Norwegian School of Economics

Bergen, Spring 2016

Decommissioning of Petroleum Installations on the Norwegian Continental Shelf

A Real Options Approach

Eline Aarrestad and Turi Regine Pettersen

Supervisor: Petter Bjerksund

Master thesis

Financial Economics | Energy, Natural Resources and the Environment

NORWEGIAN SCHOOL OF ECONOMICS

Abstract

Many fields on the Norwegian continental shelf (NCS) are maturing, and there are consequently a great number of petroleum installations that will be decommissioned in the near future. Decommissioning entails the full or fractional removal of an installation, and the process normally involves high costs. Having many of the largest extraction facilities in the world, the NCS represents the greatest share of removal costs globally.

This thesis models project value and optimal timing of abandonment for a mature field on the NCS. The field produces both crude oil and natural gas and has an exponentially declining production. The analyses are conducted using a net present value and a real options approach. The real options approach is based on a contingent claims analysis, and includes the modeling of an abandonment option through a binominal lattice. Prices of crude oil and natural gas are modeled stochastically. Both models incorporate scenarios reflecting recent decommissioning market trends.

Project data has been received from Statoil. The data is fictive, but based on a real case. The ultimate purpose is to evaluate the potential value of implementing a real options model for decommissioning analyses at Statoil. For our project, we find that the Net Present Value Model and the Real Option Model generally yield the same optimal timing of abandonment, but differ in project valuation. We conclude that the potential value of implementing a real options analysis depends on field characteristics and the purpose of the analysis. In general, the abandonment option is worth more for a field with a low decline in production compared to a rapid decline in production.

Preface

This thesis was written as a concluding part of the Master of Science in Economics and Business Administration at the Norwegian School of Economics (NHH). The thesis is interdisciplinary, meaning that it encompasses two majors: Financial Economics and Energy, Natural Resources and the Environment.

Our journey began when Turi had an internship at Deloitte last summer. There she became acquainted with a partner who was working with projects in the oil and gas sector. The partner suggested a number of topics that he believed would be interesting for a thesis, one being abandonment of offshore petroleum installations. Eline also experienced that this topic was of high relevance and interest for ConocoPhillips, where she had an internship the same summer.

Our motivation for choosing the topic also stems from a general interest for the petroleum industry, representing a vital part of the modern Norwegian economy. Our interest has further been amplified by work experience and courses at NHH like Petroleum Economics. When selecting an appropriate methodology, several methods very evaluated. We were first presented with real options theory through introductory finance courses. Having limited prior experience in applying real options theory, we wanted to use this opportunity to challenge ourselves and learn something new.

Writing a master thesis has been both challenging and valuable. Through learning a new and sophisticated financial framework we have gained a better understanding of investments under uncertainty. At the same time, we have gained further insights into the petroleum industry. The process of writing such an extensive paper has also helped us learn a lot about project management and working closely in teams.

We would first like to thank our supervisor Petter Bjerksund for all the constructive and valuable feedback we have received throughout the process. Furthermore, we would like to thank Johannes Wiik at Deloitte for the many suggestions, unique insights and continuous follow-up. We would also like to thank Henrik Mikal Sørensen at Statoil for presenting us with project data, organizing meetings and being available for questions. Thanks to the decommissioning managers Vidar Eiken at Statoil, Tim Croucher at ConocoPhillips and Ron Howard at BP for insightful information and suggestions. A final thanks to Norsk Petroleum for letting us attend the 16th Annual Decommissioning Conference in Oslo.

Table of Content

1 Introduction

As of today, many fields on the Norwegian continental shelf (NCS) are maturing, and subsequently approaching the time of abandonment (Osmudsen & Tveteras, 2003). The imminent decommissioning work on the NCS is comprehensive and involves high costs. Because there are many large installations situated on deep waters, the total abandonment cost on the NCS represents the largest share of forecasted decommissioning costs globally Some estimates indicate that the upcoming abandonment work on the NCS will entail costs equivalent of at least 8% of the Government Pension Fund of Norway (Ånestad & Løvås, 2015)[1].

In the light of the recent plunge in oil prices, decommissioning has become a topic of increased interest. The decommissioning work on the NCS affects many stakeholders, particularly the upstream oil companies, but also the Norwegian State. The upstream oil companies are liable to plan and execute the decommissioning work and to cover their share of costs. However, the Norwegian State covers the largest share of decommissioning costs in accordance with today's taxation system.

Two central and interconnected decommissioning analyses conducted by the upstream oil companies are a) the analysis that determines the optimal abandonment timing of a petroleum project, and b) the analysis that obtains the project's residual value. Both analyses largely depend on the oil price development and the final abandonment cost. The net present value approach is frequently applied for these types of analyses. Nevertheless, many authors argue that a real options approach is suitable as a supplementary analysis for oil and gas projects given the large inherent uncertainties (see for example Trigeorgis (1993)).

This master thesis models project value and optimal timing of abandonment for a mature field on the NCS. Our research question is:

"*What is the value of implementing a real options model for decommissioning analyses at Statoil?*"

[1] Based on estimated total future costs of plugging wells on the NCS and the current market value of the Government Pension Fund of Norway of approximately 7 billion NOK (Norges Bank Investment Managment, 2016).

Project data is presented by Statoil. The data is fictive, but based on a real case. The field analyzed has an exponentially declining production and produces both crude oil and natural gas. In our analysis, we take on a company perspective, although we acknowledge that the decommissioning work affects many stakeholders.

Two financial frameworks are employed: a Net Present Value Model and a Real Option Model. In our Net Present Value Model, we derive a decision rule for the optimal timing for abandonment. The Real Option Model includes the flexibility of abandoning the field at any given point during project life. Crude oil and natural gas prices are modeled stochastically. In extensions of the Real Option Model, the decommissioning cost is also modeled stochastically.

In both models we incorporate scenarios reflecting recently emerging decommissioning market trends. These trends include the cyclical nature of the decommissioning cost and the expectation that the cost will decrease over time. Another recent trend internationally has been to leave the platform idle for some years after production has ceased. This market trend might become more relevant on the NCS in the future and is therefore analyzed.

Several authors have conducted relevant studies, focusing on optimal abandonment timing and real options in the oil and gas industry. Similar to previous applications (see for instance Ekern, 1988; Pickles & Smith, 1993; Smit, 1997), we apply a binomial model based on a contingent claims approach for our real options analysis. However, instead of looking at the entire project life (see for instance M. W. Lund, 2003; Smit, 1997), we limit the scope of attention to late-life operations and abandonment.

The market for decommissioning services is relatively nascent and non-transparent (Lavelle & Jenkins, 2014). Consequently, the academic literature on decommissioning is scarce. However, as a result of several fields on the NCS approaching abandonment, more information about the decommissioning cost has become available. Previous applications (see for instance Olsen & Stensland, 1988; Nygaard & Jørgensen, 2011; M.W. Lund, 2003) incorporate either a positive salvage value for the installation or does not account for the decommissioning cost. In accordance to updated project data, we incorporate a significant salvage cost in our models.

In our analysis, we find that the decommissioning cost, together with crude oil prices, has a large impact on project value of our mature field and its optimal timing of abandonment. We observe that it is optimal to continue producing even when production has declined to a point where cash flows become negative. Furthermore, we find that all scenarios reflecting recent decommissioning market trends have a positive effect on project value. Our analysis also suggests that the abandonment option is worth more for a field with a low decline in production compared to a rapid decline in production. For our particular case, we conclude that the potential value of implementing a real options model is limited in terms of determining the optimal timing of abandonment, but that it might be useful in determining the field's residual value.

The thesis is organized in the following manner. Chapter 2 elaborates on what oilfield decommissioning practically entails, and presents the forecasted decommissioning expenditures on the Norwegian continental shelf. Additionally, we discuss how key stakeholders are affected by the decommissioning work. Chapter 3 examines relevant risk factors in analyses of mature fields, hence defining and narrowing the scope of the analysis. Chapter 4 describes the financial frameworks for project valuation that are used in the analysis. Chapter 5 presents some of the relevant literature focusing on optimal abandonment timing and real options. In chapter 6, our Net Present Value Model and Real Option Model are formally described. Chapter 7 presents the data input for the analysis. Analysis and results for the NPV Model and Real Option Model are found in chapters 8 and 9 respectively, while chapter 10 aims to compare the results of the two models. Chapter 11 answers our research question by assessing the value of implementing real options analyses at Statoil. Chapter 12 concludes the paper.

2 Decommissioning of Petroleum Installations on the Norwegian Continental Shelf (NCS)

The average age of assets on the NCS was around 24 years in 2014 (Lavelle & Jenkins, 2014). Many fields have therefore reached late-life operations and are soon to be decommissioned. The decommissioning work presents a large and uncertain liability for several stakeholders. On the other hand, it also presents a socio-economic opportunity in terms of job creation (Bonino, 2015).

The purpose of this chapter is to explain the scope of the decommissioning work on the NCS and how the decommissioning liabilities affects key stakeholders. But, first we will explain how the decommissioning work is practically executed on a typical field.

2.1 Phases in the Decommissioning of an Oilfield Asset

Decommissioning entails the full or fractional removal of an oilfield installation (Lakhal, Khan, & Islam, 2009). A field typically has several platforms and multiple wells. The platforms are situated at various water depths and the different platforms are constructed to accommodate their own respective type of petroleum field. There are many types of oilfield platforms, making the decommissioning process far from homogeneous.

Figure 2-1: *Examples of different types of petroleum platforms (Woodrow, 2012).*

Figure 2-1 illustrates some of the different types of oilfield platforms that can be found offshore. Depending on the circumstances, the platform may be fixed to the ocean floor (for instance the steel jacketed platform illustrated to the left) or float (like the floating production systems on the right).

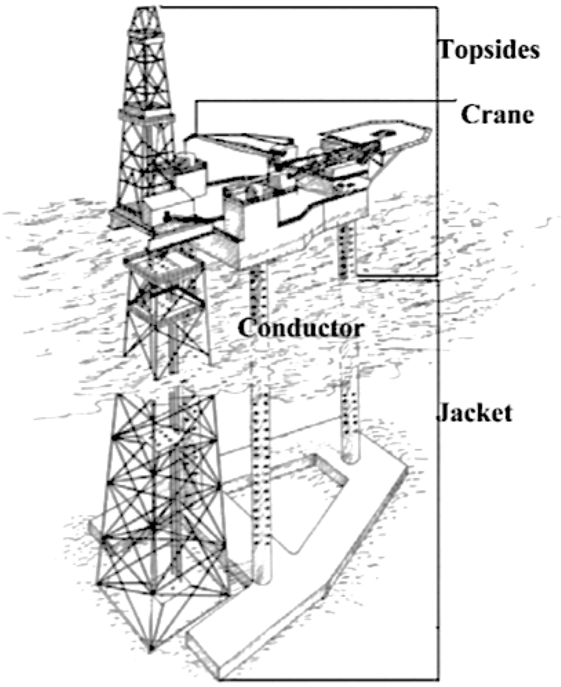


Figure 2-2: *Graphic sketch of a steel jacketed platform* (Lakhal et al., 2009).

Figure 2-2 illustrates a common oilfield platform on the Norwegian continental shelf (NCS): the steel jacketed platform. Around 65% of all oilfield platforms on the NCS fall under this category (Lavelle & Jenkins, 2014).

The platform is held in place by the jacket, which is a large steel construction elevated from the seabed (Lakhal et al., 2009). The part of the platform that is above sea level is referred to as the topside of the platform. The topside engages in pumping, receiving and processing the crude oil and natural gas extracted from the reservoir. The conductor, located inside the steel jacket, leads the hydrocarbons from the well under the seabed to the topside. Risers are typically attached to the platform legs, leading the hydrocarbons to shore through pipelines.

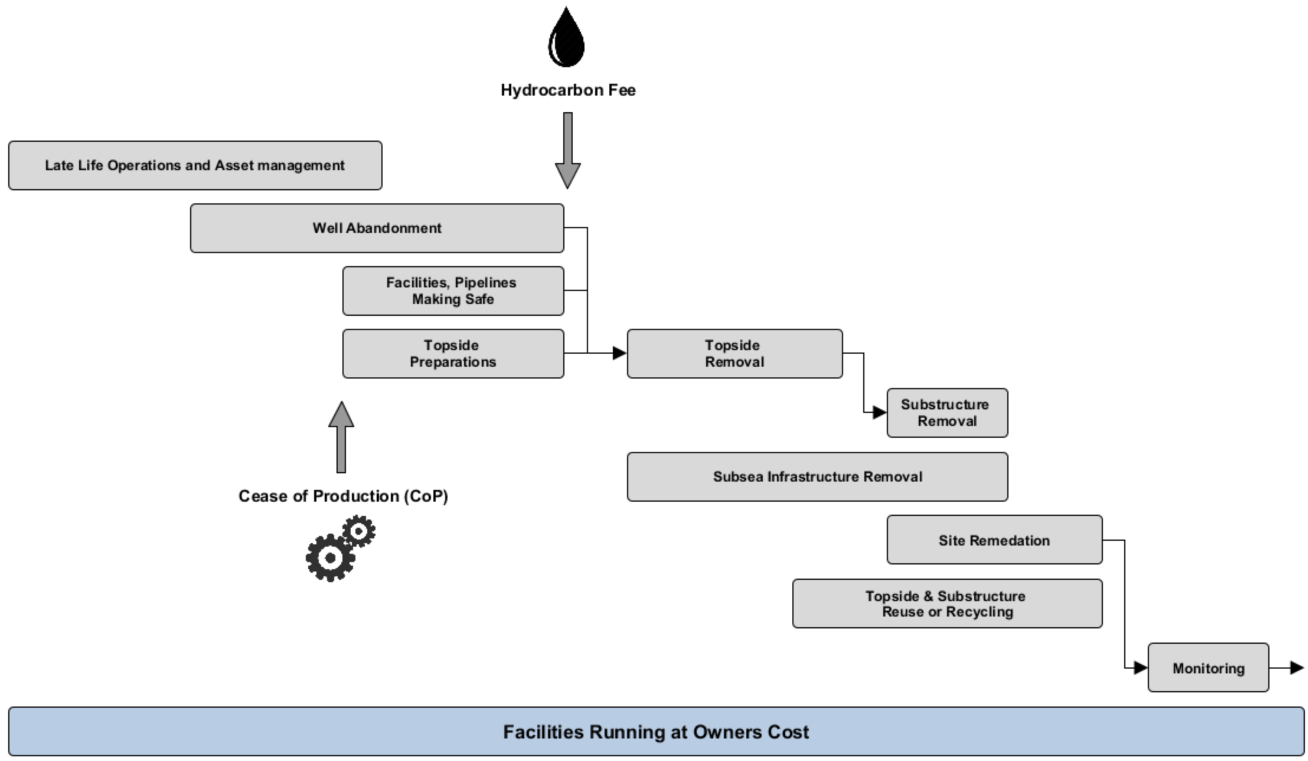


Figure 2-3*: Illustration of a typical decommissioning program. Adapted from Lavelle & Jenkins, (2014).*

When a platform is approaching the appropriate time of abandonment, the operator of the field needs to initiate a decommissioning program (Lavelle & Jenkins, 2014). The decommissioning program stretches from the management of the asset during late-life operations to the monitoring of the seabed once the asset has been fully removed.

Figure 2-3 illustrates the phases of a typical decommissioning program. During well abandonment, also referred to as permanent plugging and abandonment (PP&A), the wells are permanently filled with cement. A field contains numerous wells, and some wells will still be producing during the abandonment of other wells. Cease of production (CoP) is reached when all wells have stopped producing. After CoP, topside and other facilities are prepared for decommissioning by ensuring that the installations are hydrocarbon free. After the platform is hydrocarbon free, the removal of topside, substructure and subsea infrastructure remains. At this stage of the decommissioning program, the oil companies have some flexibility to determine the time of removal of the remaining structures. The companies could potentially postpone the removal of topside, by leaving the platform idle for some time.

Topside structures and substructures are normally fully removed. Subsea infrastructure will generally be removed or covered, although pipelines might be left in situ. All material that has been removed will be transported to shore, and steel components may then be recycled or reused. Finally, one would have to monitor the area, to reinsure that the environment returns to its natural state.

2.2 Forecasted Total Decommisisoning Expenditures on the Norwegian Continental Shelf

The NCS has proportionally larger installations in tonnage terms compared to other countries, with 1.66 million metric tons of steel related to oilfield installations (Lavelle & Jenkins, 2014). To put it into perspective, the amount of steel on the NCS is five times larger than the amount of steel found on the Dutch continental shelf (which has a similar number of installations). The large amount of steel is explained by the fact that the NCS has many deep-water installations (Osmudsen & Tveteras, 2003). Consequently, the NCS represents the largest fraction of global disposal costs.

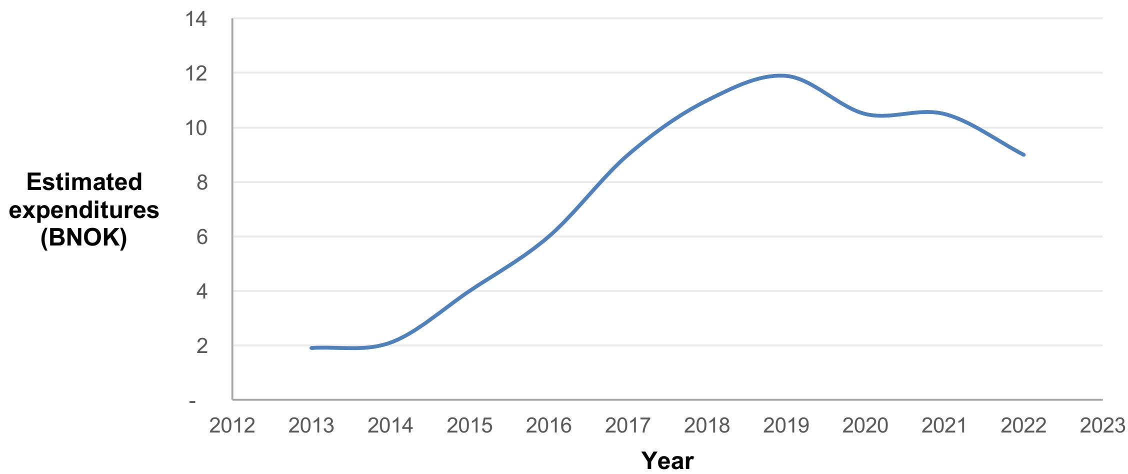


Figure 2-4: *Mackay's estimated annual decommissioning expenditures on the NCS in billion NOK. Adapted from Lavelle & Jenkins (2014).*

The total forecasted decommissioning expenditures on the NCS is uncertain (Lavelle & Jenkins, 2014). As shown in figure 2-4, an analysis undertaken by the consulting house Mackay in 2014 suggests a total decommissioning spend of 73 billion NOK up to 2022. On the other end of the spectrum; master students from the University of Stavanger[2], estimated total expenditures of 571 billion NOK, only related to permanent plugging and abandonment of current wells (Ånestad & Løvås, 2015). This estimate would be much higher if it included the rest of the decommissioning costs, although costs related to plugging and abandonment of wells often stands for the largest fraction of total costs.

There are many reasons as to why it is challenging to accurately estimate decommissioning expenditures. Decommissioning represents large costs that companies often have an incentive to postpone (Osmudsen & Tveteras, 2003). Hence, it is difficult to determine when decommissioning will occur, and the resulting costs are consequently relatively hard to predict (Lavelle & Jenkins, 2014).

Secondly, cost estimation is made difficult due to current market uncertainties. Normally, upstream oil companies procure decommissioning services from oil service companies. These service companies also deliver services to the exploration and production phase of an oilfield. When oil prices are high, the offshore activity levels are also generally high. In a situation like this, it will be relatively costly to procure services needed for the decommissioning work. The high decommissioning cost can be explained by capacity constraints of the service companies, whose services are also demanded for exploration and production activities. Due to higher cost levels, the oil companies are unlikely to procure decommissioning services in activity level peaks (Lavelle & Jenkins, 2014).

A third reason making it difficult to estimate decommissioning expenditures is the fact that the market for decommissioning is nascent. Over time it is expected that the service industry will offer more tailor-made decommissioning solutions that will bring down decommissioning cost (Osmudsen & Tveteras, 2003). Today, many solutions are over-dimensioned, and more suited for the exploration and production phase of a petroleum project rather than the decommissioning phase. It is however highly uncertain at which point in time new solutions will be provided.

In essence, the imminent decommissioning work on the NCS is both extensive and uncertain in terms of cost. Nonetheless, there is no doubt that decommissioning will have a great effect on the parties involved. In the upcoming section we will discuss how different key stakeholders are affected by decommissioning.

[2] In cooperation with the Petroleum Directorate, the Petroleum Safety Authority and oil companies on the NCS.

2.3 The Decommissioning Cost – Effect on Key Stakeholders

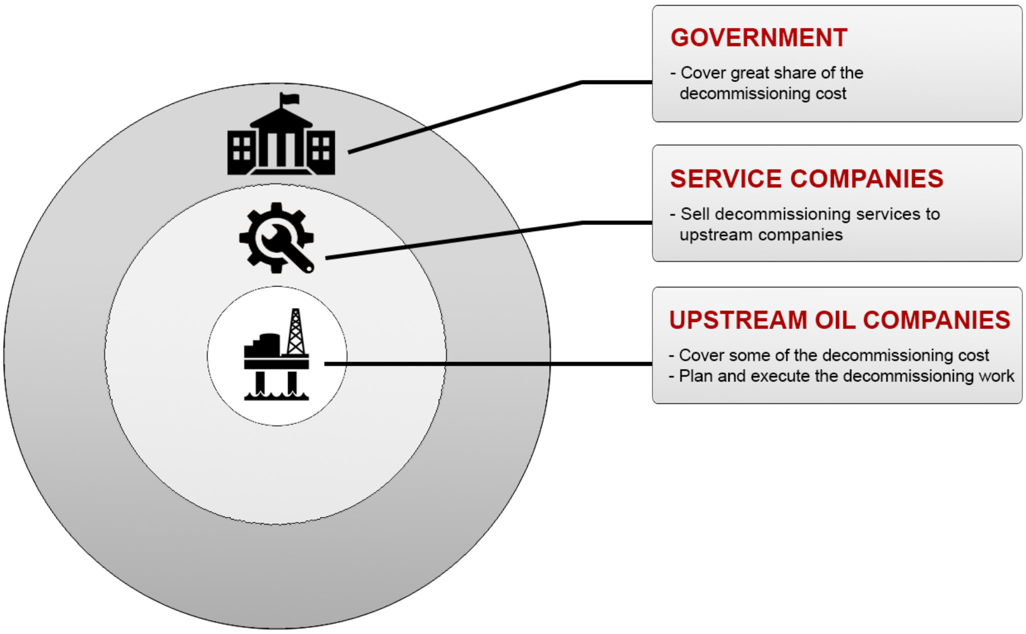


Figure 2-5: *Key stakeholders in the decommissioning work on the NCS (developed by the authors).*

Figure 2-5 illustrates some key stakeholders affected by the impending decommissioning work on the NCS. An important stakeholder is the Government, which is involved in every stage of a petroleum project through a special taxation system and by imposing regulations. In accordance to the special petroleum taxation scheme, the Government covers the largest fraction of decommissioning costs. Through the special taxation system, the SDFI[3] and ownership shares in Statoil[4], the Norwegian Government may in theory pay up to 97% of the decommissioning cost at a particular field (Osmudsen & Tveteras, 2003).

Other important stakeholders are the companies delivering services to the upstream oil companies during all phases of a petroleum project (often referred to as service companies). An example of a service could be the work of specialized oilrigs. Finally, the upstream oil companies themselves are responsible for the planning and execution of the decommissioning work and are therefore an important stakeholder.

---

[3] SDFI = State's Direct Financial Interest. The Government's directly owned exploration and production licenses on the Norwegian continental shelf (Norsk Petroleum, 2016).

[4] The Government currently owns 67% of all shares in Statoil (Norsk Petroleum, 2016).

2.3.1 The Government Perspective

By law it is the Norwegian Government that ultimately owns the petroleum resources on the NCS (Oil and Energy Department, 1997). The Government appoints licenses to oil companies to act on their behalf and extract the resource, creating a principal agent relationship. In return, the Government demands a resource rent to account for the high returns by extracting the resource (D. Lund, 2009). As of today, the normal corporate tax rate is 25%, while the special petroleum taxation is 53%, equaling to a marginal tax rate of 78% (Regjeringen, 2016).

To ensure efficient allocation of resources, the Norwegian tax system aims to be neutral (D. Lund, 2014). In a neutral tax system, taxation will not have an effect on the decision making process of a company. Neutrality is desired as companies will maximize its pre-tax values and the optimal socioeconomic investment level is consequently obtained. This is achieved by ensuring that the marginal tax rate on income is the same as the marginal tax reduction rate of all sorts of costs. The Norwegian tax system operates with six-year linear depreciation for capital costs. For neutrality to hold in this situation, the values of these capital allowances are compensated by an accumulation of interest, known as the "uplift"[5]. This is meant to offset the company's negative discounting of future deductible tax.

The practice of reimbursing costs also transcends into decommissioning (Osmudsen & Tveteras, 2003). The decommissioning costs are covered in accordance to how much the net income from the field has been taxed on average throughout its operating years. For instance, if the field has been in a tax paying position during all its operational years, it has faced an average effective corporate income tax of approximately 78%. These 78% of the decommissioning costs will be refunded by the Government and paid directly to the oil companies at the time of removal. The Government's share of costs can even be increased in cases where the estimated share is "unreasonably" low. In addition, the Government will have to carry the part of decommissioning costs that accrue to the state equity shares through the SDFI. Consequently, the Government will in most cases carry the largest fraction of the decommissioning costs, thus creating a considerable fiscal burden for the Norwegian State. The majority of the decommissioning costs are likely to incur at a point in time when petroleum revenues are declining and the share of retirees in the population is increasing.

---

[5] The uplift is calculated as 5.5% of the investment for four years from the year the investment was incurred. The overall uplift is thereby 22% of an investment (Ministry of Finance, 2013).

When assuring tax refunds for the decommissioning cost, the policy maker in turn demands to be heavily involved in the planning of the decommissioning work (Osmudsen & Tveteras, 2003). The State's involvement is regulated by law through the Petroleum Act, establishing that a plan should be submitted to the Government between two to five years before the installation is expected to be removed (Oil and Energy Department, 1997). The plan submitted to the Government includes environmental assessments, safety studies and cost analyses, and are generally not available to the public. The Government must approve the plan before the work can be initiated.

The Petroleum Act also states that the licensees of a field have solidary obligations in covering the decommissioning cost (Oil and Energy Department, 1997). Fields on the NCS are typically organized as joint ventures, in which there is one operating company and several license partners. The partners are responsible for covering the decommissioning cost in accordance to their ownership shares. Given the circumstance that a partner cannot cover its costs, the Norwegian Petroleum Act states that the financial liability of abandonment shall be shared between the remaining licensees (Oil and Energy Department, 1997). This reduces the risk of any transferal of the full liability to the Government. In the licensing rounds, the Government can also reduce its risk by appointing licenses to solid companies that are able to carry out the full project both technically and financially.

There are several abandonment considerations that create a potential conflict of interest between the Government and the oil companies (Osmudsen & Tveteras, 2003). These considerations raise some interesting policy issues. One issue is the choice of decommissioning method. Policy makers have to consider whether companies should be given the opportunity of sea disposal. Sea disposal implies that parts of an installation is left at sea permanently, and it is mainly relevant for the substructure (Osmudsen & Tveteras, 2003). The choice of decommissioning procedure is subject to stringent and extensive international regulations, but there also exists considerable local discretion. Disposal at sea of offshore installations in the North Sea and North East Atlantic is regulated by the OSPAR convention. The OSPAR convention prohibits sea disposal in the vast majority of cases[6]. However, concrete installations and steel jackets weighing over 10,000 metric tons are exempted from this rule. Having many of the largest extraction facilitates in the world,

[6] However, there are examples of derogations from the convention (U.K. Fisheries Offshore Oil and Gas Legacy Trust Fund, 2016; UK Department of Energy and Climate Change, 1998).

several of the fields on the NCS are not regulated by the OSPAR convention directly. The Norwegian Government holds full discretion over these fields, and the approved method of decommissioning is currently made on a case-by-case basis.

A case-by-case evaluation is required as the petroleum installations on the NCS are highly heterogeneous. The decommissioning work results in different external effects and removal costs for various installations (Osmudsen & Tveteras, 2003). Based on previous decommissioning cases on the NCS, the Government has generally prohibited sea disposal of substructures. In Norway, sea disposal of topsides is politically not perceived as an option. However, companies have been granted permission to leave special facilities such as pipelines offshore. There are also some examples of derogations from the general rule of decommissioning the entire substructure based on cost considerations[7]. The relatively strict Norwegian decommissioning policy can be linked to high environmental standards and considerations of other stakeholders. For instance, allowing sea disposal might present problems for the fishery industry by impeding the fishermen's ability to access certain fishing grounds.

Another abandonment consideration relates to the timing of decommissioning (Bardi, Martén, Mikhailov, & Streubel, 2015). The policy issue is whether the oil companies should be able to postpone the decommissioning of an asset for some years. This can imply considerable interest savings for the oil companies, in addition to other benefits of deferral. Nevertheless, it would cause maintenance costs to accrue after production has stopped. These benefits and costs affect the Government indirectly through the tax system. For the timing issue, the Government must also consider external effects on for instance fisheries and the environment (Osmudsen & Tveteras, 2003). In accordance to international law, local discretion is considerable for the timing of decommissioning. There are no international laws prohibiting leaving platforms idle as long as it will be decommissioned at some point. Consequently, it is up to the Norwegian Government to approve the timing of removal for individual installations on the NCS.

Although the Government formally owns the petroleum resources it is far from certain that it will be managed in the interest of the State. For the Government, there are a number of external effects that needs to be considered, including the effects on fisheries and the

[7] One exemption was for instance made at the Ekofisk field operated by ConocoPhillips, where one concrete substructure was left in place due to its weight of 1.2 metric tons (Osmudsen & Tveteras, 2003).

environment. From a pure financial perspective, these external effects are not deemed relevant for the oil companies. Consequently, there exists a principal-agent problem and several policy issues related to decommissioning.

2.3.2 The Service Market Perspective

The market for decommissioning services offshore is a rapidly growing market and presents a large opportunity for the oil service companies (Bonino, 2015). In 2014, only around 12% of North Sea installations had been decommissioned, reflecting the nascent nature of the decommissioning market (Lavelle & Jenkins, 2014).

The decommissioning service market can be divided into separate supply chain entities, with limited capacity and lack of specialized decommissioning technology (Lavelle & Jenkins, 2014). An example of a supply chain entity is lifting services. The upstream oil companies use lifting services for example when shipping the topsides to shore. The vessels employed to do large lifts are highly specialized, requiring large upfront investments from the service companies.

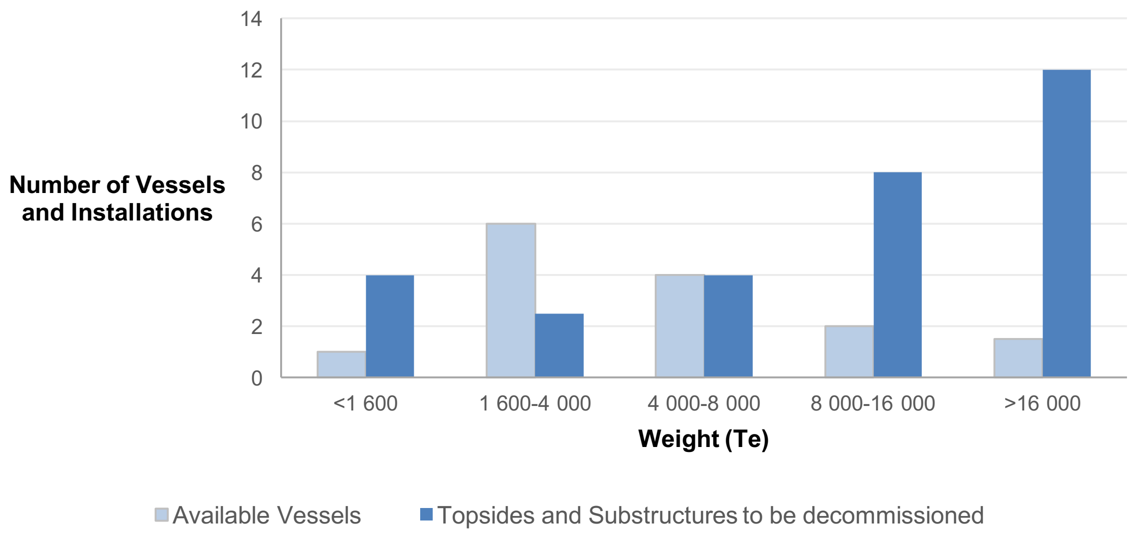


Figure 2-6: *Number of installations to be decommissioned in the Northern North Sea and available vessels globally (by respectively weight and lifting capacity). Adapted from Lavelle & Jenkins (2014).*

Figure 2-6 illustrates the discrepancy between the capacity of available vessels and future need for topside and substructure removal in the Northern North Sea[8]. As can be seen in the

[8] Includes installations located on the UK continental shelf and the Norwegian continental shelf.

figure, there is a clear need for vessels with lifting capacity of 8,000 metric tons and more. These vessels service the entire global market and are also used by other industries, further emphasizing the capacity issue.

The rig service is another example of a supply chain entity with limited capacity and a lack of specialized decommissioning technology (Lavelle & Jenkins, 2014). Currently, the same rigs that are used for exploration and production are being used for the permanent plugging and abandonment of wells. These rigs are typically too big to carry out the decommissioning work in a cost efficient manner. In addition, capacity constraints cause the rental cost of rigs to increase with high offshore activity levels. Future decommissioning solutions are believed to be rig-less and significantly cheaper than the current solutions.

The service industry points to one major problem that explains the central capacity and technology issues: the lack of transparency (Lavelle & Jenkins, 2014). Since there is a lot of flexibility and uncertainty surrounding the ideal timing of decommissioning, the oil companies have been reluctant in sharing any information regarding future needs of decommissioning services. This has again hampered the ability of the service industry to make upfront investments in necessary R&D and equipment.

2.3.3 The Upstream Oil Company Perspective

The operator of a field is responsible for planning and executing the decommissioning work. Even though the Government is highly involved in the decommissioning process, the oil companies possess some flexibility in deciding the timing of abandonment. Determining the optimal time of abandoning a field can be considered a cost minimization problem (Cole, Kar, Lock, & Christ, 2015).

When determining optimal time of abandonment there are several considerations to be made. Firstly, additional revenues and costs are associated with prolonging production. Conducting decommissioning work also forces the oil companies to divert capital and human resources away from revenue generating activities. The oil companies therefore incur an alternative cost by conducting decommissioning work. Moreover, there may be future technological improvements in removal equipment that will decrease costs. The many incentives to postpone the decommissioning costs have resulted in a recent global trend among the upstream oil companies to leave the platform idle in order to postpone parts of the decommissioning cost (Bardi et al., 2015).

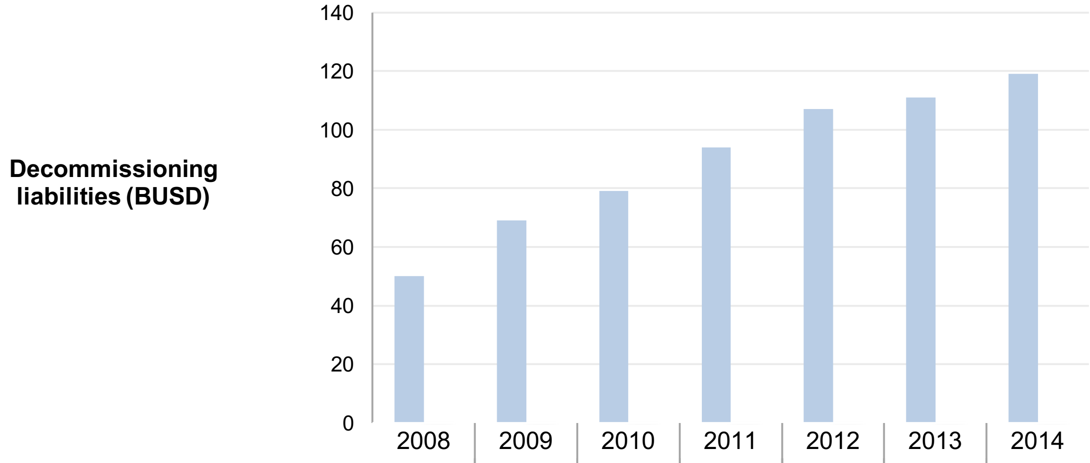
	Abandonment Expenditure (ABEX)
Asset 1	800
Asset 2	455
Asset 3	100
Asset 4	19
Asset 5	31

Table 2-1: *Examples of estimated decommissioning cost of five assets on the NCS. In million USD (Rystad Energy, 2016).*

The magnitude of the total removal costs are expected to vary greatly between the installations on the NCS (Osmudsen & Tveteras, 2003). Table 2-1 presents five assets on the NCS and their respective abandonment expenditures. These expenditures are realized for some assets and budgeted for the rest. The table gives an idea of the variations of abandonment cost between the assets. Note that abandonment expenditures vary from 31 MUSD to 800 MUSD. These variations are explained by the heterogeneity of installations on the NCS. Also, the geological conditions of individual fields differ greatly, further increasing the variations in removal costs[9].

The decommissioning liabilities will present challenges for some oil companies in terms of liquidity (Foley, Crooks, & Oakley, 2016). Operating in the mature oil and gas industry, the companies are already experiencing pressure on liquidity. To compensate for a low price to earnings ratio, oil companies often provide high dividend yields to their shareholders. During the recent fall in the oil price, some companies were forced to take out loans in order to continue paying high dividends. The aggressive dividend policy in combination with the low oil price have contributed to solvency issues for some oil companies (Forbes, 2016). When liquidity is low, the motivation to take on decommissioning costs is further reduced.

[9] The Ekofisk field has experienced challenges related to seabed subsidence, substantially impacting decommissioning costs (Nagel, 2001).



	2008	2009	2010	2011	2012	2013	2014
Decommissioining liabilities (BUSD)	50	69	79	94	107	111	119
Share of market capitalization	4%	5%	6%	7%	8%	8%	10%

Figure 2-7: *Decommissioning liabilities as share of market capitalization (2008-2014) adapted from Bardi et al. (2015).*

Following lower oil prices and maturing fields, the abandonment cost is becoming an increasingly higher share of market capitalization for the major multinational upstream oil companies (Bardi et al., 2015). Figure 2-7 illustrates that abandonment cost now presents 10% of total market capitalization of the major upstream oil companies worldwide, with a compound annual growth rate of 13% between 2008 and 2014.

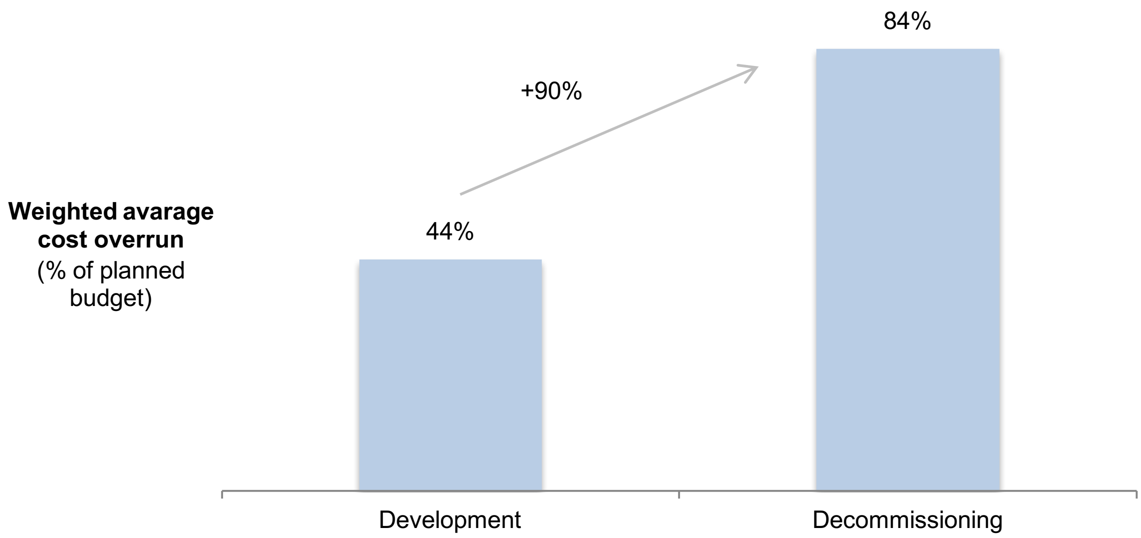


Figure 2-8: *Percentage decommissioning cost overrun for decommissioning projects versus development projects on the UK continental shelf. Adapted from Cole et al. (2015).*

Figure 2-8 illustrates the magnitude of cost overruns in decommissioning projects on the UK continental shelf. The problem of accurately estimating the decommissioning cost presents a challenge for the companies' internal budgeting and control (Cole et al., 2015). Estimating decommissioning costs for a specific project is made difficult due to both market and project specific uncertainties. The nascent nature of the decommissioning market makes it a reasonable assumption that the decommissioning cost will decrease with time. However, when and to what extent this development will happen is highly uncertain, making it difficult to predict the cost of abandoning a field in the future. In addition, the unique project specific risk and the little decommissioning experience of oil companies often results in an underestimation of decommissioning costs.

There are examples of operators on the NCS that are looking for opportunities to transfer the responsibilities of the decommissioning work to other operators (Taraldsen & Qvale, 2014). A decommissioning strategy frequently applied by upstream oil companies internationally has been to divest aging offshore assets well before the asset reach the end if their productive life-time (Bardi et al., 2015). Maturing assets are sold to smaller, specialized companies that are able to operate mature fields at a lower cost. On the NCS, at least one company has already positioned itself as an operator specialized in late-life operations and decommissioning (Ånestad, 2015).

Concluding Remarks

As we have discussed in the preceding sections, the decommissioning cost presents both challenges and opportunities for key stakeholders. The Government will bear a large fraction of the cost and are facing several policy issues. For the service industry the decommissioning work presents new business opportunities, although transparency issues might hinder the exploitation of such opportunities. Finally, the upstream oil companies are operating in a maturing industry with liquidity issues and have several incentives to postpone the cost of decommissioning. These incentives might contradict the interests of the Government, creating a principal-agency problem.

3 Risk and Uncertainties in Late-life Operations and Decommissioning

The oil and gas industry is characterized by a great deal of uncertainty, partly due to a volatile price environment, but also due to project specific risks. The risk is amplified by long investment horizons and high irreversible capital investments. Nevertheless, it is not certain that all risk factors should be taken into account when evaluating investment opportunities. The risk factors considered for project analysis should be the *relevant* risk factors exclusively (Bøhren & Ekern, 1991).

The goal of this chapter is to establish which are the relevant risk factors in valuing late-life operations. Specifically, we need to determine which risk factors to model stochastically and what risk-adjusted rate to apply for our analyses. In order to do so, the first section of this chapter categorizes the risk factors of an oilfield on the NCS. Here, the uncertainties affecting the project through its full life span are described. Secondly, we introduce the concept of relevant risk. Finally, we explain the choice of risk factors modeled stochastically for our Real Option Model, and which risk factors are considered relevant for estimating the project's risk-adjusted rate.

3.1 Risk Factors of a Petroleum Project on the NCS

According to Bøhren & Ekern (1991), the risk of an oilfield project prior to development can be grouped into five categories:

1. Reservoir risk
2. Development risk
3. Production risk
4. Revenues risk
5. Political risk

Reservoir risk relates to the uncertainties facing the oil company during the exploration phase where appraisal wells are drilled to determine the extent and size of a deposit. The development risk includes the uncertainties regarding capital investments required and the timing of initiating production. As soon as production starts, uncertainties about the field's production profile, recovery rate and operational costs emerge. During the production phase there will also be risks related to revenues, due to exchange rates and the price of crude oil and natural gas. Finally, the companies are faced with political risks concerning tax systems and regulations, which will vary globally.

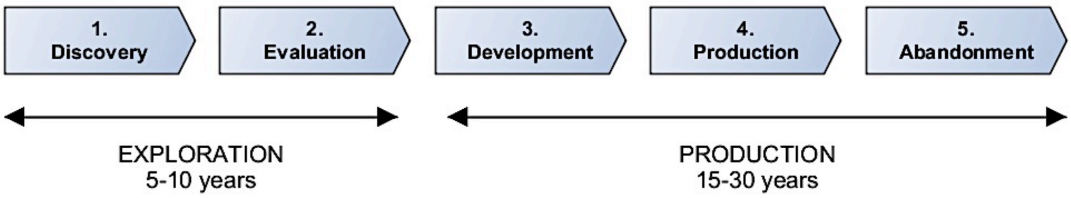


Figure 3-1: *The different phases of a petroleum project. Adapted from IFP School (2014).*

The categorization of Bøhren & Ekern (1991) does not consider risk related to the tail production and abandonment phase (see figure 3-1). Keeping in mind that there are significant uncertainties regarding the ultimate abandonment cost and which decommissioning solutions will be provided in the future, we introduce the concept of a sixth risk factor; *abandonment risk.* As discussed in the previous chapter, the companies are faced with uncertainties of what the ultimate abandonment cost will be. These are related to immature technological solutions for abandonment, supply chain bottlenecks and project specific challenges of operating mature fields.

Categorizing the risk factors of a petroleum project is merely a task of identifying uncertainties arising through the various phases of the project. For project valuation, one does not necessarily take into account all risk factors, only those that are considered relevant. Relevant risk is defined as the risk that investors require compensation for being exposed to (Bøhren & Ekern, 1991).

3.2 The Concept of Relevant Risk

A decision-maker will, according to standard financial theory, chose between investment alternatives based on his preferences[10] and the opportunities available (Bøhren & Ekern, 1991). The decision-maker is holding a starting portfolio (S) of his total economic activities; both existing and planned. Adding a new project (P) to the starting portfolio, the decision maker is left with what we will call an end portfolio (E). Their relationship can be defined as:

[10] However, under the presence of efficient financial markets and assuming the separation theorem holds, a company does not have to consider the preferences of its owners (Bøhren & Ekern, 1991).

$$E = S + P \tag{3.1}$$

Any project is preferred if the end portfolio, $E = S + P$, is preferred over the starting portfolio, S (Bøhren & Ekern, 1991). If the end portfolio is preferred, it thus implies that the project yields a positive net contribution to the starting portfolio.

The relevant risk of a project will be the project's contribution to the uncertainty in the end portfolio (Bøhren & Ekern, 1991). This risk will depend on the composition of the starting portfolio and its covariance with the project. The relevant risk of a project (P) is determined by the change in risk when moving from the starting portfolio (S) to the end portfolio (E). Based on standard rules of calculation, the relevant risk of a project can be defined as:

$$Var(E) - Var(S) = Var(P) + 2Cov(P, S) \tag{3.2}$$

In words, equation (3.2) shows that the project risk contribution to the end portfolio is defined as the project's variance, $Var(P)$, plus two times the project's covariance with the starting portfolio, $2Cov(P, S)$. The formula illustrates the relevance of the covariance between the project and its reference portfolio. In a well-diversified portfolio, a single project will have a small variance in relative terms, and the relevant risk is mainly determined by the covariance between the project and the starting portfolio.

The capital asset-pricing model (CAPM) is based on the assumption that investors are well diversified (Berk & DeMarzo, 2014). The CAPM determines the expected return of a project through its covariance with a broad market index. Using the CAPM for project valuation, it is thus assumed that the investors of a firm are well diversified by holding a starting portfolio in which the non-systematic risk is diversified away. The relevant risk of a project thereby becomes the covariance of the project with the market portfolio, which is denoted β.

In the CAPM, the covariance of the project with the market portfolio can further be decomposed into three parts: macroeconomic risk, project specific risk and a correlation coefficient between the two (Bøhren & Ekern, 1991). These components will jointly determine β and subsequently the relevant risk of a project. The macroeconomic risk is represented through the standard deviation of the market portfolio. Project specific risk is determined by the standard deviation of the project's market-based rate of return. The final component of relevant risk in CAPM is the correlation coefficient between the return of the market portfolio and the return of the project.

3.3 Risk Considerations in the two Models

For the project's risk-adjusted rate, a capital asset pricing model approach is applied. The same theory forms the basis for determining discount rates applied for project valuation in Statoil. It is thereby assumed that relevant risk factors are determined by the projects covariance with the market portfolio (Mullins, 1982). Investors are assumed to be well diversified and are consequently only compensated for holding non-diversifiable risk (or systematic risk).

It should however be noted that the risk factors considered relevant in practice might depend on the level of analysis (Bøhren & Ekern, 1991). At the project level, an analyst who does not hold a well-diversified portfolio will typically consider all project specific risk factors relevant. At the company level, the reference portfolio consists of the company's current and planned activities in addition to its investments in real assets and stocks. The relevant risk will be the covariance of the project with this reference portfolio. From a national level of analysis, the project specific risk can normally be neglected and relevant risk is determined by the contribution of the project towards domestic value creation.

For our Real Option Model, the price uncertainty of crude oil and natural gas are modeled stochastically. Only one source of uncertainty is considered for the sake of modeling simplicity. Adding more than one source of uncertainty, particularly if the uncertainties are uncorrelated, would lead to challenges in presenting the results. We believe the additional insights of such a model would not compensate for its increased complexity.

Price risk is considered a relevant risk factor for several reasons. First of all, price risk is a relevant risk factor at all levels of analysis, as it cannot be fully diversified away. Secondly, revenues are small relative to costs for a marginal field. Therefore, a drop in the crude oil and natural gas prices can make a field unprofitable overnight. The sensitivity of project value to prices is confirmed by our sensitivity analysis. In both models, changes in crude oil prices have the greatest effect on project value of the analyzed variables. The full sensitivity analysis can be found in Appendix D.

In extensions of our Real Option Model, the uncertainty of the abandonment cost is also taken into account. Following crude oil prices, changes in decommissioning cost has the second biggest effect on project value according to our sensitivity analysis. In addition, as explained in the previous chapter, there are several risks associated with the process of decommissioning an asset. For instance, there exist uncertainties of what the ultimate abandonment cost will be, depending on market conditions. In the “cyclical decommissioning cost” scenario, the abandonment cost is modeled stochastically assuming that the abandonment cost is correlated with crude oil and natural gas prices.

Concluding Remarks

In this chapter we present a categorization of the risk factors of an oilfield project on the NCS. The categorization bases on the five risk factors of Bøhren & Ekern (1991). In addition, we introduce a sixth risk factor: abandonment risk. Further, we highlight that the relevant risk of a project depends on its contribution to a reference portfolio. For the NPV Model of our analysis, we apply an equilibrium model approach (CAPM), in which relevant risk is determined by the covariance of the project with a well-diversified market portfolio. For the Real Option Model of our analysis, we model the price risk of crude oil and natural gas. In extensions of our model, abandonment cost risk is also considered. As can be demonstrated in our sensitivity analysis, project value is most sensitive to these variables (see Appendix D).

4 Financial Frameworks for Project Valuation

As discussed in the previous chapter, there is a great deal of uncertainty facing an upstream oil company, and relevant risk factors need to be accounted for in project valuation. Firms in the oil and gas industry have long used quantitative tools for decision-making, and many have been early adopters to new project valuation methods (Smith & McCardle, 1999).

Several studies suggest that the net present value method is the most widely used tool for project valuation in practice (McDonald, 2006). In a much-sited study from 2001, 75% of the 392 responding CFOs said they "always or almost always" use the NPV method (Graham & Harvey, 2001). In contrast, only 25% of those CFOs claimed to have used real option methods.

In this chapter, we provide an overview of the NPV and real option methods for project valuation. Firstly, the NPV method is summarized briefly and some advantages and disadvantages are discussed. Secondly, the real options theory will be the focus of attention. The real options methodology requires a more comprehensive explanation, as there are several ways to model and solve a real options problem. The ultimate goal of this chapter is to explain the underlying modeling choices of our Real Option Model.

4.1 Net Present Value Analysis

According to several studies, the net present value analysis is the most widely applied and taught method for project valuation (McDonald, 2006). It serves as an important input in the decision-making process at Statoil and is also a central valuation tool in other major oil companies.

The NPV method involves computing expected future cash flows and discounting these cash flows at the cost of capital (Berk & DeMarzo, 2014). The NPV calculation can be expressed as follows:

(4.1)
$$NPV = \sum_{t=0}^{\tau} \frac{CF_t}{(1+k)^t}$$

Where CF_t is the cash flow at time t and k is the discount rate. The discounted cash flows are summed over the life of the project, τ. The NPV rule states that projects with positive NPVs should be accepted, since they will contribute positively to the company value (Jagannathan & Meier, 2002).

The components that constitute the NPV formula are unknown; thus they must be estimated. The estimation needs to take into account various probable outcomes. For an offshore oilfield, the cash flows are typically highly uncertain, depending on commodity prices, retrieved quantities and costs. In addition, the life of the project is unknown. Estimating future cash flows for an offshore field requires specialized knowledge and a great deal of work due to project complexity. Once the point estimates of cash flows are obtained, the NPV calculation itself is a relatively straightforward procedure.

The risk factors considered relevant for the project are adjusted for using an estimated cost of capital, k, which is referred to as a risk-adjusted rate. In the study of Graham & Harvey (2001), the authors find that three out of four CFOs use the capital asset pricing model (CAPM) as the primary tool to calculate the cost of capital. The discount rate applied for project valuation at Statoil also bases on the fundamental concepts of the CAPM approach. The CAPM equation can be expressed as follows:

(4.2) $$k = r_f + \beta(r_m - r_f)$$

The CAPM relies on the general idea that investors holding a project should be compensated for the time value of money plus risk (Jagannathan & Meier, 2002). Time value of money is accounted for through the risk-free rate, r_f, which can be found in the market using for instance government bonds. The risk premium for holding the project is determined by its beta, β, times the excess return of the market over the risk-free rate, $(r_m - r_f)$. As a proxy for the project beta, one can use the betas of listed companies with similar risk characteristics as the project itself. The excess return of the market over the risk-free rate, also known as the market risk premium, is commonly estimated using the historical average return of a broad equity market index such as the S&P 500.

The CAPM asserts that beta is the only relevant risk measure for a project (Jagannathan & Meier, 2002). The beta of a project, i, can be decomposed as follows:

(4.3) $$\beta_i = \frac{\sigma_i}{\sigma_m}\rho_{im}$$

Where σ_i is the standard deviation of project return, σ_m is the standard deviation of market return and ρ_{im} is the correlation coefficient between the two.

In general, the cost of capital will be the expected rate of return offered to investors by the equivalent-risk investments traded in capital markets (Brealey, Myers, & Allen, 2006). The cost of capital should reflect the way in which a project is financed. In order to apply the discount rate derived from the CAPM directly, one must assume that the project is all-equity financed. Typically, a project is financed through both equity and debt, and the cost of capital should therefore include the cost of both. The weighted average cost of capital (WACC)[11] is commonly applied for this purpose. To account for the tax benefits of debt financing, one can use the adjusted WACC method or the adjusted NPV method.

Advantages of the NPV method include its intuitive and straightforward application. The NPV is a clear and consistent decision criterion that can be used for all projects (Mun, 2002). Mun (2002) further highlights that the NPV method is quantitative, obtains a decent level of precision and is economically rational. In summary, the NPV method is a relatively simple, widely taught and widely accepted method that can easily be communicated throughout the organization. The latter can be said to be particularly important for the oil and gas industry where managers have various academic backgrounds.

Several authors have criticized the NPV method. According to Mun (2002), the fundamental issue with the NPV method is that it assumes an investment is an all-or-nothing strategy. It does not account for the managerial flexibility that exists, making it possible to alter the course of an investment over time. The use of the NPV method can thereby lead to undervaluing projects by not taking into account their associated flexibilities. The difficulty in estimating and applying an appropriate discount rate has also been subject to criticism. McDonald (2006) argue that the common practice in applying a constant discount rate over time can lead to errors in project valuation.

The limitations of traditional methods have also been a subject of concern for the industry. Smith & McCardle (1999) conducted a study in collaboration with a major oil and gas company. The company used sophisticated tools to estimate future cash flows, and relied upon NPV for project valuation. Management had mainly two issues with the NPV method.

[11] In which the cost of equity and debt are weighted according to the company market value of equity and debt over total company value (Brealey et al., 2006).

Firstly, there was a concern that the method did not capture some of the flexibilities associated with projects. Secondly, management was concerned about the way they discounted cash flows. Every project was discounted at the same rate held constant over time. For projects with investment horizons of 30 to 40 years, the NPV was extremely sensitive to the discount rate.

4.2 Real Options Analysis

To account for the challenges of traditional NPV methods, new approaches to project valuation have been proposed. Real option analysis (ROA) has been presented as an alternative to the traditional NPV method by some authors (see for instance Brennan & Schwartz, 1985). Others view it as a valuation supplement to the NPV method, in which the traditional NPV is seen as a crucial and necessary input to an options-based expanded NPV analysis (see for instance Trigeorgis, 1993). Common to most applications, real options analysis copes with the problem of valuing managerial flexibility.

"Real options" refer to the application of financial option pricing theory to the valuation of investments of non-financial or "real" assets (Borison, 2005). Its first application dates back to Stewart Myers in 1977. During the past 30 years, real options theory has received extensive academic and industry attention. ROA has proved to be an appealing concept from a theoretical perspective. However, a great variety of approaches have been suggested for implementing real options in practice, resulting in application challenges. In the following sections, some key aspects of real options theory will be explained.

4.2.1 Fundamental Concepts

By definition, an option is the right, but not the obligation, to buy or sell an asset at a predefined price at some point in the future (Brealey, Myers, & Allen, 2006). The option is written on an underlying asset facing uncertainty. For financial options, the underlying is a traded asset, typically a stock. For real options the underlying will be a real asset, such as a petroleum project (or the profit streams from a petroleum project).

There are two main types of options; call options and put options (Brealey et al., 2006). A call option gives the holder of the option the right to buy the underlying at a specified exercise price on or before a specified exercise date. If the option can be exercised at its expiration date only, it is known as a European call. If the option can be exercised at any time before or at expiration, it is referred to as an American call. A put option gives its holder the right to sell the underlying. Like that of a call option, there also exist American and European put options. The payoff of a call and a put option can be expressed as follows:

(4.4) $$Call: Max(U - K, 0)$$

(4.5) $$Put: Max(K - U, 0)$$

Where U is the value of the underlying asset and K is the option exercise price (also known as strike price). The payoff of an option thus represents the difference between the underlying asset and the price of exercising the option. An option will either have a positive payoff, or a payoff of zero. The payoff of an option will never be negative, as the holder of the option is not obliged to exercise.

A call option is "in-the-money" whenever the value of the underlying is greater than the exercise price (Brealey et al., 2006). This means that exercising the option will yield a positive payoff. However, if the exercise price is greater than the value of the underlying, the call option is said to be "out-of-the-money". For the put option, the exact opposite will be true. A put option becomes valuable whenever its exercise price is greater than the value of the underlying. In other words, the put option becomes valuable since one is able to sell the underlying asset for a price above its market value.

Unlike financial options, real options are not traded in a market (Berk & DeMarzo, 2014). In general, a real option represents an opportunity available to its owner. The decision makers of a firm have such opportunities available at various points in time. It can for instance be the opportunity to invest, or opportunities emerging at the various phases of a project. The general idea of real options analysis is to value these opportunities and the flexibility they represent to management.

4.2.2 Types of Problems

Several types of real options have been studied, with the most general being the option to invest (Lander & Pinches, 1998). Specific types of real options include options to defer, options to abandon, options to switch (e.g. inputs or outputs), options to alter the operating scale, growth options and options of staged investment. Some options occur naturally while others can be acquired at some additional expense.

Kodukula & Papudesu (2006) group real options in two main categories: simple options and compound options. The deferral and abandonment options mentioned above are examples of simple options. Compound options are also known as “options on options”, and their values depend on the value of another option rather than the underlying asset value. Growth options and staged investment options are examples of options that are typically valued as compound options (Trigeorgis, 1993).

The initial application of real options was for natural resources, but over the years many different types of problems have been modeled using real options (Lander & Pinches, 1998). These include amongst others manufacturing, real estate and R&D. Applications are characterized by cases where there is a great deal of uncertainty and managerial flexibility (Copeland & Antikarov, 2001). Generally, higher uncertainty and more flexibility result in a greater option value.

The option to defer, the option to alter the operating scale and the option to abandon are examples of options that are potentially important in the oil and gas industry (Trigeorgis, 1993). The option to defer occurs when management has the option to buy a license, but can wait and see if output prices justify developing a field. The option to change operating scale of a platform can sometimes be of significant value due to fluctuating prices. The option to abandon refers to the opportunity to abandon an unprofitable field permanently. The abandonment option can be viewed as an American put option, while the option to defer is typically modeled as an American call option.

4.2.3 Modeling Approaches

There are two main modeling approaches within real options theory; dynamic programing and contingent claims analysis. These approaches are closely related and lead to identical results in many applications (Dixit & Pindyck, 1994). Nevertheless, they make different assumptions about financial markets and the discount rates used for valuing future cash flows.

Dynamic programming, or dynamic optimization, is a general tool applied for treating uncertainty (Dixit & Pindyck, 1994). It can be used for a great variety of problems. Simply explained, dynamic programming breaks down a whole sequence of decisions into two components. These components are the immediate decision plus a valuation function that encapsulates the consequences of all subsequent decisions. With a finite planning horizon, the problem can be put forward in a decision tree, and the solution can be found using standard static optimization methods. Solving a decision tree is done by considering the optimal choice at every node of the tree and using the method of backward induction. Backward induction entails working from the back of tree all the way to the initial condition using optimization.

Contingent claims analysis has a close link to financial option pricing theory, as it builds on ideas from financial economics (Dixit & Pindyck, 1994). The general idea is to utilize market data in order to value a project. A project can be viewed as a stream of costs and benefits that vary through time depending on the unfolding of uncertain events. In other words, the firm owning a project also owns the right to the stream of operating profits. For an oilfield, there will be a market price for oil and gas, which will determine its operating profits. Utilizing that market data, one can thereby compute a value of the project.

If the project output is not traded, one can still compute an implicit value for it by relating it to other assets that are traded (Dixit & Pindyck, 1994). In order to do so, one needs a portfolio of traded assets that will exactly replicate the pattern of returns from our project, at every future date and uncertain eventuality. Under the law of one price, the value of our project must equal the total value of that replicating portfolio. The law of one price states that any discrepancy between an asset and a portfolio yielding an equal payoff in all future states would represent an arbitrage opportunity: a sure profit by buying the cheaper of the two assets, and selling the expensive one. Such arbitrage opportunities would in theory not exist, as they are traded away quickly.

In practice, the two approaches described above differ in the use of input data. The contingent claims analysis utilizes market prices of a traded asset with the same risk characteristics as our project. This is known as the use of spanning assets. A spanning asset is an asset whose risk tracks or spans the uncertainty in the projects output variable (Dixit & Pindyck, 1994). The contingent claims method requires a volatility estimate of the output variable. For an oilfield this would be an estimate of the volatility of crude oil prices. The contingent claims analysis approach does not require the use of a risk-adjusted rate; the risk-free rate is sufficient. On the other hand, dynamic programming typically utilizes a risk-adjusted rate together with objective or subjective probabilities for future outcomes.

In the literature, there is not always a clear distinction between the two approaches, and they are sometimes combined. An example of this, is the so-called "integrated" approach by Smith & McCardle (1998), in which the authors integrate dynamic programming and contingent claims analysis. Another example is provided by Brandão, Dyer & Hahn (2005), who combine decision tree analysis methods with option pricing techniques. Similar to other authors, Brandão, Dyer and Hahn are not using spanning assets to estimate project volatility. They use the project's own cash flows estimated through a Monte Carlo simulation. This is often referred to as the Marketed Asset Disclaimer (MAD) approach, first introduced by Copeland & Antikarov (2003). The MAD approach assumes that the project itself can be used as a spanning asset by treating it "as if" it was a traded asset.

4.2.4 Practical Solution Methods

There are several methods for valuing real options in practice. So far, we have focused on types of real options problems and the main modeling approaches. The focus of attention is now directed to how these problems are solved in practice. In this section, we provide an overview of practical solution methods. Here, practical solution methods refer to the available methods for deriving the project value with flexibility.

Option valuation techniques can be grouped into three main categories: partial differential equations, simulations and lattices (Kodukula & Papudesu, 2006). Within each of these categories there are many alternative computational techniques to deal with the mathematics. The choice of method will in practice depend on the simplicity desired, available input data and the validity of the method for a given application. Some methods have been criticized for being too complicated with the use of complex mathematics that can be difficult to explain to management. Others are more intuitive, but often at the cost of applicability and precision.

An example of a partial differential equation method is the famous Black-Scholes model (Kodukula & Papudesu, 2006). Black & Scholes (1973) provided a theoretical valuations formula for options based on the law of one price. Its original application was for financial options, but it has also been applied for valuing real options (see Luehrman, 1997, 1998, 1998). The method has a relatively straightforward application, but relies on several restrictive assumptions limiting its application for real options. For instance, it cannot be used to value American put options.

The simulation method involves simulating thousands of paths the underlying asset value may take during the option life (Kodukula & Papudesu, 2006). The volatility of asset value will determine the boundaries for the simulation. This method requires the use of Monte Carlo simulation software, and it is not frequently applied in the literature. Simulations can easily be used for valuing European options, but it is a very time-consuming method for valuing American options and compound options.

Lattices are frequently applied in the literature, with the most popular being the binominal lattice method. The binominal lattice method was first introduced by Cox, Ross, & Rubinstein (1979), but has later been adapted by others. The method that will be described here involves two steps. It starts with the modeling of an "event tree" (Copeland & Antikarov, 2001). The event tree shows the possible future values of the underlying asset over a given number of time steps. In each time step, the value of the underlying can either go up or down[12], hence increasing the number of outcomes with time. The up and down movements reflect the volatility of the underlying asset.

In the binominal lattice method, the value of the underlying follow a multiplicative binominal process over discrete periods (Cox et al., 1979). However, the discrete binomial lattice model will approximate a continuous-time process as the number of time-steps increases. As for most real option methods, the process of the underlying is assumed to be random, typically described as a geometric Brownian motion[13].

As a second step of the binomial lattice method, one would model a decision tree (Copeland & Tufano, 2004). In a decision tree, the decision maker will compare the future values of the underlying asset against available options. In order to solve for the value of the option, one would have to start at the end of the tree (furthest out in the future). The decision tree is solved by optimizing future decisions at different points in time and folding them back using risk-neutral probabilities or the method of market-replicating portfolios. These alternative methods yield the exact same result, as both methods are built on a no-arbitrage argument.

The method for solving a real options problem through a binominal lattice with risk-neutral probabilities is further described in Appendix A.

[12] In the quadrinomial lattice, two sets of upward and downward movements are applied for each time step (Kodukula & Papudesu, 2006).

[13] A stochastic process follows a geometric Brownian motion if it satisfies the following stochastic differential equation: $dS_t = \mu S_t dt + \sigma S_t dW_t$, where S is the stochastic process, W is a Wiener process, μ is the drift and σ is the volatility (Olsen & Stensland, 1988).

4.2.5 Modeling Choices of our Real Options Model

As we have seen so far, there is no single way to formulate a real options problem. Therefore, this section is set out to explain the key modeling choices of our Real Option Model. Our model is based on a contingent claims analysis approach. Further, we model an abandonment option as an American put option. Finally, we apply a binominal lattice with risk-neutral probabilities in order to solve for the project value with flexibility.

The modeling decisions are based on three criteria we believe are important for our particular application.

1) Capture the decommissioning problem

First of all, we would like the Real Option Model to be able to capture the complex decommissioning problem. A typical late-life petroleum asset will experience negative cash flows when costs surpass the declining revenues. The model therefore needs to be able to manage a scenario where negative cash flows occur. Nonetheless, we are willing to make simplifications in order to keep the method intuitive. In other words, we accept that our model will not represent reality completely, as it never will.

To be able to model reality in the best possible way we first need to identify the type of problem we are analyzing. The option to abandon an oilfield is believed to have the same properties as an American put option. The decommissioning cost represents the exercise price of the option. The expiration of the option represents the potential life of the project. The life of the project is limited as it is likely that the production license expires at some point in time or that the equipment deteriorates such that investments must be made in order to continue production. In addition, it is likely that the company is able to abandon the field at any time during project life (making it an American option as opposed to an European option). This would however include a response time, lasting from the time the abandonment decision is made until the decommissioning process is initiated, which needs to be incorporated in the model.

2) Take advantage of available information

We believe it to be advantageous to apply a real options method in which we are able to best utilize the information at hand. A distinctive feature of the oil and gas industry relative to other industries is that the production outcome, the crude oil and natural gas, are widely traded products in relatively efficient markets (Kristoufek & Vosvrda, 2014). These commodity markets make it possible to retrieve information on historical and expected future prices. On the other hand, we are not provided with information on the underlying factors used in the estimation of cash flows. It is therefore hard to obtain any probabilities of the various outcomes of the project.

For this reason, a contingent claims approach is chosen over dynamic programming. The contingent claims approach actively applies the readily available market data. The approach is therefore frequently chosen for valuing petroleum projects (see for instance Ekern, 1988; Pickles & Smith, 1993; Smit, 1997).

3) Intuitive, comprehensible and possible to communicate

As we are evaluating the potential of applying real options analysis for abandonment decisions at Statoil, we will argue that it is of great importance that the method is intuitive, comprehensible and possible to communicate. It is important that project analysts understand how to implement the method, and that they are able to communicate it to senior management. Keeping in mind that management might be completely unfamiliar with real options, we believe this to be an important consideration. In our opinion, the approach will only be of value if the decision-makers accept it.

The Real Option Model is thus formulated in a relatively simple manner, using a binominal lattice. Binominal lattices posses the advantage of being straightforward to illustrate graphically. In addition, solving a binominal lattice only requires basic algebra. A differential equation on the other hand, requires sophisticated mathematics rarely used in practice in the industry. A simulation solution method would require computations through Monte Carlo software, hence making the results less transparent.

Concluding Remarks

This chapter provides an overview of two financial frameworks for project valuation: the net present value framework and the real options framework. The NPV method involves computing a project’s expected future cash flows and then discounting these cash flows at a risk-adjusted rate. The risk-adjusted rate should reflect the time-value of money and the riskiness of the project. The Real Option Model is somewhat harder to summarize briefly, but typically involves the modeling of a project’s future cash flows as a function of some “state variable” that is assumed to evolve randomly over time. Project value can for instance be found through the use of risk-neutral probabilities, but there exist several practical solution methods for solving a real options problem.

A great variety of modeling approaches and implementation difficulties might explain why the real options framework is less frequently applied compared to the NPV framework. Implementing a real options model requires some modeling choices depending on the problem at hand. The final section of the chapter explains the modeling choices of our real options analysis.

5 Litterature review: Optimal Abandonment Timing and Real Options Valuation

This chapter reviews a small fraction of the vast literature available on the optimal abandonment of assets and real options valuation. A special focus is paid on applications in the oil and gas industry. Most real options applications focus on the early phases of a petroleum project like exploration and development, enabling comparison of projects to assure optimal capital allocation. Nonetheless, there is also relevant literature for evaluating later stages of a petroleum project.

5.1 Optimal Abandonment Timing

Determining optimal abandonment of an asset is a central part of project valuation, as it is not necessarily optimal to abandon an asset at the end of its economic life. The decision of optimal abandonment is addressed in some early articles. For example, Bonini (1977) uses discrete time dynamic programming and derive an abandonment rule for a project with uncertain cash flows. A general decision rule for optimal abandonment is also developed by Howe & McCabe (1983). According to Howe & McCabe (1983), an asset should be held until the one-period rate of return obtained by holding the asset for an additional period is less than or equal to the cost of capital. The authors emphasize that a project neither needs to be physically exhausted nor have a negative cash flow in order for abandonment to be optimal. For instance, a positive salvage value can make early abandonment optimal.

Another optimal abandonment rule is developed by Brennan and Schwartz (1985). In the frequently cited article, the authors value the option to temporarily shut down and restart production of a mine. They use a continuous time price process and derive an optimal decision rule in implicit form. In order to account for the difficulty in forecasting future output prices using traditional approaches, the authors utilize the information inherent in the commodity futures market and apply a convenience yield.

In some resource extraction industries, restarting production is not economically feasible, and the abandonment decision is therefore irreversible. This is typically assumed to be the case for offshore oil and gas extraction. An optimal shutdown rule for resource extraction in which the abandonment decision is irreversible is derived by Olsen & Stensland (1988). Their shutdown rule is given in explicit form and bases on a continuous time model with prices and production rates following geometric Brownian processes. The authors find that uncertainty will tend to prolong the extraction period compared to the deterministic case. Olsen & Stensland (1988) do not account for the effect of any salvage value or salvage cost on the abandonment decision.

A master thesis from the Norwegian School of Economics by Nygaard & Jørgensen (2011), explore how various oil price modeling assumptions affect the optimal abandonment timing of an oilfield. A real options model is applied using the discrete-time binomial lattice approach. The authors model crude oil prices through both a geometric Brownian motion and an Ornstein-Uhlenbeck process. By using risk neutral probability trees, the authors analyze the probability of continuing operations given various assumptions. The authors conclude that the modeling of crude oil prices has a great impact on the optimal abandonment. Based on their case material, abandonment occurs immediately in the deterministic case. However, with mean reverting prices there is a possibility that abandonment will be postponed, while a random price process additionally increases the likelihood of deferring abandonment.

5.2 Project Valuation Using Real Options

Several types of oil and gas valuation problems have been modeled in a real options framework. An early adoption was published by Ekern in 1988. Ekern experimented with the real options approach in valuing an expansion option of a so-called satellite field, which is a field that is located some distance away from an existing platform. Ekern (1988) models a binominal multiplicative random walk in oil prices. He also values a compound option: an operation option as an option on a development option. Ekern (1988) thus provides an example of how to account for the contingent decisions inherent in petroleum development projects. He concludes that the real options approach to project evaluation may give worthwhile supplemental insight into project profitability, but that the challenge remains to develop real options methods which are both applicable in practice and have a sound theoretical basis.

A simple approach to how option valuation can be applied in practice to the petroleum industry is presented by Pickles & Smith (1993). The authors apply a real options model using the discrete-time binomial lattice method first described by Cox, Ross & Rubinstein (1979). The goal is to value a discovered but undeveloped oil and gas reserve in the United Kingdom. Prices are modeled following a geometric Brownian motion. The authors conclude that a real options model is a useful alternative where cash flows are uncertain and where conventional techniques fail to recognize the value of managerial flexibility. They also point out that further work is needed to fully value compound options in petroleum development projects.

Another valuation of an undeveloped oil reserve is presented by Smith and McCardle (1999). The authors apply an “integrated” approach for evaluating options, combining dynamic programming techniques with contingent claims analysis, on a real petroleum project. The analysis is conducted in conjunction with a major oil and gas company (Smith & McCardle, 1998). The authors conclude that a real options framework can be viewed as a complementary modeling approach that can be “nicely integrated” with existing financial frameworks. The authors also describe some lessons learned when implementing this “integrated” approach for evaluating real and complex oil and gas investments.

Another intricate valuation problem is approached by Smit (1997). Smit applies a real options model first described by Dixit & Pindyck (1994) to estimate project value of a complex staged petroleum project on the Dutch continental Shelf. The model is based on a contingent claims analysis approach and uses a discrete-time binomial process. The option to abandon the field is evaluated in addition to other flexibilities present during the life of the project.

5.3 Real Options Applications in the Petroleum Industry

Although most articles are written by academics, there are examples of practitioners working in oil companies that have shared ideas and experience on valuing real life projects. A practical application of a real options model is presented by Armstrong, Bailey, & Couet (2005) from the oil service company Schlumberger. The authors provide a real options model for valuing additional well information in a production enhancement project. The model includes two sources of uncertainty, crude oil prices and well characteristics. The authors find little difference between using mean reverting oil prices and prices following a geometric Brownian motion.

Woolley & Cannizzo (2005) from the upstream oil company BP argues that real options might serve as a supplement to traditional NPV analysis. The authors explain how they have applied a real options model when considering expansion of extraction capacity of a natural gas plant in Asia. By using a Monte Carlo simulation technique and assuming mean reverting prices they demonstrate that an increase in oil price volatility increases the value of the expansion option.

A scholar at Statoil, Morten W. Lund (2003), applies a real options model based on dynamic programming to value an undeveloped field. Both market risk and reservoir risk are handled in the model, as well as several options and their interactions. Lund claims that capacity flexibility in oil projects has an especially large effect on project value whereas abandonment flexibility is only of relatively minor importance. He concludes that the value of total flexibility present during a petroleum project is substantial, and highlights the shortcomings of common evaluation methods like the net present value approach.

Opposing the views of M.W. Lund, McDonald (2006) argues that the added value of using real options theory in practice is exaggerated, and that the differences between NPV methods and real options valuation are not as great as many seem to believe. Reviewing surveys on how firms make capital investment decisions in practice, McDonald (2006) suggests that managers perform a variety of formal calculations and then make decisions by weighing the results and relying on subjective judgment. He proposes that part of this subjective judgment may represent managers' adjustments of NPV methods in ways to account for real options informally, for instance through a hurdle rate.

Concluding Remarks

In this chapter we have described some of the many articles that focus on optimal timing of abandonment and applications of real options in the oil and gas industry. In these concluding remarks we will focus on how our work relates to the existing literature.

Similarly to various authors (see for instance Ekern, 1988; Pickles & Smith, 1993; Smit, 1997), we apply a binomial lattice based on a contingent claims approach for our Real Option Model. While many of the authors focus on the full life of a petroleum project (see for instance M. W. Lund, 2003; Smit, 1997), we zoom in on late-life operations and abandonment. In addition, we employ two different financial frameworks to understand their inherent differences when applied in decommissioning analyses.

We have received project data from Statoil. The data is based on a field that is producing both crude oil and natural gas. Most articles only account for the uncertainty of crude oil prices (see for instance Ekern 1988; Nygaard & Jørgensen, 2011; M.W. Lund, 2003; Olsen

& Stensland, 1988; Smit, 1997). In our real options analysis, we model the uncertainty of both crude oil and natural gas prices.

As discussed in chapter 2, the abandonment of offshore oilfields on the NCS is becoming increasingly relevant as oilfields are maturing. Subsequently, more information about the sizeable and uncertain decommissioning cost has lately become available. Previous applications (see for instance Olsen & Stensland, 1988; Nygaard & Jørgensen, 2011; M.W. Lund, 2003) incorporate either a positive salvage value for the installation or does not account for the decommissioning cost at all. Based on conversations with contact persons from the industry, the decommissioning cost of a petroleum project on the NCS will most likely be significantly greater than any potential salvage value. In our analysis, we therefore incorporate a salvage cost in accordance to the project data received from Statoil.

Since the offshore decommissioning market is a relatively nascent market, general characteristics of the market have also emerged in later years. These characteristics include the trend of leaving the platform idle and the possibility that the decommissioning cost will decrease over time. Distinctive from the articles discussed, we try to incorporate these developments and their possible effect on project value.

6 The Two Models

The goal of this chapter is to present the two models applied in our analysis: the Net Present Value Model and the Real Option Model. By doing so, we aim to prepare the reader for the analysis and results as presented in chapters 8 and 9. First, the basic elements of the analyzed problem are set up. These are the elements common for both models. Second, there is a section devoted to the Net Present Value Model. Here, the focus of attention is developing a decision rule for the optimal time of abandonment. Such a decision rule will be beneficial for presenting the analysis results, as the ultimate tail value of the project will depend on the time of abandonment. Finally, the Real Option Model is explained. The Real Option Model section introduces the various scenarios to be analyzed. These scenarios are also analyzed in the Net Present Value Model in chapter 8. However, the scenarios only influence the modeling specifications when applied to the real options framework, and are therefore introduced in the final section.

6.1 Basic Elements

To be able to place a value on the project in the two models, we first need to define the basic elements of the problem analyzed. These elements are common for both models, but their interactions are modeled differently in the net present value and real options frameworks.

The problem analyzed is an offshore field on the NCS producing crude oil and natural gas. It has an exponentially declining production profile. The field has reached tail production, and is to be abandoned within a time frame of nine years.

The field produces a yearly cash flow defined as:

(5.1) $$CF_t = (Revenues_t - OPEX_t)$$

The CF_t is the cash flow of the oil company in period t. Operational expenditures (OPEX) mainly consist of maintenance costs and are assumed to be constant over time. These are related to the size of the field and will therefore remain relatively stable over the life of the project. The revenues are a result of production volumes and price development for crude oil and natural gas.

Project revenues at time t is calculated using the following equation:

(5.2) $$Revenues_t = p_t^{co} q_t^{co} + p_t^{ng} q_t^{ng}$$

Where p_t^{co} is the crude oil price per barrel at time t, p_t^{ng} is the natural gas price per Scm[14], q_t^{co} is the production of oil in barrels at time t and q_t^{ng} is the production of natural gas in Scm.

The exponential decline in production implies that the production will decrease at a given percentage each year. The production function can be defined as:

(5.3) $$q_t = q_0(1-\theta)^t$$

Where q_0 is defined as production at time 0. The scope of the analysis is limited to tail production, thus the production at time 0 represents the production at the starting point of the analysis, not the starting point of production. At time 0, the field has been producing for several years and is subsequently approaching abandonment. θ represents the annual decline in production, in which $0 < \theta < 1$. The annual decline in production is assumed constant over the analyzed life of the project.

For the base case of both models, it is assumed that decommissioning must occur by the end of the economic life of the project. As explained in chapter 2, decommissioning entails the permanent plugging of wells and the dismantling of the platform and other production facilities, in addition to other activities necessary for restoring the environment.

During the year of abandonment, there will be no profit flow, as production ceases one year prior to decommissioning, at time τ. There will however be operational expenditures incurred during the abandonment year (at time $\tau + 1$). In addition, all decommissioning costs are assumed to occur during the same year.

The cost of decommissioning, also referred to as the cost of abandonment, is defined as:

(5.4) $$\begin{aligned} A_{\tau+1} = {} & Cost(PP\&A) + Cost(Topside\ removal) \\ & + Cost(Substructure\ removal) + Cost(Other) + OPEX_{\tau+1} \end{aligned}$$

[14] Scm = Standard cubic meter. Provides a measure for natural gas volume under standard conditions. Standard condition is defined as an atmospheric pressure of 1.01325 bars and a temperature of 15 degrees Celsius (Gassco, 2016).

Where $A_{\tau+1}$ is the total cost of abandonment incurred during the process of decommissioning at time $\tau + 1$. The total abandonment cost is the sum of all cost components plus the operational expenditures at time $\tau + 1$. These cost components are assumed to be net of any potential salvage value for the equipment. In our base case, the abandonment cost is assumed constant over time.

6.2 Net Present Value Model

First, the problem is analyzed in a hypothetical world without uncertainty. Second, we introduce uncertainty to the model.

6.2.1 Under Certainty

Imagine that the world is certain, such that future cash flows are known with certainty. In a certain world, there are no risks associated with the future. Investors will thus not require any risk compensation for holding a risk-less project. However, compensation for the time value of money is required. In the Net Present Value Model, this translates to discounting the cash flows at a risk-free rate.

The net present value can be expressed as follows:

(5.5)

$$NPV^{\tau} = \sum_{t=1}^{\tau} \frac{CF_t}{\left(1 + r_f\right)^t} - \frac{A_{\tau+1}}{\left(1 + r_f\right)^{\tau+1}}$$

Where NPV^{τ} is the net present value of the project if held τ periods, and then abandoned at time $\tau + 1$. CF_t is the cash flow produced by the asset in year *t,* received at the end of each year until the year before asset abandonment. r_f represents the risk-free rate.

The decision rule for the problem under certainty is to maximize NPV, by changing the year decommissioning takes place. Because the world is certain, the decision-maker will stick to the initial decision made at time zero. By decomposing equation (5.5), we will be able to analyze which effects make it profitable to defer abandonment until the end of the project life, and which effects makes early abandonment desirable.

The cash flow consists of revenues net of operational expenditures, as described in equation (5.1). Revenues will always be positive, while operational expenditures are constant over the life of the project. Operational expenditures are mainly fixed costs dependent on the size of the platform. Consequently, they remain constant even though production and revenues decrease. A field with an exponentially declining production will at some point in time receive negative cash flows as revenues become smaller than operational expenditures. Revenues make it profitable to defer, while operational expenditures give motivation to abandon.

The abandonment cost is assumed to always be negative. Even with a positive salvage value related to the alternative use of the construction, it is assumed that the costs of restoring the environment to its initial state will surpass any potential benefits. Deferring a cost results in benefits related to the alternative use of money. In other words, a cost incurred in the future is worth less than a cost incurred today, meaning that the cost has a more negative effect on project value today relative to tomorrow. We will refer to this as the interest savings of deferring the abandonment cost.

The identified costs and benefits of deferral can be expressed formally by deriving the net present value of holding the asset one more year:

(5.6)
$$NPV^{\tau} - NPV^{\tau-1} = \sum_{t=1}^{\tau} \frac{CF_t}{\left(1+r_f\right)^t} - \frac{A_{\tau+1}}{\left(1+r_f\right)^{\tau+1}} - \left(\sum_{t=1}^{\tau-1} \frac{CF_t}{\left(1+r_f\right)^t} - \frac{A_{\tau}}{\left(1+r_f\right)^{\tau}}\right)$$

Remembering that cash flows consist of revenues and operational expenditures, we are able to decompose the net present value change in three effects:

(5.7)
$$PV(Revenues)^{\tau} - PV(Revenues)^{\tau-1} = \sum_{t=1}^{\tau} \frac{Revenues_t}{\left(1+r_f\right)^t} - \sum_{t=1}^{\tau-1} \frac{Revenues_t}{\left(1+r_f\right)^t}$$
$$= \frac{Revenues_{\tau}}{\left(1+r_f\right)^{\tau}}$$

Equation (5.7) will be named the marginal benefit (MB) of revenues. This effect is always positive, because revenues are always positive. The risk-free rate is assumed to be positive for all cases.

(5.8)
$$PV(OPEX)^{\tau} - PV(OPEX)^{\tau-1} = \sum_{t=1}^{\tau} -\frac{OPEX_t}{\left(1+r_f\right)^t} - \left(\sum_{t=1}^{\tau-1} -\frac{OPEX_t}{\left(1+r_f\right)^t}\right)$$
$$= -\frac{OPEX_{\tau}}{\left(1+r_f\right)^{\tau}}$$

Equation (5.8) is called the marginal cost (MC) of operational expenditures, and this effect will always make it more profitable to abandon today relative to abandoning tomorrow.

The interest savings of deferring abandonment can be expressed as follows:

(5.9)

$$PV(A)^{\tau+1} - PV(A)^{\tau} = -\frac{A_{\tau+1}}{\left(1+r_f\right)^{\tau+1}} - \left(-\frac{A_{\tau}}{\left(1+r_f\right)^{\tau}}\right)$$
$$= \frac{A_{\tau}}{\left(1+r_f\right)^{\tau}} - \frac{A_{\tau+1}}{\left(1+r_f\right)^{\tau+1}}$$

As long as the abandonment cost is constant or diminishing, the effect expressed through equation (5.9) will always be positive. The risk-free rate is also assumed to remain constant over time.

Combining equations (5.7), (5.8) and (5.9) we can define a decision rule for when it is optimal to abandon the asset. It can be shown that one should hold the asset until the year where:

(5.10)

$$\underbrace{\frac{Revenues_{\tau}}{\left(1+r_f\right)^{\tau}} + \left(\frac{A_{\tau}}{\left(1+r_f\right)^{\tau}} - \frac{A_{\tau+1}}{\left(1+r_f\right)^{\tau+1}}\right)}_{\text{Marginal benefits (MB)}} - \underbrace{\frac{OPEX_{\tau}}{\left(1+r_f\right)^{\tau}}}_{\text{Marginal cost (MC)}} \leq 0$$

In theory, one should continue holding the asset until marginal benefits from revenues and interest savings subtracted marginal costs are equal to zero. However, this would only occur for a continuous problem. In our discrete model, one would continue to hold the asset as long as marginal benefits are greater than the marginal costs. At the point in time where the marginal operational expenditures surpass the benefits of deferral, it is optimal to abandon immediately. This decision rule holds for our base case application in which revenues are diminishing over time while operational expenditures and the abandonment cost remains constant over time.

6.2.2 Under Uncertainty

The traditional net present value framework does not model uncertainty directly. Nevertheless, relevant risks are accounted for through a risk-adjusted rate. The net present value under uncertainty can thus be expressed as:

(5.11)

$$NPV^{\tau} = \sum_{t=1}^{\tau} \frac{CF_t}{(1+k)^t} - \frac{A_{\tau+1}}{(1+k)^{\tau+1}}$$

Where k is the risk-adjusted rate in discrete time. The risk-adjusted rate applied for the model bases on a capital asset pricing model, as explained in chapter 4.

In an uncertain world, the future cash flows are unknown. This implies that the initial decision, made at time zero, will not necessarily be the optimal one. In reality, the cash flows received in each period will frequently deviate from the cash flow point estimates. Only in a certain world, one can be sure that the decision made at time zero is optimal.

The decision-maker still desires to maximize net present value. Cash flow estimates are assumed to become increasingly certain over time, as uncertainties are resolved. In reality, this means that the decision maker would adjust his initial decision when new information arrives. However, this flexibility is not easily modeled using the simple NPV framework. The decision rule developed for the problem under certainty will also be applied for the problem under uncertainty. Hence, the decision is assumed to be made at time zero based on risk-adjusted cash flows. This results in the risk-adjusted decision rule:

(5.12)

$$\underbrace{\frac{Revenues_{\tau}}{(1+k)^{\tau}} + \left(\frac{A_{\tau}}{(1+k)^{\tau}} - \frac{A_{\tau+1}}{(1+k)^{\tau+1}}\right)}_{\text{Marginal benefits (MB)}} - \underbrace{\frac{OPEX_{\tau}}{(1+k)^{\tau}}}_{\text{Marginal cost (MC)}} \leq 0$$

Comparing equation (5.12) to equation (5.10), the only difference is that the risk-free rate is replaced by a risk-adjusted rate, in which $k > r_f$. All else equal, applying a higher discount rate results in decreased marginal benefits from revenues, decreased marginal costs from operational expenditures and marginally increased interest savings from deferring abandonment. Thus, marginal costs are reduced, while the net effect of marginal benefits is unknown. The total effect of applying a higher discount rate will depend on the parameter values of revenues, operational expenditures and the abandonment cost.

Concluding Remarks

In this section, a decision rule for the optimal time of abandonment has been modeled, firstly under certainty and secondly under uncertainty. Applying the decision rule, the year of abandonment is chosen so that net present value is maximized. The effects incentivizing deferral of abandonment can be split into three components. Operational expenditures incurred from one year to the next can be seen as a marginal cost, making deferral less desirable. On the other hand, revenues and the interest savings of the abandonment cost create marginal benefits and thus incentivize deferral. Moving from uncertainty to certainty, the discount rate increases. The total effect of an increased discount rate on the timing decision will depend on the relative sizes of revenues, operational expenditures and the abandonment cost.

6.3 The Real Option Model

As opposed to the net present value framework, the real options framework allows us to model uncertainty directly in the model. In addition, it models the ability of the decision-maker to adjust the abandonment decision, as uncertainties are resolved over time. This implies that a set timing of abandonment is not required to estimate project value. As will be shown, the decision rule is inherent in the model itself.

Our real options model is based on a contingent claims analysis approach. The problem is modeled through a binominal lattice, and solved using risk-neutral probabilities. For details on this procedure, see Appendix A.

6.3.1 Base Case

In the base case, the focus of attention is the uncertainty of crude oil and natural gas price. The uncertainty of prices ultimately affects revenues. In the Real Option Model, revenues are modeled in discrete time by a multiplicative binominal process. Each period in the model corresponds to one year. From one year to the next, revenues can increase by a multiplicative factor u, or decline by a factor d. These are defined as follows:

(5.13) $$u = e^{\sigma}$$

(5.14) $$d = e^{-\sigma} = \frac{1}{u}$$

u is also referred to as the "up"-factor, and d as the "down"-factor. e represents the exponential function, while σ is the volatility. The volatility reflects the volatility of a portfolio consisting of a proportionally fixed amount of crude oil and natural gas. See Appendix B for an explanation of the volatility estimation.

The decision maker may at any point in time either continue production or pay a one-time shutdown cost to permanently and irreversibly abandon the property. After production has stopped, there is no opportunity to start production again at a later point in time. Authors like Smit (1997) and M.W. Lund (2003) argue that it would be very costly to stop and start production in the North Sea, as weather conditions make equipment deteriorate quickly. The abandonment option can thereby be defined as a simple American put option.

At each point in time, the following decision rule will apply to the owner of the option:

(5.15) $$V_t = Max(A_{t+1}, U_t) + CF_t$$

Where A_{t+1} is the one-time abandonment cost and exercise price of the option. U_t is a function describing the value of continuing operations after time t. The cash flow at time t is included outside the maximization condition, as the base case assumes a response time of one year[15]. This decision rule represents a situation in which the decision maker each year decides whether continuing operations or abandoning is optimal for the upcoming year. The cash flow at time t incurs regardless of the decision made. If abandonment is preferred, the field will be decommissioned the coming year, at time $t + 1$. If continuing is preferred, one receives the cash flow this year and the next.

Assuming that the abandonment cost is negative and constant, one would choose to exercise this option when the value of the project is "more negative" than abandoning the project permanently. The problem therefore becomes a cost minimization problem. In every period,

[15] Based on conversations with out contact persons in Statoil, a response time of one year is chosen. It represents reality in a fair way without adding too much complexity to the model.

the decision maker needs to decide whether it is optimal to abandon or continue operations based on equation (5.15).

The value of continuing operations after time t is given by:

(5.16)
$$U_t = \frac{pU_{t+1}^u + (1-p)U_{t+1}^d}{\left(1+r_f\right)} + A_t\left(k - r_f\right)$$

Where U_{t+1} describe the value of the underlying in the next period, as illustrated by the up and down state of the uncertain cash flow. p is the risk neutral probability of the up state, while $(1-p)$ is the risk neutral probability of the down state. $A_t(k-r_f)$ is included to account for the interest savings from postponing the abandonment from one year to the next[16]. The Real Option Model assumes that abandonment must be conducted the final year of project life the latest. Forcing abandonment in the final year results in an interest saving corresponding the risk-free rate to be included in the model. The interest savings related to the value of continuing operations is therefore added as the difference between the risk-adjusted and the risk-free rate.

The risk-neutral probability is based on a dynamic replication strategy using crude oil and natural gas futures combined with risk-free borrowing and lending. It can be expressed as:

(5.17)
$$p = \frac{\left(1 + r_f - \delta\right) - d}{u - d}$$

Where u and d are the up and down factors respectively. r_f is the risk-free discrete discount rate, and δ is the net convenience yield. The net convenience yield reflects the convenience of holding a commodity relative to its futures contract, net of storage costs. A weighted net convenience yield for crude oil and natural gas is applied. See Appendix C for more details.

The model can be illustrated through a decision tree in which the value at each node, V_t is determined by the optimal decision at each point in time. The tree is composed by time intervals of one year. Solving for project value, the model starts by the end of the project life, and works its way backwards through a recursive process. The model makes sure that

[16] Interest rate savings are normally included in the denominator as the risk-adjusted rate multiplied by the value that generates the interest savings. However, this modeling of the interest savings would not be accurate for our model formulation.

abandonment is performed during the life of the project, by making abandonment the only choice available to the decision maker at the end of the project life.

6.3.2 Idle Platform

In this scenario, we introduce an additional flexibility; the option to leave the installation idle for a certain number of years. Leaving the installation idle means only conducting a part of the decommissioning work and postponing the rest. The partial decommissioning entails that one first carry out the initial plugging and abandonment (PP&A)[17]. Then one leaves the topside and substructure installations idle, to be decommissioned at a later point in time.

The partial decommissioning cost for the work that cannot be postponed beyond the life of the project is defined as:

(5.18)
$$A_{partial} = Cost(PP\&A) + OPEX_{\tau+1}$$

Where $Cost(PP\&A)$ is the cost of the permanent plugging and abandonment of wells, and $OPEX_{\tau+1}$ are the operational expenditures incurred during the year of partial abandonment.

The decommissioning cost of the idle platform can be defined as:

(5.19)
$$A_{idle} = Cost(Topside\ removal) + Cost(Substructure\ removal) + Cost(Other)$$

Where A_{idle} represent the sum of all cost components necessary for restoring the environment after the cost of PP&A has incurred.

Keeping the platform idle comes at a cost of annual idle platform operational expenditures. These can be defined as:

(5.20)
$$OPEX^{idle} = \sum_{t=0}^{N} \frac{OPEX_t^{idle}}{(1+k)^t}$$

The operational expenditures related to a field that is no longer producing will be significantly smaller than those of a producing field, $OPEX_t^{idle} < OPEX_t$. After cease of production and the permanent plugging of wells, the platform no longer requires electricity.

[17] This is necessary to avoid additional costs related to well integrity.

In terms of labor, the company will only have to conduct maintenance work from time to time.

Assuming constant abandonment cost and constant operational expenditures before and after the partial decommissioning, the idle platform will be preferred as long as:

(5.21)
$$A_{partial} + \frac{A_{idle}}{(1+k)^N} + OPEX^{idle} < A_{\tau+1}$$

Where $A_{\tau+1}$ is the cost of performing the complete decommissioning work by the end of the project economic life. The idle abandonment cost occurs at N years after the partial decommissioning is finished, and is discounted at the risk-adjusted rate.

Given that the cost components remain stable over time; the desirability of the idle platform depends on the interest savings from postponing parts of the decommissioning cost relative to the idle platform operational expenditures.

6.3.3 Annually Reduced Decommissioning Cost

In this case, the model is reformulated such that the cost of abandonment is reduced annually. As explained in chapter 2, a reduction in the cost of decommissioning over time is likely to occur when new technological solutions are provided by the service industry, making the process of decommissioning more cost efficient. This is modeled by introducing an annual cost drop, starting in year one.

The abandonment cost at time *t* can thus be defined as:

(5.22)
$$A_t = A_0(1-\epsilon)^t$$

Where ϵ is the annual drop in abandonment cost due to technological improvements, and A_0 equals the cost of abandonment as applied to the base case.

6.3.4 Cyclical Decommissioning Cost

For the cyclical decommissioning cost scenario, it is assumed that the decommissioning cost decreases when crude oil and natural gas prices fall. The rational for doing this, is that we assume the decommissioning cost will depend on the general activity level offshore. The decommissioning costs are for instance related to the cost of rig services and transportation vessel services. Whenever crude oil and natural gas prices drop, the activity level offshore goes down, which leads to lower costs of services needed for decommissioning.

In this scenario, we assume a positive correlation between the revenues generated by the producing field and the decommissioning cost. This is done by modeling the uncertainty in the decommissioning cost in an event tree and link this to the event tree of revenues. Whenever revenues are increased by its up factor, the decommissioning cost is also increased by an up factor. As the decommissioning cost is expressed in negative terms, this would imply that higher revenues yield a more negative decommissioning cost. In order to model the uncertainty of the decommissioning cost, we need to make an assumption about its volatility.

6.3.5 Limitations of the Model

There are certain limitations of the model worth commenting. Firstly, the way the interest savings of the abandonment cost are included in the model is a simplification. As decommissioning is forced to occur by the end of project life, there will be an implied risk-free interest saving in the binomial lattice. The interest saving arise when the decommissioning cost added to the end of project life is discounted at a risk-free rate through the recursive solution method. The risk-free interest saving will be conditional on the price path, and the risk-free adjustment of the abandonment cost interest savings in our model is therefore not completely accurate.

Secondly, we apply time steps of one year in the binomial model. Having more time steps would yield a smoother distribution of outcomes and subsequently more accurate project values. A smoother distribution would in a larger extent approximate the continuous price processes of crude oil and natural gas.

The modeled scenarios also have limitations in their representation of reality. The idle platform scenario can be modeled in a number of different ways. Given that either the decommissioning cost or the cost of the idle platform changes through time, it might be more realistic to model this scenario as a compound option. In the annually reduced decommissioning cost scenario, it is assumed that the underlying technological improvements results in a smooth annual decline in cost levels. In reality, a cost decline would not necessarily happen on a constant annual rate.

The cyclical decommissioning cost scenario assumes that the decommissioning cost depends on the crude oil and natural gas prices. There is however a number of other factors that will determine the decommissioning cost. One can also reasonably assume a time lag between a change in crude oil and natural gas prices and the change in the decommissioning cost.

Concluding Remarks

In this section, our Real Option Model is described. Unlike the NPV Model, the real options framework models price uncertainty directly. Furthermore, it incorporates the ability of the decision maker to adjust the abandonment decision when prices develop favorably. The Real Option Model is applied on different scenarios that reflect recent decommissioning market developments. These scenarios affect the modeling specifications of the Real Option Model, and are therefore explained in this chapter. Some limitations of the model are also clarified.

7 Data

The upcoming chapter will present the input data used in our models. Market data is collected 17.02.2016 from the Thomson Reuters Datastream Professional database. The project data is received from Statoil. This data is fictive, but based on a real case.

We analyze a declining production case. Total production occurs over 17 years and consists of both crude oil and natural gas. As we are interested in the final years of operation, the project scope is cut so that the project is assumed to have a remaining life of nine years.

In addition, we believe it to be advantageous to base the analysis on an equilibrium situation in the market for crude oil, as opposed to the current situation of oversupply (Farrel, 2016). Hence, 2017 is chosen as a starting point for the analysis, assuming that the market for crude oil will stabilize within the next year.

All data are presented in real million US dollars.

7.1 Market Data

7.1.1 Crude Oil Price

The Brent benchmark is used for pricing crude oil from the North Sea (Hume, 2016). The marker is an index comprised by crude oil blends from the fields Brent, Forties, Oseberg and Ekofisk (Buyuksahin, Lee, Moser, & Robe, 2013). In our analysis we assume that the received price for the production of the field corresponds to the Brent crude oil price[18].

The Brent crude oil is not traded on a traditional spot market. Given the logistics of transporting oil, spot cargoes for immediate delivery are scarce (Fattough, 2011). Hence, there is an important element of forwardness in spot transactions of crude oil. We are therefore using an approximate spot price for Brent, the Crude Oil Brent Current Month Free-on-Board (FOB) in USD/bbl[19].

[18] The quality of the crude oil from various fields on the NCS differs, implying that the prices also vary. The quality differs as each reservoir has its unique properties, different pressure, temperature, permeability and quality of the hydrocarbons contained in the reservoir.

[19] A Free-On-Board (FOB) contract ensures that the commodity is provided by the seller at a lifting installation and that the buyer is responsible for shipping and freight insurance (Geman, 2009).

We apply weekly crude oil prices, dated from 25.03.1987 until 17.2.2016. Weekly data are assumed to capture short-run movements over time without adding the unnecessary random fluctuations as seen in daily data.

7.1.2 Natural Gas Price

The natural gas market is composed by many regional trading hubs and is dominated by long-term contracts (The Economist, 2016). A frequently used benchmark for the natural gas price in Europe is the National Balancing Point (NBP), which is a hub situated in the UK. We use NBP Daily Day Ahead prices (pence/thm). Price data is available from 25.02.2011 up until 17.2.2016, resulting in 253 observations. The number of observations is scarce for performing statistical analysis, but is assumed sufficient for our purpose.

7.1.3 Volatility

The volatility of total revenues is needed in the Real Option Model. Since the asset produces both natural gas and crude oil we first need the price volatility of each variable. The price volatility of crude oil and natural gas is calculated using the logarithmic cash flow returns approach (Mun, 2002). The volatility of total revenues is later estimated through a portfolio approach. The portfolio volatility of the field is estimated to be 31.19%. The mathematical formulation of the method used is found in Appendix B.

7.1.4 Risk-free Rate

As an estimate of the risk-free rate, we use a daily 10-year US treasury real long-term rate of 0.98% dated 17.02.2016 (U.S. Department of the Treasury, 2016). Considering our time-horizon of nine years from 2017, a bond with 10 years to maturity seems to be an appropriate proxy for the risk-free rate.

7.1.5 Risk-adjusted Rate

The real risk-adjusted required rate of return used in the analysis is 7%. Statoil applies the same discount rate in the official plans for development and operations of new fields presented to the Government. This is a pre-tax risk-adjusted rate.

There are several reasons for taking the risk-adjusted rate as a given instead of estimating a risk-adjusted rate as described in chapter 4. First of all, the project we are analyzing is a fictive project, and the only available information is the estimated cash flow point estimates.

Secondly, we are mainly interested in the modeling of project value rather than obtaining a "correct" valuation of the project. In addition, the project value is relatively insensitive to the risk-adjusted rate (see Appendix D).

7.1.6 Net Convenience Yield

The net convenience yield is the benefit or premium, net of storage costs, associated with holding an underlying product rather than the contract or derivate product (Gibson & Schwartz, 1990). The net convenience yield estimation is calculated using historical spot and future prices for both crude oil and natural gas. The net convenience yield of the project is estimated to be -0.17%, and is the weighted average convenience yield of both oil and gas. Further information about the estimation of the net convenience yield is found in Appendix C.

7.2 Project Data

7.2.1 Production Profile

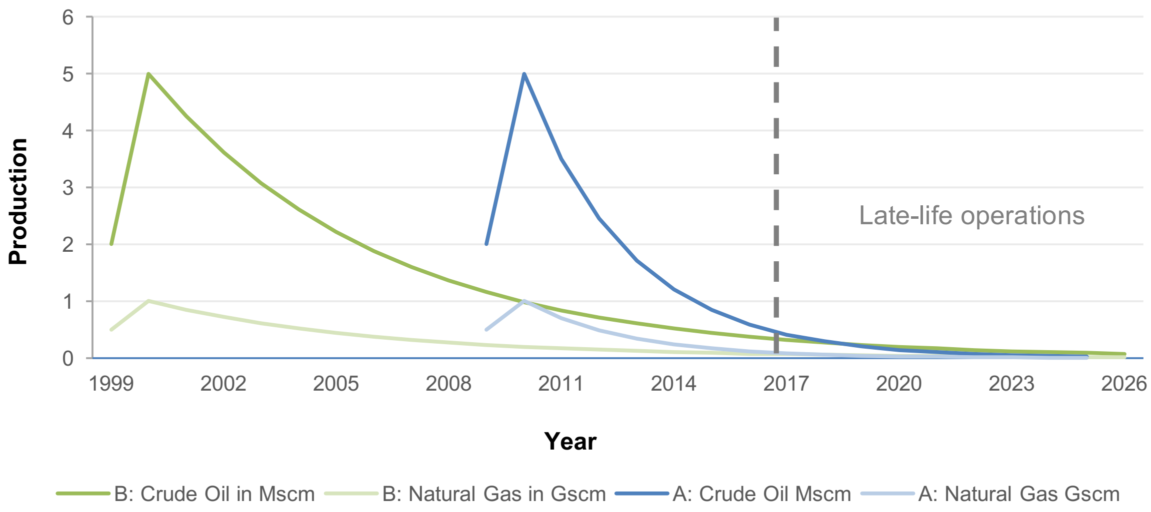


Figure 7-1: *Graphical illustration of the two production profiles analyzed.*

The production profiles analyzed are presented in figure 7-1. Production profile A represents the original production data from Statoil. This profile has a relatively steep production decline of 30% annually. In the case of production profile B, the data is modified to account for a production decline of 15% annually.

The starting point of analysis is year 2017. The majority of the production is in the past, and the asset is entering late-life operations.

7.2.2 Operational Expenditure

Operational expenditures (OPEX) are constant at 100 MUSD over the project life. The cost category is composed by various types of costs. Some costs are directly related to extraction of oil and gas. Additionally, it comprises of various costs related to the maintenance work of the platform.

7.2.3 Decommissioning Cost

Decommissioning cost, also referred to as abandonment cost, is estimated at approximately 595 MUSD for this project. As previously mentioned, the central cost components are permanent plugging and abandonment of wells (PP&A), removal of topside, removal of substructure and removal (or coverage) of pipelines.

	Cost (MUSD)
PP&A	166
Removal topside	323
Substructure and pipelines	5
Other decommissioning cost	101
Sum	**595**

Table 7-1: *Decomposition of the decommissioning costs in million US dollars.*

7.2.4 Tax

The project data received from Statoil is pre-tax. As discussed in chapter 2, the Norwegian Government has devised a petroleum taxation system with the aim of being neutral (D. Lund, 2014). In our analysis we therefore assume that taxation does not affect the abandonment decision. The project values presented are before tax.

8 Net Present Value Analysis and Results

The analysis is based on the net present value framework explained in section 5.1 and the decision rule of optimal abandonment developed in section 6.2. The ultimate goal is to analyze project value and the optimal timing of abandonment, given the various scenarios explained in section 6.3. These scenarios will be compared in order to determine their relative effect on project value.

First, we apply the model for production profile A (in which production drops by 30% annually). The case is analyzed both under certainty and under uncertainty. Under uncertainty, production profile A is analyzed for two scenarios besides the base case: the idle platform scenario and the annually reduced decommissioning cost scenario. Second, we apply the model for production profile B, where production drops by 15% annually.

	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Revenues	197	138	97	68	47	33	23	16	11
OPEX	100	100	100	100	100	100	100	100	100
Cash flow	97	38	-3	-32	-53	-67	-77	-84	-89

Table 8-1: *Cash flow profile of production profile A with a 30% drop in production annually. In million USD.*

	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Revenues	151	128	109	93	79	67	57	48	41
OPEX	100	100	100	100	100	100	100	100	100
Cash flow	51	28	9	-7	-21	-33	-43	-52	-59

Table 8-2: *Cash flow profile of production profile B with a 15% drop in production annually. In million USD.*

Table 8-1 and table 8-2 illustrate the cash flows of production profile A and production profile B, respectively. The tables illustrate the cash flows given that abandonment is chosen for the end of the project economic life.

8.1 Project Valuation under Certainty

For the valuation in the hypothetical world without uncertainty, cash flows are discounted at a risk-free rate of 0.98%. Applying the decision rule results in table 8-3.

		A	ΔA	B	ΔB	C	ΔC	ΔB + ΔC	ΔC+ΔB-ΔA
Decom year	**NPV**	**PV Σ (OPEX)**	**MC (OPEX)**	**PV (Decom)**	**MB (Decom)**	**PV Σ (Rev.)**	**MB (Rev.)**	**Sum MB**	**MB - MC**
2017	-696	0		696		0			
2018	-592	100	100	689	7	197	197	204	104
2019	-547	199	99	682	7	334	137	143	44
2020	-544	297	98	676	7	428	95	101	3
2021	-569	394	97	669	7	494	66	72	-25
2022	-613	490	96	662	6	540	46	52	-44
2023	-671	586	95	656	6	571	32	38	-57
2024	-737	680	94	650	6	593	22	28	-66
2025	-809	773	93	643	6	608	15	21	-72
2026	-884	866	92	637	6	619	11	17	-76

Table 8-3*: Abandonment decision rule applied on project under certainty (MC=marginal cost, MB=marginal benefit, decom=decommissioning, rev.=revenues). In million USD.*

The maximized NPV of -544 MUSD is achieved by abandoning the field in 2020. Table 8-3 contains the calculations for the decomposed decision rule. See the header for an explanation of how the columns are connected. Note how the NPV is maximized for the final year in which the marginal benefits (of decommissioning and revenues) exceed the marginal cost of operational expenditures. The marginal benefits exceed the marginal cost by approximately 3 MUSD given the optimal year of abandonment, 2020. Abandoning the field in 2020 implies that 2019 is the final year of operations.

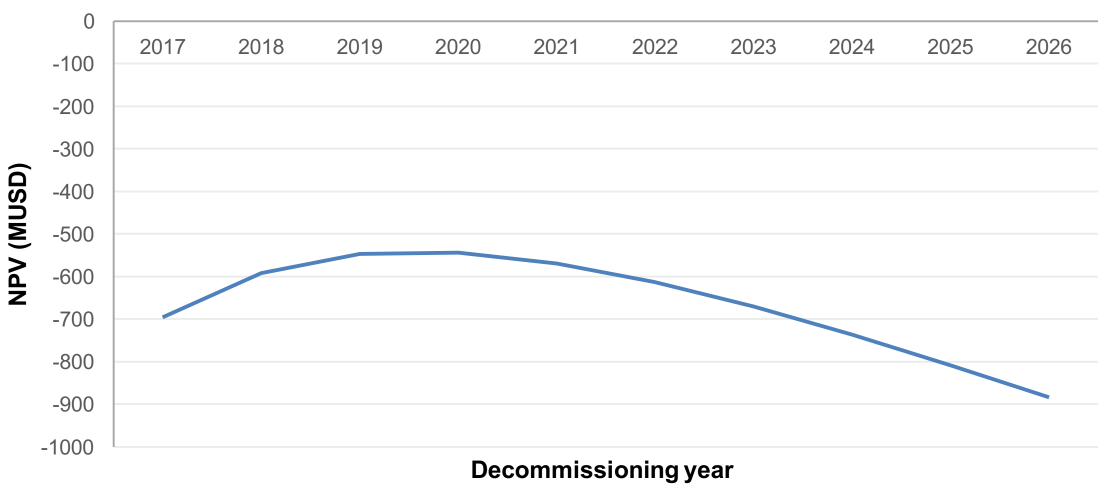


Figure 8-1: *Net present value profile as a function of decommissioning year for project under certainty. In million USD.*

Figure 8-1 illustrates the NPV profile as a function of decommissioning year. The NPV profile is a convex function of abandonment time. Note that the NPV Model is a discrete model. This implies that a timing solution is chosen for a specific year without specifying at what time during that year abandonment is optimal. The NPV profile thereby represents the point estimates of the NPV for various abandonment years with a line drawn between those point estimates. A continuous model would yield a slightly smoother line and potentially an optimal date of abandonment. An optimal data of abandonment is however not required, because the abandonment decision is assumed to be made on a year-to-year basis (in which the decommissioning program runs over one year).

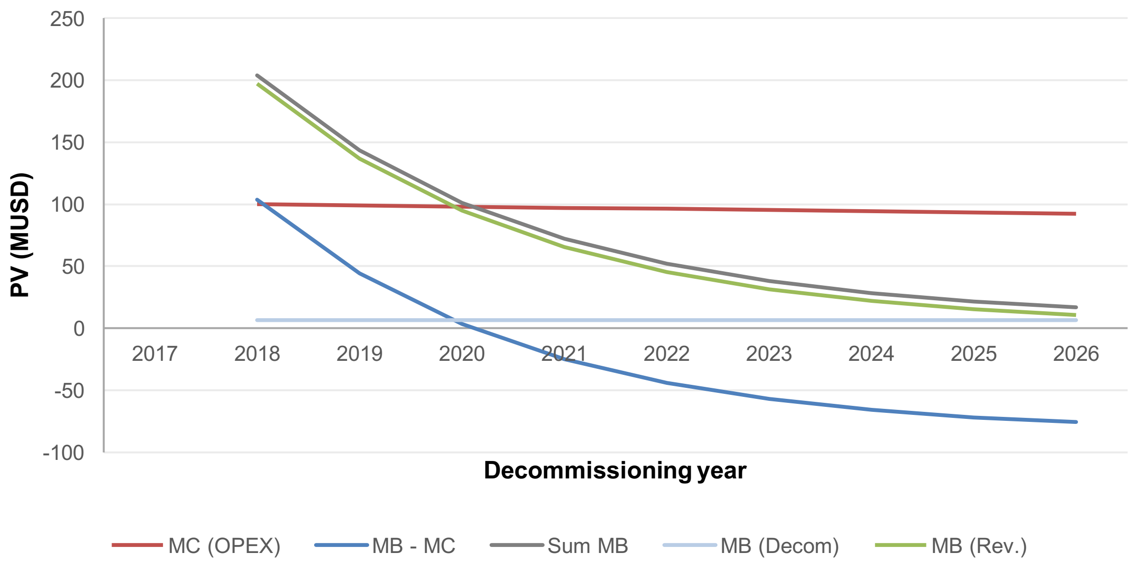


Figure 8-2: *The abandonment decision rule decomposed into marginal benefits (MB) and marginal cost (MC) for the project under certainty. In million USD.*

Figure 8-2 illustrates the abandonment decision rule decomposed into three effects: marginal cost of operational expenditures, marginal benefit of deferring decommissioning and marginal benefit of revenues. The net effect of these changes will be the marginal benefits (of revenues and decommissioning) net of the marginal cost, as displayed by the blue line. Whenever this line is equal to zero, marginal benefits equal marginal costs. The maximal NPV is in theory achieved at this intersection where MB=MC. However, as the model is discrete, the optimal solution occurs for the final year in which MB is greater or equal to MC. This occurs for decommissioning year 2020 (with 2019 as final operating year).

For the case under certainty, note that the marginal benefit of decommissioning is relatively small compared to the marginal benefit of revenues. A low discount rate explains why the interest savings from postponing decommissioning is relatively small. The sum of marginal benefits is mainly driven by the marginal benefit of revenues; the discounted benefit of receiving revenues for one more year.

8.2 Project Valuation under Uncertainty

A world without uncertainty is a hypothetical one. As discussed in chapter 3, there are several uncertainties inherent in an oil project. From this point on, we introduce risk to the NPV Model, in which two scenarios besides the base case will be studied. Additionally, the model will be applied on production profile B.

8.2.1 Base Case

Uncertainty is accounted for by discounting the project cash flows with a risk-adjusted rate of 7%. This results in the optimal abandonment timing and subsequent net present value as displayed in table 8-4.

		A	ΔA	B	ΔB	C	ΔC	ΔB + ΔC	ΔC+ΔB-ΔA
Decom year	**NPV**	**PV Σ (OPEX)**	**MC (OPEX)**	**PV (Decom)**	**MB (Decom)**	**PV Σ (Rev.)**	**MB (Rev.)**	**Sum MB**	**MB - MC**
2017	-696	0		696		0			
2018	-553	100	100	650	46	197	197	243	143
2019	-475	193	93	608	43	326	129	171	78
2020	-438	281	87	568	40	410	84	124	37
2021	-428	362	82	531	37	465	55	92	11
2022	-433	439	76	496	35	502	36	71	-5
2023	-448	510	71	463	32	525	24	56	-15
2024	-469	577	67	433	30	541	15	46	-21
2025	-493	639	62	405	28	551	10	38	-24
2026	-518	697	58	378	26	557	7	33	-25

Table 8-4: *Abandonment decision rule applied on base case (production profile A). In million USD.*

The maximized NPV of -428 MUSD is achieved by abandoning the field in 2021. Compared to the solution under certainty, abandonment is thus postponed by one year. In addition, the NPV has increased by approximately 116 MUSD, from -544 MUSD in the solution under certainty.

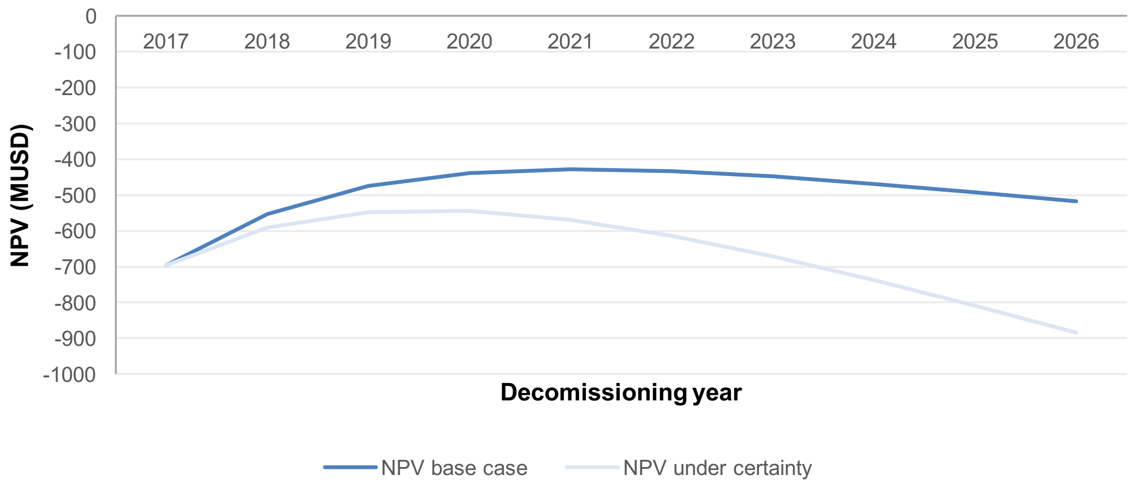


Figure 8-3: *NPV profile as a function of decommissioning year for base case. In million USD.*

Figure 8-3 illustrates the net present value profile as a function of decommissioning year for the base case. Compared to the NPV profile under certainty, the NPV profile for the base case is flatter. The difference between the two NPV profiles becomes greater for later abandonment dates. With a risk-adjusted rate, the heavier discounting will make solutions with decommissioning in the final years appear more attractive as the discounted decommissioning cost becomes increasingly smaller over time.

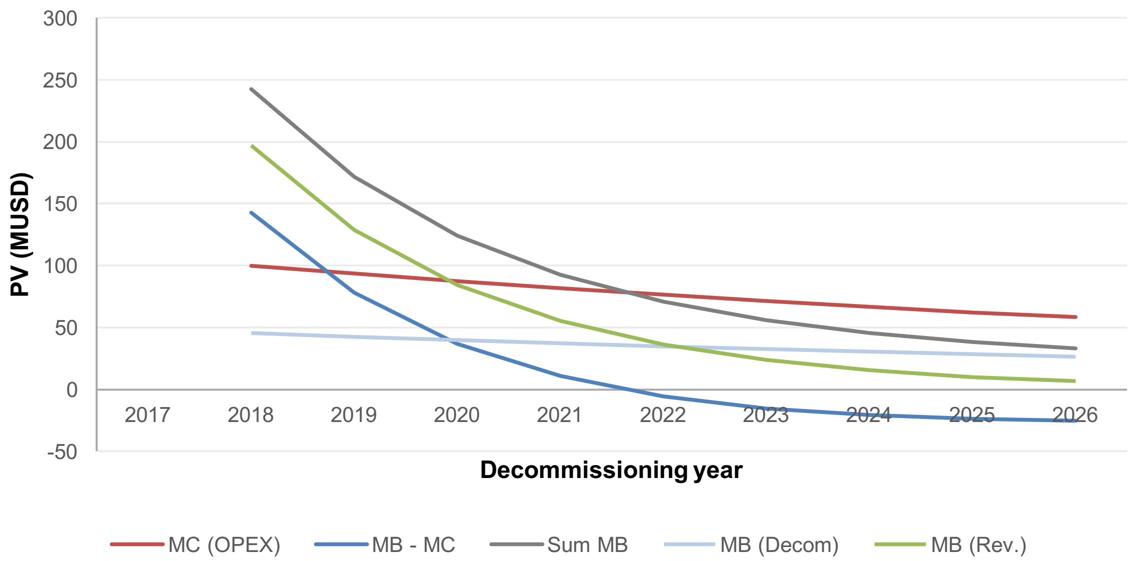


Figure 8-4: *The abandonment decision rule decomposed into marginal benefits (MB) and marginal cost (MC) for the base case. In million USD.*

An increased discount rate relative to the case under certainty, results in changes of marginal benefits and the marginal cost. The marginal cost of operational expenditures is reduced, hence incentivizing later abandonment. A higher discount rate also decreases the marginal benefit of revenues, thus incentivizing earlier abandonment. However, the marginal benefit of decommissioning has increased significantly, as the interest savings of deferring the abandonment cost becomes greater with a higher discount rate. The net effect of these changes is positive, such that deferral becomes more attractive. Analyzing the problem with a risk-adjusted rate rather than the risk-free rate thus causes the decision maker to postpone abandonment of the field by one year.

8.2.2 Idle Platform

As explained in section 6.3, the idle platform scenario involves the opportunity to perform a partial decommissioning program after cease of production. The remaining decommissioning work is postponed by leaving the platform idle for a given number of years. The idle platform opportunity will be preferred as long as the interest savings of postponing parts of the decommissioning cost surpasses the maintenance costs incurred during the time in which the platform is left idle. A total decommissioning cost for the idle platform opportunity has been estimated to be approximately 654 MUSD, representing decommissioning cost savings of 42 MUSD (from 696 MUSD in the base case). The idle platform decommissioning cost assumes that the platform can be left idle for five years at a cost of 20 MUSD per year.

		A	ΔA	B	ΔB	C	ΔC	ΔB + ΔC	ΔC+ΔB-ΔA
Decom year	**NPV**	**PV Σ (OPEX)**	**MC (OPEX)**	**PV (Decom)**	**MB (Decom)**	**PV Σ (Rev.)**	**MB (Rev.)**	**Sum MB**	**MB - MC**
2017	-654	0		654		0			
2018	-514	100	100	612	43	197	197	240	140
2019	-439	193	93	572	40	326	129	169	75
2020	-405	281	87	534	37	410	84	122	34
2021	-396	362	82	499	35	465	55	90	8
2022	-404	439	76	467	33	502	36	69	-8
2023	-421	510	71	436	31	525	24	54	-17
2024	-444	577	67	408	29	541	15	44	-23
2025	-469	639	62	381	27	551	10	37	-26
2026	-496	697	58	356	25	557	7	32	-27

Table 8-5: *Abandonment decision rule applied on idle platform scenario. In million USD.*

The maximized NPV of -396 MUSD is achieved by abandoning the field in 2021. From the base case, the optimal decision has not changed, but the net present value has increased by 32 MUSD (from -428 MUSD in the base case). The opportunity to postpone parts of the decommissioning cost thus creates value, even though additional costs of 20 MUSD over five years must be paid. This example illustrates how oil companies may be willing to incur the costs of keeping a platform idle in order to postpone the abandonment of an oilfield. In other words, the example might explain the motivation of the decommissioning market trend described in chapter 2. Given that there are no costs or uncertainties associated with the idle platform, the company would have an incentive to postpone the abandonment of the idle platform for as long as possible.

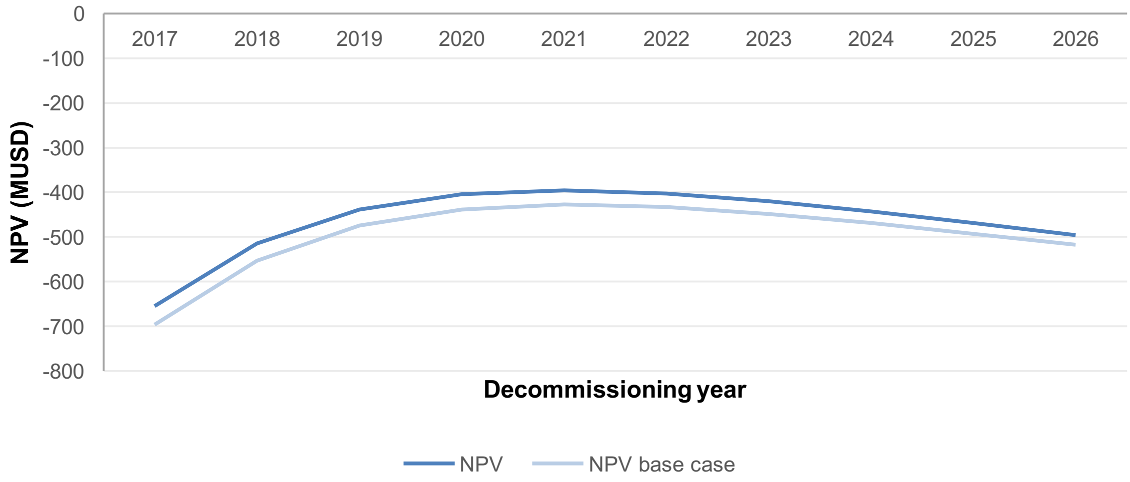


Figure 8-5: *NPV profile as a function of decommissioning year for idle platform scenario. In million USD.*

The net present value profile of the idle platform scenario, as displayed in figure 8-5, has a similar shape to the base case profile. However, the idle platform profile is less negative in terms of net present value. The idle platform opportunity yields a higher NPV for all abandonment years, compared to the base case.

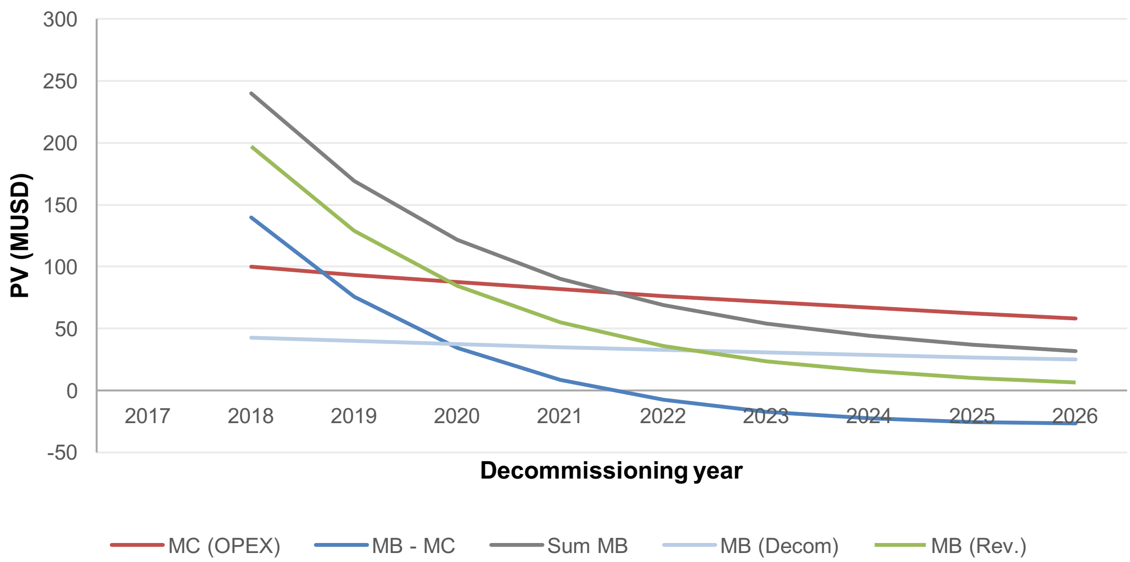


Figure 8-6: *The abandonment decision rule decomposed into marginal benefits (MB) and marginal cost (MC) for the idle platform scenario. In million USD.*

As seen from figure 8-6, the marginal cost of operational expenditures and the marginal benefit of revenues are the same as for the base case. The marginal benefit of decommissioning is however changed. With a decreased abandonment cost relative to the base case, the interest savings from postponing the abandonment of the field decreases. The MB of decommissioning curve thus shifts slightly downward. This is however not sufficient for changing the optimal decision. Introducing the idle platform opportunity consequently does not change the time of optimal abandonment. The partial decommissioning is performed in the same year as the full decommissioning in the base case. However, following the partial decommissioning the platform is kept idle for five years. In other words, the abandonment is not finished until 2026.

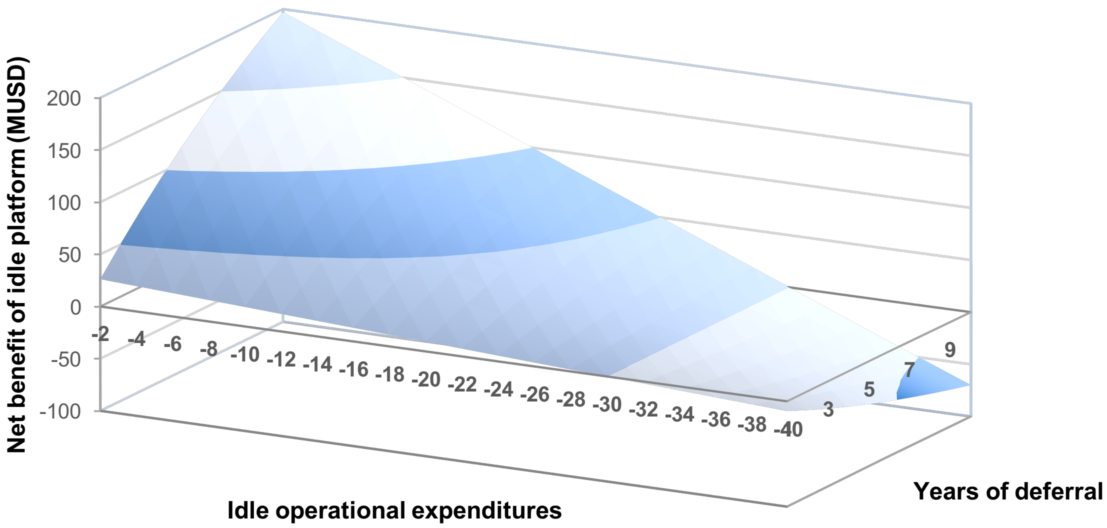


Figure 8-7: *Net benefit of the idle platform opportunity relative to the base case abandonment cost. In million USD.*

Figure 8-7 is a three-dimensional graph illustrating how the idle platform assumptions affect the decommissioning cost. The net benefit of the idle platform represents the decrease in the decommissioning cost from interest savings net of additional operational expenditures. The decommissioning cost savings depend on the years of deferring abandonment of the idle platform, and the resulting idle operational expenditure (the cost of maintaining the idle platform). For instance, deferring abandonment of the idle platform by 10 years at an annual cost of 2 MUSD would result in decommissioning cost savings of 197 MUSD. Nevertheless, for idle operational expenditures above 30 MUSD per year, the full decommissioning alternative is preferred to the idle platform opportunity. For the idle platform to be profitable, the interest savings of deferring abandonment must be higher than the discounted idle operational expenditures.

8.2.3 Annually Reduced Decommissioning Cost

For the annually reduced decommissioning cost scenario, it is assumed that the decommissioning drops by 3% annually due to technological improvements in solutions provided by the service industry. This implies that the abandonment cost decreases over time, starting at the abandonment cost of 696 MUSD if the field is abandoned in 2018. A cost drop of 3% annually within the given time frame is for several reasons unlikely. There are no clear predictions indicating that the abandonment cost will decrease in the near future. It is however likely that there will be developed specialized solutions for decommissioning in the long run, causing the abandonment cost to go down. The annually reduced decommissioning cost scenario thus serves as a hypothetical case. The goal is to study the effect of a reduced cost over time on a general basis.

		A	ΔA	B	ΔB	C	ΔC	ΔB + ΔC	ΔC+ΔB-ΔA
Decom year	**NPV**	**PV Σ (OPEX)**	**MC (OPEX)**	**PV (Decom)**	**MB (Decom)**	**PV Σ (Rev.)**	**MB (Rev.)**	**Sum MB**	**MB - MC**
2017	-696	0		696		0			
2018	-553	100	100	633	62	197	197	259	159
2019	-459	193	93	577	57	326	129	185	92
2020	-410	281	87	525	51	410	84	136	48
2021	-388	362	82	479	47	465	55	102	20
2022	-384	439	76	436	43	502	36	79	2
2023	-392	510	71	397	39	525	24	62	-9
2024	-407	577	67	362	35	541	15	51	-16
2025	-426	639	62	330	32	551	10	42	-20
2026	-448	697	58	301	29	557	7	36	-22

Table 8-6: *Abandonment decision rule applied to the annually reduced decommissioning cost scenario. In million USD.*

The maximized NPV of -373 MUSD is achieved by abandoning the field in 2022. It is thus optimal to defer abandonment by one year compared to the base case. The improvement in net present value amounts to 55 MUSD.

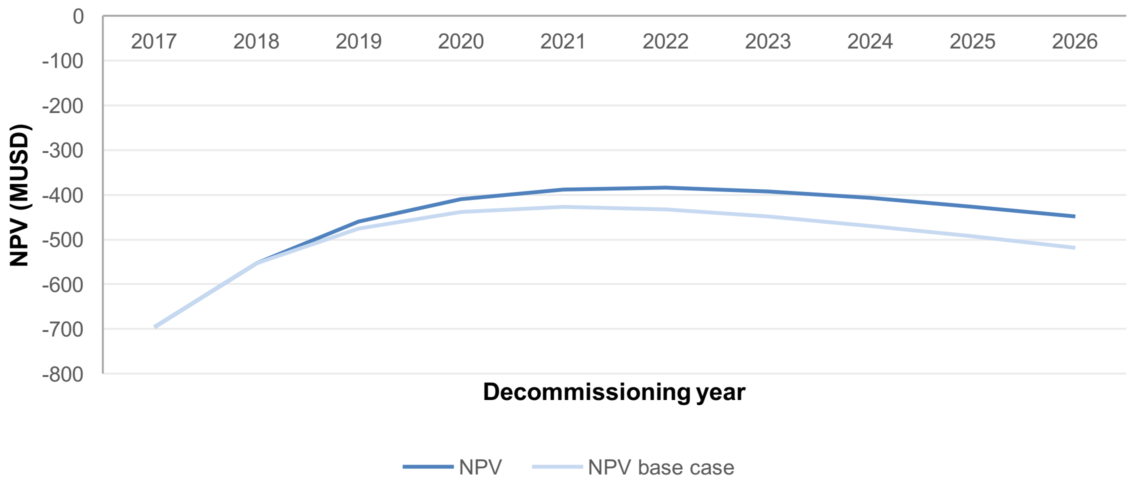


Figure 8-8: *NPV profile as a function of decommissioning year for the annually reduced decommissioning cost scenario. In million USD.*

In figure 8-8 we see that, relative to the base case, the net present value profile becomes flatter. This is particularly the case to the right of the maximum. For decommissioning in later years than 2018, the net present value is greater, as the abandonment cost becomes smaller over time. This effect is greater for abandonment furthest in the future, since the abandonment cost becomes smaller each year. It is however not optimal to defer abandonment by more than one year past the base case, as one would have to incur an increasingly negative cash flow over time.

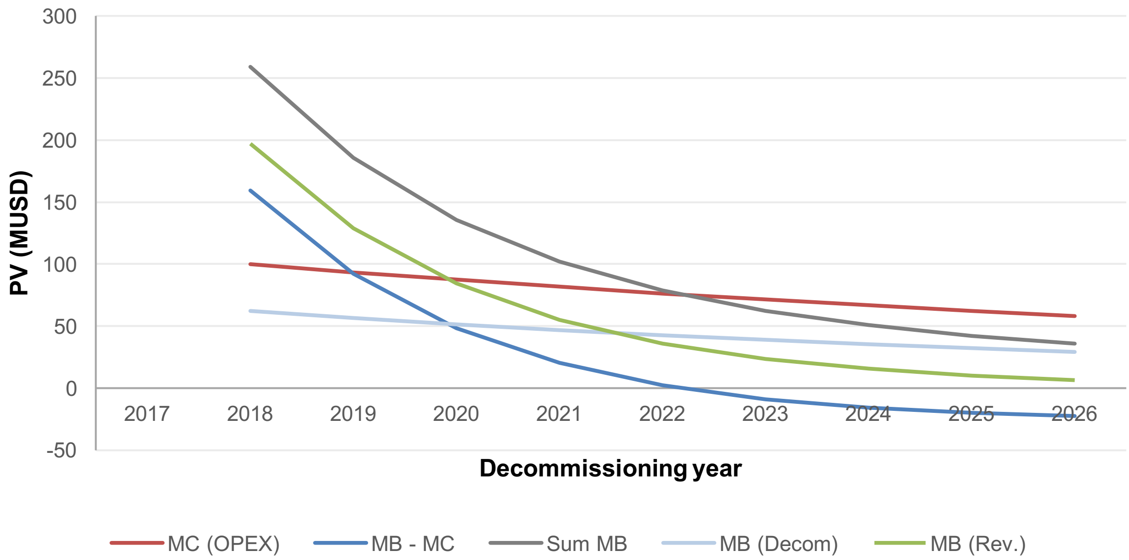


Figure 8-9: *Abandonment decision rule decomposed into marginal benefits (MB) and marginal cost (MC) for the annually reduced decommissioning cost scenario. In million USD.*

Studying the effects decomposed, we see that there is no change in the marginal benefit of revenues or in the marginal cost of operational expenditures. The marginal benefit of decommissioning has nevertheless changed. This effect no longer reflects the interest savings of postponing the abandonment cost exclusively. The effect of the reduction in cost is also reflected in the marginal benefit of decommissioning. Compared to the base case, the interest savings are reduced over time, as the abandonment cost becomes smaller. This is however offset by the gain related to the annually reduced decommissioning cost of 3%.

8.2.4 Production Profile B

Production profile B has a drop in production of 15% annually; as opposed to the 30% drop in production of production profile A. The cash flows of the two production profiles are shown in tables 8-1 and 8-2. The difference in production profiles results in a less dramatic change from positive to negative annual cash flow for production profile B relative to production profile A. All other input parameters apart from the production remain the same as for the base case of production profile A.

		A	ΔA	B	ΔB	C	ΔC	ΔB + ΔC	ΔC+ΔB-ΔA
Decom year	**NPV**	**PV Σ (OPEX)**	**MC (OPEX)**	**PV (Decom)**	**MB (Decom)**	**PV Σ (Rev.)**	**MB (Rev.)**	**Sum MB**	**MB - MC**
2017	-696	0		696		0			
2018	-599	100	100	650	46	151	151	197	97
2019	-530	193	93	608	43	271	120	162	69
2020	-482	281	87	568	40	366	95	135	48
2021	-451	362	82	531	37	442	76	113	31
2022	-433	439	76	496	35	502	60	95	19
2023	-424	510	71	463	32	550	48	80	9
2024	-422	577	67	433	30	588	38	68	2
2025	-426	639	62	405	28	618	30	58	-4
2026	-433	697	58	378	26	642	24	50	-8

Table 8-7: *Abandonment decision rule applied on production profile B. In million USD.*

The maximized NPV of -422 MUSD is achieved by abandoning the field in 2024. In other words, the change in production profile makes it optimal to defer abandonment for three years relative to the base case (production profile A). The net present value of the field with a 15% drop in production is also 6 MUSD greater than the net present value of the field with a 30% drop in production.

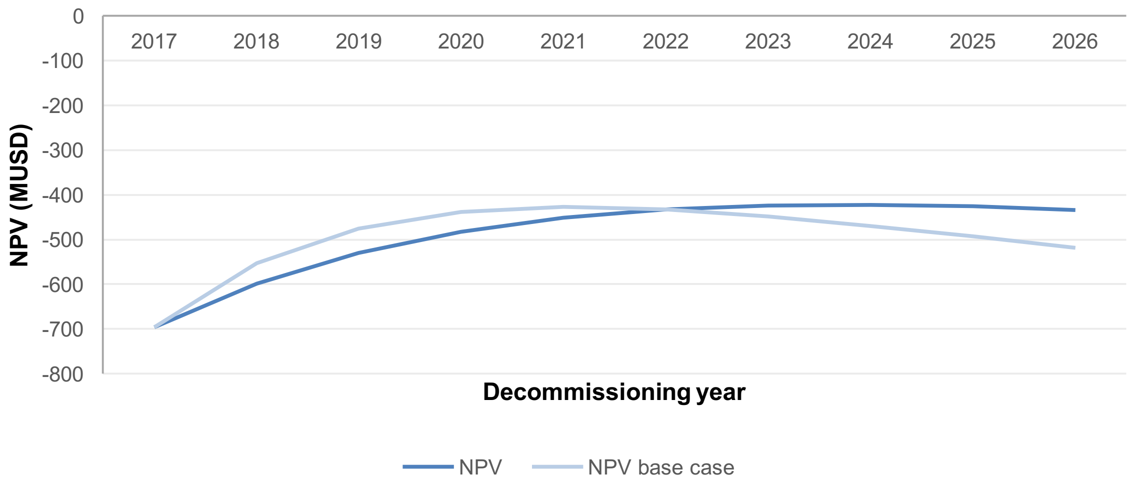


Figure 8-10: *NPV profile as a function of decommissioning year for production profile B. In million USD.*

The net present value profile for production profile B is clearly less steep than the same net present value profile for the base case of production profile A. The flatter NPV profile of production profile B can be explained by a flatter cash flow profile. In terms of the change in project value, the timing decision appears to be more critical for production profile A compared to production profile B. As the NPV does not change a lot depending on the decommissioning year, it can be argued that the decision maker is more flexible in the choice of decommissioning year.

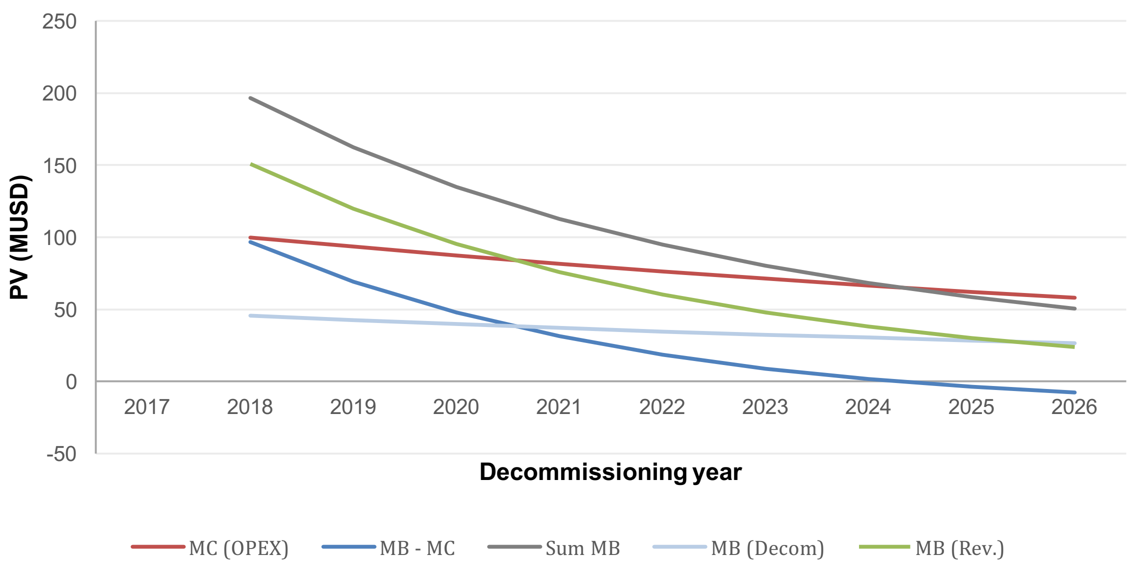


Figure 8-11: *The abandonment decision rule decomposed into marginal benefits (MB) and marginal cost (MC) for production profile B. In million USD.*

When the effects are decomposed, we note that marginal cost of operational expenditures and the marginal benefit of decommissioning remain equal to the base case. The only change from the base case is the marginal benefit of revenues. The marginal benefit curve as a function of decommissioning year becomes flatter with the 15% drop in production. For decommissioning in 2017 and 2018, marginal benefit of revenues is greater for production profile A than for production profile B. This is because revenues are greater for the first two years with production profile A. The trend turns from 2019, where the marginal benefit of revenues is greater for production profile B. Since revenues are more stable over time, one is able to defend the marginal costs for a longer time and it becomes optimal to defer the abandonment longer.

Concluding Remarks

	Under certainty		**Under uncertainty**	
	NPV	**Decom year**	**NPV**	**Decom year**
Base case	-544	2020	-428	2021
Idle platform			-396	2021
Annually reduced decommissioning cost			-384	2022
Production profile B			-422	2024

Table 8-8: *Net present value and optimal decommissioning year for the analyzed scenarios. In million USD.*

Table 8-8 sums up the results from the net present value analysis. The analysis performed under certainty (with a risk-free rate of 0.98%), yields the most negative net present value and the earliest abandonment date. Introducing uncertainty by discounting the cash flows at a risk-adjusted rate of 7% yields an increase in value of 116 MUSD. This is because the cash flow goes from positive to negative, with a relatively high negative cash flow in the final year due to the cost of abandoning the field. When discounting negative cash flows at a higher rate, they become less negative and the project value increases as a result. This might seem counterintuitive, as discounting at a higher rate will make a positive cash flow smaller, hence *decreasing* the project value. Nevertheless, in the Net Present Value Model, negative cash flows are treated in the same way as positive cash flows. The alternative cost of money is still the same and independent of the sign of the analyzed cash flows.

The idle platform scenario represents an increase in project value of 32 MUSD relative to the base case, which is explained by a lower cost of abandonment due to interest savings of deferring some of the decommissioning cost components. The timing for the partial decommissioning does not change relative to the base case. For the annually reduced decommissioning cost scenario, the abandonment cost is no longer constant, but decreases at a rate of 3% annually. This causes the optimal timing for abandonment to change by one year relative to the base case, and value increases by 44 MUSD. The idle platform and annually reduced decommissioning cost scenarios are thus similar in terms of project value.

Production profile B yields a more negative project value than the idle platform and annually reduced decommissioning case scenarios. Nevertheless, abandonment is deferred until 2024. These effects are explained by less negative cash flows during the final years of the project life (as the production profile is flatter), in addition to a higher decommissioning cost (relative to the idle platform and annually reduced decommissioning scenarios). Less negative cash flows and a higher abandonment cost causes the benefits from deferral to be greater, even though project value is lower.

9 The Real Options Analysis and Results

In the following section, we apply our Real Option Model on the different scenarios explained in section 6.3 on production profile A. First, the same scenarios presented in the NPV Model will be analyzed; the base case, the opportunity to leave the platform idle and the annually reduced decommissioning cost. Then we introduce a new scenario only applicable for the Real Option Model; the cyclical decommissioning cost scenario. Finally, the base case scenario is applied on production profile B.

9.1 Project Value

9.1.1 Base Case

As explained in section 6.3, our base case assumes a response time of one year. In other words, it takes one year before the decommissioning decision is made until the decommissioning work is initiated.

	2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
Revenues	197	138	97	68	47	33	23	16	11
OPEX	100	100	100	100	100	100	100	100	100
Cash flow	97	38	-3	-32	-53	-67	-77	-84	-89

Table 9-1: *Project data input for the Real Option Model in million USD.*

Table 9-1 illustrates the revenue, production and cash flow point estimates used in the NPV Model. The last year where production is feasible is 2025, while 2026 is the last possible year of abandonment.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
197	188	180	172	165	158	151	144	138
	101	97	92	88	84	81	77	74
		52	49	47	45	43	41	40
			27	25	24	23	22	21
				14	13	12	12	11
					7	7	6	6
						4	3	3
							2	2
								1

Table 9-2*:* *Binomial revenue lattice in million USD (up-factor: 1.37, down-factor: 0.73).*

Table 9-2 shows the binomial event tree of the revenues. As can be seen, the tree is recombining and therefore referred to as a lattice. The blue highlighted nodes are equal to the point estimates of the revenues shown in table 9-1, illustrating the symmetric qualities of the lattice. A relatively high price volatility of 31% presents a broad distribution of future possible values.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
97	88	80	72	65	58	51	44	38
	1	-3	-8	-12	-16	-19	-23	-26
		-48	-51	-53	-55	-57	-59	-60
			-73	-75	-76	-77	-78	-79
				-86	-87	-88	-88	-89
					-93	-93	-94	-94
						-96	-97	-97
							-98	-98
								-99

Table 9-3: *Cash flow event tree in million USD.*

Table 9-3 shows the same revenues, only where the operational expenditures are subtracted. Hence, table 9-3 presents the cash flows in the respective nodes. Similar to the revenue lattice, the blue highlighted nodes are here equal to the cash flow point estimates in table 9-1. As can be seen in the table, there are only a few instances where the cash flow is positive. This is when the price development is highly favorable.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
-417	-441	-464	-487	-509	-532	-559	-594	-651
	-656	-666	-675	-684	-692	-700	-708	-715
		-737	-739	-742	-744	-746	-747	-749
			-762	-763	-765	-766	-767	-768
				-775	-776	-776	-777	-777
					-782	-782	-782	-783
						-785	-785	-786
							-787	-787
								-788

Optimal decision

Decommission

Continue

Table 9-4: *Decision tree in the base case of production profile A in million USD (risk-neutral probability: 0.44).*

The decision tree in table 9-4 presents the optimal decisions, continue or shut down, given the modeled price development. The decisions are made by comparing expected future cash flows with conducting decommissioning the following year. Green nodes indicate that it is optimal to continue operations, while red nodes indicate that one would optimally decide to shut down production. The decommissioning work will commence the year after the decision is made. Hence, a red node in 2019 indicates that decommissioning would be performed in 2020.

The analysis yields a project value at time zero. Project value is -417, and is the number shown under year zero (2017) in table 9-4. The faded values in the consecutive years represents intermediate calculations needed in order to find the project value at time zero. The red and green faded nodes do not necessarily present the optimal decommissioning decision in the different years. This is because each year presents different a range of possible price outcomes based on historic volatility. Since future prices are uncertain, we do not know what the optimal decision will be. The illustrated decisions will only be optimal if the price development actually occurs.

In scenarios where the crude oil and natural gas prices develop favorably, one would choose to continue operations due to higher value of remaining production. As table 9-4 illustrates, it demands a strong positive development in prices to favor continuation of the project. This relates to the steep annual decline of production, limiting the potential upside of the project.

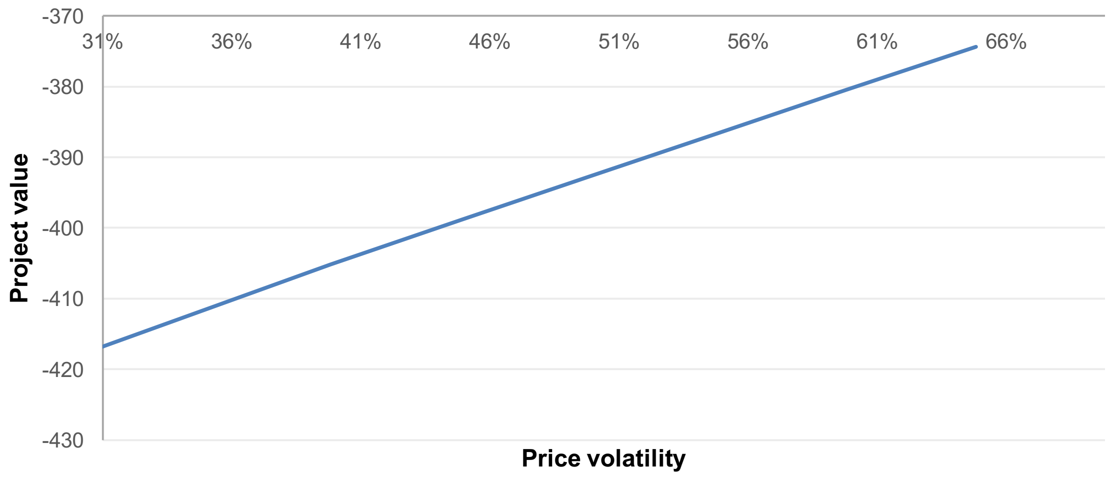


Figure 9-1: Sensitivity analysis. Price volatility and its effect on project value (MUSD).

In the Real Option Model, the project value is affected by the volatility of the revenues. The potential upside becomes greater with higher price volatility, while having the option to abandon eliminates the downside risk. As illustrated in figure 9-1, a higher volatility yields a higher project value.

9.1.2 Idle Platform

As explained in chapter 6, by introducing the idle platform scenario one gets the opportunity to leave the platform idle for five years at the cost of 20 MUSD per year. Now this opportunity will be introduced in the Real Option Model.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
-386	-410	-433	-455	-477	-499	-524	-556	-610
	-620	-630	-639	-648	-656	-664	-670	-674
		-696	-699	-701	-703	-705	-707	-708
			-721	-723	-724	-725	-726	-727
				-734	-735	-736	-736	-737
					-741	-741	-742	-742
						-744	-745	-745
							-746	-746
								-747

Optimal decision
Decommission
Continue

Table 9-5: *The decision tree of the idle platform scenario. In million USD.*

Table 9-5 presents the decision tree, demonstrating the optimal decisions given the modeled price development. Compared to the base case, the same nodes indicate continuation.

Nonetheless, the project value is higher. This reflects the lower exercise price associated with the idle platform opportunity (654 MUSD versus 695 MUSD in the base case).

As can be seen in the decision tree, project value is now 31 MUSD (+7.4%) higher than in the base case (-417 against -386).

9.1.3 Annually Reduced Decommissioning Cost

In the annually reduced decommissioning cost scenario, the exercise price decreases 3% every year. The annual cost reduction reflects the expected future improvements in available decommissioning technology that will most likely lower the decommissioning cost.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
-365	-378	-390	-402	-414	-428	-447	-475	-524
	-613	-608	-604	-599	-595	-592	-589	-587
		-702	-688	-674	-660	-647	-634	-622
			-711	-696	-681	-667	-653	-640
				-708	-693	-678	-664	-650
					-699	-684	-669	-655
						-687	-672	-658
							-674	-660
								-660

Optimal decision

Decommission

Continue

Table 9-6: *The decision tree of the annually reduced decommissioning cost scenario. In million USD.*

Table 9-6 visualizes the decision tree where the annually reduced exercise price is incorporated. As can be seen in the tree, the same nodes are green as in the base case. This indicates that in this particular case, the optimal decommissioning timing is the same as when the decommissioning cost is constant through time.

However, the project values differ, where the annually reduced decommissioning cost presents a higher project value of 52 MUSD (+12.5%) due to the lower decommissioning cost.

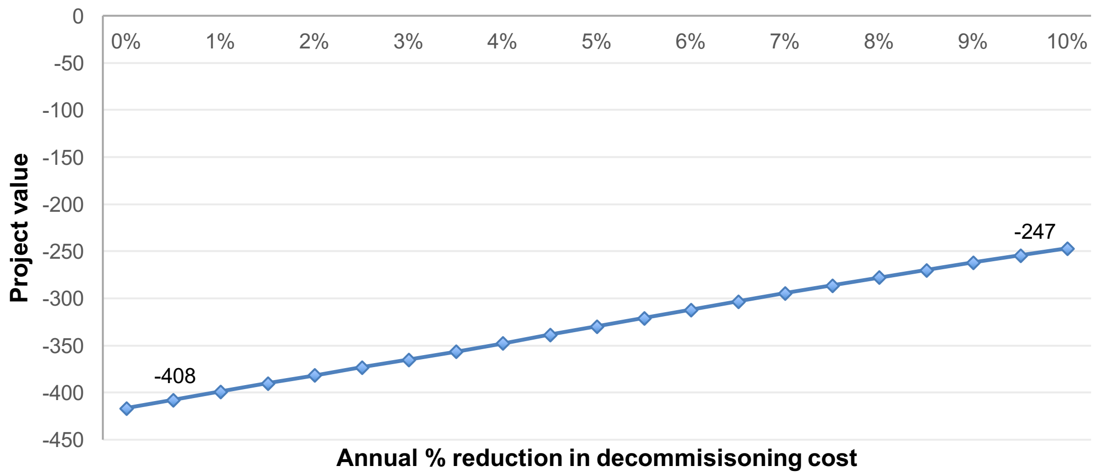


Figure 9-2: *Change in annual percentage reduction decommissioning cost and its effect on project value. In million USD.*

The project value in this scenario is relatively sensitive to the annual reduction rate of the decommissioning cost. As illustrated in figure 9-2, as little as a 0.5% annual reduction yields a project value of -408 MUSD (2% increase in project value compared to the base case). On the other hand of the scale, a 10% annual reduction in decommissioning cost would yield a project value as “high” as -247 MUSD (38% increase in project value compared to the base case).

9.1.4 Cyclical Decommissioning Cost

As explained in chapter 2, the decommissioning cost depends on crude oil and natural gas price development. Higher petroleum prices incentivize more exploration and production of petroleum reserves on the NCS, increasing overall activity levels. Due to capacity constraints at the service companies, higher activity levels also translate into higher prices for the upstream oil companies for required services. Higher activity levels also increase the decommissioning cost; since the decommissioning services are delivered by the same companies that service exploration and production.

The Real Option Model facilitates direct incorporation of this dynamic. First, the decommissioning cost is modeled stochastically in an event tree given an assumed volatility. Second, the decommissioning tree is combined with the cash flow tree, where an upward movement in the revenues tree corresponds to an upward movement in the decommissioning tree. The optimal decision is reached by comparing remaining cash flows with the decommissioning cost in the equivalent node of the decommissioning tree.

2017	2018	2019	2020	2021	2022	2023	2024	2025
Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
-596	-658	-727	-804	-888	-982	-1085	-1199	-1325
	-539	-596	-658	-727	-804	-888	-982	-1085
		-488	-539	-596	-658	-727	-804	-888
			-441	-488	-539	-596	-658	-727
				-399	-441	-488	-539	-596
					-361	-399	-441	-488
						-327	-361	-399
							-296	-327
								-268

Table 9-7: *Event tree decommissioning cost. In million USD (up-factor: 1.052, down-factor: 0.905).*

Table 9-7 illustrates the binomial lattice showing the many possible future decommissioning costs given a volatility of 10%. 2025 shows decommissioning costs running from 268 MUSD to 1,325 MUSD. Such a large gap might not be realistic, but serves to prove a point.

2017	2018	2019	2020	2021	2022	2023	2024	2025
Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
-391	-461	-536	-618	-712	-823	-962	-1142	-1374
	-594	-652	-715	-784	-861	-949	-1057	-1200
		-630	-683	-742	-806	-876	-954	-1039
			-609	-657	-708	-766	-829	-898
				-581	-623	-669	-721	-777
					-550	-588	-630	-676
						-519	-553	-591
							-490	-521
								-463

Optimal decision
Decommission
Continue

Table 9-8: *Base case versus modified base case decision tree: cyclical decommissioning cost. In million USD.*

Table 9-8 illustrates the optimal decisions and project value of the cyclical decommissioning cost scenario. The optimal decision is found by comparing the value of continuing operations with the corresponding decommissioning cost in the decommissioning cost event tree.

A 10% decommissioning cost volatility is not sufficient in altering the optimal timing decision of the decommissioning work compared to the base case. The scenario does however present a higher project value of 26 MUSD (+6%). This is because the scenario captures the effect that when prices decline, there is an additional incentive to shut down production; a lower decommissioning cost. A lower decommissioning cost has a positive effect on project value.

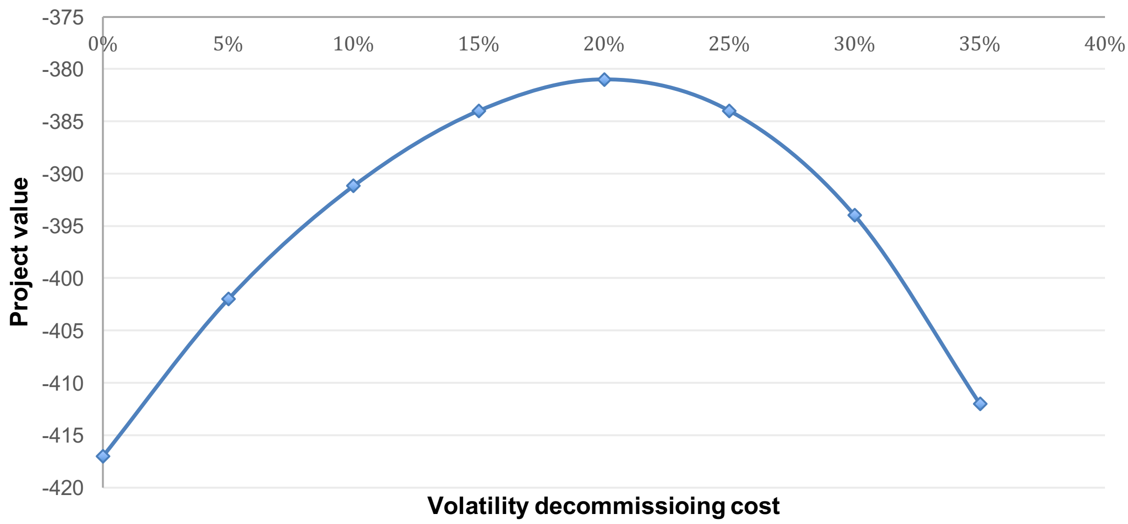


Figure 9-3: Sensitivity analysis. The effect of volatility of decommissioning cost on option value. In million USD.

Figure 9-3 demonstrates an important side note; increased volatility of the decommissioning cost has a positive effect on the project value up to a certain point. The turning point reflects the fact that volatility of decommissioning has two major opposite effects on project value. Firstly, when prices are low you would shut down and at a lower decommissioning cost. Lower decommissioning costs have a positive effect on project value. Secondly, when the prices develop favorably, decommissioning costs are high. Nonetheless, you would still need to shut down at the end of project life. Higher decommissioning cost at the end of project life has a negative effect on project value. A decommissioning volatility higher than 20% will alter the optimal timing decision, forcing the company to conduct decommissioning at a later stage given a favorable price development. The negative effect associated with a high decommissioning cost in a high price situation would in this case be stronger than the positive effect of a low decommissioning cost in a low price situation.

9.1.5 Production Profile B

In the following, the base case is applied to production profile B, where annual production decline is lower than in production profile A (30% against 15% annual decline).

	2017	2018	2019	2020	2021	2022	2023	2024	2025
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
Revenues	151	128	109	93	79	67	57	48	41
OPEX	100	100	100	100	100	100	100	100	100
Cash flow	51	28	9	-7	-21	-33	-43	-52	-59

Table 9-9: *Project data input for the Real Option Model for production profile B. In million USD.*

Table 9-9 illustrates the revenue, production and cash flow point estimates used in the NPV Model for production profile B.

2017	2018	2019	2020	2021	2022	2023	2024	2025
Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
151	175	204	236	275	319	370	430	499
	94	109	127	147	171	198	230	267
		58	68	79	92	106	123	143
			36	42	49	57	66	77
				23	26	31	35	41
					14	16	19	22
						9	10	12
							5	6
								3

Table 9-10: *Revenue lattice for production profile B. In million USD.*

2017	2018	2019	2020	2021	2022	2023	2024	2025
Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8
51	75	104	136	175	219	270	330	399
	-6	9	27	47	71	98	130	167
		-42	-32	-21	-8	6	23	43
			-64	-58	-51	-43	-34	-23
				-77	-74	-69	-65	-59
					-86	-84	-81	-78
						-91	-90	-88
							-95	-94
								-97

Table 9-11: *Cash flow event tree for production profile B. In million USD.*

Table 9-10 and 9-11 illustrate the revenues and cash flow event trees for production profile B. As can be seen in table 9-11, a lower annual decline in production compared to production profile A results in a greater number of nodes containing positive cash flows in later years.

2017 Y0	2018 Y1	2019 Y2	2020 Y3	2021 Y4	2022 Y5	2023 Y6	2024 Y7	2025 Y8
-351	-252	-149	-49	33	79	64	-44	-290
	-603	-549	-492	-437	-393	-378	-413	-521
		-720	-695	-668	-640	-615	-611	-646
			-752	-747	-740	-731	-717	-712
				-766	-763	-758	-753	-748
					-775	-772	-770	-767
						-780	-779	-777
							-783	-782
								-785

Optimal decision

Decommission (pink)

Continue (green)

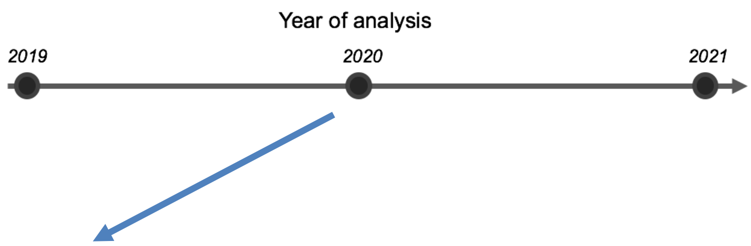
Table 9-12: *The base case decision tree of production profile B. In million USD.*

Table 9-12 shows the decision tree belonging to production profile B. More nodes are green in production profile B compared to the base case of production profile A. This relates to the fact that production profile B has a greater upside potential due to lower annual decrease in production. A more favorable price development with time would have a greater impact than in production profile A since annual production remains relatively high. The potential downside is still eliminated. The flexibility to choose the time of abandonment is consequently worth more for production profile B.

9.2 Optimal Timing of Abandonment

In the real option model, one does not have to consider the optimal abandonment timing in order to derive the project value, as the abandonment decisions are inherent in the model itself. The opposing disadvantage is that the Real Option Model does not provide a single time of abandonment, due to the modeled uncertainty. The model formulation of the Real Option Model imply that one is only able to determine whether one should shut down or continue operations at time zero.

The optimal timing of abandonment can be found by moving the analysis in time up to the point where abandonment is preferred relative to continuing at time zero. In practice, this involves conducting an updated real options analysis each year. The abandonment decision is not made until the point in time where decommissioning is preferred at year zero. In our model with a response time of one year, choosing decommissioning at year zero will imply that decommissioning should be conducted the following year.



2020	2021	2022	2023	2024	2025	2026
Y0	Y1	Y2	Y3	Y4	Y5	Y6
-721	-724	-727	-730	-732	-735	-696
	-754	-756	-757	-759	-760	-696
		-771	-772	-773	-773	-696
			-780	-780	-781	-696
				-784	-784	-696
					-786	-696
						-696

Table 9-13: *The optimal timing decision of the base case. Analyzed from year zero. In million USD.*

Table 9-13 illustrates the procedure for obtaining the optimal timing of abandonment for the base case applied to production profile A. The optimal timing is conditional on the estimated future cash flows in table 9-1 being realized. By conducting the real options analysis every year, we observe that the decommissioning decision should be made in 2020, meaning that the actual decommissioning work starts in 2021.

Equivalent analyses are performed for the remaining scenarios and for production profile B. The results are summarized in table 9-14.

	Decommissioning year
Base case	2021
Idle platform	2021
Annually reduced decom cost	2022
Cyclical decom cost	2022
Production profile B	2025

Table 9-14: *Optimal timing of abandonment in the Real Option Model.*

As can be seen from table 9-14, it is optimal to abandon the field in 2021 for the base case and the idle platform scenario. In the annually reduced and cyclical decommissioning cost scenarios it is optimal to abandon the field in 2022. Changing the production decline from 30% to 15% makes it optimal to defer abandonment until 2025. At that point in time, the operator would have received negative cash flows for five years. The incentive of deferral stems from the interest savings of the abandonment cost incorporated in the model.

Concluding Remarks

This chapter analyzes the effect of implementing different scenarios in the real option model. The model is applied to both a project value analysis and an abandonment timing analysis. In the project value analysis, we find that all scenarios add to project value. This is however given strict assumptions.

	ROA project value	**%Δ from base case**
Base case	-417	N/A
Idle platform	-386	7 %
Annually reduced decom cost	-365	12 %
Cyclical decom cost	-391	6 %
Production profile B	-354	15 %

Table 9-15*:* *Real options model: project value given the different scenarios. In million USD.*

Table 9-15 sums up the project values and the scenarios' relative effect on project value compared to the base case. Given the underlying assumptions, there is a change in project value from 6 to 12% depending on the scenario incorporated. In this analysis, the annually reduced decommissioning cost scenario has a particularly large effect on project value with +12% change in project value. In the cyclical decommissioning cost scenario, we observe that a positive correlation between prices and the decommissioning costs has a positive effect on project value, but only up to a certain point.

Furthermore, the steep annual decline in production of production profile A is limiting the upside potential of higher prices. For production profile B, the annual decline is lower, resulting in higher potential upside of increased prices and a greater value of flexibility.

In the decommissioning timing analysis, we find that it is optimal to abandon the field in 2021 in the base case and idle platform scenario, while in the cyclical and annually reduced decommissioning cost scenarios one chooses to continue one year longer. Its optimal to defer abandonment until 2025 in production profile B, even though this entails accruing negative cash flows for five years.

10 Comparing the Results

In this chapter, we compare the results derived from the two models; the Net Present Value Model from chapter 8, and the Real Option Model as presented in chapter 9. First, the results are compared regarding the optimal timing of abandonment. Secondly, the resulting project valuations of the two models are compared.

10.1 Optimal Timing of Abandonment

	Decommissioning year	
	NPV	**ROA**
Base case	2021	2021
Idle platform	2021	2021
Annually reduced decom cost	2022	2022
Cyclical decom cost	N/A	2022
Production profile B	2024	2025

Table 10-1: *Optimal decommissioning year of the Net Present Value Model and Real Option Model given the analyzed scenarios.*

Table 10-1 illustrates the optimal time of abandonment for the NPV and Real Option Model given the analyzed scenarios. The optimal timing for the Real Option Model is found by moving the analysis in time up to the point where abandonment is preferred relative to continuing. For production profile A, the results indicate that the same year of abandonment is optimal for the two models. For production profile B on the other hand, one would defer abandonment by one year in the Real Option Model relative to the NPV Model.

In other words, the Real Option Model provides the same information as the NPV Model when applied on production profile A, in which production drops by 30% annually. This is by no means a general result, but rather a result of our input data and modeling specifications. It should also be noted that the results are obtained from a discrete model. A continuous model would be more accurate when determining the exact time of abandonment, and would potentially give different results between the two models.

For the application of the two models on production profile B, the Real Option Model does however obtain a different result than the NPV Model. This is consistent with the findings of Olsen & Stensland (1988), who claim that a stochastic modeling will tend to prolong the extraction period compared to the deterministic case. The authors apply a continuous model, but do not account for the cost of abandonment. Nygaard & Jørgensen (2011) also find that the uncertain modeling of prices will make it optimal to defer abandonment, although the deterministic case indicates immediate abandonment. The authors analyze a field with a production decline of 10%.

The production profile of a field appears to be an important driver for the abandonment flexibility. With a rapid drop in production, like that of production profile A, the upside potential of increased prices is limited. Consequently, the stochastic modeling of prices does not alter the optimal timing of abandonment relative to the deterministic Net Present Value Model. For production profile B, a flatter drop in production and subsequently a flatter NPV profile, represents greater flexibility in the choice of abandonment. The upside potential of increased prices can be exploited to a larger degree, and it therefore becomes optimal to defer abandonment by one year relative to the deterministic Net Present Value Model.

For all scenarios analyzed, decommissioning is deferred past the point in which project cash flows turn negative. For production profile A, the cash flow becomes negative in 2019, while the cash flow of production profile B turns negative in 2020. For production profile B, our results indicate that it would be optimal to obtain a negative cash flow for four and five years according to the NPV analysis and ROA respectively.

10.2 Project Value

	Project value		Diff	%Δ from base case	
	NPV	ROA	(ROA-NPV)	NPV	ROA
Base case	-428	-417	11	N/A	N/A
Idle platform	-396	-386	10	7 %	7 %
Annually reduced decom cost	-384	-365	19	10 %	12 %
Cyclical decom cost	-428	-391	36	0 %	6 %
Production profile B	-422	-354	68	1 %	15 %

Table 10-2: *Difference in project valuation between Net Present Value Model and Real Option Model given the analyzed scenarios. In million USD.*

Table 10-2 sums up the project valuation of the Real Option and the NPV Model given the modeled scenarios. In addition, it displays the percentage change from the base case for each scenario within the models.

The cyclical decommissioning cost scenario is not explicitly analyzed through the NPV Model. Hence, it is given the same project value as for the NPV base case (shown in grey in table 10-2).

For all scenarios modeled, the project value derived from the Real Option Model is greater than the value from the NPV Model. The Real Option Model includes the value of flexibility inherent in the project due to the abandonment option. The value of flexibility can thereby explain, at least partially, the greater value of the Real Option Model compared to the NPV Model[20].

In the Real Option Model, revenues are modeled stochastically based on the historical volatility of crude oil and natural gas prices. The uncertainty of prices is thus modeled directly in the Real Option Model as opposed to the NPV Model. In presence of uncertainty, the flexibility to abandon a project has the potential to create value. First of all, there is a possibility that revenues increase in the future due to a favorable price development. At the same time, by having an abandonment option, the downside risk is limited. For a company having the option to abandon at any point in time during the project life, their flexibility to adapt to the price development is valuable. The value of flexibility is particularly high when the volatility of prices is high, since higher volatility results in an increased upside potential.

The difference between the project valuations of the two models is smallest for the idle platform scenario, with 10 MUSD. Note also that the change from base case by applying the idle platform is the same for the Real Option Model as for the NPV Model. The percentage change is 7% for both models relative to their base cases. It thus appears that the two models are affected to the same extent by changing the cost of abandonment, assuming that this cost remains constant over time.

Changing the production profile from a 30% annual drop in production to a 15% drop in production (from base case to production profile B), represents the greatest difference between the two models. Moving from production profile A to production profile B results in a 1% increase in project value in the NPV Model. For the Real Option Model, the same change in production profile causes an increase in project value of 15%. The difference in

[20] Some of the difference is also explained by the modeling of the interest savings of the abandonment cost. See section 6.3.5.

project value between the two models changes from 11 MUSD to 68 MUSD when moving from production profile A to production profile B.

The production profile thereby seems to be an important driver for the real options project valuation. The upside potential of increased prices is greater the lower the drop in production. A rapid decrease in production creates limits to the upside potential, as a positive price development will not be able to compensate for the negative effect of reduced production. Thus, the value of flexibility is greater for a field with a low annual production decline compared to field with a rapid production decline.

The annually reduced decommissioning cost scenario represent a higher increase in value for the Real Option Model relative to the NPV Model, with a change from base case of respectively 12% and 10%. The value of a reduction in the abandonment cost is thus greater if accounting for managerial flexibility. A cyclical decommissioning cost also represents an increase in value of 6% for the Real Option Model. This scenario is not modeled through the NPV framework, as it requires stochastic modeling of the abandonment cost.

10.3 Sensitivity of the Results

In sensitivity analyses, we find that the decommissioning cost and the crude oil price are the variables with the highest sensitivity to project value in both models. Changing these variables by 10% causes project value to change by 10 to 12%. The effect of changing the remaining variables by 10% has less than a proportional (smaller than 10%) effect on project value.

In both models, increasing the decommissioning cost to 1,200 MUSD would cause the project value to decrease by 83%. It would also be optimal to defer abandonment until 2024 due to the interest savings of postponed decommissioning. The results are less sensitive to the discount rate. Thus, the incentive to defer abandonment rationalized on interest savings seems to be driven to a largest degree by the size of the decommissioning cost rather than the risk-adjusted rate.

Also, the effect of changing a parameter value is generally higher in the Real Option Model than in the NPV Model. This is consistent with the results obtained from analyzing production profile B, and is caused by the non-linear payoff of the abandonment option. The sensitivity analyses results are presented in Appendix D.

Concluding Remarks

For the optimal timing of abandonment, the NPV Model and Real Option Model provide more or less the same results. The same year of abandonment is chosen for production profile A in all analyzed scenarios. Nevertheless, it is optimal to defer abandonment for one year in the Real Option Model compared to the NPV Model for production profile B.

The Real Option Model represents a higher project value for all scenarios analyzed. The difference in project value is primarily explained by the value of abandonment flexibility included in the Real Option Model. On one hand, the idle platform scenario results in the same percentage change of project value in the two models. On the other hand, a change in the production profile from a 30% to a 15% decline represents a significantly greater increase in project value for the Real Option Model.

The production profile thus appears to be an important driver for our results. The abandonment option is worth more for a low annual production decline, compared to a rapid decline. A rapid production decline might provide the same optimal abandonment timing in the deterministic case as for the case with price uncertainty, given a discrete problem formulation.

11 The Value of Implementing a Real Options Model in Decommissioning Analyses

In this chapter, the value of implementing a real options model for decommissioning analyses at Statoil is discussed. The potential benefits of implementing a real options model are evaluated based on the purpose of the decommissioning analysis; finding the optimal timing of abandonment or project valuation.

The discussion is made within a context in which the NPV framework is applied on a regular basis, while the real options framework is not applied formally. The context for the discussion is a simplified representation of reality, but bases on the actual use of financial frameworks in Statoil, where the NPV serves as the main tool for decommissioning analyses. When comparing the NPV Model with the Real Option Model, the question thereby becomes whether the Real Option Model has the potential to serve as a valuable supplement to the NPV Model.

The discussion bases on the analyses in the preceding chapters, and is supplemented by our experience with implementing the models and communicating them to our contact persons in Statoil. First, we discuss the potential value of implementing a real options analysis in the abandonment timing decision. Second, the value of implementing real options analysis in the valuation of tail production is discussed.

There are clearly both advantages and disadvantages of implementing a real options model in practice. In assessing the value of implementing a real options model, the potential benefits must be weighed against the resources required to implement such an analysis. The resources required are also referred to as the costs of implementation. These costs apply to the time spent for implementing an additional analysis, but also time spent for educating employees in real options theory and communicating the results to management.

11.1 The Value of Implementing a ROA in Timing Decisions

The final abandonment decision in Statoil is made on a short-term basis. More long-term analyses of when abandonment is likely to occur are also necessary for the purpose of planning. However, we have learned that it typically takes between three to six months from the final abandonment decision is made until the decommissioning work begins[21]. As the timing decision occurs shortly prior to the actual abandonment, this decision must be based on updated analyses incorporating the information at hand.

Both the NPV and the real options analysis can be performed regularly to account for new information. Due to uncertainties, the optimal abandonment timing is likely to change over time. The traditional NPV analysis uses cash flow point estimates and consequently does not model these uncertainties directly. In the real options analysis, uncertainties are however modeled directly. These differences have consequences for the way the two analyses practically can be used for timing decisions.

For long-term timing decisions, an NPV model will provide the optimal abandonment timing. As shown in our analysis, the optimal abandonment timing is obtained by performing the analysis for various abandonment years. The resulting maximized NPV represents the optimal decision. The optimality of this decision is however conditional on the estimated future cash flow being realized. On the other hand, a real options analysis will not provide information about the optimal abandonment timing on a long-term basis. The modeling of uncertainties makes it difficult to determine what is the optimal decision in the future. The optimal decisions are obtained in the various nodes of the decision tree. The decisions are conditional on the preceding cash flow development, which again depends on the evolution of the uncertain state variable(s).

For short-term timing decisions, a real options analysis might however provide more specific information on the optimal abandonment timing. At time zero, a real options model will provide information on whether it is optimal to continue or abandon at that point in time. By conducting a real options analysis on a regular basis, the optimal timing of abandonment can thereby be obtained at the point in time when it is optimal to abandon at time zero. The NPV model should also be updated to account for new information up to the point in time where abandonment is optimal.

As discussed in section 10.1, our analyses show that the timing decisions are more or less the same in the Real Option Model as in the NPV Model. For production profile A, it is optimal to abandon the field in the exact same years according to the two models. Giving no

[21] The duration of the decommissioning work will however vary greatly depending on field characteristics.

additional insights in the optimal abandonment decision, it is hard of argue that the resources required to implement a ROA are justified in this context.

Nevertheless, our analyses also show that optimal abandonment occurs one year later in the ROA as opposed to the NPV analysis for production profile B. It thus appears that the potential value of implementing a ROA in the timing decision is greater when applied to fields with flatter production declines. Consequently, it is hard to arrive on a general conclusion on the potential value of implementing a ROA for timing decisions. The additional information provided by such an analysis will depend on the characteristics of the analyzed project. The characteristics of petroleum projects on the NCS differ significantly, as explained in chapter 2.

However, we are able to draw some conclusions from our analyses. We find that the managerial flexibility of abandonment is somewhat limited with a rapid drop in production. In such a situation, a ROA is less suited compared to a situation with greater flexibility.

11.2 The Value of Implementing a ROA in Tail Production Valuation

If the ultimate goal of the analysis is to derive the residual value of a project, a real options model might provide some additional information to a static NPV model. One of the main differences between the NPV Model and the Real Option Model is that the latter incorporates the value of flexibility. The value of flexibility depends on the options available to management. In our analysis, the Real Option Model includes the option to abandon the project.

As explained in section 10.2, our analyses provided different project valuations in the two models. For all scenarios analyzed, the Real Option Model represents a higher project value. The valuation difference is mainly explained by the value of the abandonment option. The presence of such an abandonment option is not hard to argue. In reality, the companies are flexible as to when to abandon a field[22]. It can therefore be argued that a financial framework incorporating this flexibility might provide valuable insights.

[22] The Government must approve the decommissioning plan, as explained in chapter 2. However, after conversations with Statoil, we are under the impression that the plan does not hinder the flexibility of the abandonment option.

A real options analysis has the potential to create benefits in the context of project valuation through its ability to model flexibility. The size of these benefits relative to the costs of implementation will partially depend on the importance of valuing the residual value of a project correctly.

As the project is already undertaken, project valuation is not necessary for comparing projects. However, if it becomes relevant to sell the field, for instance to a smaller company specializing in decommissioning, valuing the project correctly is necessary. In this context, it might very well be worth the additional resources required to implement a real options model. The traditional NPV model does not account for the value of flexibility and thereby underestimates the project value in some instances. It is particularly interesting to apply a real options model for a field in which the drop in production is low, since the flexibility is greater. For a field with a rapid drop in production, the difference in project valuation between the Real Option Model and the NPV Model is smaller, as the upside potential of increased prices is limited by the production decrease over time.

Concluding Remarks

For the timing decision of abandonment, the value of implementing a real options analysis seems to be limited for our particular project. For production profile A, the Real Option Model does not provide any additional information regarding the optimal timing of abandonment. Generally, the potential value of implementing a ROA for timing decisions seems to be greater for fields with a low production decline, based on the presence of greater abandonment flexibility.

Incorporating a real options model might be useful when determining the residual value of a field. This would however depend on the importance of obtaining a “correct” valuation. If it for instance becomes relevant to sell a field to another operator, a real options analysis might serve as a valuable supplement in negotiations.

12 Conclusion

This thesis models the project value and optimal timing of abandonment for a mature field on the Norwegian continental shelf (NCS). The problem is analyzed through two different financial frameworks: a Net Present Value Model and a Real Option Model. Both models include various scenarios describing recent decommissioning market trends. The analysis is based on realistic project data presented by Statoil. The field of interest produces both crude oil and natural gas, and has a declining production profile. A special emphasis is put on the potentially large and uncertain decommissioning cost. Throughout the analysis we take on a company perspective, even though we acknowledge that the issue of decommissioning affects several stakeholders.

In chapter two we elaborate on the scope and overall impact of the decommissioning work. The issue of decommissioning on the NCS is becoming increasingly relevant as many fields are maturing. The Norwegian case is particularly interesting, representing the majority of forecasted decommissioning costs globally due to the large size of the installations on the NCS. There are several uncertainties involved in late-life operations and decommissioning. The decommissioning cost is highly uncertain, partly caused by market inefficiencies and lack of technological advancements. In chapter three, we therefore propose that abandonment risk should be considered as a separate risk factor for petroleum project analyses.

The net present value method discounts a project's expected future cash flows at a risk-adjusted rate reflecting the time value of money and the riskiness of the project. It is a widely taught and accepted method, and also the main tool for decommissioning analyses in Statoil. The real options method is less frequently applied, and currently not used extensively for decommissioning analyses. There are several approaches for modeling a real options problem. In short, the real options method typically involves the modeling of a project's future cash flows as a function of some "state variable" that is assumed to evolve randomly over time. The main difference between the NPV method and the real options method is that the latter aims to value the flexibility available to management.

Our Real Option Model includes management's flexibility to abandon the field at any point in time. The abandonment option is modeled as an American put option. The real options analysis bases on a contingent claims approach, in which market data for crude oil and natural gas prices are applied. The project's future cash flows are modeled as a function of crude oil and natural gas prices (that are assumed to evolve randomly over time). The problem is analyzed through the method of binominal lattices first presented by Cox, Ross, & Rubinstein (1979), due to its intuitive appeal and ability for graphical illustration.

Through our NPV Model, we develop an abandonment decision rule that is applicable for the declining production case. In the continuous solution, it is optimal to abandon the field when the marginal costs of deferral equal the marginal benefits. Marginal costs are the operational expenditures incurred while the field is producing. The marginal benefits are revenues from producing crude oil and natural gas, in addition to the interest savings from deferring the costs of abandonment.

In both models, scenarios reflecting recent decommissioning market trends are included. The first is the idle platform scenario. In the base case, it is assumed that the full decommissioning work must be conducted once production stops. In the idle platform scenario, only some of the decommissioning work must be conducted immediately, while the majority of costs can be postponed for some years at additional operational expenditures. As long as the interest savings from deferring are greater than the discounted idle operational expenditures, the opportunity is profitable and causes total abandonment costs to go down.

The second scenario modeled is the annually reduced decommissioning cost scenario, in which the abandonment cost is assumed to decrease at a given annual percentage due to technological advancements. Currently, the decommissioning solutions provided by the service industry are not specialized for decommissioning and are consequently not cost efficient. In this scenario, it is assumed that there will be technological advancements over time and that the decommissioning work thereby will become more cost efficient.

The third scenario is the cyclical decommissioning cost scenario. This scenario is only modeled through the real options framework, as it requires stochastic modeling of the decommissioning cost together with prices. The decommissioning cost is assumed positively correlated with the prices of crude oil and natural gas. Currently, services needed to perform the decommissioning work are also used for exploration and production, as well as being used by other industries. The decommissioning cost might therefore fluctuate based on the general offshore activity level. In this scenario, decommissioning becomes more expensive when crude oil and natural gas prices increase and less expensive when prices decrease.

Finally, we analyze the effect of changing the production profile in both the NPV Model and the Real Option Model. The field data presented by Statoil has a relatively steep production decline of 30% annually (production profile A). In the case of production profile B, the data is modified to account for a production decline of 15% annually.

In our analysis, we find that the decommissioning cost, together with crude oil prices, has a large impact on project value and the optimal timing of abandonment. This is confirmed by the sensitivity analysis, in which changing the decommissioning cost has the largest impact on project value after crude oil prices. For the analyzed project, we observe that the interest savings from deferring the abandonment cost makes it optimal to continue producing past the point where the cash flows become negative.

Furthermore, we find that the scenarios reflecting recent decommissioning market trends have a positive effect on project value. This result might indicate that today's total decommissioning cost estimates on the NCS are exaggerated. Our analysis also suggests that the difference between the Real Option Model and the Net Present Value Model is greater for a low decline in production compared to a rapid decline. This notion holds for both determining the optimal abandonment timing and for project valuation. When the annual production decline is lower, the upside potential of fluctuating prices is higher, making the option to abandon more valuable.

Finally, we are able to address our research question: "What is the value of implementing a real options model in decommissioning analyses at Statoil?" There is no simple answer to this question. The value of implementing a real options model crucially depends on the characteristics of the analyzed project. At the NCS, the petroleum installations are far from homogeneous. For an analysis determining optimal timing of abandonment, we conclude that the potential value of implementing a real options model is limited for fields with a steep production decline. When analyzing our project that has a 30% exponential decline in production, the Real Option Model provides no additional insight compared to the Net Present Value Model. It is therefore hard to argue that the resources required to implement a real options analysis are justified in this context. However, when analyzing the value of mature fields, we conclude that Statoil might benefit from implementing a real options model. The potential value depends on the importance of accurately estimating the value of the mature field. For instance, given the situation that Statoil would want to sell a license to a specialized company, we believe a real options analysis could serve as a valuable supplement in negotiations.

The results of our analysis might also have some further implications for Statoil. As all analyzed scenarios affect project value favorably, it would be of interest for Statoil to further explore how to realize these scenarios. Firstly, to leave the platform idle for a few years might benefit Statoil, given that the maintenance cost and associated risk with leaving the platform idle is manageable. This is however also given that this alternative is accepted by the Government that also needs to take into account externalities like the effect on local fisheries and other environmental risks.

An annually reduced decommissioning cost also has a positive effect on project value. The major obstacle to achieve this development relates to market transparency. Statoil, like any other upstream oil company, needs to have an open dialog with the decommissioning service industry to achieve the upfront investments needed to reduce cost levels. Finally, to leverage on a cyclical decommissioning cost Statoil needs to have the necessary liquidity to perform decommissioning work when the cost levels are low. With an aggressive dividend policy and low revenue stream, this might present a challenge that needs to be planned for in the next cyclical upturn.

Nonetheless, our results are far from conclusive and they rely on several assumptions. First of all, our conclusions are drawn from a declining production case, in which production drops exponentially over time. A different type of production profile would most likely present other results in terms of optimal abandonment and project value. It should also be noted that the optimal abandonment decision rule is only applicable for a declining production case. Furthermore, the size of the decommissioning cost of the project analyzed is not representative for all fields on the NCS. The installations on the NCS are highly heterogeneous with varying decommissioning costs. Therefore, it is not a general result that it is optimal to defer abandonment past the point in time where cash flows turn negative. This finding crucially depends on the size of the decommissioning cost. If an installation actually had a salvage value higher than its decommissioning costs, it would most likely be optimal to abandon the project before cash flows turned negative, all else equal.

More research needs to be conducted in order to confirm our general results and to further understand the exact effect of the analyzed scenarios. It would also be interesting to apply a similar real options analysis for various types of production profiles. There are several potential research questions to be addressed on the topic of decommissioning in general. For example, it would be interesting to consider the socioeconomic perspective of decommissioning through an analysis of decommissioning externalities. We also see an alternative way of applying a real options framework in decommissioning analyses. The decommissioning program consists of several contingent decisions, of which dynamic programming could serve as a valuable tool for minimizing the cost.

The topic of decommissioning, more specifically decommissioning on the NCS, has not received extensive academic attention. Nevertheless, it is an issue of increasing relevance to the oil and gas industry. The decommissioning liabilities on the NCS involve high and uncertain costs that affect several stakeholders. It is in the interest of society as a whole that the decommissioning work is performed in a cost-efficient, but also safe and environmentally friendly way. Therefore, we hope and believe that the topic of decommissioning will receive increased academic attention in the future.

References

Armstrong, M., Bailey, W., & Couet, B. (2005). The Option Value of Acquiring Information in an Oilfield Production Enhancement Project. *Journal of Applied Corporate Finance*, *17*(2), 99.

Bardi, F., Martén, I., Mikhailov, O., & Streubel, H. (2015). Asset Abandonment in Upstream Oil. Retrieved March 3, 2016, from www.bcgperspectives.com/content/articles/energy-environment-asset-abandonment-upstream-oil/

Berk, J., & DeMarzo, P. (2014). *Corporate Finance* (3rd ed.). Essex: Pearson.

Black, F., & Scholes, M. (1973). The Pricing of Options and Corporate Libilities. *The Journal of Political Economy*, *81*(3), 637–654.

Bonini, C. P. (1977). Capital Investment Under Uncertainty with Abandonment Options. *Journal of Financial & Quantitative Analysis*, *12*(1), 39–54.

Bonino, E. (2015, February 3). UK can become a world-class hub for decommissioning oil platforms. Retrieved February 26, 2016, from www.theguardian.com/environment/2015/feb/03/uk-can-become-a-world-class-hub-for-decommissioning-oil-platforms

Borison, A. (2005). Real Options Analysis: Where Are the Emperor's Clothes? *Journal of Applied Corporate Finance*, *17*(2), 17–31.

Brandão, L. E., Dyer, J. S., & Hahn, W. J. (2005). Using Binomial Decision Trees to Solve Real-Option Valuation Problems. *Decision Analysis*, *2*(2), 69–88.

Brealey, R. A., Myers, S. C., & Allen, F. (2006). *Principles of Corporate Finance* (8th ed.). McGraw-Hill.

Brennan, M. J. (1991). The Price of Convenience and the Valuation of Commodity Contingent Claims. *Stochastic Models and Option Values*, *200*(22-71).

Brennan, M. J., & Schwartz, E. S. (1985). Evaluating Natural Resource Investments. *The Journal of Business*, *58*(2), 135.

Buyuksahin, B., Lee, T. K., Moser, J. T., & Robe, M. A. (2013). Physical markets, paper markets and the WTI-Brent spread. *The Energy Journal*, *34*(3), 129–152.

Bøhren, Ø., & Ekern, S. (1991). Usikkerhet i oljeprosjekter: relevante og irrelevante risikohensyn. *Stiftelsen Bedriftsøkonomisk Institutt*.

Cole, D., Kar, J., Lock, E., & Christ, F. (2015). From late-life operations to decommissioning – maximising value at every stage. Retrieved March 15, 2016, from www.mckinsey.com/~/media/McKinsey/dotcom/client_service/Oil and gas/PDFs/Future of North Sea - From late life into decommissioning - McKinsey.ashx.

Copeland, T., & Antikarov, V. (2001). *Real Options: A Practitioner's Guide*. *Real Options: A Practitioner's Guide*. New York: Texere.

Copeland, T., & Antikarov, V. (2005). Real Options : Meeting the Georgetown Challenge. *Journal of Applied Corporate Finance*, *17*(2), 32–51.

Copeland, T., & Tufano, P. (2004). A Real-World Way to Manage Real Options. *Harvard Business Review*, *82*(3), 90–99.

Cox, J. C., Ross, S., & Rubinstein, M. (1979). Option pricing: A simplified approach. *Journal of Financial Economics*, *7*(3), 229–263.

Dixit, A. K., & Pindyck, R. S. (1994). *Investment under uncertainty*. Princeton: Princeton University Press.

Ekern, S. (1988). An option pricing approach to evaluating petroleum projects. *Energy Economics*, *10*(2), 91–99.

Farrel, S. (2016, January 19). Oil market could drown in oversupply in 2016, says IEA. Retrieved April 16, 2016, from www.theguardian.com/business/2016/jan/19/oil-market-2016-report-international-energy-agency

Fattough, B. (2011). An anatomy of the crude oil pricing system. *Oxford Institute for Energy Studies*.

Foley, S., Crooks, E., & Oakley, D. (2016, February 14). Investors split over oil majors' payouts. Retrieved May 7, 2016, from www.ft.com/intl/cms/s/0/3a22e926-d30b-11e5-829b-8564e7528e54.html#axzz49khlnE1I

Forbes. (2016, February 5). Dividend-Cut Risk Of The 6 Oil Super Majors. Retrieved May

4, 2016, from www.forbes.com/sites/gurufocus/2016/02/05/dividend-cut-risk-of-the-6-oil-super-majors/#503e68ac1289

Gassco. (2016). Glossary. Retrieved February 4, 2016, from www.gassco.no/en/our-activities/what-is-natural-gas/glossary/

Geman, H. (2009). *Commodities and commodity derivatives: modeling and pricing for agriculturals, metals and energy*. John Wiley & Sons.

Gibson, R., & Schwartz, E. S. (1990). Stochastic Convenience Yield and the Pricing of Oil Contingent Claims. *The Journal of Finance*, *45*(3), 959–976.

Graham, J. R., & Harvey, C. R. (2001). The theory and practice of corporate finance: Evidence from the field. *Journal of Financial Econmics*, *60*(2-3), 187–243.

Howe, K. M., & McCabe, G. M. (1983). On Optimal Asset Abandonment and Replacement. *Journal of Financial & Quantitative Analysis*, *18*(3), 295–305.

Hume, N. (2016). Platts moves to protect Brent crude benchmark. Retrieved June 2, 2016, from http://www.ft.com/intl/cms/s/0/50fe1774-ce7e-11e5-92a1-c5e23ef99c77.html#axzz4BS5WxVoD

Jagannathan, R., & Meier, I. (2002). Do we need CAPM for capital budgeting? *Finance Research Letters*, *Winter*(2001), 5–27.

Kodukula, D. P., & Papudesu, C. (2006). *Project Valuation using Real Options: A Practitioner's Guide*. *J. Ross Publishing* (Vol. 1st).

Kristoufek, L., & Vosvrda, M. (2014). Commodity futures and market efficiency. *Energy Economics*, *42*, 50–57.

Lakhal, S. Y., Khan, M. I., & Islam, M. R. (2009). An "Olympic" framework for a green decommissioning of an offshore oil platform. *Ocean and Coastal Management*, *52*(2), 113–123.

Lander, D. M., & Pinches, G. E. (1998). Challenges to the practical implementation of modeling and valuing real options. *The Quarterly Review of Economics and Finance*, *38*(3), 537–567.

Lavelle, C., & Jenkins, N. (2014). Decommissioning in the North Sea. Retrieved February 1, 2016, from http://publications.arup.com/publications/d/decommissioning_in_the_north_sea

Luehrman, T. A. (1997). What's it worth? A general manager's guide to valuation. *Harvard Business Review*, *75*(3), 132–142.

Luehrman, T. A. (1998). Investment opportunities as Real Options: Getting Strated on the numbers. *Harvard Business Review*, *76*(4), 97–105.

Luehrman, T. A. (1998). Strategy as a portfolio of real options. *Harvard Business Review*, *76*(5).

Lund, D. (2009). Rent Taxation for Nonrenewable Resources. *Annual Review of Resource Economics*, *1*(November), 287–308. doi:10.1146/annurev.resource.050708.144216

Lund, D. (2014). State participation and taxation in Norwegian petroleum: Lessons for others? *Energy Strategy Reviews*, *3*(2211), 49–54. Retrieved from http://dx.doi.org/10.1016/j.esr.2014.02.001

Lund, M. W. (1999). Real Options in Offshore Oil Field Development Projects. *3rd Annual Real Options Conference, Leiden*.

McDonald, R. (2006). The Role of Real Options in Capital Budgeting: Theory and Practice. *Journal of Applied Corporate Finance*, *18*, 28–39.

Ministry of Finance. (2013). Reduced uplift in the petroleum tax system. Retrieved May 22, 2016, from https://www.regjeringen.no/en/aktuelt/reduced-uplift-in-the-petroleum-tax-syst/id725999/

Mullins, D. W. (1982). Does the capital asset pricing model work? *Harvard Business Review*. Retrieved from http://search.ebscohost.com.idpproxy.reading.ac.uk/login.aspx?direct=true&db=bth&AN=3867993&site=eds-live&custid=s6477394

Mun, J. (2002). *Real Options Analysis: Tools and Techniques for Valuing Strategic Investments and Decisions*. *Real Options Analysis:Tools and Techniques for valuing strategic investments and decisions* (Vol. 137). John Wiley & Sons.

Nagel, N. B. (2001). Compaction and subsidence issues within the petroleum industry: From

Wilmington to Ekofisk and beyond. *Physics and Chemistry of the Earth, Part A: Solid Earth and Geodesy*, *26*(1-2), 3–14.

Norges Bank Investment Managment. (2016). Oljefondet markedsverdi. Retrieved February 16, 2016, from www.nbim.no

Norsk Petroleum. (2016). Statents Inntekter. Retrieved May 14, 2016, from http://www.norskpetroleum.no/okonomi/statens-inntekter/

Nygaard, Ø., & Jørgensen, L. (2011). Oljeprisusikkerhet og optimalt nedleggelsestidspunkt. *Unpublished Master Thesis*. Norwegian School of Economics, Bergen, Norway.

Oil and Energy Department. The Petroleum Act (1997). Retrieved from https://lovdata.no/dokument/NL/lov/1996-11-29-72#KAPITTEL_5

Olsen, T. E., & Stensland, G. (1988). Optimal shutdown decisions in resource extraction, *26*, 215–218.

Osmudsen, P., & Tveteras, R. (2003). Decommissioning of petroleum installations - major policy issues. *Energy Policy*, *31*(970911), 1579–1588.

Pickles, E., & Smith, J. L. (1993). Petroleum property valuation: a binomial lattice implementation of option pricing theory. *The Energy Journal*, *January*, 1–26.

Quandl. (2016). Crude Oil Futures [Data file]. Retrieved February 22, 2016, from www.quandl.com

Regjeringen. (2016). Statens inntekter fra petroleumsvirksomheten. Retrieved April 10, 2016, from www.regjeringen.no/no/tema/energi/olje-og-gass/statens-inntekter-fra-petroleumsverksemda/id2076770/

Rystad Energy. (2016). D-cube and U-cube Database (versions 2016-02-13 and 2016-03-17) [computer software]. Oslo.

School, I. (2014). What are the main steps of an oil or gas field development project? Retrieved February 7, 2016, from www.ifp-school.com/upload/docs/application/pdf/2015-02/3_main_steps_oil_gas_field_development.pdf

Smit, H. T. J. (1997). Investment analysis of offshore concessions in The Netherlands.

Financial Management, *26*(2), 5–17.

Smith, J. E., & McCardle, K. F. (1998). Valuing Oil Properties: Integrating Option Pricing and Decision Analysis Approaches. *Operations Research*, *46*(2), 198–217.

Smith, J. E., & McCardle, K. F. (1999). Options in the Real World: Lessons Learned in Evaluating Oil and Gas Investments. *Operations Research*, *47*(1), 1–15.

Taraldsen, L., & Qvale, P. (2014, November 4). Slik kan de få penger for å overta et helt oljeselskap. Retrieved May 3, 2016, from http://www.tu.no/artikler/slik-kan-de-fa-penger-for-a-overta-et-helt-oljeselskap/230671

The Economist. (2016, January 30). Natural Gas - Step on It. Retrieved June 1, 2016, from www.economist.com/news/finance-and-economics/21689644-it-will-take-time-fragmented-market-verge-going-global-step

Trigeorgis, L. (1993). Real Options and Interactions with Financial Flexibility. *Financial Management*, *22*(3), 202–224.

U.K. Fisheries Offshore Oil and Gas Legacy Trust Fund. (2016). Derogations so far. Retrieved April 13, 2016, from http://www.ukfltc.com/decommissioning/derogations-so-far.aspx

U.S. Department of the Treasury. (2016). Daily Treasury Yield Curve Rates. Retrieved February 21, 2016, from https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

UK Department of Energy and Climate Change. (1998). Decommissioning of Offshore Oil and Gas Installations and Pipelines under the Petroelum Act. Retrieved February 2, 2016, from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/69754/Guidance_Notes_v6_07.01.2013.pdf

Woodrow, L. (2012). Types of Drilling Rigs. Retrieved March 31, 2016, from http://development.oilguru.org/blog/2012/10/08/oil-guru-101-basic-rig-training/

Woolley, S., & Cannizzo, F. (2005). Taking Real Options Beyond the Black Box. *Journal of Applied Corporate Finance*, *17*(2), 94–98.

Ånestad, M. (2015, May 29). Tyner ut siste slant og fjerner plattformer. Retrieved April 23, 2016, from http://www.dn.no/nyheter/naringsliv/2014/10/26/2052/Energi/tyner-ut-siste-slant-og-fjerner-plattformer

Ånestad, M., & Løvås, J. (2015, June 19). Brønnplugging koster 571 mrd. kroner. Retrieved February 17, 2016, from http://www.dn.no/nyheter/2015/06/19/1549/oljesmellen/brnnplugging-koster-571-mrd-kroner

Data Sources

Project Data is received from Statoil. The following sums up other external data sources.

Crude Oil Prices

Crude Oil-Brent Cur. Month FOB U$/BBL (downloaded 17.02.16 from Thomson Reuters Datastream)

Crude Oil-Brent 1Mth Fwd FOB U$/BBL (downloaded 17.02.16 from Quandl.com)

Natural Gas Prices

Nat Gas NBP Day Ahead PENCE/THM (downloaded 17.02.16 from Thomson Reuters Datastream)

Interest Rates

Market yield on U.S. Treasury securities at 1-month constant maturity, quoted on investment basis (downloaded 17.02.16 from www.treasury.gov)

Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on investment basis (downloaded 17.02.16 from www.treasury.gov)

Abandonment Expenditure of Other Assets on the NCS

Abandonment cost in MUSD (downloaded 25.02.16 from Rystad Energy D-cube database)

Appendix A: Binominal Lattice Solution Method with Risk-neutral Probabilities

The binomial options pricing model is a numerical method for valuation of options, which was first derived by Cox, Ross, & Rubinstein (1979). Solving for the real options value using a binominal lattice can be described as a method consisting of two steps.

First, the evolution of the underlying risky asset is set up in what we will call an "event tree" (Copeland & Antikarov, 2005). For real options problems, the underlying will either be the cash flows or the present value of the project over time. Each node in the lattice represents a possible value of the underlying at a given point in time. Starting at year 0, the value of the underlying will either go up or down from one period to the next. This results in a tree as illustrated in figure A-1.

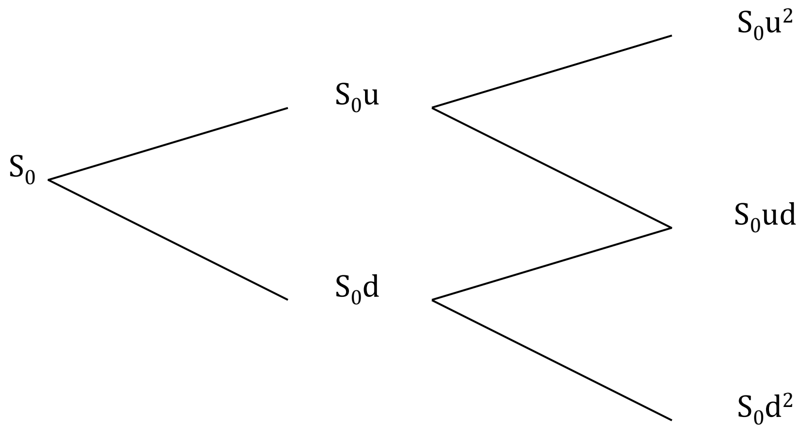


Figure A-1: *Event tree. Recombining binominal lattice.*

S_0 is the value of the underlying at time 0. u and d are the factors determining the evolution of the underlying over time. They are also known as "up" and "down" factors. The up and down factors will depend on the volatility of the underlying, and can be described as follows:

(A.1)
$$u = e^{\sigma\sqrt{\Delta t}}$$

(A.2)
$$d = e^{-\sigma\sqrt{\Delta t}} = \frac{1}{u}$$

Where e is the exponential function, σ is the volatility of the underlying and $\sqrt{\Delta t}$ is the square root of time-steps. The time-steps, Δt, simply describe the relationship between the expiration length of the project and the number of time intervals included in the binominal lattice. The down factor is the reciprocal of the up factor, ensuring that the lattice will be recombining.

The second step is to construct the decision tree. The decision tree describes the decisions available to the holder of the option over time. Finding the optimal decisions in each node, and subsequently solving the tree through a backward induction, will result in the project value with flexibility at time zero. The decision tree for an American put option can be illustrated as in figure A-2:

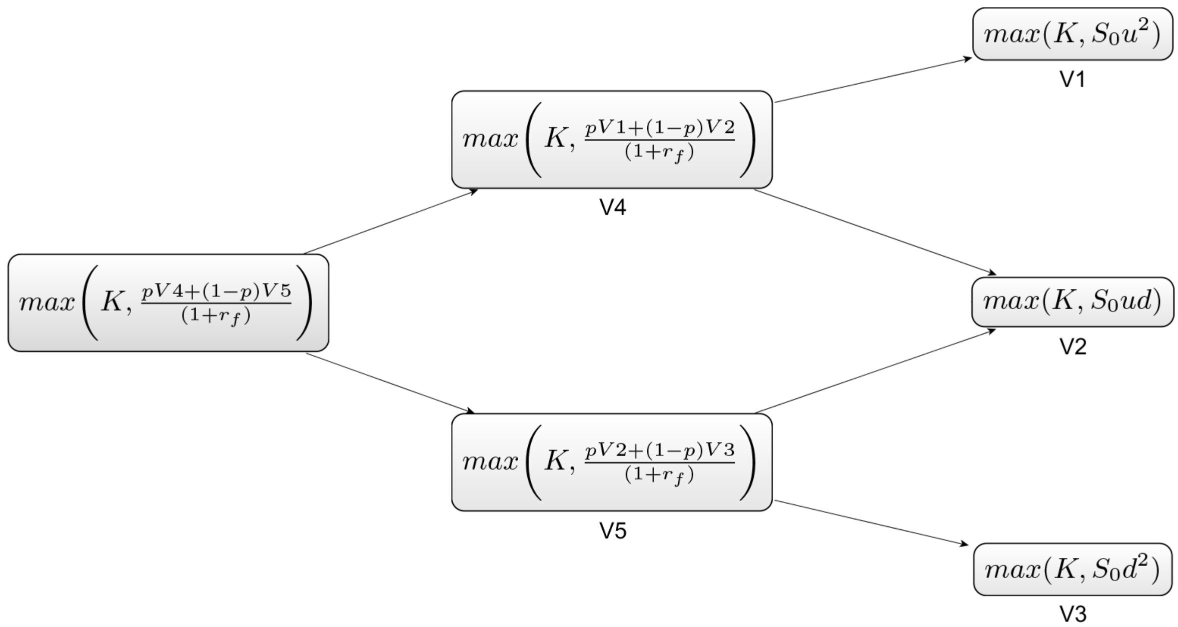


Figure A-2: *Decision tree for an American put option.*

The decision at the end nodes consists of comparing the value of the underlying as described in the event tree with the exercise price of the option, K. An American put option will be exercised when the exercise price is greater than the value of the underlying[23], as illustrated by the maximization condition. For a real options problem, we will choose to sell an asset when its salvage value (exercise price) exceeds the value of continuing to hold the project.

The method of solving the decision tree through a backward induction is easiest done through applying a risk-neutral probability, p. This risk-neutral probability value is a mathematical intermediate and by itself has no particular meaning (Mun, 2002). It is simply

[23] While a call option will be exercised at points in time where the value of the underlying is greater than the exercise price.

a mathematical convenience to adjust the cash flows so that they may be discounted at the risk-free rate (Copeland & Antikarov, 2001). The risk neutral probability is calculated as follows:

(A.3)
$$p = \frac{(1 - r_f \Delta t) - d}{u - d}$$

Where r_f is the discrete risk-free rate. The decision tree is thus solved by comparing the value of continuing to hold the project with the value of exercising the option at each node. The value of continuing is found through the use of risk-neutral probabilities, involving an adjustment for risk in the numerator and risk-free discounting.

Appendix B: Revenue Volatility Estimation

In order to estimate the volatility of revenues for our project, we need the volatility of crude oil and natural gas prices. According to Smit (1997), there are two methods for estimating commodity price volatility. One method involves calculating the implied volatility from market prices on oil and natural gas derivatives. The other method uses historical time series of spot prices in order to estimate the standard deviation. As the volume of Brent crude oil and natural gas derivatives are relatively low, the second method is preferred for our analysis.

The volatility of oil and gas prices are estimated using the full sample of weekly data (see sections 7.1.1 and 7.1.2). More specifically, we use an approach presented by Mun (2002) as "the logarithmic cash flow returns approach" for volatility estimation. The first step is to calculate the natural logarithm of relative returns from one week to the next.

(B.1)
$$\ln(relative\ return)_t = \ln\left(\frac{p_t}{p_{t-1}}\right) = x_t$$

Where p_t is the commodity price in week t.

The second step involves calculating a moving average volatility. The volatility of a given period will depend on previous period's relative returns.

(B.2)
$$Volatility = \sqrt{\frac{1}{n-1}\sum_{t=1}^{n}(x_t - \bar{x})^2}$$

Where $\bar{x}$ is the average logarithmic relative return of commodity prices over time. With weekly data, equation (B.2) will yield the weekly volatility. For the Real Option Model, the volatility should be annualized (Mun, 2002).

(B.3)
$$Yearly\ volatility = \sigma\sqrt{52}$$

Equation (B.3) annualizes the weekly volatility σ by multiplying it with the square root of number of weeks in a year.

As the third and final step, we calculate the average and the median of the moving average volatility. According to Mun (2002), the average is preferred as an estimate for the volatility given that the median is not far off the average[24]. Performing the three-step approach described above leaves us with an oil price and natural gas volatility of respectively 34.29% and 41.46%.

For the real options analysis, we need the volatility of revenues. Our revenues flow consists of a constant contribution from the production of crude oil and natural gas. Hence, the portfolio volatility will also be constant over time when combining the effect of crude oil and natural gas volatility. In order to calculate the volatility of revenues, we use the following formula:

(B.4)
$$\sigma_{revenues} = \sqrt{w_{co}^2\sigma_{co}^2 + w_{ng}^2\sigma_{ng}^2 + 2w_{co}w_{ng}\sigma_{co}\sigma_{gn}\rho_{co,ng}}$$

Where w_{co} and w_{ng} represents the weight of respectively crude oil and natural gas contribution to revenues, with $w_{co} + w_{ng} = 1$. In this case, crude oil contributes to 88% of revenues over time, while natural gas contributes to the remaining 12%. $\rho_{co,ng}$ is the correlation of oil and natural gas prices. The correlation can be expressed as:

(B.5)
$$\rho_{co,ng} = \frac{\sigma_{co,ng}}{\sigma_{co}\sigma_{ng}}$$

The covariance, $\sigma_{co,ng}$, is also estimated using the retrieved historical weekly spot price data. It can be expressed as:

(B.6)
$$\sigma_{co,ng} = \frac{\sum_{t=1}^{n}(p_t^{co} - \overline{p^{co}})(p_t^{ng} - \overline{p^{ng}})}{n-1}$$

Where p_t^{co} is the crude oil price at time t and p_t^{ng} represents the natural gas price. Using equation (B.5) and (B.6), we find a weakly positive correlation between crude oil and natural gas prices of 0.1481.

Combining the volatility estimate of oil and gas prices with their weights and correlation, we obtain a revenue volatility estimate of 31.19%.

---

[24] A large deviation between the average and median would imply that the distribution of volatilities is skewed. If so, the median should be used (Mun, 2002).

Appendix C: Net Convenience Yield

In arbitrage-free markets, the futures price would equal the current spot price of the underlying plus the interest accrued until maturity of the contract in question (Smit, 1997). However, in most commodity markets this relationship is not a given. The price of the futures contract also depends on storage costs or production benefits of physically owning the underlying. Potential benefits of holding the underlying product can for example be to avoid shortages. The benefits of having a physical inventory of a product instead of a futures contract, net of costs, are referred to as the implied net convenience yield in the futures market (Brennan, 1991).

The implied net convenience yield in the futures market can found by looking at the relationship between the futures price, spot price and risk-free rate. The non-arbitrage pricing formula for future contracts should be:

(C.1) $$F_T = S_0 e^{r_f T}$$

Where F_T the one-month future price of the product with maturity in time T, S_0 is the spot price and r_f is the risk-free rate[25]. Correcting the future pricing formula to take into account net convenience yield δ we get:

(C.2) $$F_T = S_0 e^{(r_f - \delta)T}$$

The inverted relationship becomes the function of the net convenience yield:

(C.3) $$\delta = r_f - \frac{1}{T} ln(\frac{F_T}{S_0})$$

According to Brennan & Schwartz (1985), the marginal net convenience yield is inversely proportional with the amount of the commodity held in stock. When the physical stock is high, both the spot and net convenience yield will be low. This effect can be observed in today's market, where the recent fall in oil prices has resulted in high crude oil inventory levels and low convenience yields (Farrel, 2016).

[25] One-month US treasury bond yield found at U.S. Department of the Treasury (2016).

For crude oil we use weekly spot and futures prices spanning from 17.02.1991 to 17.02.2016[26]. Applying equation (C.3) yields an average convenience yield of -0.06%.

For natural gas we use weekly spot and futures prices spanning from 01.05.2011 to 17.02.2016. We obtain an average convenience yield of -0.97%. Natural gas is harder to store and subsequently has higher storage costs, which partly explains a more negative convenience yield compared to crude oil. Nevertheless, this estimation is based on few observations. Hence, the magnitude of this gap can be questioned.

As the project compose of both crude oil and natural gas revenues, the convenience yield that reflect the project convenience yield is found by weighting the convenience yield of crude oil and natural gas according to their share of total revenues. This share is 12% for natural gas and 88% for crude oil. Hence, the project convenience yield is estimated to be –0.17%. For simplicity we assume that the net convenience yield is constant over the life of the project.

[26] Future prices are gathered at Quandl (2016).

Appendix D: Sensitivity Analysis

D.1 Net Present Value Model

In the following, we perform a sensitivity analysis of the Net Present Value Model. First, the analyzed variables are increased by 10% and reduced by 10%, in order to investigate their relative effect on net present value. Secondly, the variables are analyzed separately.

	%Δ NPV	
	Up 10%	**Down 10%**
Decom cost	-12 %	12 %
Crude oil price	10 %	-10 %
OPEX	-8 %	9 %
Production drop	-5 %	5 %
Risk-adjusted rate	3 %	-3 %
Natural gas price	1 %	-1 %

Table D-1: *The relative effect on net present value (NPV) when changing input variables by 10% up and down.*

From table D-1, the NPV results appear to be moderately sensitive to changes in the decommissioning cost, the crude oil price and OPEX. For example, increasing the decommissioning cost by 10% would cause the NPV of the project to decrease by 12%. The NPV results are somewhat less sensitive to changes in the production drop. In addition, the results are relatively insensitive to the discount rate and the natural gas price.

It should be noted that a 10% increase or decrease might be more likely for some variables than others. In addition, the sensitivity analysis above studies the effect of changes in one variable at the time, and ignores their covariance. For instance, in a scenario where the crude oil price changes significantly, it is also likely that the price of natural gas changes.

In the following, the sensitivity of each variable is studied separately, using a scale of alternative parameter values. The range of these scales reflects what we believe to be likely based on historical values and conversations with Statoil.

Decommissioning Cost

Decom cost	Decom year	NPV	%Δ base case
200	2020	-34	92 %
400	2020	-197	54 %
600	2021	-355	17 %
696	2021	-428	0 %
800	2021	-507	-19 %
1000	2022	-650	-52 %
1200	2024	-783	-83 %

Table D-2: *Net present value and decommissioning year sensitivity of changes in decommissioning cost. In million USD.*

As explained in chapter 2, it can be very difficult for oil companies to estimate the decommissioning cost. Looking at the full project life, the NPV might not be that sensitive to the decommissioning cost estimate, as the decommissioning cost incurs at the end of the project life, which is typically far in the future for an oilfield project. However, limiting the scope of attention to the final years of a project, the NPV is likely to be more sensitive to the decommissioning cost.

For the analyzed project, a reduction in abandonment cost from 696 MUSD to 200 MUSD would increase project value by as much as 92%. Changes in the decommissioning cost also affect the optimal time of abandonment. An increase in the decommissioning cost from 696 MUSD to 1,200 MUSD would create an incentive to defer abandonment by three years due to the increased interest savings from deferral. This example illustrates how the abandonment cost will be of significant importance for both project value and the optimal timing of abandonment.

Crude Oil Price

Crude oil price	Decom year	NPV	%Δ base case
20	2018	-675	-58 %
40	2020	-584	-37 %
60	2021	-470	-10 %
67	2021	-428	0 %
80	2022	-347	19 %
100	2022	-216	50 %
120	2023	-82	81 %

Table D-3: *Net present value and decommissioning year sensitivity of changes in crude oil price. In million USD.*

As can be seen from historical data, crude oil prices can fluctuate greatly from one period to the next. For a marginal field, the crude oil price can therefore be of great importance. This is apparent in table D-3, in which changes in the crude oil price will have a relatively large effect on both project value and optimal abandonment year. If the crude oil price drops to 20 USD per barrel, NPV drops by 58% and it becomes optimal to abandon the field already in 2018. In the base case, the field is abandoned in 2021. Whereas an increase in crude oil price to from 67 USD to 120 USD per barrel, would make it optimal to defer abandonment by two years and the NPV would increase by as much as 81%.

Operational Expenditures

OPEX	Decom year	NPV	%Δ base case
75	2023	-321	25 %
85	2022	-367	14 %
95	2021	-409	4 %
100	2021	-428	0 %
105	2021	-446	-4 %
115	2020	-480	-12 %
125	2020	-508	-19 %

Table D-4: *Net present value and decommissioning year sensitivity of changes in operational expenditures (OPEX). In million USD.*

Operational expenditures are not as likely to fluctuate as prices, since they are mainly related to size of the field, which will not change over time. However, unexpected expenses may occur due to the technical risks of operating an oilfield. In table D-4, OPEX is changed from 75 in the low case to 125 in the high case. The effect of changes in OPEX on project value and optimal abandonment year is clearly significant, but smaller than the effect of changes in the other variables studied so far.

Production Drop

Production drop	Decom year	NPV	%Δ base case
0.35	2020	-459	-7 %
0.33	2021	-447	-5 %
0.31	2021	-434	-2 %
0.3	2021	-428	0 %
0.29	2021	-421	2 %
0.27	2022	-406	5 %
0.25	2022	-387	9 %

Table D-5: *Net present value and decommissioning year sensitivity of changes in production drop. In million USD.*

As seen in table D-5, the parameter values for drop in production varies from 35% to 25%. There is always a possibility for production rates to suddenly drop due to the technological risks of producing wells. However, it is assumed to be unlikely that production rates will deviate by more than five percentage points on average. Changes in the production drop in this interval have a moderate impact on the NPV of the project, compared to the other variables studied so far. However, changes in the production drop will affect the optimal time of abandonment. A production drop of 35% would make it optimal to abandon the field in 2020, while a production drop of 25% would make it optimal to defer abandonment until 2022.

Risk-adjusted Rate

Risk-adjusted rate	Decom year	NPV	%Δ base case
2 %	2020	-524	-23 %
4 %	2020	-488	-14 %
6 %	2021	-448	-5 %
7 %	2021	-428	0 %
8 %	2021	-408	5 %
10 %	2022	-364	15 %
12 %	2023	-319	25 %

Table D-6: *Net present value and decommissioning year sensitivity of changes in the risk-adjusted rate. In million USD.*

In table D-6, a relatively wide range of risk-adjusted rates is presented. We believe it to be unlikely that the real risk-adjusted rate should deviate by more than five percentage points. Within this interval, changes in the risk-adjusted rate have a significant effect on project value and optimal time of abandonment. However, the sensitivity of the discount rate appears to be smaller than the sensitivity of the other parameters studied so far. Thus, the incentive to defer abandonment based on interest savings seems to be driven to a larger degree by the size of the decommissioning cost rather than the interest rate.

Natural Gas Price

Natural gas price	Decom year	NPV	%Δ base case
0.75	2021	-462	-8 %
1.25	2021	-448	-5 %
1.75	2021	-435	-2 %
2	2021	-428	0 %
2.25	2021	-421	2 %
2.75	2021	-407	5 %
3.25	2021	-393	8 %

Table D-7: *Net present value and decommissioning year sensitivity of changes in the natural gas price. In million USD.*

From table D-7, it becomes apparent that the natural gas price has a relatively small effect on project value and no effect on optimal abandonment (for the range of parameter values presented). The income portfolio of our project consists of a small fraction of natural gas relative to crude oil. Therefore, the project value is relatively insensitive for changes in the natural gas price. For a field producing more natural gas than crude oil, the project would be more sensitive to changes in the natural gas price.

D.2 Real Option Model

An equivalent sensitivity analysis is conducted for our Real Option Model. The results will be compared with the sensitivity analysis results for the Net Present Value Model.

	Net Present Value Model **%Δ project value**		Real Option Model **%Δ project value**	
	Up 10%	**Down 10%**	**Up 10%**	**Down 10%**
Decom cost	-12 %	12 %	-12 %	12 %
Crude oil price	10 %	-10 %	12 %	-12 %
OPEX	-8 %	9 %	-11 %	11 %
Production drop	-5 %	5 %	-7 %	8 %
Risk-adjusted rate	3 %	-3 %	4 %	-4 %
Natural gas price	1 %	-1 %	2 %	-2 %

Table D-8: *The relative effect of changing input variables by 10% on project value: Real Option Model versus Net Present Value Model.*

As can be seen in the table D-8, project value is relatively sensitive to the uncertain decommissioning cost in both the Real Option Model and Net Present Value Model. An increase of 10% yields a reduction in project value of 12% in both models. However, some variables present different effect on the two models. Project value is more sensitive to changes in crude oil prices and operational expenditure in the Real Option Model. Also, project value is more sensitive to production drop in the Real Option Model than in the Net Present Value Model. On the other side, both models appear to be relatively insensitive to changes in risk-adjusted rate and the natural gas price.

Decommissioning Cost

Decom cost	Project value	% Δ base case
200	-15	96 %
400	-188	55 %
600	-345	17 %
696	-417	0 %
800	-495	-19 %
1000	-637	-53 %
1200	-762	-83 %

Table D-9: *The Real Option Model: The effect of changing the decommissioning cost on project value. In million USD.*

The decommissioning cost has a relatively large effect on project value in the Real Option Model. A reduction in abandonment cost from 696 MUSD to 200 MUSD would increase project value with about 96%, reflecting the impact on project value of this variable in late-life operations. A 200 MUSD decommissioning cost require a more favorable price development to continue operations, making the shutdown decision optimal in more nodes than in the base case. A 1,200 MUSD decommissioning cost make continuation the preferred option in more nodes, by increasing the interest saving potential.

Decom cost	NPV %Δ from base case	ROA %Δ from base case
200	92 %	96 %
400	54 %	55 %
600	17 %	17 %
696	0 %	0 %
800	-19 %	-19 %
1000	-52 %	-53 %
1200	-83 %	-83 %

Table D-10: *Net Present Value Model (NPV) versus Real Option Model (ROA): The effect of changing the decommissioning cost on project value. In million USD.*

Table D-10 compares the results from the Net Present Value and the Real Option Model. As can be seen from the table, the decommissioning cost has a similar effect in the two models.

Nonetheless, although the effect is more or less identical for large decommissioning costs, the effect is different for smaller decommissioning costs. Small decommissioning costs results in a higher upside potential in the Real Option Model, a subsequently a higher project value.

Crude Oil Price

Crude oil price	Project value	% Δ base case
20	-711	-71 %
40	-598	-44 %
60	-467	-12 %
67	-417	0 %
80	-323	22 %
100	-178	57 %
120	-25	94 %

Table D-11: *The Real Option Model: The effect of changing the crude oil price (USD) on project value (MUSD).*

A change in crude oil prices has a relatively large effect on project value in the Real Option Model. A crude oil price of 20 USD will decrease project value with 71%, while a crude oil price of 120 USD increases project value with 94%.

	NPV	ROA
Crude oil price	**%Δ from base case**	**%Δ from base case**
20	-58 %	-71 %
40	-37 %	-44 %
60	-10 %	-12 %
67	0 %	0 %
80	19 %	22 %
100	50 %	57 %
120	81 %	94 %

Table D-12: *Net Present Value Model versus Real Option Model: The effect of changing the crude oil price (USD) on project value (MUSD).*

Table D-12 compares the effect of a changed crude oil price in both the Net Present Value Model and the Real Option Model. The sensitivity for crude oil prices is higher in the Real Option Model, where a crude oil price of 20 USD would reduce project value of 71% compared to a 58% reduction in the Net Present Value Model. The same sensitivity is observed with a higher crude oil price, where the Real Option Model has a larger positive effect on project value than the Net Present Value Model. This can be explained by the importance of oil price in determining the value of flexibility of the field. A higher crude oil price results in a higher potential upside of continued production in the Real Option Model.

Operational Expenditures

OPEX	Project value	% Δ base case
75	-293	30 %
85	-350	16 %
95	-394	5 %
100	-417	0 %
105	-439	-5 %
115	-481	-16 %
125	-513	-23 %

Table D-13: *The Real Option Model: The effect of changing the operational expenditure (OPEX) on project value. In million USD.*

The OPEX has the third largest effect on project value of the variables analyzed. Reducing the OPEX with 25% results in an increase in project value of 30%. Increasing OPEX by the same amount yields a 23% decrease in project value.

	NPV	ROA
OPEX	%Δ from base case	%Δ from base case
75	25 %	30 %
85	14 %	16 %
95	4 %	5 %
100	0 %	0 %
105	-4 %	-5 %
115	-12 %	-16 %
125	-19 %	-23 %

Table D-14: *Net Present Value Model versus Real Option Model: The effect of changing the operational expenditure (OPEX) on project value. In million USD.*

Table D-14 combines the results from the Net Present Value Model and the Real Option Model when analyzing the effect of changed operational expenditures. As can be seen in the table, the Real Option Model is more sensitive to changes in operational expenditures compared to the Net Present Value Model. For example, a reduction in OPEX yields a 30% higher project value in the Real Option Model, but only a 25% increase in the Net Present Value Model.

Production Drop

Production drop	Project value	% Δ base case
0.35	-464	-11 %
0.33	-448	-7 %
0.31	-428	-3 %
0.3	-417	0 %
0.29	-405	3 %
0.27	-381	9 %
0.25	-356	15 %

Table D-15: *The Real Option Model: The effect of changing the production drop on project value. In million USD.*

Changes in the annual production drop have relatively moderate effect on project value in the Real Option Model. A lower production drop does not alter the optimal timing decision for the chosen interval. However, a very high production drop would make it optimal to shut down production in year zero[27].

	NPV	ROA
Production drop	%Δ from base case	%Δ from base case
0.35	-7 %	-11 %
0.33	-5 %	-7 %
0.31	-2 %	-3 %
0.3	0 %	0 %
0.29	2 %	3 %
0.27	5 %	8 %
0.25	9 %	15 %

Table D-16: *Net Present Value Model versus the Real Option Model: The effect of changing the production drop on project value.*

As can be seen in table D-16, a lower production drop has a higher effect on the Real Option Model compared to the Net Present Value Model. A lower annual drop in production will further increase the potential upside of continued production given a favorable price development in the Real Option Model. This is consistent with the results obtained when analyzing production profile B. A lower annual production drop leads to a larger difference in project valuation between the Real Option Model and the Net Present Value Model.

[27] A 57% production drop would make immediate shut-down optimal in the Real Option Model.