AMERICAN UNIVERSITY OF BEIRUT

A ROBUST STOCHASTIC APPROACH FOR OPTIMAL SEQUENCING OF APPRAISAL WELLS

by

OMAR ADEL EL SOUKI

A thesis
Submitted in partial fulfillment of the requirements
for the degree of Master of Science in Energy Studies
to the Department of Mechanical Engineering
of the Faculty of Engineering and Architecture
at the American University of Beirut

Beirut, Lebanon
January 2016

AMERICAN UNIVERSITY OF BEIRUT

A ROBUST STOCHASTIC APPROACH FOR OPTIMAL SEQUENCING OF APPRAISAL WELLS

by
OMAR ADEL EL SOUKI

Approved by:

Dr. George Saad, Assistant Professor — Advisor
Department of Civil and Environmental Engineering

Dr. Nesreen Ghaddar, Professor — Member of Committee
Department of Mechanical Engineering

Dr. Mariette Awad, Associate Professor — Member of Committee
Department of Electrical and Computer Engineering

Date of thesis defense: 18 January 2016

AMERICAN UNIVERSITY OF BEIRUT

THESIS, DISSERTATION, PROJECT RELEASE FORM

Student Name: EL SOUKI OMAR ADEL

Last	First	Middle
EL SOUKI	OMAR	ADEL

● Master's Thesis ○ Master's Project ○ Doctoral Dissertation

☒ I authorize the American University of Beirut to: (a) reproduce hard or electronic copies of my thesis, dissertation, or project; (b) include such copies in the archives and digital repositories of the University; and (c) make freely available such copies to third parties for research or educational purposes.

☐ I authorize the American University of Beirut, **three years after the date of submitting my thesis, dissertation, or project,** to: (a) reproduce hard or electronic copies of it; (b) include such copies in the archives and digital repositories of the University; and (c) make freely available such copies to third parties for research or educational purposes.

19 January 2016

Signature Date

ACKNOWLEDGMENTS

I would like to acknowledge my thesis advisor Prof. George Saad for all his support and assistance throughout the development of the research; without him I would have not been able to complete this thesis.

Furthermore, I would like to express my recognition and gratitude to Prof. Nesreen Ghaddar and Prof. Mariette Awad, my thesis committee members, for their help and cooperation in the success of the work.

I will never be able to thank enough my mother and my family for their support through this thesis.

Last but not least, my recognition and gratitude are addressed to my very good friend Melanie Jabbour for her support and patience through every step of my graduate studies.

AN ABSTRACT OF THE THESIS OF

Omar Adel El Souki for Master of Science
Major: Energy Studies

Title: A Robust Stochastic Approach for Optimal Sequencing of Appraisal Wells

The life of a hydrocarbon field can be distinguished by five main stages: exploration, appraisal, development, production and abandonment. During the exploration phase, the prospect is located and identified as a commercially viable hydrocarbon reservoir. Following exploration is the appraisal stage, where appraisal wells are drilled to determine the initial hydrocarbon reserves. The development stage consists of determining the recovery technique and the number of production wells whereas in the production stage, monitoring the production and assisting the recovery usually takes place. When the production rates become non-commercial, the field is abandoned and the site is rehabilitated.

Of particular interest is the appraisal stage, where the use of seismic data in combination with appraisal wells permits the estimation of the initial hydrocarbons in place and quantification of the associated uncertainties. Since the appraisal stage offers the opportunity to maximize uncertainty reduction, optimizing on this stage makes it the biggest setting for maximizing project profitability. Nonetheless, amid high prices of well drillings and billions of dollars being spent on appraisal activities, limited resources are spent on assessing the usefulness of the gathered information.

This thesis proposes a comprehensive approach to determine the number of appraisal wells, their sequence of drilling and their justification based on economic merit. This approach is accomplished through the use of a combination of two methods: the uncertainty reduction method -which ranks locations based on the maximum uncertainty reduction that they can provide- and the Value of Information -which is the difference between the value of developing the project with/without appraisal. The sequential appraisal well location framework will be developed and tested on the Stratton gas field dataset.

CONTENTS

ILLUSTRATIONS

TABLES

Table Page

Dedication addressed

to my family

CHAPTER I

INTRODUCTION

The quest for oil as a major commercial energy source began when Colonel Edwin Drake drilled the first oil well in 1859 in northwestern Pennsylvania (Devold, 2013). The economic advances made in the 20^{th} and 21^{st} century ran parallel with the growth of oil as a major commercial energy source, gaining oil higher shares out of the world energy mix (Rahman, 2004).

Today, oil constitutes forty per cent of the world energy mix. Despite the environmental concerns about oil and the rise of renewable energies, OPEC's World Energy Model predicts an average annual demand growth rate of 1.7 per cent for oil up to the year 2025; corresponding to a slight reduction from forty percent to thirty-seven percent of the world energy mix (Rahman, 2004).

That being said, the ever-growing prominence of oil as major commercial energy source makes the hunt for hydrocarbons an important undertaking for petroleum geologists.

The phases associated with the search and the production of a hydrocarbon reservoirs are known as the exploration and production phases (E&P). Typically, a hydrocarbon field undergoes five major stages during the E&P: exploration, appraisal, development, production and abandonment (Cairn Energy, 2015).

In the exploration stage, seismic echography and exploration wells are used to determine if the identified prospect contains commercially viable hydrocarbon deposits. Once a commercial discovery has been identified, the appraisal stage entails drilling appraisal wells (wells drilled to collect information concerning the reservoir properties) and using the already acquired seismic data to estimate the initial hydrocarbon reserves in place and to improve knowledge about the reservoir rock and fluid properties. Following the appraisal, the field development stage establishes the number of production wells, the recovery techniques and the surface facilities among other activities. Once field development is completed, field production starts. The production is monitored, and injection wells are drilled to maintain a satisfactory recovery. When the production rate can no longer be commercially sustained, the field is abandoned, the platforms are dismantled and the site is rehabilitated. The exploration and appraisal stages constitute the exploration stages and typically last from five to ten years. Field development, production and abandonment constitute the production stages and typically last fifteen to thirty years (IFP School, 2014).

Each stage being dependent on the prior, a combination of successful exploration, effective appraisal and commercial extraction is needed to insure a successful E&P cycle (Haskett, 2003).

Of particular significance is the appraisal stage, which in a broad sense, is the act of assessing a certain activity. Concerning field development, the appraisal stage is an information-gathering activity aimed at understanding the reservoir characteristics and reducing reservoir uncertainty (Demirmen, 1996). It is worth mentioning that one of the important misconceptions concerning the aim of appraisal activities is that the ultimate aim of appraisal activities is the reduction of risks relating to field development and not to prove reserves or delineate the reservoir. The latter is achieved as a by-product of a successful appraisal process (Demirmen, 1996; Haskett, 2003).

The tools used in the appraisal stage are typically seismic data and appraisal wells (Schlumberger, 2015). Seismic echography refers to energy waves emitted from a source on the ground and aimed at the Earth's subsurface. Travelling the subsurface, the energy waves cross different geological layers. With each geological layer crossed, a part of the wave's energy bounces back to the surface, with the quantity of rebounded energy being greater when the difference in the acoustic impedance (AI) – product of velocity and density- of the two layers is larger (Cook, et al., 2008). The reflection coefficient ri is used to quantify the difference in the properties of two consecutive layers (Alves, et al., 2014) and the collection of reflection coefficient in time (corresponding to depth increasing downward) defines the reflectivity series (Cook, et al., 2008). Assuming that the pulse (emitted from the source) remains unchanged as it passes through the earth, the recorded seismic trace can be regarded as the convolution (multiplication of two arrays) of the reflectivity series with the wavelet, creating what is known as the convolutional model or the forward model. However, the real use of seismic data lies in the inversion process: taking the real seismic trace, removing the wavelet to obtain an earth model of AI. The gathering in time of AI allows geoscientists to build a geological model of the subsurface layering (Kearey, et al., 2002) and is considered one of the foundations of reservoir management (Ariffin, et al., 1995). Although the seismic data covers the entire reservoir, the missing low and high frequencies in the seismic waves, used to differentiate thin geological layers, reduces the efficiency of using this method alone (Simm, et al., 2014).

Appraisal wells drilled in a reservoir provide detailed and reliable information regarding the layering of the subsurface. The presence of more than one well in a reservoir permits the interpolation of the properties extracted from the wells to the whole reservoir. One such technique is known as geostatistics or kriging (Chambers, et al., 2000). Developed by D.G Krige in the early 1950's, kriging deals with the shortcomings of traditional interpolation algorithms by mainly accounting for the effect of data clustering (Bohling, 2005). Despite adding valuable localized reservoir information, the use of appraisal wells alone is essentially limited by their high prices, thus making this technique non-sufficient for reservoir mapping.

The true power of seismic data and appraisal wells is only achieved when combining those two methods together. Many methods were developed during the years, the most effective being the collocated cokriging model. This model works in a similar way to the kriging approach described earlier, however this time the kriging model encompasses two variables: well and seismic data. Correlations between the well-well data, seismic-seismic data and well-seismic data are modeled and used as an input in the collocated cokriging model (Xu, et al., 1992).

Whether using seismic data or wells individually or combining them, some sources of uncertainty remain and have to be taken into account when determining the initial reserves in place. These uncertainties include but are not limited to: uncertainties in the seismic data, uncertainties about the reservoir fluid and petrophysical properties, uncertainties in the measurements and uncertainties in the well-to-seismic ties (Da Cruz, 2000).

Even though optimizing all the stages in the E&P cycle is a goal set by all companies, it is in the appraisal stage that the abovementioned uncertainties can be best investigated and quantified and thus project profitability can be maximized (Haskett, 2003). Figure.1 below shows the High, Medium and Low estimates of oil in a reservoir and their variation through the E&P stages. Analyzing this figure shows that the uncertainty (difference between the High and Medium estimates) is reduced the most during the appraisal stage.

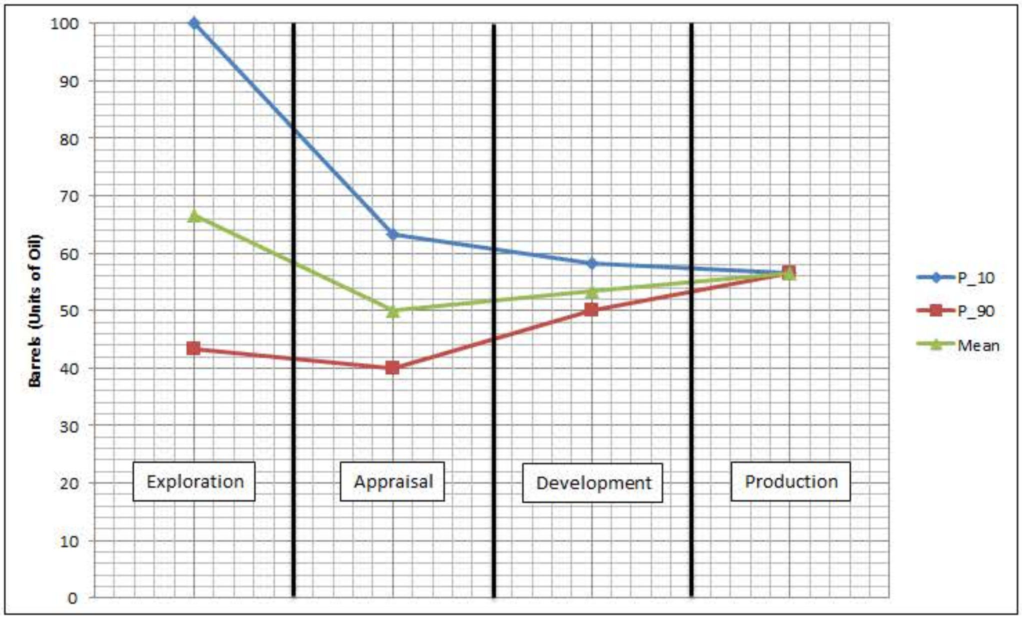


Figure 1: High, Medium and Low estimates in four E&P stages (Adapted from (Haskett, 2003)).

Drilling appraisal wells will increase the knowledge of the reservoir properties and interconnections and reduce the overall uncertainty regarding its characteristics, allowing for more informed decisions when it comes to development and production

However the hefty price tag of well drilling constitutes a direct constraint to expanding the reservoir knowledge. Hence, the goal of a successful appraisal program is to achieve maximum reduction in uncertainty while minimizing the cost.

The goal of this thesis is to determine the sequence of appraisal wells to be drilled as to increase project profitability. The location of each well will be chosen using the uncertainty reduction method. This method ranks each location according to the uncertainty reduction it can provide, with the best location being the one that maximizes the reduction in uncertainty. Once a location is chosen, the well is assessed for economic viability, i.e.

checking if the value obtained by drilling the well justifies the cost of drilling that well. The Value of Information method will be used to assess the aforementioned economic viability.

The thesis will first start with a review of the literature concerning the uncertainty reduction method and the Value of Information method. Following the literature review, the methodology and the hydrocarbon field chosen for the testing will be explained in Chapter 3. The uncertainty reduction method will be explained in details in Chapter 4 while the Value of Information method will be elaborated in Chapter 5. The results and discussion are grouped in Chapter 6 while Chapter 7 contains the conclusions of this thesis.

CHAPTER II

LITERATURE REVIEW

One of the most worrying problems facing reservoir engineers and management alike is the inherent uncertainty in all hydrocarbon reservoirs. To alleviate this problem, the Oil and Gas industry (O&G) resorts to the use of subsurface appraisal, which is a well-accepted method in this industry (Demirmen, 2001). However, caution should be used when utilizing subsurface appraisal since the O&G industry spends billions of dollars yearly on activities lacking established guidelines (Bratvold, et al., 2009). The lack of established guidelines for appraisal activities means that many times the outcomes are under-appraisal or over-appraisal of the field, in other words a non-optimal development scenario incapable of achieving the highest economic return for the project (Demirmen, 1996).

To this end, the literature review will cover the work pertaining to the uncertainty reduction method and the Value of Information method used to provide guidelines for the appraisal stage.

Haskett (2003) optimizes appraisal well locations through the efficient uncertainty reduction method. With the purpose of mapping the reservoir extents, this quantitative method prioritizes the appraisal well locations in the reservoir; with the best location being the one that contributes the greatest overall uncertainty reduction. This is achieved by choosing the well that has the highest combination of uncertainty reduction and probability of success (Haskett, 2003).

Although the problem of determining the sufficient number of appraisal wells is widely discussed in the literature, none of the studies -with the exception of the paper previously discussed- offers a recommended approach to determine the number and location of appraisal wells. Literature documents three wells as being sufficient for appraising small accumulations and four to six wells for medium and large accumulations; however, there is no systematic approach as to how those numbers are determined and to how are the prospect sizes labeled (small vs. medium vs. large) (Knoring, et al., 1999).

Though billions of U.S. dollars are spent yearly on appraisal activities, very limited amounts are paid on assessing the value of this information (Bratvold, et al., 2009). This lack of auditable criteria for subsurface appraisal methods was responsible for under- and overappraisal in many fields and impacted negatively on upstream economics (Demirmen, 1996).

One such audit criteria that ties reservoir uncertainty to possible economic consequences is the Value of Information (VoI) technique. VoI, which is an appraisal assessment tool, aids the decision maker pertaining well placement (Demirmen, 2001). It is a powerful instrument for both short term and long term justification of data acquisition costs (Koninx, 2000).

A review on the VoI and its application in the Oil and Gas industry shows that the practice of the VoI concept has been slow and VoI is not yet an integral part of the decision-making process. The lack of basic decision-analysis skills and the inexperience of petroleum engineers and managers with applying the VoI methodology are responsible for the slow rate of acceptance of this method. The widespread misconceptions' regarding the value of information only creates confusion and delays the uptake of the method (Bratvold, et al., 2009).

Since the value of a data acquisition usually spans through many of the E&P stages, the VoI analyses is thus a short-term and long-term cost-cutting and value-creation process. This stretch over the E&P stages requires the VoI to consider a full life-cycle approach, necessitating the collaboration and contribution of a multidisciplinary team, ranging from geoscientists to top management (Koninx, 2000). This complexity in the VoI computation adds to the barriers previously discussed by Bratvold, et al. (2009).

Demirmen (1996, 2001) makes use of the VoI concept to justify proposed appraisal well locations. In the appraisal context, the value of information is the difference between the value of developing the project with appraisal and the value of developing the project without appraisal (the difference between the Net Present Value between optimal and suboptimal development). If the VoI is positive then the benefits outweigh the costs and the appraisal activity is justified. The expectation curve, giving the probability distribution of reserves at the pre-appraisal stage is used to complete the decision tree and calculate the VoI. In case of having multiple proposed well locations, the location with the highest VoI is the preferred alternative (Demirmen, 1996, 2001).

Cunningham and Begg capitalize on the potential for learning to occur between the drilling of two wells. The Value of Information approach is used in this context to analyze the predicted value of this learning on development wells and to maximize it by providing recommendations regarding the best sequence of well locations. Results on two proposed well sequences show that in the VoI technique, the value is not only a function of cost and reward but also a function of learning that can affect future development decisions (Cunningham, et al., 2008).

Three appraisal targets were reviewed by Burdett and Haskett (2012) through the application of the VoI approach. The first appraisal target investigates the oil-water contact on a specific reservoir section. Although drilling this well will have a substantial impact on the expected recovery, the well is not justified because it does not result in a change to the development plan. The second well investigates an area of poor seismic quality that could turn out to be a shallow gas pocket. Once the probability of success is factored in, the VoI suggests a no-go decision since the well does not lead to a modification of the development plan. The third well, which investigates a prospect in the reservoir, turns out to be justified by means of the VoI method since it affects the overall development scheme of the reservoir. One key takeaway of this paper, which the authors stress as being a pillar of the VoI approach is the capacity of the new data acquisition to change a potential development decision; i.e. the new information to be collected should have the potential to change the development decision (Burdett, et al., 2012).

Through a practical twelve-step approach, Coopersmith and Cunningham (2002) describe a methodology to evaluate the VoI in the upstream petroleum industry. In addition to the classical concepts of the VoI previously discussed, the authors define the VoI as being the interplay of three main factors or three enquiries: the proportion of the time the decision makers chooses the wrong decision (function of the uncertainty abiding in the reservoir), the monetary impact of such a wrong decision and finally the reliability of the information under consideration. Based on those three concepts, the methodology discussed touches on understanding the asset value without additional information, determining the problem, setting up the different alternatives, their probability of occurrence and their expected benefits and finally touching on the effect of reliability of the collected information on the final outcome (Coopersmith, et al., 2002).

CHAPTER III

METHODOLOGY

The following chapter will discuss the methodology followed in this thesis. The description of the hydrocarbon field used in the model will first be presented, followed by a description of the software and its operating method. Finally the Sequential Appraisal Well Location Framework, which combines the Uncertainty Reduction method and the Value of Information method will be discussed.

A. Description of the Stratton Field

The Stratton field reservoir is a vast on-shore gas reservoir located in South Texas, Texas, USA. Being part of the FR-4 gas play, the Stratton Field is a diverse and large reservoir containing 1,295 Trillion Cubic Feet (Tcf) of recoverable natural gas resources; including proved reserves, conventional resources and non-conventional resources (Bureau of Economic Geology, 1994).

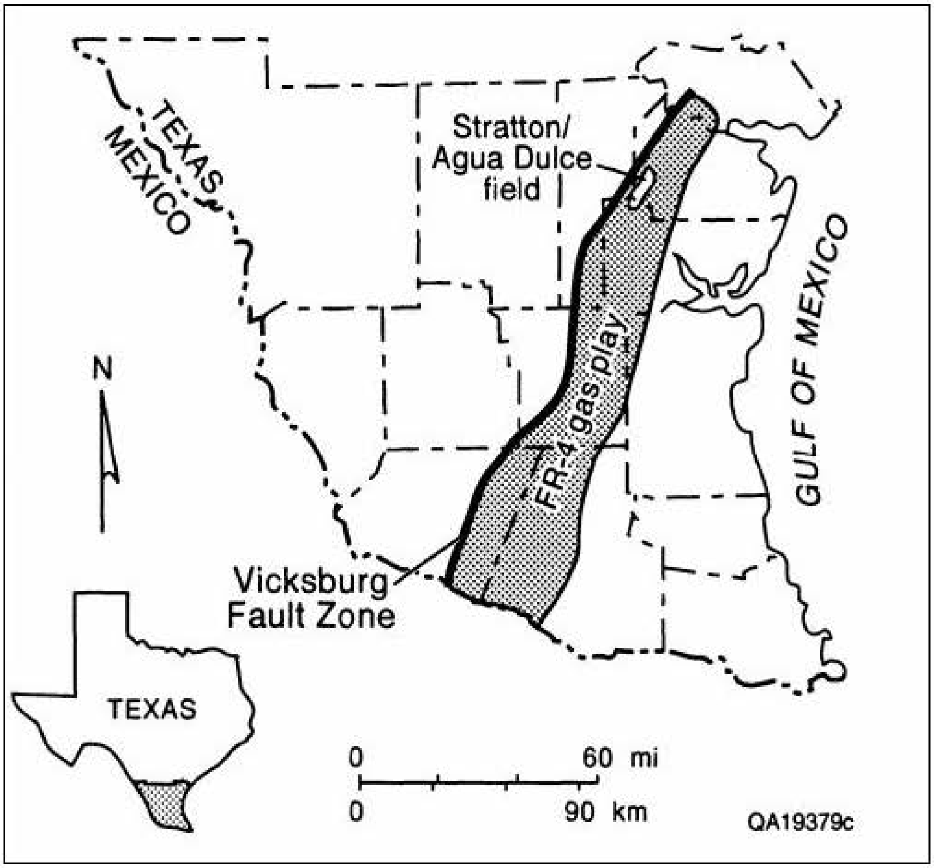


Figure 2: Stratton Field location within the FR-4 gas play (Hardage, et al., 1994)

The Stratton field produces from the Oligocene Frio formation, where the reservoir facies are characterized as splay sandstone and multiple amalgamated fluvial channel-fill. The dataset obtained for the Stratton field reservoir contains 3D seismic and well logs. The 3D seismic data, shot using vibrators, comprises 100 inlines and 200 crosslines at a sample rate of 2 ms. Concerning the well logs, a total of twenty one wells were drilled in the field. Of those drilled wells, only seven wells are usable for the purpose of this thesis; the remaining wells having limited log suites and/or only logged at sections of non-interest (Bureau of Economic Geology, 1994).

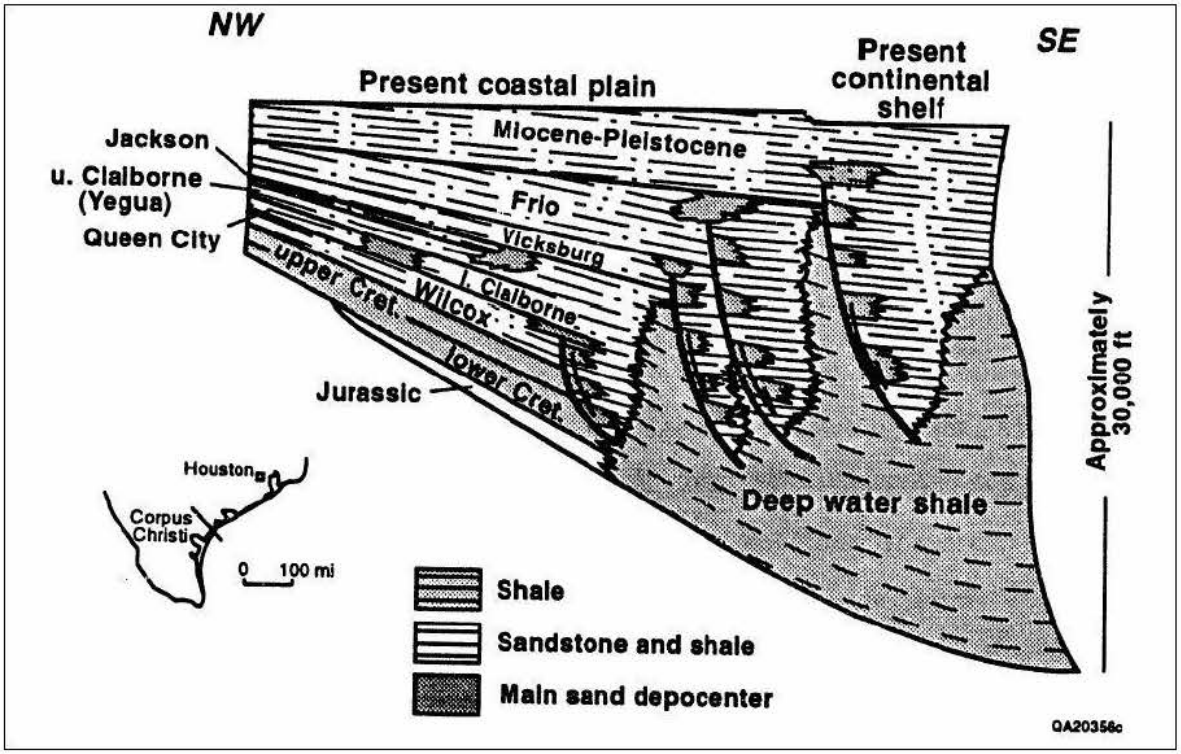


Figure 3: Formations and facies in the Stratton Field

B. OpendTect

For this thesis, OpendTect, an open source seismic interpretation software obtained under an academic license will be used along with the Stratton Field data. Following is a brief description of the OpendTect steps used in the computation of the results of this thesis. First, 3D seismic data is imported to OpendTect. After that, the well log containing the acoustic impedance values (acoustic impedance being the product of the layer velocity and the density) is imported to OpendTect. Horizons, representing the same geological layer in the subsurface are then constructed. Combining the three input parameters discussed above, the OpendTect software is then able to tie seismic data with the well and generate an acoustic impedance model covering the entire reservoir. This single generated realization is a deterministic realization, yielding only one set of acoustic impedance values for the reservoir.

Taking the results of the deterministic realization and adding to them a 2D error grid that provides a geostatistical standard deviation map based on the well location allows for the stochastic inversion (inferring acoustic impedance from seismic data) of the model. The impedance realizations obtained from the stochastic model allow the user to obtain many realizations of the same reservoir properties, thus quantifying uncertainties related to acoustic impedance.

Once the stochastic impedance model is in place, the OpendTect software and the MPSI Plugin allow the user to obtain the P10, P50 and P90 distribution also referred to as a volumetric probability map, displaying the 10% probability, the 50% probability and the 90% probability of recovering more than a specified volume (Earthworks Environment and Resources Ltd, 2010). In other terms, P10 means that there is 10% chance of finding the specified volume of hydrocarbons or more. Similarly, P90 means that there is 90% chance of finding the specified volume of hydrocarbons or more. Consequently, the P90 volume of hydrocarbons to be recovered is smaller and more accurate than the P10 volume of hydrocarbons. The use of this distribution allows companies to know with a certain level of confidence the amount of hydrocarbons that is expected to be produced, leading to an economic valuation of the field (Knox, 2003). Beside the probabilistic distribution of hydrocarbons in the field, OpendTect also generates the standard deviation maps for each stochastic run.

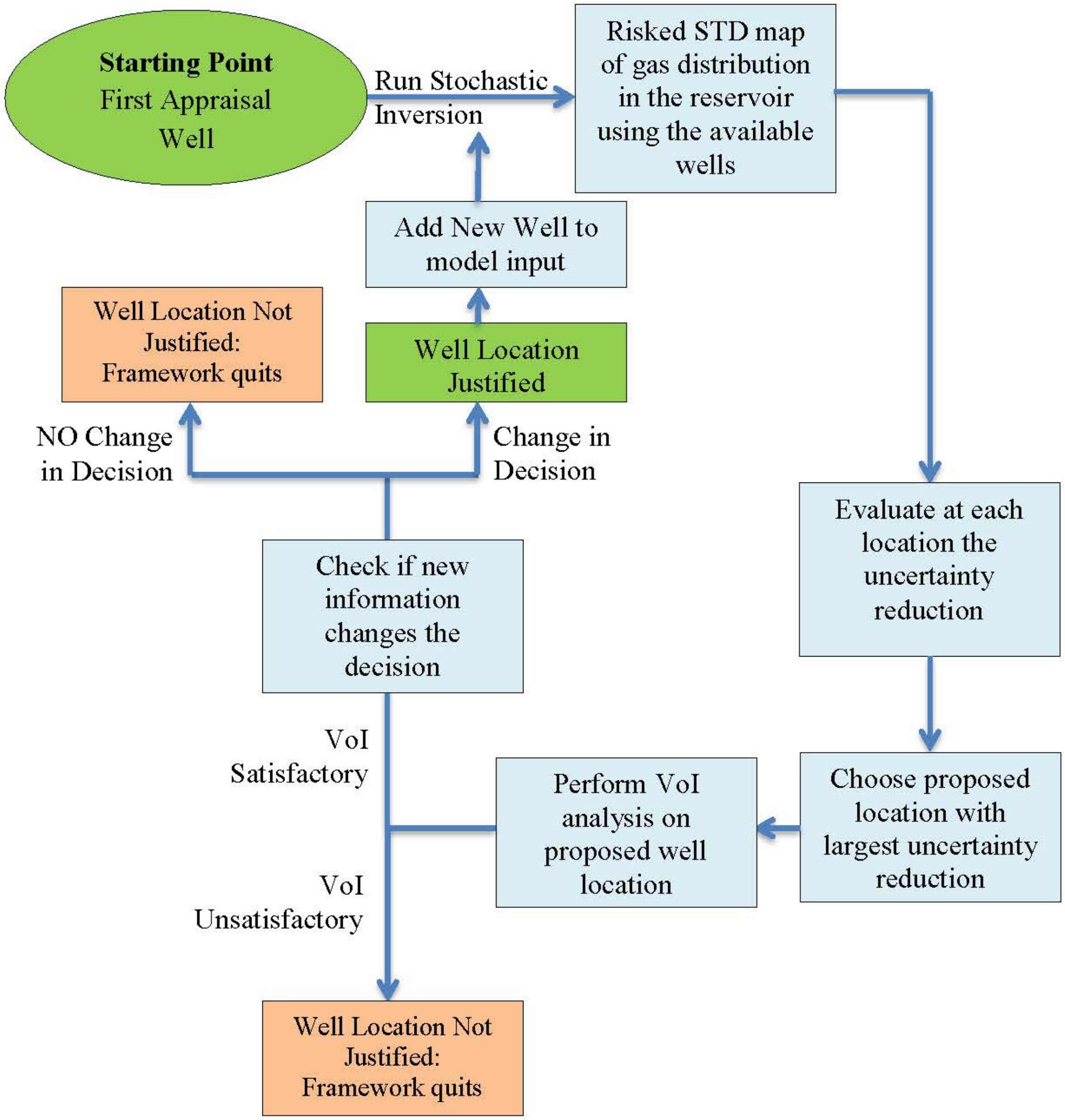
C. Framework

The framework proposed in this thesis first locates the best appraisal well location through the uncertainty reduction method and then analyses this location through the Value of Information (VoI) technique. Below is a brief description of the framework followed by a detailed description of the framework's parameters in Chapter. 4 and Chapter. 5.

By combining the uncertainty reduction method and the VoI method, this framework allows locating the next well location and justifying the drilling of this location. Using the first drilled appraisal well as the starting point, the best well is located (well that provides the most risked standard deviation reduction) and then evaluated according to the value of information it provides.

In case of satisfactory VoI, the new information is then checked for the ability to change the decision; i.e. the new information is worthwhile if it holds the ability of changing the decision that would be undertaken without further information. In case the new information leads to a change in decision, then the well is justified and is added as a new input for the next run. In case the well is not justified, the framework quits.

The framework proceeds with the same rules until a well with unsatisfactory VoI is reached and the framework quits. Eventually, this framework will allow the user to obtain the location, the number and the sequence of appraisal wells to be drilled by maximizing uncertainty reduction and minimizing costs; a novel framework that combines two techniques timidly discussed in the literature. An illustration of the general framework is displayed in Figure. 4, while the framework used with the Stratton Field model output is displayed in Chapter. 6.



VoI: Value of information

STD: Standard Deviation

Figure 4: Sequential Appraisal Well Location Framework

CHAPTER IV

UNCERTAINTY REDUCTION METHOD

A. Importance of Appraisal in Quantifying E&P Cycle Uncertainties

Many sources of uncertainties prohibit the determination of an exact understanding of the quantities of resources available at the early stages of the E&P cycle. Those uncertainties include but are not limited to: uncertainties in the seismic data, uncertainties about the reservoir fluid and petrophysical properties, uncertainties in the measurements and uncertainties in the well-to-seismic ties.

Although seismic data covers the entire reservoir giving a good representation of the geological boundaries, the resolution of seismic data is coarser than the internal heterogeneities thus subjecting the seismic processing and interpretation to errors. Petrophysical properties mainly include porosity (that is controlled by the depositional environment and the diagenesis of the rock), hydrocarbon saturation (chiefly controlled by reservoir quality and capillary pressures) and formation volume factor (dependent on the fluid type and the reservoir pressure and temperature) (Jahn, 1998). Concerning reservoir fluid and petrophysical property measurements, even the presence of wells and logs does not guarantee accurate results since the transformation from the measurement scale to the scale used in models is not mastered yet and because the well tests cannot capture the real heterogeneity present in the reservoir (Da Cruz, 2000).

Because the abovementioned uncertainties can be best investigated and quantified in the appraisal stage, it is thus vital to appraise in order to maximize project profitability (Haskett, 2003).

B. Goal of the Appraisal Stage

The goal of field appraisal is to reduce the uncertainty in the description of the hydrocarbon reservoir (Jahn, 1998; Haskett, 2003). Those appraisal activities will increase the knowledge of the reservoir properties and interconnections leading to a reduction in the risks associated with field development; such as opportunity loss, non-commercial development and sub-optimal development (Demirmen, 1996)

After gathering information from the first appraisal well drilled, many possible options are available to the decision makers (Cook, et al., 2008):

- Directly proceed with the development of the field with no further appraisal. This step is risky since the uncertainties are still high and not mitigated.
- Appraise more in order to understand the reservoir in more details leading to maximization of profitability on the long run.
- Sell the discovery which is the case of some companies who only invest in a hydrocarbon reservoir to sell it later and make profits out of it.
- Do Nothing

It is important to note that the reason for appraisal is to reduce uncertainties in an effort to better understand the reservoir. Proving additional resources (i.e. the appraisal stage will add an additional number of oil barrels) is not a reason in itself to undertake appraisal activities; and it is usually a by-product of an appraisal effort (Demirmen, 1996; Jahn, 1998).

C. Economic Constraints and the Need to Optimize the Appraisal Stage

Ideally, drilling a large number of appraisal wells will help reduce uncertainties and increase the knowledge about the reservoir. However, those wells do not come with a cheap price tag. The average cost of drilling an onshore well varies between $2 Million and $5 Million and between $10 Million and $50 Million for offshore wells and it can reach up to $100 Million for extreme climates and hard to reach areas (Center for Economics and Management, 2007). With many new exploration and discoveries tending to be in hostile and deep offshore environments, an efficient appraisal process that will maintain upstream profitability cannot be overemphasized (Demirmen, 1996). It is therefore an important task to optimize on the appraisal stage, in an effort to mitigate risk at the cheapest cost, thus maximizing overall project profitability.

D. Expressing Uncertainties

As previously stated, the aim of the appraisal stage is to reduce uncertainty concerning field development. The field development phase depends on the estimation of volumetrics in the reservoir and the range of uncertainties linked with this estimation.

The objective of volumetric estimation of a field is to determine the amount of oil and gas present in an accumulation. It is important to note that every volumetric estimation is only valid for the current situation (stable pressure and temperature conditions in the reservoir). As the production phase starts, pressure and temperature conditions change and with the addition of new information, a new and more accurate estimation of the volumes in place can be calculated (Cook, et al., 2008).

Two methods exist for volumetric estimation: deterministic approaches and probabilistic approaches. Deterministic approaches, also known as best estimate approaches, generate a single model of the volumetrics in place. This single model represents the average value of the properties of the reservoir collected from well logs and seismic-to-well ties (Earth Works, 2006). Because of the single model that is outputted using the deterministic approach, uncertainties cannot be assessed. This problem is solved by using probabilistic approaches. Those methods generate several equiprobable realizations of the volumetrics in a field, allowing the user to obtain both the mean value of the volumetrics (which theoretically and practically is the same using both methods) and the range of plausible values and their rate of occurrence (Alves, et al., 2014). It is important to note that probabilistic methods do not introduce new information; they only serve to bring clarity of the quoted quantities of oil and gas (O&G) by assigning a certain level of certainty to those quantities (SPE, 2001).

The average value of the volumetrics and the other plausible values with their related rate of occurrence may be expressed in the form of a probability density function (PDF). The PDF, which is a famous method of expressing uncertainty, describes the relative likelihood of a random variable to take on a given value. In general, the PDF is constructed by collecting the data about the population and plotting the frequency of occurrences of each value versus the value (Cook, et al., 2008). When the collected data is continuous, the histogram ranges become infinitesimal and the PDF is said to be a continuous PDF. To calculate the probability of the random variable X falling between two values of interest, A and B, the following formula is used, where $f(x)$ is the continous PDF. :

$$P(A \leq X \leq B) = \int_{A}^{B} f(x)dx$$

In the O&G industry, it is common practice to use the expectation curve to express the range of uncertainties rather than the PDF. The expectation curve, also known as the probability of exceedance curve or the reverse cumulative probability curve is linked to the PDF in a simple way. The expectation curve is calculated from the cumulative distribution function (CDF). The CDF represents the probability of the variable X to take a value less than or equal to B. For a continuous distribution of a random variable X (as is the case in the volumetrics estimation), the CDF $F(X)$ records the accumulated probability of the random variable X up to the value of interest B and has the following formula (The Pennsylvania State University, 2015):

$$F(x) = P(X \leq B) = \int_{-\infty}^{B} f(x)dx$$

The expectation curve, known in the statistics field as a survival function (complement to the CDF), is given by the formula of (U.S. Department of Commerce, 2012):

$$S(x) = 1 - F(x)$$

The following figure represents the transformation from the PDF to the expectation curve:

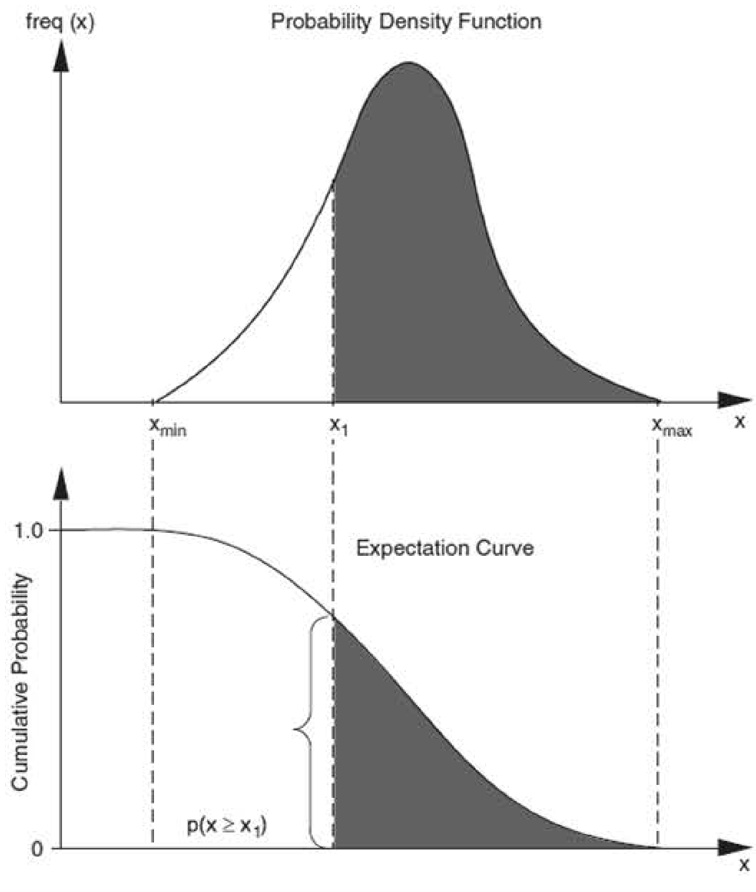


Figure 5: Transition from PDF to Expectation Curve

E. Reserves Uncertainty Categories

When probabilistic methods have been applied to evaluate the volumetrics of the reservoir resources, uncertainty categories are used to associate probabilities to each of the resource levels. Universally, the industry has adopted three standard categories to describe resources: Low estimate, Best estimate and High estimate. The Low estimate category corresponds to the proved resources (1P) and has a P90 probability associated to it; meaning that there is at least a 90% probability that the estimated resources will equal or exceed the Low estimate. The Best estimate category corresponds to the proven + probable resources (2P) and has a P50 probability associated to it; meaning that there is at least a 50% probability that the estimated resources will equal or exceed the Best estimate. The High estimate category corresponds to the proven + probable + possible resources (3P) and has a P10 probability associated to it; meaning that there is at least a 10% probability that the estimated resources will equal or exceed the High estimate (SPE, 2001). The use of this distribution allows companies to know with a certain level of confidence the amount of hydrocarbons that is expected to be produced, leading to an economic valuation of the field (Knox, 2003). Table. 1 and Figure. 6 below summarize the different resource scenarios and their uncertainties.

Table 1: Resource Uncertainty Categories

Resource Uncertainty Category	Scenario	Associated Probability
LOW ESTIMATE	Proved (1P)	P90
BEST ESTIMATE	Proved + Probable (2P)	P50
HIGH ESTIMATE	Proved + Probable + Possible (3P)	P10

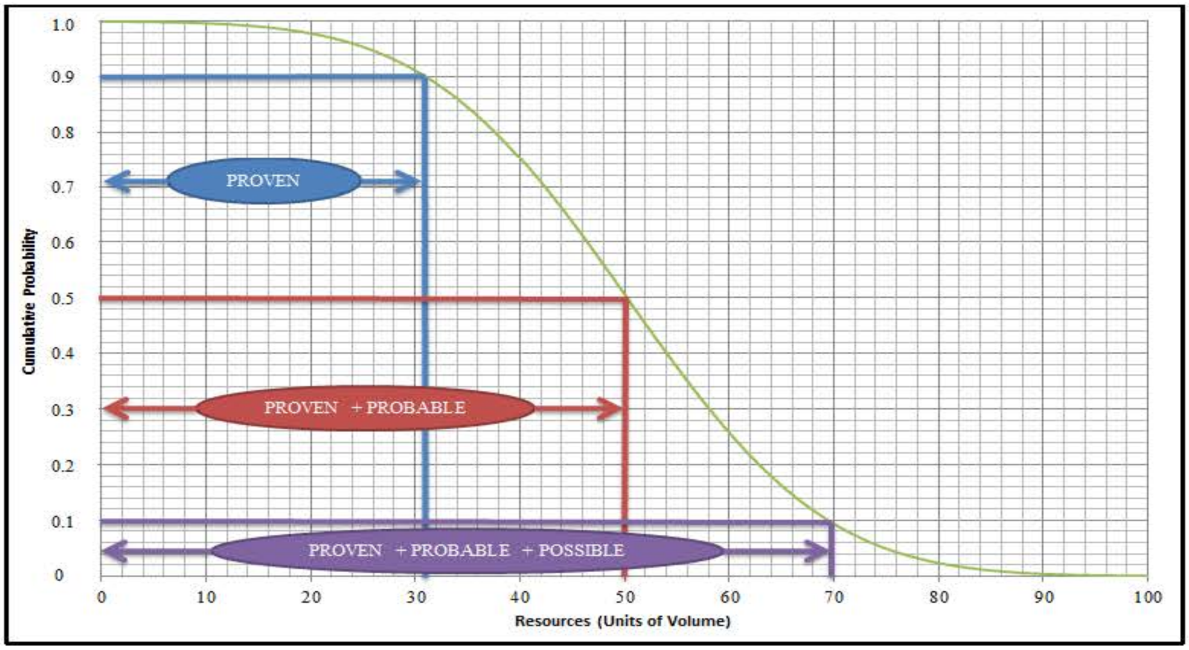


Figure 6: Expectation Curve with Resource Uncertainty Categories

As previously stated, the main goal of an appraisal program is not to add resources but to reduce uncertainty in the reservoir. The priority of appraisal activities should be determined based on the amount of reduction of uncertainty that it can provide (Jahn, 1998). Figure. 7 represents the expectation curves for four different cases of reservoirs. The purple curve represents a poorly defined reservoir with a broad range of resources in place;

most probably this reservoir will require more appraisal. On the opposite side of the spectrum, the blue curve represents a well-defined reservoir since the range of uncertainty in the resources is small. This range of uncertainty is also defined as the standard deviation (STD) of the expectation curve. The STD is calculated using the difference between P10 and P90 resources values. Therefore, curves with a lower standard deviation means that the discovery is well-defined (uncertainties are low) and appraisal activities may no longer be required. Each of these curves can be re-generated once additional information (obtained from drilling new appraisal wells or re-entry to a well) is collected. Because the ultimate aim of an appraisal program is to reduce uncertainties, the main concern is thus to determine the sequence of drilling that will reduce the most the standard deviation for the expectation curve of the resources in place. Simply put, the goal is to move from the purple curve (high uncertainty characterized by a high STD) to the blue curve (low uncertainty characterized by a low STD) by optimizing the drilling sequence of appraisal wells (Cook, et al., 2008).

As a side note, one can notice that although in the purple-curve-reservoir there are more resources in place, the blue-curve-reservoir is the favored one since it provides more certain representations of the resources in place.

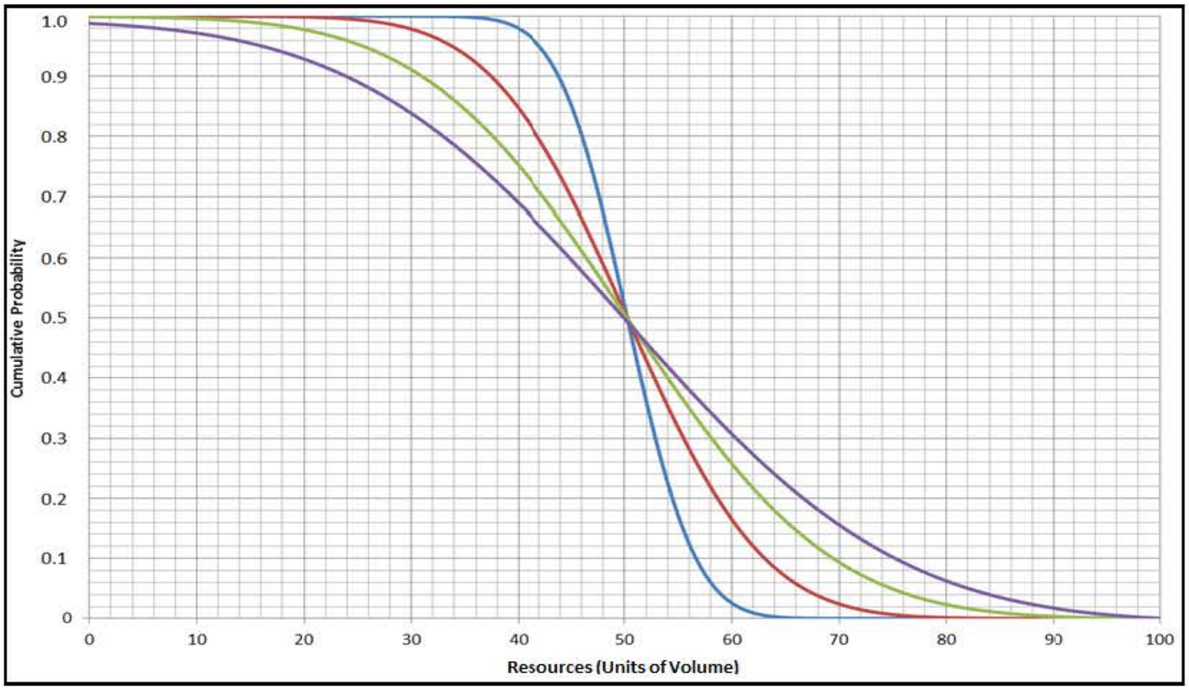


Figure 7: Expectation Curves with varying standard deviations

F. Measuring Uncertainties

The OpendTect software will be used to obtain the probabilistic distribution (P90, P50 and P10) and the STD of the net depth of the hydrocarbon column (henceforth, all the maps and figures will be a display of the net depth of the hydrocarbon column). In particular, the MPSI plugin developed by Earthworks that includes both deterministic and stochastic inversion will be used to calculate the uncertainties needed for reservoir management (Earth Works, 2010). Using this plugin and building on the first drilled well, the OpendTect software will output a stochastic inversion of the reservoir showing the net volume of hydrocarbons at each point.

This stochastic inversion is based on the use of both seismic data collected over the entire reservoir and the first drilled well. The software will first conduct a well-to-seismic-tie, which is a procedure that correlates the seismic data (measured in units of time) with the well data (measured in units of depth). This will lead to associating specific reflections on the horizon top (obtained using seismic data) with specific layers of the reservoir (obtained using well data) (Earth Works, 2010). The more wells available for the well-to-seismic-tie, the better the correlation between wells and seismic data; thus the better understanding of the whole reservoir (Schroeder, 2006).

When the first stochastic inversion is initiated, the results will be based on seismic data tied to only one well. The software will output a P90, a P50, a P10 and a STD map. Those maps will allow the user to determine the Low Estimates (P90 reserves), the Best Estimate (P50 reserves) and the High Estimates (P10 reserves) and will allow a visualization of the locations where the STD is the highest (Earth Works, 2010).

The MPSI plugin used to generate the stochastic inversion results uses the fastest stochastic inversion scheme currently available in the market. The scheme is based on the Fast Fourier Transform (FFT) method that generates stochastic realizations in the frequency domain based on a random seed number. Simply stated, the FFT decomposes the seismic wave into the frequencies that makes up the wave. Based on those frequencies, the geological layers of the hydrocarbon reservoir can be reconstructed and thus a geological model of the reservoir can be built.

Prior to initiating the stochastic inversion process, the impedance values at the well locations undergo a transformation process. This transformation process changes the impedance values from their natural PDF to a standard normal (Gaussian) PDF by using a normal score transform. Once the values are transformed, the stochastic inversion process is initiated in the frequency domain.

Building on that data, the user will then move to select a second well (based on criteria that will be discussed later). Once the second well is chosen, the software now will make use of this additional well in two ways: first, this well will enhance the well-to-seismic-tie for the entire reservoir. Second, this well will be used in combination with the first well to provide a more accurate understanding of the reservoir by means of Kriging (spatial interpolation previously discussed) (Earth Works, 2010). However, it is crucial to note that the use of the Kriging approach does not hold true for all locations of the second well, since Kriging takes into consideration the spatial variation between the two wells and by that, if the second well is far from the first well (outside of the variogram range), then the properties of the two wells are independent and there is no spatial variation function that can describe the relationship between the two wells (Shibli, 2003). The additional value of the second well is thus restricted to providing a better well-to-seismic-tie.

To conclude on that, using the first drilled well, the software will output the P90, the P50, the P10 and the STD map. Using the second well, the software will automatically recalculate and enhance the well-to-seismic-tie for the whole reservoir and will add the understanding gained from Kriging if the well location allows for a proper spatial variation function.

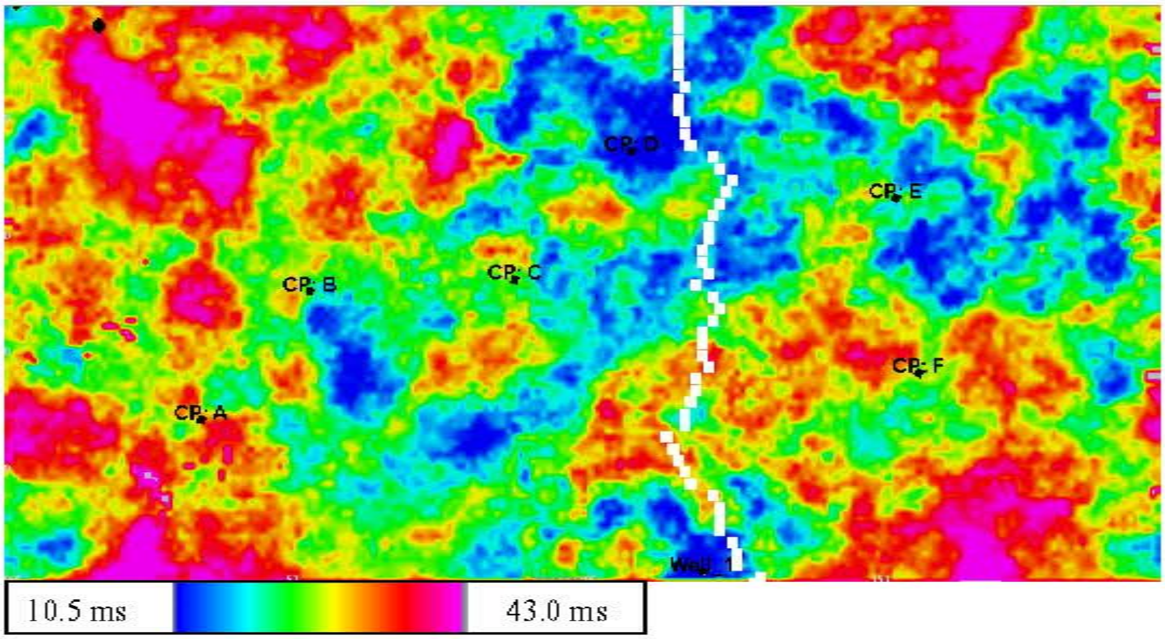


Figure 8: STD map using Well_1

The STD map above (Figure. 8) is extracted from OpendTect software using the MPSI Plugin applied on the Stratton Field dataset. This map, which corresponds to the first stage of the simulation (generating a stochastic simulation with only one well, which is Well_1 in our case located at the South of the reservoir) shows the distribution of the STD across the reservoir. As the scale shows, the blue regions represent zones where the STD is in the vicinity of 10.5 milliseconds (ms) (low range) thus the uncertainty in those zones is relatively low. On the other hand, mauve regions correspond to zones with high STD in the vicinity of 43.0 ms, meaning that high uncertainties still remain in these areas.

Upon analysis of the map and the scale, one should make two main observations: first, the scale of the map is from 10.5 ms to 43.0 ms and the reason that the values are displayed in units of time rather than the reasonable display in unit of depth (since the map represents the net depth of the hydrocarbon column) is because seismic data is used to generate those maps and seismic data is recorded in time and not depth as previously mentioned. The second and important observation is the presence of blue patches (low STD) away from Well_1. This presence means that those locations exhibit similar geological layers encountered around Well_1; the same geological layers with the same signature that was used to calibrate the well-to-seismic-tie in Well_1.

G. Justifying Appraisal Locations

The previous sections emphasized on the need to appraise and to choose a well location that will maximize the uncertainty reduction. However, no method was given on how to prioritize appraisal well locations based on the maximum uncertainty that they can reduce. For the exception of one paper, the literature has overlooked this topic so far. For this reason, this section will heavily rely on the concepts for appraisal well justification developed by Haskett in 2003.

Those concepts will be clarified in the following simplified scenario. In this situation, one well is already drilled and the second well is to be located and justified. The example below shows the first drilled well (the star shape) and four possible locations for the next well (locations: A, B, C and D) distributed on four step-outs (radii of four different colors). The number displayed near the letters A, B, C and D corresponds to the STD at that location and is in units of ms.

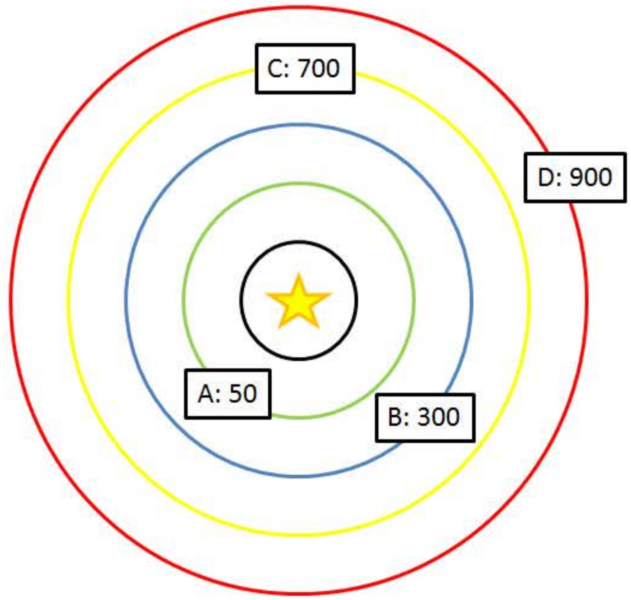


Figure 9: Location of Drilled Well and STD of four different locations

At first glance and based solely on the information in the previous sections, a good choice for well two is logically location D since drilling a well at that location could help reduce the reservoir uncertainty by 900 ms. However, this method does not account for the probability of success (POS) that can be encountered at each step-out (Haskett, 2003). Because it is riskier to drill in locations that are distant from the control well than to drill in locations that are in the vicinity of the control well, a value labeling the riskiness of the situation should be calculated; this value is the POS. The figure below shows for the same scenario and for the same step-outs, the POS associated with each radius. The shown POS are calculated based on the initial reservoir extent, with the farther step-out corresponding to a POS of 0% and the closest step-out corresponding to a POS of 100% (Haskett, 2003; Dikkers, 1985).

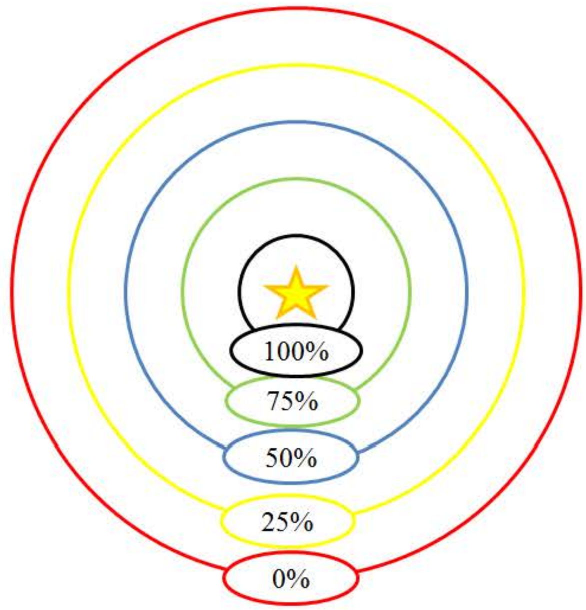


Figure 10: Location of Drilled Well and POS of five different step-outs

Taking into consideration the POS of each step-out, a more informed decision can thus be made concerning the next well location. This well location to be drilled is now the location that will provide the most risked uncertainty reduction, meaning the location that has the biggest value of $POS \times STD$ reduction. The figure below shows for the same example, the $POS \times STD$ reduction map.

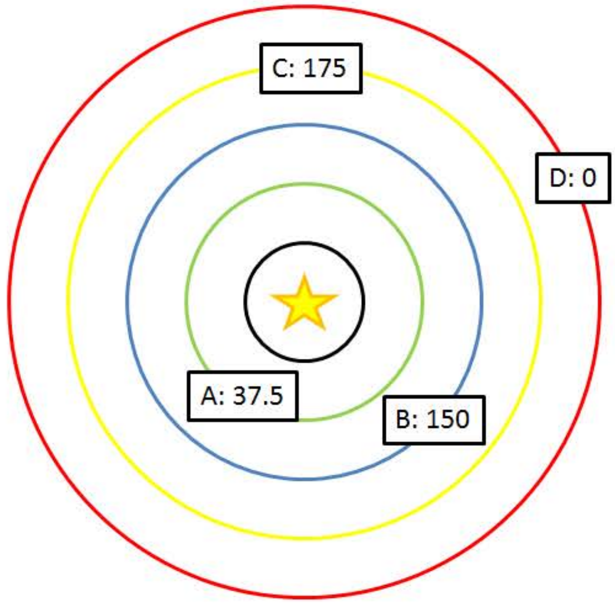


Figure 11: Location of Drilled Well and POS x STD of four different locations

One can notice that the new best well location is no longer Location D (based only on the biggest STD reduced) but is now Location C with the biggest $POS \times STD$ reduction.

CHAPTER V

THE VALUE OF INFORMATION METHOD

A. A Brief History of Decision Making

Decision making (DM) is the process of making a choice among possible alternatives based on the standards and preferences of the decision maker (Harris, 2012). The goal of DM is to provide a methodical process where opaque problems are converted into transparent decision problems using a series of transparent steps (Howard, 1988).

While contemporary decision making and decision analysis started in the late 1960s, the early days of DM date back to the renaissance period, when Girolamo Cardano, a scientist and mathematician, pondered about probability in games of chance. During the 17th century, Blaise Pascal and Pierre de Fermat developed a method to determine the likelihood of each likely result in a simple game. But it wasn't until 1738 that Daniel Bernoulli started the study of random events, which is considered now as the foundation for DM and risk management. Nowadays, decision making covers a broad range of intellectual disciplines, including mathematics, economics, political science and sociology to name a few (Buchanan, et al., 2006; Bickel, et al., 2008).

Regardless of the intellectual discipline where decision making is applied, approaches of DM were developed and the seven-step approach discussed subsequently is the most inclusive approach in the DM space. The seven self-explanatory steps are the following: 1) identifying the decision to be made, 2) gathering the required information, 3) identifying the alternatives, 4) weighing the evidence, 5) choosing from alternatives, 6) taking action and 7) reviewing the decision. Once those steps are followed, the decision maker can make the best decision in his context (University of Massachusetts Dartmouth, 2015).

In order to have a systematic approach of gathering the required information, identifying the alternatives, weighing the evidence and choosing from alternatives (Steps 2 to 5 of the seven-step approach), the decision maker relies on the use of decision tools. Over the years, many decision tools were developed (many of which are overlapping in description), the most important being described in Table.2 below (Brooks, 2014):

Table 2: Decision making tools and their description

Decision Making Tool	Description
Decision Matrix	Options (rows) and factors (columns) are considered in this approach. The decision maker scores each option/factor combination, then weighs the importance of this combination and finally adds up the scores of each combination to determine the best one.
T-Chart	The decision maker assigns weighted plus and minus signs (pros and cons respectively) to all alternatives to ensure that all the positive and negative aspects of the alternatives are taken into consideration.
Decision Tree	Uses nodes and branches to display the different alternatives and their associated probabilities of occurrence. Flipping the tree (calculating the values) allows the decision maker to know which path on the tree

	maximizes his utility.
Multivoting	Narrows a large list of options to a smaller list of options. It is most useful when many decision makers influence the decision.
Pareto Analysis	This technique is used when a big number of decisions need to be made. Pareto Analysis will prioritize the decision by determining which ones will have the highest overall impact.
Cost-Benefit	Each alternative is weighted based on its financial merit, leading to a final decision that has the greatest economic impact.
Conjoint Analysis	A method that uses statistical means to determine how users evaluate different attributes that leads to establishing consumer preferences and thus to making decisions.

B. Decision Making in the Oil and Gas Industry

Every year, decisions in the O&G industry determine the course of billions of dollars. Those decisions can range from a simple drill or no drill decision to more complex ones involving prioritizing exploration opportunities (Coopersmith, et al., 2000). With so much money at stake, evaluating uncertainties, mitigating risks and choosing workable solutions is a priority on every decision maker's agenda.

Between the different E&P stages, the appraisal stage constitutes the biggest setting for reducing uncertainties. It is in that stage where making the right decisions can make the differences between a profitable and non-profitable project. In 1996, the industry spent around US$ 1 billion on subsurface appraisal (in 1996 Dollars) but despite the amount of money spent on appraisal activities, less resources and less time are spent assessing the quality of this information (Demirmen,1996; Cunningham, et al., 2008; Bratvold, et al., 2009). As previously mentioned many tools can be used by the decision maker to aid his decisions; of particular interest is the decision tree analysis. Once the problem is identified, decision trees help the decision maker to find the best path to the most valuable solution.

In more details, decision trees are figures that depicts the flow of a decision making process as a series of events and likely outcomes (Coopersmith, et al., 2000). The nodes (or points) represent the events and the branches represent the outcomes issuing from each node. Two types of nodes are present: either decision nodes (represented by squares in the decision tree) where the decision maker decides what branch to choose or chance nodes (represented by circles in the decision tree) where probabilities rule the outcome. With each branch, an expected monetary value is associated, which is then weighted by the probability of that outcome to occur.

Figure. 12 below depicts a decision tree. As one can notice, the decision maker can either choose to appraise or not to appraise (how to make the decision will be discussed later). If he chooses to appraise, two branches are present: either success of the appraisal or failure of the appraisal. Success of the appraisal will lead to an expected monetary value of $Exp(NPVs)$ (expectation net present value of success) and failure of the appraisal will lead to an expected monetary value of $Exp(NPVf)$ (expectation net present value of failure). If the decision maker chooses not to appraise, then only one branch is present thus one outcome and expected monetary value of $Exp(NPV)$ (expectation net present value of doing nothing) is present.

The literature clearly distinguishes between two types of decision trees: decision tree with perfect information and decision tree with imperfect information. Perfect information means that the test is 100% reliable whereas having imperfect information means that the test should be assessed for its reliability and the decision tree should account for that reliability. In this thesis, the reliability is accounted for by the joint use of the probability of success and the expected net present values calculated using probability-based values rather than deterministic values.

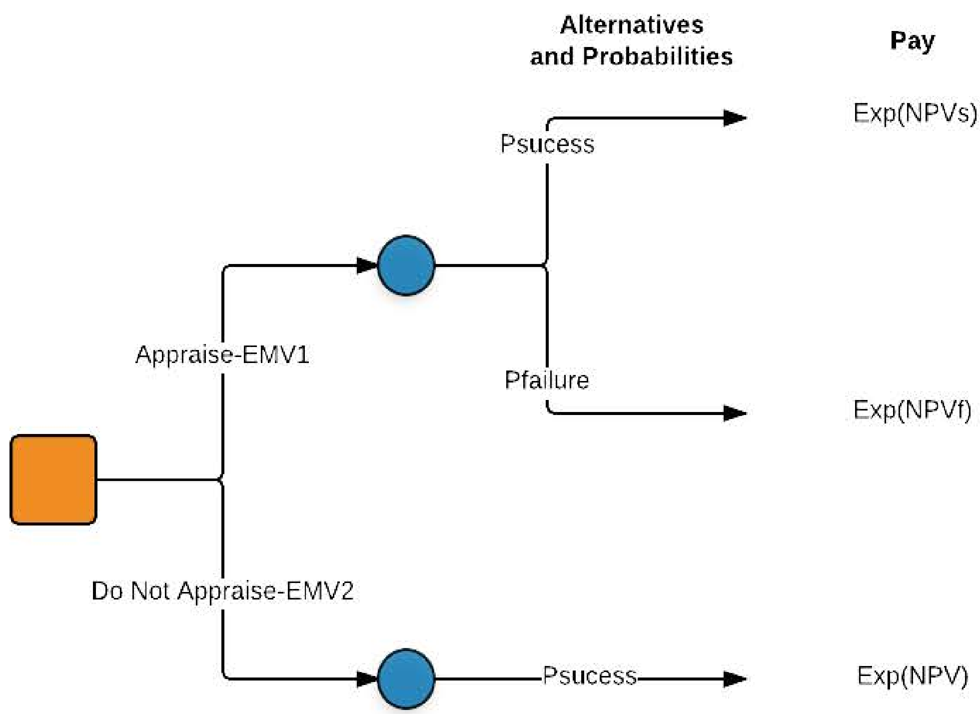


Figure 12: Decision Tree with Appraise and Do Not Appraise Branches.

Before delving into the calculation procedure involved in the tree, the steps involved in determining the input to the tree, essentially $Exp(NPV), Exp(NPVs)$, $Exp(NPVf), P_{sucess}$and $P_{failure}$ will be explained.

- In the case of appraisal activities, the Exp (NPV) can be calculated as (Demirmen, 1996):

$$Exp(NPV) = \frac{NPV_L + NPV_M + NPV_H}{3}$$

Where NPV_L represents the Low Estimate Net Present Value (NPV) corresponding to the P_90 NPV estimate, the NPV_M represents the Medium or Best Estimate NPV corresponding to the P_50 NPV estimate and the NPV_H represents the High Estimate NPV corresponding to the P_10 NPV estimate. It is critical to note that this notation is only valid when the given distribution is Gaussian, which is the case in this thesis.

- $Exp(NPVs)$ represents the Expectation Net Present Value for the P_{sucess} chance node and the "Appraise" decision; meaning the NPV that is expected if the drilled well is successful. The $Exp(NPVs)$ is equal to:

$$Exp(NPVs) = \text{Exp (NPV)} + Exp\ (NPVw) - Cost\ of\ Appraisal\ Well$$

Where Exp (NPV), as previously defined, represents the expectation NPV and is the same regardless if the appraisal well in question will be drilled or not. $Exp\ (NPVw)$ represents the additional expectation NPV that is likely to be gathered once the well is drilled, and is equal to P10 – P90 around the well. $Cost\ of\ Appraisal\ Well$ represents the cost in $ value of the appraisal well to be drilled.

- $Exp(NPVf)$ represents the Expectation Net Present Value for the $P_{failure}$ chance node and the "Appraise" decision; meaning the NPV that is expected if the drilled well is not successful. The $Exp(NPVf)$ is equal to:

$$Exp(NPVf) = \text{Exp (NPV)} - Cost\ of\ Appraisal\ Well$$

- $Exp(NPV)$ represents the Expectation Net Present Value for the P_{sucess} chance node and the "Do Not Appraise" decision. As can be seen in the decision tree, the $Exp(NPV)$ only has one probability and it is the probability of success and this means that not appraising will only yield $Exp(NPV)$with 100% probability.

- P_{sucess} is calculated from the POS maps generated and displayed in Chapter 4. $P_{failure}$ is equal to $1 - P_{sucess}$.

The next step in the decision tree is to calculate the monetary outcome of the decision nodes -a step also known as flipping the tree-, i.e. the monetary outcome behind the decision to appraise or not to appraise.

To determine the expected monetary value (EMV), the following formula is used (Dynamic Resources Corporation, 2001):

$$EMV = \sum_{i=1}^{n} p_i \times NPV_i$$

Where p_i represents the probability of occurrence of event i and NPV_i is the Net Present Value associated with event i.

In the case of the tree in figure. 13, the EMV values for appraising and not appraising are denoted as EMV1 and EMV2, respectively, and are calculated as follow:

$$EMV_1 = Exp(NPVs) \times P_{sucess} + Exp(NPVf) \times P_{failure}$$

$$EMV_2 = Exp(NPV) \times P_{sucess}$$

The tree in figure. 13 below represents the calculation process.

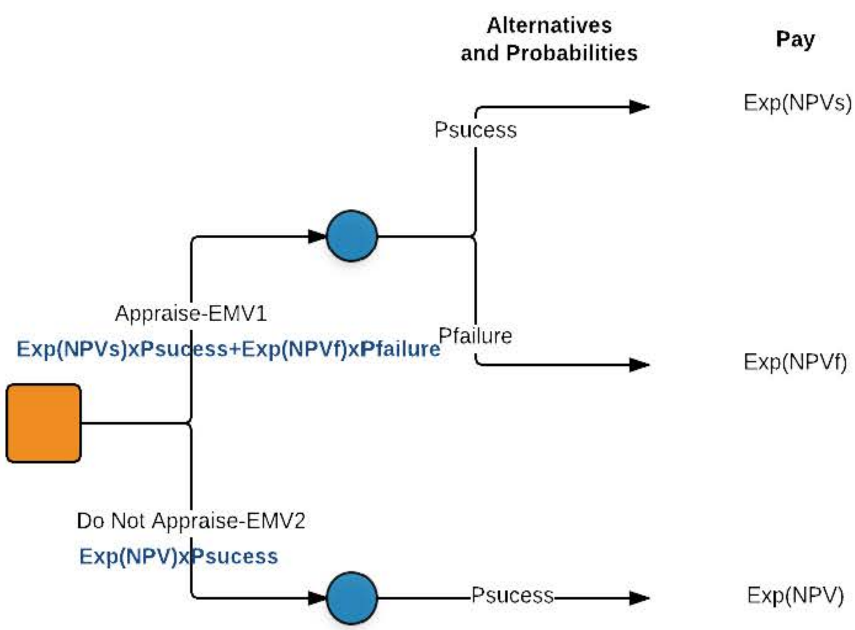


Figure 13: Flipped Decision Tree with Calculated EMV1 and EMV2.

Now that the decision maker has calculated the EMV of appraising and the EMV of not appraising, a method based on the flipped tree is used to evaluate the decision and to assign a dollar value on the quality of information, i.e. to economically evaluate the impact of adding a new well. This aforementioned method is known as the Value of Information (VoI) and is used to evaluate the impact of future learning of an activity before undertaking that activity. In other words, the VoI evaluates if the improvement in decision making stemming from the addition of the new well is worth more (or less) than the cost of drilling that well. The following equation illustrates the calculation involved in determining the VoI (Cunningham, et al., 2008):

$$VoI = Expected\ Value\ WITH\ additional\ information \\ - Expected\ Value\ WITHOUT\ additional\ information$$

In the case of the flipped decision tree in Figure. 13, the VoI is equal to:

$$VoI = EMV_1 - EMV_2$$

A positive VoI means that the additional information is beneficial to the project and should be collected.

On a side note, it is important to know that the decision tree and the VoI in particular assume that the decision maker is risk neutral, meaning the decision maker shows indifference between choices of equal expected outcome (Bratvold, et al., 2009).

CHAPTER VI

RESULTS AND DISCUSSION

This chapter summarizes the findings of this thesis. The first subsection includes the results of the uncertainty reduction method (detailed in Chapter 4). The second subsection focuses on the Value of Information analysis conducted on the chosen wells (detailed in Chapter 5). The last subsection illustrates and tests the framework using the methods and concepts of Chapter 4 and Chapter 5.

A. Uncertainty Reduction Method: Results

The uncertainty reduction method as described in details in Chapter 4 is tested on the Stratton Field Gas reservoir. Figure. 8 (previously shown in Chapter 4) displays the STD map for the Stratton Field building on one drilled well: Well_1.

Once the reservoir extremities are located (using the first drilled well and the seismic data), the POS maps can be generated. For the Stratton Field, a continuous mesh for the POS map is generated and displayed below.

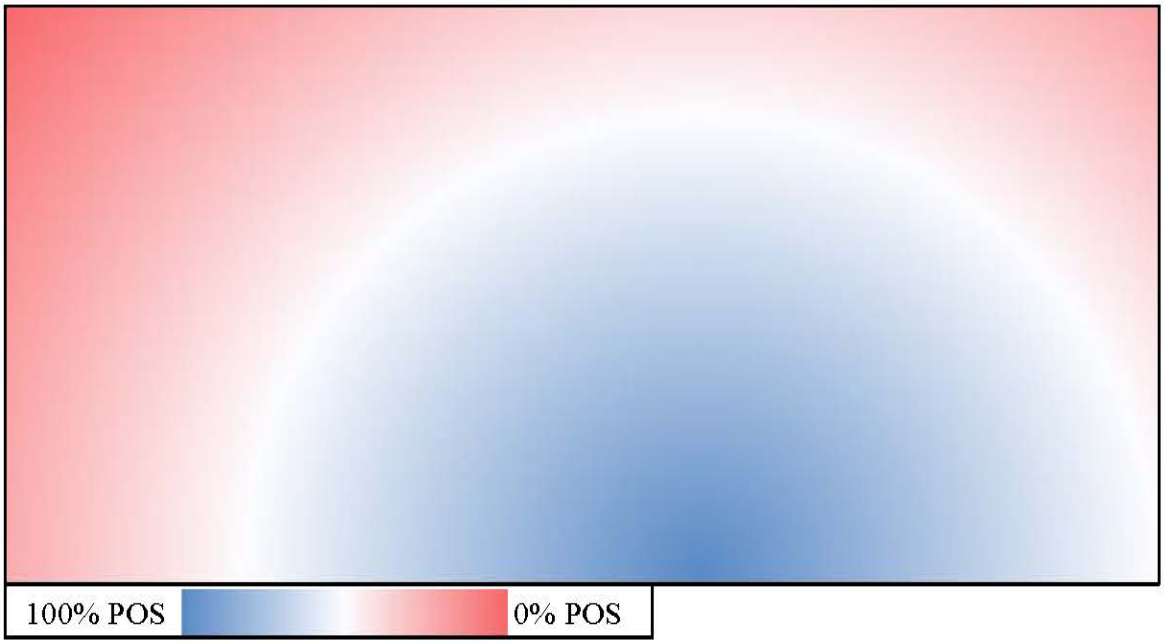


Figure 14: Continuous POS map for Well_1

Once the POS map and the STD map for Well_1 are generated, a combined map showing the $POS \times STD$ is generated and displayed below.

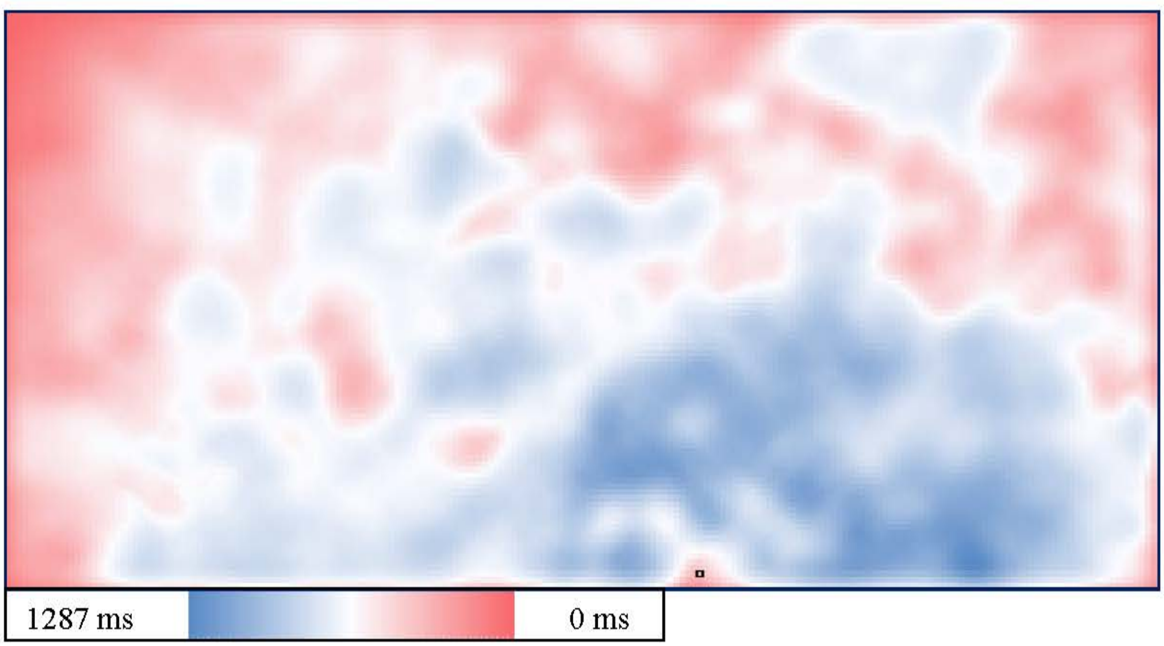


Figure 15: POS x STD map for Well_1

The $POS \times STD$ map is used to pinpoint the best and worse locations to drill the next appraisal well. The best locations correspond to the blue shaded locations and the worst areas correspond to the red shaded locations. One can notice that some location close to Well_1 are not good candidates for the next well location and this is due to the good well-to-seismic-tie at those locations; where the seismic data is able to predict with good accuracy the properties at that said location thus returning low $POS \times STD$ values.

In a real life scenario, the second well to be drilled will be in the location that displays the biggest $POS \times STD$ reduction. In this thesis however, since the Stratton Field is an actual field and not a model built for simulation purposes, there is no control data that is available for the entire reservoir; data is only available at six different locations. Having said that, for the sake of the thesis only, the second well location will be drilled in one out of the six available locations and this location will be chosen based on the biggest $POS \times STD$ reduction between the six competing control points (CP).

It is important to note that the six available control points cannot be increased by means of interpolation/extrapolation methods for two reasons: the first reason is due to the software interface that prohibits the user of virtually drilling a well in the reservoir. The second reason, regardless of the user interface in OpendTect, is due to the fact that choosing a location and determining the properties in that location using interpolation/extrapolation methods assumes that the whole area between the used control points and the location of interest is similar and heterogeneous which greatly contradicts the natural variability encountered in a hydrocarbon reservoir.

The below sections will illustrate the steps involved in determining the location of the next appraisal wells.

1. ***Searching for Well #2***

So far, only Well_1 has been drilled and the search for the location of the second well has started. The first step is to calculate the POS for the reservoir with Well_1 (Figure. 14). The next step is to obtain the STD map from OpendTect with Well_1 only in place (Figure. 8). Once those two steps are obtained, the third step is to multiply, position by position, the two maps to generate the $POS \times STD$ map that will be the key step in determining the best location for the next well. Figure. 16 below illustrates the $POS \times STD$ map for the Stratton Field Reservoir. Well_1 and the six available CP's are also shown. The total STD for the reservoir using Well_1 only is determined to be 512,000 ms. Table. 2 was compiled to rank the six control points present below.

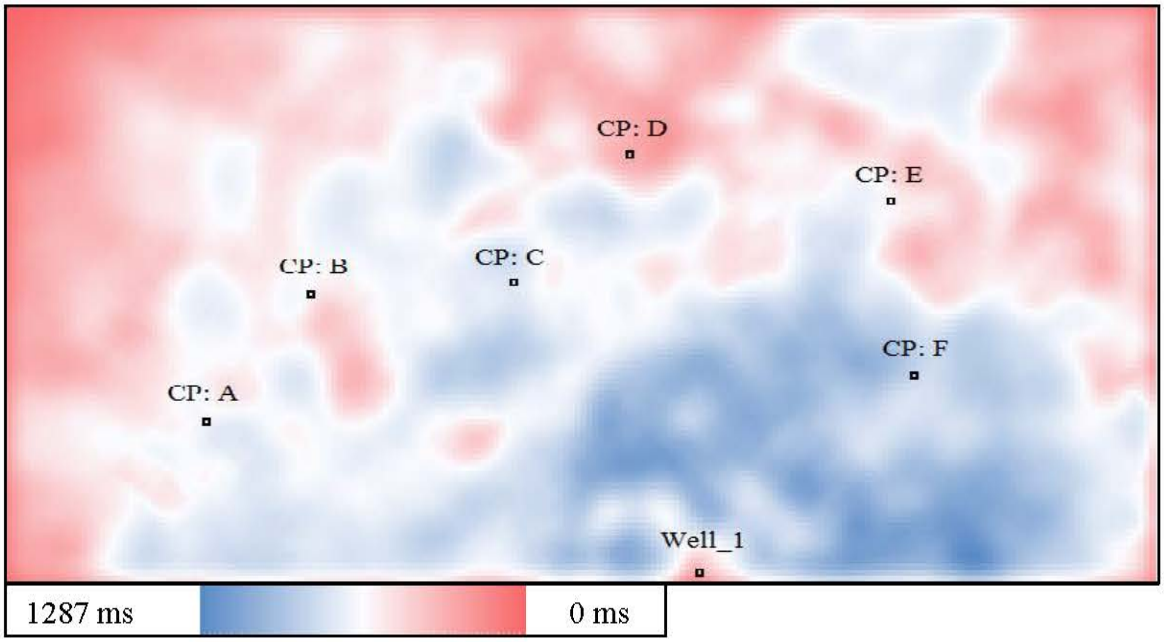


Figure 16: POS x STD map for Well_1 with location of the six control points.

Table 3: POS x STD values for six control points

	CP : A	CP : B	CP : C	CP : D	CP : E	CP : F
POS % (figure. 14)	44	48	64	55	55	70
STD ms (figure. 8)	2452	1885	1980	875	1670	2203
POS x STD ms (figure. 16)	1079	905	1267	481	919	1542
Comments on well location				Worst		Best

From the above table, it can be concluded that the best location to drill the second well is CP: F, having the biggest $POS \times STD$ value. The worse location to drill the well is determined to be CP: D, having the least $POS \times STD$ value.

CP: F will thus be drilled and now the model contains two drilled wells: Well_1 and CP: F and the search for the third location starts.

Since it was determined that the best location is CP: F and the worse is CP: D, two probabilistic maps were generated to test the choices. The results are displayed in the below table. Although adding CP: D will decrease the total STD in the reservoir, CP: F is better because of its ability to reduce more the STD. Table 3 displays the Total STD in milliseconds for three different runs. The software allows the user to obtain the STD values at each location and to export the results to an Excel file. Summing the STD at each location using Excel, the user can obtain the Total STD of the reservoir for each run.

Table 4: Total STD for Well_1 and one CP

Well Identification	Total STD (ms)
Well_1	512,000
Well_1 + CP: F	440,000
Well_1 + CP: D	480,000

Since the procedure for choosing any additional well is repetitive, the below subsections will only show the following figures and tables used to determine the best location of the n^{th} well:

- Map of the STD based on $n-1$ wells
- Continuous POS mesh for $n-1$ wells
- $POS \times STD$ values for the remaining control points

- Total STD for n wells.

A final subsection will also show the STD map based on Well_1 and the six CP's and the Total STD map for Well_1 and the six CP's.

2. *Searching for Well #3*

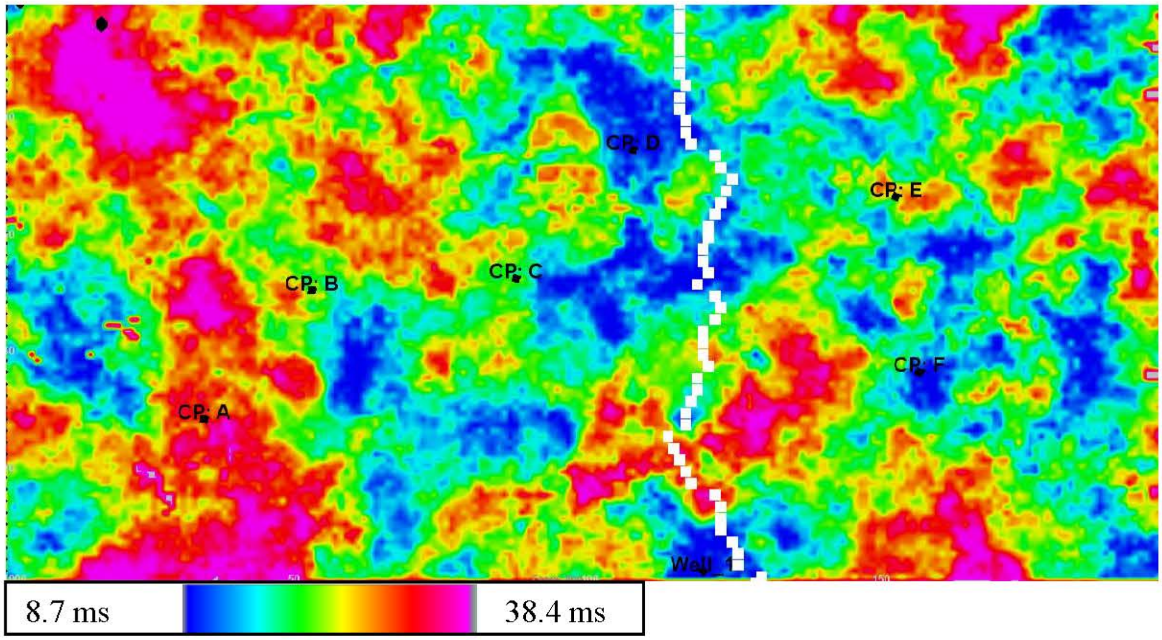


Figure 17: STD map using Well_1 and CP: F

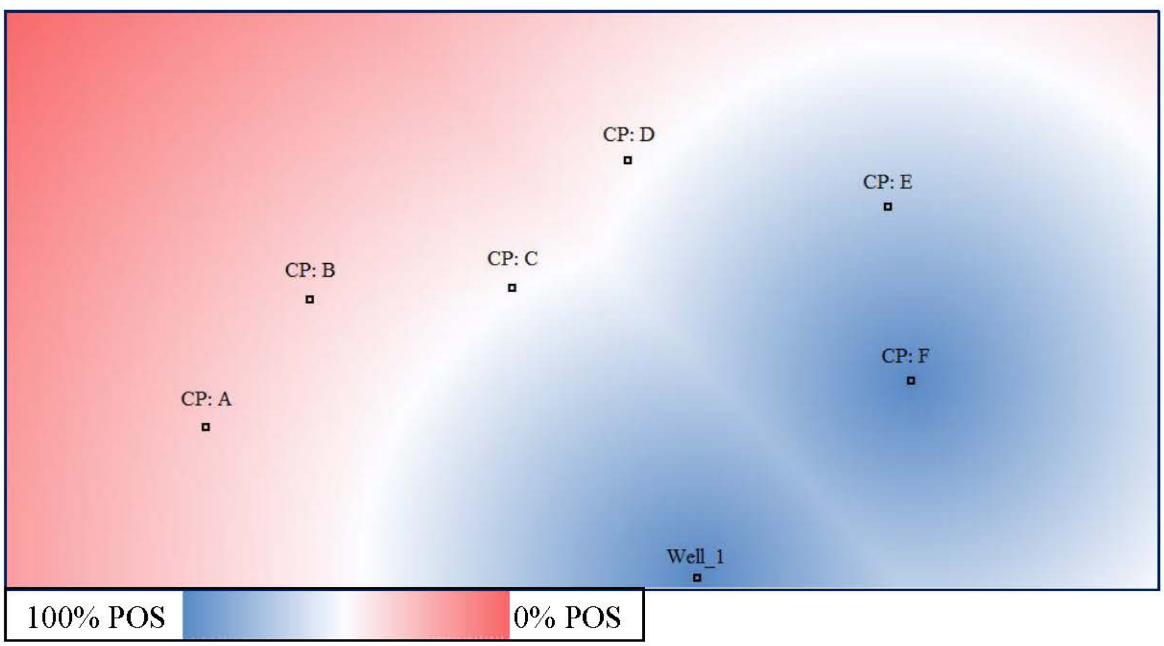


Figure 18: Continuous POS map using Well_1 and CP: F

Table 5: POS x STD values for five control points

	CP : A	CP : B	CP : C	CP : D	CP : E
POS % (Figure. 18)	44	48	64	65	83
STD ms (Figure. 17)	2645	2021	1564	822	1857
POS x STD ms	1164	970	1000	534	1541
Comments on well location				Worst	Best

Table 6: Total STD for Well_1 and two CPs

Well Identification	**Total STD (ms)**
Well_1	512,000
Well_1 + CP: F	440,000
Well_1 + CP: F + CP: E	365,000
Well_1 + CP: F + CP: D	372,000

3. *Searching for Well #4*

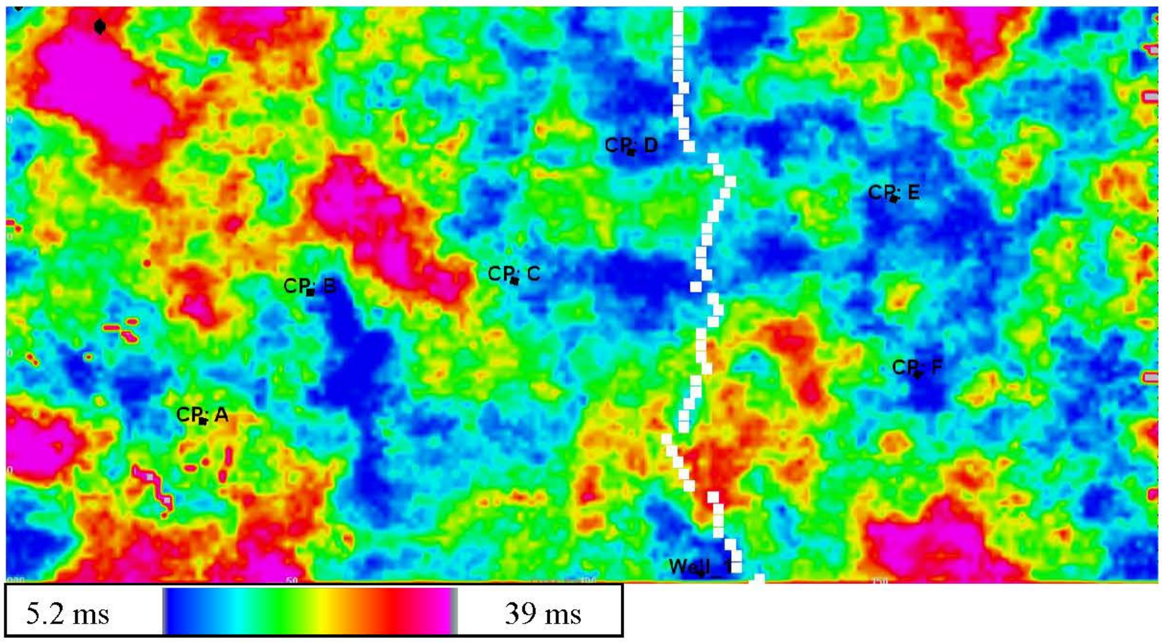


Figure 19: STD map using Well_1, CP: F and CP: E.

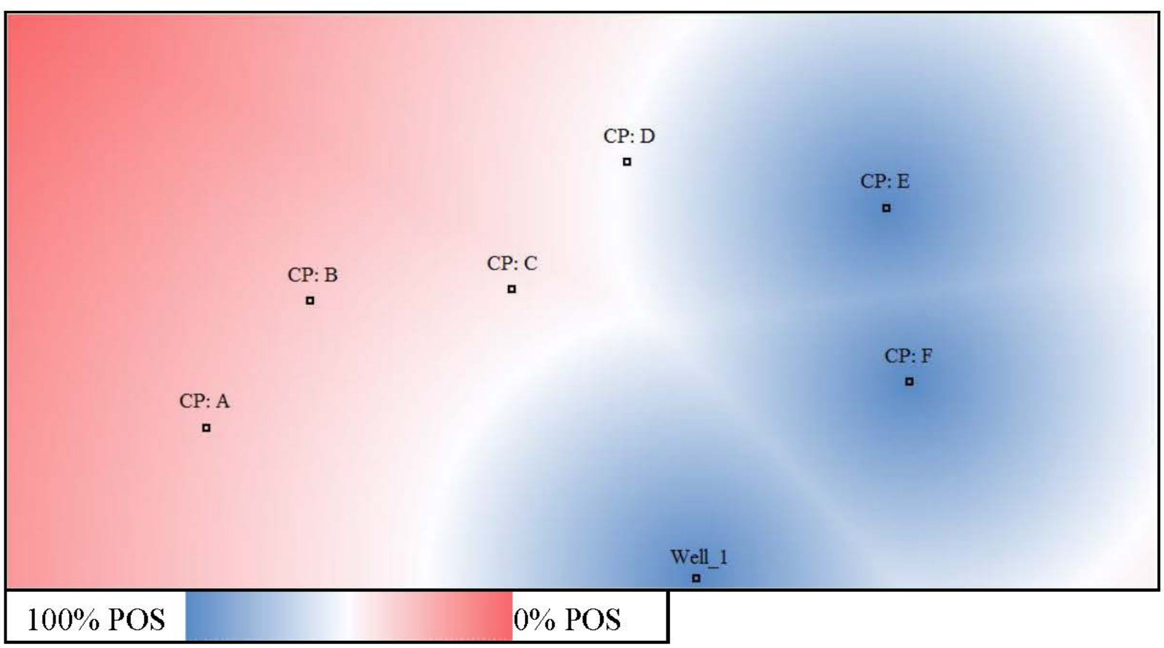


Figure 20: Continuous POS map using Well_1, CP: F and CP: E.

Table 7: POS x STD values for four control points

	CP : A	CP : B	CP : C	CP : D
POS (%) (Figure. 20)	44	48	64	675
STD (ms) (Figure. 19)	1797	1100	1095	760
POS x STD (ms)	791	528	701	570
Comments on well location	Best	Worst		

Table 8: Total STD for Well_1 and three CPs

Well Identification	**Total STD (ms)**
Well_1	512,000
Well_1 + CP: F	440,000
Well_1 + CP: F + CP: E	365,000
Well_1 + CP: F + CP: E + CP: A	323,000
Well_1 + CP: F + CP: E + CP: B	360,000

4. *Searching for Well #5*

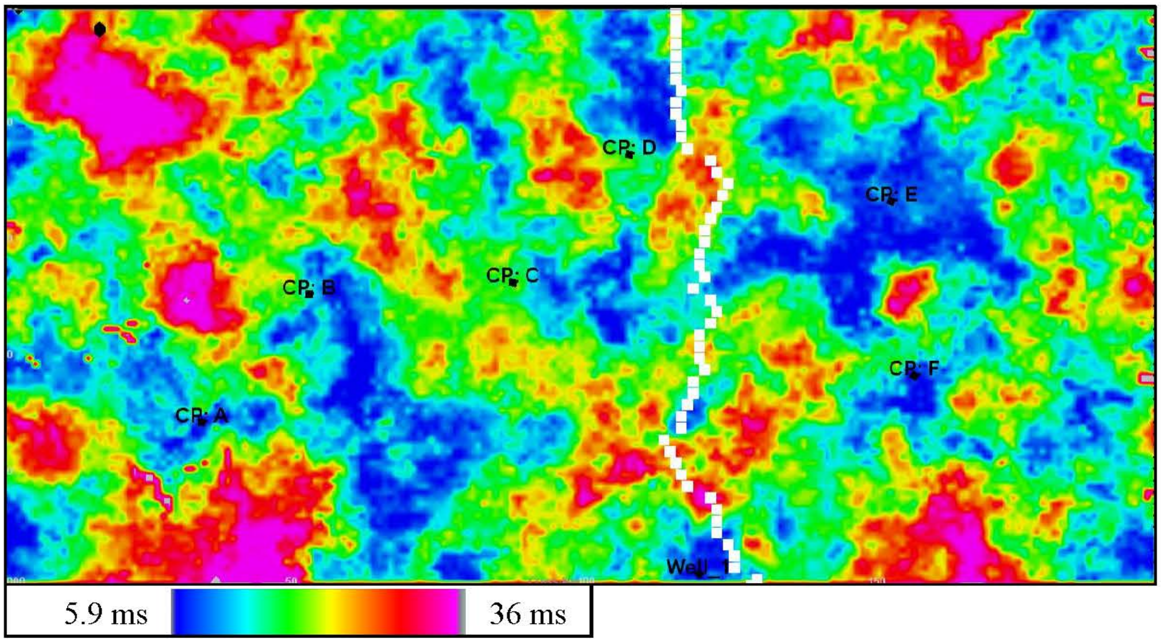


Figure 21: STD map using Well_1, CP: F, CP: E and CP: A.

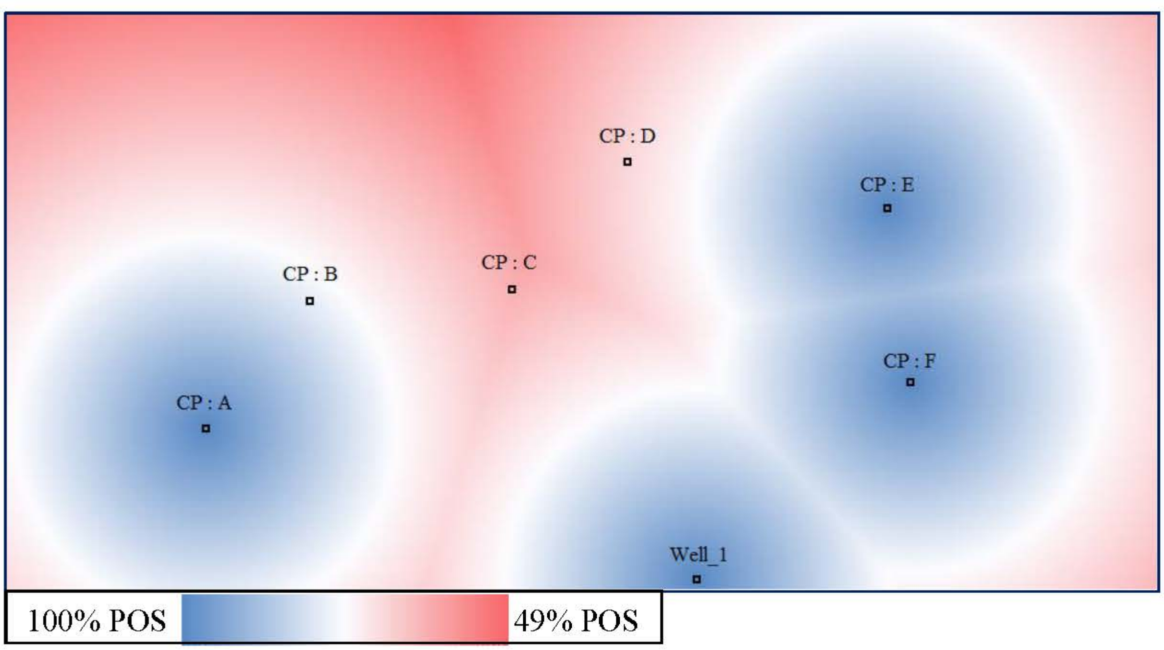


Figure 22: Continuous POS map using Well_1, CP: F, CP: E and CP: A.

Table 9: POS x STD values for three control points

	CP : B	CP : C	CP : D
POS % (Figure. 22)	86	69	75
STD ms (Figure. 21)	1086	1350	1247
POS x STD ms	934	932	935
Comments on well location		Worst	Best

Table 10: Total STD for Well_1 and four CPs

Well Identification	**Total STD (ms)**
Well_1	512,000
Well_1 + CP: F	440,000
Well_1 + CP: F + CP: E	365,000
Well_1 + CP: F + CP: E + CP: A	323,000
Well_1 + CP: F + CP: E + CP: A + CP: D	312,000
Well_1 + CP: F + CP: E + CP: A + CP: C	321,000

5. *Well 1 and the Six CP's*

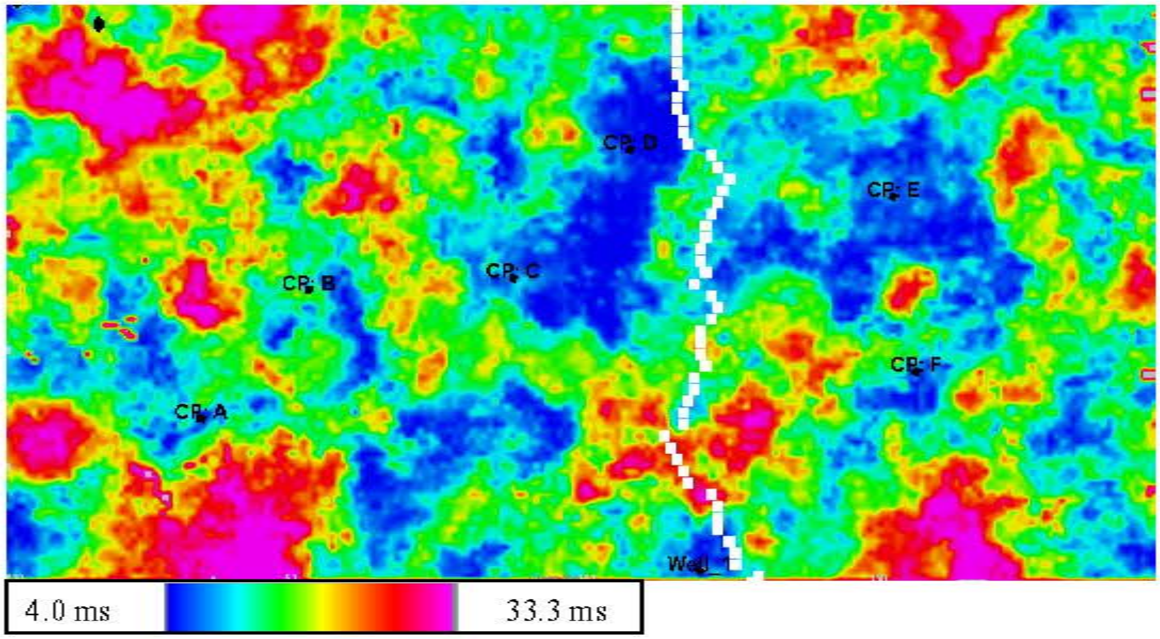


Figure 23: STD using Well_1 and the six CP's.

Table 11: Total STD for Well_1 and six CPs

Well Identification	Total STD (ms)
Well_1	512,000
Well_1 + CP: F	440,000
Well_1 + CP: F + CP: E	365,000
Well_1 + CP: F + CP: E + CP: A	323,000
Well_1 + CP: F + CP: E + CP: A + CP: D	312,000
Well_1 + CP: F + CP: E + CP: A + CP: D + CP: C + CP: B	310,000

B. Value of Information Method: Results

Once the uncertainty reduction method is used to determine the best location and sequence of the wells to be drilled, the Value of Information method is used to justify the drilling of those wells, i.e. to determine the economic feasibility of drilling those wells. As previously mentioned in Chapter 5, the VoI method compares the different alternatives based on a dollar value. With this aim, the below subsections will first assign a dollar value on the criteria needed in the VoI analysis. Following the aforementioned subsection, the VoI analysis will be conducted on the candidate wells and finally, the complete framework of choosing and justifying the drilling of the next well will be illustrated.

1. Assigning a Dollar Value

To compute $Exp(NPVs)$, $Exp(NPVf)$ and $Exp(NPV)$, the cost of the well to be drilled, the Net Present Value of the gas in place and the expected reduction in uncertainty need to be determined in terms of dollars. The following sections: 1) Cost of Wells, 2) From Time to Volume, 3) From Volume to Dollar Value of Gas; will aid in determining the required input for the decision tree. A final section will illustrate the complete and simplified steps of this transformation.

a. Cost of Wells

One of the factors in the VoI analysis is the cost of the appraisal well to be drilled. To determine the cost of this well, a dollar/foot value will be determined and used for the wells of the Stratton field. This dollar/foot value is specific to wells drilled in gas reservoirs. The 2007 dollar/foot value, which is equal to $604.04\ \$/ft.$ will be adopted since it is the most recent value reported by the U.S. Energy Information Administration (U.S. Energy Information Administration, 2015).

It is important to note that the appraisal costs are both direct and indirect; direct being the actual cost needed to collect the information (cost of drilling or cost of seismic acquisition) and indirect cost being the production delay caused by appraisal. In this thesis, for simplification purposes, it is assumed that only the direct costs of the wells enter into the VoI calculations.

To determine the costs of the wells in the Stratton field, the first well depth (Well_1) will be collected and used to calculate the Cost of Well, then after the second well is drilled, the new well depth will be averaged with Well_1 depth and used in the calculation of the Cost of Well. The same procedure will be applied to the remaining wells. However, after applying this procedure, it was found that the average well depth does not vary significantly so for consistency, only one value will be adopted in the calculations of the Cost of Wells.

The well depth is determined to be 6525.3 ft., therefore, the average cost per well for the Stratton field is equal to:

$$
\begin{aligned}
Cost\ of\ Well = {} & \frac{\$}{foot}\, for\ natural\ gas\ wells \\
& \times average\ depth\ of\ Wells\ in\ the\ Stratton\ field \\
& = 604.04 \frac{\$}{ft} \times 6525.3\ ft = \$\,3{,}941{,}542.2
\end{aligned}
$$

Table. 11 below shows the average cost of wells collected from different sources. Analyzing the table shows that the obtained Cost of Well is in accordance with the industry average.

Table 12: Cost of wells in the industry

Cost of Well	Source
\$ 2 Million - \$ 5 Million	(Center for Economics and Management, 2007)
\$ 3.5 Million - \$ 4.5 Million	(Krauss, 2015)
\$ 3.9 Million	(PetroStrategies, Inc., 2015)

As previously stated in the beginning of this chapter, since the seismic data was used to generate the STD, the P_10, the P_50 and the P_90 maps, those maps are displayed in units of time. However, in order to use the VoI technique, the decision maker needs to have all the input in $ values. To accomplish that, the time values will first be transformed to depth values. Then the depth measurements will be transformed into volumes then into $ values. Those three transformation procedures are highlighted in the below subsections.

b. From Time to Volume

i. Moving From Time to Depth

Since the velocity v is equal to the distance d divided by the time t, then moving from time to depth is done according to the equation below (Nelson, 2007):

$$v = \frac{d\ (m)}{t(ms)}; \qquad d(m) = v \times t(ms)$$

To determine the velocity v for the well, the analysis of Well_1 showed that the velocity in the horizon of interest is equal to: 2995.615 meters/second. Since the time in the model is recorded in milliseconds (ms), the velocity in the studied horizon is thus equal to:

$$v(ms) = \frac{v(\mathrm{sec})}{1000\,{}^{ms}/_{sec}} = \frac{2995.615\ m/sec}{1000\ {}^{ms}/_{sec}} = 2.995\ m/ms$$

Analysis of the remaining nine horizons show that the velocity changes with a difference of less than 0.5%. For that reason, the velocity for horizon one will be used in the transformation from time to depth.

ii. Moving From Depth to Volume

Now that the time values in milliseconds have been transformed to depth values in meters, the next step is to transform depth values to volume values. In order to do that, each coordinate point on the map will be multiplied by the depth of the horizon below it. The below figures illustrate the process in more details.

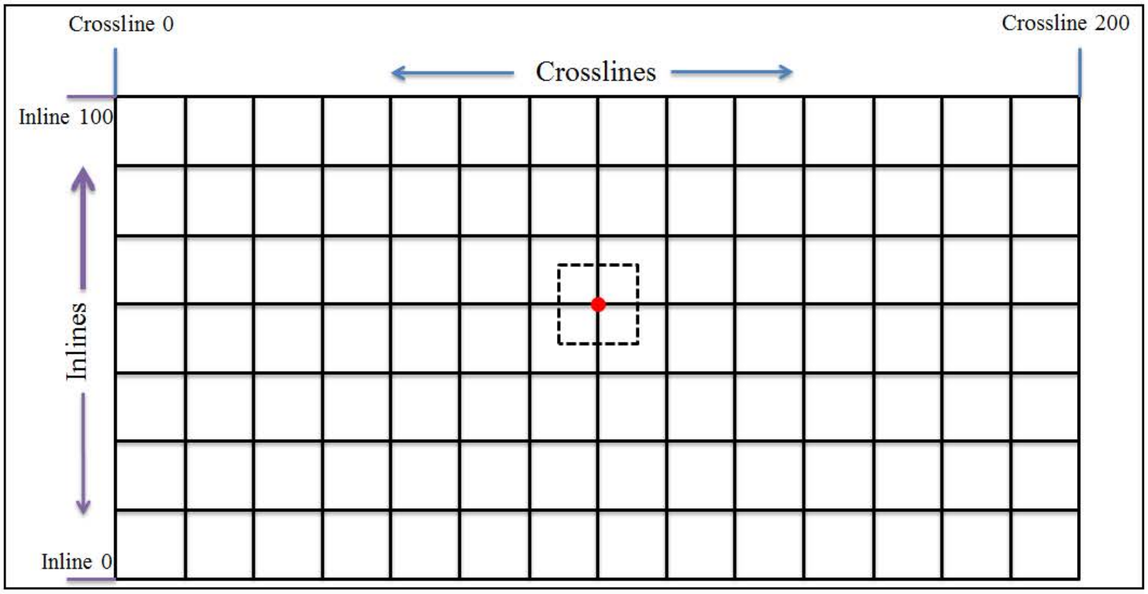


Figure 24: 2D schematic top view of the Stratton field

Figure. 24 shows a 2D top view of the reservoir in question. This reservoir has 200 crosslines and 100 inlines (Bureau of Economic Geology, 1994). Crosslines and Inlines are similar to X and Y coordinates and they are particular to the Oil and Gas industry and specifically to seismic data interpretations. Because the model has the number of crosslines and inlines mentioned, the total number of nodes where the time values are generated and displayed is thus equal to:

$$Number\ of\ Nodes = Number\ of\ Inlines\ \times Number\ of\ Crosslines = 100\ \times 200$$
$$= 20{,}000\ node$$

By analyzing Figure. 24, one can notice the dotted box in the middle of the figure. This dotted box represents a tributary area around the red node, meaning that dividing the total area of the studied reservoir into the 20,000 available nodes, each node is responsible for the tributary area around it, i.e. when the depth values of the net gas thickness are calculated for a node, those depth values are the same for all the tributary area around that node.

As such, since time was transformed to depth, now depth will be transformed to volume by multiplying the obtained net depth of gas by the tributary area of each node according to the below formula:

$$Volume\ (m^3) = Depth(m) \times Tributary\ Area\ (m^2)$$

Figure. 25 below illustrates the tributary area and tributary volume with a 3D view of the reservoir model.

Since the reservoir model area is 5.62 km^2 (equivalent to 5,620,000 m^2), then the tributary area is equal to (Bureau of Economic Geology, 1994):

$$Tributary\ Area\ (m^2) = \frac{Total\ Area\ (m^2)}{Number\ of\ Nodes} = \frac{5{,}620{,}000\ m^2}{20{,}000} = 281\ m^2$$

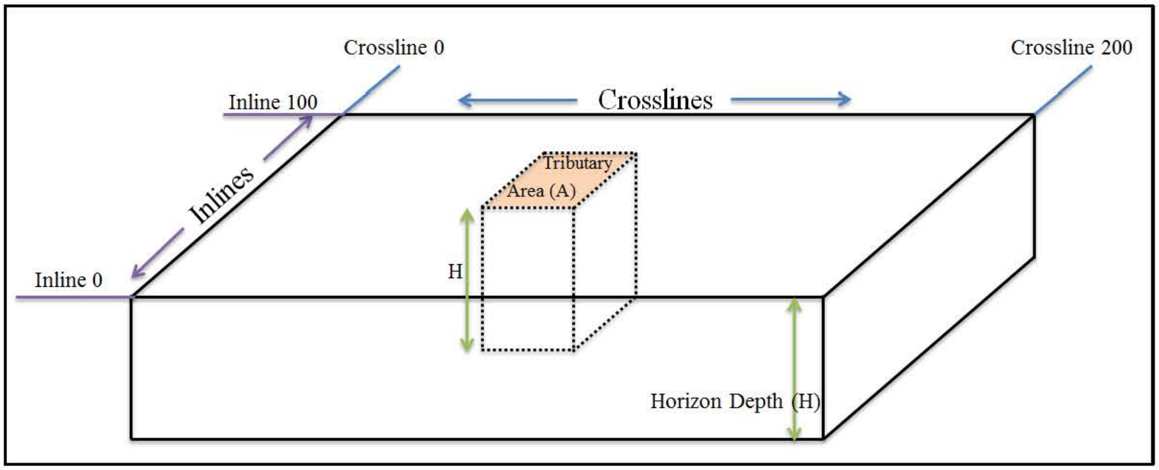


Figure 25: 3D schematic view of the Stratton field with tributary area

In the Stratton field, ten horizons that contain gas are present. In the model that is built on OpendTect, only the first horizon is considered for simplification of the model. Because the ten horizons are similar in thickness and formation, a factor of ten will be applied to move from one horizon to ten horizons since the well to be drilled and justified spans over the ten horizons not only one.

Finally, to conform with the units of the Stratton field and with the units used to calculate the cost of the well, the obtained volume will multiplied by a conversion factor of 35.31 to move from m^3 to ft^3.

iii. Value of Gas

Once the volume of gas in ft^3 is determined, this volume will be multiplied by the price/ft^3 of natural gas to obtain the value of this volume, which will serve in the calculation of the VoI. Since the 2007 value of the cost to drill a well was used, then the prices of gas in 2007 will be considered for the analysis. Table. 12 below shows the Natural

Gas Wellhead Price ($/Thousand Cubic Feet) for the twelve months of 2007 and the average value in 2007 (U.S. Energy Information Administration, 2015).

Table 13: Natural Gas Wellhead price ($/Thousand cubic feet)

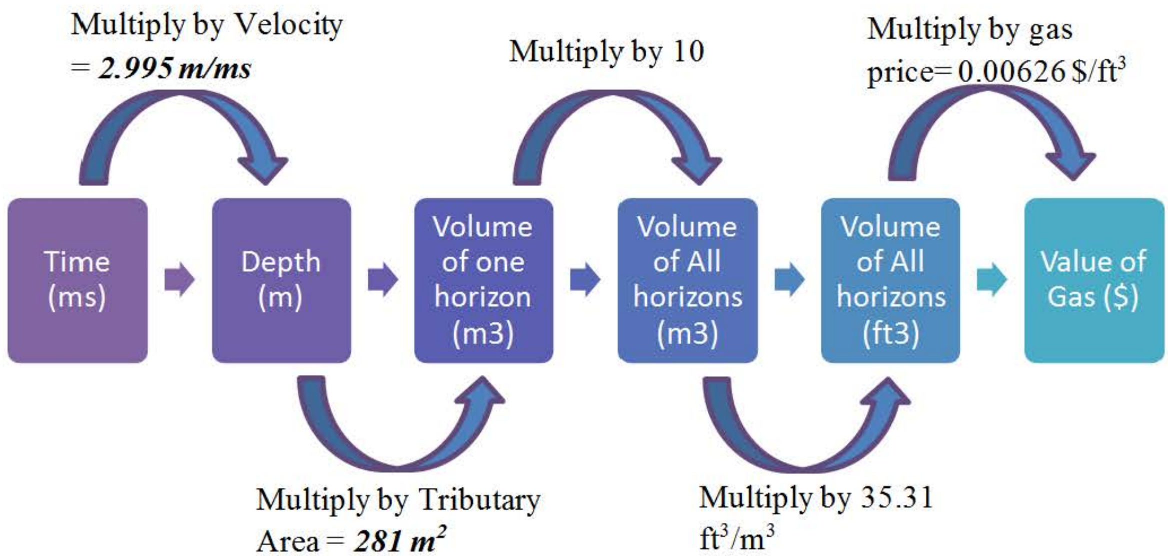
Month	**Natural Gas Wellhead Price ($/Thousand Cubic Feet)**
January	5.70
February	6.80
March	6.65
April	6.26
May	6.75
June	6.62
July	6.21
August	5.76
September	5.30
October	5.78
November	6.46
December	6.87
AVERAGE	6.26

To calculate the value of the gas volumes, the following formula is used:

$$Gas\ Value\ (\$) = Gas\ Volume\ (ft^3) \times \frac{1\ Thousand\ Cubic\ Feet}{1000\ ft^3} \times Natural\ Gas\ Well\ Head\ Price\ (\$/Thousand\ Cubic\ Feet)$$

iv. From Time to Dollar Value: Timeline

The below process summarizes the steps involved in transforming time values to dollar gas value.



2. *Value of Information Calculation*

The following section will include the calculation of the Value of Information used to justify the new appraisal well locations.

a. Justifying Appraisal Well #2 CP: F

The process of justifying the drilling of CP: F by means of the VoI method starts with filling the values of the decision tree branches. For that reason, it is necessary to determine the values of $Exp(NPVs)$, $Exp(NPVf)$, $Exp(NPV)$, P_{sucess} and $P_{failure}$.

$$Exp(NPV)with\ Well\_1 = \frac{NPV_L + NPV_M + NPV_H}{3}$$

$$= \frac{529{,}238\ ms + 1{,}002{,}580\ ms + 1{,}502{,}147\ ms}{3} = 1{,}011{,}322\ ms$$

$$= \$\ 1{,}870{,}523{,}725$$

$$Exp(NPVs) = \text{Exp (NPV)} + Exp\ (NPVw) - Cost\ of\ Appraisal\ Well.$$

In this case, the expectation NPV out of CP: F is equal to the dollar value of P_10 – P_90, which is equal to:

$$Exp\ (NPVw) = 7{,}107\ ms - 2{,}693\ ms = 4{,}414\ ms = \$\,8{,}164{,}058$$

Thus:

$$Exp(NPVs) = \text{Exp (NPV)} + Exp\ (NPVw) - Cost\ of\ Appraisal\ Well$$

$$= \$\,1{,}870{,}523{,}725 + \$\,8{,}164{,}058 - \$\,3{,}941{,}542 = \$\,1{,}874{,}746{,}241$$

$$Exp(NPVf) = \text{Exp (NPV)} - Cost\ of\ Appraisal\ Well$$

$$= \$\,1{,}870{,}523{,}725 - \$\,3{,}941{,}542 = \$\,1{,}866{,}582{,}183$$

$$P_{sucess} = 70\% = 0.7$$

$$P_{failure} = 1 - 0.7 = 0.3$$

Table 14: Decision tree inputs for CP: F

Notation	Value
$\boldsymbol{Exp(NPVs)}$	\$ 1,874,746,241
$\boldsymbol{Exp(NPVf)}$	\$ 1,866,582,183
$\boldsymbol{Exp(NPV)}$	\$ 1,870,523,725
$\boldsymbol{P_{sucess}}$	0.7
$\boldsymbol{P_{failure}}$	0.3

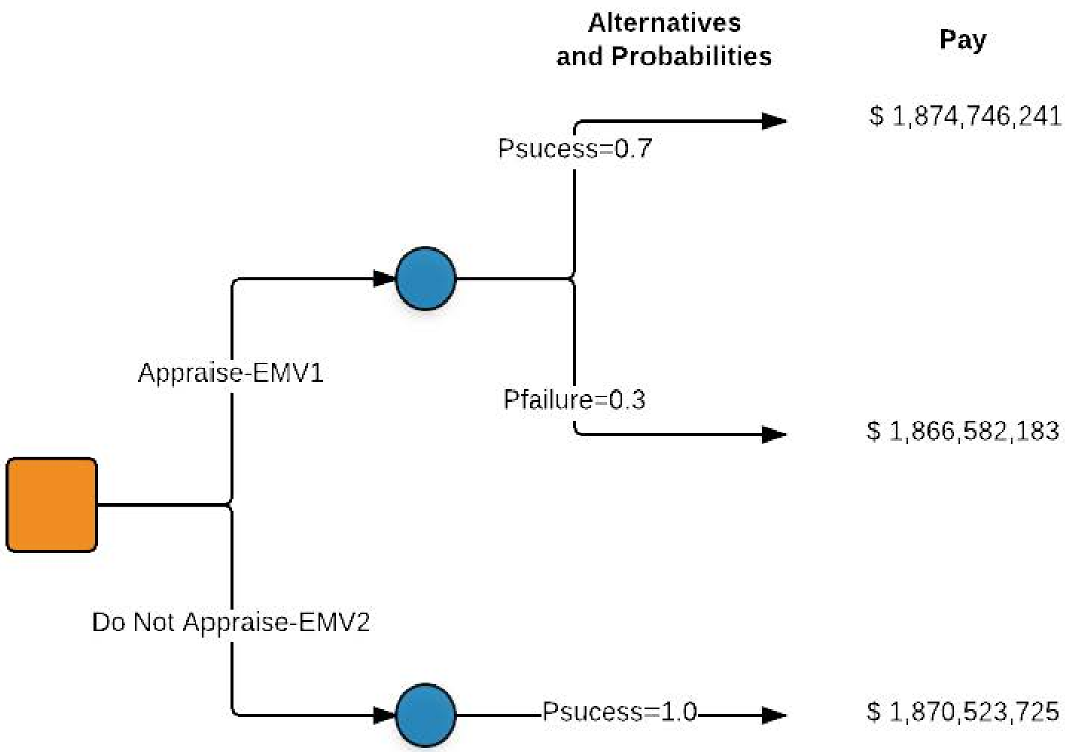


Figure 26: Decision tree for CP: F

$$EMV_1 = Exp(NPVs) \times P_{sucess} + Exp(NPVf) \times P_{failure}$$

$$= \$\,1{,}874{,}746{,}241 \times 0.7 + \$\,1{,}866{,}582{,}183 \times 0.3 = \$\,1{,}872{,}297{,}024$$

$$EMV_2 = Exp(NPV) \times P_{sucess} = \$\,1{,}870{,}523{,}725 \times 1.0 = \$\,1{,}870{,}523{,}725$$

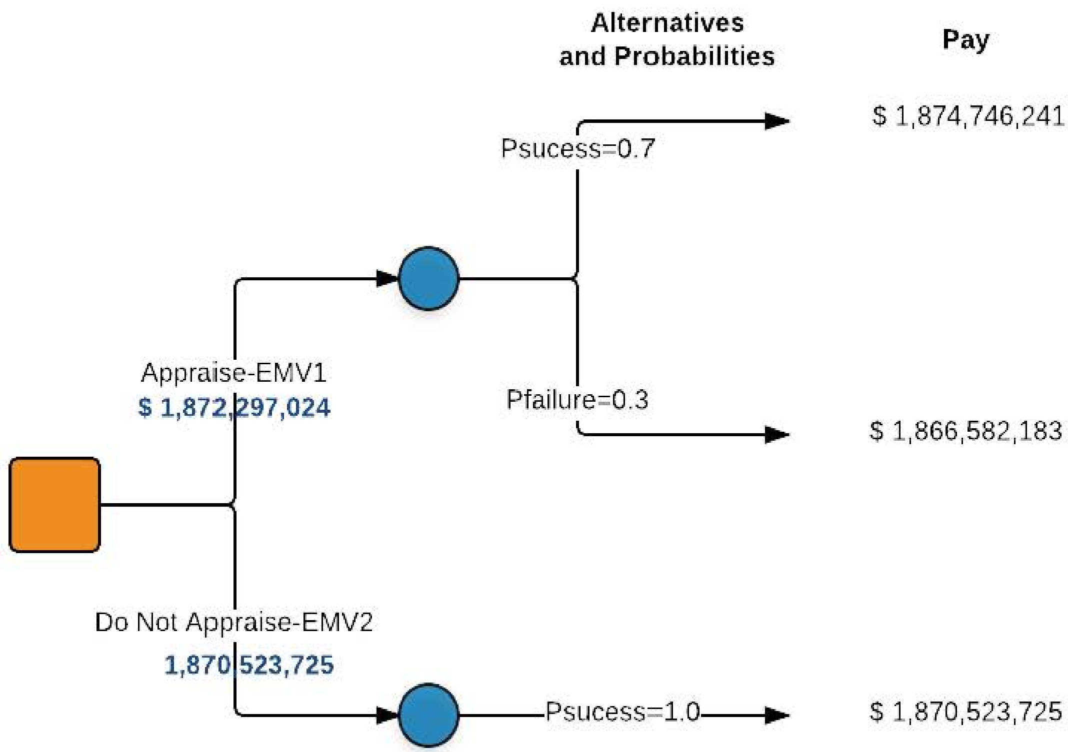


Figure 27: Flipped decision tree for CP: F

The VoI is thus equal to:

$$\begin{aligned} VoI &= Expected\ Value\ WITH\ additional\ information \\ &\quad - Expected\ Value\ WITHOUT\ additional\ information \\ &= EMV_1 - EMV_2 = \$\ 1{,}773{,}299 > 0 \end{aligned}$$

Since VoI for CP: F is positive, this well is thus justified and drilling it makes economic sense.

Table 15: Decision tree outputs for CP: F

Notation	Value
$\boldsymbol{EMV1}$	$ 1,872,297,024
$\boldsymbol{EMV2}$	$ 1,870,523,725
$\boldsymbol{VoI}$	$ 1,773,299
$\boldsymbol{DECISION}$	JUSTIFIED

Since the procedure for justifying the decision to drill the next wells through the VoI method are the same for all wells, the below subsections will only show the following tables and figures to justify the location of the nth well:

- Table showing the notation and value of the decision tree branches for the nth well.
- Flipped Decision tree for the nth well.
- Table showing EMV1, EMV2 and VoI for the nth well.

b. Justifying Appraisal Well #3: CP: E

Table 16: Decision tree inputs for CP: E

Notation	Value
$\boldsymbol{Exp(NPVs)}$	$ 1,634,272,616
$\boldsymbol{Exp(NPVf)}$	$ 1,627,262,697
$\boldsymbol{Exp(NPV)}$	$ 1,631,204,239
$\boldsymbol{P_{sucess}}$	0.83
$\boldsymbol{P_{failure}}$	0.17

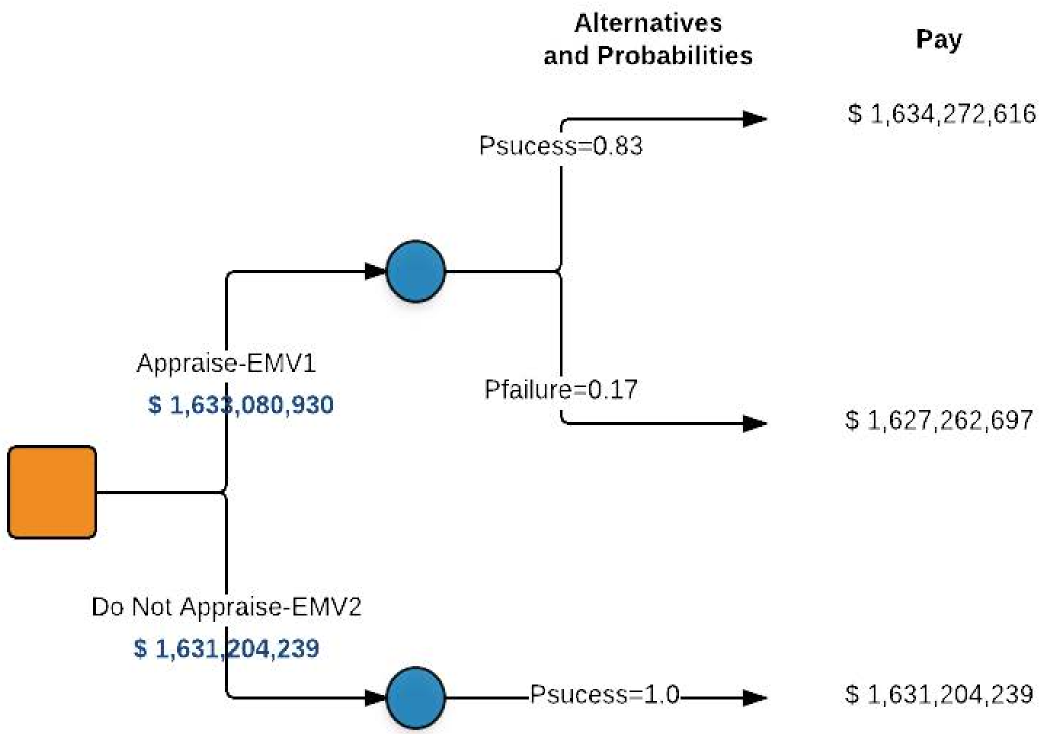


Figure 28: Flipped decision tree for CP: E

Table 17: Decision tree outputs for CP: E

Notation	Value
$\boldsymbol{EMV1}$	$ 1,633,080,930
$\boldsymbol{EMV2}$	$ 1,631,204,239
$\boldsymbol{VoI}$	1,876,690
$\boldsymbol{DECISION}$	JUSTIFIED

c. <u>Justifying Appraisal Well #4: CP: A</u>

Table 18: Decision tree inputs for CP: A

Notation	Value
$\boldsymbol{Exp(NPVs)}$	$ 1,546,061,773
$\boldsymbol{Exp(NPVf)}$	$ 1,536,867,497
$\boldsymbol{Exp(NPV)}$	$ 1,540,809,039
$\boldsymbol{P_{sucess}}$	0.44
$\boldsymbol{P_{failure}}$	0.56

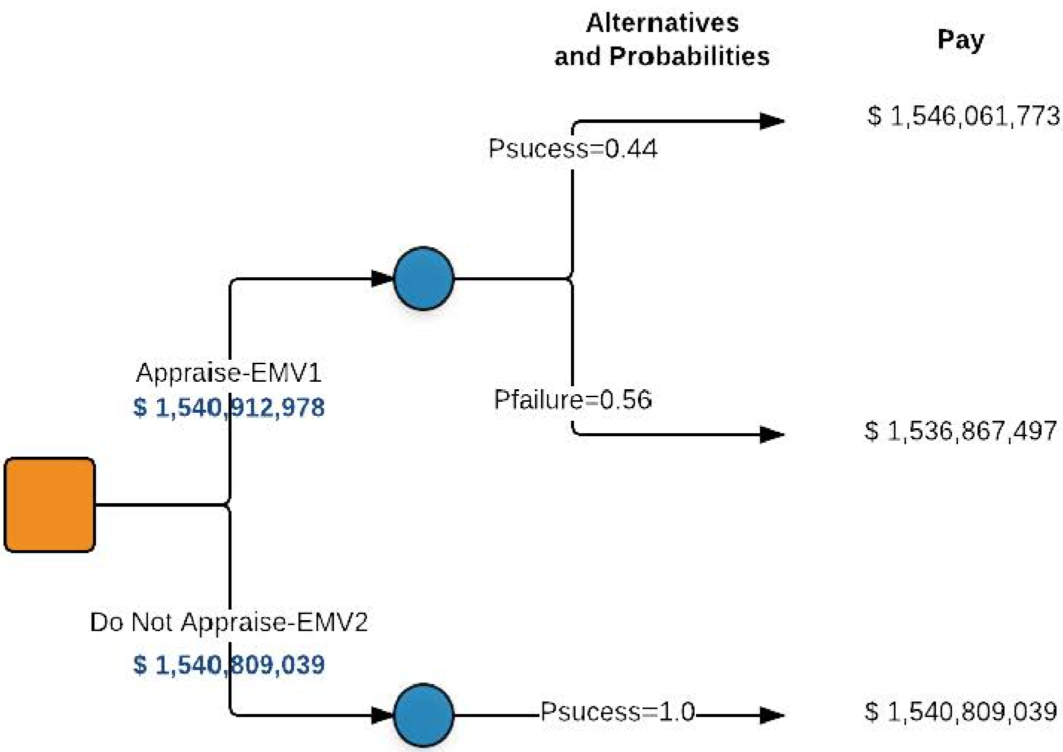


Figure 29: Flipped decision tree for CP:A

Table 19: Decision tree outputs for CP: A

Notation	Value
$EMV1$	$ 1,540,912,978
$EMV2$	$ 1,540,809,039
VoI	$ 103,939
$DECISION$	JUSTIFIED

4. <u>Justifying Appraisal Well #5: CP: D</u>

Table 20: Decision tree inputs for CP: D

Notation	Value
$Exp(NPVs)$	$ 1,361,717,880
$Exp(NPVf)$	$ 1,360,027,361
$Exp(NPV)$	$ 1,363,968,903
P_{sucess}	0.75
$P_{failure}$	0.25

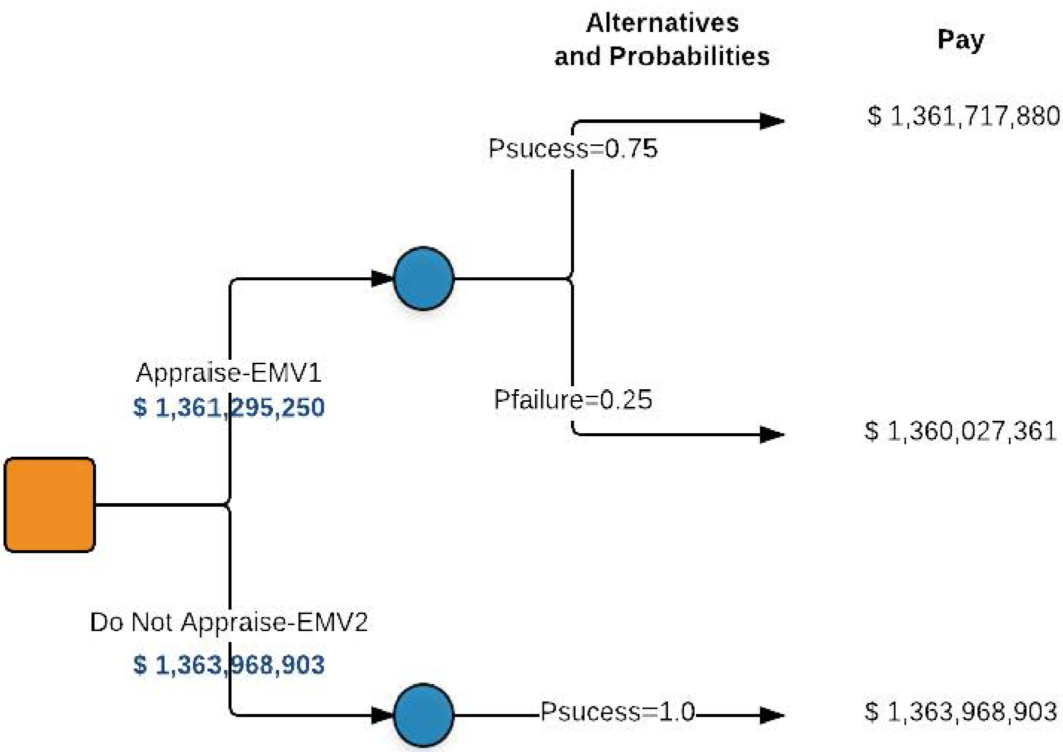


Figure 30: Flipped decision tree for CP: D

Table 21: Decision tree output for CP: D

Notation	Value
$\boldsymbol{EMV1}$	\$ 1,361,295,250
$\boldsymbol{EMV2}$	\$ 1,363,968,903
$\boldsymbol{VoI}$	$-\$\ 2,673,653$
$\boldsymbol{DECISION}$	NOT JUSTIFIED

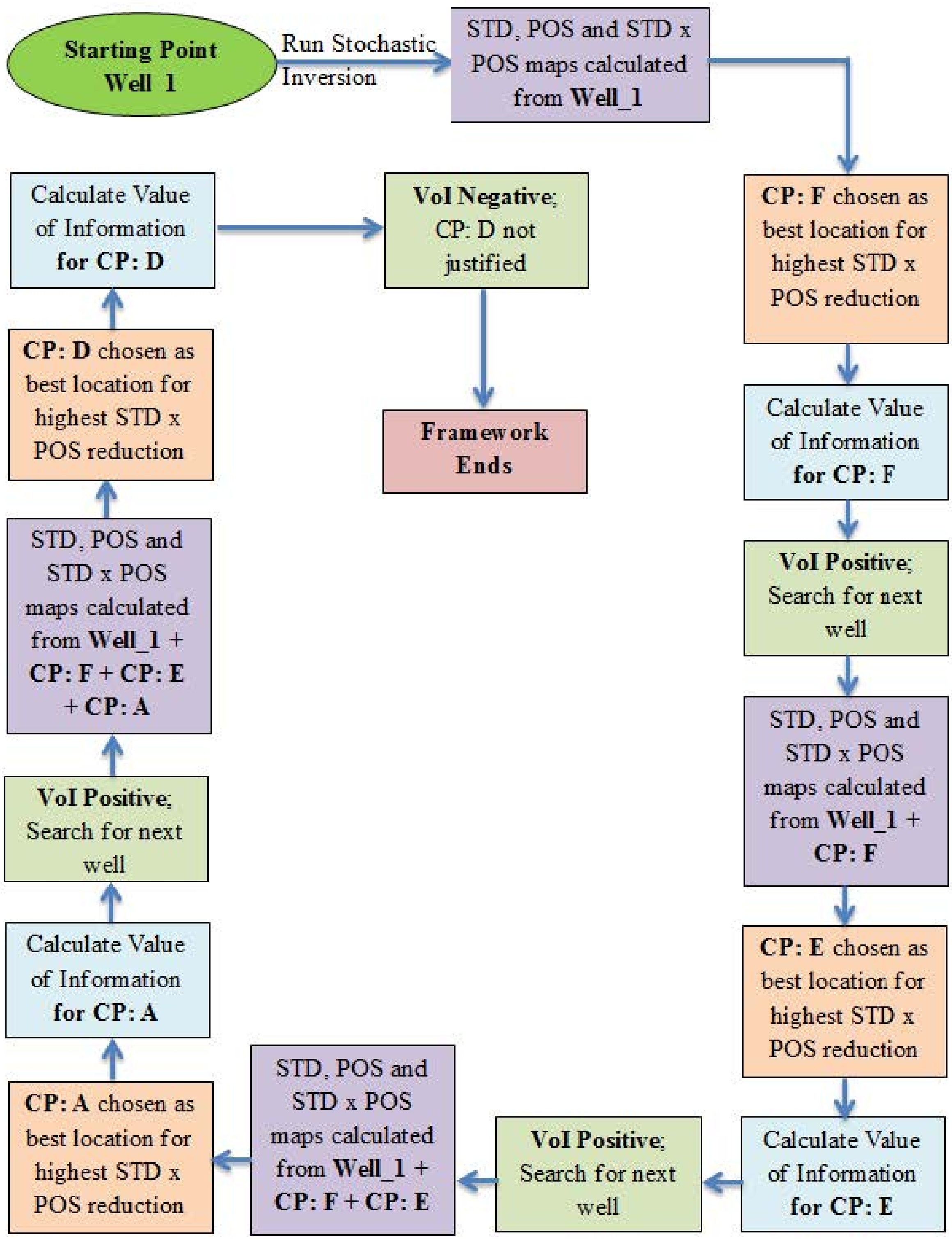
After calculating the Value of Information for CP: D, it was found that drilling this well is not justified in an economic point of view.

C. Framework

The below framework illustrates the simplified process of choosing the next well location based on the Uncertainty reduction method and justifying the drilling of the well at that location using the Value of Information method.

As previously mentioned, the first steps of the framework make use of the uncertainty reduction method. Once a well location is chosen, this proposed location is tested using the Value of Information technique. A location is said to be justified if not only its value exceeds its cost but also if it holds the ability to change the development decision.

In this thesis however, the new wells were not accessed for their ability to change the development decision. This is due to the fact that the Stratton Field reservoir on which the testing was made represents a portion of the true field and not its entirety. Because the analysis was done on only a portion, changes in development decisions cannot be made because of the unknown location of other wells in the other portion of the Stratton field (portion not available for study).


Starting Point
Well 1
Run Stochastic
Inversion
STD, POS and STD x POS maps calculated from Well_1
CP: F chosen as best location for highest STD x POS reduction
Calculate Value of Information for CP: F
VoI Positive; Search for next well
STD, POS and STD x POS maps calculated from Well_1 + CP: F
CP: E chosen as best location for highest STD x POS reduction
Calculate Value of Information for CP: E
VoI Positive; Search for next well
STD, POS and STD x POS maps calculated from Well_1 + CP: F + CP: E
CP: A chosen as best location for highest STD x POS reduction
Calculate Value of Information for CP: A
VoI Positive; Search for next well
STD, POS and STD x POS maps calculated from Well_1 + CP: F + CP: E + CP: A
CP: D chosen as best location for highest STD x POS reduction
Calculate Value of Information for CP: D
VoI Negative; CP: D not justified
Framework Ends

D. Discussion

The framework starts by checking for the best locations to drill the next well. Those locations are first assessed based on the maximum uncertainty reduction that they can provide. The calculations show that the optimal sequence of wells to be drilled after Well_1 is CP: F, CP: E, CP:A and CP: D. After CP: D, two wells can be drilled, either CP: B or CP: C. but since the potential to reduce uncertainty has considerably diminished between the first drilled well and CP: D, then the two remaining well locations were not assessed for their uncertainty reduction.

Figure. 31 below represents the total STD in the reservoir in function of the number of wells drilled in the reservoir (the values in the Y-axis were flipped to highlight the findings). This graph shows that with the increase in the number of wells drilled in the reservoir, the STD has decreased from 512,000 ms to reach 293,000 ms. This result was expected since an addition of wells will lead to decrease in the uncertainty thus a decrease in the STD in the resources estimates.

Two additional observations are important: first, as can be seen from the graph, although adding a new well reduces uncertainty, it is in the early stage of appraisal (from well 1 to well 4) were the uncertainty is reduced the most (steepest slope) vs. the late stage of appraisal (after well 4) where uncertainty is still reduced but at a slower rate. This is in accordance with the fact that learning is maximized with the first observations. Second, analyzing this graph proves the needlessness to drill and assess uncertainty reduction after CP: D since it is clear that no material reduction can occur after this well.

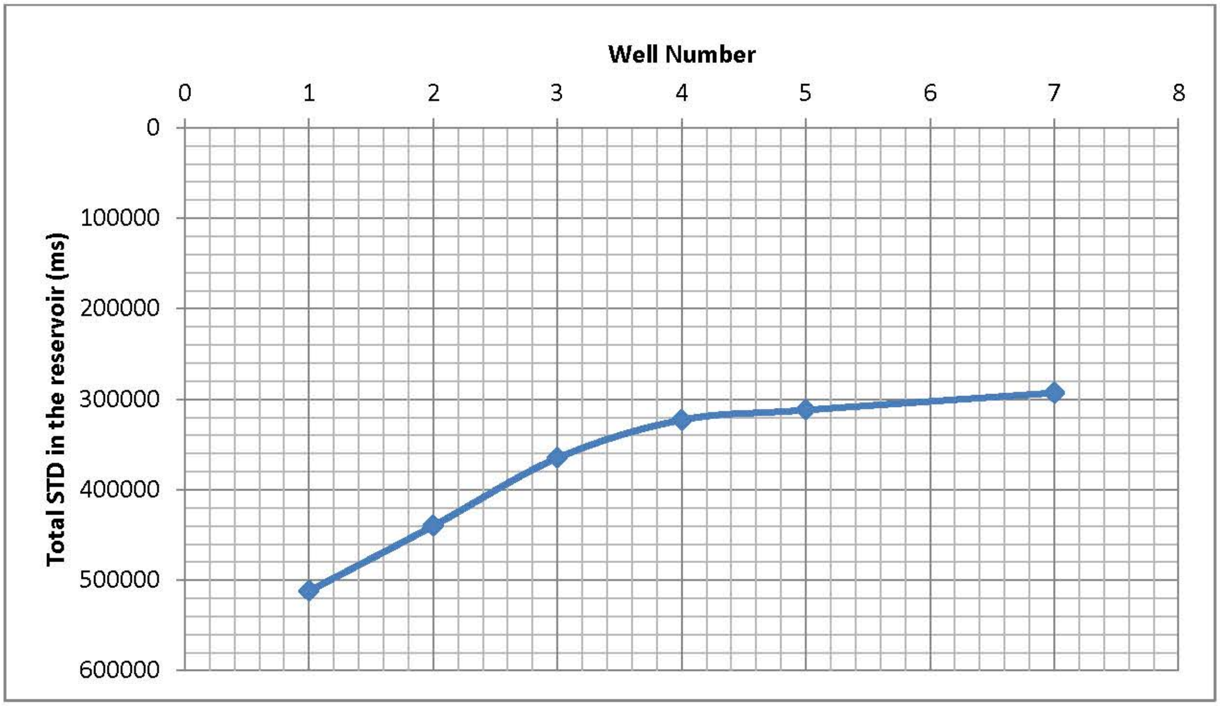


Figure 31: Total STD vs. Well Number

Once the sequence of wells to be drilled is determined, those wells need to be assessed for economic viability; meaning determining if the expected value on the decision maker due to this well justifies the cost of drilling that well. The VoI is used to aid the decision maker in his choices.

Calculating the VoI for the proposed sequence of wells, it was found that the first three wells: CP: F, CP: E and CP: A are justified in terms of economic viability. This was not the case for CP: D, where the expected value for the decision maker out of drilling CP: D does not justify its cost. As such, the reservoir model used in this thesis only requires and justifies the drilling of three additional wells after Well_1. A schematic showing the order of the drilled wells is illustrated in Figure. 32 below.

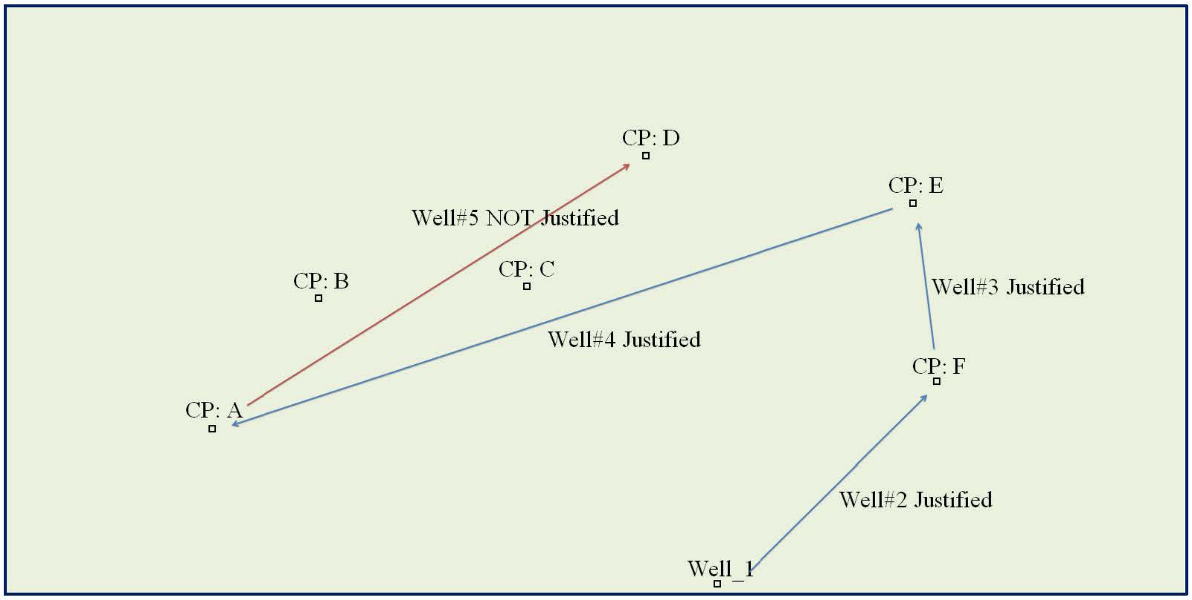


Figure 32: Sequence of wells to be drilled and their VoI

CHAPTER VII

CONCLUSIONS

Where reservoir uncertainty troubles everyone from reservoir engineers to top management, appraisal activities are considered the norm to gathering information and mitigating those uncertainties.

Although drilling more wells decreases the uncertainty in the reservoir, those wells come with very high price tags, reaching up to a 100 million USD in deep offshore reservoirs. Despite the billions of dollars spent each year on appraisal activities, many fields turn out to have a sub-optimal development leading to losses and in many cases unprofitable production of the reserves.

The varying degrees of failure in the appraisal stages calls for a systematic process that ensures that each appraisal activity is justified on both technical and economic grounds, optimizing as such the value obtained from the appraisal efforts.

The uncertainty reduction is one method that ensures that the appraisal well location is chosen as to maximize the uncertainty reduction in the reservoir, leading to a justification of appraisal activities based on technical merit.

The Value of Information techniques, which has recently gained significant momentum in the literature is now considered the standard for justifying any type of activities based on economic merit. More than being a cost-cutting technique, the VoI is viewed as being a value creator that takes the full life cycle of the reservoir in its analysis and encompasses the participation and contribution of all the teams involved in the E&P process.

While the uncertainty reduction method is discussed in details in one paper and the VoI method is discussed in a myriad of articles, a review of the literature indicates that no author up to this point combines the uncertainty reduction method with the value creation of the VoI methodology.

Building on this absence in the literature, the framework proposes a synergistic approach that allows to pinpoint the location of the next appraisal well based on both technical merit (using the uncertainty reduction method) and on economic merit (using the VoI method).

Starting from the first drilled well, the uncertainty reduction method was used and developed to rank the potential locations of the next wells as to maximize uncertainty reduction in the reservoir.

Once the best well location is chosen, the VoI technique indicates the viability of this potential location taking into consideration that value it can create and comparing it to the cost of obtaining the information at the said location.

Running this framework on the available portion of the Stratton field reservoir reveals the need for four appraisal wells in a specific sequence; one well being drilled prior to using the framework and the remaining three wells building on the first one. It was found that those wells reduce uncertainty in the reservoir but do not eliminate it completely, leaving as such a portion referred to in the literature as "irreducible uncertainty"; an uncertainty that all decision makers –being risk-neutral or not- can tolerate.

BIBLIOGRAPHY

Alves, F., Almeida, J. A., & Silva, A. P. (2014). Simulation of acoustic impedance images by stochastic inversion of post-stack seismic reflection amplitudes and well data. *Journal of Petroleum Science and Engineering,121*, 52-65.

Ariffin, T., Solomon, G., Ujang, S., Carigali, P. E. T. R. O. N. A. S., Bée, M. M., Jenkins, S., ... & Özdemir, H. (1992). Seismic tools for reservoir management. *Journal 90, no*, *42*(54), 56-57.

Bohling Geoff Kriging [Online] // Resources for C&PE940, Data Analysis in Engineering and Natural Science - Geoff Bohling. - October 19, 2005. - January 12, 2015. - http://people.ku.edu/~gbohling/cpe940.

Bratvold, R. B., Bickel, J. E., & Lohne, H. P. (2009). Value of information in the oil and gas industry: past, present, and future. *SPE Reservoir Evaluation & Engineering*, *12*(04), 630-638.

Brooks Chad Decision-Making Techniques and Tools [Online] // Business News Daily. - April 1, 2014. - November 29, 2015. - http://www.businessnewsdaily.com/6162-decision-making.html.

Burdett, P., & Haskett, W. J. (2012, January). Reining In the Data Junkies--Having the Guts Not to Appraise. In *SPE Hydrocarbon Economics and Evaluation Symposium*. Society of Petroleum Engineers.

Bureau of Economic Geology 3-D Seismic and Well Log Data Set, Fluvial Reservoir Systems, Stratton Field, South Texas [Report]. - Austin, Texas : [s.n.], 1994.

Cairn Energy Oil and gas exploration, and production life cycle [Online] // Cairn Energy. - 2015. - http://www.cairnenergy.com/index.asp?pageid=554.

Center for Economics and Management Investments and costs [Book Section] // Oil and Gas Exploration and Production: Reserves, Costs, Contracts. - [s.l.] : technip, 2007.

Chambers, R. L., Yarus, J. M., & Hird, K. B. (2000). Petroleum geostatistics for nongeostatisticians: Part 1. *The Leading Edge*, *19*(5), 474-479.

Coopersmith, E. M., & Cunningham, P. C. (2002, January). A practical approach to evaluating the value of information and real option decisions in the upstream petroleum industry. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.

Coopersmith, E., Dean, G., McVean, J., & Storaune, E. (2000). Making decisions in the oil and gas industry. *Oilfield Review*, *12*(4), 2001.

Cunningham, P., & Begg, S. (2008). Using the value of information to determine optimal well order in a sequential drilling program. *AAPG bulletin*,*92*(10), 1393-1402.

Da Cruz, P. S., & Deutsch, C. V. (2000). *Reservoir Management Decision-Making in the presence of geological uncertainty* (Doctoral dissertation, Stanford University).

Demirmen, F. (1996, January). Use of" Value of Information" Concept in Justification and Ranking of Subsurface Appraisal. In *SPE annual technical conference and exhibition*. Society of Petroleum Engineers.

Demirmen, F. (2001, January). Subsurface appraisal: the road from reservoir uncertainty to better economics. In *SPE Hydrocarbon Economics and Evaluation Symposium*. Society of Petroleum Engineers.

Devold, H. (2013). Oil and gas production handbook an introduction to oil and gas production, transport, refining and petrochemical industry. *ABB Oil and Gas*.

Dynamic Resources Corporation Locating Profitable Hydrocarbon Deposits. - 2001.

Earth Works MPSI: Plugin to OpendTect [Report]. - [s.l.] : Earthworks Envirenment & Resources Ltd. and ARK CLS Ltd., 2010.

Earth Works Understanding Stochastic Seismic Inversion [Report] : Technical Note. - Wiltshire : Earth Works Ltd, 2006.

Earthworks Environment and Resources Ltd MPSI: Plugin to OpendTect [Report]. - [s.l.] : Earthworks Environment and Resources Ltd, 2010.

Hardage, B. A., Levey, R. A., Pendleton, V., Simmons, J., & Edson, R. (1994). A 3-D seismic case history evaluating fluvially deposited thin-bed reservoirs in a gas-producing property. *Geophysics*, *59*(11), 1650-1665.

Harris Robert Virtual Salt [Online] // Introduction to decision making, Part I. - June 9, 2012. - November 26, 2015. - http://www.virtualsalt.com/crebook5.htm.

Haskett, W. J. (2003, January). Optimal appraisal well location through efficient uncertainty reduction and value of information techniques. In *SPE Annual Technical Conference and Exhibition*. Society of Petroleum Engineers.

Howard, R. A. (1988). Decision analysis: practice and promise. *Management science*, *34*(6), 679-695.

IFP School What are the main steps of an oil and gas field development project?. - Rueil : [s.n.], October 2014.

Jahn, F. (1998). *HYDROCARBON EXPLORATION AND PRODUCTION DPSDEVELOPMENTS IN PETROLEUM SCIENCE SERIES* (Vol. 46). Elsevier.

Jahn, F., Cook, M., & Graham, M. (2008). *Hydrocarbon Exploration & Production* (Vol. 55). Elsevier.

Kearey, P., Brooks, M., & Hill, I. (2002). An Introduction to Geophysical Exploration.

Knoring, L., Gorfunkel, M. V., & Chilingarian, G. V. (1999). *Strategies for Optimizing Petroleum Exploration:: Evaluate Initial Potential and Forecast Reserves*. Gulf Professional Publishing.

Knox Gordon Subsurface Risk and Uncertainty in Petroleum Exploration - The Challenges // 2002-2003 AAPG Distinguished Lecture. - [s.l.] : American Association of Petroleum Geologists, 2003.

Koninx, J. P. M. (2000, January). Value-of-Information-from Cost-Cutting to Value-Creation. In *SPE Asia Pacific Oil and Gas Conference and Exhibition*. Society of Petroleum Engineers.

Krauss Clifford Drillers Answer Low Oil Prices With Cost-Saving Innovations [Online] // The New York Times. - May 11, 2015. - November 27, 2015. - http://www.nytimes.com/2015/05/12/business/energy-environment/drillers-answer-low-oil-prices-with-cost-saving-innovations.html?_r=1.

Nelson Heather Approximating a Seismic Horizon Time-Depth Conversion Using a Two-Velocity Layer Approach in SeisWorks [Online] // Institute of Geophysics. - The University of Texas at Austin Jakson School of Geosciences, March 22, 2007. - November 27, 2015. - http://www-udc.ig.utexas.edu/people/staff/flemings/software/Solutions/Depth_Convert_SeisWorks.pdf.

PetroStrategies, Inc. Drilling Costs [Online] // PetroStrategies, Inc. Learning Center . - February 28, 2015. - November 27, 2015. - http://www.petrostrategies.org/Learning_Center/drilling_operations.htm.

Rahman Maizar Oil and gas: the engine of the world economy [Online] // OPEC. - November 10-11, 2004. - December 10, 2015. - http://www.opec.org/opec_web/en/900.htm.

Schlumberger Generating a complete reservoir model [Online] // Prospect Appraisal. - 2015. - http://www.slb.com/services/technical_challenges/exploration/prospect_appraisal.aspx.

Schroeder Fred W. Geology and Geophysics Applied to Industry:An Introduction to the Hunt For Oil for Geoscientists not within Industry [Online] // American Asociation of Petroleum Geologists. - 2006. - October 20, 2015. - https://archives.aapg.org/slide_resources/schroeder/7/index.cfm.

Shibli Syed Abdul Rahman Geostatistics FAQ [Report]. - [s.l.] : AL-GEOSTATS FAQ List, 2003.

Simm, R., Bacon, M., & Bacon, M. (2014). *Seismic Amplitude: An Interpreter's Handbook.* Cambridge University Press.

SPE Guidelines for the Evaluation of Petroleum Reserves and Resources [Book]. - Richardson : SPE, 2001.

The Pennsylvania State University Cumulative Distribution Functions [Online] // Probability Theory and Mathematical Statistics STAT 414/415. - 2015. - https://onlinecourses.science.psu.edu/stat414/node/98.

U.S. Department of Commerce Probability Distributions [Online] // Engineering Statistics Handbook. - April 2012. - http://www.itl.nist.gov/div898/handbook/eda/section3/eda362.htm.

U.S. Energy Information Administration Costs of Crude Oil and Natural Gas Wells Drilled [Online] // U.S. Energy Information Administration. - July 31, 2015. - November 27, 2015. - http://www.eia.gov/dnav/ng/NG_ENR_WELLCOST_S1_A.htm.

U.S. Energy Information Administration U.S. Natural Gas Wellhead Price [Online] // U.S. Energy Information Administration Natural Gas Data. - October 30, 2015. - November 27, 2015. - https://www.eia.gov/dnav/ng/hist/n9190us3m.htm.

University of Massachusetts Dartmouth Decision-Making Process [Journal]. - 2015.

Xu, W., Tran, T. T., Srivastava, R. M., & Journel, A. G. (1992, January). Integrating seismic data in reservoir modeling: the collocated cokriging alternative. In *SPE annual technical conference and exhibition*. Society of Petroleum Engineers.