TECHNICAL, ECONOMIC AND RISK ANALYSIS OF MULTILATERAL WELLS

A Thesis

by

DULCE MARIA ARCOS RUEDA

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2008

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Ding Zhu
Committee Members,	A. Daniel Hill
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ABSTRACT

Technical, Economic and Risk Analysis of Multilateral Wells.

(December 2008)

Dulce Maria Arcos Rueda, B.S., Instituto Technologico y de Estudios Superiores de Monterrey, Mexico

Chair of Advisory Committee: Dr. Ding Zhu

The oil and gas industry, more than at any time in the past, is highly affected by technological advancements, new products, drilling and completion techniques, capital expenditures (CAPEX), operating expenditures (OPEX), risk/uncertainty, and geopolitics. Therefore, to make a decision in the upstream business, projects require a thorough understanding of the factors and conditions affecting them in order to systematically analyze, evaluate and select the best choice among all possible alternatives.

The objective of this study is to develop a methodology to assist engineers in the decision making process of maximizing access to reserves. The process encompasses technical, economic and risk analysis of various alternatives in the completion of a well (vertical, horizontal or multilateral) by using a well performance model for technical evaluation and a deterministic analysis for economic and risk assessment.

In the technical analysis of the decision making process, the flow rate for a defined reservoir is estimated by using a pseudo-steady state flow regime assumption. The economic analysis departs from the utilization of the flow rate data which assumes a certain pressure decline. The financial cash flow (FCF) is generated for the purpose of measuring the economic worth of investment proposals. A deterministic decision tree is then used to represent the risks inherent due to geological uncertainty, reservoir engineering, drilling, and completion for a particular well. The net present value (NPV) is utilized as the base economic indicator. By selecting a type of well that maximizes the expected monetary value (EMV) in a decision tree, we can make the best decision based on a thorough understanding of the prospect.

The method introduced in this study emphasizes the importance of a multi-discipline concept in drilling, completion and operation of multilateral wells.

DEDICATION

To my Heavenly Father who has given me wisdom, strength and perseverance during times when I felt weak and insufficient.

To Roger, the love of my life, who believed in me, advised me, encouraged me when I was discouraged, and always prayed for me.

To my parents, Ignacio and Ana Maria whom I immensely love and who have been supportive of my decision to pursue my master's; they have set an example for me to follow in all of my life's endeavors.

To my brothers, Ignacio Carlos and Renato Jose, whom I love very much!

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1. INTRODUCTION

1.1 Statement of Research

As the oil and gas industry is moving away from conventional reservoirs towards unconventional reservoirs, traditional vertical wells may not be the most effective techniques to maximize hydrocarbon recovery. However, we can not assume that horizontal or multilateral technologies are always the best alternative for any field development since each reservoir has unique conditions; horizontal or multilateral wells may not be necessarily ideal for effectively draining the reservoir.

The significance of this study resides in the process that engineers could adopt prior to making a decision whether to drill and complete a well by conventional or more sophisticated methods. One needs to take into account that not only the technical considerations but also the economic and risk aspects have equally important roles when evaluating options.

1.2 Background

The development of multilateral technology began in the early 1940s when horizontal wells (where the lower part of the wellbore parallels the pay zone) was used for oil exploration in California. This was made possible by the introduction of short radius drilling tools.

After engineers began to realize that horizontal wells could increase production and ultimate recovery; the multilateral technology concept was introduced with the idea of drilling multiple branches into a reservoir from a main wellbore. The first truly multilateral well was drilled in Russia in 1953 with nine lateral branches from the main borehole that increased penetration of the pay zone by 5.5 times and production by 17 fold, yet the cost was only 1.5 times that of a conventional well cost (JPT, 1999).

This thesis follows the format of the SPE Journal.

Multilateral technology has been increasing in popularity during the last ten years because it offers significant advantages when compared to vertical or horizontal wells. A few of the benefits are described below:

- Cost reduction: The total cost incurred by implementing a multilateral well could be higher than the cost of a single completion. However, the benefit can possibly overcome the cost when compared to a vertical well. CAPEX is reduced due to lower cost of rig time, tools, services, and equipment. Therefore, the cost/bbl can also be lower.
- Increased reserves: Additional reserves may be found in isolated lenses due to faults or compartmentalized reservoirs. By drilling multilateral wells several productive blocks may be effectively intersected. Thus, marginal or smaller reservoirs can turn out to be economic projects.
- Accelerated reserves: Drainage optimization is important due to the fact that finding and development cost, and OPEX can be significantly high. Consequently, multilateral wells are usually drilled in the same horizontal or vertical plane to accelerate production and reduce the cost.
- Slot conservation: In offshore environments, slot optimization is crucial in order to bring the, per barrel, capital cost down. In addition, multilateral technology contributes to holding the cost in check by maximizing the number of reservoir penetrations with a minimum number of wells.
- Heavy oil reserves: Multilateral wells provide improved drainage and sweep efficiency from wells which normally have low recovery rates, poor sweep efficiency and low mobility ratios.

After consideration of the technical and economic benefits obtained by using multilateral technology, it is important to mention some of the suitable reservoir applications:

- Heavy oil reservoir: Steam assisted gravity drainage is possible with a multilateral well whereby the vertical steam injector and the producer are combined into one wellbore with two laterals.

- Layered reservoirs: In a layered system, heterogeneity will separate individual reservoirs due to contrast in vertical permeability. A multilateral well can exceptionally augment the value obtained by using a single horizontal well.
- Depleted reservoirs and mature development: Multilateral technology is used to access additional reserves from previously depleted reservoirs through the re-entry of existing wells and infill drilling mature fields.
- Tight and naturally fractured reservoir: Productivity can be tremendously improved in anisotropic environments, where natural fracture systems and permeability contrast exist. Multilateral technology connects and intersects these features to increase reservoir exposure.

1.3 Literature Review

There are several horizontal well models developed to evaluate well performance. These models are based on a steady-state condition, a pseudo-steady state condition or a transient flow condition.

The models presented assuming steady state conditions are generally ellipsoidal or box shaped reservoirs. One of the most popular models using an ellipsoid drainage pattern is Joshi's model (1988), which divides the three-dimensional flow problem into two two-dimensional problems to obtain the horizontal well performance. For a box shaped reservoir, Furui's model (2002) can predict horizontal well performance based on the finite element modeling.

Babu and Odeh's model (1989), under pseudo-steady state conditions, is a well known model, which calculates the horizontal well productivity considering a box-shaped reservoir. However, one of the limitations of this model is that the well has to be parallel to the y-axis.

The concept of risk analysis in several applications of the oilfield business has been typically addressed by many authors. The majority of the risk analysis studies have been exclusively performed for reserves estimation by utilizing probabilistic modeling and deterministic decision trees. Despite the significance and value of incorporating this type of analysis, only a few authors apply it to other branches of the oil and gas industry.

Waddell (1999) developed an analytical system that considers the difficulties in risk analysis for an emerging technology using quantitative risk. Decision tree, Monte Carlo Simulation or Latin Hypercube Simulation may be used to correlate information that has been assimilated through operational and experience databases. His study primarily focuses on quantifying risk factors, defining potential outcomes, contingency plans, and event probabilities in the application of emerging technologies such as multilateral technology. The applications of this method include: candidate selection, systems review, decision making, and business development.

Garrouch et al. (2004) developed a web-based fuzzy expert system for aiding in the planning and completion of multilateral wells: screening and selection of candidates, lateral-section completion types, and the junction level of complexity. This detailed system uses decision trees, matrix screening, and flow charts to take into account all type of technical considerations for the right selection of a multilateral well type, lateral completion, and junction type. However, this deterministic study does not provide for any type of economic and risk analysis since it purely emphasizes the technical approach.

Lewis et al. (2004) studied the relationship between petroleum economics and risk analysis by using an integrated approach for project management. This analytical technique systematically and intuitively overcomes complex and high risk multidisciplinary ventures that are intrinsic in oil and gas projects. Certainly, this method addresses the use of technical, economic (return on investment), and risk assessments as mutually dependent analysis from the deterministic and probabilistic stand points. Despite the emphasis on the economic and risk analysis, the technical study does not assist directly on the evaluation of different well systems to drill and complete a well; it only offers a systematic path to be followed in project management because this is a tool intended to be applied for any type of decision making in the oil and gas industry.

Bickel et al., (2006) studied dependence among geologic risks in sequential exploration decisions by developing a practical approach for modeling dependence among prospect wells and determining an optimal drilling strategy. The technique consists of constructing a joint probability distribution to measure the independence of success in a well based on another well results. Consequently, the use of a dynamic programming model for determining an optimal drilling strategy is utilized. Fortunately, this study is not limited to geologic factors; it can also include other uncertainties such as production rates and commodity prices.

Siddiqui et al. (2007) developed a tool to evaluate the feasibility of petroleum exploration projects using a combination of deterministic and probabilistic methods. The reason of this study is merely descriptive and encompasses, in a broad view, factors that must be taken into account when project feasibility is to be evaluated. This methodology does not represent an exhaustive process but a guideline of the risks that Exploration and Production ventures face; the applicability, advantages, and drawbacks of the deterministic and probabilistic models.

Baihly et al. (2007) proposed a methodology for risk management to maximize success in horizontal wells in tight gas sands. The objective of this study is to assist engineers in identifying and managing risks when planning, drilling, and completing horizontal wells in tight sandstone formations in order to improve success. The methodology emphasizes risk mitigation through the knowledge of several situations that can negatively impact the success of horizontal wells in tight gas sands. Regardless of the exhaustive aspects considered in each phase, this method does not specify where and when the deterministic and probabilistic models must take place in the process of horizontal vs. vertical wells assessment. Furthermore, this tool does not explain in detail the economic evaluation that one ought to perform; it simply refers to the technical aspects and the risk associated with.

As previously mentioned there have been several studies involving technical, economic and risk analysis. These methodologies are designed to be either applied in any type of decision making process or specific situations for exclusive well types and formations.

1.4 Objective

The objective of this study is to develop a methodology to assist engineers in their decision making process of maximizing access to reserves. The process encompasses technical, economic and risk analysis of various alternatives in the completion of a well (vertical, horizontal or multilateral) by using a well performance model for technical evaluation and a deterministic analysis for economic and risk assessment.

2. METHODOLOGY

2.1 Overview

To efficiently develop a field, each reservoir must be completed with a well system that maximizes the hydrocarbon recovery. Several alternatives can be selected based on the feasibility of the system, revenue vs. cost, and risk or uncertainty involved.

In order to properly analyze and evaluate a project, it is imperative to study first the technical features then followed by the economic and risk analysis. Prior to deciding the completion type to be used; one must be able to predict inflow performance from each well system, evaluate economic indicators which determines profitability, and risk associated with the success and/or failure.

The methodology presented in this study is designed to assist engineers in decision making process by using hypothetical examples under certain reservoir characteristics to evaluate whether a multilateral well application is the most efficient alternative to be chosen for a project. Since field data is not included in this study, several assumptions are made to help illustrate the applicability of the tool in an oil and gas well.

There are three cases used in the analysis based on the quality of the reservoir that is likely to be present: "high" (best permeability case scenario), "medium" (base permeability case scenario) and "low" (worst permeability case scenario). The methodology is described below.

2.2 Technical Analysis

In the technical study of the decision making process, a pseudo-steady state flow condition is assumed, which consists of a reservoir where no-flow boundaries are present. Drainage areas may be defined by natural limits such as faults and pinchouts, or induced by artificial limits from adjoining well production. As a result, the pressure at the outer boundary is not constant; it declines at a constant rate with time. This pressure decline in the reservoir can be estimated based on material balance of the drainage system.

This study examines the well performance in a hypothetical two layer reservoir as shown in **Fig. 2.1**; which includes the well structure of vertical, horizontal and multilateral well completions. Production rates are calculated as a function of reservoir drawdown, which is the difference between the average reservoir pressure ($\bar{p}$) and flowing bottom-hole pressure (p_{wf}), as the pressure depletes due to production. The reservoir pressure decline is assumed to be around 5% per year depending on the formation permeability.

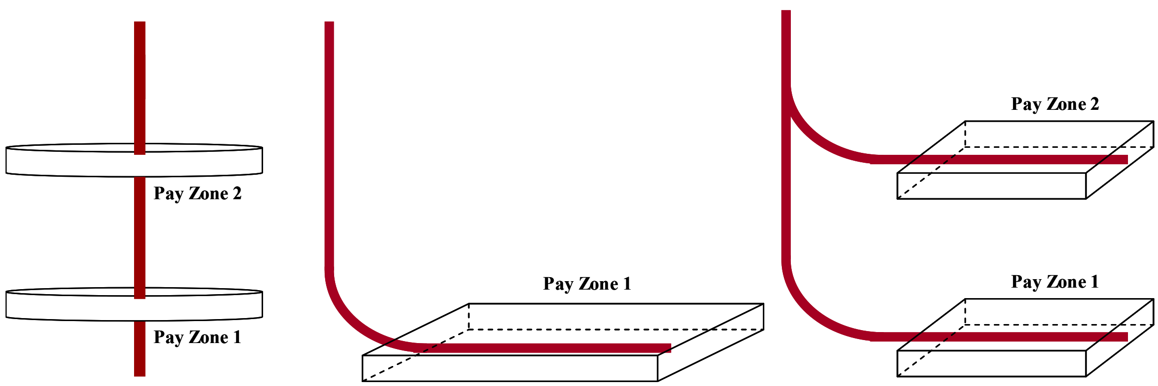

Fig. 2.1 Vertical, horizontal and multilateral well completions

2.2.1 Vertical Well Performance

The vertical well equations for inflow performance have been summarized by Economides et al. (1994). For an undersaturated oil reservoir, the inflow relationship is calculated by using **Eq. (2.1)** derived from Darcy's law:

$$q_o = \frac{kh\left(\bar{p} - p_{wf}\right)}{141.2 B_o \bar{\mu}\left(\ln \dfrac{0.472 r_e}{r_w} + s\right)} \tag{2.1}$$

where $\mathbf{q_o}$ is the oil flow rate in bbl/day, $\mathbf{B_o}$ is the oil formation volume factor in resbbl/STB, $\mathbf{r_e}$ is the drainage radius in ft, $\mathbf{r_w}$ is the well radius in ft, $\mathbf{s}$ is the dimensionless skin effect, and $\bar{\mu}$ is the oil viscosity in cp.

In natural gas wells, the previous inflow relationship can not be directly applied since the physical properties of hydrocarbon gases vary with time due to changes in pressure, temperature and gas composition.

Darcy's law for incompressible fluids can be adjusted by modifying the original Darcy's flow equation with the real gas law, in addition to a non-Darcy coefficient, **D**. The approximation for the pseudo-steady state flow regime considers instead an average value of gas viscosity ($\bar{\mu}$), temperature ($\bar{T}$) and gas compressibility ($\bar{Z}$) between $\bar{p}$ and p_{wf}; as it can be seen in **Eq. (2.2)**.

$$q_g = \frac{kh\left(\bar{p}^2 - p_{wf}^2\right)}{1424\bar{\mu}\bar{Z}\bar{T}\left(\ln 0.472\frac{r_e}{r_w} + s + Dq_g\right)} \tag{2.2}$$

where $\mathbf{q_g}$ is the gas flow rate in Mcf/day.

2.2.2 Horizontal and Multilateral Well Performance

Babu and Odeh developed one of the popular inflow models for horizontal laterals performance (1988-1989). The model assumes a box shaped drainage area with a horizontal well which has a length "**L**" parallel to the x-direction of the reservoir boundary with a length "**b**", a width "**a**", and a thickness "**h**" **(Fig. 2.2)**.

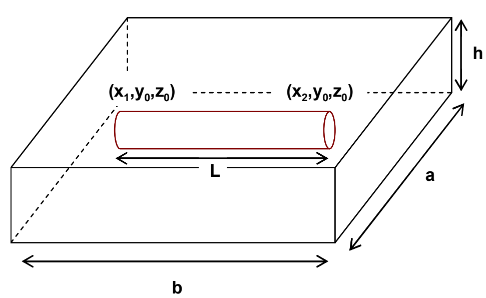

Fig. 2.2 Babu and Odeh's box shape model

One of the principles of this model is that the well can be positioned in any location of the reservoir however it must be parallel to the y-axis and not too close to any boundary.

Babu and Odeh's approach is based on a radial flow in the y-z plane which considers any deviation from the circular shape drainage area with a geometry factor, $\mathbf{C_H}$, and inflow from outside the wellbore in the x-direction or partial penetration skin factor, $\mathbf{s_R}$.

As a result, **Eq. (2.3)** shows the Babu and Odeh's inflow model for an oil well horizontal lateral performance:

$$q_o = \frac{b\sqrt{k_y k_z}\left(\bar{p} - p_{wf}\right)}{141.2 B_o \bar{\mu}\left[\ln\frac{\sqrt{A}}{r_w} + \ln C_H - 0.75 + s_R + s\right]} \tag{2.3}$$

where the shape factor, C_H, is obtained applying **Eq. (2.4)**

$$\ln C_H = 6.28\frac{a}{h}\sqrt{\frac{k_z}{k_y}}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5\ln\left[\left(\frac{a}{h}\right)\sqrt{\frac{k_z}{k_y}}\right] - 1.088 \tag{2.4}$$

since the examples presented in this study correspond exclusively to a long reservoir where (b>a) thus, s_R is calculated using **Eqs. (2.5) through (2.9)**

$$s_R = P_{xyz} + P_y + P_{xy} \tag{2.5}$$

$$P_{xyz} = \left(\frac{b}{L} - 1\right)\left[\ln\frac{h}{r_w} + 0.25\ln\frac{k_y}{k_z} - 1.05\right] \tag{2.6}$$

$$P_y = \frac{6.28 b^2}{ah}\frac{\sqrt{k_y k_z}}{k_x}\left[\frac{1}{3} - \frac{x_{mid}}{b} + \frac{x_{mid}^{\;2}}{b^2} + \frac{L}{24b}\left(\frac{L}{b} - 3\right)\right] \tag{2.7}$$

$$P_{xy} = \left(\frac{b}{L} - 1 \right) \left(\frac{6.28a}{h} \sqrt{\frac{k_z}{k_y}} \right) \left(\frac{1}{3} - \frac{y_0}{a} + \frac{{y_0}^2}{a^2} \right) \tag{2.8}$$

with

$$x_{mid} = \frac{x_1 + x_2}{2} \tag{2.9}$$

$$y_o = \frac{a}{2} \tag{2.10}$$

$$z_o = \frac{h}{2} \tag{2.11}$$

$$A = (a)(h) \tag{2.12}$$

Gas well horizontal lateral performance can be also calculated using Babu and Odeh's modified equation by Kamkom and Zhu (2006). **Eq. (2.13)** presents the adapted mathematical approach.

$$q_g = \frac{b\sqrt{k_y k_z}\left(\overline{P}^2 - {P_{wf}}^2\right)}{1424\overline{\mu}\overline{Z}\overline{T}\left[\ln\frac{\sqrt{A}}{r_w} + \ln C_H - 0.75 + s_R + s + Dq_g \right]} \tag{2.13}$$

The oil and gas flow rates at the surface are calculated by coupling the horizontal laterals well performance models with a wellbore flow model. For a single phase flow, mechanical energy balance equation is used to calculate hydrostatic and frictional pressure drop in the well. If flow becomes a two-phase system, empirical correlation is considered to calculate the pressure gradient for a particular location in the wellbore.

2.2.3 Decline Curve Analysis

In order to forecast flow rate, the analytical procedure showed before (Eqs. 2.1 through 2.13) is used to estimate production rate for six months. After the first initial rate of a vertical, horizontal and multilateral well (q_o or q_g) is obtained, we assume about 5% pressure decline rate per year to predict the next six months of production.

The DCA finds a curve that approximates the production history calculated from previously mentioned analytical models, using "least squares fit" analysis, and extrapolating this curve into the future (Mian, 2002a). Although, there are three rate-time decline curves –exponential, hyperbolic and harmonic declines (Arps, 1944) – only the hyperbolic decline curve is used since it considers the decline characteristic (**D_i**) not as a constant value but a variable that changes with producing time, and a curvature of this curve defined by a hyperbolic exponent (**b_{hyp}**).

To forecast production, the rate at time t is estimated by **Eq. (2.14).** Thus, to obtain the total produced volume (**N_p**) between the rate at an initial time (**Q_i**) and the rate at time t (**Q_t**) we use **Eq. (2.15)**. Once monthly volumes are predicted and compared to those derived from the analytical procedure, we utilize "least squares fit" analysis to constantly change Q_i, b_{hyp} and D_i variables in order to match monthly production rates.

$$Q_t = Q_i\left(1 + b_{hyp} D_i t\right)^{\left(-1/b_{hyp}\right)} \tag{2.14}$$

$$N_p = \frac{Q_i^{b_{hyp}}}{\left(1 - b_{hyp}\right) D_i}\left[Q_i^{1-b_{hyp}} - Q_t^{1-b_{hyp}}\right] \tag{2.15}$$

When Q_i, b_{hyp} and D_i for each well are obtained, production rates are forecasted using 25 years for vertical wells, and 15 years for horizontal and multilateral wells due to higher pressure drawdown and extended reservoir contact.

The production forecast is generated using a deterministic approach and different reservoir permeability conditions which have been previously determined: "high", "medium", and "low".

2.3 Economic Analysis

The economic analysis departs from FCF to obtain some of the economic yardsticks which are used to measure the economic worth of various investment proposals. **NPV**, **Eq. (2.16)**, internal rate of return (**IRR**), **Eq. (2.17)**, profitability index (**PI**), **Eq. (2.18)**, and payback period are the main indicators to be utilized.

$$NPV = \sum_{t=1}^{n} (F_v)_t \left[\frac{1}{(1+i_e)^t} \right] \tag{2.16}$$

$$IRR = NPV = \sum_{t=1}^{n} (F_v)_t \left[\frac{1}{(1+i_e)^t} \right] = 0 \tag{2.17}$$

$$PI = \frac{NPV}{CAPEX} \tag{2.18}$$

where **n** is the well life (months), $\mathbf{F_v}$ is the future sum received at time **t** ($), and $\mathbf{i_e}$ is the discount rate (%).

The net present value represents the cash surplus obtained by subtracting the present value of periodic cash outflows from the present value of periodic cash inflows. It is calculated using the discount rate or minimum acceptable rate of return. The internal rate of return refers to the discount rate at which the present value of cash inflows is equal to the present value of cash outflows. It can also be defined as the rate received for an investment consisting of payments and income that occur at regular periods. The profitability index is a dimensionless ratio that quantifies how much, in present value benefits, is created per dollar of investment. It shows the relative profitability of an investment. The payback period or breakeven point is the expected number of years or months required for recovering the original investment. It is calculated from accumulating the negative net cash flow each year until it turns positive (Mian, 2002a). The maximum negative cash flow is the amount of the CAPEX paid by the company, which is estimated from the working interest percentage.

Proposals are considered to be mutually exclusive, under a concessionary petroleum fiscal system. The concessionary system allows private ownership of mineral resources while paying royalties, and taxes to the host government to assign the right to explore and develop certain areas.

2.3.1 Economic Analysis Major Components

The economic yardsticks are obtained by calculating FCF at different interest rates that range from 0% to 25%. The major components of the economic analysis are ownership, commodity prices, CAPEX, and OPEX. Some of the considerations included in each component are presented below:

- Ownership: Working interest before payout and after payout, royalties, override, and net revenue interest before payout and after payout. Net revenue interest is associated with working interest and is highly dependant on the non-operating interest (e.g. royalties).
- Commodity Prices: Oil and gas initial prices with basis differential if needed, gathering and transportation fees, and energy content adjustment.
- CAPEX: Pre-drilling costs, drilling and completion costs, gathering and surface equipment costs, facilities costs, and abandonment costs.
- OPEX: Fixed or lease costs, variable costs, water disposal costs, and production taxes.

2.3.2 Economic Analysis Procedure

FCF is estimated by assessing the gross revenue from a certain type of well including the production forecast. The data is assimilated from royalties to be paid, OPEX, depreciation, depletion, amortization, intangible drilling cost, and taxes **(Fig. 2.3)**.

For this study, federal income taxes and deductions other than CAPEX and OPEX will be diminished since the purpose of this methodology is merely illustrative rather than an exhaustive economic analysis.

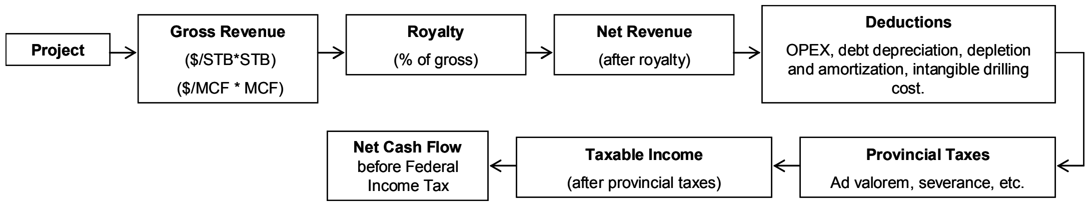

Fig. 2.3 Concessionary system cash flow diagram

2.4 Risk Analysis

After the economic analysis is finished, we further conduct a risk analysis to complete the evaluation of a project. Thus, a decision tree is used to analyze the risk involved in a project, which is a deterministic tool that aids in the decision making process by graphically representing a set of alternative courses of action that provides a set of different outcome states (Mian, 2002b). New technologies such as multilateral well systems will likely bring a higher return on investment. Their inherited risk is generally higher too.

Prior to building the decision tree, an influence diagram (Clemen and Reilly, 2001), which represents graphically the situations affecting an event or outcome, is developed to visualize all factors that have influence on the type of well system to be implemented. An influence diagram may encompass a number of different aspects that may influence whether a certain type of well is to be drilled, however we isolated only four of those which we believed play the most significant role in the decision process. **Fig. 2.4** sets forth those four aspects: geological features, reservoir engineering, drilling and completion successes (Brister, 2000), and the influence they have upon each other and the expected monetary value ($).

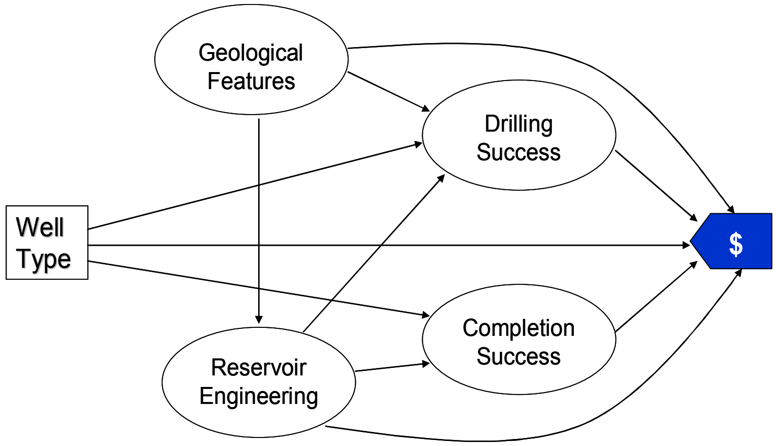

Fig. 2.4 Influence diagram for a deterministic decision tree analysis

A decision tree is created to aid in the assessment of risk involved in every aspect as previously determined in the influence diagram. The following conventions are adopted in structuring the decision tree:

- Decision node (): It illustrates nodes where decisions have to be made. The most optimal alternative between courses of action is to be selected. The option with the highest expected monetary value is chosen.
- Chance node (): It represents points where there are different possible outcomes at a node. The decision maker has no control over these actions and only chance or nature determines an outcome.
- Probability (%) or chance: It addresses the likelihood of possible outcomes. Previous experience and knowledge are used to objectively evaluate the chance of each outcome to occur.
- End, terminal or payoff node (): It is the deterministic financial outcome of a decision. It is based on any type of economic indicator, although usually NPV at certain discount rate is utilized. This type of node connects the economic estimator, based on technical evaluation, to the risk analysis. Using probability, p_i, for the event i at a chance node, C_1, the expected monetary value, **EMV**, is calculated by using **Eq. (2.19)**.

$$EMV\{C_1\} = \sum_{i=1}^{n} p_i (NPV_i) \tag{2.19}$$

The most critical decision to be made is in the "leftmost" decision node of a tree. At this point, the selection comes only after considering the expected monetary value (NPV at 10% discount rate is to be utilized for this methodology) of the various outcomes, and the probabilities of success or failure of the prospective well. The choice is made whether to drill and complete (D&C) a vertical, horizontal or multilateral well **(Fig. 2.5)**.

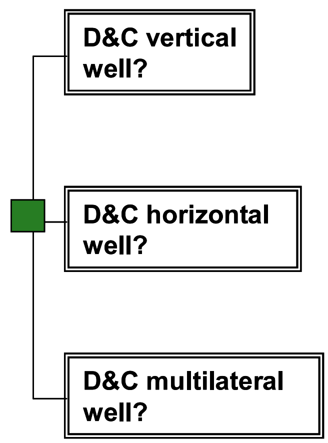

Fig. 2.5 Decision tree alternatives to drill and complete a well

One must be aware that assigning chances can be detrimental for the selection of the best option; objective and careful analysis from the decision makers is imperative. Prior to assessing probabilities in a decision tree, engineers should acquire all pertinent data and lessons learned from previous experience.

The decision tree used in this methodology starts from the geological conditions (e.g. faults/compartments); followed by the reservoir engineering evaluation or quality of the reservoir (e.g., high, medium and low permeability); and then success/failure of drilling and completing the well (**Fig. 2.6**). Each branch of this decision tree has a specific probability as function of predetermined conditions and well type in order to estimate the expected monetary value of NPV at 10% discount rate.

The first chance node from the left illustrated in Fig. 2.6 corresponds to the likelihood of the geological features to be encountered in the reservoir. Regardless the type of well under study, the chances to face a reservoir with these type of heterogeneities is independent and simply assigned according to previous experience or knowledge of the field.

The effects of geological features are taken into account on the second chance node, when the reservoir engineering characteristics are defined (Fig. 2.6). The first chance node is believed to positively and/or negatively influence this second chance node.

It is predetermined that the drilling success is affected not only by the type of well but also by the geological features and reservoir quality that is present. Meanwhile, the completion success will likewise depend purely upon the type of well system.

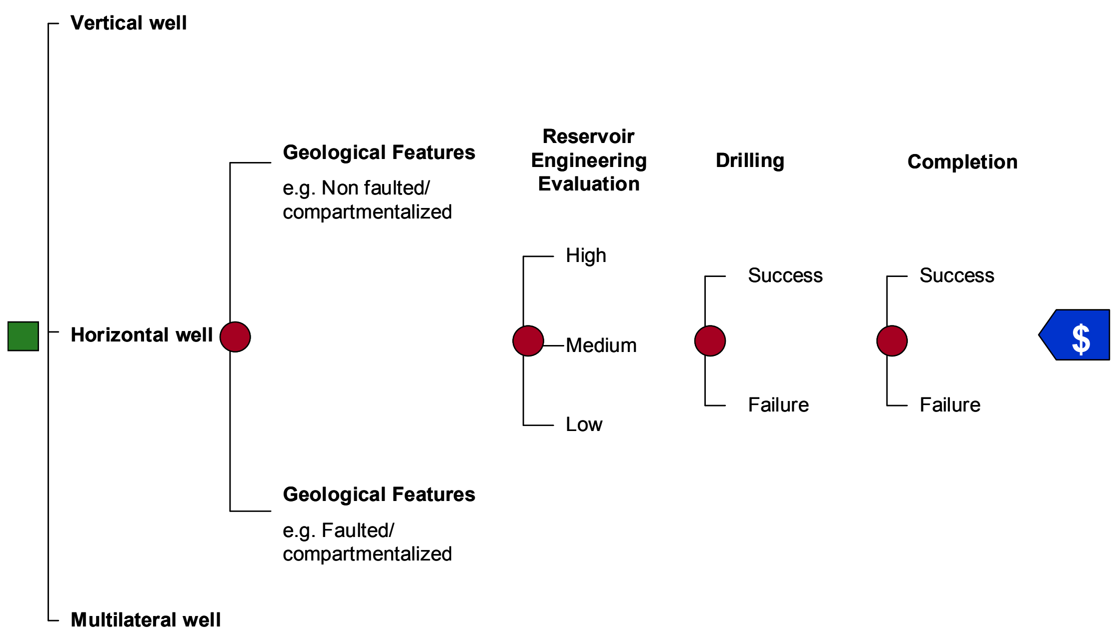

Fig. 2.6 Decision tree structure

2.4.1 Vertical Well Decision Tree Analysis

From the heterogeneity stand point, a vertical well inflow performance is not directly affected by significant anisotropy ratio (k_v/k_h) because only k_h impacts production. In addition, faults/compartments are determined to be located further than the drainage radius estimated to be reached by vertical well systems, which are intended to drain a pay zone within boundaries due to geological conditions that are present. However, the likelihood to encounter a “high”, “medium” or “low” quality reservoir can be dependant on faults/compartments.

For the various vertical well branches of the decision tree (Fig. 2.6), the following are the main factors affecting each decision and chance node:

Geological features:

- Lateral extent of the reservoir
- Lithology of target formation

Reservoir engineering characteristics:

- Thickness of the formation
- k_h
- Porosity
- Reservoir pressure and decline rate
- Fluid properties

Drilling features:

- Tubular capacity
- Wellbore stability

Completion features:

- Control of sand production
- Stimulation
- Ability to implement the lifting mechanism

2.4.2 Horizontal Well Decision Tree Analysis

The inflow performance in horizontal wells is highly affected by the degree of heterogeneity in a formation. Considerable anisotropy ratio affects the performance of a horizontal well despite faults or compartments existent in the reservoir. Horizontal wells have the ability to drain longer lateral extent reservoirs regardless of complexity of faulting, folding, compartmentalization; the drilling technique used surpasses these abnormalities. However, as it is in vertical wells, the likelihood to encounter a "high", "medium" or "low" quality reservoir can be dependant on geological features.

For the various horizontal well branches of the decision tree (Fig. 2.6), the following are the main factors affecting each decision and chance node:

Geological features:

- Structural complexity of faulting and folding
- Compartmentalization
- Natural fracture network
- Lateral extent of the reservoir
- Lithology of target formation

Reservoir engineering characteristics:

- Thickness of the formation
- k_h and k_v
- Porosity
- Reservoir pressure and decline rate
- Fluid properties
- Contact area

Drilling features:

- Re-entry feasibility
- Tubular capacity
- Wellbore stability, especially in horizontal laterals
- Kick off and build section

Completion features:

- Control of sand production
- Stimulation
- Ability to implement the lifting mechanism
- Zonal isolation

2.4.3 Multilateral Well Decision Tree Analysis

As the horizontal well branch, the multilateral branch discusses the applicability of a well based on the heterogeneity of the reservoir by the presence of faults, compartmentalization, and anisotropy ratio.

After evaluating the previously mentioned conditions and determining whether the prospect is an exceptional or poor application for multilateral, the geological features are analyzed in order to better understand the potential of the reservoir and the probabilities thereof.

For the various multilateral well branches of the decision tree (Fig. 2.6), the following are the main factors affecting each decision and chance node:

Geological features:

- Structural complexity of faulting and folding
- Compartmentalization
- Natural fracture network
- Lateral extent of the reservoir
- Lithology of target formation
- Multilayer formation

Reservoir engineering characteristics:

- Thickness of the formation
- k_h and k_v
- Porosity
- Reservoir pressure and decline rate
- Fluid properties
- Contact area

Drilling features:

- Junction stability
- Debris management
- Re-entry feasibility
- Laterals isolation
- Wellbore stability, especially in laterals
- Tubular capacity

Completion features:

- Mechanical Integrity
- Control of sand production
- Stimulation
- Ability to implement the lifting mechanism
- Zonal and lateral isolation

2.5 Sensitivity Analysis

As an additional section of the methodology, we have decided to include a brief sensitivity analysis that can be useful when it is extremely important to identify the most significant factors affecting the outcome of a project selection.

This technique is used to determine how different values of an independent variable e.g. reservoir quality, geological conditions, etc. can impact a dependent variable such as the expected monetary value of NPV at 10% discount rate.

3. UNDERSATURATED OIL WELL APPLICATION

3.1 Overview

The applicability of multilateral technology varies since reservoir conditions are always unique and each reservoir is characterized differently. As a result, vertical wells or horizontal wells can be considered as optimum choices when a multilateral technology application can not yield better production at the minimum cost in a development project.

The following describes two different examples where a decision of drilling a vertical, horizontal or multilateral well must be made. The first case (Example 1) is intended to illustrate the applicability of a multilateral system considering heterogeneity due merely to a moderate anisotropic reservoir (k_v/k_h=0.10 ratio). Conversely, the second case (Example 2) is planned to show that in some cases multilateral systems are less attractive such as in highly anisotropic reservoirs (k_v/k_h=0.01 ratio) with exactly the same formation characteristics as presented in Example 1.

These hypothetical examples depart from a technical and economic analysis; addressing geological features impact, and drilling and completion rate of success in the risk analysis section.

3.2 Example 1: Oil Well

Example 1 consists of a well with two pay zones: zone 1 with a net height of 100 ft and a "medium" permeability of 40 md, and zone 2 with 60 ft net height and 20 md of "medium" permeability. The reservoir properties may vary due to uncertainty of the information previously studied and analyzed. However, for this study, we have determined that the reservoir quality is exclusively examined based on permeability in order to simplify the number of variables affecting the reservoir quality.

Figure 3.1 shows each of the different well configurations analyzed in Example 1. By assuming a well with two pay zones, one can drill and complete the reservoir by a vertical, horizontal or multilateral well. Hypothetically, the vertical well structure produces from both zones with 1489 ft of drainage radius. The horizontal well structure is a system producing from zone 1, which has a lateral length of 3000 ft to overcome the fault estimated to be located 1500 ft away form the wellbore. The multilateral well structure differs from the horizontal by the number of laterals drilled. This configuration is designed to drain pay zones 1 and 2 with lateral lengths of 2500 ft each in order to reduce CAPEX while maximizing production.

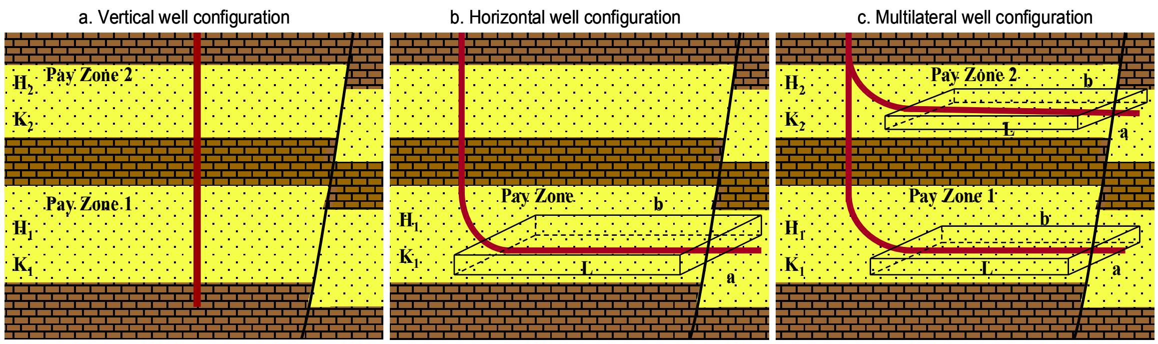

Fig. 3.1 Well planning for examples 1 through 3

3.2.1 Example 1 – Technical Analysis

Since uncertainty in the geological and reservoir engineering parameters may result in inaccurate information, three different scenarios are used to estimate production rates as function of permeability values: best, base and worst case scenarios. In order to assume that the reservoir is characterized by a highly permeable formation, 150% of the "base case scenario" permeability (k_v and k_h) is utilized for "best case scenario", and 50% for "worst case scenario".

The input data for Example 1 is presented in **Table 3.1**, which shows all reservoir information assuming "high", "medium" and "low" permeability values on the vertical, horizontal and multilateral well configurations necessary to predict production performances.

The bottom-flowing pressure is calculated for pay zone 2 based on pay zone 1 bottom-hole flowing pressure, which assumes 2000 psi. The vertical well configuration (p_{wf}) uses only a hydrostatic pressure drop of 0.433 psi/ft, subtracted from pay zone 1.

The multilateral well configuration (p_{wf}^{*}) utilizes a mechanical energy balance equation to calculate hydrostatic pressure drop and frictional pressure drop in the well.

Table 3.1 Examples 1 & 2 – Oil reservoir properties

Input Data for Examples 1 & 2						
Parameter	Worst Case Scenario		Base Case Scenario		Best Case Scenario	
	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2
k_h (md):	20	10	40	20	60	30
k_v example1 (md):	2	1	4	2	6	3
k_v example 2 (md):	0.2	0.1	0.4	0.2	0.6	0.3
h (ft):	100	60	100	60	100	60
B_o (resbbl/STB):	1.1	1.1	1.1	1.1	1.1	1.1
μ (cp):	2	2	2	2	2	2
r_e (ft):	1489	1489	1489	1489	1489	1489
r_w (ft):	0.328	0.328	0.328	0.328	0.328	0.328
s:	8	5	8	5	8	5
s*:	16	10	16	10	16	10
$\bar{p}$ (psi):	3500	3200	3500	3200	3500	3200
p_{wf} (psi):	2000	1567	2000	1567	2000	1567
p_{wf}^{*} (psi):	2000	1635	2000	1635	2000	1635
T (^{o}F):	210	190	210	190	210	190
a* (ft):	1000	1000	1000	1000	1000	1000
b* (ft):	3500	3500	3500	3500	3500	3500
$L_{horizontal}$ (ft):	3000	N/A	3000	N/A	3000	N/A
$L_{multilateral}$ (ft):	2500	2500	2500	2500	2500	2500
TVD (ft):	7100	6000	7100	6000	7100	6000

* Only applicable for horizontal and multilateral wells

For a vertical well, the flowing bottom-hole pressure in the second zone is 1567 psi (2000 psi – 433 psi). It considers only the hydrostatic pressure drop (pressure gradient for water) between pay zone 1 and pay zone 2.

First, the initial production is estimated in each well system for the first six months assuming a pressure decline rate of about 5% annually. Using Eq. (2.1), we have the following vertical well "base case scenario" initial oil production:

$$q_{o_{vertical-payzone1}} = \frac{(100)(40)(3500-2000)}{141.2(1.1)(2)\left(\ln\frac{0.472(1489)}{0.328}+8\right)} = 1233\,\text{STB/day} \tag{3.1}$$

$$q_{o_{vertical-payzone2}} = \frac{(60)(20)(3200-1567)}{141.2(1.1)(2)\left(\ln\frac{0.472(1489)}{0.328}+5\right)} = 498\,\text{STB/day} \tag{3.2}$$

As a result, the total oil production for the vertical well system is:

$$q_{o_{vertical}} = q_{o_{vertical-payzone1}} + q_{o_{vertical-payzone2}} = 1233 + 498 = 1731\ \text{STB/day} \tag{3.3}$$

For horizontal and multilateral wells "base case scenario", initial oil production is obtained using Eqs. (2.3) through (2.12).

The horizontal oil flow rate is presented below:

$$y_o = \frac{1000}{2} = 500 \tag{3.4}$$

$$z_o = \frac{100}{2} = 50 \tag{3.5}$$

$$\ln C_H = 6.28\frac{1000}{100}\sqrt{\frac{4}{40}}\left[\frac{1}{3}-\frac{500}{1000}+\left(\frac{500}{1000}\right)^2\right]-\ln\left(\sin\frac{\pi(50)}{100}\right)$$
$$-0.5\ln\left[\left(\frac{1000}{100}\right)\sqrt{\frac{4}{40}}\right]-1.088 = -0.01 \tag{3.6}$$

where

$$P_{xyz} = \left(\frac{3500}{3000} - 1\right)\left[\ln\frac{100}{0.328} + 0.25\ln\frac{40}{4} - 1.05\right] = 0.87 \tag{3.7}$$

$$x_{mid} = \frac{250 + 3250}{2} = 1750 \tag{3.8}$$

$$P_y = \frac{6.28(3500)^2}{(1000)(100)}\frac{\sqrt{(40)(4)}}{40}$$
$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{3000}{24(3500)}\left(\frac{3000}{3500} - 3\right)\right] = 1.65 \tag{3.9}$$

$$P_{xy} = \left(\frac{3500}{3000} - 1\right)\left(\frac{6.28(1000)}{100}\sqrt{\frac{4}{40}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 0.27 \tag{3.10}$$

$$s_R = 0.87 + 1.65 + 0.27 = 2.79 \tag{3.11}$$

then

$$q_{o_{horizontal}} = \frac{3500\sqrt{(40)(4)}(3500 - 2000)}{141.2(1.1)(2)\left[\ln\frac{\sqrt{(1000)(100)}}{0.328} - 0.01 - 0.75 + 2.79 + 16\right]}$$
$$= 8586 \text{ STB/d ay} \tag{3.12}$$

For multilateral well “base case scenario”, the initial oil production for lateral 1 (bottom branch) is obtained as followed:

$$P_{xyz} = \left(\frac{3500}{2500} - 1\right)\left[\ln\frac{100}{0.328} + 0.25\ln\frac{40}{4} - 1.05\right] = 2.09 \tag{3.13}$$

using y_o calculated in **Eq. (3.4)** and having x_{mid} estimated by applying Eq. (2.9), then

$$x_{mid} = \frac{500+3000}{2} = 1750 \tag{3.14}$$

$$P_y = \frac{6.28(3500)^2}{(1000)(100)} \frac{\sqrt{(40)(4)}}{40} \left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{2500}{24(3500)} \left(\frac{2500}{3500} - 3 \right) \right] = 3.72 \tag{3.15}$$

$$P_{xy} = \left(\frac{3500}{2500} - 1 \right) \left(\frac{6.28(1000)}{100} \sqrt{\frac{4}{40}} \right) \left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2} \right) = 0.66 \tag{3.16}$$

$$s_R = 2.09 + 3.72 + 0.66 = 6.47 \tag{3.17}$$

Thus, q_o for lateral 1 is estimated utilizing the same shape obtained in **Eq. (3.6)**.

$$q_{o_{lateral1}} = \frac{3500\sqrt{(40)(4)}(3500-2000)}{141.2(1.1)(2)\left[\ln \frac{\sqrt{(1000)(100)}}{0.328} - 0.01 - 0.75 + 6.47 + 16 \right]} = 7479 \text{ STB/day} \tag{3.18}$$

After using the modified Hagedorn-Brown empirical correlation to determine the pressure drop (Δp) in the wellbore between lateral 1 and lateral 2 (upper branch), the total Δp for 1000 ft wellbore length between laterals is 365 psi. Therefore, the flowing bottom-hole pressure, p_{wf} *, for lateral 2 is calculated to be 1635 psi (2000 psi – 365 psi).

If we assume that there is no pressure drop in the lateral, then the drawdown for lateral 2 will be 1565 psi (3200 psi – 1635 psi).

Next, the initial oil production rate for lateral 2 "base case scenario" is estimated by

$$z_o = \frac{60}{2} = 30 \tag{3.19}$$

with y_o calculated with Eq. (3.4) and x_{mid} estimated with **Eq. (3.14)**, then

$$\ln C_H = 6.28\frac{1000}{60}\sqrt{\frac{2}{20}}\left[\frac{1}{3} - \frac{500}{1000} + \left(\frac{500}{1000}\right)^2\right] - \ln\left(\sin\frac{\pi(30)}{60}\right)$$

$$-0.5\ln\left[\left(\frac{1000}{60}\right)\sqrt{\frac{2}{20}}\right] - 1.088 = 0.83 \tag{3.20}$$

$$P_{xyz} = \left(\frac{3500}{2500} - 1\right)\left[\ln\frac{60}{0.328} + 0.25\ln\frac{20}{2} - 1.05\right] = 1.89 \tag{3.21}$$

$$P_y = \frac{6.28(3500)^2}{(1000)(60)}\frac{\sqrt{(20)(2)}}{20}$$

$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{2500}{24(3500)}\left(\frac{2500}{3500} - 3\right)\right] = 6.20 \tag{3.22}$$

$$P_{xy} = \left(\frac{3500}{2500} - 1\right)\left(\frac{6.28(1000)}{60}\sqrt{\frac{2}{20}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 1.10 \tag{3.23}$$

$$s_R = 1.89 + 6.20 + 1.10 = 9.19 \tag{3.24}$$

Thus, q_o for lateral 2 is estimated to be:

$$q_{o_{lateral2}} = \frac{3500\sqrt{(20)(2)}(3200-1635)}{141.2(1.1)(2)\left[\ln\frac{\sqrt{(1000)(60)}}{0.328}+0.83-0.75+9.19+10\right]}$$

$$= 4308 \text{ STB/day} \tag{3.25}$$

Consequently, the total oil production for the multilateral well system is:

$$q_{multilateral} = q_{o_{lateral1}} + q_{o_{lateral2}} = 7479 + 4308 = 11787 \text{ STB/day} \tag{3.26}$$

Since the sole purpose of the examples presented in this study is to take the reader through the decision process methodology, only initial oil production calculation is depicted. Furthermore, water production is accounted for after the first year of production, starting at 5% of total oil production, and increasing 5% annually assuming a vertical well life of 25 years and 15 years for horizontal and multilateral wells, as mentioned previously.

Although, initial oil production estimation is given in detail in the equations above, **Table 3.2** shows additional six months of production (q_o) calculated using these analytical models and a reservoir pressure decline of about 5% per year. As a result, the multilateral well yields the highest production.

After the initial production is calculated, the next six months production rates are then estimated utilizing the procedure set forth earlier to perform DCA and forecast production for the different well systems. Throughout "least squares fit" analysis and Eqs. (2.14) and (2.15), we have obtained Q_i, D_i and b_{hyp} in order to estimate daily production and cumulative monthly production (**Table 3.3**). **Figs. 3.2 through 3.4** portray the matching of hypothetical production against the results obtained utilizing hyperbolic decline with estimators displayed in Table 3.3.

For exercise purpose, a minimum decline rate is assumed without considering any detailed change in the reservoir or well system thus, the decline curves are straight lines in Figs. 3.2 through 3.4. In field practice, more sophisticated decline based on production history and reservoir characterization should be applied.

Table 3.2 Example 1 – Analytical model results under "base case scenario"

Month	Vertical Well $q_{o\ payzone1}$ (STB/day)	Vertical Well $q_{o\ payzone2}$ (STB/day)	Horizontal Well $q_{o\ horizontal}$ (STB/day)	Multilateral Well $q_{o\ multilateral}$ (STB/day)
1	1233	498	8586	11787
2	1227	496	8567	11710
3	1215	492	8447	11683
4	1203	488	8320	11516
5	1186	482	8182	11334
6	1161	473	7981	11071
7	1121	460	7670	10660

Table 3.3 Example 1 – DCA results under "base case scenario"

Estimator	Vertical $Well_{payzone1}$	Vertical $Well_{payzone2}$	Horizontal Well	Multilateral Well
Q_i, STB/day	1251	504	8790	12135
D_i/year nominal rate	0.167	0.148	0.221	0.210
b_{hyp}	1.457E-06	0.027	1.525E-06	1.342E-06

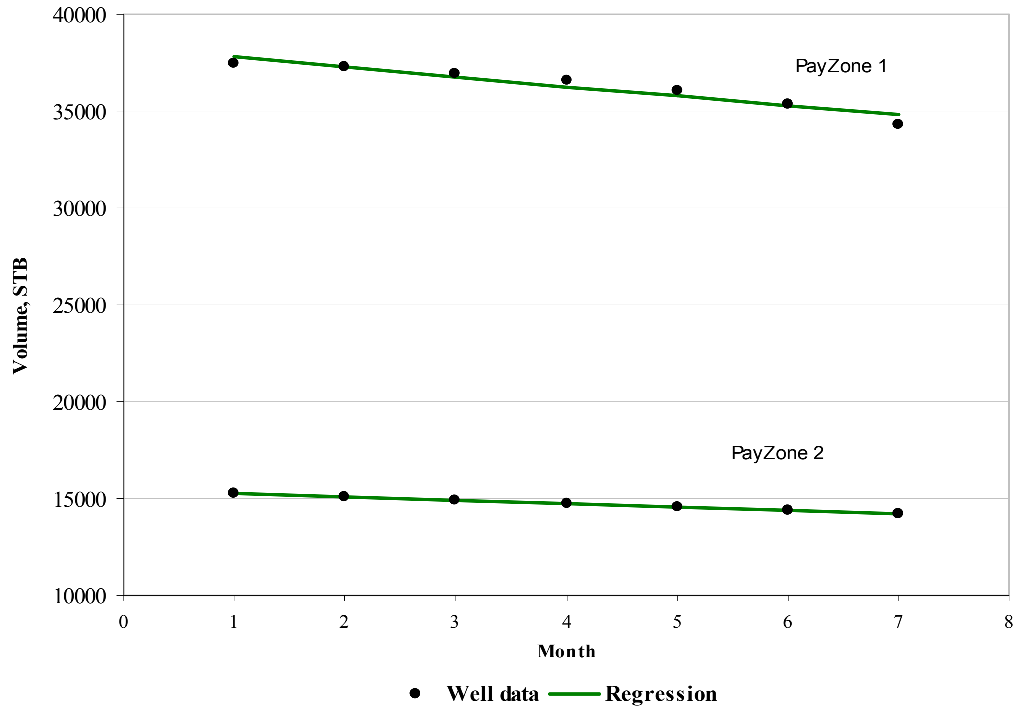

Fig. 3.2 Examples 1 & 2 – DCA for a vertical well system under "base case scenario"

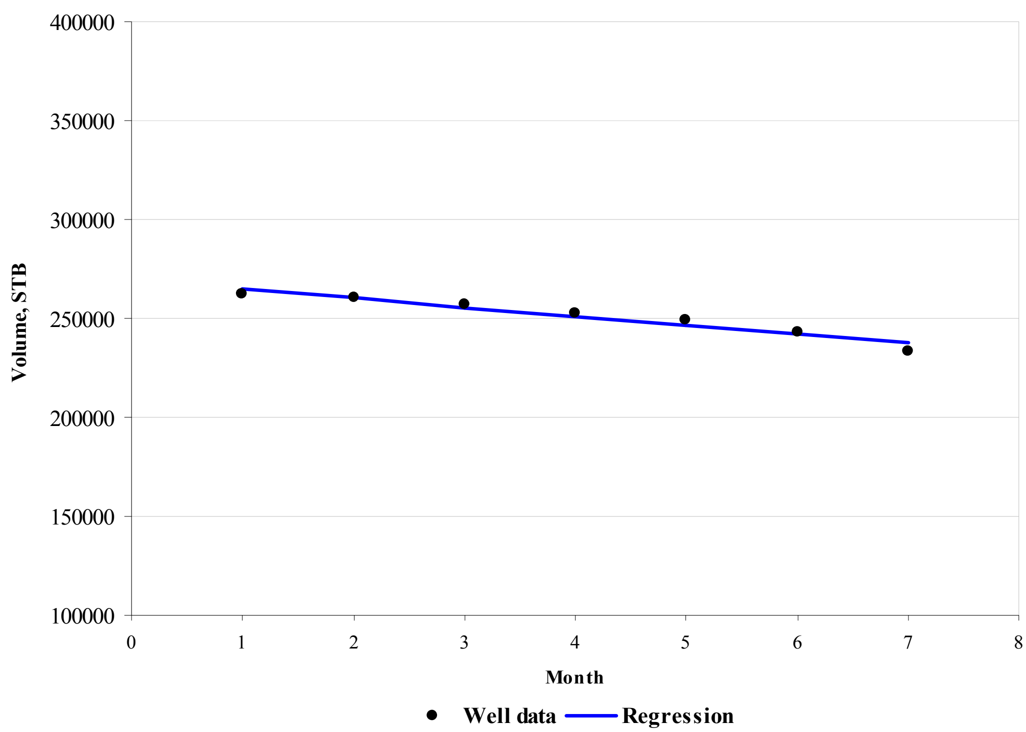

Fig. 3.3 Example 1 – DCA for a horizontal well system under "base case scenario"

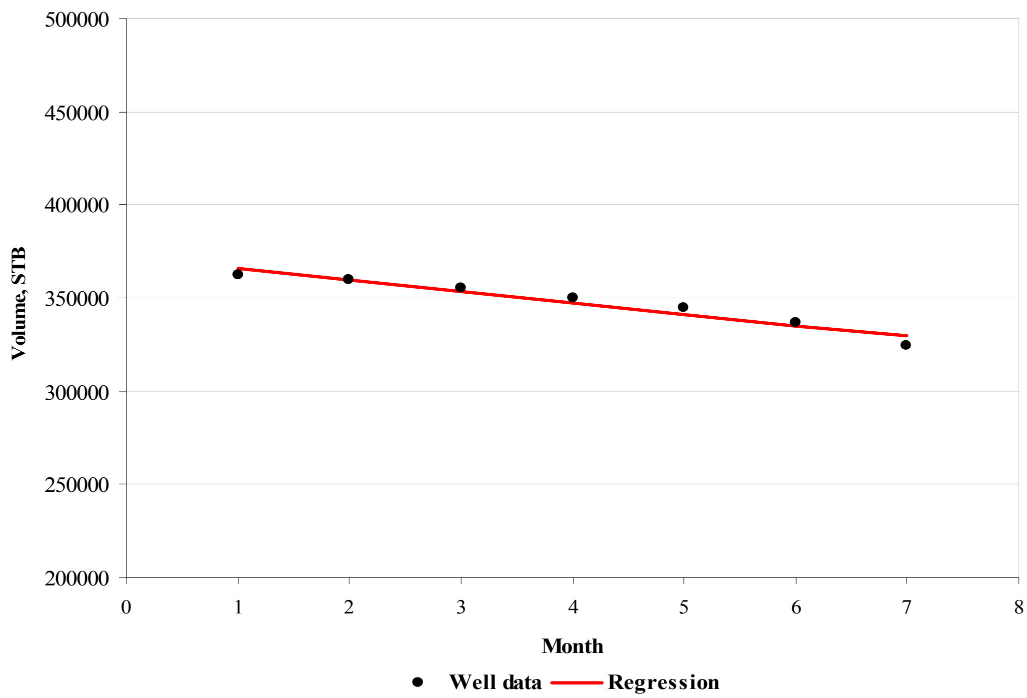

Fig. 3.4 Example 1 – DCA for a multilateral well system under "base case scenario"

After performing DCA, we can observe that the initial production rate for a horizontal well surpasses the vertical well by 5 fold while the multilateral well exceeds it by nearly 7 fold (Table 3.3). Obviously, the production increase by assuming horizontal drilling with a one or two branch system is extremely high because the moderate anisotropy ratio (k_v/k_h=0.10) does not diminish the benefits, and a significant lateral extent of the reservoir is drained.

The hyperbolic decline curve estimators, for "worst case scenario" and "best case scenario", only differ from "base case scenario" in the initial production rate. D_i and b_{hyp} estimators are kept the same since drawdown pressure remains equal regardless permeability values.

Figure 3.5 shows the monthly production data forecasted by DCA under "base case scenario". The semi-log plot reveals an increase in production from drilling and completing a multilateral well versus a horizontal well, almost 1.5 fold, due to the geometry previously defined for the box-shaped reservoir. Lateral length in a horizontal well is 3000 ft while 2500 ft for a multilateral well. Overall, **Fig. 3.6** also reflects the considerable benefit from a multilateral well in the cumulative oil production.

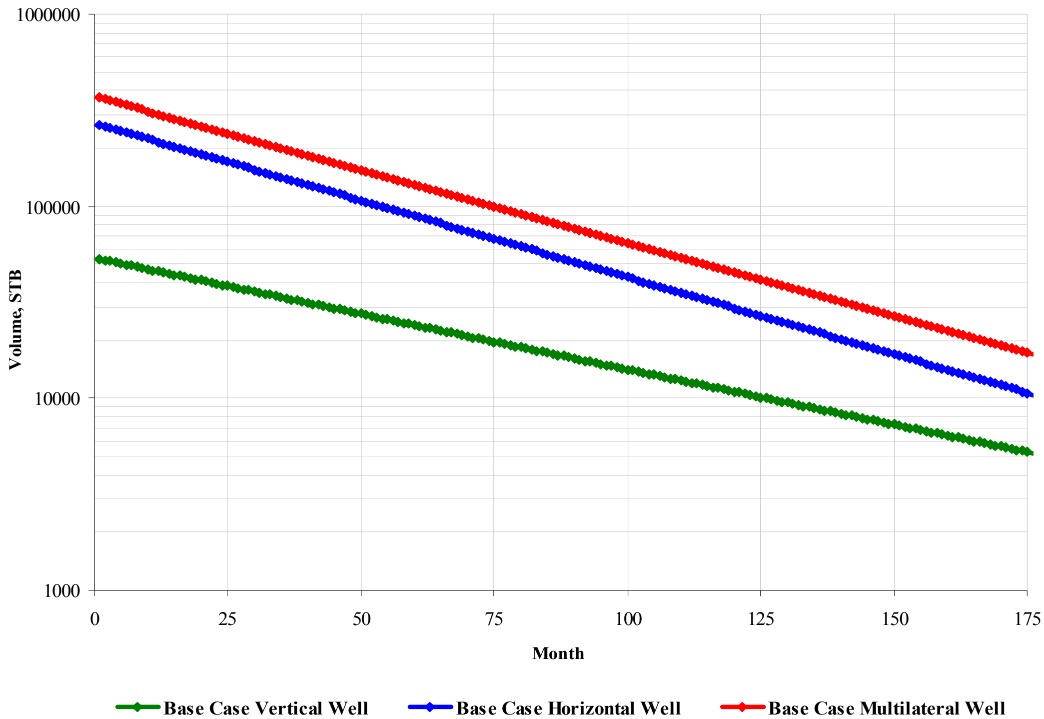

Fig. 3.5 Example 1 – Monthly production rate under "base case scenario"

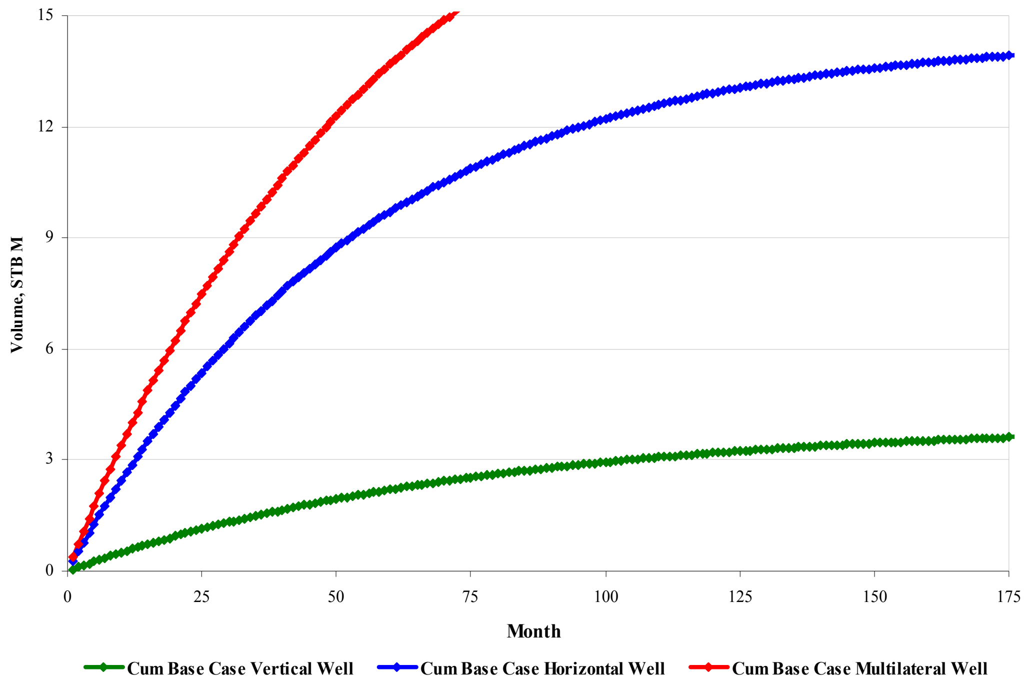

Fig. 3.6 Example 1 – Cumulative production rate under "base case scenario"

As a result of the previous DCA, **Table 3.4** summarizes the initial production rates for the different well systems assuming the three different case scenarios. The increase or decrease in production is directly proportional to the reservoir quality (permeability for this particular study).

Table 3.4 Example 1 – Summary of initial monthly production rate

Well Type	Example 1- Initial Monthly Oil Production, STB/month		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	26,544	53,086	79,635
Horizontal Well	132,547	265,097	397,644
Multilateral Well	182,979	366,137	549,718

3.2.2 Example 1 – Economic Analysis

This type of analysis must embrace several economic indicators commonly used in the industry to evaluate and rank projects. Therefore, an economic analysis before-tax program developed using Visual Basic Code (VBA) has been created utilizing expected production rates to generate cash flows.

Table 3.5 shows the main input data used for each well system to generate FCF. Drilling and completion costs for a horizontal well is 1.6 times higher than a vertical well cost, meanwhile a multilateral well exceeds a vertical well by almost 2.5 times. Variable operating cost and consequently finding and development costs are believed to decrease if horizontal or multilateral wells are adopted. For practical reasons, water disposal is set the same regardless the well system. As a result of the fiscal system assumed, royalties and working interest before and after payout are 12% and 80% respectively with 5% ad valorem.

Table 3.5 Examples 1 & 2 – Economic input data for oil wells

Economic Input Data for Oil Wells			
	Vertical Well	Horizontal Well	Multilateral Well
Oil price, $/bbl	$ 80	$ 80	$ 80
Fixed operating cost, $/well	$ 2,000	$ 4,000	$ 4,500
Variable operating cost, $/bbl	$ 10	$ 8	$ 6
Water disposal, $/bbl	$ 2	$ 2	$ 2
Drilling and completion cost	$ 2,500,000	$ 4,000,000	$ 6,000,000

NPV, internal rate of return, profitability index, payout period, and maximum negative cash flow are among some of the economic indicators calculated by a program developed in this study. Nevertheless, since NPV is selected for this study as the economic yardstick to be utilized in the risk analysis section, we only portray, without an extensive discussion, a few of the other economic indicators in **Table 3.6**. While some big operating companies do not have any major hurdle while investing, small or independent operating companies need to carefully analyze the amount of maximum negative cash flow which may be faced through an investment; e.g., for the well system alternatives described above, it is clear that a multilateral well requires approximately twice the investment of a vertical well (Table 3.6).

Horizontal and multilateral wells internal rate of return exceed the vertical well internal rate of return by 3.5 times despite the high vertical well internal rate of return estimation. Horizontal drilling by one or two branches systems have quicker payout and larger cash flows, which indicates more efficient alternatives. Furthermore, horizontal and multilateral wells profitability index surpass by 3 fold vertical well profitability index, which means that for every dollar invested (CAPEX) a horizontal or multilateral well yields 3 times more cash flow compared to a vertical well (Table 3.6).

Table 3.6 Example 1 – Summary of economic results under “base case scenario”

Example 1 - Economic Results			
Economic Indicator	Base Case Scenario		
	Vertical Well	Horizontal Well	Multilateral Well
Well payout	33 days	10 days	10 days
Profitability index	39.59	109.76	111.95
Internal rate of return	1049%	3569%	3526%
Max. negative cash flow	- $ 2.28 M	- $ 3.52 M	- $ 5.12 M

Figure 3.7 plots the cumulative FCF for a medium reservoir quality case. The return on investment occurs immediately after the well starts producing, 10 days payout period for horizontal and multilateral well systems, and one month for a vertical well system. Even though Fig. 3.7 illustrates the first 175 months of production by plotting the total well life, the total cumulative FCF for a vertical well is $ 145 M (25 years), $ 546 M for a horizontal well and $ 818 M for a multilateral well (15 years). These time frames do not represent the economic limit, but rather a life span to run a simplified economic analysis.

Similar to the technical analysis, the economic analysis leads us to believe that the multilateral well is the most profitable option from the production rate and cumulative FCF stand points. Moreover, **Table 3.7** shows the NPV results under all three different scenarios. The highest NPV is obtained by drilling and completing a multilateral well system ($ 573 M under base case scenario) while the lowest NPV is achieved by drilling and completing a vertical well system ($ 90 M under base case scenario). Despite reservoir quality, NPV results are consistently presenting the multilateral well system as the most lucrative choice.

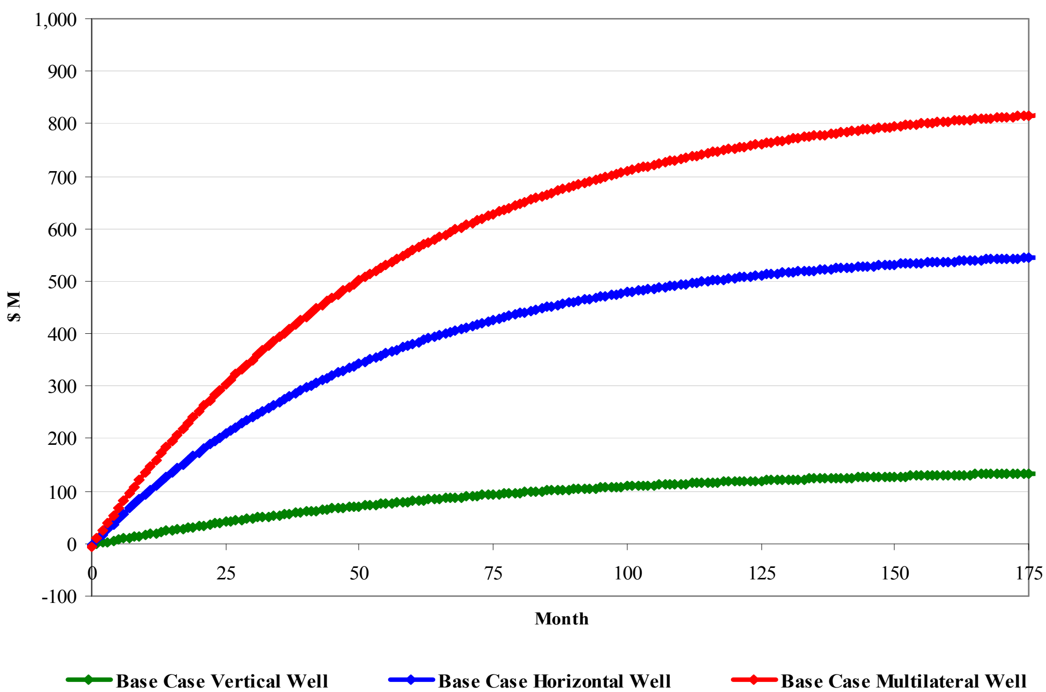

Fig. 3.7 Example 1 – Cumulative FCF under "base case scenario"

Table 3.7 Example 1 – Summary of NPV at 10% discount rate

Well Type	Example 1- NPV at 10% discount rate, $ M		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	43.77	90.26	136.14
Horizontal Well	191.19	386.36	581.44
Multilateral Well	283.63	573.21	863.74

3.2.3 Example 1 – Risk Analysis

To analyze all the risk involved in the selection of the most optimum well system, this study addresses in **Table 3.8** the likelihood of having faults as one of the geological features characterizing the formation. **Table 3.9** refers to the quality of the reservoir whether faults exist, and if a high or low anisotropy ratio is present. Although these assigned probabilities can be defined by engineers, geoscientist and geologists in real situations; for these examples we decided to allocate hypothetical chances thus, they do not relate to any particular reservoir. **Table 3.10** displays all defined drilling and completion costs that can be originated because of failure to successfully drill and/or complete a well.

Table 3.8 Examples 1 & 2 – Probability of faults

Geological Features	Examples 1 & 2
Non faulted	40%
Faulted	60%

Table 3.9 Examples 1 through 3 – Probability of low, medium and high reservoir quality

Geological Features	Anisotropy	Reservoir Evaluation		
		Low k	Medium k	High k
Non faulted	K_v/k_h=0.10	20%	50%	30%
	K_v/k_h=0.01	70%	20%	10%
Faulted	K_v/k_h=0.10	40%	40%	20%
	K_v/k_h=0.01	80%	15%	5%

Table 3.10 Examples 1 through 3 – Costs incurred due to drilling and completion failures

Well Type	Costs incurred due to drilling and completion failures, $ M	
	Drilling	Completion
Vertical Well	3.00	4.00
Horizontal Well	4.50	6.00
Multilateral Well	4.80	6.50

In order to utilize a deterministic decision tree, we have decided to use tables to represent all the probabilities corresponding to each branch of the decision tree (see Appendix A for a detailed decision tree of Example 1). **Table 3.11** depicts probabilities of drilling and completion success and failure for a vertical well; all chances remain the same for a certain reservoir quality regardless of the geological features and anisotropy ratio that may be found. Since this is a vertical well and with few assumptions being made, the drilling path is not to be cutting any potential fault. Moreover, drilling and completion rate of success are predetermined to be high due to the simplicity involving this conventional well system.

Table 3.11 Examples 1 through 3 – Probability of drilling and completion in a vertical well

Geological Features	Anisotropy	Reservoir Quality	Vertical Well			
			Drilling		Completion	
			Success	Failure	Success	Failure
Non faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	92%	8%	92%	8%
		Fair	95%	5%	95%	5%
		Good	98%	2%	98%	2%
Faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	92%	8%	92%	8%
		Fair	95%	5%	95%	5%
		Good	98%	2%	98%	2%

Conversely, **Tables 3.12 and 3.13** illustrate the probabilities assigned for horizontal and multilateral wells; which have less chance for success with drilling and completion, when compared to a vertical well. This is primarily due to the complexity involved and the effect of geological features. Therefore, the probability of success in a reservoir with a high degree of faults could be negatively affected, especially in a well with more than one branch. Although it is realized that drilling through a faulted system adds more difficult to the procedure. In addition, a completion success ratio does not depend on the geological features due to the fact that at this stage the well has already been drilled and the risk is only related to the type of tools or equipment to be placed downhole. A multilateral well requires more sophisticated tools and equipment when compared to a horizontal well thus the ratio of success is higher in a horizontal well.

Table 3.12 Examples 1 through 3 – Probability of drilling and completion in a horizontal well

Geological Features	Anisotropy	Reservoir Quality	Horizontal Well			
			Drilling		Completion	
			Success	Failure	Success	Failure
Non faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	87%	13%	90%	10%
		Fair	89%	11%	93%	7%
		Good	92%	8%	96%	4%
Faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	85%	15%	90%	10%
		Fair	87%	13%	93%	7%
		Good	90%	10%	96%	4%

Table 3.13 Examples 1 through 3 – Probability of drilling and completion in a multilateral well

Geological Features	Anisotropy	Reservoir Quality	Multilateral Well			
			Drilling		Completion	
			Success	Failure	Success	Failure
Non faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	82%	18%	87%	13%
		Fair	85%	15%	90%	10%
		Good	88%	12%	93%	7%
Faulted	K_v/k_h=0.10 K_v/k_h=0.01	Poor	80%	17%	87%	13%
		Fair	83%	14%	90%	10%
		Good	86%	18%	93%	7%

Once NPV has been obtained and the probabilities for each branch of the decision tree are defined, the expected monetary value is calculated for each well system using Eq. (2.19). **Tables 3.14 through 3.16** show the expected monetary value as a function of geological features, anisotropy ratio and reservoir engineering characteristics. The column referred as "% occurrence" is the same despite the type of well to be completed, since this chance addresses all factors involved in the decision making affecting the reservoir, except to drilling and completion, which are exclusive for each well. The expected monetary value of a vertical well system is almost \$ 79 M (Table 3.14) while the expected monetary value of a horizontal well is \$ 307 M (Table 3.15) and \$ 420 M (Table 3.16) for a multilateral well system.

Table 3.14 Example 1 – Vertical well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Vertical Well		
			% occurrence	NPV at 10% disc. rate, \$ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	8%	43.77	2.92
		Fair	20%	90.26	16.22
		Good	12%	136.14	15.67
Faulted	K_v/k_h=0.10	Poor	24%	43.77	8.76
		Fair	24%	90.26	19.47
		Good	12%	136.14	15.67
Total Vertical Well Expected Monetary Value					78.72

Table 3.15 Example 1 – Horizontal well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Horizontal Well		
			% occurrence	NPV at 10% disc. rate, $ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	8%	191.19	11.89
		Fair	20%	386.36	63.78
		Good	12%	581.44	61.55
Faulted	K_v/k_h=0.10	Poor	24%	191.19	34.82
		Fair	24%	386.36	74.80
		Good	12%	581.44	60.20
Total Horizontal Well Expected Monetary Value					307.05

Table 3.16 Example 1 – Multilateral well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Multilateral Well		
			% occurrence	NPV at 10% disc. rate, $ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	8%	283.63	16.06
		Fair	20%	573.21	87.45
		Good	12%	863.74	84.71
Faulted	K_v/k_h=0.10	Poor	24%	283.63	46.99
		Fair	24%	573.21	102.44
		Good	12%	863.74	82.77
Total Multilateral Well Expected Monetary Value					420.41

To visually represent a decision tree with the "leftmost" decision nodes, **Fig. 3.8** reveals the expected monetary value with the final results after encompassing a technical, economic and risk analysis for Example 1. The risk analysis confirms the technical and economic results by consistently indicating the multilateral well as the most effective choice that needs to be made.

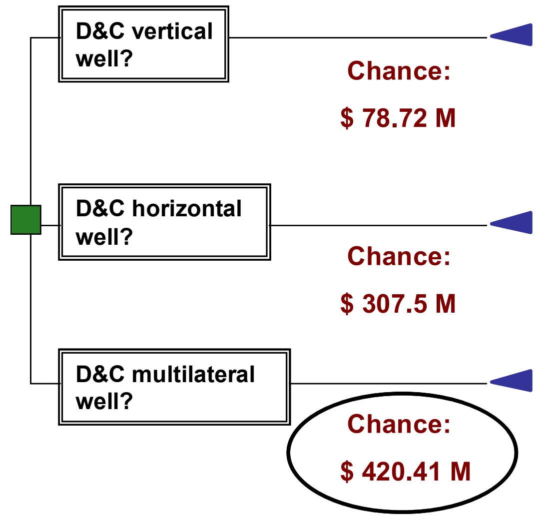

Fig. 3.8 Example 1 – Decision tree expected monetary value for each well system

3.2.4 Example 1 – Sensitivity Analysis

Figure 3.9 sets forth the effect of two different independent variables: reservoir quality and geological conditions. The expected monetary value (dependent variable) is not the net present value calculated for each case rather it is the value believed to be obtained in the likelihood of encountering a reservoir under specific characteristics. Having a lower expected monetary value when a reservoir quality is determined to be good means that the probability of that event happening is less.

When the expected monetary value of a poor quality reservoir is estimated, the results are lower because the production is less, and the probability of encountering a poor reservoir is not significantly different than the fair and good reservoir quality probability.

Figure 3.10 demonstrates that from the type of well standpoint, the associated risk to successfully drill and complete horizontal and multilateral wells has an effect on the expected monetary value. It is observed that due to geological considerations only vertical well expected monetary value is the same under any type of geological complexity.

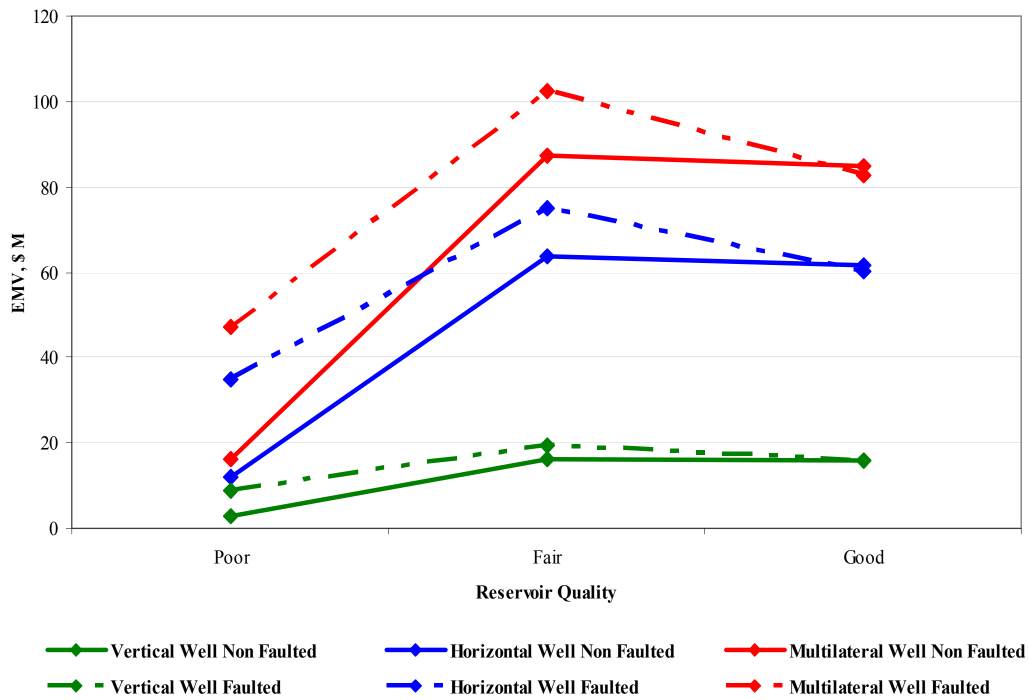

Fig. 3.9 Example 1 – Sensitivity analysis as a function of reservoir quality

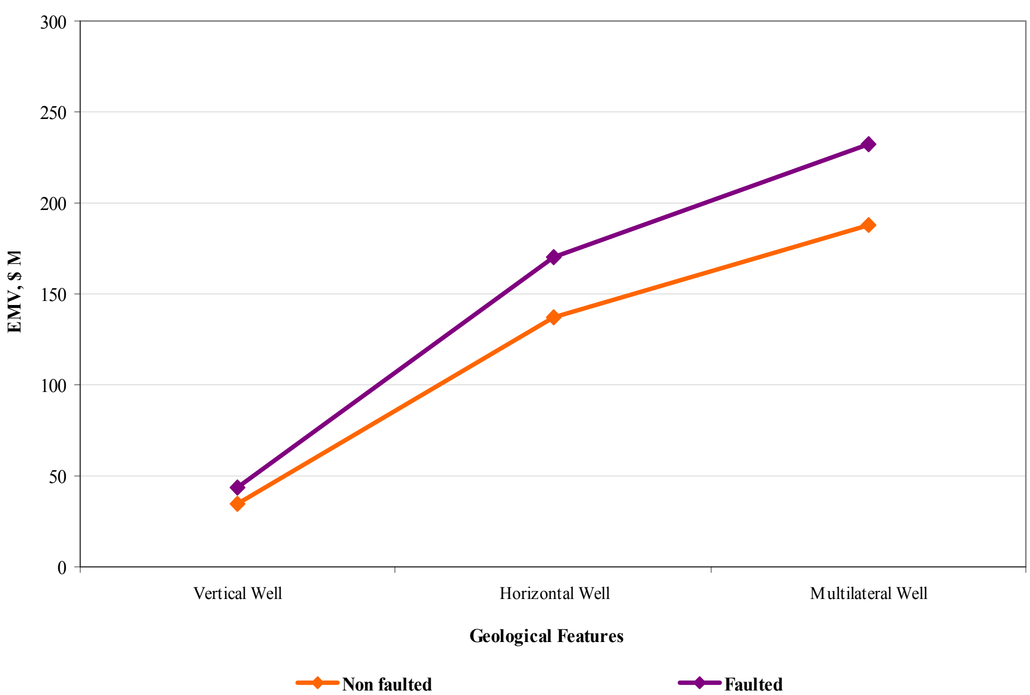

Fig. 3.10 Example 1 – Sensitivity analysis as a function of geological features

3.3 Example 2: Oil Well, Low Anisotropy Ratio

Example 2 uses the same reservoir information as described in Example 1 except that the anisotropy ratio is more severe for this case (k_v/k_h=0.01). The vertical permeability for pay zone 1 is 0.4 md, and 0.2 md for pay zone 2 (assuming a "base case scenario"). As it is described in Fig. 3.1, the horizontal well is also intended to be drilled in the lower pay zone and the multilateral well includes both pay zones with shorter lateral lengths when compared to the horizontal well configuration. The reservoir properties presented in Table 3.1 are utilized for calculation of flow rates, keeping exactly the same skin factor and other parameters. The main objective of Example 2 is to determine and evaluate the impact on production performance for horizontal and multilateral well systems when there is significant anisotropy in the reservoir.

3.3.1 Example 2 – Technical Analysis

As it was performed in Example 1, there are three different scenarios to be used in order to account for uncertainty within geological conditions and reservoir engineering parameters. In reality, information may be inaccurate and estimators may be underestimated or overestimated.

Similar to Example 1, the methodology to estimate flow rate is given in detail exclusively for "base case scenario". The vertical well production rate remains the same as **Eq. (3.3)** because k_v does not have any effect on flow rate for this type of well. Thus, the vertical well initial rate is 1731 STB/day.

For horizontal and multilateral wells "base case scenario", initial production is calculated also using Eqs. (2.3) through (2.12). However, due to the fact that the box-shaped geometry of the reservoir remains the same, z_o, y_o and x_{mid} used values are those obtained in Example 1 section.

The horizontal oil flow rate is presented below using Eqs. (3.4) and **(3.5)** to calculate the geometry shape factor:

$$\ln C_H = 6.28\frac{1000}{100}\sqrt{\frac{0.4}{40}}\left[\frac{1}{3}-\frac{500}{1000}+\left(\frac{500}{1000}\right)^2\right]-\ln\left(\sin\frac{\pi(50)}{100}\right)$$

$$-0.5\ln\left[\left(\frac{1000}{100}\right)\sqrt{\frac{0.4}{40}}\right]-1.088=-0.56 \tag{3.27}$$

where

$$P_{xyz}=\left(\frac{3500}{3000}-1\right)\left[\ln\frac{100}{0.328}+0.25\ln\frac{40}{0.4}-1.05\right]=0.97 \tag{3.28}$$

and x_{mid} = 1750 from **Eq. (3.8)**

$$P_y=\frac{6.28(3500)^2}{(1000)(100)}\frac{\sqrt{(40)(0.4)}}{40}$$
$$\left[\frac{1}{3}-\frac{1750}{3500}+\frac{1750^2}{3500^2}+\frac{3000}{24(3500)}\left(\frac{3000}{3500}-3\right)\right]=0.52 \tag{3.29}$$

$$P_{xy}=\left(\frac{3500}{3000}-1\right)\left(\frac{6.28(1000)}{100}\sqrt{\frac{0.4}{40}}\right)\left(\frac{1}{3}-\frac{500}{1000}+\frac{500^2}{1000^2}\right)=0.08 \tag{3.30}$$

$$s_R=0.97+0.52+0.08=1.57 \tag{3.31}$$

then

$$q_{o_{horizontal}}=\frac{3500\sqrt{(40)(0.4)}(3500-2000)}{141.2(1.1)(2)\left[\ln\frac{\sqrt{(1000)(100)}}{0.328}-0.56-0.75+1.57+16\right]}$$
$$=2923\ \text{STB/d ay} \tag{3.32}$$

For multilateral well "base case scenario", the initial oil production for lateral 1 is obtained as followed:

$$P_{xyz} = \left(\frac{3500}{2500} - 1\right)\left[\ln\frac{100}{0.328} + 0.25\ln\frac{40}{0.4} - 1.05\right] = 2.32 \tag{3.33}$$

using y_o calculated in Eq. (3.4) and having x_{mid} estimated in Eq. (3.14), then

$$P_y = \frac{6.28(3500)^2}{(1000)(100)}\frac{\sqrt{(40)(0.4)}}{40}$$
$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{2500}{24(3500)}\left(\frac{2500}{3500} - 3\right)\right] = 1.17 \tag{3.34}$$

$$P_{xy} = \left(\frac{3500}{2500} - 1\right)\left(\frac{6.28(1000)}{100}\sqrt{\frac{0.4}{40}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 0.20 \tag{3.35}$$

$$s_R = 2.32 + 1.17 + 0.20 = 3.69 \tag{3.36}$$

Thus, q_o for lateral 1 is estimated utilizing the same shape obtained in **Eq. (3.27)**.

$$q_{o_{lateral1}} = \frac{3500\sqrt{(40)(0.4)}(3500 - 2000)}{141.2(1.1)(2)\left[\ln\frac{\sqrt{(1000)(100)}}{0.328} - 0.56 - 0.75 + 3.69 + 16\right]}$$
$$= 2677 \text{ STB/day} \tag{3.37}$$

From the results obtained in Example 1 after using the modified Hagedorn-Brown empirical correlation to determine the pressure drop (Δp) in the wellbore between lateral 1 and lateral 2, the flowing bottom-hole pressure, p_{wf} *, for lateral 2 used in Example 2 is also 1635 psi (same distance between laterals for both examples).

Next, the initial oil production rate for lateral 2 "base case scenario" is calculated utilizing y_o, x_{mid} and z_o from Eqs. (3.4), (3.14) and (**3.19)**. Then

$$\ln C_H = 6.28\frac{1000}{60}\sqrt{\frac{0.2}{20}}\left[\frac{1}{3}-\frac{500}{1000}+\left(\frac{500}{1000}\right)^2\right]-\ln\left(\sin\frac{\pi(30)}{60}\right)$$
$$-0.5\ln\left[\left(\frac{1000}{60}\right)\sqrt{\frac{0.2}{20}}\right]-1.088=-0.47 \qquad (3.38)$$

$$P_{xyz}=\left(\frac{3500}{2500}-1\right)\left[\ln\frac{60}{0.328}+0.25\ln\frac{20}{0.2}-1.05\right]=2.12 \qquad (3.39)$$

$$P_y=\frac{6.28(3500)^2}{(1000)(60)}\frac{\sqrt{(20)(0.2)}}{20}$$
$$\left[\frac{1}{3}-\frac{1750}{3500}+\frac{1750^2}{3500^2}+\frac{2500}{24(3500)}\left(\frac{2500}{3500}-3\right)\right]=1.96 \qquad (3.40)$$

$$P_{xy}=\left(\frac{3500}{2500}-1\right)\left(\frac{6.28(1000)}{60}\sqrt{\frac{0.2}{20}}\right)\left(\frac{1}{3}-\frac{500}{1000}+\frac{500^2}{1000^2}\right)=0.34 \qquad (3.41)$$

$$s_R=2.12+1.96+0.34=4.42 \qquad (3.42)$$

Thus, q_o for lateral 2 is estimated to be:

$$q_{o_{lateral\,2}}=\frac{3500\sqrt{(20)(0.2)}(3200-1635)}{141.2(1.1)(2)\left[\ln\frac{\sqrt{(1000)(60)}}{0.328}-0.47-0.75+4.42+10\right]}$$
$$=1780\text{ STB/day} \qquad (3.43)$$

As a result, the total oil production for the multilateral well system is:

$$q_{o_{multilateral}} = q_{o_{lateral1}} + q_{o_{lateral2}} = 2677 + 1780 = 4457 \text{ STB/day} \tag{3.44}$$

At first glance, we can see how detrimental an extremely low anisotropy ratio (k_v/k_h=0.01) is in predicting flow rates for horizontal and multilateral wells. **Table 3.17** shows that the production rate in horizontal and multilateral wells "under base case scenario" can be decreased nearly 3 times if k_v is very low when compared to k_h.

One of the conditions that ought to be carefully analyzed when one considers horizontal drilling and completion for one or more branches is the anisotropy of the reservoir. Vertical wells are not significantly affected by k_v but the magnitude of the success obtained by horizontal and multilateral wells is highly dependant on anisotropy ratio.

Table 3.17 Examples 1 & 2 – Comparison of initial hypothetical flow rates

Base case scenario	Well Type		
	Vertical Well, STB/day	Horizontal Well, STB/day	Multilateral Well, STB/day
Example 1 (k_v/k_h=0.10)	1731	8586	11787
Example 2 (k_v/k_h=0.01)	1731	2923	4457

As it was calculated in Example 1, we have forecasted production rates for either 15 or 25 years depending of the well type. Initially, six months production rates are estimated utilizing the analytical approach (q_o) presented to perform DCA and forecast production for the different well systems (**Table 3.18**).

Table 3.18 Example 2 – Analytical model results under "base case scenario"

Month	Vertical Well $q_{o\ payzone1}$ (STB/day)	Vertical Well $q_{o\ payzone2}$ (STB/day)	Horizontal Well $q_{o\ horizontal}$ (STB/day)	Multilateral Well $q_{o\ multilateral}$ (STB/day)
1	1233	498	2923	4457
2	1227	496	2919	4444
3	1215	492	2878	4424
4	1203	488	2835	4361
5	1186	482	2788	4293
6	1161	473	2719	4194
7	1121	460	2613	4038

Table 3.19 results are very similar to Table 3.3, D_i values do not change because the same pressure drawdown is used. The initial rate, Q_i, is lower due to the heterogeneity condition. For horizontal and multilateral wells, **Figs. 3.11 and 3.12** depicts the matching of hypothetical production, which varies in its decline rate, from Table 3.18 against the results obtained utilizing hyperbolic decline with estimators displayed in Table 3.19 (refer to fig. 3.2 for vertical well plot).

Table 3.19 Example 2 – DCA results under "base case scenario"

Estimator	Vertical $Well_{payzone1}$	Vertical $Well_{payzone2}$	Horizontal Well	Multilateral Well
Q_i, STB/day	1251	504	2995	4595
D_i/year nominal rate	0.167	0.148	0.221	0.210
b_{hyp}	1.457E-6	0.027	1.84E-06	1.62E-04

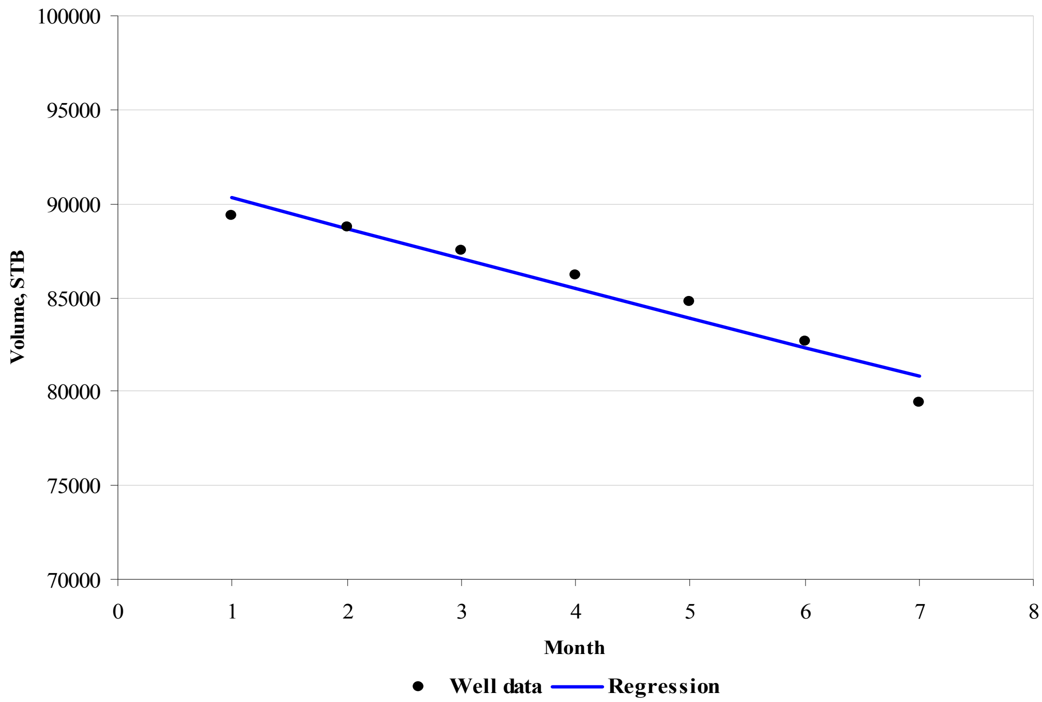

Fig. 3.11 Example 2 – DCA for a horizontal well system under "base case scenario"

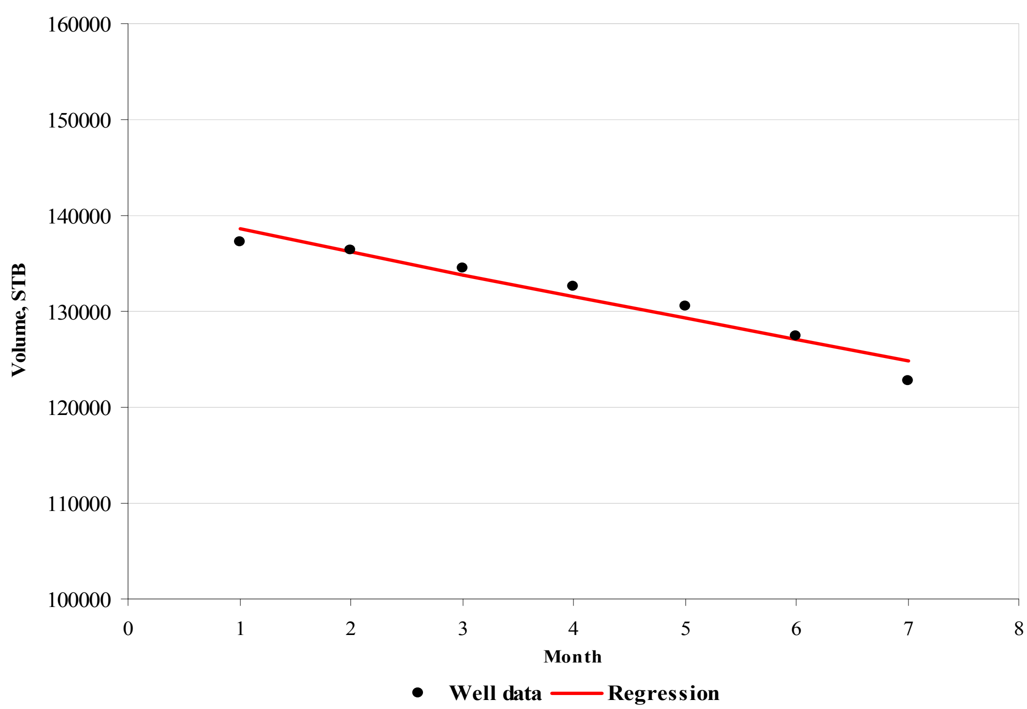

Fig. 3.12 Example 2 – DCA for a multilateral well system under "base case scenario"

Compared to Example 1, we can observe that in Example 2, the initial production rate for a horizontal well surpasses the vertical well by nearly 2 fold, and 3 fold for a multilateral well. Evidently, the production increase assuming horizontal drilling with one or two branches system is not as significant as it is in Example 1 because of the extreme anisotropy ratio.

The hyperbolic decline curve estimators for "worst case scenario" and "best case scenario" only differ from "base case scenario" in the initial production rate. D_i and b_{hyp} estimators are kept the same since drawdown pressure remains equal regardless the permeability values to be consistent with methodology used in Example 1.

Figure 3.13 Example 2 shows monthly production data forecasted by DCA under "base case scenario". The semi-log plot does not portray the same behavior depicted in Fig. 3.5 (Example 1) where horizontal and multilateral well production exceeds by a significant margin the vertical well production despite time. Example 2 vertical well production eventually reaches and surpasses horizontal well production (after 8 years) due to the severe anisotropy ratio.

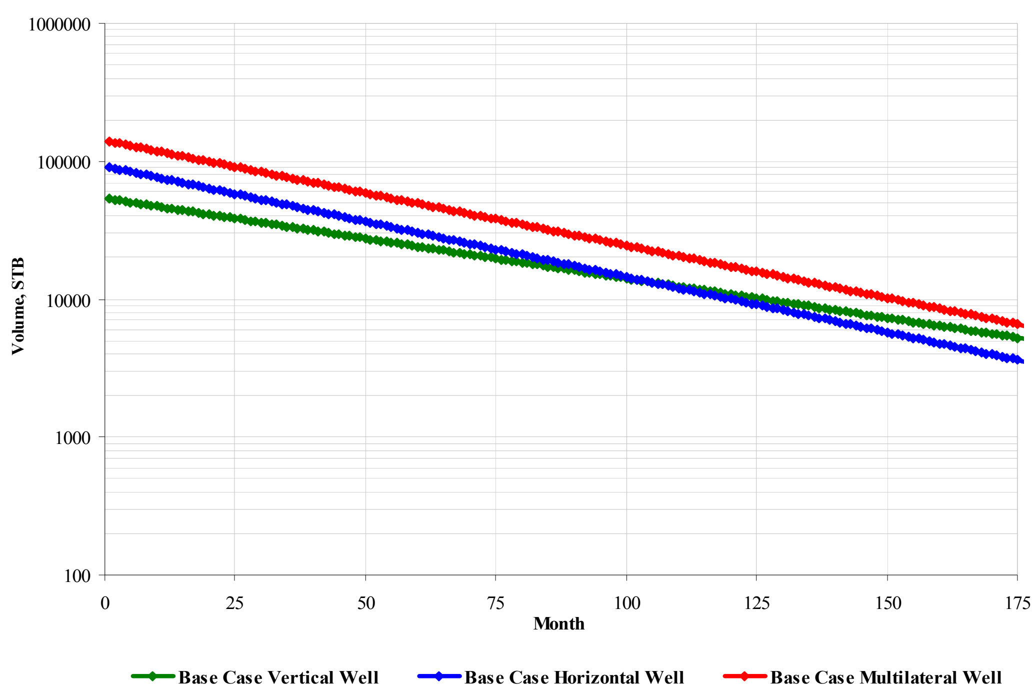

Fig. 3.13 Example 2 – Monthly production rate under "base case scenario"

Figure 3.14 presents the cumulative production for each well system. While Example 1 horizontal well has a cumulative production of 14 STB M after 175 months (Fig. 3.6), Example 2 horizontal well has a cumulative production of nearly 5 STB M (Fig. 3.14).

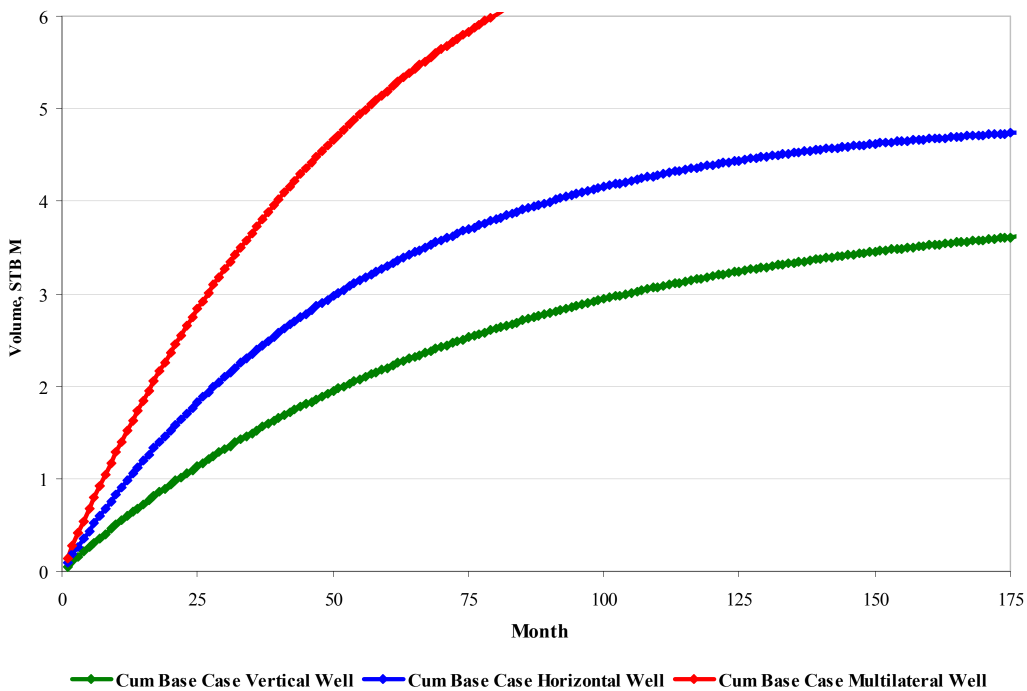

Fig. 3.14 Example 2 – Cumulative production rate under "base case scenario"

The results of the previous DCA are included in **Table 3.20**. Despite anisotropy ratio, vertical well production is consistent; however, Example 2 initial production rate in horizontal well under "base case scenario" is 175,000 STB/month less than Example 1 initial production rate. Example 2 multilateral well initial production rate drops also by 228,000 STB/month if compared to Example 1 initial production rate (Table 3.4).

Table 3.20 Example 2 – Summary of initial monthly production rates

Well Type	Example 1- Initial Monthly Oil Production, STB/month		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	26,544	53,086	79,635
Horizontal Well	45,188	90,333	135,481
Multilateral Well	69,375	138,462	208,008

3.3.2 Example 2 – Economic Analysis

For Example 2, the same economic indictors portrayed in Example 1 are calculated in order to evaluate the various alternatives to drill and complete the well.

Table 3.4 is used as input data to generate FCF, hence the economic analysis in Example 2 considers the same drilling and completion, fixed and variable operating costs, and commodity price for each type of well. **Table 3.21** depicts some economic indicators other than NPV. In spite of the lower production rates estimated in Example 2, the well payout remains the same as Example 1, less than a month, since production and commodity price still easily overcome the investment. Nonetheless, the efficiency of the horizontal and multilateral wells project drops by two thirds, profitability index in Example 1 is about 110 while profitability index in Example 2 is nearly 40. As a result, the amount of revenue generated by each dollar initially invested is three times more in Example 1 than Example 2. Furthermore, the internal rate of return keeps the same trend; internal rate of return in Example 2 is between 1200% and 1300%, an attractive rate but not as high as internal rate of return in Example 1 which is 3500%.

It is evident that Example 2 also represents a good investment, especially if a multilateral well system is chosen. Due to the reservoir conditions, an analytical approach based on material balance of the drainage system estimates high flow rates that accompanied by high commodity prices and relatively low cost, bring a high yield on investment.

Table 3.21 Example 2 – Summary of economic results under "base case scenario"

Example 2 - Economic Results			
Economic Indicator	Base Case Scenario		
	Vertical Well	Horizontal Well	Multilateral Well
Well payout	33 days	30 days	27 days
Profitability index	39.59	36.64	41.82
Internal rate of return	1049%	1201%	1322%
Max. negative cash flow	- $ 2.28 M	- $ 3.52 M	- $ 5.12 M

Figure 3.15 plots the cumulative FCF for a base case scenario. The return on investment occurs immediately after the well starts producing, less than one month payout period for a horizontal and multilateral well systems, and over one month for a vertical well system. Even though Fig. 3.15 illustrates the first 50 months of production, by plotting the wells' life, the total cumulative FCF for a vertical well is $ 145 M (same as Example 1), $ 183 M for a horizontal well ($ 360 M less than horizontal well in Example 1), and $ 307 M for a multilateral well ($ 510 M less than multilateral well in Example 1). Refer to Fig. 3.7 to compare the results with Example 1.

Similar to the technical analysis in Example 1, the economic analysis leads us to believe that the multilateral well is the most profitable option from the production rate and cumulative FCF aspects. Moreover, **Table 3.22** shows the NPV results under all three different scenarios. The highest NPV is obtained by drilling and completing a multilateral well ($ 214 M under base case scenario) while the lowest NPV is achieved by drilling and completing a vertical well ($ 90 M under base case scenario). NPV estimated in Example 2 for the horizontal and multilateral wells is only one third of the NPV estimated in Example 1, which is corroborated with previous analysis. Despite reservoir quality, NPV results are consistent, presenting the multilateral well system as the most profitable alternative.

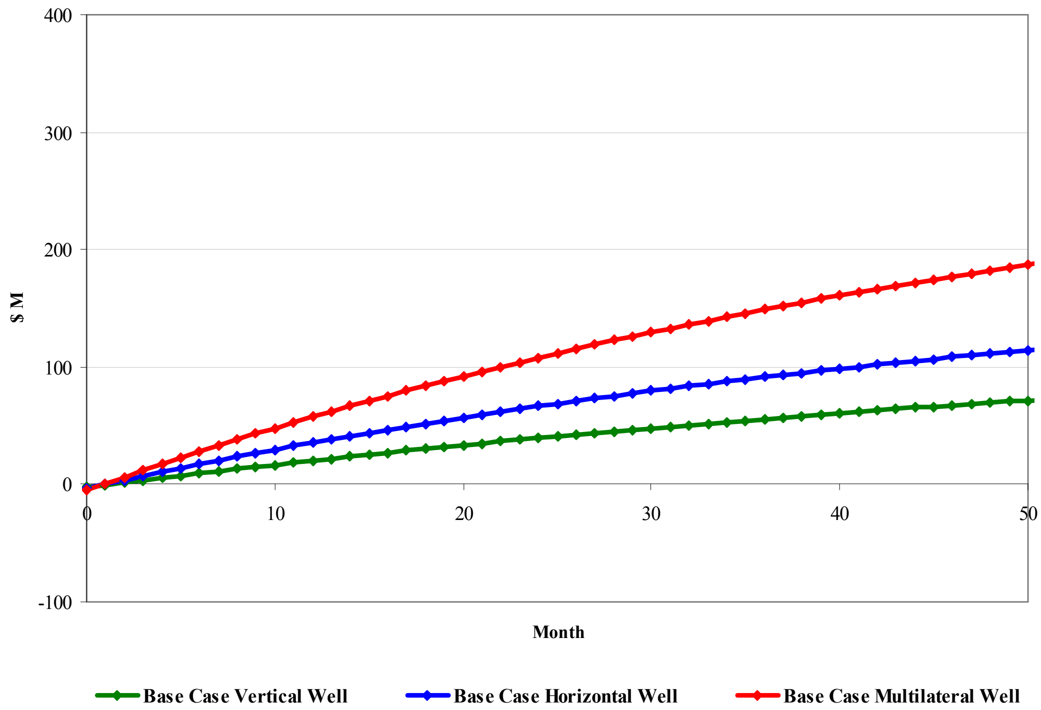

Fig. 3.15 Example 2 – Cumulative FCF under "base case scenario"

Table 3.22 Example 2 – Summary of NPV at 10% discount rate

Well Type	Example 2- NPV at 10% discount rate, $ M		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	43.77	90.26	136.14
Horizontal Well	42.22	128.96	195.62
Multilateral Well	71.08	214.14	324.31

If a severe anisotropy ratio is very likely to be encountered and one evaluates horizontal or multilateral well systems without taking into account the risk involved while drilling and completing the well, these types of wells remain the most attractive alternative. It is clear that for these two examples the flow rate drop is significant but the outstanding reservoir properties outweighed the negative effect. However, there are circumstances when heterogeneity or poor quality reservoirs could be detrimental in such cases where horizontal wells with one or more branches are the most effective choice from the technical, economic and risk/uncertainty stand points.

3.3.3 Example 2 – Risk Analysis

Similar to Example 1, we use Tables 3.8 and 3.9 to address the probability of finding geological features that can impact not only the drilling success but also the reservoir quality. Table 3.10, drilling and completion cost, is utilized for all possible failures that may occur during any of these stages. In addition, we refer to Tables 3.11 through 3.13 to associate risk to every well type considering complexity due to the geological aspect.

The probability values assigned to almost every branch of the decision tree in Example 2 is practically the same as the chances in the branches of the decision tree used in Example 1. Nevertheless, the reservoir engineering evaluation assigns a lower likelihood to high and medium reservoir quality when k_v/k_h=0.01. Example 2 illustrates a case where heterogeneity plays a role in production. **Tables 3.23 through 3.25** depict the NPV results according to the type of well, reservoir quality and geological complexities in addition to the probability of occurrence. Using Eq. (2.19), the expected monetary value for a vertical well system is nearly \$ 51 M (Table 3.23) while the expected monetary value of a horizontal well is \$ 54 M (Table 3.24) and \$ 82 M (Table 3.25) for a multilateral well system (see Appendix B for a detailed decision tree of Example 2).

After a thorough analysis of the type of reservoir that could be encountered when k_v/k_h=0.01, the expected monetary value for horizontal and multilateral wells represents only one fifth of the expected monetary value obtained for these wells in Example 1; which differs from the technical and economic analysis comparison where Example 2 represents one third of Example 1 results. The main reason of this inconsistency is due to the fact that chances to find a good or bad reservoir quality are not as highly dependent on the geological considerations as are on anisotropy ratios.

Table 3.23 Example 2 – Vertical well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Vertical Well		
			% occurrence	NPV at 10% disc. rate, $ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	28%	43.77	10.22
		Fair	8%	90.26	6.49
		Good	4%	136.14	5.22
Faulted	K_v/k_h=0.10	Poor	48%	43.77	17.53
		Fair	9%	90.26	7.30
		Good	3%	136.14	3.92
Total Vertical Well Expected Monetary Value					50.68

Table 3.24 Example 2 – Horizontal well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Horizontal Well		
			% occurrence	NPV at 10% disc. rate, $ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	28%	42.22	8.95
		Fair	8%	128.96	8.47
		Good	4%	195.62	6.89
Faulted	K_v/k_h=0.10	Poor	48%	42.22	14.93
		Fair	9%	128.96	9.31
		Good	3%	195.62	5.05
Total Horizontal Well Expected Monetary Value					53.59

Table 3.25 Example 2 – Multilateral well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Multilateral Well		
			% occurrence	NPV at 10% disc. rate, $ M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	28%	71.08	13.76
		Fair	8%	214.14	13.00
		Good	4%	324.31	10.58
Faulted	K_v/k_h=0.10	Poor	48%	71.08	22.96
		Fair	9%	214.14	14.27
		Good	3%	324.31	7.75
Total Multilateral Well Expected Monetary Value					82.33

Figure 3.16 Example 2 displays decision tree with the "leftmost" decision nodes. Despite expected monetary value results in Example 2 are lower than expected monetary value in Example 1 (Fig. 3.8); once again the multilateral well overcomes the risk involved due to production rates and high commodity prices accompanied by low CAPEX.

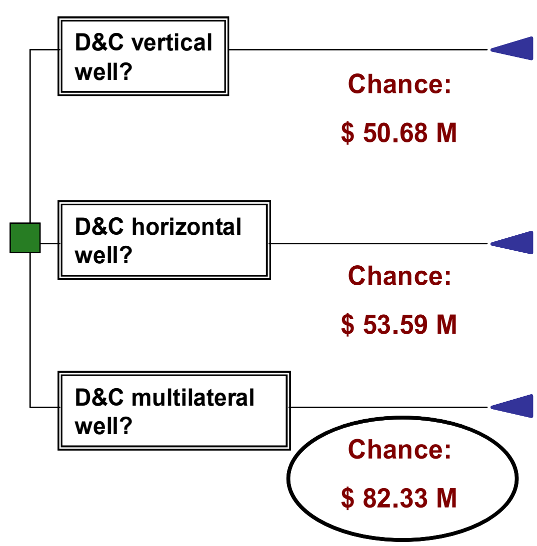

Fig. 3.16 Example 2 – Decision tree expected monetary value for each well system

3.3.4 Example 2 – Sensitivity Analysis

Figure 3.17 shows some consistency with Fig. 3.9 results, however, the expected monetary value for a highly anisotropic reservoir is affected not only in a poor and fair reservoir quality but also in a good reservoir quality. Geological features (e.g. complexity of faults, compartments, and folding) can affect more the expected monetary value as function of reservoir quality than type of well. Contrary to Example 1, vertical well trend on the sensitivity analysis as function of reservoir quality is affected by faults because we have defined a high likelihood of facing a poor reservoir quality when faults are present in highly anisotropic reservoirs.

Figure 3.18, being consistent to Example 1 results, plots a similar trend on the expected monetary value as function of the type of well and geological features (associated risk to successfully drill and complete horizontal and multilateral wells). This differs from Example 1 only in the fact that also a vertical well expected monetary value is affected by geological complexity with a k_v/k_h=0.01.

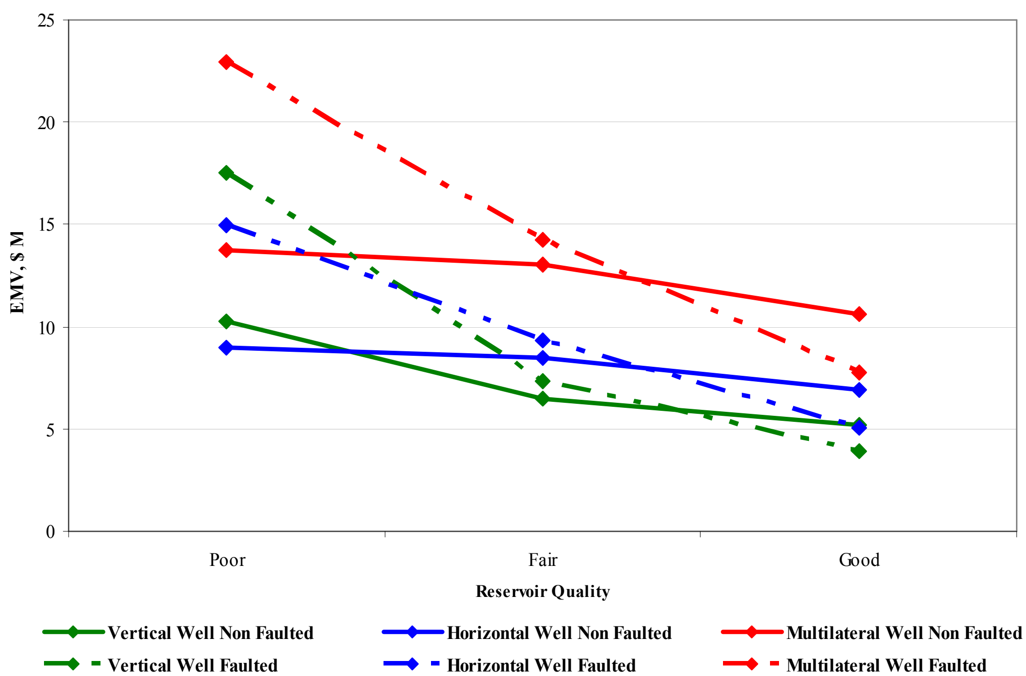

Fig. 3.17 Example 2 – Sensitivity analysis as a function of reservoir quality

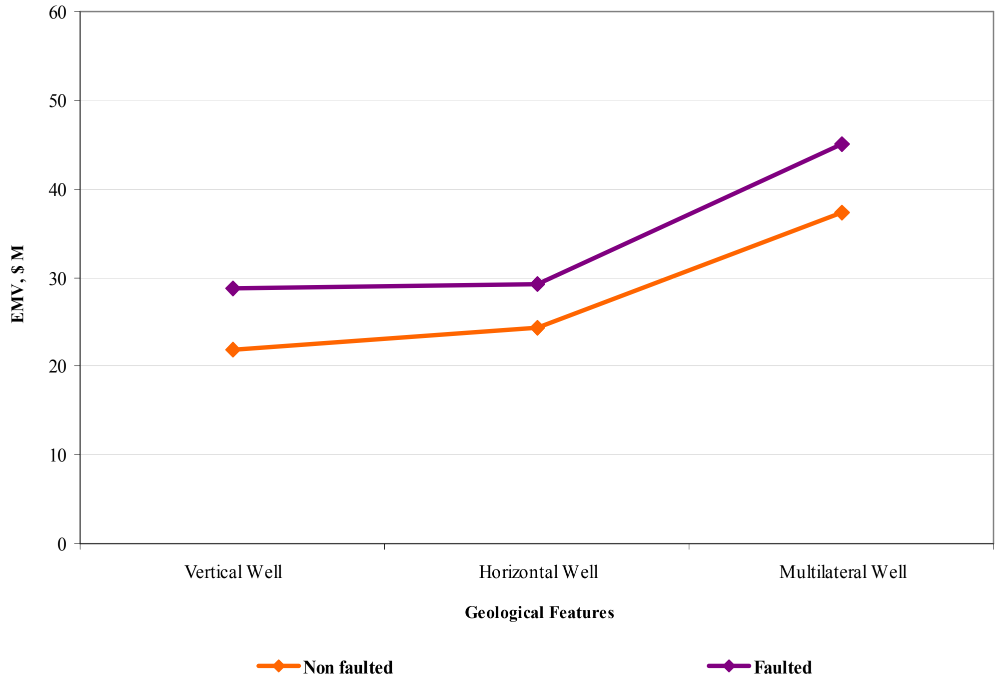

Fig. 3.18 Example 2 – Sensitivity analysis as a function of geological features

4. GAS WELL APPLICATION

4.1 Overview

Multilateral technology can be successfully applied in low permeability and highly fractured gas reservoirs, particularly when a natural fractures network can be connected due to maximum reservoir contact enhancing productivity and hydrocarbon recovery.

Gas reservoirs exhibit lower permeability than oil wells, thus prior to deciding whether a horizontal or multilateral well system is a suitable completion candidate, we need to make an exhaustive study of the technical, economic and risk analysis. Marginal gas wells do not justify a major investment and one must be careful not to allow the properties information to lead us to undesirable economic results and wrong decisions.

4.2 Example 3: Gas Well

In this section we present a gas well case (Example 3) which has the same well planning as Examples 1 and 2 (Fig. 3.1). There are two pay zones with permeability of 0.2 md and 0.1 md in “base case scenario”, and a medium anisotropy ratio (k_v/k_h=0.10) with 90 ft and 80 ft thickness respectively.

Similar to Example 2, several assumptions made in Example 1 are adopted for this gas well application. The geometry of the box-shaped reservoir remains the same, lateral reservoir length of 3500 ft with a lateral wellbore length of 3000 ft for a horizontal well and a lateral wellbore length of 2500 ft for a multilateral well.

4.2.1 Example 3 – Technical Analysis

Uncertainty in the geological and reservoir parameters does not provide us accurate information while making decisions. Therefore, the three different scenarios used in oil well examples are set for the gas well application also. A reservoir characterized by an optimistic evaluation of formation permeability, 150% of the “base case scenario” permeability (k_v and k_h) is utilized for “best case scenario”, and 50% for “worst case scenario”.

The input data for Example 3 is presented in **Table 4.1**, which shows all reservoir information assuming "high", "medium" and "low" permeability values on vertical, horizontal and multilateral well configurations necessary to predict production performance. Contrary to Examples 1 and 2, the vertical well in Example 3 uses a negative skin factor to illustrate the hydraulic fracturing application in tight gas wells.

Table 4.1 Example 3 – Gas reservoir properties

Input Data for Example 3						
Parameter	Worst Case Scenario		Base Case Scenario		Best Case Scenario	
	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2
k_h (md):	0.1	0.05	0.2	0.1	0.3	0.15
k_v (md):	0.01	0.005	0.02	0.01	0.03	0.015
h (ft):	90	80	90	80	90	80
$\overline{Z}$ (ft):	0.945	0.945	0.945	0.945	0.945	0.945
$\overline{\mu}$ (ft):	0.0244	0.0244	0.0244	0.0244	0.0244	0.0244
r_e (ft):	1489	1489	1489	1489	1489	1489
r_w (ft):	0.328	0.328	0.328	0.328	0.328	0.328
s:	-4	-4	-4	-4	-4	-4
s*:	4	1.4	4	1.4	4	1.4
$\overline{p}$ (psi):	3161	3040	3161	3040	3161	3040
p_{wf} (psi):	2500	2413	2500	2413	2500	2413
p_{wf}^* (psi):	2500	2488	2500	2488	2500	2488
$\overline{T}$ (°F):	210	205	210	205	210	205
a* (ft):	1000	1000	1000	1000	1000	1000
b* (ft):	3500	3500	3500	3500	3500	3500
$L_{horizontal}$ (ft):	3000	N/A	3000	N/A	3000	N/A
$L_{multilateral}$ (ft):	2500	2500	2500	2500	2500	2500
TVD (ft):	7300	7020	7300	7020	7300	7020

Similar to Examples 1 and 2, the bottom-hole flowing pressure in pay zone 1 is an assumed value at 2500 psi. For vertical well configuration, p_{wf} in zone 2 uses only a hydrostatic pressure drop of 0.433 psi/ft, subtracted from the pressure in zone 1. The multilateral well configuration (p_{wf}^{*}) utilizes a mechanical energy balance equation to calculate hydrostatic pressure drop and frictional pressure drop in the well.

For a vertical well, the flowing bottom-hole pressure in the pay zone 2 is 2413 psi (2500 psi – 87 psi), it considers only the hydrostatic pressure drop between pay zone 1 and pay zone 2 (200 ft * 0.433 psi/ft = 87 psi).

First, the initial production is estimated in each well system for the first six months assuming a pressure decline rate of less than 5% annually. Using Eq. (2.2), with a temperature in ^{o}R (^{o}F+460) and the reservoir properties for each pay zone, neglecting the non-Darcy coefficient, we have the following vertical well "base case scenario" initial gas production:

$$q_{g_{vertical-payzone1}} = \frac{(0.20)(90)(3161^2 - 2500^2)}{1424(0.0244)(0.945)(670)\left(\ln\frac{0.472(1489)}{0.328} - 4\right)}$$
$$= 834 \text{ Mcf/day} \tag{4.1}$$

$$q_{g_{vertical-payzone2}} = \frac{(0.10)(80)(3040^2 - 2413^2)}{1424(0.0244)(0.945)(665)\left(\ln\frac{0.472(1489)}{0.328} - 4\right)}$$
$$= 341 \text{ Mcf/day} \tag{4.2}$$

As a result, the total gas production for the vertical well system is:

$$q_{g_{vertical}} = q_{g_{vertical-payzone1}} + q_{g_{vertical-payzone2}} = 834 + 341 = 1175 \text{ Mcf/day} \tag{4.3}$$

For the horizontal and multilateral well "base case scenario", initial gas production is calculated using Eqs. (2.4) through (2.13). However, due to the fact that the box-shaped geometry of the reservoir remains the same as Examples 1 and 2, z_o, y_o and x_{mid} used values are those obtained in Example 1 section.

The horizontal gas flow rate is presented below using Eq. (3.5) to calculate the geometry shape factor:

$$z_o = \frac{90}{2} = 45 \tag{4.4}$$

$$\ln C_H = 6.28\frac{1000}{90}\sqrt{\frac{0.02}{0.2}}\left[\frac{1}{3} - \frac{500}{1000} + \left(\frac{500}{1000}\right)^2\right] - \ln\left(\sin\frac{\pi(45)}{90}\right)$$
$$-0.5\ln\left[\left(\frac{1000}{90}\right)\sqrt{\frac{0.02}{0.2}}\right] - 1.088 = 0.12 \tag{4.5}$$

where

$$P_{xyz} = \left(\frac{3500}{3000} - 1\right)\left[\ln\frac{90}{0.328} + 0.25\ln\frac{0.2}{0.02} - 1.05\right] = 0.85 \tag{4.6}$$

and x_{mid} = 1750 from Eq. (3.8)

$$P_y = \frac{6.28(3500)^2}{(1000)(90)}\frac{\sqrt{(0.2)(0.02)}}{0.2}$$
$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{3000}{24(3500)}\left(\frac{3000}{3500} - 3\right)\right] = 1.83 \tag{4.7}$$

$$P_{xy} = \left(\frac{3500}{3000} - 1\right)\left(\frac{6.28(1000)}{90}\sqrt{\frac{0.02}{0.2}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 0.30 \tag{4.8}$$

$$s_R = 0.85 + 1.83 + 0.30 = 2.98 \tag{4.9}$$

then

$$q_{g_{horizontal}} = \frac{3500\sqrt{(0.2)(0.02)}\left(3161^2 - 2500^2\right)}{1424(0.0244)(0.945)(670)\left[\ln\frac{\sqrt{(1000)(90)}}{0.328} + 0.12 - 0.75 + 2.98 + 4\right]}$$

$$= 2859 \text{ Mcf/day} \tag{4.10}$$

For multilateral well "base case scenario", the initial gas production for lateral 1 is obtained as followed:

$$P_{xyz} = \left(\frac{3500}{2500} - 1\right)\left[\ln\frac{90}{0.328} + 0.25\ln\frac{0.2}{0.02} - 1.05\right] = 2.05 \tag{4.11}$$

using y_o calculated in Eq. (3.4) and having x_{mid} estimated in Eq. (3.14), then

$$P_y = \frac{6.28(3500)^2}{(1000)(90)}\frac{\sqrt{(0.2)(0.02)}}{0.2}$$
$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{2500}{24(3500)}\left(\frac{2500}{3500} - 3\right)\right] = 4.13 \tag{4.12}$$

$$P_{xy} = \left(\frac{3500}{2500} - 1\right)\left(\frac{6.28(1000)}{90}\sqrt{\frac{0.02}{0.2}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 0.73 \tag{4.13}$$

$$s_R = 2.05 + 4.13 + 0.73 = 6.91 \tag{4.14}$$

Thus, q_g for lateral 1 is estimated utilizing the same shape obtained in **Eq. (4.5)**:

$$q_{g_{lateral1}} = \frac{3500\sqrt{(0.2)(0.02)}\left(3161^2 - 2500^2\right)}{1424(0.0244)(0.945)(670)\left[\ln\frac{\sqrt{(1000)(90)}}{0.328} + 0.12 - 0.75 + 6.91 + 4\right]}$$

$$= 2202 \text{ Mcf/day} \qquad (4.15)$$

After using an empirical correlation to determine the pressure drop (Δp) in the wellbore between lateral 1 and lateral 2 (upper branch), the total Δp is obtained for 200 ft wellbore length between laterals (12 psi). Therefore, the flowing bottom-hole pressure, p_{wf} *, for lateral 2 is calculated to be 2488 psi (2500 psi –12 psi).

If we assume that there is no pressure drop in the lateral, then the drawdown for lateral 2 will be 552 psi (3040 psi – 2488 psi).

Next, the initial gas production rate for lateral 2 "base case scenario" is calculated utilizing y_o and x_{mid} from Eqs. (3.4), and (3.14). Then, using Eq. (3.5):

$$z_o = \frac{80}{2} = 40 \qquad (4.16)$$

$$\ln C_H = 6.28\frac{1000}{80}\sqrt{\frac{0.01}{0.1}}\left[\frac{1}{3} - \frac{500}{1000} + \left(\frac{500}{1000}\right)^2\right] - \ln\left(\sin\frac{\pi(40)}{80}\right)$$

$$-0.5\ln\left[\left(\frac{1000}{80}\right)\sqrt{\frac{0.01}{0.1}}\right] - 1.088 = 0.29 \qquad (4.17)$$

$$P_{xyz} = \left(\frac{3500}{2500} - 1\right)\left[\ln\frac{80}{0.328} + 0.25\ln\frac{0.1}{0.01} - 1.05\right] = 2.00 \qquad (4.18)$$

$$P_y = \frac{6.28(3500)^2}{(1000)(80)} \frac{\sqrt{(0.1)(0.01)}}{0.1}$$

$$\left[\frac{1}{3} - \frac{1750}{3500} + \frac{1750^2}{3500^2} + \frac{2500}{24(3500)}\left(\frac{2500}{3500} - 3\right)\right] = 4.65 \qquad (4.19)$$

$$P_{xy} = \left(\frac{3500}{2500} - 1\right)\left(\frac{6.28(1000)}{80}\sqrt{\frac{0.01}{0.1}}\right)\left(\frac{1}{3} - \frac{500}{1000} + \frac{500^2}{1000^2}\right) = 0.87 \qquad (4.20)$$

$$s_R = 2.00 + 4.65 + 0.87 = 7.52 \qquad (4.21)$$

Thus, q_g for lateral 2 is estimated to be:

$$q_{g_{lateral2}} = \frac{3500\sqrt{(0.1)(0.01)}\left(3040^2 - 2488^2\right)}{1424(0.0244)(0.945)(665)\left[\ln\frac{\sqrt{(1000)(80)}}{0.328} + 0.29 - 0.75 + 7.52 + 1.4\right]}$$

$$= 1016 \text{ Mcf/day} \qquad (4.22)$$

As a result, the total gas production for the multilateral well system is:

$$q_{g_{multilateral}} = q_{g_{lateral1}} + q_{g_{lateral2}} = 2202 + 1016 = 3218 \text{ Mcf/day} \qquad (4.23)$$

Though, only initial gas production estimation is depicted in the equations above, **Table 4.2** shows additional six months of production (q_g) calculated using these analytical models and a reservoir pressure decline of about 5% per year.

Using the "least squares fit" analysis of monthly production rates from Table 4.2, and Eqs. (2.14) and (2.15), we have obtained Q_i, D_i and b_{hyp} in order to forecast daily production and cumulative monthly production (**Table 4.3**). **Figs. 4.1 through 4.3** reveal the matching of hypothetical production (Table 4.2) against the results obtained utilizing hyperbolic decline (Table 4.3).

Table 4.2 Example 3 – Analytical model results under "base case scenario"

Month	Vertical Well $q_{g\ payzone1}$ (Mcf/day)	Vertical Well $q_{g\ payzone2}$ (Mcf/day)	Horizontal Well $q_{g\ horizontal}$ (Mcf/day)	Multilateral Well $q_{g\ multilateral}$ (Mcf/day)
1	834	341	2859	3218
2	833	339	2825	3183
3	829	338	2801	3154
4	823	337	2772	3120
5	823	335	2743	3086
6	819	333	2724	3064
7	811	333	2710	3047

Table 4.3 Example 3 – DCA results under "base case scenario"

Estimator	Vertical $Well_{payzone1}$	Vertical $Well_{payzone2}$	Horizontal Well	Multilateral Well
Q_i, Mcf/day	836	341	2859	3224
D_i/year nominal rate	0.053	0.051	0.107	0.112
b_{hyp}	0.002	0.007	0.055	0.033

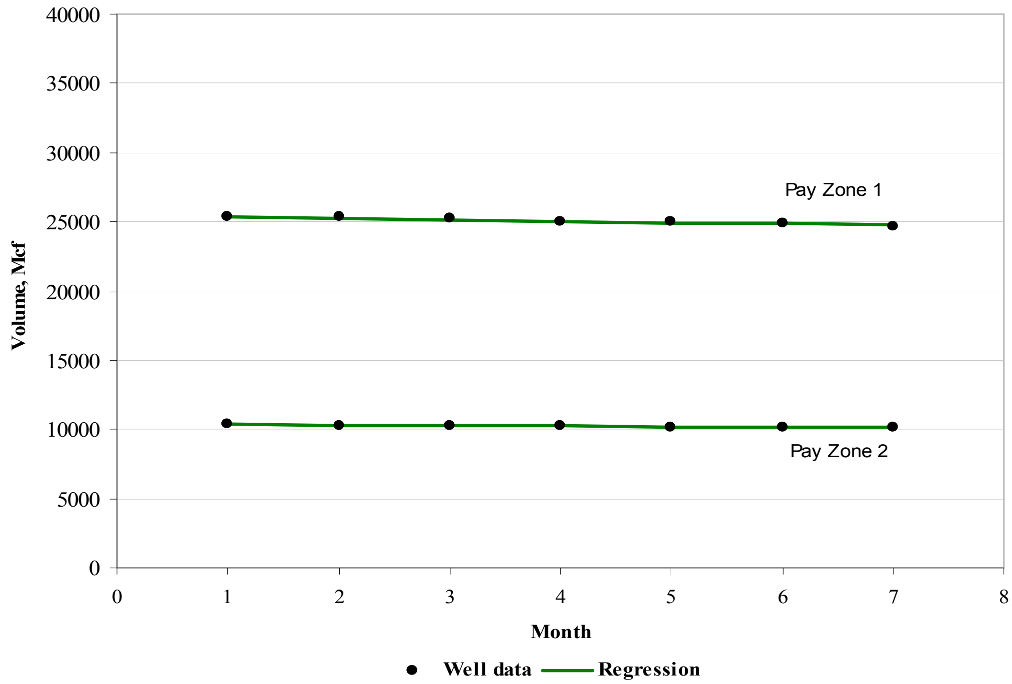

Fig. 4.1 Example 3 – DCA for a vertical well system under "base case scenario"

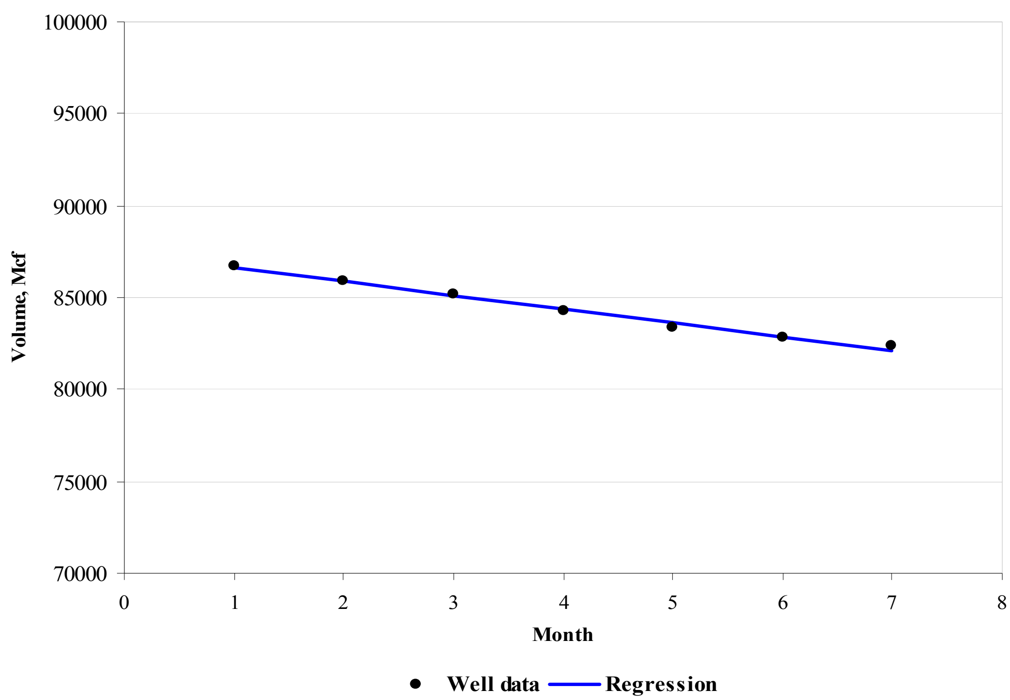

Fig. 4.2 Example 3 – DCA for a horizontal well system under "base case scenario"

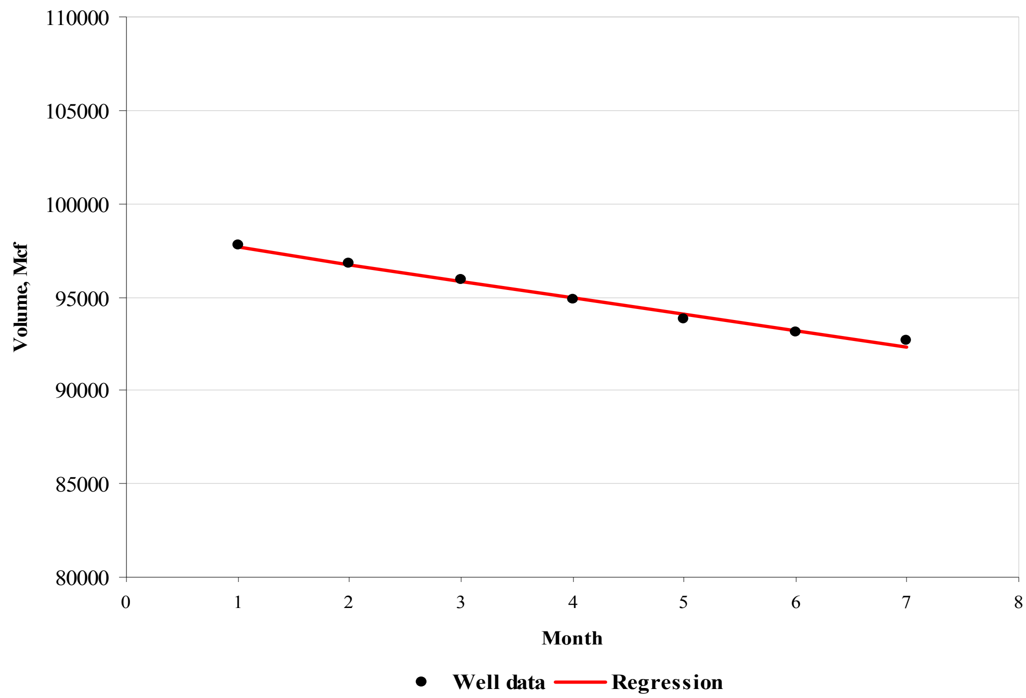

Fig. 4.3 Example 3 – DCA for a multilateral well system under "base case scenario"

From DCA, we observed that the initial production rate for a horizontal well surpasses the vertical well by 2.5 fold while the multilateral well exceeds it by 3 fold. Obviously, the production increase by horizontal drilling with a one or two branch system is significantly high.

As said in Example 1, the hyperbolic decline curve estimators for "worst case scenario" and "best case scenario" only differ from "base case scenario" in the initial production rate. D_i and b_{hyp} estimators are kept the same since drawdown pressure remains equal regardless permeability values.

Figure 4.4 shows the monthly production data forecasted by DCA under "base case scenario". It is noticed in the semi-log plot that for this very low permeability gas well (especially the upper zone), at the assumed anisotropy ratio, the vertical permeability becomes extremely small thus production from the upper lateral is significantly reduced. In such case, the production rate obtained from a multilateral well may not surpass a horizontal well production by a sufficient margin to justify the investment and risk incurred.

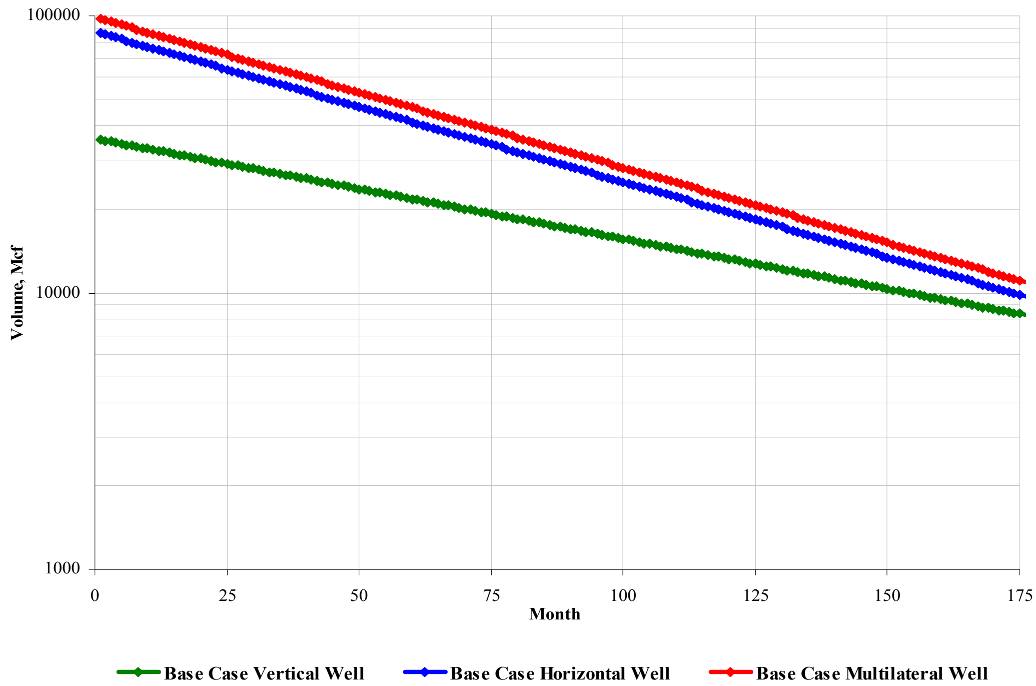

Fig. 4.4 Example 3 – Monthly production rate under "base case scenario"

Figure 4.5 also validates the previous statement; the benefit from a multilateral well regarding the cumulative oil production seems to be insignificant for the type of technology required.

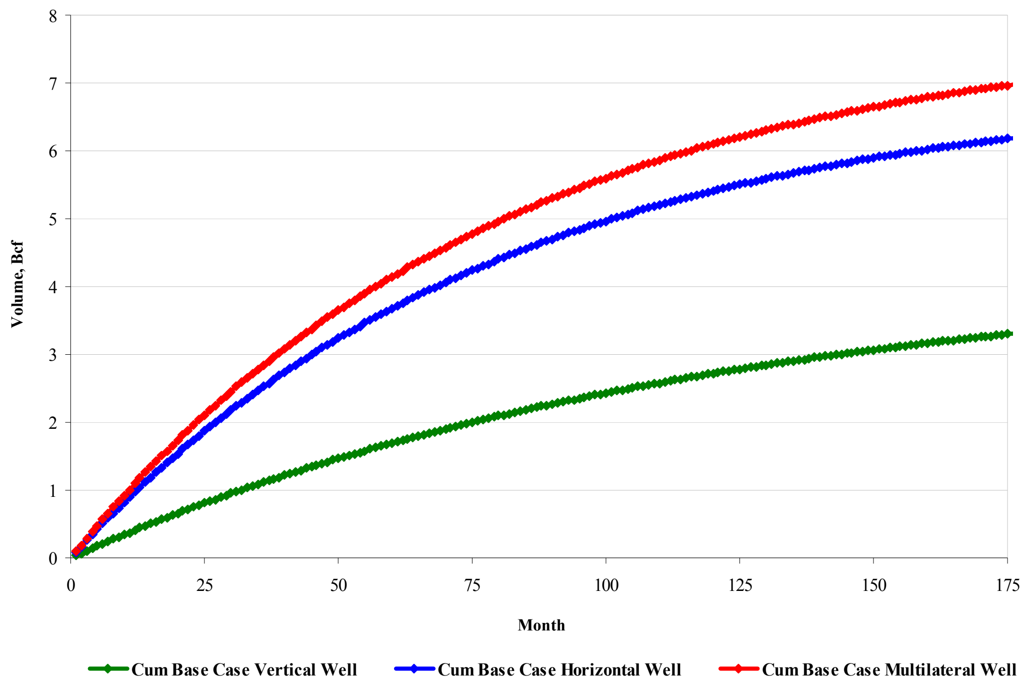

Fig. 4.5 Example 3 – Cumulative production rate under "base case scenario"

As a result of the previous DCA, **Table 4.4** summarizes the initial production rates for the different well systems assuming the three different case scenarios.

Table 4.4 Example 3 – Summary of initial monthly production rates

Well Type	Example 3- Initial Monthly Gas Production, Mcf/month		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	17,780	35,696	53,610
Horizontal Well	43,265	86,498	129,785
Multilateral Well	48,782	97,510	146,354

4.2.2 Example 3 – Economic Analysis

For Example 3, the economic analysis plays an important role because under certain conditions this well exhibits low production rates that may not represent an attractive NPV, and perhaps some poor profitability index and internal rate of return results. The economics of this well can dictate whether a well system may be included or removed from the risk evaluation section.

Table 4.5 depicts the main input data used for each well system to generate FCF. Compared to an oil well, fixed and variable costs are considerably reduced.

Table 4.5 Example 3 – Economic input data for gas wells

Economic Input Data for Gas Well			
	Vertical Well	Horizontal Well	Multilateral Well
Gas price, $/Mcf	$ 8	$ 8	$ 8
Fixed operating cost, $/well	$ 1,000	$2,000	$ 2,500
Variable operating cost, $/Mcf	$ 0.50	$ 0.30	$ 0.20
Water disposal, $/Mcf	$ 0.33	$ 0.33	$ 0.33
Drilling and completion cost	$ 2,500,000	$ 4,000,000	$ 6,000,000

Table 4.6 presents the economic results for internal rate of return, profitability index, payout period, and maximum negative cash flow. Contrary to the economics of Examples 1 and 2 where we observed exceptional internal rate of return and profitability index results (regardless anisotropy ratio), the economics of Example 3 are much lower.

Despite a moderate anisotropy ratio (k_v/k_h=0.10), horizontal and multilateral wells show low expectations. Payout for a horizontal well is 8 months, while the multilateral well is 11 months, which results in a longer wait before positive cash flow is realized. Furthermore, a vertical well shows the worst payout period, about 13 months. As an investment opportunity, one must take into account the payout period because the "time value of money" is always critical.

The profitability index of a vertical well is 3.49, which means that for every dollar invested the project will return three and half dollars of that investment dollar. On the other hand, the profitability index of a horizontal well (4.53) is better than profitability index of a multilateral well (3.36); yet both of these values can not be near those obtained in Examples 1 and 2 (Tables 3.6 and 3.20) even though they are acceptable.

Table 4.6 Example 3 – Summary of economic results under "base case scenario"

Example 3 - Economic Results			
Economic Indicator	Base Case Scenario		
	Vertical Well	Horizontal Well	Multilateral Well
Well payout	13 months	8 months	11 months
Profitability index	3.49	4.53	3.36
Internal rate of return	81%	128%	98%
Max. negative cash flow	- $ 2.28 M	- $ 3.52 M	- $ 5.12 M

Regarding internal rate of return results, the horizontal well (128%) exceeds the multilateral well (98%). However, by selecting either option the project can add value to a company since the cost of capital or rate of return unlikely exceeds the internal rate of return values.

Figure 4.6 shows the cumulative FCF for a medium reservoir quality case. The trend observed in this plot corroborates what we said before regarding the economics of a horizontal well versus multilateral well, and the less desirable performance of a vertical well. Even though Fig. 4.6 illustrates only 50 months of production, by plotting the total time of the wells life, the total cumulative FCF for a vertical well is $ 16 M, $ 26 M for a horizontal well, and $ 29 M for a multilateral well.

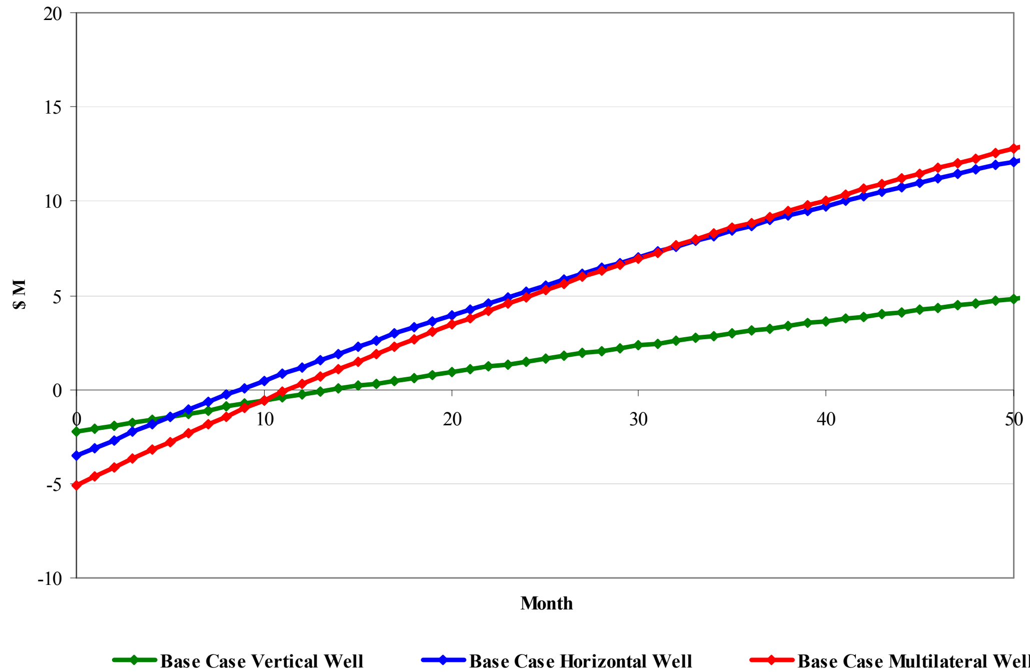

Fig. 4.6 Example 3 – Cumulative FCF under "base case scenario"

NPV results, considering all type of scenarios, point out a multilateral well system as a slightly better alternative than a horizontal well. Almost the same return on investment is obtained by using either a horizontal or multilateral well system (**Table 4.7**).

Table 4.7 Example 3 – Summary of NPV at 10% discount rate

Well Type	Example 3- NPV at 10% discount rate, $ M		
	Low k (Worst)	Medium k (Base)	High k (Best)
Vertical Well	2.79	7.95	13.12
Horizontal Well	6.14	15.96	25.80
Multilateral Well	5.93	17.19	28.47

In this particular situation, it is hard to select a type of well because of the closeness in results between a horizontal and multilateral well. The risk analysis certainly addresses other factors that can help make more evident which is the best option.

4.2.3 Example 3 – Risk Analysis

In situations where two alternatives have very similar results from the technical and economic analysis stand point, risk analysis can be extremely useful in order to magnify the pros and cons of each choice by addressing uncertainty and/or risk.

In Example 3, the likelihood of encountering a faulted reservoir differs slightly from previous examples (**Table 4.8**). Nevertheless, Table 3.9 is used to address the probability of finding a good or bad reservoir as a result of geological complexities and anisotropy ratio. Table 3.10 is utilized to estimate drilling and completion costs that can be originated because of failure to successfully drill and/or complete a well. Last, Tables 3.11 through 3.13 are used to assign chances to succeed or fail while drilling and completing a well.

Table 4.8 Example 3 – Probability of faults

Geological Features	Example 3
Non faulted	30%
Faulted	70%

The results of the risk analysis are depicted in **Tables 4.9 through 4.11**, the expected monetary value is calculated for each well type using Eq. (2.19) considering geological complexities, reservoir quality, anisotropy, and costs incurred if systems failed (see Appendix C for a detailed decision tree of Example 3).

The likelihood calculated (% occurrence) to find a non faulted or faulted reservoir under certain reservoir quality is similar in Examples 1 and 3. Example 2 is different due to the fact that the anisotropy ratio is more severe thus good reservoir quality chances are reduced. As a result, the expected monetary value of a vertical well system is \$ 6.4 M (Table 4.9) while the expected monetary value of a horizontal well is \$ 11.5 M (Table 4.10) and \$ 11 M (Table 4.11) for a multilateral well system.

Table 4.9 Example 3 – Vertical well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Vertical Well		
			% occurrence	NPV at 10% disc. rate, USD M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	6%	2.79	0.11
		Fair	15%	7.95	1.03
		Good	9%	13.12	1.12
Faulted	K_v/k_h=0.10	Poor	28%	2.79	0.51
		Fair	28%	7.95	1.91
		Good	14%	13.12	1.75
Total Vertical Well Expected Monetary Value					6.43

Table 4.10 Example 3 – Horizontal well expected monetary value

Geological Features	Anisotropy	Reservoir Quality	Horizontal Well		
			% occurrence	NPV at 10% disc. rate, USD M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	6%	6.14	0.22
		Fair	15%	15.96	1.85
		Good	9%	25.80	2.00
Faulted	K_v/k_h=0.10	Poor	28%	6.14	0.98
		Fair	28%	15.96	3.35
		Good	14%	25.80	3.03
Total Horizontal Well Expected Monetary Value					11.43

Table 4.11 Example 3 – Multilateral well expected monetary

Geological Features	Anisotropy	Reservoir Quality	Multilateral Well		
			% occurrence	NPV at 10% disc. rate, USD M	Expected Monetary Value
Non faulted	K_v/k_h=0.10	Poor	6%	5.93	0.16
		Fair	15%	17.19	1.78
		Good	9%	28.47	2.01
Faulted	K_v/k_h=0.10	Poor	28%	5.93	0.70
		Fair	28%	17.19	3.22
		Good	14%	28.47	3.04
Total Multilateral Well Expected Monetary Value					10.90

To graphically represent a decision tree with the "leftmost" decision nodes, **Fig. 4.7** reveals the expected monetary value and final results after encompassing a technical, economic and risk analysis for Example 3. The risk analysis opposes the technical and economic results by indicating that after analyzing the risk involved in a multilateral well, the horizontal well is the most effective choice; it has a better chance to successfully being drilled and completed.

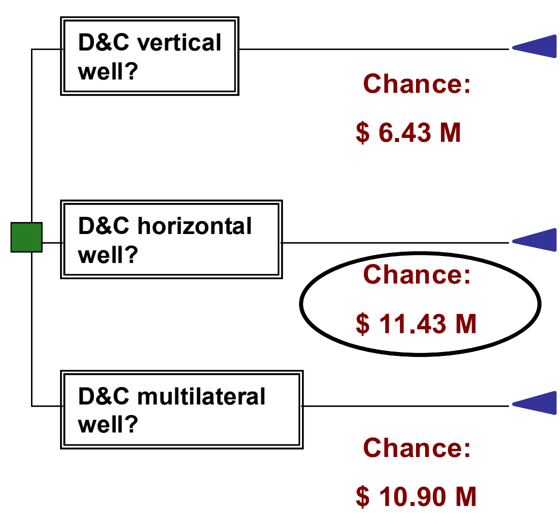

Fig. 4.7 Example 3 – Decision tree expected monetary value for each well system

4.2.4 Example 3 – Sensitivity Analysis

The sensitivity analysis results in Example 3 are not consistent with the results obtained in Examples 1 and 2 due to the different probabilities assigned in Example 3. **Fig. 4.8** illustrates a trend where the expected monetary value does not vary considerably despite geological features (e.g. complexity of faults, compartments, and folding). In addition to that, the expected monetary value does not change significantly whether the reservoir quality is fair or good.

Figure 4.9 shows that from the type of well standpoint, the associated risk to successfully drill and complete horizontal and multilateral wells do not have as much effect on the expected monetary value as geological features do.

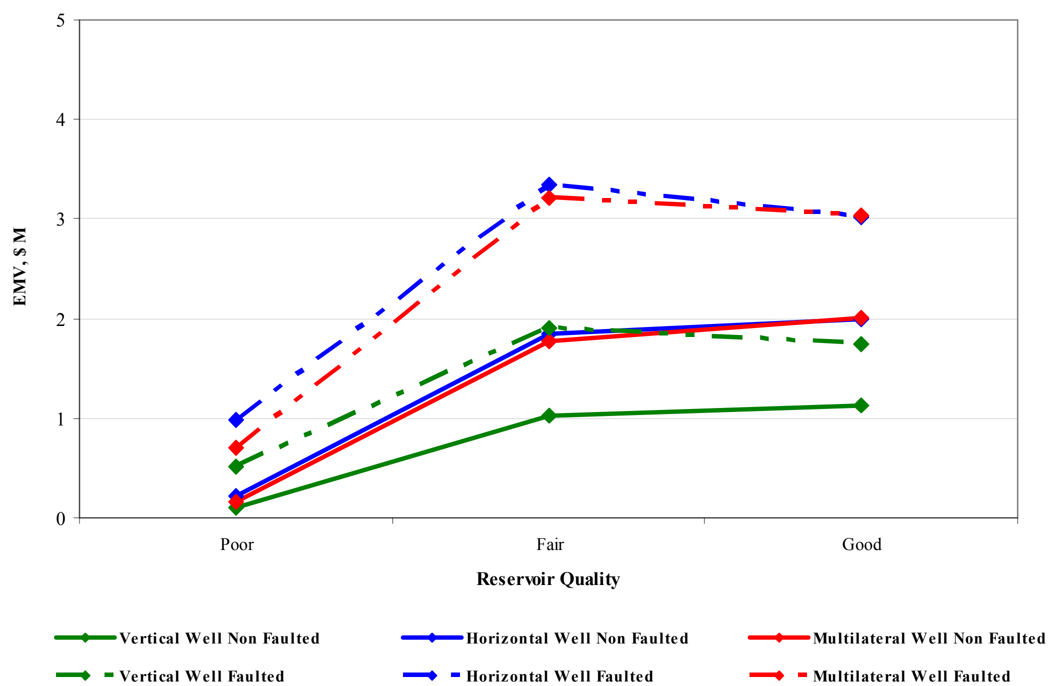

Fig. 4.8 Example 3 – Sensitivity analysis as a function of reservoir quality

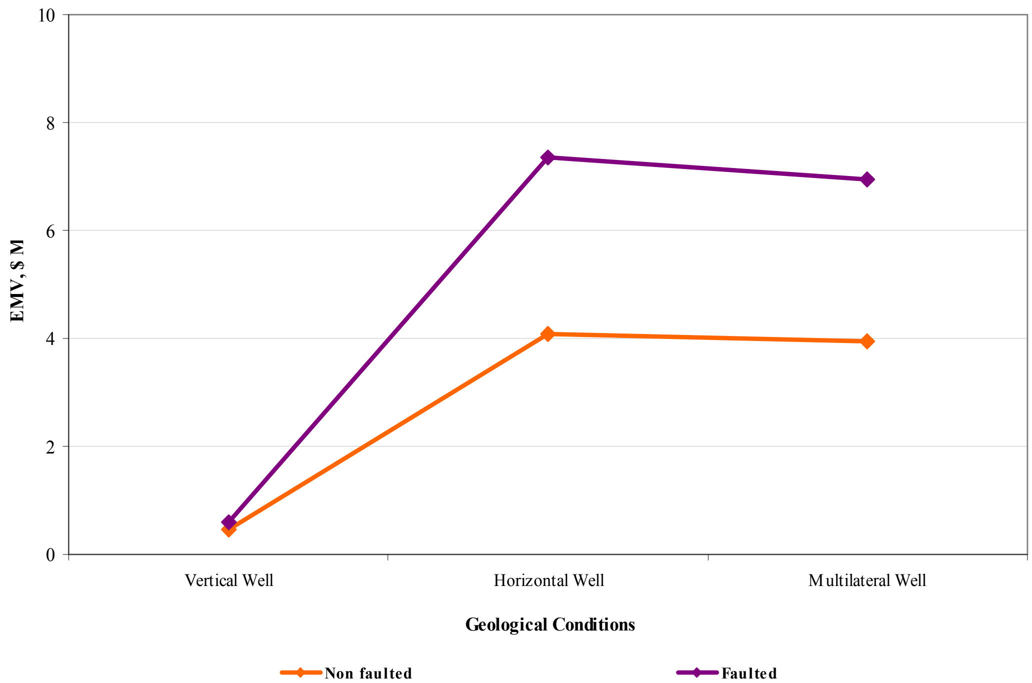

Fig. 4.9 Example 3 – Sensitivity analysis as a function of geological features

5. CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The following conclusions have been drawn from this study:

- Technical, economic and risk analysis must be concurrently performed to enable us in making better decisions. Analyzing the technical feasibility of a well system only does not necessarily ensure the most profitable and best opportunity to succeed.
- Severe heterogeneity in oil and gas reservoirs is critical to the success of each type of completion. Every reservoir presents unique characteristics and should be individually analyzed.
- Geological features such as complexity of faults, compartmentalization, natural fracture network, etc. are critical to the application of vertical drilling. Lateral extent of the reservoir is possible by drilling horizontally parallel to the zone of interest.
- Due to drilling risk, success rate is highly dependant on geological features, quality of the reservoir under study, and the well system. Completion risk is extremely influenced by the type of well system selected.
- The use of purely deterministic methods, e.g. decision trees, is very dependant on the use of existing knowledge and experience which leads sometimes to biased evaluation of options.

5.2 Recommendations

- Geologists, geoscientists, engineers and managers should collaborate together regarding development projects and must take a multidiscipline approach encompassing a technical, economic and risk analysis.
- Objective and careful analysis from the decision makers is imperative. Prior to assessing probabilities in the decision tree, engineers should acquire all pertinent data and lessons learned from previous experience.

- Deterministic and probabilistic methods can be used in conjunction to evaluate several alternatives due to the nature of the oil and gas industry: high risk involved, high capital intensive investments, complexity of operations, and income potential.
- A computer based program needs to be developed to include not only a technical analysis but also an economic and risk analysis of single and multiphase flow reservoirs.

NOMENCLATURE

Symbol	**Description**
a	Reservoir width, ft
A	Drainage area, ft^2
B_o	Oil formation volume factor, res bbl/STB
b	Reservoir length, ft
b_{hyp}	Hyperbolic curve exponent
C_H	Shape factor, dimensionless
C_i	Chance node
D	Non-Darcy coefficient, dimensionless
D_i	Hyperbolic initial nominal decline rate
F_v	Future sum received at time t
h	Thickness, ft
i_e	Effective annual interest rate (discount rate, fraction)
k	Average permeability, md
k_h	Horizontal permeability, md
k_v	Vertical permeability, md
k_y	Horizontal permeability, md
k_z	Vertical permeability, md
L	Wellbore length, ft
N_p	Oil or gas produced volume, STB or Mscf
NPV_i	Net present value corresponding to the branch with P_i, $ M
$\overline{P}$	Average reservoir pressure, psi
Pi	Conditional probability
P_{wf}	Flowing bottom-hole pressure, psi
P_{xy}	Partial penetration skin component x-y plane
P_{xyz}	Partial penetration skin component x-y-z plane
P_y	Partial penetration skin component y plane

Q_i	Initial rate, STB/day or Mcf/day (DCA)
Q_t	Rate at time t, STB or Mcf/day (DCA)
q_g	Gas rate, Mcf/day
q_o	Oil rate, STB/day
r_e	Drainage radius, ft
r_w	Wellbore radius, ft
s	Skin effect, dimensionless
s_R	Partial penetration skin factor, dimensionless
$\overline{T}$	Average reservoir temperature (^{o}F)
t	Time, months
x_{mid}	x-coordinate of the midpoint of the well, ft
y_o	Well location in y axis, ft
$\overline{Z}$	Average gas compressibility (gas deviation factor), dimensionless
z_o	Well location in z axis, ft

Greek

$\overline{\mu}$	Average oil or gas viscosity (cp)

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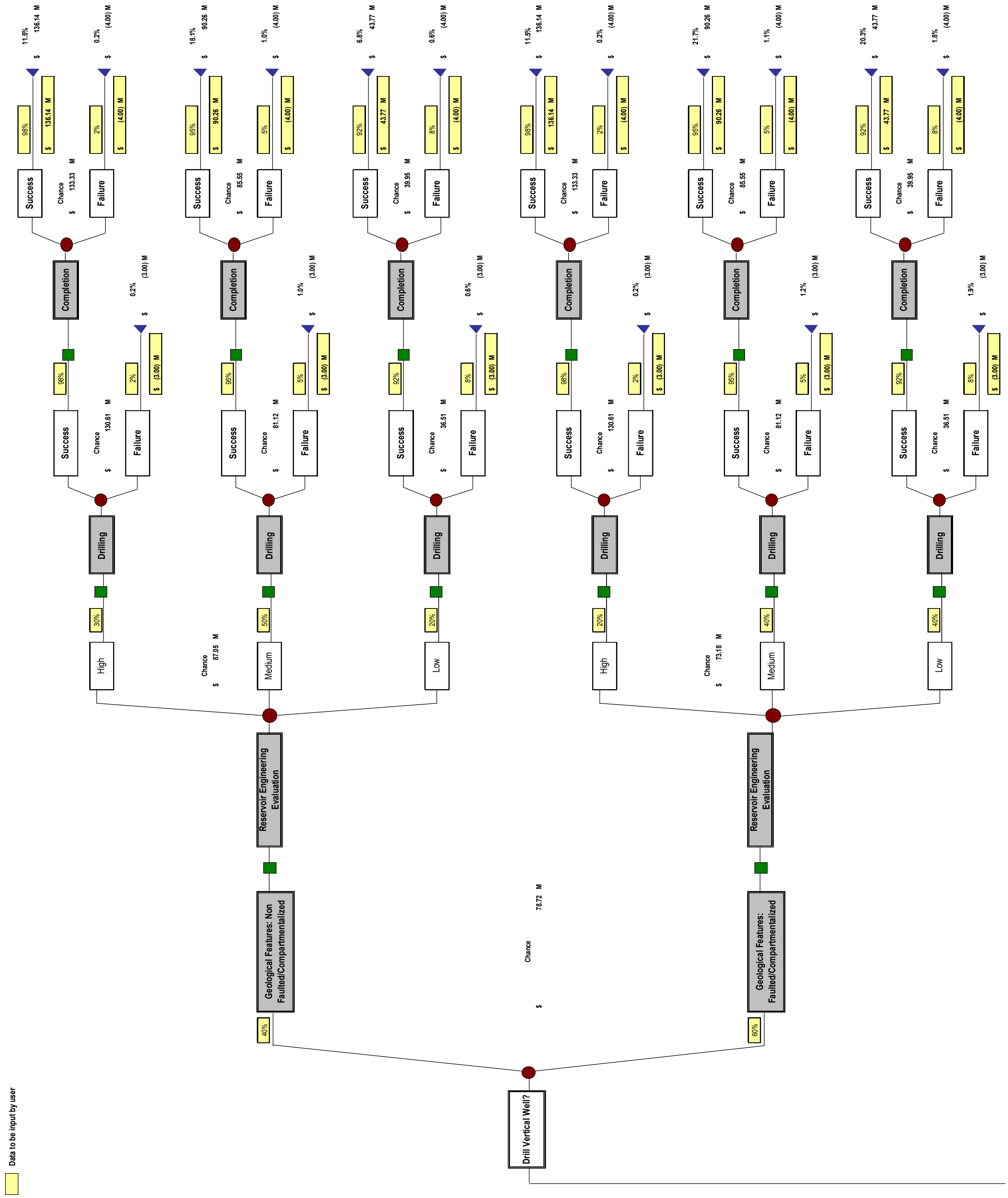
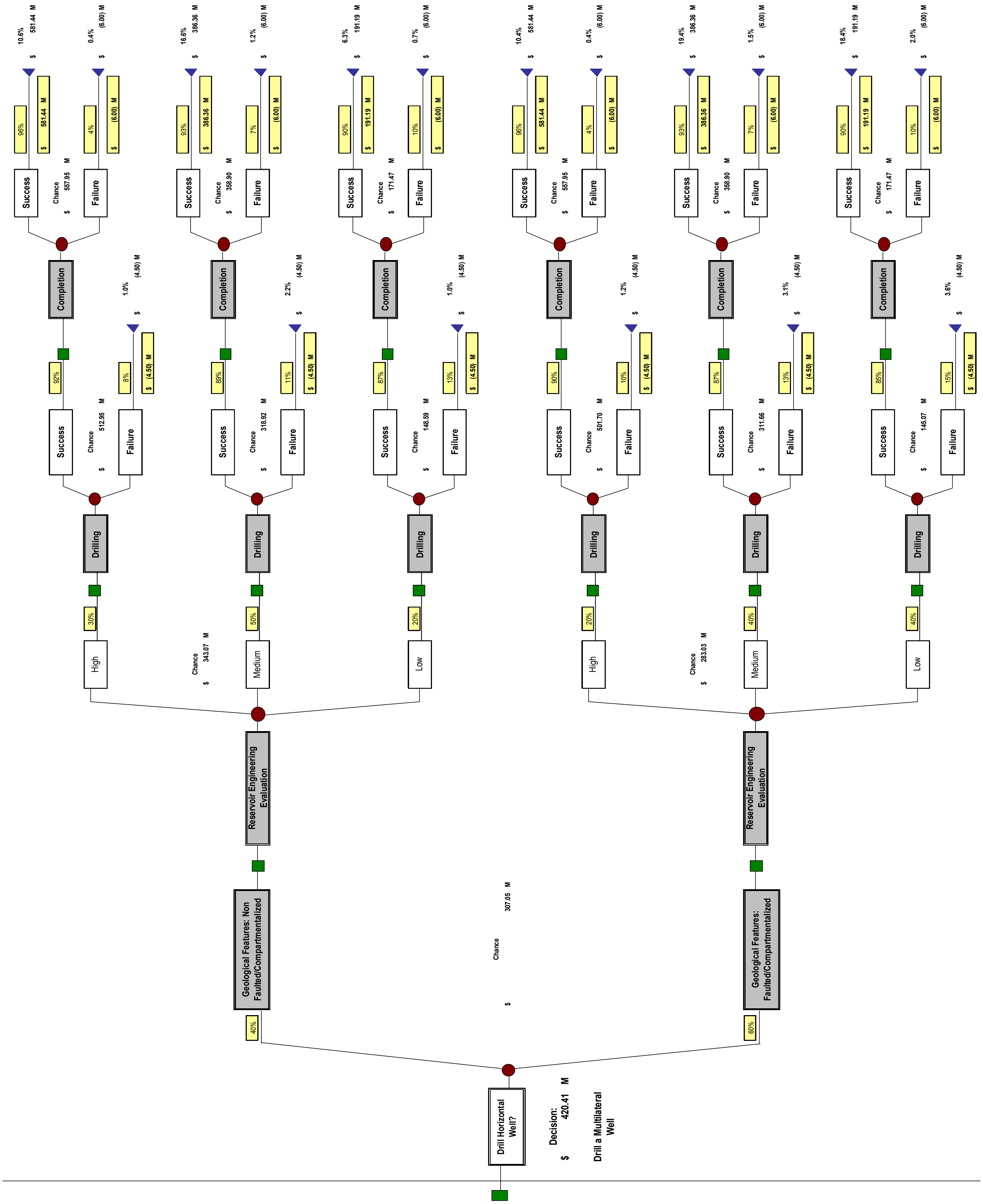
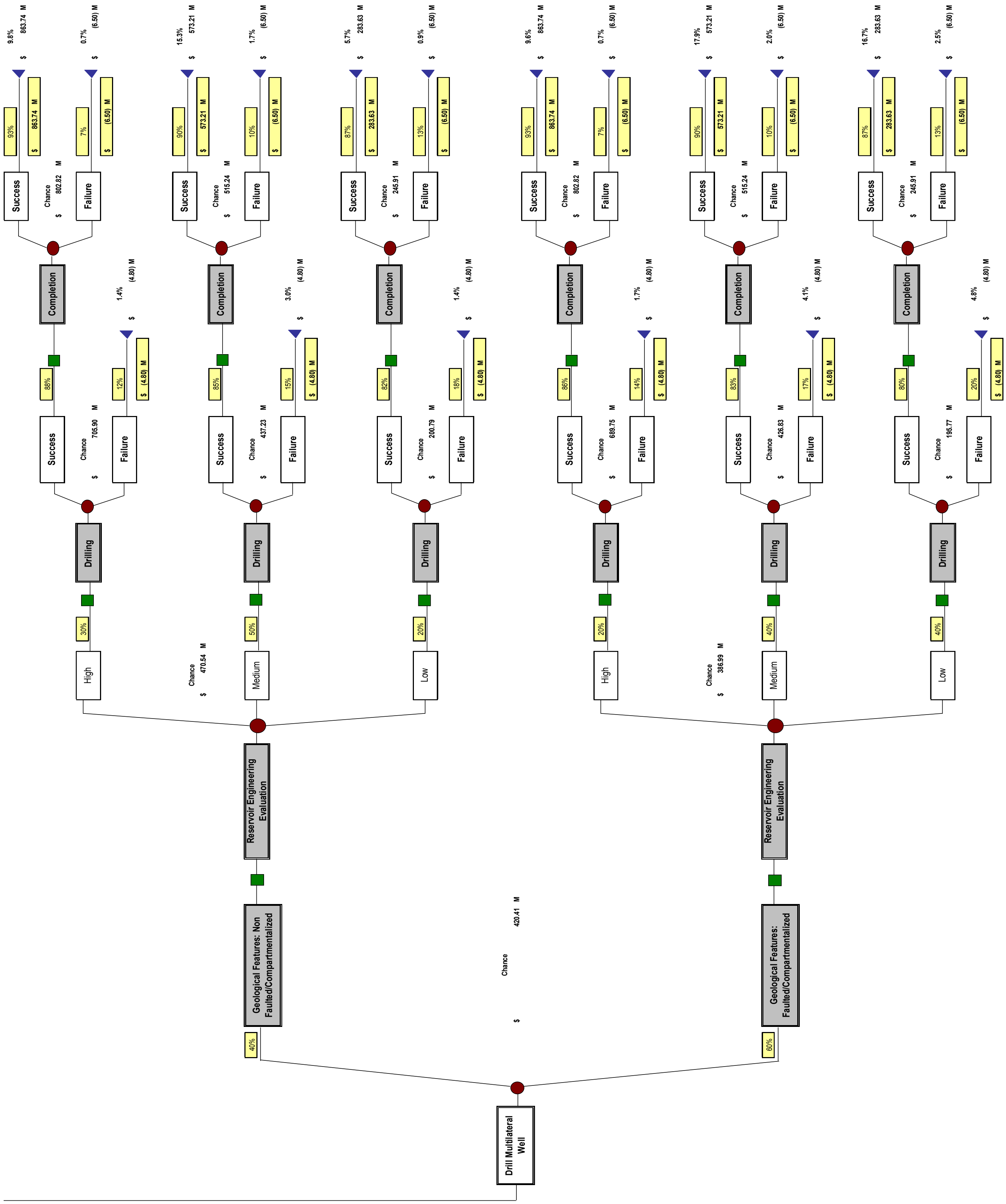
APPENDIX A

EXAMPLE 1 DECISION TREE


Data to be input by user
Drill Vertical Well?
Chance $ 78.72 M
40%
Geological Features: Non Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance $ 87.05 M
High 30%
Medium 50%
Low 20%
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance $ 73.18 M
High 20%
Medium 40%
Low 40%
Drilling
Success
Failure
Chance $ 130.61 M
Chance $ 81.12 M
Chance $ 36.51 M
98%
95%
92%
2%
5%
8%
$ (3.00) M
Completion
Chance $ 133.33 M
Chance $ 85.55 M
Chance $ 39.95 M
$ 136.14 M
$ 90.26 M
$ 43.77 M
$ (4.00) M
11.5% $ 136.14 M
0.2% $ (4.00) M
0.2% $ (3.00) M
18.1% $ 90.26 M
1.0% $ (4.00) M
1.0% $ (3.00) M
6.8% $ 43.77 M
0.6% $ (4.00) M
0.6% $ (3.00) M
11.5% $ 136.14 M
0.2% $ (4.00) M
0.2% $ (3.00) M
21.7% $ 90.26 M
1.1% $ (4.00) M
1.2% $ (3.00) M
20.3% $ 43.77 M
1.8% $ (4.00) M
1.9% $ (3.00) M

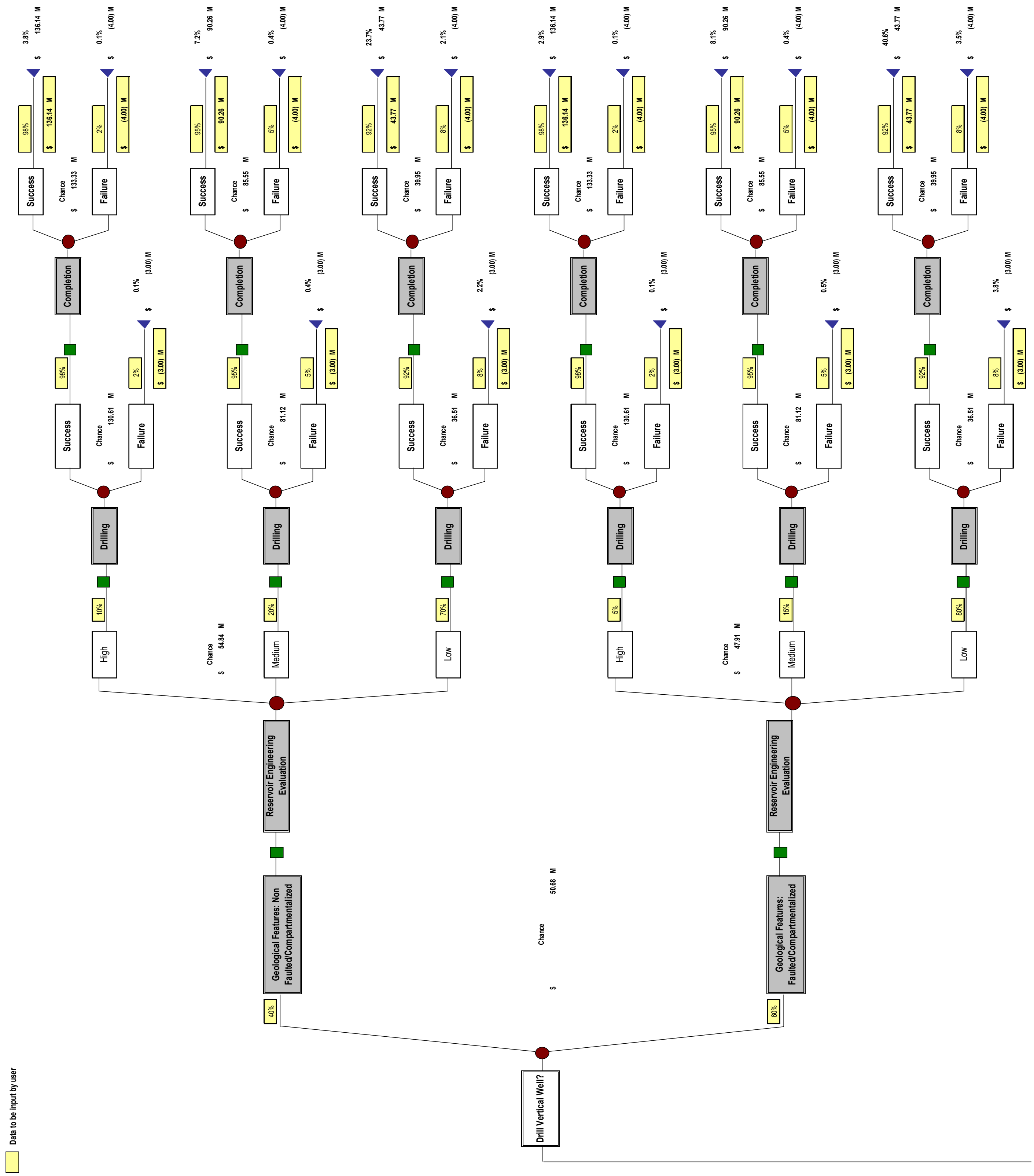


Drill Horizontal Well?
Decision: $ 420.41 M
Drill a Multilateral Well
Chance $ 307.05 M
40%
Geological Features: Non Faulted/Compartmentalized
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance $ 343.07 M
Chance $ 283.03 M
High
Medium
Low
Drilling
Success
Failure
Completion

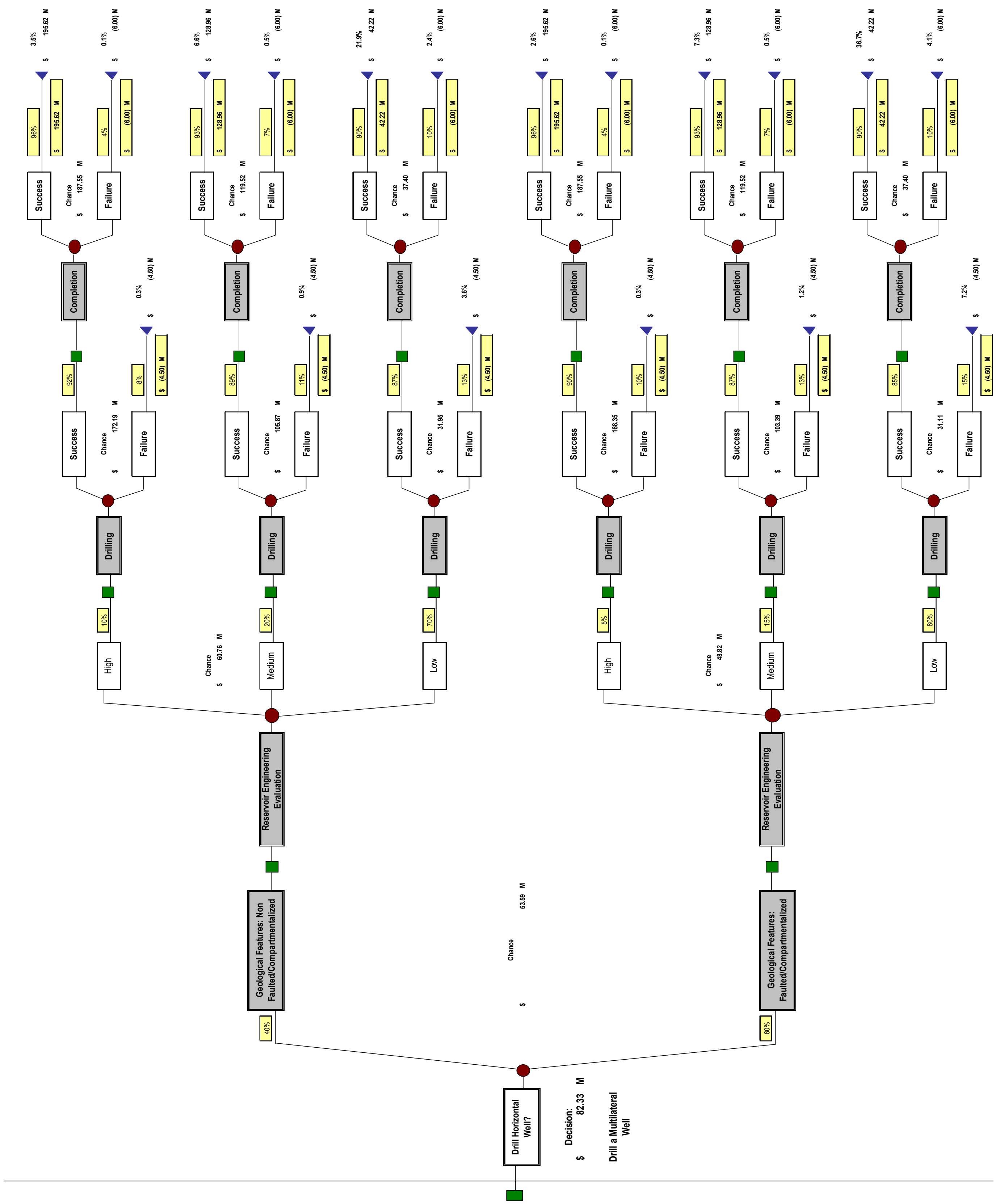

Drill Multilateral Well
Chance
$ 420.41 M
40%
Geological Features: Non Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 470.54 M
High
30%
Drilling
Success
88%
Chance
$ 705.90 M
Completion
Success
93%
$ 863.74 M
9.8%
$ 863.74 M
Chance
$ 802.82 M
Failure
7%
$ (6.50) M
0.7%
$ (6.50) M
Failure
12%
$ (4.80) M
1.4%
$ (4.80) M
Medium
50%
Drilling
Success
85%
Chance
$ 437.23 M
Completion
Success
90%
$ 573.21 M
15.3%
$ 573.21 M
Chance
$ 515.24 M
Failure
10%
$ (6.50) M
1.7%
$ (6.50) M
Failure
15%
$ (4.80) M
3.0%
$ (4.80) M
Low
20%
Drilling
Success
82%
Chance
$ 200.79 M
Completion
Success
87%
$ 283.63 M
5.7%
$ 283.63 M
Chance
$ 245.91 M
Failure
13%
$ (6.50) M
0.9%
$ (6.50) M
Failure
18%
$ (4.80) M
1.4%
$ (4.80) M
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 386.99 M
High
20%
Drilling
Success
86%
Chance
$ 689.75 M
Completion
Success
93%
$ 863.74 M
9.6%
$ 863.74 M
Chance
$ 802.82 M
Failure
7%
$ (6.50) M
0.7%
$ (6.50) M
Failure
14%
$ (4.80) M
1.7%
$ (4.80) M
Medium
40%
Drilling
Success
83%
Chance
$ 426.83 M
Completion
Success
90%
$ 573.21 M
17.9%
$ 573.21 M
Chance
$ 515.24 M
Failure
10%
$ (6.50) M
2.0%
$ (6.50) M
Failure
17%
$ (4.80) M
4.1%
$ (4.80) M
Low
40%
Drilling
Success
80%
Chance
$ 195.77 M
Completion
Success
87%
$ 283.63 M
16.7%
$ 283.63 M
Chance
$ 245.91 M
Failure
13%
$ (6.50) M
2.5%
$ (6.50) M
Failure
20%
$ (4.80) M
4.8%
$ (4.80) M

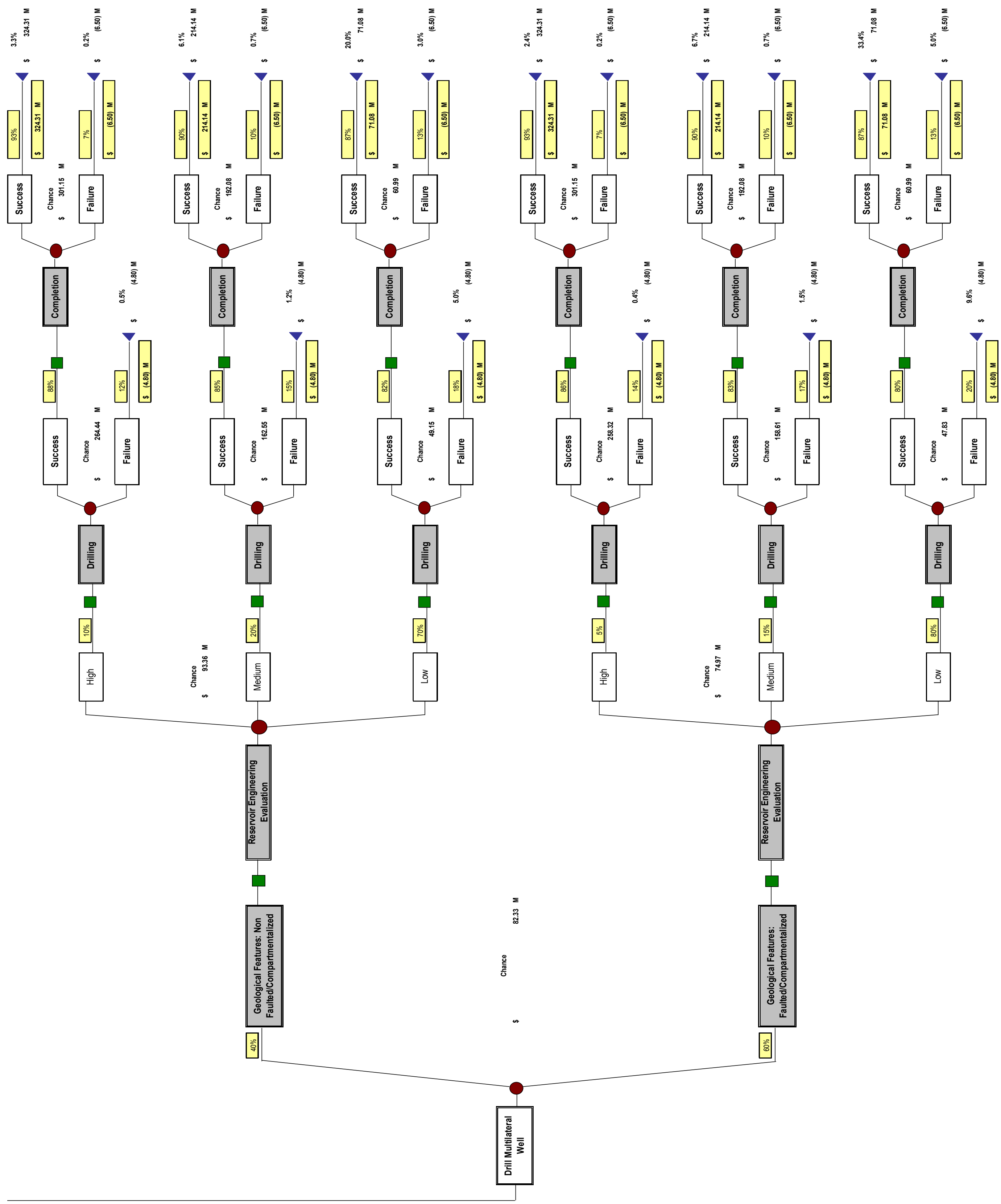
APPENDIX B

EXAMPLE 2 DECISION TREE



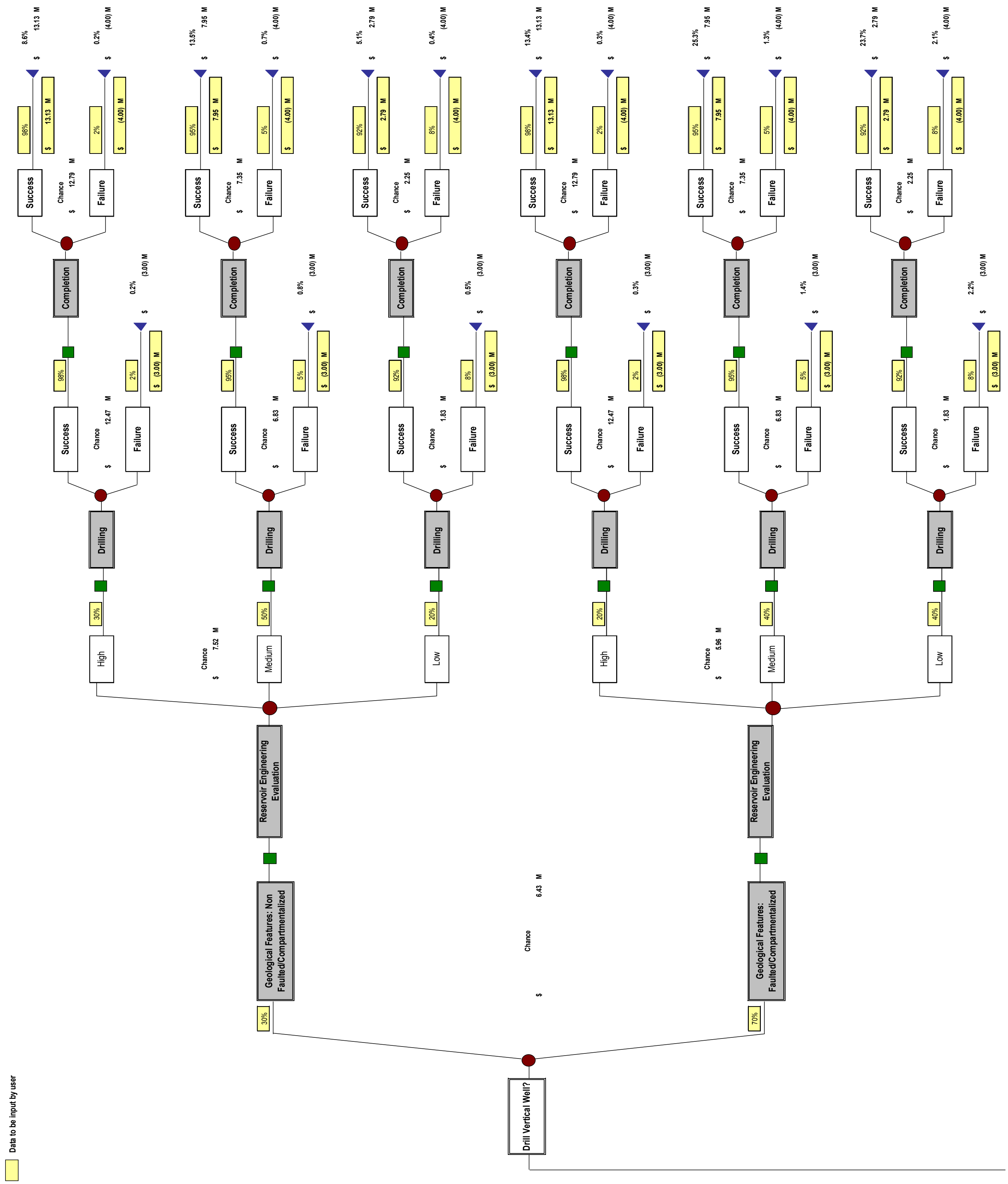
Data to be input by user
Drill Vertical Well?
Chance
$ 50.68 M
40%
Geological Features: Non Faulted/Compartmentalized
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 54.84 M
Chance
$ 47.91 M
High
Medium
Low
10%
20%
70%
5%
15%
80%
Drilling
Completion
Success
Failure

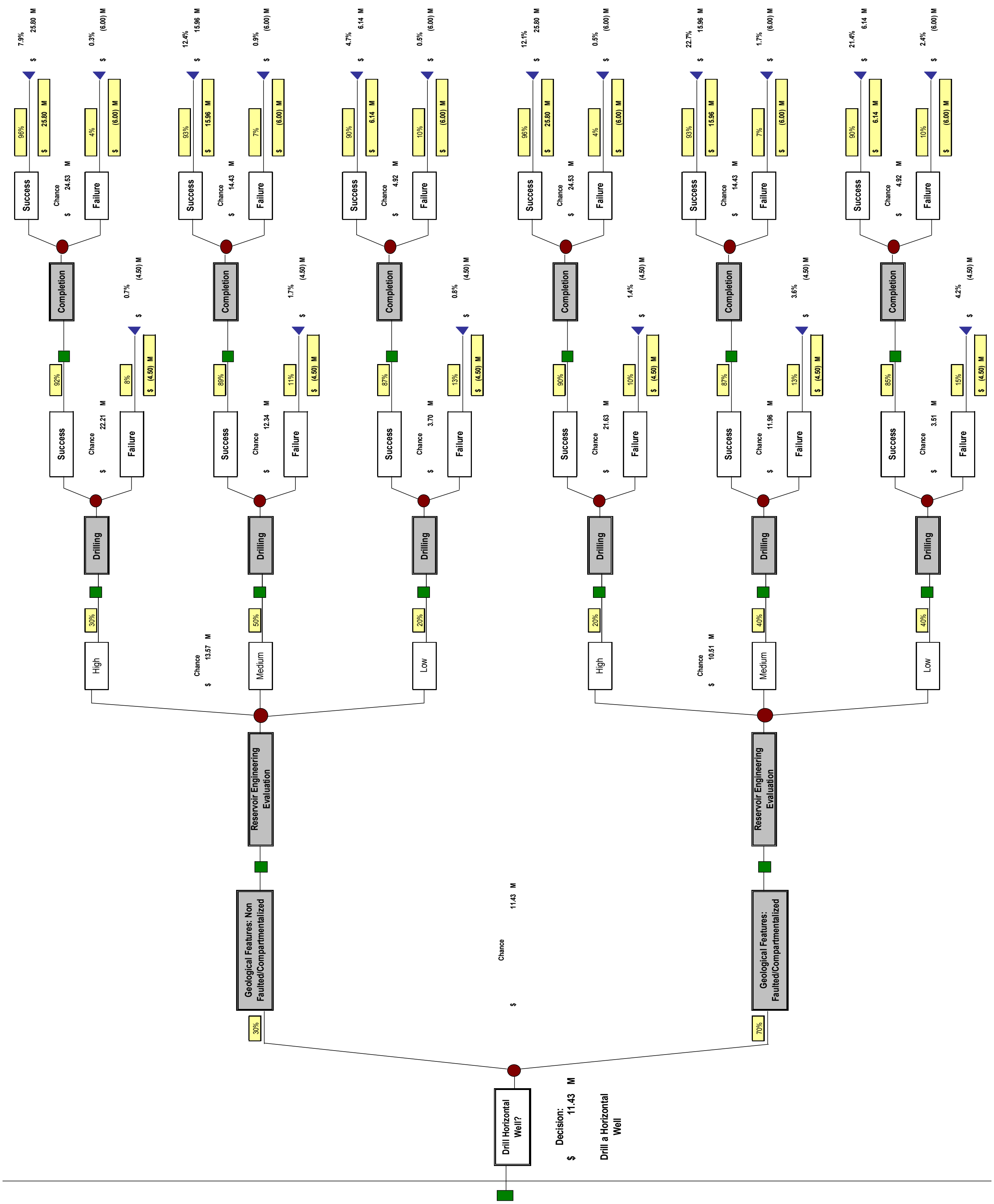

Drill Horizontal Well?
Decision:
$ 82.33 M
Drill a Multilateral Well
Chance
$ 53.59 M
40%
Geological Features: Non Faulted/Compartmentalized
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 60.76 M
Chance
$ 48.82 M
High
Medium
Low
10%
20%
70%
5%
15%
80%
Drilling
Success
Failure
Completion
Chance
$ 172.19 M
$ 105.87 M
$ 31.95 M
$ 168.35 M
$ 103.39 M
$ 31.11 M
$ 187.55 M
$ 119.52 M
$ 37.40 M
$ 195.62 M
$ 128.96 M
$ 42.22 M
$ (6.00) M
$ (4.50) M


Drill Multilateral Well
Chance
$ 82.33 M
40%
Geological Features: Non Faulted/Compartmentalized
60%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 93.36 M
Chance
$ 74.97 M
High
10%
Medium
20%
Low
70%
High
5%
Medium
15%
Low
80%
Drilling
Success
Failure
Chance
$ 264.44 M
$ 162.55 M
$ 49.15 M
$ 258.32 M
$ 158.61 M
$ 47.83 M
88%
12%
85%
15%
82%
18%
86%
14%
83%
17%
80%
20%
$ (4.80) M
0.5%
1.2%
5.0%
0.4%
1.5%
9.6%
Completion
Chance
$ 301.15 M
$ 192.08 M
$ 60.99 M
93%
7%
90%
10%
87%
13%
$ 324.31 M
$ 214.14 M
$ 71.08 M
$ (6.50) M
3.3%
0.2%
6.1%
0.7%
20.0%
3.0%
2.4%
0.2%
6.7%
0.7%
33.4%
5.0%

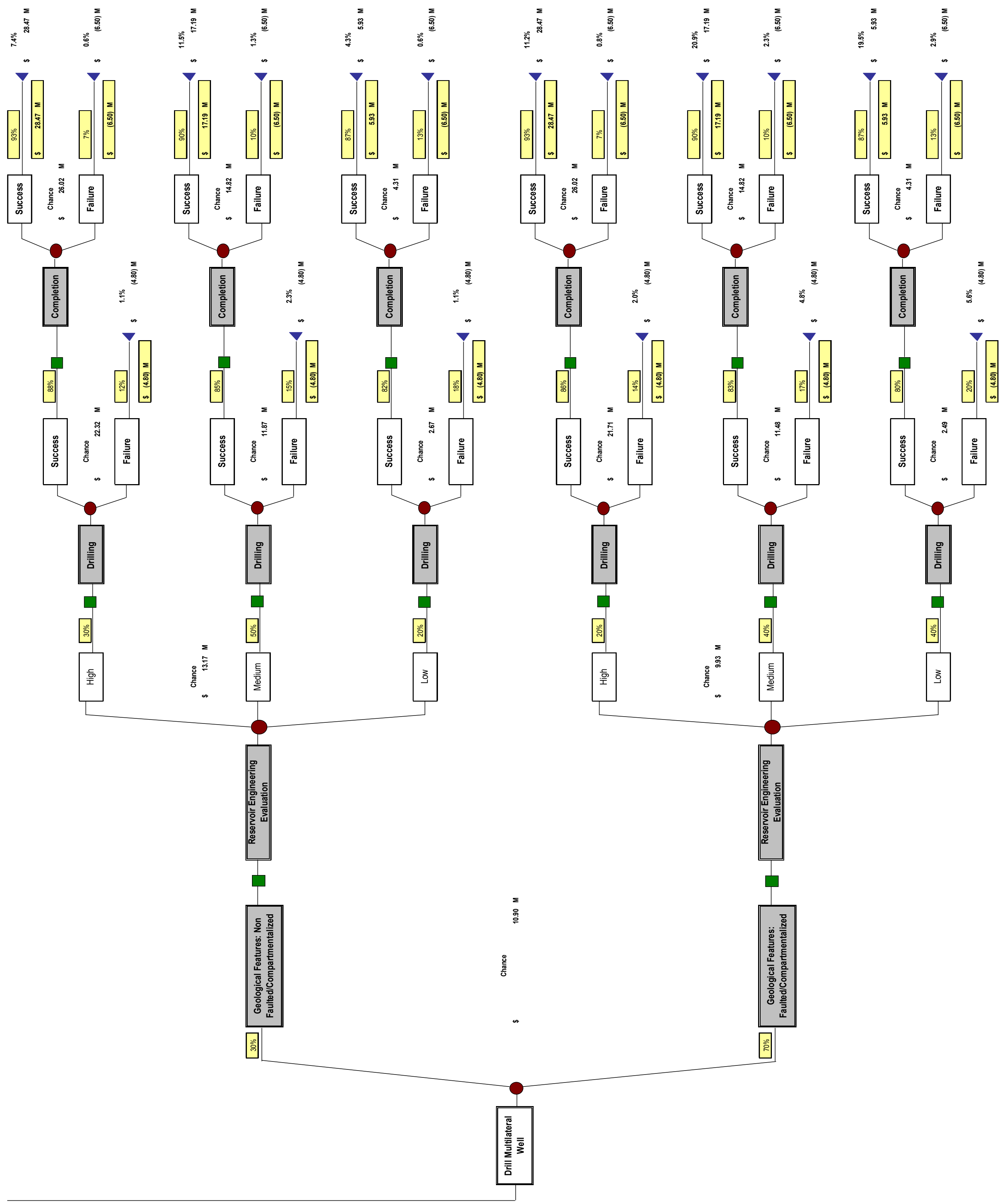
APPENDIX C

EXAMPLE 3 DECISION TREE


Drill Vertical Well?
Chance $ 6.43 M
30%
Geological Features: Non Faulted/Compartmentalized
70%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance $ 7.52 M
Chance $ 5.96 M
High
Medium
Low
30%
50%
20%
40%
Drilling
Success
Failure
Chance $ 12.47 M
Chance $ 6.83 M
Chance $ 1.83 M
98%
2%
95%
5%
92%
8%
$ (3.00) M
0.2%
0.8%
0.5%
0.3%
1.4%
2.2%
Completion
Chance $ 12.79 M
Chance $ 7.35 M
Chance $ 2.25 M
$ 13.13 M
$ 7.95 M
$ 2.79 M
$ (4.00) M
8.6%
0.2%
13.5%
0.7%
5.1%
0.4%
13.4%
0.3%
25.3%
1.3%
23.7%
2.1%
Data to be input by user



Drill Horizontal Well?
Decision: $ 11.43 M
Drill a Horizontal Well
Chance $ 11.43 M
30%
Geological Features: Non Faulted/Compartmentalized
70%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance $ 13.57 M
Chance $ 10.51 M
High 30%
Medium 50%
Low 20%
High 20%
Medium 40%
Low 40%
Drilling
Success
Failure
Completion
Chance $ 22.21 M
Chance $ 12.34 M
Chance $ 3.70 M
Chance $ 21.63 M
Chance $ 11.96 M
Chance $ 3.51 M
Chance $ 24.53 M
Chance $ 14.43 M
Chance $ 4.92 M
92% 8% $ (4.50) M 0.7%
89% 11% $ (4.50) M 1.7%
87% 13% $ (4.50) M 0.8%
90% 10% $ (4.50) M 1.4%
87% 13% $ (4.50) M 3.6%
85% 15% $ (4.50) M 4.2%
96% $ 25.80 M 7.9%
4% $ (6.00) M 0.3%
93% $ 15.96 M 12.4%
7% $ (6.00) M 0.9%
90% $ 6.14 M 4.7%
10% $ (6.00) M 0.5%
96% $ 25.80 M 12.1%
4% $ (6.00) M 0.5%
93% $ 15.96 M 22.7%
7% $ (6.00) M 1.7%
90% $ 6.14 M 21.4%
10% $ (6.00) M 2.4%


Drill Multilateral Well
Chance
$ 10.90 M
30%
Geological Features: Non Faulted/Compartmentalized
70%
Geological Features: Faulted/Compartmentalized
Reservoir Engineering Evaluation
Chance
$ 13.17 M
Chance
$ 9.93 M
High
Medium
Low
30%
50%
20%
20%
40%
40%
Drilling
Success
Failure
Chance
$ 22.32 M
$ 11.87 M
$ 2.67 M
$ 21.71 M
$ 11.48 M
$ 2.49 M
88%
85%
82%
86%
83%
80%
12%
15%
18%
14%
17%
20%
$ (4.80) M
1.1%
2.3%
1.1%
2.0%
4.8%
5.6%
Completion
$ 26.02 M
$ 14.82 M
$ 4.31 M
93%
90%
87%
7%
10%
13%
$ 28.47 M
$ 17.19 M
$ 5.93 M
$ (6.50) M
7.4%
0.6%
11.5%
1.3%
4.3%
0.6%
11.2%
0.8%
20.9%
2.3%
19.5%
2.9%

VITA

Dulce Maria Arcos Rueda received her Bachelor of Science degree in industrial engineering from Instituto Technologico y de Estudios Superiores de Monterrey, Mexico in 2000. She entered the petroleum engineering graduate program at Texas A&M University in August 2006 and received her Master of Science degree in December 2008. She has been working for Schlumberger Well Services since July 2000. Her first assignment was as Field Engineer in Longview, Texas from July 2000 to July 2003. After that, she worked as a Technical Support Engineer in Dallas, Texas from July 2003 to July 2005. Her last position prior to her graduate studies was DESC Engineer (Design and Evaluation Services for Clients) for Comstock Resources in Frisco, Texas.

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