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MASTER'S THESIS

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I. Summary

Field development is an expensive phase with a high uncertainty due to the limited reservoir knowledge prior to field production. Consequently, the field facilities must be flexible to changes, such as: new wellbores, new reservoir pressure support system or others. High field development costs due to flexibility cost and uncertainties in the production, can cause fields to be put on hold or found uncommercial. This master thesis proposes two methods to increase field information that can reduce production uncertainty and the need for flexibility.

Proposed method number one is a water injection test that measures reservoir aquifer and complexity, thus help optimize the reservoir pressure support system. Proposed method number two is a 4D seismic reservoir map showing reservoir communication, this can be used to optimize the well trajectory in a complex reservoir. Value of information of the proposed methods are analyzed in two types of reservoirs and in a decision analysis tree.

Case results shows that an injection test has a cost of approximately 75 million NOK in an existing exploration well and 4D seismic test a cost of 1,2 million NOK depending on reservoir volume and other factors. The estimated value of information by the proposed methods are 500 million NOK for a low complexity reservoir, and a value of 650 to 960 million NOK in a complex reservoir.

This thesis concludes that the suggested methods can reduce the field development cost and production uncertainty while increasing the recovery factor in some fields. The proposed test can increase development of fields that were put on hold or found uncommercial due to a too high risk, development cost or too low recovery factor. The proposed tests are unproven and will therefore have a high uncertainty in cost, time and test results. Limitation of the proposed 4D seismic test is that it can only be performed in a closed reservoir, and water injection test can only analyze one communicating reservoir layer at the time.

The further work includes additional cost and risk analysis, reservoir simulations and small scale tests of the proposed methods.

II. Acknowledgments

This master thesis was written as a finalization of my master degree in Industrial Economics during the spring semester of 2017 at the University of Stavanger, UiS, Norway.

I would like to thank my supervisor Petter Osmundsen for his helpful guidance in the field of decision analysis throughout the completion of this thesis.

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Chapter 1 Introduction

Development of a hydrocarbon field consists of the following five main steps, as illustrated in Figure 1: Discovery where the field is located from seismic images and the contents of hydrocarbons are proven with a wildcat well. Evaluation where information from appraisal wells are analyzed to estimate volume of recoverable oil. Development where the facilities for hydrocarbon production and transportation is designed, manufactured and installed. Production where the oil is produced and production rate is optimized. At last abandonment where the surface equipment is removed and the wells are permanently plugged and abandon, P&A.

This master thesis focus on two proposed methods to reduce development cost by increasing evaluation of a field. Field evaluation tests performed today, analysis the near wellbore area from tests as core analysis, drill stem test and wellbore logging. Overall reservoir properties are estimated based on near wellbore data, seismic data and geological history of the area. Overall reservoir properties might have a high uncertainty that require a flexible field development due to new field knowledge during production. Examples of required flexibility is change to number of wells, production rate or method for reservoir stimulation.

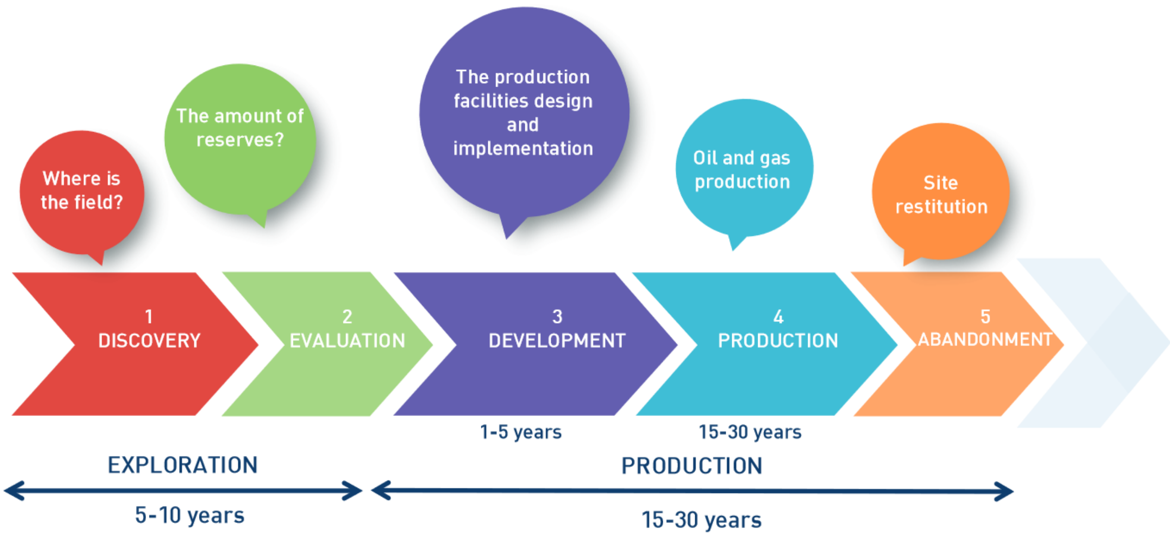

Figure 1 Exploration and Evaluation (School, 2014).

Field development optimization depend on an optimal design and flexibility of initial field facility. Initial field design can be optimized with field information from tests and flexibility from choosing a flexible facility.

Value of flexibility, VoF, is the value of choosing an option that can give additional and/or cheaper options later. During field development can the operator choose the more flexible option of a production rig or the less expensive option of a subsea facility (Osmundsen, 2011). The production rig is regarded as the more flexible option due to the lesser cost of additional wellbores and more expensive due to the higher cost of operation. Flexibility of the field facility can be used to increase the recoverable oil from the field, thus increase the income.

Value of information, VoI, is the maximum value of any given information that changes expected market value, EMV, of a project, thus should the information be acquired if cost of information is less than the value of information.

$$EVI = EMV_{with\ free\ test\ information} - EMV_{without\ test\ information}$$ **Equation 1.1**

Where EVI is expected value of information (Albright, 2012).

Expected marked value can be changed with information that reduces field uncertainties and development cost or increases production income. (Hayashi, Ligero, & Schiozer, 2007). Field information can optimize field development plan for: number of wells, well trajectory, designed production rate, designed injection rate, reservoir drainage method and other.

This master thesis suggests and evaluates two methods that can be used to increase the field knowledge before the field development phase. The proposed methods can help evaluate the reservoir complexity, natural water drive and/or recovery factor. High reservoir complexity is defined as a reservoir with a high number of sealing fault that reduces reservoir communication. Strong natural water drive, aquifer, is defined as a reservoir with sufficient water drive to maintain reservoir pressure during production, thus will the reservoir not need injection wells.

Proposed method number one is an extended water injection method that inject water to increase reservoir pressure by 20 bar, or until injected volume reaches approximately 0.6% of estimated reservoir pore volume. Collected data from the proposed extended water injection method has the possibility to predict aquifer strength and reservoir complexity.

Proposed method number two is a 4D seismic image that uses two 3D images and the increased pore pressure by the extended water injection method. The proposed 4D seismic show zones with increase pore pressure due to the extended water injection test, thus the reservoir communication.

The two-proposed method can be used to acquire reservoir information to optimize field development and production. Chapter 2 contains a literature study to explain known information for field development, reservoir evaluations and more. Chapter 3 explains the methods proposed in this master thesis, discusses how results should be interpreted and describe advantages and disadvantages. Chapter 4 estimates the cost of the proposed methods and potential value of the methods in two different reservoir types.

Chapter 2 Literature Review

Chapter 2 explains necessary theory to understand the proposed methods, why the methods is proposed and how the methods can improve field development. Main points in this chapter is to give the reader an introduction to essential knowledge regarding: decision tree analysis, reservoir evaluation, field development and equipment used in the proposed tests.

2.1. Decision analysis

This subchapter explains why decision analysis is important and the influence on value creation.

Decisions in field development are always made with an amount of uncertainty. Decision analysis includes methods and techniques, which helps the decision maker to get an overview and to choose wisely under these uncertainties. The method forces the decision maker to take a more explicit look at the options, sub options and outcomes. An important decision in field development is to choose between a platform or subsea facility. Decision analysis will help to get an understanding of building cost, expected recovery factor and amount of flexibility after facility.

Any major project must have a strict time schedule to complete on time and budget. Changes to a project must be done as early as possible to allow the project to be finished on schedule and avoid unnecessary extra costs. Figure 2 shows Influence on Value Creation vs. Investments of a typical project. The figure illustrates that changes performed during the planning phase can lead to a large value creation, while changes done during the execution phase has a small effect on value creation, due to the amounts already invested on the previous plan.

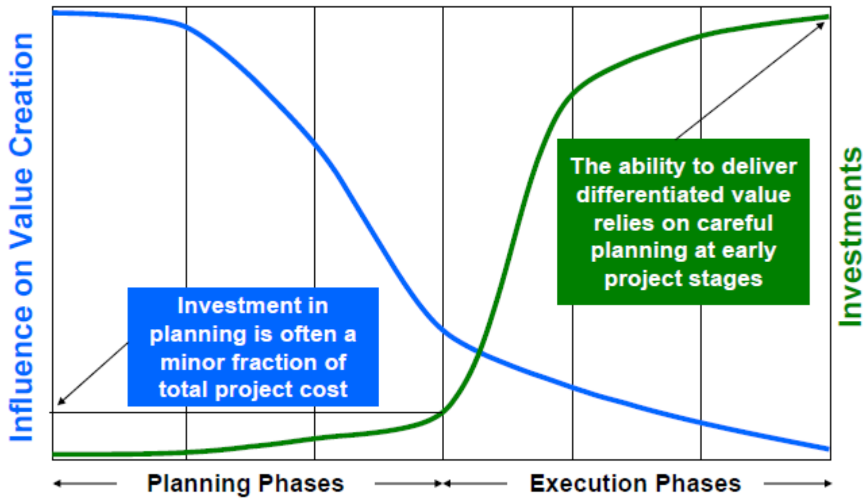

Figure 2 Influence on Value Creation and Investment Costs During the Project Planning and Execution phase (Saputelli et al., 2008).

Decision analysis is a time consuming and time critical part of a project. Consequently, it can be helpful to start with a conceptualization of the model. Figure 3 illustrates the conceptualized model to divide into groups and helps get an overview on the main risks and interdependence between activities in the project. The figure illustrates how payoff is dependent on the amount of recoverable oil, tests and field development plans, while not directly dependent of test results.

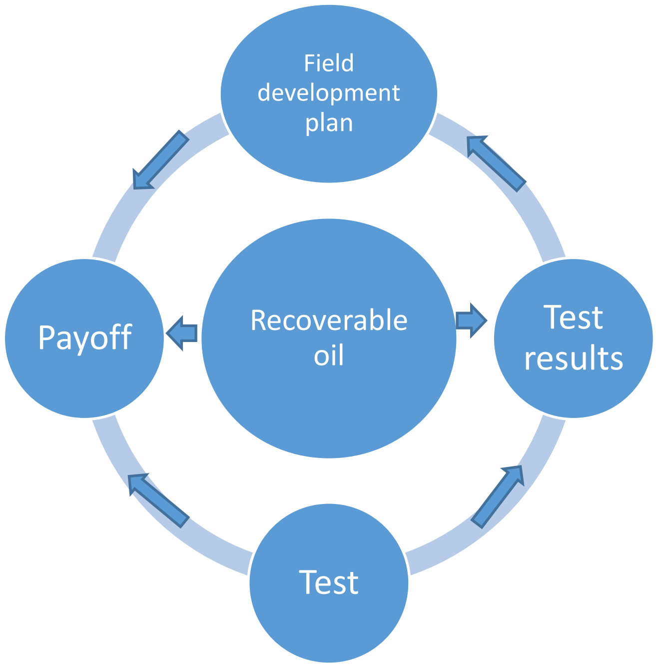

Figure 3 Conceptualized model for the making of decision tree.

Most profitable option depends on cost, potential income and probability of each outcome. Decision analysis uses expected monetary value, EMV, to evaluate the most economically beneficial. EMV is defined as:

$$EMV = \sum_{i=1}^{n} P(outcome\ i)\ x\ NPV_{Outcome\ i} \qquad \textbf{Equation 2.1}$$

2.1.1. **Decision tree analysis**

Decision tree analysis is the decision analysis method used in the thesis to evaluate the proposed methods. Following is a description and an example of decision tree analysis.

Decision tree analysis is a decision support tool. A decision tree analysis should contain every option and sub-option of a problem. A decision tree analysis should always be used when the problem involves subsequent problems.

The tool can calculate the best option with the given risk, cost and profit. Decision tree analysis should be constructed from the following steps (Newendorp & Schuyler, 2013):

1. Define the problem
2. Identify alternatives
3. Develop the decision model
4. Collect historical data and quantity judgment about uncertainty
5. Choose the best alternative

A decision tree has three types of cells: Circles that represent a possible outcome with a set likelihood of each option, squares that represent an option, and triangles that represent the end of the analysis. Figure 4 shows an example of a decision tree using the Microsoft Excel add-on "PrecisionTree 7.5".

Example

You are offered a bet of 100 NOK to potentially win 300 NOK with a 50% probability of winning. Would you take the bet?

EMV for playing can be calculated by using Equation 2.1:

$$EMV\ (win\ or\ loose) = 50\% * (-100) + 50\% * (300) = 50\ kr$$

EMW for not playing can be calculated as:

$$EMW(not\ play) = 100\% * 0 = 0\ kr$$

We can see that the EMV is positive for betting, which consequently is the best option.

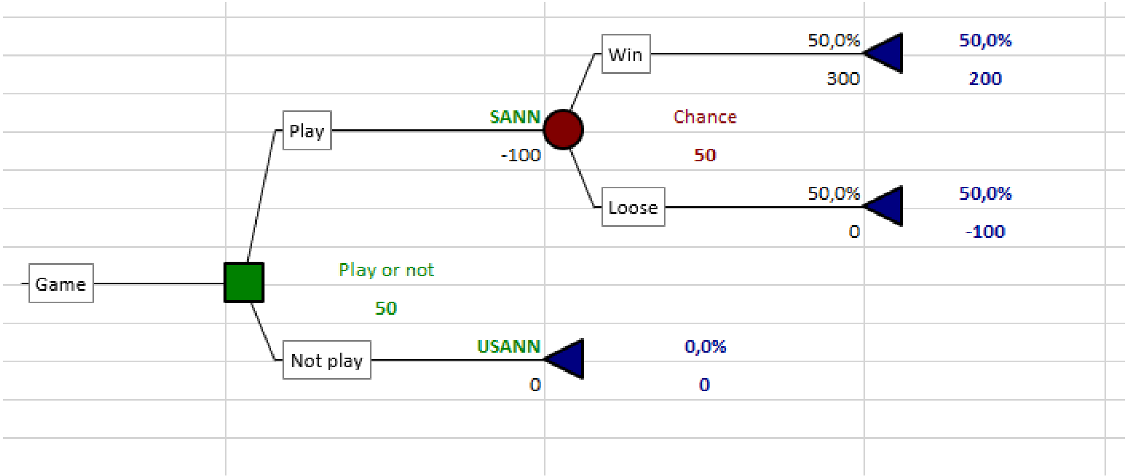

Figure 4 Example of decision tree analysis with the software "Precision Tree".

Advantages of performing a decision tree analysis (Newendorp & Schuyler, 2013):

- Explicitly Recognize Possible Outcomes
- Highlight key factors
- Comparing projects with different risk characteristics
- Clearly Communicate Judgments about risk
- Accumulate Complex Investment Decisions

Disadvantages of performing a decision tree analysis:

- Believe it will eliminate or reduce risk
- Output is only as accurate as the input data
- The analysis method doesn't replace the need for professional judgement

2.1.2. **Sensitivity analysis with tornado diagram**

The sensitivity analysis shows how sensitive the EMV is to changes. The example below will illustrate how a sensitivity analysis, tornado diagram and spider web should be used to find the optimal solution.

A sensitivity analysis is performed on the example in chapter 2.1 (Bet or not bet on coin toss). The analysis includes a -100% to +10% change in potential winning and -10 % to +100% change in the betting amount.

Figure **5** show that there is an expected value of zero when the potential winning is below 200 NOK, and increases at higher potential winnings. Consequently, the bet should only be made if potential earning is higher than 200 NOK (given a 100 NOK bet). Figure 6 shows a tornado diagram that is used to determine uncertainty effect on total expected value.

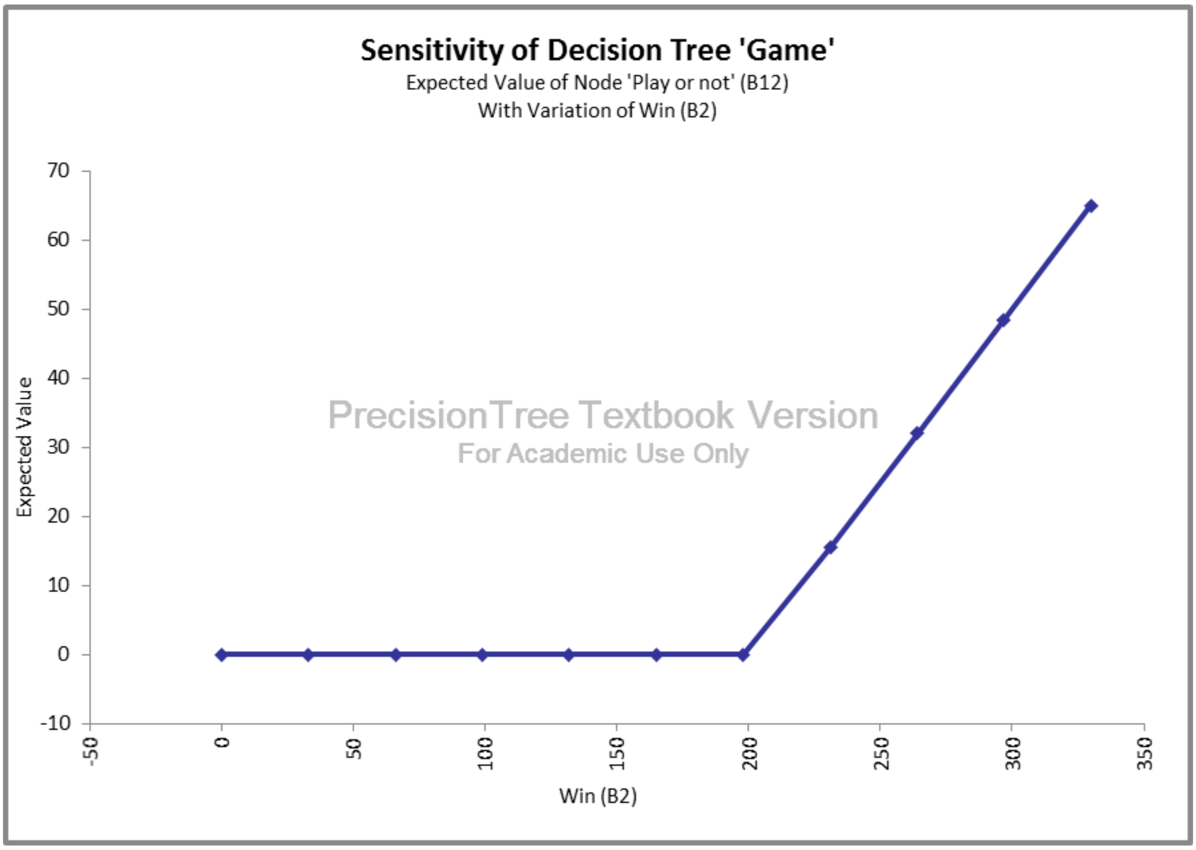

Figure 5 Sensitivity analysis of example

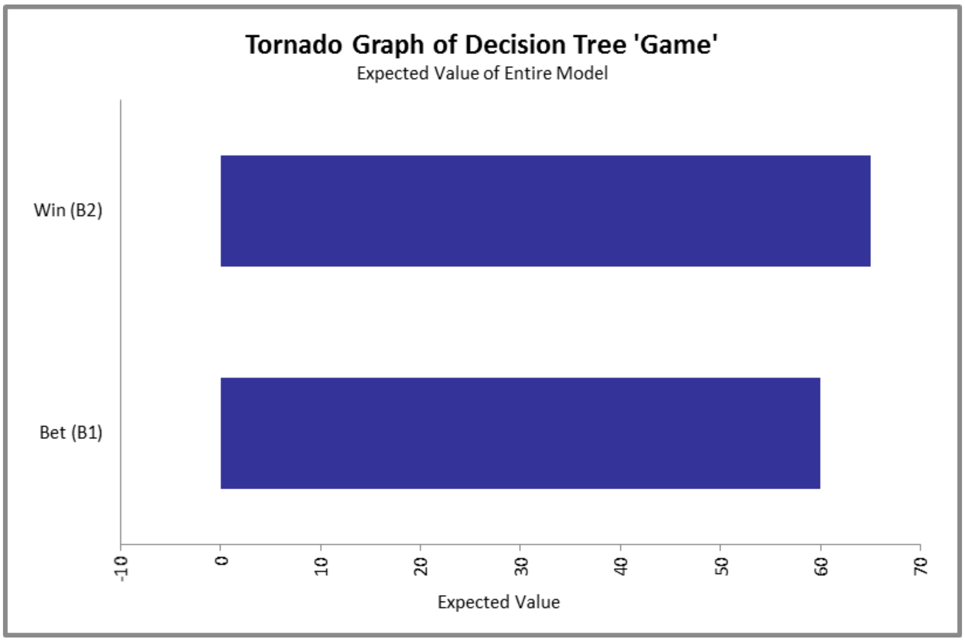

Figure 6 Example of Tornado diagram

2.2. Reservoir exploration

The following subchapter explain todays methods for reservoir evaluation and estimated cost of reservoir exploration wells. The subchapter helps the reader understand the proposed methods in this thesis by explaining todays methods for injection test and seismic images.

Interpretation of seismic data results in discoveries of prospects, and the reservoirs within them. A wildcat well is then drilled through one or several potential hydrocarbon reservoirs to confirm if the reservoir contains hydrocarbons. Appraisal wells are used to collect further reservoir information regarding size, hydrocarbon composition, lithology and more. Table 1 indicates the number of appraisal and wildcat wells drilled in some of the fields on the Norwegian Continental Shelf, NCS.

Table 1 Number of exploration wells (NPD, 2017).

Type/Field	Draugen	Grane	Snorre	Valhall
Appraisal	8	3	11	7
Wildcat	1	1	2	1
Total	9	4	13	8

Figure 7 shows the average cost of an exploration well and number of wells drilled from 2011 to 2016. The figure illustrates that an average exploration well cost approximately 600 mill NOK in 2016.

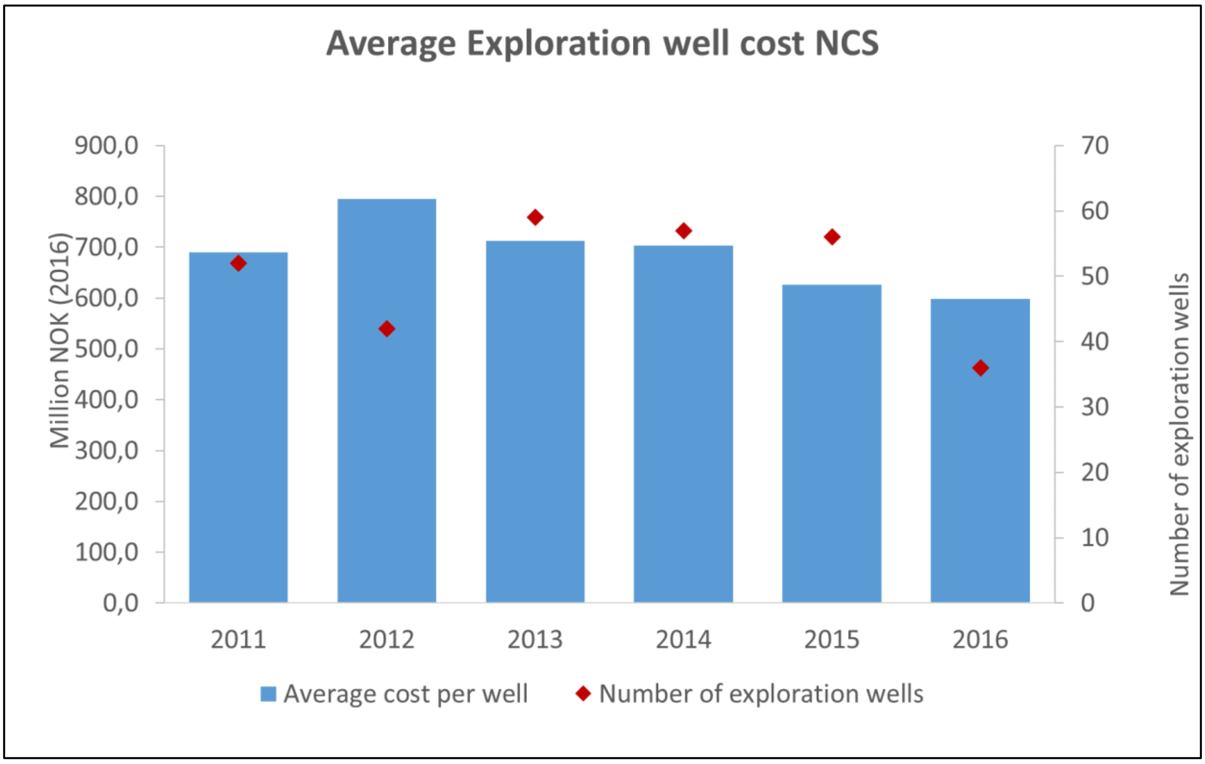

Figure 7 Average cost of exploration well (Petroleum, 2016).

2.2.1. Production / injection well test

Production and injection tests are performed to estimate the potential production from new discoveries. During a production test, the well produces for 1-2 days before it is shut down. The reservoir pressure buildup is then monitored for 1-3 days to calculate the estimated production potential for the field.

The injection test is performed by injecting seawater to measure the pressure increase during the injection and the pressure decrease during the injection stop. The injection test will inject for 1-2 days and monitor the pressure drop for 1-3 days. The injected/produced volume in these testes are relatively small and will only have a marginal effect on the average reservoir pressure. Consequently, these methods will only test the near wellbore formation.

Extended water injection test is a proposed method in this thesis to inject seawater during an extended period that will increase the average reservoir pore pressure. The proposed method is further explained in Chapter 3.1 Extended water injection test.

2.2.2. Seismic reservoir image

Seismic modeling is based on seismic images acquired from seismic vessels. The images are created from seismic reflection caused by changing layers in the formation. Fields are discovered by firstly collecting 2D seismic, which shows cross-sectional view in the strike and dip directions. Further, 3D reflection data is acquired after individual prospects are defined, due to the higher acquisition cost. 2D and 3D seismic is collected before an exploration well can be drilled. The seismic image quality depends on depth, dip of layers, formation composition and heterogeneity, formation stresses, disturbances and more.

4D seismic

4D seismic images are made from two or more 3D seismic images over time. The method is used on producing fields to show reservoir changes due to changes in saturation, fluid contacts (OWC), reservoir pressure and/or formation stress.

3D seismic for a 4D image must have a high quality to eliminate nose. The two main methods of obtaining 3D images are by boat or fixed sensors on the sea floor. Seismic from boat is cheaper, but will produce more noise due to the movements. Seismic images from boats are normal procedures on every field, while sea floor seismic is only performed on larger oil fields, as Ekofisk and Statfjord.

2.2.3. Plugging and abandonment

The proposed method in this thesis requires a rig/ship to return for plugging and abandonment of the well. This chapter will briefly explain two P&A methods used today and one method that is in the development phase.

Plugging and Abandonment, P&A, is a time consuming and costly operation that must be performed before permanently abandoning a well. Traditionally, an appraisal and exploration well uses a rig to securely cement the well closed. Below is a time estimate for a P&A operation performed from a riser less wellbore intervention, RLWI, vessel and rig. Figure 8 shows that a rig uses 67% less time than a RLWI vessel.

RLWI vessel	RLWI vessel	Semi rig	Semi rig
Operation	Estimated time	Operation	Estimated time
Mobilize equipment. Transit to template, DP trials	50	Mobilize subsea equipment. Move and position rig	20
Open hatch and pull TC	13	Open hatch and pull TC	13
Run RLWI stack and connect to VXT. Install kill hose	34	Run WOR stack and connect to VXT	57
Performed Caliper run	22	Performed Caliper run	18
Kill well	10	Kill well	10
Install and test deep set plug	18	Install and test deep set plug	14
Punch and cut tubing (2 WL runs)	36	Punch and cut tubing (2 WL runs)	28
Displace tubing and annulus to brine. Retrieve kill hose.	20	Displace tubing and annulus to brine	8
Install DHSV protection sleeve	10	Install DHSV protection sleeve	8
Install TH plug in production and annulus bore. The stack has to be retrieved to surface to modify for annulus access and before pull VXT	80	Install TH plugs (two run)	16
Pull VXT to surface	15	Pull VXT on WOR to surface	40
Install SSD, volume control system, and Jack	35	Install BOP and marine riser	35
Pump open and retrieve TH production bore plug	10	Pump open TH production bore plug	2
Deploy THRT and lift tubing and tubing hanger	8	Prepare and pull TH and 5 ½" tbg	45
Run cement log through 5 ½" tubing	25	Run USIT	14
Plug and abandon well. Establish primary barrier in 9 5/8".	30	Plug and abandon well. Establish primary barrier in 9 5/8" casing	50
Pull TH and 5 ½" tbg to surface	45	Plug and abandon well. Establish secondary barrier with perf and wash method in 13 3/8"	50
Install mechanical plug as foundation for secondary barrier	16	Establish open hole to surface plug (retrieve casing)	44
Retrieve SSD, volume control system, and Jack to surface	30	Pull MR and BOP	13
Install RLWI stack and CAT	20	Cut and retrieve wellhead	12
Establish secondary barrier in 13 3/8" casing	72	Demobilize and pull anchors	15
Establish open hole to surface barrier with use of CAT.	110		
Retrieve RLWI stack and CAT.	20		
Cut and retrieve wellhead	12		
Transit to shore and demobilize	20		
Total [hours]	**761**		**512**
Total [days]	**31,7**		**21,3**

Figure 8 Time estimate for P&A operation (Valdal, 2013).

Method under development for P&A

The company "Interwell" is testing a new method that do not require a rig, removal of tubing or a cement-bond log. The method will save both time and money for P&A operations by reducing the required equipment to only a light intervention vessel (Interwell, 2016). The method is mentioned in this thesis because it can severely reduce P&A cost for the proposed methods in this thesis.

2.3. Reservoir production potential

This subchapter will explain how recovery factor is estimated, reservoir pressure support system is planned and how reservoir compressibility effects the proposed methods. The proposed methods increase knowledge of recoverable oil and reservoir pressure support system that can optimize field development. Reservoir compressibility is used to estimate cost of the proposed extended water injection test.

The seismic images show locations of potential reservoir structures containing hydrocarbons. Exploration wells verify if the structure contain oil, the oil column height and oil saturation. Initial oil in place, IOIP, is then determined by combining the seismic images and the appraisal wellbore data. The recoverable stock tank oil initially in place, STOIIP, is determined from the IOIP and the recovery factor, RF. RF is preferably found from reservoir simulations where the four main parameters are (Wickens & Kelly, 2010):

1. Vertical reservoir heterogeneity
2. Oil viscosity
3. STOIIP area density
4. Structural complexity

Oil viscosity and STOIIP are found from exploration wells. Vertical reservoir heterogeneity and structural complexity have normally a high uncertainty, they are estimated from traditional methods as local geological history and the seismic images.

2.3.1. Improved oil recovery

Field development must plan for future improved oil recovery, IOR, and enhanced oil recovery EOR methods. This subchapter will explain some of the IOR methods used today. Improved oil recovery is any method for oil recovery beyond:

- Fluid expansion
- Rock compression
- Gravity drainage
- Pressure decline
- Water drive
- Gas drive

Examples of IOR methods are water and gas injection. Water and/or gas injection are used to displace oil and maintain reservoir pressure during production. Maintaining the reservoir pressure is important to maintain the production rate and to achieve a high recovery. Location of the injection wells are found from reservoir simulations where the most optimal trajectory is found.

2.3.2. Reservoir compressibility

Reservoir compressibility can be used to calculate reduced pressure due to depletion or increased pressure due to injection. The proposed methods use water injection to increase reservoir pressure. Consequently, reservoir compressibility must be calculated to estimate injected volume for a pressure increase. Reservoirs have different compositions thus different compressibility. Total compressibility is defined as:

$$c_t = c_g S_g + c_o S_o + c_w S_w + c_f$$ **Equation 2.2**

Where c is compressibility, S is saturation in fraction and the subscripts g, w, o, f stands for gas, water, oil and formation. Compressibility is defined as:

$$c = -\frac{1}{V}\left(\frac{dV}{dp}\right)$$ **Equation 2.3**

Rock compressibility

Normal compressibility ranges from approximately 6-30 x 10^-5 bar^-1 at a reservoir pressure above 70 bar (PetroWiki, 2017). Figure 9 illustrates how the rock compressibility changes with reservoir pressure. An initial reservoir pressure of 300 bar gives an estimated rock compressibility of 6 x 10^-5 bar^-1.

Formation water compressibility

Formation water compressibility depends on the temperature, pressure and salinity, and can be calculated from the following equation:

$$\frac{1}{c_w} = m_1 p + m_2 C + m_3 T + m_4$$ **Equation 2.4**

Where c_w is measured in psi^-1, p in psi, C (salinity) in g/L and T in Fahrenheit. The constant are: m1= 7.033, m2 = 541.5, m3= -537 and m4= 403.3 x 10^3 (PetroWiki, 2017). Figure 9 illustrates how formation water compressibility changes with reservoir pressure at 90̊C and salinity of 60 g/l NaCl.

This thesis uses a water compressibility of 4 x 10^-5 bar^-1 as can be calculated from Equation 2.4 at 300 bar, 90̊C and 60 g/L NaCl.

Oil compressibility

Oil compressibility changes with pressure, temperature and composition. Below is an illustration of a typical oil compressibility curve with changing reservoir pressure. The figure shows that a reservoir with 300 bar will have an oil compressibility of 3.09 x 10^-4 bar^-1. The oil compressibility data is collected from (Al-Marhoun, 2014).

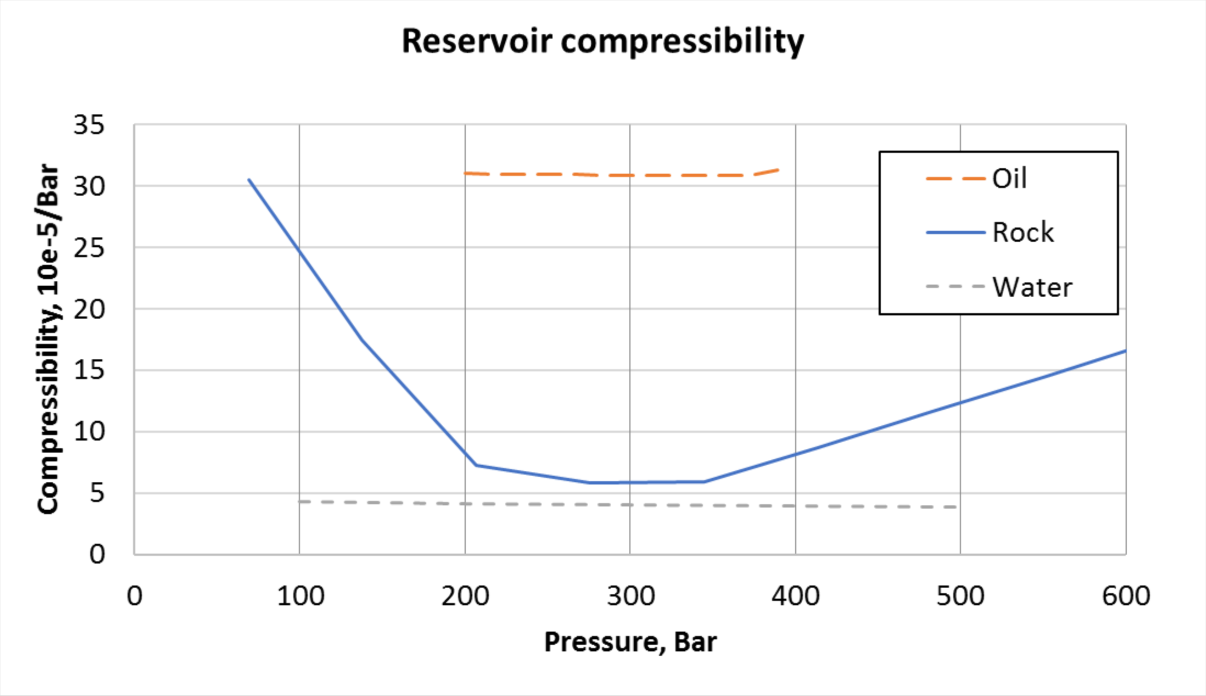

Figure 9 Illustrates approximated reservoir compressibility for the formation, oil and water.

Gas compressibility

Compressibility of free gas has a high fluctuation with pressure, temperature and composition. Free gas compressibility is approximately 207 x 10^-5 bar^-1 at 275 bar reservoir pressure (Trube, 1957).

Isothermal gas compressibility can be calculated from:

$$c_g = -\frac{1}{B_g}\left(\frac{\delta B_g}{\delta p}\right)_T \qquad \textbf{Equation 2.5}$$

Where B_g is the gas formation volume factor, which is defined as:

$$B_g = \frac{V_R}{V_{sc}} = \frac{p_{sc}}{p}\frac{T}{T_{sc}} Z \qquad \textbf{Equation 2.6}$$

Where V is volume, R is reservoir conditions and SC is standard conditions.

2.4. Seabox water injection

Following is a description of equipment suggested used in the proposed method for water injection. The equipment specifications are collected from the developer Seabox, and used to calculate the cases in Chapter 4 .

The proposed method for improved field development includes the use of the water injection system Seabox. This chapter will explain how the Seabox works and the purpose of the system. Seabox is a subsea satellite water treatment system for water injection. The system allows seawater to be filtrated and used directly for water injection into the reservoir. The system has a maintaining interval of up to 4 years, designed life of more than 20 years and do only need electricity to function. The figure below illustrates a water injection system with a floating production storage and offloading, FPSO, vessel.

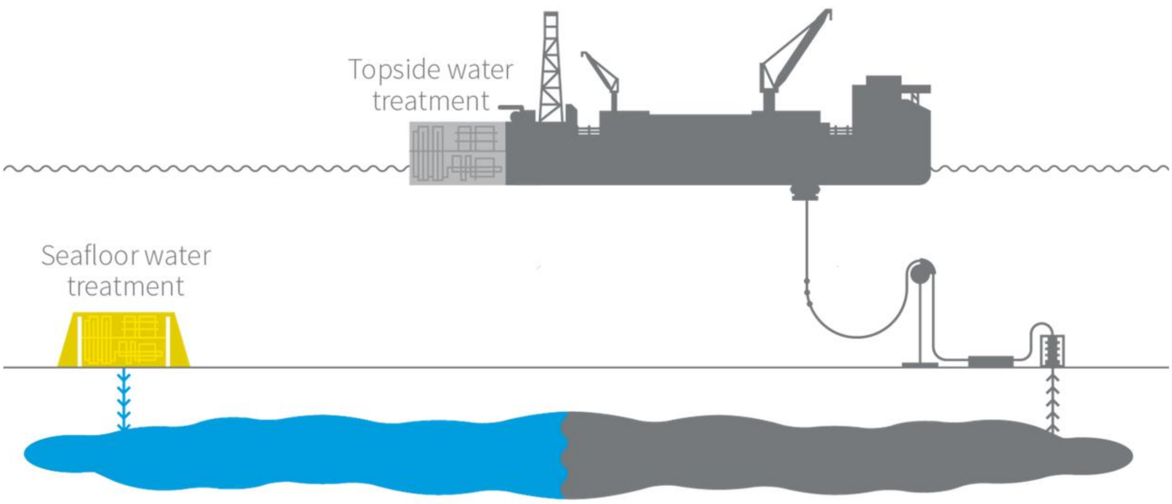

Figure 10 Seabox water injection system illustration (NOV, 2017).

A complete seabed injection system will cost between 60 – 200 mill NOK depending on the water quality (Haugstad, 2016).

Seabox specification includes (Olsen & Pinchin, 2013):

- Cost of equipment 60-200 mill NOK depending on the required water quality.
- Injection pump has an effect of 2-3 MW.
- Water treatment system uses 1-10 kW.
- Pump has an injection rate of up to 20 000 bpd and injection pressure of 350 bar.
- Template and pump can be removed/installed with a light intervention vessel.

Chapter 3 Proposed Methods

This chapter will explain and discuss the proposed methods for increased field knowledge prior to field development. The methods are explained by illustrations, procedure description and discussion of test results. Chapter 3.3 illustrate how the two proposed methods should be implemented in a decision tree analysis.

3.1. Extended water injection test

The proposed extended water injection and pressure falloff test can collect reservoir information prior to the field development. The injection should be performed by installing an injection pump, seawater cleanser and generator vessel on an exploration well, as illustrated in Figure 11.

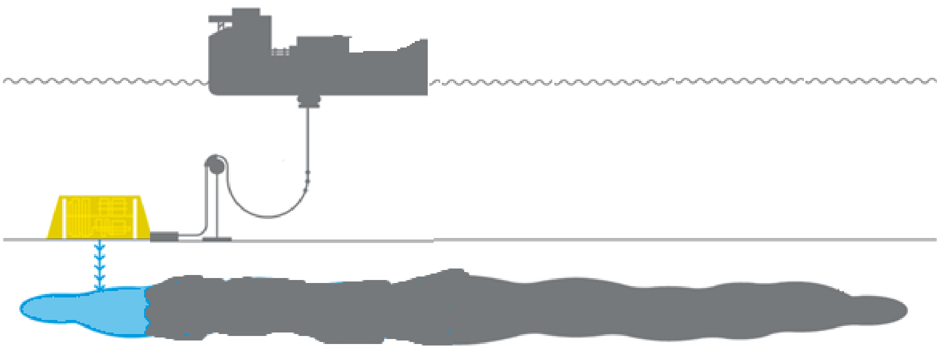

Figure 11 Illustration of extended water injection test. (Modified version of Figure 10)

The generator vessel will produce electrical power for the seawater cleanser and the injection pump. A single well with a Seabox facility can inject 20 000 bbl/day, that will require approximately 80 days of injection in a 40 million cubic meter closed reservoir (see Chapter 4 for calculation).

Figure 12 shows calculated injection time for different sizes of oil zones and water zones. The graph shows that the water zone has a lower compressibility and will need less injection time. A reservoir with a total volume of 80 mill m3 with an equal oil and water zone will require 80 + 25 = 105 days to increase the reservoir pressure with 20 bar for a single injection pump.

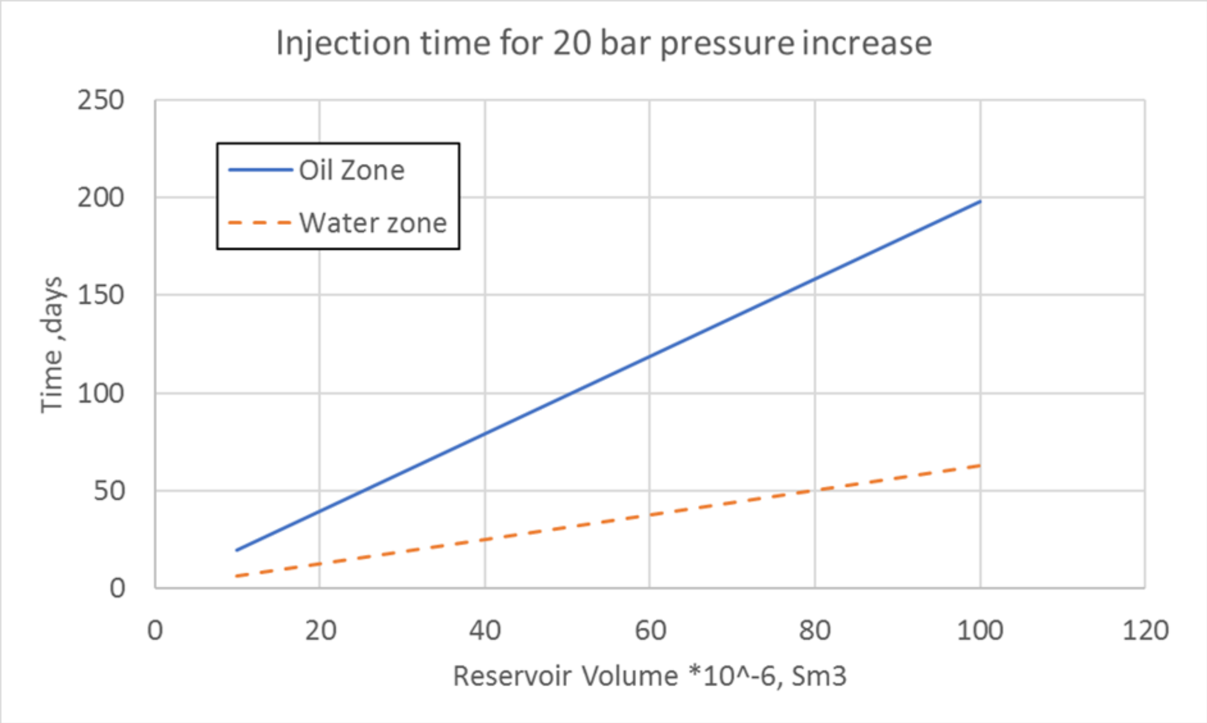

Figure 12 Shows calculated single well injection time vs. reservoir volume for a 20 bar pressure increase (See chapter 4.1 for calculations).

Procedure for extended water injection test:

1. An exploration well must be drilled to the water zone in the oil reservoir. The water injection test is suggested performed in the water zone to minimize the effect on the oil zone.
2. An injection tubing must be installed in the exploration well to insure a secure barrier during injection.
3. Installation of Seabox water injection and filtration system by a light intervention vessel.
4. A vessel with a sufficient generator to generate electricity for the subsea facility is connected to the Seabox. The vessel will then operate the subsea facility for the duration of the test.
5. The last step is to remove or leave the injection system in place. The water injection system can be removed to be used on a different well, or left in place to be used as an injection system during field production.

3.1.1. Discussion of test

The pressure and injection rate are measured during and after injection. Reservoir complexity and aquifer strength can be estimated by comparing the estimated and measured injected volume and pressure response from the reservoir. Estimated pressure response should be calculated from reservoir compressibility and volume that can be found from analysis of cores and seismic images.

Figure 13 illustrates four possible pressure responses to the proposed water injection test, P_i represent initial reservoir pressure, and P_max is the maximum increased pressure from the injection test. Pressure response number two illustrates a closed reservoir with an increase in pressure due to an expected compressibility of the reservoir. Pressure response number one has a higher-pressure response than expected which indicates a lower compressibility factor or a lower reservoir volume due to a high reservoir complexity. Pressure response number tree has a lower pressure increase than expected which indicates a weak aquifer, high compressibility factor or a large reservoir volume. Pressure response number four has no pressure increase which indicates an aquifer that is stronger than the injected rate. Further information regarding aquifer strength can be found from fall-off pressure monitoring after a pressure increase. A rapid water injection fall-off pressure during shut down indicates a strong natural water aquifer.

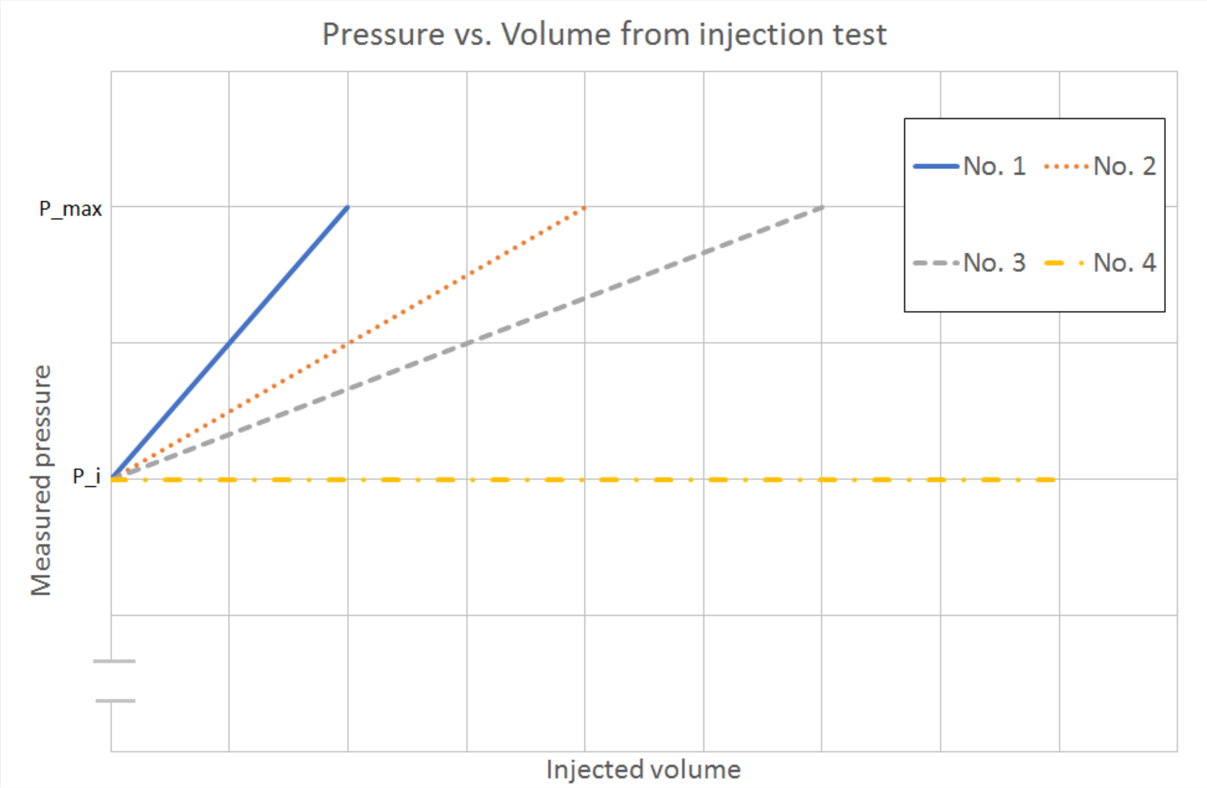

Figure 13 Illustrates measured pressure and volume response of extended water injection test.

The aquifer strength is the measurement of the reservoirs capability to maintain pressure during production. A closed reservoir will not have a sufficient aquifer and will need injection wells for pressure support during production. Consequently, the results can help to optimize the amount of injection wells that can save money on fewer wells and less water injection.

Complex reservoirs have a changing permeability in the reservoir. The proposed methods can help identify sealing and not sealing fractures. Sealing fracture information can help placement of production and injection wells for an optimal reservoir drainage, thus increased recovery factor or reduced number of wellbores.

The test can insure sufficient reservoir knowledge to decrease the amount of needed field development flexibility. Field development that requires a lower flexibility can mean that a subsea facility is the best option instead of a more expensive, but more flexible, rig facility. A higher field knowledge can increase the number of developed fields, due to an optimized field development plan and reduced risk.

Possible disadvantages of the proposed method include:

- Cost of the test
- Effect of test result mistake
- Danger of oil leaking in the formation.
- Increased probability for drilling problems

Cost of the test is further estimated in chapter 4.1 and will not be further discussed here. Test results can affect the field development to reduce flexibility. Consequently, wrong test results may have a high effect on field development cost.

Increasing reservoir pressure might cause the overburden to fracture and leak oil. Consequently, the reservoir fracture pressure should be measured with an extended leak of test before the water injection test. The proposed water injection method might also displace oil from the reservoir during the test. Risk of oil displacement is suggested minimized by injecting water into the water zone of the reservoir. Increased reservoir pressure might increase probability of drilling problems due to a slimmer margin between fracture pressure and pore pressure.

3.2. Seismic data

This thesis suggests using 4D seismic prior to field development to optimize a development plan. 4D mapping is proposed performed by reducing reservoir effective stress from increasing reservoir pressure. Reservoir pressure in a closed reservoir can be increased with water injection. Closed reservoirs will have an increase in the reservoir pressure during water injection test that might be traceable in 4D seismic. Open reservoirs with a strong aquifer have a constant pressure during water injection. Consequently, the proposed 4D seismic reservoir image can only be performed in a reservoir without an aquifer. Effective stress is defined as:

$$\sigma' = \sigma - u$$ **Equation 3.1**

Where σ' is the effective stress, σ is the total stress and u is the pore pressure. Equation 3.1 shows that an increase in pore pressure will cause a reduction in the effective stress, and opposite. The figure below shows the effect of increased and reduced effective stress on the seismic velocity, where a high change in seismic velocity will have a high impact on a 4D image. The figure shows that a reduction in effective stress has a higher effect on seismic velocity than an increase in effective stress (Landrø, 1999).

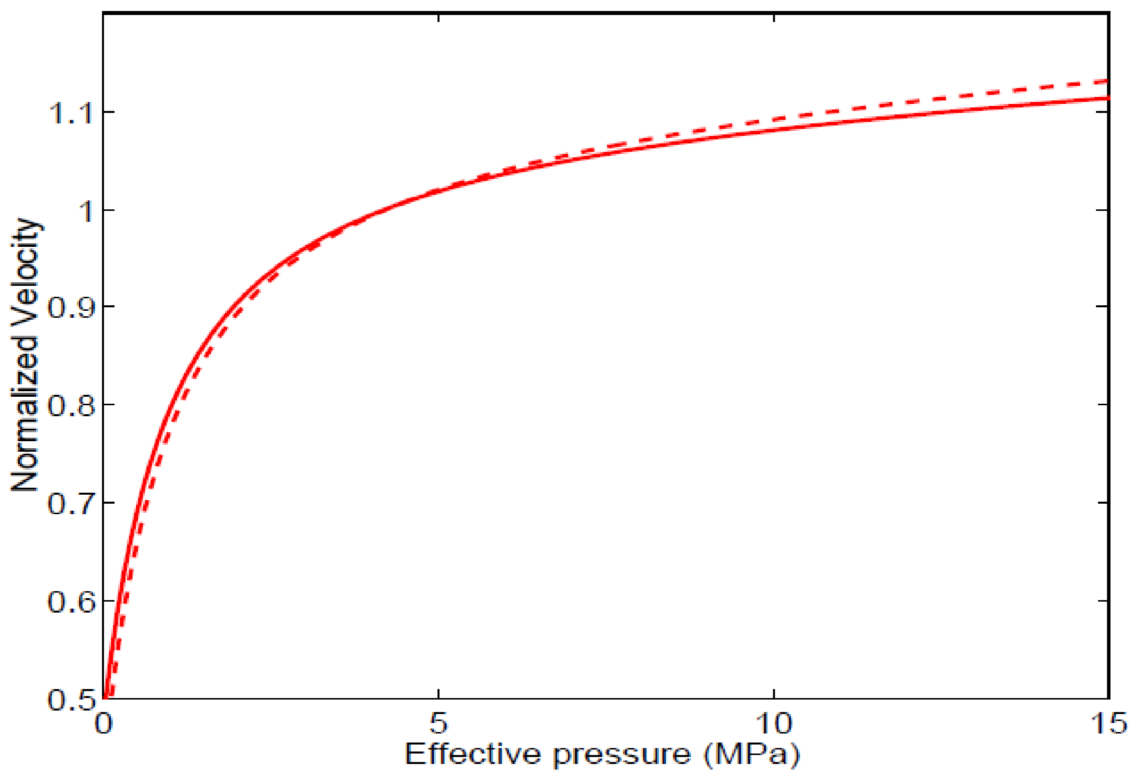

Figure 14 P-wave (solid line) and S-wave (dashed line) changes versus changes in effective pressure (Landrø, 1999).

3.2.1. **Discussion of test**

The proposed 4D seismic test will create a reservoir pressure map that shows reservoir zones with an increased pore pressure due to the proposed water injection test. The seismic test results can optimize well trajectory and reservoir drainage by uncover if faults are sealing or communicating in a complex reservoir. Other applications of a 4D reservoir image is calculation of STOIIO that can reduce the number of required appraisal wells.

The test requires a low formation stress, an increased reservoir pressure and high image quality. Consequently, there is no guarantee that the pressure increase is sufficient to map the reservoir.

In an interview with Professor Martin Landrø, a professor in applied geophysics at NTNU, he says (translated from Norwegian):

“The seismic sensitivity is good when the difference between overburden pressure and pore pressure is small. A pressure increase of 20 bar might be detectable in a reservoir with good seismic sensitivity.” (Landrø, 2017)

The disadvantages of the test are the two important factors for sufficient image quality that is required for detection of the pore pressure increase: low initial effective stress and requires a high data quality.

Figure 14 illustrates how seismic image sensitivity change with effective stress. The proposed 20 bar pore pressure increase is equal to reduction of 2 MPa in effective stress. Figure 14 shows that an initial reservoir effective stress of 6 MPa give a change in normalized velocity of 0.04, while an initial effective stress of 4 MPa give a changed normalized velocity of 0.08.

3.3. Decision tree analysis

This chapter will illustrate how the use of decision tree can help analyze the decision of performing an extended water injection test and/or 4D seismic test. Figure 15, made by the author, illustrates a decision tree designed with the Microsoft Excel add-on “PrecisionTree 7.5”.

The decision tree illustrates options from an exploration well is drilled until field development. The decision tree analysis shows how a decision effects later decisions and the EMV of the project. Figure 15 shows that 4D seismic of the reservoir only is an alternative when the reservoir has no aquifer, as mentioned in chapter 3.2.

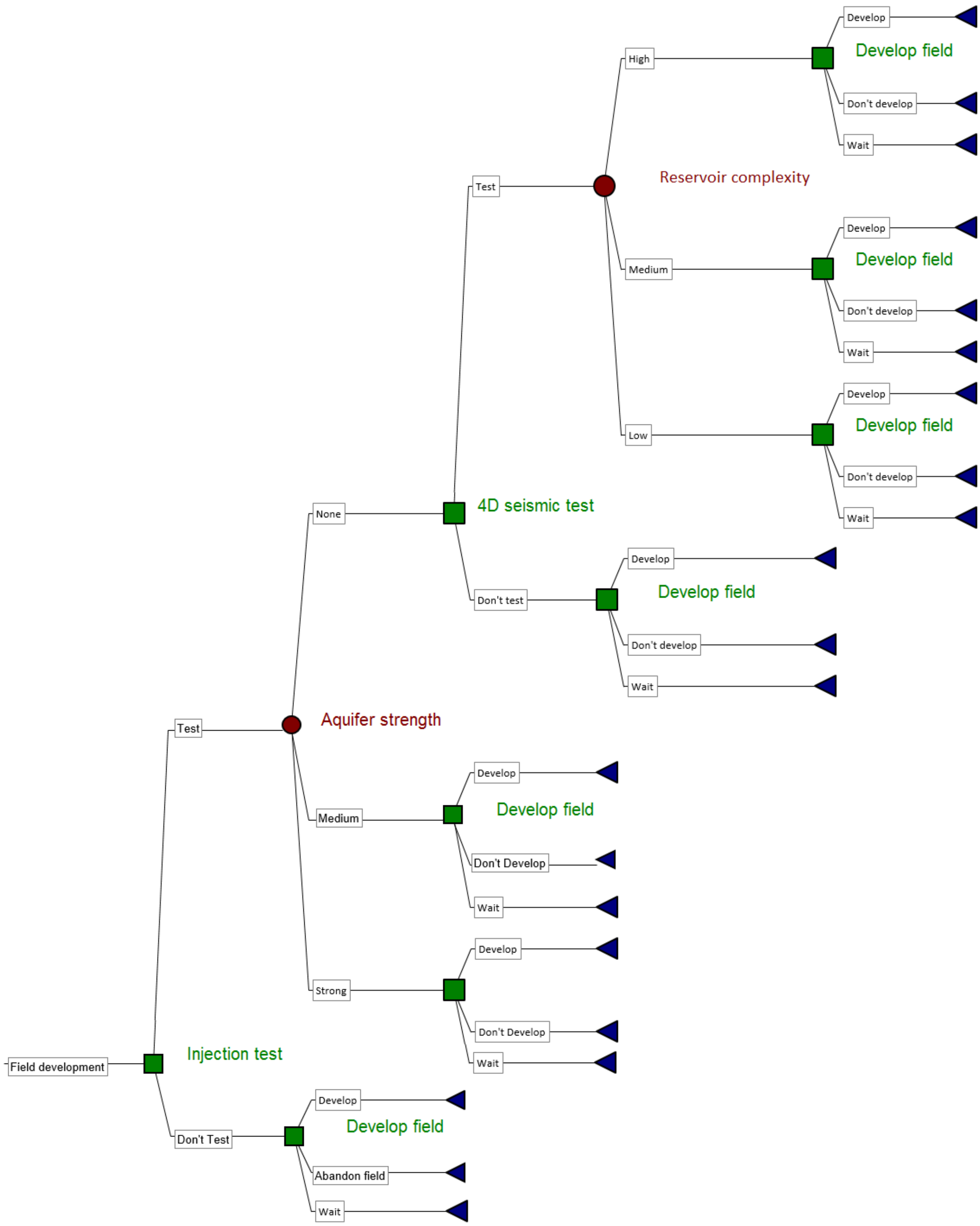

Figure 15 Decision tree analysis of proposed tests before field development

The first step when introducing data to the decision tree for field evaluation is cost, potential earnings from production and probabilities of test outcomes. Field development without any tests must have a high flexibility due to a high uncertainty in reservoir complexity and pressure support.

The extended water injection test can indicate high, medium or low aquifer strength. A high-pressure response indicate that the field might be complex and in need of pressure support. Reservoir complexity has a direct connection to RF and field development cost that might help the operator avoid investing further in the field.

The illustrated decision tree is missing probabilities, costs and potential earnings. These values should be calculated for the individual fields to analyze if the tests are a preferable option. Chapter 4.2 and 4.3 illustrate how the decision tree can be used to calculate value of the proposed test before field development.

3.3.1. Discussion of analysis

The proposed decision tree analysis has the advantage of giving a simple overview of project decisions with necessary calculations. Consequently, can decisions be made quicker and with a good overview of current options, future options, probabilities and costs.

Disadvantage of the decision tree analysis is that it does no not include detailed operational information and calculations of uncertainty and cost. Consequently, must the decision tree analysis input data have a high quality to be reliable.

Chapter 4 Case analysis

This chapter analyzes cost of the proposed methods and potential cost reduction in cases where the proposed methods can be used. The first sub-chapter calculates the cost of the proposed methods for a given reservoir. The sub-chapters 4.2 analysis value of information for a low complexity reservoir where core logging indicates high permeability sandstone. The sub-chapter 4.3 analysis cost saving of proposed method in a complex field with unknown communication through faults in the reservoir.

Table 2 shows reservoir properties that is used, if nothing else is specified, in the analyzed cases:

Table 2 Reservoir properties

Rock compressibility	6 x 10^-5 bar^-1
Formation water compressibility	4 x 10^-5 bar^-1
Oil compressibility	30.9 x 10^-5 bar^-1
Saturations	80% Oil and 20% Formation water
Initial reservoir volume	40 x 10^6 m^3

Data in Table 2 is collected from: Compressibility from chapter 2.3.2. Saturations and initial reservoir volume are suggested for the analyzed cases.

4.1. Cost of proposed methods

This sub-chapter analysis the cost of performing the proposed extended water injection test on a reservoir. The analysis assumes that an exploration well is drilled, completed and has found oil. Further is there assumed that electrical power is not accessible in the area. The reservoir volume is estimated to be 40 million cubic meter from seismic log.

Table 3 Proposed method parameters

Pressure increase by test	20 bar (estimated)
Injection rate per day	3180 m3/day = 20 000 bbl/day (Chapter 2.4)
Fuel cost	5 NOK/liter (estimated)
Vessel for power, daily cost	31500 NOK/day (OSJ, 2016)
Power consumption	2 MW (Chapter 2.4)
Fuel consumption at 2 MW	5371,5 l/hr (Supply, 2017)
Light intervention vessel	1,65 billion NOK for 5 years. 904 110 kr/day(Terdre, 2013)
3D seismic (sharp geometry with streamer separation of 75 m)	NOK 46 200 kr/km2 (Miguel, 2016)

Cost calculations:

First, we calculate the total compressibility from Equation 2.2:

$$c_t = 4{,}00\ x\ 10^{-5} * 0{,}2 + 3{,}09\ x\ 10^{-4} * 0{,}8 + 6{,}00\ x\ 10\hat{} - 5$$

$$c_t = 3{,}15\ x\ 10^{-4}\ bar^{-1}$$

Then we calculate the necessary volume to increase reservoir pressure with 20 bar from Equation 2.3:

$$dV = 3{,}15\ x\ 10^{-4}\ x\ 40\ x10^{6}\ x\ 20 = 2{,}52\ x\ 10^{5}\ m^{3}$$

The number of days required to increase the reservoir pressure with 20 bar is:

$$time = \frac{Volume}{Injection\ rate} = \frac{2{,}52\ x\ 10^{5}}{3180} = 79{,}30\ days$$

The diesel generator of 2 MW will use approximately 5371 liters per hour. The cost can then be calculated to:

$$Cost\ of\ generator\ fuel = 5371 \frac{l}{hr} x\ 24 \frac{hr}{day} x\ 79{,}30\ day\ x\ 5 \frac{kr}{liter} = 51{,}12\ mill\ NOK$$

$$Cost\ of\ vessel = 31500 \frac{NOK}{day}\ x\ 80\ days = 2{,}52\ mill\ NOK$$

The injection system has a cost of 60 mill NOK. The system has a designed life of more than 20 years. The estimated cost of necessary equipment is set to 3 mill NOK, which is equal to a depreciation of 1 year per test performed by the equipment.

$$Cost\ of\ injector\ and\ sea\ water\ cleaner = 3\ mill\ NOK\ per\ test$$

Installation and removal cost of facility will depend on the time spent on the installation. Installation time and removal time is estimated to a total of 20 days.

$$Installtion\ cost = 10\ days * 0{,}904\ mill \frac{NOK}{day} = 9{,}04\ mill\ NOK$$

The cost of plug and abandonment of the exploration well is not included as it is assumed to be independent of the proposed tests.

The cost of the proposed 4D seismic test depends on the reservoir area. We assume that the given reservoir has an size equal to the field Frøy in Norway, which has an area of 11,3 km2 and an STOIIP of 33.5 mill Sm3 (NPD, 2017). The cost of 3D seismic cube of 13 km^2 can be calculated as following:

$$Price_{3D} = 13\ km^2 x\ 46\ 200 \frac{kr}{km2} = \ 600\ 200\ kr$$

Table 4 Cost of proposed test

Description	Cost
Seabox equipment	3,00 mill NOK
Fuel for generators	51,12 mill NOK
Generator vessel	2,52 mill NOK
Installation and removal	18,08 mill NOK
P&A	0 NOK
4D seismic	2 x 600 200kr = 1,20 mill NOK
Total cost	76 mill NOK

We see that the extended water injection test has an estimated total cost of 74,72 mill NOK. The proposed 4D seismic test from a vessel has an estimated cost of 1,20 mill NOK.

4.1.1. Discussion of results

The analysis shows that the two proposed tests have an estimated cost of 76 million NOK for the given reservoir. The highest cost is the fuel for the generators at 51,12 million NOK for a power usage of 2 MW. Fuel cost depends on power usage and time spent on pumping. The power usage depends on the pump pressure, thus the reservoir pressure and sea depth. A lower reservoir pressure and deeper waters will reduce the pump power consumption. Time spent on pumping depend on aquifer, reservoir volume and compressibility. Consequently, can the test have a high increase in fuel cost due to increased fuel cost.

The analysis does not consider the potential of cost reduction due to the increased reservoir pressure. An increased reservoir pressure can reduce the initial need for water injection and increase the initial production rate.

The cost of installation, removal and P&A has a high uncertainty in the analysis and further analysis of these costs are recommended.

4.2. Low complexity reservoir

This case analysis the value of the proposed test in a low complexity reservoir. The initial seismic data and the exploration well shows that the reservoir has no faults, highly permeable sandstone and an oil water contact as illustrate, by the author, in Figure 16. Table 2 shows the relevant reservoir properties.

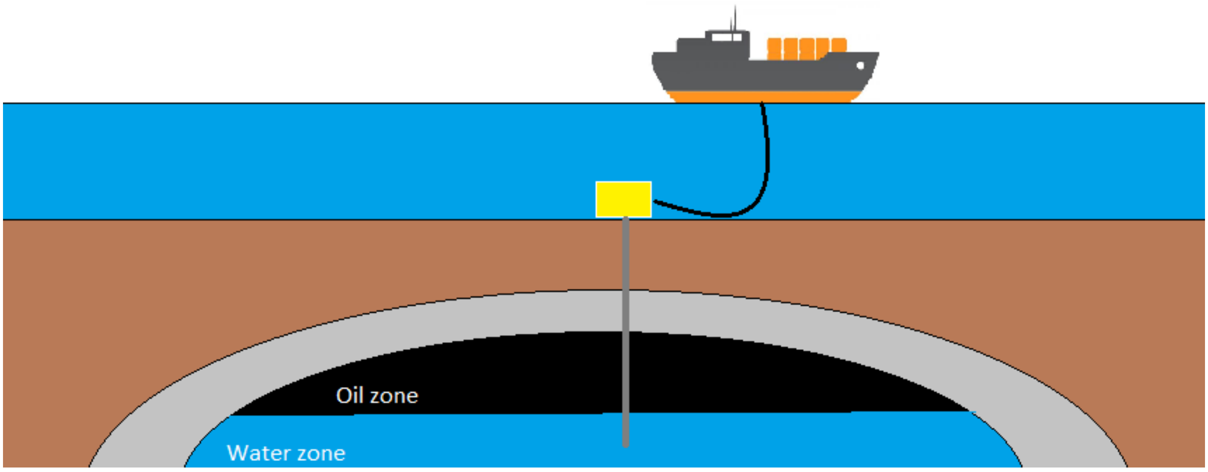

Figure 16 Illustrates a low complexity reservoir with an installed Seabox.

The value of the proposed test can be calculated from the savings created by knowing the aquifer strength. Equation 1.1 shows that the EVI is equal to the difference in the EMV with free aquifer strength information and the EMV without aquifer strength information.

We assume that there is a 50% chance of sufficient aquifer strength for a stable pressure during production, and a 50% chance that the reservoir will need immediate pressure support from the injection wells.

Figure 17 shows the calculated water production and injection cost, and formation water filtration cost for different injection rates. The water production and injection cost includes: Lifting, separating, de-oiling, filtering, pumping and injecting of water.

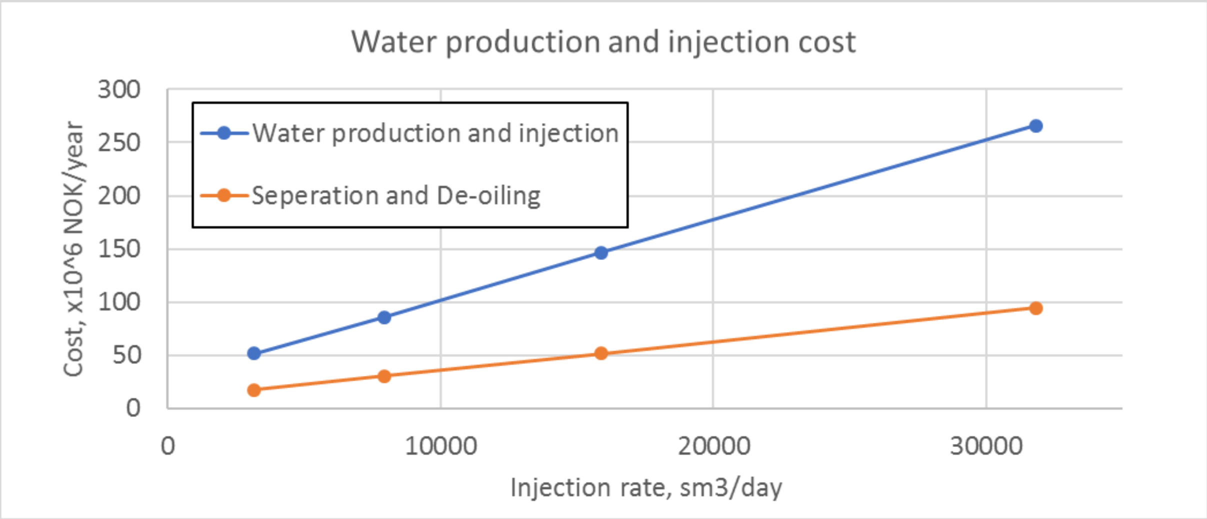

Figure 17 Shows the cost of water injection and the de-oiling per year (Baily, 2000).

We assume that the field will produce for 8 years and will only require one injection well for a production of 1,1 mill sm3 per year. A water injection well costs approximately 500 mill NOK (Haugstad, 2016). We also assume that the production well will not start water production before 3 years have passed, and that filtrated formation water can be pumped to sea.

<u>Cost without test and no aquifer:</u> Injection well + 3 years of water filtration and injection + 5 years' water injection = 500 mill+ 3 x (51,6-17,3) mill + 5 x 51,6mill = 860 mill

<u>Cost without test and strong aquifer:</u> Injection well + 5 years of water filtration = 500 mill + 5 x 17,3mill = 586,5 mill

<u>Cost with free test and no aquifer:</u> 3 years of water injection from Seabox + 5 years water injection from Seabox and surface water filtration costs = 3 x (51,6-17,3) mill + 5 x 51,6mill = 360 mill

<u>Cost with free test and strong aquifer:</u> 5 years water separation = 5 x 17,3 = 86,5 mill

Then we can calculate EVI where cost is negative:

$$EVI = (0{,}5 * -360{,}9 + 0{,}5 * -86{,}5) - (0{,}5 * -860{,}9 + 0{,}5 * -586{,}5) = 500\ mill\ NOK$$

The results show that there is an expected value of the information at 500 mill NOK if the test equipment is used for the testing and water injection. Figure 19 illustrates a decision tree of calculated expected costs of the options.

4.2.1. Discussion of results

The analysis shows that the test should be performed because it has an expected value of 500 million NOK, compared to the cost of 75,53 million NOK. The case is of a small reservoir with a limited need of only one injection well, a larger reservoir can reduce a higher number of injection well and further cut costs.

The highest uncertainties in the analysis is associated with the probability of aquifer strength and the usage of the Seabox as an injector. The probability of a strong aquifer strength requires an evaluation performed by geologies with knowledge of the area. The case uses the exploration well as an injection well that might not have the optimal trajectory for reservoir drainage. Value of information decreases to 250 million NOK if the Seabox is unusable as a water injection system during production:

$$EVI = (0{,}5 * -860{,}9 + 0{,}5 * -86{,}5) - (0{,}5 * -860{,}9 + 0{,}5 * -586{,}5) = 250\ mill\ NOK$$

4.3. High complexity reservoir

This sub-chapter analysis the value of the proposed information in a complex reservoir illustrate, by the author, in Figure 18. The reservoir complexity is estimated from 3D seismic images and core data. The operators wish to know if there is communication through the faults, which can help the well planning and estimations of the recovery factor. The reservoir is estimated to contain 32 million Sm3 oil. Probabilities for reduced number of wells and increased recovery factor is estimated in this examples.

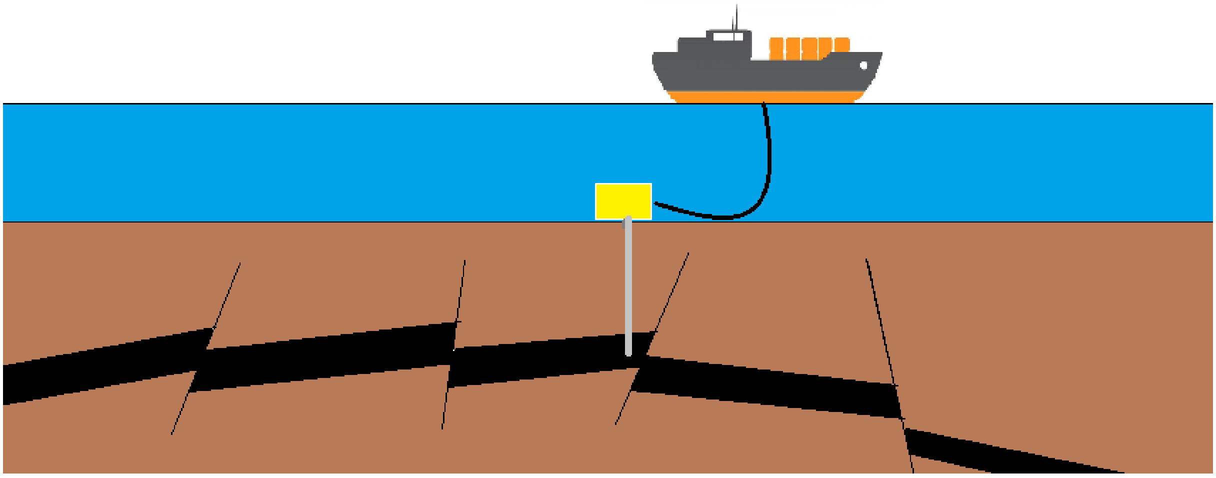

Figure 18 Illustration of a complex reservoir with rotated fault blocks and with the installed Seabox.

The proposed methods can reduce the number of wells needed and/or increase the RF due to increased field information.

Value of information if reducing number of wells: A reduction of one wellbore is assigned a probability of 50%, and a reduction of two wellbores 40%, whereas no change reduction is assigned 10% chance:

$$EVI = 0{,}5 * 500 + 0{,}4 * 1000 + 0{,}1 * 0 = 650\ mill\ NOK$$

Value of information if the method can optimize well trajectory to increase RF: A probability of 20% is assigned for no change in the RF, and a probability of 60% is assigned for 1% increase in the RF, whereas a probability of 20% is assigned for a 2% increase in the RF.

$$Value_{1\%\ RF} = 32 * 10^6\ Sm^3 x\ 3000\ Nok/Sm^3\ x\ 0{,}01 = 960\ mill$$

$$EVI = 0{,}6 * 960 + 0{,}2 * 1920 + 0{,}2 * 0 = 960\ mill$$

Figure 20 and Figure 21 illustrate a decision tree with calculated expected cost of options given a possible increased RF or reduced number of wellbores.

4.3.1. Discussion of results

The analysis show that the test should be performed because it has an expected value of 650 to 960 million NOK, compared to cost of 75,53 million NOK. Consequently, can the proposed test reduce field development cost of 574 to 884 million NOK.

The highest uncertainties in the analysis is associated with the probability of reducing the number of wellbores and increasing the recovery factor. The possibility of reducing the number of wellbores or changing the RF should be evaluated by simulating different possible cases.

Limitation of the proposed water injection test is that it can only evaluate the communicating reservoir volumes. Consequently, will additional water injection test be required to test reservoir volumes that has no communication to the initial tested reservoir volume.

Chapter 5 Conclusion

This master thesis proposes two methods to estimate the natural water drive and reservoir complexity prior to the field development phase. The methods can help optimizing the field development process by reducing the development cost, uncertainties and increasing the recovery factor. Accurate reservoir information can limit the need for field development flexibility and increase the use of subsea facilities.

A cost analysis estimates costs of 76 million NOK for the proposed water injection test and 1,2 million NOK for the proposed 4D seismic test, based on a 40 million Sm^3 reservoir. The case analysis shows that the proposed method can reduce the number of water injection wellbores in a low complexity reservoir. In a complex reservoir with unknown number of sealing faults, can the proposed test reduce the number of wellbores and/or increase recovery factor.

The proposed methods were found to optimize the field development by increasing the field knowledge during field evaluation phase. The extended water injection test can evaluate the aquifer strength and the 4D seismic method can map the communicating parts of a reservoir. Main limitation of the proposed methods is the ability to only evaluate one communicating segment of the reservoir at a time. Consequently, a complex reservoir with sealing faults require one injector per communicating segment of the reservoir.

The main disadvantages with the proposed methods are cost of the methods itself, development delay due to tests and uncertainties in the acquired data. The cost and delays due to the tests depend on reservoir volume, aquifer strength and compressibility. The acquired data from the water injection test may be affected by an abnormality in the reservoir that can affect the results and cause the development of a non-optimal development plan.

Chapter 6 Suggested further work

Authors suggestions for further work includes:

- Reservoir simulation of proposed injection test on producing fields. Reservoir models on producing fields has a high accuracy because they are improved during productions. Consequently, can the injection test result be simulated and show injection time, injection rate and pressure changes.
- Proposed 4D seismic test require a low efficient reservoir stress and high seismic image quality (see chapter 3.2). Further analysis of required seismic image quality as a function of reservoir effective stress is required to increase probability of 4D seismic image showing increased pore pressure.
- Potential of increased recovery factor and reduced number of wellbores due to optimized wellbore trajectory is only estimated. It is suggested to simulate field production on exiting fields to calculate probability and amount of increased recovery factor or reduced number of wellbores.

Chapter 7 Nomenclature

7.1. Abbreviations

BPD	Barrels per day
EMV	Expected monetary value
EOR	Enhanced oil recovery
EV	Expected value
FPSO	Floating production, storage and offloading vessel
IOR	Increased oil recovery
NPV	Net present value
OWC	Oil water contact
P&A	Plug and abandonment
RF	Recovery factor
RLWI	Riser less wellbore intervention
STOIIP	Stock tank oil initially in place
VOF	Value of flexibility
VOI	Value of information

7.2. Symbols

σ'	Effective stress
B	Formation volume factor
c	Compressibility
C	Salinity
m	Constant
P	Probability
p	Pressure
S	Saturation
T	Temperature
u	Pore pressure
V	Volume
Z	Gas factor in gas law
σ	Total stress

7.3. Subscripts

F	Formation
G	Gas
O	Oil
R	Reservoir conditions
Sc	Standard conditions
T	Total
W	Water

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A. Appendix

A.1. Decision tree analysis low complexity reservoir

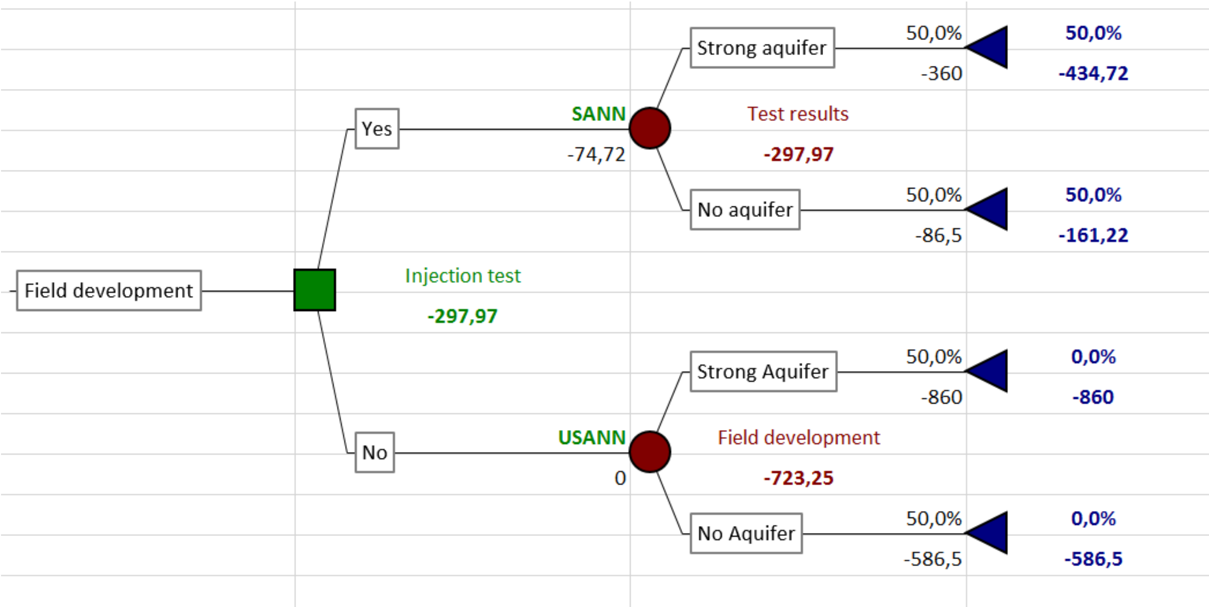

Figure 19 Decision tree for low complexity reservoir field development.

A.2. Decision tree analysis high complexity reservoir

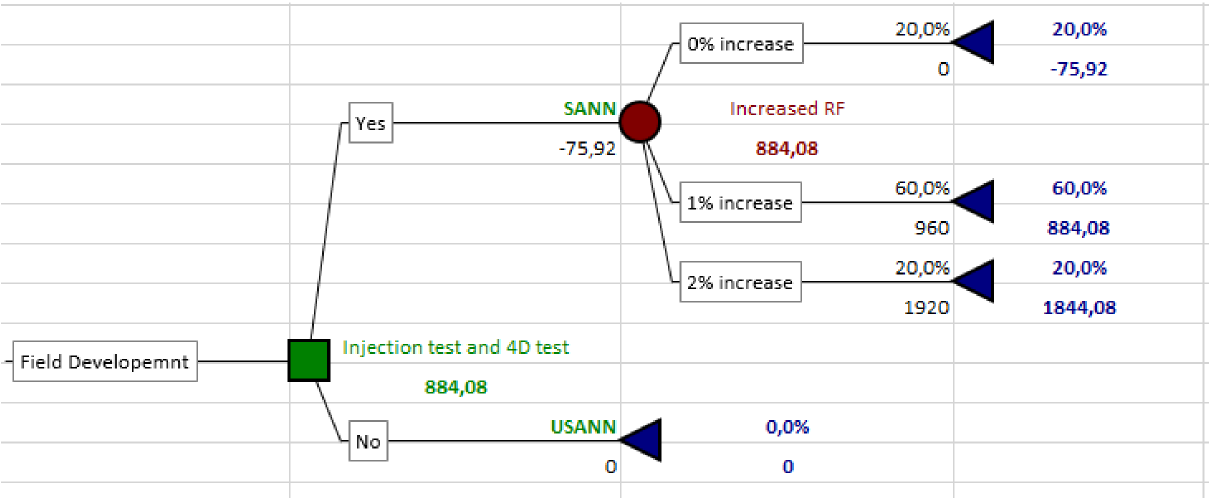

Figure 20 Decision tree analysis illustrating potential profit from proposed test (increase recovery factor).

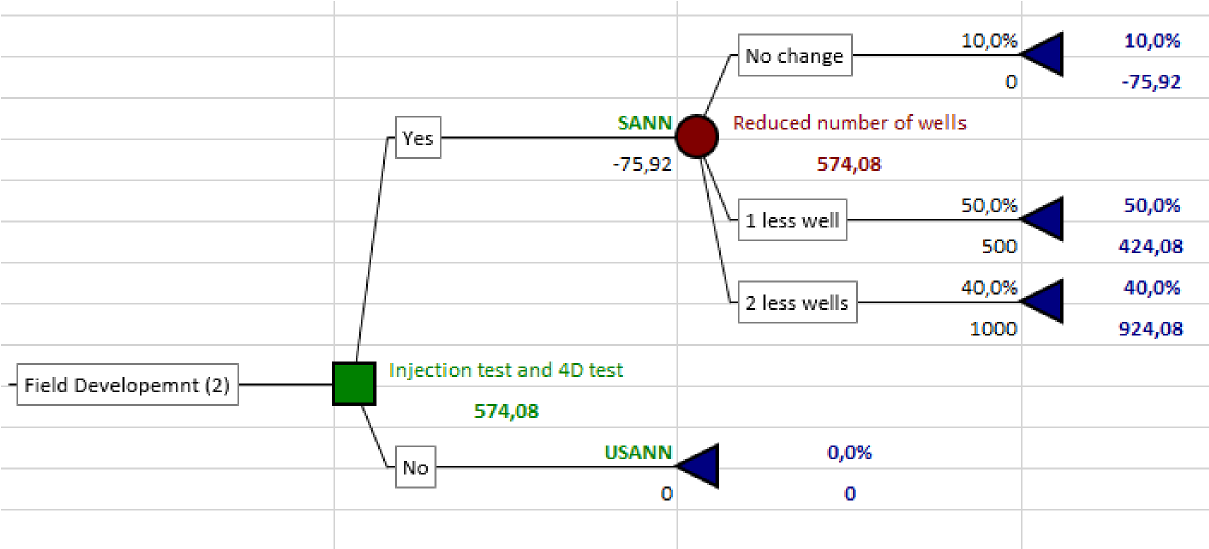

Figure 21 Decision tree analysis illustrating potential profit from proposed test (reduce number of wellbores).