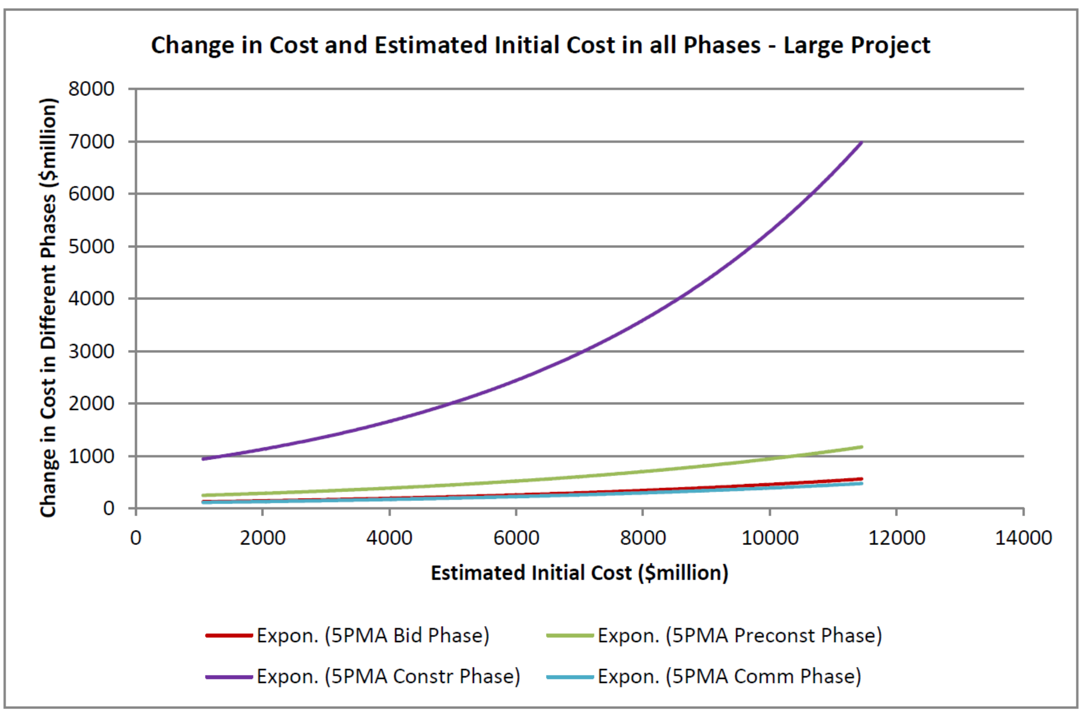


Figure 3.35 Example of change in cost analysis based on the initial cost estimation for the different project phases (Ezenta, 2015)

Analyzing more in detail the *Figure 3.35*, exponential trend describes the variance of the additional costs, due to changes, in the different phases of the project development based on the estimated initial cost. The exponential curves representing the Bid Phase and the Commissioning Phase are characterized by a small slope, while the one representing the Preconstruction Phase has a slightly more remarkable change. These results implicate a small deviation of the estimated costs with respect to the real costs faced during the phases. The Construction Phase, instead, is described by an exponential curve with higher inclination with respect to the curves related to the other phases. This indicates the large influence of the changes on the additional costs with respect to the estimated ones.

3.4.4 Conclusions: Distribution Types of Cost and Time Overruns

Based on the results of the Ezenta's (2015) research, higher estimated initial costs and longer estimated initial duration, derive principally from the changes in the Construction Phase with respect to the other phases (*Figure 3.35*). Consequently, the distribution of these overruns cannot be simplified to a Normal Gaussian distribution. In fact, the study of Love et al. (2013) on 276 constructions and engineering projects in Australia, demonstrated the poor matching of the Normal distribution to the empirical data. Instead, a three-parameter Frechet distribution demonstrates to be the best choice defining an overall fitting of the cost overruns data.

In this project, the triangular distribution is adopted in the model by defining two parameters that represent the limits of the project duration and cost overruns.

Determination of the costs and duration of a project during its execution are highly impacted by the occurrence of changes during the construction phase.

3.5 Oil and gas prices

According to the energy information administration EIA, crude oil prices are controlled by several factors, that can be categorized under the level of supply from OPEC and non-OPEC countries and demand of OECD and non-OECD countries (EIA, Analysis & Projections, 2018):

- The impact of supply is manifested from both OPEC and non-OPEC countries where the common factors affecting the price are: the changes in production capacity & GDP, the price of WTI crude and supply disruption. Considering only OPEC countries, the price is affected by the changes in production in Saudi Arabia, while considering non-OPEC countries, the price is affected by changes in production capacity generally and by the projected supply.
- The impact of demand from both OECD and non-OECD countries is directly related to world oil consumption, world GDP & WTI crude oil prices. While the impact from non-OECD countries only is due to projected non-OECD production.

However, there many other factors that affect the oil and gas price fluctuation that are different from the demand and supply dynamics (Kumar Kar & Pathak, 2017):

- Grow of the world economy that is connected to the global energy consumption and demand.
- Monetary and fiscal policies are connected to the trading market between different countries where investments and capital flow characterize the oil demand based on the value and interest rates of the money. Appreciation and depreciation of the US currency, which is used for the oil benchmarking, affect the import-export operations of the hydrocarbon resource.
- OPEC policy is an important factor which equilibrates the crude oil demand and supply and influences the variation of the price.
- Geopolitical events can also influence the oil price. This factor increases the uncertainty related to the oil price estimation. The increase in the oil price due to the sanctions against Iran is an example.

It is to note that oil pricing is associated with benchmarks classified based on oil quality (API gravity and sulphur content), this classification facilitates the exchange between buyers and sellers anywhere around the globe. The most important benchmarks are:

- the Brent blend: it refers to oil from a few fields in the North Sea, it is light and sweet and it is the most widely used. It is adopted as reference for pricing oil from Europe, Africa, Australia, Mediterranean and some Asiatic countries.
- the West Texas Intermediate: extracted from the United States, it is very light and sweet, but has high costs of shipment, basically used for pricing Canadian, Mexican, South American and American oil.
- The Dubai/Oman: it is medium-sour and heavier than the other benchmarks, it refers mainly to the oil exported to Asia from the Persian Gulf. It is mainly used to price oil produced in Saudi Arabia and shipped to Asia.

In general, the cheapest benchmark is the WTI, followed by Dubai and finally the Brent. *Figure 3.36* shows the price variation of these three benchmarks between 2011 and 2015.

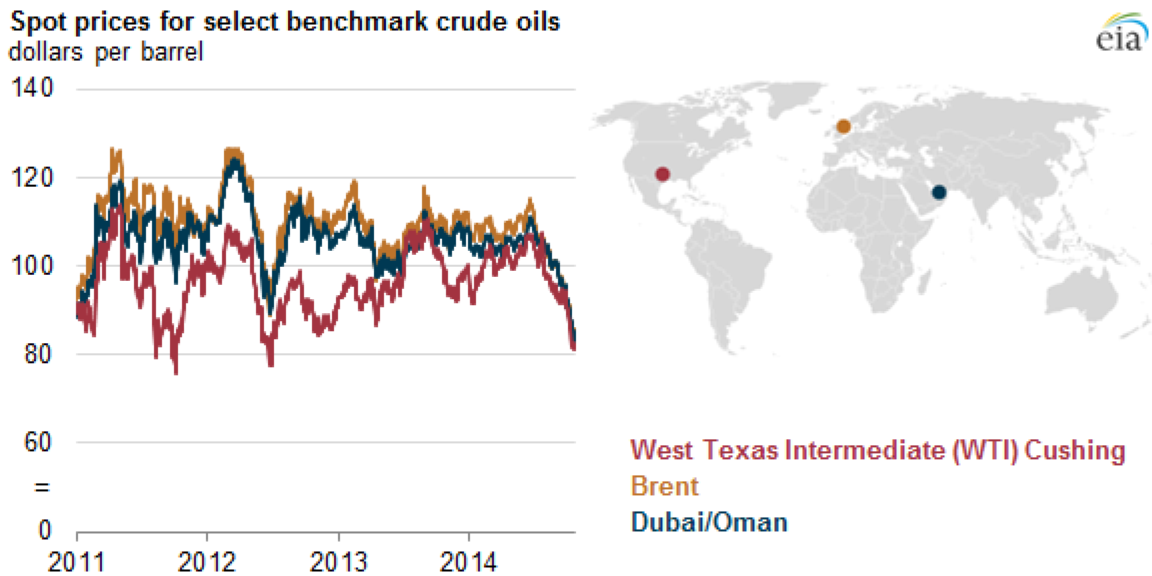


Figure 3.36 Example of variation for the oil price indices relative to the year 2014 (EIA, Benchmarks play an important role in pricing crude oil - Today in ... - EIA, 2014)

Many research studies have been conducted to forecast oil price because it is the core of an industry in which huge investments and revenues are generated and on which many countries' economy rely.

According to David Frans (2017), the forecasting of the oil price is performed by top oil exporting countries and by few institutions (NYMEX, EIA, OECD). For a long time the top exporting countries had performed a proper and accurate forecasting of the oil price. From 2009 however, unstable conditions of the market determined by the cut in production of the OPEC and the US shale oil production, inverted the roles (Frans, 2017).

Price forecasting studies can be based also on the analysis of the past price and production projections and their performance to assess the uncertainty related to the present forecasting and to help in improving price projections models for a better accuracy. The *Figure 3.37* shows an analysis of the World oil supply and price from 1950 to 2015 and their forecasting (Wachtmeister, Henke, & Höök, 2018).

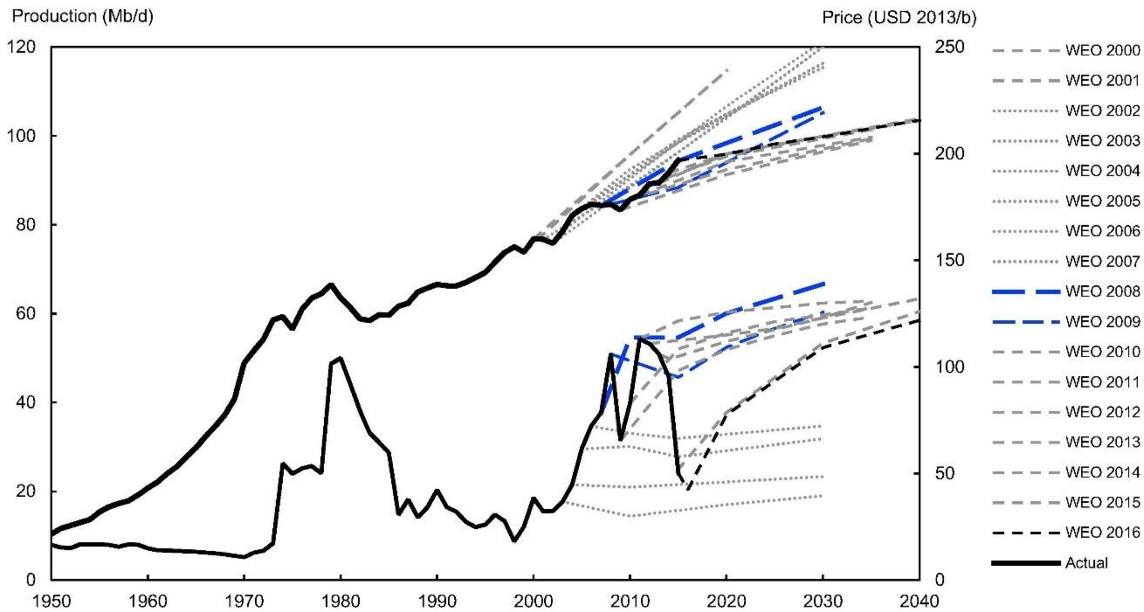


Figure 3.37 World oil supply and price from 1950 to 2015 and their forecasting (Wachtmeister, Henke, & Höök, 2018)

Chapter 4 The method

4.1Monte Carlo method and probability distributions

The deterministic approach regards the appliance of a mathematical model where there is no random variation of the inputs. As consequence, the resulting outcome of the model will not vary for a specific set of inputs. Because of its easy characterization, the model is fast to perform, and the results are easy to explain. This approach allows also to detect inconsistency between variables which can be fast solved by intervening on the variables. However, exclusion of random variation of the parameters implies that the uncertainty of the values is not accounted.

The Probabilistic method accounts for all the possible values that a parameter can assume and the statistical trend related to the occurrence of these values. The statistical trend, or better known as probability density function (PDF), is determined by the available data and expert's assumptions on each considered parameter involved.

Based on the number of repetitions of the Monte Carlo procedure, where random values for each parameter are generated based on the respective PDF, several results will be calculated, and a PDF applied to them, thus results are generated as distributions. The largest the number of iterations, the better the results. Usually, a run of 10,000 iterations is adopted for a typical well simulation (Akins, Abell, & Diggins, 2005).

Additionally, to the random generation of the parameter's values, dependencies between parameters must be considered in the probabilistic estimation (Swinkels, 2011). The scheme of Monte Carlo is shown in the following *Figure 4.1*:

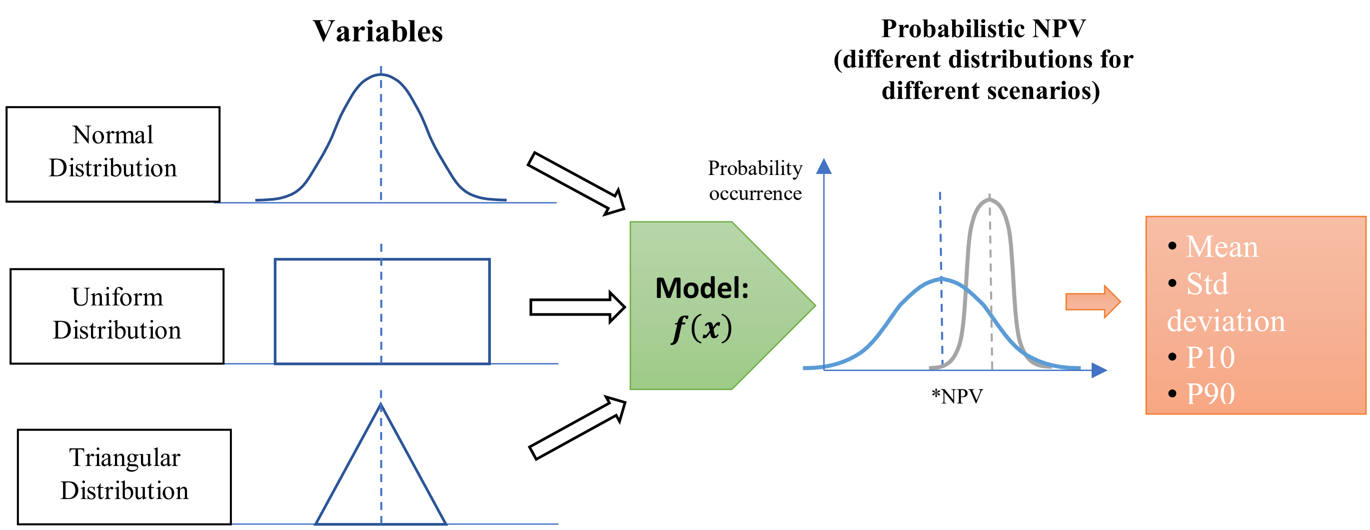


Figure 4.1 Scheme of Monte Carlo
**the distribution curves represent two possible and different results from the model*

The resulting distribution curves can vary in the probability occurrence and range of the derived statistical data, based on the level of uncertainty that characterize the variables used for the distribution estimation.

The first step to perform a Monte-Carlo simulation is to select a distribution function for the inputs; in this context, where only continuous distributions are taken into consideration.

Based on the available data and related quality, an expert can choose the PDF that better fits the information. The possibility of choosing between many PDFs is given by the availability of advanced statistical software.

A common way of specifying distributions is by calculating P10 and P90, along with a measure of central tendency such as either P50 or the mode of the distribution. P10 or 10th percentile value indicates that 90% of the estimates exceed the P10 estimate, the same considerations apply to P90, thus P10 stands for the low estimate and P90 for the high estimate. In case of normal distribution or symmetric triangular distribution, median and mean and mode estimates are equivalent, while in other distributions they do not always coincide. This last consideration is shown in the *Figure 4.2* relative to a lognormal distribution.

The different types of distributions considered are:

- The uniform distribution is characterized by an equal probability of occurrence of all its input data between a minimum and a maximum value, except some unrepresentative points that may be removed. It is generally used to describe small data sets. (Harper, 2018)
- Triangular distribution is defined by a minimum *a,* a maximum *b* and a peak value *c*. The PDF at any value *x* is given by:

$$P(x) = \begin{cases} \dfrac{2(x-a)}{(b-a)(c-a)} & \text{for } a \le x \le c \\ \dfrac{2(b-x)}{(b-a)(b-c)} & \text{for } c < x \le b \end{cases}$$

Equation 4-1

  Triangular distributions are considered artificial by professionals, however combining several triangular distributions together, gives as output normal distributions (PetroWiki, 2015). Akins et al (2005) assumed uniform and triangular distributions to be standard for model building in well time and cost estimation. Instead, the representation of field production reserves and average porosity is better done using the normal distribution.

- The normal distribution is characterized by its bell-like curve, its symmetric distribution around a mean value μ, and its spread controlled by the standard deviation σ. A small σ indicates a narrow distribution around the mean, while a large σ indicates the exact opposite.

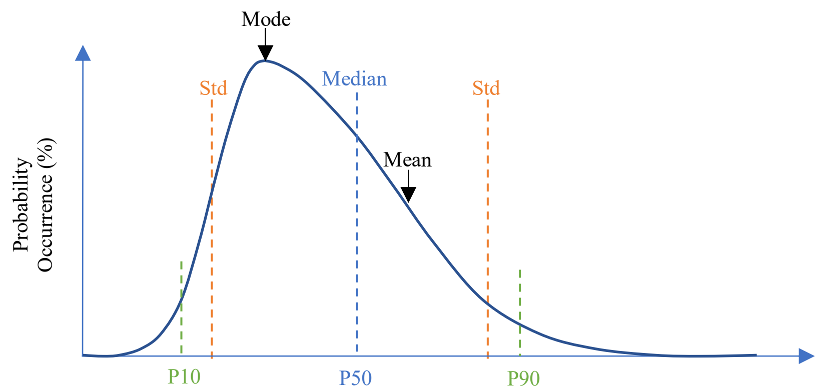


Figure 4.2 Representation of a Lognormal Distribution and its characteristics

4.1.1Monte Carlo: number of iterations and simulation's error

Implementation of the Monte Carlo' method, in a mathematical model, requires consideration of the error related to the number of iterations applied to the model. In order to increase the accuracy of the results, investigation of the number of iterations is needed. Usually, a higher number of iterations is related to a lower error, due to the Central Limit Theorem. To perform a higher number of iterations, however, requires also more time for the simulation. Therefore, the definition of the optimum number of iterations, needed by the model, allows the perfect trade between error and time required by the user to perform a reliable result.

A method of calculating the necessary number of simulations consists of the computation of the variance relative to the simulation and its standard deviation. Considering a Normal distribution, the confidence limits and levels are determined by the mean and the standard deviation. In fact, the standard deviation characterizes 68% of the area, inside the distribution, in which a generated random value will belong. Higher confidence coefficients, which are related to higher confidence levels, characterize higher percentage of the distribution area in which a random value will lie, as in *Figure 4.3* (Bukaçi, Korini, Periku, Allkja, & Sheperi, 2016).

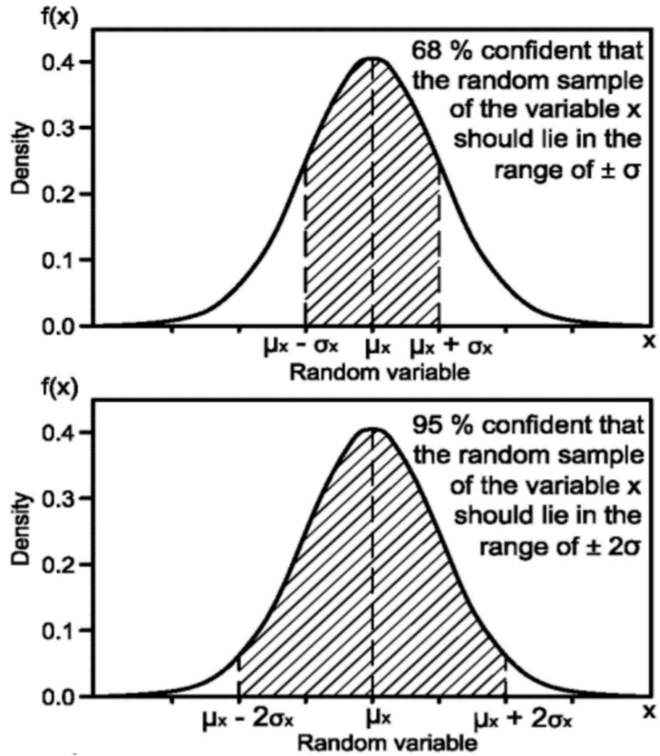


Figure 4.3 Confidence coefficient and confidence level related to a Normal distribution (Bukaçi, Korini, Periku, Allkja, & Sheperi, 2016)

Therefore, the relation between standard deviation and mean value (calculated in relation to the number of the iterations) determine different bounds and relative confidence intervals from which it is possible to calculate the standard error (in percentage) of the mean from the number of iterations used by the method of Monte Carlo as in the following equation (Bukaçi, Korini, Periku, Allkja, & Sheperi, 2016):

$$E = \frac{100 * z_c S_x}{x_{mean} * \sqrt{N}}$$

Equation 4-2

In the equation:

- E is the standard error in percentage
- x_{mean} is the mean value of the simulation
- N represents the number of iterations
- z_c represents the confidence coefficient
- S_x is the Standard deviation or variance of the simulation

Imposing the admissible level of error, it is possible to calculate the number of the iterations needed for the simulation as in the equation:

$$N = \left[\frac{100 * z_c S_x}{x_{mean} * E}\right]^2$$

Equation 4-3

Increasing the number of iterations, the error will decrease and the result will converge to a more a more accurate and reliable estimation.

For the designed model used in my thesis, the recommendation of 50 000 iterations are recommended in order to decrease the error to an average of 2%, as showed in the following example.

Example:

Simulations at the 5 000, 10 000 and 30 000 iterations were performed. The *Table 4-1* contains the results of the mean, standard deviation and the related standard error relative to a confidence coefficient equal to 2.58 that define a confidence level of 99%.

Table 4-1 Example of standard error investigation based on the number of iterations used in the model

Number of iterations per simulation	Estimated NPV Mean value (M$)	Estimated NPV Standard Deviation (M$)	Standard Error (%)
5000	108.3765	195.2628	6.57
10000	110.0838	197.9419	4.64
30000	117.5173	200.3039	2.54

As stated previously, higher number of iterations determined a lower standard error. In order to decrease the percentage of error to a value of 2 or lower, a number of iterations of 50 000 or higher have to be considered.

4.2The MATLAB algorithm – inputs and calculations

The proposed MATLAB algorithm in this project permits the estimation of a probabilistic distribution of the NPV based on a series of inputs provided by the user.

The algorithm allows the user to select a fixed value or distribution between uniform, triangular and normal and to set the representing values for the following classes of data inputs:

- **Oil Production**
  - *Oil production per day* regards the volume produced by a single well, in barrels of oil per day. It is assumed that all the wells have the same characteristics and production rate.
  - *Decline percentage* is related to the percentage that affects the production every year.
  - *Number of wells* active during the production phase.
- **Gas Production (from Oil Production)**
  - *Gas – Oil Ratio (Rs)* is related to the amount (in cubic meters) of gas dissolved in one cubic meter of produced oil (at stock tank conditions) at reservoir conditions.
- **Oil and Gas Price**
  - *Real oil price* is the price (in dollars) of one barrel of oil.
  - *Real gas price* is the price (in dollars) of 1000 cubic feet of gas.
- **Capital and Operational Costs**
  - *CAPEX* is the Capital Expenditures (in dollars) involved during the project development phase.
  - *OPEX* is the Operational Expenditures (in dollars) of producing one barrel of oil.
  - *Field development time* regards the time (in years) necessary to develop the field for the production.
  - *Project delay* is the duration (in months) related to the delay of the development operations necessary for the completion.

The user is also invited to indicate *fixed values* of the following inputs from the different classes:

- *Total years of production*
- *Starting year of decline* in production and it is relative to the year in which the plateau rates finish and continuous decrease in production occur.
- *Cost of delay* is determined by the user by imposing which percentage of monthly CAPEX has to be accounted as additional cost during the delay duration, which is in months.
- *Abandonment cost* is the cost (in dollars) for dismantling the production facilities and remediate the occupied surface.
- *Difficult Workover* (at a determined cost in a determined year) is the cost (in dollars) necessary to perform an occasional and difficult workover that is accounted during a precise year. The input of the cost and of the year are required.
- *Rent/ surface cost* is the cost (in dollars) related to the tax paid for the occupied surface during the project lifecycle and is accounted in dollars per year.
- *Total taxes* represent the percentage of GOV take from the total pre-tax revenues.
- *Discount rate* is the percentage used to discount the projected Cash Flows during the project lifecycle.
- *Number of simulations* regards the number of random values generated with the Monte Carlo's method.

The input values are chosen based on historical data or directly assumed by the user. Once the input values are set, the user must precise the desired number of simulations to launch the Monte-Carlo simulation. The program then, based on the chosen distribution that the user imposes on a variable, creates random values as many as the input *Number of simulation* and that follows the trend of the imposed distribution. This process uses a modified function of the ones built-in the software Matlab. These modified functions allow the generation of values that follow a specific distribution by:

- Declaration of maximum and minimum values for the normal distribution and uniform one which is symmetrical.
- Declaration of min, max and peak value for the triangular distribution which can be also asymmetrical.

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Normal	bbl/day	1000	2000	1800	1800
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				3
Decline percentage	Uniform	%	8	12	11	10
Number of wells	Fixed_Number	n°	5	9	7	10
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	NO_GAS	m3/m3	300	360	350	250
OIL AND GAS PRICE						
Real Oil Price	Uniform	$/bbl	65	75	68	65
Real Gas Price	Fixed_Number	$/1000cf	8	10	7	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Triangular	$	8.0E+08	8.6E+08	8.40E+08	2.1E+09
OPEX	Fixed_Number	$/bbl	26	30	28	5
Field Development time	Triangular	years	2	4	3	3
Project Delay	Normal	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				40
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				60
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**1000**			

Figure 4.4 Example of inputs and its imposed distribution of the model

To use the deterministic approach, the variables on which probabilistic distribution can be applied has to be imposed as Fixed Value and the input in the proper cell has to be declared.

The simulation consists of a series of calculations performed in the following steps:

Step 1: Calculation of the total volume of oil produced in the production period by all the wells.

The initial calculation of the total produced barrels of oil from all the wells is calculated by multiplying the Number of wells to the Oil production rate per day of a single well. The total production is then determined by the multiplication of the total daily production to the total production time converted from years to days. The production volume is calculated as a total and monthly for final discounting purposes.

$$V_{tot\ oil}\ (bbl) = Q_{oil}\left(\frac{bbl}{day}\right) * Number\ of\ wells * (Total\ years\ of\ production(y) * 365days)$$

Equation 4-4

Step 2: Calculation of the total volume of Gas produced from the oil extraction.

Conversion of the total produced oil volume (in barrels) in cubic meters. The data obtained is multiplied with the Rs (gas – oil ratio) to obtain the total volume of gas produced (in cubic meters) with the oil.

$$V_{gas}\ (m^3) = V_{oil}\ (m^3) * R_s$$

Equation 4-5

In the Selected Distribution cell relative to R_s is possible to chose the case in which production of gas is neglected by imposing the cell on NO_GAS. No gas production and derived revenues will be accounted for the final NPV estimation.

Step 3: Calculation of the Revenues generated by the produced oil and gas volume.

The revenues (dollars) from oil are determined by the multiplication of the calculated volume of oil (barrels) by the user's defined price (dollars / barrel), while the revenues from gas are calculated through the multiplication of the gas volume (cubic feet) with the gas price (dollars / 1000 cubic feet). The summation of the oil revenues and the gas revenues gives the Total Revenues. The revenues are also calculated for each year, based on the yearly production, for final discounting calculation.

$$Revenues\ (\$) = Real\ oil\ price\left(\frac{\$}{bbl}\right) * V_{oil}\ (bbl) + Real\ gas\ price\left(\frac{\$}{1000\ scf}\right) * V_{gas}\ (scf)$$

Equation 4-6

Step 4: Calculation of the total costs involved during the project lifecycle.

The costs are calculated by year and accounted differently based on the project phase, except the cost of the surface production facility renting which is active during each year for the entire lifecycle. During the Development phase, CAPEX and surface renting are the only costs considered. Since the input of CAPEX is defined as the total amount, this value is divided by the years necessary for the development in order to define a year by year total cost. When the Development time finish and production starts, the Operational Expenditure related to the yearly production, surface renting costs and taxation percentage relative to the revenues of that period are the only variables determining the costs generated during the considered years. In case that Workover is accounted for during production, it's cost has to be accounted in the year in which it occurs by the assumption. The last year of production, the cost is determined also by the Abandonment cost which is added to the OPEX and Surface renting costs. Summation of all the determined cost per year defines the Total cost.

$$1)\quad Costs1\left(\frac{\$}{year}\right)=\frac{CAPEX(\$)}{Development\ time\ (years)}+Surface\ rent\left(\frac{\$}{year}\right)$$

Equation 4-7

$$2)\quad \text{Costs2}\left(\frac{\$}{\text{year}}\right)=OPEX\left(\frac{\$}{bbl}\right)*V_{oil}\left(bbl*production_{year\ (t)}\right)+Tax(\%)*Revenues_{year\ (t)}+\text{Surface rent}\left(\frac{\$}{\text{year}}\right)$$

Equation 4-8

$$3)\quad \text{Costs3}\left(\frac{\$}{\text{year}}\right)=OPEX\left(\frac{\$}{bbl}\right)*V_{oil}\left(bbl*production_{year\ (t)}\right)+Tax(\%)*Revenues_{year\ (t)}+Cost\ of\ Workover_{year(t)}+\text{Surface rent}\left(\frac{\$}{\text{year}}\right)$$

Equation 4-9

$$4)\quad \text{Costs4}\left(\frac{\$}{\text{last year}}\right)=OPEX\left(\frac{\$}{bbl}\right)*V_{oil}\left(bbl*production_{\ last\ year}\right)+Tax(\%)*Revenues_{last\ year}+\text{Surface rent}\left(\frac{\$}{\text{year}}\right)+Abandonment\ (\$)$$

Equation 4-10

$$5)\quad Total\ cost(\$)=Cost1(\$)+Cost2(\$)+Cost3(\$)+Cost4(\$)$$

Equation 4-11

Step 5: The calculation of the Net Cash Flow (NCF).

This operation is performed by the subtraction of the costs from the revenues, relative to each year of the project. This calculation will define negative NCF during the development period and then positive ones during the production period.

$$NCF\left(\frac{\$}{year\ (t)}\right) = Revenues\left(\frac{\$}{year\ (t)}\right) + Costs\left(\frac{\$}{year\ (t)}\right)$$

Equation 4-12

Step 6: Application of the Inflation and Discount rate to the NCF.

Each value of NCF is adjusted by Inflation and Discount rate (also adjusted by the inflation) based on the years in which it generates. The adjustment is applied through the following equation:

1) $$\mathrm{NCF}_{corrected\ with\ inflation} = \sum(NCF_{year(t)} * (1 + Inflation^{year(t)}))$$

Equation 4-13

2) $$\mathrm{NCF}_{discounted} = \sum(NCF_{year(t)}/(1 + Nominal\ Discount\ rate^{year(t)}))$$

Equation 4-14

Step 7: Calculation of the Net Present Value (NPV).

The summation of the Net Cash Flows generated yearly during the different project phases determines the NPV.

$$NPV(\$) = \sum NCF_{discounted}$$

Equation 4-15

Step 8: Calculation of the Net Present Value (NPV) for a field development time increased by one year. The remaining variables are considered the same as imposed at the beginning of the running.

Chapter 5 Case Studies and Results

In this chapter, we discuss the application of the mathematical model, designed on the software Matlab and Excel, to four Case Studies related to different type of petroleum fields. The type of production field taken into consideration are:

- Onshore petroleum field
- Offshore petroleum field, in specific Tension Leg Platform (TLP)
- Offshore petroleum field, in specific Floating Production Storage and Offloading (FPSO) considered as an asset of the petroleum company which invests money to build the ship
- Offshore petroleum field, in specific FPSO which is rented by the petroleum company for the development and production operations

In the model, every Case Study is characterized by specific inputs, except the FPSO cases in which the only changing variables regards the development and production costs. The assumption regarding the production of oil and associated dissolved gas is made for all the production fields.

Additionally, the inputs considered for every Case Study are defined according to a reasonable range based on the available data and/or the advice of the Ing. Giambattista De Ghetto. Therefore, the inputs are not related to any existing project in any specific production area. Ranges of Economic Indicators like CAPEX/Reserves, Present Value Ratio (PV Ratio), Internal Rate of Return (IRR) and Operating Expenditure (OPEX), based on the indication of the Ing. Giambattista De Ghetto, are considered for a good definition of the costs and the production levels. The following ranges are considered:

- CAPEX / Reserves, between 5 $/barrel and 20 $/barrel
- PV Ratio, between 0.2 and 1
- IRR, higher than 12,25
- OPEX, between 5 $/barrel and 15 $/barrel

In order to respect the limits relative to the Economic Indicators, the Reservoir Volume and the maximum production rate is assumed and imposed as described in the *Figure 3.28* of the subchapter 3.3.2.

All the Case Studies are simulated with a Deterministic and Probabilistic approach in order to compare the results and assess the additional information provided by the Probabilistic one. In addition, the probabilistic results related to the Case Study 3 (build of FPSO) and Case Study 4 (rent of FPSO) are compared to evaluate the profit opportunity of an alternative project development concept.

5.1Case Study 1 – Onshore field

In this Case Study, inputs of a generic onshore field are imposed in the model as in *Figure 5.1*. All the inputs, on which a distribution can be applied, are imposed initially as *Fixed_Number* in order to evaluate a deterministic result. The values in the grey cells instead represent the fixed variables on which uncertainty is not accounted for and are characterized by a single value.

Since *Fixed_Number* is chosen, instead of a distribution, only the values inside the blue cells, and the one in the grey cells are used for the mathematical calculation. The imposed number of simulation, in this case, does not influence the results and is not accounted for by the model.

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Fixed_Number	bbl/day	1000	1800	1500	1600
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				3
Decline percentage	Fixed_Number	%	6	11	8	10
Number of wells	Fixed_Number	n°	5	8	6	10
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Fixed_Number	m3/m3	200	350	220	250
OIL AND GAS PRICE						
Real Oil Price	Fixed_Number	$/bbl	60	75	68	65
Real Gas Price	Fixed_Number	$/1000cf	8	10	9	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Fixed_Number	$	2.8E+08	4.5E+08	3.30E+08	4.3E+08
OPEX	Fixed_Number	$/bbl	4	6	5	5
Field Development time	Fixed_Number	years	2	4	3	3
Project Delay	Fixed_Number	months	6	10	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				40
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				60
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.1 Definition of the inputs for a deterministic calculation related to an onshore field

A difficult workover is assumed to be performed during the 8th year of the production and the cost of 10 M$ is going to be considered as a CAPEX. This cost, relative to the year in which it is performed, is accounted for an entire year, independently to its duration. The intervention is assumed to not influence the hydrocarbon production. The input interface is shown in *Figure 5.2*.

HEAVY WORKOVER DURING PRODUCTION assumption (duration = 1 year & production rate not influenced)	
Assumed	
Cost	1.0E+07
Year of occurrence	8

Figure 5.2 Interface of the Heavy Workover assumption in the model

The NPV results, together with Reserves and Economic Indicators estimations, are shown in *Table 5-1* and *Figure 5.3*:

Table 5-1 Total Reserves, NPV results and Economic Indicators evaluations from the model related to an onshore field

Results		
Total Reserve Estimation	50	Mbbl
CAPEX / Reserves	8.60	$/bbl
Present Value Ratio	0.62	-
Internal Rate of Return	16.74	-
NPV (original development time)	231.58	M$
NPV (original development time +1 year)	196.89	M$

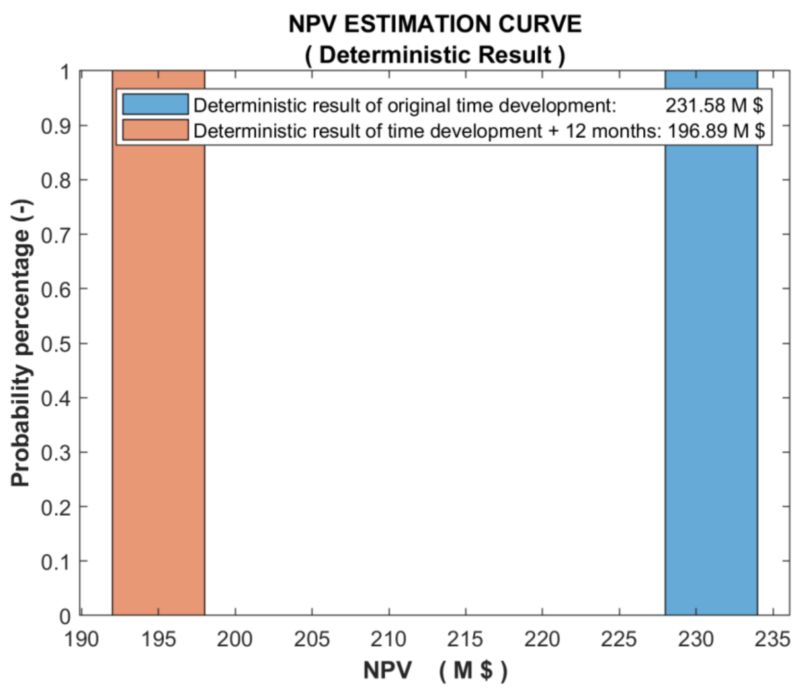


Figure 5.3 Visual representation of the Deterministic NPV results related to an onshore field with respect to two different project development durations

We can see from the deterministic results that a longer duration of the development phase, as an alternative to the original one, will decrease the NPV from 231.58 M$ to 196.89 M$. If higher development duration can justify a decrease of development costs, of more than 35 M$, then the alternative concept can be considerable.

For the Probabilistic simulation, the inputs of the model are defined as in *Figure 5.4*. In this case, probabilistic distribution and range of values are imposed on some variables. In specific:

- For the *Daily Oil production per well*, the *Normal* distribution is imposed within a range of 1000 and 1800 barrels
- *Decline percentage* is defined by a *Uniform* distribution within a range between 6% and 11% per year
- Gas-Oil ratio defined by *Rs* is defined by a *Triangular* distribution within a range of 200 to 350 $\frac{sm^3}{m^3_{stock-tank}}$, and a distribution peak at 220 $\frac{sm^3}{m^3_{stock-tank}}$
- *Oil Price* is defined by a *Uniform* distribution in a range of 60 to 75 $/barrel
- *CAPEX* is defined by a *Triangular* distribution within a range of 280 M$ to 450M$, and a distribution peak at 330 M$
- The *Field Development time* is defined by a *Normal* distribution between 2 and 4 years
- *Project Delay* is defined by a *Triangular* distribution within a range of 6 months to 10 months, and a distribution peak at 7 months

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Normal	bbl/day	1000	1800	1500	1600
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				3
Decline percentage	Uniform	%	6	11	8	10
Number of wells	Fixed_Number	n°	5	8	6	10
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Triangular	m3/m3	200	350	220	250
OIL AND GAS PRICE						
Real Oil Price	Uniform	$/bbl	60	75	68	65
Real Gas Price	Fixed_Number	$/1000cf	8	10	9	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Triangular	$	2.8E+08	4.5E+08	3.30E+08	4.3E+08
OPEX	Fixed_Number	$/bbl	4	6	5	5
Field Development time	Normal	years	2	4	3	3
Project Delay	Triangular	months	6	10	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				40
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				60
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations		→	**50000**			

Figure 5.4 Probabilistic definition of some variables in the model related to an onshore field

The results of the simulation performed at 50 000 iterations are shown in the *Figure 5.5*.

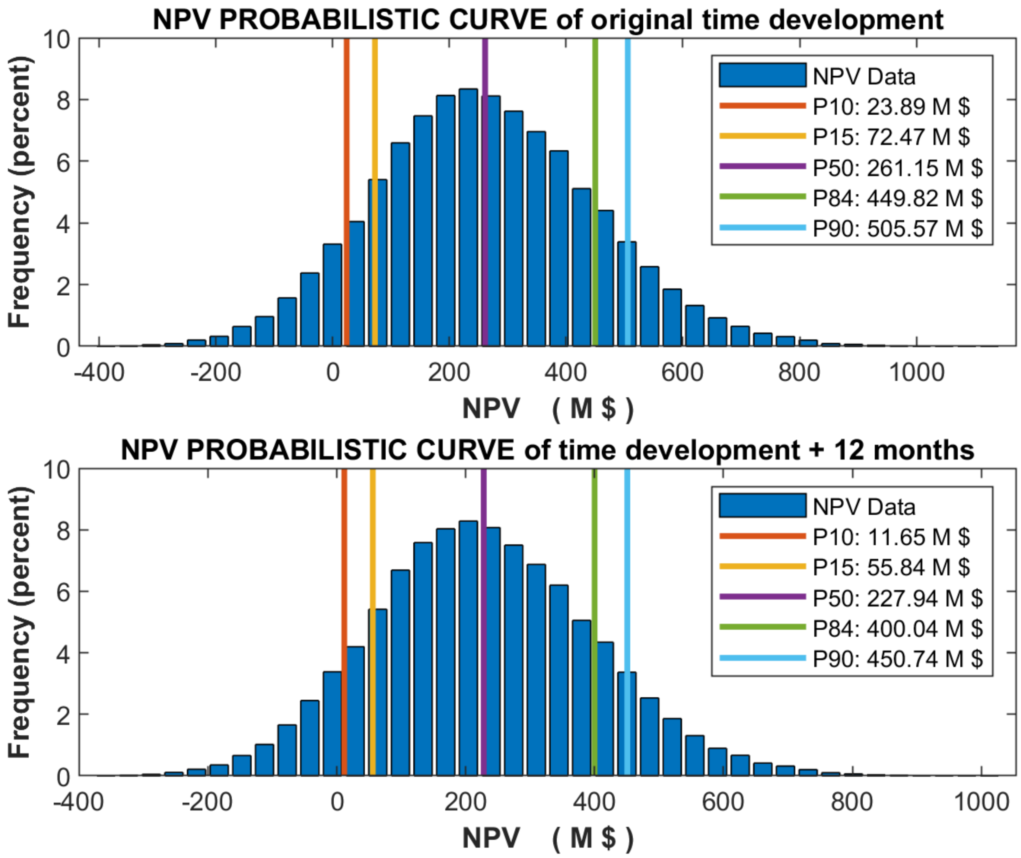


Figure 5.5 Probabilistic results of NPV from the simulation related to an onshore field with respect to two different project development durations

The additional information provided by the Probabilistic results, with respect to the Deterministic ones, regards the definition of the probability of generating a certain NPV. The NPV described by the deterministic approach gives no information about its probability and comparing it to the same one described by the probabilistic approach, we can see that it has a possibility lower than 50%. Considering the probabilistic NPV of the original time development, we can see that there is 90% of probability to have an NPV higher than 23.89 M$ and 10% of probability to have more than 505.57 M$. The resulting range of NPV is high, with a mean value of 261.15 M$. Since there is 50% to have less than 261.15 M$, the uncertainty definition related to the project should be improved to determine a better evaluation of the NPV since there is a high possibility to gain low levels of profits. In *Figure 5.6*, the additional results of the standard deviation and median are shown.

STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development)		STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development + 12 months)	
P10	23.89	P10	11.65
P15.9	72.47	P15.9	55.84
Mean or P50	261.15	Mean or P50	227.94
P84.1	449.82	P84.1	400.04
P90	505.57	P90	450.74
Median	253.86	Median	221.16
Std deviation	188.67	Std deviation	172.10

Figure 5.6 Probabilistic results including Median and Standard deviation values relative to an onshore field with respect to two different project development durations

Analysing instead, the difference between the consideration of developing the project over a longer period (one year more than the original defined time), we can see a loss of profits of almost 10%. For low NPV results, there is a low influence with around 10 -18 M$ loss. On the other hand, remarkable loss affects higher NPV outcomes within a range of 50 – 55 M$.

5.2 Case Study 2 – Offshore field (TLP)

In the second Case Study, inputs of an offshore field, related to a Tension Leg Platform (TLP), are imposed in the model as in *Figure 5.7*. As in the Case Study 1, all the inputs are imposed initially as *Fixed_Number* in order to evaluate a deterministic result. The grey cells instead, represent the fixed variables on which uncertainty is not accounted and are characterized by a single value.

The procedure related to which values and cells are considered by the model, for the Deterministic calculation, is the same as described in the Case Study 1. Again, the imposed number of simulation, in this case, does not influence the results and is not accounted for by the model.

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Fixed_Number	bbl/day	5500	6200	6000	6000
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				4
Decline percentage	Fixed_Number	%	12	17	14	15
Number of wells	Fixed_Number	n°	5	8	6	6
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Fixed_Number	m3/m3	300	360	350	350
OIL AND GAS PRICE						
Real Oil Price	Fixed_Number	$/bbl	65	70	66	67
Real Gas Price	Fixed_Number	$/1000cf	8	10	9	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Fixed_Number	$	8.6E+08	9.2E+08	9.00E+08	9.0E+08
OPEX	Fixed_Number	$/bbl	8	12	10	10
Field Development time	Fixed_Number	years	2	4	2	2
Project Delay	Fixed_Number	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				30
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				60
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.7 Definition of the inputs for a deterministic calculation related to an offshore field (TLP)

The main important elements of difference between onshore and offshore are related to the costs. Due to the complexity of the designing, building, transportation, installation of an offshore platform, and more difficult drilling operations, offshore operations are characterized by considerable higher costs in terms of CAPEX and OPEX. Despite the different values imposed in the model, we considered higher costs for the CAPEX and OPEX and a volume of reserves which allows the ratio between the CAPEX and the reserves to be between the range of 5 to 20 $/barrel.

In this simulation, the CAPEX is estimated at a value of 900 M$. The definition of this amount is defined by the elements inside the *Table 5-2.* The data used is derived from available information present in the thesis of Spera (2016).

Table 5-2 Total CAPEX estimation and individual cost of its elements (Spera, 2016)

CAPEX		
Structure + wellhead	$	403794151
CAPEX Facilities	$	313825474
Project Management	$	79026842
Offshore Drilling	$	100684561
Total	$	8.97E+08

The same assumption of heavy workover, considered in the Case Study 1, is also considered in this Case Study.

The Reserves, NPV results and Economic Indicators estimations, are shown in *Table 5-3* and *Figure 5.8*:

Table 5-3 Total Reserves, NPV results and Economic Indicators evaluations from the model related to an offshore field (TLP)

Results		
Total Reserve Estimation	120	Mbbl
CAPEX / Reserves	7.5	$/bbl
Present Value Ratio	0.52	-
Internal Rate of Return	17.12	-
NPV (original development time)	445.83	M$
NPV (original development time +1 year)	382.39	M$

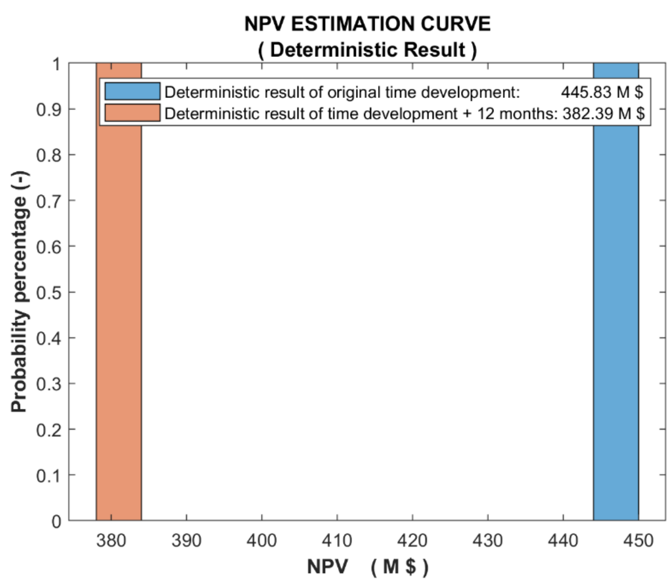


Figure 5.8 Visual representation of the Deterministic NPV results related to an onshore field with respect to two different project development durations

The deterministic results show that a longer duration of the development phase, as an alternative to the original one, will decrease the NPV from 445.83 M$ to 382.39 M$. The difference between these two values is very high and a longer development duration should not be considerable.

For the Probabilistic simulation, the inputs of the model are defined as in *Figure 5.9*. In this case, probabilistic distribution and range of values are imposed on some variables. In specific:

- For the *Daily Oil production per well*, the *Normal* distribution is imposed within a range of 5500 and 6200 barrels
- *Decline percentage* is defined by a *Uniform* distribution within a range between 12% and 17% per year
- Gas-Oil ratio defined by *Rs* is defined by a *Normal* distribution within a range of 300 to 360 $\frac{sm^3}{m^3_{stock-tank}}$
- *Oil Price* is defined by a *Uniform* distribution in a range of 65 to 70 $/barrel
- *CAPEX* is defined by a *Triangular* distribution within a range of 860 M$ to 920M$, and a distribution peak at 900 M$
- The *Field Development time* is defined by a *Triangular* distribution between 2 and 4 years, with distribution peak at 2 years

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Normal	bbl/day	5500	6200	6000	6000
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	years				4
Decline percentage	Uniform	%	12	17	14	15
Number of wells	Fixed_Number	n°	5	8	6	6
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Normal	m3/m3	300	360	350	350
OIL AND GAS PRICE						
Real Oil Price	Uniform	$/bbl	65	70	66	67
Real Gas Price	Fixed_Number	$/1000cf	8	10	9	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Triangular	$	8.6E+08	9.2E+08	9.00E+08	9.0E+08
OPEX	Fixed_Number	$/bbl	8	12	10	10
Field Development time	Triangular	years	2	4	2	2
Project Delay	Fixed_Number	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				30
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				60
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.9 Probabilistic definition of some variables in the model related to an offshore field (TLP)

The model, which executed a simulation of 50 000 iterations, performed the probabilistic results which are shown in *Figure 5.10.*

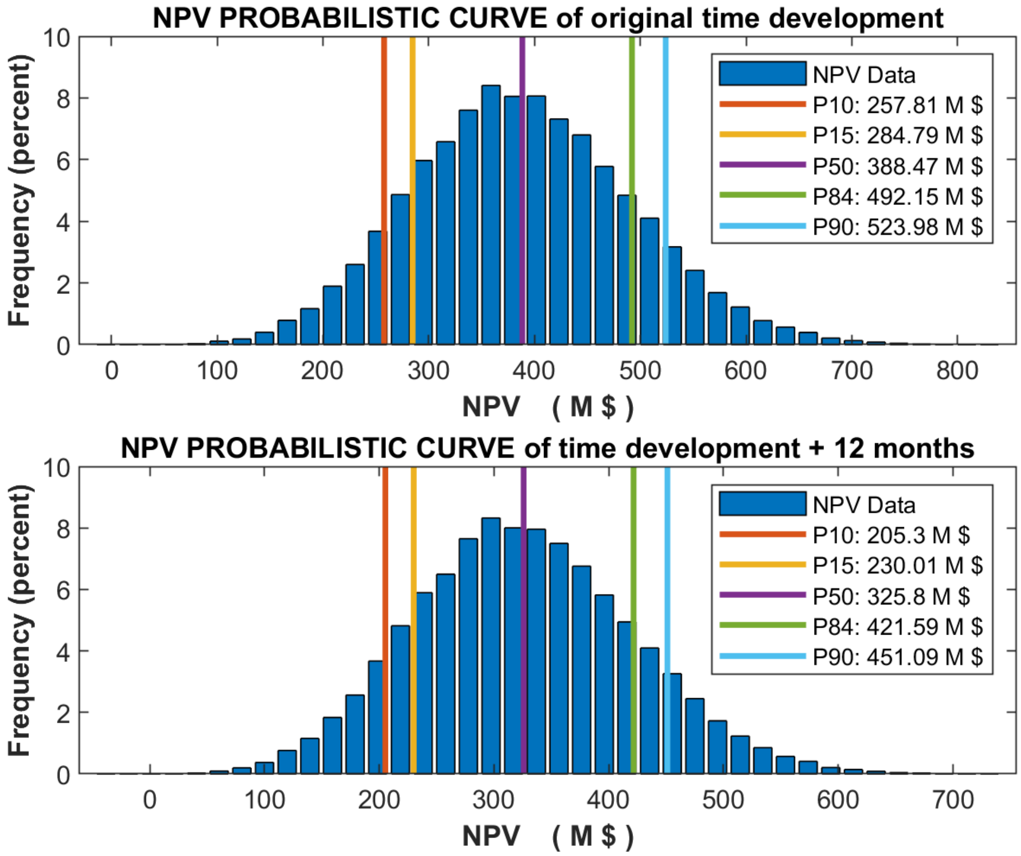


Figure 5.10 Probabilistic results of NPV from the simulation related to an offshore field (TLP) with respect to two different project development durations

In this Case Study, the Deterministic result, with respect to the Probabilistic results and without giving any information about its probability of occurrence, represents an overestimation in terms of chances. The same value compared to the probabilistic result represent a probability lower than 50% to occur. The probabilistic NPV of the original time development gives 90% of probability to have an NPV higher than 205.3 M$ and 10% of probability to have more than 451.09 M$. The resulting range of NPV is lower with respect to the analog onshore one and have a mean value of 388.47 M$. The resulting NPV, related to the project, provides optimum levels of profits. In *Figure 5.11*, the additional results of the standard deviation and median are shown.

STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development)		STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development + 12 months)	
P10	257.81	P10	205.30
P15.9	284.79	P15.9	230.01
Mean or P50	388.47	Mean or P50	325.80
P84.1	492.15	P84.1	421.59
P90	523.98	P90	451.09
Median	384.65	Median	322.35
Std deviation	103.68	Std deviation	95.79

Figure 5.11 Probabilistic results including Median and Standard deviation values relative to an offshore field (TLP) with respect to two different project development durations

Analyzing the difference between developing the project over a longer period (one year more than the original defined time), we can see a loss of profits of more than 50 M$ loss, at P10. For this reason, the consideration of the alternative project development duration extension should be avoided.

5.3 Case Study 3 – Offshore field (FPSO built)

In the third Case Study, inputs of an offshore field, related to a new built FPSO, are imposed in the model as in the *Figure 5.12*.

Between the different offshore platforms, FPSO represents the most flexible but also the most expensive option. It normally operates at very high-water depths and very harsh environments, where other types of platform cannot be transported – installed, in combination with the Subsea Production Systems. The FPSO can be a new-built vessel or can be based on converter tanker. Associated building costs of these type of vessel are very high. A petroleum company, in fact, can decide between building the vessel or renting an existing one. These two options will be analyzed and compared in the following Case Study.

As in the Case Study 1 and Case Study 2, all the inputs are imposed initially as *Fixed_Number* in order to evaluate a deterministic result. The same considerations done before are valid also for the grey cells and their values.

The procedure related to which values and cells are considered by the model, for the Deterministic calculation, is the same as described in the Case Study 1. The imposed number of simulation, also in this case do not influence the results and is not accounted by the model.

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Fixed_Number	bbl/day	6500	7200	6900	7000
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				5
Decline percentage	Fixed_Number	%	8	12	11	10
Number of wells	Fixed_Number	n°	5	9	7	7
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Fixed_Number	m3/m3	300	360	350	350
OIL AND GAS PRICE						
Real Oil Price	Fixed_Number	$/bbl	65	75	68	70
Real Gas Price	Fixed_Number	$/1000cf	8	10	7	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Fixed_Number	$	1.9E+09	2.3E+09	2.05E+09	2.1E+09
OPEX	Fixed_Number	$/bbl	8	14	12	12
Field Development time	Fixed_Number	years	2	4	3	3
Project Delay	Fixed_Number	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				30
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				50
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.12 Definition of the inputs for a deterministic calculation related to an offshore field (FPSO built)

Despite the different values imposed in the model, we considered higher costs for the CAPEX and OPEX and a volume of reserves which allow the ratio between the CAPEX and the reserves to be between the range of 5 to 20 $/barrel. Especially the CAPEX was considered very high because of the assumption of a new built FPSO. In fact, the total Capital Expenditures, based on the different elements of costs, reaches 2.1 B$. The considered elements of CAPEX are shown in *Table 5-4*. The data used is derived from available information present in the thesis of Spera (2016).

Table 5-4 Total CAPEX estimation and individual cost of its elements (Spera, 2016)

CAPEX Elements		
Ship structure	$	394975303
CAPEX facilities	$	648290158
Installation	$	3557400
SPS	$	699462000
Umbilicals	$	1102500
Risers	$	4148954
Owner cost	$	6732462
Offshore Drilling	$	177522000
Project Management	$	100986924
Contingency	$	67324616
Total	$	2.10E+09

The same assumption of heavy workover, considered in the Case Study 1 and Case Study 2, is also considered in this Case Study.

The Reserves, NPV results and Economic Indicators estimations relative to this Case Study, are shown in *Table 5-5* and *Figure 5.13*:

Table 5-5 Total Reserves, NPV results and Economic Indicators evaluations from the model related to an offshore field (FPSO built)

Results		
Total Reserve Estimation	250	Mbbl
CAPEX / Reserves	8.40	$/bbl
Present Value Ratio	0.37	-
Internal Rate of Return	13.90	-
NPV (original development time)	680	M$
NPV (original development time +1 year)	546.17	M$

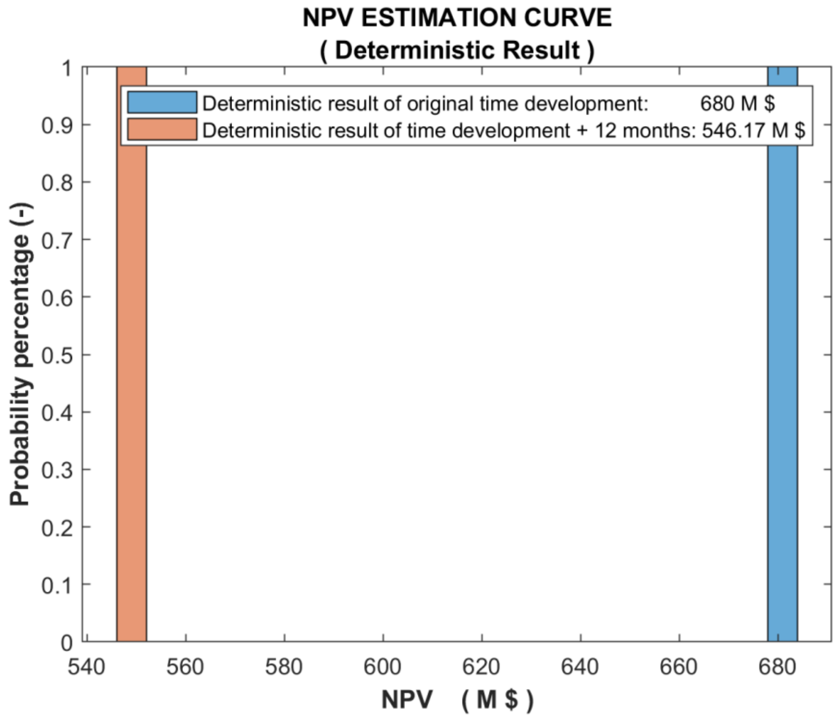


Figure 5.13 Visual representation of the Deterministic NPV results related to an offshore field (FPSO built) with respect to two different project development durations

The deterministic results show that a longer duration of the development phase, as an alternative to the original one, will decrease the NPV from 680 M$ to 546.17 M$. The difference between these two values is high and a longer development duration should be evaluated only in the case in which longer duration allows reduction CAPEX for more than 45 M$.

For the Probabilistic simulation, the inputs of the model are defined as in the *Figure 5.14*. In this case, probabilistic distribution and range of values are imposed on some variables. In specific:

- For the *Daily Oil production per well*, the *Normal* distribution is imposed within a range of 6500 and 7200 barrels
- *Decline percentage* is defined by a *Uniform* distribution within a range between 8% and 12% per year
- Gas-Oil ratio defined by *Rs* is defined by a *Triangular* distribution within a range of 300 to 360 $\frac{sm^3}{m^3_{stock-tank}}$, and a distribution peak at 350 $\frac{sm^3}{m^3_{stock-tank}}$
- *Oil Price* is defined by a *Uniform* distribution in a range of 65 to 75 $/barrel
- *CAPEX* is defined by a *Triangular* distribution within a range of 1.9 B$ to 2.3 B$, and a distribution peak at 2.05 B$
- The *Field Development time* is defined by a *Normal* distribution between 2 and 4 years
- *Project Delay* is defined by a *Triangular* distribution within a range of 5 months to 9 months, and a distribution peak at 7 months

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Normal	bbl/day	6500	7200	6900	7000
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				5
Decline percentage	Uniform	%	8	12	11	10
Number of wells	Fixed_Number	n°	5	9	7	7
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Triangular	m3/m3	300	360	350	350
OIL AND GAS PRICE						
Real Oil Price	Uniform	$/bbl	65	75	68	70
Real Gas Price	Fixed_Number	$/1000cf	8	10	7	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Triangular	$	1.9E+09	2.3E+09	2.05E+09	2.1E+09
OPEX	Fixed_Number	$/bbl	8	14	12	12
Field Development time	Normal	years	2	4	3	3
Project Delay	Triangular	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				30
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				50
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.14 Probabilistic definition of some variables in the model related to an offshore field (FPSO built)

The model, which executed a simulation of 50 000 iterations, performed the probabilistic results which are shown in *Figure 5.15.*

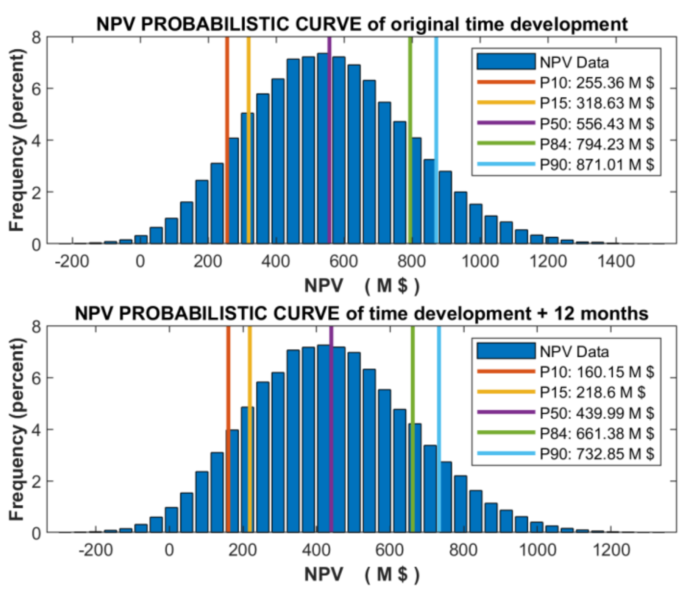


Figure 5.15 Probabilistic results of NPV from the simulation related to an offshore field (FPSO built) with respect to two different project development durations

In this Case Study, as in the previous ones, the Deterministic result gives no information about its probability of occurrence and represents an overestimation in terms of chances that has an average of 55% to occur if compared with the probabilistic results. The probabilistic NPV of the original time development gives 90% of probability to have an NPV higher than 255.36 M$ and 10% of probability to have more than 871.01 M$. The resulting range of the probabilistic NPV is high. However, there is 90% to have a profit higher than 255.36 M$, so the possibility of developing additional studies to develop the project should be done. In the *Figure 5.16*, additional results of the standard deviation and median are shown.

STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development)		STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development + 12 months)	
P10	255.36	P10	160.15
P15.9	318.63	P15.9	218.60
Mean or P50	556.43	Mean or P50	439.99
P84.1	794.23	P84.1	661.38
P90	871.01	P90	732.85
Median	547.43	Median	431.43
Std deviation	237.80	Std deviation	221.39

Figure 5.16 Probabilistic results including Median and Standard deviation values relative to an offshore field (FPSO built) with respect to two different project development durations

Analysis of the difference between developing the project in a longer period (one year more than the original defined time), we can see a loss of profits of more than 95 M$ loss, at P10, and it increases at P90. For this reason, the consideration of the alternative project development duration extension should be avoided.

5.4 Case Study 4 – Offshore field (FPSO rented)

In the fourth Case Study, inputs of an offshore field, related to a rented FPSO, are imposed in the model as in the *Figure 5.17*. This specific scenario is used to perform two types of analysis. The first analysis regards the comparison between the deterministic and probabilistic results, while the second one compares the probabilistic results of this Case Study with the ones of the Case Study 3. For comparison reasons, the inputs are the same as in the previous Case Study except for few variables which are discussed after the *Figure 5.17*.

As in the Case Study 1 and Case Study 2, all the inputs are imposed initially as *Fixed_Number* in order to evaluate a deterministic result. The same considerations, done before, are valid also for the grey cells and their values.

The procedure related to which values and cells are considered by the model, for the Deterministic calculation, is the same as described in the Case Study 1. The imposed number of simulation, also in this case does not influence the results and is not accounted for by the model.

VARIABLES	DISTRIBUTION SELECTION		UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION							
Daily Oil production per well	Fixed_Number		bbl/day	6500	7200	6900	7000
Total years of production	Fixed Value		years				20
Years of Plateau	Fixed Value		**years**				5
Decline percentage	Fixed_Number		%	8	12	11	10
Number of wells	Fixed_Number		n°	5	9	7	7
GAS PRODUCTION (FROM OIL)							
Rs (gas-oil ratio)	Fixed_Number		m3/m3	300	360	350	350
OIL AND GAS PRICE							
Real Oil Price	Fixed_Number		$/bbl	65	75	68	70
Real Gas Price	Fixed_Number		$/1000cf	8	10	7	7
Inflation percentage	Fixed Value		%/year				1
CAPITAL AND OPERATIONAL COSTS							
CAPEX	Fixed_Number		$	8.0E+08	8.6E+08	2.05E+09	8.4E+08
OPEX	Fixed_Number		$/bbl	26	30	28	28
Field Development time	Fixed_Number		years	2	4	3	3
Project Delay	Fixed_Number		months	5	9	7	6
COST of Delay	Fixed Value		% of (CAPEX/month)				30
Abandonment Cost	Fixed Value		$				2E+07
Rent/Surface Cost (annual)	Fixed Value		$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS							
Total Taxes (as % of revenue)	Fixed Value		%/$				50
Discount Rate	Fixed Value		%/year				10
SIMULATION DEFINITION							
Number of simulations		→		**50000**			

Figure 5.17 Definition of the inputs for a deterministic calculation related to an offshore field (FPSO rented)

This assumption, relative to the renting of the FPSO, influences two variables: CAPEX and OPEX. The CAPEX, as in the previous Case Study, is evaluated from the same elements of costs. However, the amount of money related to each element of the CAPEX is different because the cost of building a new vessel is not accounted for anymore. In fact, we can see a decrease in CAPEX from 2.1 B$, imposed in the Case Study 3, to 840 M$. The elements considered for the CAPEX estimation are shown in *Table 5-6.* The data used is derived from available information present in the thesis of Spera (2016).

In addition, the rent of FPSO increases the Operating Expenditures. With respect to the scenario in which the FPSO is built and the OPEX is set to 12 $/barrel, in this case, the OPEX is increased by 16 $/barrel for a final amount of 28 $/barrel.

In order to calculate a reasonable CAPEX / Reserves indicator, the additional cost accounted for the OPEX was transformed in CAPEX and added to the one accounted in the model as in the equation:

$$New\ CAPEX\ =\ Additional\ OPEX\ \left(\frac{\$}{bbl}\right) * Reserves\ (Mbbl) + CAPEX$$

Equation 5-1

Table 5-6 Total CAPEX estimation and individual cost of its elements (Spera, 2016)

CAPEX		
Ship structure	$	0
CAPEX facilities	$	98621277
Installation	$	3557400
SPS	$	699462000
Umbilicals	$	1102500
Risers	$	4148954
Owner cost	$	782709
Offshore Drilling	$	10175211
PM	$	11740628
Contingency	$	7827085
Total	$	8.4E+08

The final amount is equal to 4.84 B$. Therefore, the CAPEX / Reserves indicator for this scenario is equal to 19.2 $/barrel which is in the defined range between 5 $/barrel and 20 $/barrel. The additional Economic Indicators, NPV results are shown in the *Table 5-7* and *Figure 5.18.*

Table 5-7 Total Reserves, NPV results and Economic Indicators evaluations from the model related to an offshore field (FPSO rented)

Results		
Total Reserve Estimation	250	Mbbl
CAPEX / Reserves	19.2	$/bbl
Present Value Ratio	0.6	-
Internal Rate of Return	16.26	-
NPV (original development time)	440.77	M$
NPV (original development time +1 year)	371.8	M$

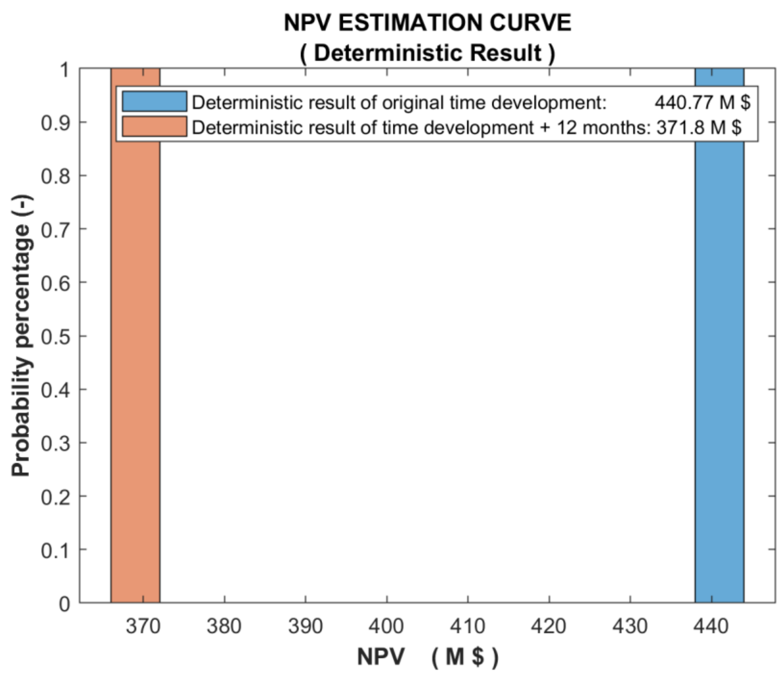


Figure 5.18 Visual representation of the Deterministic NPV results related to an offshore field (FPSO rented) with respect to two different project development durations

The deterministic results show an indicative NPV of 440.77 M$. Longer duration of the development phase, as an alternative to the original one, will decrease the NPV from 440.77 M$ to 371.8 M$. The difference between these two values is high and a longer development duration should be avoided.

For the Probabilistic simulation, the inputs of the model are defined as in the *Figure 5.19*. In this case, probabilistic distribution and range of values are imposed as in the previous Case Study. In specific, the only changes regard:

- *CAPEX* is defined by a *Triangular* distribution within a range of 1.9 B$ to 2.3 B$, and a distribution peak at 2.05 B$

- *OPEX* is defined by a *Triangular* distribution within a range of 26 $/barrel to 30 $/barrel, and a distribution peak at 28 $/barrel
- The *Field Development time* is defined by a *Triangular* distribution within a range of 2 years to 4 years, and a distribution peak at 3 years
- *Project Delay* is defined by a *Uniform* distribution within a range of 5 months to 9 months, and a distribution peak at 7 months
- *Gas Price* is defined by a *Triangular* distribution within a range of 8 $/1000cf to 10 $/1000cf, and a distribution peak at 9 $/1000cf

VARIABLES	DISTRIBUTION SELECTION	UNITS	LOWER VALUES	UPPER VALUES	PEAK VALUES (only for triangular distribution)	FIXED VALUES
OIL PRODUCTION						
Daily Oil production per well	Normal	bbl/day	6500	7200	6900	7000
Total years of production	Fixed Value	years				20
Years of Plateau	Fixed Value	**years**				5
Decline percentage	Uniform	%	8	12	11	10
Number of wells	Fixed_Number	n°	5	9	7	7
GAS PRODUCTION (FROM OIL)						
Rs (gas-oil ratio)	Triangular	m3/m3	300	360	350	350
OIL AND GAS PRICE						
Real Oil Price	Uniform	$/bbl	65	75	68	70
Real Gas Price	Triangular	$/1000cf	8	10	9	7
Inflation percentage	Fixed Value	%/year				1
CAPITAL AND OPERATIONAL COSTS						
CAPEX	Triangular	$	8.0E+08	8.6E+08	8.40E+08	8.4E+08
OPEX	Triangular	$/bbl	26	30	28	28
Field Development time	Triangular	years	2	4	3	3
Project Delay	Uniform	months	5	9	7	6
COST of Delay	Fixed Value	% of (CAPEX/month)				30
Abandonment Cost	Fixed Value	$				2E+07
Rent/Surface Cost (annual)	Fixed Value	$/year				1.0E+04
FISCAL COSTS AND ECONOMIC INDICATORS						
Total Taxes (as % of revenue)	Fixed Value	%/$				50
Discount Rate	Fixed Value	%/year				10
SIMULATION DEFINITION						
Number of simulations			**50000**			

Figure 5.19 Probabilistic definition of some variables in the model related to an offshore field (FPSO rented)

The model, which executed a simulation of 50 000 iterations, performed the probabilistic results which are shown in the *Figure 5.20*.

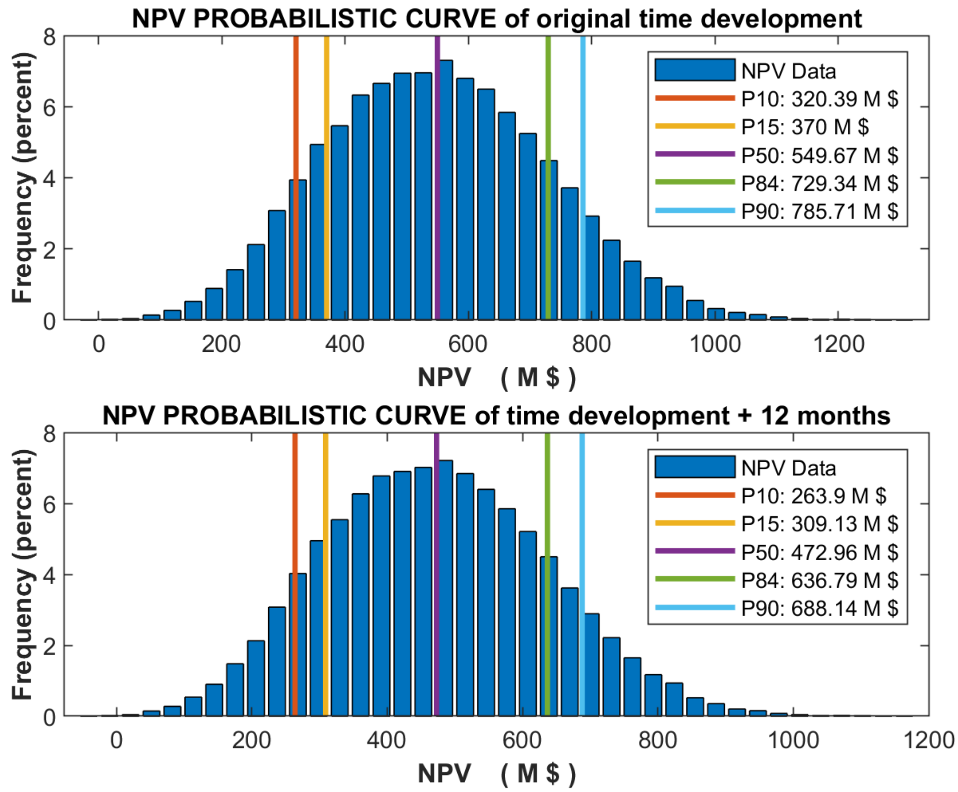


Figure 5.20 Probabilistic results of NPV from the simulation related to an offshore field (FPSO rented) with respect to two different project development durations

In this Case Study, as in the previous ones, the Deterministic result gives no information about its probability of occurrence and represents an overestimation in terms of chances that have an average of 35% to occur if compared with the probabilistic results. The probabilistic NPV of the original time development gives 90% of probability to have an NPV higher than 320.39 M$ and 10% of probability to have more than 785.71 M$. The resulting range of the probabilistic NPV is high. However, there is 90% to have a profit higher than 320.39 M$, so the possibility of developing additional studies to develop the project should be considered. In the *Figure 5.21*, additional results of the standard deviation and median are shown.

STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development)			STOCHASTIC RESULTS OF NPV (M $) (INPUT duration of development + 12 months)	
P10	320.39		P10	263.90
P15.9	370.00		P15.9	309.13
Mean or P50	549.67		Mean or P50	472.96
P84.1	729.34		P84.1	636.79
P90	785.71		P90	688.14
Median	545.21		Median	468.55
Std deviation	179.67		Std deviation	163.83

Figure 5.21 Probabilistic results including Median and Standard deviation values relative to an offshore field (FPSO rented) with respect to two different project development durations

The difference between developing the project in a longer period (one year more than the original defined time), consists in a loss of profits of more than 80 M$ loss, at P10. For this reason, the consideration of the alternative project development duration extension should be avoided.

Comparing the Probabilistic results from the Study Case 3 and Study Case 4, *Figure 5.15* and *Figure 5.21*, we can see similar probability to generate an average 550 M$ which represents the P50. However, the values that characterize P10, P90 and the Standard deviation of the results are quite different. The assumption of renting the FPSO determine higher profits for P10 (90% to generate more than 320 M$) with respect to the case in which the FPSO is built (90% to generate more than 255.36 M$). On the other hand, the opposite situation is present at P90 where in case of FPSO built there is 10% probability to have more than 871.01 M$, while in the case of FPSO rented, there is 10% probability to generate more than 785 M$. These results are shaped based on the Standard deviation which is respective 237.80 M$ (for FPSO built) and 179.67 M$ (for FPSO rented). Lower Standard deviation implicates a lower range of variability in the results.

This type of comparison can be a fundamental step in assessing the real opportunity for investments and relative profits. A company with a conservative approach that wants to minimize the risk will choose to rent a FPSO, while a company than can bare higher risks can decide to build the vessel. Based on the company's aversion to risk, the decision to develop a project, in this case by building or renting a FPSO, is well supported by probability information associated to projected profits based on variables of which uncertainty is well considered in the model.

Chapter 6 Conclusion

In this dissertation, we proposed a model designed on a specific set of variables related to an oil and gas project, which probabilistic definition combined with Monte Carlo’s method allow simulations of probabilistic NPV. The probabilistic definition of the variables, by a range and distribution, represented the most difficult phase of this project. The range and especially the distribution definition of many variables are based on historical data and literature about probabilistic studies and the experience of prof. De Ghetto. The definition of one of the most critical variables like the Capital Expenditures, in fact, was based on the research paper of Spera (2016) and discussion with prof. De Ghetto which indicated the triangular distribution to be the most representative distribution for this variable because of the rigid range limits, flexibility related to the distribution peak and its usage in the petroleum industry for evaluation purposes.

All the variables and their probabilistic definition were carefully selected and integrated in the model that was implemented with a simple user interface able to provide a fast declaration of the inputs and to perform the simulation. The additional advantage relative to the proposed model regards also its flexibility to be modified and easily integrated with additional variables and/or distributions for more accurate results. The variables considered in the model are all independent and are shown in *Table 6-1*.

Table 6-1 Classes and variables considered in the model

<table>
<tr><th>PRODUCTION</th><th>ECONOMIC</th><th>FINANCIAL</th><th>TEMPORAL</th></tr>
<tr><td rowspan="2">Oil Rate</td><td>Oil Price</td><td rowspan="3">Inflation</td><td>Total years of production</td></tr>
<tr><td>Gas Price</td><td>Plateau duration</td></tr>
<tr><td rowspan="2">Number of wells</td><td>CAPEX</td><td rowspan="2">Decline duration</td></tr>
<tr><td>OPEX</td><td rowspan="3">Taxes</td></tr>
<tr><td rowspan="2">Decline in production</td><td>Surface rent</td><td rowspan="2">Development duration</td></tr>
<tr><td>Abandonment cost</td></tr>
<tr><td rowspan="2">Rs - Gas production (from oil)</td><td>Cost of delay</td><td rowspan="2">Discount Rate</td><td rowspan="2">Delay of development</td></tr>
<tr><td>Cost of Workover</td></tr>
</table>

The model performs reasonable estimations of the probabilistic NPV. The accuracy of the results, however, as said previously, are dependent on the probabilistic definition of the variables, which is a difficult process if data and expert knowledge are not available. Therefore, additional studies related to the uncertainties and/or more simulations are needed to perform a more reasonable NPV results. In the alternative, the elements characterized by poor quality of data can be imposed with a higher range, which represents higher uncertainty, and trials with different distribution can be performed for a general evaluation of the project.

Differences between deterministic and probabilistic results are evident in the Case Studies. The additional information provided by the probabilistic approach defines values of NPV and associated occurrences. This information can be crucial in evaluating the level of profits related to a project. In the Case Study of an onshore field, in fact, the deterministic result evaluated 232 M$ of profits while the probabilistic result of NPV shown that there are 50% of possibility to have more than 261 M$. However, the probabilistic NPV indicates also that there is 10% of possibility to have less than 24 M$, which is too low and unacceptable profit for an oil and gas company. Minimum projected revenues can be imposed by the company in order to bear the risk related to an investment and decide if the project is valuable or alternatives has to be searched.

An additional advantage of the designed model regards the possibility to compare between probabilistic results relative to different concepts of project development which allows better assessment of the business opportunities and helps in the identification of the best base concept of development to expand and elaborate detailed studies. This type of assessment was done in the Case Study 3 and 4 related to the decision to build or to rent an FPSO. The assessment shown different values related to the P10 and P90 as shown in *Table 6-2*.

Table 6-2 Probabilistic results related to the Case Study 3 (FPSO built) and Case Study 4 (FPSO rented)

NPV Probability	FPSO (built)	FPSO (rented)
P10	255.36	320.39
P15.9	318.63	370.00
P50	556.43	549.67
P84.1	794.23	729.34
P90	871.01	785.71
Median	547.43	545.21
Std deviation	237.80	179.67

Building an FPSO determine an increase of the NPV value related to P90 but on the other hand, decreases the one related to P10. The opposite situation results in the scenario related to the renting of the FPSO. Therefore, the importance of this type of comparison is also related to the company's aversion to risk. A company which faces higher financial exposure by the investment will choose to rent the FPSO because it is a safer option while a company able to bare high investments can choose to risk and build the FPSO.

Each run of the model, an additional simulation related to a longer duration of the imposed development operations (of one year) is performed and associated probabilistic NPV results are produced. This feature was added to the model to allow an additional temporal and cost evaluation of the project if it is developed in a longer time. The delay related to this new duration is the same as for the original development time. The simulations performed on the Case Study of the onshore field shown a decrease of the NPV from 232 M$ to 197 M$. This case demonstrates the possibility to account for a longer period of development if this additional time can justify a decrease of development costs, of more than 35 M$.

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