Stochastic Simulation
Limited

White Paper

Stochastic Reservoir Engineering – Reserves Uncertainty Quantification

Mr. Leo Mullins, BCompt (Hons), ACA, F Fin.
Tel: +618 9446 2099, Fax: +618 9446 7906

Abstract

Stochastic Reservoir Engineering and Uncertainty Quantification

The oil and gas industry is entering a new age. Information, particularly that able to reduce risk is becoming critical to its participants ability to compete effectively in the future. Reservoir assurance, production optimisation and cashflow resilience are fundamental attributes required to underpin oil and gas company operations. The ability to achieve these is based on effective uncertainty quantification. The new field of stochastic reservoir engineering pioneered by Dr Andrew Wadsley has arisen precisely to meet this need.

Stochastic reservoir engineering is defined as "The use of Monte Carlo simulation using all relevant reservoir parameters (porosity, permeability, fluid contacts, structure, relative permeability, PVT, aquifer size, barriers, etc.) and production data to achieve a consistent description of reservoir performance in the presence of uncertainty". It is a methodology involving morphological analysis of dependency data to evaluate prior probability distributions used to create Filtered Monte Carlo Analysis rules in stochastic reservoir simulation models to arrive at data validated (history matched) probability distributions of all possible reservoir reserves outcomes.

The benefits of stochastic reservoir engineering are:

- data validated probability distributions of all possible reservoir reserve outcomes
- reduced uncertainty regimes
- fast history-matching techniques
- variable significance analysis

In summary these benefits can be described as better information leading to better decisions resulting in improved project returns through greater production or curtailed unproductive capital expenditure.

Leo Mullins

Leo Mullins is a Chartered Accountant specialising in the commercialisation of ICT applications used in the oil and gas industry. He is the co founder of Stochastic Simulation Limited and Optimiser Digital Management. Leo invented a patented digital management technology using point-of-use control over globally deployed digital assets to generate value.

He has presented at major international conferences and had several papers published in leading international journals on the management of intellectual property as it relates to eCommerce and the Internet, as well as the growing economic impact and effects of information and knowledge on corporate value and the economy

Introduction

Currently no consulting or oil industry group carries out systematic computational uncertainty analysis on hydrocarbon reserves, although much effort is made to try and solve the uncertainty problem by way of experimental design.

To date such analysis has required extraordinarily large computational resources and time to undertake which makes the effort commercially non-viable. This is because systematically quantifying uncertainty surrounding reserves assurance requires the entire solution space of possible outcomes from a reservoir simulation to be explored. Only in this way can proper systematic analysis of results quantify probabilities of outcomes.

Stochastic Reservoir Engineering and Quantification of Uncertainty

Although today, it is standard practice to use "Monte Carlo" techniques[1], to build up the final probability distribution of the resource. The problem is that "low", "base case" and"high" outcomes, require very different development strategies.

This obviously presents a considerable dilemma because the "most likely" outcome, often referred to as the "base case", which is typically used for the optimal development scheme, even with contingencies for high case outcomes, will not support optimisation of "high case"of production outcomes.

It is important to realise that reserves, unlike resources, are not fixed quantities since they depend firstly on how much effort, and additional risk, a particular company is willing to consider in bringing the oil to surface and secondly on precisely what criteria the company uses to define an economic project. From a commercial point of view the incremental recovery from drilling an additional well might not be economic. These are difficult issues to manage since the engineers are working with an incomplete technical data set and the financial analysts are using future commercial trends that have a high degree of uncertainty associated with them.

One of the principle results of this situation is that financiers to greenfield and brownfield investments, and oil field ownership transfer transactions accept a substantial degree of avoidable risk. Another outcome is unacknowledged uncertainty in oil production forecasts, that, in many oil-field developments, has reduced the effective recoverable oil resource from between 5% and 15% through inappropriate investment (either over or under-capitalisation) and through related poor management and operating practices.

To date the oil and gas industry has lost trillions of dollars in lost production and over investment[2]. This situation remains unchanged since the inception of the oil age and now presents a huge financial opportunity for both financiers and the oil producers.

The rising price of oil, cost of production and increasing volatility of the oil market is making the need for better information to support production planning, particularly in the area of reserves assurance and production risk mitigation. These are only able to be supplied by stochastic simulation technology

Stochastic simulation technology is the primarily enabler quantifying the effect of uncertainty in sub-surface oil and gas reservoirs. The core algorithm uses advanced Markov chain Monte Carlo (MCMC) techniques to define a random walk through

---

[1] Wadsley, A.W., *Markov Chain Monte Carlo Methods for Reserves Estimation*, IPTC-10065, Dohar 2005.

[2] Estimated @ 5% to 15% of total industry oil production to date

the space of all possible realisations of the reservoir conditioned to observed production, well (bore-hole) and seismic data. This procedure identifies and quantifies those oil field development plans that are robust to both geologic uncertainty and future risk, and adaptively manages the hydrocarbon resource throughout its productive life.

Experimental Design

Experimental design techniques have developed in response to the uncertainty quantification problem and looks at methods of systematically covering a range of reservoir parameters and generating a response surface which gives oil production as a function of these parameters. Because of the very large number of combinations of parameters, experimental design methods attempt to reduce the number of combinations without compromising the validity of the response surface. Given a set of reservoirs parameters, forward simulation is carried out to calculate oil & gas production for inclusion in the response surface. Examples of these approaches are:

- Integrated Reservoir Simulation System[3]
- COUGAR[4]
- ResGrid[5]
- UCoMS[6]
- EnABLE[7]
- MEPO[8]

However experimental design does not reduce the overall computational burden as a complete forward simulation has to be run for every control point on the response surface. Thus the computational task remains immense. For example, The UCoMS project (referenced above) explicitly states that one of their challenges is to carry out *"millions of simulations, each running 16-160 hours"*. Although speed itself is not the value driver, as the objective is to achieve a useful outcome for engineers to use in the course of their work. Experimental design techniques largely fails to achieve this and does not provide a viable solution to the quantification of uncertainty problem.

Background

A Brief Overview of Some Basic Oil Field Planning Concepts

The oil industry currently produces approximately 85 million barrels of oil per day. At current oil price this represents a $6 billion to $10 billion per day industry, without including the production of natural gas which is as much again.

The general public is largely unaware that even when the industry employs "best practice" only 60% of the oil in place is typically recovered, and sometimes this can be lower than 30%. The recovery of gas is somewhat better but there is always an enormous "volume of value" left under ground.

Hydrocarbon recoveries are so low because the reality is that reservoirs are made up of tightly packed solid grains, generally of sand, with oil, water and gas filling the porous space between the grains.

---

[3] http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/EP/ImprovedRec/15412UofTX.htm University of Texas, 2006.(accessed June, 2009)

[4] http://www.slb.com/content/services/software/reseng/cougar.asp, Schlumberger (accessed June 2009)

[5] http://www.cct.lsu.edu/~gallen/Preprints/CS_Lei06a.pre.pdf (accessed June 2009)

[6] http://www.cs.okstate.edu/clade2008/slides/Kosar.pdf, Louisiana State University, (accessed June 2009)

[7] http://www.roxar.com/getfile.php/Files/Product%20Datasheets/Software/Enable/EnABLE_A4_March09.pdf, Roxar, (accessed June 2009)

[8] http://www.sptgroup.com/Products/Mepo/

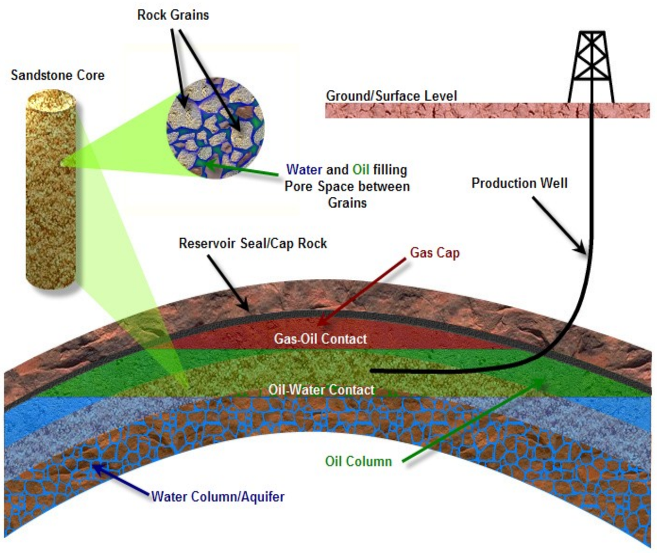

Figure 1: Schematic of Sub-Surface Oil and Gas Reservoir

Even with "perfect knowledge" of a given reservoir there is a limit to how much oil can be recovered as some is locked in the structure due to high capillary forces and some is trapped in areas that are simply inaccessible. There is not much one can do about capillary forces between oil, water and rock thus the amount of oil able to be recovered from a reservoir depends largely on the number of its wells and their positioning. Drilling wells is very expensive (anything from $5 million to $150m) and the number drilled is linked to the economics of the development which is very much dependent on the oil price.

In practice, "perfect knowledge" is never achievable and there is always considerable doubt as to how much oil (the resource) there is in a given reservoir and how much can ultimately be produced (the reserves). A principal role of petroleum engineers is the quantification of oil resources and the development of plans to maximise the economic production of the reserves.

Development planning is divided into two types: pre-production planning—which occurs before commercial production of hydrocarbons has commenced—and post-production or mature field planning, which is primarily concerned with detailed studies to support the continuous optimising of production. These studies are aimed at determining the optimum location of future wells as they are drilled, and identifying major enhanced recovery options such as water or gas injection schemes that can substantially improve the profitability of the venture.

All oil field development studies make extensive use of computer models[9]: these simulate the flow of oil, gas and water through the porous and permeable rocks (the reservoir) that contain the fluids. Such simulation models use information from two major sources: firstly, seismic survey data (that is, seismic reflectivity of the sub-surface rock formations) delineates the size of the reservoir; and secondly, valuable data is subsequently gathered from rock and fluid samples taken from wells drilled through the reservoir, and also from well tests, when wells are constrained to produce at controlled rates while various pressure measurements are taken. Despite the precise nature of much of the data collected it must be realised that a typical oil reservoir is between 1000m and 5000m below the surface of the Earth and covers an area measured in square kilometres. This means that there is always significant uncertainty in the geological model derived from these data sources. Clear trends might be observed but to expect anything other than an approximate map would be unreasonable. There are always many realisations of the reservoir (geological models) and its fluid contents that are consistent with the observed and derived data from wells and seismic data processing, and each one of these valid

---

[9] Stephen Tyson. *An Introduction to Reservoir Modeling* (2007), ISBN 978-1906-92807-0.

interpretations could lead to significantly different assessments of future oil and gas production.

Since the inherent uncertainties in deciding how much oil is present in a reservoir, and how much of this oil is ultimately recoverable, cannot be eliminated, it is incumbent on the petroleum engineer to quantify these uncertainties as rigorously as possible and then manage them to arrive at an optimum development plan. This requires assessing the impact the various uncertainties have on the economics of an oil field development and then using these insights to formulate a development plan that minimises capital and operating expenditure (CAPEX and OPEX) whilst optimising production through the installed infrastructure (in order to ensure maximum profitability).

The Traditional Approach to Managing Development Uncertainty

The oil in-place volume depends on the areal extent of the reservoir—consistent with the current geological interpretation—and on other factors such as the reservoir thickness and its capacity to hold fluids (porosity), but invariably the spatial variations of these parameters throughout the reservoir are poorly known. Even at the wells, where measurements are taken, there is some degree of uncertainty attached to individual parameter values.

The petroleum engineer therefore needs to refer to a range of maps that the geologist considers as being valid interpretations delineating the possible extent of the reservoir, and will also need to assign appropriate values to the various reservoir parameters, such as thickness and porosity, required to determine the in-place volume. The engineer will also make allowances for the range of parameter values that are possible. The normal practice is to assign reasonable value ranges to the various parameters and then to assign probabilities or levels of confidence to each value. The parameters are then combined statistically to arrive at a probability of final outcomes. Before the advent of the computer, this could only be carried out analytically (by hand), which placed restrictions on the shape of the individual distribution functions, and these were often inconsistent with distributions suggested by measured data. Nowadays it is standard practice to use computer models and "Monte Carlo" techniques, which involve random sampling of the individual distribution functions, which may now take on any desired shape, to build up the final probability distribution.

In the pre-production planning phase the probability distribution is broad, and general practice is to use concepts of "high", "most likely" and "low" outcomes to make use of this distribution with both "high" and "low" outcomes have a 10% chance of occurring. Meaning, a 10% chance of exceeding the "high" case is a 90% chance of exceeding the "low" case. The "most likely" outcome being the one that has a 50-50 chance of being achieved.

From a technical perspective a "high" outcome would almost certainly require a very different development strategy to a "low" outcome, and this obviously presents a considerable dilemma. In practice the "most likely" outcome, often referred to as the "base case", is selected and a development scheme is designed to optimise the recovery based on this volume of oil in place whilst at the same time incorporating contingencies into the planning to cater for the possibility of a "high" outcome.

Contingency planning, such as making provisions for extra wells on an off-shore platform, can be very expensive but retrofitting additional facilities at a later date can be even more expensive, and sometimes technically impossible. There is also, of course, the chance of a "low" outcome. In such cases emerging technologies may help to improve the final outcome but it is almost certain that the profitability of the project will suffer. The general rule-of-thumb is that if the development is not robust enough to be profitable in the event of a "low" outcome then it should not proceed.

Assessing the profitability of a development requires estimating the CAPEX, OPEX and income. The estimation of future CAPEX and OPEX is certainly not an exact science but generally there is less uncertainty associated with expenditure than estimation of the income stream, which depends on a production forecast, derived from all the sub-surface uncertainties, coupled with a prediction of the price of oil into the future.

Observations and Shortcomings Relating to the Current Approach

If the management of uncertainty can be improved then better estimates of reserves can be made and, more importantly, better development decisions will follow. Given the scale of the oil industry, if a field's reserves can be improved by only a fraction of one percent then the financial benefits are enormous. For example, increasing production by only 100 barrels of oil per day would increases annual revenue, at recent oil prices, by $2.5 million to $4 million. Even if it turns out that the reserves are reduced for a particular field, knowing this at an early stage of its development can reduce expenditure considerably.

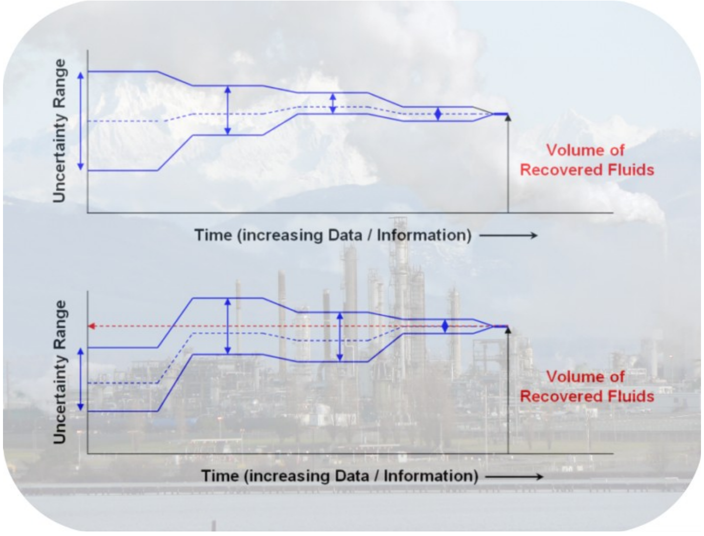

Figure 2: Uncertainty Decreases as an Oil Field Development Matures—however, initial reserves estimates may be wide of the mark!

As fields are developed more information is gathered and parameter uncertainty, is reduced—this continues as fields mature. Petroleum engineers work very hard to "history match" past field performance. History-matching tunes the various reservoir parameters so that past production and pressure measurements are matched, as far as possible, by the computer model. Once this is achieved there is a degree of confidence in using the model to predict future production and keep track of the economics of the development.

History matching is generally a very lengthy task and once a reasonable match is achieved it is understandable that the petroleum engineer is rather reluctant to further fine tune the model let alone look for a substantially different model that might give an equally good—or even better—history match. The situation for these mature fields, unfortunately, is the same as for those pre-production, in that there are many different models that will be consistent with the observed field data and each one of these could lead to significantly different predictions of future oil and gas production.

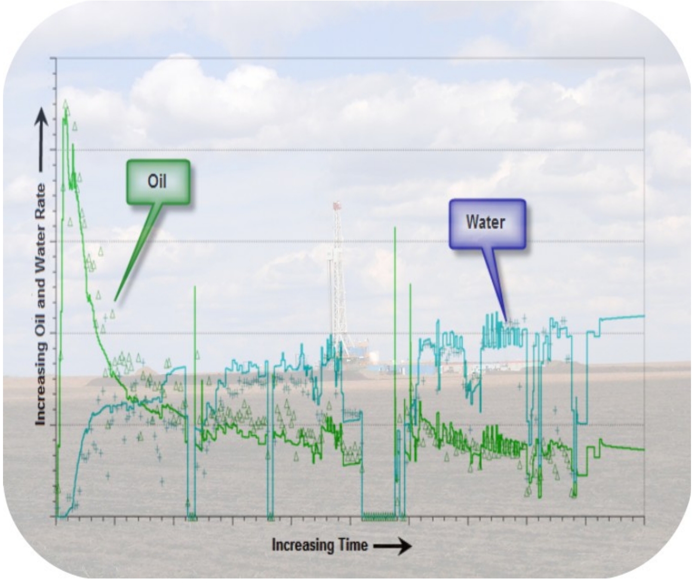

Figure 3: History Match to Oil and Water Production for an Oil Field

The problem is that these valid alternative models are often very difficult to quantify using the traditional approach and any one of these may give a better prediction than the model currently being used.

Introducing Stochastic Reservoir Engineering - A New Approach to Uncertainty Management

Stochastic reservoir engineering is defined as "The use of Monte Carlo simulation using all relevant reservoir parameters (porosity, permeability, fluid contacts, structure, relative permeability, PVT, aquifer size, barriers, etc.) and production data to achieve a consistent description of reservoir performance in the presence of uncertainty". It is a methodology involving morphological analysis of dependency data to evaluate prior probability distributions used to create Filtered Monte Carlo Analysis rules in stochastic reservoir simulation models to arrive at data validated (history matched) probability distributions of all possible reservoir reserves outcomes.

The benefits of stochastic reservoir engineering are:

- data validated probability distributions of all possible reservoir reserve outcomes
- reduced uncertainty regimes
- fast history-matching techniques
- variable significance analysis

In summary these benefits can be described as better information leading to better decisions resulting in improved project returns through greater production or curtailed unproductive capital expenditure. Stochastic reservoir simulation is a solution to the increasing need for risk quantification. It addresses reservoir uncertainty in a systematic way leading to better investment decisions.

It is estimated that global use of this technology for oil field reservoir management and operations would create value through increased hydrocarbon reserves and decreased costs in the range $15 billion to $40 billion annually[10]. Stochastic reservoir simulation is the basis for extremely fast reservoir modeling capable of accurately computing the simulated flow of oil, gas and water through porous rocks, having the unique capability of being able to quantify the impact that the sub-surface uncertainty has on project profitability. It is based on MCMC (Markov Chain Monte Carlo) a well-established mathematical technique and implemented on the latest high end computer hardware able to perform the millions of iterations of computed outcomes required to achieve the quantification analysis necessary to address uncertainties in oil-field development. This combination of advanced mathematical techniques with the latest hardware has made stochastic simulation possible to enable better manage field development uncertainties and the way financial risk is managed in the oil and gas industry.

---

[10] 1% of annual oil production (~31 billion barrels) valued between $50/bbl and $125/bbl.

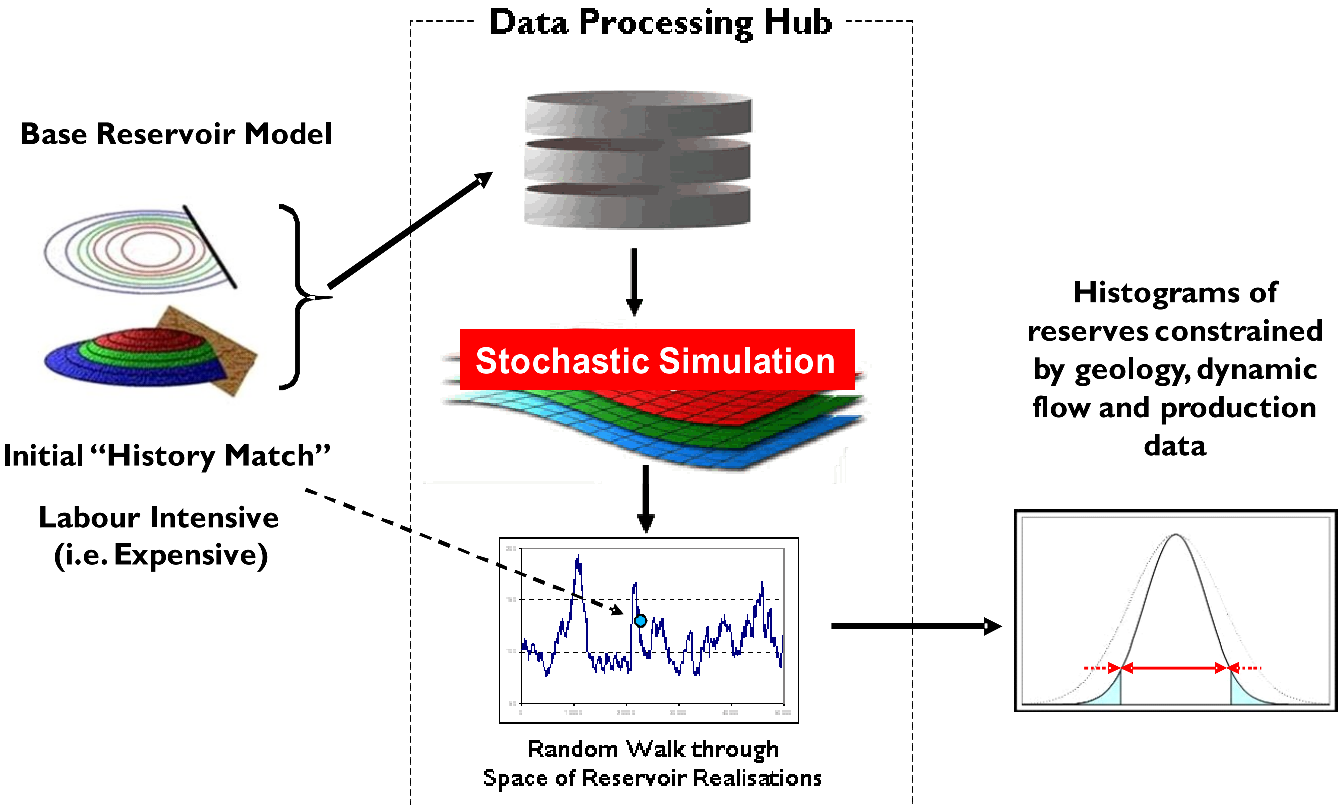

Figure 4: Stochastic Simulation process

Reservoir simulation models consume significant computational resources and are routinely run on the largest vector and multi-processing super-computers, with a typical forward simulation taking days to perform. Recent advances in hardware has meant that sizeable models (over 1 million cells) can now be run on laptop computers but, even so, it is clearly impractical to quantify the uncertainty in predicted production forecasts by carrying out a forward simulation for each and every variation in the reservoir parameters using the traditional approach to simulation modelling, because they would still take years to compute enough results to be usable. This largely because the principal simulation programs for modelling the flow of oil, gas and water in the geological sub-surface have not changed, algorithmically, for over twenty-five years.

At its centre stochastic reservoir simulation employs Advanced Markov Chain Monte Carlo (MCMC) techniques to define a random walk through the space of all possible realisations of the reservoir, conditioned to observed production, well and seismic data. This random walk is an enormous computational task, and several million realisations are needed to analyse a typical reservoir. Recent developments in computer hardware, particularly in the games industry (graphics processing units, GPUs), make these calculations feasible to apply to the world's largest reservoirs. This combination of advanced mathematical techniques with the latest hardware will be at the heart of oil and gas field development and facilities risk mitigation management of the future.

Although there will always be technical challenges to be overcome in achieving the highest possible computational speeds, a revolution in reservoir engineering is here.

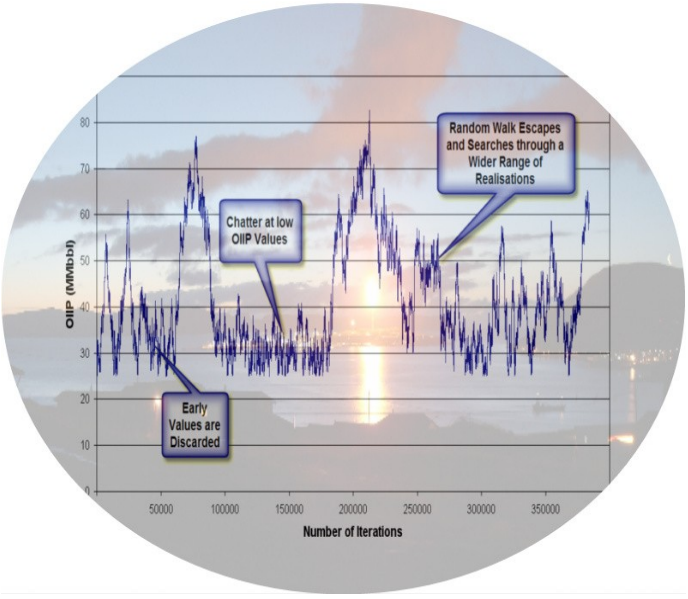

Figure 5: Typical Random Walk through the Space of Reservoir Realisations—using MCMC to Calculate Oil-Initially-in-Place (OIIP)

Examples

An example is given in a recent paper by Maučec et al[11]. Generally, Markov chain Monte Carlo (MCMC) methods work by seeking those parameters which lead to a *prior* (usually normal) probability distribution for the errors of the model when compared to observed field production or other constraints. MCMC generates the target probability distribution by running a cleverly constructed Markov chain for a long time so that the limiting or stationary distribution of this chain is the target distribution[12].

Another example was reported in the Society of Petroleum Engineer's paper SPE 39714 presented at the Asia Pacific Conference in Malaysia in 1998[13]. In this case, significant value was lost because the field operator, Petrocorp of New Zealand, relied on an "expert" who derived a single deterministic estimate of oil reserves of 27 MMbbl, and acquired the NZ Government's 11% share of the Waihapa field based on that valuation. Stochastic simulation using MCMC calculated a recovery of 23.5 MMbbl, some 15% lower. Actual recovery corresponding to the proposed develop plan was 23.2 MMbbl—remarkably close to the 23.5 MMbbl predicted at a time when only some 6.0 MMbbl of oil had been produced.

A more recent example using the stochastic reservoir simulation approach was carried out in a gas reserves dispute onshore Victoria, Australia in 2001. Reserves obtained (gas ultimately produced) differed from estimates made by the MCMC method (and derived when just 16% of gas initially in place (GIIP) had been produced), by less than 1% —a good example of the forecasting accuracy that can be achieved using this methodology.

The value of stochastic reservoir simulation in the field is also shown in actual results recently demonstrated by Table 1 and graphically in Figure 7 below. Table 1 shows results of a recent small reserves study commissioned by an Australian company and illustrates an approximate $50m difference in the P10 and P90 results respectively and $8m for the base case.

	P90	P50	P10
Conventional Monte Carlo*	4.1	5.3	6.8
Stochastic Simulation**	4.7	5.4	6.1

Table 1. Case Study Result (MMbls)—using MCMC to Calculate Oil-Initially-in-Place (OIIP)

---

[11] Maučec, M., Douma, S., Hohl, D., Leguijt, J., Jimenez, E.A. and Datta-Gupta, A., *Streamline-Based History Matching and Uncertainty: Markov-chain Monte Carlo Study of an Offshore Turbidite Oil Field*, SPE 109943, California, 2007.

[12] Gilks, W.R., Richardson, S. and Spielgelhalter D.J. *Introduction to Markov chain Monte Carlo*. In Markov Chain Monte Carlo in Practice (Gilks et al.), pp. 1-19. Chapman and Hall, London, 1996.

[13] Stoltz,L.R., Jones, M.S., and Wadsley, A.W., *Reserves Identification in the Fractured Limestone, Waihapa Field, New Zealand*, SPE 39714, 1998 SPE Asia Pacific Conference on Integrated Modelling for Asset Management, Kuala Lumpur, Malaysia.

*Conventional Monte Carlo reserves determination was based on analogue recoveries from other Gippsland Basin Fields

**Each realisation of the Stochastic Simulation reserves determination is based on full simulation of a calibrated, validated reservoir model. Calibrated stochastic simulation preserves Mean/P50 while narrowing range of P90 – P10 based on actual reservoir outcomes

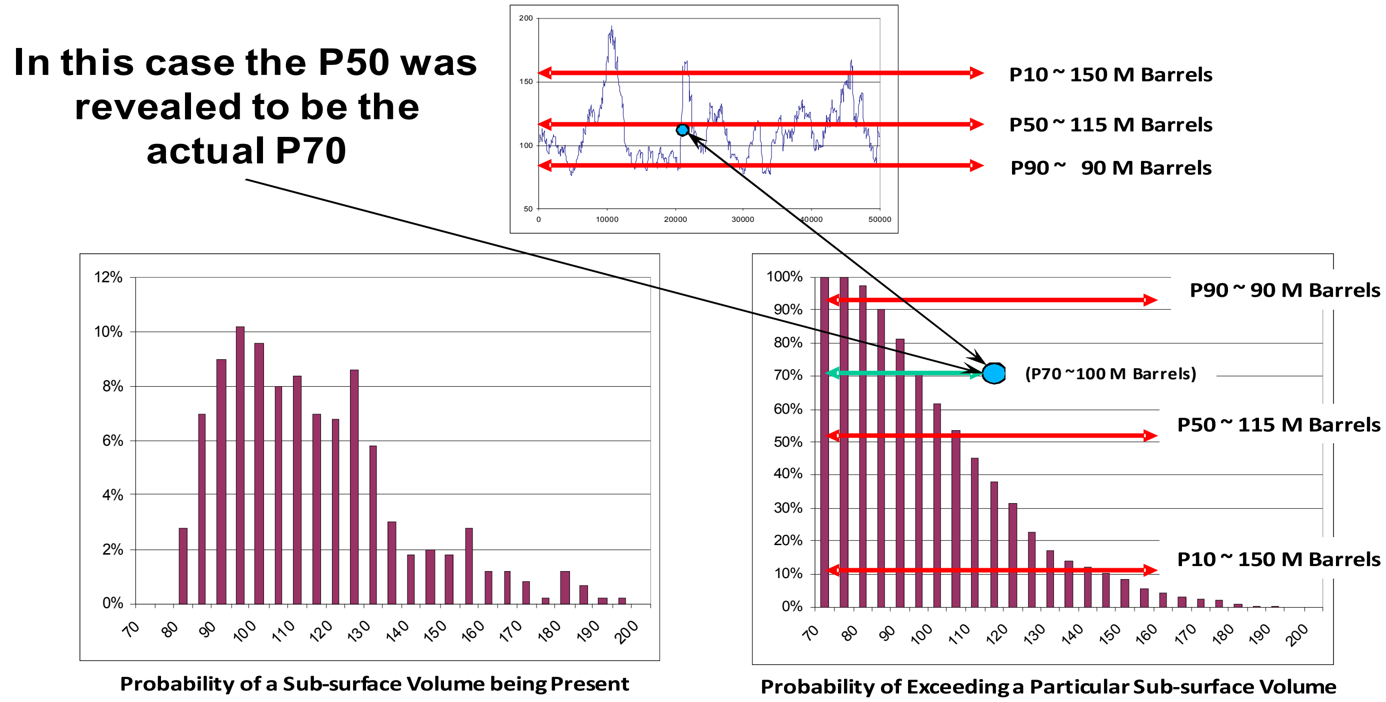

Figure 6: A simple stochastic simulation analysis

Conclusion - Uncertainty Quantification and Risk Mitigation

The oil and gas industry is now experiencing the highest volatility in prices in history, prices are now at two thirds their peak and expected to continue higher after falling by two thirds recently.

The increasing price of oil and gas, production optimisation technologies and the current communication revolution now being ushered in by the digital age and connectivity are making previously uneconomic fields commercially viable. This is introducing new opportunities for smaller enterprises to use information more effectively and significantly increase their ability to exploit mature oil field opportunities. With Hubbert's Peak[14] now generally accepted as a fact the oil and gas industry is increasingly experiencing structural industrial change as the gap between supply and demand grows. The resulting associated industry volatility will impact the status quo as, over time, high prices lead to the increasing adoption of alternative energy resources and increasing numbers of new smaller players exploit opportunities these changes will inevitable create.

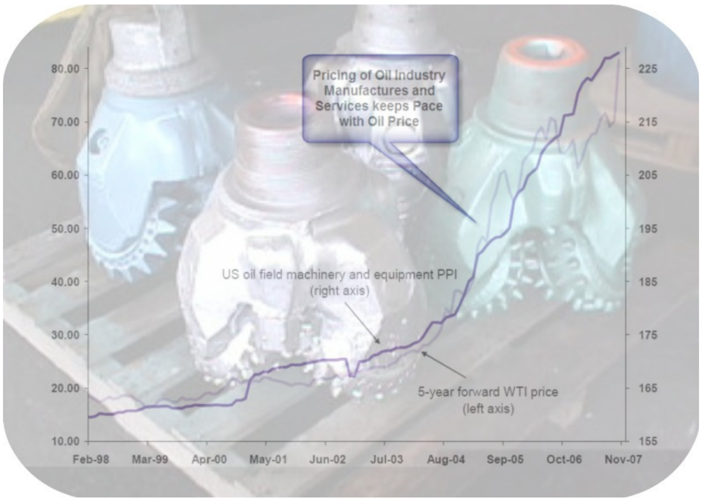

Figure 7: The Oil Industry Suppliers and Services are Experiencing Exponential Growth in Revenues – driven by the growth in oil prices!

---

[14] See http://www.energybulletin.net/primer.php for details about H

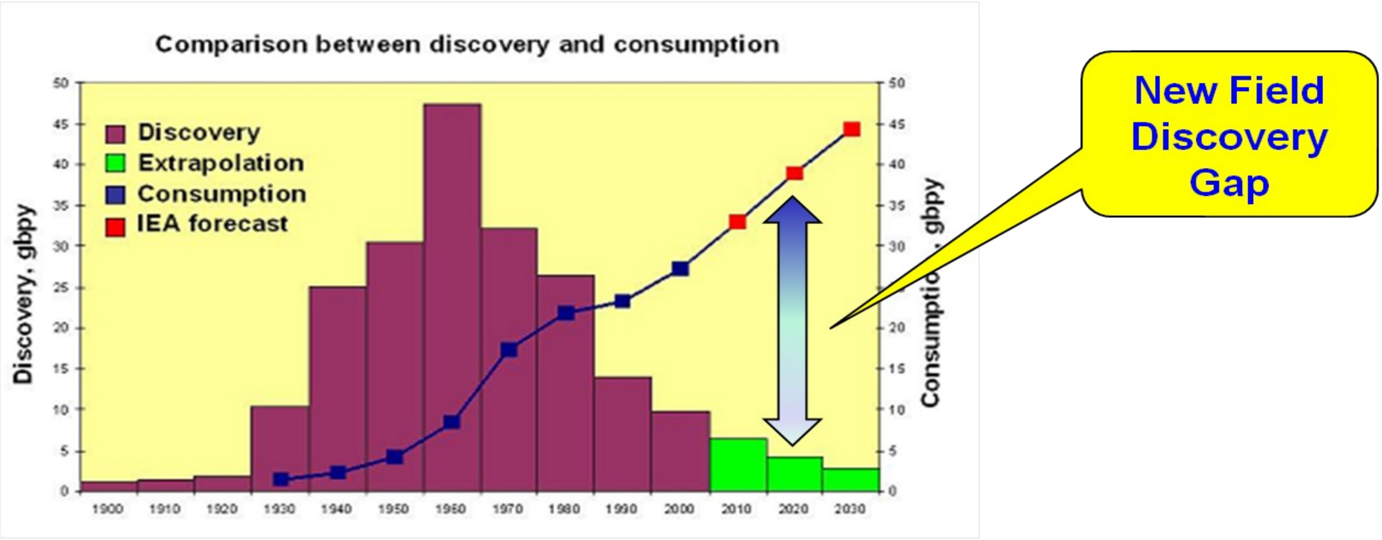

Figure 8: Hubbert's Peak

Given that the remaining hydrocarbon reserves are at least equal to or greater than the total production of oil and gas to date. The current future of the petroleum industry is enormous and will be a significantly active economic and commercial sector of the world economy for many decades to come and will be requiring both, increasingly massive investments at the big end and introducing large numbers of small operators at the small end.

The large operators will increasingly focus on the remaining massive reserves in deep water and remote areas where their size provides them with commercial advantages, whilst smaller operators will takeover an increasing number of (smaller) marginal mature producing resources requiring their lower operating costs in order to be profitably exploited. Overall demand for new technology and information will grow strongly. The drive to exploit existing resources more efficiently and expeditiously by the entire operator spectrum of the oil and gas industry is becoming increasingly intense.

The need for better information, especially quantification of uncertainty, will therefore inevitably increase in the face of rising costs, the growing new field discovery gap and associated industry volatility.

An example of one probable change to the oil and gas industry that will be caused by stochastic reservoir engineering technology is the way investment decisions are made. The P90 P50 P10 investment rule of thumb is that the P50 is usually twice the P90 and the P10 is twice the P50. Yet it is well known that P10 outcomes are as much as 10 to 20 times more valuable than P90 outcomes. Yet through lack of uncertainty measurement industry has traditionally invested on the P90, developed for the P50 and hoped for the P10.

Because the SRE enables companies to have a better understanding of uncertainty profiles oil and gas investment companies with portfolios of reserves using SRE to manage them will in future invest on the P50 (i.e. pay more) rather than the P90. This is because having confidence in uncertainty profiles enables portfolio investment decision to rely on P10 outcomes significantly covering P90 outcomes.

Other changes to work flow practices will happen as well. Stochastic reservoir engineering and simulation is without doubt the future of reservoir assurance and associated risk mitigation services within the oil and gas industry. Adding to the foundations of reservoir simulation technology development and work flow processes, it will improve support of future production planning, and financiers due diligence and decision making procresses for evaluating oil and gas projects.