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MASTER THESIS:

How do discounted cash flow analysis and real options differ as basis for decision making about oil and gas field developments?

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1.0 Introduction

The aim of profit maximizing companies is to take on investments with positive net present values (NPV) in order to create shareholder value. Capital budgeting is the process in which companies determine whether an investment opportunity is worth pursuing or not. Investment decisions should be made on the ground of some kind of valuation and evaluation. Many industries face investments involved with uncertainty. Uncertainty factors may include the development of out put prices, demand, costs, technology, delays and other known and unknown factors. These kinds of uncertainties create problems in evaluating and valuing investment opportunities.

The petroleum industry is a good example of an industry exposed to high investments and high uncertainty. The level of activity is highly affected by the level of the oil price. Investments are high when market conditions are advantageous and prospects are good, and vice versa. Projects in the petroleum industry are often characterized by long time horizons. Such projects are recognized by heavy investments and negative cash flows in the early stage, released by production and positive cash flows after development is completed. This cash flow structure creates the risk of having good market conditions in the early stage, and bad market conditions during production.

The petroleum industry has experienced high activity and high investment level due to high oil price levels since 2003. Many projects have been found profitable and been initiated. The oil price has now dropped and is threatening projects recently found profitable. An example of this is an oil and gas field named Goliat, located in the Barents Sea in the northern parts of the Norwegian continental shelf (NCS). The project has received attention due to the possibility of being the first oil field development in the Barents Sea. There has also been discussion about the profitability of the project considering the recent decrease in oil price levels. The change in market conditions has increased the requirements of evaluation and valuation methods. "All" projects are no longer profitable. Companies must work harder and better in order to find the best projects and to make good investment decisions.

According to Begg, Bratvold and Campbell (2003), studies show that the oil and gas industry has consistently underperformed various market indices like the Dow Jones Industrial Average and the Standard & Poor 500. Some attribute the underperformance to project evaluation and decision-making procedures that result in either a systematic overestimate of returns and/or underestimate of risks. A good decision should be an action companies take that is consistent with the alternatives they perceive, the information they have and the preferences they feel. In an uncertain world good decisions can lead to bad outcomes, and vice versa. Making this distinction allows us to separate action from consequences and hence improve the quality of action. By understanding existing decision-making tools and processes, and improving these tools and processes, it should be possible to make more accurate valuation of investments and better investment decisions.

Research and surveys show that traditional discounted cash flow analysis (from now on called dcf-analysis) is the standard when it comes to valuation of assets and projects in the petroleum industry. Valuations should provide decision makers with economic perspectives on investment opportunities. Research has pointed out some drawbacks of the traditional dcf-analysis. To overcome these drawbacks, a real option framework using the principles of financial option valuation to value real investments has been introduced. Due to practical challenges, it seems that the petroleum industry is reluctant to apply the real option framework. The real option framework seems logic and suitable in theory, but several practical challenges must be solved.

The motivation of the topic and the following problem statement stems from my interest in corporate finance and the petroleum industry. Literature on corporate finance and the petroleum industry often focus on the suitability of dcf-analysis and the real option framework to value investments. The recent change in market conditions has increased the importance of this matter and the need of sufficient decision making tools.

1.1 Problem statement

With regards to the introduction, the following main problem statement has been designed:

"How do discounted cash flow analysis and real options differ as basis for decision making about oil and gas field developments?"

In order to answer the main problem statement, the thesis will look closer into the following three questions:

- Which assumptions is the dcf-analysis and the real option framework based on?

- Which practical challenges exist in applying the two methods?
- How do the two methods differ in their ability to handle uncertainty?

1.2 Methodology

In order to answer the problem statement and the related questions, a case study will be performed. After an introduction of the theories of dcf-analysis and real options, the theories will be applied on an oil and gas field development case. The case chosen is the already mentioned Goliat project in the Barents Sea. Because of its small size, the discussion about the profitability of the project and the closely forthcoming start of development in 2010, the project is well fitted. Applying the two methods on a similar case should make it possible to answer the problem statement and the related questions. Results and experience from the valuation of Goliat will be discussed with regards to the questions in the problem statement. The findings are summarized and concluded in the last part of the thesis. Figure 1 shows the structure of the analysis.

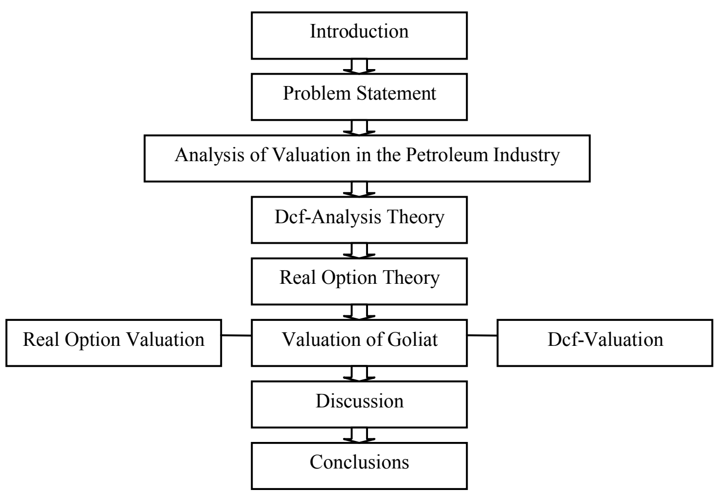

Figure 1: The structure of the analysis

According to Begg, Bratvold and Campbell (2003), there are two main areas of investigation and theory development around decision-making under uncertainty; the normative and the descriptive. The normative approach aims at developing theories about how decisions should be made. The descriptive approach aims at developing theories about how decisions are actually made. This thesis contains elements of both normative and descriptive investigation. The normative approach is handled in the chapters explaining already existing theories. The descriptive approach is handled in the case study. The sum of the analysis should create knowledge on both how decisions should be made, and how decisions are made. The next section will in further detail explain the execution of the methodology described above.

1.3 Models and Sources of information

In order to apply valuation methods in a specific context, an analysis of the specific context is required. The analysis of the upstream petroleum industry is performed by value chain analysis. The term “upstream” relates to operating stages in the petroleum industry that involve exploration and production. The aim of a value chain analysis is to recognize and examine all activities performed in a firm or an industry. By doing so, it should be possible to determine bases of competitive advantages (Porter, 1985). Evaluating the upstream petroleum industry in terms of competitive advantages is not the scope of this analysis. However, a value chain analysis can also be used to understand how projects are structured. This application should make it possible to identify when and how decisions are made. This analysis should contribute in further delimitation of the scope of the thesis, as it will identify where and how the valuation methods should be used.

The thesis also analyzes factors representing uncertainty and risk with regards to the profitability of oil and gas field developments. Identification of risk factors is essential when evaluating projects in an uncertain world. The analysis gives an overview and explains importance and implication of each factor. The analysis is based on a systematic review of the determinants of profitability in oil and gas field developments.

The choice of analyzing dcf-analysis and real options has its grounds in earlier studies of capital budgeting. Studies show that dcf-analysis has a strong position. Mukherjee and Henderson reported in 1987 that dcf-analysis was becoming the standard practice for capital budgeting. The internal rate of return was the preferred dcf-tool, with net present value being a distant second choice. The survey highlights the gap between theory and practice, as NPV is known as the theoretically preferred dcf-technique. McCormack and Sick (2001) categorize dcf-tools as fundamental to financial analysis in the petroleum industry.

However, studies also show that real option methods have gained more attention and may be better suited to value specific investments. In their article, Keefer and Corner (2004) identify and provide perspectives on trends and developments in decision analysis. Keefer and Corner take a normative approach and define decision analysis as a set of quantitative methods for analyzing decisions. They find that the importance of modeling sequential decisions with the help of new information as time goes by is becoming more widely recognized. Investments characterized by high uncertainty and downstream decision alternatives can provide real options increasing flexibility of projects. The study points out that the use of option thinking can provide more realistic evaluations than traditional dcf-analysis. Other papers and articles discussing different aspects of real options are among others published by Smith and Nau (1995), Laine (1997), Copeland and Keenan (1998), Lund (1999) and Zettl (2002).

The reason for using case study in order to analyze the two methods has partial been explained in section 1.2. Case studies provide knowledge based on analysis of one or a small number of units. The unit in this thesis is Goliat, and gives specific knowledge about application of the two methods on Goliat as an investment opportunity in the petroleum industry. A drawback of case studies is the question regarding the validity of the results. By analyzing only one specific oil field development project, it can be questioned whether the obtained knowledge about the two methods is valid for other oil field development projects. The selection of a case study approach can be supported by the possibility of analyzing the two methods on a similar case. It should make it possible to discover differences and consequences of the two methods as decision making tools. Considering that most oil and gas field developments have approximately the same cash flow- and decision making structure, it should be possible to take advantage of knowledge obtained from the case study of Goliat in other oil and gas field developments.

The various analyses in the thesis are based on various sources, information and tools. The description of dcf-analysis and the real option framework is based on existing literature and research. Both valuations are performed in Microsoft Excel. Inputs used in the valuation are based on publicly available information, comments from the company operating the project and assumptions made by the author. Due to simplification and the lack of information, some of the real option valuation is based on simplified assumptions. The application of the analysis should however not be affected. The thesis is adjusted to the Norwegian continental shelf (NCS). This is caused by Goliat being located outside the coast of Norway, and affects the valuation by the use of Norwegian taxation rules.

1.4 Delimitation

The analysis focuses on issues related to the problem statement and the three related questions. Other methods for capital budgeting exist, but are not analyzed in this thesis. The attributes, importance and size of the petroleum industry attract many stakeholders. Examples include environmental and political issues playing different roles in capital budgeting. This thesis focuses mainly on financial and structural parts of capital budgeting in the petroleum industry, and not on non-financial considerations.

The case study of the Goliat project is based on various sources of information. The aim of the analysis is to construct a realistic but simplified valuation of the Goliat project. Assumptions taken in the case study may be wrong and misleading. Assumptions about exchange rates, inflation, oil and gas price levels and net convenience yield have not been investigated empirically. Such considerations would require knowledge, research and expectations which are not included in the scope of the thesis. Assumptions are based on present market conditions and the authors beliefes about the future. The aim of the analysis is not to predict future market conditions, but to compare dcf-analysis and real options ability to account for uncertainty related to future market conditions. The utility of the analysis should not be affected by the possibility of wrong assumptions being used as input in the valuation.

Many real option valuation models exist. The case study use a real option model developed by by Zettl (2002). This model use some simplified principles for valuation of financial options developed by Cox, Ross and Rubinstein. Far more complicated, technical and complex models exist, but will not be considered in this thesis. The characteristics and application of the Cox, Ross and Rubinstein model should be capable of extracting necessary knowledge in order to answer the problem statement of the thesis.

The thesis does not focus on capital structure and how companies finance projects. Calculations assume that Eni Norge finance Goliat with equity. An analysis of the correct discount rate to be used by Eni Norge for discounting cash flows related to Goliat will not be performed. The thesis will instead focus on possible implications of choosing correct/ incorrect discount rate.

2.0 Dynamics of valuation in the petroleum industry

Figure 2 shows that the investment level on the NCS has more than doubled during the last 8-9 years. The figure also shows a clear correlation between investment level and oil price level. The petroleum industry is recognized by large fluctuations with regards to investments, activity and profitability. Fluctuations are result of factors creating uncertainty and unstable conditions in the industry. The next section gives an overview of these factors.

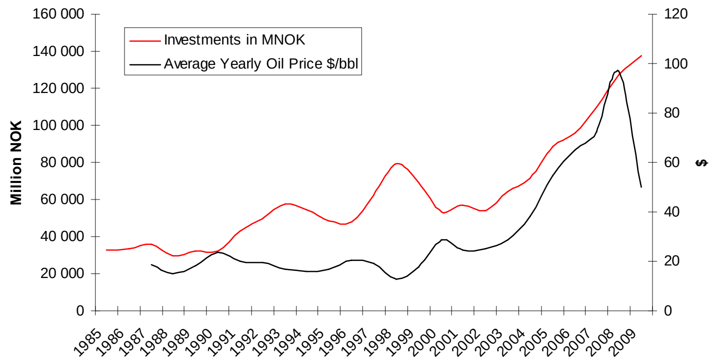

Figure 2: Investments in oil and gas activity on the NCS from 1985 to 2009 compared with average yearly oil price (Statistisk Sentralbyrå[1])

2.1 Factors representing uncertainty and risk

2.1.1 Oil price

One of the most important factors affecting the petroleum industry is the price level of oil and gas. "We mean it is impossible to foresee the level of future oil prices", states Torbjørn Kjus in DnB NOR Markets.[2] "The only certain thing about the oil price is that it is unstable", states Øystein Noreng, a professor within petroleum economics and management at BI Norwegian School of Management.[3] Although it is widely recognized that foreseeing future oil prices is almost impossible, we do have knowledge about different factors affecting the oil price. First of all, the oil price is determined by supply and demand. Contracts of oil are traded at the New York Mercantile Exchange and the International Petroleum Exchange in London. Various institutions, governments of oil exporting countries, firms, the global economy, expectations and unexpected events like natural disasters and weather conditions all have potential to influence oil price levels. The following section gives a brief summary of the most important factors affecting supply and demand of oil and gas.

[1] http://www.ssb.no/olje_gass/
[2] http://www.orapp.no/pris_og_rente/20081219/umulig_a_spa_oljeprisen/
[3] http://arkiv.na24.no/Nyhet/185380/-+Stabil+oljepris+er+umulig.html

The Organization of the Petroleum Exporting Countries (OPEC) is an organization working to coordinate and unify the petroleum policies of the member countries. OPEC wants to ensure the stabilization of oil markets in order to secure an efficient, economic and regular supply of petroleum to consumers, a steady income to producers and a fair return on capital to those investing in the oil industry.[4] OPEC controls about two thirds of the world's oil reserves, and represents about 35 % of the world's oil production. The idea is to coordinate production in order to control supply of oil. OPEC has been known to possess great control over oil price levels. This was for instance demonstrated in 1973 when OPEC stopped shipments of crude oil to the west, resulting in a dramatic increase in oil price from \$3/bbl to \$12/bbl. However, the power of OPEC has decreased after discoveries of oil in the Gulf of Mexico, the North Sea and the opening of Russia.

Other factors affecting the supply of oil are regulations and policies set by governments possessing oil and gas reserves. Environmental issues like climate changes, the fear of destroying other industries (fishery) and conservation of nature may create less exploration and less production as time goes by. Further on, natural disasters like hurricanes and other extreme weather conditions may destroy or shut down oil producing facilities. This can create lower supply and lead to higher oil price levels.

The demand side of oil and gas is equally important. The world, with China in the front seat, has during the last years experienced a global economic boom. Future expectations of high demand for energy brought the oil price to historical levels during the summer of 2008 (\$143, 68/bbl Brent Blend on July 11th 2008).[5] The pace and growth of the global economy highly affects the demand for oil and gas. Many things have happened with the global economic situation during the last half of 2008. Stock markets and housing markets have crashed around the world, and major banks and financial institutions have gone bankrupt. As we write May 2009, the world is facing financial crisis and low expectations of future growth and development. This has decreased the oil price, which is at the time trading at approximately \$55/bbl.

[4] http://www.opec.org/home/

[5] http://tonto.eia.doe.gov/dnav/pet/hist/rbrteD.htm

2.1.2 Technology

As time goes by, exploration will discover extractable petroleum reserves in new and old areas. Existing and future technology makes it possible to undertake projects in unknown areas with more difficult conditions. Examples include petroleum production in arctic areas, at deeper sea levels and more complex development concepts. Technology represents an uncertain factor in pioneer projects where new technology and new concepts play important roles. Investments in technology and the possibility of failure and delay make technology an uncertain factor.

2.1.3 Costs and inflation

The level of investment and operating costs (opex) are other factors representing uncertainty in the petroleum industry. High oil price levels results in high activity in the industry. High demand for skilled labour and petroleum related services drives up the cost level in the industry. The level of costs influences the profitability of projects.

According to Emhjellen, Emhjellen and Osmundsen (2002), one might expect that cost overruns have the same probability as completing projects below cost estimates. However, the authors argue that observations clearly indicate an over representation of cost overruns. This may be a consequence of two selection biases: (1) Project selection; it is typically the projects with the most optimistic internal cost estimates that are being pursued by the investing firm, and (2) tender selection; competition sees to it that tenders with pessimistic and realistic cost estimates are ruled out. The authors discuss the importance of accurate cost estimates and the implication of these estimates on investment decisions. The authors also point to an alternative statistical approach of estimating expected costs. The article points to Statoil and Norsk Hydro (at the time of the article two major Norwegian oil companies, today one merged company called StatoilHydro), using a 50/50 (median) capex (capital expenditure) cost estimation procedure. Due to statistical properties, this method will underestimate costs and may lead to incorrect investment decisions. Considering the attributes of petroleum projects, the authors argue that cost estimates should be assumed to be asymmetric, and not symmetric.

Uncertainty regarding inflation over long time horizons creates difficulties in estimating future real levels of revenues and costs. The level of inflation should be considered in valuations of oil and gas field developments.

2.1.4 Amount of extractable petroleum reserves

Another factor of uncertainty is the exact amount of extractable petroleum reserves in oil and gas fields. Petroleum reserves are forecasted by seismic surveys and exploration drilling. Calculations and predictions are made on the basis of the results. Errors and uncertainties may be present in these calculations. Actual amount of extractable reserves may turn out to be less than predicted. Predictions about production rates are subject to the same uncertainty as predictions about the amount of petroleum reserves. The characteristics of petroleum reservoirs and the pressure in production wells affect production rates. Predictions and calculations about total amount of extractable reserves and production rates are important inputs in valuations of oil and gas field developments. Wrong inputs may lead to bad investment decisions and unprofitable projects.

2.1.5 The issue of time

Oil and gas field developments are often characterized by long time horizons. Ekofisk was the first oilfield to be discovered on the NCS. The field, which is one of the largest on the NCS, started to produce in 1971 and will continue to produce oil and gas until 2025-2030[6]. Gyda started production in 1990 and will continue to produce until 2030[7]. Statfjord, the biggest oil field on the NCS, started production in 1979 and will continue to produce until 2020[8]. Long time horizons affect uncertainty about variables affecting the profitability of projects. In addition, valuing revenues and costs in the distant future involves challenges with regards to the choice of correct discount rates.

[6] http://energilink.tu.no/leksikon/ekofisk.aspx
[7] http://petro.no/modules/module_123/proxy.asp?D=2&C=14&I=11060
[8] http://energilink.tu.no/leksikon/tampen%20link.aspx

2.2 Value chain analysis of the upstream petroleum industry

Understanding investment decisions in the upstream petroleum industry requires an understanding of the industry's value chain. The concept of the value chain is to recognize and examine all activities performed in a firm or an industry. By doing so, it should be possible to determine bases of competitive advantages (Porter, 1985). Evaluating the upstream petroleum industry in terms of competitive advantages is not the scope of this thesis, but value chain analysis can be used in terms of understanding how projects are structured. The next section elaborates on the various activities in the industry, with emphasis on where and how investment decisions are made.

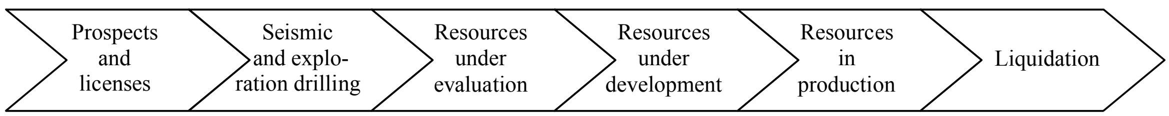

Figure 3: The value chain of the upstream petroleum industry (Gjul and Ringvold, 2006)

2.2.1 Prospects and licenses

This section takes a Norwegian approach, considering the legal framework and procedures prevalent on the NCS. Petroleum activities on the NCS are regulated by the Ministry of Petroleum and Energy on behalf of the Norwegian government. Petroleum companies operating on the NCS must comply with the existing legal framework. The Petroleum Act (Act of 29 November 1996 No. 72 regarding petroleum activities) provides the legal framework for the licensing system which regulates Norwegian petroleum activities, including exploration, production and transportation of petroleum.

Geographic areas with potential petroleum resources must be approved by the government before any petroleum activity can find place. When specific areas are approved, the government arranges a license round where interested petroleum companies can apply for the areas they find interesting. These areas are called blocks. Applicants can apply individually or in groups. Production licenses are awarded on the basis of impartial, objective, non-discriminatory and published criteria like technological and operating expertise, financial strength, geological interpretation and relevant experience. The Ministry of Petroleum and Energy puts together a group of companies for each license, or makes adjustments to groups that have submitted a joint application. An operator responsible for the day to day activities under the terms of the license is appointed.

Licenses contain both rights and obligations. It gives holders an exclusive right for exploration, exploration drilling and production of petroleum within a given specific geographical area within a specified period of time up to ten years. The license holders have the property rights of the petroleum. Each license also contains a specified work obligation to be met by the holders within a specified period of time. These obligations may include seismic data acquisitions and surveys and/or exploration drilling. If all the licensees agree, the license can be given back to the government after work obligations have been met.

Decisions in the prospects and licenses phase involve to apply/not apply for specific licenses. Considerations should be made regarding beliefs and investments needed to be taken regarding seismic data acquisitions and surveys and/or exploration drilling in order to meet specified obligations in the license. By applying for a license, companies agree to make investments that may or may not uncover profitable petroleum resources.

2.2.2 Seismic and exploration drilling

Results and interpretations of seismic surveys from areas with potentially profitable petroleum reserves determine whether companies want to start exploration drilling. Exploration drilling may already be an obligation in the license, and have to be undertaken independently from seismic surveys. If exploration drilling is voluntary, holders of a license must decide to drill/not to drill. Exploration drilling is recognized by high costs and risks of drilling a dry hole.

2.2.3 Resources under evaluation

The aim of exploration drilling is to obtain answers about the presence of petroleum resources, the size of the reservoir and the quality of the reserves. These indicators determine whether a project should be taken to the next stage, which is development. Holders of licenses must make decisions about further exploration drilling, waiting, abandonment or development. A final decision about development should incorporate economic, technological and environmental considerations. All the risks and uncertainties described in section 2.1 should be evaluated. Decision about oil and gas field developments confiscate both financial resources and labor for a long time horizon, and should be given great attention.

2.2.4 Resources under development

A decision about developing an oil and gas field means that investments in production facilities, necessary equipment and infrastructure must be made. If the field is located near other fields, it may be possible to take advantage of existing infrastructure and facilities. The issue of transporting petroleum resources to refineries and consumers must be solved and scaled according to the size of the field. The process of developing, engineering, building and installing technological and practical solutions may be time demanding. This results in a period of high investments and negative cash flows. This period is followed by positive cash flows as production gets going.

2.2.5 Resources in production

A normal production profile involves high production in the beginning of fields' lifetime. After a period of time production starts to decline, and continues to decline until the end of the field's lifetime. Different development concepts and production rates can give different production profiles. As the field gets older, different techniques are used to maintain as high production as possible. This often results in increasing marginal costs and decreasing profits per barrel of oil. Decision about shutting down and abandonment of the field should be made on the basis of total amount of extractable reserves left, production rates, oil price levels, costs of liquidation and alternative investment and resource allocation opportunities. When costs of production equal the price of oil, production should be shut down and the company should abandon the field.

2.2.6 Liquidation

Holders of licenses are responsible for shutting down production and liquidation of developed facilities. Costs and accomplishment of liquidation should be taken into account and estimated already at the time of valuation.

2.3 Phases of oil and gas field developments

Lund (1999) presents a model determining different phases of oil and gas field developments. The model gives an overview of different decisions that can be made during the lifetime of development projects, and serves as a complement to the value chain analysis performed in section 2.2. Lund considers four phases; exploration, conceptual study, engineering and construction and production.

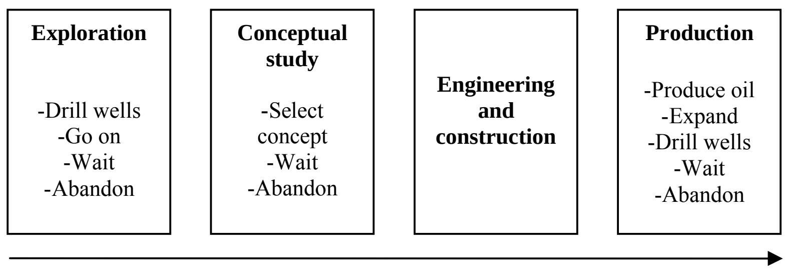

Figure 4: Decision space related to phases in oil and gas field developments (Lund, 1999)

In the first phase, companies have the possibility to decide whether to drill additional wells in order to obtain more information about total amount of extractable reserves and production rates, to go on with projects immediately, to wait and see or to abandon projects. In other words, companies can choose to invest in additional exploration wells in order to obtain more information.

In the second phase, companies should decide a development concept. A concept is defined by the installed production capacity of the production facilities and the option to increase this capacity during production. The production capacity relates to developments' production, processing and storing facilities. In other words, operators decide initial production capacity and the possibility of increasing capacity at later stages. Companies can choose to invest in a more expensive concept with capacity flexibility. In addition, companies have the choice to wait and see and to abandon projects.

The third phase, engineering and construction, contains no decisions but carries out the decisions made in the conceptual study phase. In the fourth phase, production, companies can decide the level of production according to the choices made in the conceptual study phase. The drilling of additional production wells and expansion of developments' production capacity can increase production and profitability if market conditions are advantageous. In addition, companies can choose to wait and see and to abandon projects.

3.0 Discounted Cash Flow Analysis

"Discounted cash flow techniques are rather like a loaded gun –
able to hit the target in the hands of the marksman
but a general hazard in the hands of the amateur"

-Robert Booth

3.1 Introduction

As described earlier, dcf-analysis seems to be the most popular and applied capital budgeting tool. According to Emhjellen and Alaouze (2003), the discounted net cash flow method is still the most common valuation method used by oil companies. In his article "Great Moments in Financial Economics", Rubinstein (2003) points out the publication "The Theory of Interest", written by Irving Fisher in 1930, as the first to derive present value calculations as a natural economic outcome in calculating wealth, and to justify maximization of present value as the goal of production. Fisher also derives the determinants of the interest rates used to calculate present value.

Rubinstein also points out John Burr Williams as one on the first economists to interpret stock prices as determined by "intrinsic value" (that is discounted dividends). According to Rubinstein, Williams's "The theory of Investment Value" (1938) did not originate the idea of present value, but developed many implications of the idea that the value of a stock under conditions of certainty is the present value of all its future dividends.

Dcf-analysis can be divided into two main categories, the net present value method (NPV) and the internal rate of return method (IRR). The two methods have many similarities, but also some important differences. The following section explains a general model of dcf-analysis, section 3.3 explains differences between NPV and IRR.

3.2 Variables in dcf-analysis

The logic behind dcf-analysis is to forecast relevant future cash flows and take the issue of time into account by discounting the cash flows back to present value. The process is performed by the help of a discount rate, representing opportunity costs and risk. The aim of this cost-benefit analysis is to find expected present value of future income and costs, and to compare this value with projects' investment costs. The difference between the present value of net income and the project's investment costs is the project's expected net present value (NPV).

The following section gives a comprehensive overview of the variables in the model when applied in the upstream petroleum industry. In order to make the analysis understandable and manageable, some delimitations and specifications should be made. The analysis considers an example of a development project located in the "resources under evaluation" part of the value chain (figure 3). Seismic surveys and exploration drilling have been conducted, and the holder of the license must decide whether to wait, develop, expand or abandon the project. In terms of figure 4, the project is located in the exploration phase, where decisions should be made regarding drilling more wells, going forward, wait and see or to abandon the project. Formula (1) shows the standard expression for calculation of NPVs. The next section explains the attributes of the various variables in the expression.

(1) $$NPV = -C_0 + \sum_{t=1}^{n} \frac{C_t}{(1+r)^t}$$

3.2.1 C_0 - Investments

Investments have to be made in order to develop oil and gas fields. The size and time profile of these investments depend on the scale and structure of the project. Development of oil and gas fields often involves high complexity, long time horizons and multiple phases. Projects on the NCS involve investments in exploration, conceptual studies, engineering and facilities for production, storage, processing and housing.

Infrastructure for transportation of petroleum is another important feature that must be in place. In some cases, it may be possible to cooperate with other companies on the NCS. In developed and mature areas of the NCS pipelines may already be in place. During the last years the industry's focus has turned towards areas located in the northern parts of the NCS. The fields located in the southern parts of the NCS; The North Sea and The Norwegian Sea, can be characterized as mature. Probabilities are high that these areas already have peaked in terms of production. In order to sustain high production, new big discoveries must be made. Development of new areas in the northern parts of the NCS will require high investments in infrastructure and transportation.

3.2.2 C_t - Cash Flows

In order to calculate expected NPV, future cash flows must be forecasted. Cash flows from an oil and gas field development consists of several factors that can be divided into two categories: revenues and costs. Revenues consist of the amount of oil and gas produced times the price of oil and gas. As described earlier, both oil price and production rates are subject to uncertainty and fluctuations, making it difficult to forecast income.

In order to estimate free cash flows, costs must be subtracted from revenues. Operational- and maintenance-costs are the two main categories of costs. Examples of operational costs involve personnel, transportation of personnel and various input factors like water and CO_2 for injection in wells in order to increase pressure and production, electricity/energy to operate production equipment and costs associated with renting pipelines and other infrastructure. Maintenance costs involve expected and unexpected maintenance and repairing of equipment and all other facilities connected to an oil and gas field. As described earlier, costs can be subject to inflation.

Due to operations and activities in several countries, many upstream petroleum companies are international companies. This may lead to situations where companies face costs and revenues in different currencies. Petroleum products are traded in dollar, creating revenues in dollar. Companies operating on the NCS have a great deal of its costs in NOK. Movements in the relationship dollar/NOK can give substantial currency effects, affecting the profitability of projects. When the relative price of one dollar increases, revenues increase, and vice versa.

Another important factor affecting cash flows of petroleum companies is taxes. In principal, the state of Norway has the ownership of the natural resources located on the NCS. The state of Norway claims this value through taxation of oil and gas activities and charges/fees. In addition, the state also has direct ownership in oil fields and receives dividends from its ownership in StatoilHydro. The petroleum taxation is based on the Norwegian rules for ordinary corporation tax (28 %). Due to the extraordinary profitability associated with production of petroleum resources, a special tax is charged on income from these activities (50%).

When calculating taxable income for both ordinary and special taxes, an investment is subject to depreciation on a linear basis over six years from the date it was made. Companies can deduct all relevant expenses, including exploration, research and development, net financial, operating and decommissioning expenses. In order to protect the normal return from the special tax, an extra deduction, the uplift, is allowed in the calculation base for special tax. This amounts to 30 percent of the investments (7.5 % per annum in four years from the year the investment was made). Companies that are not in tax position may carry forward their losses and the uplift with interest. An application may also be made for refund of the fiscal value of exploration costs in companies' tax returns. (Samuelsen, 2006)

Other important taxes linked to petroleum activities are the carbon dioxide tax (CO_2), NO_x tax and the area fee. The CO_2 tax was introduced in 1991 and is an instrument for reducing CO_2 emissions in the petroleum industry. CO_2 tax is charged at a rate per standard cubic meter (scm) of gas burned or directly released, and per litre of petroleum burned. The rate for 2008 is NOK 0.45 per litre of petroleum or scm of gas. Pursuant to the Gothenburg Protocol of 1999, Norway has an obligation to reduce annual emissions of nitrogen oxides (NO_X). In order to fulfil this obligation, a NO_x tax was introduced from 1 January 2007. For 2008, the tax is NOK 15.39 per kg of NO_x. The area fee is intended to be an instrument that contributes to efficient exploration of awarded acreage, so that potential resources are produced as quickly as possible within a prudent financial framework, as well as to extend the lifetime of existing fields. In 2007, direct taxes accounted for 58 % of Norway's cash flow from petroleum activities, while environmental fees and the area fee accounted for 0,1 % (FACTS- The Norwegian Petroleum Sector 2008). In other words, direct taxes are with no doubt the biggest tax expense for companies operating on the NCS. As a consequence, the case study does not consider environmental- and area fees.

3.2.3 r - Discount Rate

The purpose of the discount rate is to find the present value of future cash flows. Alternative terms for the discount rate are required rate of return, capital cost and alternative cost. Risky projects, all other things equal, are less valuable than safe projects. As a consequence, investors or companies demand higher rates of return from risky projects. R represents the company's cost related to not employing the capital in alternative investments. When considering projects where cash flows are known in advance, the rate of return associated with other risk-free investments, such as bank deposits, makes the basis for the discount rate to be used in NPV calculations. When cash flows are uncertain, like in oil and gas field developments, they are normally represented by their expected values and the rate of return is increased on the basis of the Capital Asset Pricing Model (CAPM) in order to outweigh the possibilities for undesirable outcomes (Risk Management, 2007).

It is not always straight forward to find the appropriate discount rate to be used in valuation of investments. Weitzman (2001) states: “The most critical single problem with discounting future benefits and costs is that no consensus now exists […] about what actual interest to use […] Therefore […] we should be operating from within a framework that incorporates the irreducible uncertainty about interest rates directly into our benefit-cost methodology”. In another article, he states: “While there is uncertainty about almost everything in the distant future, perhaps the most fundamental uncertainty of all concerns the discount rate itself” (Weitzman 1998).

When determining discount rates, many companies start with the company cost of capital, which is the opportunity cost of capital for investments in the company as a whole. The company cost of capital can be calculated as a weighted average cost of capital, meaning the average rate of return demanded by investors in the company’s debt and equity securities. This measure is often called “WACC”, or Weighted Average Cost of Capital. If a project is considered to be equally risky as the company’s existing business, the cash flows of the project should be discounted by the WACC. Formula (2) shows the formula for calculating WACC, the next section explains the formula in further detail.

(2) $$WACC_{Company} = \frac{Debt}{Equity} R_{Debt} + \frac{Equity}{Debt} R_{Equity}$$

R_{Debt} is the cost of debt, meaning the interest rate companies pay for their debt. The two fractions represent debt and equity ratios. In order to calculate the WACC, companies need an estimate of the cost of equity (R_{Equity}). Many companies use the Capital Asset Pricing Model (CAPM) to calculate the cost of equity. Investors investing in an upstream petroleum company should consider two types of risk; unsystematic risk and systematic risk. Unsystematic risk is company or industry specific risk, and relates to risk associated with bankruptcy, financial distress, strike and other risk inherent in each investment. Investors can remove unsystematic risk by investing in a market portfolio (diversification). Systematic risk is associated with variables that affect the entire market, and examples include wars, recessions and interest rates. These kinds of risk cannot be avoided through diversification.

The CAPM assumes that investors are well diversified when the cost of equity is calculated. Formula (3) presents the CAPM, the next section explains the model in further detail.

(3) $$R_{Equity} = R_f + \beta_{Equity}(R_{Market} - R_f),$$

R_{Equity} is the cost of equity, R_f is the risk free interest rate, β_{Equity} is the systematic risk of the equity and R_{Market} is the expected return of the market portfolio. The risk free interest rate is the amount received from investing in securities considered to have no credit risk. Examples include government bonds and bank deposits. The beta of the equity measures how much the company's share price moves compared to the market as a whole. A beta of one indicates that the share price moves in line with the market. If beta is bigger or smaller than one, the share price of the company moves respectively more or less than the market. The last part of equation (3) determines the equity market risk premium, ensuring that the cost of equity increases linearly with the systematic risk of the equity.

Estimating company beta can be done by regressing historical movements in share prices with historical movements in market returns. By doing so, it is possible to find the proportion of the total variance in the share's returns that can be explained by market movements, and the proportion that can be explained by company specific movements. Brealy, Myers and Allen (2006) emphasize that the estimation of individual betas are just estimations. Estimation errors can easily occur, and results may vary when data from different time periods are considered. In order to improve the accuracy of betas, Brealey, Myers and Allen suggest using industry betas. They found that estimation errors tend to cancel out when estimating betas of portfolios. A lower standard error of the estimates was achieved when using industry betas instead of individual betas.

Considering the possibility of estimating wrong beta, the possibility of facing a project that does not have the same risk profile as the company's existing business and the possibility of investing in assets with no convenient price record, some general guidelines for setting discount rates when you don't have a beta should be made. Brealey, Myers and Allen propose three pieces of advice. Number one is to avoid fudge factors, meaning that managers should not add fudge factors to the discount rate in order to offset possible bad outcomes. Adjustments should instead be made to forecasted cash flows. The probability of different outcomes should be taken into account in forecasted cash flows instead of increasing the discount rate by some percentage.

Advice number two highlights the importance of thinking about determinants of the asset betas. The characteristics of high- and low-beta assets can often be observed when the beta itself cannot be. Examples include cyclicality and operating leverage. Investors should demand a higher rate of return from investments whose performance is strongly tied to the performance of the economy. Further on, high fixed costs compared to variable costs equals high operating leverage. High operating leverage equals high risk. At last, Brealey, Myers and Allen state that beta should not be confused with diversifiable risk. A project may look extra risky viewed from close range, but if the project's uncertainties are not correlated with the market or other macroeconomic risks, then the project is only average-risk to a diversified investor.

In their article, Emhjellen and Alaouze (2002) argument for an alternative discount rate approach compared to the traditional WACC and CAPM. In investment projects recognized by a cost cash flow and a revenue cash flow with different systematic risk, cost cash flows should be discounted by one discount rate and revenue cash flows by another. This approach is called the separate discounting method. According to earlier work by the same authors, development cost factors in the petroleum industry have low systematic risk. The risk free rate of return was used to discount expected after tax cost cash flows, while a higher discount factor was used to discount expected after tax revenue cash flows. When comparing these two approaches on various projects, Emhjellen and Alaouze found substantially different NPV's for many projects. The paper concludes with the separate discounting method resulting in better estimates of project NPVs than the WACC method.

3.2.4 n – Time Horizon

Upstream petroleum projects often have long time horizons covering more than 20-30 years depending on amount of extractable reserves, production rates and other economical considerations. The effect of discount rates increase linearly with the length of the time horizon considered. This attribute creates additional challenges in estimation of discount rates. Small differences in discount rates can give big differences in expected net present values of projects.

In traditional dcf-analysis, discount rates are normally assumed to be constant during the lifetime of projects. However, it may be the case that discount rates should not be considered to be constant over long time horizons. The risk of projects may change as time goes by and initial investments are repaid. In their article, Dalen, Hoel and Strøm (2008) emphasize that especially for projects with long durations, the discount rate plays a crucial role when determining whether projects are profitable or not. The article gives arguments for the discount rate not being constant, but instead decreasing as time goes by. It points out that the petroleum industry has shown an increasing trend in prioritizing short term profitability measures. If this is the case, petroleum companies use higher discount rates resulting in less interest in investing in long term projects. As described earlier, long time horizons also create big ranges of possible outcomes with regards to oil price levels, costs and other unexpected events.

3.3 Different DCF-Techniques

3.3.1 NPV

The most used dcf-technique is NPV. The output of the analysis is a NPV figure, telling decision makers what the project is worth in terms of money at the date of the analysis. Projects with a positive NPV are worth more than they cost. Projects with positive NPVs should be undertaken, while projects with negative NPVs should not be undertaken. However, the NPV should always be evaluated in terms of the financial size of the project. As an example, companies should be careful about investing in projects with high capex and high opex and only marginally positive NPVs.

3.3.2 IRR

The output of IRR analysis is the project's internal rate of return. The internal rate of return is defined as the rate of discount that makes NPV=0. The IRR rule states that companies should accept investment opportunities offering rates of return in excess of their opportunity costs of capital. Finding the IRR of a project lasting T years is solved for IRR in expression (4). This calculation usually involves trial and error. The expression can also be solved graphically.

(4) $$NPV = C_0 + \frac{C_1}{1+IRR} + \frac{C_2}{(1+IRR)^2} + ... + \frac{C_T}{(1+IRR)^T} = 0$$

Brealey, Myers and Allen (2006) derive four pitfalls of the IRR method. Number one involves challenges associated with determination of whether cash flows represent lending or borrowing. If a project offers positive cash flows followed by negative cash flows, NPV can rise as the discount rate is increased. Number two involves projects with cash flows that change signs more than one time. If this is the case, the project may have several IRRs or no IRR at all. This may be the case in oil and gas field developments, where capex, production and liquidation cause cash flows to change signs more than one time throughout the lifetime of projects. Pitfall number three involves IRR not being able to rank projects of different scale, and the inability to rank projects with different patterns of cash flows over time. The last pitfall described by Brealey, Myers and Allen stems from the possibility of the cost of capital for near-term cash flows being different from the cost of capital for distant cash flows. The IRR rule requires comparison of projects' IRR with the opportunity cost of capital. Sometimes this cost of capital differs over time, and there may be no simple yardstick for evaluating IRRs of projects. (Brealey, Myers and Allen, 2006)

It seems that pitfall two and four are most relevant in terms of oil and gas field developments. Cash flows changing signs more than one time, and long time horizons make the NPV rule better suited than the IRR rule in valuation of oil and gas field developments.

3.4 Accounting for Uncertainty and Risk

According to French and Gabrielli (2005), uncertainty impacts upon the valuation process in two ways: first, cash flows from investment are to varying degrees uncertain, and secondly, the resulting valuation figure is therefore open to uncertainty. The authors state that: "Uncertainty is anything that is not known about the outcome of a valuation at the date of the valuation, whereas risk is the measurement of the value not being as estimated". A major challenge in valuation of oil and gas field developments is to incorporate the factors of uncertainty into the valuation model. Two main methods for accounting for uncertainty exist. The first involves adjusting the discount rate (see section 3.2.3). By increasing the discount rate, future and uncertain cash flows are valued lower. This results in lower project NPVs, and increases projects' requirements of quality and profitability in order to be undertaken. The second method involves adjusting forecasted cash flows. Variables determining cash flows can move in different directions. Companies can account for uncertainty by forecasting subjective or statistical movements in these variables. Expected NPVs of projects are only as accurate as the accuracy of forecasted cash flows and the correctness of the discount rate. The following sections examine different ways of accounting for uncertainty by adjusting forecasted cash flows.

3.4.1 Sensitivity Analysis

Sensitivity analysis involves identifying key factors that determine the profitability of projects. In oil and gas field developments key factors include oil price, total amount of extractable reserves, production rates, opex and capex. Other unidentified variables may be identified as projects move forward. Optimistic and pessimistic estimates should be given for the value of these identified factors. By changing key factors one at the time according to the optimistic and pessimistic estimates, it is possible to see how profitability is affected by changes. This analysis enables decision makers to get a better understanding of key drivers in projects, which should result in better investment decisions. Decision makers will be able to identify uncertainty factors of highest importance, and to locate areas where the company should invest in order to get additional information before final decisions are made.

Sensitivity analysis has some important drawbacks. The first is that it will always produce ambiguous results. It is difficult to determine what optimistic and pessimistic levels really are or should be. Another important problem is that key factors probably are interrelated. An increase in oil price levels will probably increase the activity in the industry, creating higher demand and probably higher costs. Estimation of future correlation between different key factors represents an important challenge in valuation of projects. (Brealey, Myers and Allen, 2006)

3.4.2 Scenario Analysis

Considering that key factors may be correlated, a possible approach is to analyze various possible scenarios. An example of the application of this approach is the Norwegian Petroleum Directorate's scenario analysis about the development of the NCS. The analysis proposes four possible scenarios: Full speed ahead, Techno lab, Sorry we're closed and Blood, sweat and tears. This is done by anticipating the development of oil and gas prices, the amount and size of new discoveries and global supply and demand of oil and gas.[9]

[9]http://www.npd.no/English/Produkter+og+tjenester/Publikasjoner/Ressursrapporter/2007/ress_kap6.htm

With regards to oil and gas field developments, scenario analysis can be used to anticipate different oil and gas price levels with combinations of different values of other key factors. It allows project managers to look at different, but consistent combinations of key factors. Different NPVs are calculated under different scenarios, and serves as a help in the decision making process. (Brealey, Myers and Allen, 2006)

3.4.3 Break-Even Analysis

Break-even analysis involves asking the question: At what level of oil and gas prices is the project no longer profitable? , or alternatively: What amount of extractable reserves does the field need in order to be profitable? The aim of the analysis is to find levels of key factors that ensure projects to not lose money. These measures are easy to interpret, easy to understand and an intuitive way of framing investment decisions. (Brealey, Myers and Allen, 2006)

3.4.4 Monte Carlo Simulation

The methods described above consider changes in one or a limited number of key factors at a time. Monte Carlo simulation is a tool for considering all possible combinations and enables decision makers to inspect an entire distribution of project outcomes. It is a problem solving technique used to approximate the probability of certain outcomes by running multiple trial runs using random variables.[10] A Monte Carlo simulation is undertaken by modeling a project and its key factors affecting the profitability of the project. A computer with proper software is asked to simulate all possible outcomes for the project. The simulation should be done as many times as possible. By analyzing the results it is possible to plot a frequency distribution of the outcomes and to calculate expected values, upper limits and lower limits.

The process can be divided into four steps. Step number one is to model the project. The computer needs a precise model of the project, including revenue and cost equations and the interdependence between different periods and different variables. Step two involves specifying probabilities for estimation errors. The estimation of different key factors should be given with corresponding optimistic and pessimistic estimates. This should enable you to specify probabilities for estimation errors. Step number three involves simulation of cash flows. The computer samples from the distribution of the forecast errors, calculates the resulting cash flows for each period, and records them. After many simulations, accurate

[10] http://www.investopedia.com/terms/m/montecarlosimulation.asp

estimates of probability distributions of project cash flows will occur. The last step involves calculating NPVs. The distributions of the project cash flows should enable decision makers to calculate expected cash flows more accurately. (Brealey, Myers and Allen, 2006)

Monte Carlo simulation allows decision makers to combine knowledge from many individuals into one model. Different analysts from specific competence areas, such as costs, market conditions and engineering can communicate their beliefs about the project. These beliefs can be transformed into probability distributions and incorporated into a model of Monte Carlo simulation. It allows different experts to work individually, but at the same time incorporate all expertise into one model and one output. (Mccray, 1975)

Drawbacks of the Monte Carlo simulation include time and resources in building an accurate model of the project. It is difficult to estimate correlation between variables and underlying probability distributions. If the model and the underlying variables are wrong, the results of the simulations will be wrong. The simulation will only be as good as the estimates and the correctness of the model. (Brealey, Myers and Allen, 2006)

3.4.5 Implicit Valuation Models vs. Explicit Valuation Models

In their article, French and Gabrielli (2005) highlight the difference between implicit valuation models and explicit valuation models. They apply the theory on property investments, but parallels can be drawn to oil and gas field developments. In the implicit valuation model, the valuer derives an appropriate all risks yield from market evidence or other transactions. The all risks yield states that comparable investments customarily sell for a certain multiplier of the income (rent, or revenues from oil production). Adjustments to the all risks yield in order to reflect differences between comparables and the subject investment are made subjectively. When there are sufficient sales transactions, or similar projects, it is possible to build up a picture of market sentiment to be reflected in the choice of an appropriate all risks yield for the subject property. This method gives no indication of the holding period or the overall required rate of return. The all risks yield is supposed to include all these factors implicitly. (French and Gabrielli 2005)

This method does not seem applicable for oil and gas field developments. The reason is that petroleum projects are normally very different in terms of capex, size, complexity, risk and technology. Contrary to real estate and properties, it is not possible to find sufficient “sales transactions”, extensively traded projects or similar projects in order to obtain sufficiently market information.

The explicit valuation model is in line with the principles described in sections 3.4.1-3.4.4. The method makes assumptions about future rents (or oil price levels), holding period, depreciation, opex and other variables explicit. Making these assumptions explicit allows decision makers to question the certainty of input variables. An advantage of this process is that it makes the valuation more “transparent”. The hidden assumptions implied in the all risks yield method are analyzed and questioned individually instead of wrapped into one big package. It seems that the characteristics of oil and gas field developments make the explicit valuation model better suited to account for uncertainty in dcf-analysis.

3.4.6 Probability Distributions

Valuation of projects requires the valuer to have some thoughts about how certain he or she is about the development of different inputs in the valuation model. Depending on market conditions, the valuer may believe that the inputs considered will move up or down or remain at present levels. According to French and Gabrielli (2004), this thought process can be represented in statistical terms by a probability distribution. Equal likelihood of the adopted figure being higher or lower results in a symmetrical distribution; an unequal probability results in a skewed distribution. Each input in the model is represented by a probability density function (pdf), which allows decision makers to consider a range of values instead of a single value. The single value is the most likely value. The uncertainty connected to that figure is represented by the extent of the range around that figure. (French and Gabrielli, 2004)

In the same article, French and Gabrielli discuss the correct probability distribution to be used in valuation of real estate properties. They find a probability-based model using the triangular approach and Monte Carlo simulation as most appropriate. The triangular approach requires the valuer to provide three absolute figures about a given input; the most likely, the maximum and the minimum. This is a closed distribution that can either be symmetrical or skewed. It is an easy and simple approach that uses the valuers subjective beliefs about the future. These figures can be used in a Monte Carlo simulation, giving different statistical measures to be used in investment decisions.

French and Gabrielli (2004) also discuss the normal probability distribution. It is a symmetrical distribution, meaning there is equal probability that the observed figure will be above or below the central assumed figure. The standard deviation is a measure of how widely values are dispersed from the average value (the mean). It is an easily understood probability distribution, as it can be modeled with reference only to the mean and the standard distribution. The mean and the standard deviation can be used in a Monte Carlo simulation, producing different statistical measures to be used in investment decisions. (French and Gabrielli, 2004)

French and Gabrielli refer to valuation of real estate properties. Many of their arguments can be applied to oil and gas field developments. The oil price level, maybe the single most important input in such projects, has already been described as difficult to predict. It may be more appropriate to use subjective beliefs, mean reversion and historical data to assess possible outcomes of future oil price levels. History has shown demand, supply, speculation and unexpected events drive the oil price up and down. Compared to statistical estimation, it may be easier to consider the present oil price level, the last few years' development and mean reversion in order to predict the direction of future oil price levels. It can be argued that the attributes of the oil market does not support the use of a normal probability distribution. It may be more appropriate use triangular distribution in project valuation. The argument of using triangular distribution in valuation of oil and gas field developments is supported by Mccray (1975, p.202).

3.5 Previously Research and Literature

As mentioned in the introduction, the understanding of existing decision-making tools and processes, and improvements of these tools and processes, should make it possible to make more accurate valuation of investments and better investment decisions. An important part of understanding and improving dcf-analysis involves analyzing pros and cons. The following two sections give an overview of some of the pros and cons of dcf-analysis described in the academic literature.

3.5.1 Pros

Dcf-analysis has a strong position in financial theory with many applications, especially within valuation. It provides a systematic and logical framework for making investment decisions. The method takes costs, revenues, the issue of time and risk into consideration. It does not only encourage decision makers to analyze all relevant factors in projects, but also to understand the importance of each factor and possible outcomes of different factors. The dcf-analysis is well understood and is easy to communicate to both decision makers and other stakeholders.

3.5.2 Cons

In their article, Hodder and Riggs (1985) discuss pitfalls in evaluating risky projects. They come up with three critical issues that managers and decision makers should consider: the effects of inflation, different levels of uncertainty in different phases of projects and management's own ability to mitigate risk.

The first issue claims that users of dcf-analysis often ignore how inflation will affect various cash flows. Most likely, inflation will affect different components of the cash flows in different ways. A proper dcf-analysis requires an understanding of inflation adjustment patterns for different cash flow segments. Not including expected inflation may lead to undervaluation of future cash flows resulting in rejection of profitable projects. As long as the inflation rate is positive, the gap between projected real cash flows and their nominal equivalents grows with time. Mistreatment of inflation is also discussed by Booth (1999). He claims that the use of a nominal discount rate (does not includes the effect of inflation) with real cash flows (includes the effect of inflation) underestimates benefits of future returns on investments. The importance of treating inflation consistent is also addressed by Brealey, Myers and Allen (2006). If the discount rate is stated in nominal terms, then consistency requires that cash flows are estimated in nominal terms, accounting for trends in oil price development, opex, maintenance costs and other factors subject to inflation. Real cash flows should be discounted at a real rate. Formulas linking the nominal interest rate and the real rate are:

(5) $$r_{nominal} = (1 + r_{real})(1 + Inflation) - 1$$

(6) $$r_{real} = \frac{(1 + r_{nominal})}{(1 + Inflation)} - 1$$

The second issue mentioned by Hodder and Riggs is different levels of uncertainty in different phases of a project. The use of a single discount rate for a project in which risk declines dramatically over time makes the project appear less attractive than it really is. By adjusting for different risks in different stages of projects, investments become more attractive.

NPV calculations are often performed using a constant discount rate. According to Hodder and Riggs, this assumption is reasonable if we anticipate that errors in predicting real cash flows result from a random walk process, meaning that predictions one period into the future always entail the same uncertainty. The risk adjustment factor for a cash flow in a future period t is $1/(1+r)^t$, meaning that the risk adjustment grows geometrically. In petroleum projects risk probably declines as developments are successfully completed and production is started. As years go by initial investments are paid back, and the risk of projects decrease. This pattern does not support the simple random walk assumption, and may support the use of different discount rates at different stages of projects. It should be mentioned, however, that key factors may change in unfavorable directions, and actually increase the risk of projects. Considering the structure of petroleum projects, companies normally try to start production as fast as possible in order to pay back initial investments. If oil prices decline unexpectedly, pay back time will be longer resulting in higher risk.

The third issue discussed by Hodder and Riggs is the failure of dcf-analysis to acknowledge how management can reduce project risk by diversification. Risk appearing to be too large to a project manager may appear reasonable to a corporate executive or a shareholder who can diversify risk by spreading it across other investments. Financial theories stress that a project's total risk usually consists of both unsystematic and systematic risk, which are respectively diversifiable and non-diversifiable. Projects may seem less risky from the perspective of a well diversified public shareholder compared to the perspective of the individual performing the dcf-analysis. According to Hodder and Riggs, this excessive risk aversion is often taken into account by discounting cash flows with a too high discount rate. Although it may be difficult to overcome this risk aversion, management needs to be aware of its existence and its consequences. Booth (1999) also mentions this issue, and claims that companies deal with the issue by using exaggerated discount rates and arbitrary increases in discount rate. As mentioned in section 3.2.3, Brealey, Myers and Allen (2006) give warnings about the use of these kinds of "fudge factors" in order to deal with uncertainty.

In their article, Smith and Mccardle (1999) address two concerns of dcf-analysis. The first concern is the failure of including the value of flexibility into the valuation. They claim that the model typically assumes that management makes an initial investment decision, and then project uncertainties are resolved and cash flows determined. In reality, companies make a series of investment decisions as the uncertainties resolve over time. They use the development of a new oil field as an example. If oil prices, production rates or total amount of extractable reserves exceed expectations, or if production technology improves, the company might be able to develop more aggressively or expand to nearby fields. Similarly, if prices, rates or reserves are below expectations, the company might be able to scale back planned investments and limit their downside exposure.

The second issue involves the way companies discount cash flows. The authors claim that petroleum projects with time horizons as long as 30 or 40 years make expected NPVs of investments extremely sensitive to the discount rate. They state that there is concern in the industry that the use of a risk adjusted discount rate causes undervaluation of projects with long time horizons.

In his article, Zettl (2002) mentions three drawbacks of dcf-analysis. The first drawback is linked to the first concern of Smith and Mccardle (1999), and involves the failure of including the value of management flexibility into the valuation. The second drawback is linked to the second concern of Smith and Mccardle (1999), and involves cash flows in dcf-analysis not being discounted at the risk-free rate. The third drawback mentioned by Zettl is that the probability for the occurrence of certain events (changes in key factors) must be subjectively determined.

Smith and Mccardle mention an additional drawback in their 1998 article. They point to the fact that dcf-analysis rarely take into account market opportunities to hedge project risks by trading securities, even though these opportunities may have an impact on project values and optimal investment strategies. As an example, companies may be able to hedge the risk of declining oil prices by trading oil derivatives in the futures market.

The issues of management flexibility, the focus on "now or never" decisions and the dependency of the choice of correct discount rate are addressed by Laughton, Sagi and Samis (2000). Dixit and Pindyck (1995) point to three main failures of dcf-analysis; lack of a suitable treatment of uncertainty, misevaluation of the opportunity cost to invest since it does not take into account that expenditures are sunk and does not incorporate managerial flexibilities. Drawbacks of the traditional dcf-analysis have contributed in developing the Real Option approach.

4.0 Real Options

"To factor real-world uncertainties
into your decisions,
look beyond net present value"

-Dixit and Pindyck

4.1 Introduction

An option is a security giving the right to buy or sell an asset, subject to certain conditions, within a specified period of time. An "American option is one that can be exercised at any time up to the date the option expires. A "European option" is one that can be exercised only on a specified future date. (Black and Scholes, 1973) The holder of the contract has the possibility of payoff from an underlying security or asset, without initially owning/buying the underlying security or asset. The contract specifies the exercise price. The exercise price is the price the holder of a call option must pay for the underlying security if he chooses to exercise the option. If the exercise price is lower than the market value of the underlying security, the option gives a positive payoff and the option is said to be "in the money". If the exercise price is higher than the market value of the underlying security, the option does not give a positive payoff and the option is said to be "out of the money". An investor would not exercise a call option if he could buy the security in the market at a lower price. In contrast, if the call option gives the holder the right to buy the security cheaper than he could do in the market, he would do so and achieve a positive payoff. If X is the exercise price, and S_t the stock price at the expiration date, the payoff structure for a European call option is:

(7) $$\max(S_t - X, 0)$$

Financial options on stocks, stock indexes, bonds, foreign exchange and commodities are extensively traded, and represent important tools for investors with regards to speculation and hedging. The most popular valuation method of financial options is the Black-Scholes formula. This method was introduced by Fischer Black and Myron Scholes in their 1973 article "The Pricing of Options and Corporate Liabilities". A further application of the thoughts and insights by Black and Scholes was developed by Stewart Myers. In his 1977 article "Determinants of Capital Borrowing" he was the first to use the term "real options", identifying that many corporate real assets can be viewed as call options (Bratvold, Laughton, Enloe and Begg, 2005).

The idea of the real option approach is to use techniques used to value financial options to value real projects where management can exercise options on different strategic directions throughout the lifetime of projects. The main types of real options include the option to delay, abandon, expand and decrease investments in projects. Investment profiles of projects can often be characterized as sequential, giving companies time to learn about the project and market conditions as time goes by. The knowledge acquired may give rise to new possibilities increasing the value of projects, or giving companies the chance to stop projects moving in wrong directions.

There are some important differences between real options and financial options. First of all, investment projects are normally not traded securities as compared to financial options. Given that markets of financial options work like they should, the correct market value of financial options are set by various buyers and sellers operating in the market. Real options are not traded securities, resulting in more uncertainty in terms of valuation.

Secondly, real options are often more complicated than financial options. Financial options often depend on only one underlying variable, for instance the value of a stock. The value of real options is often determined by more than one underlying variable. Due to this, the value of projects is often not known at the time investment decisions are made (Laine, 1997).

Third, real options normally have longer time to expiration compared to financial options. This is caused by the already mentioned issue of projects having long time horizons. Projects with long time horizons often have different real options attached that can be exercised throughout the lifetime of projects.

Fourth, private uncertainty often plays a bigger role in real options compared to financial options. Issues like technology, extractable reserves, capex and opex can be considered as private uncertainty, and have a big potential in affecting the value of real options. Another difference involves the decision rule being more important in real options than in financial options. Decisions about exercising real options normally have bigger consequences than decisions about exercising financial options. As an example, the option to expand a project may lead to high investments and confiscation of a company’s resources.

The real option approach is usually regarded appropriate when investments are recognized by a great deal of uncertainty regarding the actual value of projects, and when companies can learn more about the value of projects as time goes by and uncertainties are resolved. Further on, companies and projects need to have sufficiently flexibility to adapt to new information and knowledge. (Smith and Mccardle, 1998) Examples of projects with these characteristics include investments in R&D, flexible production systems and oil field licenses containing possible profitable petroleum reserves. According to Laughton et al (2000), the future role of the real option approach is not clear, and much fundamental work still remains in developing the approach. They point to the fact that The Economist reported that 46% of a sample of companies that experimented with real options had abandoned their experiments. There has been much academic research on the application of real options. In theory, the approach seems logic and appropriate. In real life there seem to be several practical issues that need to be solved before real options can be used for project valuation. The following sections explain valuation of financial options and valuation of real options.

4.2 Valuation of Financial Options

In order to understand valuation of real options, it is necessary to understand valuation of financial options. The following sections are based on option pricing theory as it is described by Brealey, Myers and Allen (2006).

4.2.1 The Binomial Method for Valuation of Financial Options

Valuation of financial options can be done by replicating the expected payoff structure from a call option by creating a portfolio of stock and borrowing. The objective of creating a replicating portfolio is to use a combination of borrowing and the underlying asset to create the same cash flows as the option being valued. The value of this position has to be the same as the value of the call no matter what the stock price does. The logic is that investments with equal expected payoff must be traded at the same price. Brealey, Myers and Allen use a numerical example to demonstrate. One stock is traded at \$60. It is possible to buy a call option with an exercise price of \$60 expiring eight months from now. The risk free interest rate of the eight month period is assumed to be 1 %. The stock is assumed to be traded at either \$45 or \$80 at the expiration date, resulting in the following possible payoffs eight months from now:

(8) $$\max(\$45 - \$60, \$0) = \$0$$

(9) $$\max(\$80 - \$60, \$0) = \$20$$

The number of leveraged shares that replicates the payoff structure of the call option must be identified. This fraction is called the hedge ratio, or option delta, and can be found by using the following formula:

(10) $$Option\ delta = \frac{Spread\ of\ possible\ option\ prices}{Spread\ of\ possible\ stock\ prices}$$

(11) $$Option\ delta = \frac{20 - 0}{80 - 45} = \frac{20}{35} = \frac{4}{7}$$

Investors need to buy 4/7 stock. In addition, investors need to borrow the present value of the difference between the payoff from the call option and the payoff from 4/7 stocks. This figure is the same whether the stock price moves up or down:

(12) $$\frac{\left(\frac{4}{7} \times 45\right) - 0}{1 + 0{,}01} \quad \leftrightarrow \quad \frac{\left(\frac{4}{7} \times 80\right) - 20}{1 + 0{,}01} = 25{,}46 \text{ (25, 71 if not discounted)}$$

The payoff from the call option (equation (8) and (9)) equals the payoff from the replicating portfolio:

Replicating portfolio	Stock price = \$45	Stock price = \$80
4/7 Stocks	$25,71	$45,71
Repayment of loan + interest	-25,71	-25,71
Total payoff	$0	$20

Figure 5: Replicating portfolio of a call option

The value of the call option is found by subtracting the amount borrowed from the value of 4/7 stock:

(13) $$Value\ of\ call = (60 \times \frac{4}{7}) - 25{,}46 = \$8{,}83$$

The price of the call option should be \$8, 83. If the price is higher, investors could make a profit by buying 4/7 stock, selling a call option, and borrowing \$25, 46. Similarly, if the option price is less, investors could make a profit by selling 4/7 stock, buying a call option and lending the balance. In either way, there would be an arbitrage opportunity.

The assumption of no arbitrage opportunities leads to the concept of risk neutral valuation. If arbitrage opportunities did exist, the risk preferences of investors would not make a difference, as arbitrage is seen as risk free. As a consequence, the expected future value of an option can not depend on investors risk preferences. This results in the possibility of finding the expected NPV of an option by discounting cash flows by the risk free interest rate. In the example described above, the risk free interest rate was 1 % during the eight month period. According to the principles of risk neutral valuation, the following relationship must hold:

(14) $$Expected\ return = 1\% = [probability\ of\ rise \times u] + [probability\ of\ down \times d]$$

In formula (14), u is the upside change and d is the downside change. The relationship can be rewritten to a general formula capable of finding the risk neutral probability of a rise in value (formula (15)). This probability is also called the "pseudo" probability.

(15) $$p = \frac{Interest\ rate - downside\ change}{upside\ change - downside\ change}$$

The value of downside change and upside change must be calculated in order to demonstrate risk neutral valuation of the call option. Assuming that the stock trades at either \$45 or \$80 at the expiration date, the stock moves up by 33, 3 % (80/60) or down by 25 % (60/45). This gives the following valuation:

(16) $$risk\ neutral\ probability\ of\ rise = \frac{0{,}01 - (-0{,}25)}{0{,}333 - (-0{,}25)} = 0{,}446$$

(17) $$Value\ of\ call = (0{,}446 \times 20) + ((1 - 0{,}446) \times 0) = \$8{,}92$$

(18) $$Current\ (Discounted)\ value = \frac{Expected\ future\ value}{1 + \mathrm{int}\,erest\ rate} = \frac{8{,}92}{1{,}01} = \$8{,}83$$

As shown, the value of the call option is the same using risk-neutral valuation and the replicating portfolio approach. An important question is how to find sensible figures for the up moves and the down moves in each period. According to Brealey, Myers and Allen (2006), this can be done by using the following formulas:

(19) $$1 + upside\ change = u = e^{\sigma \times \sqrt{h}}$$

(20) $$1 + downside\ change = d = \frac{1}{u}$$

In formula (19) and (20), e is the base for natural logarithms, σ is the standard deviation of stock returns and h is the interval as fraction of a year.

According to Brealey, Myers and Allen (2006), the risk neutral valuation approach is a simplified version of what is known as the binomial method. The method starts by reducing the possible changes in next period's stock price to an up move and a down move. This assumption states that there are only two possible outcomes of the stock price when the expiration date is reached. The method can be made more realistic by considering shorter time periods between the valuation date and the expiration date. It is possible to chop the periods into shorter and shorter time intervals, eventually reaching a situation where the stock price changes continuously resulting in a continuum of possible future stock prices at the end of the eight month period. Since stocks have a limitless number of future values, the binomial method gives a realistic and accurate measure of options' value when applying a large number of sub periods. The further we chop an option's life into smaller pieces, the closer we come to the Black-Scholes formula.

4.2.2 The Black-Scholes Formula

Black and Scholes developed a formula making it possible to divide an option's life into infinite small periods. The formula creates the possibility of a continuum of possible stock price changes at the expiration date. The lognormal distribution is often used to summarize the probability of different stock price changes. It recognizes that stock prices never can fall more than 100% and the small chance that they can increase by more than 100%. The Black-Scholes formula is:

(21) $$Value\ of\ call\ option = [N(d_1) \times S] - [N(d_2) \times PV(X)]$$

(22) $$d_1 = \frac{\log \frac{P}{PV(X)}}{\sigma \times \sqrt{t}} + \frac{\sigma \times \sqrt{t}}{2} \;\; ; \;\; d_2 = d_1 - \left(\sigma \times \sqrt{t}\right)$$

where

$N(d) = cumulative\ normal\ probability\ density\ function$

$X = exercise\ price\ of\ option$

$PV(X) = X\ discounted\ by\ the\ risk - free\ \text{int}erst\ rate$

$t = number\ of\ periods\ to\ exercise\ date$

$P = price\ of\ stock\ now$

$\sigma = s\tan dard\ deviation\ per\ period\ of\ rate\ of\ return\ on\ stock$

The Black-Scholes formula have the following assumptions: (a) the price of the underlying asset follows a lognormal random walk, (b) investors can adjust their hedge continuously with no transaction costs, (c) the risk free rate is known and (d) the underlying asset does not pay dividends.

The Black-Scholes formula implies that the value of call options are determined by the stock price level, the exercise price, the risk-free interest rate, the time to expiration and the volatility of the stock. If there is an increase in the stock price, the interest rate, the time to expiration or the volatility of the stock, the value of the call option increases, and vice versa. If there is an increase in the exercise price, the value of the call option decreases, and vice versa. According to Brealey, Myers and Allen (2006), the Black-Scholes model has proved very flexible as it can be adapted to valuation of options on a variety of assets with special features, such as foreign currency, bonds and commodities. It has become the standard model for valuation of financial options. The next section discusses valuation of real options.

4.3 Valuation of Real Options

Option pricing theory was developed for valuation of financial options. The analogy between financial options and corporate investments has led to the adoption of this theory for the valuation of such projects. According to Zettl (2002), the occurrence of multiple interacting options in corporate investments requires a modification of the methods developed for valuation of financial options. In his article, he develops a model that attempts to consider all possible options and fully take care of uncertainty in exploration and production projects in the petroleum industry. The model is based on a simplified approach of the Black-Scholes formula given by Cox, Ross and Rubinstein (1979). Zettl claims that this model is not the preferred to value financial options, but is better suited for the specific needs of real options valuation like long times to expiration and multiple interacting options. The following section explains the model in detail. An application of the model is given in the case study of Goliat.

4.3.1 The Model by Cox, Ross and Rubinstein (CRR)

Compared to the Black-Scholes formula, the CRR model is discrete instead of continuous. A basic assumption of the model by CRR is that the price of the underlying asset follows a multiplicative binomial process. This means that the price of the underlying asset can move up by a fixed factor *u* or down by a fixed factor *d* within one time period. *u* and *d* depend on the volatility of the underlying asset and the length of the time period. An example of an underlying asset may be the oil price, moving up and down and affecting the value of the option (oil and gas field development). This creates a binomial tree that can be solved recursively, giving the value of the option. At the expiration date an option is worth its intrinsic value. However, real options can usually be considered as American options, meaning that they can be exercised not only on the expiration date, but also throughout the complete lifetime of projects. As a consequence, each node of the binomial tree needs to be examined in terms of whether options should be kept alive or exercised. Figure 6 shows an example of an underlying asset *S* following a multiplicative binomial process in three periods with corresponding values of the option *C*.

			$S*u^3$					$C_{3,uuu}$
		$S*u^2$					$C_{2,uu}$	
	$S*u$		$S*u^{2*}d$			$C_{1,u}$		$C_{3,uud}$
S		$S*u*d$		→	$C_{0,0}$		$C_{2,du}$	
	$S*d$		$S*u*d^2$			$C_{1,d}$		$C_{3,udd}$
		$S*d^2$					$C_{2,dd}$	
			$S*d^3$					$C_{3,ddd}$
t=0	t=1	t=2	t=3		t=0	t=1	T=2	T=3

Figure 6: Binomial tree with multiplicative process and corresponding option values

Options are valued using equations for the option value ($C_{j,i}$), the pseudo-probability (p), the up factor (u) and the down factor (d). The formulas are:

(23) $$C_{j,i} = \frac{p \times C_{j+1,i} + (1-p) \times C_{j+1,i}}{e^{r_f \times dt}}$$

(24) $$p = \frac{e^{(r_f - D) \times dt} - d}{u - d}$$

(25) $$u = e^{\sigma \times \sqrt{dt}} \quad ; \quad d = \frac{1}{u}$$

where

$$D = dividend\ \ yield$$

$$r_f = risk - free\ rate$$

$$dt = length\ of\ \ binomial\ \ period$$

$$\sigma = volatility$$

$$j = index\ for\ time$$

$$i = index\ \ for\ state\ at\ time$$

Using option pricing theory for valuation of real investment projects requires an understanding of the analogies between variables in financial options and real options. According to Zettl (2002), the following analogies exist:

Option terminology	**Financial option (on stock)**	**Real option**	**Petroleum project**
Value of underlying asset	Stock price	PV of expected cash flows	PV of developed reserves
Exercise price	Exercise price	PV of investments	PV of development costs
Time to expiration	Time to expiration	Time period in which investment can be undertaken	Negotiated development period
Volatility	Volatility of stock price	Volatility of project value	Volatility of oil price
Risk-free interest rate	Risk-free interest rate	Risk-free interest rate	Risk-free interest rate
Dividend	Dividend	Net convenience yield	Net convenience yield

Figure 7: Analogies between financial and real options (Zettl 2002)

4.3.2 Three Main Real Options in the Upstream Petroleum Industry

Academic literature on real options often describes four main types of real options. These include the option to expand, the option to wait, the option to shrink or abandon and the option to vary the mix of output. Considering oil and gas field developments, the first three real options are of highest importance.

The option to expand involves the opportunity of follow-on investments. If a company decides to develop an oil and gas field, it faces sequential phases of investments as the project moves forward. As projects move forward, companies acquire new information about market conditions, technology, costs, total amount of extractable reserves and production rates. If oil price levels are rising, and production has shown promising results, the company may wish to expand the number of exploration wells and production wells. Investments in facilities have often already been made, and expansion of projects may be found profitable. In addition, companies often have interest in developing oil and gas fields as fast as possible in order to take advantage of good market conditions. These opportunities, which are rights, but not obligations, are valuable as they can contribute in increasing the profitability of projects.

The option to wait and see, or the timing option, gives companies the chance of assessing projects and market conditions before they choose to develop fields. Even if project NPVs are positive, it may be in the interest of the company to wait. Again, oil price levels serves as a good example. If oil prices are expected to increase in the future, it may be valuable to wait even if a project is profitable undertaken already today. Delay does not waste barrels of oil in the ground; it postpones production and associated revenues. Costs of waiting are the decline in the present value of today's revenue from production. In theory, companies should wait as long as the present value of future increase in oil price levels are larger than the decline in the present value of today's production.

The last real option is the opportunity to abandon or shrink projects. This is the opposite of the option to expand projects. If companies encounter technological challenges, lower production rates, higher costs and lower oil prices than expected, they may be interested in shrinking or abandoning projects. If costs of abandoning are lower than going forward, projects should be shut down. Companies may also face the option of abandoning projects temporarily. If market conditions after a temporary shut down change to the better and project challenges are resolved, it may once again be in the interest of the company to go on with a given project.

4.4 Previously Research and Literature

As described in section 3.5, an important part of understanding and improving existing investment decision tools involve analyzing pros and cons. The following two sections give an overview of some of the pros and cons of the real option approach described in the academic literature.

4.4.1 Pros

The most appreciated advantage of the real option approach is the incorporation of management flexibility. In contrast to traditional dcf-analysis, real options equip management with different opportunities to change the course of projects as time goes by and more information is known. These options have value, and should be incorporated in the capital budgeting process. This insight is among others supported by Zettl (2002), Brealey, Myers and Allen (2006), Smith and Mccardle (1998), Dixit and Pindyck (1995) and Booth (1999).

Another advantage of the real option approach is that cash flows are discounted at the risk-free rate. There is no need to add a "fudge factor" in order to risk adjust the discount rate, which is an important drawback related to dcf-analysis. The possibility of risk free valuation is achieved by building a replicating portfolio with the same payoff structure as the option itself (See section 4.2.1 and Figure 5). The fundamental principle underlying this point is the "no arbitrage" principle, or the "law of one price", saying that two investments with equal payoffs at all times and in all states must have the same value. When evaluating two equal opportunities, the risk preference of the investor will not make a difference, and cash flows can be discounted at the risk free rate. This insight is among others supported by Zettl (2002) and Smith and Mccardle (1998 and 1999).

The real option approach helps decision makers to model projects in a more realistic way. In contrast to dcf-analysis, where opportunities often are evaluated in terms of "now or never", real option take a more dynamic approach and encourages management to understand the importance and implication of new information. In real life, companies learn (or at least ought to) all the time, and take new information into account as it comes along. This information may create new opportunities in terms of the real options described in section 4.3.2.

4.4.2 Cons

Brealey, Myers and Allen (2006) mention some practical challenges in applying real options analysis. First of all, real options can be very complex. Valuation requires investments in both development and knowledge about the real options approach. In addition, investments in computational resources in terms of software and hardware need to be made. Brealey, Myers and Allen state: "Sometimes an approximate answer now is more useful than a "perfect" answer later, particularly if the perfect answer comes from a complicated model that other managers will regard as a black box". This insight is also supported by Booth (1999), stating that "Real options are usually more complex still and the modelling expertise involved is substantial".

The next issue mentioned is lack of structure. In some cases, the range of possible project outcomes may be too large and too complex to be fitted into a model. If it is not possible to model all possible payoffs, or at least a sufficiently number of payoffs to make a logic and applicable valuation, there is a big chance that output from the model is not very accurate. Further on, a third problem arises when competitors have real options. The upstream petroleum industry on the NCS is recognized by low project standardization and relatively few players. This may create a situation where competitors all have real options, and where there is a danger of assuming passive competitors. In some circumstances, players should be careful that they don't wait and learn that a competitor has moved first. Competitive interactions may change the rules of the game, and should be given sufficiently attention. Modelling these kinds of interactions may not be straightforward, and consequently serves as a drawback of the real options approach.

Zettl (2002) and Smith and Mccardle (1999) discuss the use of a multiplicative binomial process for modelling oil price levels. The size of the binomial trees grow larger as the length of the time horizon considered increases. When considering long term projects, the model may assume unrealistic levels of the oil price, both upwards and downwards. This problem may also be an issue when using multiplicative binomial processes to forecast other underlying variables. The authors propose to overcome the problem by using an oil price band that forces the oil price to stay within a certain range. This is similar to modelling the oil price as a mean reverting process. However, introducing an oil price band has high potential of affecting the value of the real option considered. As mentioned in section 4.2.2, the value of an option increases when volatility increases. Introducing an oil price band reduces volatility (the upside potential) and the value of the option. A consequence may be that the optimal time to development is decreased, and the option is exercised earlier than it would be without a price band.

Zettl (2002) and Smith and Mccardle (1999 and 1998) discuss the challenge of creating a portfolio that replicates the payoff structure of a real option. Smith and Mccardle (1998) state:"The weakness of the option pricing approach is its lack of generality. In order to determine a unique project value, one must be able to find a portfolio and trading strategy that perfectly replicates the project's cash flows. This "completeness" assumption is quite reasonable when valuing put or call options on a stock……but seems unrealistic for most real projects." There are well developed financial markets capable of managing oil and gas price risk, but there are no securities capable of hedging project-specific risks like production rates, costs, technology and delays. It should be mentioned, however, that there may be problems in managing oil and gas price risk on a long term basis as projects in the upstream petroleum industry often have time horizons covering more than 30-40 years, and do not fit maturities in the futures market. The classic option pricing theory assumes that markets are complete, and all risks can be perfectly hedged by trading securities. Smith and Mccardle (1999) propose to distinguish between market risk and private risk, and to use option valuation techniques to value market risk at the risk-free rate, and traditional probability distributions for different outcomes of private risk discounted at the risk free rate for valuation of private risks.

5.0 Applying the Theory

5.1 Introduction

In order to answer the problem statement according to the approach and methodology described earlier, we need to apply the theories described in the previous theory sections. This is done by valuing a simplified version of a real life oil and gas field development on the NCS. The valuation is undertaken using the two methods described in the theory sections. The inputs used in the valuation consist of publicly available information, comments from Eni Norge and assumptions made by the author. The main goal is to increase the understanding of the two methods by deriving similarities, differences, weaknesses, strengths and its implication on capital budgeting.

5.2 The Goliat Project

Goliat was discovered by exploration drilling in 2000 and 2001, and was the first discovery of oil in The Barents Sea. It is located 85 kilometres northwest of Hammerfest and 50 kilometres southeast of the large gas field Snøhvit. Eni Norge is the operator and has 65 % ownership of the license. StatoilHydro owns the remaining 35 %. Because of its location in a vulnerable environment with regards to fishery, the project has gained much interest among environmentalist, politicians and other stakeholders. The Goliat field is expected to hold 27, 5 million sm^3 extractable oil and 8 billion sm^3 extractable gas. On the 18th of February 2009 Eni Norge submitted the PDO (Plan for Development and Operation) to the Ministry of Petroleum and Energy. The company plans to start production in 2013. The Golat field has an expected lifetime of 15-20 years. The lifetime of the project can be extended if new discoveries make it possible to take advantage of already developed Goliat facilities at a later point of time.

As a result of the large decrease in oil price levels during the last part of 2008, several stakeholders have expressed their concern about the profitability of the project. As an example, the Norwegian magazine "Teknisk Ukeblad" stated that the project depend on an oil price of at least $58 in order to be profitable.[11] This has caused discussion and debate about whether the project should be undertaken now, or at a later point of time with better market conditions. Eni Norge has real options in terms of undertaking the project right away and start production in 2013 as planned, or to wait for better market conditions. Another interesting

[11] http://www.tu.no/olje-gass/article192832.ece

aspect of the Goliat Project is that it is closely located to Snøhvit. Snøhvit is first of all a gas field, but has oil reserves that have not been found profitable to extract. The development of the Goliat field can make extraction of the oil reserves on Snøhvit profitable. In other words, the development of Goliat may hold an option of oil extraction from Snøhvit.[12] The development of Goliat also creates options of future exploration drilling and discoveries in The Barents Sea that are not profitable as separate projects, but profitable if connected into already existing Goliat facilities.

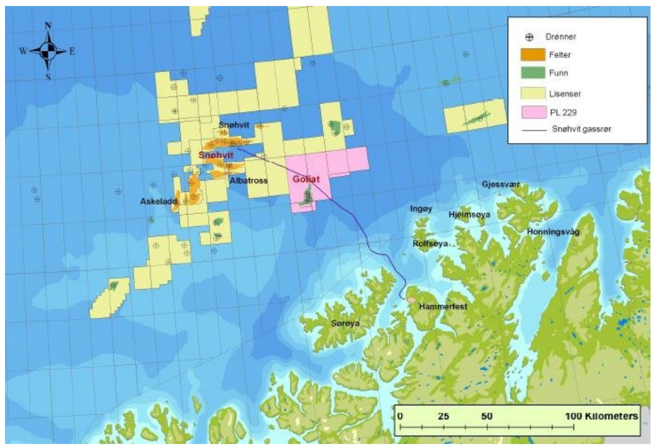

Figure 8: Location of the Goliat field in The Barents Sea in the northern parts of the NCS

5.3 General Assumptions and Base Case

The next sections explain assumptions taken in the valuation of Goliat. On areas where information does not exist, assumptions are made by the author. The assumptions made in these sections are regarded as base case, where the values of the different variables reflect the information given by Eni Norge. The information is mainly obtained from the webpage of Eni Norge, the web page of the project, the Impact Assessment Plan of the project and comments from Eni Norge.

5.3.1 Extractable reserves and production rates

Goliat is assumed to hold 27, 5 Msm^3 of oil and 8000 Msm^3 of gas. According to Eni Norge production is expected to peak already in the second year of production with 5, 4 Msm^3. After the second year, production is assumed to decrease relatively fast to 1, 7 Msm^3, and continue to decrease before it reaches 0, 5 Msm^3 during the last years of the project's lifetime. The case

[12] http://www.tu.no/nyheter/offshore/article45669.ece

study assumes a lifetime of 16 years. The production of gas is expected to have the same relative production profile as oil. This gives the following production profile of oil and gas:

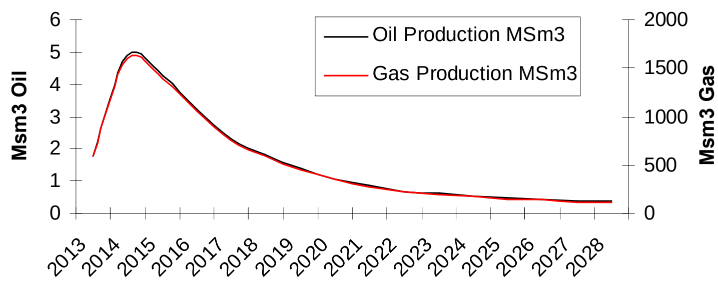

Figure 9: Assumption of Base Case production profile from Goliat

In order to give the production profile meaning, some guidelines about the measurement of oil and gas should be given. Many different measures exist, but calculations should aim at measuring the amount of oil and gas into measures in which the two commodities are traded: barrels of oil and standard cubic meters of gas. Given that the production profile is measured in standard cubic meters (sm^3), we need to transform 1 sm^3 of oil into barrels of oil. 1 sm^3 of oil equals 6, 29 barrels of oil.

5.3.2 Oil and Gas Price Levels

One barrel of oil is in late March 2009 trading at approximately \$55. This value is used as a starting point. The volatility of the oil price plays an important role in the binomial process described by CRR to model the oil price. A yearly oil price volatility of 20 % is assumed in the analysis.

In late March the price of gas from the NCS is trading at NOK 1, 20 per sm^3 of gas.[13] The production of gas involves costs of transportation and processing. As a consequence, the price realized by the holders of Goliat will be lower than the trading price. There are high uncertainty regarding the actual cost of transportation and processing, but a cost of NOK 0, 5 per sm^3 of gas is assumed. As a consequence, NOK 0, 7 is used as a starting point. Another possibility would be to incorporate these costs into opex. In order to keep the model as simple as possible, these costs are directly incorporated into the gas price. The gas price is assumed to follow the same price pattern as the oil price over long time horizons. In other words, a 10 % increase in the oil price is assumed to be followed by a 10 % increase in the gas price.

[13] www.energilink.no

5.3.3 Investments (capex) and Operating costs (opex)

Capex on Goliat are estimated to be approximately NOK 27 billion, measured in NOK 2008. Investments will be made from 2010 to 2013. The analysis assumes that capex is NOK 3 billion in 2010, NOK 6 billion in 2011, NOK 10 billion in 2012 and NOK 8 billion in 2013. This is in line with a typical capex profile in petroleum projects. Fixed operating costs (opex) are estimated to be slightly under NOK 1 billion each year during the lifetime of the project, measured in NOK 2008. An opex of NOK 950 million is assumed each year.

5.3.4 Depreciation of capex

As described in section 3.2.2, companies on the NCS can depreciate capex linearly over a six year period, starting from the year investments are made. In addition, companies are allowed to an extra depreciation used as deduction when calculating the special tax base. This depreciation is called uplift, and equals 30 % of capex spread over a four year period, starting from the year investments are made. If a company is not in a tax paying position, unused depreciation and uplift can be carried forward indefinitely. The calculations assumes that Eni Norge is able to take advantage of deductions in all years, starting in year one.

5.3.5 Tax System and Fees

As described in section 3.2.2, companies on the NCS pay a standard corporate tax of 28 %. In addition, after deduction of the uplift, companies pay a special tax of 50 %. (Samuelsen, 2006) Taxes are paid two times a year. This means that payable taxes in a given year consist of one half of last year's taxes and one half of the given year's taxes, resulting in a delay in payable taxes. This is taken into consideration in the valuation.

As described in section 3.2.2, other taxes involve CO_2-tax, NO_x tax and area fee. These taxes do not represent substantial expenses. In addition, the prediction of CO_2 and NO_x would be subject to high uncertainty. As a consequence, these taxes are not taken into consideration in the calculations.

5.3.6 Inflation

When evaluating a project with a lifetime of 16 years, inflation may play an important role. Inflation in terms of the oil price will not be considered. The reason for this is that history has shown that other variables play more important roles than inflation. However, inflation can play an important role when it comes to opex. During the last years with high activity on the

NCS, costs have increased dramatically. As we write March 2009, the level of costs in the oil industry is an important and actual topic. Several oil companies have contacted their suppliers with demand of lower prices.[14] The opex estimate of NOK 950 Million is measured in NOK 2008. It is assumed that the focus on costs in the industry makes prices stay at the same level until start of production in 2013. From 2013, it is assumed that opex is subject to 2 % yearly inflation. The same goes for capex. Considering the focus on costs in the industry, it is assumed that capex will not be subject to inflation during the time of development.

5.3.7 Liquidation

Costs involved with shutting down production and liquidation of facilities are assumed to occur in 2029 and 2030. These costs are assumed to be NOK 1 billion in 2029 and NOK 2 billion in 2030 (measured in NOK 2008). These costs are considered as opex and are added to fixed opex in 2029 and 2030. Considering 2 % yearly inflation from 2013, costs of liquidation are assumed to be MNOK 1373 in 2029 and MNOK 2800 in 2030.[15]

5.3.8 Discount Rate

In the PDO submitted to the Ministry of Petroleum and Energy, Eni Norge uses a discount rate of 7 %. This is in line with the requirements set by the Ministry of Petroleum and Energy in evaluation of profitability of projects.

5.3.9 Guidelines set by the Norwegian Petroleum Directorate

The Norwegian Petroleum Directorate has determined guidelines to be used by companies applying for licenses on the NCS. As we write spring 2009, the 20th licensing round on the NCS is in progress, and the following economic assumptions must be followed by the participants: Discount rate of 7 %, oil price of $65/bbl, gas price of NOK 1, 48/sm^3 and exchange rate of NOK 5, 7/$1.[16] Some of these assumptions differ from the assumptions described above. The main reason for this is that the guidelines were made at an earlier point of time, and does not reflect the market conditions at this point of time.

[14] http://www.aftenbladet.no/energi/oljeservice/979998/Leverandoerer_maa_kutte_30_prosent.html

[15] $1000 \times 1,02^{16} = 1373$, $2000 \times 1,02^{17} = 2800$

[16] http://www.npd.no/20runde

5.4 Base Case Valuation

The standard NPV function in Microsoft Excel assumes that all cash flows arrive at the end of the year. By adding (1+discount rate)^0,5 to the standard NPV formula, calculations discounts 2010 by 1,5 years, 2011 by 2,5 years and so on. This makes the calculation more realistic, and assumes that cash flows come evenly throughout the year.

Considering the assumptions described, the Goliat project will be profitable with an oil price of $45, 22 and a corresponding realized gas price of 0, 48 NOK (Appendix 1). Considering today's price level of oil and gas, the project is profitable and should be undertaken. The NPV of the project has the following profile:

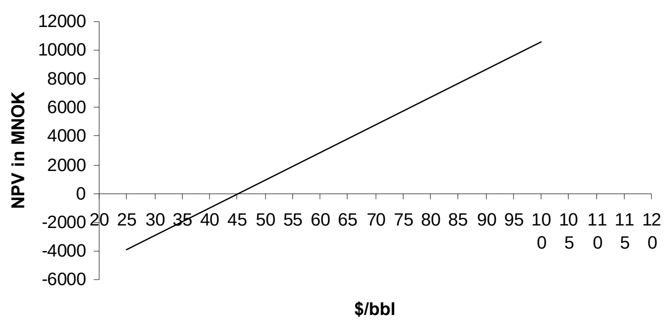

Figure 10: NPV profile of Goliat assuming Base Case

The next section analyzes how dcf-analysis combined with NPV calculations are able to account for uncertainties, and how the NPV of the project differs when the methods described in section 3.4 are applied.

6.0 Valuation under uncertainty using dcf-analysis and NPV

6.1 Sensitivity Analysis

The following sections analyze different variables important in determining the NPV of Goliat. In addition to the already described base case, the analysis uses a triangular distribution with a pessimistic case and an optimistic case. Considering the difficulty of predicting oil price levels, the analysis does not predict the oil price, but analyzes the oil and gas price levels resulting in a profitable/unprofitable project. This approach is in line with the break-even analysis described in section 3.4.3, giving decision makers an intuitive and understandable measure regarding projects' profitability and economical downside/upside.

6.1.1 Extractable reserves and production rates

Total extractable reserves have been estimated to 27, 5 Msm^3 of oil and 8000 Msm^3 of gas. Eni Norge characterizes the uncertainty (P10-P90) of the estimate as respectively 18, 2 Msm^3 and 32, 6 Msm^3 of oil. This means a 90 % probability of extractable reserves being at least 18, 2 Msm^3 or more, and a 10 % probability of extractable reserves being 32, 6 Msm^3 or more. As a consequence, the analysis uses the following assumptions when it comes to total amount of extractable oil: 27, 5 Msm^3 as base case, 18, 2 Msm^3 as pessimistic case and 32, 6 Msm^3 as optimistic case. The same relative relationship is used for gas, resulting in 5300 Msm^3 as pessimistic case, 8000 Msm^3 as base case and 9500 Msm^3 as optimistic case. Using the same production profile as in base case, but with different inputs, yields the following NPV profiles:

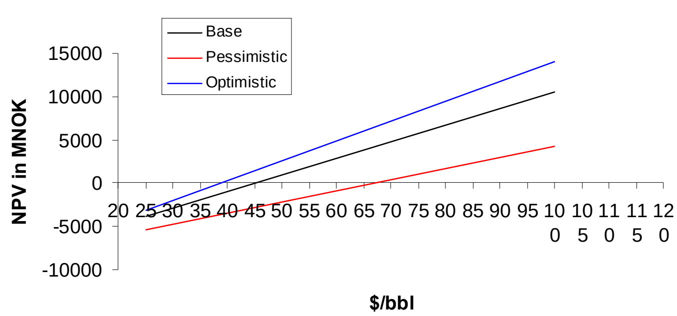

Figure 11: Sensitivity analysis: NPV profile with various amounts of extractable reserves

The pessimistic case is profitable with an oil price of $66, 74 or higher. The optimistic case requires an oil price of $38, 62 or higher (Appendix 2). This means that the total amount of extractable reserves has a high impact on project NPV. As shown in figure 11, the higher oil price levels the higher importance of total amount of extractable reserves. If the pessimistic case is realized, the project is not profitable with the level of oil price we face today. The optimistic case gives a profitable project already at $38, 62, giving the project a buffer in terms of profitability.

6.1.2 Capex

Expected capex in base case is MNOK 27 000. Considering the arguments of Emhjellen, Emhjellen and Osmundsen (2002) described in section 2.1.3, where the probability of a cost overrun should be considered higher than the probability of a cost under run, base case +30 % is used as pessimistic case and base case -10 % is used as optimistic case. This results in a pessimistic case of MNOK 35100 and an optimistic case of MNOK 24300.

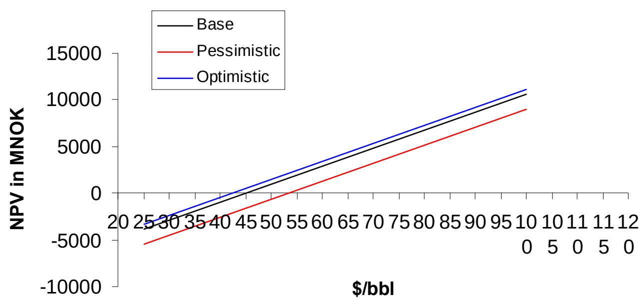

Figure 12: Sensitivity analysis: NPV profile with different capex

The pessimistic case is profitable with an oil price of $53, 37 or higher. The optimistic case requires an oil price of $42, 5 or higher (Appendix 3). Especially the optimistic case should receive attention. A cost reduction of 10 % lowers the risk of Goliat. As already mentioned, the cost level on the NCS has increased rapidly during the latest years of high activity. Oil companies are now focusing on this problem, and are active in negotiating lower prices from suppliers. If Eni Norge can manage to reduce the capex of Goliat by 10 percent, there is a high probability that the project turns out profitable. The analysis also point to the fact that a cost overrun of 30 % makes the project come close to break even considering the oil price levels we face today.

6.1.3 Opex

Expected opex in base case is MNOK 950. Using the same principles as described above, base case +30 % is used as pessimistic case, and base case -10 % is used as optimistic case. This results in a pessimistic case of MNOK 1235 and an optimistic case of MNOK 855.

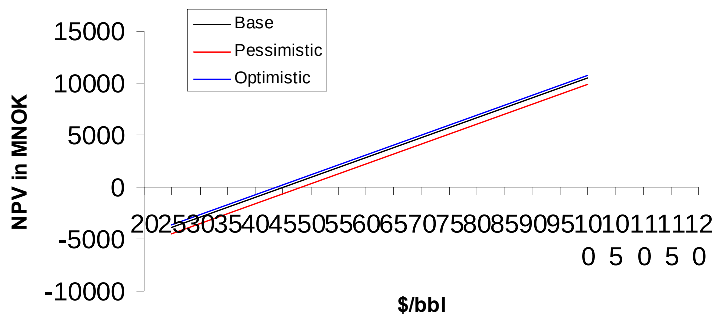

Figure 13: Sensitivity analysis: NPV profile with different opex

The pessimistic case is profitable with an oil price of $48, 5 or higher (Appendix 4). The optimistic case requires an oil price of $44, 12 or higher. The uncertainty of the opex does not highly affect the NPV of Goliat. This is confirmed by the low distance between the different lines in figure 13.

6.2 Scenario Analysis

In addition to base case, five other possible scenarios that can be realized during the lifetime of the project are used to perform a scenario analysis. In contrast to sensitivity analysis where only one variable is changed at a time, the idea of the scenario analysis is to change many variables at a time. In contrast to the sensitivity analysis, an average oil and gas price is assumed. Variables are assumed to be correlated. As an example, a high oil price affects the activity in the industry and results in higher costs, and vice versa. The assumptions are made by the author, and have no connection to real life. The next sections briefly describe the various scenarios considered. Section 6.2.5 summarizes the scenarios with corresponding NPVs. The calculations can be found in appendix 5-10.

6.2.1 Delay

The delay scenario involves start of production in 2015 instead of 2013. The development of Goliat takes more time than expected, and turns out to be more expensive than estimated. This may be a consequence of technological challenges, environmental issues, politics or other unknown factors. The other variables in the analysis are assumed to have the same values as in base case.

6.2.2 Low production

The low production scenario has a lower total amount of extractable reserves and consequently lower production rates than estimated. This may be a consequence of miscalculations of extractable reserves, technological challenges or other unknown factors. The other variables in the analysis are assumed to have the same values as in base case.

6.2.3 High production

The high production scenario has a higher total amount of extractable reserves and consequently higher production rates than estimated. This may be a consequence of miscalculations of extractable reserves, improvements in technology, new discoveries or other unknown factors. The other variables in the analysis are assumed to have the same values as in base case.

6.2.4 Low oil price levels

The low oil price level scenario realizes an average oil price of $30/bbl during the lifetime of the project. This lowers the activity in the industry, and result in lower opex and capex. The other variables in the analysis are assumed to have the same values as in base case.

6.2.5 High oil price levels

The high oil price level scenario realizes an average oil price of $80/bbl during the lifetime of the project. This increases the activity in the industry, and result in higher opex and capex. The other variables in the analysis are assumed to have the same values as in base case.

6.2.6 Summary of Scenario analysis

	DELAY	LOW PRODUCTION	HIGH PRODUCTION	BASE CASE	LOW OIL PRICE	HIGH OIL PRICE
Oil price $/bbl	55	55	55	55	30	80
Gas price NOK/sm3	0,7	0,7	0,7	0,7	0,15	1,25
Production oil	Base	Pessimistic	Optimistic	Base	Base	Base
Production gas	Base	Pessimistic	Optimistic	Base	Base	Base
Capex MNOK	35000	27000	27000	27000	25000	32000
Opex MNOK	950	950	950	950	800	1200
NPV MNOK	**- 892**	**-1509**	**3755**	**1887**	**-2599**	**151**

Figure 14: Summary of scenario analysis using 7% discount rate

The scenario analysis reveals that the profitability of Goliat is very sensitive to oil price levels and production rates, creating both a big upside potential and a down side potential in terms of profitability. The analysis also shows that Eni Norge should have strong focus on avoiding delays and cost overruns. The conclusion of the analysis should be that various scenarios have the ability to affect the profitability of the project, both upwards and downwards. This represents risk and uncertainty.

6.3 Monte Carlo Simulation

The following sections show a Monte Carlo simulation performed on the basis of the cash flow model used in the sensitivity analysis and the scenario analysis. The most difficult part in this process is to come up with suitable probability distributions for the different variables involved. A triangular distribution is used, supporting the principles of simplicity and the possibility of incorporating subjective beliefs about the variables involved. The analysis is performed using Microsoft Excel and the software Risk Solver created by Frontline Systems.[17] The following sections explain the assumptions of the model. Section 6.3.5 summarizes the findings.

6.3.1 Oil and Gas price levels

A triangular distribution with a likely average oil price of $55/bbl is assumed throughout the lifetime of the project. An average oil price of $20/bbl. and $80/bbl. is assumed to be minimum and maximum respectively. According to the triangular distribution this results in a mean of $51, 67/bbl. As described in section 5.3.2, the same relative distribution is used on average gas price levels. According to the software, the triangular distribution is rarely an accurate representation of a dataset, but may be used when little or no data is available. Considering the difficulty of predicting oil price levels and the possibility of mean reversion, the triangular distribution gives users the possibility of choosing a level they think is realistic, and in addition adding an expected minimum and maximum level. In my opinion, the triangular distribution seems better suited than other statistical distributions. The distribution takes the following form:

[17] http://www.solver.com/risksolver.htm

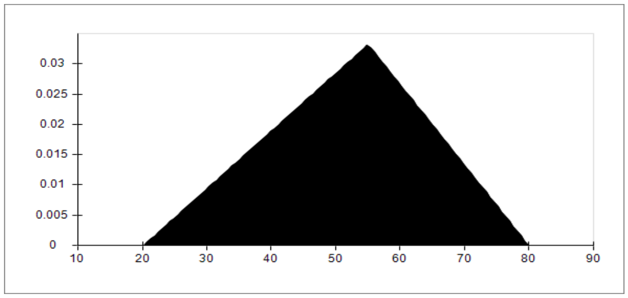

Figure 15: Triangular distribution of oil price used in Monte Carlo simulation

6.3.2 Extractable reserves and Production rates

The same triangular distribution is used to model total amount of extractable reserves and consequently production rates. The same relative production profile used in the base case is assumed, but total extractable reserves are subject to change according to the triangular distribution. 27, 5 Msm^3 is used as likely, 18, 2 Msm^3 as minimum and 32, 6 Msm^3 as maximum. According to the triangular distribution this results in a mean of 26, 1 Msm^3. The production of oil and gas is assumed to be perfectly correlated, meaning that a 10% increase in extractable oil reserves is followed by a 10% increase in extractable gas reserves. The distribution takes the following form:

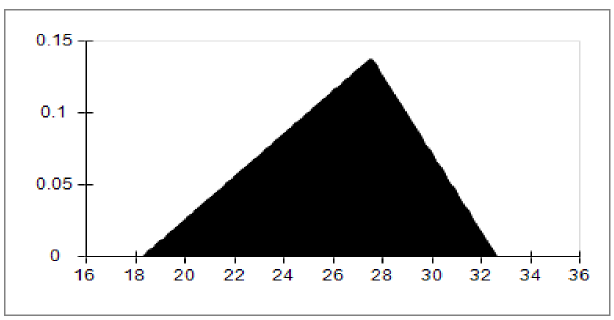

Figure 16: Triangular distribution of extractable reserves used in Monte Carlo simulation

6.3.3 Capex

MNOK 27 000 is used as likely, MNOK 24 300 as minimum and MNOK 35 100 as maximum. According to the triangular distribution this results in a mean of MNOK 28 800. This is in line with the figures used in the sensitivity analysis, supporting the probability of a cost over run being higher than the probability of a cost under run. The distribution takes the following form:

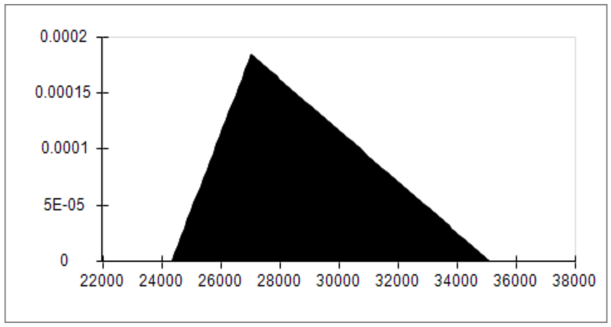

Figure 17: Triangular distribution of capex used in Monte Carlo simulation

6.3.4 Opex

MNOK 950 is used as likely, MNOK 855 as minimum and MNOK 1235 as maximum. According to the triangular distribution this results in a mean of MNOK 1013. This is in line with the figures used in the sensitivity analysis, supporting the probability of a cost over run being higher than the probability of a cost under run. In addition, the opex has been correlated with the level of the oil price. A correlation of 0, 7 is used, meaning that an increase in oil price levels increases the activity in the industry, creating a higher probability of higher opex. The distribution takes the following form:

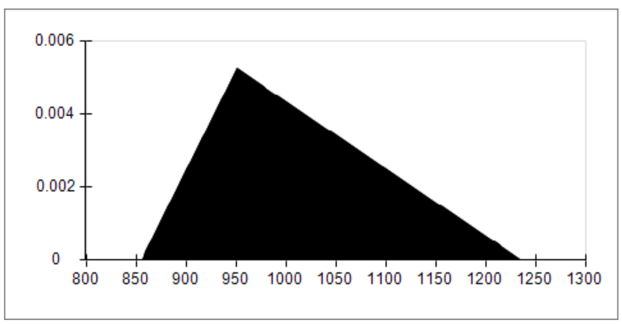

Figure 18: Triangular distribution of opex used in Monte Carlo simulation

6.3.5 Summary of Monte Carlo Simulation

The model consists of four uncertain variables, modelled according to the distributions described above. In each simulation the model picks different values of the different variables and delivers an output in the form of a NPV. 2000 simulations are done, and the average NPV of these simulations should represent the true expected NPV of the project. The expected NPV of Goliat differs each time the Monte Carlo simulation is done, but never turns out far from MNOK 280. This means that according to the Monte Carlo simulation the expected NPV of Goliat is approximately MNOK 280. Figure 19 shows the total distribution of possible outcomes. The distribution shows that worst case realizes a negative NPV of approximately MNOK -6000. Best case realizes a project NPV of approximately MNOK

7000. Further on, the distribution shows that there is a 55 % probability of a positive NPV, and a 45 % probability of a negative NPV.

Eni Norge should identify the most important factors that may make Goliat an unprofitable project, and make an effort in reducing the uncertainty of these factors. The aim should be to realize an as high probability of a profitable project as possible.

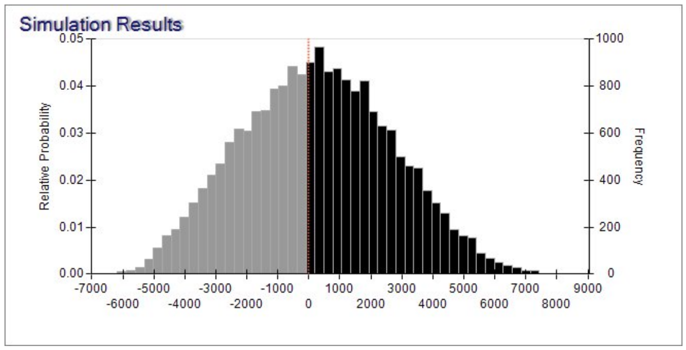

Figure 19: Range of NPV outcomes in Monte Carlo simulation

Figure 20 shows the scatter plots of the simulation. The upper boxes show oil price levels on the left, and opex to the right. The lower boxes show capex to the left and total extractable reserves of oil to the right. The upper boxes show that oil price levels and opex are correlated, while the lower boxes with capex and total amount of extractable reserves are dispersed. Appendix 11 shows the excel spreadsheet from the simulation, and appendix 12 shows a complete simulation report generated from the software.

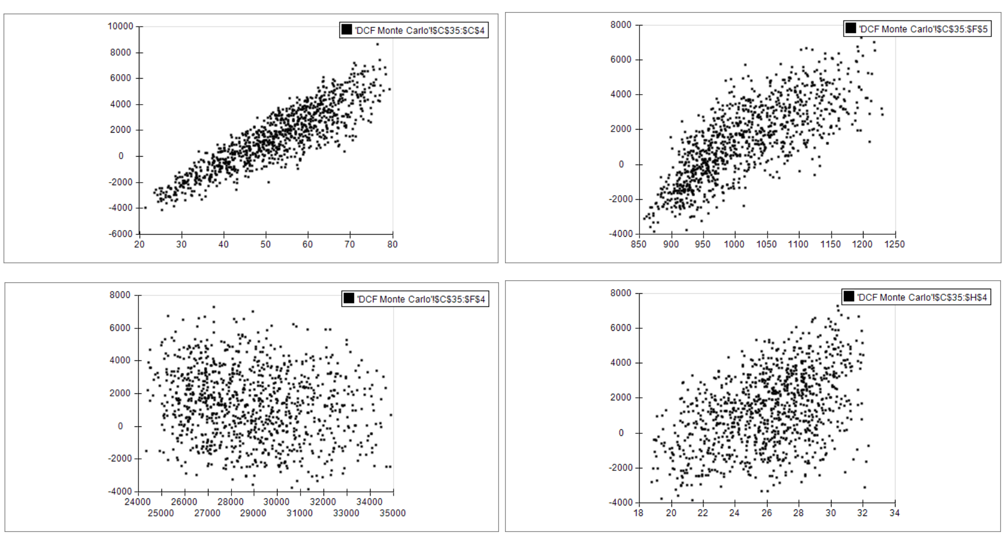

Figure 20: Scatter plots of variables in the Monte Carlo simulation.

7.0 Valuation under uncertainty using Real Options

The real option valuation is based on the three main real options described in section 4.3.2. The valuation is performed using the CRR model described in section 4.3.1. Section 7.1.1-7.1.5 explain some general assumptions. The valuation is performed in section 7.2-7.4. The specific assumptions regarding the three different real options are explained in the sections of the given valuations.

7.1 General Assumptions

7.1.1 Oil Price and Volatility

The starting point of the oil price level is assumed to be $55/bbl. The oil price is treated as a stochastic variable, moving up and down according to a multiplicative binomial process and an annual standard deviation. An annual standard deviation of 20 % is used in the analysis. According to Lund (1999) the volatility of the oil price level reported in the literature is typically in the range between 15 % and 25 %, depending on the time period considered. Laine (1997) reports that volatility estimates presented in literature range between 10 % and 23 %, depending on the time period considered. The choice of 20 % lies within both these ranges. In order to stop the development of what may seem like unrealistic oil price levels, a lower price band of $25/bbl and an upper price band of $110/bbl are assumed.

According to option theory, the volatility of the stochastic variable represents value. With regard to stocks, the higher the volatility of the stock, the higher the value of the option. This is a result of the payoff structure of the option. The holder of the option can only lose the amount paid for the option, meaning that the downside is limited. The upside, however, has no limitations and can be considered higher as the volatility of the stock increases. The introduction of an upper and lower price band affects the volatility of the oil price, and may affect the optimal investing strategy derived from the real option valuation. Decision makers that use real option valuation in decision making processes should be aware of this issue.

7.1.2 Length of Binomial Period

Each year is divided into two periods. This means that values of the oil price and corresponding project values are given every half year. Finding the correct length of binomial period is connected to uncertainty and difficulty. Theoretically, the choice should be influenced by decision making processes in the company evaluating the investment. Decisions about large investments are normally not taken on a day to day basis and require meetings, information gathering and decision processes. Further on, the choice of the length of the binomial period also affects the complexity of the analysis. Shorter and shorter time periods make the size of binomial trees increase rapidly. This affects the practical application of the analysis.

7.1.3 Risk Free Rate

A risk free rate of 2 % is assumed. This is in line with the key policy rate set by Norges Bank on the 26th of March 2009.[18]

7.1.4 Net Convenience Yield

The term convenience yield relates to the advantage of holding an underlying product or physical good rather than the contract or derivative product.[19] According to Laine (1997), the net convenience yield is positive if the value of holding an inventory exceeds storage costs. For instance, if oil price levels suddenly start to rise, the value of a developed Goliat would be more profitable than just holding the option to develop Goliat. According to the analogies between financial and real options, the net convenience yield can be related to dividends on stock. In contrast to a holder of a stock, the holder of an option on a stock is not entitled to dividends. Eni Norge holds an option to develop Goliat. As long as the option is not exercised, the company must incorporate the cost of not receiving net convenience yield when calculating optimal exercise strategies. According to the "pseudo-probability" formula (24), the lower the net convenience yield, the lower the cost of holding an option. The convenience yield can be measured from market information by various methods. In his paper, Laine (1997) reports that research have shown that the rate of net convenience yield in many occasions should equal the risk free rate. The same principle is used in this analysis, meaning that a net convenience yield equal to the risk free rate of return of 2 % is assumed.

7.1.5 Cash Flow Model

The cash flow model used in the dcf-analysis is also applied in the real option valuation. However, the inputs are changed according to the different assumptions taken in the different real options considered.

[18] www.norges-bank.no
[19] http://www.investopedia.com/terms/c/convenienceyield.asp

7.2 The Timing Option

The timing option, or wait and see option, can be viewed as a call option to develop Goliat. Eni Norge has the right, but not the obligation to develop Goliat. If market conditions suddenly get worse, it may be in the interest of Eni Norge to not develop Goliat until market conditions get better.

As mentioned in section 5.2, Eni Norge has submitted the PDO for Goliat. This has not yet been approved. The PDO is assumed approved, giving Eni Norge the possibility to wait and see six years before a final decision about development has to be made. The assumption of six years has no link to real life, and is chosen randomly for simplicity and convenience. Each year is divided into two periods, resulting in a total number of 12 periods where decisions about development or waiting are to be made.

The analysis contains three binomial trees (Appendix 13). The upper tree models the development of the oil price. The tree in the middle reports corresponding project values given the different oil price levels. These values are found with the help of the CRR formula, valuing the project on the base of the possibility of an increase and a decrease in oil price levels, and the time value of money. The analysis assumes that the oil price moves up and down until a decision about development is made. From the point of time where a decision of development is made, the level of the oil price is assumed to be constant throughout the lifetime of the project. The lower tree reports the optimal strategy given the assumptions already described. The expected payoff of waiting or developing is the base of decision. If the expected value of waiting is higher than the expected value of developing the project now, the tree reports wait, and vice versa.

The analysis shows that Eni Norge should not develop Goliat until the oil price reaches the upper price band of $110/bbl. The possibility of this occurring increases the value of the project at time 0 compared to the traditional dcf-analysis. A traditional dcf-analysis using the risk free rate of 2 % as discount rate, gives an expected Goliat NPV of MNOK 4774, 9[20]. The real option valuation gives an expected Goliat NPV of MNOK 5947, 6. When the option expires, the company should undertake the project as long as the expected NPV is positive. In the dcf-analysis, the decision rule is to undertake the investment as long as NPV is positive.

[20] The use of the risk free rate as discount rate in the dcf-analysis when comparing expected NPVs from dcf-analysis with real options is in line with the methodology used in Zettl (2002).

The real option analysis shows that the company should wait, even though the NPV is positive at time 0. The value of the option gets bigger as the oil price gets closer to the upper price band. This is in line with the development of the value of a call option, which is most valuable when underlying variables are developing favourably. The findings are summarized in figure 21.

TIMING OPTION	Real Option	DCF-Analysis	Difference
NPV in MNOK at time 0	5947,6	4774,9	1172,7
Year of first exercise	2,5	0	2,5
Oil Price Level at first exercise	110	55	55

Figure 21: Summary of timing option

7.3 The Option to Expand

Like the timing option, the option to expand can be viewed as a call option. Eni Norge has the right and option, but not an obligation, to expand the project. Goliat is the first planned oil field development in the Barents Sea. The project has the potential to serve as a milestone, opening up further geographic areas for petroleum activity in the northern parts of the NCS. Further exploration in areas close to Goliat, Snøhvit and the rest of the Barents Sea may discover new petroleum resources. This can lead to expansion of already developed Goliat facilities in order to take advantage of already developed infrastructure.

In order to keep assumptions and the analysis applicable, the real option to expand in the analysis assumes that Eni Norge has the possibility to expand production by further investments. It is assumed that surveys show that more production wells than initially planned will generate higher production from already proven petroleum reserves. Eni Norge can expand Goliat by investing MNOK 10 000 in order to achieve the production of additional 4, 2 Msm^3 of oil and 1221 Msm^3 of gas. The expansion project has a lifetime of ten years, and will generate fixed opex of MNOK 190 each year. The investments are undertaken throughout one year. The expansion project will generate liquidation costs of additional MNOK 2000 compared to the original project. Because of the characteristics of the reservoir and the lifetime of the original project, the option to expand expires after six years. For reasons of simplicity, opex, capex and liquidation costs are all assumed to be fixed, and not subject to inflation. The assumptions described above have no link to real life, and are chosen randomly for simplicity and convenience.

The structure of the analysis is the same as in the timing option, consisting of three binomial trees (Appendix 14). The analysis shows that Eni Norge should not expand the project until oil price levels reach the upper price band of $110/bbl. As the option moves closer to the expiration date, the requirement of the oil price level gets lower. At the expiration date, Eni Norge should expand the project if the NPV of the expansion is positive. This is the case when the oil price is above $71, 6/bbl. At time 0, the option to expand generates a higher project NPV compared to the traditional dcf-analysis. The value of the option gets bigger as the underlying variable, the oil price, is developing favourably. The findings are summarized in figure 22.

EXPAND OPTION	Real Option	DCF-Analysis	Difference
NPV in MNOK at time 0	6213	4774,9	1438,1
Year of first exercise	2,5	x	x
Oil Price Level at first exercise	110	x	x

Figure 22: Summary of expand option

7.4 The Abandonment Option

The option to abandon a project can be viewed as a put option. This means that the holder of the option has the right, but not the obligation to sell the underlying variable. In the case of Goliat, an option to abandon involves that the company has a possibility to shut down the project if oil prices move in the wrong direction. Instead of completing the project with unprofitable oil price levels, the company can shut down the project if expected economical consequences show that the project is more worth dead than alive.

It is assumed that Eni Norge has the possibility of receiving MNOK 800 if they decide to shut down the project within six years. This amount relates to the market value of facilities and equipment that can be realized if the project is shut down. The analysis assumes that the initial project is undertaken in year 0. The project value will change as the oil price level move up and down. The assumptions of MNOK 800 and six years have no link to real life, and are chosen randomly for simplicity and convenience.

The structure of the analysis is slightly different from the structure of the timing option and the option to expand (Appendix 15). The first binomial tree in the analysis shows the development of the oil price. The second tree shows the value of the project as the project and the oil price moves forward. Each node shows the value of the project assuming that the oil price has moved up and/or down in the binomial tree in order to end up in the specific node, and that the remaining periods of the project will realize an oil price equal to the oil price at the corresponding node in the oil price development binomial tree. The next tree shows the value of the option given by the CRR formula. The last tree shows the optimal strategy given the assumptions above. Eni Norge should go on with the project if the expected value of continuing is higher than abandoning the project and receving MNOK 800.

The analysis shows that Eni Norge should abandon the project on the date of expiration if the oil price is lower than approximately $44/bbl. The option to abandon is not very valuable at year 0, but increases in line with a put option as the value of the underlying variable moves in an unfavorable direction. As the oil price moves up, the value of the option to abandon gets lower. An important reason for this finding is the production profile of the project. A large fraction of total reserves are extracted during the first years of production. The characteristics of the formulas and the binomial tree modeling the oil price does not allow the oil price level to decrease to very low levels during the first years of production. This ensures that a large fraction of the reserves are sold at a relative high oil price and reduces the probability of a profitable abandonment option. The findings are summarized in figure 23.

ABANDONMENT OPTION	Real Option	DCF-Analysis	Difference
NPV in MNOK at time 0	4841,44[21]	4774,9	67,24
Year of first exercise	6	X	X
Oil Price Level at first exercise	<44	X	X

Figure 23: Summary of abandonment Option

[21] Real option value is obtained from value of project without option + option value: 4774,2+67,24=4841,44

8.0 Discussion

In order to answer the problem statement and the related questions, the findings of the case analysis should be summarized and discussed. Decisions about oil and gas field developments should be based on decision making tools. The quality of a decision can be related to the quality of the decision making tool. The three questions outlined in connection with the problem statement deal with assumptions, practical challenges and uncertainty related to traditional dcf-analysis and real options. Being aware of characteristics of valuation methods both in theory and practice should help decision makers to understand the quality of the output and possible drawbacks of the method. The findings of the case analysis are related to research described in the theory chapters of the thesis. It should be mentioned that some of the issues related to the three questions overlap each other. Such issues will be handled in the section considered most fitted.

8.1 Which assumptions is dcf-analysis and the real option framework based on?

8.1.1 Cash Flow Model

The same cash flow model has been used to generate cash flows for both the traditional dcf-analysis and the real option framework. The model consists of capex, opex, production rates, oil and gas price levels and taxation rules. The model generates free cash flows each year throughout the lifetime of the project. The cash flows are discounted by a discount rate of 7 % in the traditional analysis and by a risk free rate of 2 % in the real option analysis. An important assumption of the model is that the company takes advantage of depreciation and tax reliefs the year they occur. This means that Eni Norge is assumed to be in tax position and able to deduct expenses occurred on Goliat from taxes paid on other projects. Both the traditional dcf-analysis and the real option framework can be viewed as cash flow models. Both models need cash flows in order to generate NPVs. The cash flow model is in line with traditional cash flow analysis, and should be a representative model for cash flow analysis related to oil field development projects on the NCS.

8.1.2 Subjectivity vs. Objectivity

One important difference between dcf-analysis and real options is the way underlying variables are modeled. The level of the oil price serves as a perfect example. The real option framework models different oil price scenarios with the help of formula (24) and (25). This approach can be characterized as objective, as the features of the formulas and the inputs determine the path of the oil price. In contrast, the dcf-analysis depends on a subjective input about the expected level of the oil price. Some oil price level must be chosen as input in the cash flow model. This input may be a result of statistics and /or beliefs about the future level of the oil price.

The dcf-analysis in the case study assumes a constant average oil price during the lifetime of the project. Unless the company is able to completely hedge oil price risk, the company will experience different levels of oil price. In other words, this assumption can be considered as wrong, and represents a drawback of the dcf-analysis. It would be possible to incorporate an oil price subject to changes throughout the lifetime of the project. This would, however, not serve as an improvement of the dcf-analysis. The assumption of an average oil price is easy to interpret and communicate. It also simplifies calculations. In addition, it is equally difficult to predict a changing oil price and an average oil price. The average oil price required to realize a positive net present value should be identified, as it serves as an intuitive and easily communicated decision input.

As mentioned, instead of predicting the future oil price and assuming a constant average oil price, the real option framework aims to model different oil price scenarios. The real option analysis undertaken in the case study assumes a constant oil price level after a decision about exercising different options is made. This means that the oil price will move up and down until a decision is made, and is thereafter assumed to be at the same level as at the point of time where the decision is made. The main reason behind this assumption is the complexity of calculating different project values according to a changing oil price level after a decision about development is made. In real life, the oil price will continue to fluctuate after a decision is made, and the assumption about constant oil price after exercising an option should therefore be considered as a drawback. The magnitude of this drawback may not be substantial. A decision about development of Goliat, independently of valuation method, is based on expected project value. It can be argued that the path of the oil price after a development decision is irrelevant. This is in line with the decision structure assumption taken in the dcf-analysis. It is also in line with the timing option and the option to expand, as the expected values of the options are realized when actions are taken and the actions are considered irreversible. It conflicts with the abandonment option, as this option assumes development of Goliat and the value of the option relates directly to the development of the oil price after a decision about development is made. This feature is handled with a different analysis structure compared to the timing and the expand option (section 7.4).

The modeling of underlying variables is not only related to the level of the oil price. All variables, including capex, opex, inflation and total oil reserves, can be modeled objectively or subjectively. The real option valuation of Goliat considers the oil price as the only stochastic variable. This is a large simplification, as the value of the project also depends on the variables mentioned above. This brings up the question whether the real option valuation should treat all variables affecting project value as stochastic variables. This would make the valuation more realistic, but far more complex. A problem in the process of modeling stochastic variables according to a multiplicative binomial process is to determine the volatility of the underlying variable. Again, the level of the oil price may serve as an example. The volatility of the oil price is an important input in formula (25), which is used to determine the size of up and down movements in the oil price. As mentioned in section 7.1.1, literature operates with an annual oil price volatility range between 10 % and 25 %. The extent of this range has the ability to create very different oil price paths, resulting in very different project NPVs.

These insights can also be related to the net convenience yield. Net convenience yield can be measured by different methods, and results are highly affected by the chosen measurement period. The volatility of the oil price changes constantly, and can be considered as equal difficult to predict as the oil price level itself. Estimation of oil price volatility can be based on historical data. Historical data of opex, capex and total extractable oil reserves for a specific project does not exist. This further complicates the process of modeling variables with a multiplicative binomial process. The quality of the model is only as good as the quality of the inputs and the assumptions taken. Making decisions on the grounds of real option valuation requires trust in assumptions made about the volatility of underlying variables.

Another issue related to oil price levels is the combination of volatility and the length of the binomial periods. Different combinations may create oil price levels that can be characterized as unrealistic values. The case study takes this into consideration by introducing an upper and lower oil price band, meaning that the oil price can not fall below \$25/bbl and can not rise above \$110/bbl. This consideration conflicts with the main idea behind option valuation, as uncertainty and unlimited upside potential are factors that represent option value. The introduction of an oil price band also incorporates subjective prediction into the real option framework. This can be categorized as a drawback, as one of the main ideas behind oil price modeling should be to leave out subjective beliefs about oil price development.

8.1.3 Decision Structure

The decision structure assumed in traditional dcf-analysis and real options represents a big difference between the two methods. Dcf-analysis assumes a now or never decision. If the project is undertaken, the project will go on no matter how market conditions or other relevant factors develop. The method assumes that companies have no possibility or option to change the direction of projects as circumstances change.

In contrast, real options assume that companies can change projects as time goes by. It is assumed that companies have both the ability and possibility to wait, expand or abandon projects. This issue is widely recognized in the academic literature, and is seen as one of the most important differences between traditional dcf-analysis and real options. It is also believed that the ability of real options to model strategic flexibility represents the main advantage compared to traditional dcf-analysis. The ability and possibility to change the direction of a project clearly have value. It is no doubt that the option to wait, expand or abandon are real life options that need to be considered. Dcf-analysis, in its traditional form, is not capable of modeling these options. The question still remains whether the real options framework is capable of doing it. The academic literature seems to a large extent to agree in the logic behind the real option framework. However, there seem to be much debate, discussion and disagreement about different real option models and the right way to apply the logic. In my opinion, the now or never assumption is a drawback compared to the real option framework. Investment decisions in the petroleum industry, especially development projects, are seldom now or never, and contain flexibility and real options.

8.1.4 Decision Rule

Closely connected to the decision structure is the decision rule. The traditional dcf-analysis states that projects should be undertaken as long as expected NPVs are positive. This is in conflict with the decision rule of the real options framework. The timing option from Goliat can be used as an example. The company should compare the expected value of the project undertaken today with the expected value of the decision to wait and see. Even if the project has a positive NPV today, it may be more valuable to wait and see. This is confirmed by the analysis of Goliat. The dcf-analysis states that the project should be undertaken immediately, but the real option analysis states that Eni Norge should wait and see and not develop Goliat until oil price levels reach $110/bbl. The aim of the company should be to maximize shareholder value. Not taking the timing option into consideration would be to not maximize shareholder value. In other words, the real option framework supports the traditional principle of maximizing shareholder value. Comparing traditional dcf-analysis and the real option framework in this perspective makes the real option framework look better suited for decision making.

8.1.5 Discounting

Dcf-analysis and real options use different principles in discounting cash flows. The dcf-analysis use a risk adjusted discount rate consisting of the risk free rate of return plus a risk premium related to the risk of the project. The real option framework discount cash flows using the risk free rate. The case study uses 7 % as risk adjusted discount rate, and 2 % as the risk free rate. The logic of using risk free rate for discounting has its grounds in the principles of risk neutral valuation of financial options. Risk neutral valuation requires the possibility of finding a portfolio and trading strategy that perfectly replicates the project cash flows of Goliat. As described in section 4.5.2, the academic literature has discussed these challenges. It is not in the scope of this thesis to investigate the possibility of replicating the cash flows from Goliat. It is, however, important to be aware of the requirement of the assumption to hold in order to discount the cash flows by the risk free interest rate.

The choice of a 7 % risk adjusted discount rate has its grounds in the guidelines set by the Norwegian Petroleum Directorate (section 5.3.9). It is not in the scope of this thesis to investigate the correctness of this discount rate, but a discussion regarding the importance of this figure is required. According to existing theory, all companies should calculate a discount rate according to the principles described in section 3.2.3. Considering long time horizons in most oil and gas field developments, the choice of discount rate highly affects expected NPVs of projects. The risk adjusted discount rate is connected to many of the drawbacks described in section 3.5.2.

The first of these issues is related to the use of a constant discount rate during the lifetime of projects. Eni Norge expects high production during the first years of production. This makes Goliat dependent of sufficiently high oil price levels during the first years of production. This would ensure the payback of capex, and lower the risk of the project. This leads to the question of whether Eni Norge should use a higher discount rate during the first years of Goliat, and a lower discount rate after production has peaked. This brings us to the drawback of adding a so called "fudge" factor to the discount rate discussed by Hodder and Riggs (1985) and Brealey, Myers and Allen (2006). The main element in the problems mentioned above, and discount rates in general, is the difficulty of choosing a correct discount rate. A too low discount rate may result in companies undertaking unprofitable projects, and a too high discount rate may result in companies not undertaking profitable projects. This problem is especially relevant in the petroleum industry, where cash flows are to be discounted over long time horizons. In other words, the choice of adjusted discount rate has a big potential in affecting decisions about oil and gas field developments. Given that the assumption of a replicating portfolio holds, the real option framework has an advantage compared to dcf-analysis as it discounts cash flows at the risk free interest rate.

8.2 Which practical challenges exist in applying the two methods?

The real option framework has received much academic attention, but does at the moment not look like a real competitor to traditional dcf-analysis. Important reasons for this are practical challenges related to the application of the method. This section discusses the practicability of the two methods on the grounds of experience obtained from the valuation of Goliat. The application of dcf-analysis in its traditional form is relative straightforward, and does not involve any particular practical challenges. As a result, the discussion regarding practical challenges will mostly relate to the real option method. Practical challenges related to evaluation of uncertainty and dcf-analysis is discussed in section 8.3.

8.2.1 Modeling expertise

Modeling and valuation of real options are quite different from traditional dcf-analysis. Dcf-analysis has great traditions and represents the standard of capital budgeting. The methodology of valuing a project by traditional dcf-analysis is widely recognized and well understood. The methodology of real options does not have the same status, and is not widely recognized and not well understood. This insight is supported by Booth (1999), stating that: "Real options are usually more complex still and the modelling expertise involved is substantial". In their paper, Laughton, Sagi and Samis (2002) state that future developments in modern asset pricing (real options) are needed on among other key fronts: More efficient and easily used computational methods; and more and better training and operational tools for implementation of modern asset pricing methods into real organizations.

The real option framework used in the case study of Goliat can be regarded as basic and simple. More technical advanced models exist. Application of state of the art real option modeling and valuation requires a high degree of modeling expertise. This knowledge must be made more accessible through education and training tools. In addition, development of software able to make computational issues easier is necessary. According to Laughton, Sagi and Samis, it took at least 80 years to sort out dcf-analysis and make its use widespread. It is likely to take a shorter, but still significant, time to sort out real options.

8.2.2 Complexity

It is desired to work with as short time periods as possible in the multiplicative binomial process, aiming at reaching a continuous distribution of possible project values. The realism of the stochastic process in real options increases as the length of binomial time periods are made shorter. A drawback of binomial trees is that they grow large and complex as time periods are made shorter. The case study confirms this difficulty. The binomial trees would grow extremely large in order to give the stochastic variable in the case study a continuous distribution.

Modeling and valuing real options requires detailed information about real options involved. This represented a big problem in the case study. The option to expand involves high uncertainty with regard to capex, opex and total amount of extractable reserves. Companies facing an actual or a possible option need detailed information about the characteristics of the option in order to make an accurate and applicable valuation. This information may not be possible to obtain at the time where decisions regarding development are to be made. The option to abandon involves high uncertainty with regard to the market value of facilities and equipment. Due to uncertainty with regards to liquidation and shutting down, it may the case that the option to abandon will generate a negative cash flow. This conflicts with the assumption taken in the case study, where Eni Norge is assumed to realize MNOK 800 due to a sale of facilities and equipment within six years of production. The assumptions regarding the option to expand and abandon has been invented by the author and has no link to real life.

Another practical (and theoretical) challenge involves consideration of option interaction. Three real options have been modeled and valued in the case study of Goliat. The NPVs of the options have been obtained valuing the options individually. An expected project value combining the base case and a real option have been found on the three real options respectively. The analysis does not consider the combined value of the three options. In real life, however, the total expected project NPV should incorporate the value of all possible options. As a consequence, there should be a way of combining the value of all options into one expected project NPV. A possible way of doing this would be to follow the principle of NPV-additivity, and summarize the excessive NPVs from the real options to the base case of the dcf-analysis. This would mean that the value of all real options would be added to the base case. The probability of management to realize all real options in Goliat seem unrealistic. If market conditions are good, the abandonment option will not be realized. If market conditions are bad, the expansion option will not be exercised. As a consequence, not all value related to the real options considered will be realized. This leads to the question about the correctness of incorporating all real option values into one expected project value. It seems that valuations of various individual real options are difficult to incorporate into one combined NPV. A correct real option project valuation would require all possible real options to be considered. This represents both a practical and theoretical challenge that needs more research and investigation.

Another practical challenge involves identifying all possible real options. Goliat may have an unlimited number of real options attached. These options may or may not be known at the point of time when valuation is performed. A valuation should consider all options, not just the option to wait, expand and abandon. Practical challenges of identifying and modeling all possible real options are substantial. In addition, the complexity of the valuation increases as more options are considered.

The practical challenges described above may make decision makers view real option valuation as a black box. The method does not seem developed enough to be a stand alone valuation method for oil and gas field developments. Information obtained from three oil companies supports these findings. The logic seems clear and well understood, but the real option method is not used in practice. In general, the three oil companies explain their reluctance to use real option analysis by better knowledge and traditions of traditional dcf-analysis, and practical challenges related to real options.

8.2.3 Organizational issues

The introduction of a new valuation method is recognized by a cost-benefit trade off. The choice of incorporating a real option framework for valuation requires investments and resources in terms of development of the method, acquirement of software and operational tools and training. Effort should be made in making results and the logic of real options easy to communicate and easy to understand. The aim and benefit of the introduction should be better investment decisions. Companies should analyze the environment they operate in, and the possible costs and benefits of introducing a new valuation method. Considering the already mentioned practical challenges, and the earlier described assumptions that must hold in order to justify a risk free valuation, the real option method may not be ready to be introduced for real life organizations and applications quite yet.

8.3 How do the two methods differ in their ability to handle uncertainty?

As already mentioned, the petroleum industry is recognized by high uncertainty. Various factors characterized by uncertainty make project valuation and evaluation difficult. Good investment decisions require valuation methods capable of handling uncertainty. An important difference between the two methods is the way they discount cash flows. Traditional dcf-analysis use a risk adjusted discount rate and the real option method use the risk free rate. This issue was discussed in section 8.1.5, and will not be handled in this section.

8.3.1 Dcf-analysis

The dcf-analysis in the case study use sensitivity analysis, scenario analysis and Monte Carlo simulation to handle uncertainty. These tools are easy to work with and provide decision makers with important inputs. The sensitivity analysis considers the development of one variable at the time, and produces outputs according to a base case, a pessimistic case and an optimistic case. It gives an impression of the different variables importance on the profitability of the project. The output of the analysis tells us the required average oil price in order to realize a positive NPV. This measure is intuitive and easy to communicate. The analysis use subjective beliefs to determine inputs in the base case, the pessimistic case and the optimistic case. The quality of the analysis depends on the quality of these subjective beliefs. The importance and implication of subjectivity and objectivity is discussed in section 8.1.2.

The scenario analysis considers the development of several uncertain variables at a time. Scenario analysis allows decision makers to consider possible scenarios. It increases the overall understanding of projects and encourages investigation of possible correlations between important variables. In the case study, and in general, the assumptions and beliefs taken are subjective and subject to high uncertainty. Especially the difficulty of estimating correlation between different variables is prevalent. This issue represents a drawback of the scenario analysis.

The case study also performs a Monte Carlo simulation. The biggest challenge in this process is to determine the distribution of the variables involved. The case study uses a triangular distribution in line with the principles of simplicity and subjective beliefs. The triangular distribution consists of three inputs; minimum value, maximum value and likely value. It then draws random values of the variables according to the three inputs in the distribution. The case study considers four variables following a triangular distribution. It simulates 2000 values, and calculates an average project NPV based on the 2000 project values obtained from the simulation. The result of the analysis produces an expected average project NPV of approximately MNOK 280. This should encourage Eni Norge to go on with Goliat. However, the analysis also shows a 45 % probability of a negative project NPV. This should make Eni Norge focus on reducing the risk of variables having high effect on the profitability of the project.

The drawback of the method is the triangular distribution. The result of the simulation is only as good as the quality of the inputs in the distribution. However, the Monte Carlo simulation gives a good impression of possible bad outcomes. It helps identifying possible pit falls and the probability of a positive and negative NPV.

Experience from the case study shows that it is relative easy to incorporate and analyze various variables representing uncertainty with dcf-analysis. The variables can be analyzed both individually and combined. The models applied in the case study are easy to work with and intuitive. The quality of the models relies on the assumptions taken by the persons performing the analysis. All assumptions are subjective, and should be made by experts on different areas involved. This allows incorporation of inputs from various experts from different business areas into one model.

8.3.2 Real options

The real option method handles uncertainty by modeling stochastic variables according to the formulas (23)-(25) and a standard deviation representing volatility. The aim of the process is to achieve an objective development of the variables considered. The case study of Goliat considers the oil price as the only stochastic variable determining the expected project value. In order to incorporate all uncertainty, all uncertain variables affecting the profitability of the project should be treated as stochastic variables and modeled accordingly. Problems and challenges related to this are described in section 8.1.2. These problems make it difficult to consider the uncertainty of many variables. Modeling only one variable is straightforward, but as soon as the number of stochastic variables increases, the complexity of the calculations increases rapidly. Further on, the lack of historical data on specific project capex, opex and extractable petroleum reserves make it difficult to calculate a suitable standard deviation to be used as volatility input in formula (25).

As described earlier, the real option method takes advantage of uncertainty. Uncertainty represents value as it can be used to increase the profitability of projects. This conflicts with the approach taken in the traditional dcf-analysis, where uncertainty is associated with something negative, something that can reduce the profitability of projects. This makes the two methods' underlying view on uncertainty quite different. This difference may have the potential to affect decisions about oil and gas field developments.

8.4 Implications

With regards to the above discussion, possible implications of choosing either traditional dcf-analysis or real options as valuation method for oil and gas field developments should be discussed.

The real option method normally results in a higher expected project NPV compared to the dcf-analysis. This is supported by Dickens and Lohrenz (1996), stating that option valuation leads to greater values than NPV valuations. Hence, option valuation analysis would lead to "accept" decisions more often. This leads to the question about possible dangers of overestimation of NPV and returns. Over estimation of returns may lead to bad investment decisions and development of unprofitable fields. This is connected to the point mentioned by Begg, Bratvold and Campbell (2003). They state that studies show that the oil and gas industry has consistently under performed various market indices like the Dow Jones

Industrial Average and the Standard & Poor 500. Further on, they state that some attribute the under performance to project evaluation and decision-making procedures that result in either a systematic overestimate of returns and/or underestimate of risks. The real option analysis may be both overestimating returns and underestimating risks. Oil and gas field developments are often characterized by high investments. The real option method may not be able to truly treat all possible risks and scenarios related to projects. This may lead to projects realizing bigger abandonment costs and bigger losses than anticipated.

The traditional dcf-analysis does not include management's possibility and ability to change strategic directions of projects. This normally results in a lower expected project NPV compared to the real option method. This leads to the question about the danger of underestimating returns and overestimating risks. The academic literature often claim that not incorporating management flexibility in dcf-analysis leads to underestimation of returns. A possible consequence of this may be that profitable projects with truly low risks are not found profitable when valued by dcf-analysis. This can also be related to the issue of diversification mentioned by Hodder and Riggs in section 3.5.2. A specific project should always be related to the company's overall portfolio of projects. A project may be too risky as a stand alone project, but not too risky as a part of a project portfolio.

The previous sections have discussed issues related to assumptions and practical challenges like modeling expertise and complexity in the application of real options. An implication of this is that the real option method may be too difficult to apply. This is in line with arguments by Copeland and Keenan (1998), stating that option pricing has not been used in the evaluation of corporate investments for three reasons; the idea is relatively new, the mathematics are complex making the results hard to grasp intuitively, and the original techniques required the source of uncertainty to be a traded world commodity such as oil, natural gas or gold. This insight is supported by Brealey, Myers and Allen (2006) stating: "Sometimes an approximate answer now is more useful than a "perfect" answer later, particularly if the perfect answer comes from a complicated model that other managers will regard as a black box".

So far, it seems that real options are connected to several issues that need to be developed and improved in order to make the method viable. However, considering that the method is logical, it should be determined in what kind of projects and environments a viable real option method would be valuable and suitable. In the context of this thesis, the question relates to the suitability of real options to value oil and gas field developments. Copeland and Keenan (1998) have developed a framework for analyzing when flexibility is valuable and when real options should be used. They found that real options are most valuable in situations where uncertainty is high and management can respond flexibly to new information. In addition, real option valuation is most important when projects valued without flexibility are close to breakeven. The logic behind this argument is that projects with very high NPVs will be undertaken anyway. Projects with strongly negative NPVs can probably not be helped with flexibility, and will not be undertaken anyway. The findings of Copeland and Keenan are illustrated in figure 24, and should be discussed with regard to oil and gas field developments.

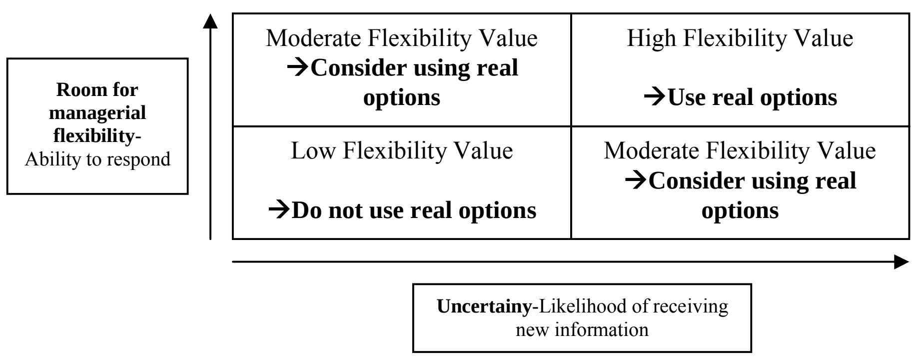

Figure 24: When to use real option valuation

Petroleum projects are with no doubt characterized by high uncertainty. New information about market conditions, extractable petroleum reserves, capex, opex and technology will come by as projects move forward. The issue of managerial flexibility is more unclear. The options of deferring, expanding and abandonment have been described earlier. These options are sound in theory, but the decision structure in these kinds of projects may provide management with limitations. Oil and gas field developments often have many stakeholders. Due to environmental issues in the Barents Sea, decision processes and applications related to real options in the Goliat development may be long and demanding. The Norwegian government, environmental organizations, the local society and other stakeholders may make it hard for Eni Norge to respond to new market conditions and new information related to the development of Goliat. This analysis should locate oil and gas field developments somewhere between the upper and lower box on the right side of figure 24. These kinds of projects have high uncertainty, and to varying degree room for managerial flexibility. A viable real option method should be considered used in valuation of oil and gas field developments.

9.0 Conclusions

An analysis of the upstream petroleum industry, a description of theory related to dcf-analysis and real options and a case study applying the two methods have been performed in order to answer the three questions related to the main problem statement. This section briefly summarizes the answers of the three questions and relates them to the main problem statement.

9.1 Findings

The first question relates to the assumptions behind the two models. The most important differences involve real options using risk neutral valuation and the dcf-analysis using a risk adjusted discount rate. In addition, the dcf-analysis considers a “now or never” decision while real options use a dynamic approach. This results in different treatment of managements’ flexibility and ability to change projects. The last important point involves different decision rules. According to dcf-analysis, projects should be undertaken as long as expected NPVs are positive. A positive NPV is not necessarily enough to undertake a project in the real option method.

The second question relates to practical challenges. Experience from the case study revealed that the real option method is more complex and more difficult to work with. No standard solutions for real option valuation seem to exist in the academic literature, which results in questions and uncertainty regarding calculations and outputs. Dcf-analysis, on the other hand, is well understood and relatively easy to work with.

The last question relates to the methods’ ability to handle uncertainty. Real options treat uncertainty as a consequence of the characteristics of the model. Dcf-analysis use methods like sensitivity analysis, scenario analysis and Monte Carlo simulation to treat uncertainty. The difference of the two methods in treatment of uncertainty can be summarized in real options aiming at using objective methods and dcf-analysis using subjective beliefs in the analysis.

9.2 Conclusions

The conclusion of the thesis is that dcf-analysis and real options do differ as basis for decision making about oil and gas field developments. Important implications are:

- **Real option valuation results in higher expected project values than dcf-analysis, and may lead to unprofitable projects being undertaken.**

- **Dcf-analysis results in lower expected project values than real option valuation, and may lead to profitable projects not being undertaken.**

- **Real option valuation does not seem sufficiently developed with regard to practical challenges and standardization to overcome the drawbacks of dcf-analysis.**

- **Given that a viable real option framework is developed, real options should be considered for valuation of oil and gas field developments.**

9.3 Future research

The conclusions of the thesis lead to several issues that should be further investigated in order to develop a viable real option valuation method that could lead to better investment decisions. First of all, the practical challenges mentioned in section 8.2 should receive more attention. Efforts should be made in developing a standard methodology for real option calculations. A standard framework would make it easier to transfer real option valuation from being an academic logic theory to become a sensible applied real life valuation method. A standard model would make it easier to communicate methodology and outputs. This would make it easier for companies and educational institutions to use the real option framework. These issues are closely connected to the issues of software development and training tools. In order to make the use of real option valuation easier, software models that overcomes the practical challenges described and experienced in the case study should be developed.

When it comes to dcf-analysis, future research should focus on the methods ability to handle management flexibility. Flexibility represents value, and not incorporating this value into the analysis represents one of the main drawbacks of dcf-analysis. This insight leads to the fact that it should be advantageous to use both valuation methods. Using both models would increase the understanding of projects, and probably improve investment decision making. Development of a hybrid, or methods of combining the two methods, may contribute in better decision making.

Appendices

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Appendix 1: Valuation Base Case

ASSUMPTIONS BASE CASE

Oil Price $/bbl - NOK	45,22	293,93
Gas Price NOK/sm3		0,486618182
CAPEX MNOK		27000
OPEX MNOK		950
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (M/bbl)					11,322	33,97	27,68	21,39	15,73	11,95	8,81	7,55	6,29	5,66	5,03	4,4	3,77	3,15	3,15	3,15	0	0	0	173
	Gas production (Msm3)					523,64	1571	1280	989,1	727,3	552,7	407	349	291	262	233	204	175	145	145	145	0	0	0	8000
	Oil price NOK		293,93	294	293,9	293,93	293,9	293,9	293,9	293,9	293,9	294	294	294	294	294	294	294	294	294	294	293,9	293,9	293,9	
	Gas price NOK		0,486618182	0,49	0,487	0,4866	0,487	0,487	0,487	0,487	0,487	0,49	0,49	0,49	0,49	0,49	0,49	0,49	0,49	0,49	0,49	0,487	0,487	0,487	
	Revenue Oil MNOK					3327,9	9984	8135	6286	4622	3513	2588	2219	1849	1664	1479	1294	1109	924	924	924	0	0	0	
	Revenue Gas MNOK					254,81	764,4	622,9	481,3	353,9	269	198	170	142	127	113	99,1	84,9	70,8	70,8	70,8	0	0	0	
	Total Revenue MNOK					**3582,7**	**10748**	**8758**	**6767**	**4976**	**3782**	**2787**	**2388**	**1990**	**1791**	**1592**	**1393**	**1194**	**995**	**995**	**995**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-1867,3	5279	3269	1759	947,6	1400	1717	1297	877	656	434	212	-10,6	-234	-258	-283	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-522,85**	**1478**	**915,4**	**492,6**	**265,3**	**391,9**	**481**	**363**	**246**	**184**	**122**	**59,4**	**-2,97**	**-65,4**	**-72,3**	**-79,3**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-3892,3	3479	1919	1159	947,6	1400	1717	1297	877	656	434	212	-10,6	-234	-258	-283	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-1946,2**	**1740**	**959,6**	**579,6**	**473,8**	**699,8**	**858**	**649**	**439**	**328**	**217**	**106**	**-5,3**	**-117**	**-129**	**-142**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-2469	3218	1875	1072	739,2	1092	1339	1012	684	512	339	165	-8,27	-182	-201	-221	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-2825,8**	**374,3**	**2546**	**1474**	**905,6**	**915,4**	**1215**	**1175**	**848**	**598**	**425**	**252**	**78,6**	**-95,3**	**-192**	**-211**	**-646**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-2541,6**	**9405**	**5223**	**4286**	**3042**	**1817**	**501**	**122**	**29,2**	**58**	**9,06**	**-40**	**-89,2**	**-138**	**-66,4**	**-72,1**	**-727**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**1,825830564**

Appendix 2: Sensitivity Analysis: Extractable reserves, Optimistic Case

ASSUMPTIONS OPTIMISTIC CASE

Oil Price $/bbl - NOK	38,62	251,03
Gas Price NOK/sm3		0,342618182
CAPEX MNOK		27000
OPEX MNOK		950
Oil prod. Msm3		32,6
Gas prod. Msm3		9500
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					13,422	40,27	32,81	25,35	18,64	14,17	10,4	8,95	7,46	6,71	5,97	5,22	4,47	3,73	3,73	3,73	0	0	0	**205,1**
	Gas production (Msm3)					621,82	1865	1520	1175	863,6	656,4	484	415	345	311	276	242	207	173	173	173	0	0	0	**9500**
	Oil price NOK		251,03	251	251	251,03	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	
	Gas price NOK		0,342618182	0,34	0,343	0,3426	0,343	0,343	0,343	0,343	0,343	0,34	0,34	0,34	0,34	0,34	0,34	0,34	0,34	0,34	0,34	0,343	0,343	0,343	
	Revenue Oil MNOK					3369,3	10108	8236	6364	4680	3556	2621	2246	1872	1685	1497	1310	1123	936	936	936	0	0	0	
	Revenue Gas MNOK					213,05	639,1	520,8	402,4	295,9	224,9	166	142	118	107	94,7	82,9	71	59,2	59,2	59,2	0	0	0	
	Total Revenue MNOK					**3582,3**	**10747**	**8757**	**6767**	**4975**	**3781**	**2786**	**2388**	**1990**	**1791**	**1592**	**1393**	**1194**	**995**	**995**	**995**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-1867,7	5278	3268	1758	947,1	1399	1716	1297	877	656	434	212	-10,7	-234	-258	-283	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-522,96**	**1478**	**915,1**	**492,4**	**265,2**	**391,7**	**481**	**363**	**246**	**184**	**122**	**59,3**	**-3**	**-65,5**	**-72,4**	**-79,4**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-3892,7	3478	1918	1158	947,1	1399	1716	1297	877	656	434	212	-10,7	-234	-258	-283	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-1946,4**	**1739**	**959,2**	**579,2**	**473,6**	**699,6**	**858**	**648**	**439**	**328**	**217**	**106**	**-5,36**	**-117**	**-129**	**-142**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-2469,3	3217	1874	1072	738,7	1091	1339	1012	684	512	339	165	-8,37	-182	-202	-221	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-2825,9**	**373,7**	**2546**	**1473**	**905,2**	**915**	**1215**	**1175**	**848**	**598**	**425**	**252**	**78,5**	**-95,4**	**-192**	**-211**	**-646**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-2541,8**	**9404**	**5223**	**4285**	**3042**	**1817**	**501**	**122**	**29,2**	**58**	**9,03**	**-40**	**-89,2**	**-138**	**-66,4**	**-72,1**	**-727**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**0,948809072**

Appendix 3: Sensitivity Analysis: Capex, Optimistic Case

ASSUMPTIONS OPTIMISTIC CASE

Oil Price $/bbl - NOK	42,5	276,25
Gas Price NOK/sm3		0,427272727
CAPEX MNOK		24300
OPEX MNOK		950
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenue	Oil production (Mbbl)					11,322	33,97	27,68	21,39	15,73	11,95	8,81	7,55
	Gas production (Msm3)					523,64	1571	1280	989,1	727,3	552,7	407	349
	Oil price NOK		276,25	276	276,3	276,25	276,3	276,3	276,3	276,3	276,3	276	276
	Gas price NOK		0,427272727	0,43	0,427	0,4273	0,427	0,427	0,427	0,427	0,427	0,43	0,43
	Revenue Oil MNOK					3127,7	9383	7645	5908	4344	3301	2433	2085
	Revenue Gas MNOK					223,74	671,2	546,9	422,6	310,7	236,2	174	149
	Total Revenue MNOK					**3351,4**	**10054**	**8192**	**6330**	**4655**	**3538**	**2607**	**2234**
Costs	**Capex MNOK**		**2699,99973**	**5400**	**9000**	**7200**							
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**
Taxes	Depreciation capex 2010		449,999955	450	450	450	450	450					
	Depreciation capex 2011			900	900	900	900	900	900				
	Depreciation capex 2012				1500	1500	1500	1500	1500	1500			
	Depreciation capex 2013					1200	1200	1200	1200	1200	1200		
	Corporation tax base 28%		-449,999955	-1350	-2850	-1648,6	5035	3154	1722	926,5	1289	1537	1143
	Corporation tax MNOK		**-125,9999874**	**-378**	**-798**	**-461,6**	**1410**	**883,1**	**482,3**	**259,4**	**360,9**	**430**	**320**
	Uplift 7,5% of capex 2010		202,4999798	202	202,5	202,5							
	Uplift 7,5% of capex 2011			405	405	405	405						
	Uplift 7,5% of capex 2012				675	675	675	675					
	Uplift 7,5% of capex 2013					540	540	540	540				
	Special tax base 50%		-652,4999348	-1957	-4132	-3471,1	3415	1939	1182	926,5	1289	1537	1143
	Special tax MNOK		**-326,2499674**	**-979**	**-2066**	**-1735,5**	**1708**	**969,5**	**591,2**	**463,2**	**644,4**	**768**	**572**
	Corp. Tax + Special Tax		-452,2499548	-1357	-2864	-2197,1	3118	1853	1073	722,6	1005	1199	892
	Payable taxes MNOK		**-226,1249774**	**-904**	**-2110**	**-2530,7**	**460,2**	**2485**	**1463**	**898**	**863,9**	**1102**	**1045**
Cash flow	**Free cash flow MNOK**		**-2473,874753**	**-4496**	**-6890**	**-2267,9**	**8625**	**4719**	**3859**	**2728**	**1625**	**435**	**97,9**

	Time	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)	6,29	5,66	5,03	4,4	3,77	3,15	3,15	3,15	0	0	0	**173**
	Gas production (Msm3)	291	262	233	204	175	145	145	145	0	0	0	**8000**
	Oil price NOK	276	276	276	276	276	276	276	276	276,3	276,3	276,3	
	Gas price NOK	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,427	0,427	0,427	
	Revenue Oil MNOK	1738	1564	1390	1216	1043	869	869	869	0	0	0	
	Revenue Gas MNOK	124	112	99,4	87	74,6	62,1	62,1	62,1	0	0	0	
	Total Revenue MNOK	**1862**	**1676**	**1490**	**1303**	**1117**	**931**	**931**	**931**	**0**	**0**	**0**	
Costs	**Capex MNOK**												
	Opex MNOK	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010												
	Depreciation capex 2011												
	Depreciation capex 2012												
	Depreciation capex 2013												
	Corporation tax base 28%	749	540	331	122	-87,7	-298	-323	-348	-1373	-2800	0	
	Corporation tax MNOK	**210**	**151**	**92,8**	**34,2**	**-24,6**	**-83,4**	**-90,3**	**-97,3**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010												
	Uplift 7,5% of capex 2011												
	Uplift 7,5% of capex 2012												
	Uplift 7,5% of capex 2013												
	Special tax base 50%	749	540	331	122	-87,7	-298	-323	-348	-1373	-2800	0	
	Special tax MNOK	**374**	**270**	**166**	**61,1**	**-43,8**	**-149**	**-161**	**-174**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax	584	421	259	95,3	-68,4	-232	-252	-271	-1071	-2184		
	Payable taxes MNOK	**738**	**503**	**340**	**177**	**13,4**	**-150**	**-242**	**-261**	**-671**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**	**11**	**37,6**	**-8,54**	**-54,8**	**-101**	**-148**	**-80,5**	**-86,3**	**-702**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**1,773110727**

Appendix 4: Sensitivity Analysis: Opex, Pessimistic Case

ASSUMPTIONS PESSIMISTIC CASE

Oil Price $/bbl - NOK	48,5	315,25
Gas Price NOK/sm3		0,558181818
CAPEX MNOK		27000
OPEX MNOK		1235
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					11,322	33,97	27,68	21,39	15,73	11,95	8,81	7,55	6,29	5,66	5,03	4,4	3,77	3,15	3,15	3,15	0	0	0	173
	Gas production (Msm3)					523,64	1571	1280	989,1	727,3	552,7	407	349	291	262	233	204	175	145	145	145	0	0	0	8000
	Oil price NOK		315,25	315	315,3	315,25	315,3	315,3	315,3	315,3	315,3	315	315	315	315	315	315	315	315	315	315	315,3	315,3	315,3	
	Gas price NOK		0,558181818	0,56	0,558	0,5582	0,558	0,558	0,558	0,558	0,558	0,56	0,56	0,56	0,56	0,56	0,56	0,56	0,56	0,56	0,56	0,558	0,558	0,558	
	Revenue Oil MNOK					3569,3	10708	8725	6742	4957	3768	2776	2380	1983	1785	1586	1388	1190	991	991	991	0	0	0	
	Revenue Gas MNOK					292,28	876,9	714,5	552,1	406	308,5	227	195	162	146	130	114	97,4	81,2	81,2	81,2	0	0	0	
	Total Revenue MNOK					**3861,5**	**11585**	**9439**	**7294**	**5363**	**4076**	**3003**	**2574**	**2145**	**1931**	**1716**	**1502**	**1287**	**1073**	**1073**	**1073**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**1235**	**1260**	**1285**	**1311**	**1337**	**1364**	**1391**	**1419**	**1447**	**1476**	**1505**	**1536**	**1566**	**1598**	**1630**	**1662**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-1873,5	5825	3654	1983	1026	1379	1613	1156	698	455	211	-33,9	-279	-525	-557	-589	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-524,57**	**1631**	**1023**	**555,4**	**287,4**	**386,2**	**452**	**324**	**196**	**127**	**59**	**-9,48**	**-78,1**	**-147**	**-156**	**-165**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-3898,5	4025	2304	1383	1026	1379	1613	1156	698	455	211	-33,9	-279	-525	-557	-589	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-1949,2**	**2012**	**1152**	**691,7**	**513,2**	**689,6**	**806**	**578**	**349**	**227**	**105**	**-16,9**	**-140**	**-262**	**-278**	**-295**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-2473,8	3643	2175	1247	800,6	1076	1258	901	545	355	164	-26,4	-218	-409	-434	-460	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-2828,1**	**584,8**	**2909**	**1711**	**1024**	**938,2**	**1167**	**1080**	**723**	**450**	**260**	**69**	**-122**	**-314**	**-422**	**-447**	**-765**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-2545,3**	**9740**	**5245**	**4272**	**3003**	**1774**	**446**	**76,1**	**-24,8**	**5,11**	**-48,8**	**-103**	**-157**	**-211**	**-135**	**-142**	**-608**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**1,990685243**

Appendix 5: Scenario Analysis: Delay

ASSUMPTIONS DELAY

Oil Price $/bbl - NOK	55	357,5
Gas Price NOK/sm3		0,7
CAPEX MNOK		35000
OPEX MNOK		950
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Revenue	Oil production (M/bbl)							11,32	33,97	27,68	21,39	15,7	12	8,81	7,55	6,29	5,66	5,03	4,4	3,774	3,145	3,145	3,145	0	**173**
	Gas production (Msm3)							523,6	1571	1280	989,1	727	553	407	349	291	262	233	204	174,5	145,5	145,5	145,5	0	**8000**
	Oil price NOK		357,5	358	357,5	357,5	357,5	357,5	357,5	357,5	357,5	358	358	358	358	358	358	358	358	357,5	357,5	357,5	357,5	357,5	
	Gas price NOK		0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	
	Revenue Oil MNOK					0	0	4048	12143	9894	7645	5622	4272	3148	2698	2249	2024	1799	1574	1349	1124	1124	1124	0	
	Revenue Gas MNOK					0	0	366,5	1100	896	692,4	509	387	285	244	204	183	163	143	122,2	101,8	101,8	0	0	
	Total Revenue MNOK					**0**	**0**	**4414**	**13242**	**10790**	**8338**	**6131**	**4659**	**3433**	**2943**	**2452**	**2207**	**1962**	**1717**	**1471**	**1226**	**1226**	**1124**	**0**	
Costs	**Capex MNOK**		**3500**	**7000**	**10500**	**7000**	**7000**																		
	Opex MNOK							**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**2627**	**5479**		
Taxes	Depreciation capex 2010		583,3333333	583	583,3	583,33	583,3	583,3																	
	Depreciation capex 2011			1167	1167	1166,7	1167	1167	1167																
	Depreciation capex 2012				1750	1750	1750	1750	1750	1750															
	Depreciation capex 2013					1166,7	1167	1167	1167	1167	1167														
	Depreciation capex 2014						1167	1167	1167	1167	1167	1167													
	Corporation tax base 28%		-583,3333333	-1750	-3500	-4666,7	-5833	-2369	7023	5718	4996	3936	3611	2363	1852	1339	1072	804	535	266,6	-2,77	-1400	-4355	0	
	Corporation tax MNOK		**-163,3333333**	**-490**	**-980**	**-1306,7**	**-1633**	**-663**	**1967**	**1601**	**1399**	**1102**	**1011**	**662**	**518**	**375**	**300**	**225**	**150**	**74,64**	**-0,78**	**-392**	**-1219**	**0**	
	Uplift 7,5% of capex 2010		262,5	263	262,5	262,5																			
	Uplift 7,5% of capex 2011			525	525	525	525																		
	Uplift 7,5% of capex 2012				787,5	787,5	787,5	787,5																	
	Uplift 7,5% of capex 2013					525	525	525	525																
	Uplift 7,5% of capex 2014						525	525	525	525															
	Special tax base 50%		-845,8333333	-2538	-5075	-6766,7	-8196	-4207	5973	5193	4996	3936	3611	2363	1852	1339	1072	804	535	266,6	-2,77	-1400	-4355	0	
	Special tax MNOK		**-422,9166667**	**-1269**	**-2538**	**-3383,3**	**-4098**	**-2103**	**2987**	**2597**	**2498**	**1968**	**1805**	**1182**	**926**	**670**	**536**	**402**	**268**	**133,3**	**-1,39**	**-700**	**-2177**	**0**	
	Corp. Tax + Special Tax		-586,25	-1759	-3518	-4690	-5731	-2767	4953	4198	3897	3070	2816	1843	1444	1045	836	627	418	207,9	-2,16	-1092	-3397		
	Payable taxes MNOK		**-293,125**	**-1173**	**-2638**	**-4103,8**	**-5211**	**-4249**	**1093**	**4576**	**4048**	**3484**	**2943**	**2330**	**1644**	**1244**	**940**	**731**	**522**	**312,8**	**102,9**	**-547**	**-2244**	**-1698**	
Cash flow	**Free cash flow MNOK**		**-3206,875**	**-5828**	**-7862**	**-2896,3**	**-1789**	**7713**	**11180**	**5226**	**3282**	**1619**	**667**	**33,6**	**208**	**94,8**	**131**	**72,3**	**13,1**	**-46,2**	**-106**	**-853**	**-2110**	**-1698**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**-892,770434**

Appendix 6: Scenario Analysis: Low Production

ASSUMPTIONS LOW PRODUCTION

Oil Price $/bbl - NOK	55	357,5
Gas Price NOK/sm3		0,7
CAPEX MNOK		27000
OPEX MNOK		950
Oil prod. Msm3		114,2
Gas prod. Msm3		5280
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Revenue	Oil production (M/bbl)					7,4725	22,42	18,27	14,11	10,38	7,888	5,81	4,98	4,15	3,74	3,32	2,91	2,49	2,08	2,08	2,08	0	0	0	**114,2**
	Gas production (Msm3)					389,4	1056	858	660	495	396	264	231	185	145	132	119	99	92,4	79,2	79,2	0	0	0	**5280**
	Oil price NOK		357,5	358	357,5	357,5	357,5	357,5	357,5	357,5	357,5	358	358	358	358	358	358	358	358	358	358	357,5	357,5	357,5	
	Gas price NOK		0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	
	Revenue Oil MNOK					2671,4	8014	6530	5046	3710	2820	2078	1781	1484	1336	1187	1039	890	742	742	742	0	0	0	
	Revenue Gas MNOK					272,58	739,2	600,6	462	346,5	277,2	185	162	129	102	92,4	83,2	69,3	64,7	55,4	55,4	0	0	0	
	Total Revenue MNOK					**2944**	**8753**	**7131**	**5508**	**4057**	**3097**	**2263**	**1943**	**1613**	**1437**	**1280**	**1122**	**960**	**807**	**798**	**798**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-2506	3284	1642	499,9	28,5	714,8	1193	851	500	302	122	-59,2	-245	-422	-456	-481	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-701,68**	**919,7**	**459,9**	**140**	**7,981**	**200,2**	**334**	**238**	**140**	**84,6**	**34,1**	**-16,6**	**-68,6**	**-118**	**-128**	**-135**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-4531	1484	292,4	-100	28,5	714,8	1193	851	500	302	122	-59,2	-245	-422	-456	-481	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-2265,5**	**742,2**	**146,2**	**-50,1**	**14,25**	**357,4**	**596**	**426**	**250**	**151**	**60,8**	**-29,6**	**-123**	**-211**	**-228**	**-241**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-2967,2	1662	606,1	89,91	22,23	557,6	930	664	390	236	94,9	-46,1	-191	-329	-356	-375	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-3074,8**	**-653**	**1134**	**348**	**56,07**	**289,9**	**744**	**797**	**527**	**313**	**165**	**24,4**	**-119**	**-260**	**-342**	**-365**	**-723**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-2931,2**	**8437**	**5008**	**4152**	**2972**	**1758**	**449**	**54,2**	**-26,8**	**-10,9**	**-43,6**	**-83,5**	**-126**	**-162**	**-114**	**-116**	**-650**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**-1509,038289**

Appendix 7: Scenario Analysis: High Production

ASSUMPTIONS HIGH PRODUCTION

Oil Price $/bbl - NOK	55	357,5
Gas Price NOK/sm3		0,7
CAPEX MNOK		27000
OPEX MNOK		950
Oil prod. Msm3		32,59
Gas prod. Msm3		9484
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					13,421	40,26	32,81	25,35	18,64	14,17	10,4	8,95	7,46	6,71	5,96	5,22	4,47	3,73	3,73	3,73	0	0	0	**205**
	Gas production (Msm3)					699,42	1897	1541	1185	889,1	711,3	474	415	332	261	237	213	178	166	142	142	0	0	0	**9484**
	Oil price NOK		357,5	358	357,5	357,5	357,5	357,5	357,5	357,5	357,5	358	358	358	358	358	358	358	358	358	358	357,5	357,5	357,5	
	Gas price NOK		0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	
	Revenue Oil MNOK					4798	14394	11729	9063	6664	5065	3732	3199	2666	2399	2132	1866	1599	1333	1333	1333	0	0	0	
	Revenue Gas MNOK					489,59	1328	1079	829,8	622,4	497,9	332	290	232	183	166	149	124	116	99,6	99,6	0	0	0	
	Total Revenue MNOK					**5287,6**	**15722**	**12807**	**9893**	**7286**	**5562**	**4064**	**3489**	**2898**	**2582**	**2298**	**2015**	**1724**	**1449**	**1432**	**1432**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-162,36	10253	7319	4885	3258	3180	2994	2398	1785	1446	1140	834	519	220	179	154	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-45,462**	**2871**	**2049**	**1368**	**912,2**	**890,5**	**838**	**671**	**500**	**405**	**319**	**234**	**145**	**61,6**	**50,1**	**43,1**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-2187,4	8453	5969	4285	3258	3180	2994	2398	1785	1446	1140	834	519	220	179	154	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-1093,7**	**4226**	**2984**	**2142**	**1629**	**1590**	**1497**	**1199**	**892**	**723**	**570**	**417**	**259**	**110**	**89,4**	**76,9**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-1139,1	7097	5034	3510	2541	2481	2335	1870	1392	1128	889	651	405	172	140	120	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-2160,8**	**2979**	**6065**	**4272**	**3026**	**2511**	**2408**	**2103**	**1631**	**1260**	**1009**	**770**	**528**	**288**	**156**	**130**	**-475**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-1501,5**	**11774**	**5753**	**4613**	**3232**	**2003**	**586**	**295**	**154**	**186**	**132**	**64**	**-8,7**	**-68,2**	**23,3**	**24,1**	**-898**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**3755,550634**

Appendix 8: Scenario Analysis: Base Case

ASSUMPTIONS BASE CASE

Oil Price $/bbl - NOK	55	357,5
Gas Price NOK/sm3		0,7
CAPEX MNOK		27000
OPEX MNOK		950
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					11,322	33,97	27,68	21,39	15,73	11,95	8,81	7,55	6,29	5,66	5,03	4,4	3,77	3,15	3,15	3,15	0	0	0	173
	Gas production (Msm3)					523,64	1571	1280	989,1	727,3	552,7	407	349	291	262	233	204	175	145	145	145	0	0	0	8000
	Oil price NOK		357,5	358	357,5	357,5	357,5	357,5	357,5	357,5	357,5	358	358	358	358	358	358	358	358	358	358	357,5	357,5	357,5	
	Gas price NOK		0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	0,7	
	Revenue Oil MNOK					4047,6	12143	9894	7645	5622	4272	3148	2698	2249	2024	1799	1574	1349	1124	1124	1124	0	0	0	
	Revenue Gas MNOK					366,55	1100	896	692,4	509,1	386,9	285	244	204	183	163	143	122	102	102	102	0	0	0	
	Total Revenue MNOK					**4414,2**	**13242**	**10790**	**8338**	**6131**	**4659**	**3433**	**2943**	**2452**	**2207**	**1962**	**1717**	**1471**	**1226**	**1226**	**1226**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**950**	**969**	**988,4**	**1008**	**1028**	**1049**	**1070**	**1091**	**1113**	**1135**	**1158**	**1181**	**1205**	**1229**	**1254**	**1279**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-1035,8	7773	5302	3330	2102	2277	2363	1852	1339	1072	804	535	267	-2,77	-27,3	-52,4	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-290,04**	**2177**	**1485**	**932,3**	**588,7**	**637,6**	**662**	**518**	**375**	**300**	**225**	**150**	**74,6**	**-0,78**	**-7,66**	**-14,7**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-3060,8	5973	3952	2730	2102	2277	2363	1852	1339	1072	804	535	267	-2,77	-27,3	-52,4	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-1530,4**	**2987**	**1976**	**1365**	**1051**	**1139**	**1182**	**926**	**670**	**536**	**402**	**268**	**133**	**-1,39**	**-13,7**	**-26,2**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-1820,5	5163	3460	2297	1640	1776	1843	1444	1045	836	627	418	208	-2,16	-21,3	-40,9	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-2501,5**	**1671**	**4312**	**2879**	**1969**	**1708**	**1810**	**1644**	**1244**	**940**	**731**	**522**	**313**	**103**	**-11,7**	**-31,1**	**-556**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-2034,4**	**10602**	**5490**	**4451**	**3134**	**1902**	**554**	**208**	**94,8**	**131**	**72,3**	**13,1**	**-46,2**	**-106**	**-15,6**	**-21,3**	**-817**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**1887,278387**

Appendix 9: Scenario Analysis: Low Oil Price

ASSUMPTIONS LOW OIL PRICE

Oil Price $/bbl - NOK	30	195
Gas Price NOK/sm3		0,154545455
CAPEX MNOK		27000
OPEX MNOK		800
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					11,322	33,97	27,68	21,39	15,73	11,95	8,81	7,55	6,29	5,66	5,03	4,4	3,77	3,15	3,15	3,15	0	0	0	173
	Gas production (Msm3)					523,64	1571	1280	989,1	727,3	552,7	407	349	291	262	233	204	175	145	145	145	0	0	0	8000
	Oil price NOK		195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	
	Gas price NOK		0,154545455	0,15	0,155	0,1545	0,155	0,155	0,155	0,155	0,155	0,15	0,15	0,15	0,15	0,15	0,15	0,15	0,15	0,15	0,15	0,155	0,155	0,155	
	Revenue Oil MNOK					2207,8	6623	5397	4170	3066	2330	1717	1472	1227	1104	981	859	736	613	613	613	0	0	0	
	Revenue Gas MNOK					80,926	242,8	197,8	152,9	112,4	85,42	62,9	54	45	40,5	36	31,5	27	22,5	22,5	22,5	0	0	0	
	Total Revenue MNOK					**2288,7**	**6866**	**5595**	**4323**	**3179**	**2416**	**1780**	**1526**	**1272**	**1144**	**1017**	**890**	**763**	**636**	**636**	**636**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2999,9997**	**6000**	**10000**	**8000**																			
	Opex MNOK					**800**	**816**	**832,3**	**849**	**865,9**	**883,3**	**901**	**919**	**937**	**956**	**975**	**995**	**1015**	**1035**	**1056**	**1077**	**1373**	**2800**		
Taxes	Depreciation capex 2010		499,99995	500	500	500	500	500																	
	Depreciation capex 2011			1000	1000	1000	1000	1000	1000																
	Depreciation capex 2012				1667	1666,7	1667	1667	1667	1667															
	Depreciation capex 2013					1333,3	1333	1333	1333	1333	1333														
	Corporation tax base 28%		-499,99995	-1500	-3167	-3011,3	1550	262,3	-526	-687	199,3	879	607	334	188	42	-105	-252	-399	-420	-441	-1373	-2800	0	
	Corporation tax MNOK		**-139,999986**	**-420**	**-886,7**	**-843,16**	**434**	**73,45**	**-147**	**-192**	**55,8**	**246**	**170**	**93,6**	**52,7**	**11,8**	**-29,3**	**-70,5**	**-112**	**-118**	**-123**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		224,9999775	225	225	225																			
	Uplift 7,5% of capex 2011			450	450	450	450																		
	Uplift 7,5% of capex 2012				750	750	750	750																	
	Uplift 7,5% of capex 2013					600	600	600	600																
	Special tax base 50%		-724,9999275	-2175	-4592	-5036,3	-250	-1088	-1126	-687	199,3	879	607	334	188	42	-105	-252	-399	-420	-441	-1373	-2800	0	
	Special tax MNOK		**-362,4999638**	**-1087**	**-2296**	**-2518,1**	**-125**	**-544**	**-563**	**-344**	**99,63**	**440**	**303**	**167**	**94,1**	**21**	**-52,3**	**-126**	**-200**	**-210**	**-220**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-502,4999498	-1507	-3182	-3361,3	309,1	-470	-710	-536	155,4	686	473	261	147	32,8	-81,6	-196	-311	-327	-344	-1071	-2184		
	Payable taxes MNOK		**-251,2499749**	**-1005**	**-2345**	**-3271,9**	**-1526**	**-80,6**	**-590**	**-623**	**-190**	**421**	**580**	**367**	**204**	**89,8**	**-24,4**	**-139**	**-254**	**-319**	**-336**	**-707**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2748,749725**	**-4995**	**-7655**	**-3239,4**	**7576**	**4843**	**4064**	**2936**	**1723**	**459**	**27,3**	**-32,8**	**-15,5**	**-47,8**	**-80,2**	**-113**	**-145**	**-100**	**-105**	**-666**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**-2599,661895**

Appendix 10: Scenario Analysis: High Oil Price

ASSUMPTIONS HIGH OIL PRICE

Oil Price $/bbl - NOK	80	520
Gas Price NOK/sm3		1,245454545
CAPEX MNOK		32000
OPEX MNOK		1200
Oil prod. Msm3		27,5
Gas prod. Msm3		8000
Currency		$1=6,5NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (Mbbl)					7,4725	22,42	18,27	14,11	10,38	7,888	5,81	4,98	4,15	3,74	3,32	2,91	2,49	2,08	2,08	2,08	0	0	0	114,2
	Gas production (Msm3)					389,4	1056	858	660	495	396	264	231	185	145	132	119	99	92,4	79,2	79,2	0	0	0	5280
	Oil price NOK		520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	
	Gas price NOK		1,245454545	1,25	1,245	1,2455	1,245	1,245	1,245	1,245	1,245	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,25	1,245	1,245	1,245	
	Revenue Oil MNOK					3885,7	11657	9498	7340	5397	4102	3022	2590	2159	1943	1727	1511	1295	1079	1079	1079	0	0	0	
	Revenue Gas MNOK					484,98	1315	1069	822	616,5	493,2	329	288	230	181	164	148	123	115	98,6	98,6	0	0	0	
	Total Revenue MNOK					**4370,7**	**12972**	**10567**	**8162**	**6013**	**4595**	**3351**	**2878**	**2389**	**2124**	**1891**	**1659**	**1419**	**1194**	**1178**	**1178**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**3555,5552**	**7111**	**11852**	**9481,5**																			
	Opex MNOK					**1200**	**1224**	**1248**	**1273**	**1299**	**1325**	**1351**	**1378**	**1406**	**1434**	**1463**	**1492**	**1522**	**1552**	**1583**	**1615**	**1373**	**2800**		
Taxes	Depreciation capex 2010		592,5925333	593	592,6	592,59	592,6	592,6																	
	Depreciation capex 2011			1185	1185	1185,2	1185	1185	1185																
	Depreciation capex 2012				1975	1975,3	1975	1975	1975	1975															
	Depreciation capex 2013					1580,2	1580	1580	1580	1580	1580														
	Corporation tax base 28%		-592,5925333	-1778	-3753	-2162,6	6415	3985	2147	1159	1690	2000	1500	983	690	429	167	-103	-358	-405	-437	-1373	-2800	0	
	Corporation tax MNOK		**-165,9259093**	**-498**	**-1051**	**-605,54**	**1796**	**1116**	**601,3**	**324,5**	**473,1**	**560**	**420**	**275**	**193**	**120**	**46,8**	**-28,9**	**-100**	**-114**	**-122**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		266,66664	267	266,7	266,67																			
	Uplift 7,5% of capex 2011			533	533,3	533,33	533,3																		
	Uplift 7,5% of capex 2012				888,9	888,89	888,9	888,9																	
	Uplift 7,5% of capex 2013					711,11	711,1	711,1	711,1																
	Special tax base 50%		-859,2591733	-2578	-5442	-4562,6	4282	2385	1436	1159	1690	2000	1500	983	690	429	167	-103	-358	-405	-437	-1373	-2800	0	
	Special tax MNOK		**-429,6295867**	**-1289**	**-2721**	**-2281,3**	**2141**	**1193**	**718,2**	**579,4**	**844,8**	**1000**	**750**	**491**	**345**	**214**	**83,5**	**-51,7**	**-179**	**-203**	**-219**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-595,555496	-1787	-3772	-2886,9	3937	2308	1319	903,9	1318	1560	1170	767	538	334	130	-80,6	-279	-316	-341	-1071	-2184		
	Payable taxes MNOK		**-297,777748**	**-1191**	**-2779**	**-3329,4**	**525,1**	**3123**	**1814**	**1112**	**1111**	**1439**	**1365**	**968**	**652**	**436**	**232**	**24,8**	**-180**	**-298**	**-329**	**-706**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-3257,777452**	**-5920**	**-9073**	**-2981,4**	**11223**	**6196**	**5074**	**3603**	**2159**	**561**	**135**	**14,7**	**37,3**	**-7,5**	**-65,3**	**-128**	**-178**	**-108**	**-108**	**-667**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**151,8282378**

Appendix 11: Monte Carlo Simulation

MONTE CARLO SIMULATION

Oil Price $/bbl - NOK	48,91	317,8877068
Gas Price NOK/sm3		0,567035659
CAPEX MNOK		26081,51156
OPEX MNOK		936,5372785
Oil prod. Msm3		26,91466556
Gas prod. Msm3		7829,720865
Currency		$1=1,65NOK
Inflation from 2013 and on		2 %

	Time	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Revenue	Oil production (M/bbl)					11,081	33,24	27,09	20,93	15,39	11,7	8,62	7,39	6,16	5,54	4,92	4,31	3,69	3,08	3,08	3,08	0	0	0	**169,3**
	Gas production (Msm3)					512,49	1537	1253	968	711,8	541	399	342	285	256	228	199	171	142	142	142	0	0	0	**7830**
	Oil price NOK		317,8877068	318	317,9	317,89	317,9	317,9	317,9	317,9	317,9	318	318	318	318	318	318	318	318	318	318	317,9	317,9	317,9	
	Gas price NOK		0,567035659	0,57	0,567	0,567	0,567	0,567	0,567	0,567	0,567	0,57	0,57	0,57	0,57	0,57	0,57	0,57	0,57	0,57	0,57	0,567	0,567	0,567	
	Revenue Oil MNOK					3522,5	10568	8611	6654	4892	3718	2740	2348	1957	1761	1566	1370	1174	978	978	978	0	0	0	
	Revenue Gas MNOK					290,6	871,8	710,4	548,9	403,6	306,7	226	194	161	145	129	113	96,9	80,7	80,7	80,7	0	0	0	
	Total Revenue MNOK					**3813,1**	**11439**	**9321**	**7203**	**5296**	**4025**	**2966**	**2542**	**2118**	**1907**	**1695**	**1483**	**1271**	**1059**	**1059**	**1059**	**0**	**0**	**0**	
Costs	**Capex MNOK**		**2897,945439**	**5796**	**9660**	**7727,9**																			
	Opex MNOK					**936,54**	**955,3**	**974,4**	**993,9**	**1014**	**1034**	**1055**	**1076**	**1097**	**1119**	**1142**	**1164**	**1188**	**1212**	**1236**	**1260**	**1373**	**2800**		
Taxes	Depreciation capex 2010		482,9909065	483	483	482,99	483	483																	
	Depreciation capex 2011			966	966	965,98	966	966	966																
	Depreciation capex 2012				1610	1610	1610	1610	1610	1610															
	Depreciation capex 2013					1288	1288	1288	1288	1288	1288														
	Corporation tax base 28%		-482,9909065	-1449	-3059	-1470,3	6137	4000	2345	1384	1703	1911	1466	1021	787	553	318	83,3	-152	-177	-201	-1373	-2800	0	
	Corporation tax MNOK		**-135,2374538**	**-406**	**-856,5**	**-411,69**	**1718**	**1120**	**656,5**	**387,6**	**476,8**	**535**	**411**	**286**	**220**	**155**	**89,2**	**23,3**	**-42,6**	**-49,4**	**-56,4**	**-384**	**-784**	**0**	
	Uplift 7,5% of capex 2010		217,3459079	217	217,3	217,35																			
	Uplift 7,5% of capex 2011			435	434,7	434,69	434,7																		
	Uplift 7,5% of capex 2012				724,5	724,49	724,5	724,5																	
	Uplift 7,5% of capex 2013					579,59	579,6	579,6	579,6																
	Special tax base 50%		-700,3368144	-2101	-4435	-3426,5	4398	2696	1765	1384	1703	1911	1466	1021	787	553	318	83,3	-152	-177	-201	-1373	-2800	0	
	Special tax MNOK		**-350,1684072**	**-1051**	**-2218**	**-1713,2**	**2199**	**1348**	**882,6**	**692,2**	**851,5**	**956**	**733**	**511**	**394**	**277**	**159**	**41,6**	**-76,2**	**-88,3**	**-101**	**-687**	**-1400**	**0**	
	Corp. Tax + Special Tax		-485,405861	-1456	-3074	-2124,9	3918	2468	1539	1080	1328	1491	1144	796	614	431	248	65	-119	-138	-157	-1071	-2184		
	Payable taxes MNOK		**-242,7029305**	**-971**	**-2265**	**-2599,6**	**896,3**	**3193**	**2003**	**1309**	**1204**	**1409**	**1317**	**970**	**705**	**523**	**340**	**157**	**-26,9**	**-128**	**-147**	**-614**	**-1627**	**-1092**	
Cash flow	**Free cash flow MNOK**		**-2655,242508**	**-4825**	**-7395**	**-2251,7**	**9588**	**5154**	**4205**	**2973**	**1787**	**502**	**149**	**51**	**82**	**30,3**	**-21,5**	**-73,4**	**-125**	**-48,3**	**-53,9**	**-759**	**-1173**	**-1092**	

Discount rate	**0,07**
NPV measured in MNOK 2009	**732,5819012**
MONTE CARLO AVERAGE	**281,6956496**

Appendix 12: Monte Carlo Simulation Report

Microsoft Excel 11.0 Simulation Report

Simulation Report [Monte Carlo.xls]DCF Monte Carlo

Report Created: 4/17/2009 10:12:49 AM

Simulation time: 0,577 seconds

General Simulation Information

Simulation Options		Value
Simulations Run		1
Trials per Simulation		20000
Random Number Generator	CMRG	
Sampling Method	Monte Carlo	
Random Number Stream	Independent Stream	
Simulation Seed		0
Interpreter Used	Automatic	
Correlations Used	Yes	

Model Information	Quantity
Uncertain Variables	4
Uncertain Functions	1
Correlated Variables	2

Global Bounds	Measure	Value
Lower Cutoff	None	-1E+30
Upper Cutoff	None	1E+30
Lower Censor	None	-1E+30
Upper Censor	None	1E+30

Uncertain Variable Summary Information

Cell	Name	Distribution	Mean	StdDev	Minimum	Maximum	25th Percentile	50th Percentile	75th Percentile
$C$2	Oil Price $/bbl - NOK	PsiTriangular(20,55,80,PsiName("Oil price"), PsiCorrMatrix($B$57:$C$58, 1))	51,66666667	12,30401922	20	80	42,91287847	52,40370349	60,63508327
$D$4	CAPEX MNOK	PsiTriangular(24300,27000,35100,PsiName("capex"))	28800	2294,558781	24300	35100	27000	28486,37769	30423,46282
$D$5	OPEX MNOK	PsiTriangular(855,950,1235,PsiName("opex"), PsiCorrMatrix($B$57:$C$58, 2))	1013,333333	80,73447563	855	1235	950	1002,298474	1070,455173
$D$6	Oil prod Msm3	PsiTriangular(18.2,27.5,32.6,PsiName("Production rates"))	25,66666667	2,89635786	18	32	23,6124860	25,9372539	27,8166998

Uncertain Function Summary Information

Cell	Name	Formula	Mean	StdDev	Minimum	Maximum	25th Percentile	50th Percentile	75th Percentile
$D$46	NPV measured in MNOK 2009 $1=1,65NOK	NPV(D45,C43:Y43)*((1+D45)^0.5) + PsiOutput()	281,408875	2418,67719	-6268,11234	8472,810131	-1457,36981	263,114370	1969,42697

Appendix 13: Real Option Analysis: Timing Option

TIMING OPTION

Oil Price Starting point $/**bbl**	55
Oil Price Volatility,**σ**	0,2
Binomial Period,**dt**	0,5
Risk free rate,**rf**	0,02
Net Convenience yield,**D**	0,02

Pseudo probability,**p**	0,464703469
Up Factor,**u**	1,15190991
Down Factor,**d**	0,868123445

$$p = \frac{e^{(rf-D)\times dt} - d}{u - d}$$

$$u = e^{\sigma \times \sqrt{dt}}$$

$$d = \frac{1}{u}$$

Oil Price Trend

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Oil Price $/bbl	55	63,35504506	72,97930426	84,06558382	96,8359791	110	110	110	110	110	110	110	110
		47,7467895	55	63,35504506	72,97930426	84,06558382	110	110	110	110	110	110	110
			41,4501074	47,7467895	55	63,35504506	72,9793	84,06558	96,83598	110	110	110	110
				35,98381005	41,4501074	47,7467895	55	63,35505	72,9793	84,06558	96,83598	110	110
					31,23838916	35,98381005	41,45011	47,74679	55	63,35505	72,9793	84,06558	96,83598
						27,11877803	31,23839	35,98381	41,45011	47,74679	55	63,35505	72,9793
							25	28,79775	33,17241	38,21163	44,01635	50,70287	58,40514
								25	28,79775	33,17241	38,21163	44,01635	50,70287
									25	28,79775	33,17241	38,21163	44,01635
										25	28,79775	33,17241	38,21163
											25	28,79775	33,17241
												25	28,79775
													25

Project Value

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
NPV MNOK	5 947,62	7 701,72	9 915,55	12 651,04	15 806,66	18724	18724	18724	18724	18724	18724	18724	18724
		4 536,52	5 924,45	7 726,97	10 149,09	13 570,82	18724	18724	18724	18724	18724	18724	18724
			3 416,79	4 470,88	5 769,34	7 369,16	9 352,01	11 824,33	14 906,86	18724	18724	18724	18724
				2 565,87	3 427,59	4 488,81	5 786,16	7 381,31	9 370,31	11 872,99	14 987,57	18724	18724
					1 865,96	2 570,67	3 446,83	4 510,01	5 793,19	7 373,61	9 392,06	12 025,28	15384,2
						1 289,21	1 858,32	2 588,57	3 480,73	4 529,96	5 759,79	7 282,44	9335,1
							819,36	1 259,26	1 862,67	2 635,22	3 547,37	4 546,08	5637,2
								452,86	759,06	1 226,98	1 892,84	2 746,96	3684,2
									195,54	367,09	671,98	1 186,89	1984,9
										50,29	109,31	237,59	516,4
											0,00	0,00	0
												0,00	0
													0

$$C_{j,i} = \frac{p \times C_{j+1} + (1-p) \times C_{j+1,i+1}}{e^{rf \times dt}}$$

Strategy

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Action	Wait	Wait	Wait	Wait	Wait	Develop	Develop	Develop	Develop	Develop	Develop	Develop	Develop
		Wait	Wait	Wait	Wait	Wait	Develop	Develop	Develop	Develop	Develop	Develop	Develop
			Wait	Wait	Wait	Wait	Wait	Wait	Wait	Develop	Develop	Develop	Develop
				Wait	Wait	Wait	Wait	Wait	Wait	Wait	Wait	Develop	Develop
					Wait	Wait	Wait	Wait	Wait	Wait	Wait	Wait	Develop
						Wait	Wait	Wait	Wait	Wait	Wait	Wait	Develop
							Wait	Wait	Wait	Wait	Wait	Wait	Develop
								Wait	Wait	Wait	Wait	Wait	Develop
									Wait	Wait	Wait	Wait	Develop
										Wait	Wait	Wait	Develop
											Wait	Wait	Wait
												Wait	Wait
													Wait

Appendix 14: Real Option Analysis: Expand Option

EXPAND OPTION

Oil Price Starting point **$/bbl**	55
Oil Price Volatility,**σ**	0,2
Binomial Period,**dt**	0,5
Risk free rate,**rf**	0,02
Net Convenience yield,**D**	0,02

Pseudo probability,**p**	0,464703469
Up Factor,**u**	1,15190991
Down Factor,**d**	0,868123445

$$p = \frac{e^{(rf-D)\times dt} - d}{u - d}$$

$$u = e^{\sigma \times \sqrt{dt}}$$

$$d = \frac{1}{u}$$

Oil Price Trend

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Oil Price $/bbl	55	63,35504506	72,97930426	84,06558382	96,8359791	110	110	110	110	110	110	110	110
		47,7467895	55	63,35504506	72,97930426	84,06558382	110	110	110	110	110	110	110
			41,4501074	47,7467895	55	63,35504506	72,9793	84,06558	96,83598	110	110	110	110
				35,98381005	41,4501074	47,7467895	55	63,35505	72,9793	84,06558	96,83598	110	110
					31,23838916	35,98381005	41,45011	47,74679	55	63,35505	72,9793	84,06558	96,83598
						27,11877803	31,23839	35,98381	41,45011	47,74679	55	63,35505	72,9793
							25	28,79775	33,17241	38,21163	44,01635	50,70287	58,40514
								25	28,79775	33,17241	38,21163	44,01635	50,70287
									25	28,79775	33,17241	38,21163	44,01635
										25	28,79775	33,17241	38,21163
											25	28,79775	33,17241
												25	28,79775
													25

Project Value

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
NPV MNOK	6 212,96	8 128,24	10 583,06	13 658,06	17 243,13	20578,2	20578,2	20578,2	20578,2	20578,2	20578,2	20578,2	20578,2
		4 666,90	6 149,77	8 112,27	10 802,21	14 671,61	20578,2	20578,2	20578,2	20578,2	20578,2	20578,2	20578,2
			3 467,20	4 561,54	5 929,37	7 645,90	9 819,42	12 591,92	16 125,01	20578,2	20578,2	20578,2	20578,2
				2 582,28	3 459,74	4 550,54	5 902,57	7 596,91	9 761,17	12 561,84	16 153,68	20578,2	20578,2
					1 869,01	2 577,75	3 462,24	4 542,50	5 860,70	7 513,11	9 679,53	12 615,93	16593,7
						1 288,82	1 858,30	2 589,45	3 483,42	4 536,24	5 773,44	7 312,11	9399,6
							818,64	1 258,47	1 861,99	2 634,85	3 547,37	4 546,08	5637,2
								452,18	758,17	1 226,01	1 892,14	2 746,96	3684,2
									195,03	366,25	670,76	1 185,56	1984,9
										50,05	108,78	236,43	513,9
											0,00	0,00	0
												0,00	0
													0

$$C_{j,i} = \frac{p \times C_{j+1} + (1-p) \times C_{j+1,i+1}}{e^{rf \times dt}}$$

Option Strategy

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Action	Hold	Hold	Hold	Hold	Hold	Expand	Expand	Expand	Expand	Expand	Expand	Expand	Expand
		Hold	Hold	Hold	Hold	Hold	Expand	Expand	Expand	Expand	Expand	Expand	Expand
			Hold	Hold	Hold	Hold	Hold	Hold	Hold	Expand	Expand	Expand	Expand
				Hold	Hold	Hold	Hold	Hold	Hold	Hold	Hold	Expand	Expand
					Hold	Hold	Hold	Hold	Hold	Hold	Hold	Hold	Expand
						Hold	Hold	Hold	Hold	Hold	Hold	Hold	Expand
							Hold	Hold	Hold	Hold	Hold	Hold	Hold
								Hold	Hold	Hold	Hold	Hold	Hold
									Hold	Hold	Hold	Hold	Hold
										Hold	Hold	Hold	Hold
											Hold	Hold	Hold
												Hold	Hold
													Hold

Appendix 15: Real Option Analysis: Abandonment Option

ABANDONMENT OPTION

Oil Price Starting point $/bbl	55
Oil Price Volatility,σ	0,2
Binomial Period,dt	0,5
Risk free rate,rf	0,02
Net Convenience yield,D	0,02

Pseudo probability,p	0,464703469
Up Factor,u	1,15190991
Down Factor,d	0,868123445

$$p = \frac{e^{(rf-D)\times dt} - d}{u - d}$$

$$u = e^{\sigma \times \sqrt{dt}}$$

$$d = \frac{1}{u}$$

Oil Price Trend

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Oil Price $/bbl	55	63,35504506	72,97930426	84,06558382	96,8359791	110	110	110	110	110	110	110	110
		47,7467895	55	63,35504506	72,97930426	84,06558382	110	110	110	110	110	110	110
			41,4501074	47,7467895	55	63,35504506	72,9793	84,06558	96,83598	110	110	110	110
				35,98381005	41,4501074	47,7467895	55	63,35505	72,9793	84,06558	96,83598	110	110
					31,23838916	35,98381005	41,45011	47,74679	55	63,35505	72,9793	84,06558	96,835979
						27,11877803	31,23839	35,98381	41,45011	47,74679	55	63,35505	72,979304
							25	28,79775	33,17241	38,21163	44,01635	50,70287	58,405144
								25	28,79775	33,17241	38,21163	44,01635	50,702875
									25	28,79775	33,17241	38,21163	44,016354
										25	28,79775	33,17241	38,211629
											25	28,79775	33,172411
												25	28,797748
													25

Project Value as Project and Oil Price Moves Forward

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
NPV MNOK	4 774,20	6 744,20	8499,2	10 052,30	10675	12383,1	12383,1	12383,1	12383,1	12383,1	12383,1	12383,1	12383,1
		3 067,00	4 390,00	5 560,70	6598,4	7 540,50	9287,7	9287,7	9287,7	9287,7	9287,7	9287,7	9287,7
			1917,7	2 799,70	3 582,00	4 293,70	4941,2	5 552,50	6118,2	6592,4	6592,4	6592,4	6592,4
				1 151,50	1741,8	2 271,20	2 763,80	3 226,60	3653,7	4 053,20	4414,1	4701,7	4701,7
					640,30	1 043,70	1414,7	1 755,70	2 080,60	2 382,50	2655	2 897,00	3102,2
						289,70	566,40	830,30	1075,1	1 298,00	1 505,20	1 688,30	1843,4
							148,2	357,1	552,9	732,6	897,2	1043,3	1167,7
								148,2	317,3	475,4	617,3	743,8	852
									148,2	284,7	409,6	518,6	612,3
										148,2	256	352	432,7
											148,2	231	302,1
												148,2	231
													148,2

Option Value

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
NPV MNOK	67,24897876	37,80425844	17,57003618	6,048118401	1,168089571	0	0	0	0	0	0	0	0
		94,07322721	56,07983435	27,90235974	10,39813898	2,204066339	0	0	0	0	0	0	0
			128,8224027	81,59425693	43,62204966	17,70683012	4,158849	0	0	0	0	0	0
				172,2408979	116,0907487	66,93866126	29,80059	7,847326	0	0	0	0	0
					224,2199736	160,9404264	100,4359	49,41825	14,80711	0	0	0	0
						283,3641516	216,4875	146,6111	80,39281	27,93951	0	0	0
							346,7415	281,2134	206,8494	127,4381	52,71901	0	0
								410,138	351,0503	279,6718	194,6962	99,47541	0
									469,1338	419,6066	358,6919	281,015	187,7
										520,9375	480,3661	432,8594	367,3
											565,939	530,6267	497,9
												607,2199	569
													651,8

$$C_{j,i} = \frac{p \times C_{j+1} + (1-p) \times C_{j+1,i+1}}{e^{rf \times dt}}$$

Option Strategy

Year	0	0,5	1	1,5	2	2,5	3	3,5	4	4,5	5	5,5	6
Strategy	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
		Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
			Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
				Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
					Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
						Continue	Continue	Continue	Continue	Continue	Continue	Continue	Continue
							Continue	Continue	Continue	Continue	Continue	Continue	Continue
								Continue	Continue	Continue	Continue	Continue	Continue
									Continue	Continue	Continue	Continue	Abandon
										Continue	Continue	Continue	Abandon
											Continue	Continue	Abandon
												Continue	Abandon
													Abandon