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Writer: Steven Mellum	………………………………………… (Writer's signature)
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Optimized Field Development – Shale Gas

Written by:

Steven Mellum

Student Nr.:

212024

Preface

This master thesis marks the end of my 5-year MSc program at the University of Stavanger. This program includes a 3-year BSc in petroleum technology and a 2-year MSc program in industrial economics which combines economical and technical subjects.

My work experience and interest within offshore field development and offshore pumping services has been important in the writing in order to make estimates that are as realistic as possible.

The recent drop in the oil price and the lower gas prices caught my attention and I wanted to look into the possibilities for having a more stable and elongated production from shale gas formations by using multilateral technology and nitrogen injection.

My knowledge regarding field development and shale gas has increased during this thesis and has given me an insight in all the different factors that need to be in place in order to develop such a project.

Field development consists of many aspects and in order to complete all the necessary research and the experiment in a timely manner, this thesis has been written in cooperation with Eirik Magnus Barkved. The topics regarding multipurpose wells and multilateral design, methane displacement with nitrogen (enhanced gas recovery), recovery rate and project economics have been done in cooperation. Except of the previous mentioned topics Eirik has focused on the subsurface part and why nitrogen is chosen and its physical properties, while I have focused on the surface part and flow theory in formations.

And last but not least, I want to thank Kim André Nesse Vorland and professor Jann Rune Ursin at the University of Stavanger for their guidance regarding this thesis.

Stavanger, June 14th 2015.

Steven Mellum

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1 SUMMARY

In the recent decade there have been big changes in the oil and gas industry as the USA have increased their domestic oil and gas production due to shale oil and gas. The production from shale formations has been made possible due to implementation of horizontal drilling and hydraulic fracturing as well as higher prices for oil and gas. As the domestic production in the USA led to an increase in the oil and gas supply to the market, prices have fallen with around 40 % from recent year levels. This has led operators to shut down producing wells because they no longer are profitable. By having projects with short time perspective and lower margins on future production, large amount of resources sit unused in the shale formations which possibly may not be economical to produce in the future.

By developing a new field development concept using nitrogen displacement and multilateral technology in North American shale formations as presented in this thesis, the philosophy is to increase and elongate production in order to increase the recovery rates and make better use of the existing resources which in a long run are scarce.

A laboratory experiment has been performed to see if existing theories regarding water/oil and gas/oil displacement also are applicable for nitrogen/natural gas (gas/gas) displacement. The tests have been done using a low permeable chalk core plug where changes in density of the flowing gas is measured. The experiment is done by filling and saturating the core with methane and thereafter displacing the methane with nitrogen.

In the final parts of the thesis, an economical study has been done in order to see if the project is realistic and to present todays costs of the equipment and facilities needed.

2 ABBREVIATIONS

ADNOC	-	Abu Dhabi National Oil Company
BHA	-	Bottom Hole Assembly
BOP	-	Blow Out Preventer
DC	-	District of Columbia
EIA	-	US Energy Information Administration
EU	-	European Union
ICI	-	Intelligent Completion Interface
IGIP	-	Initial Gas In Place
ID	-	Internal Diameter
MLT	-	Multilateral Technology
MMscf	-	Million Standard Cubic Feet
MT	-	Montana
MWD	-	Measurement While Drilling
μD	-	microDarcy
mD	-	milliDarcy
Misc.	-	Miscellaneous
nD	-	nanoDarcy
ND	-	North Dakota
OD	-	Outer Diameter
P&A	-	Plug & Abandonment
P&ID	-	Piping & Instrumentation Diagram
Sm^3	-	Standard Cubic Meters
SPE	-	Society of Petroleum Engineers
TAML	-	Technical Advancement for Multilaterals
TCF	-	Trillion Cubic Feet
TOC	-	Total Organic Content
TVD	-	True Vertical Depth
TX	-	Texas
US	-	United States
USA	-	United States of America
USD	-	United States Dollar

3 SHALE GAS

3.1 Introduction

Stable demand and increasing supply has during the recent year made the price for oil and gas drop drastically from recent year levels. This is partially due to the increased production from unconventional resources, such as the North American shale gas formations, which have become economically viable for the oil and gas companies. The North American (USA, Canada & Mexico) gas-bearing shale formations have shown to be important for the supply of natural gas to consumers with current technically recoverable reserves estimated by the EIA in 2009 to be 54 trillion standard cubic meters. This has made the USA less dependable on imported oil and gas, which has forced the exporting nations to reduce their prices in order to be more competitive. The reduced price has led to many shale oil and gas producers shutting down their wells because they are no longer economically viable.

With today's challenges, where the oil companies are facing low oil and gas prices, the shale formations need to be produced in a smarter way in order to ensure that the resources are handled and produced in a most optimal way to prevent them from sitting unused in the ground. Since shale gas is an unconventional resource, these resources have not proved economically feasible to produce for a long time. They require special development strategies, often with the help of advanced technology. Conventional resources, however, are producible using technology that has been around for a long time.

Enormous unconventional resources have been turned into reserves because of two major technology advancements; hydraulic fracturing and directional drilling, which are the two main technologies that unlock both shale oil and shale gas. As an example, the first economically viable shale gas well in the Barnett shale in Texas was drilled in the 1990s because of this technology progression. However, regardless of the good results from these methods, we are still only able to extract approximately 20 % of IGIP (initial gas in place) from shale gas reservoirs as opposed to 75 % of IGIP from conventional reservoirs.

Large amounts of gas are left in the ground, and with today's gas prices the recovery rates will probably be even lower as the economic life of a well will be much shorter than what is technically possible. Figure 3-1 shows an overview over the vast areas of shale plays under production as well as prospective shale plays that are covering large parts of North America.

The number of active drilling rigs in the USA has dropped by 53 % to 760 rigs (April 10th 2015) compared with the peak of 1609 rigs in October 2014 according to BakerHughes. The reduction of drilled wells will result in lower production in the future as the daily production from shale formations drops very fast in the first year, with around 80 % less daily production than during the first days. As the shale formations have a relatively low permeability, today's production is sustained by drilling many wells to compensate for the rapid decline in daily production. In order to have a more predictable energy supply with less shocks, production from shale formations could really benefit from a higher, longer and more stable production to ensure that the resources are managed in the best possible way.

Figure 3-1: Figure 2.1: North American shale plays (EIA.gov, April 17th 2013).

3.2 The future of natural gas

Regardless of the current market situation, shale gas has already become a key component of the future of energy supply. Energy companies are looking towards unconventional resources such as shale gas because of an always-increasing demand of energy in the world, as well as conventional resources being scarcer. Shale gas formations have become the number one exploration-drilling target after more than 2000 TCF (trillion cubic feet) of gas in place has been identified in only five shale gas plays in the US (Agrawal & Wei, 2010). In addition, there are still many more basins and plays waiting to be explored. The US Energy Information Administration (EIA) has projected a significant increase in production from unconventional resources, as can be seen from Figure 3-2.

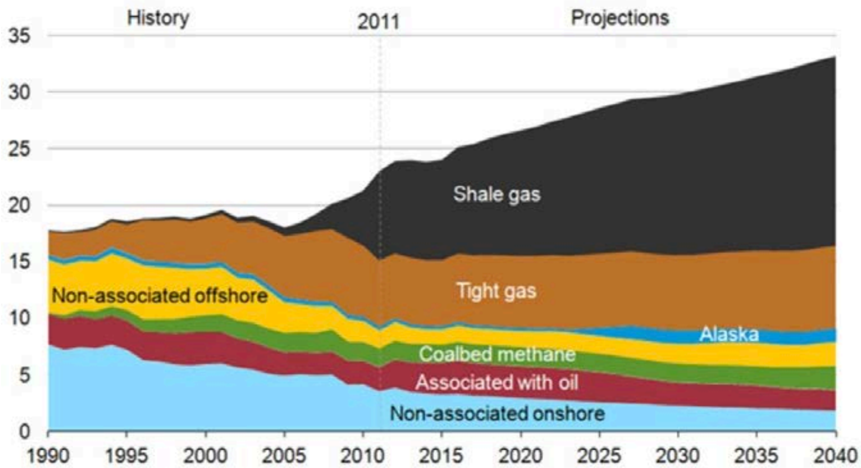

Figure 3-2: U.S. dry natural gas production in trillion cubic feet (Energy Information Administration, Annual Energy Outlook 2013 Early Release).

Natural gas demand in the future is also looking positive according to major energy companies. BP has reported that the growth in Asia, especially in China and India, will contribute to the increase in demand of fossil fuels towards 2035. The demand of natural gas is the fuel type they predict will have the highest rise in demand (BP.com, 2015). ExxonMobil is also predicting that natural gas will be the big winner in the fossil fuel market, where more countries will go from high-emission coal to natural gas instead. Their predicted rise in natural gas demand towards 2040 is 65 %, as well as there being 200 years of gas consumption remaining (ExxonMobil.com, 2015). Figure 3-3 shows this rise in demand. Another thing worth noticing from the diagram is the high-predicted increase in unconventional gas production, especially in North America.

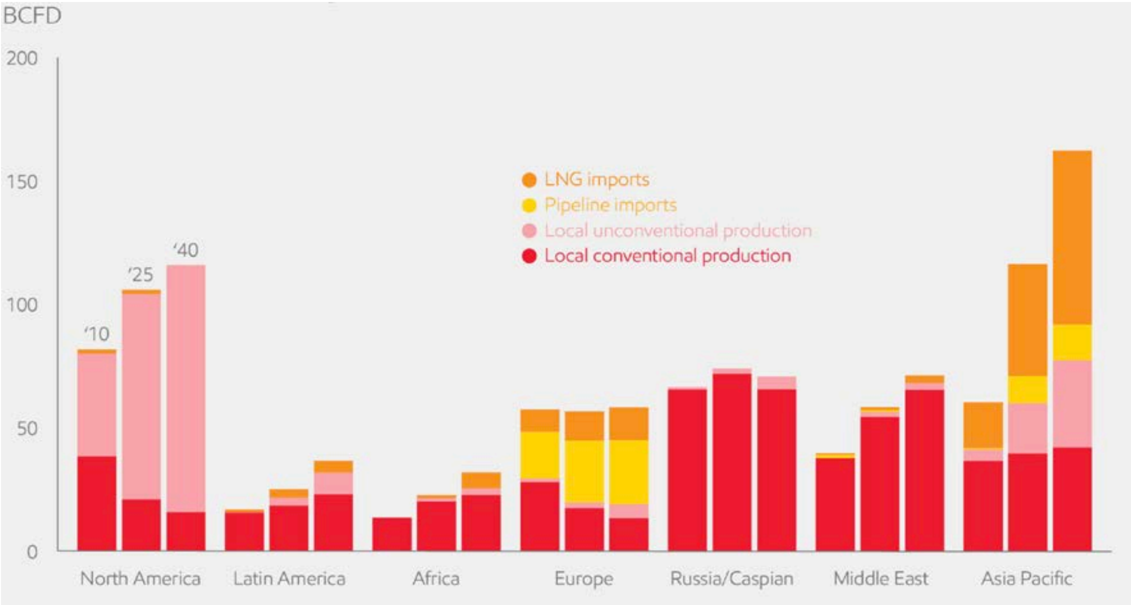

Figure 3-3: Forecast of gas demand by region and supply type (ExxonMobil.com, March 15th 2015).

It is not only in North America that the interest towards shale gas has grown. After seeing how the shale gas revolution has benefited USA, other nations also want to evaluate their own shale gas resources. There are trillions of cubic feet of proven shale gas, only in Europe, waiting to be extracted. Potential formations exist in a range of countries like Poland, Ukraine, Romania, France, India and China. The development of shale fields is however more difficult elsewhere in the world because few countries have the same level of onshore petroleum infrastructure as in the USA. The number of wells required, the environmental impact from fracking, water requirements, emissions, land leasing and permitting are some of the barriers. But also technical equipment such as the huge amount of horsepower required for one single pad operation sets barriers to the industry.

3.3 Environmental effect

Hydraulic fracturing, also called "fracking", is used to stimulate the shale formation to achieve desired production rates. Hydraulic fracturing has been controversial because of the changes to the environment such stimulation techniques can induce. Excessive fracking has in some areas lead to fractures reaching potable water and thus polluting the ground water with natural gas. Concerns that are more recent are possible connections between earthquakes in certain areas and excessive hydraulic fracturing.

Despite such potential environmental effects, shale gas investments have significant influence in the local community of the actual area. An example is the Marcellus shale industry in Pennsylvania, where the indirect and induced impact has been estimated to be almost as large as the direct spend. For every 1 USD that the industry spent, 1.9 USD was generated in the commonwealth (Considine, 2010).

While direct costs are associated with ordering equipment and executing the actual field development, there are several other impacts on the local economy. A shale investment sets off a chain of business- to business reactions throughout the economy. Indirect impact is for example a trucking firm hiring drivers and using spare parts from local parts distributors. The induced impact occurs when the truck driver spends his salary in the local market leading to a similar chain reaction.

These effects can be seen in the Bakken area, where the oil boom has led to an increase in wealth and population. The increase in oil and gas revenue has had positive effects on the economy of North Dakota, and the unemployment rate in the state is among the lowest in the USA.

An increase in unconventional oil and gas production would expectedly lead to an increase in the emission of climate gases. Quite the opposite has been happening in the USA, where the emissions are actually declining. This is significant in a country where the emission per capita is one the highest in the world. The most important reason for this is that there is a transition from the use of high emission coal energy to the use of shale gas for energy production. Besides, this shale gas energy is also locally produced and transported by pipelines, meaning that the transportation emissions are low. A switch to shale gas has cut the US emissions by 12 % in the period 2007-2012 (The Economist, 2014). This is a number far greater than what the EU could show for, where there have been heavy investments in renewables and pollution taxation politics. The coal used in the USA earlier is now exported to other countries, including countries in Europe.

4 SHALE GAS RECOVERY

4.1 Challenges

Even though shale formations have a large geographical abundance and containing enormous amounts of resources, it faces some basic challenges. The two most relevant challenges are determining exactly what the shale is consisting of and how to get the most resources out of the formations.

Shale deposits make up more than half of earth's sedimentary rocks and have a large variation in composition. Shale is normally referred to as a generally homogenous, fine-grained rock with certain physical properties similar to clay. Some formations grade from a typical shale to a tight sand formation, and some have gas adsorbed in the rock in addition to free gas. Even if the shales vary from location to location, they have two things in common. They are classified as organic carbon rich, and they form low permeable formations.

The challenge which this thesis is focusing on is how to get the most out of the formations. The recovery rates are very low due to rapid depletion of pressure in the vicinity of the well and fractures. The low permeable formation requires large differential pressures in order to have a decent production rate. A shale formation has the tendency to produce at a high rate the in the first months before it stabilizes on a low level on which it can produce for many years. Due to the rapid decline and low production rates, the wells are not economical viable after a couple of years as it costs more to operate the wells than it generates in income. The problem with rapid decline and short life of a well can be solved by introducing nitrogen injection as done in the Cantarell oilfield in Mexico. Figure 4-1 shows an example of nitrogen injection in a reservoir consisting of an oil zone and a gas zone.

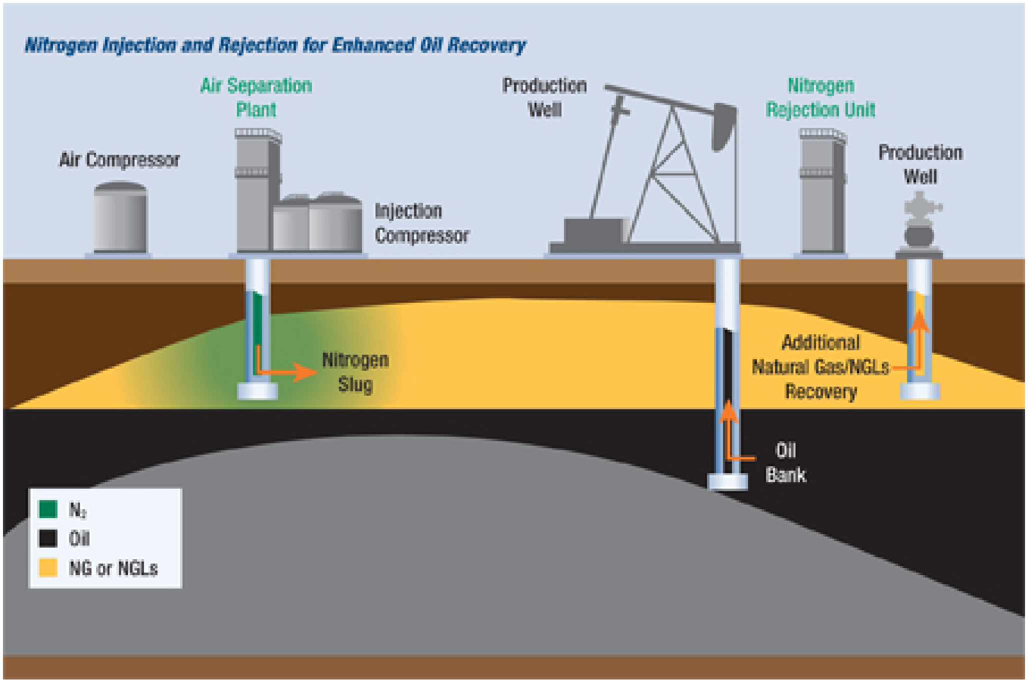

Figure 4-1: A nitrogen slug preserving the gas cap as well as displacing natural gas (Airproducts.com, April 14th 2013).

Another challenge related to the oil and gas industry is the way the resources are managed. Today, operators are typically most interested in developing fields that give large returns on the investments and abandon resources even though it still is possible to make good money by continue production. The reason it has been this way is because the industry is so international that they can simply move their money and knowledge to a new field and/or country that gives large returns. Something that may be profitable for society is not necessarily profitable from a company perspective. The reason it is profitable for society is that the oil and gas investments generate activity in other parts of society that also contributes to the commonwealth, while the only income the oil and gas company will see is the income generated by the production. One can ask the question if this is the best way to handle natural resources that are scarce to begin with if one looks at it with a long perspective.

4.2 Field development of a shale gas formation

The field development stages of a shale formation consist of discovery, drilling, formation evaluation, production and abandonment.

Since the geographical locations of shale formations are largely known, the discovery stage is more focused on analyzing core samples to evaluate if production is economically viable and determine how the area can be developed. The results from the discovery stage largely depend on the acquired knowledge of the reservoir through formation evaluation.

Today's practice during the drilling and formation evaluation is that there is a high focus on implementing a best possible practice to increase exposure to the reservoir and have a low cost per unit as possible. In the case presented in this thesis the focus is on setting up the wells to get a best possible drainage through displacement and to recover as much volume as possible instead of focusing on lowering the costs. At this stage, it is important to address the issues regarding transportation of the nitrogen for injection. How to get the product to the market through infrastructure, preferably through existing, must also be considered. The gasses preferably need to be transported through pipelines in order to reach the processing plants and existing pipelines to be sold on the market.

The focus is on displacing as much as possible from the formation in the production phase, where the hydraulic fractures and nitrogen injection are determining factors. The efficiency of hydraulic fracturing operations has a big impact on production and nitrogen injection wells since re-fracturing can turn out to be a challenge when the completion string and the lower completion has been installed. For the most optimal drainage through displacement, it is preferable to have a stable nitrogen injection and hydrocarbon production.

4.3 Shale as a source rock

Source rocks in petroleum geology are rocks where hydrocarbons have been generated or are capable of being generated. Shale formations are considered to be the primary source of hydrocarbons because of their high abundance and their potential for having a high organic content. Shale formations are in fact the most abundant clastic sedimentary rock. They are formed by depositions of small sediments in a range of environments such as deep water, bottoms of rivers, lakes and oceans. Because of the extremely low permeability in most shale formations, it is important to select the appropriate well completion technique if one wants to produce the resources located in them.

How natural gas is stored in shale is somewhat complex. It can either be dissolved in the organic content in the shale, stored in the "micro-pore" space of the shale, adsorbed to the surface of the shale or be contained in the shale matrix (Schweitzer & Bilgesu, 2009). The shale matrix contains most of the gas in the formation. Shale does also have a fracture network with significantly higher permeability, but the storage capacity of those is low. While some of the gas is adsorbed to the shale surface, part of the gas is also physically attached to the shale surface by Van der Waals forces. Such forces are caused by polarization attractions between particles. This thesis has only accounted for the "free" gas in calculations and no adsorbed gas is taken into account as part of the IGIP.

The Bakken Shale play has been used as a base for calculation purposes because of the low grade of adsorbed gas in the shale.

4.4 The Bakken Shale and Williston basin

The name Bakken has its origins from the Norwegian-American farmer Henry O. Bakken who owned the farmland where the discovery well was drilled in 1951. After this date, the Bakken formation has frustrated geologists for many years because they knew oil existed there, but without having the technology to extract it. Today the basin is holding one of the world's most important and industrially fastest growing oil and gas formations.

The Bakken Shale spans through North Dakota (USA), Montana (USA) and Saskatchewan (Canada), and is part of the petroleum rich Williston Basin, which is a large sedimentary basin. The Bakken Shale is 3350 meters below surface at the center of the formation and rises to 950 meter below surface on the edges of the basin. Figure 4-2 shows the location of Bakken Shale and Williston Basin.

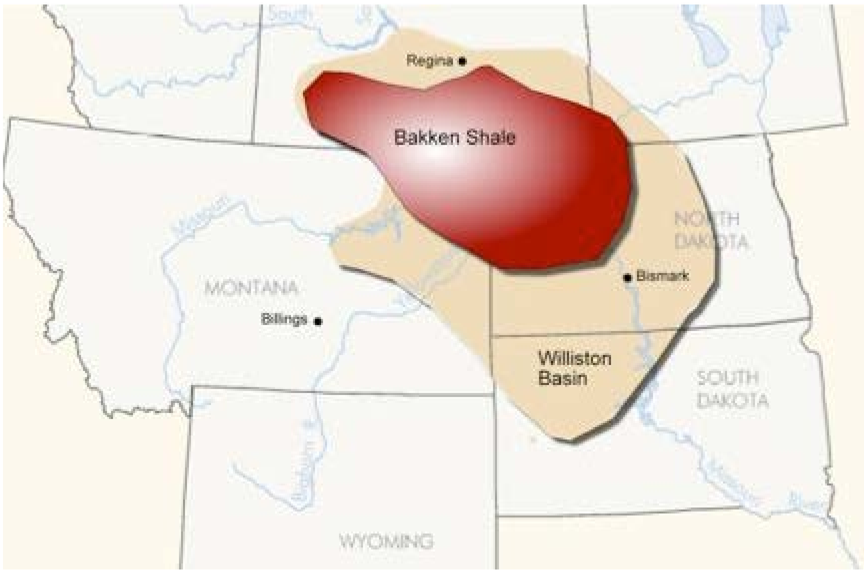

Figure 4-2: Williston Basin and the Bakken Shale play (Johnson & Courrege, 2010).

The Williston Basin lies above the Trans-Hudson Orogenic Belt that developed about 1.8 to 1.9 billion years ago. The basin was formed as a result of a sag in the area. The Bakken is a formation within the Williston Basin that comprises of three distinctive intervals that were deposited during the periods of Upper Devonian and Lower Mississippian. The three intervals upper shale, middle dolomite and lower shale become thinner and gradually converge to the margin of the basin. The Three Forks lies below Bakken and is regarded as a distinct formation across parts of the basin.

A cross-section of the variation in formation depth and thickness through Montana and North Dakota can be seen from Figure 4-3. The upper and lower Bakken shales consist of quite productive thick, black and organic rich mudstones (Rankin et al., 2010) that were deposited during the time of sea level rise. They are mostly lithological similar throughout the formation. Middle Bakken in the North Dakota region consists of a silty or sandy dolomite that was deposited in a coastal regime.

The majority of wells in the Bakken area have targeted middle Bakken even though the surrounding shale has a lot higher TOC (12-36 % in the shale and 1-3 % in the middle Bakken). This is because the upper and lower shale layers act as sealing rock for the more easily accessible oil in the middle member.

The porosity in the formation is between 1 to 16 %, and averages at 5 %. At depths lower than 3000 m the porosity is between 5 to 7 %. At depths greater than 3000 m the porosity is between 3 and 6 %.

Measured permeability in the middle shale ranges from 0 to 20 mD, and is normally very low with an average at 0.04 mD. The permeability of the shale is dependent on where the measurement is done and varies with thermal maturity and depth.

In this thesis a permeability of 0.01 mD has been used for the formation calculations.

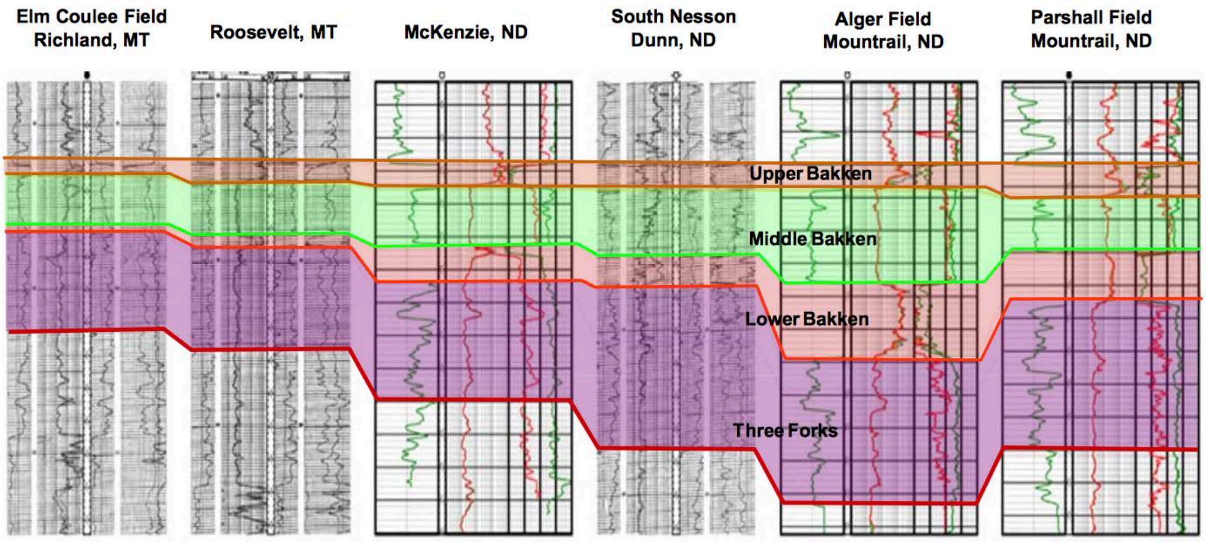

Figure 4-3: Variation in formation depth and thickness through Montana and North Dakota. The cross-section goes from west (left) to east (right) (Rankin et al., 2010).

4.5 Using gas for displacement

The complex nature of shale results in big challenges regarding pressure depletion. After initial production in a shale play, the plateau rate rapidly decreases.

Injection of nitrogen, water, CO_2 and natural gas into formations are commonly used methods for enhanced recovery of both oil and gas. Which product that is used and the effect it is designed to have is different from formation to formation, all depending on what the field needs to produce more of. The products can be used to displace, maintain pressure and to lower the viscosity all depending on how it is used.

Natural gas is commonly used for displacement and pressure maintenance in oil and gas formations. When using natural gas for displacement of oil it lowers the viscosity of the oil as they are miscible. When used for pressure maintenance it is either to increase the pressure in the wells and/or to prevent water coning, where the water zone moves upwards towards the wells and leads to halting oil production.

Water is commonly used for displacement and pressure maintenance in oil formations. Water can also be used to regulate the depth of oil layers as it can be used to push oil upwards in formations to increase oil production and decrease gas production.

Oxygen is easy to obtain, but it reacts with hydrocarbons and creates water and carbon dioxide. This will not help in the production of as pure gas as possible as well as it can lead to the formation of gas-hydrates which will block the pores.

CO_2 is commonly used to displace and maintain pressure in natural gas formations as well as it is used to displace oil. When displacing oil it also lowers the viscosity of the oil as they are miscible and further increases oil recovery rates. CO_2 can be sourced from byproducts of various processes, or it can be obtained from natural springs. However, there are some downsides with using this gas compared to nitrogen. A larger amount of the gas would be required to create a high pressure in the reservoir since it requires higher compression. Nitrogen would therefore be more energy efficient. CO_2 also turns into solid when facing high pressures, which would potentially block pores in the reservoir.

Nitrogen is commonly used for pressure maintenance and to regulate water breakthrough in oil and gas formations by preventing water moving towards producing wells. Nitrogen will be used for displacement and pressure maintenance in this thesis because of its numerous benefits. A comparison between the gases CO_2, nitrogen and methane can be seen in Table 4-1.

Table 4-1: Nitrogen, CO_2 and methane properties. Conditions are at 1 bar/20 ℃.

Gas	**Density [kg/m³]**	**Dynamic viscosity [10^{-6} Pa·s]**	**Compressibility coefficient, Z**
Nitrogen	1.1508	17.594	1
CO_2	1.815	14.69	0.9948
Methane	0.65957345	10.9945	0.998163

Nitrogen is a colorless, odorless, inert and abundant gas comprising of 78 % of the earth's atmosphere. It is a bi-product of oxygen production, where liquid air is fractionally distilled to produce liquid oxygen. Nitrogen is suitable for injection in reservoirs due to the low viscosity and molecular size. It does not react with the hydrocarbons in the reservoir because it is inert.

Nitrogen is already used in drilling, completion and workover of oil and gas wells. Some of the many usage areas are inert gas lift, flow initiation, corrosion protection, cleaning wells or hydraulic fracturing.

In the case of hydraulic fracturing it can reduce the high amounts of water required to successfully fracture a well. This might prove useful for water sensitive formations, for example shale that swells when in contact with water. Liquids could be trapped in the tight formation, potentially blocking pore throats and reducing permeability even further. Fracturing using nitrogen reduces the significant cost of hydraulic fracturing by reducing transport, treatment and disposal costs of water. The flowback rate after a fracturing treatment would also be larger because of the lower density and viscosity resulting from mixing nitrogen into the water. Studies have shown that as much as 80 % less water was needed in such "energized foam" completions using N_2 or CO_2 (Reynolds et al., 2014). By already having the necessary infrastructure in place for nitrogen injection in a shale play, an energized fracturing completion could be a good alternative to using water.

Large-scale nitrogen plants are being used for petroleum production in various locations around the world. To name a few examples: The joint venture between Linde and ADNOC constructed two large air separation plants in Mirfa, Abu Dhabi in 2011. They produce about 670 000 Sm^3 of nitrogen per hour, which is used for enhanced oil and gas recovery in the inland Habshan field. Another example is the largest oil field in Mexico, Cantarell, which was placed on nitrogen injection for pressure maintenance in 2000. This more than doubled their production to 2.1 million barrels per day from the field. Projects of this size show what nitrogen is capable of.

In Figure 4-4 nitrogen is injected to prevent water from going over the top and down to the oil producing wells and in that way preventing oil production. By injecting the nitrogen, pressure is maintained and stimulates increased recovery of natural gas and oil. If water was injected to maintain pressure in this case it would have gone over the top and would have led to premature shut down of the field. This example is taken from the Akal formation in the Cantarell field offshore in Mexico. Alternatively CO_2 or natural gas could be injected instead of nitrogen. In the case of the Akal formation in the Cantarell field they chose nitrogen because of difficulties in CO_2 and natural gas supply.

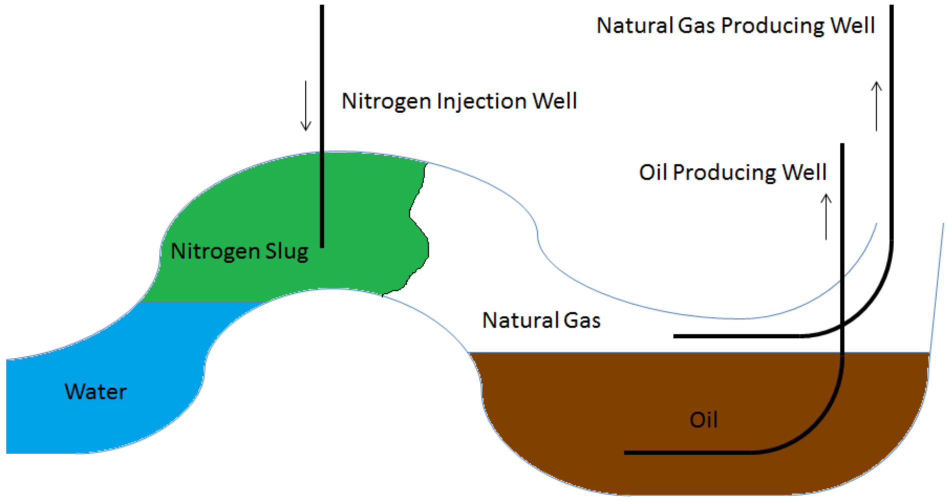

Figure 4-4: Nitrogen injection to prevent water production in the Cantarell field, Mexico.

In Figure 4-5 water and natural gas are injected to keep the oil zone around the oil producing wells and preventing premature production of natural gas or water. In addition to place the oil zone where the oil producing wells are it also functions to maintain pressure in the formation. Alternatively CO_2 and nitrogen could replace the injection of natural gas, but due to diffusion it would lead to premature shut down of natural gas production after the oil is produced. This example is taken from the Troll Vest formation in the Troll field offshore in Norway.

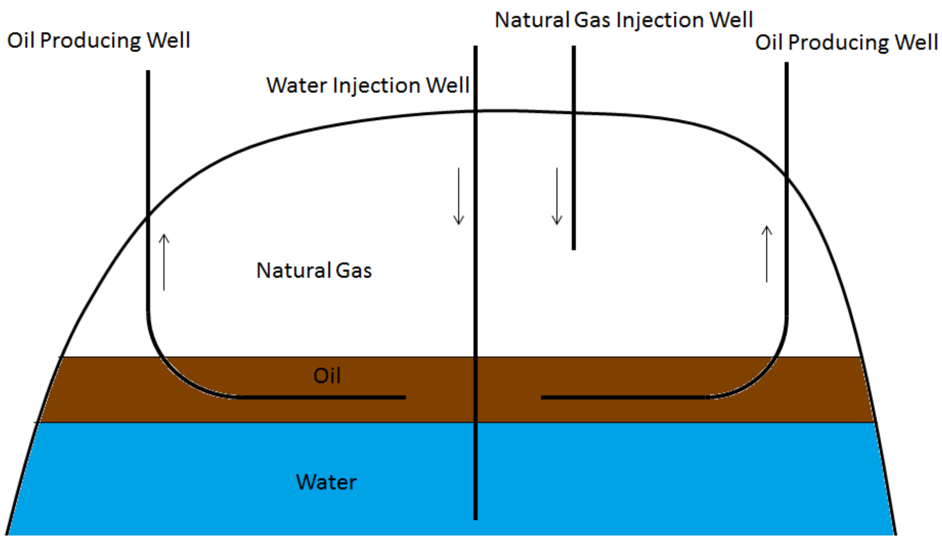

Figure 4-5: Placing an oil zone by gas and water injection.

In Figure 4-6 water is injected below the oil zone to maintain pressure in the formation in order to increase oil production, and it will also displace the oil as the formation is drained for oil. In this case it is best to have the well as far up as possible in order to delay the water breakthrough as much as possible. The water injection wells can be placed well below the oil-water contact to have the pressure distributed throughout the oil-water contact zones and therefore preventing water from migrating directly to the oil producing well.

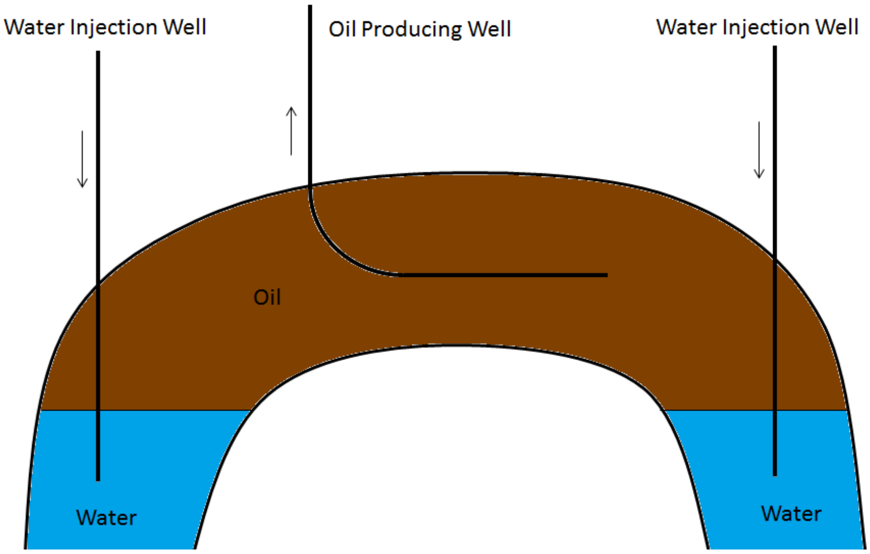

Figure 4-6: Water injection below the oil zone.

In Figure 4-7 water is injected to displace oil towards the oil producing well. Drainage in this scenario will mostly depend on the mobility ratio, which is based on the permeability of the formation and the viscosity of the oil. This method is commonly used in oilfields around the world.

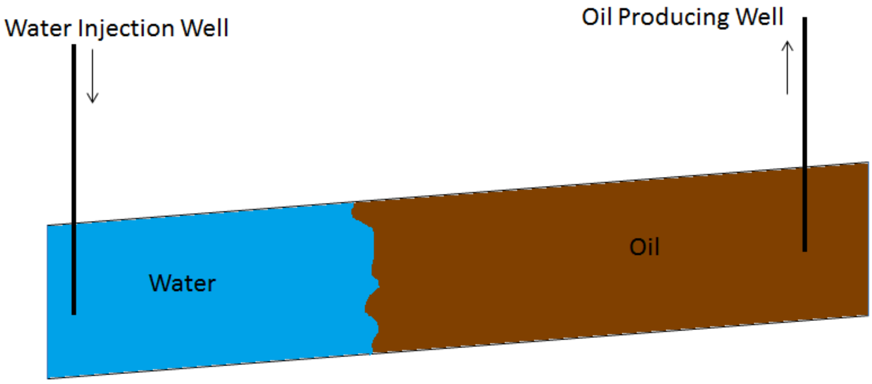

Figure 4-7: Water displacing oil.

Figure 4-8 shows a scenario where nitrogen is injected in order to displace the natural gas. This example is based on a low permeable shale formation where the pressure around the natural gas producing well decreases rapidly. In order to increase daily production and overall recovery rate of the formation nitrogen is injected to maintain pressure and to displace the natural gas.

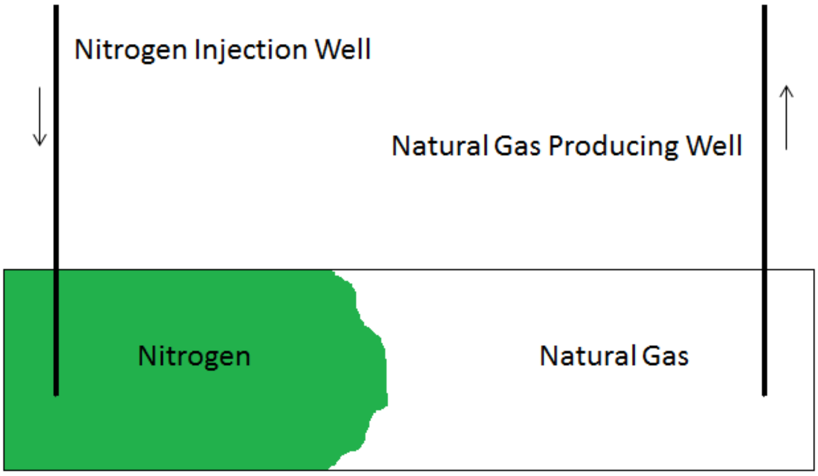

Figure 4-8: Nitrogen displacing natural gas.

4.6 Mobility ratio

Natural gas consists of many gases, mainly methane. The composition of shale gas is very similar to gas in conventional reservoirs. A typical composition of natural gas is given in Table 4-2.

Table 4-2: Composition of natural gas (shalegaswiki.com, May 15th 2015).

Component	**Typical molar content**	**Range of molar content**
Methane	95 %	87 % to 96 %
Ethane	2.5 %	1.5 % to 5 %
Propane	0.2 %	0.1 % to 1.5 %
Butane	0.06 %	0.02 % to 0.6 %
Pentane	0.02 %	0 % to 0.18 %
Hexane and heavier components	0.01 %	0 % to 0.06 %
Nitrogen	1.3 %	0.7 % to 5.6 %
Carbon Dioxide	0.7 %	0.1 % to 1 %
Oxygen	0.02 %	0.01 % to 0.1 %
Hydrogen	0 %	0 % to 0.02 %

To make calculations easier we make the assumption that the free gas in the reservoir consists only of methane. The amount of methane in the shale that is displaced depends on the mobility ratio between the displacing gas and methane. The mobility ratio is used to describe the ability of one phase displacing the other phase.

$$Mobility\ ratio = M = \frac{\frac{k_{porous\ medium}}{\mu_{displacing\ phase}}}{\frac{k_{porous\ medium}}{\mu_{displaced\ phase}}} \Rightarrow M = \frac{\mu_{displaced\ phase}}{\mu_{displacing\ phase}}$$

The lower the mobility ratio is the more effective the displacement will be. When the mobility ratio is equal or less than one the displacing phase will, to a certain extent, act as a piston. If the mobility ratio is more than one the displacing phase will partially mix with and bypass the displaced phase.

A correlation between the mobility ratio, relative injectivity and areal sweep can be seen in Figure 4-9. The dotted line shows the breakthrough of the displacing phase, at the point when it has flowed through the porous medium. After breakthrough the concentration of nitrogen in the produced gas will increase and production will not be economically viable at a given nitrogen concentration.

Once the mobility ratio is given, the percentage of volume swept when there is a breakthrough can be found by checking the diagram.

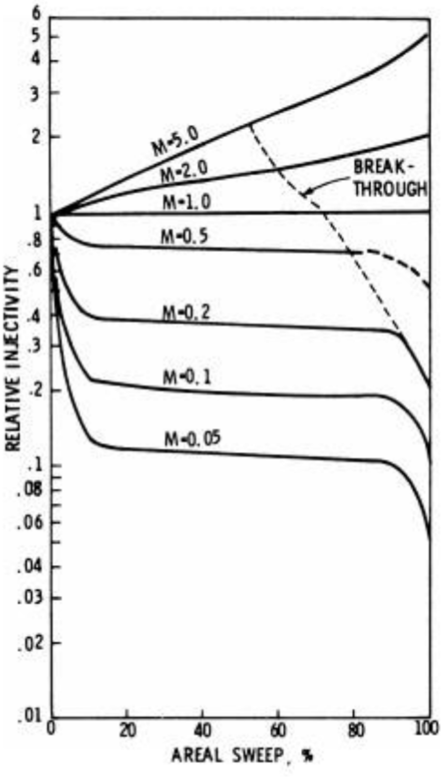

Figure 4-9: Relative injectivity (Willhite, 1986).

Figure 4-9 is taken from the case of water injection into an oil reservoir for displacing oil and is therefore only accurate to a certain point. The case is based on injection and production between two points through a reservoir and has therefore not taken into account flow through fractures or multiple injection and production points that are close. The nitrogen will flow faster through the bottom of the reservoir than in the top of the reservoir due to pressure drop in the fractures, which leads to a faster breakthrough at the bottom of the reservoir.

As the injection points and production point are closer to each other than accounted for in Figure 4-9, an overlapping will occur which will lead to a better areal sweep. This will be explained more in detail under the section about perforations.

A fingering effect will occur in a nitrogen injection scenario because the mobility ratio between the two miscible phases is above one. This effect can be described as the displacing phase working its way through the reservoir at various speeds and thus creating an uneven displacing front. The fingers will leave behind gas, and combined with the tight formation of the shale, a certain amount of time will have to be accounted for before the shale is drained for natural gas. Since the mobility ratio is approximately 1.5 for nitrogen/methane-displacement, the fingering effect will not be that severe. The fingering effects shown in Figure 4-10 are therefore not representative for this thesis because they are based on relatively high mobility ratios. However, they give a good illustration of what can happen to a displacing front where the mobility ratio is high.

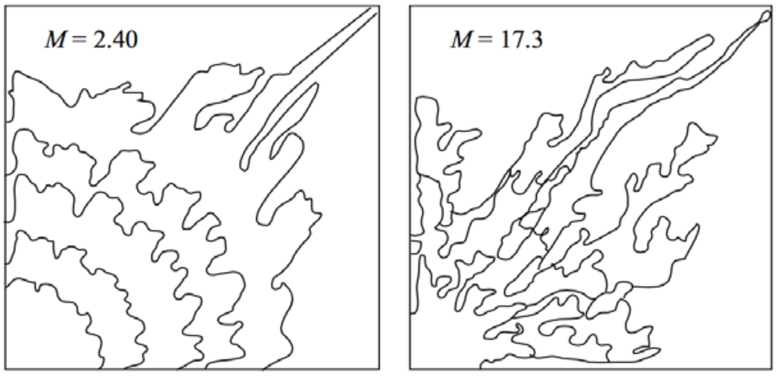

Figure 4-10: Fingering effects in the displacement front. Mobility ratio between displacing and displaced phase is shown in the upper left corner (Habermann, 1960).

5 METHANE DISPLACEMENT WITH NITROGEN

5.1 Summary

Laboratory experiments using a chalk plug with low permeability have been done to look at how methane behaves when displaced by nitrogen. Several trials of this experiment was conducted using a coriolis flowmeter, and the results showed that the water/oil displacement theories correlate to nitrogen/methane displacement. The experiment has also given results that can be used to determine the recovery rate and the fractions of methane and nitrogen in the flow at a given time.

5.2 Purpose

The purpose of the experiment was to find out how effective methane gas is displaced by nitrogen gas through a core sample. This is done to see if the mobility ratio theory also is applicable for the used gases. The experiment was done to find out how much methane that can be displaced in shale formations by using nitrogen. The concept is to use nitrogen to displace methane as water is used to displace oil in conventional reservoirs in order to increase total recovery. If the results turn out to be similar for water/oil displacement it enables the use of water/oil displacement theories for the nitrogen/methane displacement.

5.3 Equipment Used

The following equipment in Table 5-1 was used in order to get the results from the experiment.

Table 5-1: Equipment used for experimental work.

Item:	**Function:**
Methane (200 barg bottle)	Used to fill the system prior to displacement
Nitrogen (200 barg bottle)	Used to displace the methane in the system
Regulator	Used to regulate the outlet pressure from the methane and nitrogen bottles.
Coriolis flowmeter	Used to measure mass flow and density.
Valves	Used to isolate one part of the system from another.
Pressure gauges 0-100 bar	Used to measure the pressure in the system.
Differential pressure gauge 0-20 bar	Used to measure differential pressure over the core sample.
Core sample – Low permeable chalk	Used to simulate a reservoir.
Core sample container	Used to hold the core sample in place and to prevent gas to bypass the core sample.
Backpressure regulator up to 35 bar	Used to increase the pressure in the system in order to get better measurements with the coriolis flowmeter.
High pressure tubing	Used to prevent any unwanted incidents like leaks and bursting tubing.

5.4 Theory

To find how effective the displacement through the core sample was, the break through time was calculated to see if it is a piston displacement or if the methane is partially displaced. To find out the nitrogen/methane ratio in the core sample at breakthrough one measures the time it takes to flood it with nitrogen.

To find out the theoretical time it takes for nitrogen to displace the methane, tests to find the porosity of the core sample is done.

The porosity of the core sample is found by the following formula:

$$\phi = \frac{W_{Saturated} - W_{Dry}}{\rho_f * V_b}$$

Symbol	**Description**	**Unit**
ϕ	Porosity	%
W	Weight	g
ρ	Density	g/cm³
V	Volume	cm³

Index	**Description**
Saturated	Core saturated with distilled water
Dry	Dry core
f	Fluid
b	Bulk

To find out how much methane that was displaced as a percentage of the core pore volume the density of the gas on the downstream side of the core was measured. The breakthrough of nitrogen was indicated when the density started to increase, and complete displacement of all methane in the core was indicated when the density reached the maximum. This measurement can be used to find fractional flow, total volume flowed, recovery rate and fractional flow of nitrogen as function of nitrogen saturation.

The core data is given below:

Core data:	
Length:	12,25 cm
Diameter:	3,80 cm
Permeability:	3,0 mDarcy

Water density is 1.0 kg/m^3.

5.5 Method

To find the pore volume the dry weight of the core is measured, and then the core is put in a vacuum chamber and saturated with water. The weight of the water saturated core is measured and the bulk volume is calculated by the given core sample measurements.

The steps in Table 5-2 and the P&ID in Figure 5-1 describe how to perform the experiment in order to do the methane displacement with nitrogen through the core sample.

Table 5-2: Experiment procedure.

Step:	**Description:**
1.	Rig up the equipment according to the P&ID and connect the instruments to the data logger.
2.	Set the backpressure regulator to 30 barg.
3.	Ensure that the valve going to the nitrogen and methane tanks is closed.
4.	Start datalogging.
5.	Purge the system for 30 seconds with methane at 40 barg to saturate the system.
6.	Decrease the methane pressure to 30 barg, then close the valve to the methane tank.
7.	Set the regulator on the nitrogen tank to 32 barg, then open the valve to the nitrogen tank. Displace the methane until the density measurement has stabilized after a clear change in the values.
8.	When the density measurement has stabilized close the valve to the nitrogen tank, bleed off the pressure through the bleed valve and ensure that the system doesn't have any trapped pressure.
9.	Repeat the steps 5. to 8. to acquire more data.

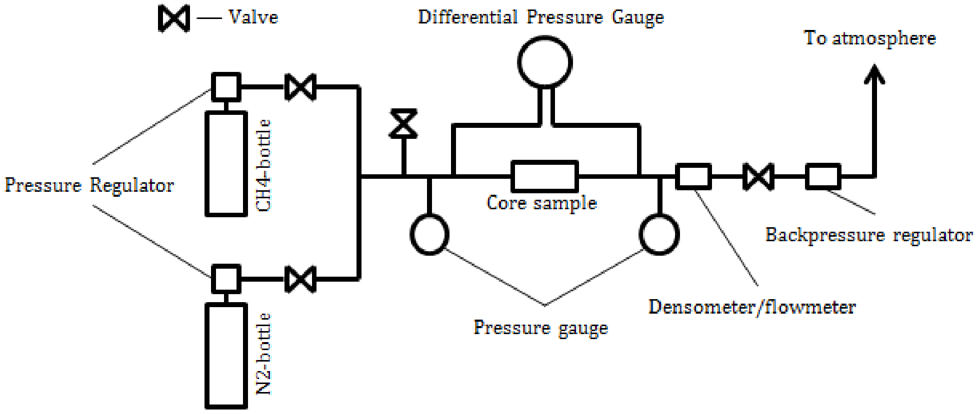

Figure 5-1: Experiment P&ID.

5.6 Results

A core porosity of 44.9 % is calculated below, which gives a pore volume of 62.4 cm^3.

$$\phi = \frac{W_{Saturated} - W_{Dry}}{\rho_f * V_b} = \frac{267.9 - 205.5}{1.0 * 138.86} = 0.449 = 44.9\ \%$$

Figure 5-2 shows measured density data for seven trials, from the start of injecting nitrogen until the core is completely saturated with nitrogen. Methane is displaced with nitrogen until the density measurement has stabilized after a clear change in the values.

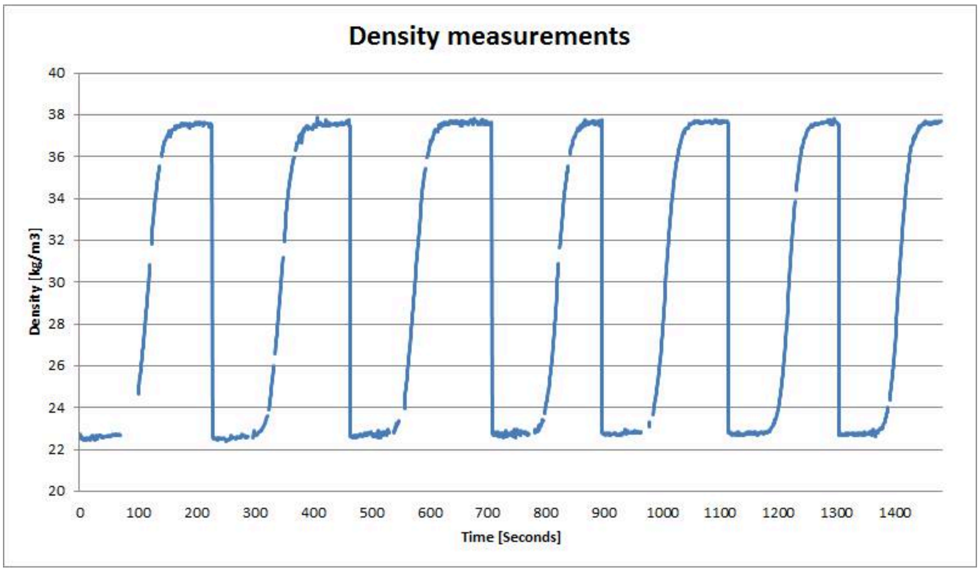

Figure 5-2: Density flow as function of time for seven trials. Some of the points are missing because the software used these as reference points and thus corrupting them.

Figure 5-3 gives a closer look at the average density measurement trial. The breakthrough of nitrogen is at around 69 seconds, and complete nitrogen saturation is at 161 seconds.

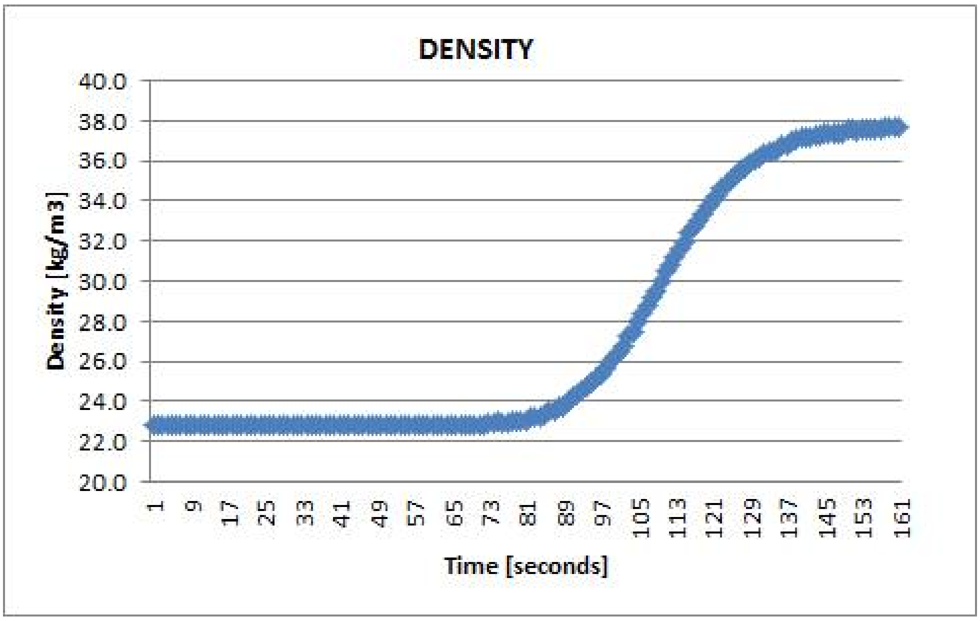

Figure 5-3: Density of flow as function of time.

Figure 5-4 shows the fractional flow of nitrogen and methane. This graph is used to find the point where it is no longer economically viable to produce the well. The economical breakeven nitrogen to methane ratio is calculated, and thereafter the graph is used to find the time of that point. When the time is found, it is used to find the recovery rate from the recovery rate graph.

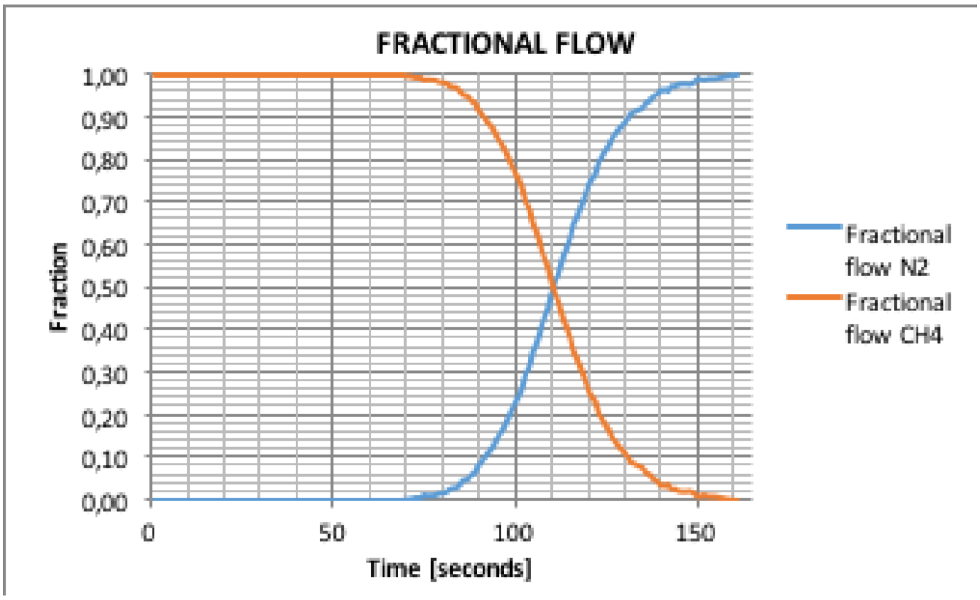

Figure 5-4: Fractional flow of nitrogen and methane.

Figure 5-5 shows how many cubic centimeters have flowed through the core at a given time. The total volume flowed combined with the fractional flow is used to find the recovery rate at a given time.

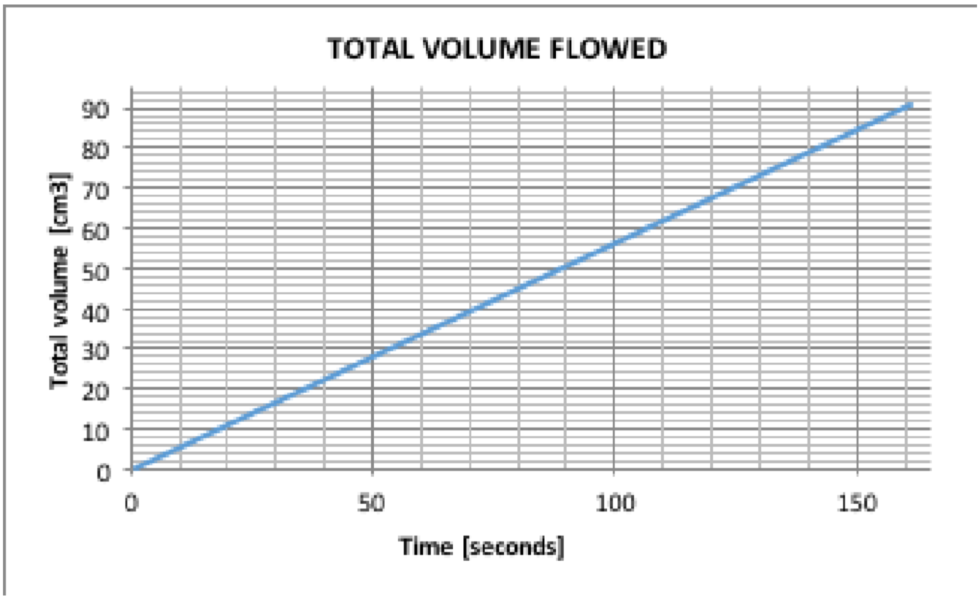

Figure 5-5: Total volume flowed through the core at a given time.

Figure 5-6 shows the methane recovery rate as a function of time. This graph is used to find the recovery rate at certain scenarios such as breakthrough of nitrogen and the point of breakeven.

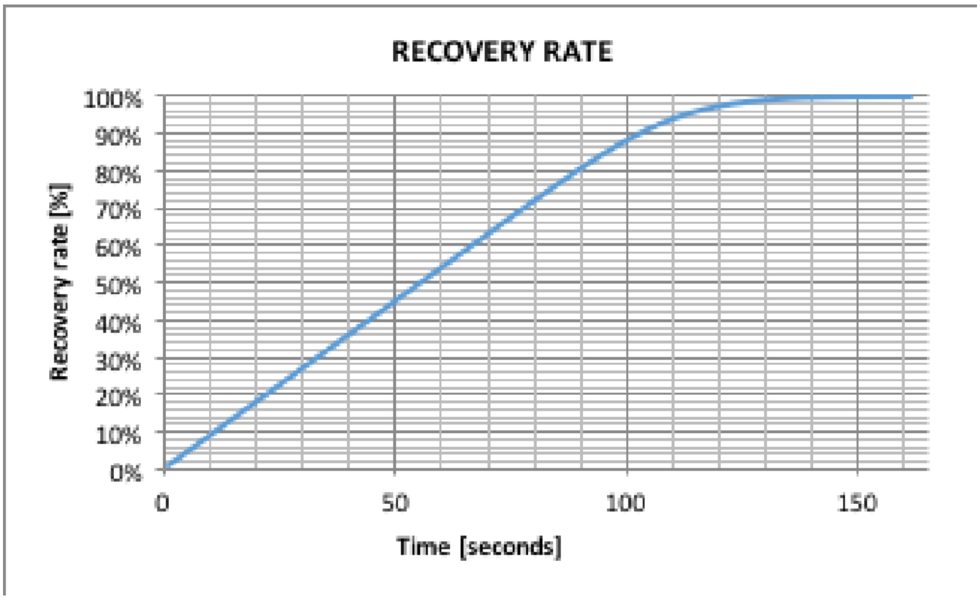

Figure 5-6: Methane recovery rate as a function of time.

Figure 5-7 shows the fractional flow of nitrogen as a function of the nitrogen saturation of the core in this experiment. This graph is used to find the methane recovery rate at a given fractional flow of nitrogen.

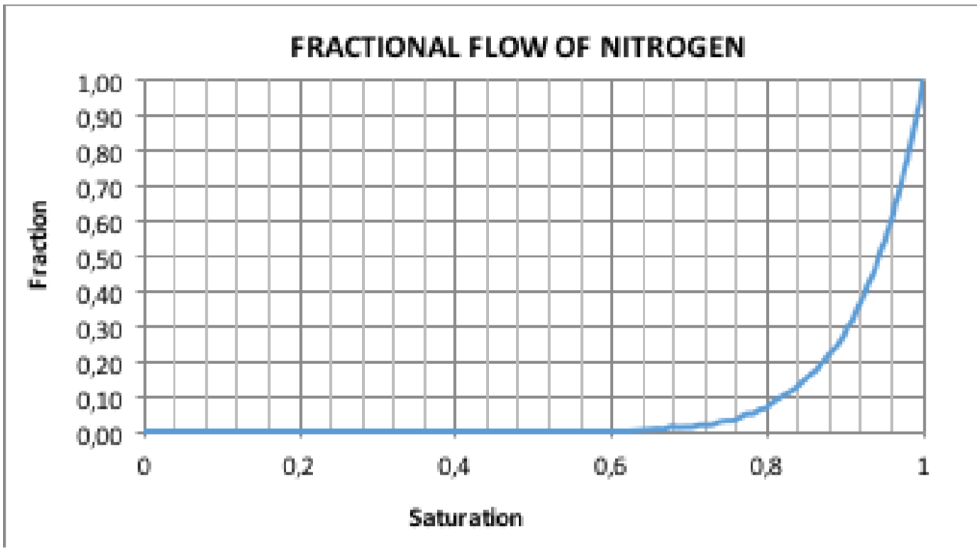

Figure 5-7: Fractional flow of nitrogen.

5.7 Uncertainties

Ten (10) trials were performed and the measured results were the same every time with negligible instrument uncertainty regarding time. The uncertainty in this experiment is determining the exact time of breakthrough as a couple of seconds amounts to a couple percent in the recovery rate. Besides the time aspect in this experiment there are not other factors that are believed to be sources of considerable error and therefore not taken into account. The reason time is an uncertainty is due to human error in determining the time of breakthrough. A standard deviation of 1.5 % is thought to cover the uncertainty more than enough for this experiment.

5.8 Conclusion

From the results, it is concluded that the mobility ratio, water/oil displacement and enhanced recovery by displacement theories can be applied to nitrogen/methane displacement for enhanced recovery. This conclusion can be made due to the recovery rate at breakthrough correlates with the recovery rate at breakthrough for water/oil displacement. The recovery rate at breakthrough is at 60 % ±3 % with 95 % certainty. When the flow consists of 50 % of each gas, methane and nitrogen, the recovery rate is approximately 94 %. From the results it is given that large amounts of methane gas can be recovered from shale formations by injecting nitrogen to displace it.

6 SUBSURFACE FIELD DEVELOPMENT

Development of a well consists of multiple project phases. Typical phases can be seen in Figure 6-1 where the lifecycle of a well starts with leasing and permitting and ends with plug and abandonment. This chapter focuses on the subsurface field development (blue elements) and explains the choices done in the surface field development in the next chapter. The phases drilling and completion are important to the field development concept presented in this thesis, especially well technologies such as multilaterals and hydraulic fracturing.

Figure 6-1: Typical phases in developing a well site.

It is important to understand that the economics behind wells can vary greatly depending on the characteristics of the well and the well site. The thickness and geology of the shale may vary, and logistical elements like where to get water for drilling and fracturing also plays a role. The prices listed in the text are acquired from numerous sources including meetings, e-mail, phone, work experience and published literature. The Value Chain study of a Marcellus shale well done by Hefley & Seydor (2011) has been of particular help to determine prices of various services. Parts of the technical information has also been gathered and verified through meetings with people from the industry.

6.1 Field development premises

Production calculations and economical calculations are done in this thesis to make a rough estimation on the feasibility to determine a realistic recovery rate from the formation of the nitrogen injection field development. Some field development premises are therefore assumed in this subchapter to make calculations easier. Others are actual well data and geological information from the Bakken area. Table 6-1 shows reservoir properties for Bakken Shale in the Williston basin.

Table 6-1: Bakken shale reservoir properties.

Pressure	386 bara
Temperature	60 °C
Porosity	5.0 %
Permeability	10 000 nD
Depth	3048 m
Thickness	46 m
Adsorbed gas as % of IGIP	0.0 %
Total area	517 998 000 000 m^2
Total volume	23 672 500 000 000 m^3
sm^3 of gas per m^3 of reservoir	16.69 sm^3/m^3
Average density	2370 kg/m^3
Fracturing pressure	710 bara

To be able to calculate recovery rates, assumed reservoir dimensions are given in Table 6-2, and wellbore dimensions are given in Table 6-3.

Table 6-2: Dimensions for producing area in the reservoir.

Length	3000 m
Width	850 m
Height	45.7 m

Table 6-3: Wellbore dimensions.

Wellbore vertical depth	3048 m
Wellbore horizontal length (in reservoir)	3000 m

The horizontal wellbores are placed in parallel to each other, where the injection wellbore placed in the middle and the production wellbores placed at the borders of the producing field. With a width of the production area of 850 m, the distance between the production wellbores and the injection wellbore becomes 425 m. The length of the production area is 3000 m, which gives a total area of 2 550 000 m^2. Figure 6-2 illustrates the wellbores seen from above. The red lines illustrate producing wellbores and the blue line illustrates the nitrogen injection wellbore. The true vertical depth (TVD) of the vertical wellbore is 10 000 ft which translates into 3048 m.

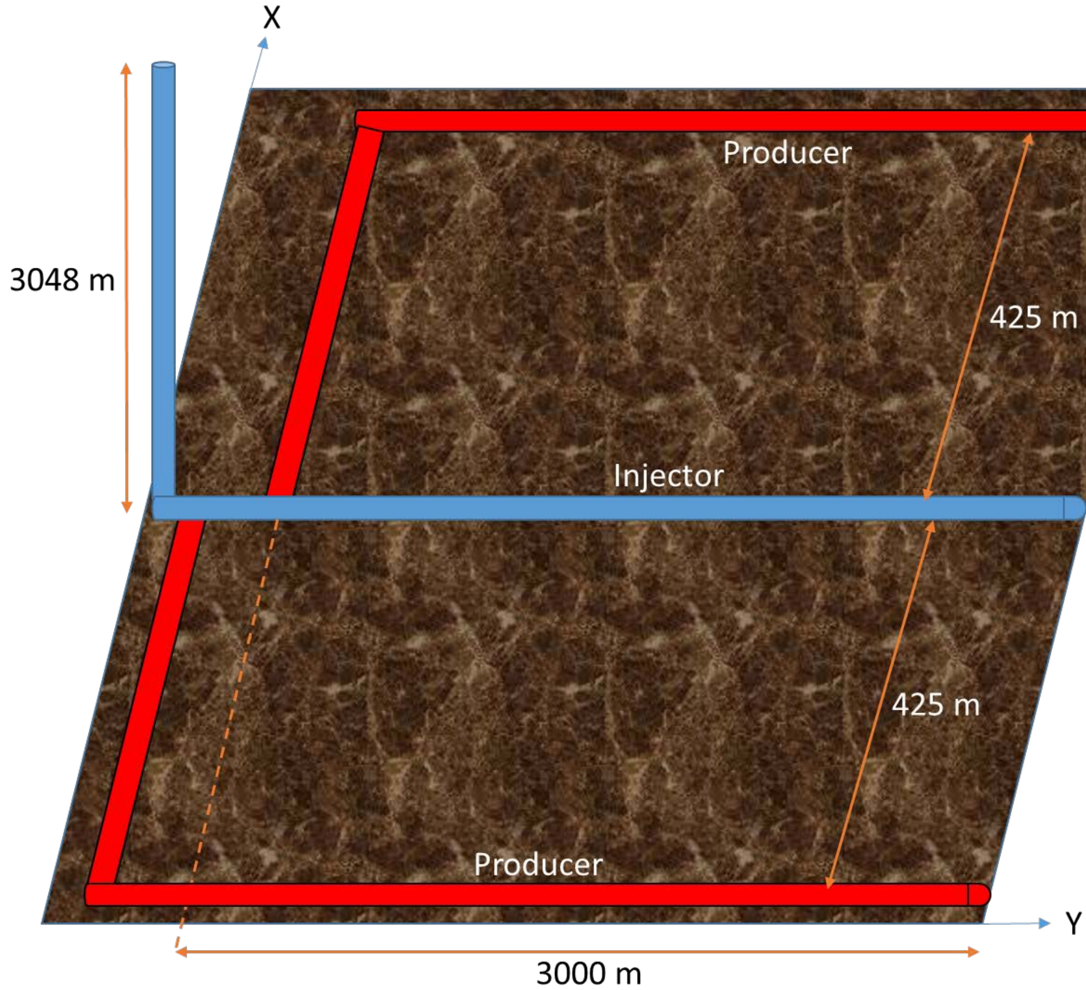

Figure 6-2: Top view of the producing area containing the horizontal wellbores.

6.2 Drilling

The drilling phase involves drilling down vertically to a just above the target shale section (kick-off point). A curved section is drilled afterwards before the horizontal section can be drilled in the reservoir. In general the curved section takes 1000 ft TVD to drill out. While the vertical drilling utilizes traditional methods, the directional drilling requires modern technologies such as electromagnetic survey equipment, downhole motors and steering equipment. The service company Archer estimates an average price of 11 000 USD/day for directional drilling services including all charges.

A broad range of services and equipment for the drilling rig, drilling operation and processing/disposal of mud and cuttings are needed. Casings, drill strings, BOP, pumps and downhole BHA tools are some of those items. The drilling phase for a well without the sidetracks, with mobilization of equipment taken into account, might take up to a month to complete.

6.3 Drilling rig

To perform the operations a rig with a skid that can drill up to 10 000 m, and where drill string, BOP and MWD services are included, is required. Due to the high costs involved in keeping and maintaining a drilling rig, most production companies do not own their own rigs. Drilling companies that specialize in performing drilling operations for production companies have a broad range of drilling rigs for various purposes. Usually different rigs are used separately for the vertical and horizontal parts of the well. By doing this the operators can save costs and time by using a cheaper and smaller rig for the vertical section, and by utilizing air drilling. This thesis uses a larger rig, used for horizontal sections, for the entire drilling phase in the cost estimates.

A Hydraulic Super Single rig from a drilling company that delivers to Bakken is sufficient. This type of rig has a relatively small footprint, which means lower construction costs and less environmental impact. The complete package rig rate including crew, mobilization and Drill Site Manager is 16 000 USD/day (sandersdrilling.com, February 10th 2015). There can be placed multiple wells per drilling pad with this type of drilling rig because of the skidding possibilities. Skidding involves using hydraulic power to move the rig laterally to a new location, and thus avoiding spending time on disassembly.

Other costs involved with the drilling rig are fuel, pit liners and disposal of drilling cuttings. The fuel used by the rig is usually covered by the production company and will be approximately 85 000 USD. It is assumed that it takes 160 truckloads for the multilateral well and the total cost of cuttings disposal becomes 40 000 USD. The number is based on a Marcellus shale well, where every 28 metric tons costs 250 USD to dispose of. Pit liners are encasing the drilling rig during operations to prevent contamination of soil in case of unplanned release of fluids, and has a cost of approximately 25 000 USD.

6.4 Drilling fluid and bits

Drilling fluid required for shale wells depends on the amount of horizontal drilling that is required. Halliburton operates with an average cost of 105 000 USD for drilling fluids in the Williston Basin on a per well basis. Much of this mud can be reused for a limited amount of time before desired properties have changed too much, and will give the project with multiple wells an economical upside potential.

In single-bore Bakken shale wells 8.75” is the common bit size used in the intermediate section down to kick-off and the curve section, and 6” is common production bit size. It is expected to spend about 70 000 USD on bits in a regular well. However, since the junction-section of the well requires a 9 5/8” casing size to hold the multilateral completion tool, a 12 ¼” intermediate hole-size is required. It is estimated to use approximately 100 0000 USD on bits for the intermediate hole size without taking laterals into account.

6.5 Casing and cementing

Wells in the Bakken are usually lined with casing from the surface to the base of the curve section of the well. This is in accordance to state and federal regulations made to protect the environment and groundwater in overlying formations. The casing protects the formation from well fluids, and it protects the well from infill from the formation. The casing used in the well is going to have an additional role, which is to support natural gas production through the annulus.

Four casing sizes are going to be used throughout the well:

- 20” conductor in a 26” hole that goes 20-40 feet long depending on the depth of solid rock first encountered.
- 13 3/8” surface casing in a 17 ½" hole that goes down to a depth that surpasses the water table.
- 9 5/8” liner in a 12 ¼" hole, which is going to reach beyond all possible water aquifers and mines.
- 5 ½” production casing in a 8 ½” hole.

It is expected to use about 565 000 USD on casings. This includes additional equipment required to set the casings, such as cement, a wellhead to hold the casings in place, centralizers, float equipment and baskets. The cement used needs at least 24 hours to cure before the completion phase can be initiated.

7 WELL COMPLETION – MULTILATERAL DESIGN

The official policy and strategy during the Soviet era was to produce as much oil as possible since it could easily be traded for other consumer goods. Drillers wanted to achieve this by drilling as many holes into the reservoir as possible. Alexander Mikhailovich Grigoryan (1914), looked upon as the "father of multilateral wells", approached the problem in a different way. His theory about increased production from branching wells instead of increasing borehole was put into practice in 1953 in Bashkortostan, Russia. His well with 9 branches produced 17 times more oil compared with other wells in the area at a cost of 1.5 times that of a conventional well.

Multilateral (MLT) wells are wells with more than one branch. They have a number of application areas like production from compartmentalized reservoirs, increased reservoir drainage and reduction of well slots or area on pads or platforms.

Today multilateral systems are much more advanced with sophisticated junction tools like the FlexRite systems by Halliburton or RapidX systems by Schlumberger.

Halliburton Norway has the largest MLT team in the world and at the moment they complete 30-40 new MLT junctions per year. In this chapter it is looked at how this technology can be implemented in a shale gas field development.

Technical Advancement for multilaterals was a group of experienced operators and suppliers that made a MLT classification system with six levels in 1997. The classification system is illustrated in Figure 7-1. An MLT completion based on TAML level 5 well design is used in this thesis.

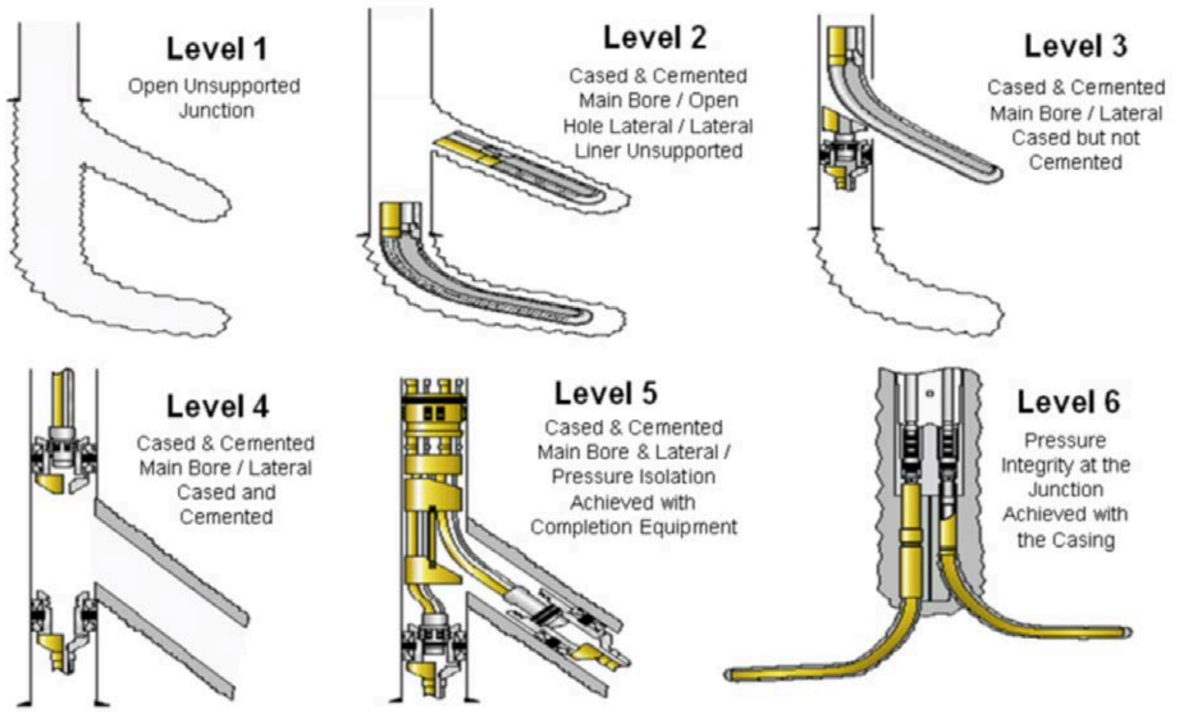

Figure 7-1: The TAML classification system for multilateral wells (Drillingcontractor.org, March 15th 2015).

The usual way to choose an appropriate TAML level for a well design is to start at a low level and check whether it is feasible or not. Level 1 to 3 provides little to no pressure integrity at the junction. The level 4 junctions however, provide better pressure integrity by having both the main bore and lateral cemented and cased. However, a TAML level 4 system has not been installed in Norway for over 10 years, and the largest oil company in Norway, Statoil, has stopped using it completely.

A level 4 MLT completion was successfully installed and used in the Smørbukk field in the Norwegian Sea for a gas injection well (Balstad et al., 2009). They developed a single-trip hollow whipstock system that resulted in the operator saving two rig-days. The operation itself was very complex. It would however be hard to do something similar in a simultaneous nitrogen injection- and gas producing well since the annular area between liner and formation is completely cemented making a multipurpose completion difficult.

If one looks at the junction of a level 4 system one will notice that the only element keeping pressure integrity is the cement. This means that the junctions need to be kept in the target section of the shale to avoid high differential pressure over the junction. It would also be necessary to have a thorough pressure integrity study to make sure that no future problems would arise. As an example, a burst scenario could occur when pressure in the formation where the junctions are located depletes. One positive side with the level 4 system is that it requires a smaller borehole diameter in the junction section compared to TAML level 5. The consequence is lower drilling costs because of the smaller hole. If a TAML level 5 junction is installed, a 9 5/8" casing is needed in the junction area to get pressure integrity. This means that a 12 ¼" hole must be drilled.

One concern with using MLT is connected to the reservoir performance over time in shale gas fields. Well intervention operations, like re-fracturing or stimulating the formation, might be necessary after some time, and could prove difficult in a multipurpose well. This is due to the risk of injected and produced mediums being mixed during the operations.

A level 5 system allows to have inflow control to prevent crossflow from one of the laterals to the other. Pressure integrity over the junction is also achieved. A modern system like the FlexRite TAML 5 from Halliburton makes it possible to do through-tubing intervention and lateral re-entry. Another improvement from lower level MLT completions is that less installation time is needed (a reduction from 15 to 3 days).

By having nitrogen injected in the main bore, high intervention costs and re-fracturing costs later in the well life are avoided. Nitrogen under pressure will continuously keep the fractures open in this well. Nitrogen is also an inert and harmless gas that will not lead to corrosive damage to the tubular. Production goes through the laterals, which have the required accessibility for intervention.

7.1 Multipurpose well design

Figure 7-2 shows a FlexRite ICI (Intelligent Completion Interface) TAML level 5 junction. It uses a flexible junction with two semi-circular sections to maximize the flow area. The D-formed tubing is illustrated with a cross-section in the upper right corner of the figure. The tool is modified for the multipurpose well design used in this thesis, with both injection and production in the same wellbore.

After the hole section for the MLT tool is drilled, a hollow drilling whipstock is set. Mainbore is then completed. The window where the lateral is drilled out from the main bore is pre milled and wrapped with aluminum. This reduces costly clean-out trips and minimizes risk compared to milling out a steel window. After it is milled out, the lateral branch is drilled. The lateral branch is then completed, the whipstock is retrieved and a deflector (blue color) is installed instead. The deflector will receive the mainbore stinger on the junction tool. In the end the upper completion is landed with a seal stinger.

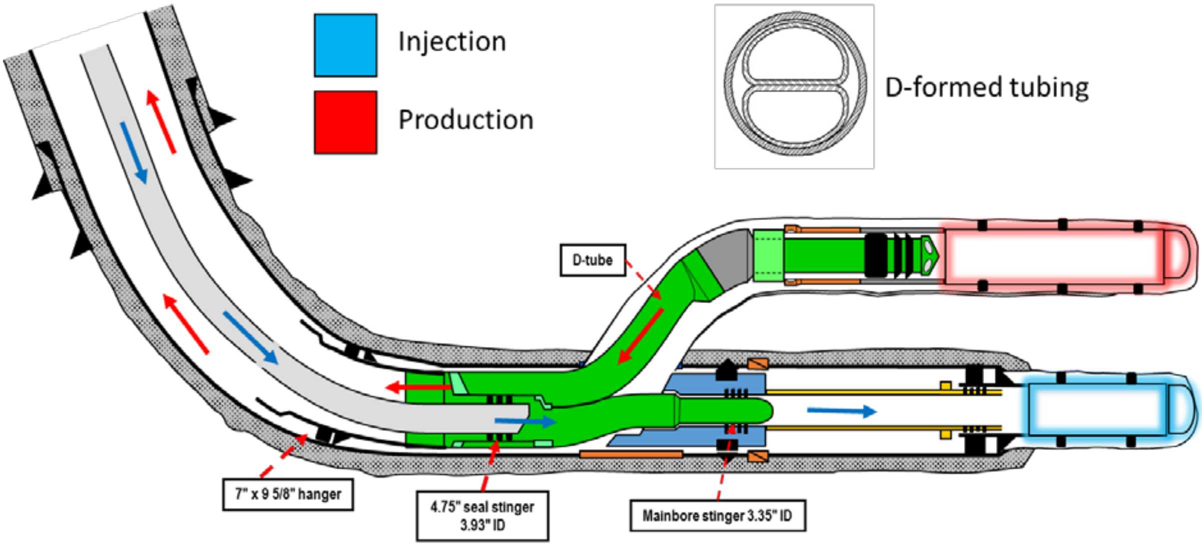

Figure 7-2: A Halliburton FlexRite ICI (Intelligent Completion Interface) junction modified for nitrogen injection.

An illustration showing the entire lower completion of our production concept can be seen in Figure 7-3. The junctions can be placed close to each other, roughly 40-50 m between them. Sand screens are normally included on the liners but the well in this thesis will contain a multistage fracturing system instead to ease stimulation operations.

An installation procedure for the MLT tool in the well concept is proposed below. A 9 5/8" casing or liner installed and cemented in place before an 8 1/2" hole is drilled horizontally into the reservoir.

1. Run 7" liner with pre milled windows
2. Drill and complete mainbore
3. Install first whipstock and drill lower lateral
4. Run lateral liner and cement liner in place
5. Perforate and hydraulically fracture lower lateral
6. Washover whipstock and retrieve remnant from lateral liner
7. Install second whipstock and drill upper lateral
8. Run lateral liner and cement liner in place
9. Perforate and frack upper lateral
10. Washover whipstock and retrieve remnant from lateral liner
11. Complete mainbore as required

A one-way valve arrangement may be required for temporarily use to avoid crossflow of nitrogen and natural gas.

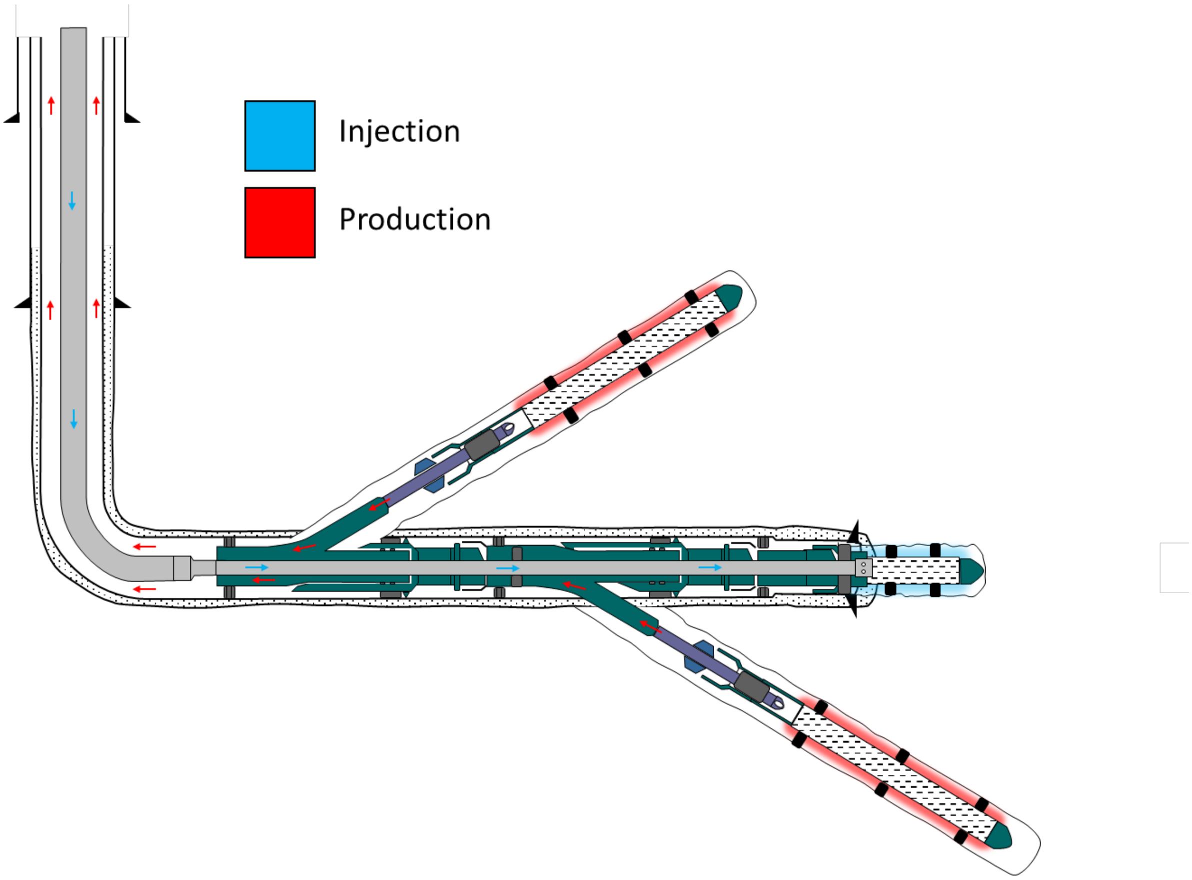

Figure 7-3: Concept figure of a multipurpose, multilateral injection and production system.

7.2 Environmental impact

The primary cost savings normally associated with multilateral wells is that drilling two or more separate wells no longer is required. Instead of having to drill down to the junction depth twice using conventional wells, MLT only requires 3-5 days of extra work per junction according to Halliburton experience.

The big cost saving element is that an MLT well has a construction cost of less than 30 % of the drilling and completion costs of a conventional well, based on Halliburton project experience in Norway. This should also be applicable to a project in the US. The resulting reduction in drilling costs are considerable since these are 10 000 ft TVD wells, even though the rig rates on a Bakken field well (15-25k USD/day) is much lower compared to that of an offshore field in Norway (500-600k USD/day).

There is also a reduction in environmental impact connected to rig moving, surface equipment for processing and transportation and permission to drill additional wells. There is less time needed for rig rental, and pad space is conserved with fewer wellheads. Multilaterals also reduces the need for drilling, completion and fracturing fluids and the containment of these fluids.

7.3 Challenges

Even though multilaterals have had widespread application since the 1980s and the positive sides are clear, they are still relatively sparsely used. A reason could be that when the cost reduction focus is on the well, and not the project, then well technologies get evaluated away because of risk averse behavior. Drilling multilateral wells involves risks such as borehole instability, stuck pipe, overpressured zones to casing and cementing problems (Bosworth et al., 1998). Another concern with using MLT in a shale play is that it might be challenging to effectively isolate and hydraulically stimulate the complex wellbores.

However, MLT completions have had a quite successful history in Norway. No other country is at the same scale of level 5 junctions installed. Only 10 wells have not been completed as intended, those being everything from dual to quad lateral wells. Only main bore completed, only lateral completed, or other issues were the cause of this (Stavanger SPE tech. meeting, March 18th 2015).

214 multilateral TAML 5 junctions have been installed in Norway as of February 2015. The benefits in these fields are the increased reservoir exposure leading to high production rate at low drawdown and delayed water/gas breakthrough, which in turn leads to a higher cumulative production and recovery rates. The fields with the most junctions installed by far are Troll (159) and Grane (28).

MLT does have significant benefits through cost reduction and increased reservoir exposure. One of the drivers in the Bakken shale is the possibility of exploiting several economically feasible formations. As an example, dual laterals can be used in the Bakken or Three Forks formations. A combination of dual laterals and stacked laterals can be used in both formations.

The chosen MLT concept will be beneficial both environmentally and economically to the nitrogen injection concept, where a given area is going to be swept for natural gas. It implies a reduction in costs, reduction of time, good well integrity and has a successful history in Norway.

Engineers want to use technology where they know the outcome. MLT means additional operations, which makes the technology less attractive, but common organization theory is key in using this system. The challenges can be overcome through success factors such as early commitment, dedicated personnel and thorough planning.

8 MULTISTAGE FRACTURING

Because of the low permeability shale plays face, which are often in the μD or nD range, hydraulic fracturing is needed. The channels that the fracturing creates, dramatically increases the permeability by allowing flow through the channels and into the wellbore. Fractures are kept open with the assistance of non-sealing ceramic proppants or sand grains that are pumped with fracturing fluid down into the well. This method, often referred to as "frackpacking", involves pumping fluid at a very high rate and is an expensive operation. The permeability of a resulting fracture can vary from almost zero Darcy to a couple of hundred Darcy depending on how well the proppants are placed.

8.1 Rock mechanics

Hydraulic fractures are normally identified by their length, height and width, and are not only a function of the amount of fracturing fluid pumped down. They are also dependent on the in-situ stresses in the formation. The pressure needed to fracture the formation is dependent on the minimum principal stress and additional pressure to overcome the tensile strength of the rock. Fractures normally propagate perpendicular to the minimum principal stress, which in a regular reservoir is in the horizontal direction.

Figure 8-1 represents the in-situ stresses appearing in the formation. σ_1 is the vertical (overburden) stress, σ_2 is the minimum horizontal stress and σ_3 is the maximum horizontal stress.

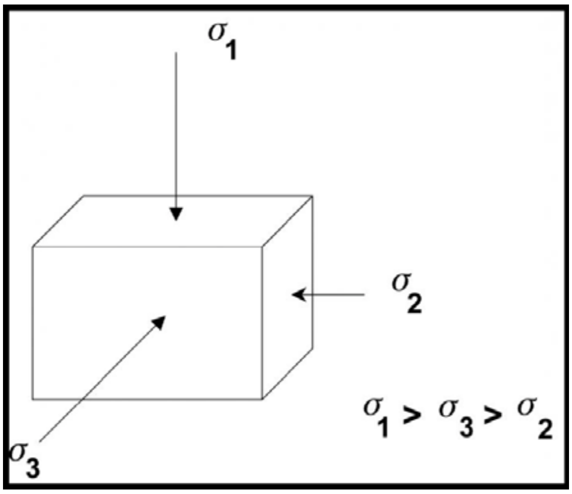

Figure 8-1: In-situ stresses in the formation.

The overburden stress is considered to be the smallest of the three stresses in shallow formations. If a fracture were to be initiated from the wellbore, it would propagate in the horizontal direction. The reason for this behavior is that the fractures widens in the direction of the least stress, as illustrated in Figure 8-2.

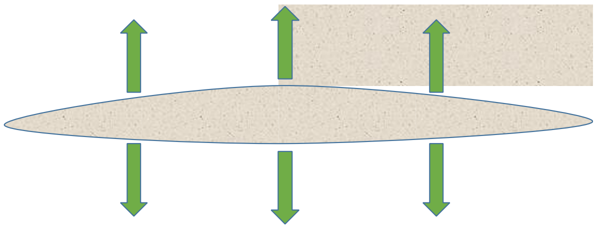

Figure 8-2: Fracture propagating in the horizontal direction as a result of minimum horizontal stress being in the vertical direction (shallow formation).

When the wells become deeper, σ_1 tends to become the dominant stress. At this point the hydraulic fracture will propagate in the vertical direction. The fractures are formed vertically upwards from the borehole, as shown in Figure 8-3, by perforating upwards and taking advantage of this rock mechanic.

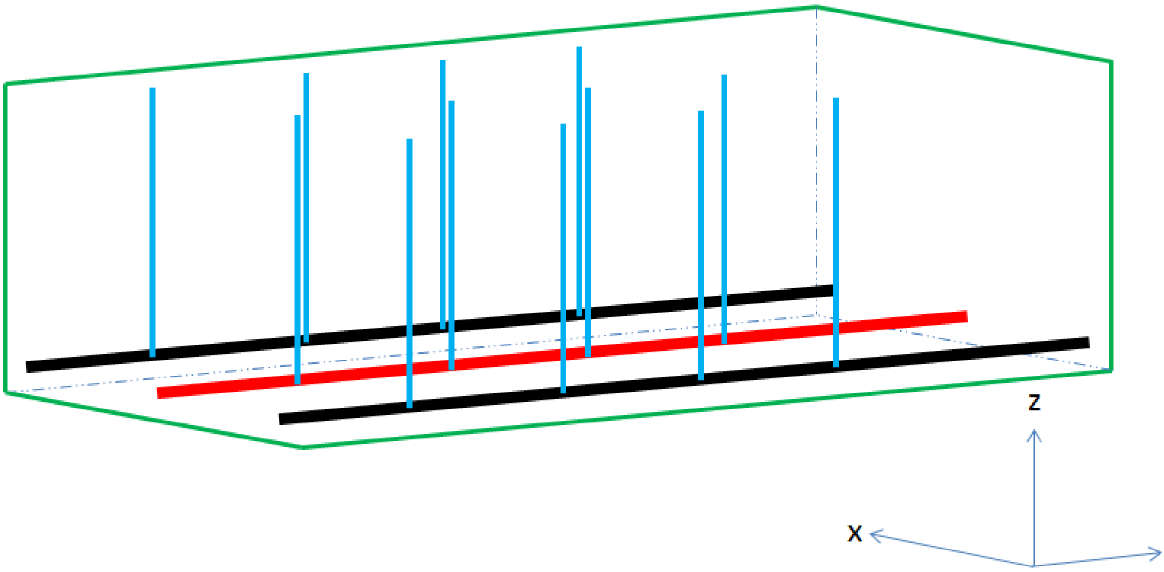

Figure 8-3: A section of the wellbores in the production area with fractures pointing upwards in the vertical direction.

The stress induced by the overlying formation is a product of its density ρ, the acceleration of gravity g and the height h:

$$P_{fracture} = \rho_{overlying\ rock} * g * h$$

Directional wells in the Bakken shale play are usually positioned in a north-south direction because it is believed to be in the approximate direction of the minimum horizontal stress. This direction helps creating fractures that are transverse to the wellbore. Transverse fractures points out from the bore, as opposed to longitudinal fractures that propagates along the bore. In this thesis, it will be an advantage to drill in the east-west direction so that the hydraulic fracturing creates a "wall" of longitudinal fractures which helps to drain the formation in a more optimal way.

Figure 8-4 shows the wellbore layout with dimensions for each wellbore and the fractures that have propagated longitudinally.

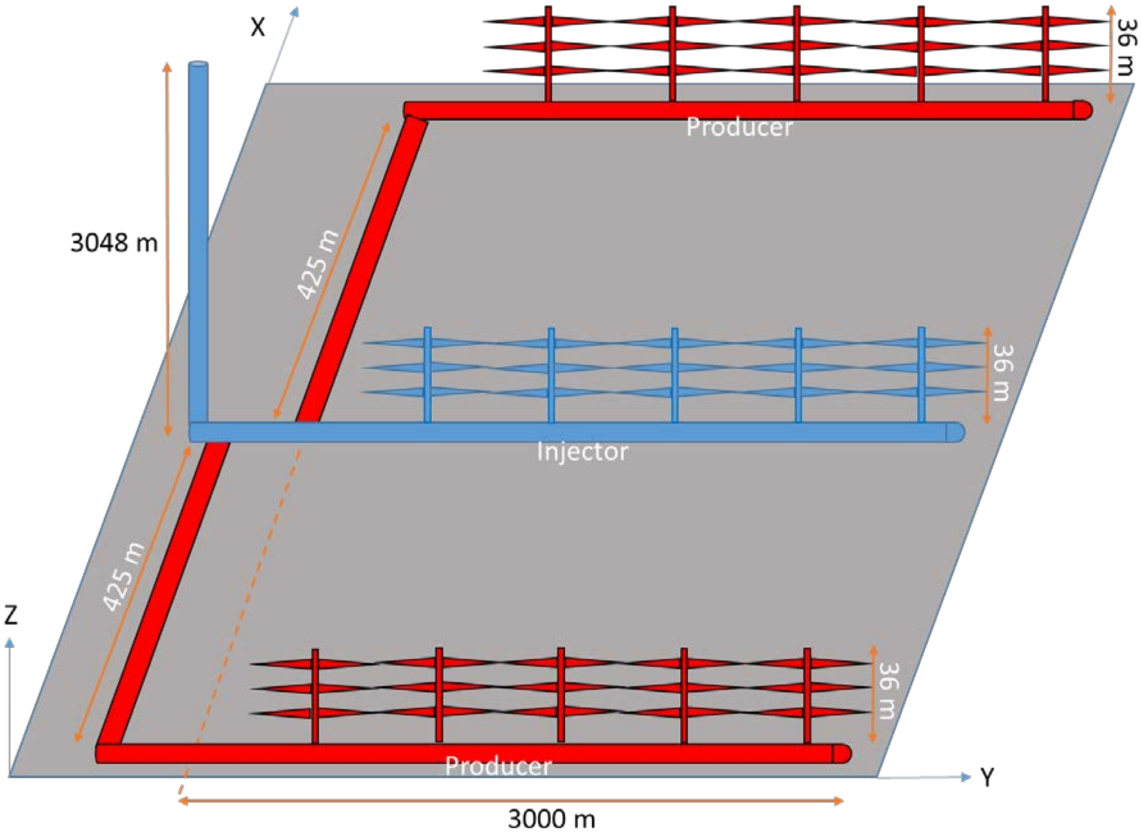

Figure 8-4: Wellbore layout with fractures.

8.2 Multi-stage hydraulic fracturing

Horizontal Drilling and hydraulic fracturing technology have been contributing to a boom in production from both conventional and unconventional reservoirs in the past 30 years. Another technology, that has gotten widespread application in the last decade, has taken this to the next level. It is now possible to do economical stimulation of very long horizontal wellbores through multi-stage hydraulic fracturing. The concept of this technique is to seal off a section in the well while it is being fractured so that a reasonable amount of fracturing fluid can be used for each stage.

This is a common method employed in wells with cemented liners, but it can also be used with uncemented liners. In this case the liner has attached swellable packers on the outside in various intervals that swells when in contact with hydrocarbons and/or water. This way, when the liner is introduced to the downhole environment (fluids and temperature), a tight seal is formed between the formation and the liner.

Since the laterals are 10 000 ft long, uncemented liners with swellable packers are favorable due to the complexity and cost of cementing and the amount of fracture stages needed in the well. The two different completion systems that can be accommodated with this are the multistage frac-sleeve system and the “plug-and-perf stimulation system.

8.3 Multistage frac-sleeve system

"Ball actuated" sliding sleeve systems are extensively used in Bakken completions. A ball is pumped down that will seat in the mechanical sleeve and open it up for fracturing. Pumping down progressively larger-sized balls operates the system. The sleeves can then be operated from the toe to the heel of the horizontal section.

Bakken has been pushing the limit of fracturing stages in open hole packer and sleeve completions, allowing operators to maximize production from very long horizontal wells. Figure 8-5 shows a common completion for Bakken wells. It has a liner with swellable isolation packers in contact with the formation and fracturing sleeves between the packers.

One of the benefits of this system is the reduced time needed to complete each stage because no perforating is involved. The timing is driven by the fracturing design and lasts typically 1-2 hours per stage (Pearson, 2013).

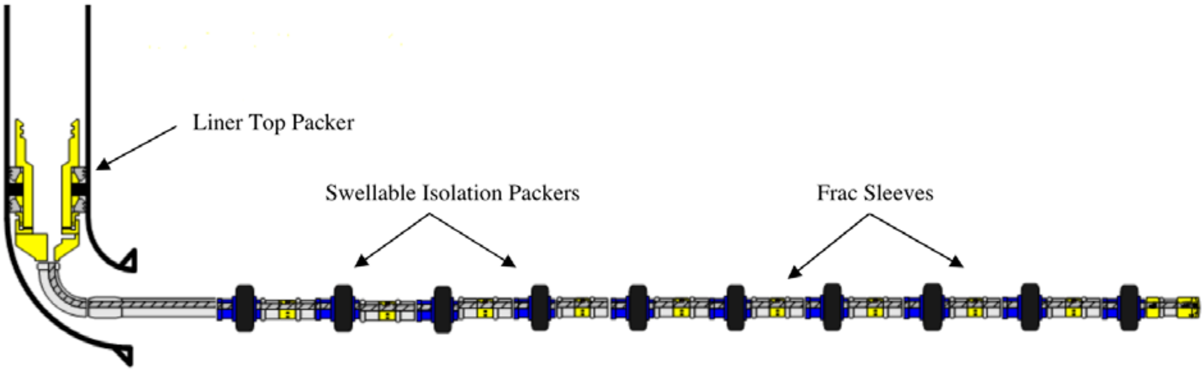

Figure 8-5: Multistage frac-sleeve system (Johnson & Courrege, 2010).

8.4 "Plug-and-perf" stimulation system

While the multistage frac-sleeve system is typically limited to 20 stages and one opening per stage, the plug-and-perf system can have multiple perforation clusters per stage. The method includes pumping down a bridge plug near the toe of the horizontal section. The plug prevents water from entering the completed stage and prevents gas from flowing to the surface. A perforation gun attached to a wireline or coiled tubing follows the bridge plug downhole. The section is perforated after the plug is set.

Afterwards the tools are removed and the section is hydraulically fractured using a similar ball-activated system as the frac-sleeve method. The difference is that the fluid is lead through the perforations going through the liner and into the formation instead of the sliding sleeves. When the section is completed, the next plug and perforation is initiated. This process is repeated for the desired amount of fracturing stages until one reaches the heel of the well, as illustrated in Figure 8-6.

One of the downsides with using this method is that it takes significantly longer time than the frac-sleeve system. Because of the repetitive nature with perforation guns and bridge plug for every stage, one can estimate to use 3-5 hours per stage (Pearson, 2013). This method is however a good choice for a completion in a shale play where both perforations and hydraulic fracturing will be performed, and will be the method of choice in this thesis.

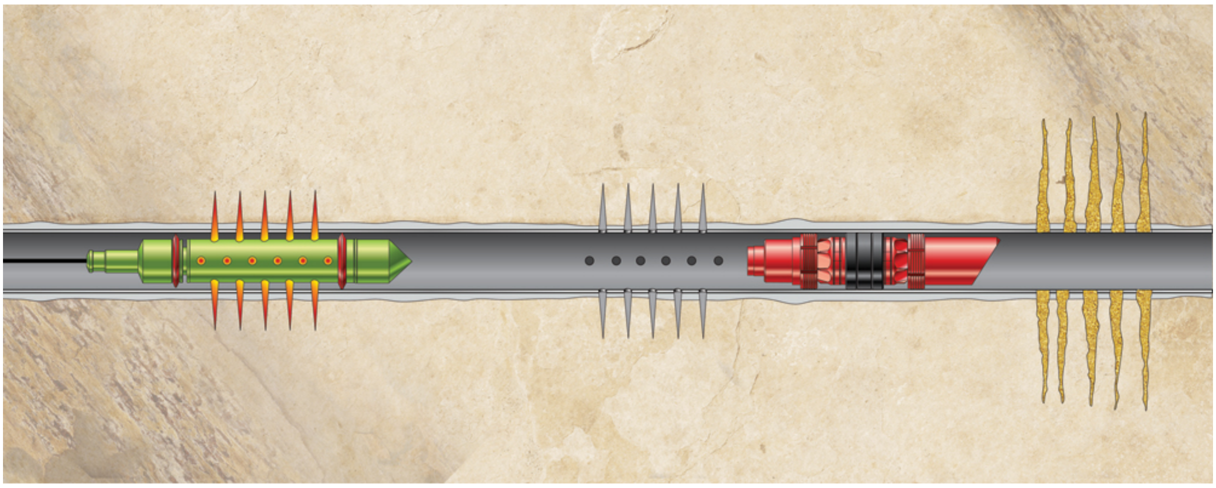

Figure 8-6: "Plug-and perf" stimulation system progressing from well toe to well heel (Drillingcontractor.org, March 10th 2015).

8.5 Perforations

A completion in a 9500 ft long lateral can typically consist of 30-36 stages. The lateral can be drilled with brine fluid so that the annular swell packers do not react before they are in contact with hydrocarbons from the formation. Stages typically have four perforation clusters containing six perforations per cluster. Every stage then has 24 perforation holes.

The American operator Continental Resources operates with 24-25 stage fracs in their plug-and-perf completions in the Bakken area. They perforate 6 one foot intervals per stage with 6 shots per foot. 8 stages are typically completed per day. Since this also applies for 9500 ft long laterals, it means that amount of stages and perforations per feet are up to the operator completing the well.

The perforations and fractures are designed according to the theory presented by Willhite (1986), where isopotentials and streamlines between an injection well and a producing well is illustrated in a simple manner. This can be seen from Figure 8-7. An ideal interval for the perforations on both producers and injectors would be overlapping streamlines that cover most of the reservoir section. Perforations will be in intervals of 50 m, resulting in a total of 171 perforations (vertically upwards).

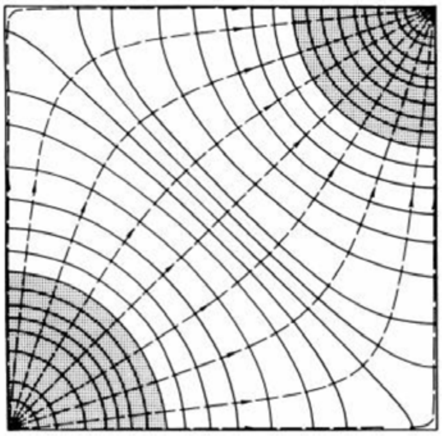

Figure 8-7: Isopotentials and streamlines between an injection well and a producing well (Willhite, 1986).

Figure 8-8 shows a section of the multilateral well where the blue areas illustrates the area that is swept by nitrogen. The flow lines between injection well and producing well are shown as blue lines.

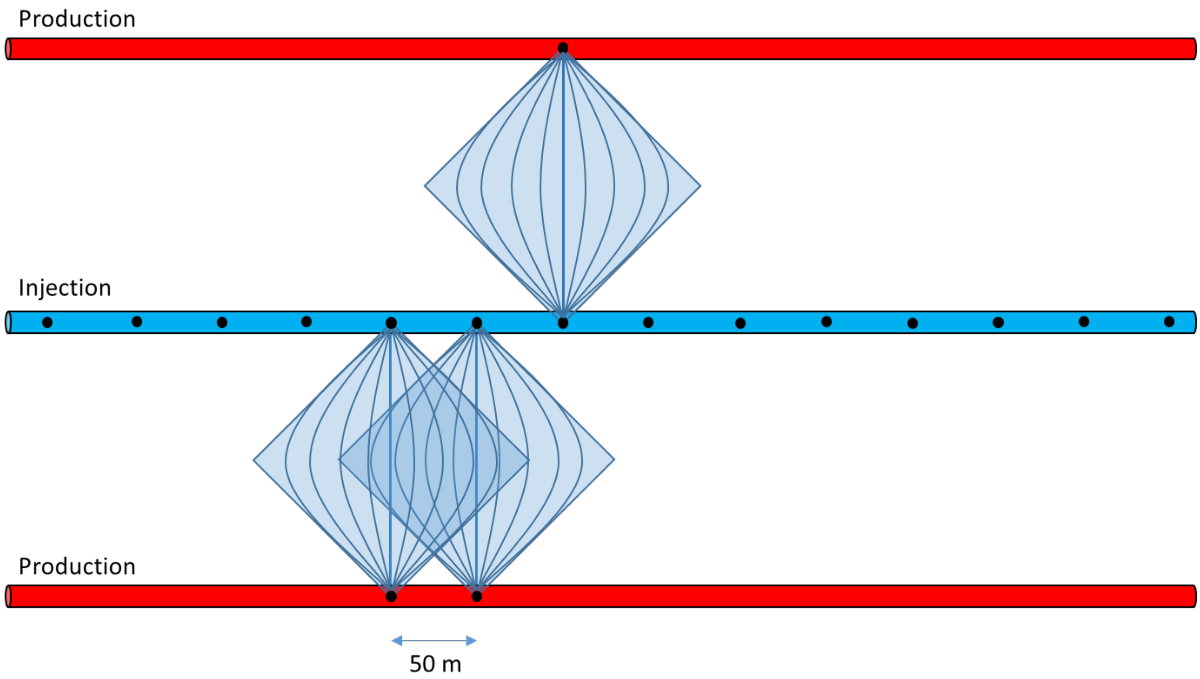

Figure 8-8: A section of the well system showing streamlines between perforations in the production wells and the injection well.

Figure 8-9 shows the dimensions of the fractures after stimulating the well. The fracture will also branch out longitudinal with the wellbore.

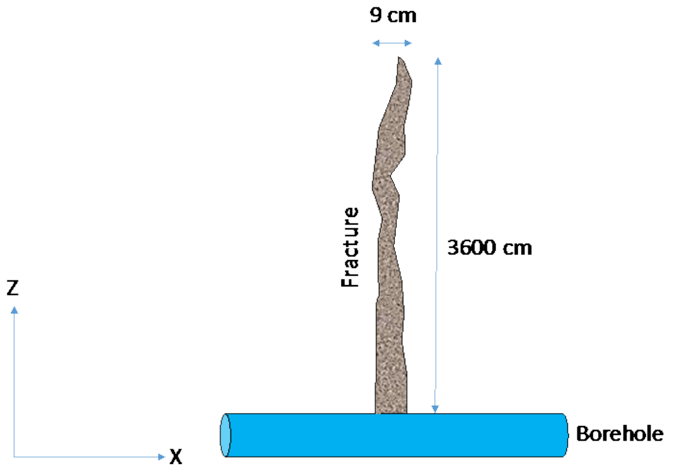

Figure 8-9: Illustration of a fracture.

8.6 Fracturing economics

Fracturing fluid consists mostly of water but it also contains about 1-2 % chemicals, for example gelifying additives, hydrocloric acid (HCl), biocides and scale inhibitors. It also consists of between 5 % and 10 % sand with an estimated usage of 250 tons per 300 foot stage. The Bakken operator Continental Resources uses a plug and perforate method where they pump in either sand or ceramic proppant in 2000 bbl of crosslinked gel in their 9500 ft lateral wells. This is achieved using a treating pressure of 5000-8000 psi at 40 bbl/min. It is estimated to use about 10-15 larger water pumps on trailers that are positioned around the wellhead. One horizontal lateral might require between 2-4 million gallons of water for fracturing. The water can be obtained from the Missouri river, from large water pools like the Lake Sakakawea for a project in the Bakken area. The water is then stored in pits on the well site. If the water is gathered via pipeline to the pits from a water source, this incurs high costs as the lease of pipeline is estimated to 90 USD/foot. Total cost for i.e. a 5-mile pipeline is 2 376 000 USD.

The unit cost and transport costs of perforating, water, sand and diesel used for pumps and so on adds greatly to the total well cost. An industry average of fracturing is 500 USD - 600 USD per foot for a 4500 ft lateral with 15 stages (Hefley et al., 2011), but this depends on the number of fracturing stages. If the number of fracturing stages is high, the equipment required topside during the operation is more expensive, but there is more length to divide the costs on at the same time. The operation would therefore be less expensive in this thesis where 30 000 ft is going to be fractured per well. Some of the fracking water will also flow back through the well and would incur high costs for purification and disposal. This water will however be reused for other wells and avoid this expense. In other words, for the well consisting of three 3000 m branches, the total costs should be lower than the industry average. Using 400 USD/ft then total fracturing cost for one MLT well becomes approximately 12 000 000 USD.

When the fracturing phase is over, the plugs needs to be drilled out from the horizontal section, and the well needs to be flowed back and cleaned. Additional activities involve well testing, water recycling or disposal, flaring and installation of an x-mas tree. 10-15 days should be accounted for in the completion phase excluding the installation of MLT junctions.

9 SURFACE FIELD DEVELOPMENT

9.1 Mineral leasing and permitting

The first step in the field development process is to acquire mineral rights. Landowners in the US will lease their mineral rights to the oil and gas industry primarily because of the huge amount of income they can get from a successful field development. They can expect to get money from a signing bonus/paid-up lease and the chosen royalty rate, which is a percentage of revenue from petroleum production. In most countries minerals below a property belongs to the government, however in the US the mineral rights traditionally belong to the landowner. Signing bonus and the associated costs of leasing land can vary a lot. This thesis uses a rather high royalty rate and leasing cost of 25 % and 2500 USD/acre respectively in the calculations. One single MLT well field development will require approximately 1000 acres (4.05 km^2).

9.2 Nitrogen recovery and rejection

Nitrogen is separated from natural gas by using a distillation process in a Nitrogen Rejection Unit (NRU). The natural gas/nitrogen stream is converted into liquid state and then goes into a fractional distillation process to extract the nitrogen. The same process is used for separation of nitrogen from air.

Large costs are avoided by having a Nitrogen Rejection Unit on-site since the nitrogen no longer has to be bought at the market price and since there is no longer transport costs associated with it. The nitrogen that is produced from the shale play together with the natural gas can also be re-injected after going through the separation process. Figure 9-1 illustrates how natural gas production can be used to power a compressor and a separation unit for nitrogen injection into an oil/gas-field.

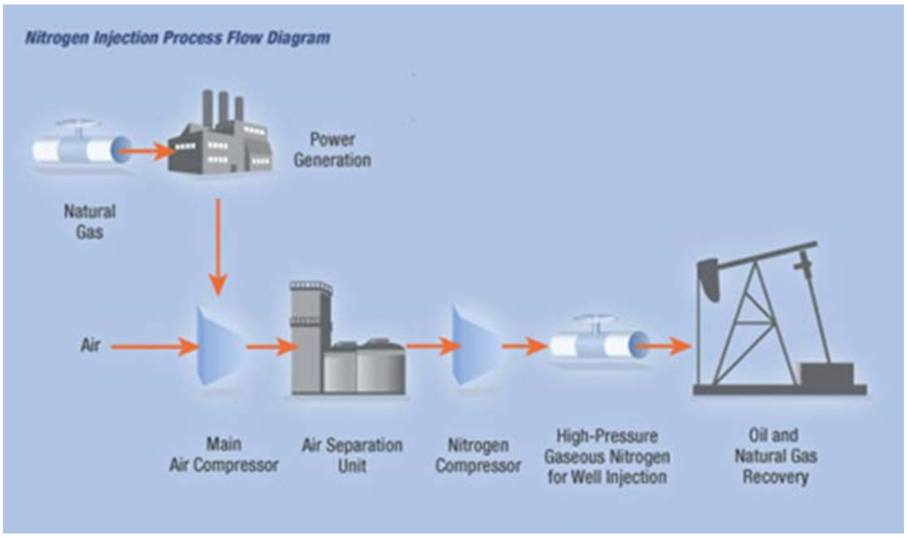

Figure 9-1: Nitrogen injection in an oil/gas-field (Airproducts.com, May 1st 2015).

9.3 Pad area, pipelines and compressor

The topside development consists of having well pads built with approximately 1100 meters between them along the nitrogen and natural gas pipelines. The distance between two parallel pipelines is approximately 7000 meters. The distances are chosen according to the distance between the producer on the flank and injector in the middle which is around 425 meters. The approximate distance from injection well to injection well between two well pads would then be around 850 meters, but to mitigate the risk of colliding wells the distance is set to 1100 meters. The length from the well pad to the end of the wells is around 3200 meters and the total distance between two pads could be around 6400 meters, but the distance is set to 7000 meters to have good margin between the wells.

Each well pad has two well slots to allow drilling one well in eastwards direction and one well in westwards direction. One well requires around 3.85 MMscfd of nitrogen and production is set to the same, 3.85 MMscfd of natural gas. The total amount of wells is set to 72 wells divided onto 36 well pads for one area and is limited by the 300 MMscfd nitrogen production plant which can supply around 77 wells at maximum production.

In a case where there are 2 rows with 18 well pads per row the total area covered is 277.2 km^2 with a total required length per pipeline of 33.8 km. The pipeline from the natural gas compression hub to the process plant is set to 20 km. The pipeline internal diameter has been chosen in order to have around 5 bar friction loss during full production from all 72 wells. The diameter needed for the nitrogen injection pipeline is 16 inches and the diameter needed for the natural gas production pipeline is 24 inches. The average price for shale gas pipelines averages around 200,000 USD/inch-mile which gives a total cost of 228 million USD. The pipeline price per well is then 3.16 million USD.

The nitrogen is produced at the nitrogen production plant and pumped into the wells through the nitrogen distribution pipelines. The produced natural gas is transported through the natural gas production pipelines and into the natural gas compression hub which pumps the natural gas to a process plant for processing into sales quality natural gas. The field layout is based on the illustrations in Figure 9-2 and Figure 9-3 on the next page for nitrogen distribution and natural gas production.

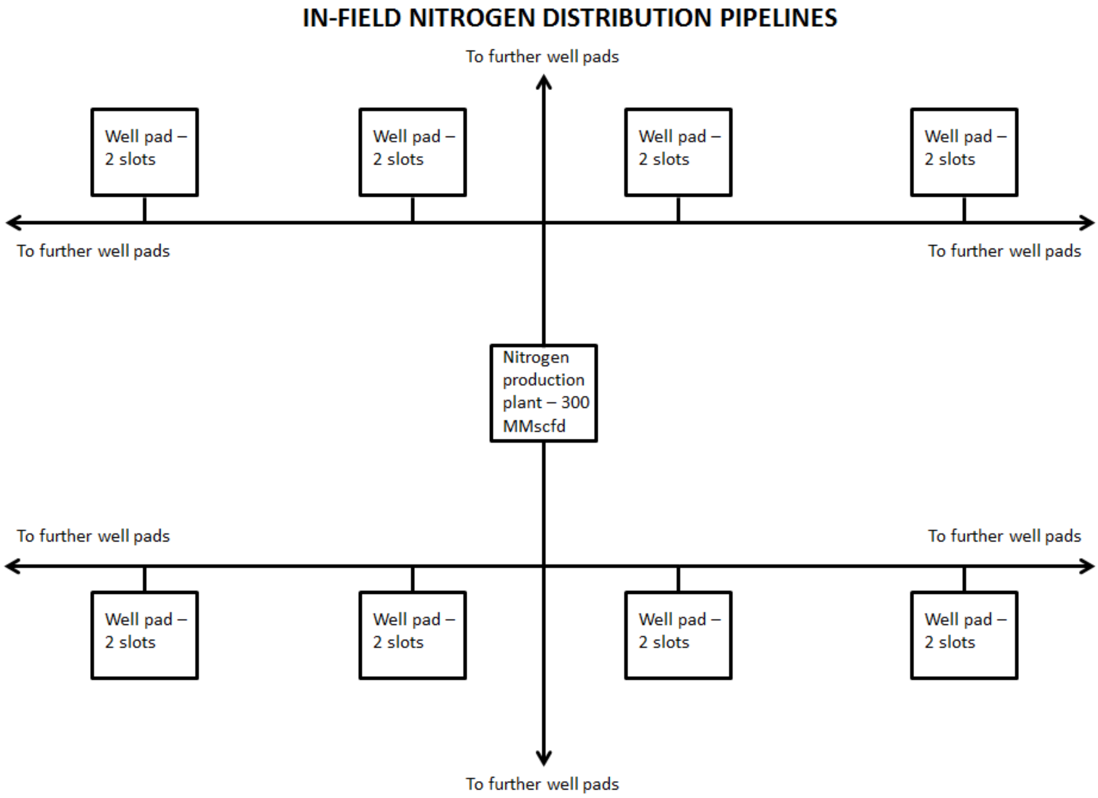

Figure 9-2: In-field nitrogen distribution pipelines.

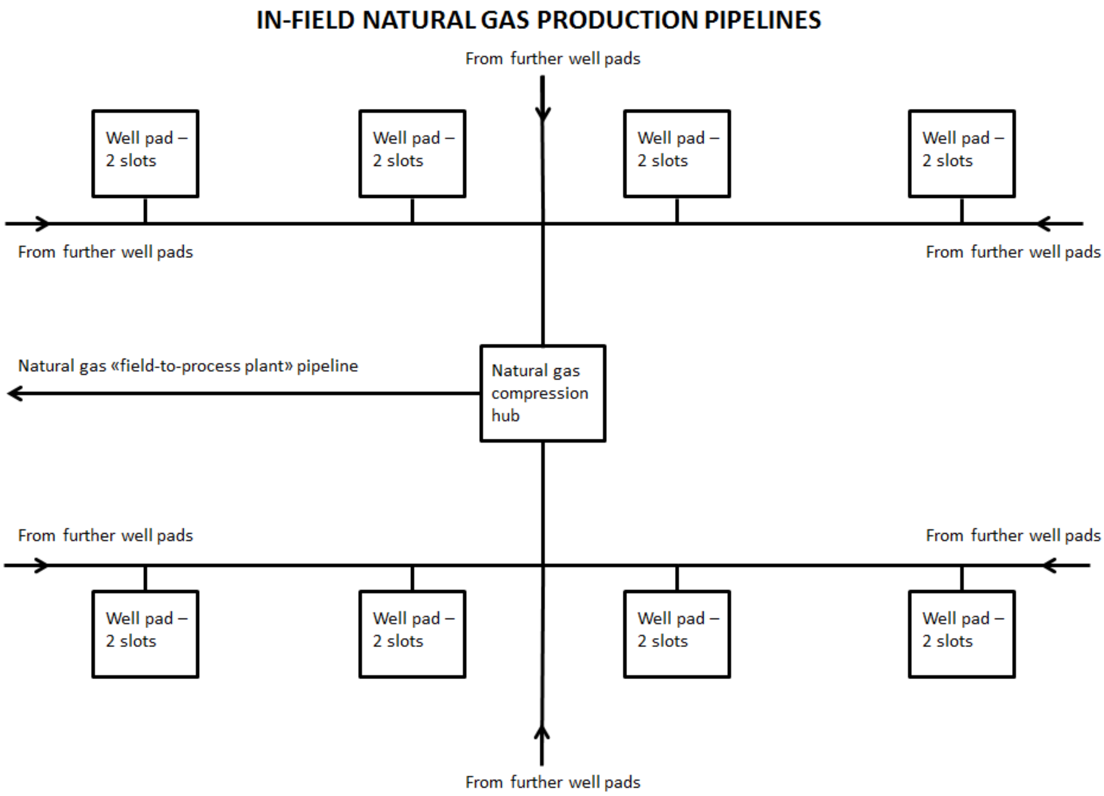

Figure 9-3: In-field natural gas production pipelines.

9.4 X-mas tree arrangement

The x-mas tree arrangement is put up in a manner to have double isolation into the well from the pipelines and entry points for service if needed. A radioactive production flowmeter needs to be used in order to measure the fractional flow of nitrogen in the production stream. If the nitrogen/natural gas ratio becomes too large it will be possible to measure it with a radioactive production flowmeter and the well can be shut down. Figure 9-4 shows how the x-mas tree arrangement is thought to be.

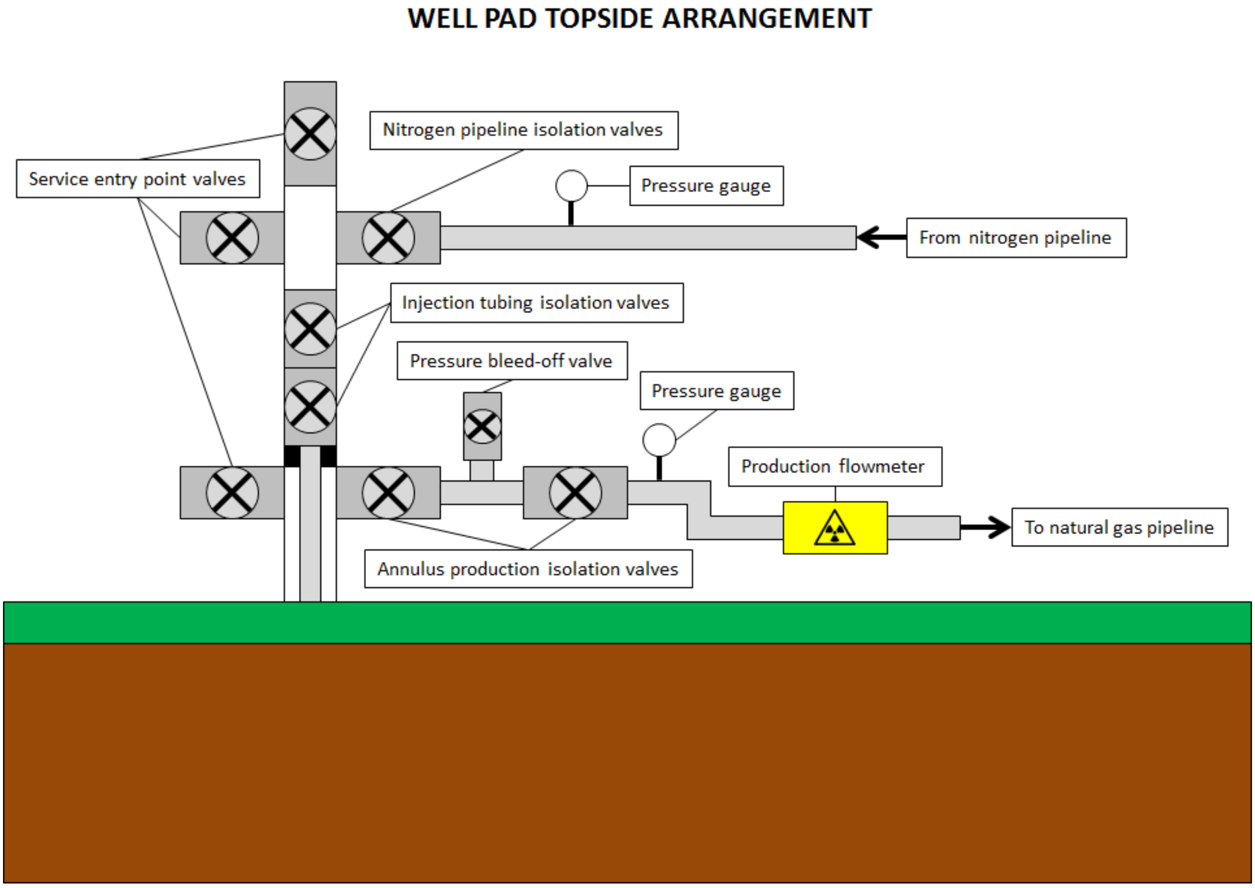

Figure 9-4: X-mas tree arrangement.

10 RECOVERY RATE AND REVENUE

10.1 Production calculations

In order to get an estimate of the total natural gas production from a well certain calculations have been done. Several factors need to be considered, especially those regarding pressure friction loss. The pressure friction loss is mainly dependent on the pipe internal diameter and sufficient size on tubing and pipes need to be used in order to keep the friction pressure loss to a minimum, as well as taking consideration to downhole tool restrictions.

Casing in vertical section down to multilateral junctions:

For multilateral wells a 9 5/8" casing size is required in order to install the TAML level 5 junction tool, as described in chapter 7 about MLT. The casing must tolerate the pressure from the formation as well as not creating too large friction pressure loss.

Based on the formation pressure of 386 bara, a 9 5/8" casing has been chosen with sufficient safety margin with the properties given in Table 10-1:

Table 10-1: Casing properties.

Nominal size (OD)	9.625 in
Wall thickness	0.545 in / 13.8 mm
Inside diameter (ID)	8.535 in / 216.8 mm
Capacity	36.91 l/m
Grade	L80
Collapse resistance	456 bar
Internal yield pressure	547 bar

Friction pressure loss from tubing and casing walls:

$$\Delta p_f = \frac{{\rho_{sg}}^{0.8} * \mu^{0.2} * Q^{1.8}}{70696 * (D+d)^{1.8} * (D-d)^3} \frac{bar}{m} = \frac{0.025^{0.8} * 0.0112^{0.2} * 2117^{1.8}}{70696 * (8.535 + 5.5)^{1.8} * (8.535 - 5.5)^3}$$

$$= 0.000090 \frac{bar}{m} \Rightarrow 0.27 \; bar \; per \; 3050 \; m$$

Symbol	Description	Unit
Δp_f	Friction pressure loss	bar/m
ρ_{sg}	Density	Density relative to water (1000 kg/m^3)
μ	Viscosity	cP
Q	Flow rate	liters/min
D	Internal diameter of casing	inches
d	Outside diameter of tubing	inches

3050 m is chosen because the well is 3048 m TVD, and we can add two meters to account for the x-mas tree.

Methane head pressure:

A graph has been made to model the head pressure of methane gas in the well to find the average pressure of the gas. The maximum head pressure the methane will face is 40.5 bara 3048 m below the surface, which can be seen from Figure 10-1.

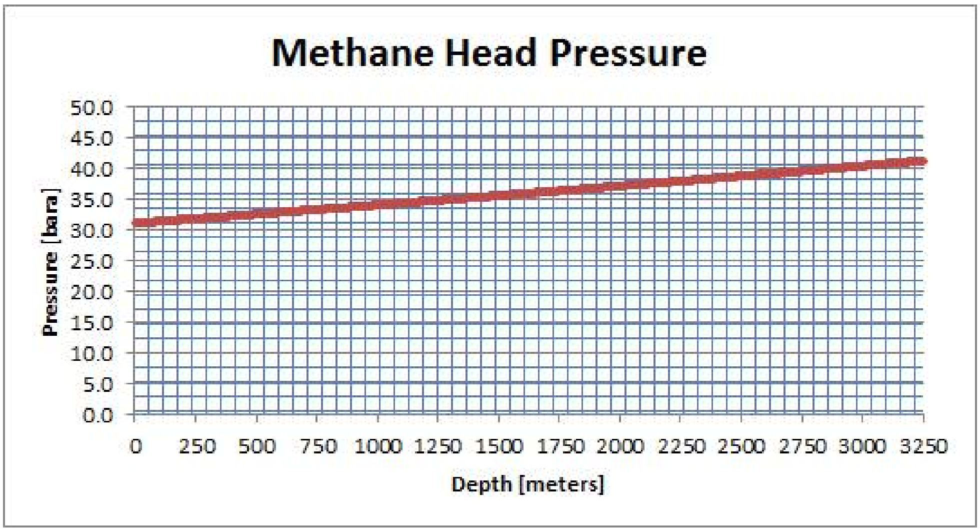

Figure 10-1: Methane head pressure. Y-axis: Pressure(bara), X-axis: meters below surface.

Nitrogen head pressure:

The nitrogen needs to have a pressure of 330 bara at the surface when it is injected down into the completion tubing so that the natural gas will have a pressure of 31 bara at surface. The head pressure of nitrogen in the well is illustrated in Figure 10-2.

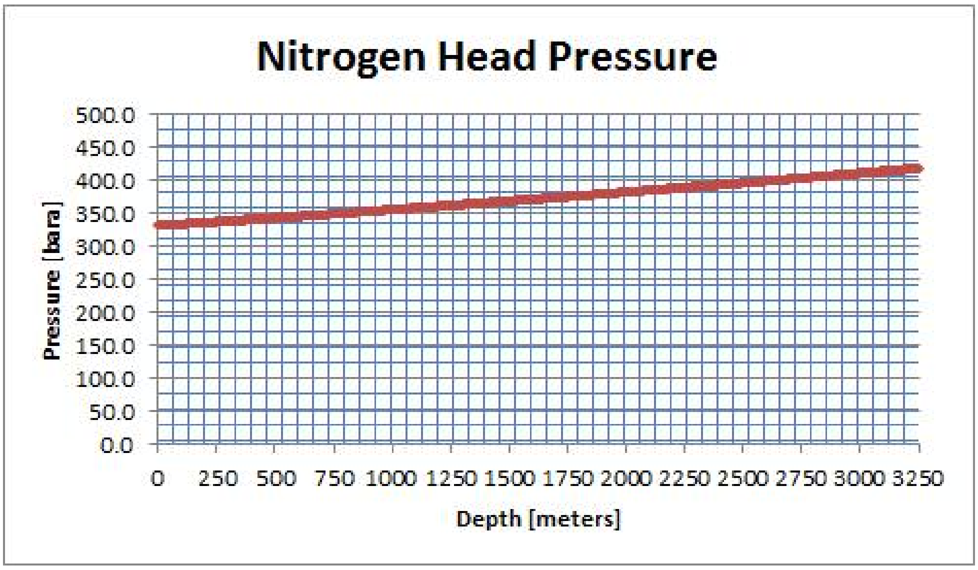

Figure 10-2: Nitrogen Head Pressure. Y-axis: Pressure(bara), X-axis: meters below surface.

Completion tubing:

A 5 1/2" completion tubing will be used inside the well from the junction to the wellhead. It has to withstand a pressure of 411 bara which is the injection pressure of nitrogen at 3048m. The properties of this tubing is given in table Table 10-2.

Table 10-2: Tubing properties.

Nominal size (OD)	5.5 in
Wall thickness	0.304 in / 7.7 mm
Inside diameter (ID)	4.892 in / 124.3 mm
Capacity	12.13 l/m
Grade	L80
Collapse resistance	433 bar
Internal yield pressure	534 bar

Friction pressure loss inside tubing:

$$\Delta p_f = \frac{\rho_{sg}{}^{0.8} * \mu^{0.2} * Q^{1.8}}{90163 * D^{4.8}} \frac{bar}{m} = \frac{0.349^{0.8} * 0.0296^{0.2} * 204^{1.8}}{90163 * 4.892^{4.8}}$$

$$= 0.000017 \frac{bar}{m} \rightarrow 0.05\ bar\ per\ 3050\ m$$

Symbol	**Description**	**Unit**
Δp_f	Friction pressure loss	bar/m
ρ_{sg}	Density	Density relative to water (1000 kg/m^3)
μ	Viscosity	cP
Q	Flow rate	liters/min
D	Internal diameter	inches

Nitrogen injection:

Calculations in the following section have been done to find the required pressure difference between injector and producer with the given parameters. Horizontal producer (red) and injector well (blue) with arrows indicating the direction of flow is illustrated in Figure 10-3. For calculation purposes the natural gas consists of methane only.

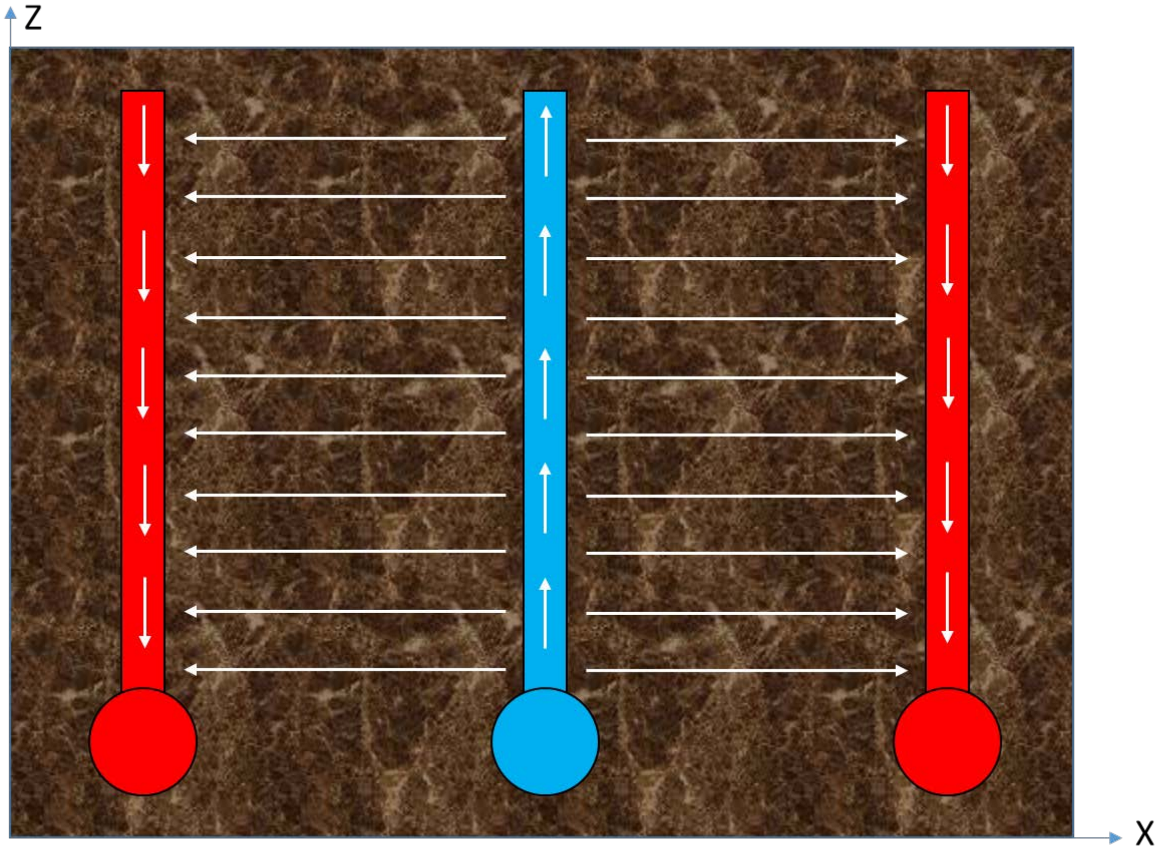

Figure 10-3: Top view of a section of the horizontal producer and injector wells, with arrows indicating the direction of flow.

The calculations are based on Darcy's law for an ideal gas. The viscosity of nitrogen is used in the calculation for simplification. The viscosity of methane is lower than for nitrogen so the calculations have an upside potential.

The calculation below uses Darcy's law for calculating the flow rate through the reservoir. The injector and producers will then act as the start and end of a porous medium. The calculations for the fractures have been included to calculate the injection pressure needed to acquire the flow rate as given by the calculation below.

Injection pressure	405.32 atm (410.71 bara)

Note: *The flow rate through the injection fracture is twice the flow rate through the formation and producer fracture since it needs to provide the given flow for two formation areas.*

Darcy's law derived to apply for an ideal gas at a given reference condition.

$$q = \frac{k * H * W}{\mu * L}\left(\frac{dp}{dL}\right)$$

$$q_b * p_b = q * p = constant$$

$$q_b * p_b = \frac{k * H * W}{\mu * L} * p * \left(\frac{dp}{dL}\right)$$

$$q_b = \frac{k * H * W}{\mu * L * p_b} * \frac{1}{2} * (p_s - p_e)^2$$

The formula is then altered to calculate the pressure at the end of the medium.

$$p_e = p_s - \sqrt{q_b * \frac{\mu * L * p_b}{k * H * W} * \frac{1}{2}}$$

The pressure difference across each medium is done by selecting an injection pressure (410.71 bara) and flow rate (11000 cm³/s (1 atm, 20°C)).

$$p_{e1} = p_{s1} - \sqrt{2 * q_b * \frac{\mu * L_1 * p_b}{k * H * W} * \frac{1}{2}} = p_{e1} \rightarrow p_{e2} = p_{e1} - \sqrt{q_b * \frac{\mu * L_2 * p_b}{k * H * W} * \frac{1}{2}} = p_{e2}$$

$$\rightarrow p_{e3} = p_{e2} - \sqrt{q_b * \frac{\mu * L_3 * p_b}{k * H * W} * \frac{1}{2}} = p_{e3}$$

$$q_b = \frac{q_1}{2} = q_2 = q_3$$

$$q_b = \frac{\frac{k_1 * H_1 * W_1 * ({p_{s1}}^2 - {p_{e1}}^2)}{\mu_{N_2} * 2 * p_b * L_1}}{2} = \frac{k_2 * H_2 * W_2 * ({p_{s2}}^2 - {p_{e2}}^2)}{\mu_{N_2} * 2 * p_b * L_2}$$

$$= \frac{k_3 * H_3 * W_3 * ({p_{s3}}^2 - {p_{e3}}^2)}{\mu_{N_2} * 2 * p_b * L_3}$$

$$q_b = \frac{\frac{120 * 0.2 * 9 * (405.32^2 - 381.27^2)}{0.0258 * 2 * 1 * 3600}}{2}$$

$$= \frac{0.00001 * 3600 * 5000 * (381.27^2 - 106.53^2)}{0.0258 * 2 * 1 * 42500}$$

$$= \frac{120 * 0.2 * 9 * (106.53^2 - 43.45^2)}{0.0258 * 2 * 1 * 3600}$$

$$q_b = 11000\ \frac{cm^3}{s}\ (1\ atm, 20\ °C)$$

To find the total injected nitrogen into the well, all the "zones" are taken into account. The total amounts of "zones" are 114, which is the space between two parallel fractures on the injecting and producing wellbores.

For all 114 "zones":

$$q_b = \frac{11000\ \frac{cm^3}{s} * 114\ zones * (60 * 60 * 24)\ \frac{s}{day}}{1\ 000\ 000\ \frac{cm^3}{m^3}} = 108\ 346\ \frac{m^3}{day}\ (1\ atm, 20\ °C)$$

The above calculation shows that the nitrogen injection rate is 108 346 m^3 (1 atm, 20°C) per day.

The daily natural gas production from the well is given by the derived formula PQ=ZRT at given conditions (1 atm, 20°C).

$$Q_{methane} = Q_{nitrogen} * \frac{Z_{nitrogen}}{Z_{methane}} = 108\ 346\ \frac{m^3}{day} * \frac{0.9997}{0.998}$$
$$= 108\ 531\ \frac{m^3}{day}\ (1\ atm, 20\ °C)$$

Symbol	**Description**	**Unit**
q	Flow rate	cm^3/s (unless stated otherwise)
k	Permeability	Darcy
H	Height	cm
W	Width	cm
p	Pressure	atm (atmospheres)
μ	Viscosity	cP
L	Length	cm
Z	Compressibility	No dimension

Index	**Description**
b	Base condition (1 atm, 20 °C)
1	Injector fracture
2	Formation between two parallel fractures on the injecting and producing wellbores
3	Producing fracture
i	Injector
p	Producer
s(1,2 or3)	Start of medium
e(1,2 or 3)	End of medium

Natural gas production from start to end:

The natural gas production is determined by two factors, differential pressure over the formation and fractional flow of nitrogen after breakthrough. The calculations that have been done give a daily production of 108,531 m^3/day (1 atm, 20 ^oC) which will be stable until breakthrough of nitrogen. At breakthrough the production of natural gas will decrease as the fractional flow of nitrogen increases.

The graph in Figure 10-4 shows how the production curve would look like from start of production until there is no more natural gas in the formation. Figure 10-5 shows cumulative natural gas production over time.

The production in the start is kept at a lower rate than could be achieved by choking the production.

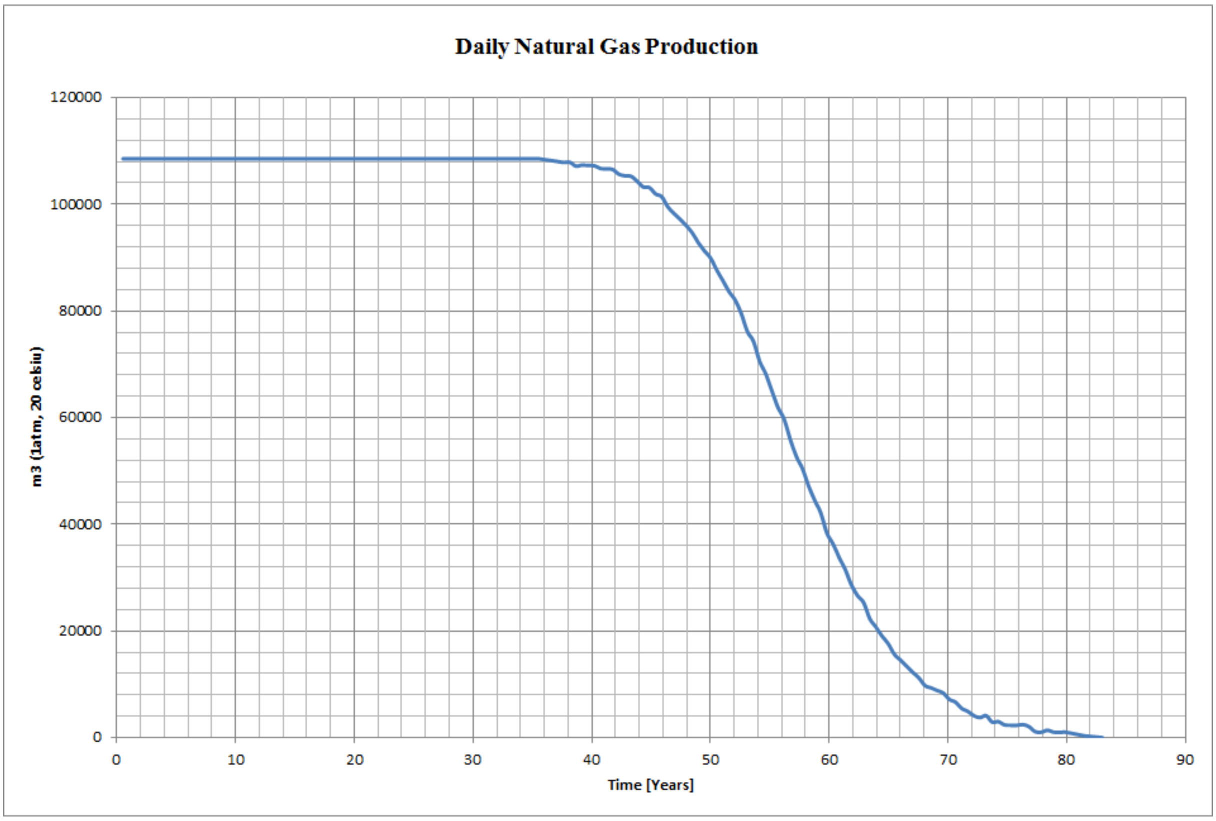

Figure 10-4: Natural gas production over time.

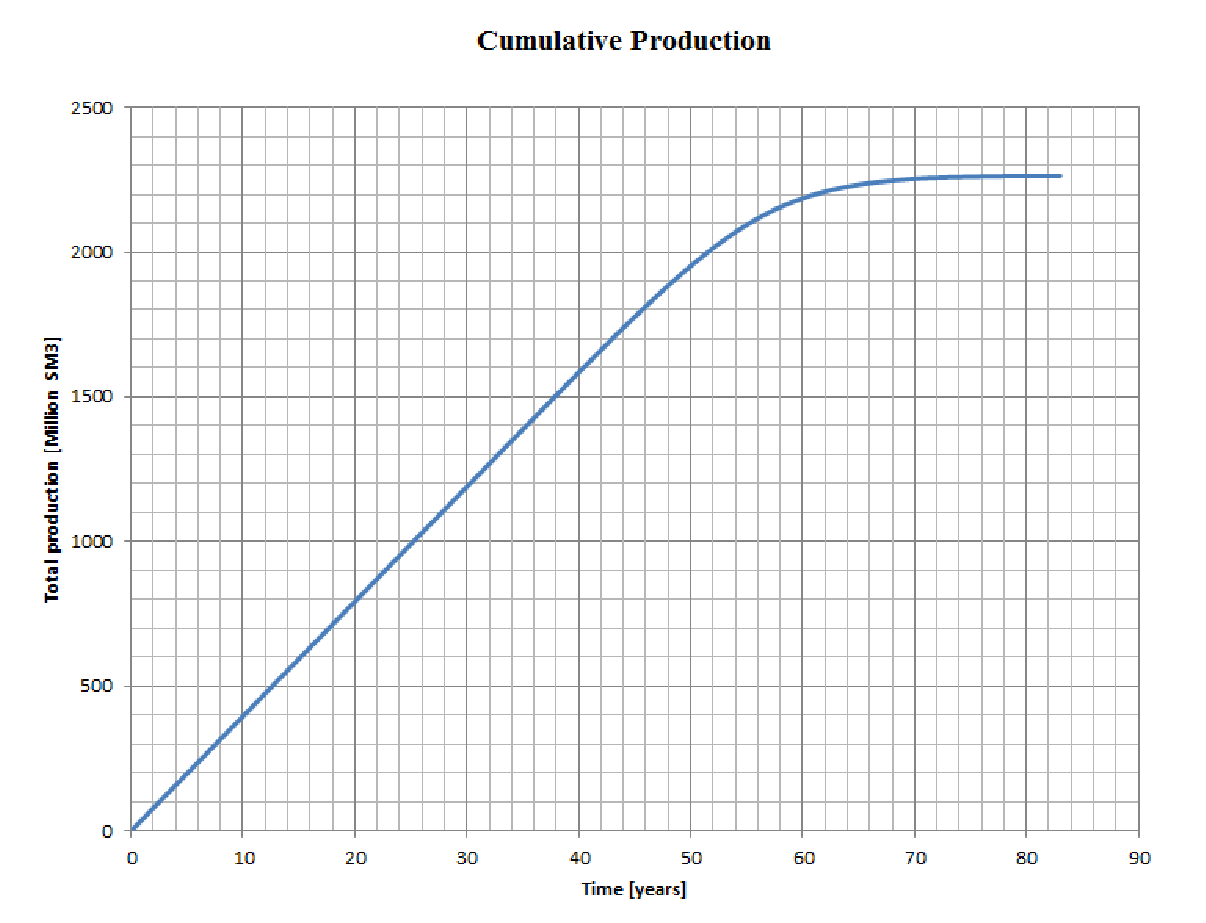

Figure 10-5: Cumulative natural gas production over time.

10.2 Project costs

Costs associated with developing the field that have been explained in previous chapters, as well as accompanying costs, are listed in the following tables. Most of the costs are high estimates, and the field development will have an economical upside potential because of this.

Adding the costs together gives the following result, where project cost is the total cost of developing 72 wells with both natural gas and nitrogen pipelines on the surface:

SUBSURFACE COSTS PER WELL:	16 241 600,00 USD
TOPSIDE COSTS PER WELL:	6 263 555,56 USD

Cost per well:	***22 505 155,56 USD***
Project cost:	***1 620 371 200,00 USD***

Well costs:

Drilling	**Day rate**	**Days**	**Total cost**
Rig (all incl.)	16 000,00 USD	30	480 000,00 USD
Directional drilling	11 000,00 USD	22	242 000,00 USD
Diesel to power rig			85 000,00 USD
Cuttings disposal			40 000,00 USD
Pit liners around rig			24 000,00 USD
Drilling fluid			105 000,00 USD
Drilling bits			90 000,00 USD
Casings			390 000,00 USD
Casing cement		1	140 000,00 USD
Casing centralizers, float equipment and baskets			30 000,00 USD
Wellhead			5 000,00 USD
Geological services			30 000,00 USD
Misc. trucking needs			30 000,00 USD
Diesel to power site			250 000,00 USD
Total drilling costs		31	1 941 000,00 USD

Completion	**Days**	**Total cost**
Tubing		200 000,00 USD
Casing head		250 000,00 USD
Tubing head		60 000,00 USD
X-mas tree		100 000,00 USD
Gas metering system		50 000,00 USD
Installation labor	15	50 000,00 USD
Total completion costs	15	710 000,00 USD

MLT	**Days**	**Total cost**
Laterals all inclusive (2*30 % of mainbore price)		1 590 600,00 USD
Installation of junction x 2	8	- USD
Total MLT costs	8	1 590 600,00 USD

Hydraulic fracturing	**Days**	**Total cost**
Plug and perf 25 stages (400 USD/ft)	12,5	12 000 000,00 USD
Total fracturing costs	12,5	12 000 000,00 USD

Surface costs:

Pipeline	Unit cost	Amount	Cost
16 in nitrogen pipeline (km)	2 000 000,00 USD	0,469	938 888,89 USD
24 in natural gas pipeline (km)	3 000 000,00 USD	0,747	2 241 666,67 USD
Water pipeline (ft)	90,00 USD	366,667	33 000,00 USD
Total pipeline costs			3 213 555,56

Land	Unit cost	Amount	Cost
Signing bonus	2 500,00 USD	1000	2 500 000,00 USD
Misc. costs (landman, legal etc.)			300 000,00 USD
Site construction			250 000,00 USD
Total land costs			3 050 000,00 USD

Every well has to be plugged and abandoned in the end of the well life according to regulations. P&A is an operation done after the well is uneconomical to produce from, where the well is sealed with cement or other suitable substance to avoid hydrocarbons leaking into the environment. The cost can vary a lot, depending on depth and complexity of the well. One well might cost 100 000 USD, but costs can be much higher. Some companies even go bankrupt to avoid paying for the plugging of their wells, a cost that can add up significantly depending on the amount of wells. This thesis uses a P&A cost of 1 500 000 USD per well for the calculations.

10.3 Recovery Rate & Revenue

By injecting nitrogen into the formation the recovery rate will increase since the pressure in the formation will be maintained and the gas is displaced.

The below figures are based on the information provided in this thesis.

Description:	
Land owner royalty rate	25 %
North Dakota tax rate	11.5 %
Recovery rate at breakthrough	60 %
Economical recovery rate in displacement area	99.5 %
Time at breakthrough	29 years – 6 months
Time at economical recovery rate (25 % royalty rate)	47 years – 2 months
Time at economical recovery rate (15 % royalty rate)	48 years
Reservoir bulk volume	8 445 600 000 m^3
Porosity	5 %
Pore volume	422 280 000 m^3
Volume subject to nitrogen injection	330 480 000 m^3
Volume flooded	328 827 600 m^3
Natural gas produced	126 927 453 600 m^3 (1 atm, 20 ^oC)
Nitrogen injected	138 354 659 194 m^3 (1 atm, 20 ^oC)
Total recovery rate	77.8 % of IGIP
Natural gas price per 1000 Sm^3 in USA	93.937 USD
Sales value of total produced methane in USA	11 923 184 208 USD
Natural gas price per 1000 Sm^3 in Europe	387.365 USD
Sales value of total produced natural gas in Europe	49 167 253 063 USD
Nitrogen price per 1000 Sm^3	4.432 USD
Cost of nitrogen to produce above amount of methane	613 187 849 USD
Well and infrastructure costs	1 620 371 200 USD
Plug and abandonment costs	108 000 000 USD
Project balance after plug and abandonment – low case	2 991 720 896 USD
Project balance after plug and abandonment – base case	5 867 680 629 USD
Project balance after plug and abandonment – high case	9 112 661 604 USD

Graph Figure 10-6 illustrates the cumulative project balance for three different cases. The high case is based on a 12.5 % royalty rate to the landowners, a natural gas price at wellhead of 4.00 USD/Mscf and nitrogen expense of 0.10 USD/Mscf. The base case is based on 19.0 % royalty rate, 2.66 USD/Mscf gas price at wellhead and 0.1255 USD/Mscf nitrogen price. The low case is based on 25.0 % royalty rate, 2.00 USD/Mscf gas price at wellhead and 0.18 USD/Mscf nitrogen price. The curves flattening out on the right side of the graphs indicate that operational expenses equals operational income. The drop itself is the plug and abandonment cost.

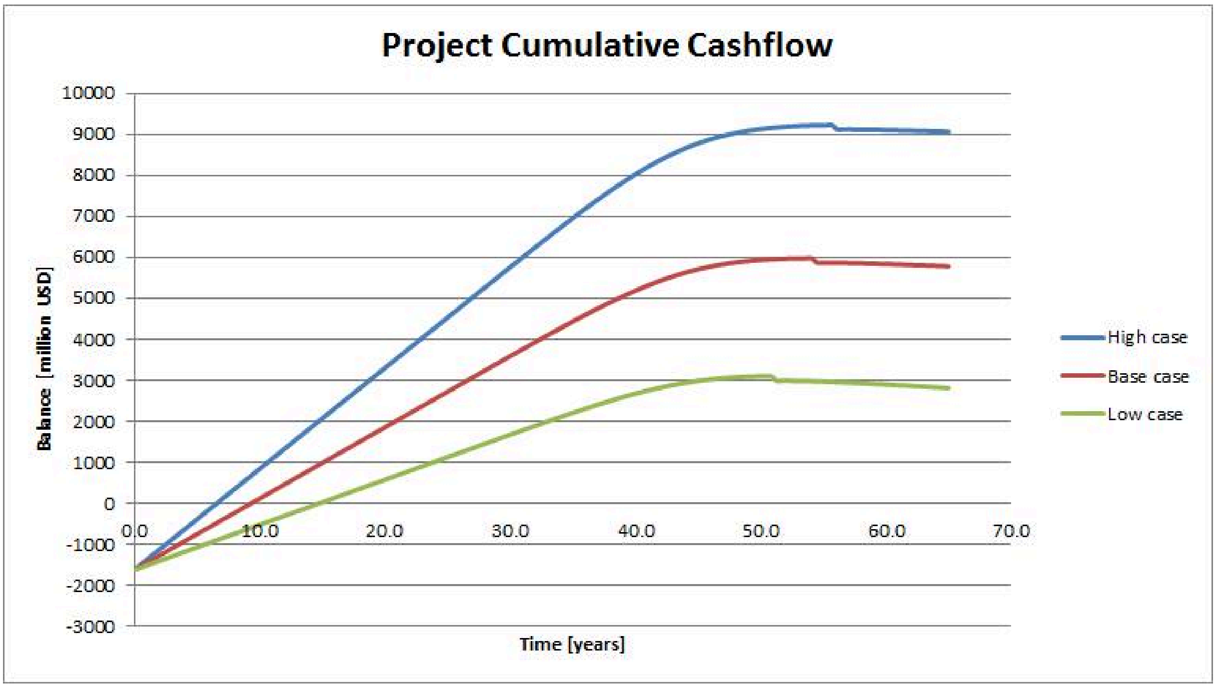

Figure 10-6: Cumulative project balance for three different cases.

11 CONCLUSION

Shale gas has seen an enormous increase in production in the last decade from new technology advancements within horizontal drilling and hydraulic fracturing, but pressure depletion in the shale plays makes long term production uneconomical due to low production rates. This is because of the low permeability of the shales.

To compensate for the large pressure drop in the shales, nitrogen can be used for injection into the shale reservoirs due to its physical properties. By using a nitrogen production plant to separate nitrogen from air by fractional distillation, low cost nitrogen can be used for injection into many wells.

Multilateral technology has so far been used solely in wells for either production or injection. In order to reduce the total costs and surface impact and new type of multilateral completion has been designed for use in the shale formations. Instead of having one well for injection and one well for production the technology has been modified to accommodate production and injection in one single well. Since the gasses will not see such a large pressure loss due to the smaller tubular and annular area in the multilateral completion compared to conventional wells, there will not be any significant constraints for the flow.

From the laboratory experiment it is concluded that the mobility ratio, water/oil displacement and enhanced recovery by displacement theories can be applied to nitrogen/methane displacement for enhanced recovery. The recovery rate at breakthrough correlates well with the theoretical recovery rate at breakthrough for water/oil displacement using mobility ratio.

Society has become more environmentally conscious. There is more awareness around the potential effects of hydraulic fracturing and the oil/gas-industry as a whole. There are several environmental advantages by using multilateral well technology in conjunction with hydraulic fracturing and nitrogen injection of shale plays. At the same time the world will see positive effects from replacing the heavily polluting coal and oil industries with natural gas.

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13 APPENDIX

- Nitrogen price per thousand standard cubic feet given by PEMEX.
- Experiment set-up photos
- Experiment results

PEMEX
EXPLORACION Y PRODUCCION ®

Oficio

		Fecha	6 de abril de 2015
Remitente	SUBDIRECCIÓN DE ADMINISTRACIÓN Y FINANZAS GERENCIA DE CONTROL DE GESTIÓN	Número Número de expediente	PEP-SAF-GCG-651-2015
Destinatario	LIC. ÉRIC RAÚL CARRILLO RIVAS TITULAR DEL ÁREA DE QUEJAS DEL OIC EN PEP	Antecedentes: Número(s): Número único de expediente: Fecha(s):	 OIC-AQ-PEP-18.575-997-2015 V-84/2015 1 de marzo de 2015
Asunto:	Átención al C. Steven Mellum	Anexo	☒

En respuesta a la solicitud citada en el cuadro de antecedentes, remito copia del oficio PEP-SPRMNE-GCO-179-2015, de fecha 31 de marzo de 2015, a través del cual el E. D. de la Gerencia de Coordinación Operativa informa que el precio del nitrógeno inyectado en el Campo Akal, en el mes de febrero de 2015 fue de 0.1255 USD/Mpc.

Reciba usted un cordial saludo.

Atentamente,

Lic. Noé Zuarth Corzo
Gerente

Ccp.- Ing. Rafael Rodríguez García, E.D. de la Gerencia de Coordinación Operativa
Steven Mellum, s.mellum@stud.uis.no

Elaboró: JCA' Claudia Leyva ext. 811 38123

CJG

2015, Año del Generalísimo José María Morelos y Pavón

PEMEX
EXPLORACION Y PRODUCCION ®

Oficio

		Fecha	31 de marzo de 2015
Remitente	**Subdirección de Producción Región Marina Noreste** **Gerencia de Coordinación Operativa**	Número	PEP- SPRMNE-GCO-179-2015
Destinatario	**Lic. Noé Zuarth Corzo** **Gerente de Control de Gestión**	Antecedentes Número(s): PEP-SAF-GCG-522-2015 Número único de expediente: Fecha(s): 19 de marzo de 2015	
Asunto:	Precio del nitrógeno	Anexo: ☐	

En atención al oficio citado en el apartado de antecedentes, donde solicita se brinde atención que conforme a derecho corresponda de lo siguiente:

"Me refiero al correo electrónico del 5 de marzo de 2015, a través del cual el C. Steven Mellum manifiesta que es estudiante en Noruega y está elaborando su tesis para su maestría de inyección de nitrógeno en depósitos de petróleo y pregunta el precio de nitrógeno por metro cúbico estándar que inyectan en el depósito Akal" [sic].

Derivado de lo anterior, le informo que el precio del nitrógeno inyectado en el campo Akal, que corresponde al contrato No. PEP-S-IT-112/97, en el mes de febrero de 2015 fue de 0.1255 USD/Mpc.

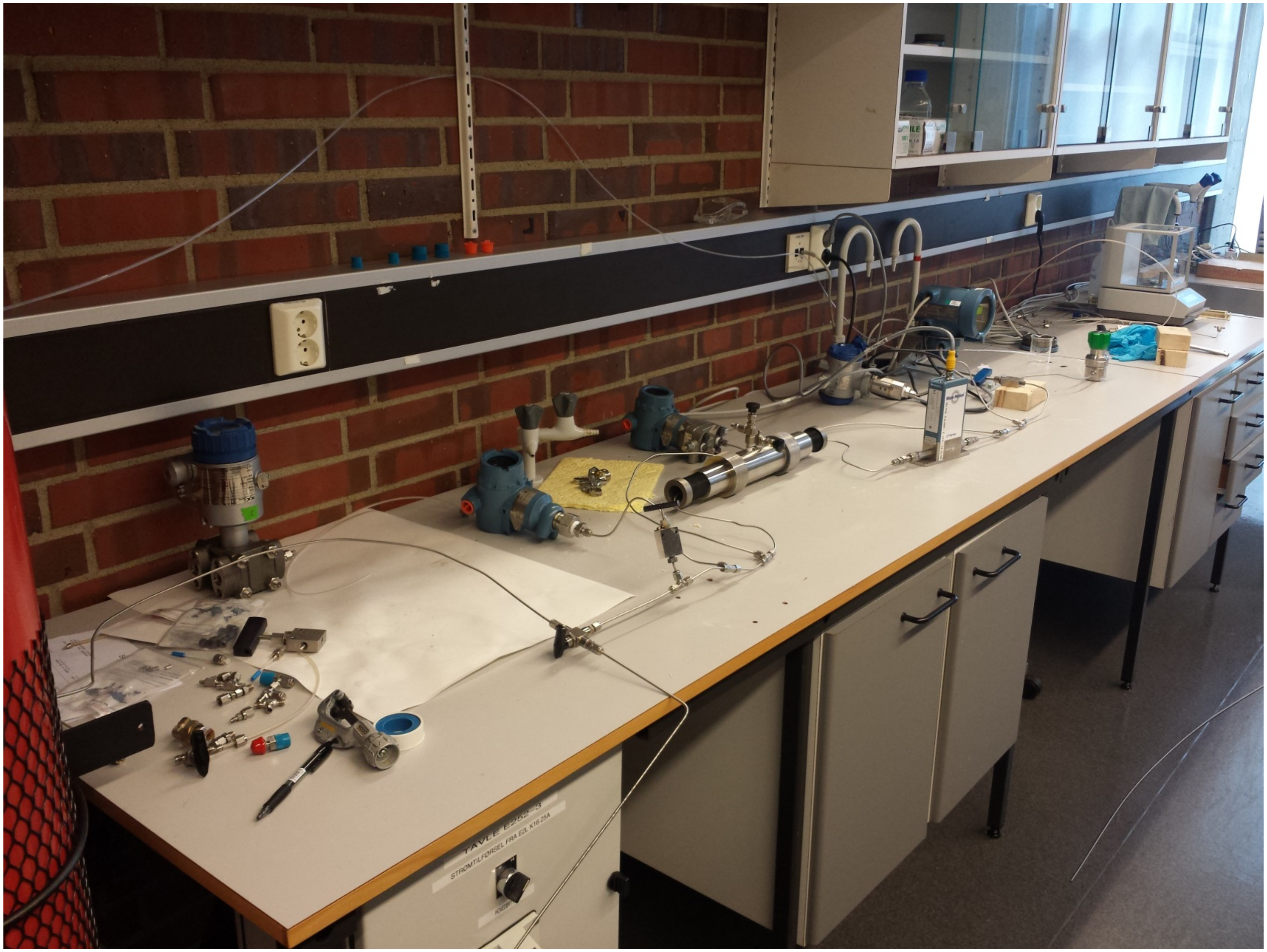
Atentamente

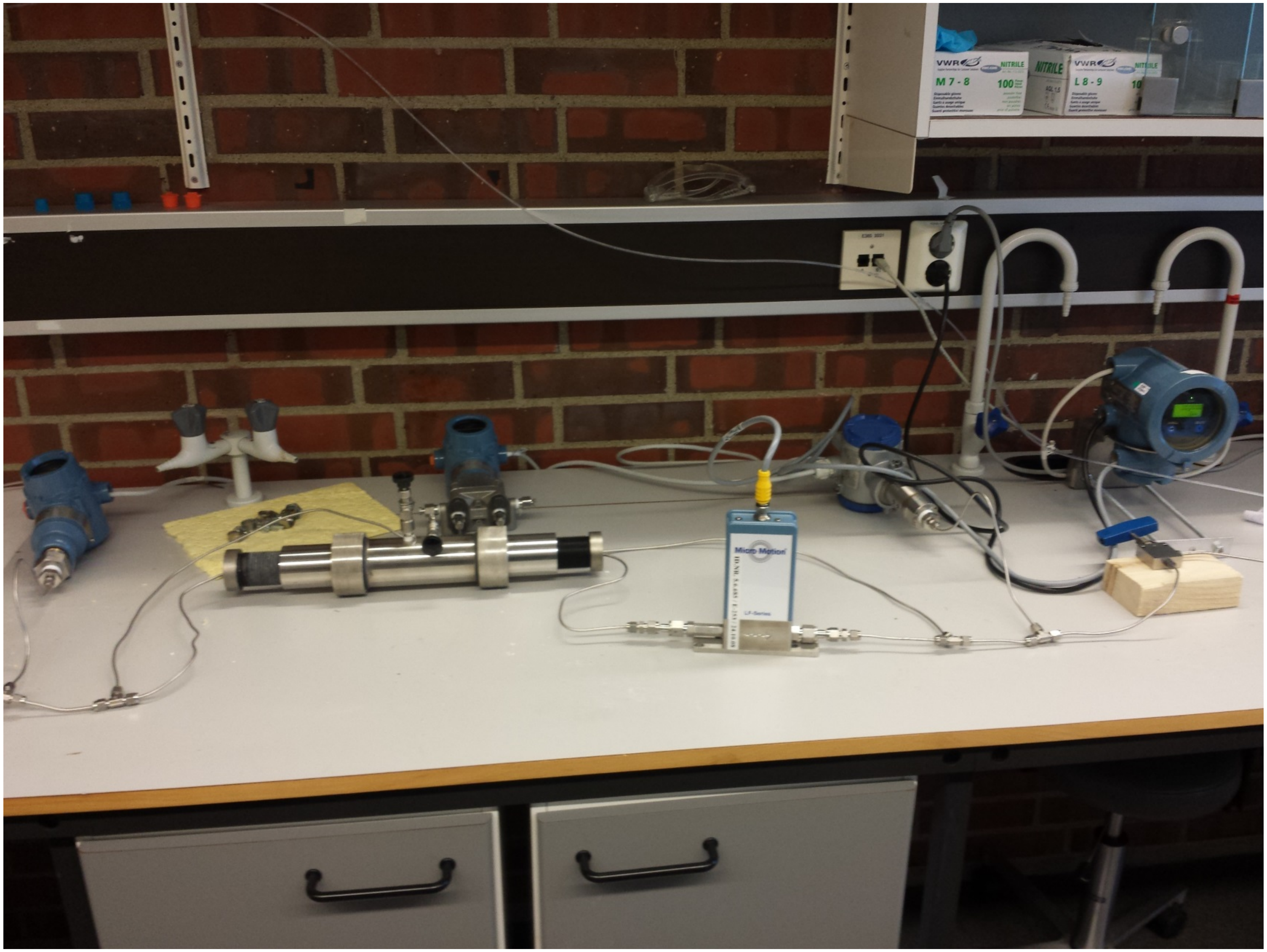
Ing. Rafael Rodríguez García
Encargado de Despacho

C.p.: Lic. Eric Raúl Carrillo Rivas.- Titular del Área de Quejas del OIC en PEP.

Elaboró: JAMG / MACT


VWR




VWR
NITRILE
M 7 - 8
100
VWR
NITRILE
L 8 - 9
Micro Motion

Seconds	Density [kg/m3]	Fractional flow N2	Fractional flow CH4	Total amount of CH4 displaced [%]	Total amount of CH4 displaced [cm3]	Total flow CH4 & N2 [cm3]
1	22.7950	0.00	1.00	0.903%	0.56	0.56
2	22.7950	0.00	1.00	1.806%	1.13	1.13
3	22.7950	0.00	1.00	2.709%	1.69	1.69
4	22.7950	0.00	1.00	3.612%	2.25	2.25
5	22.7950	0.00	1.00	4.514%	2.82	2.82
6	22.7950	0.00	1.00	5.417%	3.38	3.38
7	22.7950	0.00	1.00	6.320%	3.94	3.94
8	22.7950	0.00	1.00	7.223%	4.51	4.51
9	22.7950	0.00	1.00	8.126%	5.07	5.07
10	22.7950	0.00	1.00	9.029%	5.63	5.63
11	22.7950	0.00	1.00	9.932%	6.20	6.20
12	22.7950	0.00	1.00	10.835%	6.76	6.76
13	22.7950	0.00	1.00	11.737%	7.32	7.32
14	22.7950	0.00	1.00	12.640%	7.89	7.89
15	22.7950	0.00	1.00	13.543%	8.45	8.45
16	22.7950	0.00	1.00	14.446%	9.01	9.01
17	22.7950	0.00	1.00	15.349%	9.58	9.58
18	22.7950	0.00	1.00	16.252%	10.14	10.14
19	22.7950	0.00	1.00	17.155%	10.70	10.70
20	22.7950	0.00	1.00	18.058%	11.27	11.27
21	22.7950	0.00	1.00	18.960%	11.83	11.83
22	22.7950	0.00	1.00	19.863%	12.39	12.39
23	22.7950	0.00	1.00	20.766%	12.96	12.96
24	22.7950	0.00	1.00	21.669%	13.52	13.52
25	22.7950	0.00	1.00	22.572%	14.08	14.08
26	22.7950	0.00	1.00	23.475%	14.65	14.65
27	22.7950	0.00	1.00	24.378%	15.21	15.21
28	22.7950	0.00	1.00	25.281%	15.78	15.78
29	22.7950	0.00	1.00	26.183%	16.34	16.34

30	22.7950	0.00	1.00	27.086%	16.90	16.90
31	22.7950	0.00	1.00	27.989%	17.47	17.47
32	22.7950	0.00	1.00	28.892%	18.03	18.03
33	22.7950	0.00	1.00	29.795%	18.59	18.59
34	22.7950	0.00	1.00	30.698%	19.16	19.16
35	22.7950	0.00	1.00	31.601%	19.72	19.72
36	22.7950	0.00	1.00	32.504%	20.28	20.28
37	22.7950	0.00	1.00	33.407%	20.85	20.85
38	22.7950	0.00	1.00	34.309%	21.41	21.41
39	22.7950	0.00	1.00	35.212%	21.97	21.97
40	22.7950	0.00	1.00	36.115%	22.54	22.54
41	22.7950	0.00	1.00	37.018%	23.10	23.10
42	22.7950	0.00	1.00	37.921%	23.66	23.66
43	22.7950	0.00	1.00	38.824%	24.23	24.23
44	22.7950	0.00	1.00	39.727%	24.79	24.79
45	22.7950	0.00	1.00	40.630%	25.35	25.35
46	22.7950	0.00	1.00	41.532%	25.92	25.92
47	22.7950	0.00	1.00	42.435%	26.48	26.48
48	22.7950	0.00	1.00	43.338%	27.04	27.04
49	22.7950	0.00	1.00	44.241%	27.61	27.61
50	22.7950	0.00	1.00	45.144%	28.17	28.17
51	22.7950	0.00	1.00	46.047%	28.73	28.73
52	22.7950	0.00	1.00	46.950%	29.30	29.30
53	22.7950	0.00	1.00	47.853%	29.86	29.86
54	22.7950	0.00	1.00	48.755%	30.42	30.42
55	22.7950	0.00	1.00	49.658%	30.99	30.99
56	22.7950	0.00	1.00	50.561%	31.55	31.55
57	22.7950	0.00	1.00	51.464%	32.11	32.11
58	22.7950	0.00	1.00	52.367%	32.68	32.68
59	22.7950	0.00	1.00	53.270%	33.24	33.24
60	22.7950	0.00	1.00	54.173%	33.80	33.80

61	22.7950	0.00	1.00	55.076%	34.37	34.37
62	22.7950	0.00	1.00	55.978%	34.93	34.93
63	22.7950	0.00	1.00	56.881%	35.49	35.49
64	22.7950	0.00	1.00	57.784%	36.06	36.06
65	22.7950	0.00	1.00	58.687%	36.62	36.62
66	22.7950	0.00	1.00	59.590%	37.18	37.18
67	22.7950	0.00	1.00	60.493%	37.75	37.75
68	22.7950	0.00	1.00	61.396%	38.31	38.31
69	22.7969	0.00	1.00	62.299%	38.87	38.87
70	22.8190	0.00	1.00	63.200%	39.44	39.44
71	22.8411	0.00	1.00	64.100%	40.00	40.00
72	22.8656	0.00	1.00	64.999%	40.56	40.56
73	22.8901	0.01	0.99	65.896%	41.12	41.13
74	22.8853	0.01	0.99	66.793%	41.68	41.69
75	22.9852	0.01	0.99	67.685%	42.24	42.25
76	22.9564	0.01	0.99	68.578%	42.79	42.82
77	22.9689	0.01	0.99	69.470%	43.35	43.38
78	22.9737	0.01	0.99	70.362%	43.91	43.94
79	23.0457	0.02	0.98	71.250%	44.46	44.51
80	23.0553	0.02	0.98	72.137%	45.01	45.07
81	23.0697	0.02	0.98	73.023%	45.57	45.64
82	23.1915	0.03	0.97	73.902%	46.11	46.20
83	23.2340	0.03	0.97	74.778%	46.66	46.76
84	23.2465	0.03	0.97	75.654%	47.21	47.33
85	23.3752	0.04	0.96	76.521%	47.75	47.89
86	23.5212	0.05	0.95	77.380%	48.29	48.45
87	23.5356	0.05	0.95	78.238%	48.82	49.02
88	23.6999	0.06	0.94	79.086%	49.35	49.58
89	23.7710	0.07	0.93	79.930%	49.88	50.14
90	24.0332	0.08	0.92	80.758%	50.39	50.71
91	24.2023	0.09	0.91	81.576%	50.90	51.27

92	24.3512	0.10	0.90	82.384%	51.41	51.83
93	24.5135	0.12	0.88	83.183%	51.91	52.40
94	24.7028	0.13	0.87	83.970%	52.40	52.96
95	24.9583	0.15	0.85	84.742%	52.88	53.52
96	25.1706	0.16	0.84	85.501%	53.35	54.09
97	25.3531	0.17	0.83	86.249%	53.82	54.65
98	25.6605	0.19	0.81	86.978%	54.27	55.21
99	25.9314	0.21	0.79	87.691%	54.72	55.78
100	26.2158	0.23	0.77	88.387%	55.15	56.34
101	26.4338	0.24	0.76	89.069%	55.58	56.90
102	26.7796	0.27	0.73	89.731%	55.99	57.47
103	27.2446	0.30	0.70	90.364%	56.39	58.03
104	27.4943	0.32	0.68	90.982%	56.77	58.59
105	28.0083	0.35	0.65	91.569%	57.14	59.16
106	28.3320	0.37	0.63	92.137%	57.49	59.72
107	28.7691	0.40	0.60	92.678%	57.83	60.28
108	29.1966	0.43	0.57	93.193%	58.15	60.85
109	29.4992	0.45	0.55	93.690%	58.46	61.41
110	30.0169	0.48	0.52	94.155%	58.75	61.97
111	30.4607	0.51	0.49	94.593%	59.03	62.54
112	30.7720	0.54	0.46	95.013%	59.29	63.10
113	31.2177	0.57	0.43	95.406%	59.53	63.66
114	31.5885	0.59	0.41	95.776%	59.76	64.23
115	31.9170	0.61	0.39	96.126%	59.98	64.79
116	32.4348	0.65	0.35	96.445%	60.18	65.35
117	32.7134	0.67	0.33	96.747%	60.37	65.92
118	33.0631	0.69	0.31	97.028%	60.55	66.48
119	33.3753	0.71	0.29	97.290%	60.71	67.04
120	33.7701	0.74	0.26	97.528%	60.86	67.61
121	34.0429	0.75	0.25	97.749%	61.00	68.17
122	34.2254	0.77	0.23	97.960%	61.13	68.73

123	34.6385	0.79	0.21	98.145%	61.24	69.30
124	34.8498	0.81	0.19	98.318%	61.35	69.86
125	35.0861	0.82	0.18	98.476%	61.45	70.42
126	35.2782	0.84	0.16	98.623%	61.54	70.99
127	35.5520	0.86	0.14	98.753%	61.62	71.55
128	35.6990	0.87	0.13	98.874%	61.70	72.11
129	35.8565	0.88	0.12	98.986%	61.77	72.68
130	36.0170	0.89	0.11	99.087%	61.83	73.24
131	36.1591	0.90	0.10	99.181%	61.89	73.80
132	36.3570	0.91	0.09	99.262%	61.94	74.37
133	36.4175	0.91	0.09	99.340%	61.99	74.93
134	36.4857	0.92	0.08	99.413%	62.03	75.50
135	36.5520	0.92	0.08	99.483%	62.08	76.06
136	36.7134	0.93	0.07	99.542%	62.11	76.62
137	36.7855	0.94	0.06	99.598%	62.15	77.19
138	36.9459	0.95	0.05	99.643%	62.18	77.75
139	37.0208	0.95	0.05	99.684%	62.20	78.31
140	37.1351	0.96	0.04	99.719%	62.22	78.88
141	37.1860	0.97	0.03	99.750%	62.24	79.44
142	37.1342	0.96	0.04	99.784%	62.27	80.00
143	37.3013	0.97	0.03	99.808%	62.28	80.57
144	37.2879	0.97	0.03	99.833%	62.30	81.13
145	37.3705	0.98	0.02	99.853%	62.31	81.69
146	37.3820	0.98	0.02	99.872%	62.32	82.26
147	37.3839	0.98	0.02	99.891%	62.33	82.82
148	37.3628	0.98	0.02	99.911%	62.34	83.38
149	37.4156	0.98	0.02	99.929%	62.36	83.95
150	37.5453	0.99	0.01	99.938%	62.36	84.51
151	37.5616	0.99	0.01	99.946%	62.37	85.07
152	37.5098	0.99	0.01	99.958%	62.37	85.64
153	37.5578	0.99	0.01	99.966%	62.38	86.20

154	37.5626	0.99	0.01	99.975%	62.38	86.76
155	37.5607	0.99	0.01	99.983%	62.39	87.33
156	37.5895	0.99	0.01	99.990%	62.39	87.89
157	37.6202	0.99	0.01	99.994%	62.40	88.45
158	37.6513	1.00	0.00	99.997%	62.40	89.02
159	37.6692	1.00	0.00	99.999%	62.40	89.58
160	37.6827	1.00	0.00	100.000%	62.40	90.14
161	37.6990	1.00	0.00	100.000%	62.40	90.71