UNIVERSITY OF AGDER

Exploitation of Shale Oil & Gas in the U.S.

An Evaluation of Refracturing Completion Techniques based on Technical and Economical Criteria.

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University of Agder, 2014

Faculty of Engineering and Science

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Preface

This master's thesis represents the final work of the M.Sc degree in Industrial Economics and Technology Management at the University of Agder, the Faculty of Engineering and Science, the Department of Engineering Sciences. The master's thesis accounts for 30 credits, and was conducted during the period from January 2015 to May 2015.

The thesis is written as part of Comitt Well Solutions' desire to better understand the potential in the new emerging refracturing market. Our interest in the rapid evolving shale oil and gas market led us to contact Innovation Norway in Houston to find a thesis within this topic. Comitt Well Solutions got recommended and wanted to cooperate with us. The research area has been challenging and complex, but also incredibly interesting and fun to work with.

The thesis is highly technical and uses words and expression that may be hard to understand for readers with little experience or knowledge within the field of shale oil and gas. To ease the reading experience we recommend that the reader actively uses the abbreviation list and expression list provided. This thesis is also written with the imperial system since the thesis is written for an American company.

During this thesis, we have received great support and guidance both from Comitt Well Solutions and the University of Agder. We would like to thank or external supervisor BDM Eivind Moen, and CEO Roger Antonsen (Comitt Well Solutions) who have been fantastic in terms of hosting us in Houston, provide us with offices, necessary training and contacts. The research of the thesis is also conducted through cooperation with field experts in several oil- and service companies. We would like to thank all those involved in interviews, training, and data gathering. Finally, we would very much like to thank our internal supervisors Professor Tom Lassen and Professor Bo Terje Kalsaas (University of Agder) for all the help and guidance throughout the process of writing this master thesis.

Grimstad, 25.05.2015

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Executive Summary

Production of oil and gas from shale is often described as a revolution to energy production in North America. This development is made possible by technology advancements as horizontal drilling and hydraulic fracturing. Due to the decreasing oil and gas prices in 2014, the industry is now investigating the potential of refracturing old wells more comprehensively than before. Refracturing horizontal wells is a relatively new operation, where the completion techniques' performances are uncertain. Even so, the published refracturing projects show that most of them have been highly successful with an economical success rate around 90 percent.

The presented work has evaluated the economical- and technical performance of eight refracturing completion techniques, and in addition investigated the magnitude of the refracturing market. This was done by answering the following questions:

- What is the potential magnitude of the refracturing market?
- What is the technical- and economical performance of the refracturing completion techniques?

Our scope of work is limited to the horizontal refracturing operation, and will for that reason not include every parameter needed to give the oil- and gas companies a complete economical evaluation of the profitability.

To answer the research questions an exploratory constructive research design was chosen. The constructive research approach is a research procedure for developing constructions that in turn can contribute to the theory connected to the field of research. The validation of the result can come from both practical- and theoretical relevance. During the exploratory study, we conducted several qualitative interviews and a comprehensive study of refracturing. Due to lack of data on horizontal refracturing operations, a profit calculation tool was constructed to improve the evaluation of the economical performance of the refracturing techniques. The tool is built upon a technical- and economical evaluation that determines net present value (NPV), breakeven price and payback period of refracturing. A Monte Carlo simulation was applied to take account for the uncertainty in the calculations.

Our most important findings indicate that there is a higher potential in refracturing than the industry utilizes today. We found the best well selection criteria to be wells with good reservoir quality, steep decline and poor design- or job quality. Selecting good candidates for refracturing will likely be more successful compared to drilling a new well, because of more available information about the reservoirs. We have estimated that up to 70 percent of the wells in the U.S. will be refracturing candidates in the future. Based on the refracturing success criteria and the experienced steep declining production, we found it likely that refracturing will be economically multiple times in the same well. This further strengthens our conclusion that there is a huge potential when it comes to refracturing horizontal wells.

The technical evaluation of the refracturing techniques resulted in a technical grade, which represented the techniques' ability to achieve the identified success criteria. The success criteria are based on how good the technique is able to increase the production post-refracturing. Comitt Well Solutions' new refracturing technique was given the highest possible grade in the evaluation, which indicates that this technique is able to effectively achieve all the success criteria, see Table 0-1.

Regardless of the high costs of Comitt Well Solutions' technique, the technical performance is significantly higher than the most commonly used technique, Bull-head diversion, which results in the highest profit potential according to our profit calculation tool, see Table 0-1. By comparing the experienced production increase with the investment costs and risks of refracturing, our profit calculation tool estimates low break even prices and high NPV's for refracturing operations. With the use of Comitt Well Solutions' technique we estimate a NPV of $ 6 710 000 and a breakeven price of $ 16 two years after a refracturing operation, see Table 0-1.

Table 0-1: Comparison between the techniques calculated on a 2 years perspective after a refracturing recompletion operation. The refracturing operation is done after 3 years of production in a well with an oil price of $60. The technical grade is rated from 1-10 after how good the techniques are technically

Refracturing Technique	Technical Grade	Cost	NPV (Oil Price of $ 60)	Breakeven price
Comitt Well Solutions	10.0	$ 2 500 000	$ 6 710 000	$ 16
Bull-head diversion	4.0	$ 1 675 000	$ 2 450 000	$ 24

In the numerical analysis we have identified a trend between the initial production ratio and the decline factors, in form of an equation. This equation can be used to improve the forecasting of production post-refracturing, and are for that reason integrated into the production forecasting in our profit calculation tool. This supplementary finding will help to forecast refracturing production more accurate in the future.

The constructed profit calculation tool gives a highly relevant contribution to the oil and gas industry today, with an easy way of forecasting technical performance and future production. The tool also contributes with an economical presentation of the refracturing operations, which can give the companies a better economical understanding of refracturing. Yet, we acknowledge the need for adjustments of the cost, risk, production increase and forecasting method in order to customize our constructed tool to be more accurate in calculating the profitability of the individual wells. The tool calculations in this thesis are based on estimated numbers and are for that reason not precise. However, the calculations give a good indication on how the techniques perform in comparison to each other, and the general profitability of refracturing. Furthermore, we believe that the profit calculation tool will be a platform that can be built upon to better be able to understand the economics of refracturing in the future.

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Abbreviations

Bbl	-	Barrel
Bcfd	-	Billion cubic feet per day
bopd	-	Barrels of oil per day
BP	-	British Petroleum
Btu	-	One Btu is the heat required to raise the temperature of one pound of water by one degree Fahrenheit
CT	-	Coiled tubing
DCA	-	Decline curve analysis
EUR	-	Estimated ultimate recovery
Fracture	-	Cracks in the shale formation, creating flow paths for hydrocarbons
Ft	-	Feet
HAZOP	-	A hazard and operability assessment
ID	-	Inner diameter
IP	-	Initial production
Mbod	-	Thousand barrels of oil per day
MCS	-	Monte Carlo Simulation
Mscfd	-	One thousand cubic feet per day
MIT	-	Mechanical Integrity Test
Mbod	-	Thousand barrel of oil per day
MMbod	-	Million barrel of oil per day
MMBtu	-	Million British thermal units (Btu)
MMscfd	-	One million cubic feet per day
NPV	-	Net Present Value
OD	-	Outer diameter
OGIP	-	Original gas in place
OH	-	Open hole
OOIP	-	Original oil in place
P&P	-	Plug and Perf
ROI	-	Return on Investment
ROR	-	Rate of Return
scf	-	Square cubic feet
SPE	-	Society of petroleum engineers
SRV	-	Stimulated rock volume
Tcf	-	Trillion cubic feet
WTI	-	West Texas intermediate

Definitions and Expression

Annulus	-	The space between the shale formation and the casing
Area of pay	-	Hydrocarbon rich areas in the shale formation
Bridge plug	-	A plug used to isolate stages inside the lateral
Casing	-	A metal tube that protects the wellbore from the formation
Casing string	-	The full length of a casing
Cluster	-	A part/length of the lateral consisting of multiple perforations

Diversion agents	-	Rubber-, biodegradable balls or proppant slugs used to divert fluid
Enlarged fractures	-	Fracture growth, adding connections with more hydrocarbon
EUR	-	An estimate of the expected ultimate recovery of oil or gas, based on forecasted production
Fishing operation	-	Retrieval of lost equipment
Forecast	-	A prediction of future events
Fracturing valve	-	The part of the tool that regulates the flow, by opening and closing
Jet-nozzle	-	A device using fluid under very high pressure to perforate a casing
Kick of point	-	The point where the vertical parts of the well starts curving into the horizontal part.
Liner	-	A type of horizontal casing
Lateral	-	The horizontal part of the well
Lateral heel	-	The first part of the lateral where the last stages are
Lateral toe	-	The last part of the lateral where the first stages are
NPV	-	Net Present Value, using economic discount factors to discount future cash flow
OGIP	-	Total gas content of a reservoir prior to production
OIP	-	Total oil content of a reservoir
OOIP	-	Total oil content of a reservoir prior to production
Screen-out	-	When proppant are over-placed in wellbore
Shale play	-	A shale play is a defined geographic area containing a hydrocarbon rich fine-grained sedimentary rock
Sleeve	-	An inner mechanical part that isolate the fracturing valve and can slide into an open position which opens the valve
Stage	-	A part/length of the lateral consisting of multiple clusters
Straddle Packer	-	An assembly consisting of one packer at each side of the fracturing valve
Stress gradient	-	The in-suit stress in the rock formation
Packer	-	A standard component of the completion tool used to provide a seal between the formation and the inside of the system
Pay	-	Shale containing extractable hydrocarbon content
Recompletion	-	The process of going down a previously fractured well, and perforate new perforations and then stimulate the well again
Refracturing	-	The process of going down a previously fractured well, and stimulate the well again
Perforation	-	A hole in the casing/liner that connects the system to the formation
Permeability	-	the state or quality of a rock that causes it to allow liquids or gases to pass through it.
Proppant	-	Solid material, usually sand or ceramics used to keep an induced fracture

1 Introduction

This chapter gives a short presentation of the background of this master thesis and the general topics discussed. The objectives and scope of work will be presented, along with two research questions. Finally a brief introduction of Comitt Well Solutions is presented followed by the structure of the thesis.

1.1 Background

Oil and gas exploitation from shale formations is a relatively new phenomenon. Production started this century and large-scale production is so far restricted to shale formations in Canada and in the U.S. The last few years the production of oil and gas from shale formations has gone from 0.4 MMbod and 4 bcfd in 2007 to 4.5 MMbod and 38 bcfd in 2014, see Figure 1-1 (U.S. Energy Information Administration, 2014). A little more than a decade ago the U.S. natural gas production from shale accounted for two percent of the total U.S. output. In 2014 the figure was 37 percent, and a study by IHS (Information Handling Service) predicts that due to technology advancement it will rise to more than 75 percent of the domestic supply by. Because the exploitation of oil and gas from shale has increased tremendously in a short period of time, the North American revolution in energy production is often called for the “shale boom” or the “shale revolution” 2035 (American Oil and Natural Gas Industry, 2014).

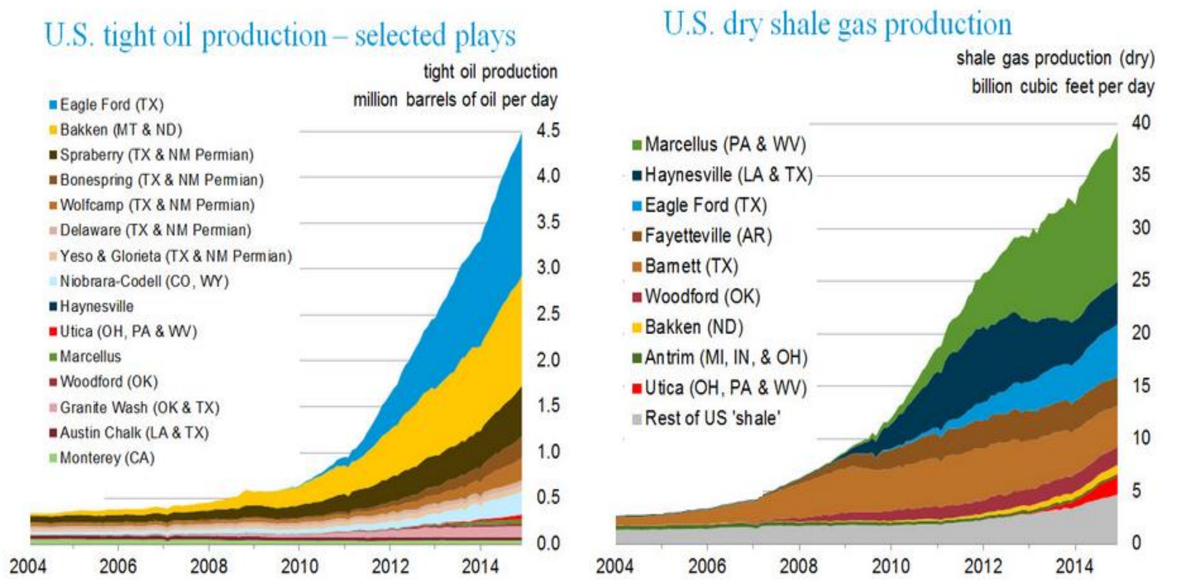

Figure 1-1: U.S. unconventional oil and gas production from 2004 to 2015 (U.S. Energy Information Administration, 2014)

Oil and gas were previously uneconomical to produce from unconventional wells of shale, sandstone, and carbonate. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has provided access to large volumes of oil and natural gas (U.S. Energy Information Administration, 2014). This combination in addition to technology advancements, especially multi-stage fracturing, have been the main factors in commercializing oil and gas exploitation from shale.

The recent shale revolution started with gas exploitation around the year 2000, but decreasing gas prices became a driving force for the exploitation of shale oil. The Bakken formation in North Dakota was the first shale play to be exploited for oil extraction with modern horizontal drilling and hydraulic fracturing (Maugeri, June 2013). Eagle Ford in south Texas is the formation with the highest shale oil production. Eagle Ford and Bakken alone account for approximately 65 percent of the shale oil production in the U.S (American Oil and Natural Gas Industry, 2014). Figure 1-2 illustrates Eagle Ford, Bakken and the other active shale plays in the lower 48 states in the U.S.

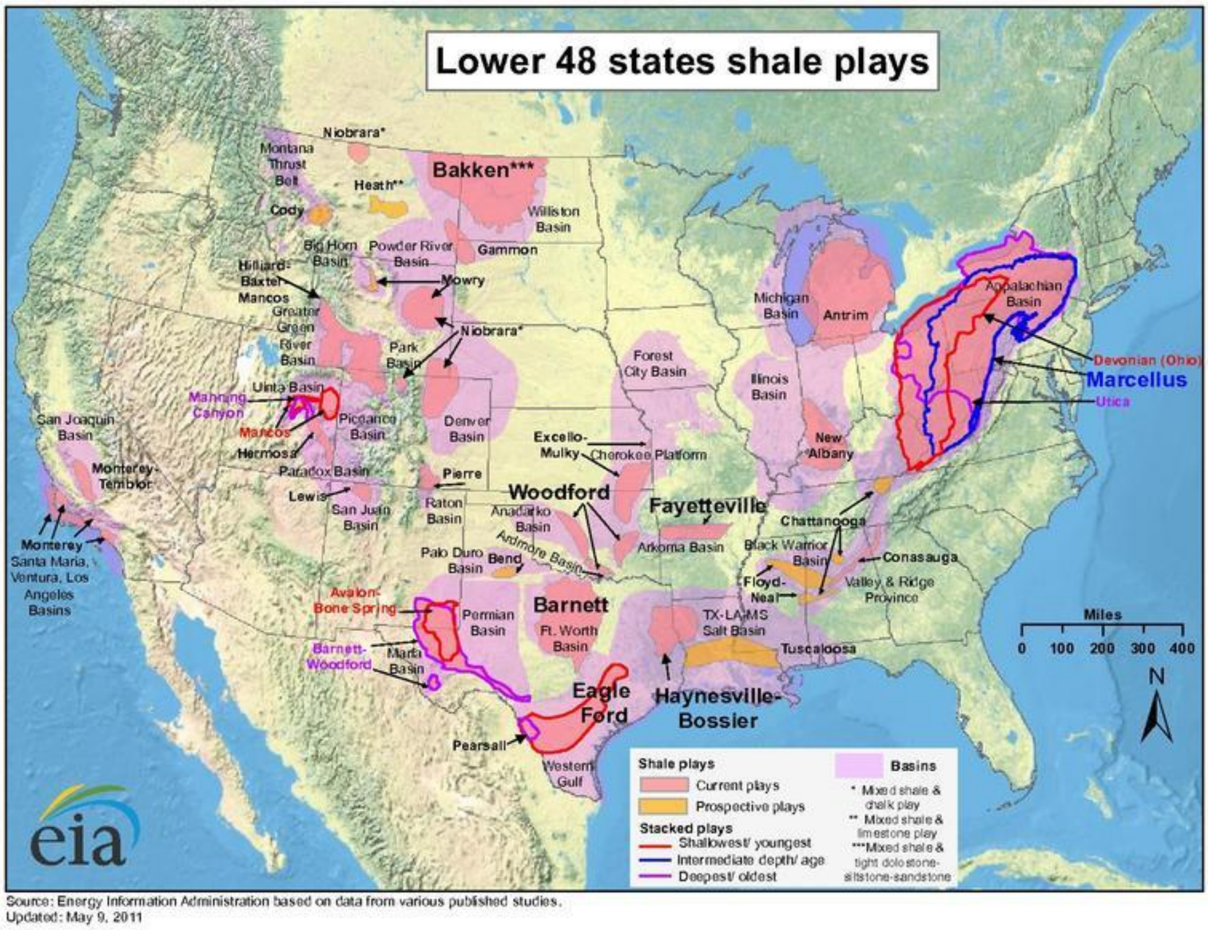

Figure 1-2: Map of shale plays in the lower 48 states of the U.S. (American Oil and Natural Gas Industry, 2014)

The production decline in shale wells is in general more rapid than in conventional reservoirs because of the ultra-low permeability of the rock. Individual well decline rates are high, typically ranging from 50 to 70 percent after 12 months (King, George E., 2015). The overall field declines require 30 to 50 percent of the production to be replaced annually by drilling new wells in the U.S. This translates into $42 billion annually capital investments (Hughes J. , 2013).

There are several techniques and processes being used today during the completion phase to deploy multi-stage fracturing operations. The “plug & perf” technique, further explained in subchapter 4.3, has been the most popular approach in the U.S. This widespread fracturing completion approach has allowed fracturing operations to be rapidly executed. In fulfilling the desire to complete these wells in a timely and economical matter, the design efficiency and the general stimulation efficiency have been poor. For that reason it is apparent that there likely remains a significant portion of un-stimulated pay in the wells post-refracturing (French, Rodgerson, Feik, & BP America Production Company, 2014).

The sudden decrease in the oil price in 2014 made several drilling projects of new wells uneconomical. To keep up the fast declining production and to exploit opportunities of un-stimulated pay, the industry has been looking into refracturing. Refracturing is a term used for the process of going back to an old well and stimulate it again to increase the production. While drilling a new unconventional well costs 7 – 10 million dollars, refracturing an old well only costs from 0.5 – 3.5 million dollars. Recent refracturing attempts have shown that it is possible to attain around the same or even higher initial production rate of the well with a subsequent similar initial decline curve. (French, Rodgerson, Feik, & BP America Production Company, 2014). Refracturing also reduces the environmental impact by reusing the wellbore and not drilling a new well in a different location (Eshkalak, Aybar, & Sepehrnoori, 2014).

Refracturing operations in shale are still in the infancy stage where the technologies are relatively new and the technical solutions not optimal. The techniques most commonly used in refracturing operations today is said to be an economical success, but a technical failure (King, George E., 2015). In other words "the holy grail" of refracturing has yet to be discovered, leaving a huge innovative potential in the techniques to be exploited. With over 1.1 million hydraulic fracturing jobs performed in North America only, refracturing has become a highly discussed topic these days (Kelso, 2014). Some people states that the oil- and gas companies should today even evaluate refracturing as part of their strategy when designing new wells (STI Group, 2013). However, uncertainties associated with the outcome of refracturing and the economical analysis of key parameters influencing its profitability are still challenging and needs a wider investigation and more data (Eshkalak, Aybar, & Sepehrnoori, 2014).

1.2 Objectives and Scope of Work

So what is the economical potential in the new emerging field of refracturing? Comitt Well Solutions, a company presented in chapter 1.3, desired to expand their understanding of the economical potential of refracturing and look into the performance of refracturing completion techniques. Furthermore, we were interested in conducting research in the field of refracturing, thus Comitt Well Solutions invited us over to help us conduct the research. A comprehensive study on different refracturing techniques has never been conducted or published, hence together with Comitt Well Solutions we limited, developed and raised the following research questions to better understand the economics of refracturing:

1. What is the potential magnitude of the refracturing market?
2. What is the technical- and economical performance of the refracturing completion techniques?

The objectives of the present work are to make an assessment of the potential magnitude of the refracturing market. Both the refracturing techniques and the economical performance are addressed. To reduce the scope of this thesis, due to time- and data limitations, we have made a multitude of limitations. Our scope of work are limited to horizontal refracturing operations in the U.S., and will for that reason not include every parameter needed to give the companies a complete economical evaluation of the profitability. The economical calculations are limited to the refracturing operations, and will for that reason not include costs like transportation of oil, maintains of the well, tax etc. Furthermore, our main goal in researching the economical performance is to compare the refracturing techniques to each other. Due to the time constraint, a limited number of people have been interviewed to be able to analyze the data and conduct the interviews. The multitude of refracturing techniques is too extensive and it will create insignificant value to investigate them all. The focus in the thesis is on the most relevant refracturing techniques on the market today, in addition to Comitt Well Solutions' new technique. There are few published refracturing results because of a strict confidentiality policy in the business, and the fact that refracturing in horizontal wells is a new phenomenon. The confidentiality limits our ability of gathering sufficient data on production increase numbers, costs, and risks associated with refracturing operations. For that reason our quantitative data is based on the SPE reports presented in chapter 6 and numbers estimated by our respondents in subchapter 7.3. Further limitations to the thesis are presented "as they come".

1.3 Comitt Well Solutions

Comitt Well Solutions is a startup company focusing on refracturing technology. The company was founded in January 2015 with 5 employees, each of them experts in their field with more than 10 years of experience. The founders have previously started a service company focusing on fracturing completion technology which is a huge success today. Commit Well Solutions is based in Houston and located strategically near energy corridor where several of the major oil companies operate from. The company has developed a new refracturing technique which is further described in chapter 4 and analyzed in chapter 9.

1.4 Structure of the Thesis

Chapter 1 consists of the introduction of this thesis. Here the background, objectives, scope of work, and Comitt Well Solutions are presented. In chapter 2, there will be an in-depth explanation of the methodology used in the thesis. The data collection and research methods will be presented in detail. Chapter 3 and 4 presents relevant information and knowledge about shale oil and gas, the fracturing process and refracturing. This knowledge is gained through our training associated with the research of this thesis and we believe this information is crucial to be able to understand and appreciate the work done in this thesis. Chapter 5, 6 and 7 presents the information, theories and data gathered to be able to answer the questions raised in this thesis. Chapter 5 presents fundamental theoretical concepts, Chapter 6 summarize important information and data gathered through our literature study, and chapter 7 presents our main interview findings briefly. In chapter 8 we will present our way of analyzing and thinking which will help the reader to easily follow our discussion, evaluation and analysis presented in chapter 9. Chapter 9 consists of the discussion, evaluation and analysis around the research questions. There will also be presented a profit calculation tool which we have constructed to be able to do a better economical analysis and provide the industry with a tool to calculate the potential profitability of refracturing operations. Based on the discussion, evaluation and analysis, a conclusion is drawn in chapter 10. In this chapter our main findings are presented. Figure 1-3 shows the overall process on which this thesis is constructed from the initial problem to the final conclusions. Figure 1-3

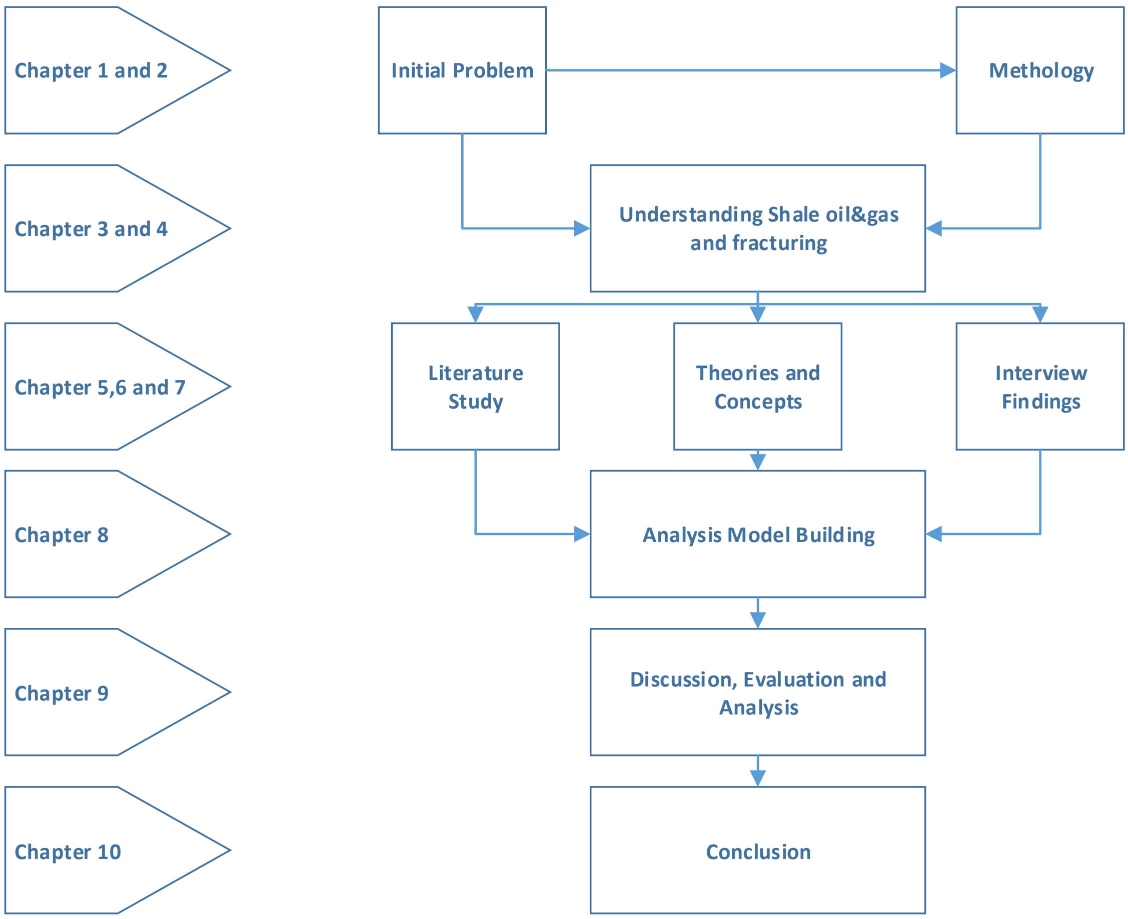

Figure 1-3: Illustration of how the thesis is structured

2 Methodology

The purpose of this chapter is to describe and explain the methodology applied in our research work. Throughout the thesis we have used a combination of approaches, sources and data of evidence. This chapter will include strategies and the use of method to answer the research questions. A justification of strengths and weaknesses in choices made is also included. An observation made by researchers should be systematic, arguable and challengeable (Ghauri & Grønhaug, 2005).Our goals as researchers are to challenge today's practices, find links between results, explore new ways of practice and present this as objectively as possible. The chapter is structured as follows: Firstly, we present our research design. Secondly we describe our research process, every step of the way including why and how we shifted our construct goal along the way. Thirdly, we present our data collection methods and how we proceeded. Finally we discuss the validity and reliability of the research.

2.1 Research Design

The research design provides a plan or a framework for data collection and its analysis (Ghauri & Grønhaug, 2005).Research design is a logical plan for getting from a set of initial questions, to a set of conclusions (Yin, 2009). Yin (2009) describes research design as a "blueprint" for the research, dealing with at least four problems; which questions to study, what data is relevant to the study, what data to collect, and how to analyze the results (Yin, 2009). According to Ghauri & Grønhaug (2005) we may distinguish between three main classes of research design; Exploratory, descriptive, and causal. Exploratory research design is used when the problem's nature is unclear and unstructured. By unstructured, we refer to problems were it is unknown or disagreed upon how to reach the goal and/or the goal itself. Descriptive research on the other hand is structured, the problem is well understood and the task to solve is clear. The purpose of the research is to identify one or more variables, and any relationship between them. Causal research is somewhat similar to descriptive research where the problems under scrutiny are structured as well. In contrast to descriptive research, the researchers are confronted with "cause-and-effect" problems. In other words, causal research design is used if the researchers want to investigate the effect of one or more independent variable on a dependent variable (Selnes, 1999).

The case being studied in this thesis is refracturing. A constructive research approach has been chosen which is an exploratory research design suited for unstructured problems, as recently explained. Refracturing in horizontal wellbores is a very recent phenomenon and the area of research is not well defined, thus exploratory research is necessary.

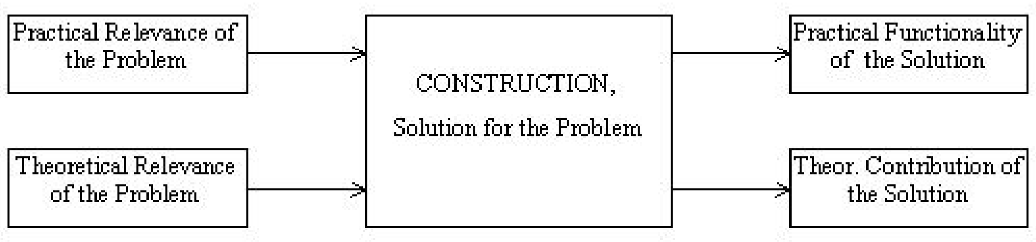

Figure 2-1: Central elements of the constructive research approach (Lukka, 2003)

Constructive research is a procedure used to solve real problems, see Figure 2-1. Finding a solution to the initial problem should start with finding a practical relevant problem which has potential for a theoretical contribution (Lukka, 2003). By obtaining an understanding for the problem as well as the theoretical relevance, a solution for the problem can be constructed. The construct refer to entities, i.e. human artifacts such as models, diagrams, tools, plans, organization structures, and communication systems which produce solutions to explicit problems or attain goals. *(Kasanen, Lukka, &Siitonen, 1993) (simon, 1996).* By testing the solution/Construct one can analyze the practical functioning of the solution in a real world atmosphere in addition to evaluate its theoretical contribution.

2.2 Research Process and Approach

Research can be thought of as a process that is a set of activities over time. (Ghauri & Grønhaug, 2005). To able to conduct the research our journey started with moving to Houston for two months. Face to face interaction with the interview respondents and other experts in the industry was essential to speed up our learning and research process. During the first four weeks the company gave us theoretical courses, we enrolled in a two days training course with SPE were we obtained the SPE certification of shale selection, completion, fracturing and production, we conducted a comprehensive literature study, and we went to the SPE oil and gas conference. This work was time-consuming, but essential to be at a knowledge level that abled us to conduct the research. We have summarized important information and theory from this process in chapter 3 and 4. We believe this knowledge is essential for the reader to be able to understand and appreciate the work done in our thesis. Further in this chapter we present our journey to find a solution to the research questions, connection to prior theory, the construct/solution to the problem, the practical functioning of the solution and the theoretical contribution of our research.

2.2.1 The Practical Relevance

Research questions are not given; they are detected and constructed (Ghauri & Grønhaug, 2005). Without research questions there would hardly be research. The economics in refracturing is affected by an enormous amount of unknown factors and uncertainties. To be able to contribute with significant value to Comitt Well Solutions we conducted explorative meetings with the BMD, Moen, to identify the factors determining the economical success of Comitt Well Solutions. The major factors were used as a basis to create research questions within refracturing that was possible to do within the time limitations. After several discussion meetings and learning sessions, the profitability of the refracturing completion techniques on the market compared to Comitt Well Solutions' and the potentially magnitude of the market was found to be important factors determining the company's success. According to Selnes (1999), the Research questions should be as simple as possible to avoid a too complex and difficult research (Selnes, 1999). We arrived at these two presented research questions:

1. What is the potential magnitude of the refracturing market?
2. What is the technical- and economical performance of the refracturing completion techniques?

In order to answer these questions, we started out by identifying the different refracturing completion techniques tested in the shale market today. Through an exploratory literature study, interviews and training courses we managed to identify these refracturing techniques. These techniques, including Comitt Well Solutions' technique, are explained in chapter 4. The work was necessary to be able to find out which techniques we needed to compare technically and economically in the evaluation and analysis. Furthermore we contacted experts in the field of refracturing with a request of relevant information sources, and interviews to be able to conduct our research. Initially we wanted to analyze the economical performance of the different techniques purely by analyzing quantitative refracturing data, but after talking to experts and conducting a literature study there was not enough published data to do a thorough enough comparison. To combat this issue, we decided to construct a profit calculation tool based on the technical and economical evaluation of the different refracturing techniques. After talking to experts in the industry we found out that this work and area of research has never been done before and will provide the industry with a more comprehensive understanding of the refracturing completion techniques used, and the magnitude of the refracturing market.

2.2.2 Connection to Prior Theory

There is a limited understanding in the magnitude of the factors leading to a technical successful refracturing operation and in general which kind of wells that make the best refracturing candidates. We have gathered and analyzed literature of research and cases previous done by experts in the field of refracturing through our literature study, presented in chapter 6. The Academy of Sciences defines theory as a well-substantiated explanation of some aspect of the natural world, based on facts that have been repeatedly confirmed through observation and experiment (The National Academy of Sciences, 1999). Some of the literature analyzed are based on experience and are discussable, and thereby do not qualify under the term theory. To be able to evaluate the economical performance of the refracturing completion techniques we make use of several theories presented in chapter 5. To be able to understand the diversity in profitability of the different refracturing techniques, financial concepts like NPV, IRR, ROI, breakeven period, and breakeven price are presented and fundamental. A HAZOP analysis is conducted to identify risks involved with different refracturing techniques. The theoretical concept behind decline curve theory is discussed and later used to forecast production. Further, least square method is used to fit historical production data to a modified hyperbolic decline curve in the profit calculation tool.

2.2.3 The Construct

Our construct is the profit calculation tool. The tool comes in two versions. Version one is based on numbers gathered or anticipated by the industry and indicates the different profitability or loss gained by using different refracturing completion techniques. Version two is an input tool which is based on input data provided by the user, which can easily be adjusted, and indicates the potential profitability of a refracturing operation. The construct is built upon a technical and economical evaluation of the refracturng completion techniques presented in chapter 9. How the profit calculation tool is designed and works will be discussed further in chapter 8 and 9.

2.2.4 Practical Functioning of the Solution

The profit calculation tool will simplify the refracturing decision making for the oil companies and will be a tool for the service companies to show how good their refracturing completion techniques are performing. Due to time limitations and confidentiality we have not been able to test our tools estimation to real well output. Regardless, the tool will serve as a fundamental platform to be built on and developed into a more comprehensive and accurate tool as more information and research becomes available.

2.2.5 The Theoretical Contribution of the Solution

The technical and economical evaluation will help the oil and gas industry in comparing the refracturing completion techniques. In addition the evaluation will give them a further understanding of which criteria to focus on when designing a refracturng technology. There is no public paper today doing a technical evaluation of refracturing completion techniques. This will give researchers and developers easy access to an assessment of the refracturing techniques available on the market and their technical performance. A supplementary finding in our thesis is a trend between the IP ratio and the forecasting decline factors, in form of an equation. The equation can be used to improve forecasting of production post-refracturing. Our thesis also provides insight into the potential magnitude of the refracturing market and in addition general economical findings.

2.3 Data Collection

The purpose of this section is to describe the methods used to collect data. We have relied on multiple sources to achieve a higher state of reliability and validity in the thesis.

There are essentially two alternative research methods; qualitative and quantitative method. The main difference between qualitative and quantitative method is of procedure and not of quality. The basic distinction is considered to be that quantitative researchers employ measurement and qualitative researchers do not. Qualitative methods are more open, flexible and emphasize on understanding the respondent. However, the collection method is more influenced by the respondent than quantitative data collection. Quantitative method is emphasized on testing and verification, preferably through hypothesis testing (Ghauri & Grønhaug, 2005).

Quantitative data collections are mostly used when the researchers have a good prior understanding and knowledge of the phenomenon studied. The method usually applies statistics or questionnaires with fixed response options to obtain information. Quantitative information can be standardized and are therefore easier to process using statistical tools and applications. This advantage helps the researchers to reach more respondents and reduce time and cost associated with processing and collecting the data (Jacobsen, 2005). The disadvantage with the quantitative method is that surveys are often superficial and lack the ability to include additional potentially important information. This emphasizes the importance of accurately defining what is relevant to answer beforehand (Jacobsen, 2005).

Qualitative data is preferred when analyzing a phenomenon in depth, or when the researchers have low prior knowledge of the phenomenon (Jacobsen, 2005).The data is gathered through interviews, which is a common method of qualitative data collection, and literature studies. The problem with qualitative data gathering is that it is resource intensive and demand time to execute. This can lead to problems in the representativeness of the interview respondents as well as keeping track of all the data gathered during the interview (Jacobsen, 2005).

Qualitative and quantitative data collections are not mutually exclusive. By including both multiple choice questions (elements from quantitative data collections) and open questions where the respondent can answer in their own words (elements from qualitative data collections) you are combining the methods (Jacobsen, 2005). Our data collection is based on both qualitative and quantitative methods. The interviews are purely qualitative and conducted through an open environment, but the risk, cost and production data collected are quantitative data from the literature study or from the respondents after the interviews through emails.

2.3.1 Literature Study

Doing a literature review was essential to gain appropriate knowledge to answer our research questions. Literature review is data and information that is useful to both understand and solve the research problems. The prime purposes of the literature review are to frame the problem under scrutiny; identify relevant concepts, methods/techniques and facts; and position the study (Ghauri & Grønhaug, 2005). Qualified research often builds on prior research. Since our research is in a new and unknown area it was essential to be familiar with the newest concepts within the field. The first step in literature review is to locate sources of relevant data and evaluate the usefulness of the content (Ghauri & Grønhaug, 2005). In the review of literature various search engines have been used. Our main source of information is papers published by SPE (Society of Petroleum engineers). To answer our research questions we needed to understand which criteria that made wells suitable for refracturing and which factors that increase the refracturing success. SPE has published several papers discussing these factors which we have studied closer in chapter 6.

It is important to evaluate the validity of the data throughout the literature review. Some sources may be outdated and some may simply not tell the whole truth. Various web-searches resulted in hits from reports, articles, journals and books. The information and theory used, in this thesis, was reviewed closely to ensure validity and relevance. The author was researched to see if the data was academically recognized or published in a recognized journal. SPE is a well-recognized organization with more than 143 000 members that can be everything from experts working in oil and gas companies, professors at universities, and students. The papers published by SPE are often research papers associated with pioneer projects, new technology or important factors influencing the success of aspects in the industry. SPE publishes everything from technical papers, economical papers, conference papers and journals. The papers up for submission are closely reviewed by a committee of experts to ensure the validity and reliability of the data (SPE). The theories presented in the theoretical chapters in this thesis are collected based on the methods described in this section.

2.3.2 Interviews

Interviews demand real interaction between the researcher and the respondent. To efficiently be able to run the interviews without disturbances, the researchers need to know the respondent, his values, expectations and background (Ghauri & Grønhaug, 2005). While preparing for an interview there are three steps recommended by Ghauri & Grønhaug (2005). Firstly, analyze the research problem. Secondly, understand what kind of information you need from the respondent. Thirdly, and finally, find which persons that would be able to provide this information. A respondent is defined by Jacobsen (2005) as a person with direct knowledge of the phenomenon researched as the person is directly involved in the phenomenon. An informant is defined as a person with good knowledge of the phenomenon, but does not represent the phenomenon. We chose to only interview respondents which we define in our thesis as persons that have experience working directly with refracturing projects. All interviews were conducted in Houston through direct contact except two interviews which was conducted over Lync, as it was the only way of reaching this person. An interview guide was constructed and used as a basis, see appendix A. Since we based the interviews on qualitative data collection, we customized the questions according to the expertise of the respondent and the answers provided.

All the respondents were chosen based on the companies' and individuals' expertise in the shale oil and gas industry, see appendix B for the full list of the respondents. Ghauri & Grønhaug (2005) emphasize the connection between a successful interview and orienting the respondents of the purpose of the interview beforehand (Ghauri & Grønhaug, 2005). When the respondent first was contacted, the background for the interview and how their contribution will be used in the thesis was described. Most of the respondents were eager to contribute and found the research field interesting. Before the interview the respondent also got an email reviewing the main topics of the interview. By doing so the respondents got a chance to prepare themselves. Every interview started with a 5-10 minutes presentation of the thesis' field of research and how their information would be used in the evaluation and analysis. It was in total conducted 8 interviews. During the interview one person was responsible for leading the interview, while the other one took notes along the way. However, both of us helped with follow-up questions and took notes when needed. A voice recording device was used during every interview and used later on to add more information to the answers. The voice recorder provided additional validation of the notes taken and helped us to have a more open conversation focusing more on the respondent than taking notes. Using a voice recorder makes it possible to pay more attention to non-verbal communication and plan the next follow up question.

2.4 Validity and Reliability of the Research

The quality of the empirical data is judged on the data's validity and reliability (Jacobsen, 2005). Validity is how relevant and valid the empirical data are, while reliability is how trustworthy or reliable the empirical data are. According to (Yin, 2009) there are four factors commonly being used to establish the quality of any empirical social research, as shown in Figure 2-2. Further, we will discuss these factors in the context of our research.

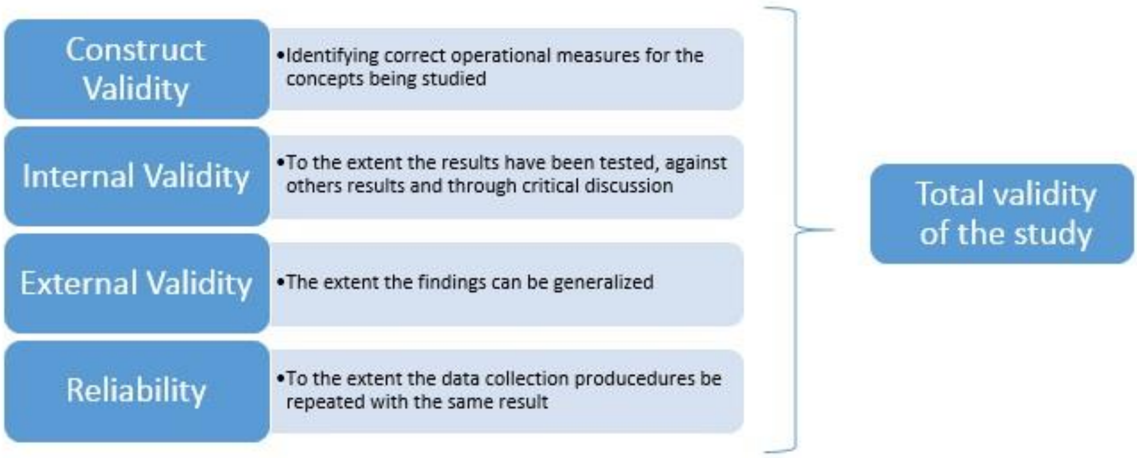

Figure 2-2: Elements in total validity of research (Jacobsen, 2005)

2.4.1 Construct Validity

Construct validity is necessary for meaningful and interpretable research findings. Jacobsen (2005) explains that construct validation in general is the extent to which operationalization measures the concept which it purports to measure. According to Bagozzi, Yi, & Phillips (1993), eliminating and minimizing measurement errors are important when evaluating construct validity. These errors refer to variance in the measurement method like archival biases, key informant prejudices or limitations, social desirability and halo effects (Bagozzi, Yi, & Phillips, 1993). In our research we have relied on multiple sources of evidence to capitalize a source's strength and compensate for its weaknesses. This was done through interviews, observations, training courses and literature study. We collected all the data in a database, recommended by Yin (2009). Data should result from clear and logical processes (Yin, 2009). By establishing a chain of evidence we were able to evaluate the data and question deviations in the results. The deviations are discussed, or not used in the thesis to minimize errors in the data and maximize the validity.

2.4.2 Internal Validity

In qualitative research the internal validity is often high (Jacobsen, 2005). Qualitative research is often based on people's perspectives of certain situations and there is no strict rules dictating the information received. According to Jacobsen (2005), the internal validity is assessed by testing the results against others and through critical discussion. The qualitative data in this study is tested by comparing the results of the different interviews and by confronting the informants with the findings. The quantitative data in this thesis is based on estimates from experts working with different refracturing completion techniques and data collected in the SPE papers in, chapter 7.3 and 6.2 in this report. This is due to strict confidentiality and the fact that there are not enough refracturing operations done in horizontal well to accurately be able to forecast the data.

2.4.3 External Validity

Yin (2009) claims that external validity only can be tested by replicating the research in another situation. According to Jacobsen (2005), qualitative methods rarely have the purpose to ascertain the scale of things or the frequency, but rather to understand the purpose or to get a deeper understanding of a phenomenon (Jacobsen, 2005). This is the case in this thesis when it comes to finding the magnitude of the refracturing market and in the technical performance evaluation of the refracturing techniques. Many of the respondents' answers are based on experience and the respondents are from different companies with no communication between each other about the findings published in this thesis. Thus we believe these findings also are generalizable if one undertakes research in another situation. Our economical evaluation and numerical analysis are built on the quantitative data in addition to some qualitative data. The quantitative data can be generalized to some extent, but the data will vary with shale play and between the wells which is one of the significant problems in the industry when it comes to forecasting profitability.

2.4.4 Reliability

According to Yin (2009), the goal of reliability is to minimize the errors and biases in a study. Detailed specification and data documentation should be kept throughout the study in order to maintain the reliability. In other words, the data should not be affected by the methods and the procedures used in collecting data. Jacobsen (2005) mentions two main categories to consider in reliability of the research, the effect of the data collection methods, and sloppiness (Jacobsen, 2005). In qualitative data collection methods, it is unlikely to obtain the same results. The market of horizontal refracturing is new and the technology is poorly documented. Other researchers could find other methods to arrive at solutions, especially in the economical performance evaluation where we constructed a tool, based on different quantitative inputs from the interviews and the literature study. Yet, we believe that the results obtained would be similar in answering the first research question and the technical evaluation in research question two, at least to a certain degree. The economical performance of the different refracturing techniques is highly based on quantitative data estimated and collected after the interviews by email. Other researchers would most likely end up with different results here, but we believe the economical comparison between the techniques would end up in the same conclusions. In addition we also believe that our constructed tool will be able to forecast good indications of possible refracturing profitability.

To prevent sloppiness in our data collection we have maintained a database of recordings from interviews and all the papers the research is built upon. The database has been used as a source of information when uncertainties have arisen, and to ensure the data used is accurate. Any ambiguities throughout the work have been discussed with the respondents to straighten the data.

3 Shale Oil and Gas as an Energy Source

The energy consumption has more than doubled since the energy crises in the 1970s, and is forecasted to grow by a further 44 percent in the next 22 years with fossil fuels continuing to provide around 80 percent of the demand (Hughes J. , 2013). The question is how to provide the raising energy need of the world. Renewable energy is growing slowly, but will most likely not be able to provide a sufficient portion of the growing energy demand. However, it has been a great enthusiasm for the recent revolution in shale oil and gas production starting with calls in the 2008 presidential election to “drill, baby, drill!”. The U.S. wanted to decrease the raising gas price and regain its crown as the world’s foremost oil producer. The shale optimism is based on advances of technology, like hydraulic fracturing and horizontal drilling, making previous inaccessible shale reservoirs economical (Hughes J. , 2013) .

Shale oil and gas are produced from shale reservoirs with vertical depths typically ranging from 5000 – 10000 ft. Shale oil and gas are considered unconventional and created in shale rock formations by pyrolysis, hydrogenation, or thermal dissolution. These processes convert the organic matter within the rock, called kerogen, to synthetic oil and gas, referred to as hydrocarbons. Unconventional oil and gas refers to hydrocarbons trapped in reservoirs with low permeability, meaning little or no ability for the oil or natural gas to flow through the rock and into a wellbore. In order to produce economically from unconventional shale, companies must use sophisticated technology to drill down and stimulate the formation. Conventional oil or gas refers to petroleum, crude oil or natural gas extracted from the ground by conventional means and methods. They don’t need specialized technologies to unlock their potential like unconventional resources do. This made conventional oil the first targets of industry activity (Patch Works, 2013). Figure 3-1 illustrates the different types of reservoir rocks.

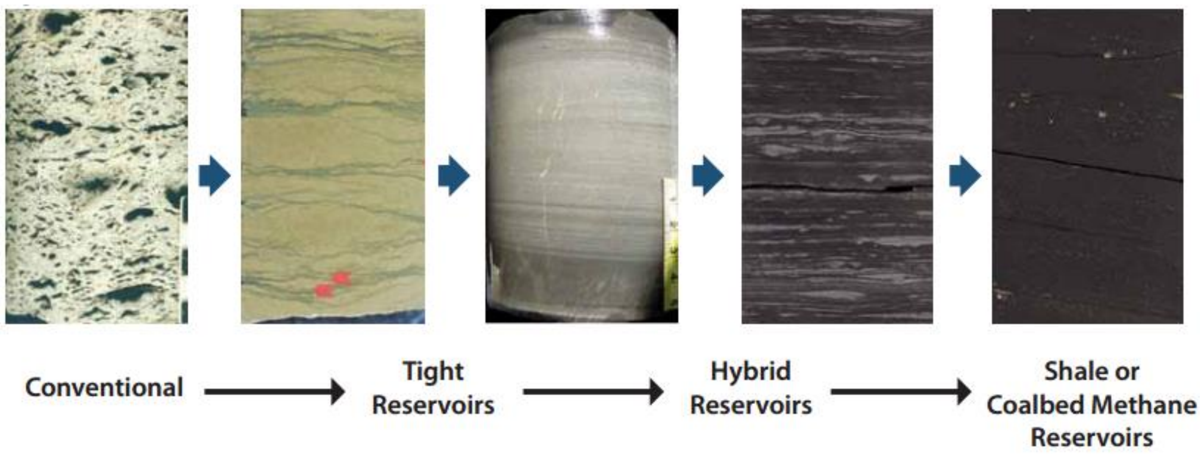

Figure 3-1: Illustrates the different porosity and permeability of different types of reservoirs (Canadian Society for Unconventional Gas)

Conventional wells have permeability varying from 1 mD up to some Darcies while unconventional Shale vary from less than 1 nD up to some µD (King, George E., 2015). Sources defined today as unconventional sources include, sand hydrates, coal bed methane, shale gas, shale oil and gas hydrates. (Patch Works, 2013). Only about a third of worldwide oil and gas reserves are conventional. The remainder is in unconventional resources, see Figure 3-2.

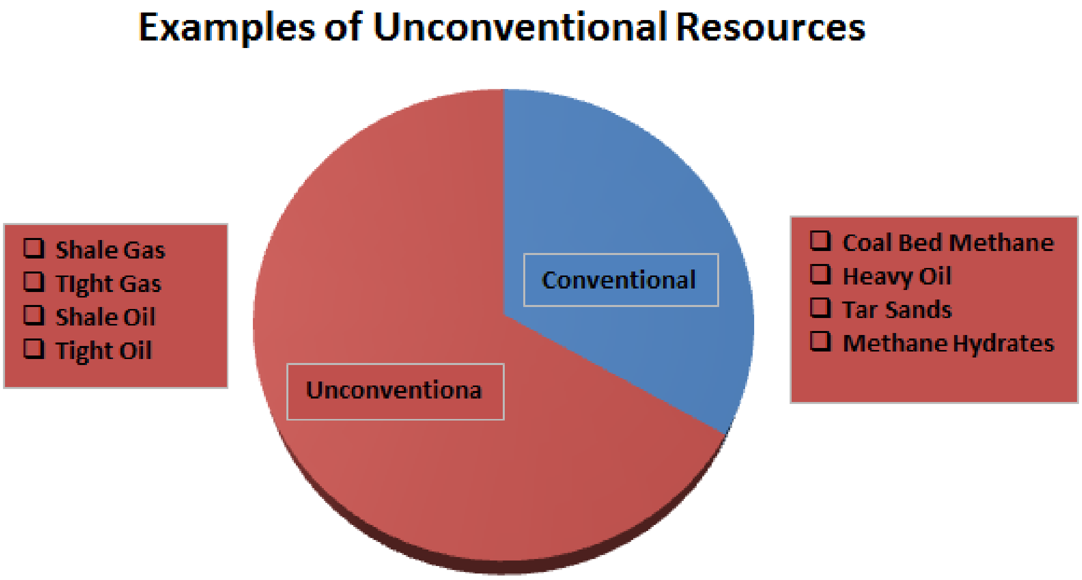

Figure 3-2: Examples of unconventional resources (Jennings, 2013)

3.1 Recoverable Oil & Gas in the U.S.

The annual energy outlook (2014), estimated that the U.S. has approximately 59 Billion barrels technically recoverable shale oil resources and 610 Tcf of technologically recoverable shale natural gas resources. This results in the U.S. being ranked globally second after Russia in shale oil resources and fourth after China, Argentina and Algeria in natural gas resources. (Annual Enrgy Outlook 2014 with projections to 2014, April 2014)

The largest operator in Bakken, Continental Resources, estimates that the Bakken play alone may hold around 900 billion barrels OIP. That would make Bakken's endowment alone larger than Saudi Arabia's. With Continental Resources' self-proclaimed 4 percent expected recovery rate, Continental predicts roughly 36 billion barrels of oil could be recovered in all (ThreeForksShale, 2014).

Technology advancement, especially in hydraulic fracturing and horizontal drilling, has made extraction of unconventional reservoirs economical. With a recovery percentage typically ranging from 20 to 30 percent for gas and 3-7 percent for oil, the potential is huge in the unconventional oil and gas market (U.S Energy Information and Administration, June 2013). Oil and gas from shale formations may be considered conventional in the future due innovation in technology.

3.2 Declining Production

Production from all wells, both conventional and unconventional, has declining production over time, see Figure 3-3. Some wells starts declining after a few years and others after a few hours. This often starts as a result from pressure depletion, reserves depletion, loss of conductivity and ingress of water or gas into the previously oil bearing strata (Mearns, 2013).

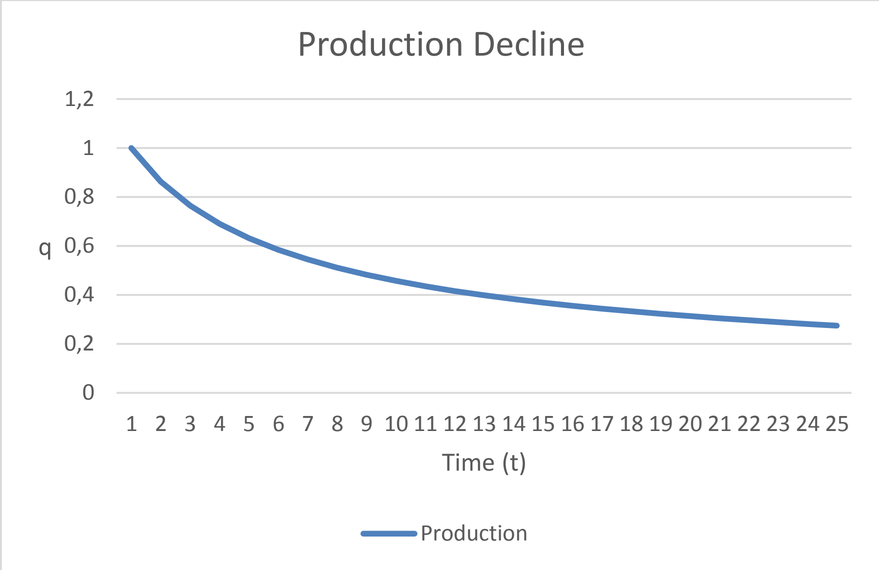

Figure 3-3: Illustrates production decline over two years with a normalized y-axis

The concept of decline rate is fundamental when estimating future production in an oil field or an oil well. The decline rate is the reduction in production-rate from an individual well, a group of wells or fields, after the production has peaked (Höök, Davidsson, Johansson, & Tang, 2013). The decline rate is defined in the following equation:

$$Decline\ rate_n = \frac{Production_n - Production_{n-1}}{Production_{n-1}} \tag{3-1}$$

n, is usually month or year, to calculate monthly or annually decline.

Years of experience have resulted in documented decline rates of conventional wells and oil fields. This has made it possible to forecast future production rates with some accuracy. The problem with shale is that economical wells are much harder to forecast than Conventional wells. Each well has its own unique production profile; there is no such as an “average” well. Producers attempt to estimate likely future output by finding similar wells located nearby in the same shale play, but even this involves a lot of uncertainty. It takes over six months to get a reasonably accurate decline curve for unconventional wells (King, George E., 2015). Nonetheless, the decline curves give an indication on the future output.

Conventional wells have a typical production decline around 4 - 15 percent each year depending on reservoir size and location, among other factors. Unconventional horizontal wells on the other hand, have a production decline around 50 - 70 percent the first year, around 25 percent second year and around 6 - 15 percent the third year (King, George E., 2015). Furthermore, shale oil wells will also typically decline 10 - 15 percent faster than shale gas wells over the first year of production. Decline rates above 90 percent over the first year are not uncommon in the high pressure zones in Bakken (Hughes J. , 2013).

The fast decline in shale wells are caused by a combination of these factors:

- Flush production. Natural fractures emptying their fluid volume quickly
- Low permeability
- Small flow passages through natural fractures
- Deterioration on fracture flow conductivity (physical crushing, prop embedment and/ or chemical deterioration
- Loss of pressure
- Plugging of flow paths by spilling formation or cement debris
- Fractures close due to the production of fluids which removes an overburden load supporting element
- Lack of surface area contact
  (King, George E., 2015)

3.3 Economics of Shale Operations

According to King (2015), of the shale wells drilled to date, an estimation can be made that:

- 1/3rd of the wells are not economical.
- 1/3rd of the wells are marginally economical
- 1/3rd of the wells are highly economical

The highly economical wells carry the total projects and pays for the uneconomical wells. The not economical wells are often due to poor reservoir quality with low hydrocarbon content in place and low permeability. In some cases the operations are not economical because of failures during the fracturing operations (King, George E., 2015).

The profitability of shale drilling and fracturing operations is highly dependent of the oil and gas price. The average breakeven prices of fracturing projects are high. Rystad Energy, (2015) estimates an average WTI breakeven price of $ 58/bbl. As Figure 3-4 is showing, the breakeven prices are ranging from 42 dollar to 80 dollar. Companies tend to drill in core areas with high quality formations as much as possible. As a result the breakeven price would be even higher if it was based on the general shale play quality (Rystad Energy, 2015).This makes a lot of shale formations uneconomical to operate today.

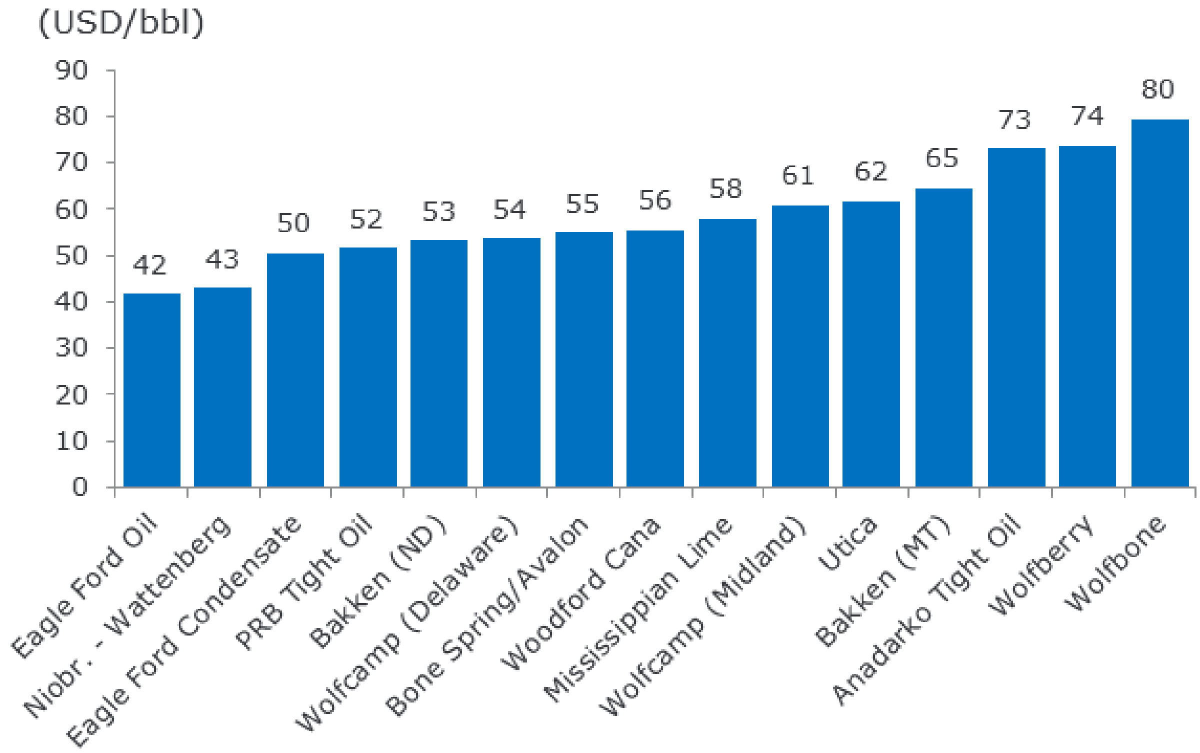

Figure 3-4: Average WTI Breakeven oil price per shale play (Rystad Energy, 2015)

Because of the high initial production and the rapid declining production, the payback time is short for fracturing project compared to other projects. According to Rystad Energy (2015), the payback period for shale oil- and gas operations are usually 18 – 24 months for horizontally drilled wells.

3.4 Fracturing Mapping

Microseismic fracturing mapping is a diagnostic technique that measures created hydraulic fracture dimensions in real-time. It provides an image of the fractures by detecting microseisms or micro-earthquakes that are triggered by shear slippage adjacent to the hydraulic fracture, see Figure 3-5.

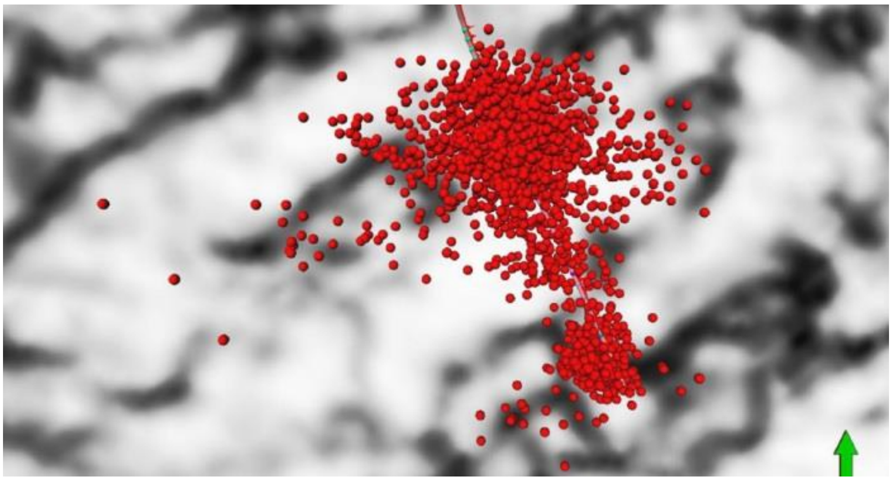

Figure 3-5: Illustrates Microseismic events along a well (Diakhate, et al., 2015)

The location of the microseismic events is obtained using a downhole receiver array that is positioned at the depth of the fracture in an offset wellbore. This crucial information enables optimization of hydraulic fracture treatments and well placement strategies. Microseismic fracture mapping is used to improve the economics by increasing reservoir productivity and/or reducing completion costs. This capability helps assure that the fracture stays in the intended zone and that the complete zone is stimulated. This capability can help optimize production and minimize the number of wells and fractures required. Results from microseismic fracture mapping can be used to "calibrate" fracture growth models (Halliburton).

Radioactive tracers are used to determine the height of the fractures created during hydraulic stimulation procedures. A recent advancement in the technology has been to tag proppant with different radioactive materials. The proppant are then used in different stages of a fracturing operation with a corresponding radioactive material. This provides the capability to determine the injection profile and location of the fractures created, see Figure 3-6.

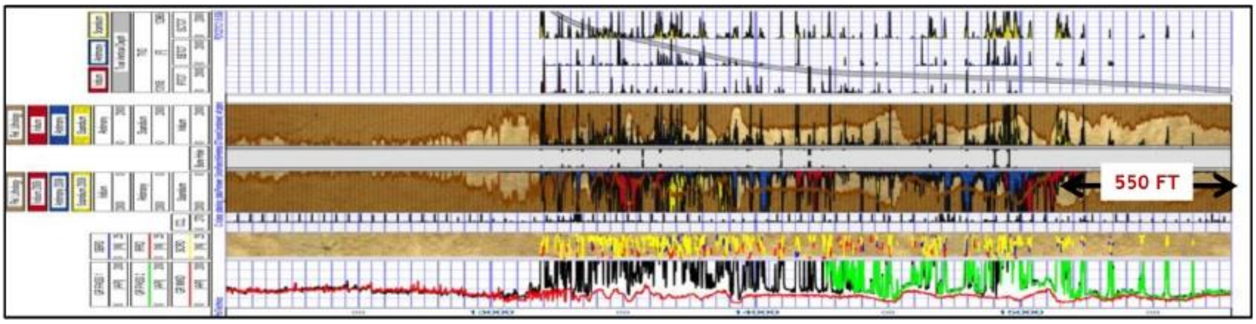

Figure 3-6: Illustration of a radioactive tracer log. The different colors represent the different radioactive materials (Diakhate, et al., 2015)

3.5 Climate Risk and U.S. Fracturing Regulations

The U.S. economy is highly dependent on oil and gas. When the fuel price reached 4 dollars in 2008 politicians started a movement called “drill, baby drill” with the sole purpose of retaining U.S.’ previous position as leaders within oil and gas production (Hughes J. , 2013). However, the new emerging field of Refracturing poses several environmental threats.

The continuous increase in the energy consumption of the world leads to higher oil and gas dependency which does not come without cost. The combustion of oil and gas involves emission of large amounts of carbon dioxide (CO_2), whose increasing concentration in the atmosphere is considered the principal cause of the climate change (NASA). The effects of the global climate change scientists had predicted in the past, is now occurring. The Intergovernmental Panel on Climate Change (IPCC) forecasts a temperature rise of 2.5 to 10 degrees Fahrenheit over the next century. We can today observe loss of sea ice, accelerated sea level rise and longer, more intense heat waves. The exploitation of shale oil and gas will contribute to these effects (IPCC, 2013).

The revolution within shale oil and gas fracturing has also created a growing concern about its environmental and health impacts. The concerns are regarding the threat fracturing procedures pose to water, air, land and the health of communities. Specifically there are concerns of exposure pathways that could cause the pollution of drinking water. Increased risk of cancer and birth defects in neighboring areas have been observed, where studies indicate polluted drinking water because of toxic chemicals used in fracturing procedure may be the cause. Previous studies have also shown levels of toxic air pollution near fracturing sites and increased seismic activity. (Gottlieb, 2012). Even though, the cases are few and how much hydraulic fracturing is to blame is not yet determined.

The U.S. Regulations of the technology used in fracturing operations and of the oil and gas industry are largely left to the states. In fact the oil and gas industry, and in some cases hydraulic fracturing specifically, enjoys exemptions from major federal environmental statues, including the safe drinking water act, the resource conservation and recovery act, the clean air act among others. The state regulations vary widely in their complexity and level of protection of human health and the environment (Brady, 2012). The state regulations of fracturing operations generally address regulations in relation to (ALS):

- Pre-drilling
- Groundwater and surface impact
- Liquid wastes, and fluids
- Solid wastes

International organizations are collaborating to mitigate the global climate change and other environmental risks of extracting oil and gas from both conventional and unconventional wells. Organizations and states protect the environment and society by making regulations the companies have to follow. Therefore it is important for the company to pay attention and evaluate risk regarding new regulations which can prevent or stop new technology and exploitation of the resources.

4 Extraction of Shale Oil & Gas by Fracturing

The technologies of hydraulic fracturing, horizontal drilling and multistage fracturing, have enabled extraction of oil and gas from geological structures that previously used to be uneconomic to produce. The technique of hydraulic fracturing has been used since the 1940's, but what has changed recently is the advance in more complex wellbores such as horizontal wellbores (American Oil and Natural Gas Industry, 2014). It is all about drilling down to the hydrocarbon reserves to extract oil and gas as efficient as possible from the formations. Because of the low permeability of the shale formations, hydraulic fracturing technology is needed to increase the permeability and conductivity in the formation. This will create a flow of oil- and gas particles from the created fractures to the wellbore. The amount of oil and gas extracted from the formation is highly depended on the amount of area with hydrocarbon content that is stimulated and connected to the wellbore. There are huge variations in the amount of hydrocarbons in shale formations. The amount can vary from 2 – 18 percent as in the Bakken play and 3-5 percent as in the Haynesville play (King, George E., 2015). The amount of area with hydrocarbons contacted by the well is highly dependent on the complexity and amount of stimulated natural fractures, and the effectiveness of the hydraulic fracturing process. Some wells are superior in their productiveness just because they drilled into complex hydrocarbon rich, natural fracture networks.

4.1 Horizontal Drilling

Horizontal drilling has been common practice of operating in the unconventional oil and gas industries since the 1990s, but the concept was first experimented with as early as in 1929. Advances in drilling and completion technology, since the early 2000s, have made the horizontal wellbores much more economical (Robbins, 2013). Horizontal wellbores gives greater exposure to the formations than vertical wellbores, making each horizontal well more productive and economical than vertical wells. While the cost factor for horizontal wells may be two or three times of a vertical well, the production factor can be enhanced as much as 15 -20 times. (Horizontal Drilling) . Horizontal wellbores are also useful when there are surface obstructions compared to vertical wells since multiple horizontal wells can be drilled from the same surface location, referred to as pad drilling (New York State Departmernt of Enivronmental Conservation, 2011).

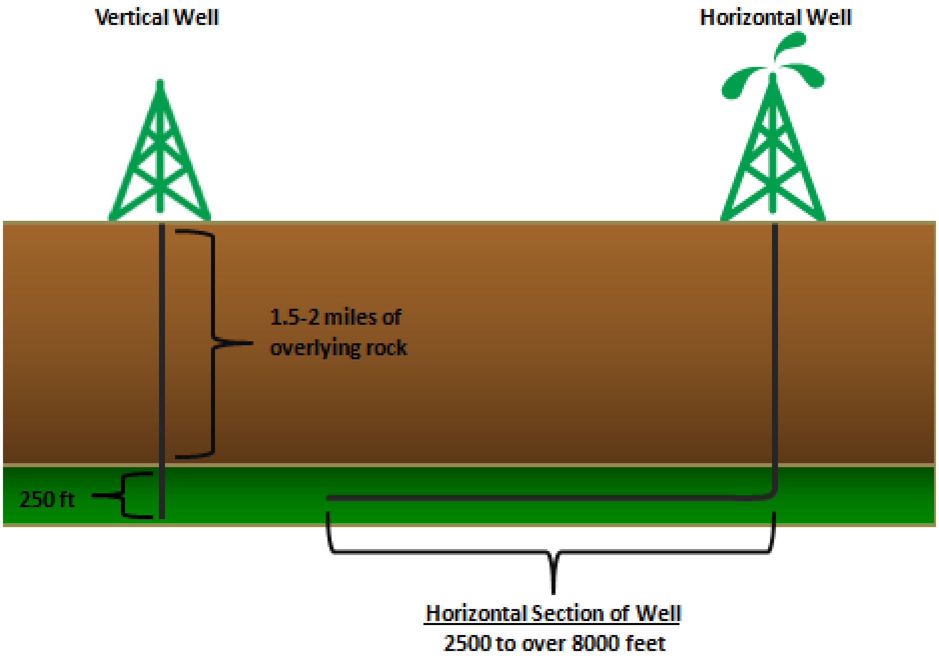

Figure 4-1: Illustrates a vertically drilled well and a horizontally drilled well (Biederman, March 2012)

The horizontal wells start as vertical wells at the surface, see Figure 4-1. To protect ground water and aquifers during drilling unconventional well, the vertical wellbore consists of several cycles of drilling, running casing and cementing the casing to ensure isolation. Casing is hollow steel pipe that is used to line the inside of the wellbore. The full length of casing is often referred to as a casing string. The first stage in drilling is to install the conductor casing, see Figure 4-2. The conductor casing secures the ground the rig is placed on and prevents the sides of the hole from carving into the wellbore (API, 2009). After the conductor string is set in place the next casing string is essential for protecting the groundwater and aquifers in a drilling operation, and is called the surface casing. Cementing the casing sufficient is crucial to prevent oil and gas to move vertical into the deep water zones (King, George E., 2015). The cement is pumped down the inside of the casing and forced up between the casing string and the outside formation of the well, called the annulus. This method ensures that the cement fills the entire annulus space. Once the cement has had time to cure, the same procedures are used for the next casing strings. After quality is ensured sequentially deeper holes are being drilled to install the intermediate casing, and the production casing.

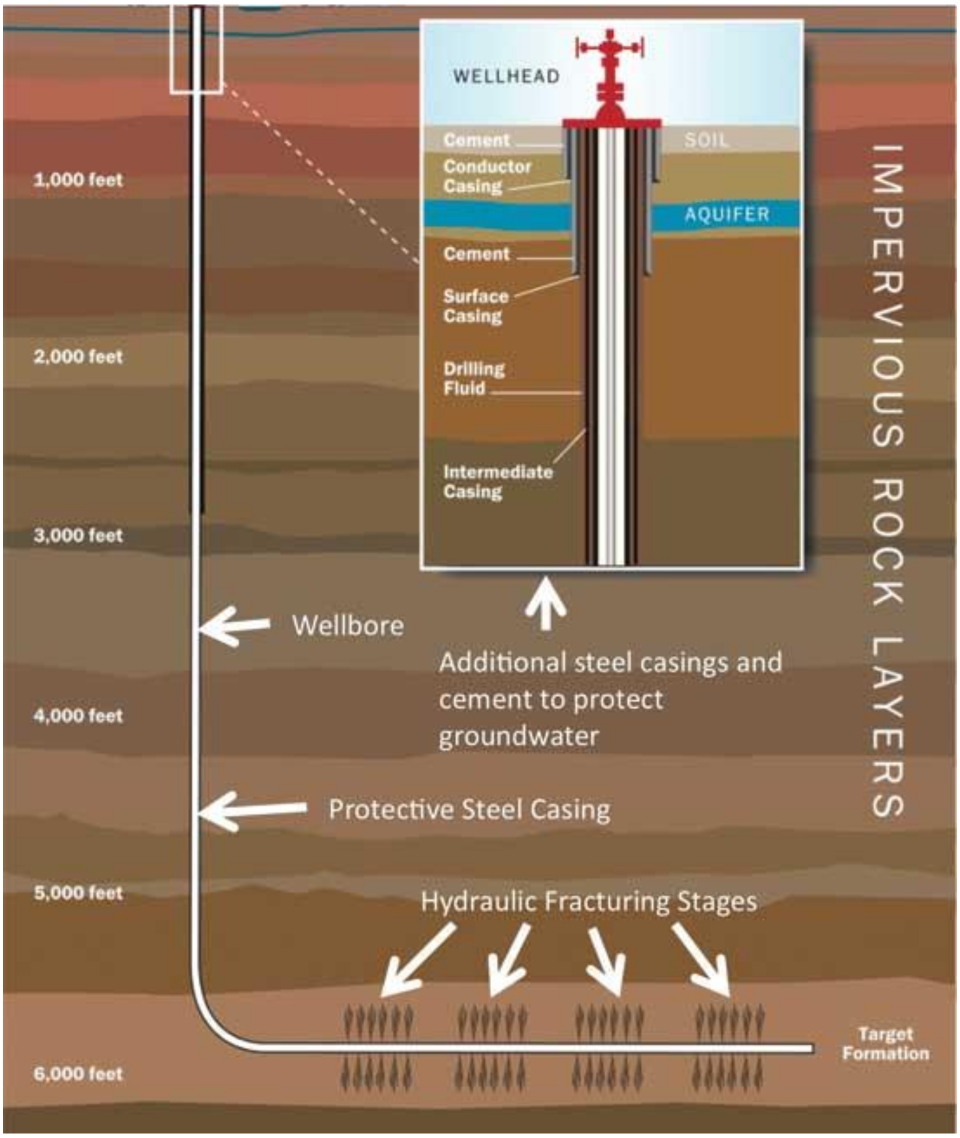

Figure 4-2: Illustrates a horizontal well drilled into a shale layer that has been hydraulically fractured (Suchy & Newell, 2012)

When the drill bit reaches the “kickoff point” about 300- 500 ft. above the target formation the drill pipe is pulled out and a hydraulic motor is inserted between the drill pipe and the drill bit. This enables the drill bit to rotate without the whole pipe rotating which means the direction of the drilling patch can be steered in a different direction (Person, 2012). When the well has achieved the desired angle the drilling continues to drill in one direction horizontally into the desired rock formation. The horizontal part of the well, called the lateral, usually have a length between 2500 and 8000 ft. The two most popular ways of completing the lateral are as an open hole with an uncemented production casing or with a cemented production casing. (FracFocus)

Drilling from a pad allows operators to drill more efficiently and reduce costs and surface footprints. Drilling several wells in different horizontal directions from the same pad saves the operators the time to move equipment, trucks etc. from one location to another (Person, 2012). Today a drilling pad may have 4, 10, 20 or more wells drilled from one single pad spaced fairly closed together (Thuot, 2014). Figure 4-3 under shows four pads with six horizontal wells drilled on each pad.

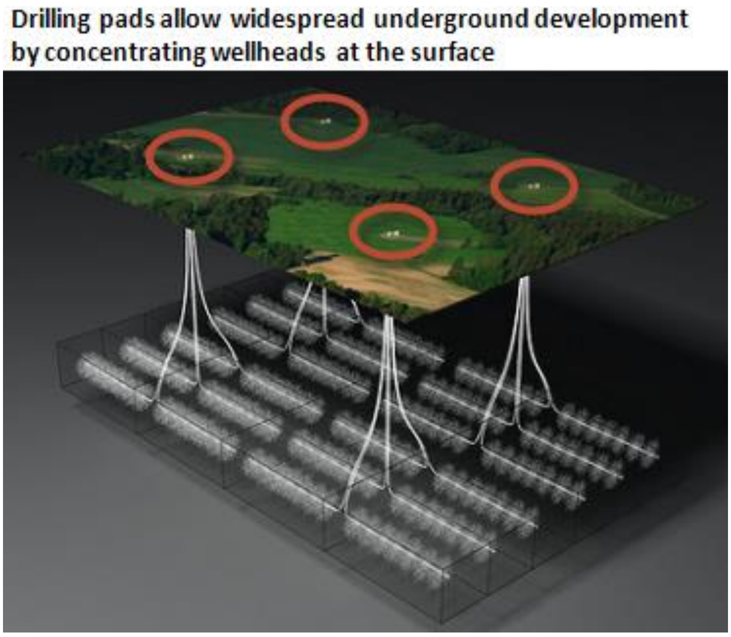

Figure 4-3 Four pads are drilled, each with six horizontally drilled and fractured wells to save cost and surface footprint (U.S. Energy Information Administration, 2012)

4.2 Hydraulic Fracturing

Hydraulic fracturing increases the permeability of shale reservoirs by creating new fractures in the rock. Hydraulic fracturing is basically a stimulation method enhancing oil and gas recovery from wells by injecting liquid, proppant and chemicals, referred to as fracturing fluid. Proppant are sand or other material used to prohibit the fractures from closing. Before the fracturing process is initiated the production casing is perforated in certain places to allow the fracturing fluid and proppant to enter the formation, and later allow the oil and gas to flow the opposite way back to the well, see Figure 4-4.

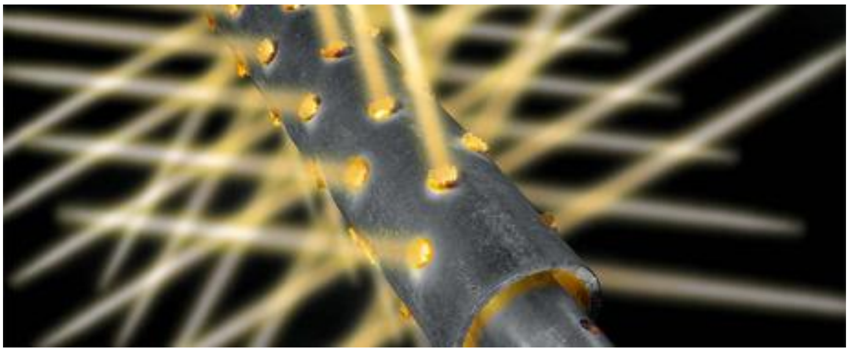

Figure 4-4: Illustrates how perforation guns perforate 360 degrees through the steel casing in a stage of several clusters (Baker Hughes)

The hydraulic fracturing process can be divided up into four steps. The first step is to pressure the reservoir rock using a fluid to create fractures. The second step is to grow the fractures by continuing to pump fluids under high pressure into the fractures, see Figure 4-5. Thirdly, fracturing fluid including proppant, are pumped down the wellbore and into the fracture in the form of slurry, to prop the fractures which prohibit the fractures from closing. The fourth and final step is to stop pumping and allow flow-back to the well to recover the fracture fluid while leaving the proppant in place. (Canadian Society for Unconventional Gas)

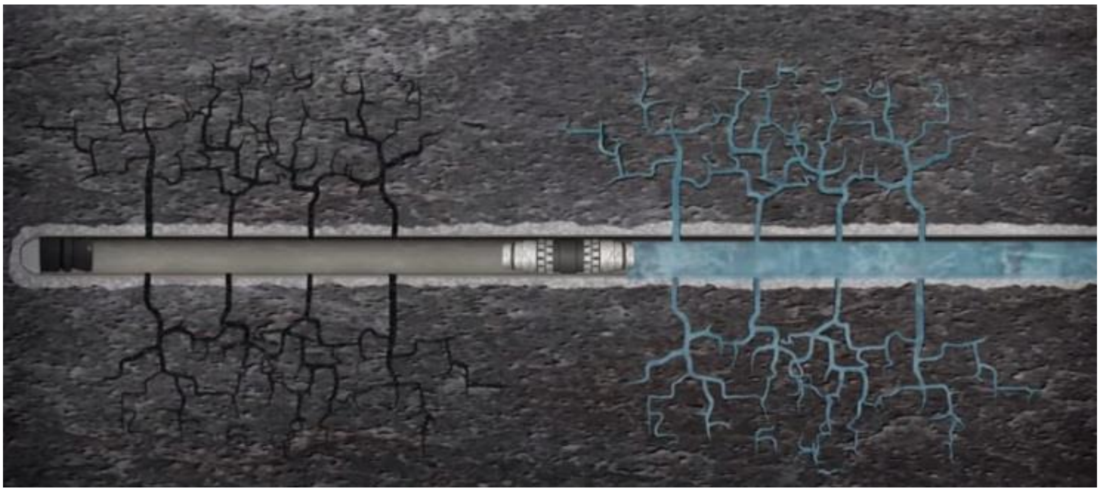

Figure 4-5: Fractures created by perforating the casing and then hydraulically fracturing the well with water and proppant afterwards (Conoco Phillips, 2011)

Some shale rocks naturally contain abundant fractures and connected pore space, allowing fluid to move freely through them, see Figure 4-6. Other shale rock formations have few natural fractures and visible pore space. Oil and gas trapped in these formations require fracturing technology to be extracted. (Suchy & Newell, 2012) The proppant is carried into the fractures by the hydraulic fracturing fluid to prop them open, preventing the fractures from closing and allowing gas and oil to flow through (Petrowiki).

Figure 4-6: Illustrates the natural fractures and layers in shale formations

Because of the length of the lateral, the perforation and four steps of hydraulic fracturing are conducted in several stages, see Figure 4-7. Starting from the toe (end of the lateral) to the heal (beginning of the lateral). The multistage completion approach consists of a sequence of stages being performed along the lateral, with each stage being composed of multiple sets of clusters covering 200 to 300 ft. of the lateral. There can be up to 100 stages in one horizontal well with 1-5 clusters, geometrically spaced every 40 to 50 ft. apart (Halliburton). The multistage completion systems are designed to isolate and stimulate several stages of the horizontal section of a well separately and continuously. There is different completion systems used depending on if the well is completed as an open-hole (OH) or cemented casing, see Figure 4-8 and Figure 4-9 respectively. The choice of refracturing completion technique can be crucial for the technical success and the possibility for how many times the well could be re-stimulated.

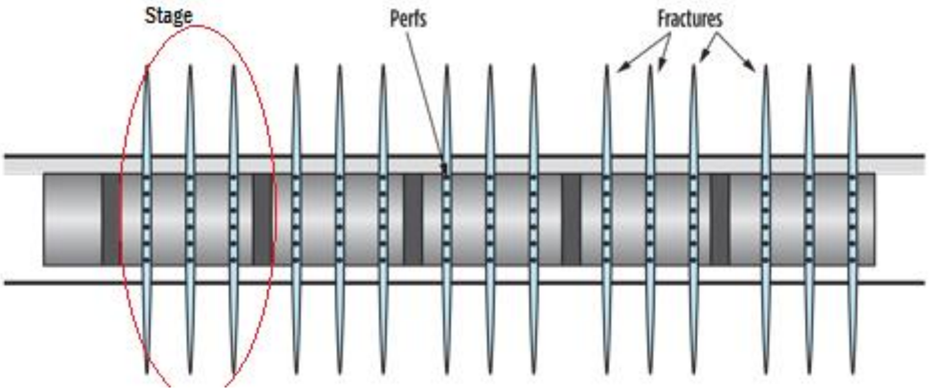

Figure 4-7: Illustration showing stages of perforations and fractures (Daneshy, 2013)

Figure 4-8: Illustration of an open-hole completion, with a sleeve and packers (Baker Hughes)

Figure 4-9: Illustration of a cemented casing (Baker Hughes)

The liquid required for a multi-stage hydraulic fracturing treatment and drilling a well is called fracturing fluid. In general, a fracturing fluid can be thought of as the sum of three main components, see Equation 4-1. The base fluid can be foam- or gel fluids, but normally water is used. Proppant is particles that are induced into the fractures to increase the conductivity and prohibit the fractures from closing. And the additives are chemicals which are added for numerous reasons, see Figure 4-10.

$$\text{Fracturing fluid} = \text{Base fluid} + \text{additives} + \text{proppant} \qquad 4\text{-}1$$

The base fluid and proppant makes up 98 -99.5 percent of the fracturing fluid, see Figure 4-10. Fracturing fluids are required to transport large amount of proppant into the fractures and maximize proppant travel distance (University of North Dakota).

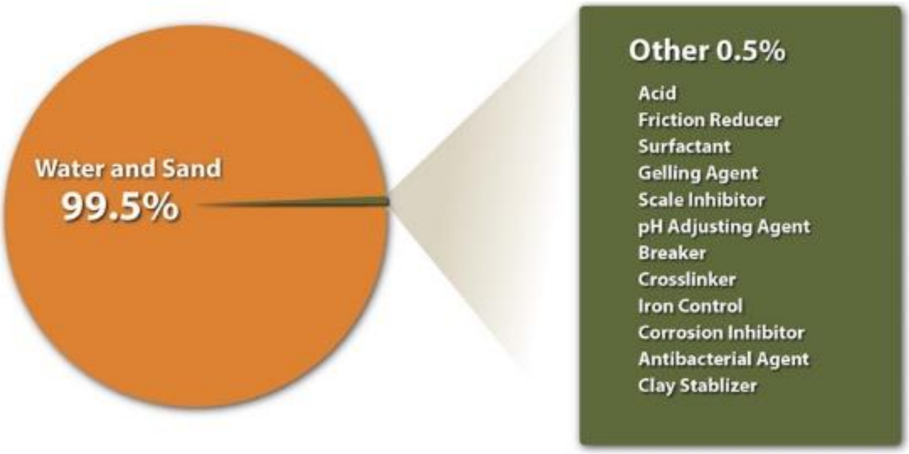

Figure 4-10: Illustration of components that might be added in the fracturing fluid (University of North Dakota)

4.3 Fracturing Completion Techniques

When it comes to horizontal wellbores, the key aspect for a good hydraulic fracturing treatment is zonal isolation. In horizontal wells there are two main ways of zonal isolation, either the well can be completed as an open-hole, or with a casing cemented inside the lateral. OH completions use packers for zonal isolation, which is integrated in the completion system, see Figure 4-11. There are multiple types of packers as inflatable, swellable or mechanical set packers. These are set under completion and will make zonal isolation with multiple open holes in the annulus. In cemented completion there is a casing inside the lateral which is cemented in place, closing the system from the rock formation. The only contact with the rock will be through the perforations which are added after the casing is cemented in place. Inside the casing the zonal isolation are done by plugs that is set under completion.

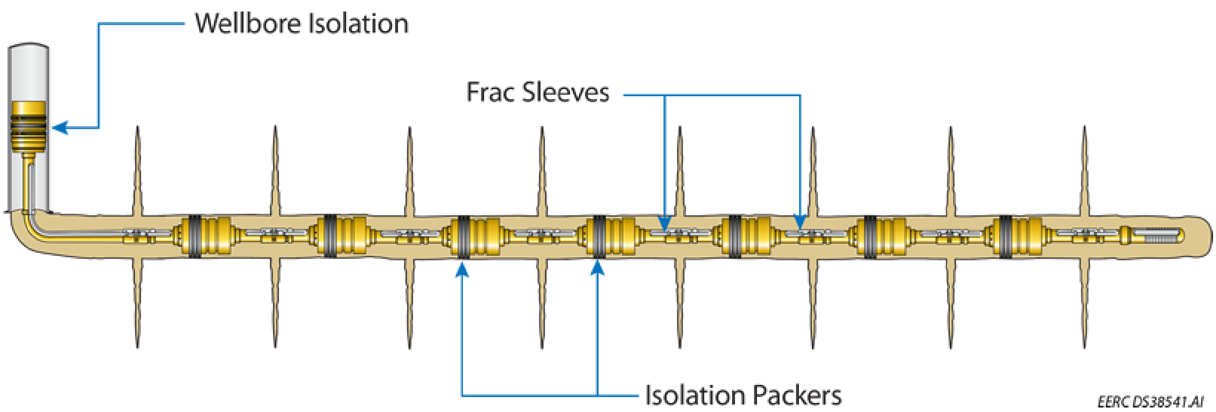

Figure 4-11: Illustration of an open-hole completion with use of a sting which has pre-mounted packers for zonal isolation (University of North Dakota)

Further in this chapter we will introduce the fracturing completion techniques most commonly used today, these are known as; Plug and Perf and Sliding Sleeve (French, Rodgerson, Feik, & BP America Production Company, 2014).

4.3.1 Plug and Perf

Plug and Perf (P&P) is a flexible multistage completion technique for wells with cemented casing or liner. When the stimulation process is initiated there is pumped down a bridge-plug with a following perforation gun to a given location near the toe of the wellbore, see Figure 4-12.

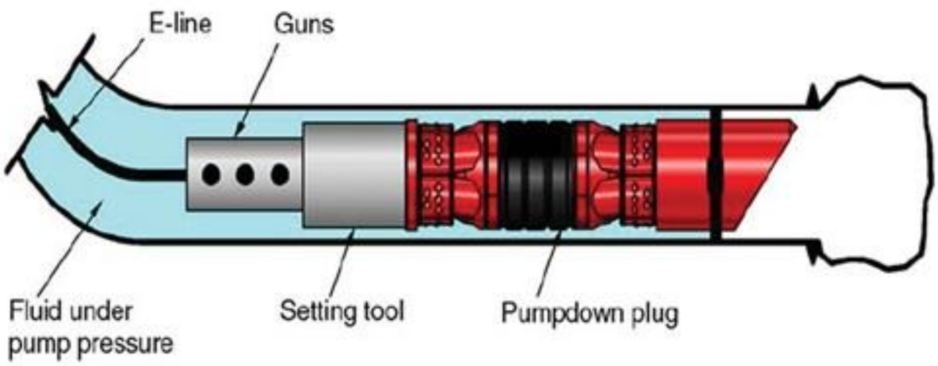

Figure 4-12: Illustration of the plug and perf technique, with a bridge-plug, perforation gun and setting tool (Hsieh, 2011).

Perforation-guns use copper bean as fire material, which will blast trough the casing and 1-2 ft. into the shale. When the plug is set, the first zone is perforated by the gun, then the setting tool releases the plug and the rest of the tool is pulled back up to surface, see Figure 4-13. The hydraulic fracturing treatment is then pumped down the wellbore. The fracturing fluid is diverted through the perforations into the formation, and after a treatment period the first stage is completed. The next stage is then initiated with a new plug and new perforations, with a following hydraulic fracturing treatment. This is now repeated moving further up the well for as many stages as the well is designed for. When all the hydraulic fracturing treatments are completed, all the bridge-plugs are milled out, and the production will start. (Slumberger, slb.com, 2015)

Figure 4-13: Illustration showing a released ridge plug making zonal isolation, plug and perf technique (Weatherford, 2014)

4.3.2 Sliding Sleeve

A relatively new technique of completing horizontal wells is OH completions using a sliding-sleeve technique. The technique consists of a downhole tubing string with premade zonal isolation. Zonal isolation is made by setting the tool and packers under pressure, which creates the zonal isolation of each stage, see Figure 4-11. Sliding Sleeves are normally used in OH completions. However, there are some techniques that can be used in a cemented completion. We can divide sliding sleeve techniques in two categories; Ball-activation and Mechanical-activation. (Seale & Athans, 2008)

Ball-activation

Within each stage of the string there is a sleeve which can be opened to access the surrounding formation, by the use of a ball, see Figure 4-14 and Figure 4-15. The ball is pumped down the wellbore with a corresponding outer diameter (OD) to the inner diameter (ID) of the ball-seat in stage one, see Figure 4-16. Once the ball is seated on the ball-seat, the ball blocks the flow, and the pressure starts to build up. The increased pressure on the ball shifts the ball-seat and sliding sleeve forward, hence opening the sleeves as well as isolating the system from the wellbore. There is no need for perforation guns, since there is pre-made perforations in the sting where the ball-seat used to be. The system is now in connection with the shale formation, and the stage is now ready for the hydraulic fracturing treatment. After the hydraulic fracturing treatment of the first stage, a new ball is dropped. However, this ball is slightly larger (increased OD), which then correspond to the ball-seat of the next stage (stage two), see Figure 4-16. This operation is continued for as many stages as the sting is designed for, and in the end of the operation the balls are milled out, which allows the production of oil and gas. (Wozniak, 2010) (King, George E., 2015)

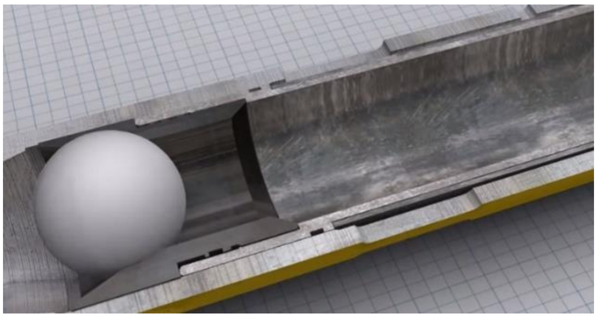

Figure 4-14: Closed sleeve - Ball activation (Baker Hughes, 2010)

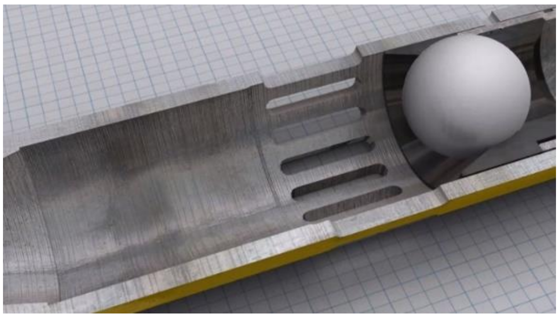

Figure 4-15: Open sleeve - Ball activation (Baker Hughes, 2010)

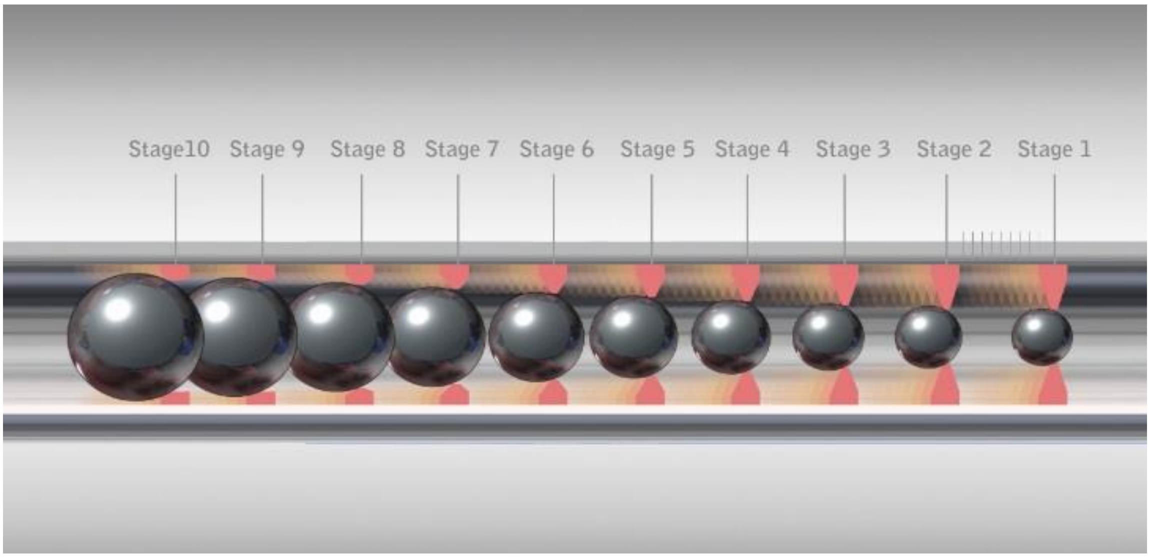

Figure 4-16: Illustration of ball activation, showing ball sizes and an illustration of ball-seats

Mechanical-activation

The string with mechanical activation of the sliding sleeves has the same design as the ball-activation, with one exception, there are no ball seats. The principles are the same as with ball activation, the only difference is that the sleeves are mechanically moved in the open position before the hydraulic fracturing treatment, see Figure 4-17. When the treatment of the first stage is completed, the first sleeve is mechanically closed, and the next is opened. This operation is continued for as many stages as the string is designed for. In the end all sleeves are mechanically opened, which allows the production of oil and gas. (King, George E., 2015)

Figure 4-17: Coiled tubing used to slide a sleeve - Mechanical activation (Baker Hughes, 2010)

4.4 Refracturing

Refracturing can be described as a new stimulation of oil- and gas wells that have been fractured in the past. Refracturing is a new stimulation treatment of the existing fractures, where the objective is to improve the production. Some of the motivation behind refracturing is the sharp decline in production, pore initial fracture spacing, insufficient fracture conductivity and bypassed pay. Refracturing treatments can potentially increase the wells productivity and extend the wells productive lifetime. This will be further described in chapter 6 and 7 and discussed and analyzed in chapter 9.

Refracturing can be done with or without adding new perforations to the lateral. When new perforations along the lateral are added, it is referred to as a recompletion by the industry. Throughout this thesis refracturing will be used as a general term, while recompletion will refer to a refracturing operation where there are added perforations to the lateral.

- Refracturing: A new stimulation treatment of existing fractures (Also used as a general term)
- Recompletion: A new stimulation treatment of existing fractures and new perforations

Figure 4-18: Definition of refracturing and recompletion (Dozier, et al., 2003)

The main technical challenge in refracturing is to selectively stimulate the source rock by diverting the treatment to every perforation with enough treating pressure. In the initial treatments this is done by dividing the lateral into multiple stages, where each stage are perforated and fractured one by one. The treatment starts in the far end of the lateral, which makes it possible to seal of the previous stage from the next treatment. Treating desired zones effectively becomes a challenge in refracturing operations, because the lateral is full of existing perforations.

4.4.1 Refracturing Completion Techniques

There are several different refracturing techniques used by the industry today. We have chosen to describe, and later analyze, the most frequently used techniques by the industry in the following section. Some of these techniques are quite similar, but can have a quite different technical performance. We have also included Comitt Well Solutions' new technique. This is a technique not yet commercialized, but we are still capable of doing a technical evaluation of this technique later in chapter 9.

Non-mechanical Refracturing Techniques:

Pump and Pray

Pump and pray is almost self-describing; it is a technique where the fracturing fluids are pumped down the wellbore without any zonal isolation. The entire lateral is treated in one single operation, where the fluids are naturally diverted into the perforations. The treatment pressure will be divided over all perforations, which results in a low treatment pressure per perforation. There is no way of knowing where the fluids are going, or how much of the lateral is being treated. For that reason this technique is called pump and pray (King, George E., 2015).

Bull-head diversion

This could be classified as the next generation of the pump and pray technique. This technique is also pumped in one single operation. However, under the treatments there are dropped diversion agents to seal off the perforations that are accepting fluids. The agents are material that sets either on the perforations or inside the fractures, which then seals of the fractures. This result in diversion of the fluids to other perforations and fractures, see Figure 4-19.

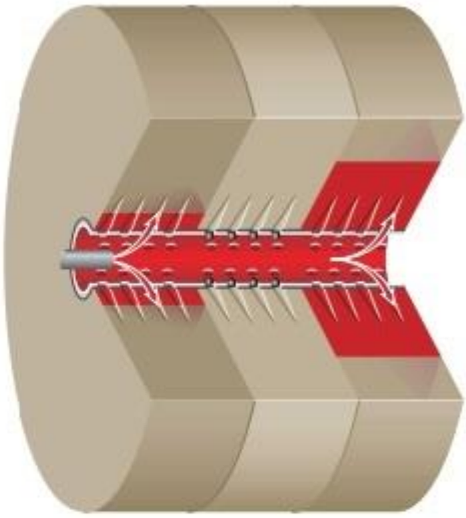

Figure 4-19: Illustration shows diversion agents sealing of the middle stage, diverting the treatment fluids to other parts of the lateral (Slumberger, 2003)

The diversion agents could be rubber balls, biodegradable balls or high proppant concentrations, called slugs. Biodegradable balls are used to ensure that the production reaches its fully potential, by dissolving after a certain time. (Slumberger, Stimulate the Flow, 2003)

The diversion agents are incorporated into the fracturing fluid and pumped with it. The diversion agents are dropped in sequence, which results in a form of zonal diversion where the treatment are diverted to new perforations as more agents are dropped. There is however no way of determine were the agents are accurately set, or where the fluids are going (Slumberger, Stimulate the Flow, 2003).

Mechanical Refracturing Techniques:

Coiled Tubing – Straddle packer

Coiled tubing (CT) is a thin metal tube that are being used for different operations inside a wellbore, like cleaning of the wellbore, set and remove tools, retrieval operations, etc. CT can also be used for refracturing operations with use of a straddle packer assembly, see Figure 4-21. A straddle packer assembly consists of two packers at each end of the fracturing valve. The packers are set at a desired stage, sealing off the stage at each end, which offers the ability to pinpoint the hydraulic fracturing treatment, see Figure 4-20.

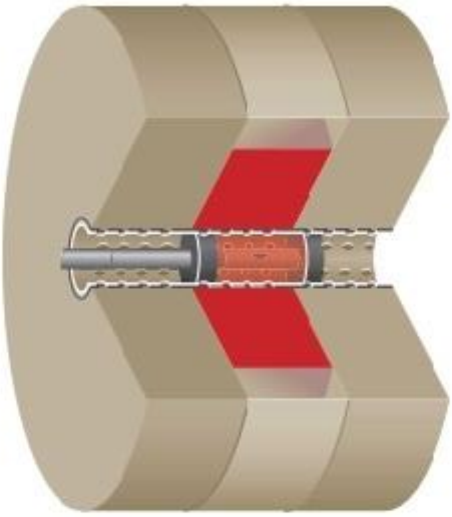

Figure 4-20:Illustration of a straddle packer assembly isolation a zone (Slumberger, 2003)

After the treatment, the packers are released and moved to the next stage. The fracturing fluid is pumped inside the CT and out between the straddle packer assembly, see Figure 4-21. The CT can also be used to perforate new perforation with the use of a jet-nozzle. After the refracturing operation the CT is pulled up to surface and the well is ready for production.

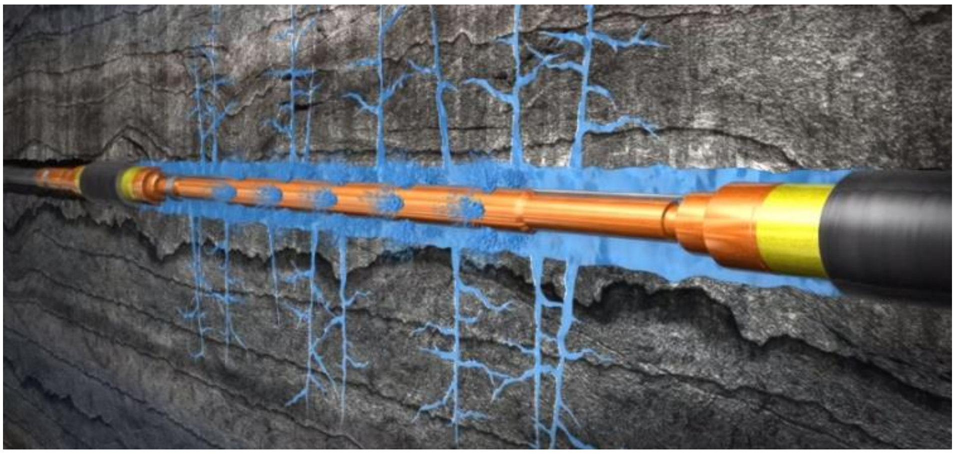

Figure 4-21: Illustration of CT with straddle packer assembly (TAM International , 2013)

Sliding sleeve – Inner string

Sliding sleeve is as mentioned a technique used in fracturing operations. An inner string is a traditional sliding sleeve tool with a smaller ID, beeing used inside an existing production casing for refracturing operations. This technique can isolate each stage with the use of packers, like a traditional sliding sleeve. The existing perforations in the production casing will still be used, and the inner string can be designed with new stage spacing. Mechanical activation or ball activation is still being used like in traditional sliding sleeve systems. However, in this thesis we will just look into sliding sleeve with ball activation. New perforations can be added by using a CT unit for recompletion operations.

Cemented - insert liner

As mentioned, one of the main challenges with refracturing is sealing of your treatment area from the existing perforations. With the traditional use of P&P the earlier steps cannot be sealed. A solution to that problem is to insert a liner inside the existing production casing. The liner can then be cemented inside the existing casing, which brings the well back to an initial condition with a reduced ID. By doing this, the lateral is completely sealed off from the formation, and new perforations are needed to make contact with the surrounding formation, hence this technique is not able to do a refracturing operation, without adding perforations. No illustration of a cemented insert liner has been found, however Figure 4-22 shows a cemented liner in a normal fracturing operation. The insert liner will be cemented inside this casing.

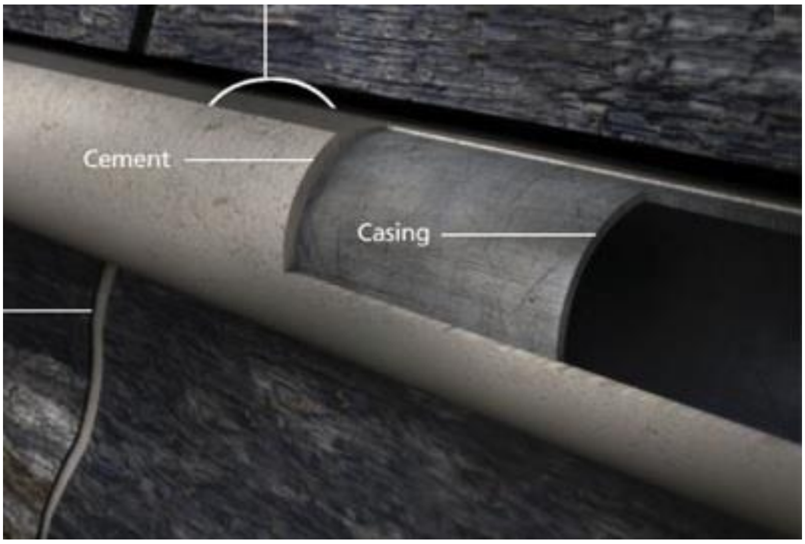

Figure 4-22: Illustration of a normal cemented completion, an insert liner would be placed inside this casing (Themig, 2011)

Cemented Squeeze

To avoid some of the costs and risks of the cemented liner there has been done some refracturing operations with cemented squeeze. With this technique, cement is pumped down the wellbore to seal all existing perforations, without any new casing. The whole lateral is filled with cement and squeezed into the perforations, which seals off the system from the formation. When the cement has cured, it is drilled out; leaving only the cement that is squeezed into the perforations and fractures. Every existing perforation is sealed off, which enables this technique to do a refracturing operation. The refracturing operation can now be done by the traditional P&P technique, where new perforations can be made in between the old ones.

Expandable Liner

There are also some examples where expandable liner has been tried, where an expandable liner is inserted into the horizontal part of the wellbore. Instead of cementing the new casing in place, the expandable liner is expanded under pressure to seal of all existing perforations, leaving no space between the old casing and the new expandable liner. For that reason this technique cannot be used for refracturing operations, because new perforations have to be made to access the surrounding formation. With this technique the ID will not be reduced by as much as with cemented casing, but the general idea is the same.

Comitt Well Solutions

Comitt Well Solutions has a new technique that has some of the same attributes as the CT technique described earlier. The different is that Comitt Well Solutions' technique utilizes a pipe instead of a metal tube. The difference between a pipe and a tube is mainly the ID and the strength, where a pipe has a larger ID and more strength to support a higher treating pressure. The pipe has a smaller ID than the original casing, but it is larger than coiled tubing. This gives the technique an opportunity to use a pump rate of 15-30bpm/cluster, rather than +/- 4bpm with CT. This technique is using a type of straddle packer assembly, as the CT technique. A straddle packer assembly consists of two packers at each end of the fracturing valve, see Figure 4-23. The packer assembly may be activated and re-activated by hydraulic pressure numerous times so that they can treat the whole length of the lateral in one operation. This assembly can seal off clusters with high accuracy and can be used for both refracturing- and recompletion operations.

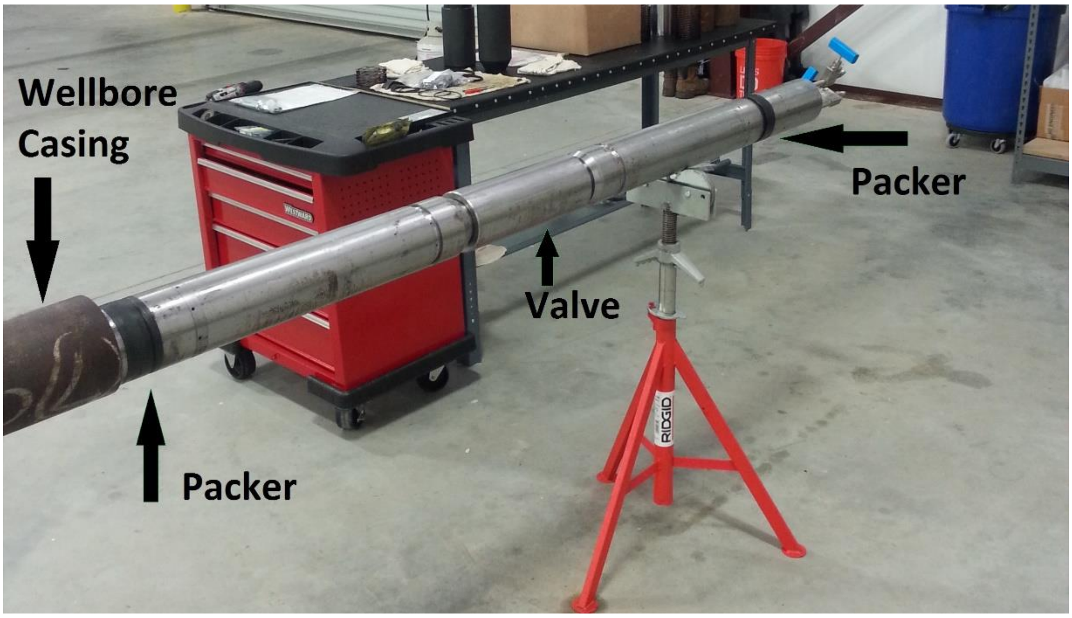

Figure 4-23: Illustration of Comitt Well Solutions' technique, with one packer at each side of the valve (valve not installed)

5 Theory and Technology Concepts

In this chapter we will present fundamental theory and technological concepts used in chapter 8 and 9 to evaluate and compare the technical and economical performance of the different refracturing techniques. The constructed profit calculation tool is also built upon these theories and concepts.

5.1 Hazard and Operability Assessment (HAZOP)

HAZOP (Hazard and Operability Analysis) is a structured and systematic analysis technique that is used in system research and risk management in order to identify potential hazards in a system, caused by incorrect operation or malfunction of processes or equipment. A HAZOP analysis is usually carried out in a set of meetings by a multi-disciplinary team. (Lassen, 2004)

HAZOP is described as a technique in "brainstorming" and as a systematic approach to investigate each element of a process to identify all of the ways in which parameters can deviate from the intended design conditions and create hazards or operability problems. A HAZOP analysis begins with a description and understanding of the whole process. This is usually done by studying drawings of the installation and flowchart for the process. Secondly, systematic questions about individual parts of the process are necessary to identify how deviations from operations can occur, and if these discrepancies may be the cause of hazardous risk. To identify potential deviations it is often used a systematic list containing words and phrases from a deviation perspective, see Table 5-1 .The words and phrases will easily and effectively help the user in identifying operational risks. (Lassen, 2004)

Table 5-1: A systematic list of questions that helps identifying hazards in a HAZOP analysis

Guide Words	Meaning
NO or NOT	Complete negation of the design intent
MORE	Quantitative increase
LESS	Quantitative decrease
AS WELL AS	Qualitative modification/increase
PART OF	Qualitative modification/decrease
REVERSE	Logical opposite of the design intent
OTHER THAN	Complete substitute
EARLY	Relative to the clock time
LATE	Relative to the clock time
BEFORE	Relating to order or sequence
AFTER	Relating to order or sequence

5.2 Decline Theory

Decline curve analysis (DCA) is one of the most commonly used methods for forecasting reserves in unconventional reservoirs. At a fundamental level, DCA involve fitting an empirical model of the trend in production decline from a well’s history, and projecting the trend into the future. This allows you to determine the well’s economic life and forecast cumulative production

Because of the different decline trends of the individual wells there is really not one model that fits all cases. The model used may give good projections in one well, but bad in another well.

Dutta et al. (2014) presents eight DCA models that can be used to forecast future trends of production:

1. Duong
2. Modified Duong
3. Modified Stretched Expnonital
4. Exponential
5. Hyperbolic
6. Modified Hyperbolic
7. Power Law
8. Analytical

The modified hyperbolic model is by far the most used technique for forecasting future trends of production. According to Dutta et al. (2014) this is because of the ease of use, and its availability in multiple DCA software (Dutta, Meyet, Burns, & Van Cauter, 2014)

Arps' Decline Curves

Arps (1945) developed the mathematical relations of three types of graphical representation of production decline for conventional reservoirs. These empirical equations define the historical exponential, hyperbolic, and harmonic decline types observed for different qualities of traditional reservoirs. Arps decline model is established from the empirical observations that the loss ratio is constant with time.

When b = 0, the decline is exponential, b value of 1 is considered harmonic, while a b value between 0 and 1 is hyperbolic. A b value between 0 and 1 are often observed when matching production data from conventional reservoirs. Assumptions used when using Arps' model are that the drainage radius is constant, production remains at a constant bottomhole pressure and the well exhibits a constant productivity. If all the conditions are satisfied, b remains constant for the life of the well (Dutta, Meyet, Burns, & Van Cauter, 2014).

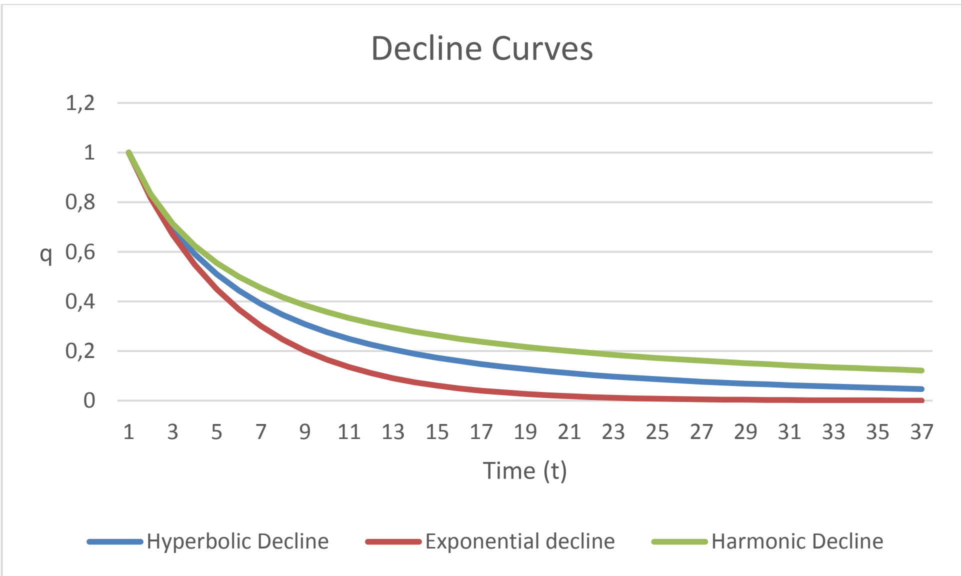

Figure 5-1: Illustrates decline curve trends of hyperbolic-, exponential-, and harmonic decline.

The hyperbolic decline formula is (b <0, 1>):

$$q = q_i(1 + bD_it)^{-\frac{1}{b}} \tag{5-1}$$

The exponential decline formula is (b = 0):

$$q = q_ie[-D_it] \tag{5-2}$$

The harmonic formula is (b = 1):

$$q = q_i(1 + bD_it)^{-1} \tag{5-3}$$

q	=	flow rate at time t
q_i	=	initial flow rate
D_i	=	the initial nominal decline rate
b	=	the decline exponent

In exponential decline, the decline rate is defined by the nominal decline, which is the rate of decline at a specific point of time. The effective decline rate D, is the decline measure over a specific time period, usually a year.

Cumulative production for hyperbolic decline is:

$$G_p = \frac{q_{gi}}{(1-b)D_i}[1 - (1 + bD_it)^{1-\left(\frac{1}{b}\right)}] \tag{5-4}$$

Cumulative production for exponential decline is:

$$G_p = \frac{q_{gi}}{D_i}[1 - e(-D_it)] \tag{5-5}$$

"t" represents the economic life of the well and "q_{gi}" the minimum economic flow rate. If "q_{gi}" is known, the economic life of the well as well as the cut-off point for the production can be predicted.

Low permeability unconventional reservoirs usually exhibit transient flow at the start of production, and can remain in transient flow for years. Arps' formula assumes boundary dominated flow, where b<1. However, wells in the Barnett have also given a b-factor as high as 1.59 (Baihly, Altman, Malpani, & Luo, 2011). If b remains greater than 1 during the well life, EUR consistently increase. Another consideration is that bottom-hole pressure may drop significantly in the early stages of a wells life, creating artificially high b values (Dutta, Meyet, Burns, & Van Cauter, 2014).

To get rid of this problem Robertson (1988) combined Arps' hyperbolic and exponential decline curves by making a switch from hyperbolic decline in the early life of the well, to exponential decline during its later life. The switch occurs at a predetermined limiting decline rate, D_{lim}, which occurs at t*, generally at some point during the production forecast rather than in the period covered by the data (Dutta, Meyet, Burns, & Van Cauter, 2014).

Arps' combined hyperbolic and exponential equations are given as:

$$q = \begin{cases} q_i(1 + bD_i t)^{-\frac{1}{b}}; & t < t* \\ q_{gi} e[D_{lim} t]; & t > t* \end{cases} \qquad 5\text{-}6$$

The method is referred to as Arps' modified hyperbolic decline or Arps' method with minimum terminal decline. Although this method is commonly used in production forecasting, the selection of D_{lim} can be quite arbitrary and has no physical basis (Dutta, Meyet, Burns, & Van Cauter, 2014).

5.3 Nonlinear Least Squares Method

The method of Least squares is a procedure to determine the best fit to data. The method uses calculus and linear algebra. Non-linear least square method is basically an analysis used to fit a set of observations with a model that is non-linear. Often in the real world one expects to find perfect relationships. Unfortunately, it is extremely unlikely to observe. There are two main reasons for this. The first is experimental error and the second is that the underlying relationship may not be exactly, but rather an approximate. A careful analysis will show that the method is capable of great generalizations. Instead of finding the best fitted line, we could find the best fit given by any finite combinations of specified functions (Miller).

In the oil and gas industry the non-linear least squares method could be used find the best fitted line to a hyperbolic function by minimizing the residuals between the historical data and the hyperbolic function. The residuals are given by the following function.

$$r_i = Q_j - F(q) \qquad 5\text{-}7$$

r_i = the residual between historical data and the hyperbolic function
Q_j = the historical data provided
F(q) = the hyperbolic function

Unfortunately this is a signed quantity, and large positive deviations can cancel with large negatives. This, would therefore be a terrible measure of the variability in data, as it is zero regardless of what the values of the data are. We can rectify this problem by using squared values.

$$r_i = (Q_j - F(q))^2 \qquad 5\text{-}8$$

The best fitting curve to the historical data will be the curve that minimizes this function

$$\sum_{i=0}^{m} r_i(x)^2 \tag{5-9}$$

If you are trying to fit a hyperbolic function to well data this means in other words, the combination of b and D in the hyperbolic function that minimizes equation 5-9.

5.4 Probability and Monte Carlo Simulations

Probability is used in a risk context to estimate the chance of an event to occur. Risk is a combination of probability and the consequence of an event. That is why it is important to have a good understanding of statistics and probability when trying to handle and make sense of risks in a good way.

5.4.1 Stochastic Variables

A deterministic variable has only one possible outcome, but may thus only represent one value. This is not very useful in a risk context, when we want a more accurate description of reality. In reality, a variable like the economic outcome can vary a lot within a wide range of values. To represent this we have to use a stochastic (random) variable. The variable then takes into account the likelihood that different values occur.

We distinguish between discrete and continuous random variables. Discrete random variables can take on the value to a limited number of specific values. Continuous random variables can take any value within an interval. We use in this context continuous stochastic variables.

A continuous random variable, **x**, is characterized by:

$\text{Avarage value}, \mu_x \quad \text{Standard deviation}, \sigma_x \quad \text{Frequency function}, f(x)$

5.4.2 Monte Carlo Simulations

A Monte Carlo simulation (MCS) is a type of algorithm that generates a numerical solution to a problem with the usage of random drawing from a number of data sets. MCS is a method that takes into account the uncertainty in the calculations by defining input parameters as stochastic variables. With the usage of random drawing we are generating multiple data sets of input variables, look random drawing is shown in Figure 5-3. The values generated by these input variables are inserted into the assembly function, which further gives us several datasets with result/assemble values. These can be presented in a histogram. (Harbitz)

The histogram, or assembly distribution, can then be used to calculate probabilities for different outcomes. This assembly distribution now represents the uncertainty of all the input variables. There could be made a function representing the assembly distribution by using e.g. Weibull distribution.

Decisions can be made with respect to this probability distribution together with qualitative factors and our preference to risk (ref. risk neutral, risk averse, risk lover), shown in Figure 5-2.

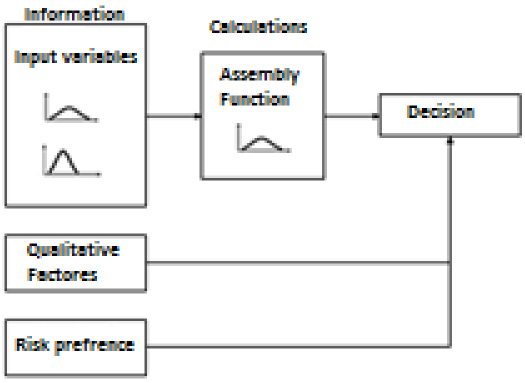

Figure 5-2: Monte Carlo Simulation of uncertainties (FMC Technologies, 2014)

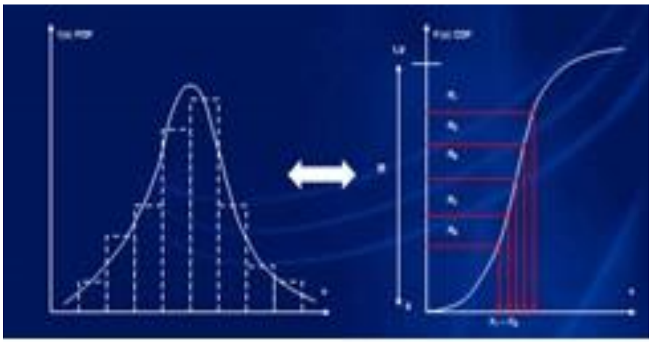

Figure 5-3: Illustration of random drawing (FMC Technologies, 2014)

The random drawing is based on equation 5-10, where F(x) is the cumulative distribution function to one of the input variables (x), and R is a random number between 0 and 1, with a uniform distributed see Figure 5-3. For each drawing we can see that a result variable (y) is generated. The result variable can be put into an assembly distribution, which can be used to evaluate the uncertainty to an activity based on given probabilities. The cumulative distribution function is shown in equation 5-10. The result function is shown in equation 5-11. (Harbitz)

$$F(x) = R \qquad 5\text{-}10$$

$$y = f(x_1, x_2, x_3 \ldots\ldots x_n) \qquad 5\text{-}11$$

5.5 Return on Investment

The rate of return is the profit as a proportion of the initial outlay. The return on an investment (ROI) can be calculated as (Brealey, Myers, & Allen, 2011):

$$ROI = \frac{\text{profit}}{\text{investment}} \qquad 5\text{-}12$$

The investment is worth undertaking if its rate of return exceeds the opportunity cost of capital. The opportunity cost of capital is the return foregone by not investing in best financial markets or opportunities.

Rate of return rule → Accept investments that offer rates of return in excess of their opportunity costs of capital.

5.6 Net Present Value and Cash Flow

Present value in economics is defined as the current worth of money or stream of cash flows given a specified rate of return determined as of the date of valuation. The present value is always less than or equal to the future value because money can be invested to earn interest. Therefore a $ 100 today is worth more than a $ 100 dollar in the future because you can invest and earn interest on the $ 100 today. Hence the expression:

A dollar today is worth more than a dollar tomorrow (Brealey, Myers, & Allen, 2011)

The future value is calculated as follows: FV = PV * $(1+r)^t$,

where "r" is the periodic interest rate and "t" is the number of periods earned interest over.

In general to calculate a received cash flow of "C_t" dollars at the end of period "t" the present value of the future payment is:

$$\mathrm{PV} = \frac{\mathrm{C_t}}{(1+\mathrm{r})^{\mathrm{t}}} \tag{5-13}$$

Suppose that you wish to value a stream of cash flows extending over a number of periods. The rule of present value calculates that the total present value is (Brealey, Myers, & Allen, 2011):

$$\mathrm{PV} = \frac{\mathrm{C_1}}{(1+\mathrm{r})} + \frac{\mathrm{C_2}}{(1+\mathrm{r})^2} + \frac{\mathrm{C_3}}{(1+\mathrm{r})^3} + \cdots + \frac{\mathrm{C_T}}{(1+\mathrm{r})^{\mathrm{T}}} \tag{5-14}$$

This is called the discounted cash flow. Also written as

$$\mathrm{PV} = \sum_{\mathrm{t}=1}^{\mathrm{r}} \frac{\mathrm{C_t}}{(1+\mathrm{r})^{\mathrm{t}}} \tag{5-15}$$

∑ refers to the sum of the series. The net present value is the present value minus the investment. To find the net present value (NPV) we add the (usually negative) initial cash flow which often is the investment or payout.

$$\mathrm{NPV} = \mathrm{C_0} + \mathrm{PV} = \mathrm{C_0} + \sum_{\mathrm{t}=1}^{\mathrm{r}} \frac{\mathrm{C_t}}{(1+\mathrm{r})^{\mathrm{t}}} \tag{5-16}$$

Instead of dividing the future payment by$(1+\mathrm{r})^{\mathrm{t}}$, you can equally well multiply the payment by $1/(1+\mathrm{r})^{\mathrm{t}}$ which is called the discount factor. It measures the present value of one dollar received in period "t".

Net present value rule → Accept investments that have positive net present values.

5.7 Internal Rate of Return

The Internal rate of return (IRR) is defined as the rate of discount that makes NPV = 0 (Brealey, Myers, & Allen, 2011). The IRR is the rate of growth a project is expected to generate. The IRR is a rate of return used to measure and compare the profitability of investments. The actual rate of return that a given project ends up generating will often differ from its IRR rate. However projects with substantially higher IRR value than other options will still provide a significant better chance of strong growth. To find the IRR for an investment we have to solve the following expression:

$$\mathrm{NPV} = \mathrm{C_0} + \frac{\mathrm{C_1}}{(1+\mathrm{IRR})} = \frac{\mathrm{C_2}}{(1+\mathrm{IRR})^2} = \frac{\mathrm{C_3}}{(1+\mathrm{IRR})^3} + \cdots + \frac{\mathrm{C_r}}{(1+\mathrm{IRR})^{\mathrm{T}}} = 0 \qquad 5\text{-}17$$

To solve this expression with a long stream of cash flows can be very hard. The usual way to solve the function is by using computer programs or by guessing. By guessing IRR you can calculate the NPV. If the NPV is positive the IRR have to be greater than guessed and if the NPV is negative the IRR have to be less than guessed.

Because the IRR is a rate quantity, it is an indicator of the efficiency, quality or yield of an investment. This is in contrast with the net present value, which is an indicator of the value or magnitude of an investment (Brealey, Myers, & Allen, 2011).

5.8 Payback Period

A project's payback period is found by counting the number of periods it takes before the cumulative cash flow equals the initial investment. In other words the payback period is the time necessary to recover the initial outlay on an investment (Vernimmen, Quiry, Dallocchio, Salvi, & Fur, 2014).

Where cash flows are identical, the payback period is equal to

$$\text{Payback period} = \frac{\text{Investment}}{\text{Periodical cash flow}} \qquad 5\text{-}18$$

For following investment:

Table 5-2: Payback period example with identical cash flow

Period	0	1	2	3	4	5
Cash flows	-2.1	0.8	0.8	0.8	0.8	0.8

The payback period is 2.1/0.8 = 2.6 years.

Where the periodical cash flows are not identical, the cumulative cash flows are compared with the amount invested, as the example below:

Table 5-3:Payback period example with not identical cash flow

Period	0	1	2	3	4	5
Cash flows	-2.1	0.3	0.4	0.4	0.5	0.2
Cumulative cash flows		0.3	0.7	1.1	1.6	1.8

The cumulative flow is 0.7 for period 2 and 1.1 for period 3. The payback period is thus 2-3 years. A linear interpolation gives us a payback period of 2.75 years.

If we assume cash flow is in NPV, see equation 5-16. The payback time is equal to the point in time where:

$$\mathrm{NPV} = 0 \qquad (5\text{-}19)$$

Once the payback period has been calculated, it is compared with an arbitrary cut-off date determined by the financial manager or the projects life time. If the payback period is longer than the cut-off period, the investment should be rejected. (Vernimmen, Quiry, Dallocchio, Salvi, & Fur, 2014)

5.8.1 Breakeven Price

Breakeven is the level of activity at which total revenue covers total costs. With business running at this level, earnings are thus zero. The breakeven price is the amount of money for which a product or service must be sold to cover the costs of manufacturing or providing it. This can also be translated to the investment cost (Vernimmen, Quiry, Dallocchio, Salvi, & Fur, 2014).

Breakeven statements:

- If the company does not reach breakeven, the company posts losses
- If sales are exactly equal to the breakeven point, profits are zero
- If the company exceeds its breakeven point, it generates profit

The breakeven point is the level of sales at which fixed costs are equal to the contribution margin, which is defined as the difference between sales and variable costs.

$$\text{Contribution margin} = \text{Fixed costs} \qquad (5\text{-}20)$$

Further, the breakeven price can be calculated with the following formula:

$$\text{Breakeven price} = \frac{\text{Total fixed cost}}{\text{Volume of production}} + \text{Variable cost per unit} \qquad (5\text{-}21)$$

If the investment and volume of production is long term you would want some return on the investment. A project which simply breaks even on an accounting basis will always have a negative NPV. Therefor NPV breakeven price is often a better measurement when doing project decisions. It is more useful to focus on the point that the NPV switches from negative to positive. Therefore the breakeven price is equal to the price at a chosen point of time, where:

$$\mathrm{NPV} = 0 \qquad (5\text{-}22)$$

6 Literature Study of Refracturing Performance

There was conducted a comprehensive literature study during the work with this thesis. The prime purpose of this literature study is to use previous research and theory in answering the research questions. The public case studies and literature in this chapter are mainly published by SPE, and SPE is therefore the main source of data. Other papers are gathered directly from oil- and service companies in the US.

Chapter 6.1 will present a summary of the most frequent well selection criteria and refracturing success- and failure criteria. This will help in the evaluation of which wells that are suitable and economical to refracture, and further in evaluating the magnitude of the refracturing market. In chapter 6.2 there will be presented a summary of public case studies of horizontal refracturing projects. The chapter will focus on which refracturing completion techniques the industry has used in the different refracturing projects, and which production increase they have experienced. This data will later be used to look at trends in the economical evaluation in chapter 9. Cost and risk will be included; however, this is usually confidential information and is rarely included in public literature.

6.1 Important Refracturing Criteria

To answer the first research question in this thesis it is necessary to find out how many wells that is likely to be good candidates for refracturing operations. It is important to know which criteria that needs to be fulfilled to find out how many wells that is suitable for refracturing. Well selection criteria from the literature study are summarized in the first subchapter. When the oil companies have selected potential refracturing candidates it will be important to know what makes a refracturing operation a success and what makes it a failure. The following subchapters will present criteria the industry believes lead to refracturing success and what they believe leads to failure. These success criteria will be the fundamental base of the technical evaluation of each refracturing technique, presented in chapter 9. For that reason, the most important criteria are further described in more detail at the end of this chapter.

6.1.1 Well Selection Criteria

Identifying the most lucrative candidates for refracturing is a challenging task. Each shale formation is unique, and every well within a field may have different characteristics. For that reason, a single procedure or flowchart will likely fail to yield the most promising candidates in all fields. Although Vincent (2012), among others believes that the candidate selection procedures should be customized to the particular field, there are several general criteria that are of importance in every field (Vincent M. C., 2010). The most frequently well selection criteria found in the literature study are summarized below to highlight what the industry consider as good selection criteria today, see Table 6-1. It is important for the reader to know that these are guidelines for well selection, and not absolutes.

Table 6-1: Well Selection Criteria frequently emphasized in the literature

Selection criteria	Explanation
Mechanical and annular integrity	If the mechanical integrity of the well has been jeopardized, refractures are often economically hindered, unless the integrity is cheaply restored (Vincent M. C., 2010). In BP's pilot project one of the well selection criteria was no previous faults (French, Rodgerson, Feik, & BP America Production Company, 2014). If the annular integrity is poor it can be experienced pressure communication between stages, which could lead to high breakdown pressures and poor fracture intensity (King G. , 2015).
Well productivity	This can be a good indicator of a successful refracturing candidate. Numerous authors have concluded that highly productive wells are frequently the most economic refracturing candidates (Vincent M. C., 2010), (Flores & Indriati, 2009), (Husen, 2003), (Ely, 2000). However, high cumulative production conversely correlates to depleted zones. And Vincent (2010) argues in another paper that average recoveries were deemed preferable, arguing that low recovery indicates poor reservoir quality, and high recovery may indicate adequate existing stimulation (Vincent M. C., 2010). BP selected candidates with low cumulative production to minimize the risk of damaging production in their pilot project (French, Rodgerson, Feik, & BP America Production Company, 2014). However, King (2015) argues that the wells with high cumulative production might be the best refracturing candidates, if the fractures reorient.
Reservoir pressure	Wells with high skin and high remaining pressure are excellent candidates for refracturing (Vincent M. C., 2010). However absence of the ability to document good reservoir pressure is not a reliable predictor of failure, as it appears hydraulic refracturing treatments can fracture into higher pressured layers or regions in many reservoirs (Craig, Wendte, & Buchwalter, 2012). High current reservoir pressure is also an important criterion in BP's pilot project (French, Rodgerson, Feik, & BP America Production Company, 2014).
Pressure communication	If there is pressure communication with offset wells, there is likely that the offset wells have contributed in depleting the well (King G. , 2015). Theft production from offset wells may occur, which will affect the production post-refracturing in a negative way (Hughes B. , 2015).
Poor conductivity in initial fracturing performance	Low conductivity in initial treatments is a strong indicator of success. Refracturing operations usually restores and increase the conductivity in the well (Vincent M. C., 2010). This was also an important criterion for BP's pilot project (French, Rodgerson, Feik, & BP America Production Company, 2014). Proppant durability is an issue, and more frequent refracturing operations appear to be needed with lower strength proppant (Shah, Vincent, Rodriquez, & Palisch, 2010).
Bypassed perforation pay	Wells with unstimulated productive intervals are excellent refracturing candidates. Identifying and stimulating bypassed pay is frequently a technical success. Besler (2008) argues that incomplete zone coverage indicated by tracers or production logs, or evidence that refracturing can contact new reserves, is a good candidate for refracturing. (Besler, 2008). Lateral with unperforated intervals at the heel and fracture

	stage spacing > 500 ft./stage were also some of BP's highly ranked selections criteria (French, Rodgerson, Feik, & BP America Production Company, 2014). King (2014), argues that wells with stage spacing >300 ft. will be good candidates (King G. , 2015).
Number of previous refracturing operations	The number of previous refracturing operations is a poor indication of refracturing success. Some wells have been successfully refractured as many as five times and still remain as economical candidates for future refracturing operations. (Vincent M. C., 2010) However, Vincent (2010) presented some other selection criteria used in the Canadian Bakken play, where they argued that wells that had been refractured within the past 5 years were considered poorer candidates than wells with older or no previous refracturing operations (Vincent M. C., 2010).
Shape of decline curve	A great deal of information can be extracted from analyses of historical production. In general, long term flat production is frequently indicative of an understimulated well. Steep production declines can be attributed to numerous phenomena ranging from proppant degradation to limited drainage area. Interpretations are generally non-unique without additional data or engineering judgment. (Vincent M. C., 2010)

6.1.2 Refracturing Success Criteria

There have been published more than 140 papers documenting the success and failure of refracturing operations in a wide variety of reservoirs (Vincent M. C., 2010). One of the major difficulties with evaluating the effect of refracturing operations is that more than one design factor is altered between the initial- and refracturing operations in the different wells. In the vast majority of the published papers there are commonly changes of the total mass of proppant concentration, the transportation fluid and the refracturing completion technique. This makes it difficult to identify exactly which portion of the increased productivity that should be attributed to each of these changes (Vincent M. C., 2010).

Vincent (2010) has published an analysis of some of the successful case studies where he highlighted the refracturing mechanisms that can improve production. The majority of these criteria are supported by King (2015) and Dozier et al. (2003) who has defined similar refracturing success criteria. The common success criteria was found to be:

- Enlarged fracture geometry, enhancing reservoir contact and add contact points.
- Improved pay coverage by greater lateral coverage in horizontal wells or initiation of more transverse fractures.
- Increased fracture conductivity compared to the initial fracturing operation.
- Restoration of fracture conductivity loss due to embedment, cyclic stress, proppant degradation, etc.
- Increased conductivity in previous unpropped or inadequate propped portions of fracture.
- Use of more suitable fracturing fluids.
- Fracture reorientation due to stress field alternations, leading to contact of "new" rock.

(Vincent M. C., 2010), (King G. , 2015), (Dozier, et al., 2003).

6.1.3 Refracturing Failure Criteria

Unsuccessful refracturing operations are also common, but are less frequently published. The industry tends to publish success stories more frequently than it discloses failure, because there is little incentive to publish failures. However, Vincent (2010) and King (2015) highlight the following factors as common reasons for refracturing failures:

- Wells with questionable mechanical integrity of tubing, casing and cement.
- Low pressured, depleted wells, posing challenges with recovery of fracturing fluids.
- Wells in which diagnostics indicate effective initial fractures and drainage to reservoir boundaries.
- Access to better parts of formation is prevented.
- Wells which has pressure communications to offset wells might be depleted.

(Vincent M. C., 2010), (King G. , 2015).

6.1.4 Description of Important Criteria

In this chapter each refracturing success criteria will be explained in more detail. The use of more suitable fracturing fluids is not evaluated in our analysis, explained in chapter 8, and will for that reason not be described in the following section. It is important for the reader to understand the success criteria when we later are going to evaluate today's refracturing completion techniques based on these criteria.

Enlarged Fracture Geometry

We can define fracture geometry as the fractures capability of connecting geological surface area to the wellbore. Good fracture geometry will be a complex fracture network that connects a big surface area to the wellbore, see Figure 6-1. Typically unconventional shale consists of natural fracture networks which may help in getting enlarged fracture geometry. It is important to design an effective perforation-, cluster- and stage spacing to effectively utilize the shale formation. Initial fracture design haven't been done effectively in many of the older wells, and in those wells there could be a great potential of getting an enlarge fracture geometry. There will also be a potential of enlargement in initially good designed wells, because of the possibilities of creating new fractures in a different direction than the initial fractures. More about fracture reorientation will be presented later in this chapter.

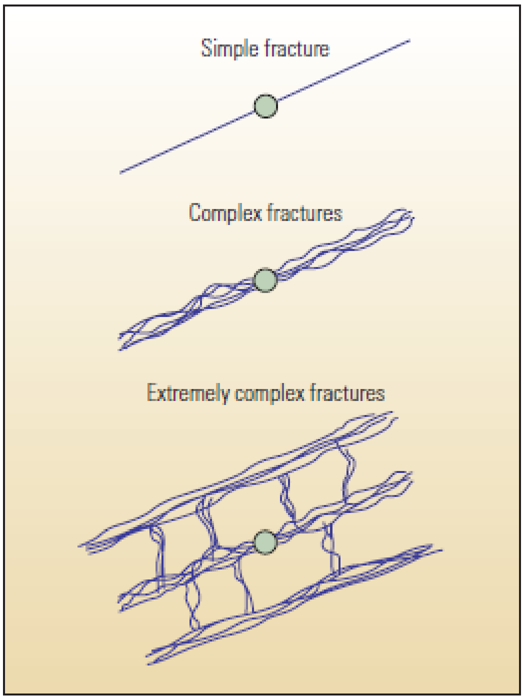

Figure 6-1: Illustration of different fractures, simple fractures are normally obtainable, however complex and very complex hydraulic fractures may also develop in some formations (Dozier, et al., 2003)

Enlarged fracture length in previous created fractures may be achieved by refracturing a well, which leads to more connected stimulated rock volume (SRV) to the wellbore. The complexity of new fractures is very hard to predict because fractures tends to propagate in the direction of the maximum compressional stress in the source rock. As a result the refracturing techniques' ability to divert pressure to the desired fractures and perforations will have a huge impact on the success. The controllability depends on how good the refracturing techniques are able to apply enough pressure to desired fractures and perforation while isolating the others. To enlarge fracture geometry there could also be made new perforations in previously bypassed pay. However, this is explained in more detail later. (Dozier, et al., 2003)

None-mechanical techniques does not have the ability to isolate stages, which makes it hard to control where the fluids are going. The fractures will initiate in the regions with the lowest formation stress, and grow until the pressure inside those fractures exceeds the formation stress elsewhere, then new fractures will be initiated, see Figure 6-2. New fractures can be initiated until the pressure drop in the lateral reduces the treatment pressure below fracture initiation pressure (Dozier, et al., 2003).

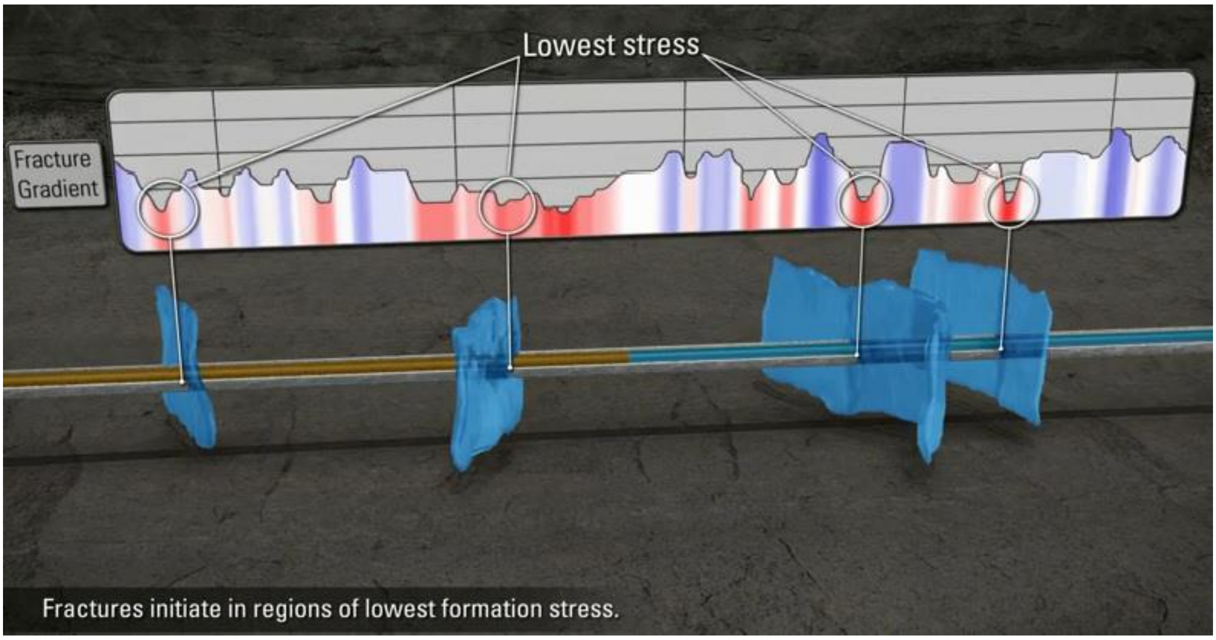

Figure 6-2: Fractures tends to initiate in regions with the lowest formation stress, referred to as low fracturing gradients (Schlumberger, 2015)

Reorientation of Fractures

Reorientation of fractures is another way of increasing the fracture geometry under refracturing operations. Reorientation occurs because of stress changes around the initial fractures, which are a result of depletion of hydrocarbons in the source rock. The production, after placement of the initial fractures, will cause a local redistribution of pore pressure in an expanding elliptical region around the wellbore and initial fracture, see Figure 6-3. The pore pressure depletion, changes the stress distribution in the reservoir which will affect the direction of new fractures (Siebrits E. , et al., 1998). Induced fractures tend to propagate in the direction of the maximum compressional stress, as this orientation allow them to open (generate width) against the smallest principal stress, Figure 6-3. The tendency of fractures to grow toward high stress (to avoid opening against high stress) may induce hydraulic treatments to become "reserve seeking missiles" as they may reorient toward higher stress, undrained regions of the reservoir (Vincent M. C., 2010).

New fractures can orient at 90 degree to an initial fracture under certain conditions. In such cases, the new fractures can penetrate untapped sections of the reservoir, significantly increasing production rate and reserves (Siebrits, Elbel, & Hoover, 2000). Wells with an effective initial hydraulic treatment can therefore also be refractured to create new fractures that propagate along a different direction than the original fracture. In these cases, refracturing significantly improves SRV and well production. (Dozier, et al., 2003)

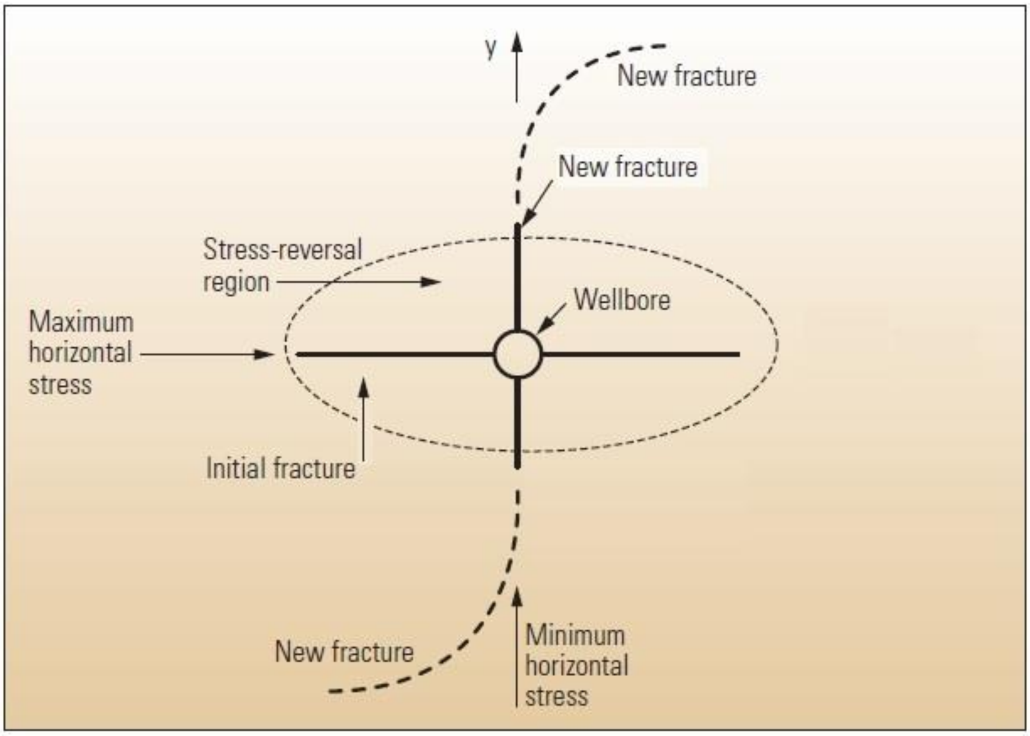

Figure 6-3: Illustrates fracture re-orientation. The horizontal line is the initial fracture orientation, and the stress reversal region makes the new fracturing orient in a different plane, because fractures tends to propagate in the direction of the maximum compressional stress (Dozier, et al., 2003)

Improved Pay Coverage

Dozier et al. (2003) estimated that 20 percent of all wells drilled in the U.S, equal to 40 000 wells, were potential refracturing candidates in 2003 due to initial poor fracture design and bypassed pay. Pay coverage can be explained as the efficiently utilized part of the lateral. That does not necessarily mean that the entire lateral should be perforated, but where there is potential of hydrocarbon materials. In the past there was no good way of predicting where those hydrocarbons were, which led to an undesirable fracturing design. Operators used standard stage length designs of roughly 300-500 ft. until around 2010 (Ingram, Lahman, & Persac, 2014). The source rock between the old perforation clusters is unstimulated if the stage spacing is too long. If there is hydrocarbon material in the formation the stage spacing should be closer, where todays practice is about 50 ft. in between perforation clusters (Ingram, Lahman, & Persac, 2014). The old practice have contributed to bypassed pay and not efficiently utilized zones in quite many wells. Today, there are technology that could be used to achieve a better picture of where those hydrocarbons are trapped, which gives an opportunity of going back and re-perforate those portions of the lateral with new and improved techniques and designs. Thereby it might be huge potentials of increased pay coverage in many existing wells. However, it is not just the initial design that may be improved. In BP's refracturing pilot project they were really focused on improving their initial pay coverage. They confirmed the potential of three distinct opportunities for refracturing application, namely:

1) Understimulated initial stages that may have left several adjacent clusters unfractured,
2) Understimulated areas due to inappropriate original cluster and stage spacing,
3) Understimulated sections in the heel

(French, Rodgerson, Feik, & BP America Production Company, 2014)

This is closely linked to some of the other success criteria as well. But it shows that there is opportunity of increased pay coverage in initial fractures, in between clusters and stages, and in the heel of some existing wells. Quite many of the wells that are being completed today also experience understimulated stages or clusters. Stages can be understimulated because of technical or mechanical problems, but even without any problems there are experienced understimulated clusters. This is mainly due to technical constraints with the completion techniques being used, were the techniques don't divert the fracturing fluid into every cluster as preferred. It is not unlikely to experience 40 percent understimulated clusters when having stages with around five clusters. (French, Rodgerson, Feik, & BP America Production Company, 2014). For that reason it might be economical to go back and refracture those clusters.

Stress Shadowing

Stress shadowing is also one important factor to be aware of when trying to increase the pay coverage. Stress shadowing occurs when fracturing adjacent stages. After fracturing a few stages the stress field in the adjacent stages might be too extensive to grow any substantial width. However it might grow in length past the extensive stress field, and from there grow in width, see stage 4, 5 and 11 in Figure 6-4. The adjacent stages with thin fractures near the well might close easily and not contribute much to the production. For that reason, refracturing might increase the pay coverage in cases where stress shadowing has occurred under initial treatment. This because of stress alteration in the formation.

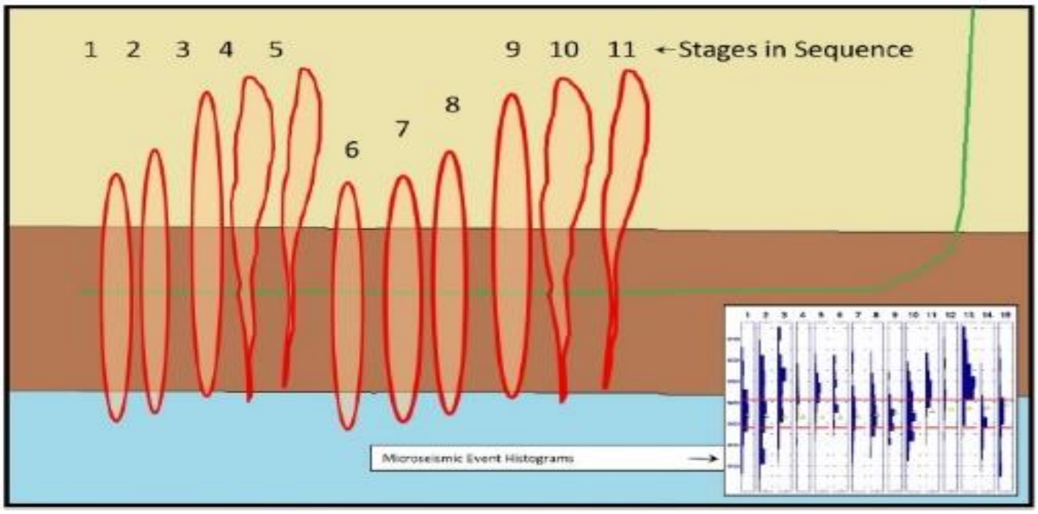

Figure 6-4: Illustration of the stress shadowing effect in fractures 4,5,10 and 11 (thin fractures close to the wellbore), experienced in initial treatment (Dohem, Zhang, & Blangy, 2014)

Fracture Conductivity and Proppant

The fracture conductivity is a measure of how easy oil or gas flow through the fractures. It is the product of propped fracture width and the permeability of the proppant. Proppant are as explained in chapter 5, particles like sand used to keep the fracture open once the pumps are shut down and the fractures begin to close, see Figure 6-5. However, the conductivity of the fracture will be reduced during the life of the well because of proppant degradation which is a result of stress corrosion affecting the proppant strength, and embedment into the formation (Petrowiki). If an original hydraulic fracturing treatment was inadequate or an existing proppant pack becomes damaged or deteriorates over time, fracturing the well again could reestablish linear flow into the wellbore. Vincent (2010), presents several examples of success in restoring conductivity to fractures that were damaged due to proppant embedment, degradation, and other phenomenon that result in compaction and/or loss of permeability within the proppant pack. Dozier et al. (2003) argued that refracturing can generate higher conductivity to propped fractures that may penetrate deeper into a formation than the initial treatment. Some have also looked at the correlation between the amount of proppant placed and production. Coulter (2004), have shown a slight correlation between total amount of sand and production, where the wells with the most sand had a tendency of higher production (Coulter, Benton, & Thomson, 2004). However, the correlation may have been affected by other parameters like number of stages and clusters, which will normally give higher amount of placed sand.

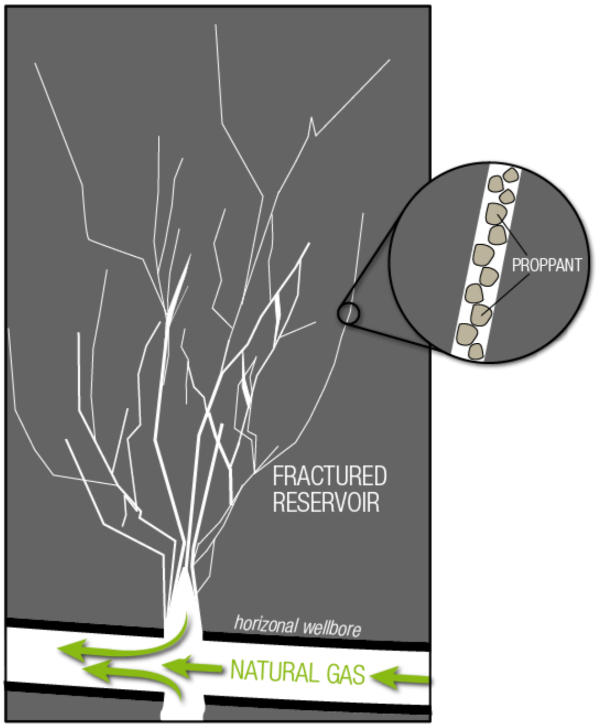

Figure 6-5: Illustration show that proppant holds fractures open to allow natural gas and oil to flow from the fracture network to the wellbore (Zuppann & Steinmetz, 2015)

6.2 Data Presentation from Public Refracturing Case Studies

The first part of this chapter presents our gathered public refracturing case studies done on horizontal wells in the U.S. The cases gathered includes production increase and which completion technique that is used. The costs of refracturing operations are rarely published, and the few costs included in the public papers are too inadequate to be used in the analysis. For that reason the costs of refracturing are gathered from the interview respondents, see chapter 7. The costs gathered through literature study will only be used to validate the costs gathered from the respondents. Risks associated with refracturing are also excluded in some public papers. However, there will be a presentation of the published experienced failures at the end of this chapter.

6.2.1 Production Increase and Techniques

There are a significant amount of case studies done on refracturing, however the majority of these are done on vertical wells and will not be included in the quantitative data collection. Identification of existing refractured wells from public data is a difficult task, primarily because of poor record keeping. There are however a few published SPE papers on refracturing operations which include production increase and which refracturing techniques that are used. One of the most recent published papers on refracturing by SPE and Baker Hughes with Ourganti et al. (2015) are included, but does not include which techniques that have been used. This data cannot be used in an evaluation of the different refracturing completion techniques, but will give good indications on the general potential of refracturing. A short introduction to the papers will be presented first, followed by a summary of the experienced production increase.

Devon Energy Corp. with Mark Craig et al. (2012)

This case study reviews performance and cost of thirteen horizontal refracturing operations of gas wells in the Barnett Shale, from 2008- 2012. Devon Energy targeted older wells with long distances between the perforation clusters (~400-450 ft.). There were used different refracturing techniques, of which the most common technique was bull-head diversion. In some of the wells new perforations were added in between the old clusters.

Tom Lantz et al. (2007)

Lantz et el. (2007) refractured 17 oil wells which were all recompleted with the use of Bull-head diversion technique. Perforations were added in an attempt to increase the wellbore contact with the shale formation. The original perforation design was reduced from around 700 ft. between stages to 300 ft. or less. High-concentration proppant slugs were used as diversion agents, in an attempt to divert the treatment into new sections along the lateral, ref chapter 4. (Lantz, Greene, Eberhard, Norrid, & Pershall, 2007)

British Petroleum, with Sam French et al. (2014)

This paper presents the planning, execution and results of a five well refracturing pilot program in the Woodford Shale. They identified the five best well candidates amongst their refracturing candidates. Under the process selection multiple refracturing techniques was evaluated, however they argued that the best way to refracture these wells were to add new perforations in the previously bypassed pay, and then use the bull-head diversion techniuqe. (French, Rodgerson, Feik, & BP America Production Company, 2014)

Baker Hughes with Ourganti et al. (2015)

In this paper there is done a study of existing refractured wells in the Eagle Ford and Bakken formations. The wells were identified by going through public data with use of an algorithm that selected wells which have been refractured. All of the identified wells from the Bakken shale were oil wells. 21 wells were identified in the Eagle Ford, of which 16 were oil wells and five were gas wells. Yet, there were no descriptions of the initial completion or refracturing designs, making it difficult to use this information in the evaluation of the different refracturing completion techniques. However, the production increase can be used in a general evaluation of the economical potential of refracturing. (Oruganti, Mittal, McBurney, & Rodrigues, 2015)

6.2.2 Production Matrix

Table 6-2 and Table 6-3, summaries the data collection from the previously mentioned papers. The data collection is sorted by the use of completion techniques to get a better view of how each technique is performing. However, there are some techniques that has not been used or just used in a few cases in the public case studies. The none-mechanical techniques are the most frequently used techniques used by the industry so far, which in most cases are because of the low cost, low risk and short refracturing operation period. There is important to mention that this is just a collection of public data, while there are several projects done by the industry which are confidential at this time.

As it can be seen from the tables below there are different ways of showing the production increase. Every paper shows to different parameters which makes it difficult to see the trends. Some papers presents increase in EUR while others presents the increase is daily production, ref. “Delta EUR (Bcf)” and “Delta (Mscf/d)” respectively . The column “% increase, Mscf/d” shows the difference in 30 days average production pre- and post- refracturing operation. Where the cells are empty there are no available data at this time.

Gas Wells

Table 6-2: Data collection from literature study - Gas wells

Bull-head Diversion - Refracturing			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
-	-	1.3	1.2
-	-	1.0	1.2
-	-	0.9	1.0
-	-	0.8	0.8
-	-	0.4	0.7
-	-	0.4	0.8
-	-	***0.80***	***0.95***

Unknown Technique			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
1042	600 %	0.10	-
2326	712 %	0.69	-
2672	542 %	-0.07	-
757	271 %	-0.80	-
2883	1796 %	0.40	-
1936	***784 %***	***0.06***	-

Bull-head Diversion Recompletion			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
-	-	0.6	1.1
540	98 %	2.6	-
750	114 %	3.7	-
800	900 %	-	-
550	68 %	-	-
660	***295 %***	***2.30***	***1.10***

Cemented Squeeze - Recompletion			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
-	-	3.2	0.8
-	-	1.0	0.6
-	-	0.6	0.4
-	-	0.5	0.7
-	-	***1.33***	***0.63***

Pump and Pray - Refracturing			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
-	-	0.5	0.5
-	-	***0.50***	***0.50***

Expandable Liner - Recompletion			
Delta (Mscf/d)	**% increase, Mscf/d**	**Delta EUR (Bcf)**	**Cost, MM$**
-	-	-0.4	1.5
-	-	***-0.40***	***1.50***

<u>Oil Wells</u>

Table 6-3: Data collection from literature study - Oil wells

Bull-head Recompletion			
Delta bopd	% increase, bopd	Delta EUR, Mbbl	EUR ratio
79.0	188 %	26.1	-
92.0	214 %	60.9	-
89.0	144 %	191.9	-
75.0	114 %	139.4	-
105.4	197 %	68.4	-
147.5	372 %	147.0	-
79.0	282 %	79.0	-
121.0	324 %	95.3	-
113.2	250 %	119.3	-
109.1	287 %	77.2	-
58.2	149 %	37.2	-
172.0	449 %	71.0	-
166.2	342 %	45.3	-
97.4	235 %	77.2	-
158.9	434 %	95.1	-
110.9	**265 %**	**88.7**	**-**

Unknown Technique			
Delta bopd	% increase, bopd	Delta EUR, Mbbl	EUR ratio
484	421 %	56	1.38
415	483 %	97	1.65
233	388 %	76	1.75
406	483 %	72	1.51
332	342 %	49	1.21
20	154 %	4	1.13
290	644 %	240	2.85
121	367 %	21	1.21
464	418 %	310	2.07
432	508 %	51	1.21
755	1987 %	42	1.33
342	372 %	275	1.75
248	590 %	18	1.11
282	1880 %	54	1.63
143	841 %	84	1.75
128	138 %	166	1.62
223	769 %	304	2.85
321	1605 %	60	1.61
115	442 %	64	1.44
157	424 %	150	1.87
52	289 %	23	1.27
176	191 %	60	1.17
244	436 %	41	1.16
285	279 %	59	1.16
50	278 %	37	1.37
113	452 %	74	1.73
120	414 %	44	1.32
111	336 %	110	1.62
187	603 %	117	1.65
180	1000 %	80	1.70
27	245 %	6	1.08
83	268 %	81	1.37
78	211 %	109	1.38
343	1225 %	359	2.95
646	1576 %	246	1.86
683	1453 %	158	1.45
203	781 %	253	2.72
351	1132 %	360	2.51
259.0	**643 %**	**116.1**	**1.6**

Table 6-4 presents a more detailed data collection of the oil wells with no specified technique presented above. The table presents the original initial production (IP), pre-refracturing IP and post-refracturing IP, which gives a picture on the production increase experienced post-refracturing. The IP ratio is the ratio between the original IP and the post-refracturing IP, while the EUR ratio is calculated based on the new decline factors post-refracturing. Further analysis of the data collection will be presented in Chapter 0.

Table 6-4: A more comprehensive data collection - Oil wells

	Production Increase					Decline Factors	
Well	**Original IP (bopd)**	**Pre-refracturing IP (bopd)**	**Post-refracturing IP (bopd)**	**IP Ratio**	**EUR Ratio**	**(b) Factor Ratio**	**(D) Factor Ratio**
1	657	115	599	0.91	1.38	1.00	1.00
2	940	86	501	0.53	1.65	1.00	0.89
3	479	60	293	0.61	1.75	1.00	0.85
4	711	84	490	0.69	1.51	1.00	0.94
5	641	97	429	0.67	1.21	1.15	0.95
6	43	13	33	0.77	1.13	1.07	0.98
7	579	45	335	0.58	2.85	1.86	0.75
8	342	33	154	0.45	1.21	1.00	0.88
9	822	111	575	0.70	2.07	1.00	0.74
10	598	85	517	0.86	1.21	1.50	1.10
11	769	38	793	1.03	1.33	1.00	1.04
12	1040	92	434	0.42	1.75	1.00	0.65
13	276	42	290	1.05	1.11	1.00	1.20
14	331	15	297	0.90	1.63	1.00	1.02
15	290	17	160	0.55	1.75	1.00	0.77
16	201	93	221	1.10	1.62	1.00	0.80
17	275	29	252	0.92	2.85	1.00	0.61
18	160	20	341	2.13	1.61	1.00	1.11
19	262	26	141	0.54	1.44	1.13	0.82
20	233	37	194	0.83	1.87	0.88	0.70
21	211	18	70	0.33	1.27	1.00	0.73
22	497	92	268	0.54	1.17	1.36	0.91
23	577	56	300	0.52	1.16	1.22	0.98
24	677	102	387	0.57	1.16	1.00	0.90
25	179	18	68	0.38	1.37	1.08	0.67
26	171	25	138	0.81	1.73	1.00	0.80
27	133	29	149	1.12	1.32	0.83	1.03
28	365	33	144	0.39	1.62	1.00	0.64
29	361	31	218	0.60	1.65	1.08	0.79
30	176	18	198	1.13	1.70	1.00	0.97
31	177	11	38	0.21	1.08	1.42	0.77

32	324	31	114	0.35	1.37	1.00	0.59
33	377	37	115	0.31	1.38	1.50	0.57
34	447	28	371	0.83	2.95	0.80	0.61
35	217	41	687	3.17	1.86	1.00	1.56
36	349	47	730	2.09	1.45	0.67	1.21
37	227	26	229	1.01	2.72	1.25	0.79
38	300	31	382	1.27	2.51	1.15	0.81

(Oruganti, Mittal, McBurney, & Rodrigues, 2015)

6.2.3 Experienced Refracturing Failures

In this thesis mechanical problem and none mechanical problems under refracturing operations will be referred to as failure mechanisms. The most frequent failure mechanisms disclosed from the literature study are failure of mechanical integrity tests (MIT), tools getting stuck downhole, Equipment erosion or malfunction, and screen-outs, see Table 6-5. These failure mechanisms are further described in appendix C. Some papers have not disclosed what the failure mechanisms have been, and will be referred to as other mechanical problems. As mentioned earlier, an extended data collection of cost and risk will be presented in the interview findings, subchapter 7.3.

Table 6-5: Failure mechanisms found in the literature studies

Failure Mechanisms	Experience from public case studies
MIT	British Petroleum, with Sam French et al. (2014) ○ Reported that 3 out of 5 wells failed the MIT. Causes was mainly leakage from poor integrity of the wells.
Stuck	British Petroleum, with Sam French et al. (2014) ○ Reported that the CT was stuck for six days in one of the wells.
Equipment erosion and malfunction	British Petroleum, with Sam French et al. (2014) ○ Reported that a bridge-plug came apart, resulting in several days of "fishing" operation. ○ Reported that the ball gun misfired in one well, which might have resulted the high treating pressure that caused 40% of the lateral to be understimulated. ○ Reported that one of the packers in the sliding sleeve had a leakage, resulting in total failure.
Screen-out	British Petroleum, with Sam French et al. (2014) ○ Reported that three wells experienced screen-out. Tom Lantz et al. (2007) ○ Reported that one well screened out.
Other mechanical problems	British Petroleum, with Sam French et al. (2014) ○ Reported one minor mechanical problem. Tom Lantz et al. (2007) ○ Reported two mechanical problems, one of which resulted in no production (total failure). Devon Energy Corp. with Mark Craig et al. (2012) ○ Reported one mechanical problem that resulted in total failure.

Baker Hughes with Ourganti et al. (2015) did not report any mechanical problems because they don't have any information on the refracturing operations. As seen in Table 6-5, Devon Energy Corp. with Mark Craig et al. (2012) reported only mechanical problems resulting in total failure, however the two other papers reported both major and minor mechanical problems.

6.3 Validity and Reliability of the Literature Study

As explained in the methodology, ref. subchapter 2.3.1, it is important to evaluate the validity of the data throughout the literature study. The petroleum industry tends to publish success stories more frequently than it discloses failures. This leads to enriched literature with success stories with less representation of failures. As a result the data may not represent the full spectrum of outcomes and the correct proportions of success- or failure rate. Regardless, we believe that this issue doesn't affect the validity of the data presented in this chapter.

7 Interview Findings

In the qualitative interviews we aimed to gather as much information as possible to be able to answer the research questions and to construct the profit calculation tool. See appendix A for the interview guide and appendix B for the list of the interview respondents.

The first subchapter will present the findings associated with answering the first research question, what is the magnitude of the refracturing market. The second subchapter will present the techniques the respondents are familiar with and their opinions of the different techniques. Finally cost-, and risk data estimated by the respondents will be presented. This quantitative data is used in the economical evaluation and numerical analysis, and is also the foundation in the profit calculation tool presented in chapter 8 and 9. The data presented in the next subchapter are extracts from the transcribed interviews stored in our research database.

7.1 The Potential of Refracturing

Refracturing in horizontal wells is a relatively new concept which needs to be investigated to be able to fully understand the magnitude of the new arising refracturing market. To investigate this matter, we asked the respondents the following three questions:

1) What do you think is the potential of refracturing?
2) Which criteria do you evaluate when you consider wells suitable for refracturing?
3) How many wells are candidates for refracturing, in your opinion?

We have summarized the findings from the interviews below. The findings presented are validated by the respondents after the interview process.

1) What do you think is the potential of refracturing?

In general the respondents were optimistic toward refracturing. The companies that have done refracturing operations are actively promoting it, while the companies which have no experience with refracturing are more skeptical. However, everyone seems curious about the potential. In the following table our most important findings from the first question are summarized.

Table 7-1: Interview findings about the potential of refracturing

Opinions	Explanation
The industry is guardedly optimistic	Refracturing is mostly done on underperforming wells, and not on the best performing wells due to the high risk of losing a productive well. In several cases people tend to choose the low hanging fruits, even though they know the potential is higher in better performing wells.
Refracturing is economical successful	Operators have experienced up to 90% success rate, and they argue to make money every time. It has been experienced significant production increase post-refracturing.
Easier to achieve a higher success rate	Because of the available information, well selection is easier. 1/3 of the wells that's being drilled have shown not to be economical, likely because of poor reservoir quality.
There is still a lot of recoverable reserves in the wells	The success from refracturing show that the decline is not because of depletion, but they run out of flow area, hence conductivity loss. Production logs also show that not all the stages and clusters produce, something that can be optimized by refracturing.

Low oil and gas price promotes refracturing	Refracturing has an investment cost of about 10-30% of the investment cost needed to drill a new well, which makes it a low cost alternative to increase or keep up the production.

2) Which criteria do you evaluate when you consider wells suitable for refracturing?

A problem with drilling a new well is the lack of reservoir quality information before drilling. Some quality tests are taken, but the tests just reveal indications and you can never be sure of the ultimate quality. The respondents emphasized that a significant advantage of doing refracturing is the fact that you know the initial reservoir quality and have a lot more information about the well, making it easier to do calculated decisions, and improve pay. In Table 7-2 we present the respondents evaluations when selecting candidates.

Table 7-2: Well selection criteria emphasized by the respondents

Selection criteria	Explanation
Bypassed pay	There is evidence of unexploited pay and reservoirs not being depleted in past fractured wells.
Underperforming wells	Some wells that are underperforming in comparison to other wells in the reservoir. This includes bad initial fractured wells. Some respondents indicate the huge potential in these wells.
Reservoir quality	Wells within poor reservoir quality zones will not be profitable to refracture.
New technology	The opportunity to increase the declined production and add more pay with new technology, compared to the technology initially used.
Initial high performing wells	The production experienced post-refracturing has shown that the decline in most cases is not because of depletion, but the fact of reduced flow area, hence conductivity loss. The respondents emphasize the connection to proppant degradation.

3) How many wells are candidates for refracturing, in your opinion?

There seems to be no common understanding of the refracturing market today. The respondents argue that 10-60 percent of today's wells are refracturing candidates, even though the majority of the respondents are evaluating some of the same selection criteria. There is a uniform understanding that not every well is a candidate.

7.2 Experience with Refracturing Completion Techniques

One of the main purposes of our qualitative interviews was to identify which refracturing completion techniques that were most commonly used by the industry, and the reasons why the industry chose to use those techniques. The techniques' advantages and disadvantages identified by the respondents are summarized in Table 7-3. The respondents also answered if they had knowledge of any documented use of the different techniques.

Table 7-3: Advantages and disadvantages of refracturing completion techniques, interview findings

Technique	Advantages	Disadvantages	Been used?
Coiled tubing – Straddle packer	1. Use of wellbore in current state. 2. Isolation of individually access points 3. Control of which access points are treated	1. High cost and risk 2. Equipment erosion and malfunction 3. Operationally complex 4. Highest risk of getting stuck. 5. Time consuming 6. Lower treatment rates	No
Sliding sleeve – inner string	1. Fast completion 2. Control of which access points are treated	1. Reduced treating pressure because of lower ID 2. High stage/cluster spacing because of lower ID 3. High cost and risk	Few times
Cemented - insert liner	1. Create opportunities to replicate the original completion conditions 2. Allows for the use of original completion technology 3. The cement might not damage the perforation as much as others think, at least not in low producing wells.	1. Costly and time consuming 2. Complex operation 3. Limits additional refracturing possibility 4. The cement might damage the perforations. 5. Reduced ID 6. Debris from cement	Several times
Cemented - Squeeze	1. No reduced ID 2. Cement might not damage the perforations as much as other think.	1. Same cement problem as cemented liner. 2. High risk with mechanical tools downhole (debris) 3. Time consuming 4. Need multiple runs with CT	Few times
Expandable liner	1. Create opportunities to replicate the original completion conditions 2. Possible to use new technology with no cement issues.	1. High cost 2. Not reliable enough	One time
Pump and pray	1. Lowest cost 2. Allows continuous pumping 3. Fast completion 4. Lowest risk	1. Lack control of the sequences in which access points are treated. 2. Do not treat all cluster efficiently 3. Lowest technical success profile	Many times
Bull-head diversion	1. Low cost 2. Low risk 3. Allows continuous pumping 4. Fast completion 5. Slugs work as diversion, and is something you want downhole anyway.	1. Lack control of the sequences in which access points are treated 2. Do not treat all clusters efficiently 3. Insufficient sealing and diversion 4. Balls can move off perforation when the pumping stops	Many times
Comitt Well Solutions' technique	1. Use of wellbore in current state. 2. Isolation of individually access points and control of which access points are treated 3. Possibilities to refracture multiple times 4. Fast completion 5. Can treat stages in different order to limit the stress shadowing effect	1. High cost 2. Equipment erosion and malfunction 3. Operationally complex 4. Risk of getting stuck	Not yet commercialized

It is important for the reader to understand that the results presented in Table 7-3 is based on the interviews, and does not represent a complete evaluation of the techniques. We will later present a comprehensive technical evaluation where these results will be used along with other technical theory, see subchapter 9.2. The respondents emphasized that there were no techniques that "fits all wells". Every shale play and every well is unique, for that reason some techniques might be great in one well, and poor in another. However, these results show the strong and weak sides of the techniques commonly experienced by the industry.

At the end of each interview we asked the respondents what they thought were missing in today's technology and what they thought would be the best technical solution. The majority of our respondents answered that mechanical isolation was likely to be the best solution. However, the cost and risk associated with those techniques needs to be economically competitive. Some respondents even mentioned single point entry and isolation of clusters to be the technology they would like to see in today's market.

The best solution would be a technique able to achieve mechanical isolation with a low cost where cluster isolation and high treating pressure is possible. (Respondent, David Cramer, Conoco Phillips)

7.3 Refracturing Cost and Risk

Cost and failure mechanisms have a tendency of not being published in the public literature, for that reason it was necessary to obtain this data from other sources. The data presented in the following section were obtained by email after the interviews by the respondents. It is important for the reader to understand that this data is based on calculated estimations done by the respondents and will vary in magnitude between different wells and shale formations. The total collection of data is processed and sent to the respondents for a total validation. The data collections give an indication on what the costs of a refracturing project might be, which is necessary to evaluate the economical performance of the refracturing techniques. Cost of operation will be presented followed by the risk.

7.3.1 Cost of Operation

Identification of exact costs of a refracturing operation is a particularly troublesome task, primarily because of the different characteristics in each well and shale formation. U.S. service companies operate with different prices and are prohibited of giving away exact numbers by a strict confidentiality policy. However, calculated estimations have been made to represent cost of operation for each technique evaluated in this thesis. The cost calculations are presented as unit cost, and the cost parameters have been generalized into five categories to make it easy for the companies to adjust the numbers later. By doing this we will be able to indicate the cost of operation for each technique, even for quite different wells. However, it is important for the reader to understand that these costs are for comparison purposes only, and will not reflect the true cost of a refracturing operation.

A general explanation of the cost categories will be presented in Table 7-4, while a comprehensive explanation of each technique's category and pricing can be seen in appendix D. Table 7-5 and Table 7-6 shows the unit costs for each technique.

Table 7-4: Explanation of the cost categories in a refracturing operation used in this thesis

Category	Explanation
Downhole equipment	○ Cost of equipment, liners, tools, rentals, cement etc. ○ Cost of milling out plugs and cement (relevant only for a few techniques). ○ Cost of diversion balls
New perforations	○ Cost of perforation runs with CT ○ Cost of plug and perforation (P&P) techniques with CT
Crew	○ Cost of crew (dependent on complexity of operation)
Workover rig	○ Cost of rig, including install run and clean out run.
Fluid	○ Cost of (Ottawa) sand, included transportation and delivery charge.

Table 7-5: Cost of operation as unit cost for mechanical technique, interview findings

Technique	Category	Annotation	Unit cost
Coiled Tubing - Straddle Packer	Downhole Equipment	$/stage	$ 20 000
	New perforations	$/stage	$ 35 000
	Crew	$/stage	$ 60 000
	Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0.10

Technique	Category	Annotation	Unit cost
Sliding Sleeve - Inner string	Downhole Equipment	$/stage	$ 18 000
		$/well	$ 15 000
	New perforations	$/stage	$ 35 000
	Crew	$/stage	$ 60 000
	Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0.10

Technique	Category	Annotation	Unit cost
Cemented liner	Downhole Equipment	$/ft.	$ 50
		$/ft.	$ 5
	Milling	Day rate	$ 50 000
	New perforations	$/stage	$ 40 000
	Crew	$/stage	$100 000
	Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0.10

Technique	Category	Annotation	Unit cost
Cemented squeeze	Downhole Equipment	$/ft.	$ 25
	Milling	Day rate	$ 50 000
	New perforations	$/stage	$ 40 000
	Crew	$/stage	$ 100 000
	Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0,10

Technique	Category	Annotation	Unit cost
Expandable liner	Downhole Equipment	$/ft.	$ 100
	Milling	Day rate	$ 50 000
	New perforations	$/stage	$ 40 000
	Crew	$/stage	$125 000
	Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0.10

Table 7-6: Cost of operation as unit cost for none-mechanical technique, interview findings

Technique	Category	Annotation	Unit cost	Technique	Category	Annotation	Unit cost
Pump and Pray	Downhole Equipment	$/stage	$ -	**Bull-head diversion**	Downhole Equipment	$/ball	$ 50
	New perforations	$/stage	$ 35 000		New perforations	$/stage	$ 35 000
	Crew	$/stage	$ 25 000		Crew	$/stage	$ 50 000
	Work over rig	Day rate	$ 50 000		Work over rig	Day rate	$ 50 000
	Fluid	$/lb	$ 0.10		Fluid	$/lb	$ 0.10

The cost of Comitt Well Solutions' technique is at this time a fixed cost of $ 1 500 000 for refracturing, and $ 2 500 000 for recompletion, this may however change after the technique is commercialized. (Moen, 2015)

7.3.2 Cost of Risk

Failure mechanisms identified by the literature study is inadequate. For that reason it is necessary to complement with experience form the respondents. To identify the failure mechanisms there were done a HAZOP assessment under each interview, see appendix E for the HAZOP assessment. A summary of the identified failure mechanisms are presented in Table 7-7. The HAZOP identified all failure mechanisms identified in the literature study, in addition to a few new failure mechanisms. The cost related to each failure mechanism is highly uncertain, because the cost will be dependent on so many different factors in each project. However, there was discussed both probability and cost for each failure mechanism, which resulted in the probability- and cost estimates seen in Table 7-7. The probabilities reflect the chance of occurrence per refracturing operation, hence the possibility of a failure mechanism occurring in one well.

There will always be a chance of getting stuck when using mechanical tools downhole. However, the probability and cost will vary depending on the tool, complexity of the operation, and the integrity of the well. Even the techniques classified as none-mechanical uses mechanical tools when adding perforations, and are for that reason given a risk factor. Equipment erosion and malfunction are also one of the most frequent failure mechanisms when fracturing. Some techniques are more complex than others, and will for that reason have a higher probability and higher cost variations. Some techniques use multiple tools under a refracturing operation, and some might have to do multiple runs downhole while others just need a few runs to complete the operation. This will clearly affect the probabilities and the costs associated with the failure mechanisms. Screen-out is basically not connected to which technique being used, however some techniques makes it easier to clean-out than others, which will affect the total cost of screen-outs. A more comprehensive explanation of each technique's specific failure mechanisms can be found in appendix C.

Table 7-7: Cost of failure mechanisms based on recompletion operation, interview findings

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Coiled Tubing - Straddle packer	Stuck	0-10%	$ 0 - 2 000 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 1 500 000
	Screen-out	10 %	$ 10 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Sliding sleeve - Inner sting	Stuck	0-10%	$ 0 - 2 000 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 2 000 000
	Screen-out	10 %	$ 100 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Cemented - Insert liner	Stuck	0-10%	$ 0 - 1 500 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 1 500 000
	Screen-out	10 %	$ 100 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Cemented - Squeeze	Stuck	0-10%	$ 0 - 1 000 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 2 000 000
	Screen-out	10 %	$ 100 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Expandable liner	Stuck	0-10%	$ 0 - 1 500 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 2 000 000
	Screen-out	10 %	$ 100 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Comitt Well Solution	Stuck	0-10%	$ 0 - 2 000 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 2 500 000
	Screen-out	10 %	$ 10 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Pump and Pray	Stuck	0-10%	$ 0 - 750 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 750 000
	Screen-out	10 %	$ 100 000

Technique	Failure mechanisms	Probability	Cost variations Re-Completion
Bull-head diversion	Stuck	0-10%	$ 0 - 750 000
	Equipment Erosion and Malfunction	0-25%	$ 0 - 750 000
	Screen-out	10 %	$ 100 000

8 Analysis Model Building

The purpose of this chapter is to present the structure and our way of doing the analyses, to give the reader a better understanding of how we have constructed our analysis. Firstly we will present a general overview where we describe the connections between the data collection, analysis and conclusion. Then we will look more comprehensively into the different parts of the analysis.

8.1 General Overview

The analysis aims to answer the two research questions raised in this thesis;

1) What is the potential magnitude of the refracturing market?
2) What is the technical- and economical performance of the refracturing completion techniques?

Figure 8-1 illustrates a general overview of how the analysis is structured and connected. As the figure shows, the evaluation of the magnitude of the refracturing market is based upon the qualitative interviews and the literature study, further described in subchapter 8.2. The technical evaluation of the refracturing techniques is based on the success criteria in the literature study, and the interview findings, described more closely in subchapter 8.3. The economical evaluation and numerical analysis is built upon the quantitative cost-, risk- and production data and trends, presented in the literature study and interview findings. This is described more closely in subchapter 8.4. As mentioned previously, a profit calculation tool was constructed to be able to compare the refracturing techniques. This tool is based and built upon the technical evaluation, and the economical evaluation and numerical analysis, performed in subchapter 9.2 and 9.3. The construction of the tool is further described in subchapter 8.5. The analysis is divided into subchapters with a summary which summarizes our main findings in the end of each subchapter. Finally our main findings and evaluations are discussed in the conclusion.

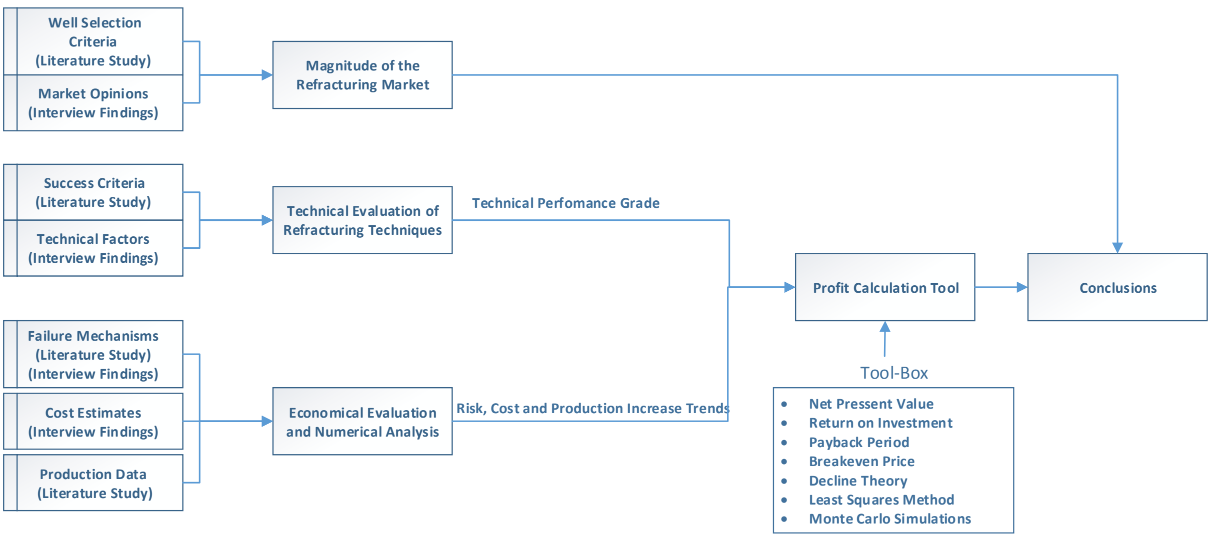

Figure 8-1: Illustrates general overview of how the analysis is structured and connected

8.2 The Magnitude of the Refracturing Market

To evaluate the magnitude of the refracturing market and the benefits of refracturing we use the qualitative interviews and information gained by doing the literature study, as illustrated in Figure 8-2.

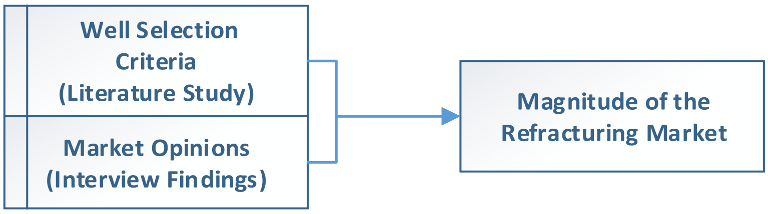

Figure 8-2: Illustrates what the evaluation of the magnitude of the refracturing market is built upon

The most important well selection criteria are identified by comparing the findings in the literature study with what the respondents highlighted as important well selection criteria. Past experience, literature findings and economical trends will be used as a foundation to discuss the magnitude of refracturing market today, and in the future.

8.3 Technical Evaluation of the Refracturing Techniques

Throughout the interviews the respondents were asked to define a technical refracturing success and a technical good refracturing technique. They all agreed that a technical optimal refracturing solution would be able to isolate all clusters and threat the desired clusters with precision and high pressure. Based on the interviews we defined that a technical refracturing success is based on how good and precise the refracturing technique is able to reach the goals and objectives of the refracturing operation. This can be translated into how good the refracturing technique is able to meet the success criteria presented in the literature study, see subchapter 6.1. For that reason we have used the success criteria as a foundation when we technically evaluated and compared the different refracturing techniques, described in subchapter 4.4. The technical discussions that took place in our qualitative interviews are used to supplement the arguments in the evaluation.

Figure 8-3: Illustrates what the technical evaluation is built upon, and the contribution to the profit calculation tool

The success criteria we have used in the technical evaluation are presented in Table 8-1. We have excluded the criterion regarding more suitable fracturing fluids and proppant, based on the fact that every technique is able to use the same fluids and proppant. Fluid and proppant will for that reason not differentiate the techniques. The identified success criteria are processed and presented as four main success criteria, see Table 8-1. A more comprehensive description of the success criteria can be found in our literature study, see subchapter 6.1. Our evaluation is based upon these assumptions:

To get in contact with new pay in a refracturing operation, the technique has to be able to enlarge the fracture geometry, or be able to achieve fracture reorientation. To achieve this, the technique needs to be able to treat the perforations with a high treatment pressure. However, to restore conductivity the technique does not need a high treating pressure, because it does not have to create new fractures, only open the existing ones. There is also possible to get in contact with new pay by making new perforations in areas that was previously not perforated, referred to as recompletion. To initiate new fractures there is usually a need for high treatment pressure. The most important factor in the technical evaluation will for that reason be the technique's capability to treat every perforation with high treating pressure to:

- Increase fracture geometry
- Improve pay coverage
- Restore- and increase conductivity
- Possibly create reorientation of fractures

In the technical evaluation each technique will be evaluated after their ability to meet these success criteria. Each technique will be graded on each success criterion and the final evaluation will be represented in form of a technical performance grade. The grades are given from 1 to 10, where 10 is the best achievement. The technical grade will be the average sum of the grades given to each success criterion, see Table 8-1Figure 8-1 for an example.

Table 8-1: Example of technical evaluation based on success criteria, with a given technical grade

Technical Evaluation with Description	Grade
Enlarged fracture geometry ○ High treating pressure into every perforation is desired ○ Isolation of stages or clusters	5
Improved pay coverage (added perforations) ○ The technique has to be able to divert the fluid and proppant into the whole lateral with a high treating pressure. ○ Isolation of stages or clusters	7
Restoration or increase of fracture conductivity ○ The technique has to be able to treat new and old perforation to restore or increase conductivity.	4
Fracture reorientation due to stress field alternations ○ Dependent on the treating pressure, and access to old fractures	8
Technical grade	**6.0**

Throughout the interviews we identified many different opinions and arguments associated with the performance of each technique. This indicates that the industry's experience and knowledge differs to some extent in certain areas. For that reason we believe that parts of the industry will not agree with our grads. However, based on the discussion we believe that they will understand our arguments, but not necessarily agree with all of them.

The grade is given for two reasons:

1) To clearly summarize our technical discussion
2) To use the technical grad to indicate the expected post-refracturing production

The technical grade excludes the parameters: costs, risks, and future refracturing possibilities. The technical grade will for that reason not provide the reader with the most economical technique. However, the technical grade will reflect the technique's ability to achieve the success criteria. The grade will further be used as an indication on how high production that can be expected post-refracturing, benchmarked to the other techniques in our profit calculation tool.

8.4 Economical Evaluation and Numerical Analysis of the Refracturing Techniques

To do the economical evaluation it was necessary to find the costs of refracturing and the production increase after a refracturing operation. For that reason cost-, risk- and production data was collected through a comprehensive literature study and by interaction with the interview respondents, see chapter 6 and 7. The failure mechanisms used in the risk evaluation is based on a HAZOP assessment conducted with the respondents, and identified failure mechanisms in the literature study. As seen in Figure 8-4, this is the foundation of our economical evaluation and numerical analysis.

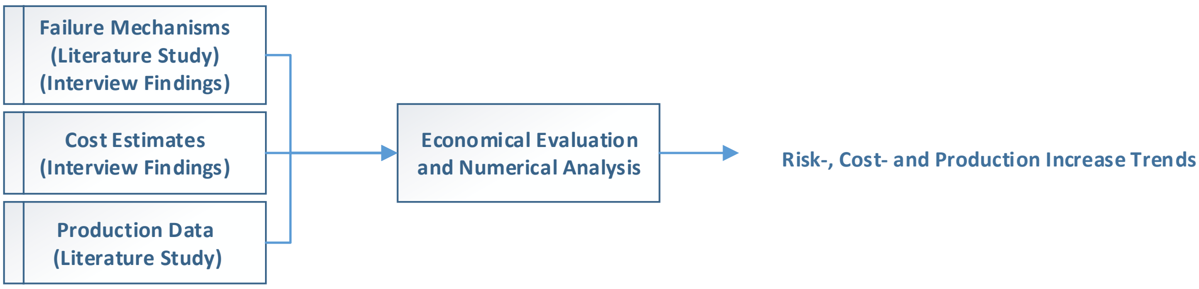

Figure 8-4: Illustrates what the economical evaluation and numerical analysis is built upon, and the contribution to the profit calculation tool

There are three variables that needed to be found to be able to do the economical evaluation:

- Cost of normal operation for each technique
- Cost of stochastic risk for each technique
- Benefit from production increase that can be expected from each technique

In subchapter 9.3 there will first be an analysis of the risk of each technique, which will be used to calculate the total cost of operation, how this is done will be presented below. Further, there will be a numerical analysis of the production increase trends and other production increase related factors as the IP ratios, EUR ratios, and decline ratios. In the numerical analysis we will try to do a statistical generalization of the trends gathered through the public available literature presented in subchapter 6.2.

Cost of Operations

Cost calculation in this thesis will be divided into two categories, cost of refracturing and cost of recompletion. Recompletion includes the cost of adding new perforations, while refracturing is as mentioned in subchapter 4.4 considered as a treatment of existing perforations, and will for that reason not include the cost of new perforations. Because the costs of each technique are based on normal operation without the risk of failures, it was necessary to calculate the risk of each technique to be able to generalize the total cost of operation. For that reason the total cost of operation for each technique will be the sum of the cost of operation and the identified risk of each technique, see equation 8-1.

$$\text{Total cost of operation} = \text{Cost of operation} + \text{Risk} \qquad \text{8-1}$$

Risk Calculation

The identified failure mechanisms had both a huge variation in probabilities and cost estimates, which makes it hard to estimate the risk for each technique. From the interviews we knew that minor failures occur more often than the major failures, and that the costs are related to the consequence. As a result, a major consequence has a high related cost, and a minor consequence has a lower related cost. For that reason we have divided the failure mechanisms into three classifications of consequences, hence minor, moderate and major. Each consequence has a related probability range and a related cost variation, see Table 8-2.

Table 8-2: Illustration of the consequence classification with probability ranges and cost variations

Example			
Failure Mechanism	**Consequence**	**Probability range**	**Cost variations**
Stuck	Minor	5% - 10%	$ 0 -200 000
	Moderate	3% - 7%	$ 200 000 - 800 000
	Major	1% - 2%	$ 800 000 - 2 000 000

All failure mechanisms are the same for each refracturing technique, however each technique has been given an individual and unique probability and cost, based on trends from the literature study and the respondents' experience, see appendix C for complete overview of the consequence, probability range and cost variations. This is done to reflect that the minor and less costly failure mechanisms tend to occur more frequently than the major and more costly failure mechanisms. The risk will be calculated for each consequence as the product of the probability and cost, see equation 8-2, and are further simulated with Monte Carlo simulations by the use of a simulation program called @Risk.

$$\text{Risk} = \text{Probability x Cost} \qquad \text{8-2}$$

We tried to place these failure mechanisms into a traditional risk matrix, to illustrate the risk of each technique. However, the huge variations in probability and cost made it difficult to use a traditional matrix. For that reason we decided to use a logarithmical scale in our risk matrix to illustrate the risk perspective, see Figure 8-5. The logarithmical scale provides a more detailed picture on the risks of each failure mechanism. Yet, it might be easily misinterpreted. The most likely risk is plotted as a small circle in the risk matrix, while the related probability- and cost range are illustrated as a red dotted circle around the average. These risk matrixes provides the reader with an illustration of the risks. However, to be able to use the risk in calculations we are using equation 8-2 in the following analysis. For that reason the risk matrixes can be found in appendix F.

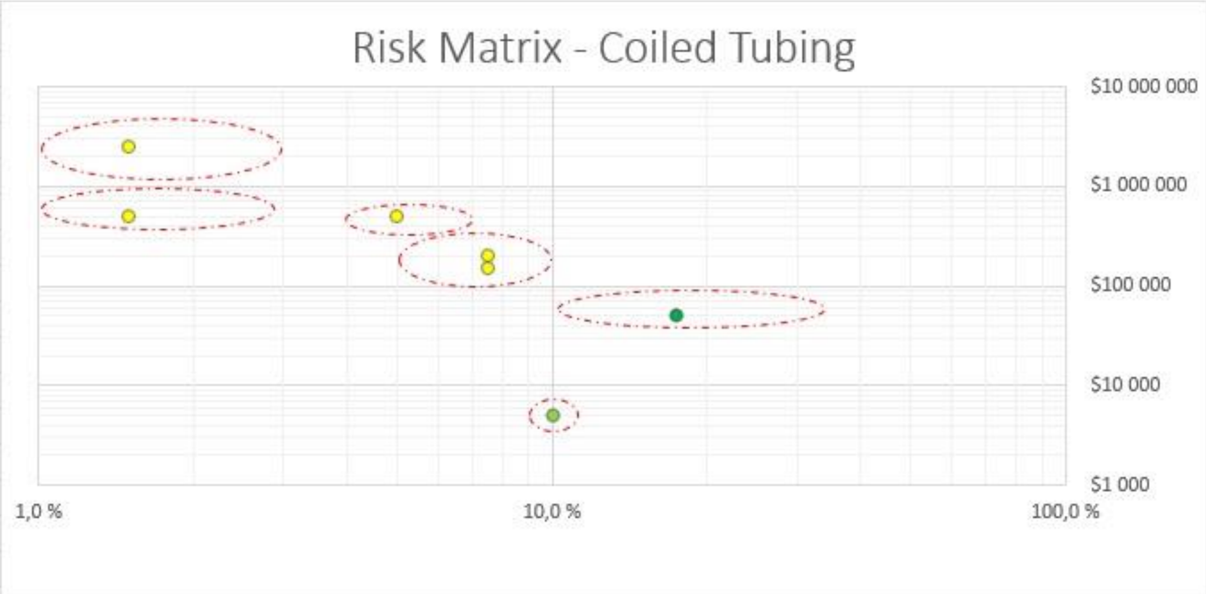

Figure 8-5: Risk matrix, most likely risk illustrated as colored circle, while the red dotted line represents the probability and cost variations.

8.5 Profit Calculation Tool

Confidentiality and lack of refracturing data made us unable to do precise calculations on the profitability of each refracturing technique. As mentioned previously we constructer a profit calculation tool to be able to do a better evaluation of the economics in refracturing. The technical grades from the technical evaluation, and cost, risk and production increase trends from the economical evaluation, are a foundation in the tool. See Figure 8-6.

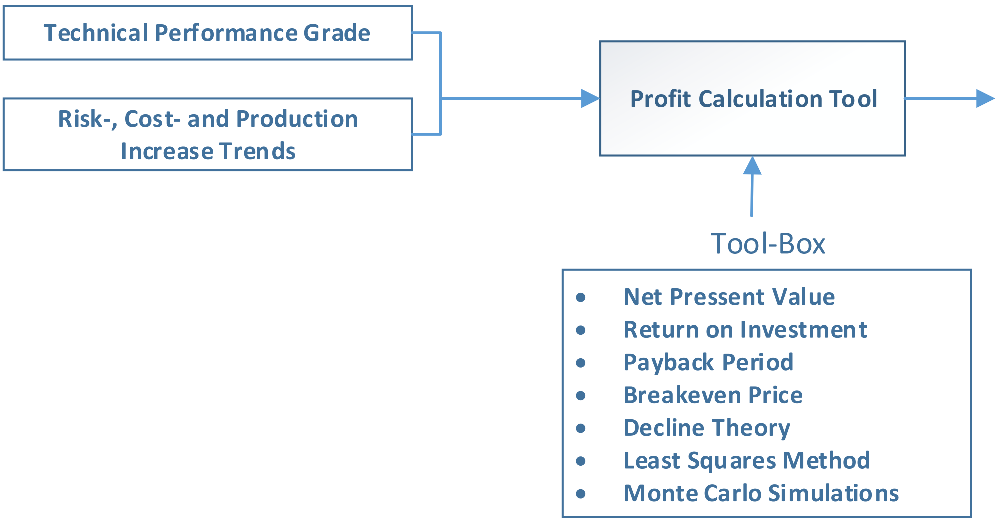

Figure 8-6: Illustrates what data the profit calculation tool is constructed upon

The profit calculation tool is able to compare the economical potential of each refracturing technique. Furthermore, it provides the industry with a tool to calculate the potential profitability of different wells up for refracturing decisions. Although our economical- and technical evaluation is based on qualitative- and quantitative data, the profit calculation tool is solely based on quantitative data gained by the respondents, literature study and estimated in subchapter 9.2 9.3 and 9.4.1.

How Does the Tool Work?

The profit calculation tool is created in Microsoft excel by the use of Microsoft excel programming, and constructed with a high focus on user-friendliness. There is basically one page were you type in input and were the output is displayed, see appendix G. We have also constructed a user manual, attached in appendix H, which explains thoroughly every step needed to use the tool. Figure 8-7 shows how the tool interacts and how it is structured fundamentally.

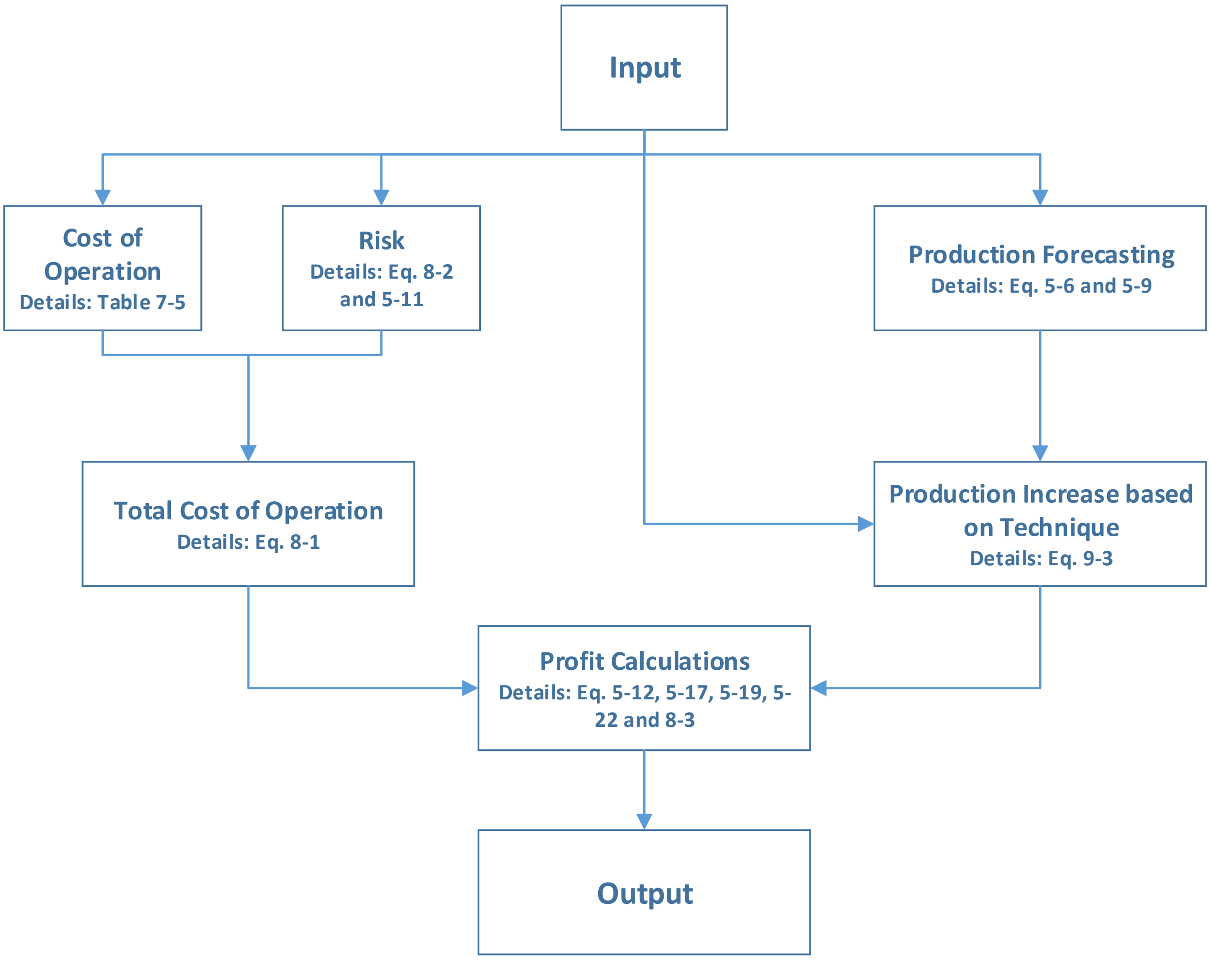

Figure 8-7: Illustrates how the tool is constructed and interacts from input to produced economical output

As mentioned the tool has two main functions. Firstly it is used to compare the potential profitability of each refracturing technique and to give an indication of potential profit. Secondly the tool can be updated by the individual user or company to customize their costs, risks and estimated production increases by doing easy adjustments in the cost, risk and production increase sheet. While the cost and risk numbers are based on estimates, this function will make the companies able to change the data according to their own estimated or calculated numbers for specific wells. This gives the tool the ability to become more accurate when better data and research becomes available in the future.

As Table 8-3 shows, the main input variables are oil or gas price, which refracturing technique to use, historical well production data, refracturing month, and the cost data. The tool displays profitability indications in form of NPV, ROI, IRR, payback period and breakeven price. In addition the profitability is shown in various graphs to illustrate profitability potential in different ways and help the companies in doing refracturing decisions, see Figure 8-8 example of NPV graph.

Table 8-3: Illustrates the input data needed in the profit calculation tool, and the output generated

Input	Output
○ Oil/gas price ○ Refracturing technique ○ Historical data ○ Refracturing point of time ○ Total cost of refracturing and/or recompletion ○ Well data (tool is calculating total cost)	○ NPV (EQ 5.16) ○ ROI (EQ 5.12) ○ IRR (EQ 5.17) ○ Breakeven period (EQ 5.19) ○ Breakeven price (EQ 5.22)

The results without a refracturing operation are deducted from the results with a refracturing operation to purely show the effect of the refracturing. The predicted future revenue without a performed refracturing operation is referred to as an opportunity cost. All the economical calculations in the tool are further based on NPV values calculated with the following formula:

$$\mathrm{NPV_{refrac}} = -\mathrm{TCO} - \mathrm{OC}\sum_{t=1}^{r}\frac{\text{Refracturing revenue}}{(1+r)^t} \qquad \text{8-3}$$

NPV_{refrac}	=	is the Net present value at a future point of time
TCO	=	the tol cost of operation (explained in chapter 8.4 and calculated in chapter 9.3)
OC	=	Opportunity cost
$\sum_{t=1}^{r}\frac{\text{Refracturing revenue}}{(1+r)^t}$	=	is the revenue after the refracturing operation at a future point of time (t)

All the calculations use a monthly discount rate of 0,958 percent which is regular in the oil and gas industry. Figure 8-8 illustrates how the potential NPV of a particular refracturing operation is displayed graphically in the tool.

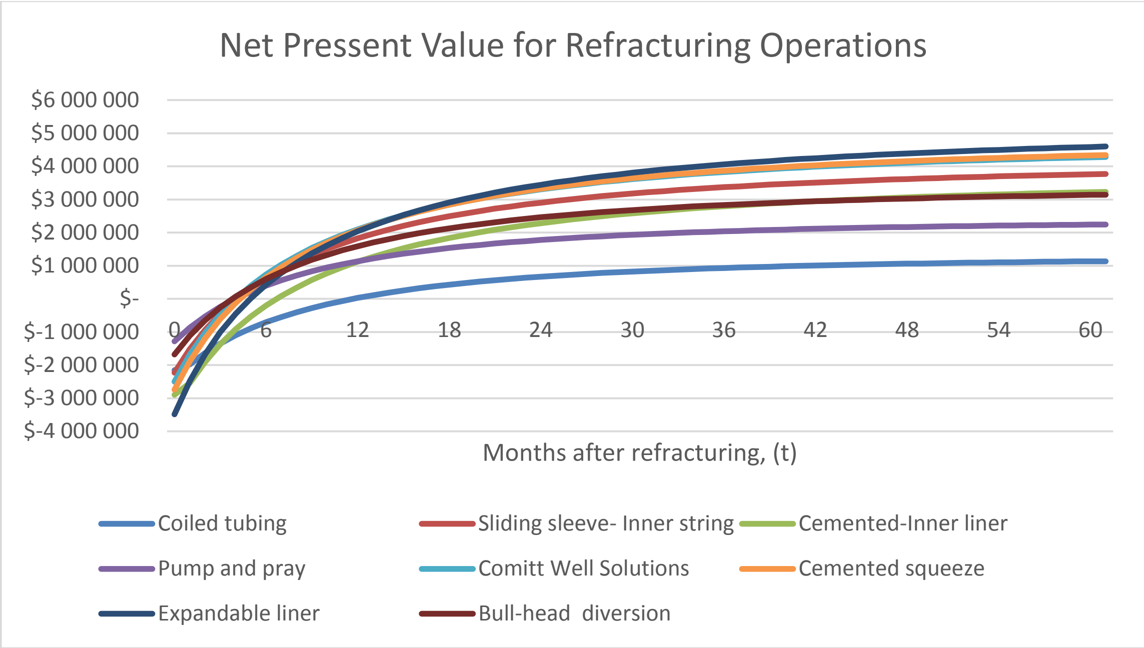

Figure 8-8: Example of graph created by the tool to compare the refracturing techniques potential profitability with NPV

The tool uses Monte Carlo simulations, by the use of @Risk to estimate the risk of using each technique. These simulations are integrated in the tool and utilize the formulas and principles presented in chapter 5.4.

The production forecasting is based on Arps modified hyperbolic decline theory (equation 5.6) which is the most commonly used method in production forecasting for unconventional wells. The “b” and “D” factors are further estimated with Microsoft Excel’s multisolver tool by the use of historical data input and least squares method (equation 5.9), to fit the modified hyperbolic curve to the historical production data. The best fitted curve is used in the tool to forecast future monthly- and cumulative production, see Figure 8-9. All the operations needed to fit the curve and forecast production are recoded in a macro which enables the user to do every operation automatically by the use of just one click. The functionality of the tool will further be explained in subchapter 9.5.1.

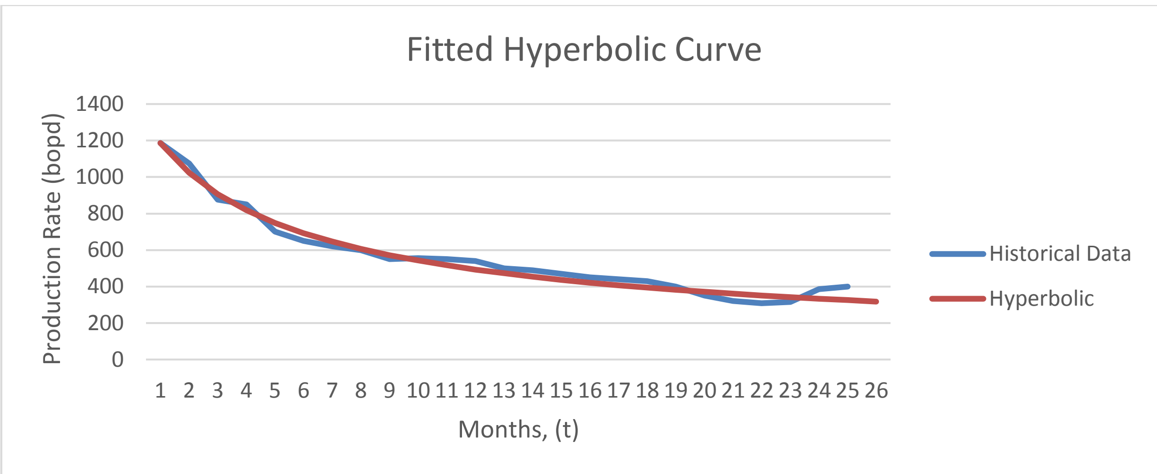

Figure 8-9: Illustrates a modified hyperbolic curve fitted to the historical data to be able to forecast future production

9 Discussion, Evaluation and Analysis

The purpose of this chapter is to answer the research questions raised in this thesis. Firstly we will present an evaluation and analysis of the potential magnitude of the refracturing market. Secondly an evaluation of the different refracturing techniques ability to achieve the success criteria will be presented. Thirdly an evaluation of the techniques economical potential will be presented. Finally we compare the techniques profitability potential by the use of the constructed profit calculation tool.

9.1 The Potential Magnitude of the Refracturing Market

The low oil and gas price today pose a threat to the shale oil and gas industry. The high breakeven prices of drilling new shale wells make a significant amount of projects uneconomical, see subchapter 3.3. The profitability of refracturing, as with drilling a new well, is highly dependent on the oil and gas price. The respondents in the interviews claimed an economical success rate of 90 percent in their operations. However, these refracturing projects have been executed while the oil and gas prices were at a higher level than today. But even with a lower oil and gas price, the oil and service companies still need to keep up their production and income. Refracturing has become a highly discussed and relevant topic in the U. S today, likely because of the combination of the low investment cost compared to a new well, and the low oil and gas prices. Although refracturing is a highly discussed and relevant topic, the industry seems guardedly optimistic. By that we mean that they are cautious in their approach toward refracturing investments, and they seem optimistic without really understanding how to consistently perform a highly successful refracturing operation. There seems to be a common understanding that the high performing wells have the highest economical potential. However, the industry generally doesn’t want to risk losing their high productive wells, and for that reason they tend to choose lower productive wells instead.

With a significant production increase, it looks like refracturing has a huge potential. Interviews revealed that major oil- and service companies are using a significant amount of resources to look into this potential. Technology advancements today have increased the recovery rate from 10 percent up to about 70 percent for some conventional wells. Unconventional recovery rates are today only up to about 7 percent for U.S oil wells. With this information in mind, we can argue that the same increase in recovery rates may be expected to occur in shale wells in the future, due to technology advancements. Improved knowledge and technology advancements indicate a higher pay and lower breakeven prices in unconventional shale in the future, which will ultimately make some of the wells considered as uneconomical today, economical with a certain oil and gas price in the future.

9.1.1 Candidate Selection

History has shown that of the wells drilled up to January 2015; 1/3 have been highly economical, 1/3 have been marginal economical and 1/3 have not been economical at all, as Figure 9-1 illustrates (King, George E., 2015). To put this in perspective, experience in the industry show that 20 percent of the wells accounts for 80 percent of the total production. These wells are often in what the industry calls "sweet spots" which in other words are wells in shale reservoirs with significant quality (high permeability and carbon contents).The uneconomical wells have in most cases been due to poor reservoir quality (low permeability and/or carbon content), and fracturing failures. The uneconomical wells might never be economical to refracture because of an insignificant amount of hydrocarbon content in the shale formation, or because the experienced failures prevent an economical refracturing operation. However, if the experienced failures under the initial fracturing operation do not prevent a new refracturing operation, these wells might be good candidates. A huge advantage of refracturing compared to drilling a new well is the available information about the reservoir quality before the operation. A significant amount of information about the well can be gained through the production data compared to the initial completion design, which makes it easier to avoid the wells with less hydrocarbon material. From Figure 9-1, we can see that 1/3 of the drilled wells are not economical, which is argued to be mainly because of poor reservoir quality. Those wells will most likely not be candidates for refracturing, and that will by itself increase the success rate of about 1/3 for refracturing operations. For that reason, there is possible to achieve a higher success rate when refracturing compared to drilling a new well.

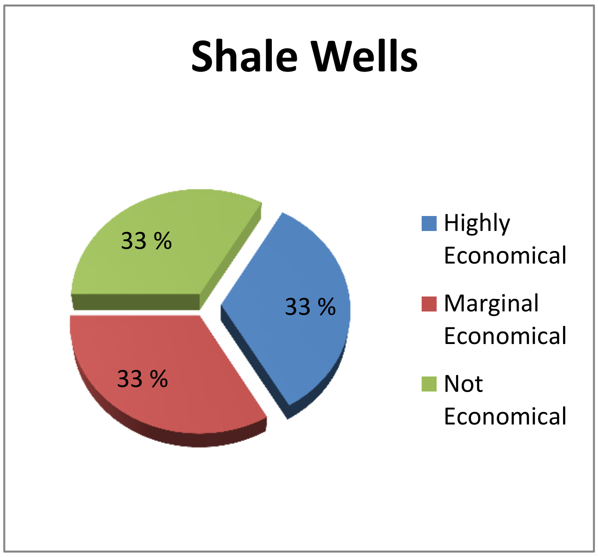

Figure 9-1: Indicates how economical the wells fractured have been

The best candidates to refracture are the wells with the highest economical potential. We have constructed a list of the most important well selection criteria by combining our findings in the literature study with the criteria our respondents emphasized in the interviews, see Table 9-1. This is not a complete list of the well selection criteria, but a list which indicate the most common criteria determining how profitable the refracturing candidates potentially are.

Table 9-1: The most important refracturing profitability factors based on our literature study and interviews

	Candidate Matrix	Good candidates	Poorer candidates
1	Reservoir quality	High	Low
2	Steep decline	High	Low
3	Past fracture design and job quality	Low	High
	Past productivity	High	Low
	Refracturing technology improvements	High	Low
	Mechanical Integrity	High	Low
	Underperforming well	High	Low
	Pressure Communication	Low	High

The well's productivity is highly dependent on how much SRV that is connected to the well, hence the production will be limited if the carbon content or the permeability is low. Based on our interviews, literature study and the fact that it is impossible to gain production of oil and gas if there is no hydrocarbon content in the formation, the most important selection criteria is the reservoir quality. Conductivity loss is argued to be one of the main reasons for the steep decline in shale formations by the respondents and to some degree in the literature study. Refracturing projects have shown great results in restoring the conductivity and for that reason we argue that this will be one of the main contributions to an economical outcome, hence one of the most important selection criteria. A poor fracture design or job quality will in most cases leave possibilities in bypassed pay. Bypassed pay can be because of large stage- and cluster- spacing which is common in older wells, or because of failure mechanisms during the fracture treatment. In these cases, a new fracture treatment might be able to correct the failures and even improve the design, which will contribute in more SRV connected to the wellbore. As a result this is one of the three most important selection criteria. Further, we do not have enough data to arrange the importance of the other selection criteria. However it will be important for the oil companies to have them in mind when selecting their refracturing well candidates.

Dozier et al. (2003) estimated that 20 percent of all wells drilled in the U.S, equal to 40 000 wells, were potential refracturing candidates in 2003. His estimation was solely based on initial poor fracture design and bypassed pay, hence the number will be higher if you take in consideration all the other selection criteria mentioned in Table 9-1, and the fact that the well count has exploded since 2003. The more skeptical people in the industry believe that about 10 percent of the wells today are candidates for refracturing, while the more optimistic people believe that about 60 percent could be candidates. By looking at the well selection criteria we argue that there are a significant amount of existing horizontal wells that are candidates for refracturing. The experienced conductivity loss alone, gives a strong indication that refracturing is a necessity to be able to get a good recovery rate from each wellbore.

9.1.2 Future Outlook

Previous research, supported by a majority of the respondents, show that the conductivity in the fractures will be reduced over time. This is a significant factor in explaining the rapid production decline. According to our literature study and interviews, refracturing is an alternative which increases the recovery rate by restoring conductivity in the closed fractures, as well as contribute with other effects like; enlarged fracture geometry and the possibility of fracturing reorientation. These success criteria show that even wells with a good initial fracturing operation will be candidates in the future. As a result even wells that are stimulated with today's best techniques have a potential of becoming refracturing candidates in the future.

One of the respondents mentioned that he had seen several refracturing operation been performed in the same horizontal well which raised the production level back to the initial production level every time, Illustrated in Figure 9-2**Error! Reference source not found.**. While this require substantial carbon content left near the well, the respondent believes most of the success can be attributed to placing new proppant, fracture enlargement and reorientation of the fractures. And for that same reason, we argue that refracturing can be done multiple times in the same well with a significant potential of increasing production. However, it is difficult to say how much increase in the production that can be expected, or how many times it will be economical to refracture a well.

This indicates that companies should include refracturing in a long term strategy when initially making the drilling and fracturing decisions in the future. Including refracturing in the decision will most likely lead to a lower breakeven price for the initial fracturing projects, and give a more correct picture of the long term profitability potential. Yet, it is hard to predict the oil and gas price in the future and furthermore estimate how successful the refracturing will be in terms of increased production. In the future, fracturing-, refracturing- and reservoir- data will be more comprehensive and available. This will make it easier to predict post-refracturing production and EUR, which will help the oil companies to make better refracturing decisions, and in general plan long-term wells.

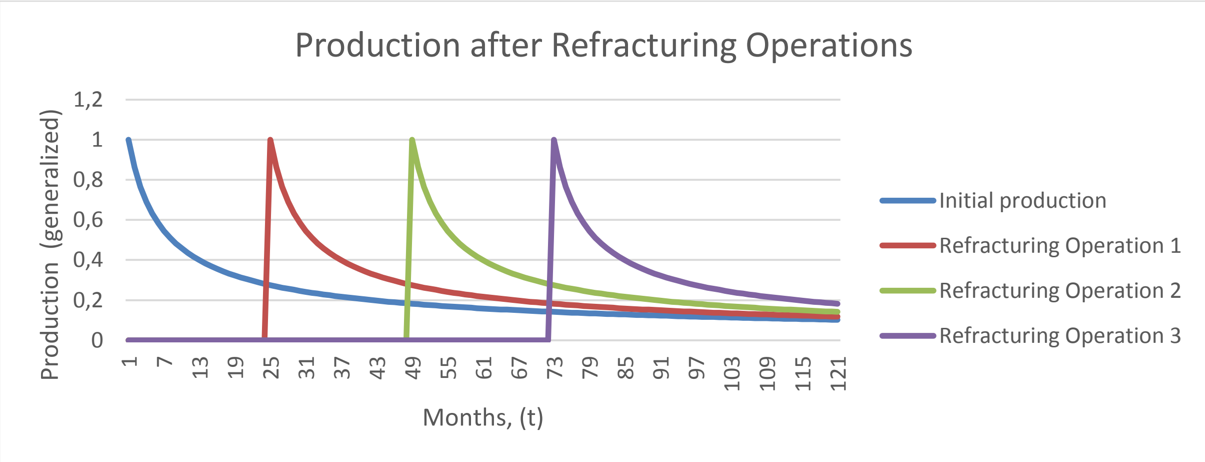

Figure 9-2: Illustrates potential increased production of doing several refracturing operations

Shale oil and gas extraction poses several threats to the environment, ref subchapter 3.5. The industry should be aware of new regulations in the future prohibiting part of the industry to operate in the way they do today. However, while there most likely will be more regulations in the future in the U.S. preventing shale oil and gas extractions, these will probably not prohibit the refracturing business of growing because of the following reasons. When the fuel price reached 4 dollars in 2008, politicians started a movement called “drill, baby drill” which shows how highly the U.S. economy is dependent on oil and gas. In addition, natural gas has less environmental impact than coal. Replacing the use of coal with natural gas will not be a long term solution, but a step closer in reducing the human made emissions. Furthermore, refracturing operation is done in existing wellbores which reduces the environmental impact compared to drilling new wells.

Summary of the Main Findings

An improved success rate of refracturing operations can be achieved compared to the success rate of drilling new wells, because of more available information and good well selection criteria. The well selection criteria discussed in this thesis indicates that the majority of today’s wells are candidates for refracturing. We estimate that 33 – 66 percent of today’s wells are potential candidates, depending on the oil and gas price. We also believe that this number will increase to about 70 percent in the future, as technology advances and poorer reservoirs become economical. The success criteria discussed indicates that refracturing can be done multiple times in the same well, with a significant increase in production each time. There are however not enough data to say anything about how many times this may be economical. Based on these arguments refracturing should become a part of the long-term strategy when drilling new wells, which likely will affect the breakeven price in a positive direction in the future.

9.2 Technical Evaluation of Refracturing Techniques

The technical evaluation will be presented as following. None-mechanical refracturing techniques will be presented first, followed by the mechanical techniques. The first part of each discussing will be a general insight in the opinions and experience by the interview respondents, followed by a technical discussion and a final summary with a technical grade. The technical evaluation will only be based on the techniques ability to achieve the success criteria; hence cost and risk are excluded in this evaluation, as described in more thoroughly in subchapter 8.3.

9.2.1 None-Mechanical Techniques

The none-mechanical refracturing techniques do not utilize any mechanical tools downhole. However, a mechanical tool can be used to prepare the well for refracturing, make new perforation pre-refracturing, and clean out the well post-refracturing.

Pump and Pray

This technique is clearly the cheapest technique, and it has been used in several operations. From the literature study it looks like the majority of all the refracturing operations done with Pump and Pray have been successful. However, the technical success of this technique is difficult to determine because of the fact that there is no zonal isolation used to isolate the stages. The refracturing treatment is done in one sequence where the fracturing fluids will be going into the fractures with the least stress gradients, see Figure 6-2 in subchapter 6.1. This makes it difficult to predict where the fracturing fluids are going. Microseismic mapping is widely used to get a fairly detailed look at the fracture contact area within the perforated interval, and to get a profile of the production entry into the well, see subchapter 3.4. However, the mapping technology used today is inadequate to get a detailed picture of what is happening downhole. Yet, the industry uses this technology to get an indication on which of the fractures that get stimulated and which do not. The result is hard to generalize, since every well has its own characteristics and not every treatment design is the same. Regardless, we have asked the interview respondents to put a number on how many percent of the perforations that they think are getting treated based on their experience. The respondents have experienced that maybe 40 percent of the lateral is getting stimulated.

Technical Discussion

There are seen limited economic results and increased initial production levels after the use of Pump and Pray refracturing technique. This gives an indication that the refracturing treatment has attached new pay to the well, or at least restored conductivity in the existing fractures. The drawback of this technique is clearly that there is no control of where the fracturing fluids are going, because there is no diversion of the fluids or mechanical isolation in each stage. A disadvantage with no isolation or diversion is that there is no way of forcing the treatment to the stages which have the highest hydrocarbon content. These stages might not be stimulated at all. The fracturing fluids will be pumped down the well and go into the fractures with the least stress, and those fractures might experience a high treating pressure. However, there is a pressure drop in the lateral that will prevent all perforations to experience the same treating pressure. Regardless of this, there will be some form of natural diversion after the first fractures have been stimulated. The stimulated fractures will at some point have built up an internal pressure that excides other fractures minimum break-down pressure. As a result, the fluids will start stimulating the fractures with less break-down pressure than the built up pressure in the already stimulated fractures. In the end there will likely be some fractures that did not receive stimulation because of the pressure loss and the low treating pressure left. Some fractures might not be fully stimulated, but can have received enough fluid and proppant to restore fracture conductivity. However, because this technique treats the whole lateral in one sequence, the treating pressure in each perforation will be minimal, hence the majority of the perforations will not receive a high enough treating pressure to increase fracture geometry substantially, or experience reorientation. Yet, a few fractures will likely receive high enough treating pressure to reorient fractures, or enlarge the fracture geometry, which will connect more SRV to the wellbore. There could also be argued how effective it is to add perforations, based on the high treatment pressure that is needed to initiate new fractures.

Technical Grade

This technique has no control of the treatment, and there is a high uncertainty of which fractures that get stimulated. Several case studies and respondents mentioned that this method is a poor technical solution. We argue the same, based on that the treating pressure is divided over several stages of perforations, which gives low treatment pressure per perforation. However, the technique will be capable in restoring conductivity to a certain degree. For that reason the technique gets a technical grade of 3 out of 10.

Table 9-2: Technical evaluation of the Pump and Pray technique, based on the success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	2
Improved pay coverage	3
Restoration or increase of fracture conductivity	4
Fracture reorientation due to stress field alternations	3
Average	**3.0**

Bull-head Diversion

Bull-head diversion seems to be the most used refracturing technique in today’s market, likely because of the low cost and risk associated with this technique. There seems to be a general understanding that this technique does not give an efficient technical solution, but it is used to get the “low hanging fruits” with low cost and risk. Some of our respondents also think that an optimization of this technique might be the best way to go, for that reason a lot of resources are put into improving this diversion technique. As described earlier, a highly technical successful technique is a technique where all perforations are getting treated with a high treating pressure. With this technique it can be used different forms of diversion agents, like different ball-sealers or proppant slugs. The approach relies heavily on how efficient the diversion is and does not provide the same level of accuracy as achieved with mechanical isolation.

Technical Discussion

The fact that there is often seen an economic success with the use of this technique, indicates that the refracturing treatment has gotten in contact with some new pay, or at least restored conductivity in the existing fractures. The effectiveness of diversion is strongly dependent on the differential pressure across the perforations and the geometry of the perforations itself. The perforations are most likely not circular as a ball, because corrosion and proppant injection will have made the perforations somewhat deformed. This will affect the diversion effect if ball-sealers are used, and it is one of the reasons why some operators like to use proppant slugs as diversion. A few operators have used proppant slugs and ball sealers in combination, but this appears to be rare. Regardless of the type of diversion material, the intent is diverting the treatment into the perforations in sequences. The use of diversion agents will likely help in initiating new fractures if there is added perforations, because the fractures which are accepting fluids are sealed off. If the diversion is effective, the treatment pressure will be higher per perforation than with the Pump and Pray technique. This will result in a better stimulation of each perforation. However, the reliability of this technique is poor, and there is no way of knowing where the diversion will happen. Furthermore stages with high hydrocarbon content might be unstimulated.

Technical Grade

The use of diversion agents will most likely give a better stimulation compared to the Pump & Pray technique, but there is high uncertainty in how efficient the stimulation will be. There is today no efficient solution of diverting the fluid into each of the perforations. The treating pressure will likely be sufficient to restore conductivity in existing fractures to some degree. However the treatment pressure will likely be insufficient in creating enlarged fracture geometry, fracture reorientation and to initiate new perforations. There is too high uncertainty of where the fracturing fluid will go, and which fractures will be stimulated to give this technique a high technical grade. This technique will for that reason be given a technical grad of 4.0 out of 10.

Table 9-3: Technical evaluation of the Bull-head diversion technique, based on the success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	3
Improved pay coverage	4
Restoration or increase of fracture conductivity	5
Fracture reorientation due to stress field alternations	4
Average	**4.0**

9.2.2 Mechanical Techniques

The mechanical refracturing completion techniques will be evaluated in the following subchapter. They are categorized as mechanical techniques based on the mechanical tool they are dependent of. These mechanical tools are often associated with higher cost and higher risk, which will be analyzed in the economical evaluation and numerical analysis in subchapter 9.3.

Coiled Tubing – Straddle Packer

Coiled tubing (CT) is a well-known tool in the fracturing industry, used in many different operations. CT is suitable to do refracturing operations with at least two configurations. In this technical evaluation we will only evaluate CT with straddle packer assembly. However, as far as we know this technique has never been used for refracturing, even though every respondent knew this was an option. This is likely because of the high cost and risk associated with this technique, and the fact that there are more suitable techniques on the market today.

Technical Discussion

CT with a straddle packer assembly can be a highly efficient approach to pin-point stimulation intervals. The straddle packer assembly can isolate clusters, which is something unique in the refracturing market today. However, the treating pressure is highly restricted by the low ID of the tube. Normally the initial completions utilize a pump rate of about 15-20 bpm/cluster, and 60-80 bpm/stage. With CT, the ID restricts the treating pressure to +/- 4 bpm, this indicates quite clearly that the treating pressure with CT would be too low to increased fracture geometry compared to initial fracture treatment. However, there could be some wells containing fractures with low break-down pressures where +/- 4 bpm could be enough to improve production.

The straddle packer assembly has the possibility to treat clusters one by one. And the fact that CT can pin-point the treatment to desired fractures, and force the initiation of fractures with good accuracy, makes it easy to reach any bypassed pay and increase the pay coverage. It also has a unique opportunity to treat the stages in a different order, which can improve the fractures initially affected by stress shadowing (explained in subchapter 6.1 and illustrated in Figure 9-3). There could be seen some good results with use of CT if restoration of fracture conductivity can be done with a pump rate of +/- 4bpm. However, because of the low treating pressure, there is unlikely that CT would create any significant new fractures or make reorientation.

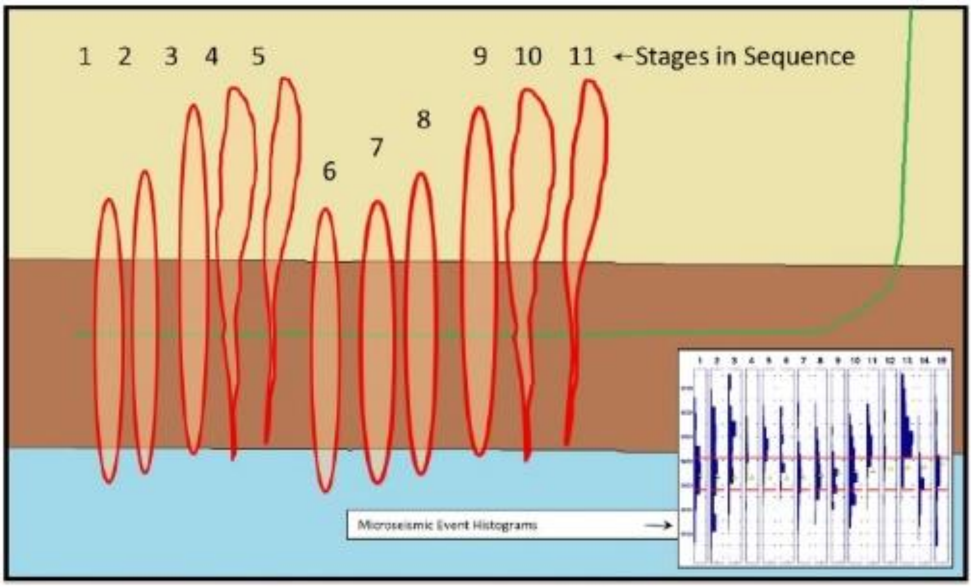

Figure 9-3: Illustration of the stress shadowing effect in fractures 4,5,10 and 11 experienced in initial treatment (Dohem, Zhang, & Blangy, 2014)

Technical Grade

This technique is close to be a technical great technique because of its possibility to isolate and treat each cluster one by one. However, the low treatment pressure will restrict its ability to meet all the success criteria. Yet, there are some fields that can be fractured with a low treatment pressure, where CT can be used with success. For that reason this technique is given a technical grade of 3.0 out of 10.

Table 9-4: Technical evaluation of CT- Straddle packer, based on the success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	2
Improved pay coverage	5
Restoration or increase of fracture conductivity	4
Fracture reorientation due to stress field alternations	1
Average	**3.0**

Sliding Sleeve – Inner String

Sliding sleeves is one of the most used completion techniques in Canada. However, in the U.S. it is more common to use cemented liners with the P&P technique. There are a few examples of this technique being used in refracturing operations in the Bakken shale play. However, no public data have been found where sliding sleeve – inner string have been used. The main difference between original completion and an inner sting is the diameter of the tube, where an inner sting naturally has a smaller diameter. As explained in subchapter 4.4, there are different techniques used to slide the sleeves and seal of each stage. In this technical evaluation we will only evaluate the ball-activation technique, because that seems to be the most commonly used technique today.

Technical Discussion

The technical performance will be restricted by the reduced ID of the string. One of our respondents mentioned that the treating pressure could be reduced by as much as 60 percent, from 80 bpm as used in an initial refracturing completion to as low as 30 bpm/stage (6 bpm/cluster, assuming 5 cluster/stages). The string will most likely have a higher treating pressure than with CT, but not as much as in the initial fracturing completion. As discussed under the CT technique, this indicates that the treating pressure with an inner sting would be too low to increase fracture geometry compared to the initial fracturing treatment. Where the CT has the possibility to isolate and hydraulic fracture each clusters independently, an inner sting with ball-activation treats multiple clusters (one stage) at once. Experience from fracturing operations shows that clusters tends to be left understimulated when treating multiple clusters at once.

The reduced ID of the inner string also prevents the inner string to be designed with smaller stages, mainly because of the pressure drops over the ball-seats, see Figure 9-4. The figure illustrates a sliding sleeve used in an initial fracturing operation, however it illustrates the lower ID in the ball-seats which causes a pressure drop.

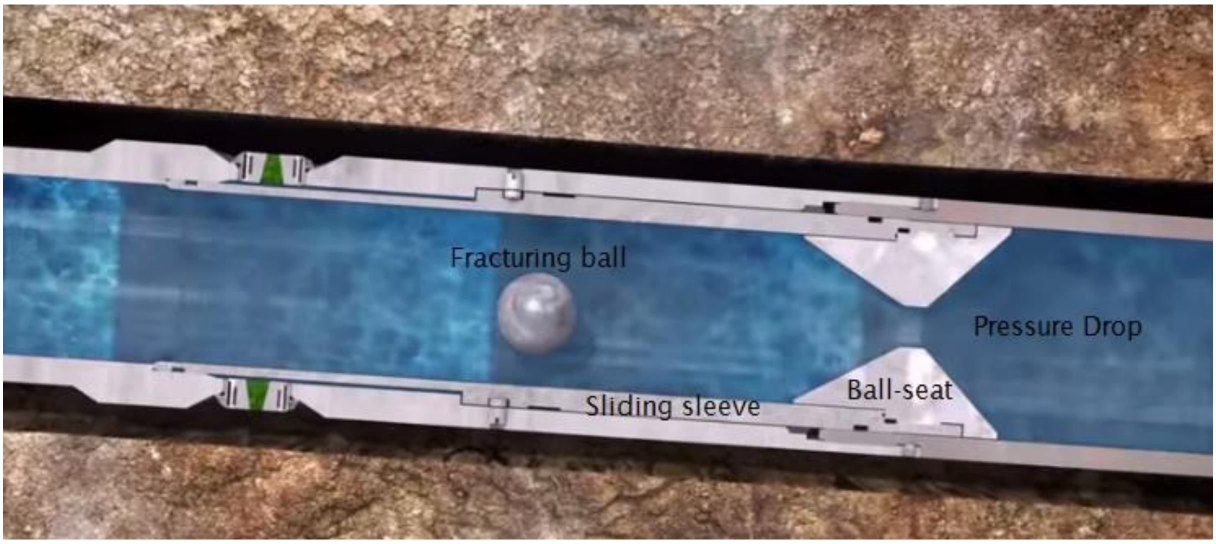

Figure 9-4: Illustration of pressure drop in sliding sleeves, showing ball-seats, sleeves and a fracturing ball

As shown in Figure 4-16 in subchapter 4.3, the ID of the ball-seats will be smaller as longer into the lateral they are. This will result in a lower treating pressure in the toe. For that reason the first stages will likely be understimulated. The last stages will most likely receive the highest pressure, however the pressure may be restricted by the low ID of the inner string.

The low treating pressures will reduce the possibility to improve the fracture geometry as well as experiencing fracture reorientation. The conductivity in the original fractures will likely be restored, but increasing the conductivity demand higher pressure which is less likely to occur. The pay coverage can still be increased with new perforations and the right sting design.

Technical Grade

This technique will not be able to treat the whole lateral with a high treating pressure or isolate each cluster. It would also likely have to increase the stage length by reducing the number of stages. Even though the conductivity may be restored and the pay coverage increased, there is a high uncertainty of how good the treatment will be. For that reason this technique is given a technical grade of 5.0 out of 10. The use of this technique also limits the possibility of refracturing multiple times, because of the fact that the ID of the inner string will reduce the ID of the well further. This is however not taken into account in this technical evaluation.

Table 9-5: Technical evaluation of sliding sleeve – inner string, based on success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	4
Improved pay coverage	6
Restoration or increase of fracture conductivity	6
Fracture reorientation due to stress field alternations	4
Average	**5.0**

Cemented - Insert Liner

Cemented insert liner is not a complete completion technique by itself; the perforation- and fracturing operation can be done with multiple techniques. However, in this technical evaluation there is assumed that P&P completion is used to recomplete the wells.

From our interviews there have been different opinions about this technique. Some of the respondents say that this technique might be the best one to go forward with, while other respondents argue that the likelihood of creating additional damage within the existing fracture network far outweighs the advantages of stimulating new pay. Our interpretation is that some of them look at different refracturing candidates when they are arguing, based on their arguments. Some of the arguments for using this technique are based on doing refracturing completions on wells with a low cumulative production. They argue that cementing existing perforations won't give a big impact on future production. While others, who considers wells with high cumulative production as refracturing candidates, say that they would not risk damaging the existing perforations. Another respondent argues that cement does not destroy the fractures at all, and based on the arguments, he might be right.

Technical Discussion

As discussed, one of the main argued downsides with this technique is that it seals of the existing perforations, which is argued to result in failure of at least one of the success criteria (Restoration or increase of fracture conductivity). But does cement really destroy the existing fractures? When cementing, all existing perforations are getting filled with cement and sealed off, but when the hydraulic refracturing treatment starts, that cement will fracture and crack more easily than the shale. Shale has a break-down pressure tenfold the pressure needed to break down the cement. For that reason the arguments of cement destroying the perforations can be argued with; they only get temporarily sealed off, and will most likely reopen with a refracturing treatment. Even if the fractures are filled with cement, the refracturing treatment will be able to reopen those fractures. Fractures close over time due to proppant degradation among other factors. We will for that reason challenge the arguments of cement damaging existing fractures, because the fractures may already be closed. Even if the fractures are filled with cement, the refracturing treatment will be able to reopen the fractures. After some time of extraction, we might experience fracture reorientation because of the stress changes in the formation. Another potential downside is cement segments plugging off the fractures or perforations when the production starts.

The result of using this technique is a "new" well that can be completed with use of the P&P technique, where new stage- and cluster designs can be made. This technique can be designed to add perforations in between the old once to get in contact with bypassed pay. Even new perforations might get in touch with the previous fracture networks if they are placed close enough to existing perforations.

However, as with the previous mechanical refracturing techniques discussed above, this technique will reduce the initial ID because of a new casing. This will affect the treatment pressure that is needed to enlarge the fracture geometry, increase the fracture conductivity and reorient the fractures. However, this can be improved if the stages are designed shorter or by reducing the number of clusters in each stage. Then the treating pressure will be concentrated over fewer perforations, increasing the treatment pressure per perforation. Fracture conductivity is likely to be restored anyway, but the other success criteria will be dependent on the design.

Technical Grade

Based on the fact that the industry argues the subject of cement damaging the existing fractures, there is no way of saying with certainty how good this technique is technically. However, based on our arguments we will argue that the cement will likely not destroy the existing fracture networks. There is however some drawbacks with use of cement that could give an impact on production. The technical performance of this technique will be negatively affected by the reduced ID and treating pressure, but this effect might be reduced with a good design. However, in comparison with the sliding sleeve -inner sting technique, this technique is quite similar and we do not see any major advantages except the opportunity for a better design. For that reason this technique gets a technical grade of 5.5 out of 10, with a slight improvement in improved pay coverage and fracture geometry compared to sliding sleeve – inner string. The use of this technique also limits the possibility of refracturing multiple times, because of the decreased ID of the new casing, but that is as mentioned not taken into account in this technical evaluation.

Table 9-6: Technical evaluation of cemented -insert liner, based on success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	5
Improved pay coverage	7
Restoration or increase of fracture conductivity	6
Fracture reorientation due to stress field alternations	4
Average	**5.5**

Cemented - Squeeze

Cemented squeeze is not a complete refracturing completion technique by itself, the perforation and fracturing can be done with multiple techniques. However, in this technical evaluation there is assumed that a P&P completion is used to recomplete the wells. This technique has been tried to some extent, but there's not much public data on it.

Technical Discussion

A discussion of this technique would include many of the aspects discussed under the cemented insert liner. However, with the use of this technique the ID of the well will remain the same as the initial ID, which is of great importance in obtaining a high treating pressure.

The main difference between cemented squeeze and cemented insert liner is the ID. However, there are a few other differences that need to be included in the discussion, like the fact that this technique relies heavily on a proper sealing of the cemented perforations. As mentioned earlier, the cement has a low break-down pressure. The cement might withstand the pressure of the hydraulic fracturing treatment, or fracture the cement sealing off the existing perforations. The respondents have different opinions regarding this matter. Furthermore, we were not able to find any information to answer this question, hence we concluded that the industry does not know exactly what's going on downhole. As a result, we do not have any good documentation on the effectiveness on sealing perforations with cement. However, we assume that if the cement is being broken down from the hydraulic fracturing treatments, the pressure drop would be extensive, and the desired perforations will not receive the optimal treating pressure.

Regardless of this effect, the treating pressure with this technique can be designed to be as high as the initial completion, or even higher. With a good stage spacing design, this will clearly have a potential of increasing the fracture geometry, pay coverage, and the conductivity. With a high treating pressure it is also more likely that reorientation will happen, which will enlarge the fracture geometry and increase the pay coverage. However, this technique will use the P&P technique, and with normal stage spacing with +/- 4 clusters, there is always a risk of not stimulating some of the clusters. This technique will not economically be able to isolate clusters and treat those with a high pressure.

Technical Grade

There is uncertain how effective the cement is sealing off the perforations, and there might be mechanical problems because of cement debris in the well under operation. However, if a high treating pressure can be achieved with this technique, it will increase the potential of improving fracture geometry, pay coverage, and conductivity. The uncertainty of the sealing effect, and the uncertainty of the effect cement has on the fractures will affect the technical grade. For that reason this technique is given a technical grad of 6.0 out of 10. This is based on the assumption that the cemented perforations withstand the hydraulic fracturing treatment, at least to a certain extent.

Table 9-7: Technical evaluation of cement squeeze, based on success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	6
Improved pay coverage	6
Restoration or increase of fracture conductivity	6
Fracture reorientation due to stress field alternations	6
Average	**6.0**

Expandable Liner

Expandable liner is not a complete completion technique by itself, the perforation and hydraulic fracturing can be done with multiple techniques. However, in this technical evaluation there is assumed that the P&P completion is used to recomplete the wells.

Expandable liner has been used to some extent in repairing parts of damaged wells. However, this technique has also been tried in refracturing operations. The majority of our respondents were clear on the matter that this technique could be a great technical solution; however they argued that the cost of this technique would far outweigh the benefits. Another respondent informed us that they were looking into this technique, with a belief that this could be one of the best solutions available on the market. As technology advances the cost tends to be reduced and this technique might be allocated more resources to be further developed in the future.

Technical Discussion

In comparison with a cemented insert liner, the expandable liner will not reduce the ID of the well to the same extent. The casing is thinner and there’s no need for cement in between the casing and the liner. This will result in a higher achievable treating pressure, which will indicate a great possibility to increase the fracture geometry and pay coverage. The pay coverage is however dependent on the perforation- and stage design. Because the new liner will seal off all existing perforations, it needs to be perforated to access the existing fractures. Increased pay coverage can also be improved by adding new perforations in bypassed pay areas. Zonal isolation can be achieved with the P&P technique; however this technique will likely not be able isolate clusters because of the extensive cost that is needed to achieve cluster isolation. To restore conductivity in initial fractures, these fractures need to be accessed by the new perforations. This might be difficult because it is hard to predict exactly where those fractures are. However, reorientation may occur in close range from the existing fractures, which will result in enlarged fracture geometry.

Technical Grade

Even though this technique is quite similar to cemented casing, there are some advantages with using an expandable liner. The fact that the old perforations do not get cemented gives the opportunity to access the existing fracture network more easily. The result could be good if the expandable liner covers the whole length of the lateral. Enlarged fracture geometry can be achieved, and new perforations can be added to get in contact with new pay, as well as contacting the existing fracture network. Even though, the technique is not able to achieve a higher treating pressure than in the initial fracturing operation. For that reason this technique gets a technical grade of 7.0 out of 10. The reason why it does not get any higher score is because of the fact that this is just a technique for preparation of the well before a new completion can be done. The technical result will therefore heavily rely on the completion technique being used, which in this case is P&P.

Table 9-8: Technical evaluation of expandable liner, based on success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	7
Improved pay coverage	8
Restoration or increase of fracture conductivity	6
Fracture reorientation due to stress field alternations	7
Average	**7.0**

9.2.1 Comitt Well Solutions

In our interviews we asked the respondents what they thought were missing in today's technology, and what they thought would be the best technical solution. And the answers were really interesting. The majority of our respondents mentioned that mechanical isolation of clusters would be an ideal technical solution. This is exactly what Comitt Well Solutions now has developed. The reason why a technique like this has not been commercialized is because of the high associated costs. Comitt Well Solutions is now testing a technique that can mechanically inflate and deflate packers to isolate each cluster. The cost and risks of this technique is naturally higher than the non-mechanical techniques, but the question is if the potential profit margin generated by this technique is greater than the other techniques.

Technical Discussion

This technique will be capable of treating each cluster with a pump rate close to 30 bpm, which will be enough to fracture each cluster properly. As mentioned earlier each stage is normally designed with a treating pressure of 60-80 bpm (15-20bpm/cluster). However, the techniques available today, treat multiple clusters at a time, hence one stage at a time. For that reason each cluster is not treated with the same amount of pressure, and usually just a few of the clusters are getting treated properly. This indicates that the technique most likely will be successful in creating enlarged fracture geometry and in addition improve the conductivity in existing fractures. Improved pay coverage can be made by adding new perforations, and will be stimulated properly with this pump rate. The conditions for fracture reorientation will also be great with this technique because of the high treating pressure. The technique will be able to treat multiple clusters without going back up to the surface, which will reduce the time of operation. However, since each cluster will be treated separately the total time of operation might be like the other techniques.

Technical Grade

This technique will clearly be more expensive than non-mechanical techniques discussed earlier, but there is no other techniques that have the possibility to ensure as good technical solution as this technique. The interviews indicated that a mechanical isolation of clusters with high treating pressures will be an ideal technical completion solution, and this technique will manage that. The fact that this technique can achieve a higher treating pressure than most initial designs clearly indicates that the initial hydraulic fracturing treatment can be improved. The only uncertainty so far, is how much the production will increase with this technique compared to the other techniques. For that reason this technique is given the maximum grade 10 out of 10.

Table 9-9: Technical evaluation of Comitt Well Solutions' technique, based on success criteria

Technical Evaluation	Grade
Enlarged fracture geometry	10
Improved pay coverage	10
Restoration or increase of fracture conductivity	10
Fracture reorientation due to stress field alternations	10
Average	**10.0**

We are subject to our own opinions, and likely influenced by the opinions of Comitt Well Solutions. However, we have tried to evaluate each technique as objective as possible with the use of the success criteria identified in the literature study. There will likely be other techniques in the future that will exceed the technical performance of this technique, which then should be graded higher.

Summary of the Main Findings

The none-mechanical techniques are in need of mechanical tools to be able to recomplete the wells. And other mechanical techniques are not able to refracture the wells because they seal of every existing perforation, which require new perforations to be able to get the well back in production. This applies to; cemented insert liner, cemented squeeze and expandable liner.

The main factor the techniques need to achieve is a high treatment pressure, and be able to treat every desired perforation with this pressure. The techniques have different ways of doing this, with different success. The best technical techniques are for that reason those who can isolate the treatment and achieve a high treatment pressure. Restoration of conductivity can however be obtained with a lower treatment pressure. As discussed, the techniques used by the industry today are not capable of effectively divert the treatment into every perforation in the lateral, leaving potentially huge pay behind. The techniques have their strong and weak sides, and none of the commercialized techniques will be the best solution in every well. However, based on the success criteria and the discussions above, we argue that Comitt Well Solutions' technique will give the best technical outcome in every well. The technical performance grades are summaries in Table 9-10.

Table 9-10: Summary of technical grades from the technical evaluation

Techniques	Grade
Pump and Pray	3.0
Bull-head diversion	4.0
Coiled tubing	3.0
Sliding sleeve – Inner string	5.0
Cemented – Insert liner	5.5
Cemented - Squeeze	6.0
Expandable liner	7.0
Comitt Well Solutions	10.0

9.3 Economical Evaluation and Numerical Analysis

The structure and our way of doing the economical evaluation and numerical analysis, is presented in subchapter 8.4. As mentioned a calculated risk for each technique will be added to the cost of production, which are based on the unit costs presented in the interview findings. This will result in an indication on the total cost associated with each technique. Further we are going to look at general profitability of refracturing operations, and then take a further look at the production increase of each technique. In the numerical analysis we are going to look at these factors:

- IP ratios pre- and post-refracturing.
- Correlation between EUR ratio and IP ratio
- Decline factors (b and D) pre- and post-refracturing.
- Correlation between IP ratio and decline factors.

An economical evaluation will be presented throughout this chapter. However, there will be presented more comprehensive profit calculations in the next subchapter.

9.3.1 Risk Analysis

The risk matrix presented in subchapter 8.4 illustrates the risks associated with each technique. However, it is not accurate enough to calculate a risk of each technique. For that reason a further risk assessment will be done to assign a risk to each technique by using Monte Carlo simulations.

As illustrated in Table 9-11, we have given the probabilities a uniform distribution. The occurrence is uniform within our defined probability range, i.e. a minor consequence can be as likely to happen 5 percent of the time, as 10 percent of the time. The costs have been given a normal distribution, because the failure mechanisms have an average cost, but will vary from case to case. The standard deviations used are discussed and supported by the respondents from the interviews. The assigned probability- and cost distributions for each technique can be found in appendix C.

Table 9-11: Distribution of probability and cost

Example					
Failure Mechanism	**Consequence**	**Probability range**	**Distribution**	**Cost variations**	**Distribution**
Stuck	Minor	5% - 10%	 Uniform	$ 0 -200 000	 Normal
	Moderate	3% - 7%		$ 200 000 - 800 000	
	Major	1% - 2%		$ 800 000 - 2 000 000	

With the use of Monte Carlo simulations we have taken into account the uncertainty in the calculations by defining the parameters as stochastic variables. The values generated for each consequence are inserted into an assembly function, which further gives several datasets with results for each failure mechanism, as presented in Figure 9-5. There are three failure mechanisms for each technique. With the use of random drawing (equation 5-10), we are generating multiple sets of input variables, which are inserted into a new assembly function, resulting in several datasets represented as a histogram in Figure 9-5.

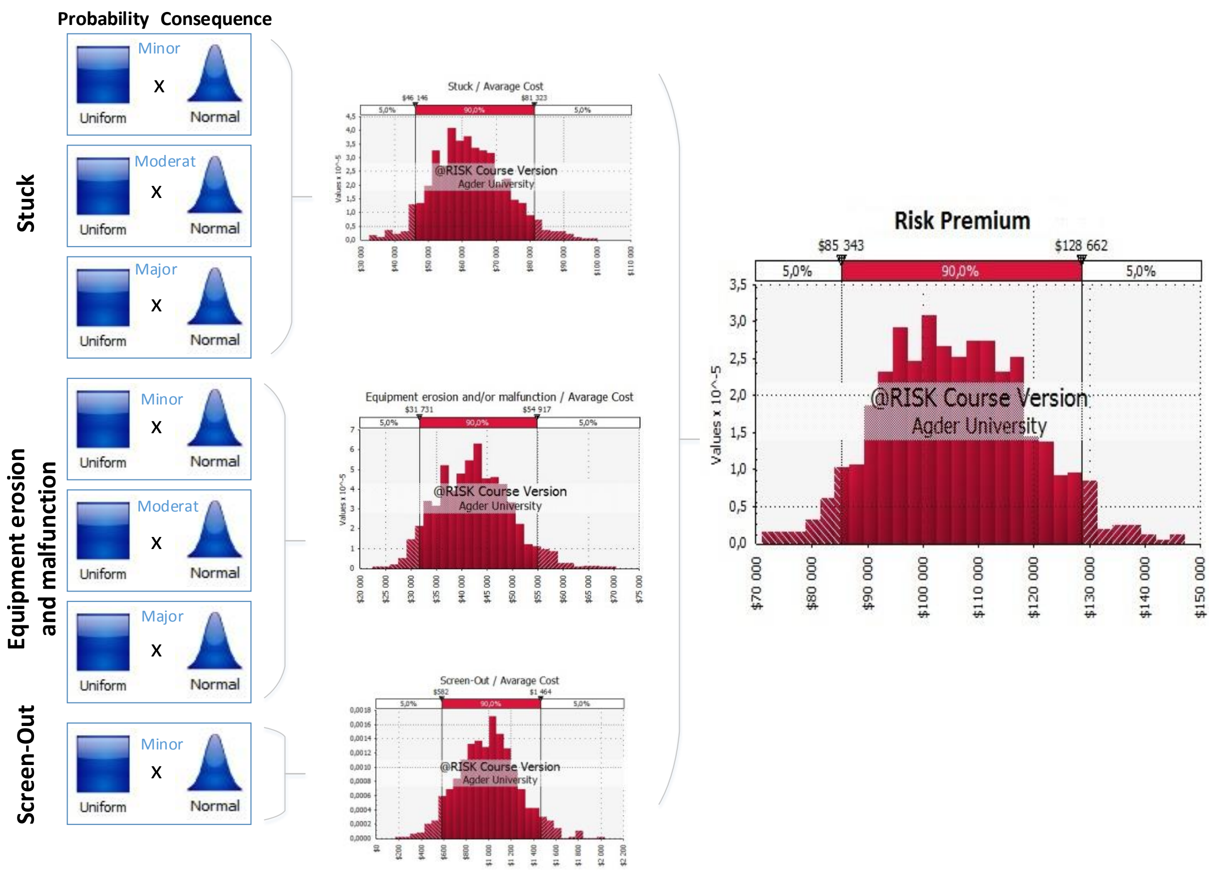

Figure 9-5: illustration of how the risk is calculated by the use of Monte Carlo simulation

The risk of refracturing and recompletion are calculated separately, because recompletion requires additional mechanical operations to add perforations in the lateral. The mechanical risk of adding perforations is calculated based on the cost of none-mechanical techniques identified in the interviews. This is done because the only mechanical operations these techniques require are related to adding perforations. The Monte Carlo simulations gave an average cost of $ 44 375 for adding perforations. This is calculated by excluding the risk of screen-out from the none-mechanical techniques, because screen out is not related to the mechanical operations of adding perforations, see Table 9-12 and equation 9-1.

Table 9-12: Risk calculations for none-mechanical re-completion

Risk	Consequence	Probability	Distribution	Average Cost	Distribution	Most likely cost based on MCS
Stuck	Minor	5% - 10%	Rectangular	$ 100 000	Normal	$ 25 000
	Moderate	3% - 7%	Rectangular	$ 200 000	Normal	
	Major	1% - 2%	Rectangular	$ 500 000	Normal	
Equipment erosion and malfunction	Minor	10% - 25%	Rectangular	$ 100 000	Normal	$ 19 375
	Moderate	5% - 10%	Rectangular	$ 200 000	Normal	
	Major	1% - 2%	Rectangular	$ 500 000	Normal	
Screen-out	Minor	10 %	Normal	$ 10 000	Normal	$ 10 000
Average cost						**$ 54 375**

$$\text{Risk of adding perforations} = \text{“Stuck”} + \text{“Equipment erosion and malfunction”} \qquad 9\text{-}1$$

It is important for the reader to understand that these are average risks for each technique. In reality the risk is a stochastic variable which will vary from case to case, and needs to be calculated based on the complexity of the well and the total length of the operation.

Table 9-13 summarizes the results from the Monte Carlo simulations. As we can see, the none-mechanical techniques have mechanical risks even though they are not using any mechanical tool directly in their operations. This is because the none-mechanical techniques have a risk of screening out under the operation, which may require mechanical tools. Some of the techniques have a higher risk than others; this is related to the complexity of the possible failures, and/or the number of mechanical runs that is required downhole. The extra risk with recompletion, is as mentioned, the risk related to adding perforations.

Table 9-13: Illustration of the risks which are divided in two, refracturing and recompletion

	Risk	
Technique	**Re-fracturing**	**Re-completion**
Pump and Pray	$ 10 000	$ 54 375
Bull-head diversion	$ 10 000	$ 54 375
Coiled tubing	$ 61 625	$ 106 000
Sliding sleeve - Inner string	$ 101 875	$ 146 250
Cemented - Insert liner	Unable	$ 92 500
Cemented - Squeeze	Unable	$ 101 875
Expandable liner	Unable	$ 135 000
Comitt Well Solutions	$ 107 875	$ 152 250

Validation

The public data do not to include the cost and risk associated with the loss of an entire well. The risk of losing the entire well is the cost of lost production and the cost associated with the refracturing attempt. However, because every well has a unique amount of hydrocarbons in their surrounding formation, it is no way of generalizing the cost of losing an entire well. For that reason the risk for each technique should be higher, yet this does not affect the comparison of the techniques significantly. This is because the risk of losing the well is not directly related to the techniques, but the integrity of the well and other well specific factors, ref. mechanical and annular integrity Table 6-1 in chapter 6. The well might for that reason be lost regardless of which technique is being used.

The failure mechanisms identified in the literature study includes risks associated with MIT. This failure mechanism was mentioned through the interviews, however, we have included failure mechanisms associated with MIT within the category “stuck” and “equipment erosion and malfunction”. This was done because the failure mechanisms associated with the integrity of the well will reflect the chance of experiencing failure mechanisms like getting stuck, equipment erosion or malfunction.

9.3.2 Cost Evaluation

To be able to calculate the cost of operation for each technique, based on the unit costs presented in subchapter 7.3, a fictive well had to be simulated. Table 9-14 shows the input needed to calculate the cost presented in Table 9-15. The design varies significantly from well to well, but this could be a typical average well.

Table 9-14: Customized input for a fictive well, to be able to calculate a cost of operation based on unit costs

Input variables	Customized well input
Lateral length (ft.)	5000 ft.
Number of stages	15
Number of clusters/stage	5
Designed Proppant/stage (lb.)	15000 lb./stage
Number of diversion balls/stage	40

Table 9-15: Generalized cost of operation for every technique, based on a fictional well

	Cost of operation	
Technique	**Refracturing**	**Recompletion**
Pump and Pray	$ 700 000	$ 1 225 000
Bull-head diversion	$ 1 095 000	$ 1 620 000
Coiled tubing	$ 1 525 000	$ 2 050 000
Sliding sleeve - Inner string	$ 1 560 000	$ 2 085 000
Cemented - Insert liner	Unable	$ 2 800 000
Cemented - Squeeze	Unable	$ 2 650 000
Expandable liner	Unable	$ 3 350 000
Comitt Well Solutions	$ 1 500 000	$ 2 500 000

Validation

As seen in Table 6-2 in subchapter 6.2, the Bull-head diversion technique had an average cost of $ 950 000 (no stages count specified). The cost calculations estimated these costs to about $ 1 100 000 for the fictive well. This indicates that the costs estimated could be realistic.

Total Cost of Operation

In Table 9-16, the total cost of operation is simulated and calculated with the use of equation 8-1 presented in subchapter 8.4. The costs are based on the fictive well calculations presented above, and the risks identified earlier, see Table 9-13. The fictive well with the total cost presented will be further used in the profit calculation tool calculations presented in subchapter 9.4.

Table 9-16: Total cost of operation, based on calculated cost and risk for each technique

	Total Cost of Operation	
Technique	Refracturing	Recompletion
Pump and Pray	$ 710 000	$ 1 279 375
Bull-head diversion	$ 1 105 000	$ 1 674 375
Coiled tubing	$ 1 586 625	$ 2 156 000
Sliding sleeve - Inner string	$ 1 661 875	$ 2 231 250
Cemented - Insert liner	Unable	$ 2 892 500
Cemented - Squeeze	Unable	$ 2 751 875
Expandable liner	Unable	$ 3 485 000
Comitt Well Solutions	$ 1 607 875	$ 2 652 250

By comparing Table 9-15 and Table 9-16 there is no significant changes in the relation between the costs of each technique, which indicates that the risk does not affect the total cost in any significant way. This is because the risk is far less than the cost of operation, and will for that reason not differentiate the techniques.

Validation

The risk should also be based on unit costs, because the failure mechanisms are likely to happen more often in a time consuming operation. This is excluded in this thesis because of lack of data. For that reason these costs are just for comparisons purposes, and will not represent the true risk of operation. However, the risk is calculated based on the most likely average risk of each technique, which will likely be representative for an average well. For that reason, this exclusion will not change the profitability calculations in the next subchapter significantly.

9.3.3 Numerical Analysis

In this subchapter we will try to do a statistical generalization of the trends gathered through the public available literature presented in subchapter 6.2. The analysis of production increase is mainly based on the incremental increase of EUR, because the EUR will give an indication on the total profitability of the refracturing operation. The numerical analysis of the initial production and decline factors will give us an indication of what to expect post-refracturing.

General Profitability

In Figure 9-6 and Figure 9-7, the incremental EUR from the data collection are plotted to illustrate the incremental production increase of gas- and oil wells respectively. As we can see from Figure 9-6, there are a few refractured wells that have experienced a negative EUR, which indicates loss of recoverable reserves. However, a positive EUR will not necessarily indicate that the overall economics are positive. It has to be compared with the total cost of operation.

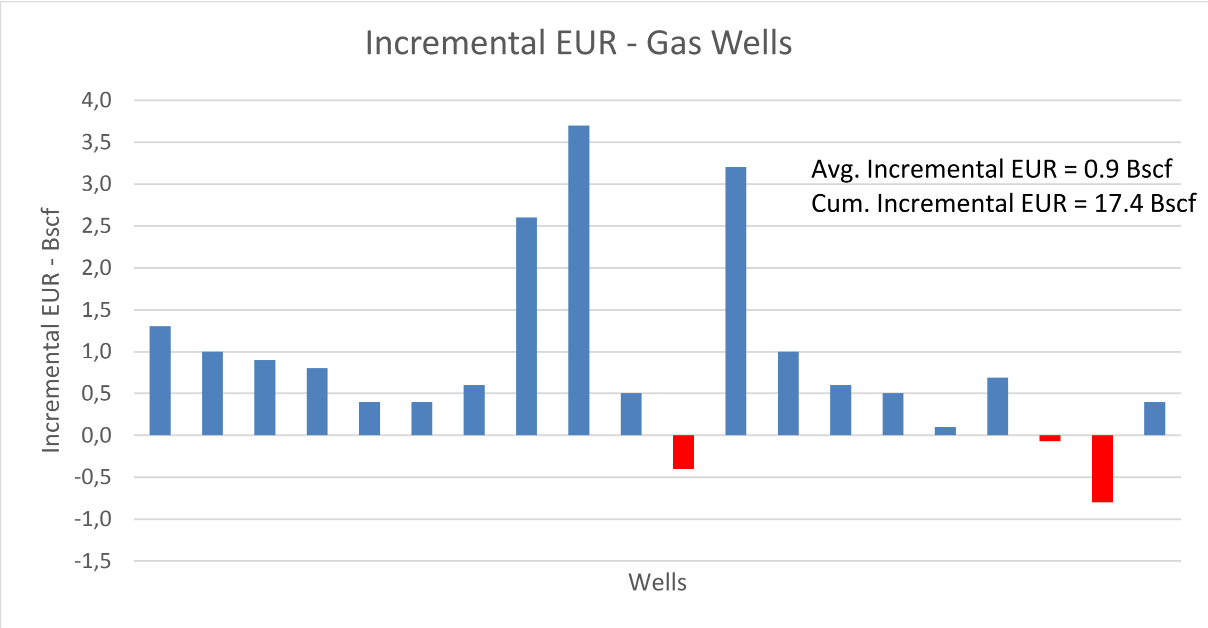

Figure 9-6: Graph of estimated ultimate recovery (gas wells), showing an average increase in potential recovery of 0.9 Bscf (technique unknown)

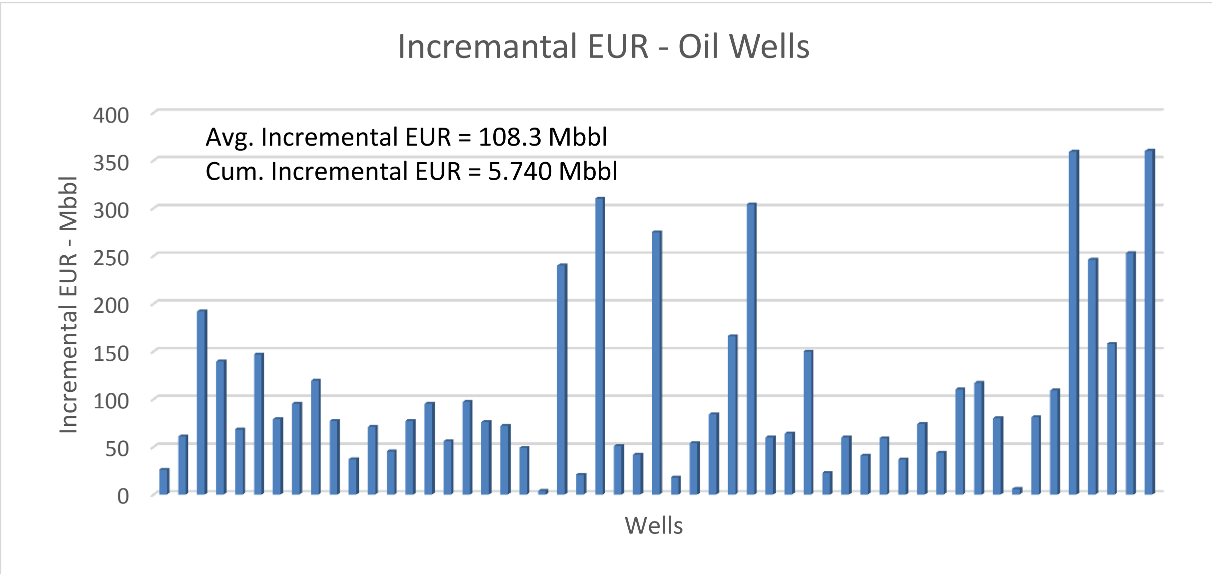

Figure 9-7: Graph of estimated ultimate recovery (oil wells), showing an average increase in potential recovery of 108.3 Mbbl (technique unknown)

As illustrated in Figure 9-6, the average EUR has increased by 0.9 bcf, which equals to 900 000 Mcf. Table 9-17 show a potential average revenue of $ 2 300 000 for each well with a fixed gas price of $ 2.5/MMBtu. For the oil wells inn Figure 9-7, there was an average EUR increase of 108.3 Mbbl, which at an oil price of $ 60 will be about $6 500 000 in increased recoverable reserves per well.

Table 9-17: Simple calculation of potential revenue with a fixed gas price of $ 2.5/MMBtu

Gas price (MMBtu)	$ per MMBtu x 1.028 = $ per Mcf *	EUR increase (Mcf)	Potential revenue
$ 2.5/MMBtu	$ 2.57/Mcf	900 000 Mcf (0.9 Bcf)	~ $ 2 300.000

* (U.S. Energy Information Administration, March 2015)

As calculated earlier, the majority of the techniques have a cost below these incremental recoveries. These numbers are however not in NPV values, and will as a result not be decision relevant. The NPV was not possible to calculate due to lack of monthly production data. For that reason NPV calculations will be simulated in the next subchapter with the use of the profit calculation tool. However, the average revenue of the oil wells are significantly higher than the total costs of operation calculated earlier, which indicates a huge economical potential in refracturing oil wells. Gas wells seem to be less economical, but there is still a significant potential of economical success.

Even though some wells have a low or even negative EUR trend post-refracturing operation, there are some wells that contribute with a significant EUR increase which overall indicate a really positive production increase of refracturing operations. As indicated in Chapter 9.1, there are shown that a minority of the wells represents the majority of the production. Some wells might not be economical to refracture, while others seem to be highly economical. By doing a good candidate selection the success rate of refracturing can be improved, and lead to an even higher economical success.

Profitability of each Refracturing Technique

Figure 9-6 and Figure 9-7 do not distinguish which techniques that have been used for the refracturing operations, and for that reason it is hard to evaluate anything about the overall economics associated with the techniques. However, Figure 9-8 presents the incremental EUR of recompleted wells with the use of bull-head diversion technique with added perforations.

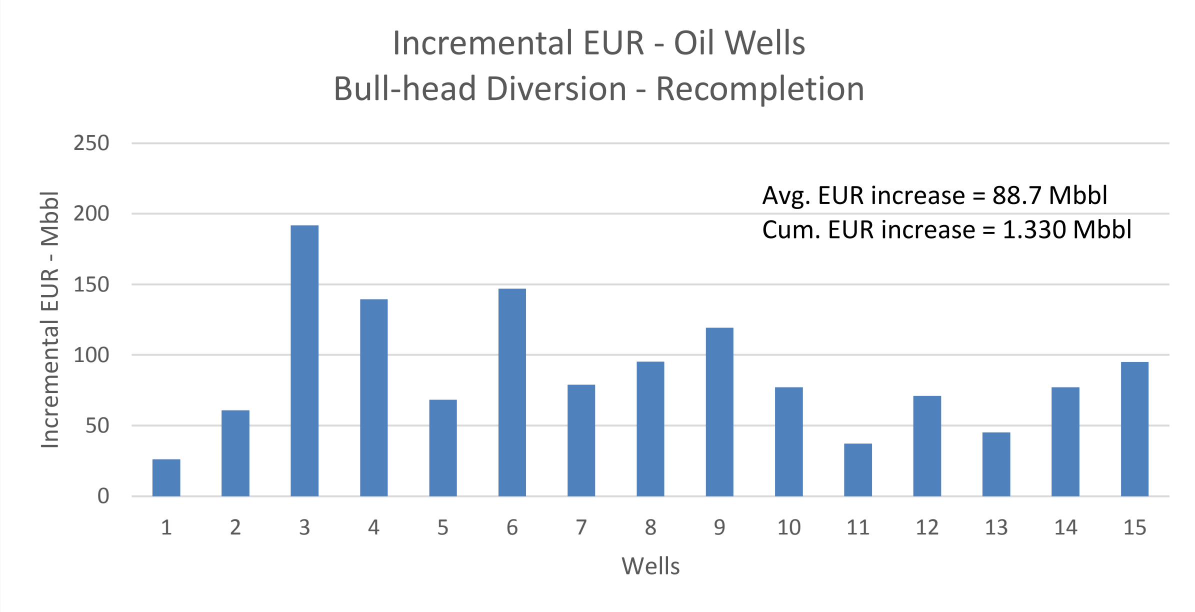

Figure 9-8: Graph showing incremental recoveries for recompleted wells with Bull-head diversion technique

As mentioned previously, lack of monthly production data prevents us from calculating the NPV for these wells. Regardless, some assumptions can be made to get a picture of the profitability. With an oil price of about $ 60, the average revenue will be about $ 5 300 000, based on an average EUR increase of 88.7Mbbl.

Flush production experienced from shale wells contributes with a high production the first few months, which will indicate that the NPV of the production increase will be less affected than if the production was uniformed distributed. For that reason the NPV will be close to the calculated numbers above. From the cost calculations presented earlier we can see that a none-mechanical technique, like Bull-head diversion, cost about $ 1 700 000 in average for a recompletion operation. This is significant lower than the calculated profit from the incremental production increase, which indicates that this technique has been really profitable. However, these calculations are based on a small data set and a fixed oil price, which likely don't represent the overall economics. However, it gives us a picture of the profitability.

The public data on other refracturing techniques are poor, as it can be seen from the literature study and the summary in Figure 9-9. No trends can be accurately calculated based on this inadequate data set.

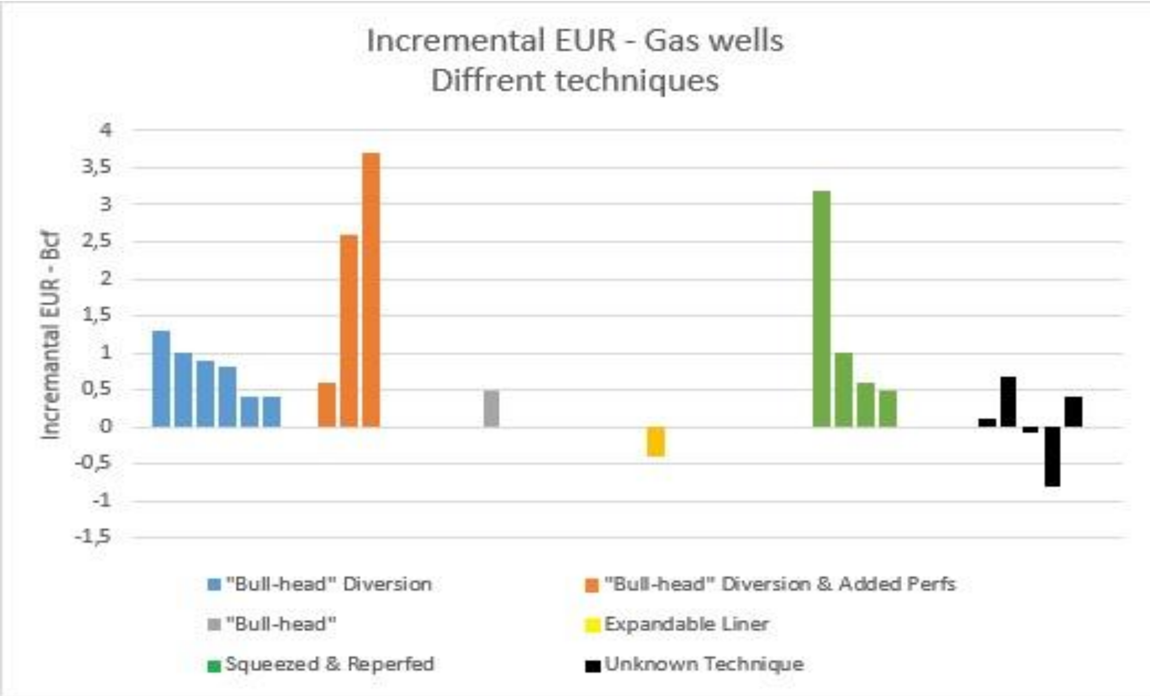

Figure 9-9: illustration of experienced production increase in gas wells. The different colors represent different refracturing techniques

Initial Production and Decline Factors

In this section the initial production and decline variables are analyzed to be able to predict more accurately what is going to be the outcome of future refracturing treatments. First an analysis regarding the original IP versus the IP post-refracturing operation will be conducted, to investigate what can be expected as an average result. Then an analysis of the comparisons between the EUR ratio and the IP ratio is conducted to see if a high IP ratio is related to a high EUR ratio. Finally an analysis of the decline factors is presented. The trends might help us predict the post-refracturing decline, which will be of great importance to the oil companies around the world.

Original Initial Production vs. Initial Production Post-refracturing

From the literature study we have presented the original IP, the IP pre-refracturing and the IP post-refracturing in Figure 9-10. As it can be seen, the original production in every well has declined significantly since the initial refracturing completion, which is typical for unconventional shale wells, explained in subchapter 3.2. However, production data shows that it is possible to get high production rates post-refracturing operation. Ten of the 38 wells achieved higher production post-refracturing operation than the wells achieved after the original fracturing operation. It is also interesting to see the increased production from pre-refracturing. The post-production has in almost every case increased by several hundred percent from the pre-production. Even though the production declines fast, it indicates the potential benefits of refracturing.

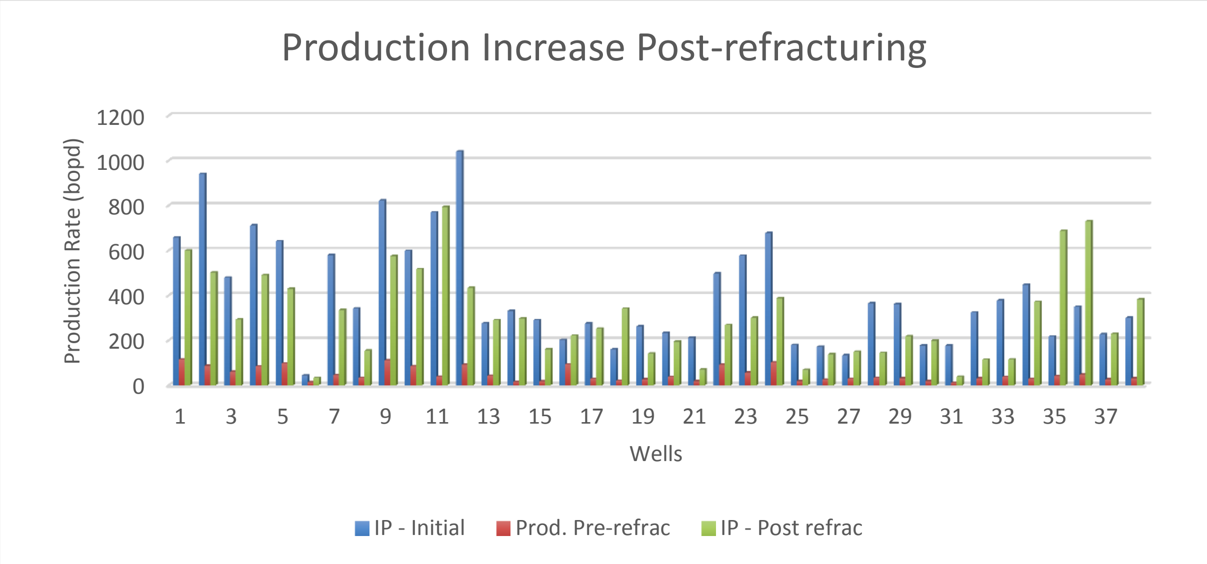

Figure 9-10: Graph showing the initial production from the original treatment, the initial production pre-refracturing operation and the post-refracturing production of 38 oil wells

In Figure 9-11, we have simulated the IP ratio between original- and post-refracturing productions. A few wells experienced a production increase of over 200 percent of the original IP. Average IP ratio for those wells was about 0.84, indicating a post-production of 84 percent of the original IP. As we can see, there are a few quite high exceptions, but these are argued to be because of poor original fracturing operations by our respondents. There is not enough data to analyze why the IP ratio is under 1.0, but one of the common presumptions is because of depletion. However, as mentioned in subchapter 9.1, one of our respondents has seen a well refractured multiple times were initial production rates were achieved every time, hence depletion might not be the reason for a lower IP.

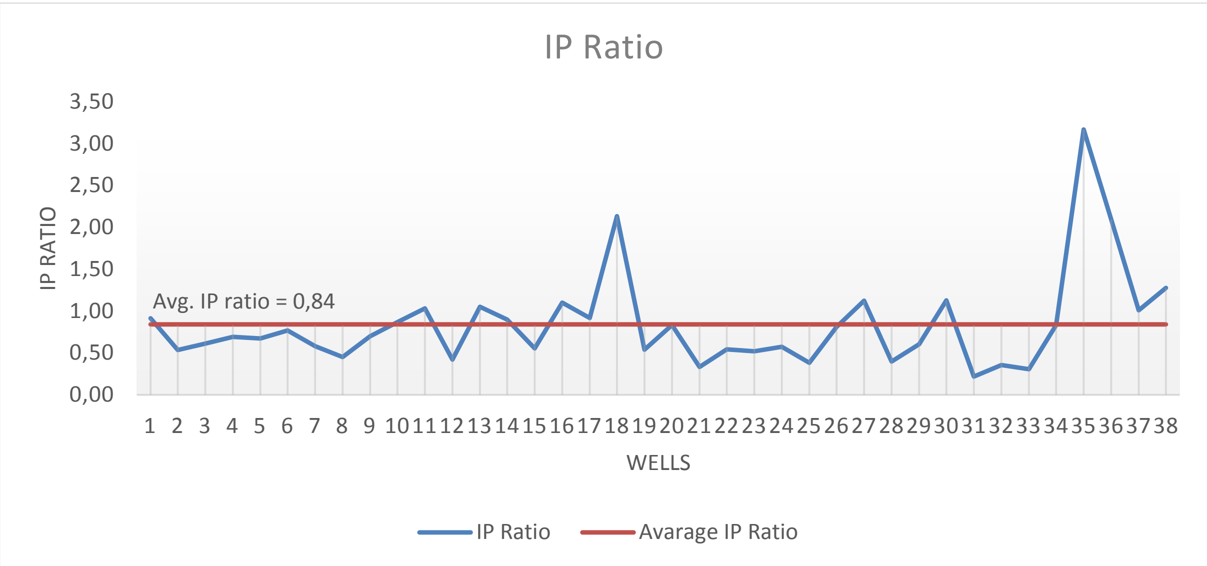

Figure 9-11: Illustration shows the Initial production ratio, where the average production increases is about 84% of the original treatment

Initial Production Ratio vs. Estimated Ultimate Recovery Ratio

We raised the following question:

- Does a high IP ratio indicate a high EUR ratio?

In other words, does the IP indicate anything about the profitability of the refracturing operation? The IP- and EUR ratio is plotted in Figure 9-12. As shown, there is no good correlation between the two. Some wells with high IP ratio have the same EUR ratio as many of the wells with a fairly low IP ratio, and vice versa. This is likely because the decline factors (b- and D- factor) are changing. We are for that reason going to analyze the decline factors in the following section.

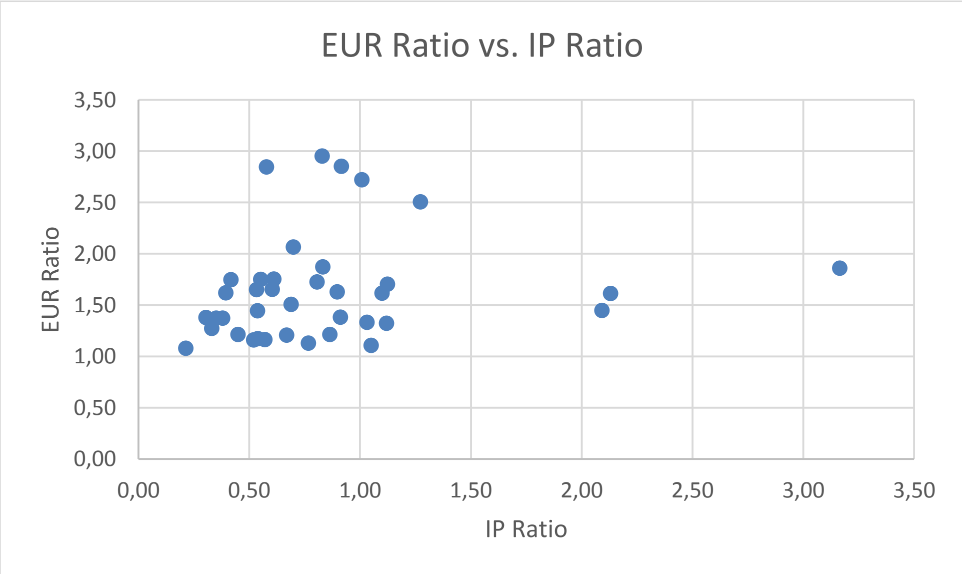

Figure 9-12: The illustration shows no correlation between the ultimate recovery ratio and the initial production ratio

Initial Production Ratio vs. Decline Ratio

As show in Figure 9-12 above, there is no correlation between the IP- and EUR ratios. For that reason we raised the following questions:

- Does the post-refracturing decline have the same trend as the original decline?
- How do the decline factors change?

As presented in the literature study, Oruganti et al. (2015) retrieved data on horizontally refractured wells. They could see a trend between initial decline rates and post-refracture decline rates. The post-refracturing decline rates was found to have the same b-factors as the initial decline rates, and that the secant decline rates (D-factor) were typically lower after refracturing operating. This trend is shown in Figure 9-13. As shown in Figure 9-13, the b-factor did not change in 21 of 38 wells, while the D-factor changed in every well except one. The average b-factor increased by 8 percent, and the D-factor declined by 13 percent in average. This trend will decrease the decline of the curve, and slightly shift the curve towards a flat trend, as illustrated in Figure 9-14. In this analysis a more comprehensive analysis is conducted in the following, where we look at the correlation between the IP ratio and the decline factors.

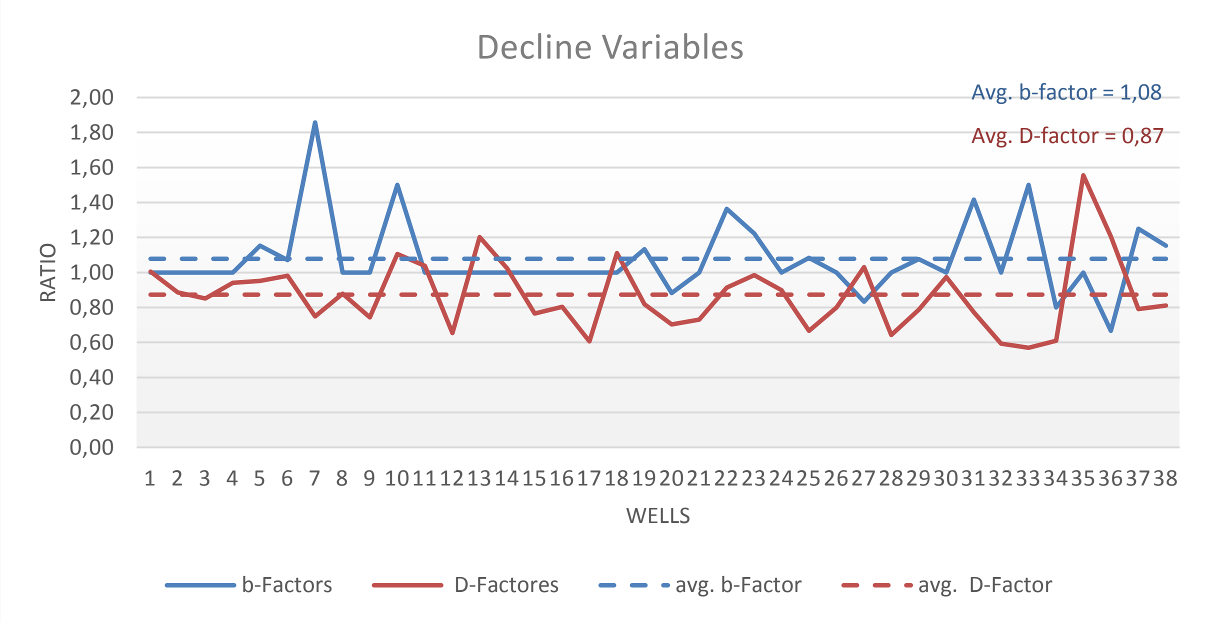

Figure 9-13: Incremental change in decline variables, where 1.0 represents no change

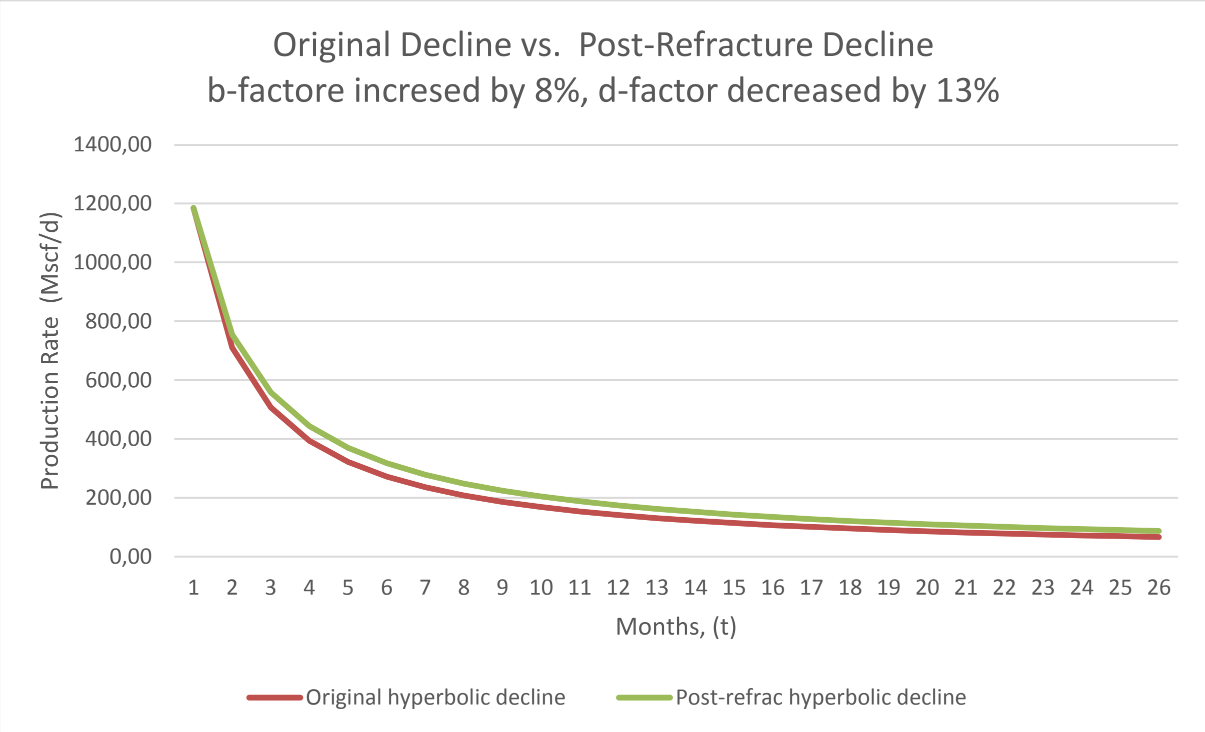

Figure 9-14: Original decline curve and post-refracture decline curve are plotted to illustrate the effect of the changing decline variables post-refracturing

We have now illustrated that the decline variables tend to change post-refracturing, and that the trend is moving the decline towards a flatter trend, which is favorable for the economics in refracturing. The b-factor looks to be unchanged in the majority of the wells, and will for that reason not be further analyzed. However, a further analysis of the decline variable “D” is conducted to see if there is any trends that may help in forecasting production more accurately.

Trends between IP Ratio and Decline Factor "D"

In Figure 9-15, we have simulated the relation between the IP ratio and the decline factor "D". The findings were of sever interest. As it can be seen, there seems to be a slight correlation between the IP ratio and the decline factor. Even though these simulations are based on a data set with few wells, we want to look closer at the trend seen in Figure 9-15. A trend line is simulated to show that the D-factor tends to increase with the IP ratio.

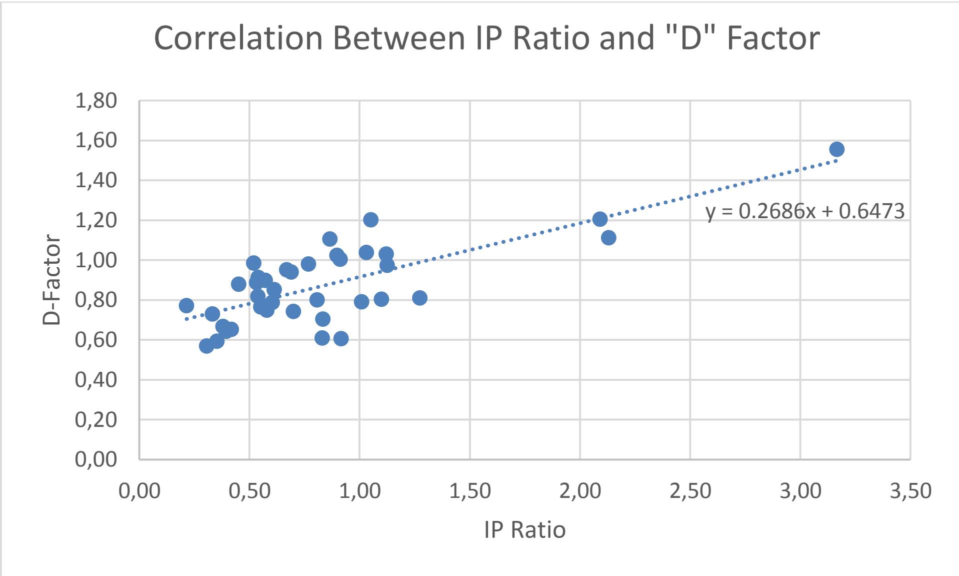

Figure 9-15: Correlation between the initial production ratio and the decline factor "D", resulting in a formula

$$y = 0.2686x + 0.6473 \qquad 9\text{-}2$$

The trend shows that with an IP ratio under 1.0, the D-factor tends to be lower than initial D-factor, and high IP ratio over 1.0, the D-factor tends to increase. This indicate that wells with an IP ratio under 1.0 do not decline as fast as they did initially, and that wells with high IP ratios declines faster than initially, this is illustrated further in Figure 9-16. This trend gives an indication that, if a well is experiencing a high IP ratio, it is likely to decline fast due to flush production. Equation 9-2 corresponds to the trend line in Figure 9-15 and can be used to give an indication when predicting the decline change in future wells. Equation 9-2 will further be used in the profit calculation tool calculations in subchapter 9.4.

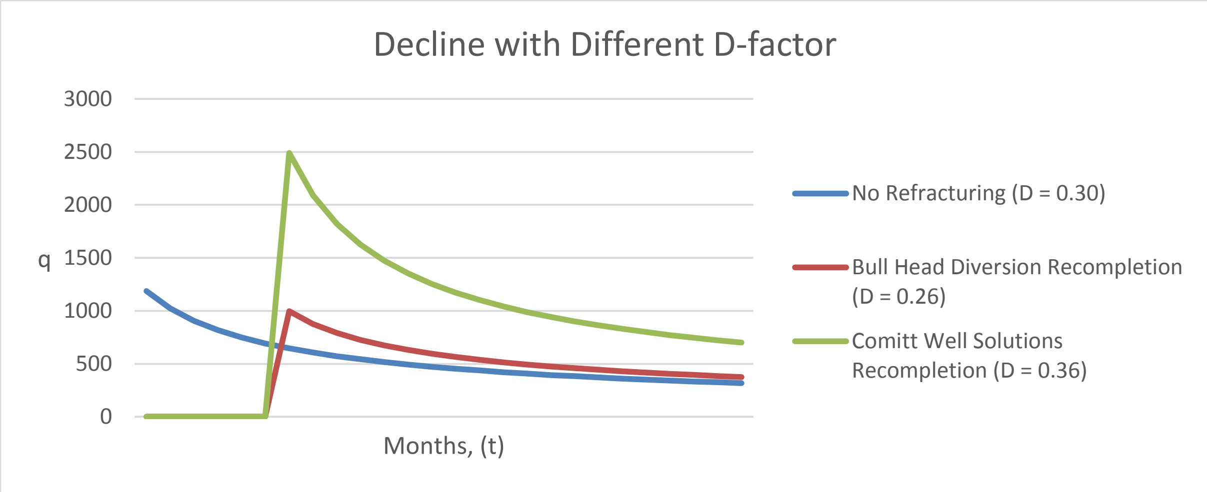

Figure 9-16: The illustration show that wells with a higher IP than the original treatment will decline faster, hence a higher decline variable, and vice versa

Summary of the Main Findings

One of our main findings throughout this chapter was the correlation between the IP ratio and the decline factor "D". This is a finding that can be perfected as more data becomes publicly available and will likely improve the production forecasting of refracturing operations. This finding is classified as a supplementary finding because it does not directly answer our research questions, however we integrated this finding in our profit calculation tool to better be able to forecast the production. Another main finding has been the huge economic revenue, seen from the significant production increase post-refracturing operations compared to the calculated total cost of operations. It seems to be a higher economical potential in oil wells because of the high oil price. Another supplementary finding was that the risk did not have any significant effect on the total cost of operation, mainly because of the low risk compared to the investment cost. The average production increase seems to be almost as high as the original IP, resulting in a significant increase of production compared to the production pre-refracturing operation, with low investment costs.

9.4 The Profit Calculation Tool

As earlier shown in chapter 8, we constructed a profit calculation tool based on the technical evaluation, and the economical evaluation and numerical analysis to be able to do a better evaluation of the economics in refracturing. The profit calculation tool is able to compare the economical potential of each refracturing technique. Furthermore, it provides the industry with a tool to calculate the potential profitability of different wells up for refracturing decisions. In this chapter we will firstly explain and discuss the production increase foundation and functionality of the tool. Secondly we will calculate, evaluate and compare the economical potential of the different refracturing techniques by using the profit calculation tool on a fictive well.

9.4.1 Production Increase and Functionality in the Profit Calculation Tool

The production increase generated by the different refracturing completion techniques is based on the technical grade estimated in the technical evaluation, see subchapter 9.2, and the production increase trends in the economical evaluation, see subchapter 9.3. As defined earlier, in this thesis we use refracturing as a term of restimulating the well without adding new perforations and recompletion as refracturing the well and in addition add new perforations.

To be able to forecast production increase for the different techniques, Bull-head diversion technique is used as a base. The Bull-head diversion technique's production increase is based on an average production increase seen in the economical evaluation in subchapter 9.3. This is the only technique with enough data to estimate an average production increase post-refracturing. The other techniques' production increase post-refracturing, shown in Table 9-18, is calculated with the following equation with the use of the technical grade ratios:

$$\text{Prod. increase technique X} = \frac{\text{Tech. grade Tech. X}}{\text{Tech. grade Bull} - \text{head}} * \text{Prod. increase Bull} - \text{head} \tag{9-3}$$

Table 9-18: Production increase estimated for each refracturing completion techniques based on trends from Bull-head diversion technique.

Production Increase			
Techniques	**Refracturing**	**Recompletion**	**Technical grade**
Pump and Pray	43 %	72 %	3,0
Bull-head diversion	50 %	84 %	4,0
Coiled tubing	50 %	84 %	3,0
Sliding sleeve – Inner string	93 %	156 %	5,0
Cemented - Insert liner	86 %	144 %	5,5
Cemented - Squeeze	64 %	108 %	6,0
Expandable liner	100 %	168 %	7,0
Comitt Well Solutions	143 %	240 %	10,0

The production increases estimated are used in the tool as a percentage of how high the initial production post-refracturing will be compared to the original Initial production of the well. The post-refracturing decline forecasting is based on the initial decline rate, but adjusted with equation 9-2 because of the trends seen in subchapter 9.3. The production increase will vary with each well and reservoir, and are therefore just indications. Yet, the tool can be updated as more information becomes available, and further customized by the companies to fit each well. As seen in Table 9-18 recompletion will most likely increase the production more compared to a general refracturing operation, because of the additional area of pay added by the new perforations.

The production increases calculated for each refracturing technique, see Table 9-18, is fixed and does not vary with the refracturing time horizon in the profit calculation tool. If the opportunity cost of the production that would be generated without a refracturing operation is excluded, the NPV estimated for each technique will be independent of the refracturing point in time. Reaching the same amount of production independently of the time horizon is unlikely because of the properties of the well, including the depletion rate, will change over time as the well gets older. The opportunity cost is included in all the profit calculation tool's calculations because of the relevance when it comes to making refracturing decisions.

By basing the future post-refracturing production increase on a new hyperbolic decline curve, there is a possibility to attain less production post-refracturing than before refracturing. This is because the hyperbolic function has a rapid decline rate in the beginning and flattens out over time. Refracturing operations, or in our case, techniques with around 50 percent production increase of the initial production, may fall in this pitfall. We have eliminated this pitfall by programming the tool to make the post-refracturing production forecast equal to the pre-refracturing production forecast curve if the production forecast before-refracturing in the future is higher than the post-refracturing forecast. To clarify the phenomenon Figure 9-17 shows a graph without this tool adjustment, while Figure 9-18 shows a graph with the adjustment. The respondents emphasized that the production after a refracturing procedure is unlikely to decrease below what the production would have been at a particular time without the refracturing procedure. Thereby we believe this is a valid assumption.

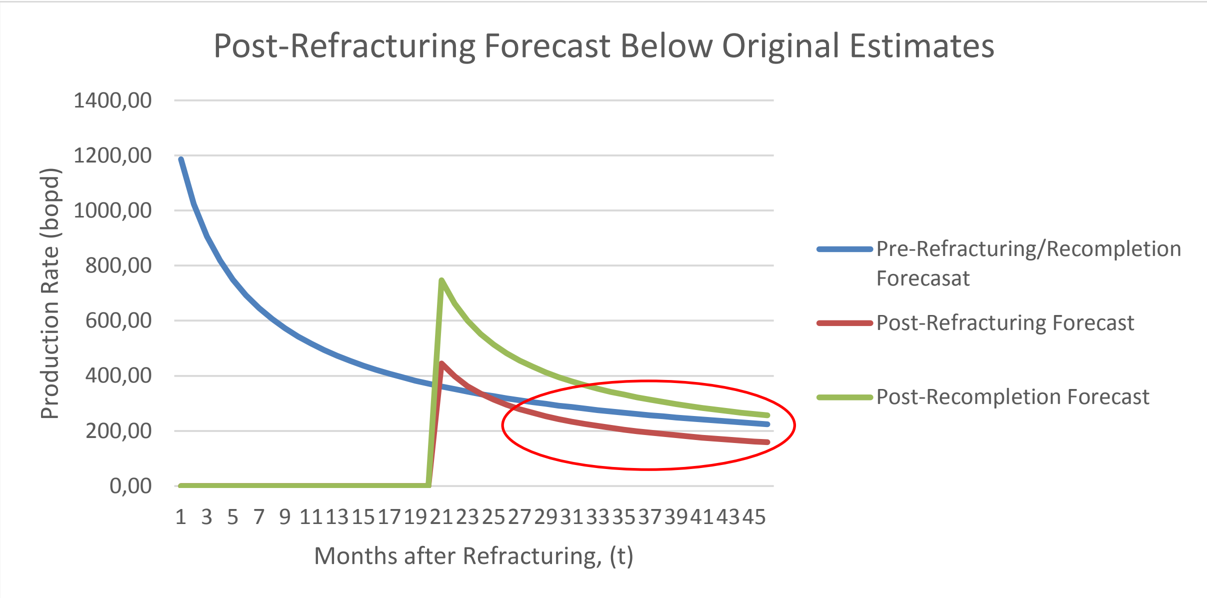

Figure 9-17: Without the tool adjustment. A production increase around 50 % of initial production leads to a post-refracturing forecasting curve with less production than the pre-refracture production curve after a certain time (In this case about 27 months)

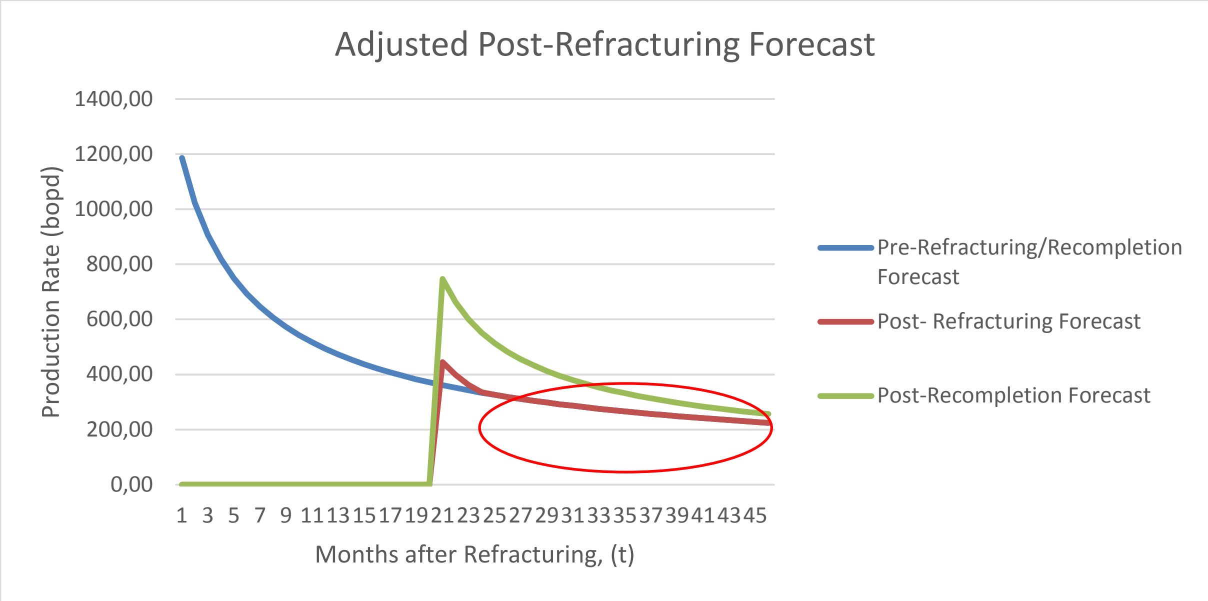

Figure 9-18: With the tool adjustment. A production increase around 50 % of initial production leads to a post-refracturing forecasting curve with equal production as the pre-refracture production curve after a certain time (In this case about 27 months).

9.4.2 Economical Calculations and Evaluations

In this chapter the constructed profit calculation tool is used to compare the economical performance of the different refracturing completion techniques and look into the general potential profitability in refracturing a candidate well. We will analyze a fictive oil well which could be a realistic refracturing candidate. The well is based on 12 months of historical data and is according to Figure 9-10, an average oil producing well. The costs and risks of refracturing this fictive well, with different refracturing techniques, are estimated in subchapter 9.3. The well analyzed is further referred to as Well 1. See appendix I for the historical well production data. The oil price used in this analysis is $ 60 and the refracturing operation took place three years after the original fracturing job.

Breakeven Price

Every well has unique characteristics and some wells are more productive than other wells. The breakeven price of a refracturing operation is connected to, the oil or gas price, how much higher production you attain in the well post-refracturing and how much the investment costs of refracturing the well are. Figure 9-19 and Figure 9-20 show the breakeven price of the different refracturing techniques for refracturing- and recompletion operations on well 1 respectively.

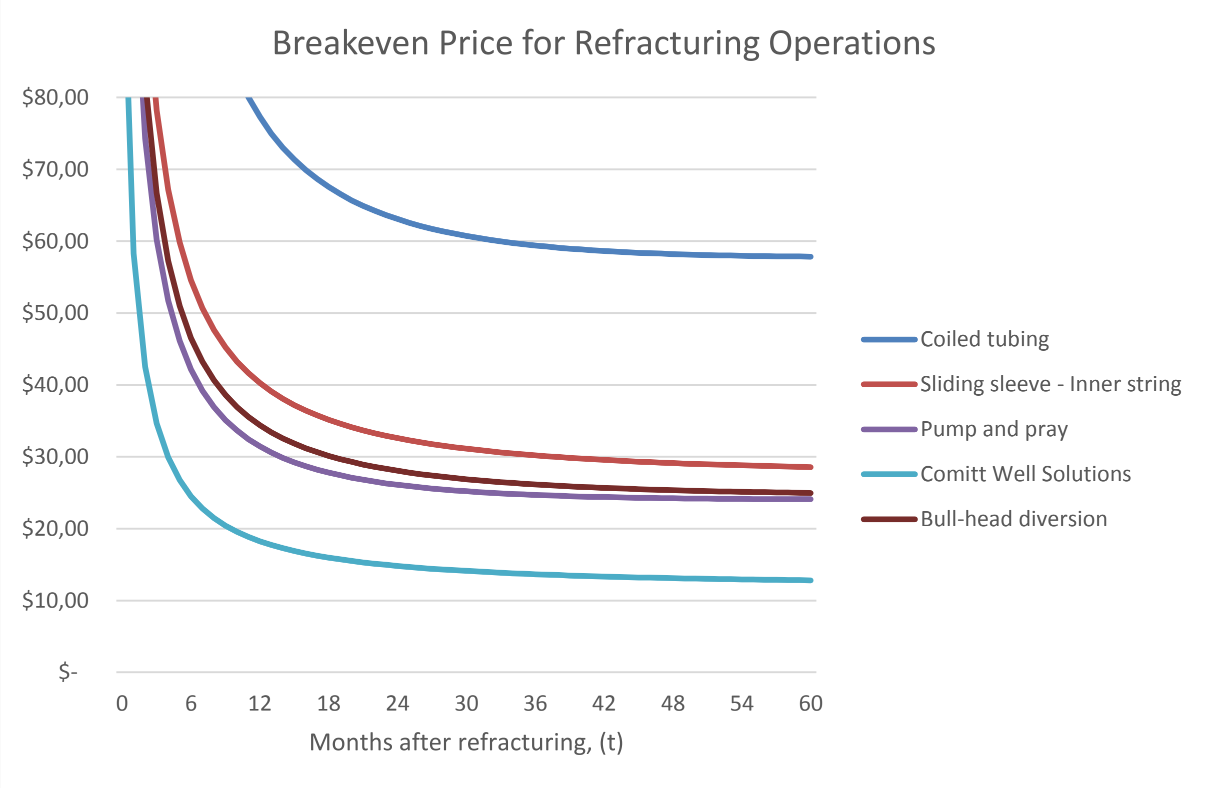

Figure 9-19: Breakeven price of the different refracturing completion techniques estimated by the tool, post-refracturing, on well 1.

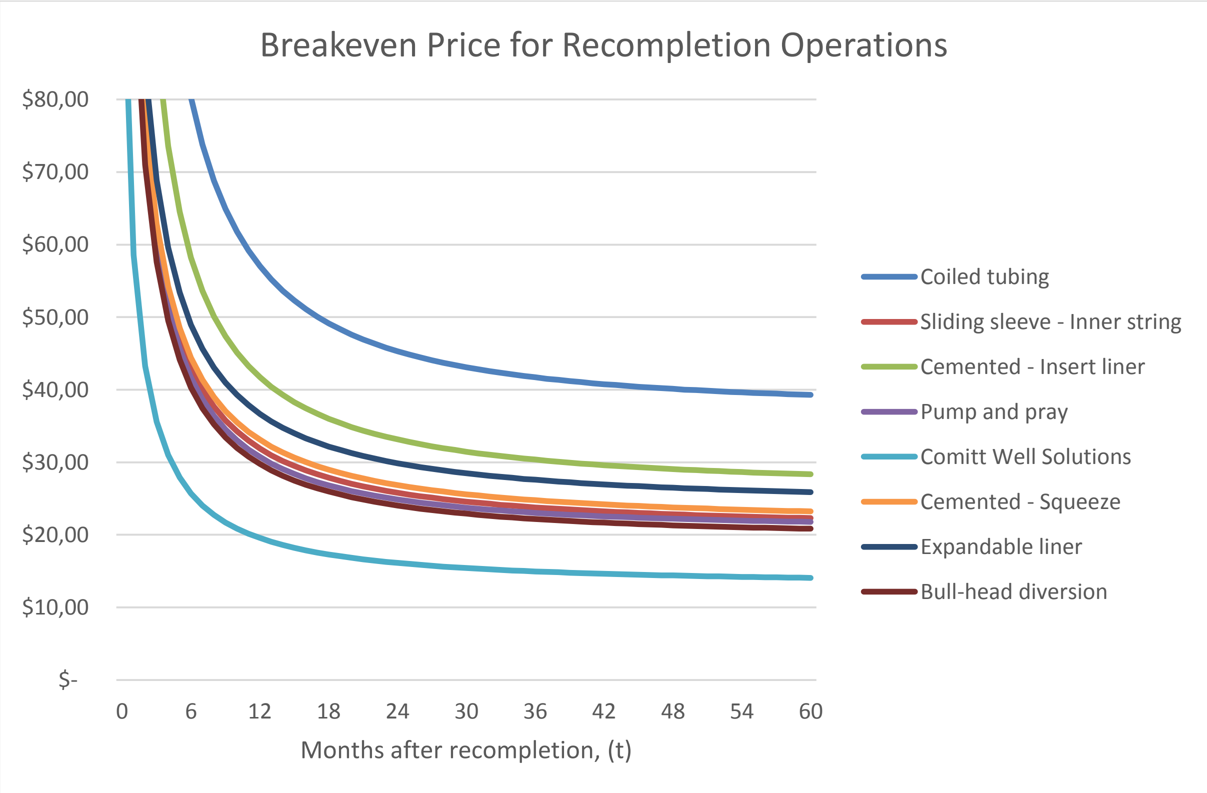

Figure 9-20: Breakeven price of the different refracturing completion techniques estimated by the tool, post-recompletion, on well 1.

As we can see recompletion has generally lower breakeven prices than refracturing. This is because by adding new perforations and refracturing you will attach more are of pay to the well than with just fracturing old perforations. Further the tool indicates that Comitt Well solutions has the technique with the lowest breakeven price, around $ 18 after 12 months when doing a refracture and $ 20 when doing a recompletion, while Coliled tubing has the highest breakeven price, around $ 80 after 12 months when doing a refracture and $ 60 when doing a recompletion. We also observe that the breakeven prices relatively flatten out after12 months. According to the estimations, every technique, except coiled tubing, will break even eventually with a minimum price of $ 30 for both refracturing and recompletion. This indicates a huge economical potential in refracturing, when initial drilling and fracturing operations operate with a breakeven price of $ 58, ref subchapter 3.3. However, it is important to have in mind that costs not directly involved with the refracturing operations, as administration costs, and increased transportation costs, are excluded from this thesis. This will impact will give higher breakeven prices, but not significantly.

Return on Investment (ROI) and Net Present Value (NPV)

Figure 9-21 and Figure 9-22 show the estimated ROI of refracturing- and recompletion operations by the different refracturing techniques on well 1.

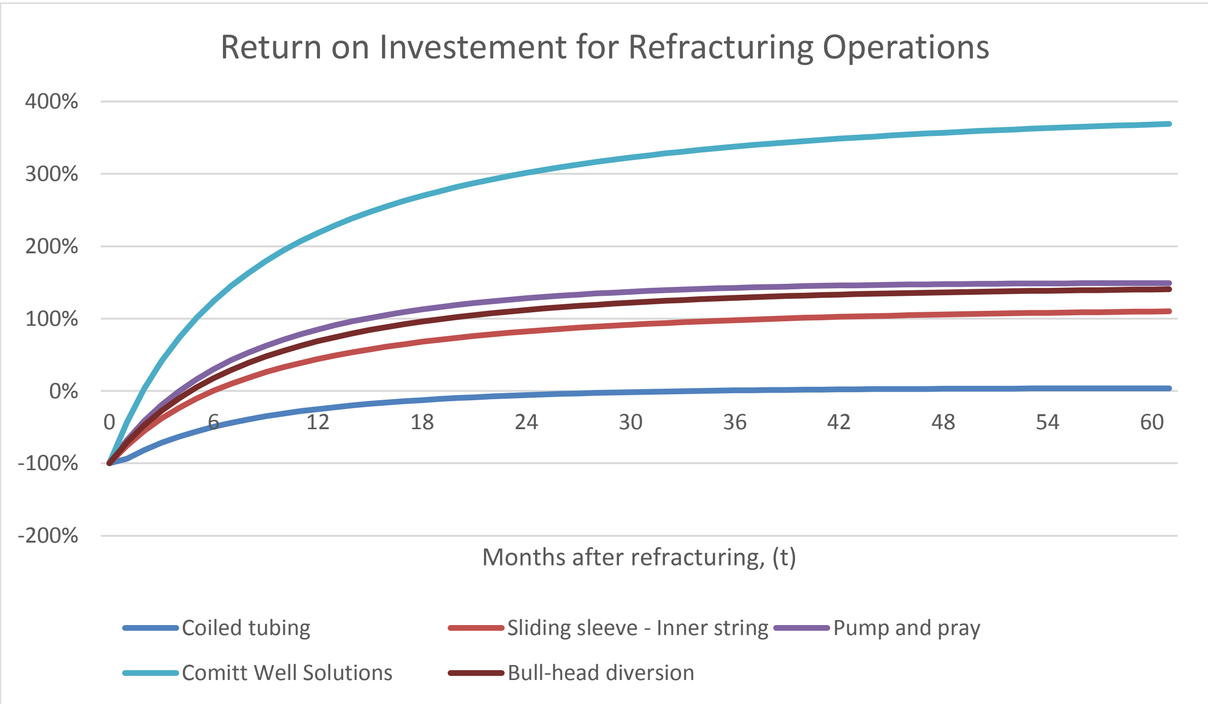

Figure 9-21: ROI estimated after a refracturing operation on well 1 with the use of different refracturing completion techniques.

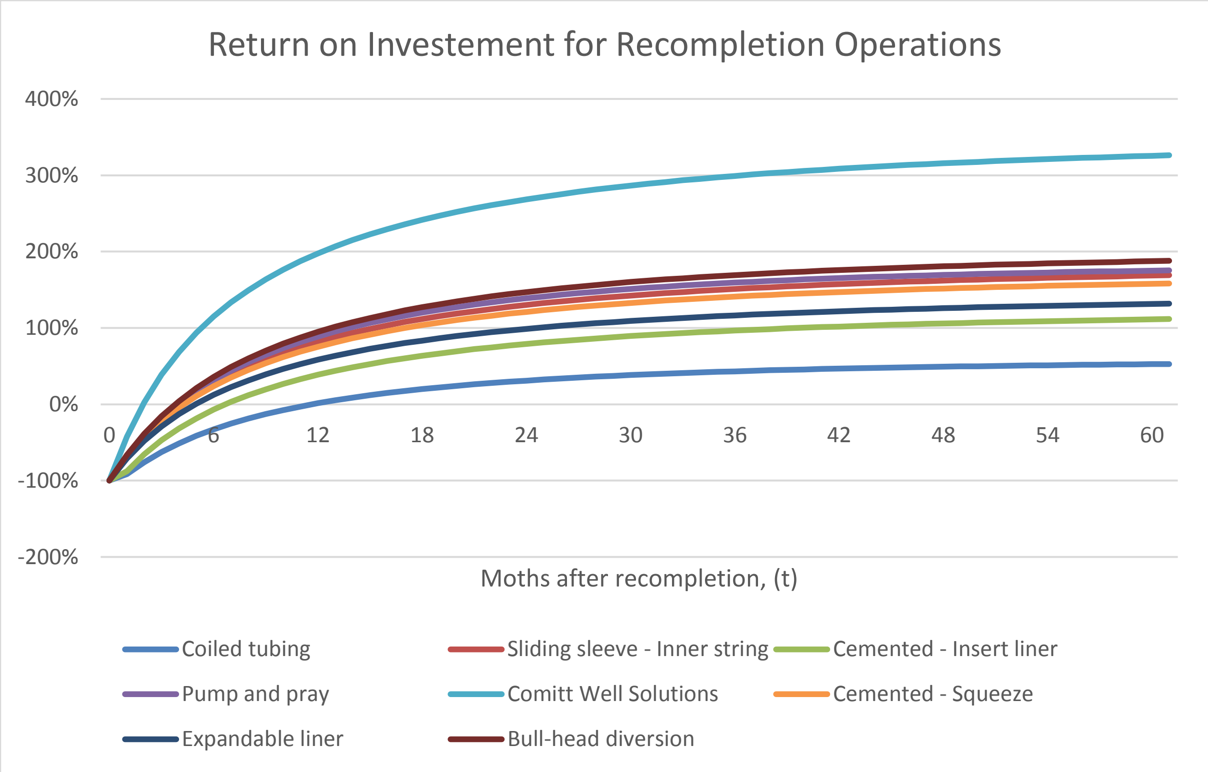

Figure 9-22: ROI estimated after a recompletion operation on well 1 with the use of different refracturing completion techniques.

Figure 9-23 and Figure 9-24 show the estimated NPV of refracturing and recompletion operations by the different refracturing completion techniques on well 1.

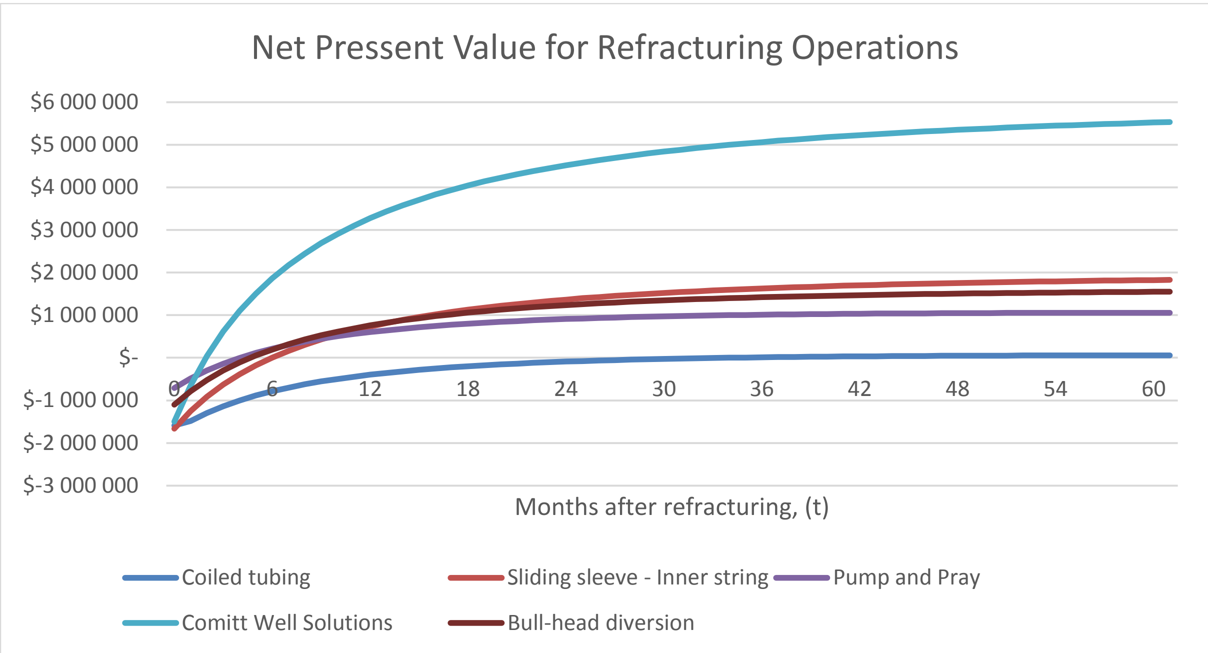

Figure 9-23: NPV values estimated after a refracturing operation on well 1 with the use of different refracturing completion techniques

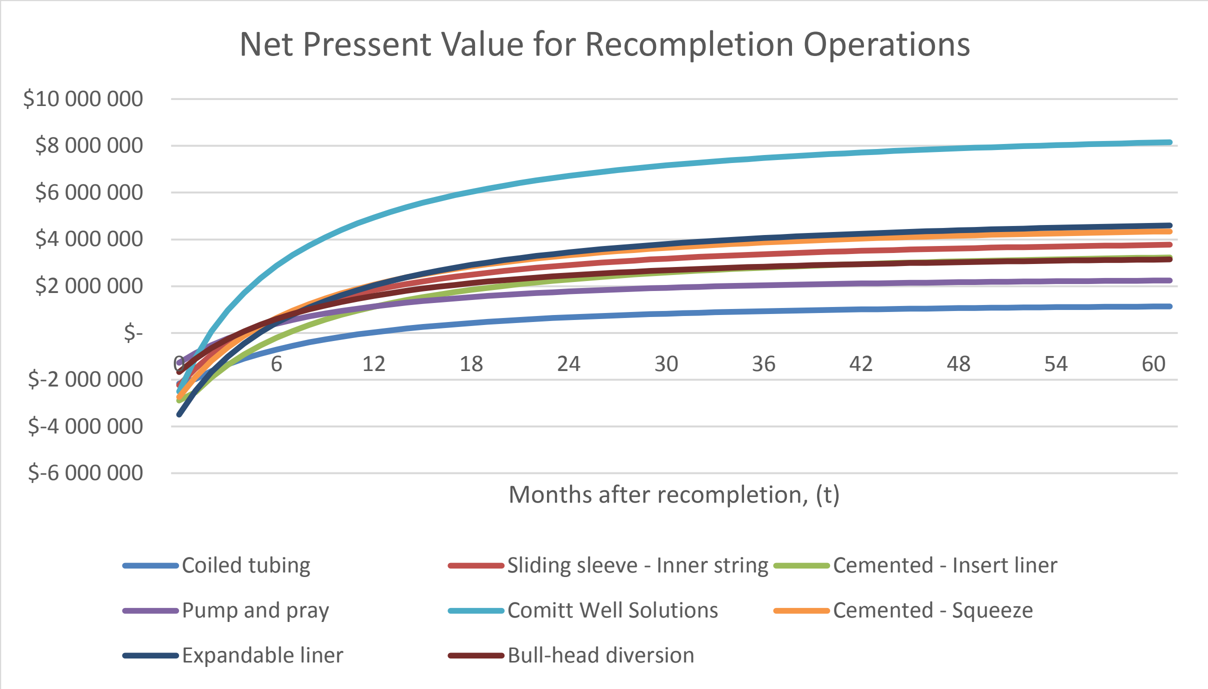

Figure 9-24: NPV values estimated after a recompletion operation on well 1 with the use of different refracturing completion techniques

All the figures indicate that Comitt Well solutions' technique is the most profitable refracturing technique regardless of performing a refracturing- or a recompletion operation. We can also see that Coiled tubing is the most uneconomical technique in addition to the graphs, Table 9-19 and Table 9-20 show how profitable the different techniques are performing after a refracturing- or recompletion operation. The results are shown in NPV two years and ten years into the future respectively, for oil production in well 1. The tables along with the graphs show that recompletion is more profitable than refracturing for every technique.

Table 9-19: Well 1's Profitability (NPV) of the refracturing operation calculated two years in to the future

Technique	Refracturing	Recompletion
Pump and Pray	$ 910 054	$ 1 776 464
Bull-head diversion	$ 1 237 136	$ 2 461 656
Coiled tubing	$ -90 284	$ 668 798
Sliding sleeve - Inner string	$ 1 367 179	$ 2 904 691
Cemented - Insert liner	Unable	$ 2 286 300
Cemented - Squeeze	Unable	$ 3 322 414
Expandable liner	Unable	$ 3 445 858
Comitt Well Solutions	$ 4 522 164	$ 6 713 355

Table 9-20: Well 1's Profitability (NPV) of the recompletion operation calculated 10 years in to the future

Technique	Refracturing	Recompletion
Pump and Pray	$ 1 060 112	$ 2 341 119
Bull-head diversion	$ 1 593 144	$ 3 317 433
Coiled tubing	$ 59 773	$ 1 233 454
Sliding sleeve - Inner string	$ 1 924 242	$ 4 004 503
Cemented - Insert liner	Unable	$ 3 493 287
Cemented - Squeeze	Unable	$ 4 627 923
Expandable liner	Unable	$ 4 925 559
Comitt Well Solutions	$ 5 818 640	$ 8 575 400

As mentioned in subchapter 9.3, the average EUR increase post-refracturing operations, shown in Figure 9-8, is equal to an average revenue of $ 5 300 0000 with an $ 60 oil price. Since this refracturing operation was a recompletion with the bull-head diversion technique, we can compare this average EUR revenue to the estimated profit calculated by the profit calculation tool, see Table 9-21. If the investment cost of the recompletion operation estimated in Table 9-16 is deducted, the profit is $ 3 625 625. This value would have been less if calculated it in NPV because of the discount rate, ref -X in Table 9-21. Ten years after a recompletion operation with Bull head Diversion is estimated to yield a NPV of $ 3 317 433 with the use of the profit calculation tool, see Table 9-20. In EUR these estimation would have been higher, ref +y in Table 9-21. This indicates that the calculations done by the tool is pretty good.

Table 9-21:Comparing average production increase seen from the literature study with NPV calculations by our tool

	EUR* $ 60	Cost	NPV	Comparing
Average EUR Lit. study	$ 5 300 000	$ 1 674 375		$ 3 625 625-X
NPV (tool)			$ 3 317 433	$ 3 317 433+Y

Table 9-22 shows when the investment cost is paid back if you perform a refracturing or recompletion operation with the use of the different refracturing completion techniques. After this month, all revenue gained by the well will be profit. As we can see by using Comitt Well Solutions' technique you are able to pay back the well by doing both a refracturing- and recompletion after two months. In comparison the next most profitable technique Bull-head diversion will pay back the investment after five months by doing refracturing and four months by doing a recompletion. All the techniques pay back the investment within a year except Coiled tubing. The short payback period of fracturing projects is due the fact that the largest part of the production is directly after the fracturing operation, and that the production starts to decline relatively fast after. Even though, the payback period is short for all the techniques, except Coiled tubing, and extremely short for the best techniques which indicate a huge economical potential in refracturing. Fracturing operations usually operate with a payback time from 18 – 24 months, ref. subchapter 3.3.

Table 9-22: Investment payback period in months based on well 1

Technique	Refracturing	Recompletion
Pump and Pray	5	4
Bull-head diversion	5	4
Coiled tubing	34	12
Sliding sleeve - Inner string	6	5
Cemented - Insert liner	11	7
Cemented - Squeeze	7	5
Expandable liner	9	5
Comitt Well Solutions	2	2

Generalization of The Profit Calculation Tool's Profitability Results

Even though the profitability comparison between the refracturing completion techniques is only showed on one well, they can be generalized to some extent. Regardless of how productive the wells are, Comitt Well Solutions will be the best technique economically because of its huge production increase potential. Coiled tubing on the other hand will always be the worst technique because of the high cost and the low production increase potential. The low cost non-mechanical refracturing techniques pump & pray and bull head diversion, will perform better economically than the mechanical techniques, except Comitt Well Solutions' technique, on low productive wells. The mechanical techniques, expandable liner, cemented squeeze and Sliding sleeve-inner string, will perform better than the non-mechanical techniques, on high productive wells. This is due these two facts:

1) Low investment cost becomes more relevant in low productive wells because of less economical potential in production increase
2) High production increase potential becomes more relevant in high productive well because of high economical potential.

This generalization is built upon the assumption that the production increase achievable for each refracturing completion technique is fixed as mentioned in 9.4.1.

Summary of the Main Findings

Table 9-23 arranges how good the techniques are performing in comparison to each other after potential refracturing profitability. The techniques are arranged after the most profitable techniques according to NPV in a ten years perspective calculated based on well 1.

Table 9-23: Refracturing completion technique arranged after their profitability. Based on the fictive well estimated by our profit calculation tool

Rank	Technique
1	Comitt Well Solutions
2	Expandable liner
3	Cemented - Squeeze
4	Sliding sleeve - Inner String
5	Cemented - Insert Liner
6	Bull-head diversion
7	Pump and Pray
8	Coiled tubing

As observed in the graphs and tables, Comitt Well Solutions' technique is the most profitable, while coiled tubing is the least profitable technique. It is worth mentioning that the other techniques vary in how good they are compared to each other on different profitability measures. The breakeven prices for the techniques are very low compared to initial drilling and fracturing operations, and the profitability of refracturing seems to be highly economical with the best techniques and an oil price of $ 60.

The economical performance of the different refracturing completion techniques is highly depended on the total cost of the technique, and the production increase received in reality. Anyhow our assumptions are based on valid information and we believe the calculations done in this subchapter give good comparisons of the techniques, and also good indications of the potential profitability achievable by performing a refracturing operation.

The constructed profit calculation tool contributes with ways of analyzing the profitability of refracturing operations. The tool's main contributions are as follows:

- The tool can forecast production increase by the use of each technique, based on the technical evaluation.
- The tool can forecast production decline, not only based on decline theory, but improved by trends from our numerical analysis in subchapter 9.3.
- The tool calculates NPV, ROI, IRR, breakeven period and breakeven price for refracturing operations, based on the user's input.
- The tool has several options which help the user in making the right refracturing decision.

For these reasons we believe that our constructed profit calculation tool gives a highly relevant contribution to the oil and gas industry today, as well as it gives the companies a better economical understanding of refracturing. Furthermore, this is something the industry lacks.

9.5 Validity and Reliability of Applied Data and Calculations

During the case study, we did our best to ensure reliability and validity; however, there are factors that threaten the validity of the data collection. The quantitative data collection is based on estimates by the respondents. The data does not present a particular refracturing case, but is estimated and generalized so that I could be the realistic cost, risk and production increase data of a real well candidate. Furthermore each well has significant different characteristics and therefore the cost and risk will vary accordingly.

There are several weaknesses with our construct. The production increase in the profit calculation tool is based on the initial production, which technique that are being used, and if you did a recompletion or a refracturing operation. You have no direct input if the well was highly operational success or a failure. Therefore this tool will not give a good estimate on really poorly and really successful initially fractured wells. The poorly initially fractured wells, as long as there is sufficient hydrocarbon material present, will probably receive a significant higher production post-refracturing than the original initial production with a successful refracturing operation. The production increase will vary from well to well. The increase is highly dependent on how much more area of pay you are able to connect to the well, especially while doing a recompletion (add more perforations). In the profit calculation tool we have estimated and generalized a fixed production increase by the use of each technique. This should be customized to each well when using the tool if you want more accurate predictions.

In the profit calculation tool we have assumed that oil and gas wells follow the same statistics. This is not a correct assumption because of the different characteristics of oil and gas, among other reasons. Anyhow, we found no good method proven with significant enough validity to differentiate production increase or production decline of oil and gas. The fact that oil and gas wells vary significantly in characteristics and production trends across the wells, indicates that the tool may produce good estimated results for both oil and gas wells, but should be adjusted and customized after the candidates' characteristics and the information the user have of the candidates.

Furthermore the tool is based on past refracturing production trends, technical evaluation and estimated risk and cost data which disables the profit calculation tool, as it is today, to produce accurate data. Regardless, we believe the tool will produce good calculations of the profitability of the different refracturing completion techniques if it is customized to the candidate well. Furthermore the tool is able to give a comparison of the potential different profitability of the techniques.

10 Conclusion

Refracturing in horizontal wells is relatively new and the effects are poorly documented. Due to low oil and gas prices, low investment costs and the ability to achieve initial production rates, refracturing is a highly discussed and popular topic in the shale oil and gas industry today. Throughout the interviews and literature study we discovered that the industry in general does not know the magnitude of the market, or how the refracturing completion techniques perform in general, or in comparison to each other. In this thesis, we have investigated the magnitude of the refracturing market, evaluated the refracturing completion techniques and looked into the economics in refracturing. In order to be able to get a better understanding of the potential profitability of refracturing, we developed a profit calculation tool based on the technical- and economical evaluation. Even though the thesis is written for Comitt Well Solutions; it contributes in a broader perspective and helps the shale oil- and gas industry to achieve a higher level of understanding regarding the economics of refracturing. In the following paragraphs, we summarize our research findings and contributions.

We have identified some of the most important refracturing well selection criteria and which type of wells the industry has been refracturing so far. Today, the industry seems guardedly optimistic about refracturing, where they do not want to refracture their best performing wells in fear of damaging or loosing these wells, see Figure 10-1. The cost and risk of refracturing are the major constraints when it comes to refracturing decisions. For that reason the industry tends to use less costly none-mechanical techniques which they know leads to a poor technical performance. This has resulted in poor candidate selections and poor technical performances in the majority of the refracturing operations done by the industry today. Even so, the economical evaluation shows that these operations have experienced an average initial production of 84 percent of the original initial production, and have for that reason been economical successful.

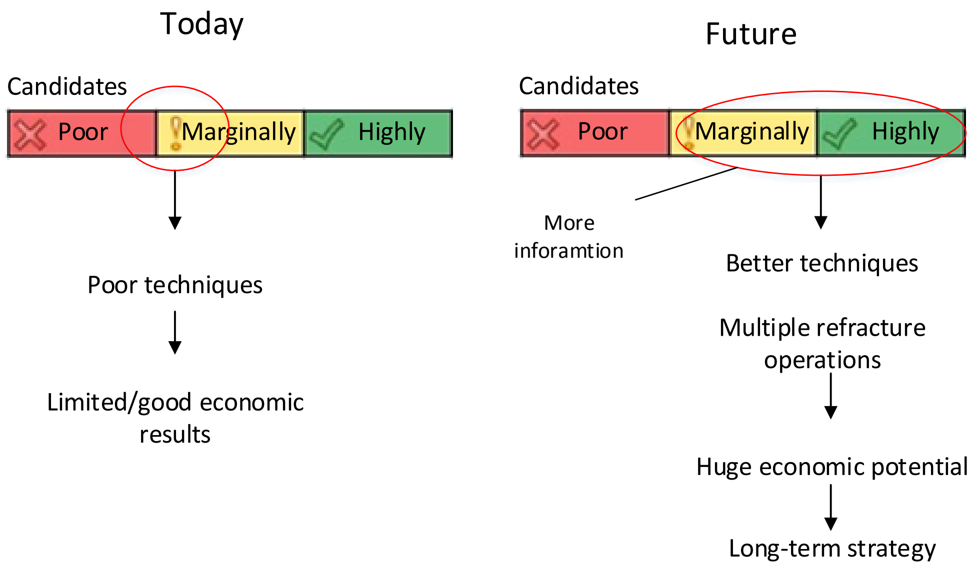

Figure 10-1: Improved candidate selection, better techniques, and multiple refracturing operations leads to huge economical potential

Our findings indicate that there is a greater potential in refracturing than the industry utilizes today. More information about the formation is available when making a refracturing decision compared to drilling a new well. The best candidates are found to be those with good reservoir quality, steep decline, and poor design- or job quality. Wells that are drilled in shale formations with poor quality will not be candidates for refracturing, and this will by itself increase the success rate of refracturing with about 1/3 compared to drilling a new well. We estimate that up to 70 percent of the wells will be potential refracturing candidates in the future due to technology advancement among other factors. By refracturing the marginally and highly economical wells, with techniques which has a better technical performance, we believe that refracturing will be highly economical. Based on the success criteria and steep decline, there will likely be economical to refracture wells multiple times, which further strengthens our conclusion that there is a huge economical potential in the refracturing market. Refracturing can play an important role to increase the low exploitation rates of oil and gas in shale formations. For these reasons we believe that refracturing should be a part of the long-term strategy when drilling new wells. This will result in lower breakeven prices for unconventional shale wells in the future.

The technical evaluation of the refracturing techniques indicates their strength and weaknesses in their ability to achieve the identified success criteria. The level of fulfillment of these criteria will affect the production that can be expected post-refracturing. We identified four important success criteria:

- Enlarged fracture geometry
- Improved pay coverage
- Restoration or increase of fracture conductivity
- Fracture reorientation

The technical performance is based on how good the technique is able to meet these success criteria. The most important factor to meet these success criteria is the technique's ability to achieve a high treatment pressure over desired perforations. Table 10-1 summarize the total evaluation of the techniques and is arranged after their technical performance.

Table 10-1: Comparison between the techniques calculated on a two years into the future perspective after a refracturing recompletion operation. The recfracturing operation is done after 3 years of production in the well with an oil price of $60. The technical grade is rated from 1-10 after how good the technique is technically

Techniques	Technical Grade	Cost	NPV	Breakeven price
Comitt Well Solutions	10.0	$ 2 500 000	$ 6 710 000	16
Expandable liner	7.0	$ 3 485 000	$ 3 450 000	24
Cemented squeeze	6.0	$2 740 000	$ 3 320 000	27
Cemented – Insert liner	5.5	$ 2 890 000	$ 2 286 000	34
Sliding sleeve – Inner string	5.0	$ 2 230 000	$ 2 904 000	26
Bull-head diversion	4.0	$ 1 675 000	$ 2 475 000	24
Coiled tubing – Straddle packer	3.0	$ 2 156 000	$ 668 000	46
Pump and pray	3.0	$ 1 280 000	$ 1 776 000	25

Comitt Well Solutions' new technique scores the highest grade in the technical evaluation, which indicates a high economical potential by the use of our profit calculation tool. The technique's ability to isolate each cluster and to get optimized pressure where it is desired, gives the technique a significant higher technical grade than the most common technique, Bull-head diversion. In addition the majority of the interview respondents have expressed that this kind of technique is something the industry needs.

In this thesis our constructed profit calculation tool is used to compare the refracturing techniques economically and indicate the economical performance of the different techniques. The tool is something the industry lacks and will help them forecast production decline and make better economical refracturing decisions in the future.

A general finding by our calculations is that Comitt Well Solutions' technique is the most profitable, while Coiled tubing is the least profitable technique, as observed in Table 10-1 and Figure 10-2. It is worth mentioning that the economical standing between the other techniques varies with different settings and wells. The calculations also indicate that refracturing in general will be highly economical. The NPV of a refracturing operation by the use of Comitt Well Solutions' technique is estimated to $ 6 710 000 with a breakeven price of $ 16, see Table 10-1. The numbers are relative and used for comparison purposes, however the numbers indicates a high economical potential with far lower breakeven prices compared to drilling new wells.

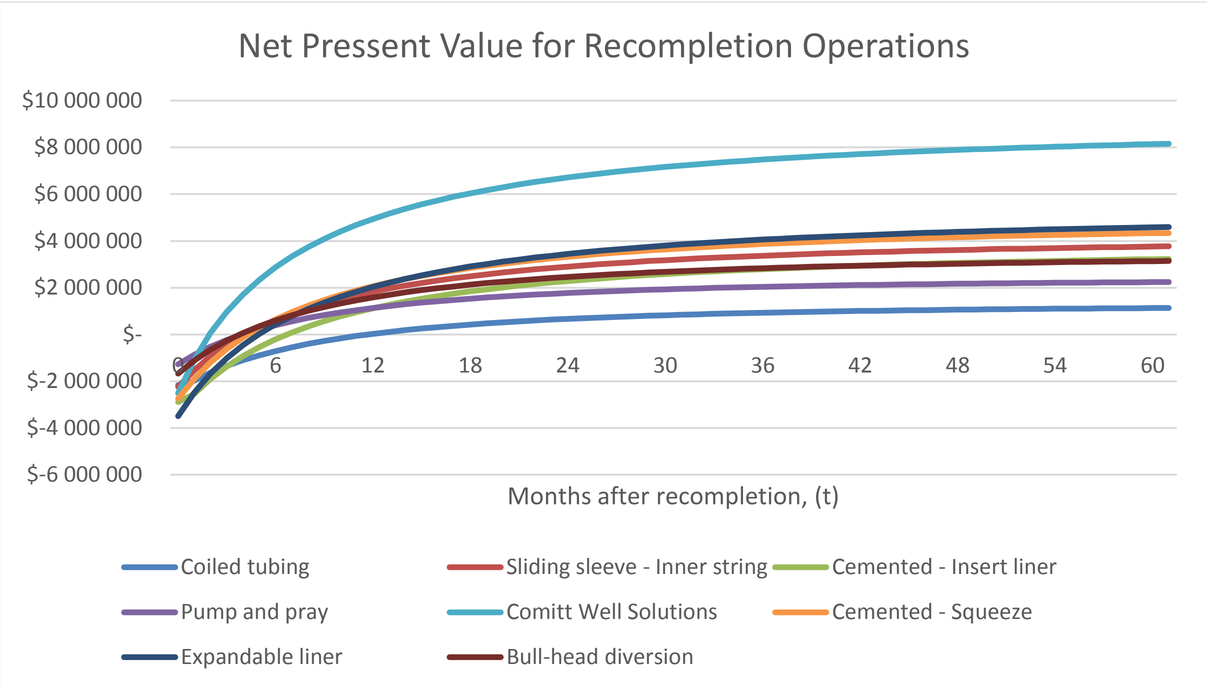

Figure 10-2: NPV estimated after a recompletion operation with the use of different refracturing techniques

Throughout our evaluation and analysis there were findings that did not directly contribute in answering our research questions. However, we believe these supplementary findings will contribute to the industry and are for that reason summarized in bullets below.

- Our risk calculation did not differentiate the techniques in any significant way. This is because the risk associated with each technique is far less than the cost of operation. For that reason the risk will only affect the total cost of operation and not affect which technique that is the most profitable.
- Forecasting production is nothing new in the industry of fracturing, but the trend that we have generalized an equation for in the numerical analysis, contributes to an improvement of the forecasting of refracturing operations. The decline post-refracturing is being forecasted with the same decline factors by the industry, while our findings indicate that the decline factor (D) is related to the initial production ratio. The equation we have calculated does likely not represent the correct relationship, and can most likely be improved as more data becomes available.

To maintain the validity and reliability of our research, we have relied on data, previous research verified in our interviews, theory and maintained a chain of evidence throughout the report. The validity is thought to be solid, and the reliability of our findings is in the extent that it can be generalized to a certain degree. Yet, we acknowledge the need for adaption and adjustment of the cost, risk, production increase and forecasting method in order to customize our constructed tool to be more accurate in calculating the profitability of the individual wells because of the different characteristics. The tool calculations in this thesis are based on estimated numbers and are therefore not absolute, but give a good indication on how the techniques perform in comparison to each other. The construct has been verified throughout our research, and our interview respondents believe our technical evaluations will help the industry to choose better refracturing completion techniques. Furthermore, we believe that the profit calculation tool will be a platform that can be built upon to better be able to understand the profitability in refracturing. However, we have not been able to test how accurate our tool's profit calculations are, due to the limited time available. In optimal conditions we would have estimated the refracturing profitability in several wells and evaluated our estimates by comparing them to real performance after the refracturing operations have taken place. Due to the limited data collections available today, we propose several areas for future research and development to increase the accuracy and functions in our profit calculation tool.

10.1 Scope of Future Work

This thesis points out several uncertainties that affect the economical result of refracturing. We suggest that the effect of the refracturing success criteria should be studied in more detail. It would be beneficial to the industry if they could determine in which degree the success criteria affect the production increase. Furthermore, it would be interesting to compare the economical results of the profit calculation tool to the refracturing results obtained over time. We also suggest that the tool is being updated as more information becomes available.

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12 Appendix

Appendix A: Interview Guide

Appendix B: Interview Respondents

Appendix C: Specified Risk Estimates

Appendix D: Specified Unit Cost Estimates

Appendix E: Hazard and Operability Assessment

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Appendix I: The Historical Production Data of Well 1

Appendix A: Interview Guide

Name	
Company	
Posistion	
Expertise	

The purpose of the interview:

Master's thesis in Industrial Economics and Technology Management at the University of Agder

Exploitation of Shale Oil & Gas in the U.S.

- *An Evaluation of Refracturing Completion Techniques based on Technical and Economical Criteria.*

Questions:

1. What is the oil companies' attitude toward refracturing?
2. What do you think about the potential of refracturing (economically and technically)?
3. How many refracturing project have you been a part of?
4. Which criteria's do you evaluate when you consider wells suitable for refracturing
    a. Which criteria's do you think are most important?
5. How many wells do you think is economical to consider for refracturing? (%)
    b. Short term (today)
    c. Long term (increase in oil& gas price).
    c. Long term (with the use of better technology)
6. Which recompletion/refracturing completion techniques are you familiar with?
    a. Is the technique
        i. Technically good?
        ii. Economically good?
        iii. Are these techniques applicable in every well?
7. Which recompletion/refracturing completion techniques are you using at the moment?
8. Could you explain the techniques?
    a. Why you are using these techniques?
        i. Pros:
        ii. Cons:
    b. Is this technique suitable for recompletion as well as refracturing?
9. What do you think about the different refracturing completion techniques? (technically, economically)
    a. Coild Tubing:
    b. Sliding sleeve – inner string
    c. Cemented insert liner

    d. Ball sealer diversiation
10. Which parameters are essential when we are comparing different refracturing techniques?
    a. Technically
    b. Economically
    c. Geology
11. Which refracturing completion technique do you think is the best and worst technique?
    a. Why?
12. What is missing in today's technology and what is your opinion of the best future solution?

Appendix B: Interview Respondents

Respondent	Company
George King	Apache
David Cramer	Conoco Phillips
Steve Wolhart	Pinnacle - Halliburton
Mikael Vincent	FracWell
James Rodgerson	BP
Matthew Laham	Halliburton
Eivind Moen	Comitt Well Solutions
Daniel Snyder	Packers Plus

Appendix C: Specified Risk Estimates

First an explanation of the failure mechanisms will be presented, then there will be a presentation of the foundation of our risk assessment.

The HAZOP assessment done with the respondents identified some of the same failure mechanisms as identified in the literature study. These are presented in the following:

Failure Mechanism	Discription
Stuck	○ This failure mechanism includes the risk associated with equipment getting stuck downhole. It can include reparations, retrieval operations, "fishing" operations, etc. It is often associated with a poor integrity of the well, but might happen from time to time in every well.
Equipment erosion and malfunction	○ This failure mechanism includes the risk associated with equipment used in the refracturing operation. It can include erosion, repair, malfunction, delayed operation etc, equipment used in the downhole operation.
Screen-out	○ Screen-out can be explained as when proppant are over-placed in the wellbore under a hydraulic fracturing operation. This may occur with every technique that uses proppant. However, some techniques can clean out the well more easily than others.
Mechanical integrity	○ The integrity of the well has a huge impact on the risk associated with a refracturing operation. However, there are mainly the mechanical techniques that are being affected by the integrity of the well. Some techniques are more robust than others, but if the integrity is poor, there will likely be difficult to do any mechanical operations.

In the following the foundation for our Monte Carlo simulations are presented. The calculations are based on the assumption that minor failures occur more often than the major failures, and that the costs are related to the consequence. As a result, a major consequence has a high related cost, and minor consequence has a lower related cost. This is done to reflect that the minor and less costly failure mechanisms tend to occur more frequently than the major and more costly failure mechanisms.

The first numbers represents the risk assosiated with **a recompletion operation:**

Consequence:	
Minor:	Easy fix. Houers/days
Moderate:	Costly fix. Days/weeks
Major:	Major impact on economics. Weeks/months

Method	Risk	Consequence	Probability	Distribution	Avarage Cost	Distribution	Std. Deviation (σ)	Total cost
Coiled Tubing - Straddle Packer	Stuck	Minor	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	
		Moderate	3% - 7%	Rectangular	$ 500 000,00	Normal	100000	$ 62 500,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	5% - 10%	Rectangular	$ 250 000,00	Normal	45000	$ 42 500,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 1 000,00
Total Cost of Coiled Tubing								$ 106 000,00
Sliding Sleeve - Inner sting	Stuck	Minor	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	
		Moderate	3% - 7%	Rectangular	$ 500 000,00	Normal	100000	$ 58 750,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	5% - 10%	Rectangular	$ 500 000,00	Normal	100000	$ 77 500,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Sliding Sleeve -Inner sting								$ 146 250,00
Cemented - Insert liner	Stuck	Minor	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	
		Moderate	3% - 7%	Rectangular	$ 350 000,00	Normal	65000	$ 43 750,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	$ 38 750,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Cemented - Insert liner								$ 92 500,00
Cemented - Squeeze	Stuck	Minor	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	
		Moderate	3% - 7%	Rectangular	$ 300 000,00	Normal	50000	$ 37 500,00
		Major	1% - 2%	Rectangular	$ 750 000,00	Normal	150000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 75 000,00	Normal	15000	
		Moderate	5% - 10%	Rectangular	$ 250 000,00	Normal	45000	$ 54 375,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Cemented - Squeeze								$ 101 875,00

Expandable Liner	Stuck	Minor	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	
		Moderate	3% - 7%	Rectangular	$ 500 000,00	Normal	100000	$ 55 000,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	5% - 10%	Rectangular	$ 400 000,00	Normal	75000	$ 70 000,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Expandable Liner								**$ 135 000,00**
Comitt	Stuck	Minor	5% - 10%	Rectangular	$ 250 000,00	Normal	45000	
		Moderate	3% - 7%	Rectangular	$ 500 000,00	Normal	100000	$ 66 250,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	5% - 10%	Rectangular	$ 500 000,00	Normal	100000	$ 85 000,00
		Major	1% - 2%	Rectangular	$ 2 000 000,00	Normal	400000	
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 1 000,00
Total Cost of Comitt								**$ 152 250,00**
Pump & Pray	Stuck	Minor	5% - 10%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	3% - 7%	Rectangular	$ 200 000,00	Normal	40000	$ 25 000,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	$ 19 375,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Pump and Pray								**$ 54 375,00**
Bull-head - Diversion	Stuck	Minor	5% - 10%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	3% - 7%	Rectangular	$ 200 000,00	Normal	40000	$ 25 000,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	$ 19 375,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Bull-head diversion								**$ 54 375,00**

These numbers represents the risk **assosiated with a refracturing operation:**

Consequence:	
Minor:	Easy fix. Houers/days
Moderate:	Costly fix. Days/weeks
Major:	Major impact on economics. Weeks/months

Method	Risk	Consequence	Probability	Distribution	Avarage Cost	Distribution	Std. Deviation (σ)	Total cost
Coiled Tubing - Straddle Packer	Stuck	Minor	5% - 10%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	3% - 7%	Rectangular	$ 300 000,00	Normal	50000	$ 37 500,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 25 000,00	Normal	5000	
		Moderate	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	$ 23 125,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 1 000,00
Total Cost of Coiled Tubing								$ 61 625,00
Sliding Sleeve - Inner sting	Stuck	Minor	5% - 10%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	3% - 7%	Rectangular	$ 200 000,00	Normal	40000	$ 33 750,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 75 000,00	Normal	15000	
		Moderate	5% - 10%	Rectangular	$ 400 000,00	Normal	75000	$ 58 125,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Sliding Sleeve -Inner sting								$ 101 875,00
Cemented - Insert liner	Stuck	Minor	5% - 10%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	3% - 7%	Rectangular	$ 150 000,00	Normal	25000	$ 18 750,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 25 000,00	Normal	5000	
		Moderate	5% - 10%	Rectangular	$ 100 000,00	Normal	20000	$ 19 375,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Cemented - Insert liner								$ 48 125,00
Cemented - Squeeze	Stuck	Minor	5% - 10%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	3% - 7%	Rectangular	$ 100 000,00	Normal	20000	$ 12 500,00
		Major	1% - 2%	Rectangular	$ 250 000,00	Normal	45000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 50 000,00	Normal	10000	
		Moderate	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	$ 35 000,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Cemented - Squeeze								$ 57 500,00
Expandable Liner	Stuck	Minor	5% - 10%	Rectangular	$ 100 000,00	Normal	20000	
		Moderate	3% - 7%	Rectangular	$ 300 000,00	Normal	50000	$ 30 000,00
		Major	1% - 2%	Rectangular	$ 500 000,00	Normal	100000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 75 000,00	Normal	15000	
		Moderate	5% - 10%	Rectangular	$ 200 000,00	Normal	40000	$ 50 625,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Screen-out	Minor	10 %	Normal	$ 100 000,00	Normal	10000	$ 10 000,00
Total Cost of Expandable Liner								$ 90 625,00
Comitt	Stuck	Minor	5% - 10%	Rectangular	$ 150 000,00	Normal	25000	
		Moderate	3% - 7%	Rectangular	$ 300 000,00	Normal	50000	$ 41 250,00
		Major	1% - 2%	Rectangular	$ 1 000 000,00	Normal	200000	
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ 75 000,00	Normal	15000	
		Moderate	5% - 10%	Rectangular	$ 400 000,00	Normal	75000	$ 65 625,00
		Major	1% - 2%	Rectangular	$ 1 500 000,00	Normal	300000	
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 1 000,00
Total Cost of Comitt								$ 107 875,00

Pump & Pray	Stuck	Minor	5% - 10%	Rectangular	$ -	Normal		
		Moderate	3% - 7%	Rectangular	$ -	Normal		$ -
		Major	1% - 2%	Rectangular	$ -	Normal		
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ -	Normal		
		Moderate	5% - 10%	Rectangular	$ -	Normal		$ -
		Major	1% - 2%	Rectangular	$ -	Normal		
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 10 000,00
Total Cost of Pump and Pray								**$ 10 000,00**
Bull-head - Diversion	Stuck	Minor	5% - 10%	Rectangular	$ -	Normal		
		Moderate	3% - 7%	Rectangular	$ -	Normal		$ -
		Major	1% - 2%	Rectangular	$ -	Normal		
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular	$ -	Normal		
		Moderate	5% - 10%	Rectangular	$ -	Normal		$ -
		Major	1% - 2%	Rectangular	$ -	Normal		
	Screen-out	Minor	10 %	Normal	$ 10 000,00	Normal	1000	$ 10 000,00
Total Cost of Bull-head diversion								**$ 10 000,00**

Appendix D: Specified Unit Cost Estimates

The unit costs were obtained by email after the interviews by the respondents. It is important for the reader to understand that this data is based on calculated estimations done by the respondents and will vary in magnitude between different wells and shale formations. The total collection of data is processed and sent to the respondents for a total validation.

Technique	Category	Discription
Coiled Tubing - Straddle Packer	Downhole Equipment	○ Cost of equipment, trucks and CT tool, some of the cost of "downhole equipment" is included in "new perforations", because adding perfs requires downhole equipment.
	New perforations	○ CT can make new perforations by the use of a jet-nozzel or a perforation gun. Total cost of each run is estimated to be about $ 35 000. About 5 clusters can be perforated in each run.
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. CT is argued to be a complex operation, but a fast completion, which makes the cost about average.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Sliding sleeve – inner string	Downhole Equipment	○ Cost of downhole sting, and fracturing balls. ○ The majority of the equipment is dependent on how many stages there are. However, in the toe of each well there will be some extra costs related to components called "flow-lock sub", "flow shoe" etc. ○ The cost per stage is the cost of the sting and the cost of installation
	New perforations	○ The string cannot make new perforations by itself. ○ CT can make new perforations by the use of a jet-nozzel or a perforation gun. Total cost of each run is estimated to be about $ 35 000. About 5 clusters can be perforated in each run.
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. The sleeve can save up to 40% of the completion time compared to plug and perf (King G. , 2015)
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Cemented – Insert liner	Downhole Equipment	○ Cost of downhole casing, tools, equipment, rentals and cement. ○ $ 50 /stage is for casing tools, equipment, installation ○ $ 5 /stage are for the cement job.
	New perforations	○ This is not a complete technique by itself. This thesis assumes that plug and perf technique is used to recomplete the well. ○ Plug and perf can be done by using CT, with perforation guns and bridge-plugs. Cost of each run is estimated to be about $ 35 000, in addition to the cost of a bridge plug in each stage of about $ 5 000, resulting in $ 40 000/stage. (About 5 clusters can be perforated in each run.)
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. The sleeve can save up to 40% of the completion time compared to plug and perf (King G. , 2015). For that reason this technique has a higher cost per stage than the sleeve system. ○ Install time is believed to be about the same for a sleeve system as a cemented liner.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Cemented – Squeeze	Downhole Equipment	○ No cost related to new casing. ○ The cost of downhole equipment is related to the cement job, as cement and milling operations.
	New perforations	○ This is not a complete technique by itself. This thesis assumes that plug and perf technique is used to recomplete the well. ○ Plug and perf can be done by using CT, with perforation guns and bridge-plugs. Cost of each run is estimated to be about $ 35 000, in addition to the cost of a bridge plug in each stage of about $ 5 000, resulting in $ 40 000/stage. (About 5 clusters can be perforated in each run.)
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. The sleeve can save up to 40% of the completion time compared to plug and perf (King G. , 2015). For that reason this technique has a higher cost per stage than the sleeve system. ○ This technique does not need time to install a casing, however the cementing job is more extensive, we believe the cost will be about the same for that reason.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Expandable liner	Downhole Equipment	○ High cost related to the expandable liner. ○ Cost of operation, liner, equipment and tools to expand the liner downhole.
	New perforations	○ This is not a complete technique by itself. This thesis assumes that plug and perf technique is used to recomplete the well. ○ Plug and perf can be done by using CT, with perforation guns and bridge-plugs. Cost of each run is estimated to be about $ 35 000, in addition to the cost of a bridge plug in each stage of about $ 5 000, resulting in $ 40 000/stage. (About 5 clusters can be perforated in each run.)
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. The sleeve can save up to 40% of the completion time compared to plug and perf (King G. , 2015). For that reason this technique has a higher cost per stage than the sleeve system. ○ This technique needs more time for installation than the others.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Pump and Pray	Downhole Equipment	○ No downhole equipment needed
	New perforations	○ CT can make new perforations by the use of a jet-nozzel or a perforation gun. Total cost of each run is estimated to be about $ 35 000. about 5 clusters can be perforated in each run.
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. ○ This technique is done in one sequence, and will not be time consuming as other mechanical techniques. The cost is argued to be $ 25 000. It might be a bit higher.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Technique	Category	Discription
Bull-head diversion	Downhole Equipment	○ Only donwhole equipment needed is diversion agents. ○ Cost of balls is believed to be about $ 50/ball.
	New perforations	○ CT can make new perforations by the use of a jet-nozzel or a perforation gun. Total cost of each run is estimated to be about $ 35 000. about 5 clusters can be perforated in each run.
	Crew	○ Cost of crew is dependent on the complexity of the operations and if it is time consuming or not. ○ This technique is done in one sequence, and will not be time consuming as other mechanical techniques. The cost is argued to be more that the pump and pray, because diversion will need more supervision and operation time.
	Work over rig	○ Argued to be $ 50.000 for install run and the same for clean out run.
	Fluid	○ With delivery and transportation charges, we are looking at about 10 cents per lb.

Appendix E: Hazard and Operability Assessment

HAZOP is described as a technique in "brainstorming" and as a systematic approach to investigate each element of a process to identify all of the ways in which parameters can deviate from the intended design conditions and create hazards or operability problems. A HAZOP analysis begins with a description and understanding of the whole process. This is usually done by studying drawings of the installation and flowchart for the process. However, we had to limit our HAZOP analysis because the risk assessment is just a minor part of our economical evaluation. For that reason we asked our respondents the following three questions while we discussed each technique:

1. How can the technique NOT complete the intended operation
2. What can cause the equipment to NOT work as intended?
3. What can affect that there is experienced a HIGHER or LOWER treatment pressure than designed?
4. What can cause a MORE time consuming operation?

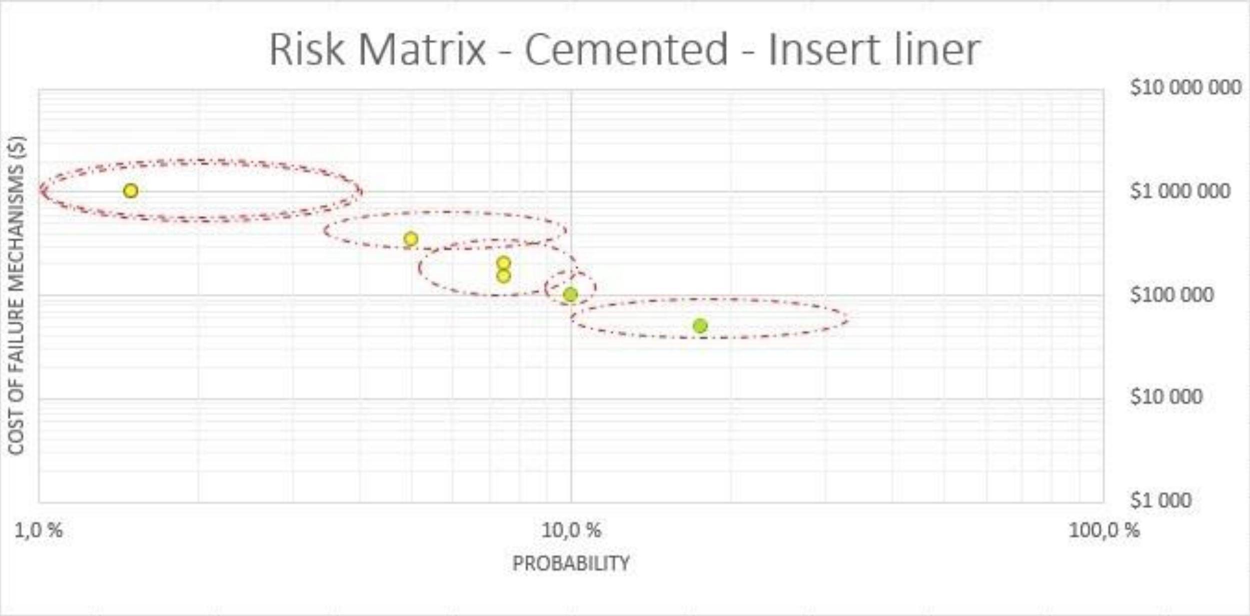
The results from this light HAZOP assessment was generalized into these general failure mechanisms:

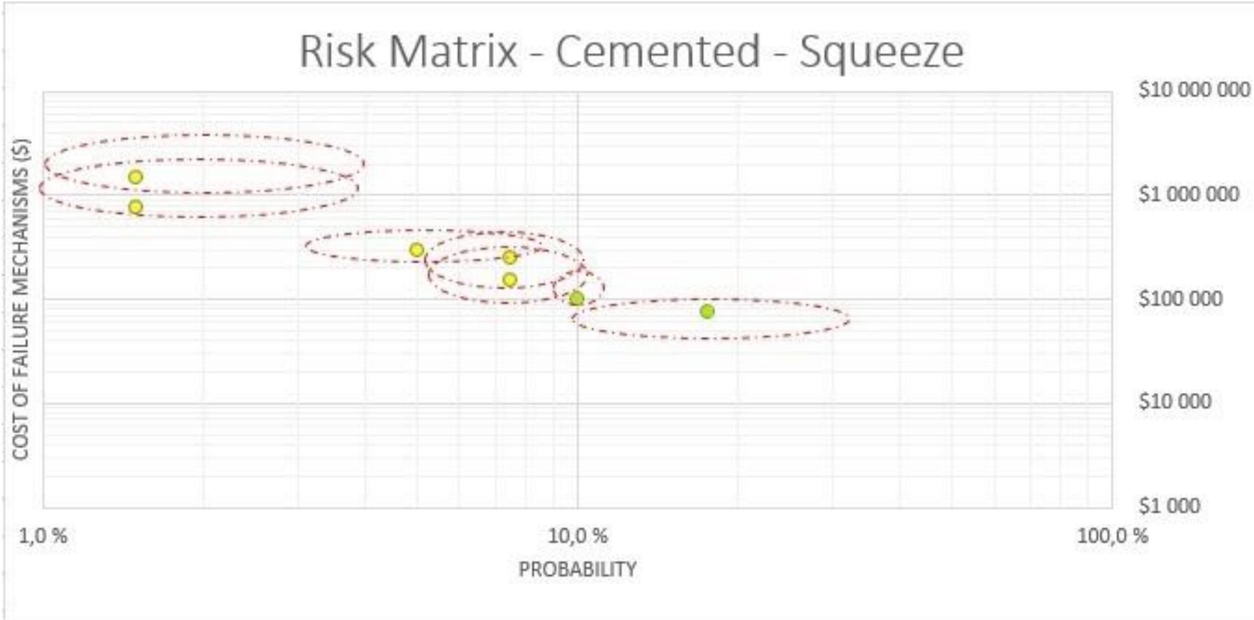
- Stuck
- Equipment erosion and malfunction
- Screen-out

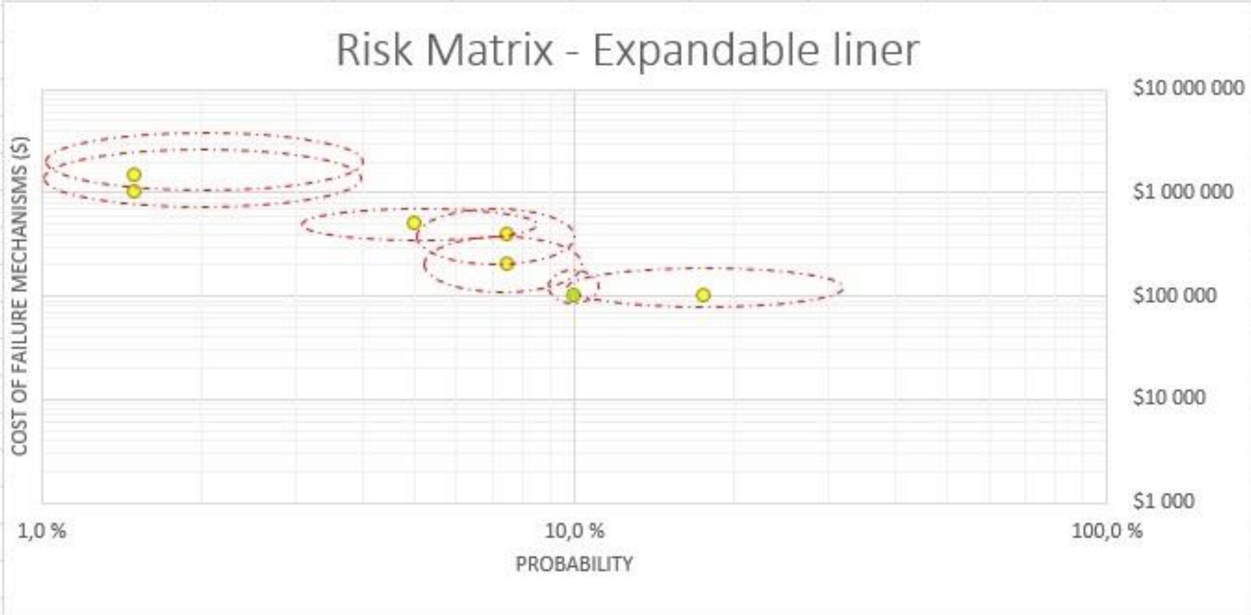
A further explanation of these failure mechanisms can be found in appendix C.

Appendix F: Risk Matrix

In the following there will be a presentation of each techniques' risk matrix.


Risk Matrix - Cemented - Insert liner
COST OF FAILURE MECHANISMS ($)
$10 000 000
$1 000 000
$100 000
$10 000
$1 000
1,0 %
10,0 %
100,0 %
PROBABILITY


Risk Matrix - Cemented - Squeeze
COST OF FAILURE MECHANISMS ($)
$10 000 000
$1 000 000
$100 000
$10 000
$1 000
1,0 %
10,0 %
100,0 %
PROBABILITY


Risk Matrix - Expandable liner
COST OF FAILURE MECHANISMS ($)
$10 000 000
$1 000 000
$100 000
$10 000
$1 000
1,0 %
10,0 %
100,0 %
PROBABILITY


Risk Matrix - Comitt Well Solutions
COST OF FAILURE MECHANISMS ($)
$10 000 000
$1 000 000
$100 000
$10 000
$1 000
1,0 %
10,0 %
100,0 %
PROBABILITY

Appendix G: Screenshots of the Profit Calculation Tool

The function of the screenshots is to get an idea of how the tool looks like. It is not intended that the reader should understand the profit calculation tool by looking at these print screens. All the sheets in the tool are not included in the appendix because it would not give the reader any deeper understanding of the tool.

Input/output sheet

The only screen only sheet you need to use if you don't want to make adjustment to the tool

Inputs:

		Historical production	
Oil or Gas?	Oil	Months (t)	Historical prod (q)
Price	$ 5,00	Initial prod	1186
		0	1186
Refrac method	Cemented inner liner	1	1074
Refrac or Recompletion	Refrac	2	876
refrac month	36	3	850
		4	701
Costs		5	650
Total investment cost Refracturing	$ -	6	620
Total investment cost Recompletion	$ -	7	600
		8	550
Specified input		9	556
Total Water costs		10	550
Total transportation costs		11	540
Extra pipe costs		12	500
		13	490
Lateral lenght		14	470
Stages		15	450
New stages		16	440
Cluster per stage		17	430
lb/stage		18	400
Diversion agents:		19	350
Nr. balls		20	321
		21	308
		22	316
		23	386
		24	400
		25	344

Outputs:

After Re-frac		After Re-completion	
NPV 1 mnd	$ -1 941 965	NPV 1 mnd	$ -2 430 323
NPV 6 mnd	$ -1 699 317	NPV 6 mnd	$ -1 929 073
NPV 12 mnd	$ -1 547 373	NPV 12 mnd	$ -1 581 884
NPV 24 mnd	$ -1 405 754	NPV 24 mnd	$ -1 190 780
IRR 1 mnd	-96 %	IRR 1 mnd	-94 %
IRR 6 mnd	-38 %	IRR 6 mnd	-31 %
IRR 12 mnd	-20 %	IRR 12 mnd	-13 %
IRR 24 mnd	-10 %	IRR 24 mnd	-5 %
ROI 1 mnd	-96 %	ROI 1 mnd	-94 %
ROI 6 mnd	-84 %	ROI 6 mnd	-75 %
ROI 12 mnd	-77 %	ROI 12 mnd	-61 %
ROI 24 mnd	-70 %	ROI 24 mnd	-46 %
Break even price oil/gas 12 mnd	$ 21,44	Break even price oil/gas 12 mnd	$ 12,90
Investment paid back (months)	Not paying bac	Investment paid back (months)	Not paying back

Presentation | Info | Decline Curves | Refrac | Profit Calc | Investment Cost | MonteCarlo_Risk_Recompletion | MonteCarlo_Risk_Refracturing | Cost of Risk - Recompletion

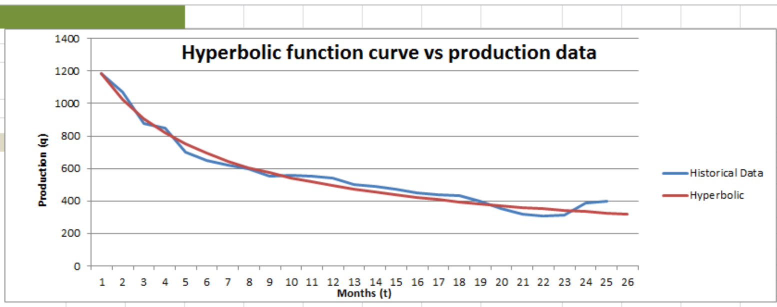
The sheet were historical data gets fitted to a modified hyperbolic curve

Forecasting Decline

qi	1186	
b	**1,50**	b and Di are estimated based on production data with Excel Solver
Di	**0,17**	
SR cum. 12 months	**14081,58**	

Determining the Swich

Di	16,5 %	Monthly nominal decline (hyp) or
Di	60,1 %	Annual effective decline
b	1,50	
Switch Rate to Exp	5 %	annual effective decline or
	0,43 %	monthly nominal decline (exp)
End Time	600	months
End Rate	10	mscf/d
Switch Time	147	months
(q) at Switch Time	106	mscf/d or bbl/d
EUR	0	mmscf @ eco limit



					Swich calculations			Forecasting models		
months (t)	**Historical (q)**	**Hyperbolic (q)**	**Residual**	**Squared Residual**	**Monthly Nominal Decline**	**Annual Effective Decline**	**Decline type**	Hyp (q)	Exp (q)	Hyp + Exp (q)
0	1186	1185,80	0,0	0,0	16,52 %	60,14 %	Hyp	1185,8	1185,8	1185,8
1	1074	1023,11	-50,5	2549,0	13,24 %	55,62 %	Hyp	1023,1	1005,3	1023,1
2	876	906,74	31,1	969,6	11,04 %	51,80 %	Hyp	906,7	852,2	906,7
3	850	818,65	-31,3	982,8	9,47 %	48,50 %	Hyp	818,7	722,4	818,7

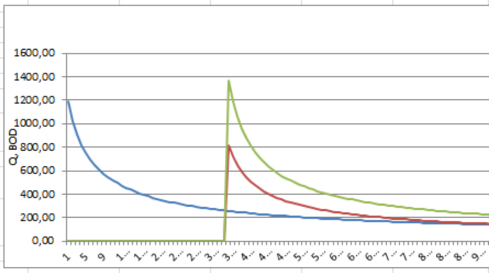
$$q = \begin{cases} q_i(1+bD_it)^{-\frac{1}{b}}; & t < t* \\ q_{gie}e[D_{lim}t]; & t > t* \end{cases}$$

$$q_i(1+bD_it)^{-\frac{1}{b}} - q = 0$$

$$q = q_ie[-D_it]$$

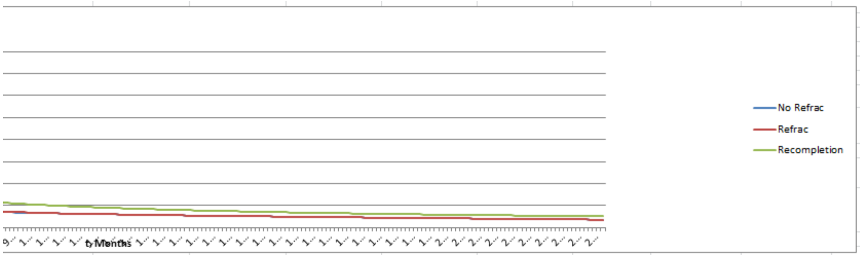
The sheet where refracturing and recompletion revenue are calculated and compared

Qi (initial production)	1186				
Q-Oil @ date of RF/RC	1186	BPD - Production rate at time of Re-Completion			
Di	0,17				
Di post refrac	0,14				
Di post recomp	0,16				
b	1,50		Hyperbolic	$q = q_i(1 + bD_i t)^{-\frac{1}{b}}$	
Realized Price/bbl oil	$ 5,00				
Refrac month	36				
Refrac method	Cemented inner liner			paid back	204
Increased Production, RE-FRAC	69 %				
Increased Production, RE-COMPLETION	116 %		Cell num, month 1 after refrac	38	
Cost - Re-Frac	kr -2 018 125,00				
Cost - Re-Comp	kr -2 582 500,00			This cell used	



t, Month	Month after refrac (t)	mod Hyp, no refrac [BPD]	Q after Refrac [BPD]	Q after Refrac not below initial [BPD]	Q,ReComp. [BPD]	Monthly No Re-frac /re-comp	Montly, No-refrac/Re-comp after refrac month	Monthly Revenue, Re-Frac	Monthly Revenue, Re-comp	Monthly Revenue, No Refrac starting in refrac month. Moved up.	Monthly Revenue, Re-Frac, moved up	Monthly Revenue, Re-Comp, moved up
0	0	1185,80	0,00	0,00	0							
1	0	1023,11	0,00	0,00	0	$ 165 668	$ -	$ -	$ -	$ 38 213,85	$ 115 104	$ 191 849
2	0	906,74	0,00	0,00	0	$ 144 739	$ -	$ -	$ -	$ 37 597,87	$ 102 535	$ 168 421
3	0	818,65	0,00	0,00	0	$ 129 404	$ -	$ -	$ -	$ 37 006,13	$ 92 930	$ 151 077
4	0	749,24	0,00	0,00	0	$ 117 592	$ -	$ -	$ -	$ 36 437,14	$ 85 306	$ 137 619
5	0	692,89	0,00	0,00	0	$ 108 160	$ -	$ -	$ -	$ 35 889,53	$ 79 078	$ 126 815
6	0	646,07	0,00	0,00	0	$ 100 422	$ -	$ -	$ -	$ 35 362,04	$ 73 878	$ 117 914
7	0	606,42	0,00	0,00	0	$ 93 937	$ -	$ -	$ -	$ 34 853,52	$ 69 458	$ 110 430
8	0	572,35	0,00	0,00	0	$ 88 408	$ -	$ -	$ -	$ 34 362,90	$ 65 645	$ 104 032
9	0	542,69	0,00	0,00	0	$ 83 628	$ -	$ -	$ -	$ 33 889,19	$ 62 317	$ 98 488
10	0	516,60	0,00	0,00	0	$ 79 447	$ -	$ -	$ -	$ 33 431,47	$ 59 381	$ 93 630
11	0	493,44	0,00	0,00	0	$ 75 753	$ -	$ -	$ -	$ 32 988,91	$ 56 769	$ 89 329
12	0	472,70	0,00	0,00	0	$ 72 460	$ -	$ -	$ -	$ 32 560,70	$ 54 426	$ 85 492

The sheet are continuing..



CUM. Revenue, No Re-frac/Re-comp	CUM. Revenue, No-refrac/Re-comp after refrac month	CUM.Revenue Re-Frac	CUM.Revenue Re-Comp	CUM.Revenue Re-Frac, moved up	CUM.Revenue Re-Comp, moved up	CUM. Re-Frac Vs NO Re-Frac	CUM. Re-Completion VS NO Re-Comp	CUM. Re-Completion VS Re-Frac	CUM. Re-Frac Vs NO Re-Frac, moved up	CUM. Re-Completion VS NO Re-Comp, moved up	Refrac VS No refrac. Needed for NPV	Recomp - No Refrac. Needed for NPV
				$ -2 018 125,00	$ -2 582 500,00						$ -2 018 125,00	$ -2 582 500,00
$ 165 668	$ -	$ -	$ -	$ 115 104	$ 191 849	No refrac yet	No refrac yet	No Data	$ -1 941 234,68	$ -2 428 865,03	$ 76 890	$ 153 635
$ 310 407	$ -	$ -	$ -	$ 217 639	$ 360 270	No refrac yet	No refrac yet	No Data	$ -1 876 297,33	$ -2 298 042,17	$ 64 937	$ 130 823
$ 439 812	$ -	$ -	$ -	$ 310 570	$ 511 346	No refrac yet	No refrac yet	No Data	$ -1 820 373,12	$ -2 183 971,68	$ 55 924	$ 114 070
$ 557 404	$ -	$ -	$ -	$ 395 876	$ 648 965	No refrac yet	No refrac yet	No Data	$ -1 771 504,44	$ -2 082 789,72	$ 48 869	$ 101 182
$ 665 564	$ -	$ -	$ -	$ 474 954	$ 775 781	No refrac yet	No refrac yet	No Data	$ -1 728 315,58	$ -1 991 863,99	$ 43 189	$ 90 926
$ 765 986	$ -	$ -	$ -	$ 548 832	$ 893 695	No refrac yet	No refrac yet	No Data	$ -1 689 799,58	$ -1 909 311,83	$ 38 516	$ 82 552
$ 859 923	$ -	$ -	$ -	$ 618 290	$ 1 004 124	No refrac yet	No refrac yet	No Data	$ -1 655 195,46	$ -1 833 735,58	$ 34 604	$ 75 576
$ 948 331	$ -	$ -	$ -	$ 683 935	$ 1 108 157	No refrac yet	No refrac yet	No Data	$ -1 623 913,24	$ -1 764 066,46	$ 31 282	$ 69 669
$ 1 031 959	$ -	$ -	$ -	$ 746 251	$ 1 206 645	No refrac yet	No refrac yet	No Data	$ -1 595 485,68	$ -1 699 467,34	$ 28 428	$ 64 599
$ 1 111 407	$ -	$ -	$ -	$ 805 632	$ 1 300 274	No refrac yet	No refrac yet	No Data	$ -1 569 536,16	$ -1 639 269,30	$ 25 950	$ 60 198
$ 1 187 160	$ -	$ -	$ -	$ 862 401	$ 1 389 604	No refrac yet	No refrac yet	No Data	$ -1 545 756,50	$ -1 582 928,79	$ 23 780	$ 56 341
$ 1 259 620	$ -	$ -	$ -	$ 916 827	$ 1 475 095	No refrac yet	No refrac yet	No Data	$ -1 523 891,24	$ -1 529 997,75	$ 21 865	$ 52 931

A sheet illustrating some of the risk calculations

Consequence:

Minor:	Easy fix. Houers/days
Moderate:	Costly fix. Days/weeks
Major:	Major impact on economics. Weeks/months

Method	Risk	Consequence	Probability	Distribution	Std. Deviation	Avarage Cost	Distribution	Std. Deviation	Total cost
Coiled Tubing - Straddle Packer	Stuck	Minor	5% - 10%	Rectangular		$ 200 000,00	Normal		
		Moderate	3% - 7%	Rectangular		$ 500 000,00	Normal		$ 62 500,00
		Major	1% - 2%	Rectangular		$1 500 000,00	Normal		
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular		$ 50 000,00	Normal		
		Moderate	5% - 10%	Rectangular		$ 250 000,00	Normal		$ 42 500,00
		Major	1% - 2%	Rectangular		$1 000 000,00	Normal		
	Screen-out	Minor	10 %	Normal		$ 10 000,00	Normal		$ 1 000,00
Total Cost of Coiled Tubing									**$ 106 000,00**
Sliding Sleeve - Inner sting	Stuck	Minor	5% - 10%	Rectangular		$ 150 000,00	Normal		
		Moderate	3% - 7%	Rectangular		$ 500 000,00	Normal		$ 58 750,00
		Major	1% - 2%	Rectangular		$1 500 000,00	Normal		
	Equipment erosion and/or malfunction	Minor	10% - 25%	Rectangular		$ 100 000,00	Normal		
		Moderate	5% - 10%	Rectangular		$ 500 000,00	Normal		$ 77 500,00
		Major	1% - 2%	Rectangular		$1 500 000,00	Normal		
	Screen-out	Minor	10 %	Normal		$ 100 000,00	Normal		$ 10 000,00
Total Cost of Sliding Sleeve -Inner sting									**$ 146 250,00**
Cemented - Insert liner	Stuck	Minor	5% - 10%	Rectangular		$ 150 000,00	Normal		
		Moderate	3% - 7%	Rectangular		$ 350 000,00	Normal		$ 43 750,00
		Major	1% - 2%	Rectangular		$1 000 000,00	Normal		
	Equipment	Minor	10% - 25%	Rectangular		$ 50 000,00	Normal		

A sheet illustrating some of the cost calculations

Category	Coiled Tubing					Sliding sleeve system				
	Cost Parameter	Annotation	Quantity	Unit Cost	Total	Cost Parameter	Annotation	Quantity	Unit Cost	Total
Down Hole equipment	CT - Tool	$/stage	13	$ 20 000	$ 260 000	General Cost	$/Well	1	$ 15 000	$ 15 000
Cost of rental etc.						String - Tool	$/stage	13	$ 18 000	$ 234 000
					$ 260 000					$ 249 000
New Perforations	CT w/perf gun	$/stage	13	$ 35 000	$ 455 000	CT w/perf gun		13	$ 35 000	$ 455 000
Cost of operation, and plugs.					$ 455 000					$ 455 000
Milling					$ -	Ball-Seats	Day rate	1	$ 50 000	$ 50 000
Cost of drilling out cement or plugs.					$ -					$ 50 000
Frac Crew		$/stage	13	$ 60 000	$ 780 000		$/stage	13	$ 60 000	$ 780 000
Cost of crew					$ 780 000					$ 780 000
Work Over Rig		Day rate	2	$ 50 000	$ 100 000		Day rate	2	$ 50 000	$ 100 000
Should be the same to do install run and clean out run.					$ 100 000					$ 100 000
Frac-fluids		$/lb	1950000	$ 0,1	$ 195 000		$/lb	1950000	$ 0,1	$ 195 000
Some methods place more proppant than others.					$ 195 000					$ 195 000
Total Cost of Refracturing					**$ 1 335 000**					**$ 1 374 000**
*Pricing for comparison purposes only.										
Total Cost of Recompletion					**$ 1 790 000**					**$ 1 829 000**

A sheet illustrating some of the profit calculations

Economic calculations				
Interest	10 %	APR = EAR (Interest paid anually)		
Discount rate per month	0,83 %			
Maturity of the investment	25 år			
Monthly inflation adjustment	0,125 %			
monthly discount rate adjusted for ir	**0,958 %**			
Cost refrac	**$ -2 018 125,00**			
Cost recomp	**$ -2 582 500,00**			
Investment paid back months refrac	Not paying back		Investment paid ba	203
Investment paid back months refrac	Not paying back			

Economic calculations									
t, Month after refrac	NPV No refrac	NPV refrac	NPV Recomp	IRR Refrac	IRR Recomp	Break even price refrac	Break even price Recomp	ROI Refrac	ROI Recomp
0									
1	$ 164 095,87	$ -1 904 113,44	$ -2 392 472,28	-94 %	-93 %	$ 88,51	$ 67,95	-94 %	-93 %
2	$ 306 099,96	$ -1 803 515,58	$ -2 227 233,80	-64 %	-59 %	$ 47,02	$ 36,35	-89 %	-86 %
3	$ 431 854,01	$ -1 713 206,59	$ -2 080 418,69	-38 %	-31 %	$ 33,09	$ 25,72	-85 %	-81 %
4	$ 545 044,39	$ -1 631 093,96	$ -1 947 950,98	-20 %	-13 %	$ 26,07	$ 20,35	-81 %	-75 %
5	$ 648 167,73	$ -1 555 698,20	$ -1 827 041,42	-8 %	-1 %	$ 21,82	$ 17,09	-77 %	-71 %
6	$ 743 004,25	$ -1 485 929,22	$ -1 715 685,57	1 %	7 %	$ 18,96	$ 14,90	-74 %	-66 %
7	$ 830 874,23	$ -1 420 957,45	$ -1 612 387,79	6 %	12 %	$ 16,90	$ 13,31	-70 %	-62 %
8	$ 912 787,70	$ -1 360 134,84	$ -1 515 998,31	10 %	16 %	$ 15,34	$ 12,11	-67 %	-59 %
9	$ 989 537,05	$ -1 302 944,16	$ -1 425 611,49	13 %	18 %	$ 14,11	$ 11,16	-65 %	-55 %
10	$ 1 061 756,99	$ [illegible] 1 248 965,05	$ [illegible] 1 340 499,44	15 %	20 %	$ 13,12	$ 10,40	[illegible] 62 %	[illegible] 52 %

Appendix H: The Profit Calculation Tool User Manual

The profit calculation tool is made is made in Microsoft Excel. Do not change any of the cells' location or values unless you know what you are doing or you follow this manual. The functions used in the tool are complicated and you may prevent them of functioning the intended way.

Before using the tool you have to set up the tool. There are four easy things needed to be activated.

1. **Enabling the solve function**
2. **Enable solver when using macros**
3. **Make the developer tab visible**
4. **Enabling the use of @Risk**

1) To enable the solve function, follow these easy steps:

1) Click on file in the main bar
2) Click options
3) Click Add ins
4) Click on the dropdown list at the bottom on the page an chose Manage Excel Add ins. Click go
5) Enable solver add in

2) To enable Microsoft solver when using macros, follow these steps:

1) In Microsoft Excel, start the Visual Basic Editor (press ALT+F11)
2) On the Tools menu, click References.
3) Click to select the Solver check box, and then click OK.
4) Close visual basic editor

3) To make the developer tab visible, follow these steps:

1) Click on file in the main bar
2) Click on options
3) Click on customize ribbon
4) Under Customize Ribbon, in the Main Tabs box, make sure that the Developer check box is selected.
5) Click OK.

4) Enable @Risk

@Risk is an excel program that among other things allows you to simulate risk in Monte Carlo simulations. The tool uses @risk to estimate riks premiums used by the model. Unless you intend to rewrite the risk sheet of this program, you do not have to learn @risk's functionality. However you will have to enable @risk in Microsoft excel.

1) If you do not have @Risk installed on your computer download and install @Risk.
2) Run @risk after you have opened the Profit Calculation Tool.

If you have followed these steps the tool is ready to be used. The tool has one input and output page making it easy to see how your own input affect the economic output. Put in the input requested in the input page. The historical production data provided should at least have a time horizon on 12 months. After the historical data is provided the tool need to adjust the modified hyperbolic curve to fit the historical data to be able to indicate a good forecast of future production. We have recorded macros how to fit the curve. Follow these steps to fit the curve to the provided historical data.

NB: *The historical data provided should be sorted to exclude huge deviations from a natural curve to get the best fitted curve. The data should preferably be descending each month.*

The tool fits a modified hyperbolic function by default based on 12 months of production.

To adjust how many months of historical data the fitting shall be based on, follow these steps.

1) Click on the sheet "Decline Curves"
2) Click on cell B6 (beside "SR cum. 12 months")
3) Adjust the sum of the function according to how many months of historical data you would like the modified hyperbolic fitting to be based on.

Using the macro to automatically estimate b and D best fitted the historical data provided:

1) Click the developer tab
2) Click on Macros
3) Run "SolveSetupDeclineParameters" to set up the multivariable solver
   a. "SolveSetupDeclineParameter" has the restriction of max b- factor of 1.5.
   b. "SolveSetupDeclineParameter2" has the restriction of max b- factor of 1.5
4) In Macros run "DeclineFactorsEstimator" to fit the curve (you will see the b- and d- factor adjust to best fit the curve of historical data.

Providing data to the Profit Calculation Tool:

The input output sheet is found in the presentation sheet. The economical potential of each technique will be displayed by NPV, ROI, IRR, Breakeven price, and payback time. These concepts are described in chapter 5 in the thesis.

Input:

- The yellow input fields in the presentation sheet is where you provide the historical data
- If you provide input to the "Total investment cost Refracturing" and/or "Total investment cost Recompletion". The economical calculations will be based on these costs. If you choose not to provide the tool with total investment costs, the tool will use our estimated cost and risk numbers. These numbers should be tailored to each well to get more accurate and realistic results. See the next two bullets for where you adjust the cost and risk data.
- To adjust the cost data of refracturing or Recompletion specifically go to the "Cost of Refracturing" or Cost of Recompletion sheet.
- To adjust the risk data of refracturing or Recompletion specifically go to the "MonteCarlo_Risk_Refracturing" or MonteCarlo_Risk_Recompletion sheet.

Appendix I: The Historical Production Data of Well 1

The historical data of well 1 one used in the calculations in subchapter 9.4. This is an average oil producing well which has the same characteristics of the well that the cost calculations are based on in subchapter 9.3

Month	Average bopd
0	446
1	370
2	300
3	250
4	225
5	200
6	170
7	165
8	140
9	120
10	112
11	105
12	100