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Preface

This thesis is the final part of my Master of Science degree in Industrial Asset Management at the University of Stavanger (UiS), and was written in the period January 2020 - June 2020. Due to the Covid-19 virus, with self-isolation and social distancing, the making of this thesis has been very mentally challenging. I will use this opportunity to thank my supervisor Professor Jayantha P. Liyanage at the Department of Mechanical and Structural engineering, and Material science at UiS for helping me face and overcome these challenges.

Stavanger, June 2020.

Abstract

Several oil and gas producing assets on the NCS (Norwegian Continental Shelf) are entering a phase where the costs of extracting the hydrocarbons from the reservoir exceeds the income generated from production, and thus many operators on the NCS are now facing a huge "plug-wave". As Permanent Plugging and Abandonment (PP&A) is time consuming and expensive, the industry is in need for solutions that can lead to more effective and efficient P&A operations that will reduce the related costs. Another concern that operators of late life oil and gas producing assets are facing, is to decide when to PP&A the asset in order to achieve enhanced value.

This thesis gives an introduction to P&A, and some related challenges and uncertainties that are important for decision makers to understand, and handle, to make decisions that will maximize the probability of a good outcome. Several models has been developed to represent the behaviour of oil price, production rate, operational expenses, and the cost of P&A. These models are put together to a NPV model in order to perform Monte Carlo Simulations to see if there is value in postponing P&A compared to P&A at the time where the first negative cash flow of the oil and gas producing asset is seen. The NPV model is used to run through tree different fictitious simulation cases with several waiting strategies.

The main contribution of this thesis is the framing of the P&A decision context by developing a P&A decision framework and the development of the decision support model. The main conclusion is that enhanced value can be achieved by not P&A right after the first negative cash flow is seen, as several factors like fluctuation in oil price and the time value of money concept of the P&A cost can lead to a larger NPV by postponing.

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Chapter 1

Introduction

1.1 Background

Since the start of production on the Norwegian Continental Shelf (NCS), oil and gas have been produced from 112 fields across the Shelf (NPD, 2019), and close to 6700 wellbores has been drilled on these fields since 1966 (NPD, 2020). Today (2020), 87 fields are producing with roughly 4000 wellbores including injection, observation and production wellbores. A significant portion of these fields are aging, and wells are experiencing an inevitable cessation of production. As these wells are reaching the end of their life cycle, the decision to plug and abandon comes to light. Plug and abandonment (P&A) operations are time consuming, costly, and take a lot of resources. In a presentation held during a P&A seminar in 2014 (NorskOlje&Gass, 2014), an example was presented which indicated that 15 rigs must do P&A work for 40years to be able to permanently plug roughly 6000 wells, which will have a total cost of 876 billion NOK. Due to the fact that during P&A operations the wells that are being plugged will not produce, and hence not generate any income, the process in itself will not create any monetary value for the operator. This implies that the industry should focus on reduce cost and time related to P&A activities, and make better decisions regarding when to carry these activities out.

1.2 Challenges

Permanent Plug and Abandonment of wells is a critical part of the decommissioning phase of oil and gas producing assets, and include several strategic, tactical, and operational challenges. In this section some of these challenges are discussed.

1.2.1 Strategic Challenges

When an oil and gas producing asset moves to its economic limit, operators are faced with several options. They could do an Increased Oil Recovery (IOR) project, they could sell it to another operator that can continue production at a lower cost, they can start plugging right away, or they can postpone it in hope for higher oil price or more cost effective P&A solutions. To decide what to do is not an easy task as all the alternatives include uncertain elements that will affect the outcome of each alternative.

1.2.2 Tactical Challenges

As every well has its own unique characteristics, planning P&A design can be a challenging and time consuming task. Khalife (2020) mentions several challenges including changes in formation strength, formation permeability, tectonic stresses, and lack of data from old drilled wells. All these challenges will have an impact on the planning stage of P&A.

1.2.3 Operational Challenges

All P&A activities are exposed to some degree of uncertainty that could lead to unexpected events, and thus have an impact on the costs and time duration of the P&A activity. Problem to cut the casing, not able to pull the casing, and uncemented casing across the setting interval, are examples of such unexpected events. In addition to these events, wait on weather (WOW) can be a major factor that will impact the time duration of P&A operations. The WOW factor ranging from roughly 2% on average for fixed installations to roughly 7% on average for semi-submersible rigs (Birkeland, 2011). This factor will off course depend on what time of year it is.

1.3 Scope and Objective

This thesis looks into one of the strategic challenges with late life offshore oil and gas producing assets, where the objective of this thesis is to develop a decision support technique based on a modelling method and simulation based analysis that can help decision makers in the oil and gas industry to find the optimal time to Permanent Plug and Abandon (PP&A) petroleum producing fields based on the identified potential for maximum Net Present Value (NPV) of the cash flows generated in late life of the asset.

In order to achieve the aforementioned objective, several tasks has been conducted. Starting with a general state of art- and literature review related to P&A and Decision Making in order to get a deeper understanding about the theme of this thesis. Then the decision situation was framed in order to get a holistic view of the decision context, before modeling and simulation could start. Several models has been developed in order to put together a NPV simulation model. Assessing and deciding is done with the help of Monte Carlo simulations.

1.4 Methodology

After a general state of art- and literature review was conducted, the search for relevant data could start. After contacting several operators on the NCS, it turned out that cost and time data related to P&A was not easily obtained. This resulted in data gathering from other thesis and scientific papers, and most of the data used in the models in this thesis is collected from other thesis and scientific papers. However, "dummy data" has been used when documented data was not obtainable. The different models was developed in excel by combining multiple in-build functions. Collected data or "dummy data" was then put in the models, and Monte Carlo simulations was performed. The results from these simulations was then analysed by using statistic theory.

1.5 Assumptions and Limitations

Several assumptions has been made and limitations has been identified. The main assumptions and limitations related to this thesis are given in Table 1.1.

Assumptions and Limitations	**Comments**
Considering only one objective in the decision context	In real life context, decision makers in oil and gas companies must handle several objectives which add more complexity to the process. Some other relevant objectives are mentioned in section 3.2.1
The only reason for PP&A is negative cash flow	This is also not the case in reality. In section 2.2, several possible reasons for PP&A is mentioned.
Only two alternatives are considered in the decision context	In fact, the decision makers are faced with several other alternatives. Some of these are mentioned in section 3.2.2
When the decision to plug is made, all wells on the installation is plugged successively	This was done in order to not include more complexity to the model. In reality, operators can choose to P&A some wells in order to increase the production of other wells.
Using historical prices to forecast the oil price	By using historical prices it is assumed that uncertainty in future prices reflects the variation in the past. This might not be the case.
Several input values in the model does not necessarily reflect reality	Due to challenges associated with data gathering, several ”dummy data” has been used.

Table 1.1: Assumptions and Limitations

1.6 Structure of Thesis

This thesis is build up by seven chapters. The first chapter, which is this chapter, is an introduction to the thesis. In chapter 2, a state of art- and literature review related to both P&A and Decision Making is presented. In this chapter a short introduction to production on the Norwegian Continental Shelf (NCS), a definition of P&A, a P&A procedure, a discussion about current and future P&A

technology as well as how to make good decisions are given. In the next chapter, chapter 3, the developed P&A decision framework is presented, and chapter 4 describes the development of the P&A decision support model. Results from simulations is presented in chapter 5, where also analytical remarks are given. In chapter 6 the work done in this thesis is discussed, and in the last chapter, chapter 7, main findings and conclusions of the work done is given.

Chapter 2

State Of Art- and Literature Review

In this chapter, a short presentation related to production on the NCS is given i section 2.1. In section 2.2, Plug and Abandonment is defined and several important P&A aspects is discussed. Then, in section 2.3, certain steps of P&A operations is discussed and a P&A procedure is presented. Section 2.4 includes a discussion on current and future technologies and methods related to P&A operations. In the last section of this chapter, section 2.5, a general discussion on how to make good decisions is given.

2.1 Production on the NCS

After almost 50 years of production on the Norwegian Continental Shelf (NCS), the Norwegian Petroleum Department (NPD) states that the remaining resources exceeds those already produced, which indicates a high level value creation for the oil and gas industry in the decades to come. Production from the NCS accounts for roughly 2% of oil and 3% of gas consumed globally (Solvberg, 2019), and in 2019 Norway produced 214.1 million standard cubic metres of oil equivalents (Petroleum, 2020). Figure 2.1 illustrates the total production, distributed by product, on the NCS historically from 1970 to 2019 and forecasted from 2020 to 2024.

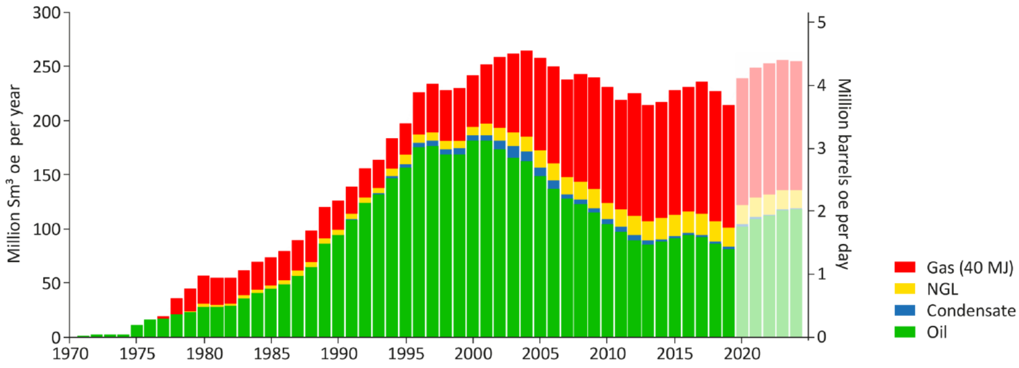

Figure 2.1: Production on the NCS (Sølvberg, 2020)

Compared to other countries like Saudi Arabia and Russia, Norway holds a relative small part of the total production worldwide. However, the Norwegian petroleum industry is one of the technological world leaders with expertise, technology development and a commitment to reducing the production footprint as important aspects (Solvberg, 2019). These aspects will help the Norwegian petroleum industry to face the decommissioning work needed on the NCS.

Production on an oil field goes through several phases during its lifetime. After hydrocarbons is discovered by a discovery well, another well called appraisal well is drilled. This well is drilled in order to determine the potential of the reservoir. Then it is time for production wells to be drilled, and production of oil starts to build up as shown in Figure 2.2, inspired by (Höök et al., 2009).

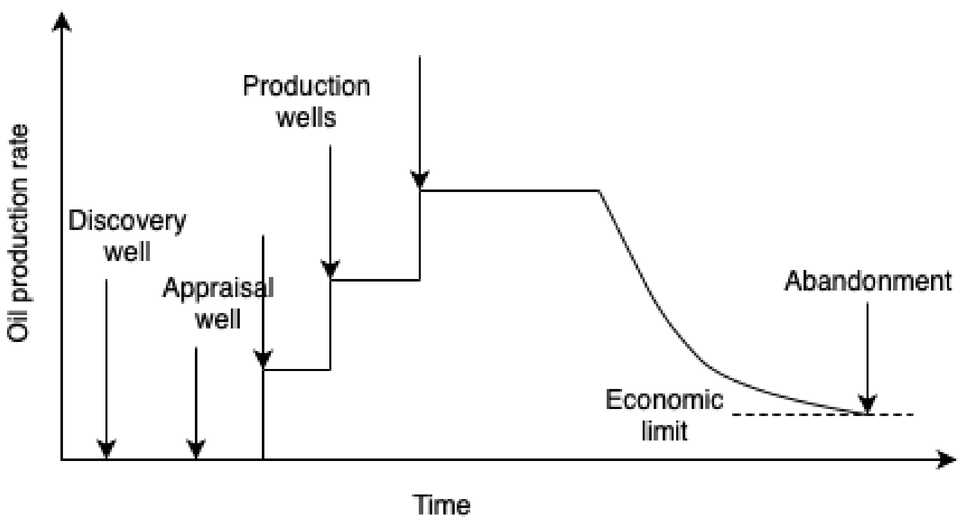

Figure 2.2: Simplified production life time of an oil field

One can also see from Figure 2.2 that after some time the production starts to decline down to the economic limit where it is no longer profitable to produce due to operational expenses exceeds income from production. At this point, plug and abandonment usually take place.

2.2 Plug & Abandonment Definition

In a perfect life, a well is drilled, then it produce, and then it is plugged and abandoned. However, this is not the case in reality. As illustrated in Figure 2.3, a well experience several phases like well intervention and drilling of sidetrack before it reaches the final phase of the life cycle, namely P&A.

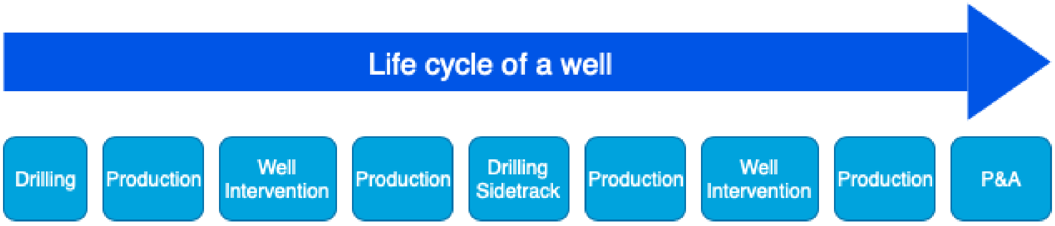

Figure 2.3: Life Cycle of a well

The reason for a well to enter its last phase of its life cycle can be many including integrity issues, subsidence induced well failure, or it is no longer economical sustainable meaning that the cost of extracting hydrocarbons exceeds income from selling these products. Plug and abandonment (P&A) can be defined as a collection of tasks taken in order to isolate and protect the environment and all fresh water zones and surroundings from a potential source of inflow (Khalife, 2020). This definition indicates that the main goal of P&A is to secure all formations that have the potential to leak, by installing well barriers. Figure 2.4 illustrates a production well both before and after P&A.

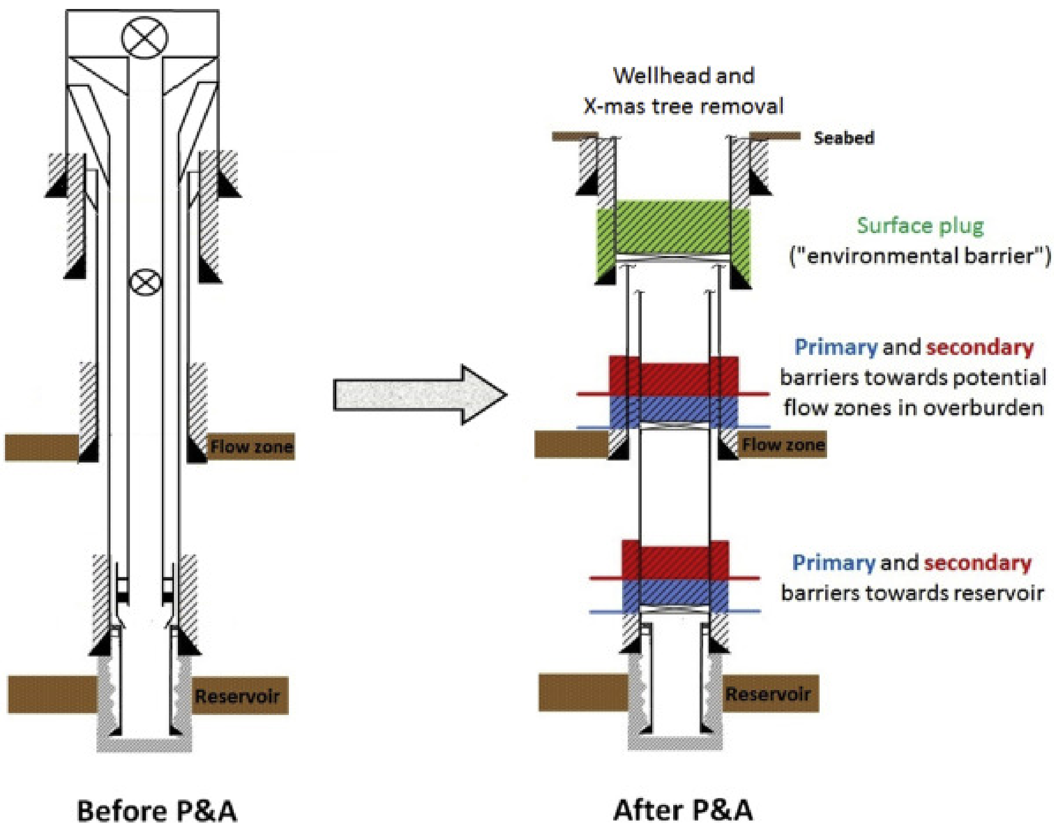

Figure 2.4: Production well - Before and after P&A (Vrålstad et al., 2019)

Plug and abandonment can in general be divided into two categories; Temporary abandonment and Permanent abandonment. Temporary abandonment is conducted when the operator wants to have the possibility to re-enter the well or permanent abandon the well at a later time. This type of abandonment is characterised by that the main reservoir has been isolated from the well, but one has the possibility to re-enter the reservoir with the same well. According to Standard (2013), a temporary abandoned well may include a monitoring system depending on the abandonment period. Permanent abandonment is carried out when the well is abandoned with an eternal perspective, meaning that the well will not ever be used again. To permanently abandon a well, one need permanent well barriers to isolate the source of inflow from the surface. According to Standard (2013), permanent well barriers shall extend across the full cross section of the well including all annuli, and seal both horizontally and vertically. It is also listed in Standard (2013) several properties that a permanent well barrier should have, which are given in Table 2.1.

Permanent Well Barrier Properties	**Comments**
Impermeable	Meaning no fluid shall pass through the barrier
Long term integrity	The barrier shall keep its integrity with an eternal perspective
Ductile	Meaning that the material used shall withstand some degree of bending and stretching
Resistant	The barrier shall not lose its integrity when in contact with chemicals/substances like H_2S, CO_2, Hydrocarbons and other that can be present
Wetting	Is the ability of liquids to form interfaces with solid surfaces, and in this context the material used shall bond to steel

Table 2.1: Properties of Permanent Well Barriers

NORSOK D-010 Well integrity in drilling and well operations (Standard, 2013), is a standard developed by the petroleum industry in Norway. This standard provide the minimum requirements for all well operations, including permanent plugging and abandonment, on the NCS. Other related standards for P&A is standards developed by American Petroleum Institute (API), International Organization for Standardization (ISO), and Oil & Gas UK (OGUK).

Plug and abandonment can be conducted from several types of installations and vessels depending on placement and type of well. According to Liversidge et al. (2006), offshore plug and abandonment can in general be divided into three categories;

- P&A from fixed platforms
- P&A from Diving Support Vessel (DSV) or a support vessel with dynamic positioning system (DPS)
- P&A from a floating installation like semi-submersible or jack-up rigs

The cost related to plug and abandonment depends on what type of installation/vessel is being used. However, P&A from fixed platforms is usually the most cost-beneficial method (Liversidge et al., 2006).

2.3 P&A Procedure

It is almost impossible to standardize P&A operations due to the fact that each well has its own unique characteristics. However, most wells need to go through certain steps during P&A including; killing the well, pull tubing and lower completion, plug reservoir by setting primary and secondary barriers, set surface plug, and remove upper part of conductor and wellhead (Henriksen, 2013). How these steps are performed will vary based on several factors like casing design, multiple reservoir, geology, and type of well, just to mention some.

Before killing the well, information about the well like well integrity, bottom hole pressures, quality of the cement etc, should be collected as this information could lead to better planning of the P&A operations (Henriksen, 2013). A drift run, performed by wireline or coiled tubing, are normally done to gather the necessary information. Killing the well is done by pumping heavy fluids, like Brine, into the wellbore until overbalance is achieved. Meaning that the formation fluids are forced back into the formation. After the well is killed, it is time to pull the tubing. Pulling the tubing is often a time consuming and challenging operation, including detach the tubing from the reservoir liner using a fishing tool called spear assembly. When the tubing is pulled up, some debris, scale and swarf may lie in the wellbore, and a cleanout run may be needed before setting the plugs (Mortensen, 2016).

When, or if, the quality of the cement outside the casing is verified to be good, a cement plug inside the casing can be set. If the quality of the cement outside the casing is not good enough, there will be a need for section milling or perforate, wash and cementing to establish a valid barrier. The primary and secondary plugs are then placed, normally on top of the reservoir. It is also required to have a permanent plug in the last open hole section of the well. This plug is called a surface plug. When the surface plug is placed, cutting knives or abrasive water jet technology are used to remove the upper part of the conductor and wellhead (Khalife, 2020).

A P&A operation can in general be divided into three phases (Khalife, 2020). In the first phase, Reservoir Abandonment, the activities presented in Table 2.2 are carried out normally with the use of wireline.

Activity	**Comments**
Well diagnostics	As well design forms the basis for planning a P&A job, original well design and current condition is important to know
Kill the well	In order to entering a live well, the well needs to be taken under control. This is usually done by bullheading brine into the well which force the production fluid back to the reservoir
Install deep set plug	A mechanical plug needs to be installed deep into the well to function as a temporary barrier against the reservoir
Punch and release ASV and displace well to Brine	Wells with gas lift have an Annular Safety Valve that needs to be released to be able to pull the tubing.
Cut tubing	The tubing is cut a few meters above the packer
Install shallow set plug	A plug is installed below the Down Hole Safety Valve (DHSV) in order to have two barriers towards the reservoir

Table 2.2: Activities in phase 1 of P&A

When these activities are completed by the intervention crew, the well is handed over to drilling to complete phase 2: Intermediate Abandonment. Some of the activities conducted by the drill crew in phase 2 of P&A, are presented in Table 2.3 and 2.4.

Activity	Comments
Nipple down XMT and prepare WH	In order to get access to the well with drill pipe, the X-mas three (XMT) need to be removed. When the XMT is removed, one has access to the well head (WH) which then can be prepared for the riser
Nipple up BOP and Riser, and test BOP	When the WH is ready, the riser can be place on top of the WH and connected by the use of a clamp. After the riser is connected to the WH, the Blow Out Preventer (BOP) can be placed on top of the riser. When everything is in place and tightened, the BOP can be tested to make sure that it works before removing the shallow plug
Pull shallow plug	When the BOP is tested and ready, a retrieving tool can be run down to the shallow plug in order to retrieve it
Pull upper completion string	The upper completion is pulled from PBR (tubing cut) with a tubing hanger retriever tool
Clean out run in production casing	A clean out run might be necessary in order to remove debris so that better results from the log can be obtained
Log the production casing	Wireline is rigged up and a log run is performed in order to verify the cement behind the casing
Set mechanical plug	A mechanical plug is run down to the setting area and is placed by use of rotation and pressure. This plug works as a base for the cement plug
Place cement plug	This is normally done in the same run as placing the mechanical plug, and is done by pumping cement down the string
Remove tubing head	This is done in order to pull the production casing. However, a shallow barrier plug need to be placed before removal of the tubing head. This plug is pulled when the tubing head is removed
Cut and pull production casing	A BHA with a cutting tool and a spear is run down to the desired depth where the casing is cut by knives. After the cut is made, the spear latches on with cutting tool and a spear

Table 2.3: Activities in phase 2 of P&A

Clean out run in the intermediate casing	When the intermediate casing is cut and pulled, some swarf and debris can be found in the well and a clean out run might be required
Log the intermediate casing	Wireline is rigged up once again, and a log run is performed
Set mechanic plug	When log run is completed and results are analysed to good, the mechanical plug can be run down and placed
Place cement plug in intermediate	Cement is pumped down the string to the mechanical plug. When the cement plug is placed, the string can be pulled out of the well
Cut and pull intermediate casing	The intermediate casing is pulled in order to place surface plug
Clean up run in the surface casing	A clean up run might be needed to make sure good results from the log can be obtained
Log Surface casing	The surface casing is logged to make sure that the cement behind is of good quality so that when setting the surface plug, its seals both horizontally and vertically
Set surface plug	If the log shows good results, the surface plug can be placed

Table 2.4: Cont. Activities in phase 2 of P&A

The last phase of P&A, phase 3: wellhead and conductor removal, is usually regarded as a marine operation and not as a drilling operation (Khalife, 2020). In this phase the wellhead and conductor are cut and retrieved in order to not be in conflict with fishing activities or other marine activities.

2.4 Current and Future P&A Technology

Due to very few wells have been P&Aed since the start of production on the NCS, the need for developing new technology that will increase efficiency and thus decrease the related costs has not been present until recent years. However, there has been a lot of research going on over the last years to explore new technologies that will improve P&A operations when it comes to time, costs, resources, and safety. At the P&A seminar that where held October 18th 2018 by Norsk Olje & Gass, a roadmap for new P&A technologies, given in Figure 2.5, was presented.

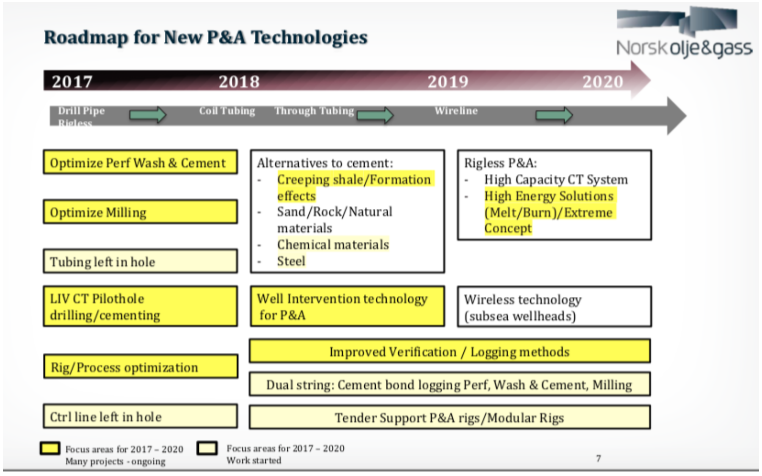

Figure 2.5: Roadmap for New P&A Technologies.

In this section, some of these technologies as well as current technologies used is discussed.

2.4.1 Cut and Remove Casing

When Permanently plugging and abandon a well, a rock to rock barrier is required. In some cases the annular barrier behind casing is not good enough or completely absent. This is the reason for the rock to rock requirement. There exists several solutions in the petroleum industry today to handle this operation like cut-and-pull, casing milling and section milling. There are also some new solutions like perforate-wash-cement (PWC), upward section milling, melting downhole completion, and plasma-based milling (Khalife, 2020). Some of these has been taken in use, and some are under development.

In cases where the length of uncemented casing is long, a cut-and-pull operation is probably the necessary action. With this operation, a cut is made in the casing and then a spear latch on to the inside of the casing before the "fish" can be pulled out. This method is preferably done in one singe trip, but several cases like scale deposits or collapsed formation can lead to several cut-and-pull trips due to limitation on pulling capacity.

Other methods used is casing milling or section milling, depending on the length of the interval that needs to be removed. In section milling a window is milled out in order to remove a section of casing and cement. After this is done, the window needs to be under-reamed to get access to new formation before the cement plug can be placed. Section milling is a time consuming operation due to low rate of penetration (ROP) and the need to change the mill as it get frequently worn from milling the casing which results in more trips in and out. The time consumption of section milling has led to new technologies and solutions that will increase the efficiency of the operation and thus reduce the time. One of these new technologies are PWC.

The Perforiate, Wash and Cement technique makes it possible to place effective barriers, both in the annular and wellbore section, without removing any casing, in one single trip (Delabroy et al., 2017). This makes the PWC technique a more efficient method for cross-sectional barrier placement compared to section milling. The PWC technique starts with run in hole (RIH) with the PWC tool down to the barrier dept where the cement is absent or of poor quality. The casing is then perforated, and a mechanism let the perforating gun drop down into the well (Khalife, 2020). When this is done, the next step of the operation is to place the Bottom Hole Assembly (BHA) at the bottom perforations and cement will be pumped down the string. After a certain volume of cement is pumped, the work string is slowly pulled out of hole (POOH) while cement is pumped down until the BHA reaches the top of the perforated interval. Then the BHA is pulled at least two stands (Khalife, 2020) above the top of cement, before the wellbore is circulated clean. There is no questions that the PWC technique has its advantages, but it also has some limitations. According to Khalife (2020), the most challenging limitation is the lack of qualification methods. with current technology the cement inside the casing must be drilled out to be able to log the cement placed behind the casing to qualify the cement job. This is not really a challenge, but it is time consuming. The real challenge is that holes created during perforating makes the logging data less reliable (Khalife, 2020).

2.4.2 Cut and Remove Wellhead

One of the last operations during P&A is to cut and remove the wellhead, which can be a costly and complex operation (Khalife, 2020). There exists several different method for this operation including explosive cutting, laser cutting, abrasive- and mechanical methods.

The explosive cutting technology uses shaped charged cutters to make slot type cuts (De Frank et al., 1966). This system consists of a command unit, detonator, and charge where the command unit sends a signal to the detonator which initiates the charge (Khalife, 2020). The advantage of using explosive cutting technology to cut the wellhead is that it is easy to install and handle, it has no limitation in size of cut, and it is a fast method. However, Khalife (2020) also mentions some possible limitations like no control on cutting stages, restrictions from regulatory authorities on wellhead cutting, and some safety issues.

When it comes to mechanical cutting methods they can be divided into categories like diamond wire cutting system, milling cutter, sawing, and grinding. The diamond wire cutting system uses several remotely operated machines to create an external cut. This system consists of several subsystems, and since it is a mechanical operation there is no limitation on water depth. Other advantages is that one has full control on the cutting operation, there is no limitation in size of cut, and it has a fast cutting performance (Khalife, 2020). However, one of the main limitations is that only external cuts can be performed with this method, and the cut has to be made above the seabed which is not optimal.

2.5 How to make good decisions

Decision making is something everyone is facing on a daily basis, and can range from minor decisions that can have a small impact, to big decisions that can have a huge impact. The decision regarding when to PP&A a field is a big decision that can have a significant economically impact for the operator. It is therefore important to maximizing the probability of a good outcome by making good decisions. In this section there will be discussed how to make good decisions with reference to Bratvold and Begg (2010).

2.5.1 Decision Elements

There are several elements that create the basis for the decision which are important to identify in order to evaluate the decision situation. One of these elements is the alternatives that the decision maker is facing. There has to be more than one alternative to choose between for it to be a decision, and the alternatives can range from simple to more complex depending on the situation. Another element is the objectives which describes the preferred direction of the company, organization or individual. Without objectives it is impossible to choose the best suited alternative. Information and uncertain events related to the alternatives is also an important element to identify. Information can come from quantitative data or be of more qualitative or descriptive nature, and will have an impact on the decision situation. Uncertain events are specific events where the outcome of the event are unknown at the time where the decision is made (Bratvold and Begg, 2010). Knowledge/information about uncertain events can be quantified by using probability. To be able to do so, all possible outcomes must be identified.

Objectives, alternatives, and information are elements that creates the basis for the decision. A decision can in general be defined as a conscious, irrevocable allocation of resources to achieve desired objectives (Bratvold and Begg, 2010), where a good decision is an course of action that is logically consistent with the objectives, alternatives, and information available. The aforementioned elements contribute to the predicted payoffs. A payoff is the result with respect to an objective after the decision is made and all outcomes of uncertain events are resolved (Bratvold and Begg, 2010). In most cases payoffs have to be forecasted in terms of expected value due to uncertainty.

2.5.2 The three main phases of Decision-Making

To be able to handle more complex decisions, there are three phases that should be carried out in order to make good decisions. The first phase is about structuring the decision situation to be able to identify and structure the relationship between the main elements (Bratvold and Begg, 2010). This phase is crucial as successive phases depends on what is stated/collected in it. In this phase, decision context is defined, objectives are stated, and alternatives are generated. There are several tools like decision hierarchies, brain-storming, decision trees, influence diagrams, and SWOT analysis, that can be very helpful when structuring the decision situation. The next phase is about modelling and evaluating, where the goal is to reach a preliminary decision based on the alternatives identified, the objectives, and the relative importance of those objectives (Bratvold and Begg, 2010). In this phase, the payoffs of each alternative is assessed, the relative priority of the objectives is determined, and the performance is combined with each objective to get an overall score for each alternative. In the third, and last, phase; assessing and deciding, tradeoffs between competing objectives are assessed, and sensitivity analysis is performed to see how sensitive the decision is to changes in variables and parameters.

Chapter 3

Development of a P&A Decision Framework

The decision of interest in this thesis is when to plug and abandon an offshore oil and gas producing field. To make such a decision there are, as mentioned in section 2.5.1, several elements that need to be considered in order to establish the decision context. In this chapter, a P&A decision framework is developed based on the methodology presented in section 2.5.2. This decision framework will act as a foundation for the modeling part later in this thesis.

3.1 Objectives

The first element that must be in place is the operators objectives, that provides the basis for all decisions made by the company. Major oil and gas operating companies usually have multiple objectives that supports their vision. These objectives can typically be; maximize resource allocation, minimize environmental impact, develop innovative technologies, and attract, develop and hold on to the best talents. However, there is one objective that is standing out which is maximizing shareholders value. This is specially true for major oil and gas operating companies that are traded on a stock exchange. One contribution that can maximize shareholders value is to maximize the Net Present Value (NPV) of the company's assets. Thus, the objective of this decision context will be to maximize the NPV of the cash flows generated in the late life of the asset. Other possible objectives are excluded.

3.2 Alternatives

Now that the objective is stated, it is time for the second element needed, which is defining the alternatives, or paths, the company can choose between. Operating companies has multiple alternatives for what they can do with an late life oil and gas producing asset. They can for instance sell the asset to another company, they can do an increase oil recovery project (IOR Project) to boost the production, or they can start with P&A operations right a way. Another alternative is to postpone the P&A work, and continue production in hope for higher oil price and/or more efficient P&A technologies that will result in a higher NPV. Figure 3.1 is a decision tree illustrating the alternatives the decision makers are facing in a holistic manner.

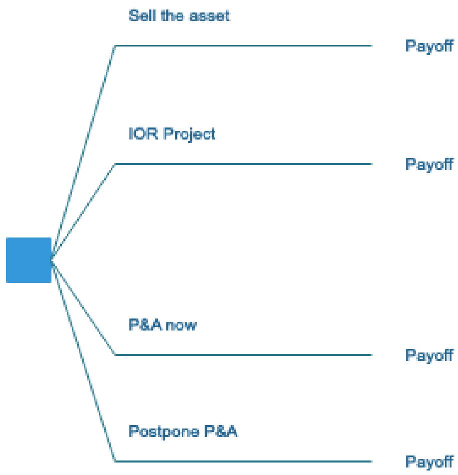

Figure 3.1: Decision tree.

Including all these alternatives is outside the scope of this thesis, so the alternatives of interest is to P&A right a way, or postpone. Meaning that the other alternatives are excluded in this work. The updated decision tree, is presented in Figure 3.2.

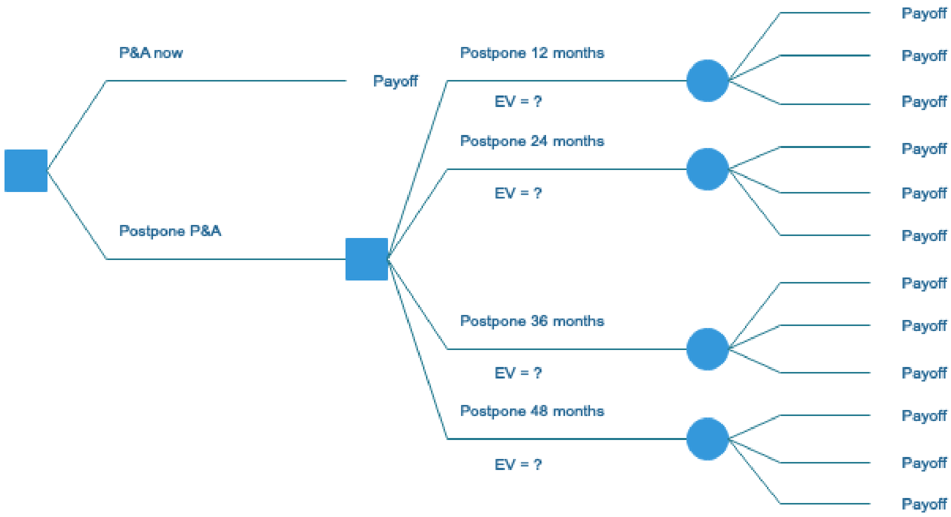

Figure 3.2: Decision tree including alternatives inside the scope of this thesis.

The alternatives in this decision context is framed in a way that let the decision maker(s) decide between four waiting strategies if it is decided to postpone P&A for some time after the first negative cash flow is seen. All these alternatives include a degree of uncertainty when it comes to the payoff. The payoff in this context is the NPV, as maximizing NPV is the objective. Future cash flows include uncertainty which make the NPV of the alternatives also uncertain. This uncertainty is illustrated as "chance nodes" in Figure 3.2. Due to the uncertainty, the expected NPV should be analysed. In order to do so, information about elements that are affecting the cash flows, as well as how they affect, needs to be collected.

3.3 Decision Influence Factors

Relevant information about each alternative need to be collected and analysed in order to see which alternative scores highest based on the objective. The outcome of these alternatives will depend on several variables like production rate, oil price, operational expenses, and P&A related costs. In this subsection, these factors will be discussed.

3.3.1 Decline Rates of Oil Production

Production rate depends on reservoir depletion, external fluid injection, and several other factors. However, as illustrated in Figure 2.2, the production will eventually starts to decline down to the economic limit where it is no longer profitable to produce due to operational expenses exceeds income from production. The rate of declination, or the decline rate, is equal to the difference in production rate from one period to the next, and is usually expressed in monthly or annually numbers. The decline rate will be affected by both physical factors like decreased reservoir pressure and increased water cut, and by non-physical factors like politics, damage, or production quotas (Höök et al., 2014). Mathematically, it can be expressed as;

$$\lambda = Cq^{\beta} \tag{3.1}$$

Where:
λ = The decline rate
C = A constant
q = Current production rate
β = The exponent

The decline rate can be constant ($\beta = 0$), directly proportional with the production rate ($\beta = 1$), or proportional to a fractional power of the production rate ($0 < \beta < 1$). A hyperbolic decline curve, where ($0 < \beta < 1$), is the general case and the production rate at time t can then be expressed as;

$$q(t) = q_0[1 + \lambda_0\beta(t - t_0)]^{-1/\beta} \tag{3.2}$$

For its simplicity, the exponential decline rate ($\beta = 0$), can be used which mathematically can be expressed as;

$$q(t) = q_0 \exp -\lambda(t - t_0) \tag{3.3}$$

This exponential decline rate describes the physical flow equation for a homogeneous field with a given initial drive pressure that will decrease over time as oil and gas is extracted. Initial decline in production is often exponential, but tends to move towards a hyperbolic decline later on (Höök et al., 2014).

3.3.2 Oil Price Behaviour

Oil has been, and still is, a high-demand global commodity where major fluctuations in the oil price can in general have a significant impact on the macroeconomics all over the world. Historical oil price data has been collected and plotted in Figure 3.3 in order to illustrate how the oil price has been fluctuating over time.

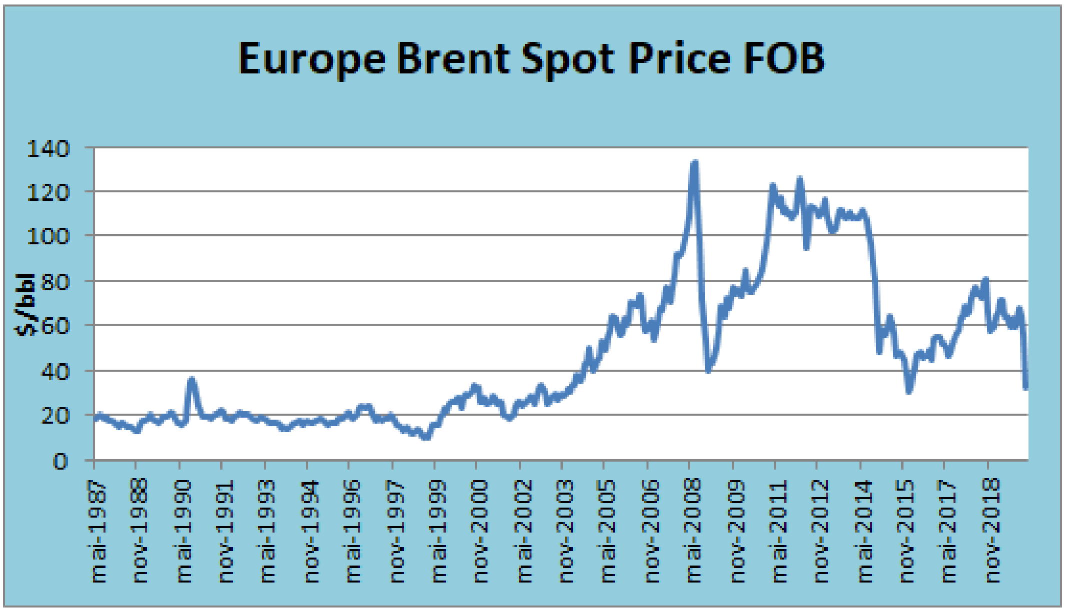

Figure 3.3: Historical Oil Price (EIA, 2020).

There are several reasons for these fluctuations including supply and demand situations, market sentiment, and abnormal events such as war, conflicts and pandemics. This fluctuation in the oil price creates uncertainties related to when an oil field reach the economic limit, and also cost related aspects such as daily rates for rigs and equipment used offshore.

Due to the impact that the oil price have on when an oil field reach its economic limit, it is important to embrace the oil price uncertainty. There exists several stochastic oil price models like Geometric Brownian Motion, Mean Reversion, and Mean Reversion with Jumps that can be used to model how the oil price fluctuates over time in a random fashion (Al-Harthy, 2007). In this section a short description of these models will be given.

Geometric Brownian Motion (GBM)

The GBM model has been used in several studies (Al-Harthy (2007), Postali and Picchetti (2006), Meade (2010)) to forecast the oil price. Due to simplicity, the GBM model is common to use in real options applications. It is a stochastic process that mathematically can be expressed by the equation;

$$dP = \alpha P dt + \sigma P dz \tag{3.4}$$

Where:
dP=change in price

α=the drift
P=current price
dt=change in time
σ=volatility
dz=$\epsilon\sqrt{dt}$, Where ϵ=Wiener process that is normally distributed with mean=0 and standard deviations=1, N(0,1)

If $\alpha > 0$, the drift of the oil price is positive, and negative if $\alpha < 0$. σ represents the variance of the lognormal price distribution that will increase over time due to more uncertainty in the oil price as time evolves.

There are two parameters that need to be estimated to run the GBM model, namely the drift and the volatility. According to Dixit et al. (1994), the volatility can range from 15-25% per year.

Mean Reversion (MR)

The MR model can mathematically be expressed as;

$$dP = \eta P(\overline{P} - P)dt + \sigma P dz \tag{3.5}$$

Where:
η=the number of years for price to revert to the long-term equilibrium
$\overline{P}$=the long term oil price equilibrium
The rest of the parameters are the same as in equation 3.1

This model shows that if the current oil price is lower, or higher, than the long term equilibrium, the price will be drawn to the long term equilibrium. This means that the model argues that the oil price will always revert to the long term equilibrium, which make sense when thinking of basic supply and demand theory. If the oil price goes up, operators will produce more, which again will lower the oil price. The reversion speed (η), the volatility (σ), and the long term equilibrium price ($\overline{P}$) needs to be estimated to use this model.

Mean Reversion with Jumps

Abnormal events such as war and conflicts tends to have a significant effect on the oil price. Dias and Rocha (1999) suggested a model that included the uncertainty of such events, namely mean reversion with jumps. This model is very similar to the mean reversion model, but it adds the effect of abnormal events like war. The model can mathematically be expressed as:

$$dP = \eta P(\overline{P} - P)dt + \sigma P dz + P dq \tag{3.6}$$

Where dq is the jump factor, consisting of frequency, size, and the direction, which is modelled as discrete Poisson process.

3.3.3 Operational Expenses

The main operating costs on the NCS are related to maintenance of platforms and wells, and the daily operation of the installation which include labour costs for involved personnel. This can further be broken down into cost categories such as ordinary operating costs, maintenance, well maintenance, modifications, other operational support, logistics costs, and other operating costs. Figure 3.4 is taken from NorskPetroleum (2020), and illustrates historical yearly operating costs as well as a forecast for the next five years on the NCS.

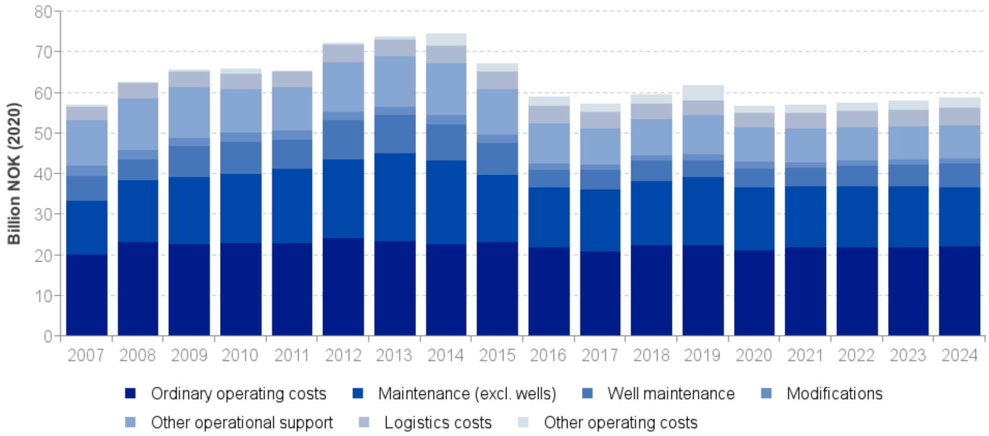

Figure 3.4: Total operating costs by main category on the NCS (NorskPetroleum, 2020)

The total operating cost on the Norwegian Continental Shelf reached a peak in 2014 after several years of very high activity level on the shelf. However, after 2014 the trend reversed, and the costs went down to a more sustainable level. It is expected that the operating costs will be reduced, but due to more and more fields are coming upstream, the total cost for the hole NCS will remain at the current level (NorskPetroleum, 2020).

The yearly operating cost per installation is dependent on the activity level that year, and will therefore change with a change in activity level. To illustrate the fluctuation in operation expenses per year for an oil and gas producing asset, some production data for the fixed installation Grane and the semi submersible installation Visund was obtained from Rystad Energy (RystadEnergy, 2020). These data sets is plotted in Figure 3.5 and 3.6.

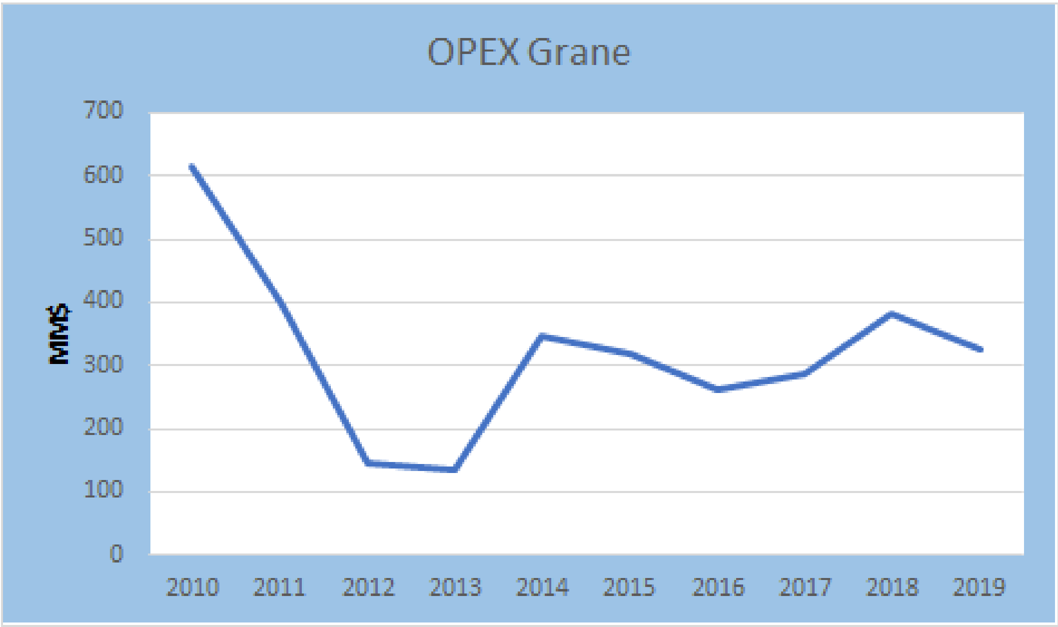

Figure 3.5: OPEX for the Grane Installation

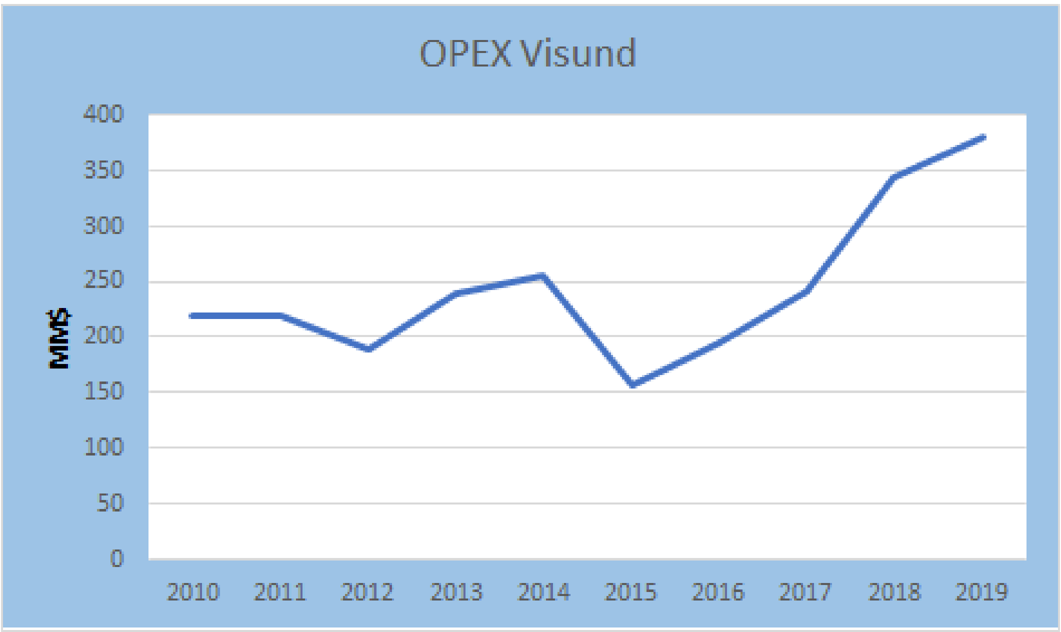

Figure 3.6: OPEX for the Visund Installation

From these two figures, one can easily see that the OPEX change from year to year, and also from installation to installation. There are several factors that is going to affect the operational expenses. However, according to Oil&GasAuthority (2018), the main operational cost drivers are facility type, region, and field age.

3.3.4 Time and Cost Estimation of P&A

There are several factors that will have an impact on time and cost related to P&A operations. Khalife (2020) lists the following factors; well characteristics and complexity, site characteristics, working unit, operator philosophy, regulations, exogenous events, dependent variables, and unobservable variables. There will not be given a description of these factors, as the time and cost estimation in this thesis will be based on historic data from several P&A jobs done on the NCS. However, there will be given short introduction to probabilistic method for time estimation that will be used when modelling.

Time Estimation - a probabilistic approach

A probabilistic approach means that one consider the present uncertainty in the given situation, also called stochastic modelling. The opposite of a stochastic model, is a deterministic model which predict outcomes in the form of just a fixed number meaning the deterministic models describes the inputs and outputs exactly with a set of equations. Stochastic models however, will produce different results every time since it is considering the uncertainty related to the input data. The use of a probabilistic approach makes it possible to include uncertainty and unexpected events in the model, and to perform sensitivity analysis.

Stochastic modelling will make it possible to assign a probability density function (pdf) for each phase in P&A. These probability density functions will describe the behaviour of each phase as a random variable, where different probabilities can be assigned to different time intervals.

Chapter 4

Development of a P&A Decision Support Model

Net Present Value (NPV) can be defined as the present value of future cash flows, and is often used in decision making processes. Mathematically it can be expressed as;

$$NPV = \sum_{i=1}^{n} R_t/(1+i)^t \tag{4.1}$$

Where;
R_t = Net cash flow (income-expenses) during a single period t
i = The discount rate
t = Number of time periods

In order to find the optimal time to plug and abandon a field, a NPV model is needed. Due to fluctuations in the oil price, fields can experience positive cash flows after the first negative cash flow is seen, and thus it is interesting to investigate how this will have an impact on the NPV. It is not only the oil price that will affect the NPV. The production rate, operational expenses, cost of P&A, and the discount rate will also have an impact on the NPV. Thus, developing models that includes the uncertainty in these factors can be very beneficial. In this chapter, models developed are presented.

4.1 Production Rate Model

It was decided to use a exponential decline rate model to describe the future production behavior because of its simplicity and since reservoir analysis is outside the scope of this thesis. This means that only two parameters need to be established, namely the initial production rate and the decline rate. The initial production rate is given by the sum of production per well in the given field, where the initial production rate per well was selected to be a random number between 1000-2000 bbl/day. The decline rate chosen is based on the work done by Höök and Aleklett (2008), and is set to 14% annually. As the model is run on a monthly scale, these parameters had to be converted to fit the model. The initial production rate is found by the following equation;

$$q_0 = w \sum_{i=1}^{n} x_i \tag{4.2}$$

Where;
q_0 = Total initial production rate per month
x_i = Represents the initial production rate per day for well i, and is given by the excel function: RANDBETWEEN(1000;2000)
w = Number of days of production per month

In order to see how the production rate is changing over time,

$$q(t) = q(t-1)e^{-(\sqrt[12]{1+\lambda}-1)} \tag{4.3}$$

Where;
q(t) = Production rate at time t
λ = Yearly decline rate

From these two equation, the following figure, Figure 4.1, that illustrates the production rate behavior for a field with 20 production wells, can be generated.

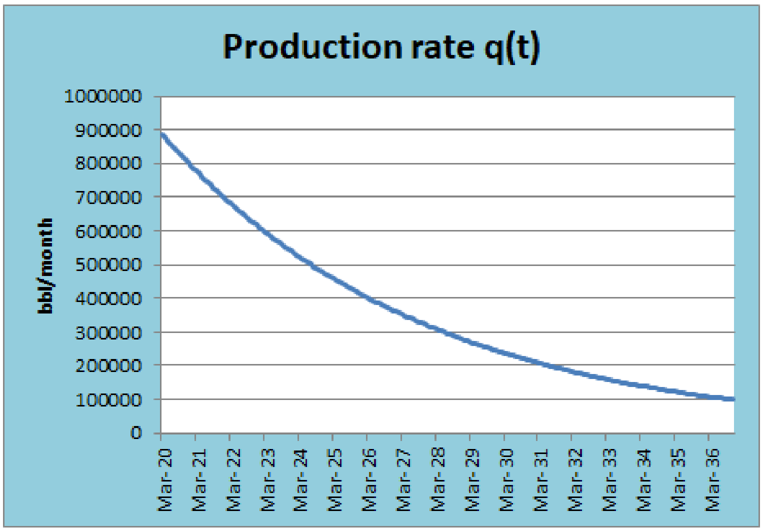

Figure 4.1: One iteration from the production rate model.

4.2 Oil Price Model

For the purpose of this thesis, a Mean Reverting model is used to demonstrate the fluctuation in the oil price. As stated in section 3.2.3, there are some parameters including the mean reversion rate, the volatility, and the long term equilibrium price, that needs to be estimated. In this thesis historical, monthly spot prices collected from (EIA, 2020) is used to estimated the aforementioned parameters. According to Begg et al. (2007), the first step of analysing the historical prices is to look at the distribution of the yearly changes given in the natural logarithm of prices. However, in this thesis, the monthly changes from 1987-2020 is used, and presented in Figure 4.2.

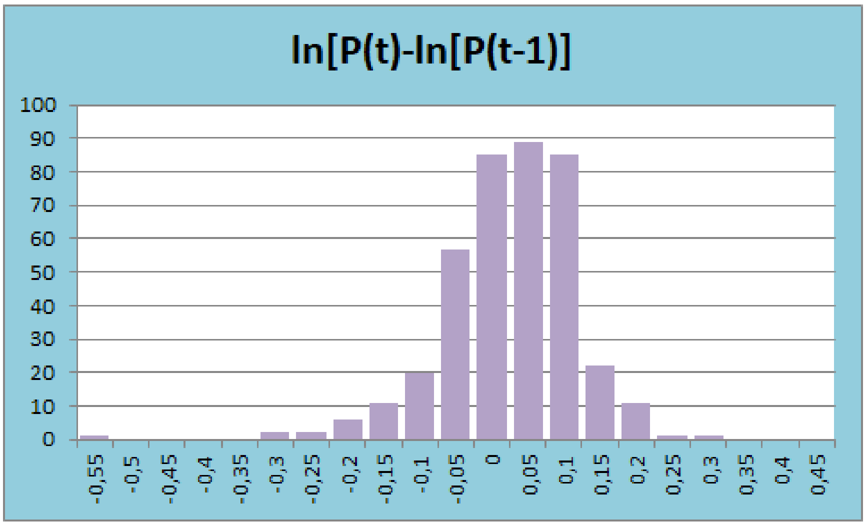

Figure 4.2: Histogram of monthly logarithm of price changes.

The parameters needed for the MR process was estimated based on results from a linear regression of ln[P(t)]-ln[P(t-1)] against ln[P(t-1)]. These results are given in Table 4.1, where all values are presented in natural logarithm.

Parameter	**Result**
Mean reversion rate (η)	0.00977
The volatility (σ)	0.09313
Long term equilibrium price ($\overline{P}$)	3.73735

Table 4.1: Estimated parameters for the mean reverting oil price model.

The oil price is then forecasted by the use of the following equation;

$$ln[P(t)] = ln[P(t-1)]e^{-\eta} + ln(\overline{P})(1 - e^{-\eta}) + \sigma\sqrt{\frac{1 - e^{-2\eta}}{2\eta}}\omega_t \tag{4.4}$$

Where;
ln[P(t)] = The logarithmic oil price at time t
η = Mean reversion rate
σ = The volatility
$ln(\overline{P})$ = The logarithmic long term equilibrium price
ω_t = Standard normal distribution function given by the excel function: NORM.S.INV(RAND())

The exponential of the results from equation 4.4 is then calculated to get the price in $ per barrel, by using the following equation;

$$P(t) = e^{ln[P(t)]} \tag{4.5}$$

These equations is then used to forecast the oil price. The oil price model can be visually presented like in Figure 4.3. Here, one iteration of the model is presented including P10 and P90 values, all given in $/bbl. The initial price is set to 32 $/bbl as this is the latest data point in the data set collected from EIA (2020).

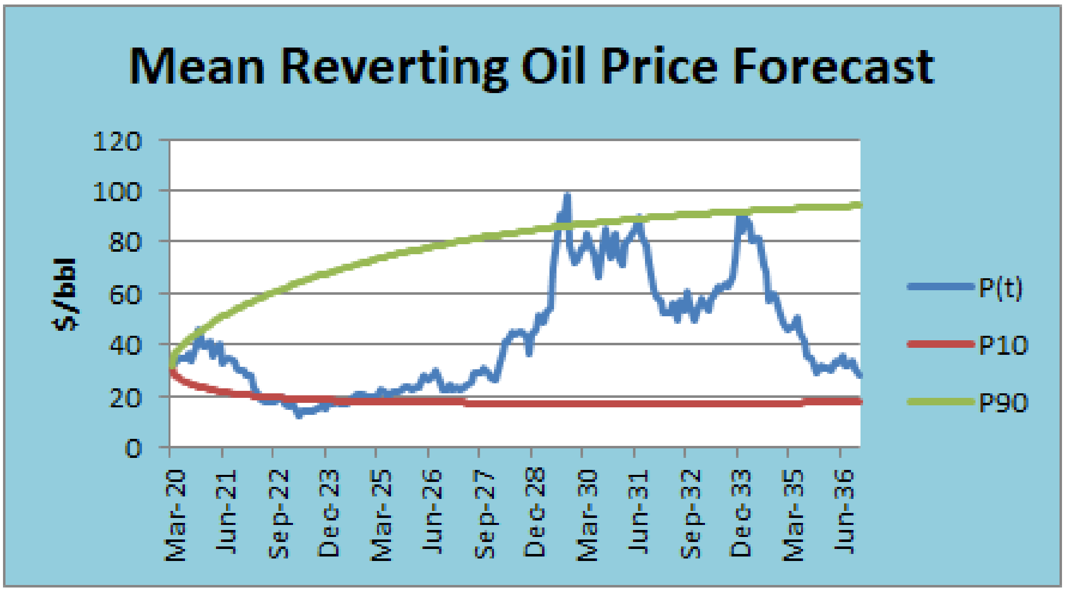

Figure 4.3: Illustration of one iteration of the oil price model

4.3 OPEX Model

The OPEX model consists of both fixed (per year) and variable (per barrel) expenses. This means that this model is dependent on the production rate model, and both of the aforementioned parameters need to be selected. The operational expenses per month at time t is calculated by the following equation;

$$E(t) = \frac{E_{fixed}}{12} + E_{variable} q(t) \tag{4.6}$$

Where;
E(t) = The monthly OPEX at time t
E_{fixed} = Fixed OPEX per year
$E_{variable}$ = Variable OPEX per barrel
q(t) = Production rate at time t

Figure 4.4 illustrates how the operational expenses are decreasing over time as the production rate is decreasing. In this example the fixed OPEX was set to \$200 000 000/year and the variable OPEX was set to \$6/bbl.

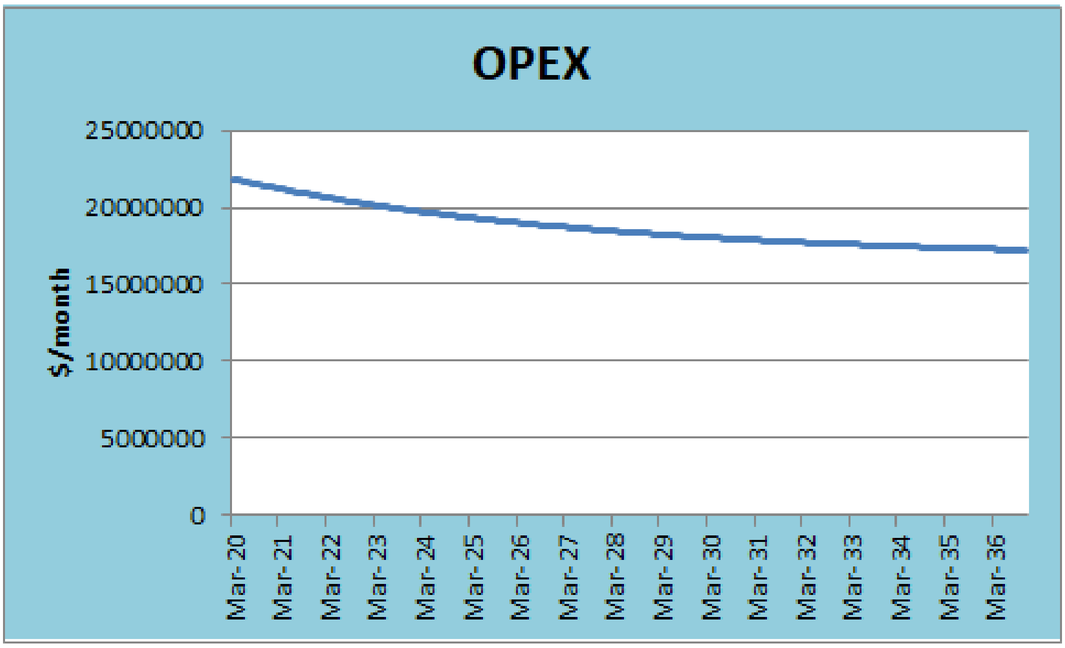

Figure 4.4: Operational Expenses

4.4 P&A Cost Model

The P&A cost model assumes that the total cost of permanently plug a well equals to the time it takes to plug it multiplied by the daily rig rate, as it is believed that the rig rate dominates other cost aspects. In order to estimate the P&A cost, the initial plan was to gather data from previous P&A jobs done on the NCS in order to analyse these data and set up time distributions for each of the three phases described in section 2.3. However, as I was not able to obtain the data needed, min and max values for the different phases collected from Aarlott (2016) was used. The P&A time per well is then obtained by adding the random value between the min and max values for each phase;

$$t_i = t_{phase1} + t_{phase2} + t_{phase3} \tag{4.7}$$

Where;
t_i = Time it takes to plug well i
t_{phase1} = time to complete phase 1 given by the excel function:
RANDBETWEEN(MIN;MAX)
t_{phase2} = time to complete phase 2 given by the excel function:
RANDBETWEEN(MIN;MAX)
t_{phase3} = time to complete phase 3 given by the excel function:
RANDBETWEEN(MIN;MAX)

Then the cost per well is calculated by;

$$c_i = t_i R \tag{4.8}$$

Where;
c_i = Cost to plug well i
R = Rig rate

Then the total time and total cost for n wells can be calculated by;

$$T_{P\&A} = \sum_{i=1}^{n} t_i \tag{4.9}$$

Where;
$T_{P\&A}$ = Total time to plug n wells.

and

$$C_{P\&A} = \sum_{i=1}^{n} c_i \tag{4.10}$$

Where;
$C_{P\&A}$ = Total cost of plugging n wells.

In order to convert the P&A cost to monthly cash flows, the following excel function is used;

$$C_t = IF(T_{P\&A} \geq 30t; 30R; C_{P\&A} - (t-1)30R) \tag{4.11}$$

This equation gives the cash flows per month generated from the cost of P&A.

4.5 NPV Model

The objective of the NPV model is to give information to the decision maker regarding when permanent plugging and abandonment should be carried out in order to maximize the net present value of the cash flows generated in late life oil fields offshore on the Norwegian Continental Shelf. This model uses data generated from the other developed models, and put them together in order to calculate the net cash flow at each month. Figure 4.5, show one iteration of the model including the income from production, operating expenses, the net cash flow and the present value of the net cash flow.

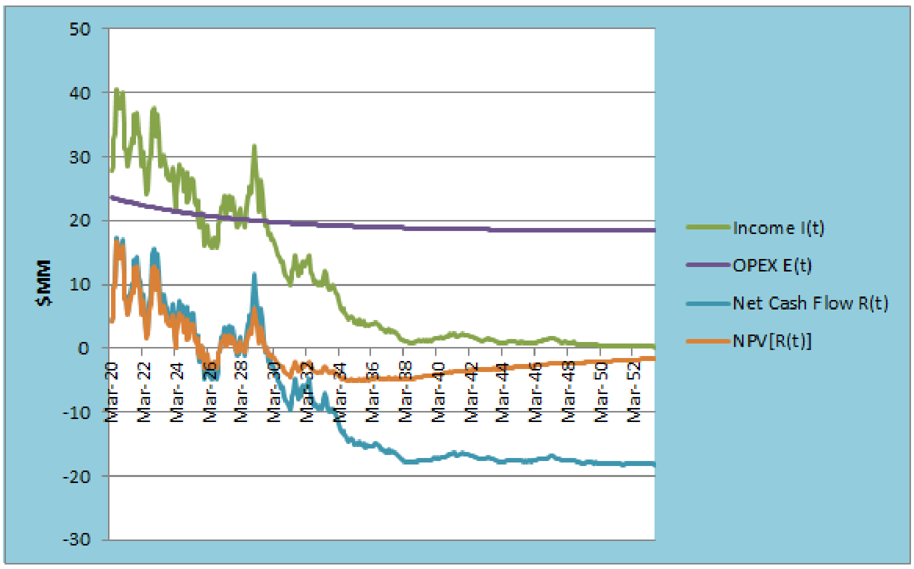

Figure 4.5: Income, OPEX, NCF, and Present value of the NCF

From Figure 4.5 one can see that after the first negative cash flow is seen, several positive cash flows follows later on. But the interesting point is to see if these positive cash flows will overcome the effect of several months of negative cash flows. This is illustrated in Figure 4.6.

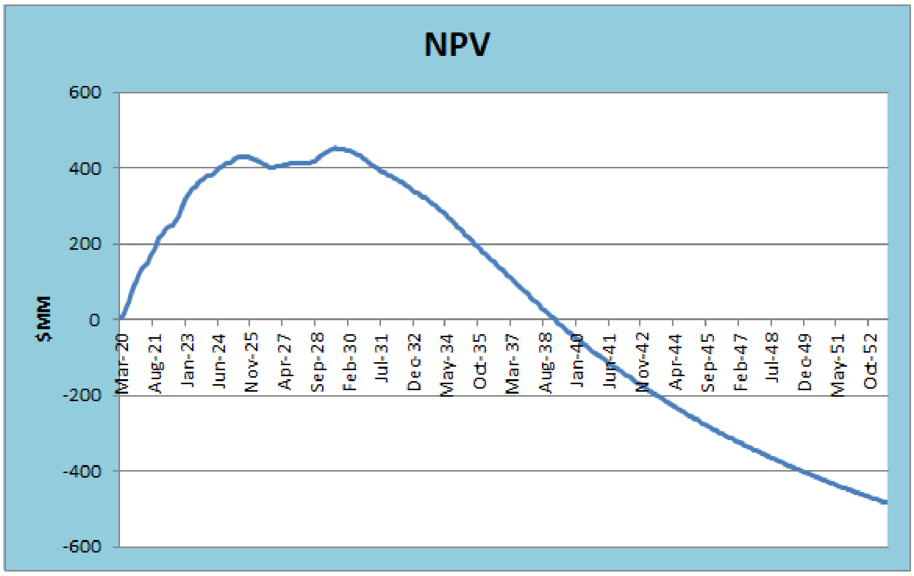

Figure 4.6: Accumulated NPV as a function of time

This figure shows the accumulated NPV of the cash flows. As one can see from Figure 4.6, the Accumulated NPV reaches the peak approximately around year 2030 in this case, and indicates that this is the time that this field should be P&Aed. However, the cost of P&A is not included in this figure. The next figure, Figure 4.7, illustrates the NPV including the cost of P&A.

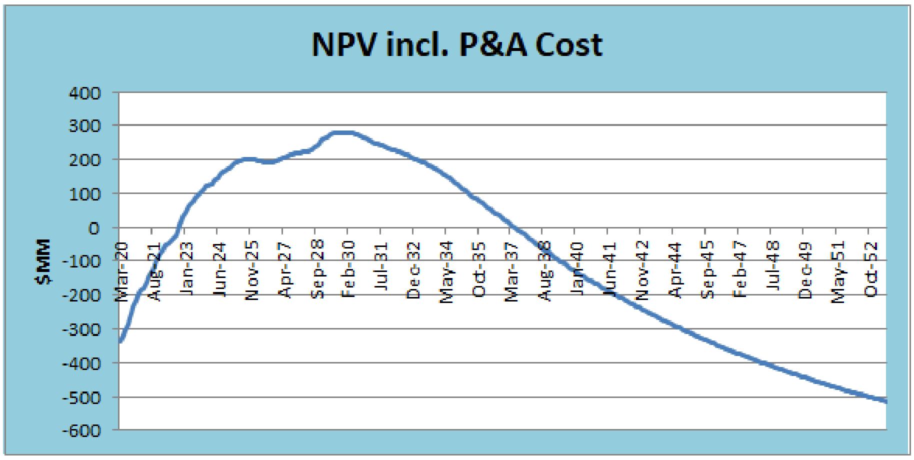

Figure 4.7: Accumulated NPV, including cost of P&A, as a function of time

The NPV, including the cost of P&A, follows almost exactly the same trend as the NPV without the P&A cost. However, by comparing Figure 4.6 and Figure 4.7, one can clearly see the effect of the discounted P&A cost as time increase.

The model find the first negative cash flow and return which month it appears and the accumulated NPV of the cash flows up to that point in time. These data points give information about the alternative to plug and abandon right after the first negative cash flow is seen. Several waiting strategies is then defined to see how the NPV will be affected by postponing. Just to illustrate the logic of the model, an example with a waiting strategy of 12 months is presented;
The first negative cash flow is seen at time t. The model takes then out the NPV at time t. Then it takes the NPV at time t+12 and subtract this value with the NPV at time t. This difference in NPV is the value of interest and Monte Carlo simulation with 10 000 iteration is then performed to get some statistics related to this value. In Table 4.2, the statistical values generated from the simulation results, used when presenting and discussing the results, are explained.

Terminology used	**Comments**
P90 (NPV)	Based on the simulation results, the probability of the true value is under P90 (NPV) equals to 90%
E(NPV)	This is the expected Net Present Value based on the results obtained from the simulations
P10 (NPV)	The probability that the true value is under this value is 10%
P(NPV<0)	This value indicates the probability of ending up with a negative Net Present Value

Table 4.2: Description of statistical values from simulation results

4.6 Dynamics of the Simulation Model

Figure 4.8 is a simplified illustration of how the Monte Carlo simulations process is conducted. The process consists of four steps, where the first step is to collect the input parameters. The second step is where the model compute the results based on the input parameters, and then in step three, the result is stored before the next iteration can start. For each iteration, different values for the input parameters are generated to illustrate the uncertainty in these parameters. After n iterations are completed, the results are analysed and presented in a graph or a histogram which is the fourth and final step.

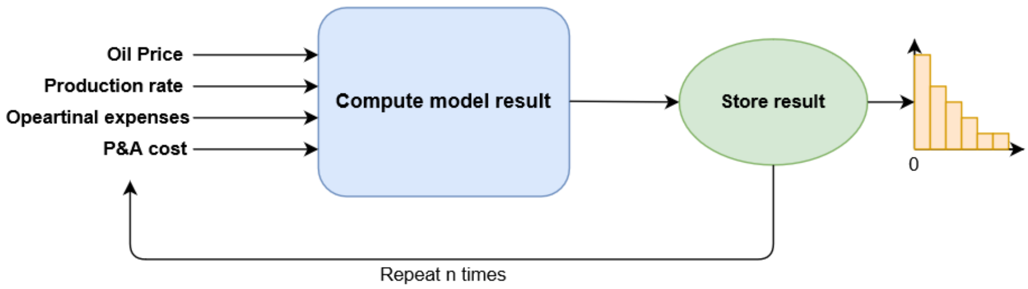

Figure 4.8: Illustration of how the model work

Chapter 5

Case Simulations, Results & Analysis

In order to see how the Decision Support Model work, different cases was simulated. In this chapter, three different simulation cases is presented where results that was found interesting are presented and analysed. A short description including the parameters used is given for each of the cases. Results obtained without the cost of P&A is presented as it was found interesting to see the fraction of times that an increase in the oil price led to positive cash flows after the first negative cash flow is seen, which then would increase the Net Present Value without including the discounted P&A cost. It is also believed that some operators does not include the cost of P&A when deciding when P&A should be conducted.

5.1 Case 1 - Fixed Installation

The first simulation case is a fixed installation producing from 20 wells. A fixed installation is an installation that are resting on the seabed. Either on a steel frame called Jacket, or on huge concrete legs called Condeep. The wellhead area on these installations are found topside, meaning easy access to the X-mas tree and Wellhead. The wells on these type of installations can normally be P&A with the use of the installations own derrick, making the operation more cost effective as no extra rig need to come to sight.

For this simulation case it is assumed a production decline rate of 14 % per year, as discussed in section 4.1. It is assumed that the total OPEX consists of both fixed and variable costs where the fixed operating cost is set to be $200 000 000 per year, and the variable operating cost is $6 per produced barrel of oil. The discount rate is set to be 7,4 % per year as it is assumed that the operating company could get 7,4 % yearly return on another investment. Min and Max values for the different phases of P&A is set to 9-15, 11-19, and 1,5-4 days respectively. The P&A cost is set to \$400 000 per day. The parameter used is summarized in Table 5.1.

Parameter	**Value**
Production decline rate (%/year)	14
Number of wells	20
Fixed OPEX (MM\$/year)	200
Variable OPEX (\$/bbl)	6
Rig Rate (MM\$/day)	0,4
Time (days) Phase 1 P&A	9-15
Time (days) Phase 2 P&A	11-19
Time (days) Phase 3 P&A	1,5-4
Discount rate (%/year)	7,4

Table 5.1: Selected parameters for the first case - Fixed Installation.

5.1.1 Without P&A Costs

In this section, some of the results which where found interesting without including the cost of P&A is presented. The first interest point of the developed model was to see the number of months between the first negative cash flow and the largest NPV of the cash flows without considering the P&A costs. This was done in order to get information related to the probability of the NPV will increase later on after the first negative cash flow is seen. The results from 10 000 iterations is presented in Figure 5.1.

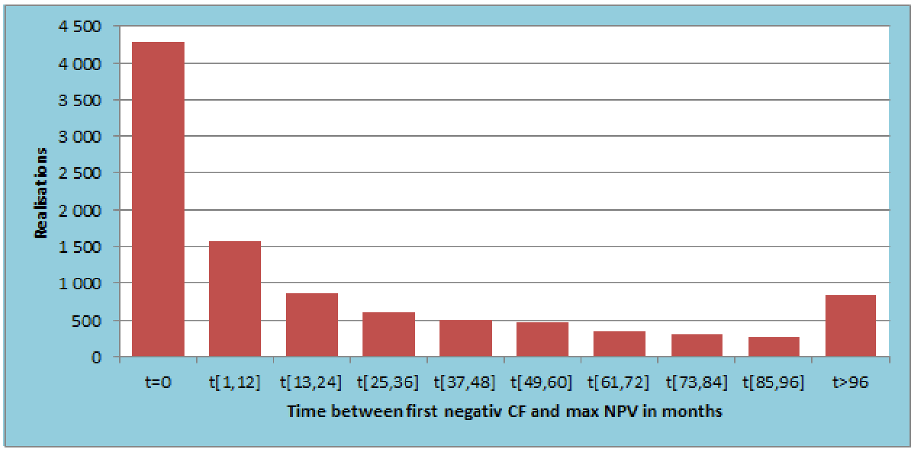

Figure 5.1: Histogram presenting the number of months between first negative cash flow and max Net Present Value without P&A costs - Fixed Installation.

The results from these simulations shows that the time between first negative cash flow and max NPV range from 0 months and 233 months, with an average of 27 months. The mode of the results where 0 with 4274 realisations, meaning that, based on these results, in 57.26% of the times after the first negative cash flow is seen, positive cash flows will increase the NPV later on.

Another point of interest is to see how the NPV is affected by the time difference between the first negative cash flow and max NPV. As one can see from the scatter plot below, Figure 5.2, where the NPV is plotted against the difference in time, there can be a significant upturn if the field experience positive cash flows after the first negative cash flow is seen.

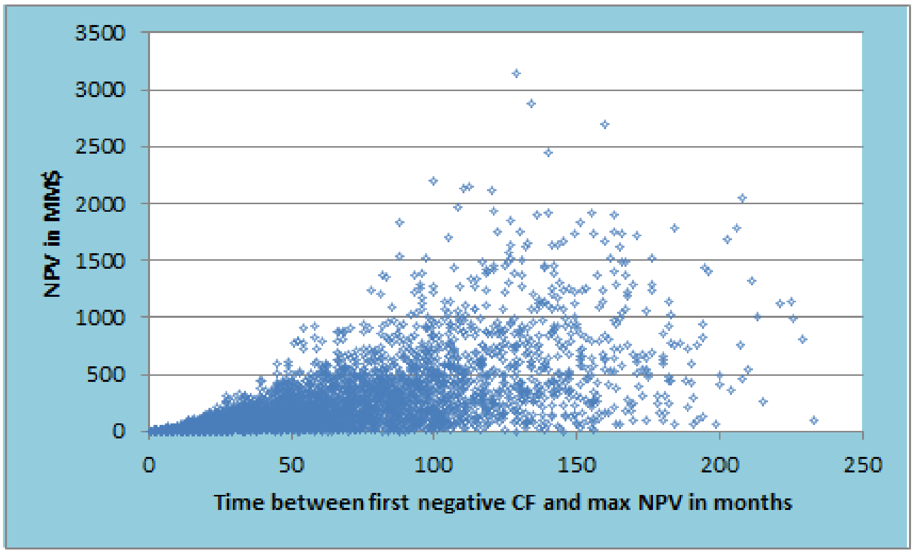

Figure 5.2: NPV vs. time difference - Fixed Installation.

The mean of these NPV results is calculated to be slightly over MM$100, with the highest simulated value at over MM$3 000. However, it is important to remember that these numbers are maximum numbers without the cost of P&A.

5.1.2 With P&A Costs

From results presented in the section above, it is clear that enhanced value can be achieved by postpone the P&A work for some time after the first negative cash flow is seen. In this section, results from several waiting strategies are presented. Here, the difference in NPV including the P&A cost between plugging right after the first negative cash flow is seen and at different waiting times are investigated. This was done to see if there is any value in using a waiting strategy. In Table 5.2, the results of several waiting strategies are presented.

	12months waiting strategy	**24months waiting strategy**	**36months waiting strategy**	**48months waiting strategy**
P90 NPV	52,0	121,4	191,2	239,1
E(NPV)	3,3	1,8	-4,0	-18,5
P10 NPV	-40,8	-100,7	-167,1	-236,0
P(NPV<0)	0,503	0,554	0,587	0,619

Table 5.2: Results from several waiting strategies - Fixed Installation.

P90, P10, and expected values as well as the probability of ending up with a negative NPV is listed in the table, given in MM$. Results from waiting strategies exceeding 48 months after first negative cash flow, is decided to be excluded as the expected NPV of these strategies are strictly decreasing over time and thus, not relevant in this case. From the table, one can see that the expected NPV is greatest in the strategy with postponing the P&A work 12 months after the first negative cash flow, with an expected value of MM$3,3. One can also see from the table that the upside is increasing with time, but at the same time, the probability of ending up with a negative NPV is increasing. This results has been used as information to update the decision tree as illustrated in Figure 5.3.

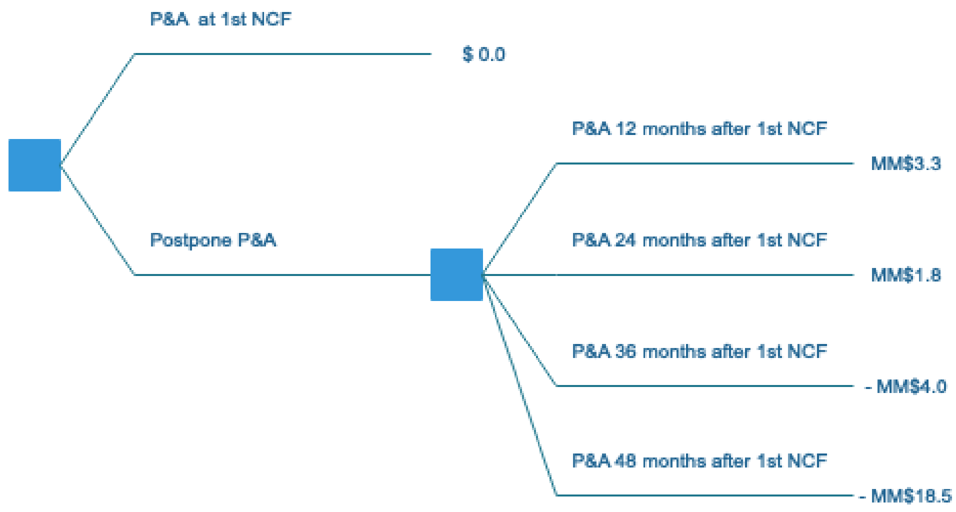

Figure 5.3: Updated decision tree - Fixed Installation.

5.1.3 Analytical Remarks

Results from the first case without P&A costs, indicates that the probability of getting positive cash flows that will increase the NPV later on after the first negative cash flow is seen, is 57%. This indicates that 57% of the times, it will be beneficial to postpone the P&A work for some time. The max NPV was found on average 27 months after the first negative cash flow. However, from the results including the P&A cost, the expected NPV for the 12 month waiting strategy is higher then it is for the 24 month strategy. This indicates that the P&A cost has an impact on when P&A should be conducted.

From the P90 values presented in Table 5.2, one can see a clear trend that the longer waiting criteria, the larger upside. However, the same trend can be seen from the P10 values where the downside is getting larger with longer waiting criteria. This results indicates that with increasing waiting strategies, more uncertainty is associated with the NPV. When looking at the probability of ending up with a negative NPV, one can see that it is increasing as number of months in waiting strategy is increasing.

If the decision maker is risk neutral, meaning that he/she makes the decision based on expected value, the 12 months waiting strategy should be selected, as this strategy has the highest NPV compared to the other strategies.

5.2 Case 2 - Subsea Tieback

The second case is a subsea tieback with 6 wells in an integrated solution. In this case the X-Mas Trees and Wellheads are located on the seafloor, and the produced oil and gas flows from the wells to a nearby host facility like a FPSO (Floating Production, Storage and Offloading vessel), or a fixed installation. The term "SURF" is often used when discussing subsea solutions. "SURF" stands for Subsea Umbilicals, Risers and Flowlines, and include a category of the utilities needed for subsea production systems where umbilicals is used to control different equipment subsea from topside, and flowlines and risers are used to transport the produced fluids from the wells to topside. In this simulation case, a semi submersible rig is needed to do the P&A work.

The same production decline rate as in the first simulation case is assumed here as well. The total OPEX is also in this simulation case assumed to come both from fixed and variable costs, where the fixed OPEX is set to be $20 000 000 per year and the variable to be $6 per barrel. The same number of days as in case 1 for phase 1 and 2 are used, but phase 3 is reduced down to 0,5-1 days according to what is discussed in section 4.4. The cost of P&A per day is set to be $700 000 per day which reflects the daily rate of a semi submersible rig. The discount rate is the same as in case 1. All parameters used in simulation case 2 is given in Table 5.3.

Parameter	**Value**
Production decline rate (%/year)	14
Number of wells	6
Fixed OPEX (MM$/year)	20
Variable OPEX ($/bbl)	6
Rig Rate (MM$/day)	0,7
Time (days) Phase 1 P&A	9-15
Time (days) Phase 2 P&A	11-19
Time (days) Phase 3 P&A	0,5-1
Discount rate (%/year)	7,4

Table 5.3: Selected parameters for the second case - Subsea Tieback.

5.2.1 Without P&A Costs

The same simulations was performed for the second case as in the first case. When looking at the results presented in Figure 5.4, one can see that it follows the same trend as in the first case.

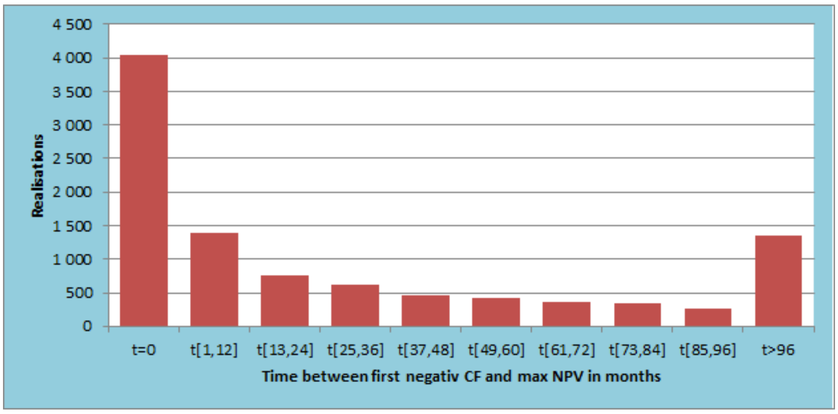

Figure 5.4: Histogram presenting the number of months between first negative cash flow and max Net Present Value without P&A costs - Subsea Tieback.

In this case, the range between first negative cash flow and max NPV where 0 to 299 months with an average of 35 months. 4043 of the iterations resulted in 0 months between first negative cash flow and max NPV. This means that, based on these results, the probability of getting positive cash flows that will increase the NPV later on, is 59.57%.

The scatter plot given in Figure 5.5, illustrates how the NPV can be affected by continue with production after first negative cash flow is seen.

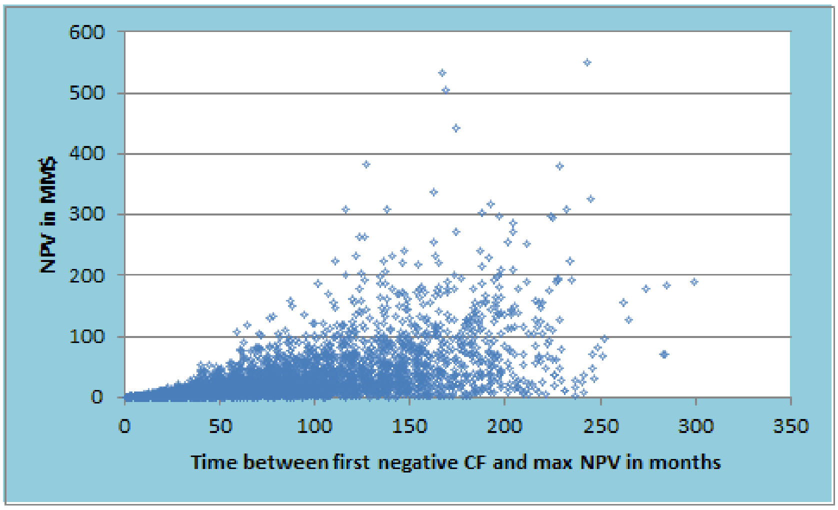

Figure 5.5: NPV vs. time difference - Subsea Tieback.

From the scatter plot, one can see that the highest simulated value is around MM$550 in NPV. However, most of the iterations ends up under MM$100, and the mean was calculated to be MM$12.

5.2.2 With P&A Costs

The results from simulations of case 2, including P&A costs, are presented in Table 5.4.

	12months waiting strategy	**24months waiting strategy**	**36months waiting strategy**	**48months waiting strategy**
P90 NPV	7,7	17,1	19,4	35,9
E(NPV)	3,6	7,0	7,9	13,1
P10 NPV	0,5	-0,1	-0,4	-2,7
P(NPV<0)	0,051	0,104	0,124	0,192

Table 5.4: Results from several waiting strategies (1/3) - Subsea Tieback.

From table 5.4, one can see that the expected NPV is strictly increasing as the number of months of the waiting strategy increases. Due to this, it was decided to investigate some more waiting strategies to see if the expected NPV, at some point, will start to decrease. Results from these waiting strategies are presented in Table 5.5 and 5.6.

	60	**72**	**84**	**96**	**108**	**120**
P90 NPV	43,9	50,7	57,0	61,1	65,8	67,7
E(NPV)	15,3	17,2	18,6	18,9	19,8	20,1
P10 NPV	-4,2	-5,7	-7,4	-8,8	-10,2	-11,8
P(NPV<0)	0,230	0,272	0,286	0,316	0,342	0,352

Table 5.5: Results from several waiting strategies (2/3) - Subsea Tieback.

	132	144	156	168	180	192
P90 NPV	67,8	71,0	72,7	73,2	75,5	71,6
E(NPV)	19,6	19,5	19,3	17,8	17,5	15,9
P10 NPV	-13,5	-14,6	-16,0	-17,5	-19,6	-20,3
P(NPV<0)	0,389	0,399	0,423	0,452	0,466	0,481

Table 5.6: Results from several waiting strategies (3/3) - Subsea Tieback.

In order to get a clearer view on how the different values change over time, the values was plotted against time and is presented in Figure 5.6.

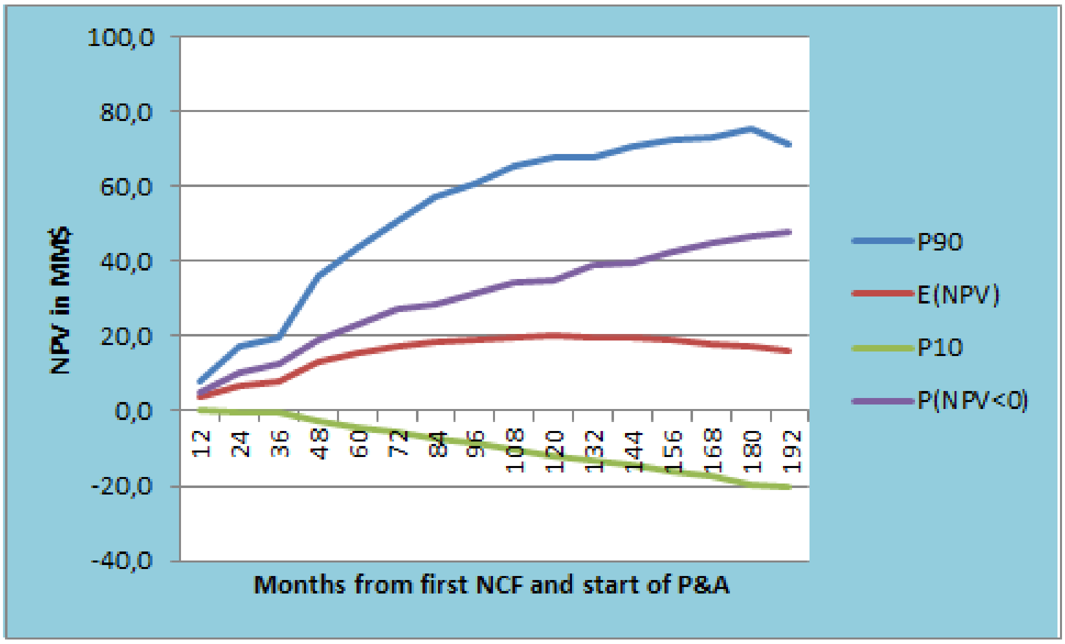

Figure 5.6: NPV at different waiting strategies - Subsea Tieback.

As Figure 5.6 illustrates, the expected NPV is increasing and hit the maximum value of MM$20,1 at the strategy of start plugging 120 months after the first negative cash flow is seen. From there on, the expected value is slowly decreasing. The probability of ending up with a negative NPV is only 5,1% with the 12 month waiting strategy, but it is strictly increasing with time.

5.2.3 Analytical Remarks

The second case had a much lower OPEX than the first case, and since this case only had 6 wells, the production rate was also much lower. However, when comparing the results without P&A cost from case 1 and case 2, the number of times positive cash flows increases the NPV later on is almost the same for both cases. 57% vs. 60%. The average of months between first negative cash flow and max NPV was calculated to be 35 in case 2, which is slightly higher then the average in case 1.

Comparing the 12 month waiting strategy for both the cases, one can see that the expected NPV is roughly the same. However, as the waiting strategy is increasing, the two cases is affected very differently. In the second case, the expected NPV is increasing all the way until a waiting strategy of 120 months, whereas the NPV for the first case is strictly decreasing after the 12 month waiting strategy. For the second case, this indicates that the best strategy is to postpone the P&A with 120 months after the first negative cash flow is seen. The reason for this huge difference is because of the relative difference between OPEX and the P&A cost. Due to the low fixed OPEX in the second case, the change in the present value of the P&A costs by postponing it will be much higher in case 2 than in case 1, relative to the reduction in income from production.

5.3 Case 3 - Fixed Installation with Subsea Tieback

The third, and last, simulation case is a combination of the two previous cases. This fictitious field produces from 20 dry wells and 6 subsea wells that are tied back to the fixed installation. In this simulation case the total production from both the subsea tieback and the dry trees is added together as well as the total cost. It is assumed that P&A of the dry wells and the wet wells starts at the same time, meaning that a semi submersible rig starts plugging the subsea wells at the same time plugging of the dry wells by using the existing derrick on the fixed installation starts.

In this simulation case, the total number of producing wells is 26, where the total production is the sum of production per well. Same production decline rate and discount rate as in the two previous simulation cases is used. The fixed OPEX is set to be \$220 000 000 per year and the variable to be \$6 per barrel. The time and cost parameters of P&A is the same used in the two previous cases, meaning that the total cost is calculated by adding the cost for the wet wells together with the cost of the dry wells. The input parameters used in this simulation case is summarized in Table 5.7.

Parameter	Value
Production decline rate (%/year)	14
Number of wells	20 dry + 6 wet
Fixed OPEX ($MM/year)	220
Variable OPEX ($/bbl)	6
Rig Rate (MM$/day)	0,4 + 0,7
Time (days) Phase 1 P&A	9-15
Time (days) Phase 2 P&A	11-19
Time (days) Phase 3 P&A	1,5-4 (0,5-1 for the wet trees)
Discount rate (%/year)	7,4

Table 5.7: Selected parameters for the third case - Fixed Installation with Subsea Tieback.

5.3.1 Without P&A Costs

Results from 10 000 iterations without including the P&A costs is presented in Figure 5.7. These results follow the same trend as in case 1 and 2, where in over 40% of the times the difference, given in months, in first negative cash flow and max NPV equals 0.

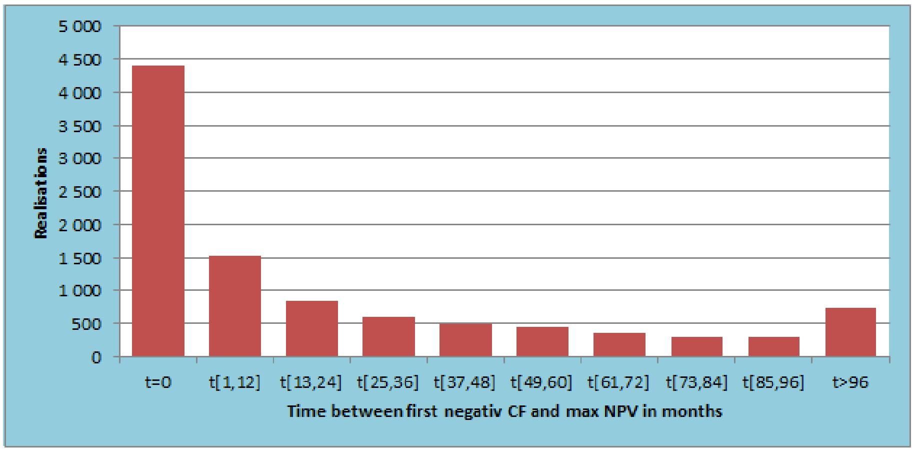

Figure 5.7: Histogram presenting the number of months between first negative cash flow and max Net Present Value without P&A costs - Fixed Installation with Subsea Tieback.

Based on the results in case 3, the probability of getting higher NPV by continue production after the first negative cash flow is seen, is 55,9%. The largest difference between first negative cash flow and max NPV was 239 months, but the average was calculated to be 25 months. The average difference in the NPV was calculated to be roughly MM$106. Results from all the iterations is presented in Figure 5.8.

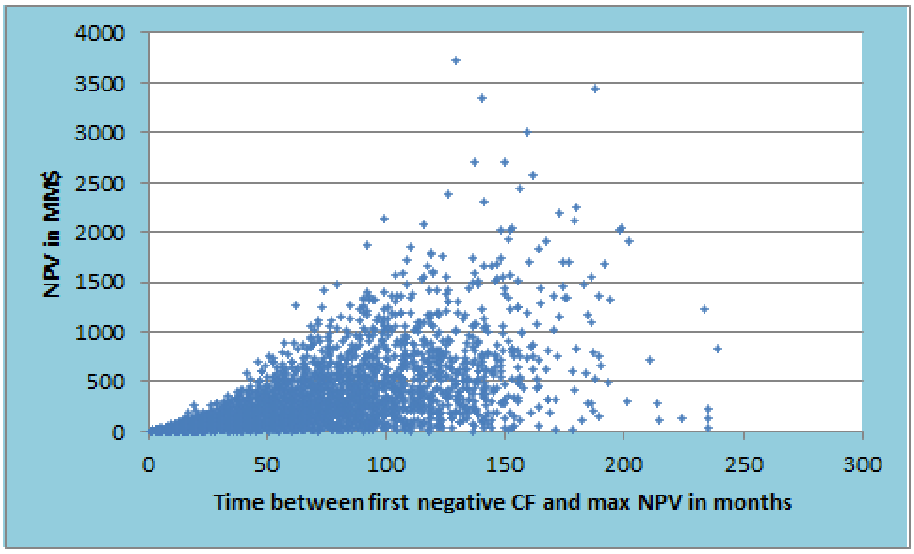

Figure 5.8: NPV vs. time difference - Fixed Installation with Subsea Tieback.

5.3.2 With P&A Costs

In case 3, it is assumed that P&A of both the dry wells and the subsea wells can start at the same time, and the cost of P&A is calculated based on that assumption. NPV results obtained from case 3 is given in Table 5.8.

	12months waiting strategy	**24months waiting strategy**	**36months waiting strategy**	**48months waiting strategy**
P90 NPV	62,0	143,2	220,0	283,0
E(NPV)	6,3	6,8	0,5	-11,0
P10 NPV	-43,7	-108,0	-181,3	-258,2
P(NPV<0)	0,484	0,540	0,569	0,595

Table 5.8: Results from several waiting strategies - Fixed Installation with Subsea Tieback.

From the different waiting strategies, one can see that the strategy of postponing the P&A work with 24 months after the first negative cash flow has the highest expected NPV, with a NPV equal to MM$6,8. The expected NPV is also positive for the 12 month- and 36 month strategy. However, with a lower expected NPV compared to the 24 month strategy. The 48 month waiting strategy ends up with a negative expected NPV of -MM$11,0. One can see from the table that the uncertainty in the NPV increases with longer waiting strategies, and the probability of ending up with a negative NPV is also increasing.

5.3.3 Analytical Remarks

The third case was the case with highest OPEX, compared to all tree cases. However, very similar results was found when not including the cost of P&A. This implies that the main factor for positive cash flows that will increase the NPV after the first negative cash flow is seen, is the fluctuation in oil price. Higher oil price later on can compensate several months with negative cash flows.

When looking at the results where the cost of P&A is included, one can see that these results are almost the same as in the first case. The main difference is that the highest expected NPV is found with the 24 month waiting strategy in case 3, but in case 1 the 12 month waiting strategy was found to give the highest expected NPV.

Chapter 6

Discussion

In this chapter, after a short summary of the thesis is given, I reflect on the work done in this master thesis, what I have learned when working with this thesis, some practical challenges I have met, and some suggestion for further research.

6.1 Thesis Summary

When an offshore oil and gas producing asset should be plugged and abandoned is one of the strategic challenges that operators with late life offshore oil and gas producing assets are facing. The objective of this thesis was to develop a decision support technique based on modelling method and simulation based analysis that can help decision makers in the oil and gas industry to find the optimal time to Permanent Plug and Abandon petroleum producing fields based on the identified potential for maximum Net Present Value of the cash flows generated in late life of the asset. This objective has been achieved by developing a P&A Decision Framework based on the objectives, alternatives and information regarding decision influence factors, developing a P&A decision support model that models the various decision influence factors and put them together in a Net Present Value model, and by doing case simulations where results has been presented and analysed. The main contribution of this thesis is the framing of the P&A decision context by developing a P&A decision framework and the development of the decision support model.

6.2 Thesis Reflections & Learning Points

This thesis started out with an idea of combining a topic that is in the wind nowadays, with a topic I find very interesting. For that reason, I wanted to look at how I could combine Plug & Abandonment with Decision Making. After doing some research, I decided to look at one of the strategic challenges with P&A, which is the decision related to when an offshore oil and gas producing asset should be plugged and abandoned.

As I had minimal theoretical knowledge of P&A, a state of art- and literature review was done in order to get a holistic understanding of the theme. I mostly used scientific research papers and a newly published book about P&A (Khalife, 2020) to do the state of art- and literature review, but also master thesis and web pages was used. It is not presented an in-dept review of all aspects linked to P&A. However, it is believed that it is sufficient for the purpose of this thesis. Doing the state of art- and literature review increased my knowledge related to P&A significantly, and can probably also help other people increase their knowledge about P&A. The literature review related to Decision Making was done in order to increase my state of knowledge, as well as helping the reader of this thesis understand why the Decision Framework is presented as it is. The Decision Making literature works as a foundation for the developed Decision Framework.

After the state of art- and literature review was done, the P&A Decision Framework was developed. This Framework was developed in order to understand the decision context and to introduce the various factors that could influence the decision. The development of the Framework was a demanding task, especially searching and gathering information about the decision influence factors was time consuming and challenging.

A lot of time was used to think about how I could develop the decision support model. The initial plan was to use the software Python, but after spending some days trying to learn Python I decided to do it Excel instead to decrease the complexity as the time was running away. As given in Chapter 4, models related to the decision influence factors was developed to include the uncertainty and time aspect of the factors. Some of the models was fairly simple to develop, but others where very demanding. The Oil Price model was one of the most challenging model to develop, and one could probably have written a whole thesis about oil price forecasting.

After all the models was developed separately, it was time to put them together to an NPV model in order to get the output of interest. This was done by using in-built function and conditional formatting in excel. In order to get the logic of the model right, several trials was needed.

In order to illustrate how the developed Decision Support Model could be used, three different simulation cases was run in the model. The input parameters used where mostly "dummy data" as I was not able to get data from real cases. However, it is believed to be sufficient to illustrate an example. For each simulation case, several waiting strategies was simulated to see how the Net Present Value was affected. 10 000 iteration was performed for each waiting strategies. It is believed that 10 000 iterations was sufficient, but if I had more data power I would probably increased that number to 100 000 to make the results even more stable.

I decided to run Monte Carlo simulations both with and without the cost of P&A. The reason for this is that I wanted to see how the NPV was affected mostly by fluctuations in the oil price. I decided to illustrate the results without the cost of P&A in form of a histogram and a scatter plot, as I found them to illustrate the results in a good way. The results from the simulations including the cost of P&A is presented mostly in tables, as they present the different values in a nice way.

I have learned a lot during the period of working with this thesis, both academically and personally. First of all, I have learned a lot about Plug & Abandonment. What it is, how it is done and different aspects that affects the time and cost of P&A is something that I might need to know in my future career. I have also learned how to structure a decision problem with the use of certain steps which will increase the probability of making good decisions. By developing models and simulating in Excel, my skill level in Excel has increased significantly. I have also developed some basic skills in Python during this period.

6.3 Practical Challenges

During the period of working with this thesis, I have faced some practical challenges. The biggest challenge was the self isolation and social distancing due to the Covid-19 virus which led to closed University and the bedroom turned into an office. Not being able to work with the master thesis at the university, made it very challenging to distinguish between working with the master thesis and leisure time, ending up with thinking about the master thesis all the time. Another practical challenge was the data gathering. As time and cost data is sensitive, I was not able to obtain the data I wanted. Several operating companies on the Norwegian Continental Shelf was contacted in hope for guiding and help with data gathering related to the thesis, unfortunately with poor outcome.

6.4 Further Work

In the oil price model, fluctuation in oil price is based on historical data. In order to represent the believes of major oil and gas companies, the use of futures and options data might be more accurate to use.

In order to get a more holistic view on the decision context, the other alternatives like selling the asset or doing a IOR project should be looked at.

Use the decision support model developed in this thesis as starting point when investigating when real life oil and gas producing assets should be plugged & abandoned by using more specific field data.

Chapter 7

Conclusions

When to permanent plug & abandon a field is a complex decision with a significant amount of uncertainty associated to it. Structuring the decision context, and develop models to run simulations in order to get information can be very helpful for the decision makers.

Enhanced value can be achieved by postponing P&A from the time the field first experience a negative cash flow. This value comes partly from uncertainty in the oil price, as an increase in oil price can lead to positive cash flows later on which can again increase the overall NPV. And partly from the cost of P&A which will decrease over time due to time value of money.

There is value in establishing a waiting strategy with a specified number of months after the first negative cash flow is seen. However, this is field sensitive meaning that not all fields can have the same waiting strategy in order to get the value from it. OPEX seems to be the factor that affect the waiting strategies the most.

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