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Hydrocarbon Reserves Valuation Management

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DECLARATION

I certify that this thesis does not incorporate without any acknowledgement any material previously submitted for any unit in any institution for any other degree or diploma in any university.

The best of my knowledge and belief, this thesis does not contain any material previously published or written by another person except where due references has been made in the text.

Signature ……………………………………

Date …………………………………………

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Abstract

Given the importance of the reserves disclosures for investors and regulators, it is surprising to them that there has been a lot of focus, which is elaborated on in Chapter 2, on how the reserves data are prepared and reported on by companies. Currently, reserves disclosures in financial statements are not audited by independent public accountants, nor are they audited by any petroleum industry-designated independent evaluators. Performing the critical “reserves evaluator” function currently does not require any recognised certification program or other mandatory industry-wide training requirements.

Despite the highly technical nature of the reserves estimation process, both preparers and users of the reserves information know that reserves estimation is not an exact science. Estimates are based on limited data obtained from small regions, which are then extrapolated to the whole field. Reserves estimations are also based on expected production paths over long periods of time. Many alternative procedures are often available and widely used for making similar technical or economic determinations. These factors make reserves disclosures inherently subject to information quality problems. Estimates of proved reserve quantities may often be imprecise and change over time as new information, for example, through new technologies becomes available.

Accurate reserves data are extremely important to investors to value and assess the performance of energy companies, and are equally important to regulators and the public given the critical role of the energy sector in the economy. It is clear, then, that reserves data should be disclosed in a way that minimizes the credibility gap that afflicts the current disclosures. Key problem in structuring information about reserves is that relatively objective estimates of reservoir characteristics must be combined with subjective forecasts of project feasibility and commerciality.

In this thesis, the Dynamic Reserves Estimation Model (DREM) is considered as a new method to estimate reserves. This model is based on complex parameters; however it has the capability to simplify many problems concerned with reserves estimations.

Nomenclature

A	Reservoir Area Acres
a	Loss Ratio
b	Hyperbolic Exponent
Bg	Gas Formation Volume Factor
Bgi	Initial Gas Formation Volume Factor
BIg	Injected Gas Formation Volume Factor
BIw	Injected Water Formation Volume Factor
Bo	Oil Formation Volume Factor
Boi	Initial Oil Formation Volume Factor
Bp	Booking Price
Bt	Two-phase Formation Volume Factor
Bti	Initial two-phase Formation Volume Factor
Bw	Water Formation Volume Factor
Cf	Formation Compressibility
Cw	Water Isothermal Compressibility
D	Initial Decline Rate
G	Initial Gas in Place
Gp	Cumulative Gas Produced
GR	Growth Rate
h	Average Reservoir Thickness
n/g	Net/Gross
Np	Volume of Hydrocarbon Produced
$N(t)$	Oil in Place at time t
Pi	Initial Formation Pressure
PS	Probability of a Seal Mechanism

Pt	Probability of Existence of Trap
$p(t)$	Current Reservoir Pressure
qo	Initial Production Rate
qt	Production Rate at Time
RE	Recovery Efficiency
RF	Recovery Factor
Rp	Cumulative Produced gas-oil Ratio
Rso	Solution gas-oil Ratio
$Rsoi$	Initial Solution gas-oil Ratio
Sw	Water Saturation
Swi	Initial Water Saturation
t	Time
Ti	Initial Formation Temperature
UR	Ultimate Recovery
Vb	Bulk Reservoir Volume
We	Water Influx into Reservoir
WI	Cumulative Water Injected into Reservoir
Wp	Cumulative Water Produced
Zi	Gas Compressibility of Pi and Ti
Δpt	Reservoir Pressure Drop
Δqt	Drop in Production Rate at Tim
Φ	Porosity
$1P$	Proved Reserve
$2P$	Proved Plus Probable Reserves
$3P$	Proved plus Probable plus Possible reserves

Abbreviations

AAPG	American Association of Petroleum Geologists
ASR	Accounting Series Released
DREM	Dynamic Reserve Estimation Model
ECM	Error Correction Model
EIA	Energy Information Agency
FASB	Financial Accounting Standard Board
FC	Full Cost Method
GBV	Gross Bulk Volume
HIIP	Hydrocarbon Initially in Place
NBV	Net Bulk Volume
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
PDF	Probability Density Function
PGS	Probability of Geological Success
PM & PT	Probability of Migration and Timing
PSR	Probability of Source Rock
RRA	Reserve Recognition Standard
SE	Successful Effort Method
SEC	Securities and Exchanges Commission
SPE	Society of Petroleum Engineers
STOIIP	Stock Tank Oil Initial in Place
WPC	World Petroleum Congress

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CHAPTER ONE

Introduction to the Research

1.1 Introduction

The existing practice for the recognition and disclosure of reserves has generally proved to be satisfactory. This practice has been based on general industry experience with minor scientific and recognized commercial principles applied. These existing practices tended to have relevance to reserve production potential.

Technological advances, including availability, and additional resource development has been converting particular non-commercial resources into commercial resources. In addition, non-traditional resources have taken a significant role in downstream activities and vast amounts of money are being invested in bringing these resources to the market.

In implementing this view, the Security and Exchange Commission and Society of Petroleum Engineers, which are two giant organizations in the petroleum industry, aim to convert resources into the future reserves. However, these two organizations have their own reserves definition systems, which were developed using technology that was available during the 1970s (Morris 2008).

Technology advancement and its continuing development is proportionately increasing efficiency when converting non-producible resources to producible resources. In addition the technological advancement also allows for a reduction in the costs of production potential in most circumstances. New technology and resource valuation methods have over taken the traditional resource valuation views, such as horizontal drilling, extended-reach drilling and seismic techniques (3D and 4D) and simulation methodologies which were unheard of in past years. For example, due to technology innovation deep water drilling, although very costly, is now possible today. In Brazil, around 2000 m deep water have been drilled and it is expected to drill 1000 m more reaching depths of 3000 m, once thought impossible a few years ago (Roodhart 2009).

In terms of reasonable certainties, reserve estimates are derived from reliable information extracted and processed from geological and engineering data, based on various scientific methods to express probabilities of future reserves. Additionally, investment decision making companies require probability methods rather than deterministic methods to classify reserves as proved (90%), probable reserves (50%) and possible reserves (10%) probability of the estimated quantities to be recoverable (Roodhart 2009).

This thesis will review and compare the SEC approach, definitions promulgated by the Society of Petroleum Engineers (SPE), the World Petroleum Congress (WPC), and the American Association of Petroleum Geologists (AAPG), the most prominent technical organizations operating in this arena. Also discussed are the changes that have occurred in the industry during the past two decades, and the application of the information to develop new standards that recommend the use of all available data. Decision analysis of developed oil field and reservoir management is being associated with some level of risk that becomes visible due to uncertainty in process but it is considered as a reasonable tool to illustrate decisions making (Schiozer et al. 2004).

In addition, reserves are estimated accurately based on available data that is obtained from geologists, economists and engineers to demonstrate knowledge and information about reservoir rock and its fluid content to estimators (Estimation of Reserves and Resources 2000).

1.2 Identification of the Problem Statement

Even though there are many different developed methodologies that have been carried out to determine hydrocarbon reserve estimates technically, the accuracy of the reserves estimation also will be challenged by the uncertainty factors that associated with commercial risks. According to Saito et al (2001) discounted cash flow analysis and Real Options are considered two important methods to determine the probability of the project. However in certain aspects, unexpected situations can arise that are not economically suitable for the project’s achievability by using discounted cash flow. For instance, cost of the production will be more than the prediction of prices in the market.

For the Decline Curve methodology, Petroleum Resources Management System 2007 claims that the Decline Curve applies to estimate a reserve with production rates requirements. Therefore, economic limits occur when the production rate meets the operating cost rate. One pitfall to avoid in decline-curve analysis, for example, is to aggregate well-decline trends to represent a composite decline for the whole field.

In the production phase, on the nearing of the depletion stage, estimators must understand an entire range of complicated factors that have major impacts on production performance and commercial uncertainties. These factors can significantly influence the decision whether to abandon a well. Another problem of the decline curve is that it is not applied to a reservoir that has a constant production rate or roughly a constant rate (Ayeni & pilat 1992). On the other hand, the material balance equation is considered as a tank model equation which is used to predict a reservoir size and measurement of fluids within the reservoir. Abdel-Al, Bakr and Al-Sahlawi's (1992, p. 279) found that in consideration of this method incorrect assumptions can be made from the interpretation of the reservoirs performance through data such as oil and gas formation volume factor, cumulative produced gas-oil ratio, solution gas-oil ratio and production rate.

Therefore, it is clearly to be seen among estimators that there is not a single method that can address all the requirements to estimate reserves in an accurate procedure. This is basically due to the weaknesses and strengths involved in the methodologies. In reserves estimations processes the use of multiple methods are preferable by the companies rather than the application of a single method. It should be kept in mind each one of the scientific methodologies have different usages, for instance, engineers usually utilize a computer software to perform repetitive calculations to estimate full range of possible outcome of reserve valuation. Theoretically, the final results from the different methodologies should be comparable otherwise they must be re-evaluated or there must be a reasonable explanation at why there is a difference in the determined results. (Campbell & Herman 2008).

The issues outlined above leave little doubt that the oil and gas industry needs to improve its ability to estimate reserves. Our objective and challenges is to enhance the consistency and reliability of reserves estimates early in field history and avoid the surprise element during production.

1.3 Objective and Significance of the Research

The significance of this research is the ability to apply a comprehensive, logical method to estimate recoverable oil and gas reserves and understanding the values that come through the performance of the development and production processes.

In terms of understanding the development process and performed value of reserve, considerations of risks and uncertainties have to be noted because of the number of the variables that are used in the method to design the management system and predicting future reserves. Uncertainties that range from price volatility to geological uncertainty factors will always challenge the accuracy of even the most advanced valuation methods. Although margins of error are inherently large, the aim of this work is to determine and apply methodologies that will provide hydrocarbon property valuations that will have a reasonable precision based on an averaging process. Analytical methods developed in recent years have made some marked progress toward that goal, but the remaining obstacles are not inconsequential.

The proposed model has been developed with consideration of assuming price, determining the value of developed oil field and estimation of investment for hydrocarbon production. The major objectives of this new method include;

- Assess the current practice (probabilistic versus deterministic method)
- Technical risks and uncertainties related to reserves estimations according to locations offshore or onshore as well as shallow or deepwater, and therefore remote locations, which support the core operational processes of the oil and gas industry.

- The relationship between current price and development price of crude oil and the impact of annual growth rate of cumulative oil produced on the return of the investment as a function of recoverable volumes.
- Best practice in calculating reserves base.

1.4 New proposed technical method Dynamic Reserve Estimation Model (DREM)

Many current reasonable methods have been utilized for assessing the value of oil and gas in reservoirs, and evaluating the economic feasibility of projects based on available data and accuracy of the data. This may also apply to the viability of an exploration, development and/or operating company.

In this research, oil and gas reservoirs are evaluated by using a new dynamic method which is called dynamic reserve estimation model (DREM) in order to make an investment decision or strategy.

The equations used in this new model are (1) Dynamic Reserve (DR) and (2) Petroleum Reserve Bankability (PRB) as shown below:

- Dynamic Reserve (DR)

$$DR = OIIP \times RF \times PGS \quad \text{...} \; (1)$$

Which it depends on

(1) Oil initial in place ($OIIP$),
(2) Recovery factor (RF) and
(3) Probability of geological success (PGS).

- Petroleum Reserve Bankability (Booking Price "Bp")

$$Bp = ((Cp - Dp) \times (GR)) \quad \text{...} \; (2)$$

Which it depends on:

(1) Current price of oil (CP)

(2) Development price of oil (DP)

(3) Annual growth rate of cumulative oil produced (GR).

1.5 Thesis Outline

This thesis explains the challenge for hydrocarbon reserve evaluation which is the estimation of current and future recoverable reserves as well as the considerations of technical and commercial prospects in the reserves valuation and management processes. The thesis is subdivided into five chapters. These chapters are organised in logical order to reflect the progress in achieving the above mentioned objectives.

- Chapter one presents the introduction to the thesis, identification of the problems, objective and significant of the research and new proposed technical method "Dynamic Reserve Estimation Model" (DREM). Final point in this chapter is the outline of the thesis.

- Chapter two includes an intense literature review on a brief history of some of the organizations which have their own regulations and systems of reserve classification and definition, and also comparing the overall structures, terminologies and key differences between these organizations by declining the subtopics and highlighting what could be the key elements to be evocated. Moreover, this chapter also presents the methods for calculating costs in different stages for example; exploration, development and production stages to define the costs that either should be capitalized or expensed in reserve assessment. Finally, the concept of geological factors will be discussed for the purpose of estimating the probability of geological risk that are involved in reserve estimations.

- Chapter three, in this chapter reserves are evaluated economically by using Dynamic Reserve Estimation Model (DREM) as a process for estimating the return on the investment over a given period of time as a function recoverable volume. The equations of this model are summarized by depending on the following factors such as, current price of oil reserves, development price of oil reserve, growth rate of cumulative oil produced.

- Chapter four presents a model application to show how the Dynamic Reserve Estimation Model (DREM) for estimating hydrocarbon reserves can be used to provide the basis of a comprehensive valuation, planning and management control system to meet all the reserves reporting requirements of a hydrocarbon exploration and production company. It also demonstrates both technical and commercial recoverable reserves and how these two sides will be combined for the purpose of economic valuation, planning and management control. Moreover, the discussions of the results for this new model are illustrated as well in this chapter.

- Chapter five provides the conclusion from this research work as well as the recommendations for the new model in hydrocarbon reserve evaluation and management.

CHAPTER TWO

Society of Petroleum Engineers/ World Petroleum Congress/ American Association of Petroleum Geologists (SPE/WPC/AAPG) Regulations of Reserves and Resource Definitions

2.1 History of Reserves and Resources Definitions and Classifications System

In the world petroleum industry, the economic classification and definition of petroleum reserve and resource has become fundamental for changing and continuing the development in booking and reporting reserves (or in reserve evaluation and reporting).Over the past 60 years, many international organisations and financial institutions have performed various different types of definitions, guidelines and classification of petroleum reserves with numerous different rules and necessary requirements (McMichael 2001).

In 1987, the Society of Petroleum Engineer (SPE) established standard definitions and classifications for estimating all the types of petroleum resources and reserves. These definitions and classifications were seen to be beneficial for both countries and companies. Moreover, the World Petroleum Congress (WPC) independently introduced reserves definitions in the same year that the Society of Petroleum Engineering did (Petroleum Resources Management System 2007).

In March 1997 both organizations, SPE and WPC, worked together and established Petroleum Reserves Definitions. The purpose of these two organizations collaborating was to supply sufficient flexibility for countries and companies to provide their commercial activities and needs in a convenient way (McMichael 2001).

Furthermore, the combined definitions that were introduced by the SPE and WPC are not mandatory and can be expanded by the user countries, companies and organizations according to the exposed location, circumstances and expected conditions.

The SPE and WPC have been aiming to develop and maintain consistency with respect to definitions Both organizations have been concentrating to keep the definitions, that were previously defined, consistent as much as possible to the reserves reporting definition approved in 1997 (Martinez & McMichael 1999).

In February 2000 the SPE and WPC jointly with the American Association of Petroleum Geologists (AAPG), introduced Reserves and Resource Classifications to provide standard international definitions based on the complement of the reserves definitions that were previously developed and established by SPE and WPC in 1997 (Etherington et al. 2005).

In addition, the three organizations SPE, WPC and AAPG also together established “Guidelines for the Evaluation of Petroleum Reserves and Resources” with definitions for whole terms of reserves and resources. These terminologies have been given in the “Glossary of Terms 2005” without any change made in the published works by SPE and WPC in 1997 (Etherington et al. 2005).

Recently, a new Petroleum Resources Management System has been introduced, being considered as a most important step forward to improve accepted standards in the current reporting conventions of reserves estimations. This was established as a standard system in March 2007 by SPE with the cooperation with WPC, AAPG, and the Society of Petroleum Evaluation Engineers, being based on previous definitions. This new system is now commonly used as a standard across industries and is being accepted worldwide (Petroleum Resources Management System 2007).

2.1.1 Current standard System of Petroleum Reserve and Resource Classification and Definition SPE/WPC/AAPG

Hydrocarbon resources and reserves are the life source of oil and gas companies. Companies require detailed information and knowledge about resources and reserves to be developed through precise evaluation, planning, and management. As differing Standards and methodologies can apply to the determination of resources and reserves, required results can then be expected to be impacted by these variations and associated uncertainties. In addition, difficulties can be experienced by the companies in the identification of resources and reserves - the reason might be different standard systems of reserve evaluations being applied by companies for classification of resources and reserves. Also, there is no specific confidence to confirm a reasonable certainty in reserve evaluation due to the risks in technical and commercial factors that involve in classify reserves.

In terms of petroleum, total hydrocarbons initially in place are abbreviated as a THIIP which represent those estimated volumes or quantities of petroleum accumulations in place which cannot yet be commercially recovered. These quantities could initially be partially extracted with further development dependent upon improvements on the understanding of the reservoir expectations such as geological, engineers' interpretations and expectation of economical, commercial circumstances and feasible technologies.

Those quantities of total petroleum initially in place should be associated with some conditions that are considered as an accepted standard used in decision making to determine a development and production status of the reserves as a project, such as what needs to be discovered, recoverable, commercial and remaining (Petroleum Resources Management System 2007).

Project status classifications, as stated by the SPE/WPC/AAPG resource classification system, demonstrate the level of maturity of a project, making the recoverable quantities that are arranged in groups according to classification systems. These are more suitably recognized in areas such as the difference between reserves, contingent and prospective resources (Ross 2004). For total petroleum initially in place based on resource, the classification system can be further divided into categories of discovered and undiscovered petroleum initially in place.

In addition, discovered PIIP can be classified as commercial and sub-commercial petroleum initially in place. Therefore, commercial PIIP includes reserves and sub-commercial PIIP includes contingent resources. Moreover, undiscovered quantities of petroleum initially in place are subdivided as prospective resources (See Fig 1).

In an identical way, the aim of all those companies and organizations that are involved in oil and gas exploration and production activities is to maximize the extraction of those hydrocarbons based on project basis and maturity. In addition Project status includes reserves and resources therefore, maturity of the project is determined in accordance to technical and commercial maturity (Henry 2005). In general, the definitions of the three major sub classification for recoverable quantities of petroleum such as reserves, contingent and prospective resources are clarified according to the maturity of project as defined in the context of Guidelines of the Evaluation of Petroleum Reserves and Resources SPE/WPC/AAPG.

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date under forward defined conditions. Therefore, Reserves must satisfy four criteria:

- Discovered
- Recoverable
- Commercial
- Remaining (as of the evaluation date).

Reserves are classified based on project status such as:

On Production: The project is currently producing and selling petroleum to market.

Under Development: All necessary approvals have been obtained, and development of the project is underway.

Planned for Development: Satisfies all the criteria for reserves, and there is a firm intent to develop, but detailed development planning and/or necessary approvals/contracts have yet to be finalized.

Contingent Resources: Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

Contingent Resources are divided into;

- Marginal

Technically feasible and economic, but not committed due to some other contingency

- Sub-Marginal

Technically feasible, but not economic and/or other contingencies exist

Development Pending: requires further data acquisition and/or evaluation in order to confirm commerciality.

Development on Hold: Of significant size, but awaiting development of a market or removal of other constraints to development, this may be technical, environmental, or political, for example.

Development not Viable: No current plans to develop or to acquire additional data at this time due to limited production potential.

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

Prospect—Potential accumulation is sufficiently well-defined to represent a viable drilling target.

Lead—Potential accumulation is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Play—Recognized prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects (McMichael 2001).

This system of resources classifications explain sufficient guidance of various classes of resources as standards and clarifies the occurrence risk that appears during estimates of resources and reserves over the life cycle of the project. Therefore, the reserve can be estimated only and not measured directly. Commercial achievement of the project also is demonstrated by this system from low maturity to high maturity which leads to increase chance of probability of production with the consideration of increasing uncertainties (Ross 2004).

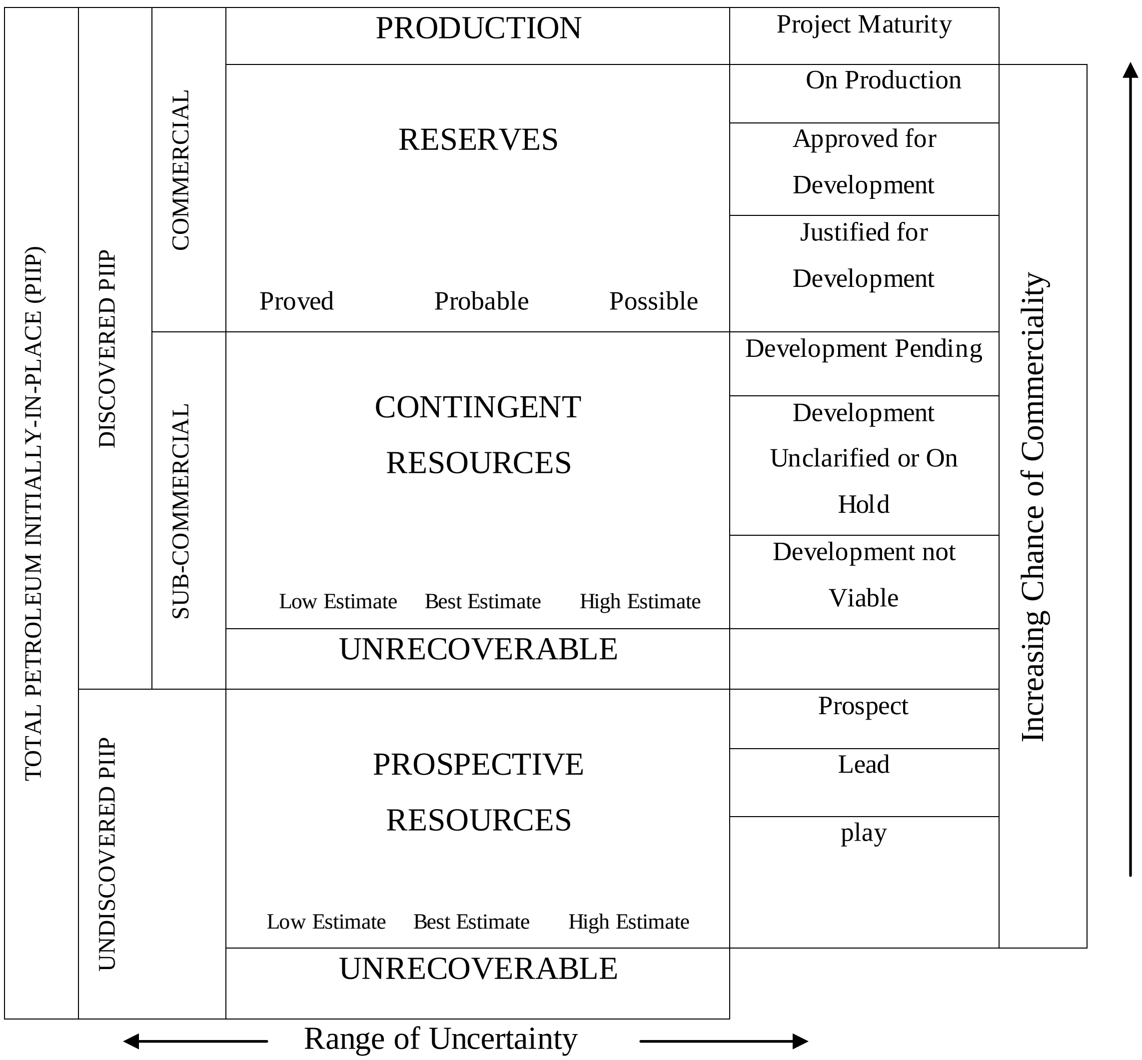

Figure 1: Sub-classes based on Project Maturity
Source: Petroleum Resource Management System 2007

2.1.2 Range of Uncertainty SPE/WPC/AAPG

Risk and uncertainty are two factors extensively involved in the petroleum industry. In addition, determination of project maturity depends on whole accumulated volumes and the decisions are made on estimations of those hydrocarbon reserves in the reservoir. Thus, estimating, developing and managing hydrocarbon reserves or/and resources to establish a project maturity effectively associated to risk due to surrounded uncertainties (Schiozer et al.2004).

The probability of reserves value will be related with the amount of collected data from different sources. As the quantity of data increases, the probability of uncertainty distribution decreases and opportunity of commerciality increases for the project maturity (Estimating and Auditing Standards for reserves, 2007).

Therefore, there are two traditional methodologies in reserve estimation; namely the probabilistic and deterministic approaches, which are explained in detail in the next section. Under the SPE 2007 definitions, reserves can be estimated by utilizing either deterministic or probabilistic approach. With the deterministic approach, a single possible value is chosen for each factor according to the estimator's determination of the value that is most suitably related with reserves classification (Petroleum Resources Management System 2007). On the other hand, probabilistic approach is considered as an analysis method in reserves estimation. It involves determination of full range of possible value for each unwell-known factor to create possible results (Estimating and Auditing Standards for reserves 2007).

Validity of degrees of uncertainty can be determined more precisely when determined in accordance to clarifications of recognizing differences between proved and unproved reserves. Proved reserves are categorized such as probable and possible therefore, related to higher degrees of certainty than unproved reserves to be recoverable (Martinez & McMichael 1999).

In the glossary of used terms in evaluation resources, different terms are used to determine acceptable and sensible range of uncertainty of recoverable quantities of hydrocarbon according to proven reserves. For example 1P is for estimating quantities of proved reserves, 2P for proved plus probable, and 3P for proved plus probable plus possible.

In set circumstances of prospective resources classification low, high and best are used to illustrate range of uncertainty. Furthermore, accordance to contingent resources terms 1C, 2C and 3C represent low, high and best estimate to illustrate range of uncertainty (See Fig 2) (Petroleum Resources Management System 2007).

High degrees of certainty are related to proved reserves to be recovered commercially by using deterministic approach, while the levels of certainty associated with probable reserves will be less likely to be recoverable than proved plus probable reserves (2P). Additionally, possible reserves would be less likely than proved plus probable plus possible reserves (3P) to be recoverable. Moreover, if probabilistic methods are used at least 90% of proved reserves (1P), 50% of probable (2P) and 10% (3P) of possible reserves quantities should be recovered (Sircar et al. 2003).

Indeed, a true value of the volume of hydrocarbon trapped in the ground is constant over a life time of the project. In addition, there are many factors used to determine the volume of the reservoir coupled to the physical factors of the hydrocarbon fluid; therefore, those factors contribute to the uncertainty of the volume and value. Moreover, this would be the reasons that make those quantities to be changed afterward.

However, technical uncertainty associated with the accumulated volume of hydrocarbon can be defined according to project maturity, while for economical uncertainty of hydrocarbon reserves remain as unquestionable issues because of unpredictable occurrences that would be involved in forecasting future hydrocarbon price (Ross 2004).

In terms of the probabilistic method, it is considered more accurate than the deterministic model due to the term of reasonable confidence of certainty that will be involved in this approach for assessing reserves estimations. The processes rely on using computer software based Monte Carlo Simulation to recognize available outcomes in the reported reserves (Mang 2006).

The financially probabilistic method is more preferable rather than utilizing the deterministic estimates due to decrease in the costs that occur in the activities or processes that will take place in the exploration and development drilling of a project (Poroskun et al. 2004).

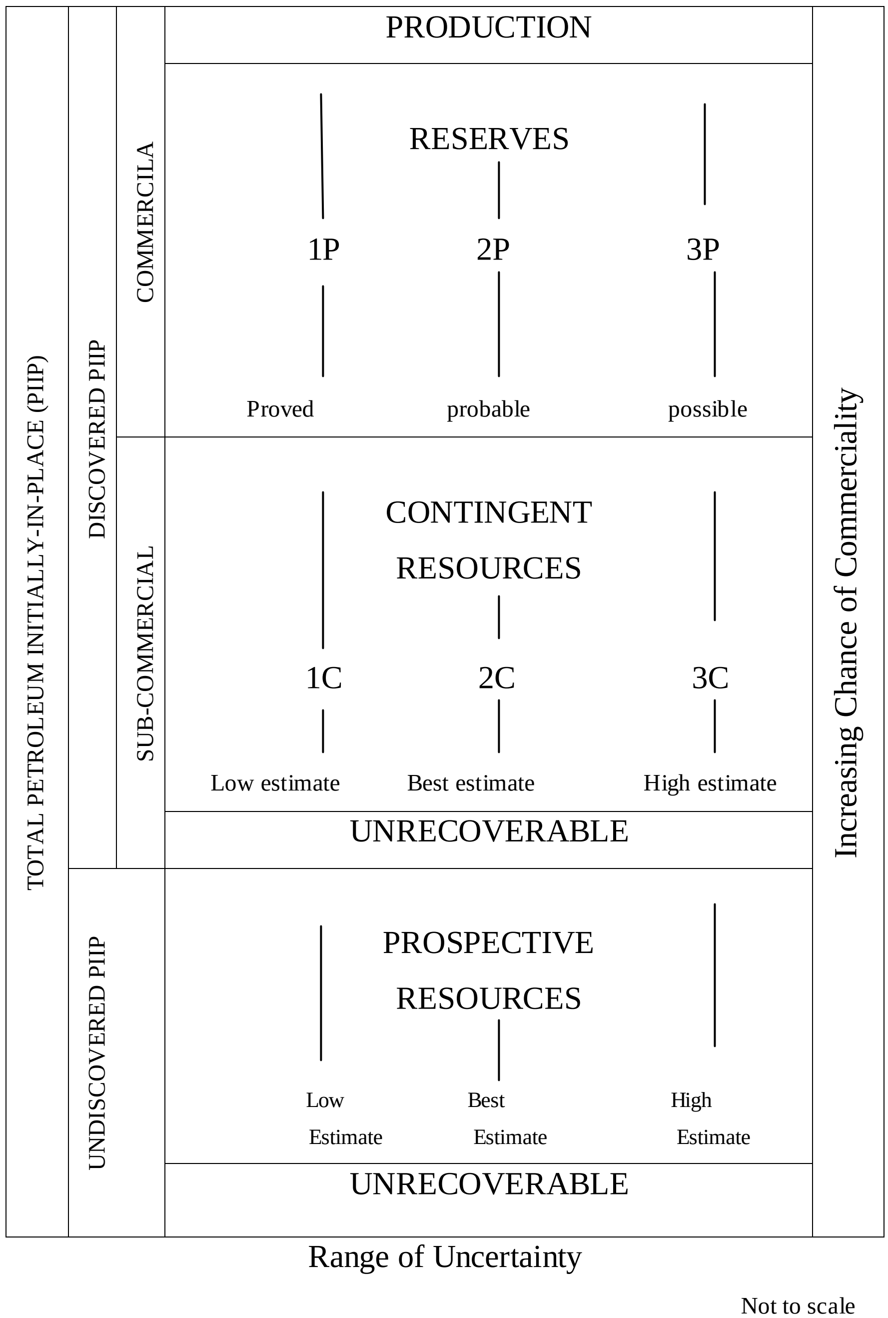

Figure 2: Resource Classification Framework
Source: Petroleum Resource Management System 2007

2.1.3 Comparisons between SPE PRMS 2007 and SPE/WPC 1997 of Reserve and Resource Systems

Proved reserve

SPE/WPC 1997	SPE PRMS 2007	Comments
"Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate"	*"Proved Reserves are those quantities of petroleum, which by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate"*	*"Very similar definition, with the key difference being the use of defined economic conditions still requires "reasonable certainty"*

Table 1: Comparison of proved reserve between SPE/WPC 1997 and SPE PRMS 2007

Probable reserve

SPE/WPC 1997	SPE PRMS 2007	Comments
"Probable reserve are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves"	*"Probable reserves are those additional reserves which analysis of geosciences and engineering indicate are less likely to be recovered than proven reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus probable reserve (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability the actual quantities recovered will equal or exceed to the 2P estimate."*	*"Removed mathematical inconsistency in the definitions of Probable and 2p"*

Table 2: Comparison of probable reserve between SPE/WPC and SPE PRMS 2007

Possible reserve

SPE/WPC 1997	SPE PRMS 2007	Comments
"Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves"	*"Possible Reserves are those additional reserves which analysis of geosciences and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate"*	*"Essentially identical definitions"*

Table 3: Comparison of possible reserve between SPE/WPC and SPE PRMS 2007

Contingent resource

SPE/WPC 1997	SPE PRMS 2007	Comments
"Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable"	*"Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies"*	*"Essentially identical definitions"*

Table 4: Comparison of contingent resource between SPE/WPC and SPE PRMS 2007

Prospective resource

SPE/WPC 1997	SPE PRMS 2007	Comments
"Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations"	*"Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects"*	*"Essentially identical definitions"*

Table 5: Comparison of prospective resource between SPE/WPC and SPE PRMS 2007

2.1.4 Securities and Exchange Commission (SEC)

The Securities and Exchange Commission (SEC) particularly plays a key role in oil and gas reserves definitions and in those companies or institutes who desire to access capital markets through the USA, because it claims to reduce shareholders risks. Important features of SEC regulations, that makes SEC classification and definition system different from others, is that it defines only proved and it forbids other types of reserves. Its regulation is stricter than other definitions that have been defined by other organizations (Poroskun et al. 2004).

SEC relies on the Financial Accounting Standards Board (FASB) for representation, interpretations, guidance and practices about changes in asset requirements of proved oil and gas reserves for getting additional information to clarify estimations of Discounted Future Net Cash Flow (Heiberg et al. 2002). The definition of proved reserves according to the Security and Exchange Commission, established in Rule 4-10 (a) (2) is: " the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made." (Harmon 2007).

Based on the current definition of SEC about proved reserves, which originally has been defined and revealed by the Department of Energy and adopted by SEC in 1978, reserves can be called 'proved' where they are economically producible. This refers to high confidence in commercial producibility, which is demonstrated by formation test or/and actual production (Financial Accounting Standards Board 1979).

The term of "under existing economic conditions" stands for economically producible which demonstrates that producible amount of hydrocarbon in a reservoir can be sold for more than the costs that will go into producing the estimated hydrocarbon, such as extraction and transportation costs (SPE oil and gas reserves committee 2005).

Reporters and analysts of reserves estimation are concerned about those quantities of reserves that are still undeveloped. Thus, these quantities are placed on hold until viable technology with acceptable levels of uncertainty can be applied for providing reasonable reserves estimations (Harmon 2007).

In general reserves include both proven and unproved reserves. Under the Security and Exchange Commission regulations, based on Rule 4-10(a) (4), proved reserves only are inferred and they are categorized into proved developed and proved undeveloped oil and gas reserves. According to Security and Exchange Commission (SEC) based on the Regulation SX4-10, proved reserves sub classified into two categories (Gallun et al. 2001, p. 776), the definitions of which are given below:

Proved developed oil and gas reserves.

"Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved".

Proved undeveloped oil and gas reserves

"Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir".

For an accounting system, reserves are considered economically proved under current economic conditions such as present prices and taxes, viable technology and the high level of uncertainty involves in the accumulative volumes of oil and gas that can be recoverable (Mitchell 2004). Hence, SEC suggests that the value of reserves could be considered as assets based on Reserves Recognition Accounting (RRA) which mentioned in FASB Statement No.19 (Johnston & Johnston, p 500. 2005). Therefore, reserves are taken into account for progressing future company's profits (income) and the economic feasibility of the reserves is associated with the year-end prices of the projects under SEC's rules and guidelines (Laherrere 1998).

2.1.5 Comparison between SPE and SEC Regulations of Reserve Definitions

In the oil and gas industry, international operating companies or organizations and government agencies are tasked to disclose and produce the recoverable amount of petroleum. The purpose is the same target in different way to bring the producible amount of hydrocarbon to the surface (Henry 2005).

The Security and Exchange Commission defined reserves in 1978. This organization was suggested by the oil and gas industry to make changes in its own rules and regulations for reporting reserves relying on the principle of SPE Petroleum Reserves Management System in 2007 and discuss its renew reserves rules with technical experts (Reservoir Solutions 2008).

Moreover, the Security and Exchange Commission insisted to impose the Society of Petroleum Engineers with its authorized standards of reserves estimations, such as how reserves can be estimated financially according to Financial Accounting Standards Board (FASB) which is considered as the rule makers for the private sector. Therefore, SEC enforces authorized FASB and should decide to accept the use of SPE guidelines was defined in PRMS Standard 1997 (Reservoir simulation 2006), The key differences between SPE and SEC are:

- Security and Exchange Commission (SEC) permits only the quantification of proved reserves and prevents unproved reserves such as probable and possible reserves in its own reserves classification system. Therefore, proved reserves in this organization's regulations is sub classified into two categories, proved developed reserves and proved undeveloped reserves ((Boone et al. 1998). On the other hand, SPE does not mandate only proved reserves, but it authorizes unproved reserves to be used for oil and gas producing companies. Moreover, unproved reserves in SPE's classification systems are categorized into probable and possible reserves with consideration of level of certainties for each category such that they are more likely to be recoverable for possible reserves and less likely to be recoverable for probable reserves (SPE oil and gas reserves committee 2005).

- Under the SEC and SPE regulations, reasonable information demonstrates the degree of certainties should be utilized for their reserves estimations relying on clarification of given data by geological and engineering data. SPE states that in the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limits unless otherwise indicated by definitive geological engineering or performance data. SEC claims that in the absence of information on fluids contacts the lowest known occurrence (LKO) of hydrocarbons controls the lower proved limited of the reservoir.

- SPE does not mandate which method should be used for reserves estimating. Hence, reserves are estimated by using either deterministic or probabilistic methodology with the consideration of indicated certainty of the reserve. For example, under deterministic methodologies, the degree of certainty is demonstrated as a reasonable certainty, that the quantity will be recoverable for proven reserve, less degree of confidence than proven reserve of the quantity that will be recoverable for probable reserve and so on for possible reserves. For probabilistic methodologies the term of certainty indicates that there is 10%, 50% or 90% probability of the quantities to be recoverable for proven, probable and possible reserves (Yup Kim 1999). While, SEC does mandate deterministic methodology rather than probabilistic method, it states that the disclosed quantities of reserves must be estimated according to deterministic regulations (SPE oil and gas reserves committee 2005).

- The requirements of reserves estimates and classification of reserves, as approved by SEC for achieving economic and operating conditions of given data from the geological and engineering about cores and well tests, seismic studies, and testing and well logs, are necessary to explain the basis for the reserve estimates and provide an explanation of the economic producibility of the reservoir. The requirement of a well test is only avoided in the deep water of the Gulf of Mexico when it is supported by conclusive formation tests. Thus SEC regulations need to be expanded not only in the deepwater Gulf of Mexico, but to other producing areas as well (Reservoir solutions 2008). On the other hand, classification of reserves as approved in SPE regulations needs an authorized well test. However, it will be replaced if the estimate is supported by conclusive formation tests, core and log data (SPE oil and gas reserves committee 2005).

- Even though SPE claims that economic evaluations are fundamentally estimated and demonstrated based on estimated future conditions, such as prices and costs in the life cycle of the project with the considerations of expected production under economic condition (Henry 2005), in some events SPE applies year end prices for its economic evaluation (SPE oil and gas reserves committee 2005). For example, future cash inflow is calculated at the year end price associated with the reserves in the end year quantity. This is applied to interpret that proved reserves are feasible under economic conditions according to statement of the Financial Accounting Standards Board (FASB) 69 (Henry 2005). In addition, both SPE and SEC are relying on market trends and market expectations regarding production, transportation and lease extension to evaluate the economic viability of the project (SPE oil and gas reserves committee 2005).

To sum up, the main differences between the Security Exchange Commission standards and Society of Petroleum Engineer standards relate to interpretation of licence conditions, including the licence duration. For example, under SEC rules, oil and gas deposits may not be classified as proved reserves if they will be recovered after the expiration of the current licence period unless the licence holder has the right to renew the licence and there is a demonstrated history of licence renewal (Stern 2005).

2.2. Methods for Calculating Cost in Reserve Estimation

For an oil and gas company, calculating costs in acquisition, exploration, development and production phases are relaying on two comprehensive approaches, namely successful efforts (SE) and full costs methods (FC). Financially, the acceptance of requirements and dealing with these costs in the whole stages such as exploration, development and production, based on the methodologies presented FC and SC generate various and contentious results for the purposes of taking appraisal, managing and planning in the oil and gas accounting into account (Pruett & Vanzante 2008).

Investigations into the ideologies of these methods took place in recent times where the Security and Exchange Commission placed specific guidelines on each method used by companies to calculate the costs that occur in each phase of oil and gas operations. The SEC has not determined which one of these two methods should be utilized; it has allowed companies to decide whichever they desire either the successful efforts or full costs method based on the applications that have been defined (Lilien & Pasten 1981). In the relation to the consequences of the economic environment, accounting issues have been taken into the account in the Financial Accounting Standards Board (FASB) to form unique standards consisting of diverse principles for financial reporting of petroleum operations (Collins & Dent 1979).

.In addition, the only successful approach approved in the statement No. 19 [1977] by FASB is successful efforts (Pruett & Vanzante 2008). In the same year 1977 full cost (FC) method was not taken into account by FASB as accounting methods, while, in1978 SEC was stated full cost method officially and it considered full cost approach as an acceptable method (Johnston & Johnston 2005).

Usage of successful efforts (SE) method for producing oil and gas has been used by large oil and gas companies. Recently (FASB) has encouraged other companies to transform from full costs to successful efforts methods for accounting oil and gas producing activities (Collins & Dent 1979). However the beliefs of the FASB in applying the SE method have been challenged through the SEC regulations. This has resulted in the full costs (FC) method being the only method permitted by oil and gas procedures for accounting oil and gas producing activities. Therefore, in 1981 the Security and Exchange Commission established that Reserves Recognition Accounting (RRA) as a supplementary method (Lilien & Pasten 1981).

Under full costs accounting method all costs are to be capitalized even if the process is success or failure in oil and gas producing activities relatively to cost centers basis. In successful efforts the costs are capitalized only when the result of activities in searching of oil and gas estimations has found commercial reserves (Lilien & Pasten 1981). On the other hand, the other costs that occur in an unsuccessful search in exploration and development stages in oil and gas producing activities (dry hole) are charged as an expense (Collins & Dent 1979).

In 1978 the Security and Exchange Commission defined specific applications for the two methods to be followed by oil producing companies. In Accounting Series Released (ASR) No.253, as shown in Table 6, the SEC specified guidelines for Successful Efforts and in the Accounting Series Release No.258, defined specific applications of the full costs method for those companies that intend to utilize these methodologies for accounting incurred costs in exploration and development process according to the Table 7 (Lilien & Pastena 1982).

1. Undeveloped leases and properties-Property Acquisition Cost
    a- Capitalized and charged to expense when surrendered or abandoned
    b- Capitalized and amortized over some period of time
        i- Term of the lease
        ii- Overall abandonment experience life of the company
        iii- Some overall life based on exploration experience of the company
2- Delay rentals-Costs of Carrying Undeveloped Properties
    a- Charged to expense when paid
    b- Capitalized as part of undeveloped lease cost and then the various practices as set forth in (1) above are followed.
3- Geological and geophysical costs-Exploration costs
    a- Charged to expense as incurred
    b- Capitalized and amortized over some period time
    c- Allocated between successful and unsuccessful-unsuccessful costs charged off and successful costs allocated to undeveloped leases acquired
4- Development dry holes
    a- Charged to expense as incurred
    b- Capitalized as part of producing lease cost
5- Property unit for amortization purposes-Method of Amortization
    a- Unit-of-production for each lease
    b- Unit-of-production for each field
    c- Composite unite-of-production method for district or area of interest
    d- Composite unit-of-production method for overall company
6- Write-down of production property-Tests of impairments
    a- Write-down on an individual property on unit basis when the fair value of the property unit is less than the net unamortized cost
    b- No write-downs of individual producing property units are made, regardless of relationship of fair value and unamortized costs, unless total producing properties of the company have a value less than total unamortized cost of producing properties.
7- Tax allocation accounting
    a- No tax allocation on intangible development costs and other capitalized costs which are deducted currently for Federal income tax purposes
    b- Complete tax allocation accounting on all such costs in (a) with an election as to the interaction of statutory depletion and percentage depletion.

Table 6: Summary of differences in application of successful efforts method prior to ASR No. 253 [SEC, 1978a]
Sources: (Lilien & Pasten 1981)

1- Inclusion of undeveloped leases in amortization base-Acquisition Costs
   a) Costs included in amortization base from date of acquisition
   b) Costs excluded from amortization base until drilled and recoverable reserves are unknown
   c) Significant undeveloped leases excluded (such as Alaska and offshore) and all others included in amortization base

2- Property accounting unit-Cost Centers
   a) Separate accounting unit for each country
   b) Separate accounting unit for North America continent and for each other foreign country or for other foreign countries as a group.
   c) One global property unit

3- Recoverable reserves used to compute amortization rate for each Property accounting unit-Pattern of Amortization
   a) Developed reserves only with incurred costs included in amortization base
   b) Proved reserves with estimated cost to develop also included in the amortization base
   c) Proved and probable reserves with estimated cost to develop also included in the amortization base

4- Method of determining ceiling on total unamortized cost of oil and gas property-Test of impairment
   a) Fair market value of all oil and gas properties using only proved reserves
   b) Fair market value of all oil and gas properties using proved and probable reserves
   c) Future net revenue discounted to present value for using the cost of money
   d) Future net revenue and deducting actual interest expense to be incurred (no discount on equity funds)
   e) Future net revenue without any discount

5- Tax allocation accounting
   a) No tax allocation for any of the exploration and development costs which are capitalized in the accounts and deducted currently for Federal income tax purposes
   b) Tax allocation for the nonproductive exploration costs but no tax allocation for the productive costs
   c) Complete tax allocation accounting for all costs which are capitalized in the accounts but deducted currently of Federal income tax purposes. Tax allocation for intangible drilling costs, development costs and other costs but with recognition of interaction of statutory depletion and percentage depletion [see FASB. 9, para. 13].

Table 7: Summary of difference in application of the full cost method prior to ASR NO.258 [SEC, 1978b]
Sources: (Lilien & Pasten 1981)

The successful interpreted information is required regarding to the two methods for making a successful decision about oil and gas reserves.   Therefore, financial statements need to be illuminated and understood by estimators according to FASB statement No.19 in relation to their oil and gas producing process, such as providing and clarification of information about mineral interests (Financial Accounting Standards Board 1982). The financial costs associated with the discovery of reserves are more likely to be affected by the level of uncertainties and accuracy of calculating the costs than would be incurred in the determination of the reserves.

2.2.1 Historical Cost

In the term of reserves, managers are being less restrictive to disclose quantity of reserves when they have confidence in the information about production costs. Considerations of costs measurement of reserves make managers likely to optimize the degree of disclosure in the company's annual reports (Mirza 1999). Thus, in commercial reserves, companies follow the historical cost in the oil and gas industry and most of their expenditures are capitalized in the exploration and development phases in accounting reports to shareholders.

Historical costs are considered as comprehensive tools for assessing and analyzing proven oil and gas reserves. The costs that incur in disclosure of reserves should be either capitalized or expensed while significant contribution to the costs of proven reserves ought to be disclosed separately from other reserves for acquiring interests (Financial Accounting Standards Board 1982). In most circumstances, Statement of Financial Accounting Standards No. 19 deals with the properties (reserves) based on their mineral interests that participate in the right for extracting oil and gas such as royalty interests, production payments, lease and concessions. Reserves are underlined based on the formal contracts that would be made between government and authorities relatively to the leases at the end of each year (Lev 2001).

The historical acquisition of oil and gas reserves is the collective total of the expenditures that are spent in the exploration and development stages of the project (Financial Accounting Standards Board 1980). All these costs are capitalized in the cost center where the reserve is considered commercially producible therefore; they will be amortized based on a unit of production (Financial Accounting Standards Board 1980). When production begins, producible assets that are still in use cannot be determined as assets for the reason of capitalizing interests. In addition, non producible assets, which mean those assets that are not used yet by the project cannot be considered to be amortized because reserves associated with non producible assets are considered as unknown (Financial Accounting Standards Board 1980).

In general, those costs that have not resulted in being identifiable future benefits are considered as a loss. According to accounting methodologies for calculating costs, under successful efforts only costs that are incurred in successful activities can be charged as capitalized. On the other hand, under full costs method whole costs incurred in acquisition, exploration and development are capitalized in costs center basis (Lilien & Pastena 1981). Moreover, in FASB Statement No.34, it is stated that interest on the assets that are still in use or ready to be used cannot be capitalized, but they are capitalized when they are producible in earning activities or when they start producing oil and gas (Financial Accounting Standards Board 1980). Moreover, in an oil and gas life cycle, the costs are incurred in the phases, acquisitions, exploration, and development need to be disclosed either charged to capitalize or expense with the consideration of acquiring mineral interests (Financial Accounting Standards Board 1982).

2.2.2 Future Costs and Reserves Production

Future production rate of oil and gas can be estimated from confirmed production patterns. If development of production is not identified, then an analogy approach is used to estimate future rate of production of reservoirs. This is achieved through the assessment of quite similar geographic region with identical geological features and reservoir quality. For example: either finding production rate patterns by using a group of data for reserves that are already being produced, especially when there is sufficient historical data that illustrates declining patterns to production rates or using similar reservoirs.

Therefore, in this case production rate patterns can be estimated based on the consumption of the decline rate of future production with the considerations of the estimated quantities of oil and gas that are anticipated to become producible before forecasted production decline in relation to the predicted ultimate production. Moreover, reservoir simulation can also be used to estimate future production rate regardless to some important matters that need to be taken into account, (i) define reservoir pay, volume and reserves, (ii) numbers of the wells to be drilled and capacity of production, (iii) select optimum recovery factors and process, (iv) estimate future potential performance, (v) estimate future economic limit or future abandonment, (vi) assess uncertainty and a viability of data requirement. This method is applied to the reservoir and can be claimed as a process to estimate fluid flow behavior of petroleum reservoirs either by using arithmetical or physical approaches. As the term of petroleum reservoir requires reservoir rock/fluid characteristics and surface facilities.

Future costs and reserves production can be either less or more than the expected estimations because of unexpected changes in the reserves market. Moreover, the number of wells and their capacity might either in reality under-produce or over-produce based on the predicted rate of production.

Under information about historical costs and information about quantity of proved reserves, knowledge and information could be available about future cost of production, development and existing and future reserves, and estimates of a specific data of future production. Hence, reserves financially can be estimated by oil and gas companies based on estimated future cash flow with the consideration of future prices and risks of relative to the determined reserves (Financial Accounting Standards Board 1982).

In addition, estimation of costs and prices are considered as critical issues because they are directly affected by some factors such as taxes policy, business risks, political issues and price controls. For instance, a lot of confusion and errors are made by estimators in deciding on the discount rate (Financial Accounting Standards Board 1977).

2.2.3 Categorization of Cost Calculations

First of all, in the exploration phase, costs that occur for a selected area are mainly associated with the seismic studies as to whether oil and gas exist or not. . The aims of this exploration phase are to make decisions about the selected area either to be drilled or not. Important underlying costs or assumption required in this phase consist of depreciation and costs for maintaining equipment and facilities (Securities Lawyer's Deskbook 1975). The costs of drilling are associated directly with results that come out from the drilled area. If the achievement of the drilling is resulting in successful commercial results, then the occurrence costs are charged to be capitalized, but if is not commercially successful then the results of drilling are transferred to operating costs (Babusiaux 2004).

In addition, operating costs of geological and geophysical surveys, tax of properties, lands, lease and legal costs, and delay rentals due to undeveloped reserves incurred in exploration stages should be expensed (Financial Accounting Standards Board 1977). After the exploration stage, if the oil and gas reserves were not found in the reserves that where expected to have oil and gas, then the reserves will be abandoned. If oil and gas reserves existed then the next phase will be taken in to the consideration of producing the oil and gas reserves (Pruett & Vanzante 2008).

Secondly, development costs are those costs incurred and deemed to be necessary to provide facilities for producing oil and gas, treating and storing them. Costs in this stage consists of the costs occurred to study and clear the land, design roads and power lines, seismic studies, drilling for production, drilling and injection of the well, development of the well and installation and then production (Securities Lawyer's Deskbook 1975). In particular, in the development stage costs also include depreciation and applicability of operating costs for maintaining and supporting the equipment and facilities financially applicable to the development stage activities. Therefore, all the costs incurred in this stage should be capitalized, whether the incurred costs lead to commercial potential or not (Financial Accounting Standards Board 1977).

Future costs of the development stage, according to Financial Accounting Board (FASB) No. 33, require appreciation for the current amortization of achieving the quantities that can be ready to be produced. On the other hand, the other portions of the proved reserves are more likely to be unproducible at the current production. However, they can be named as proved reserves, but they are still considered undeveloped (Financial Accounting Standards Board 1980).
As soon as the development phase is finished, it will be followed by production. Financially, the amount of the capitalized costs of acquisition, exploration and development activities should be disclosed separately in the activities of producing oil and gas. In addition, the costs incurred for disclosing reserves in the development phase are more than the costs that occur in the production phase (Financial Accounting Standards Board 1982).

Thirdly, production costs are those costs that are considered necessary to maintain the project's production support equipment and facilities, such as depreciation and operating costs. Moreover, in this stage there are other costs, including labor cost, insurance, repairing and maintaining materials, property taxes. In general, these costs could be named as lifting costs (Financial Accounting Standards Board 1977). Estimation of costs is considered as a significant process to illustrate the estimated productivity outcomes of the project. Different types of methodologies result in different results and can impact the accuracy of the estimations costs.

Thus, availability of time and using several different methodologies can provide more precise and correct information about the costs and chosen state of the real arrangement of the project (Taal et al. 2003). Costs of producing oil are significantly influenced by physical and reservoir characteristics (such as natural and/or artificial lifting) according to the geographic locations region, depth and production rate.

The report of the Energy Information Administration, as given in Figures (3-4), illustrates an exclusive relation between oil and gas operating costs, equipment costs, and price at oil and gas producing activities. The report also includes   lease equipment costs and annual operating costs for domestic oil and natural gas field related to prices. Oil and gas equipment and operating costs are subject to cost fluctuations, such as well services, rig costs, costs of chemical, labor, and general equipment (Energy Information Administration 2007).

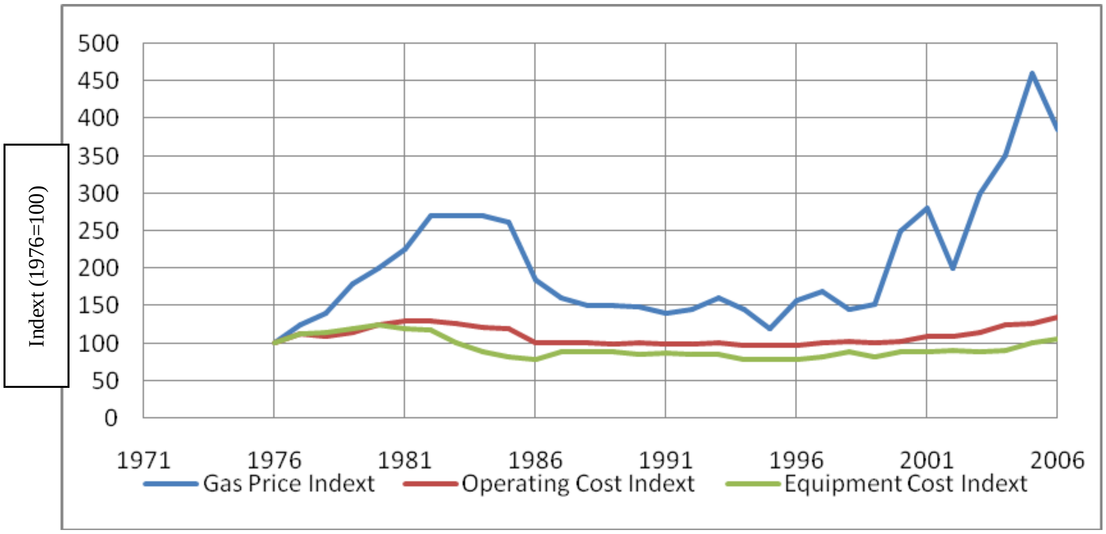

Figure 3: Deflated Indices for Natural Gas Prices, Equipment Costs and Operating Costs
Source. Energy Information Administration, Office of Oil and Gas

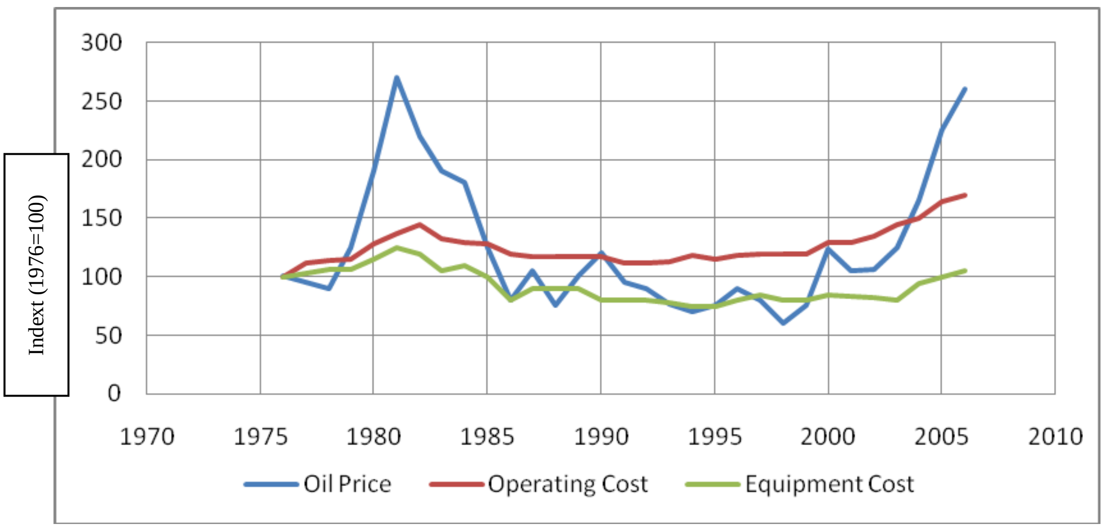

Figure 4: Deflated Indices for Oil Prices, Equipment Costs and Operating Costs
Source. Energy Information Administration, Office of Oil and Gas

2.3 Geological Risk of Reserves

For the comprehensive hydrocarbon potential evaluation of a reservoir, engineers, corporate executives, stockholders, and government leaders all look to one critical number for the valuation of their oil holdings for the understanding of the factors that influence the quantities of oil and gas from reservoirs. This information can be applied by geologists, geophysicists, petro-physicists, land management specialists and managers in reservoir engineering to control the hydrocarbon generation, migration and accumulation within a reservoir. The data can also identify prospects within different basins, through a synthesis of all available sequence stratigraphy, geologic history, structural evolution and reservoir data and integrated with hydrocarbon habitats of the basins. The basic purpose of every estimator in a producing company is the same; to find and produce oil and gas in an efficient manner to the economic benefit of the company. A reservoir engineer cannot predict the production performance of an oil reservoir with any degree of certainty without knowledge of the physical characteristics, the geology of the reservoir. Even a geologist cannot describe the physical characteristic of a reservoir without considering the producing characteristic as evidenced by production and pressure data. In particular, the gap can be categorized into four groups:

- Reservoir Rock Properties; as porosity, fluid saturations and permeability
- Reservoir physical characteristic: structural and geology of the reservoir
- Reservoir Fluid Properties; as fluid types, reservoir oil, reservoir gas
- Reservoir Drive Mechanisms
- Reservoir Production Evaluation Techniques; as volumetric calculations, material balance, decline curves and deliverability

2.3.1 Estimation of geological risk of exploration

A good estimate of risk must consider both sides, namely the geological and commercial factors. The purpose of risk analysis in the exploration phase is to disclose those risky factors involved in the confirmation of the occurrences of hydrocarbon initially in place (HIIP) prior to drilling of a mapped prospect. . There are five main tasks involved in this risk factor analysis, which are: (1) finding the probability of geological risk of the reservoir; (2) estimating the cumulative (HIIP); (3) estimating what can be recoverable; (4) finding commercial profitability; and (5) commercially developing and producing what has been found. . These points will be discussed in more detail.

Over the entire the exploration phase, different classes of geologic reserves require different amounts of data acquired from seismic, drilling, logging, production tests and sampling analysis to reflect the phase of exploration, development and certainty of geological understanding to a specific reservoir.

2.3.2 Geological Risk Components (probability of success)

The geological success assessment requires an evaluation of those geological factors that are critical to the discovery of recoverable quantities of hydrocarbons. The probability of discovery is a value that is based partly on objective knowledge and historical data, partly on extrapolations and partly on estimator's subjective judgments of geological parameters. It is defined as the product of the following major probability factors, each of which must be evaluated with respect to presence and effectiveness (Yup Kim 2000). For this purpose, four different concepts of exploration activity will be required to estimate the probability of the geological risk of a reservoir as is shown in Table 8:

		Reservoir		Trap		Charge		Retention
	Probability factors / Volumetric factors	Facies	Porosity	Mapping	Seal	Source	Migration	Retention
VOLUMETRIC ESTIMATION	Structural shape, Volume							
	Hydrocarbon Column							
	Reservoir Thickness							
	Porosity							
	Net/Gross ratio							
	Saturation							
	Proportion of oil & gas							
	Recovery factor							
	Formation Volume factor							

Table 8: The Relation between Geological Models and Input Parameters to the Volumetric Calculation. Source: (Yup Kim 2000).

2.3.3 Concepts of Exploration

- Basin framework:

  This includes sedimentary basin containing source rock, reservoir, trap and migration in proper timing.
- Petroleum system:

  It is defined as a volume of sedimentary rock containing hydrocarbon and charged by source rock. In a defined system there will be single source rock.
- Play:

  Play is the element part of a petroleum system, and recognized as having on or more hydrocarbon accumulations identified by common geological character of reservoir, trap and seal; timing and migration.
- Prospect

  A prospect is identified and mapped on the basis of geological and engineering data. Therefore, reliability of the prospect definition will depend on the sufficiency of the database and the choice of reliable models for the relevant geological factors (Yup Kim 2000).
- Prospect Definition
- Geological Model and risk assessment
- Reservoir
- Presence of Reservoir facies
- Effective pore volume
- Trap Mechanism
- Presence of mapped structure
- Effective seal mechanism
- Petroleum charge
- Presence of mature source rock (sufficient)
- Effective migration
- Retention after accumulation

Geological factors and risk factors in the exploration activities can be summarized in the table 9 below.

Geological Factors	Risk Factors	Comments
Closure Area	- Existence of folds - Faults - Presence of Reservoir Facies	1- Evaluates reactivation of faults, regional uplift and tilting after accumulation. 2- Movement after accumulation.
Trap control	- Depth, area, and - Thickness *Facies Change *Cementation - Spill point - Stricture *Fault Leak *Poor Top Seal - Stratigraphic *Poor lateral seal due to no facies	1- Describes the probability that the structures have been present before the end of the hydrocarbon generation. 2- Describes the existence of the mapped structural/geometrical body with a bulk rock volume equal or larger than the minimum value used in the analysis. 3- Describes the probability of an efficient top, base and lateral seal of the structure.
Reservoir parameters	- Net/Gross Ratio - Oil Fill Fraction - Porosity - HC Saturation - Formation Volume Factors - Recovery Factor *Permeability *Viscosity *salinity	1- Describes the probability of the existence of an effective reservoir facies with reservoir parameters equal to or higher than the minimum estimate
Source Rock	- Amount of organic matter *lack of Reducing Environment - Type of Organic Matter *Lack of Herbaceous and Amorphous - Maturation *Low Temperature *Gradient Short Burial History Poor of Conduit Rock	Describes the probability that a sufficient mature source rock exists: Factors to be examined –Quality of potential source rock –Type of hydrocarbon generated –Areal and spatial distribution of mature source rock within play area –Poinin time for onset and end of oil generation –Volume of hydrocarbon generated
Migration	- Viscosity of fluid - Presence of Empty Space - Driving Force (gravity, pressure, etc)	Describes the probability of efficient migration of hydrocarbons from the source to the mapped structure.

Table 9: Geological Factors Controlling Reservoir

To summarize the table, the probability factors of geological risk are evaluated with respect to presence of reservoir facies with minimum net thickness and net/gross-ratio; therefore probability of effectiveness of reservoir, with prospect to minimum porosity, permeability and hydrocarbon saturation (See Fig 5).

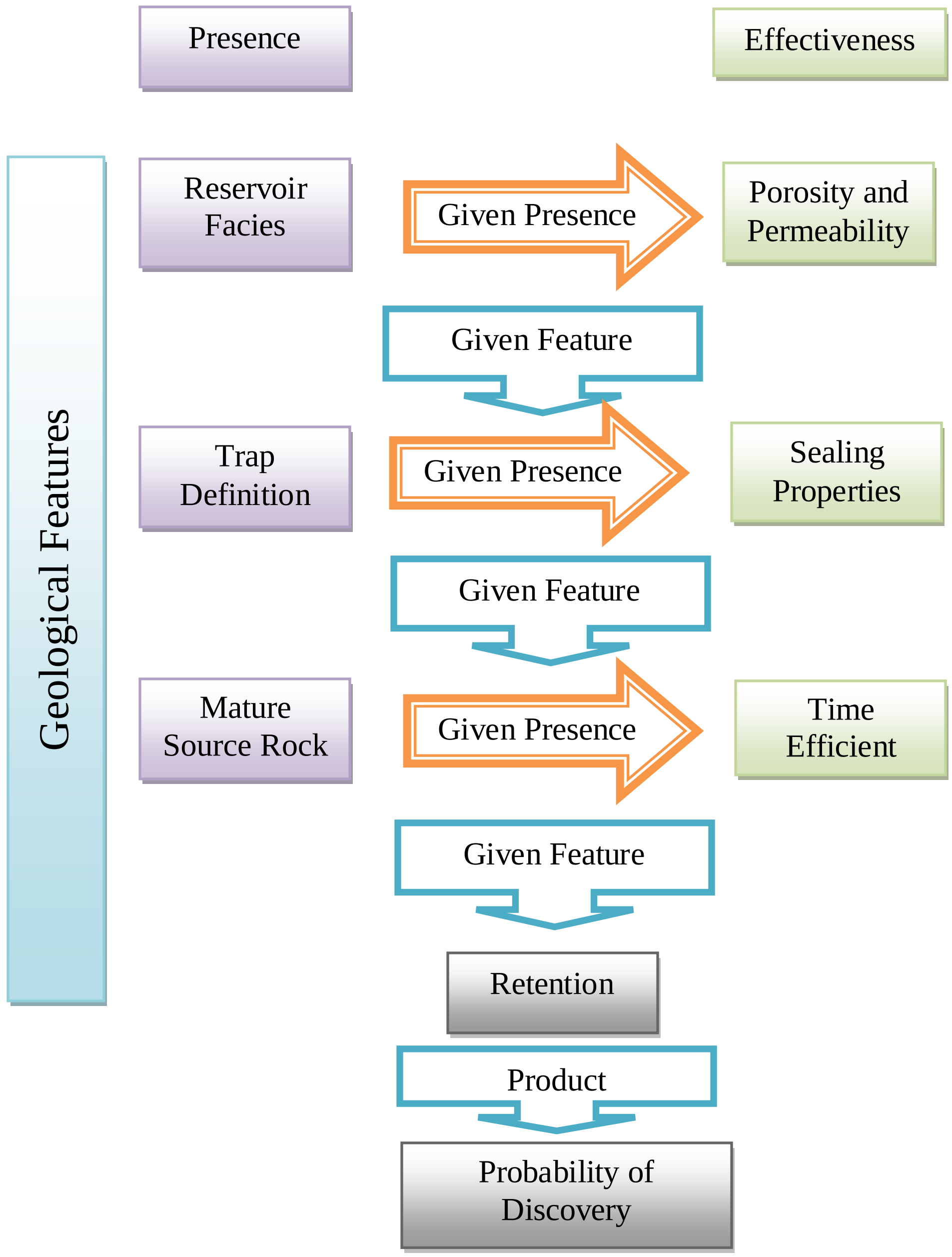

Figure 5: Schematic Overview of the Risking Procedure
Source: (Yup Kim 2000).

2.3.4 Probability of Discovery

The product of major probability factors probability of discovery

$$P_{discovery} = P_{play} \times P_{prospect} \quad \text{................................} \quad (1)$$

Play probability

It is named conditional probability which means the chance that the prospect will be an accumulation on the condition that the play is favorable to hydrocarbon accumulation (Yup Kim 2000). For this case two assumptions are taken into account:

Conditional probability = P reservoir facies x P mature source x P timing

1- Confirmed play

- Probability (P) is 1
- Test and flowed hydrocarbon to the surface (technical discover)

Play risk factors	Probability (Play)
Presence of reservoir facies	Xx
Presence of mature source rock	Xx
Timing of structuring	Xx
Marginal play probability	Xx

Table 10: Confirmed Play Risk Factors

2- Unconfirmed play

- Probability is between0 and 1
- Play is not drilled yet or play has no technical discovery

Play risk factors	Probability (Play)
Presence of reservoir facies	Xx
Presence of mature source rock	Xx
Timing of structuring	Xx
Marginal play probability	Xx

Table 11: Unconfirmed Play Risk Factors

Prospect Probability

It is also named as conditional probability, which means the chance that the prospect will be an accumulation on the condition that the play is positive to hydrocarbon accumulation (Yup Kim 2000).

P prospect= P porosity x P geometry x P seal x P migration x P retention

Prospect risk factors	Probability (Prospect Play)
Presence of effective porosity	Xx
Presence of structure	Xx
Presence of effective seal	Xx
Migration into the structure	Xx
Retention after accumulation	Xx
Conditional prospect probability	Xx

Table 12: Prospect Risk Factors

Petroleum exploration and production is a risky activity. The primary source of uncertainties are presented in geological factors controlling the occurrence of an oil deposit (oil generation, migration, reservoir, seal rock, etc) and also technical factors that controls the extraction of hydrocarbons (permeability, porosity, natural pressure, depth, etc). The other source of uncertainty is related to financial aspects such as dynamics of future oil price and operational cost, demand of petroleum products, taxation, political stability, environmental liabilities, among others.

In this chapter, the level of global risk plays an important role in the process of both valuation and decision-making of oil and gas opportunities, especially in case of big projects which may require a huge amount of investments on the level of billions of dollars.

As a final mark, internal guidelines for the risk procedure should be established before doing volumetric resource assessment. For this purpose a method has been adopted which originally was developed by Megill (1984) to estimate the probability of geological risk and the probability of geological success of a reservoir (Lima et al. 2005). The equation of this method is:

$$PG = PSR \times PR \times PM \ \& \ PT \times PT \times PS \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. (2)$$

Where:

PSR = Source Rock

PR = Reservoir

$PM \ \& \ PT$ = Migrating and Timing

PT =Presence of the Trap

PS = Presence of a Seal Mechanism

Therefore, based on this mentioned equation the degrees of the probability of the geological risk will be categorized into five groups as it is shown in the table.

Probability of geological risk (PG)	
Between 0.5 and 0.99	the PG is very low risk
Between 0.25 and 0.5	the PG is low risk
Between 0.125 and 0.25	the PG is moderate risk
Between 0.063 and 0.125	the PG is high risk
Between 0.01 and 0.063	the PG is very high risk

Table 13: Degree of Geological Interpretation of Risk

2.4 Methodology of Reserves Estimates

It is not enough to simply deploy data and applications to create a digital oilfield and evaluate its reserves. To create a true digital oilfield and realize the next step, that of production, information and applicable software needs to be integrated with core exploration and production operational processes to enhance the value across the entire chain. In the oil and gas field life, reserves are evaluated to estimate the accumulative amount of recoverable hydrocarbon in place. Hence, many methodologies have been presented to estimate the producible hydrocarbons in reservoirs. On the other hand, difficulties and complicated issue face oil and gas reserve estimations due to risks and uncertainties that are associated with rock properties of oil and gas in reservoirs, and other influencing factors such as economic and political aspects.

2.4.1 Estimating Reserves by the Volumetric Method

Reserve estimation according to volumetric approach regulations requires estimates of petroleum originally in place. This relies on assessment and examination or description of the documents and information in detail in order to draw conclusion such as:

(i) ownership and development maps,
(ii) geological maps and models
(iii) conclusive formation tests,
(iv) correlations between reservoir characteristic,
(v) wire-line formation test, logs and cores data and fluid properties,
(vi) Sensible or logical connection of seismic studies and establishment of the studies meaning, and
(vii) Definite knowledge acquired on the subject of the existing wells and equipments and additional planned completion of performance oil and gas production.

The effective application of the participated recovery factor can be relevant for achieving the amount of oil and gas in place as a purpose of interpreting the estimated initial reserves. The original term of reserves are considered to be applicable for remaining petroleum quantities, net accumulation of production from a specific given date or/and from any efficient reporting data. The effectiveness of estimated recovery might be different, as it is a function for which reserves are classified.

The volumetric method is utilized for estimating initial oil or gas in place in a reservoir and is usually applicable to use in the early life of a property as long as geological and engineering data is available before production occurrences. This method requires the estimation of the reservoir rock volume, net sand/net gross, reservoir area acreage, porosity, average oil or gas saturation and formation volume factor. In spite that, volumetric does not only require the parameters method, it also requires accurate estimation of reservoir geometry and trap limit that impact gross rock volume. Therefore, it requires the geological characteristics that define the pore volume and rock properties and fluid contact. Moreover, volumetric method involves estimating the amount of hydrocarbons initially in place and the portion of hydrocarbon that are anticipated becoming recoverable.

The key unknowns in volumetric reserves determinations may be rock volume, porosity and fluid saturation (Satter et al. 1999). The reservoir type, including whether it is in development, full progress or depletion, will also add determination. The parameters identified above must be taken into account for this standard equation. The two established volumetric approaches are deterministic and stochastic. In both approaches, mathematical equations are utilized to estimate volumes. For oil, UR is a function of the stock-tank oil initially in place (STOIIP) and recovery efficiency (RE), as follows (Demirmen 1997).

$$UR = STOIIP \times RE \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (3)$$

Where

Equivalent formulas for STOIIP use gross bulk volume (GBV) or net bulk volume (NBV):

$$GBV = A \times h \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (4)$$

and

$$NBV = GBV \times (n/g) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (5)$$

The determination of the recovery efficiency is estimated by using either reservoir simulation techniques or an analogy approach. Therefore, it should be taken into account that in a reservoir calculation the parameters of gross bulk volume and recovery efficiency be considered the most uncertain factors.

In North America, oil reserves at pre-discovery stage are generally estimated by utilizing the parameter recovery factor (RF):

$$UR = A \times h_n \times RF \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (6)$$

Where area, A, is expressed in acres, net reservoir thickness, h_n, in feet, and RF in bbl/acre-ft. RF is determined as follows:

$$RF = \Phi_i \times S_{oi} \times b_{oi} \times RE \times 7758 \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

Maps of thickness, porosity, and initial oil saturation are prepared by verification of the differences in porosity and saturations in the reservoir rock. Then, when the volumes of the reservoir are estimated, the quantities of oil and gas originally in place can be calculated. (Satter et at.1999).

The parameters are used in the volumetric reserves estimate are outlined below:

$$N_o = \left[\frac{V_b \times \phi \times S_o(t)}{B_o(t)}\right] \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (8)$$

Similarly, for a gas reservoir the volumetric method

$$N_g = \left[\frac{V_b \times \phi \times S_g(t)}{B_g(t)}\right] \ \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (9)$$

(N_o): Oil in place at time t, STB

(N_g) : Gas in place at time t, STB

V_b **:** Bulk reservoir volume

A: Reservoir area acres

h: Average reservoir ft

ϕ: Porosity, fraction

$S_o(t)$: Average oil saturation, fraction

$S_g(t)$: Average Gas Saturation, fraction

$B_o(t)$: Oil formation volume factor at reservoir pressure p, RB/STB

$B_g(t)$: Gas formation volume factor

2.4.2 Deterministic Approach

This approach is the traditional technique for volumetric calculations. In this approach, the input parameters are single values, which are considered representative values of the reservoir. The calculated or measured volumetric value obtained also is a single "best-estimate" value. The input data is linked directly to a physical model.

Technical graphic issues are widely utilized to extend the information base for, and therefore improve volumetric reserves calculation. For instance, gross bulk volume is achieved with instrument measurements of the top area and the base area of the reservoir plots, down to the oil/water contact, and the other fluid contact.

Calculation of STOIIP can be performed by taking net oil sand against area maps into account. Therefore, structural contours should be interpolated over highly dipping fault planes and are included in calculations. Care needs to be exercised in the application of the various reservoir areas plotting software as differing results can be obtained which can lead to confusion of the reservoir structural and stratigraphic complexities.

While, the recovery efficiency (RF) relies on the fluid and rock qualities, reservoir geometry and reservoir drive mechanisms, they should be associated with the actual development scheme for achieving well spacing, operations, and economics. Therefore, recovery efficiencies could not accurately be determined from new fields without any consideration of those contractual constraints such as the development scheme and economics analysis. Additional information development of the projects should be justified based upon the appropriate resources category, as shown in Fig. 1.

In addition, term of reasonable certainty by using deterministic method regarding to proven reserves 1P is intended to express high degree of confidence that the estimated quantity will be recoverable. While applying the deterministic approach to probable reserves 2P, the term of reasonable certainty is intended to express less degree of confidence than 1P and more degree than possible reserves 3P that the estimated quantity will be recovered, as explained in the Figure 7.

As already discussed, the estimation of quantity or uncertainty of a project maturity are derived as 1P, 2P and 3P values according to deterministic approach regulations that have been proposed. Although these parameters are applied, Demirmen (1997) does not recommend their use.

The desire to make use of only the low input values for 1P, or the high input values for 3P, respectively, awareness is required to avoid gross values (too low or too high estimated value). While, for 1P, 2P and 3P values, mostly is considered as a practice or a function to demonstrate descriptive definition of the proved area and then illustrate the average reservoir properties for the area as the final remark for the methodology to be summarized (Petroleum Reserves Definitions 1997).

2.4.3 Probabilistic Reserves Estimation

Despite the clear applicability of the Probabilistic method to development and production activities, it has widely been able to be put to practical use to estimate uncertainties that are associated with reserves which can have a direct influence on production rate, but still have some limitations especially when a decline curve analysis is applied. Therefore it relies on historical data to illustrate production forecast (Ross 2007).

Typically reserves are estimated at three different degrees of confidences 90%, 50% and 10% probability as it is shown in the Figure 6. When there is 90% probability (proven reserve), it means the term reasonable certainty will express a high degree of confidence that the estimated reserves will be greater than 90% of estimated quantities. This expression directly confirms that there are proven reserves.

Likewise 50% probability means the estimated reserves will be greater than 50 % and 10 % probability means that there is 10% probability that the estimated quantities will be recoverable. The percentage of probability between 90P and 10P states that there will be 80% degree of confidence.

As mentioned above, using the probabilistic method does have some limitations and restrictions. Using (estimated) input parameters in reserves calculations, according to this method, can only estimate the final results for the reserves, but will not do the same with the real value of each input parameter, such as what is the most likely and/or maximum value for each input (Mang 2006).

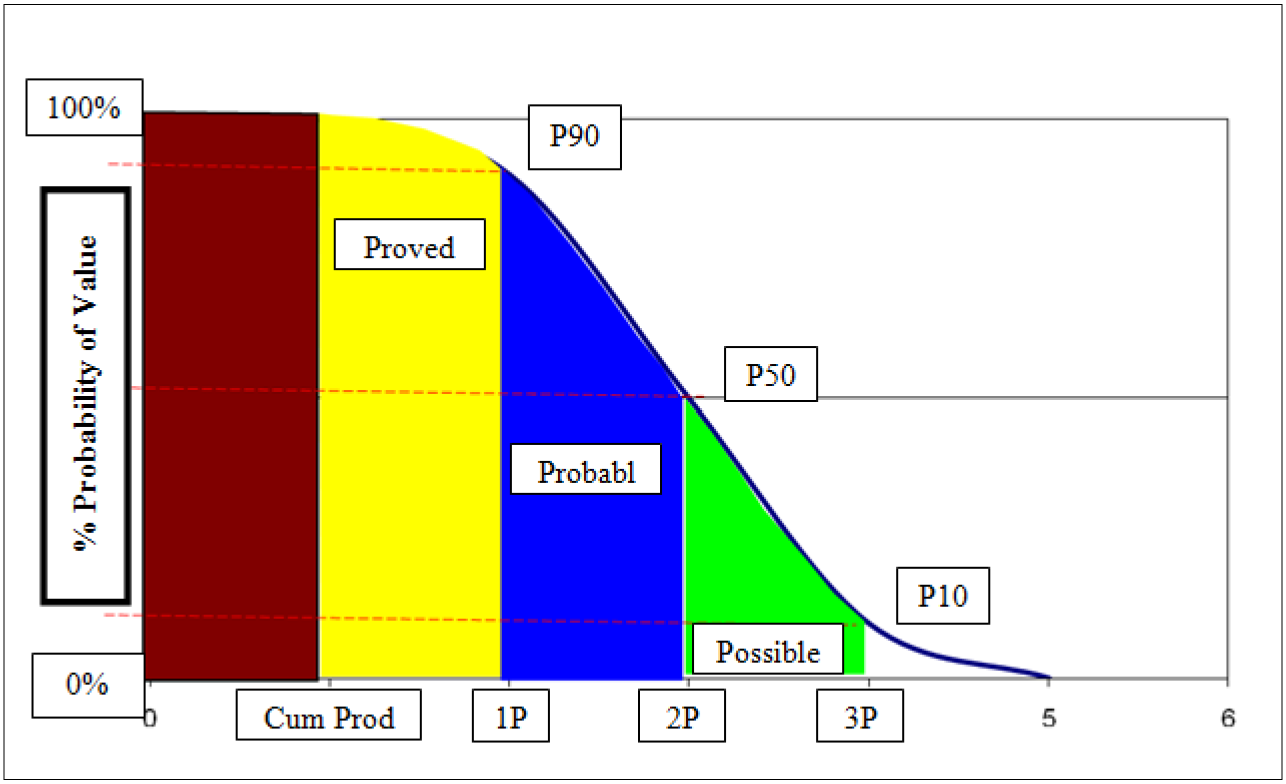

Figure 6: Probabilistic Method
Source: Petroleum Resource Management System 2007

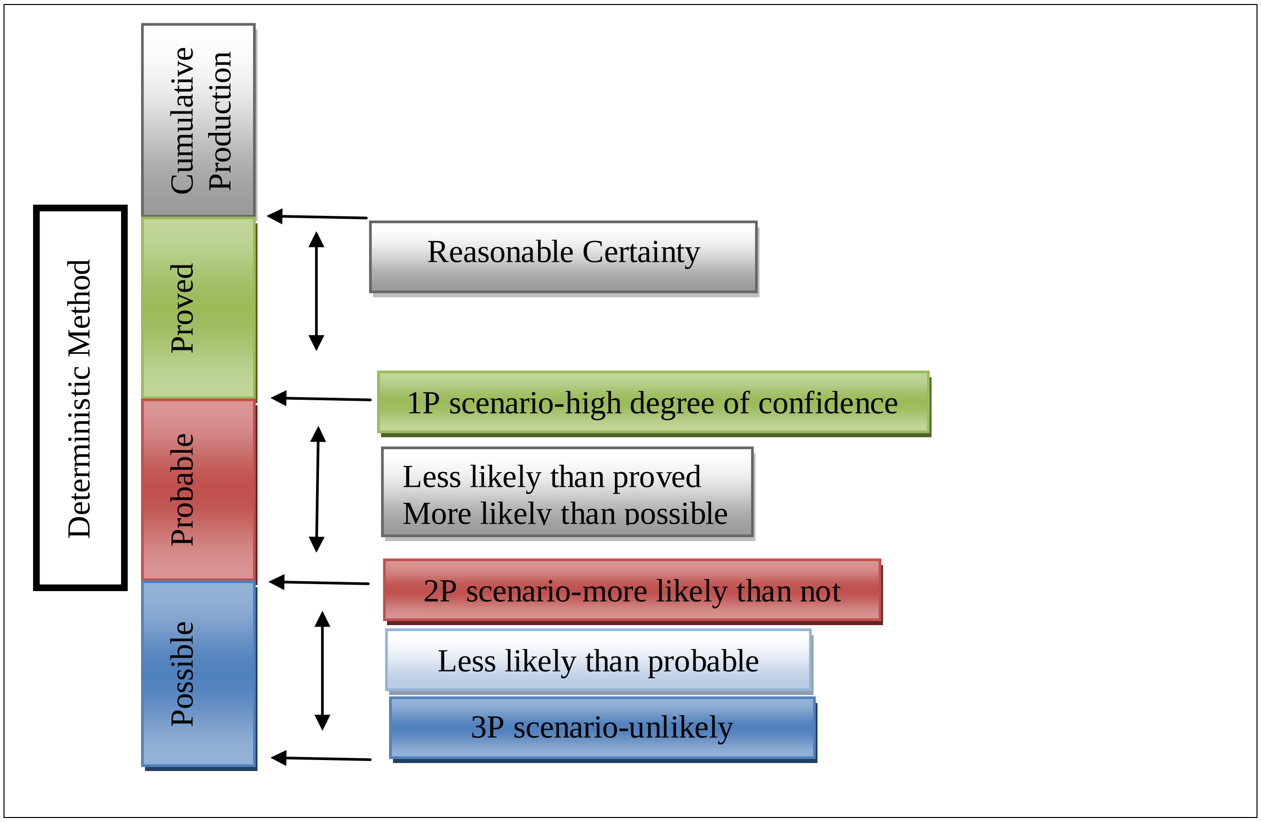

Figure 7: Deterministic Method
Source: Petroleum Resource Management System 2007

Differences between Probabilistic and Deterministic Methods in Reserves Estimation

The fundamental problem with the deterministic approach is that it implies certainty that simply does not exist. It does so by attempting to represent a highly uncertain parameter or segments of that uncertain range with a single implicitly precise number. It does not attempt to quantify how wide the range of uncertainty is perceived to be around each estimate, except by the use of descriptive terms like proved, probable, and possible. Unless such terms are mathematically defined and widely understood in future guidelines, it can be much more difficult to measure and calibrate estimating abilities objectively. As a result, the deterministic method can actually (through the introduction of estimation bias) lead to technical and financial unaccountability. Further discussion of the advantages of the probabilistic method over the deterministic method is given by Rose (2007):

The advantages of the probabilistic method can be grouped in six categories:

1. Accuracy of estimates can be measured, so estimators can be accountable.
2. Use of statistics improves estimates
3. Predrill reality checks can detect errors before drilling.
4. Reserves estimating are faster, more efficient, and avoid false precision.
5. Realistic communication of uncertainty to decision makers and investors is facilitated.
6. Results are immediately usable in modern holistic portfolio management

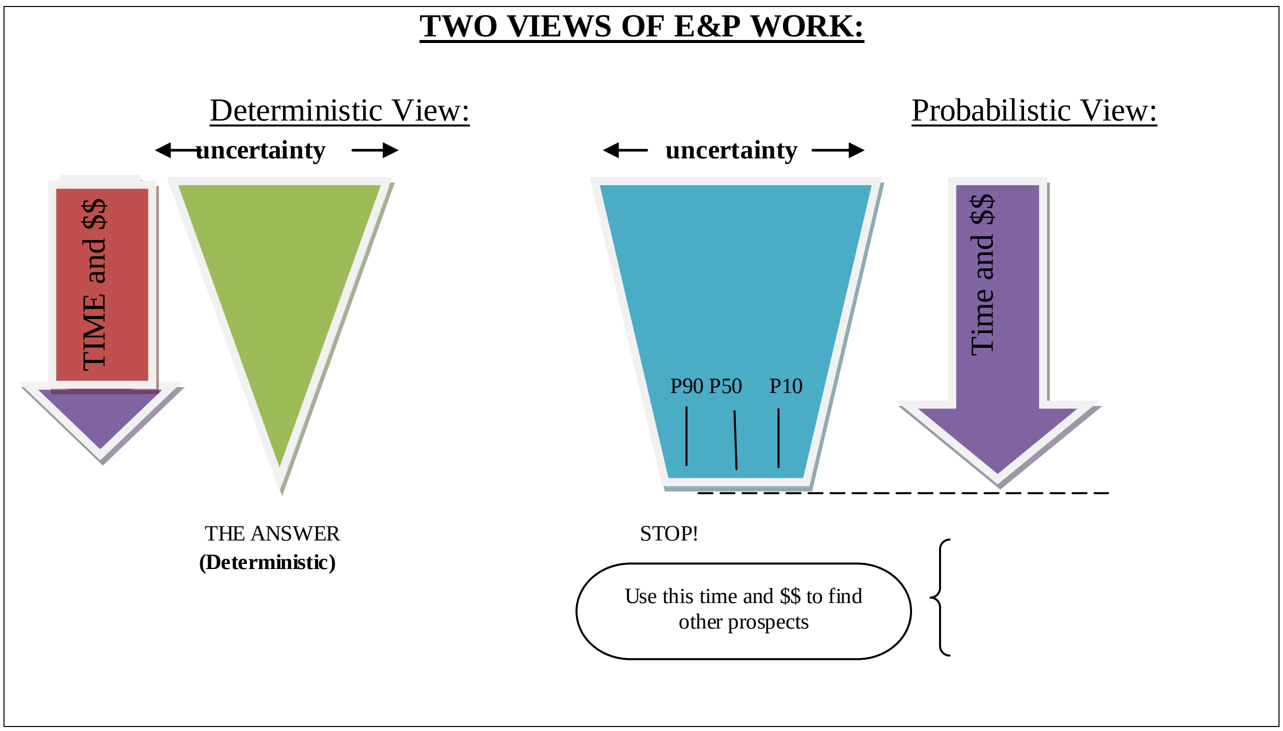

Figure 8: Comparison of Deterministic versus Probabilistic Approaches to Estimating E&P Geotechnical Parameters that are Critical to Measuring Reserves of Undeveloped and Developed Oil and Gas Fields.
Source: Ross, P 2007

2.4.4 Stochastic Approach

Stochastic method is used to determine the continuous probability density function (PDF). It is combined to generate PDF for reserves by either analytical techniques which consider reserves to be log-normal by relying on computer software (Monte Carlo Simulation) to perform repetitive calculations to stabilize the results, or/and by random sampling results of the reserves distribution. These results will be theoretically analyzed regardless of the type of input parameters.

There is another stochastic technique, which is called decision tree analysis. Decision tree analysis is a graphical demonstration of complex decisions with a preparatory step taken to meet a possible expected need for the calculation of decision paths in which risk discrete probabilities are used to estimate reserves. Another similar approach is the parametric technique. It is roughly associated with quantity of reserves. In addition, distributed contribution of not specified type will be mandated. Even though these two techniques were in use prior to recent technology advances over the past 4 decades, nowadays lots of companies have gone back to use basic again (Demirmen 1997).

2.4.5 Performance Methods

These methods of estimating reserves are significant tools frequently limited by lack of data when there is not enough pressure and production data to permit the use of the Decline-Trend Analysis. In addition numerical calculations would be in use to simplify reserve estimating through reservoir conditions such as well testing, flow rate and production rate or cumulative hydrocarbon produced (Estimating and Auditing Standards for Reserves 2007).

The volume of production from a well can be a result of general trends obtained from the historical extrapolative behavior of the estimated value of the hydrocarbon reserves. This extrapolative process is continued until the wells economic limit is determined. The essential statement is that, the future behavior of production the rate will be based on the general manner established in the past.

These estimations from the beginning might be predicted but cannot be limited in the future to just the basis of an assessment of the rate of production decline with accomplishment of other performance factors. For example, gas/liquid ratios, reservoir pressures, gas/oil ratios, and oil/water ratios (Demirmen 1997).

The basic assumption is that the volumes of oil in the reservoirs are limited. Therefore, the rate of production will decline over the time period due to the occurrence of pressure decline within the reservoir. Sufficient history of a demonstrated production trend is obtained when the two combined sets of time production rate and cumulative production can be taken into account to confidently determine the useful life for productive time and the estimated remaining volume of reserves. Commercial software programs are available that employ various types of mathematical routines can be used to assist in the projection of future rates of production and/or trends of reservoir pressure that in turn can lead to make a revision in production rate. In addition, the mathematical results that can be brought from analogy approach, requires a professional judgment dependent upon the specialized decision, knowledgement and experience (Lyons & Plisga 1996).

2.4.6 Decline Curve Analysis

The basic concept of the decline curve approach is to match historical production. A formal usage of the decline curve analysis will usually be requested for the applicable reservoir when there is not enough data available to demonstrate accurate results from a complex reservoir simulation by using volumetric and material balance approaches.

While utilizing several methods to define a high degree of confidence of recoverable oil and gas reserves for the purpose of draw down a full picture and a better understanding of how the estimated recoverable volume is going on when the projects go ahead.

A further predictive method is now considered, namely the Arps method. This method was proposed almost 60 years ago, being developed to predict the decline in production rate using three different types of curves, such as an exponential curve, hyperbolic curve and harmonic curve to represent the relationship between the rates of production and time (Wahyuningsih et al. 2006).

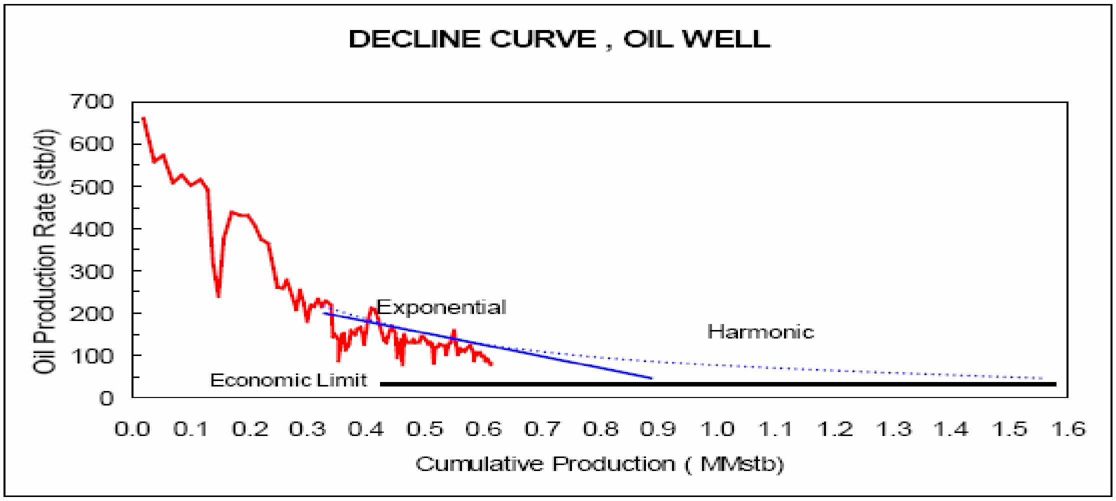

Figure 9: Decline Curve of an Oil Well
Source: Petroleum Reserve Estimation Methods, 2004

(1) Hyperbolic Decline Curve

The equation represents

$$q_t = \frac{q_0}{(1+bDt)^{1/b}} \quad \text{...} \quad (10)$$

Where

q_t : Production rate at time t,

q_0 : Initial production rate,

D : Initial decline rate,

t : Time,

b : Hyperbolic exponent and $0 \le b \le 1$.

Equation (12) can be reduced in two special cases: $b=0$ and $b=1$. $b=0$ Represents an exponential decline, which is expressed as follows:

$$q_t = q_0 e^{-Dt} \quad \text{………………….. (11)}$$

$b=1$ Represents a harmonic decline, which is expressed as follows:

$$q_t = \frac{q_0}{(1+bDt)} \quad \text{…………………………………………… (12)}$$

A particular large numbers of reserves selection terminologies have been introduced in the petroleum world for the determination of the rate of decline of production. Each one of those defined methods can be used in a successful way in order to achieve production rate. The methods consist of graphical methods, approximate methods, least squares methods and general nonlinear least squares methods. Approximate methods include loss ratio methods which are derived by the rate of production for per unit of time divided by the first derivativeness formed from the rate-time curve to decide the type curve (Al-Reshedan 2009).

The loss ratio method, which is reasonably stable in its determinations, is considered as the easiest method to be used to clarify the exponential curve characteristics which results in the following derivations.

$$\frac{q_t}{dq_t/dt} = a \ , \ a < 0 \quad \text{………….. (13)}$$

Decline is defined as

$$D = -\frac{1}{a} \quad \text{……………………………………………….. (14)}$$

The hyperbolic type of decline analysis more often are defined through a mathematical series to the loss ratios approach and, the approximate stability of the loss ratios, that will be given by the following derivations.

$$\frac{d\left(\frac{q_t}{dq_t / dt}\right)}{dt} = b\,,\; b < 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (15)$$

(2) Exponential Equation

Arps, which has been derived from the loss ratio approach, will be utilized to determine the type curve. It is claimed that the easiest approach to understand and identify exponential decline by relying on those achievements that become available from the loss ratio approach. (Demirmen 1997).

$$\frac{q_t}{dq_t / dt} = a \;,\; a < 0 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (16)$$

Where:

q_t: Production rate at time

Δq_t: Drop in production per unit

a: Loss ratio

The rate-time curve of a constant loss ratio approach or the exponential decline rate which can be formulated from equation (16)

We can rewrite equation (16) as

$$\frac{q_t}{\Delta q_t / \Delta t} = a \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (17)$$

or we can write equation (17) as

$$q_t = \frac{-a}{\Delta t - a} q_{t-1} \quad \text{.....................................} \quad (18)$$

We know AR (1) process is modeled:

$$Z_t = \phi Z_{t-1} + \varepsilon_t \quad \text{...} \quad (19)$$

So, we can substitute,

$$\begin{aligned} \phi &= \frac{-a}{\Delta t - a} \\ Z_t &= q_t \\ Z_{t-1} &= q_{t-1} \\ \Delta t &= t - (t-1) \end{aligned}$$

and we have equation (19) as AR(1) representation of Arps exponential equation. Since a is a negative constant and Δt is a positive constant, we have $0 < \frac{-a}{\Delta t - a} < 1$.

(3) Harmonic Decline

A special case of the hyperbolic decline is known as "*harmonic decline*", where b is taken to be equal to 1. The following table summarizes the equations used in harmonic decline:

Description	Equation
Rate	$q = \frac{qi}{1 + bDit}$
Cumulative Oil Production	$Np = \frac{qi}{Di} In \frac{qi}{q}$
Nominal Decline Rate	$Di = \frac{Dei}{1 - Dei}$
Effective Decline Rate	$Dei = \frac{qi - q}{qi}$
Life	$t = \frac{(qi / q) - 1}{Di}$

Table 2.14 Harmonic Decline Equations

To conclude, the decline curve analysis can be applied to draw a map of production rates by using selected parameters. It is used for short periods, for example six months production. When the results of the data result in a straight line map it means it is formed with a constant percentage decline or “an exponential decline”.

2.4.7 Material Balance

It is a tank model equation that can be usefully applied to different types of reservoirs by relying on the viability of available data and precision of the predicted production rate for selected producing wells. This is useful for calculating the recovery factors that will be determined by reservoir simulator and well performance with reliable estimates. For instance, there must be sufficient pressure and production data (for all fluids) and reliable pressure/volume/temperature data, and the reservoir must have reached constant operating conditions.

Therefore, the formulas will be written from the commencement of production to a selected time as given in the following equations:

Mathematically, this can be written as:

$$N(Bt - Bti) + G(Bg - Bgi) + (NBti - GBgi)\left[\frac{CwSwi}{1 - Swi}\right]\Delta pt +$$
$$(NBti + GBgi)\left[\frac{Cf}{1 - Swi}\right]\Delta pt + We + WIB1w + GIBIg = NpBt + Np(Rp - Rsoi)Bg + WpBw$$

Expansion of oil in the oil zone + Expansion of gas in the gas zone + Expansion of connate water in the oil and gas zones + Contraction of pore volume in the oil and gas zones + Water influx + Water injected + Gas injected = Oil produced + Gas produced + Water produced

Where:

N = initial oil in place, STB

Np = cumulative oil produced, STB

G = initial gas in place, SCF

GI = cumulative gas injected into reservoir, SCF

Gp = cumulative gas produced, SCF

We = water influx into reservoir, bbl

WI = cumulative water injected into reservoir, STB

Wp = cumulative water produced, STB

Bti = initial two-phase formation volume factor, bbl/STB = Boi

Boi = initial oil formation volume factor, bbl/STB

Bgi = initial gas formation volume factor, bbl/SCF

Bt = two-phase formation volume factor, bbl/STB = Bo + (Rsoi - Rso) Bg

Bo = oil formation volume factor, bbl/STB

Bg = gas formation volume factor, bbl/SCF

Bw = water formation volume factor, bbl/STB

BIg = injected gas formation volume factor, bbl/SCF

BIw = injected water formation volume factor, bbl/STB

Rsoi = initial solution gas-oil ratio, SCF/STB

Rso = solution gas-oil ratio, SCF/STB

Rp = cumulative produced gas-oil ratio, SCF/STB

Cf = formation compressibility, psia-1

Cw = water isothermal compressibility, psia-1

Swi = initial water saturation

Δpt = reservoir pressure drop, psia = pi - p(t)

$p(t)$ = current reservoir pressure, psia

2.4.8 Reservoir Simulation

From the utilization of methods for developing fields and predicting production in order to make applicable investment decisions, the reservoir simulation studies will identify the opportunities to increase production. These procedures represent the reservoir with a grid and upscale of geological methods. Other factors that contribute to the simulation include history matching and production uncertainty forecasting. In general, development activities and operating conditions are illustrated to assess reservoir performance and/or potential productivity according to the usage of Darcy's equation. It requires a computer software package to achieve repetitive material balance calculations in diverse cells and migration of fluids between adjoining cells.

Good resolution of geological and engineering data is required in order to determine the parameters that affect flow through the reservoir such as seismic information, well log and core data, pressure data and rock/fluid data with the application of numerical mathematical simulation models for production forecasting. Based upon the mathematical simulation models, the level of confidence will increase when there are accurate matches of the performance history at well production rates.

Because validation of reservoir models cannot determine an accurate history match when the physical and geological modification of the parameters are still wrong (uncertain), even though, the model is fully validated due to level of uncertainty involved in the geological and engineering parameters. In this case when the performance history is not available, sensitivity analysis should be taken into account using the most valid data to calculate reservoir flow. Based on the given reserves definition and classification, the sensitivity analysis is done for the factors that are involved in the confirmation of reserve volume to obtain the probability of ultimate recovery (Demirmen 1997).

As a final remark for mathematical simulation models, the operator is advised to make a better understanding of the use of the properties from the internal mathematical algorithms and their correlations as to how they affect each other in reserve estimations.

2.4.9 Hybrid Methods

The deterministic and probabilistic methods are the more widely used to the determination of operating reserves evaluation. There is also a hybrid numerical scheme which deals with the fundamental problems for descriptions of large spread numbers that result through different methods in reserves assessment. Therefore, certain hybrid approaches can be used to put the methods together to solve for a final result of reserve estimation. However, this approach is not sufficiently tested, but it might have a significant role in future. The basis elements of this proposed approach is to perform a power system to combine strength of both deterministic and probabilistic methods together.

Evaluators are recommended for probabilistic approach reliability, and generally can be used for disclosing reserves in exploration activities. In addition, this method can be put to a practical use such as Monte Carlo Simulation, beside volumetric approach which makes information more comprehensively available to clarify the level of uncertainties associated with hydrocarbons originally in place. Moreover, other methods such as decline curve analysis and material balance are widely used to estimate production rate. Thus, more often companies use combinations methodologies to estimate reserves. Therefore, by comparing final results that are defined by deterministic and probabilistic criteria could lead to increase in confidence to provide a picture of production output probability (Etherington 2008).

2.4.10 Analogy Method

This is one of the methods considered less accurate in reserves estimations because it does not take specific well test information into account. For instance, it is used to estimate reserves based upon proximity information from similar reserves without any consideration of data about the average porosity of the reservoir rock and, the average connate water saturation in the reservoir and net bulk volume.

The best way to use this method is by taking into consideration similar information of other wells that have the same evaluated information and characteristics such as estimated ultimate recovery (EUR). EUR is estimated from the exploration activity and information about recovery factor (RF) will be taken into account from another analogous field together with barrel per acre foot (BAF).

In addition, for estimates of ultimate recovery (UR) if there is not enough data available about UR in most of the circumstances the other identified methodologies are utilized (as decline curve analysis) to make probability maps of estimated ultimate recovery alongside the percentage of accumulative quantities of hydrocarbons. As a result, there will be normal reserves distributions when the mapped line is straight. On the other hand, the probability distribution will be imbalanced when the mapped line is not straight (Lyons & Plisga 1996)

This method is useful in making an economic decision as to whether the wells should be drilled or not. The information on the wells being used for this method must be similar; otherwise there will be a lesser degree of confidence.

As a result, barrels per acre foot are estimated from similar values from the other well. The given equation is:

$$BAF = 7758\frac{\phi So(t)}{Bo(t)}RF \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(20)$$

As well as for recovery factor, abandonment stage will be taken from similar wells or fields. In conclusion if the calculation of estimated ultimate recovery was doubled more than the UR of the similar well or field, the estimation must be recalculated.

CHAPTER THREE

Price Estimating Standards for Reserves Using Dynamic Reserves Estimation Model (DREM)

3.1 Introduction

The executive summary of this chapter demonstrates a comprehensive model that establishes steps towards booking and quantifying hydrocarbon resources and reserves, and their evaluation issues that are associated with upstream and downstream activities. In particular how and whether reserves and resources should be financially measured, disclosed and recognized is discussed.

The key importance that comes across from this model is a better understanding of the concept and estimate of reserves and their definitions and classifications, because the value of reserve represents the value of a company. To deal with these issues, industry has published a specification that establishes a common language, and contains technical specifications or other precise criteria, and as a rule is designed to be used consistently as a guideline or a definition.

The strategy of this model is to remain geographically focused, with activity restricted to proven oil and gas producing area. This model also has a near-term drive on cumulative oil production and its growth rate to add value through the development and enhancement of its existing portfolio of oil and gas discoveries.

3.2 Economics of Oil Prices

Like all goods, oil price is affected by supply and demand. Global supply of oil originates from non-OPEC countries, which produce at full capacity whatever the price, and from OPEC, where production is regulated to maintain the price of a basket of various types of crude oil within a target band. Thus, oil is marred by political concerns in an oligopolistic market dominated by a strong cartel. OPEC is responsible for 55% of global oil exports and continues to play a crucial role on price formation as a result of its policies regarding the regulation of supply Energy Information Agency EIA (2007). Most worldwide demand for oil comes from the OECD (58% in 2006). However, since the mid 1990s emerging nations such as China and India have substantially increased oil imports. This study uses a demand and supply model which focuses on the physical market price of crude oil. Thus, there is explicit conditional modelling of the short-term fluctuations in inventories and distortions to market behaviour (caused by OPEC). The oil price (C_p) is subject to substantial change.

3.3 Modeling Price Volatility via Difference Equations

This model explains in a basic manner the nature of price volatility in oil markets, in particular the influence of excess demand. The oil price for any given year depends on the excess supply during the previous season as described by:

$$P_{t+1} = P_t - \alpha(Q_{s,t} - Q_{d,t}). \tag{1}$$

We want to solve for an expression for the price at any time *t*. First, solve for $Q_{s,t} - Q_{d,t}$ which is some function of price at time *t* and a constant. Inserting this into (1), we can solve for a difference equation that relates the present price to the price in the previous season:

$$P_{t+1} - \lambda P_t = \delta. \tag{2}$$

Now we can solve for an expression for price. The general solution to (2) has two components: (a) a particular integral; and (b) a complementary function, which is the general solution to the reduced form equation of (2):

$$P_{t+1} - \lambda P_t = 0. \tag{3}$$

First, it can be shown that the solution of a general homogeneous difference equation is given by:

$$P_t = Ab^t, \tag{4}$$

where A is the initial value. In order to calculate the complementary function for (2), we substitute (4) into (3) to provide:

$$Ab^{t+1} + aAb^t = 0. \tag{5}$$

Dividing both sides by Ab^t leaves:

$$b = -a \tag{6}$$

Thus, the complementary function is given by:

$$P_c = Ab^t = A(-a)^t. \tag{7}$$

Substituting the simplest possible type of solution, where P is some constant k, into (2) gives:

$$k - \lambda k = \delta \tag{8}$$

so that the particular integral is given by:

$$P_p = k = \frac{\delta}{1-\lambda}. \tag{9}$$

Thus, the general solution takes the form:

$$P_t = P_c + P_p = A(-a)^t + \frac{\delta}{1-\lambda}. \tag{10}$$

The solution is not completely determinate, as *A* is an arbitrary constant. The solution is made definite by using P_0, the initial condition, to remove *A*. This gives:

$$P_t = \left(Y_0 - \frac{\delta}{1-\lambda}\right)(-a)^t + \frac{\delta}{1-\lambda} \tag{11}$$

where a, δ and λ are parameters to be estimated. With these parameters ‘known’ the future path of oil prices can be determined.

3.4 Error Correction Model

Simplistic models of the oil price model outlined above demonstrate the fundamental relationships between market supply, demand and price. The difficulty of these procedures is that parameters are generally not known, and must be estimated. An approach used to empirically model such phenomena is an Error Correction Model (ECM), where oil price is expressed as a function of the parameters to be estimated. This oil price time path will be obviously affected by supply and demand shocks. Such departures from equilibrium are captured by the ECM. ECMs in the context of oil prices are interpreted as modeling the change in the oil price as a result of changes in the supply and demand for oil and also, in part, to correct for any disequilibrium that existed during the previous period (Brooks, 2007). Thus, the level of oil price is modeled conditionally on supply and demand.

3.5 Simulation Model

A recent substantial analysis of global oil pricing was made by Chevillon and Rifflart (2009). This model has as its dependent variable the real spot price for North Sea Brent crude oil which is often used as the world reference. In the London-based ICE Futures exchange, the Brent is used to specify the price of two thirds of crude oil exchanged worldwide. The price of oil is specified as a function of the variables outlined in Table 14.

Variable
Cumulated past supply in excess of demand outside OECD
Past supply in excess of forecasted demand in OECD
Cumulated past supply in excess of demand within OECD[b]
Change in OECD demand[a]
Difference between observed oil price and OPEC target price

Table 1: Independent Variables

Member Countries (OECD)	
Australia	Austria
Belgium	Canada
Czech Republic	France
Finland	Greece
Germany	Iceland
Hungary	Italy
Ireland	Korea
Japan	Mexico
Luxembourg	New Zealand
Netherland	Poland
Norway	Slovak Republic
Portugal	Sweden
Spain	Turkey
Switzerland	United state
United Kingdom	Denmark

Table 2: Organization for Economic Co-operation and Development (OECD) Countries

In particular, when inventories (i.e., cumulated past supply in excess of demand) increase outside the OECD, and when they are high in the OECD compared to expected demand, prices are expected to fall. Wedges between supply and demand in the OECD represent the (highly seasonal) deviation of OECD inventories from their long term decreasing trend.

Excess supply directly implies a lower price next period with a reinforced impact if inventories are high compared to the previous year. Inventory variations are proposed to play a more significant role in OECD economies compared with the industrialized economies that have a more stable average consumption, but with strong seasonality. Further, demand outside the OECD has kept increasing due to the growth in China and India and is proposed to have a direct impact.

This model is translated into an Excel simulation model (*Simulation.xlsx*). Here, the values of the variables outlined in Table 14 can be modified to assist in forecasting oil prices for particular years. In particular, cells coloured light-green may be modified as necessary (cells coloured light-purple should not be modified) (See Table 15). This model uses 2001 and 2002 data to forecast the 2003 oil price. With more recent data, the model can be modified to provide more accurate forecasts.

Forecast Year (t)		2003								
Supply in OECD countries (millions per day)$_{t-1}$		21.9								
Expected OECD demand$_{t-1}$		22		Test simulation to calculate the 2003 Brent Oil price (which is on average about $25)						
OECD demand (millions per day)$_{t-1}$		48								
OECD supply (millions per day)$_{t-2}$		21.8								
OECD demand (millions per day)$_{t-2}$		47.9								
Nominal price of oil$_{t-1}$		25								
Non OECD supply$_{t-1}$		24.4								
Non OECD supply$_{t-2}$		23.2								
Non OECD demand$_{t-1}$		29.3								
Non OECD demand$_{t-2}$		29								
$\varepsilon_{2,t-1}$		-0.76235								
$\varepsilon_{2,t-2}$		-0.76485								
Previous year - 1989		13								
	Lnp_{t-1}	cr_{t-1}	$\Delta s^{non\text{-}OECD}_{t-1}$	$\Delta d^{non\text{-}OECD}_{t-1}$	$\Delta^2 d^{non\text{-}OECD}_{t-1}$	$c^{\mu}_{1,t-1}$	$c\Delta_4{}^{\mu}_{2,t-1}$	$c^{\mu}_{2,t-1}$		Price Forecast
	3.2189	-0.00456	0.0504309	0.01029169	0.00010592	-1.1	-3.14751	-7.162		24.21042340970

Table 3: Excel Simulation Model

3.6 Petroleum Reserve Bankability

The Reserve Bankability model is applied to estimate the value of reserves regarding to the estimated recoverable volume of reserve by using conceptual scenarios. The precision of this model is extremely associated with the accuracy of the calculations that can be performed by relying on available and accurate data of exploration stage, development stage and the attitudes of operating companies. In addition, these statements are naturally subject to uncertainty and change in circumstances. The purpose of this model is to estimate the return on the investment over given period of time as a function of recoverable volume.

In addition, this model deals with the estimation of the combined effects of geological and financial uncertainty of hydrocarbon reserves. For example, the geological uncertainty is mainly associated with the quality and quantity of hydrocarbon reserves which is different according to the nature of rock and fluid properties, as well as the location offshore or onshore; shallow or deepwater. Therefore, the financial uncertainty is associated with production rate and future oil prices of hydrocarbon reserves. Moreover, two main equations are used for developing this model, Dynamic Reserve and Booking Price.

3.7 Dynamic Reserve Estimation

This model is applied to estimate reserves and resources by relying on available and accurate data of the exploration stage, development stage and the attitudes of operating company to estimate reserve volumes and quantify the range of recoverable quantities using conceptual scenarios. The equation of this model is summarized by depending on the following factors such as: hydrocarbon initially in place, recovery factor, and probability of geological success. The equation is written:

$$DR = OIIP \times RF \times PGS \quad \text{..........} \quad (12)$$

1- Factors affecting hydrocarbon initially in place
    a. Trap type
    b. Vertical closure
    c. Field area and associated hydrocarbon column height
    d. Reservoir thickness
    e. Net/gross ratio
    f. Porosity
    g. Generate reservoir property statistics, such as porosity and directional permeability (X, Y, Z) for an entire flow unit within reservoir model
    h. Water saturation
    i. Fluid type, gas/oil ratio
    j. Formation volume factor
    k. Calculate and distribute effective properties
2- Factor affecting recovery factor
    a. Permeability
    b. Well productivity
    c. Number of wells
    d. Effects of heterogeneity
    e. Production technology
    f. Technical innovation in improving exploration, drilling and production
    g. The oil in place after water injection
    h. The gas in place after water injection
3- Factor affecting probability of geological success
    a. Source rock
    b. Reservoir
    c. Fluid: migrating &timing
    d. Existence of trap
    e. Presence of seal mechanism

3.8 Petroleum Reserve Bankability (Booking Prices "Bp")

After the estimation of the probabilistic distribution for representing the level of uncertainties for each one of the volumetric variables in the reservoir, the next step is an economic evaluation of the oil and gas reserves. In addition, since the book value of the reserves is controlled by reserve estimation methods, the booking price will be determined on average as a barrel of oil worth around a percentage of the booking price for the current oil spot price. It is volatile according to the ratio between the purchase price of a barrel of oil and oil spot price. Thus, the relation is, as price rises, the purchase price declines slightly for reasons such as: oil and gas quality, reserve volume, depth and geographic location.

Therefore, booking price is the price which will be determined based on the difference between current price, which is a market price of a barrel of oil, and the development price. There are two types of booking prices, these are:

Booking price in term of growth rate, which will be calculated, based on the difference of current and development price of a barrel of oil multiplied by annual growth rate of cumulative oil produced.
Booking price in term of money, it is the same calculation, but the key dissimilarity is that the difference between current market price and development price of oil will be multiplied by the booking price in term of growth rate.

Moreover, the equation of booking price in term of growth rate is written as;

$$Bp_{Gr} = ((Cp - Dp) \times (GR)) \quad \text{..} \quad (13)$$

BP_{Gr} : Booking price \$ in term of growth rate

Cp : Current price \$

Dp : Development price \$

GR : Growth rate of annual cumulative oil produce from one period to another, fraction

While formula of booking price in term of money is written as;

$$Bp_{money} = ((Cp - Dp) \times (Bp_{GR})) \quad \text{...} \quad (14)$$

BP_{money} : Booking price in term of money

Cp : Current price $

Dp : Development price $

BP_{GR} : Booking price in term of growth rate $

3.9 Development Price

The Development Price is a price of producing a barrel of oil which depends on experience with and location of a reserve; it is different from one region to another. For example, in Iraq, Iran and Saudi Arabia the development price a reserve is around 1.5 US$ to 2 US$, but in the other regions, for example we take three countries into account as a sample being Australia, Norway and US the development price is around 15 to 20 US$. Thus, development price can be seen as the overheads required for producing hydrocarbon and keeping the project running.

3.10 Reserve Growth

As it is known, petroleum reserves continue to decline. Therefore, reserve growth has become an important tool to estimate total potential reserve. In this section, the key difference between reserve and reserve growth is: reserve is considered as the defined accumulations that can be extracted profitably with existing technology under present economic conditions (both future price and the time frame of assessment) and therefore, hydrocarbon reserve growth is the observed increase in reserves for fields over time. In fact, the concept of hydrocarbon reserve growth can be applied even to undiscovered resources with some qualification as to the inherent risk and also applied to discovered resources due to increase in recovery factor which can be achieved by development of new enhanced recovery technologies.

Technically and economically, factors that contribute to the reserve growth of fields can be grouped into five categories:

- Improved reserve calculations based on better knowledge of the field.
- Improvements in recovery percentage based on new drilling technology (multiple wells, directed at targets several miles distant, and multiple laterals extending).
- Delineation of additional oil and gas in-place.
- Production technology (e.g. enhance oil recovery).
- Political and economic changes.

In this case, the equation of growth rate is considered as an important equation of this model to estimate annual growth rate of cumulative oil produced from one period to another. The selected period of growth rate for different periods of times of the life cycle of the reserves is determined by using decline curve analysis (e.g. hyperbolic decline) to make the investment strategy. The equation of growth rate depends on three factors, start and finish volume of the cumulative oil produced and also number of years (year start and finish).

$$GR = \left(\frac{V(tn)}{V(to)}\right)^{\frac{1}{tn-to}} - 1 \quad \text{...} \ (15)$$

GR : Growth rate of cumulative oil produce

$V(tn)$: Finish volume STB

$V(to)$: Start volume STB

$tn - to$: Number of years

In addition, the volatility of hydrocarbon prices might fluctuate with the value of reserves. Rises in hydrocarbon prices encourages oil companies to produce more hydrocarbons and it will lead to a decline in reserve values while, estimating value of reserves at the end of the year will have lower figure in declining values rather than current price. In this circumstance, the estimators will not have any control over the prices and then this will swap the effect of cost and production efforts.

Economically, valuing of reserves is estimated based on their potential as to whether they will be commercially recoverable or not. This will be observed from the assessment of the reserves therefore, for some reason usually companies prefer proved and probable reserves because a company with proven reserves 1P will have higher values and will reduce costs, depreciation, depletion and amortization of evaluating the value of reserve. Furthermore, estimates in valuing reserves illustrate future capacity of production potentially and therefore provide incomes to pay shareholders and debt-holders under accounting regimes whether or not the costs are charged to current revenues according to the methodologies for calculating costs, successful effort, or full costs methods.

On the other hand, there are some further considerations that must be taken into account. For example, there are many sources or factors of risk, uncertainty. Even though, the factors are not limited, while the assumption of them has a direct effect on the actual results of this model, such as:

1- Crude oil and natural gas prices.
2- Potential failure to achieve and potential delays in achieving expected reserves or production levels from existing project.
3- Future oil and gas development projects due to operating hazards, for example, drilling risks and the inherent uncertainties in interpreting engineering data relating to underground accumulations of oil and gas.
4- Unsuccessful exploratory drilling activities such as lack of exploration success; potential disruption or unexpected technical difficulties in developing new reserve processes.
5- Potential failure of new reserves to achieve acceptance in the market, for example, unexpected cost increases or technical difficulties in constructing or modifying company manufacturing and facilities.
6- Unexpected difficulties in developing new products and manufacturing, transporting, international monetary conditions and exchange controls.
7- Potential liability under existing or future environmental regulations.
8- Potential liability resulting from pending or future legal action.

9- General domestic and international economic and political conditions that affect supply and demand of oil and gas in a market.
10- As well as changes in tax and other laws applicable to the project.

These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict.

CHAPTER FOUR

Model Application

4.1 Introduction

The aim of this chapter is to apply the new model “Dynamic Reserve Estimation Model” for clarifying which factor mostly affects the final results of the model. The variable involved in this chapter will be associated with geological factors, volumetric variables and the factors that have impacts on the physical market price of oil.

According to a published Case Study by www.petrobjects.com in 2003-2004 Petrobjects, as it is shown in the table below:

Probability of geological factors		
Reservoir	0.4	fraction
Trap identification	0.9	fraction
Effective seal	0.8	fraction
Effective source rock	0.7	fraction
Effective migration	0.9	fraction
Probability of retention	0.1	fraction
Probability of volumetric factors		
Area	26,700	Acres
Thickness	49	ft
Porosity	8	%
Average water saturation	45	%
Initial reservoir pressure Pi	2980	Psia
Abandonment pressure Pa	300	Psia
Oil formation volume factor at Pi	1.68	bbl/STB
Oil formation volume factor at Pa	1.15	bbl/STB
Gas saturation at Pa	34	%
Oil saturation after water invasion	20	%

Table 1: Case Study

First, let's start by estimating the probability of geological success:

$$PG = PSR \times PR \times PM \ \& \ PT \times PT \times PS$$

$PG =$ 0.4 * 0.9 * 0.8 * 0.7 * 0.9 * 0.15 = 18.144%

Probability of Geological Failure (PG) % + Probability of Geological Success % = 100%

Probability of Geological Success = 100% - 18.144% = 81.856%

Second, let's start by calculating oil initial in place (OIIP):

Let's start by calculating the reservoir bulk volume

$V_b = 7758 \times A \times h$ = 7758 x 26,700 x 49 = 10.15 MMM bbl

1- Initial oil in place (OIIP) by volumetric method:

$$N_o = \left[\frac{V_b \times \phi(1 - S_w)}{B_o(t)} \right]$$

$$N_o = \frac{10.15x10^9(0.08)(1-0.45)}{1.68} = 266 MMSTB$$

2- The oil in place after volumetric depletion to abandonment pressure:

$$N = \frac{Vb\Phi(1 - Sw - Sg)}{Bo}$$

$$N1 = \frac{10.15x10^9(0.08)(1-0.45-0.34)}{1.15} = 148 MMSTB$$

3- The oil in place after water invasion at initial reservoir pressure:

$$N = \frac{Vb \times \Phi \times Sor}{Bo}$$

$$N2\frac{10.15x10^{9}(0.08)0.2}{1.68} = 97MMSTB$$

4- The oil reserve by volumetric depletion:

$(Ni - N1) = (266 - 148) \times 10^{6} = 118\ MM\ STB$

i.e. RF = 118/266 = 44%

5- The oil reserve by full water drive:

$(Ni - N2) = (266 - 97) \times 10^{6} = 169\ MM\ STB$

i.e. RF = 169/266 = 64%

Third, applying Dynamic Reserve Estimation Model for estimating reserve:

1- Dynamic reserve estimation:

$$DR = OIIP \times RF \times PGS$$

DR = 266 MMSTB * 64%* 81.856%

DR = 139.35 MMSTB

2- Estimation of booking price of the reserve:

Estimating growth rate (GR) of cumulative oil produced of the reserve by using decline curve analysis to estimate the selected periods of the reserves and calculating cumulative oil produced for each periods as it is demonstrated. According to a published case study, production rate of a well at time 0 is 100 BOPD, initial nominal exponential decline rate is 0.5/year, and hyperbolic exponent is 0.9. Assuming hyperbolic decline predict the amount of oil produced for five years. To find out the growth rate, production at the end of each year must be determined.

Solution:

i. Calculate the well flow rate at the end of each year for the five year by using equation hyperbolic decline.

$$q = qi(1 + bDit)^{\frac{-1}{b}}$$

Where:

q Well's production rate at time t, STB/day

qi Well's production rate at time 0, STB/day

b Hyperbolic exponent

Di Initial nominal exponential decline rate

t Time

For year (0):

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 0^{(\frac{-1}{0.9})})$$

$q = 100$ BOPD

For year (1)

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 365^{(\frac{-1}{0.9})})$$

$q = 66.176$ BOPD

For year (2):

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 2 * 365^{(\frac{-1}{0.9})})$$

$q = 49.009$ BOPD

For year (3):

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 3 * 365^{(\frac{-1}{0.9})})$$

$q = 38.699$ BOPD

For year (4):

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 4 * 365^{(\frac{-1}{0.9})})$$

$q = 31.854$ BOPD

For year (5):

$$q = ((100)(1 + 0.9 * (\frac{0.5}{365}) * 5 * 365^{(\frac{-1}{0.9})})$$

$q = 26.9992$ BOPD

ii. Calculate the cumulative oil produced at the end of each year (BOPY) to find out production rate, as written below:

$$Np = \frac{qi^{b}}{Di(1-b)}\left(qi^{1-b} - q^{1-b}\right)$$

For the first year:

$$Np = \frac{(100)^{0.9}}{\frac{0.5}{365} * (1-0.9)}\left(100^{(1-0.9)} - 66.176^{(1-0.9)}\right)$$

$Np = 29{,}524 BOPY$

For the second year:

$$Np = \frac{(100)^{0.9}}{\frac{0.5}{365} * (1-0.9)}\left(100^{(1-0.9)} - 49.009^{(1-0.9)}\right)$$

$Np = 50{,}248$

For the third year:

$$Np = \frac{(100)^{0.9}}{\frac{0.5}{365} * (1-0.9)}\left(100^{(1-0.9)} - 38.699^{(1-0.9)}\right)$$

$Np = 66{,}115$

For the fourth year:

$$Np = \frac{(100)^{0.9}}{\frac{0.5}{365} * (1-0.9)}\left(100^{(1-0.9)} - 31.854^{(1-0.9)}\right)$$

$Np = 78{,}914$

For the fifth year:

$$Np = \frac{(100)^{0.9}}{\frac{0.5}{365}*(1-0.9)}\left(100^{(1-0.9)} - 26.992^{(1-0.9)}\right)$$

$$Np = 89{,}606$$

Thus, growth rate of the reserve cumulative production for five year is:

$$GR = \left(\frac{89606}{29524}\right)^{\frac{1}{5-1}} - 1$$

GR = 31.98983 % per-barrel

a. Estimating of current price of oil for the selected periods, based on the excel simulation model which is mentioned in the previous chapter :

Years	Flow Rate	Cumulative Production	Yearly Production	Current price $
0	100	0	-	0
2001	66.176	29,524	29524	24.21$
2002	49.009	50,248	20724	50$
2003	38.699	66,115	15867	60$
2004	31.854	78,914	12799	90$
2005	26.992	89,606	10692	30$

Table 2: Calculate the Flow Rate, Cumulative Oil Produce, Production and Current Price.

b. Development price of oil reserve is considered constant; it will be different from one country to another due to geological, environmental and political factors. For this case we assume that the current price is 15$ for a barrel of oil for the selected period.

Estimating of booking price in term of growth rate:

$$BP_{GR} = (Cp - Dp) \times GR$$

BP_{Gr} = (24 – 15) * 31.98983%

BP_{Gr} = 0.0288 $ /barrel

Estimating of booking price in term of money:

$$BP_{money} = (Cp - Dp) \times BP_{GR}$$

BP_{money} = (24 – 15)*(0.0288)

BP_{money} = 0.2592 $ /barrel

years	Current price $	BP_{Gr}	BP_{money}	Revenue
1	24.21$	0.0288%	0.2592%	76.52621
2	50$	0.111%	3.885%	805.1274
3	60$	0.1431%	6.4395%	1021.755
4	90%	0.2391%	17.9325%	2295.181
5	30$	0.0471%	0.7065%	75.53898

Table 3: Calculate Booking Price in Terms of Growth Rate and Money

4.2 Results and Discussions

Discussion of results: after risk analysis of oil reservoir, the geological and financial risk can be estimated for the entire value of the hydrocarbon reserve. The oil volume possible to be extracted depends on a numbers of parameters that described in the volumetric equation which are all uncertain. According to the case study, for oil reservoirs under volumetric control; i.e. no water influx, the produced oil must be replaced by gas the saturation of which increases as oil saturation decreases plus the expansion of connate water and rock gases. If Sg is the gas saturation and Bo the oil formation volume factor at abandonment pressure, then oil in place at abandonment pressure is given by:

$$N = \frac{Vb\Phi(1 - Sw - Sg)}{Bo}$$

On the other hand, for oil reservoirs under hydraulic control, where there is no appreciable decline in reservoir pressure, water influx is either edge-water drive or bottom-water drive. In edge-water drive, water influx is inward and parallel to bedding planes. In bottom-water drive, water influx is upward where the producing oil zone is underlain by water. For this circumstance the estimated quantities of oil remaining at abandonment is demonstrated as:

$$N = \frac{Vb\Phi Sor}{Bo}$$

Nevertheless, for gas original in place is given as:

$$Gi = \frac{Vb\Phi i(1 - Swi)}{Bgi}$$

Based on this equation, reserves economically can be analyzed. In addition, an economic reserve is clarified dependent upon accumulated hydrocarbon production which is achieved from the estimated production rates.

A diagram which can be mapped by using decline curve analysis would show the relationships between production rate and the time period of the reserve life cycle to point out the economic limit. Furthermore, economic limit indicates the point when the revenue of estimated production corresponds with total resulted costs in disclosing and producing the estimated quantities of reserves.

Even though, this factor is influenced by many parameters, significantly it is affected by the price of hydrocarbons in the market. Thus, production is abandoned when the cost of producing the recoverable quantities become more than the price, and the remaining amount in the reserve might be recoverable in the future by using conceptual scenario. In this circumstance, in order to estimate the future uncertainty surrounding oil price, historical oil price has been used to forecast future oil price for particular years. Moreover, petroleum reserve bankability combined both the effects of both financial and geological uncertainties to evaluate the project as a success or a failure and therefore, estimate the return on the investment if the project goes ahead as a function of recoverable volume.

CHAPTER FIVE

Conclusions and Recommendations

5.1 Conclusions

Depending on locations, size and nationalities, companies use different reserve estimation methods for internal and external purposes, and sometimes different companies involved in the same particular field may report different estimates. It is accordingly very difficult to apply standard valid estimates across companies, and even more difficult to determine reserve evolution over time. However, it is the intention through this thesis to develop a standard estimate method. Further, many years can elapse between the decision to explore for, drill and eventually produce oil. Large fields face established production schedules based on long-term corporate needs. Hence, a considerable lag exists between oil price changes and substantial changes in reserve or oil production.

Further, existing oil fields experience reduction of hydrocarbon production to the age of the field. In the short term the decline oil field overwhelm price changes for established fields. The DREM method presented in this thesis build to account for the above characteristics of oil production by modeling oil production in any stage of field production by applying time series analysis for 10 year price period. This is combined with stage regression analysis to capture the price related to the category of the reserve that incorporates production cost to reduce the risk and uncertainty in hydrocarbon reserve estimation. It brings risk and uncertainty as integral parts of the calculations rather than correction methods on the estimated numbers. This new estimation method base introduces a new technique for the computation and analyze of reserve volumes, category and economic exploitation so that it has useful value.

The fundamental outputs produced by the DREM model consist of predicted reliability and viability for the overall reserve calculation and for individual parameter inputs used to generate the output by accounting for uncertainties in dynamics model that account for future value. Most importantly, it brings probability into the calculations of the initial inputs for geological and rock properties data then each of these inputs is subjected to the risk and uncertainties associated with it before the individual values are multiplied together.

5.2 Recommendations

In this study, a method has been adopted, which was originally developed by Megill (1984), to estimate different levels of risk in reserve evaluation to clarify the chance that the prospect will be an accumulation. This research recommends that:

a. Reserves should (often) be categorized by using a collection of varied subjective terms to reflect the various levels of risk, generally during the acquisition, exploration, and development stages such as 1P, 2P, and 3P. It is also recommended that the terms of contingent and prospective resources should have an applied, graded identification to determine risk and project maturity by determining low estimate (1C), best estimate (2C) and high estimate (3C) of the resource.

b. Technically, it will be useful to apply another method on the reservoir instead of volumetric method to estimate the recovery factor of the reserves to run the new model. In addition, estimation of uncertainty level of the volume of reserve must consider all sources of uncertainty, because the volume of reserve is profoundly sensitive to a variation of geological and engineers uncertainty.

c. Financially, uncertainty assessment that associated with the volume of hydrocarbon reserves estimated regarding to historical petroleum cost and price. Therefore, it is recommended that financial factors need to be estimated based on petroleum cost and price when the estimate is made in order to estimate the value of reserves by applying DREM.

d. The development of the financial features through this research recommend that the relevant processes of exploration, development activities should be different between reserve classifications due to feasibility of applied technology, government regulations, such as taxes, the environmental and social impact on the development of the project, and future hydrocarbon prices.

e. To optimize the performance of the model in this research, Petroleum Reserve Bankability was used to estimate the return on the investment. It is required to utilize Net cash flow analysis and discounted cash flow method to clarify and distinguish the results regarding to Booking Price in term of growth rate and also Booking Price in term of money. Therefore, the analyzed results must be used to make investment decision on the project. For example,

- If petroleum reserve bankability is positive, this means the project yields a rate of return exceeding the costs.
- If petroleum reserve bankability equals zero just earning the costs.
- While, petroleum reserve bankability is negative, the project should be rejected.

f. After demonstrating technical and financial definitions, economic concepts should be the next step. These concepts should be taken into account to achieve economical analysis of, and estimation for the value of reserves. Economical values of reserves are mainly affected by current price.

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