Master Thesis MSc Finance and Investments

Valuation of the equity of Det Norske Oljeselskap ASA

Assessing the value of an E&P company through three different lenses

Master Thesis

Copenhagen Business School 2016

MSc Finance and Investments

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Number of pages: 119

Number of standard pages: 119.8

Number of characters: 272 442

Date handed in: 12.08.2016

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Executive Summary

The modern day *Det Norske Oljeselskap* was born in 2014 with the acquisition of Marathon Oil Norge, and positioned the company as a strong market participant with ambitious exploration programs and significant ownership stakes in the unparalleled Johan Sverdrup oil field, as well as other low cost oil fields.

The analysis of the historical financial statements of both *Det Norske Oljeselskap* and the selected peer group showed inconsistency across time and peer companies in terms of both profitability and liquidity, due to the high dependency on selected oil fields. *Det Norske Oljeselskap* is highly levered, with low profitability in the past years as many of the oil fields in the portfolio are either in a decline phase, or under development. Alongside projections of future production levels in the current oil field portfolio, and extensive strategic analysis, we were able to forecast the future financial statements of *Det Norske Oljeselskap*.

As the world has been shaken by plummeting oil prices, companies in the oil exploration and production industry have encountered declining revenues and large upheavals in their operating environment. However, in this changing industry, some factors are kept constant, with demand for petroleum products expected to be sustained in the future due to the high dependence upon these resources in industrializing economies, and the traditional transporting sector. The consistency in future demand coupled with extensive exploration programs and increased focus on the less saturated Barents Sea basin leads us to believe that future supply of petroleum from Det Norske Oljeselskap is very plausible, despite petroleum being a non-renewable resource.

For the purpose of valuing the company we apply a *residual operating income (ReOI)* model, *net asset value (NAV) model*, and *real option (ROV)* model. The model choice relies on the investor's assumption of how the company will operate in the future, whether or not it can exist in all eternity, as well as whether the management has flexibility in undertaking oil field projects. Our ReOI and NAV uses a deterministic approach to assess the future price of oil, whereas the ROV is based on a stochastic joint-diffusion process of the oil price and the convenience yield, where the latter of the two is mean reverting. The ROV concludes that the option is an American call, where a least Square Monte Carlo method is applied to assess the final value of the option to develop an oil field.

With a share of *Det Norske Oljeselskap ASA*'s equity trading at NOK 62 per share as of 31.03.2016, the ROV model is by far the most pessimistic at NOK 9.99 per share, whereas the ReOI model is most optimistic at NOK 86.68 per share, and the NAV model is in between at NOK 76.33 per share. We argue that in a country with reliable and publicly accessible information about oil fields, the NAV is superior to the two compared models, resulting in a target share price for *Det Norske Oljeselskap ASA* at NOK 76.33 per share.

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1 Introduction

1.1 Introduction and motivation

Few people believed that treasures such as oil and gas could be found on the Norwegian Continental Shelf[1]. From Phillips Petroleum's application for exploration on the Norwegian Continental Shelf in 1962, the oil industry has provided a substantial income to the Norwegian government. In 2015, the petroleum industry represented 20 percent of total incomes for the Norwegian government[2], and 15 percent of GDP[3], making it the most important industry in Norway in recent years[4].

However, with the oil price dropping from an all-time high of USD 143.60 in July 2008[5] to hovering around USD 35-40 in March 2016, a new question arises – is the fairytale now over? High oil prices have attracted new market participants, which alongside a stable supply by existing producers have created a discrepancy between supply and demand. While global oil consumption has experienced a 1.3 percent compound annual growth rate (CAGR) from 2011 to 2015, global oil supply has seen a CAGR of 2.0 percent over the same period[6]. A natural effect of this over-supply is a lower oil price, where we can easily point our fingers across the Atlantic, where North American oil and gas production volumes have enjoyed a tremendous 7.1 percent CAGR from 2010[7]. The tension between established participants and entrants in the market is extensive these days, and has a huge ripple effect on companies operating on the Norwegian Continental Shelf.

Due to the Norwegian economy's dependency upon an evidently turbulent industry, with huge challenges looming in both near and distant future, we wanted to better understand the dynamics of the market through the lens of one specific market actor. From its inception in 1971, *Det Norske Oljeselskap* has grown to become one of the most interesting pure oil exploration and development companies in Norway, with operations on the Norwegian Continental Shelf stretching from the Barents Sea in the north to the North Sea in the south.

This thesis seeks to value *Det Norske Oljeselskap ASA*, more commonly called Detnor, in the light of the recent oil price plunge. In assessing the true value of Detnor we will discuss a range of different valuation techniques, in order to better understand which model can capture the true value of an E&P company. The models we apply are an accounting based valuation model, a model based on net asset value, and finally a real options model.

[1] Regjeringen: "Norway's Oil History in 5 Minutes"
[2] Regjeringen: "Oil and gas"
[3] Regjeringen: "Olje og gass"
[4] Regjeringen: «Norges viktigste næring»
[5] Market data from Thomson Reuters: Brent Crude Oil prices
[6] U.S. Energy Administration: "Global petroleum and other liquids"
[7] U.S. Energy Administration: "International Energy Statistics"

1.2 Problem statement

In order to value the equity of *Det Norske Oljeselskap ASA* properly, we need to analyze the usefulness and appropriateness of different theories in the field. In our set of sub questions, we seek to discover the main drivers of the equity value of Detnor, before compiling these components into our valuation models. The main research question of this thesis is:

"What is the value of Det Norske Oljeselskap ASA's equity, as of 31.03.2016, and how does introducing optionality in development projects affect the results?"

The sub questions will be partially answered along the way through concluding remarks in selected chapters where appropriate, as well as summarized in a final conclusion.

After a brief introduction to the industry, we should be able to understand the dynamics of the industry, as well as Detnor's place in it. In order to forecast future financial statements, we need to acquire an understanding of how these have evolved in the past. By analyzing the financial statements of Detnor and a carefully chosen peer group, we seek to build a foundation from which we can forecast the future:

(1) *How has the profitability and liquidity developed for Detnor in the past, relative to its peers?*

The financial statement analysis should however be accompanied by an internal analysis of the company's resources. An internal analysis will shine a light on the core competences and resources of Detnor, and can bridge the gap between the historical financial statement analysis, and how the company can develop in the future. Hence, the second sub question yields:

(2) *What are Detnor's core resources, and how do they utilize them?*

In the next two sub questions we seek to bridge the gap between internal competences and external factors. For an oil exploration and production (E&P) company, the oil price development has a significant impact on profitability. Thus, understanding what affects the oil price is of essence to know more about how *Det Norske Oljeselskap ASA* will perform in the future. Acknowledging that the current oil price is historically low, Detnor and its competitors are all prone to a changing competitive environment, thus a natural extension to the previous question is:

(3) *What are the main drivers of the oil price, and how will these affect Detnor and the E&P industry?*

In addition to the oil price there are other external factors that may impact an E&P company. An E&P company is prone to several stakeholders that can affect its operations, hence our next sub-question is:

(4) *How is Detnor affected by other external factors?*

We have predetermined three valuation methods we will use in the thesis. In order to estimate the value of the Detnor equity, we need to examine the three valuation methods, and how they capture the value of an E&P company. The analysis will include a discussion of present value models and real option models, and how these differ when applied to such a company. The main question to be answered is:

(5) *What are the characteristics and assumptions of the three different valuation methods?*

Answering questions 1-5 should provide a deep understanding about the company, industry and the required input variables for the three valuation methods. Now we want to utilize these analyses to estimate parameters for the valuation methods.

(6) *How does answering the previous sub-questions translate into appropriate forecasts within the respective frameworks of our chosen valuation models?*

Combined, all of these questions will lead up to a suggested valuation framework, and furthermore result in a valuation of Det Norske Oljeselskap ASA's equity.

1.3 Methodology and data

1.3.1 Research paradigm

A research topic can usually be assumed to fit under one of four paradigms, presented by Guba[8]; positivism, post positivism, critical theory and constructivism. The choice of paradigm generates a framework and direction of the thesis, and defines the angle of which the findings should be read. The former two paradigms are rooted in quantitative theory, whereas the two latter paradigms are subject to a qualitative epistemology and a complex methodology. Our thesis seeks to find a generalizable truth that is easily replicated by others, under our pre-determined assumptions. The shortfalls in obtaining completely independent and generalizable results exclude the positivism paradigm, where reality is fully quantifiable and allows no room for subjectivity. The post-positivism approach loosens this objectivity, and allows more complexity to realism through acknowledging that the researcher can never be fully objective. Hence, our thesis belongs under the post-positivistic paradigm, where objectivity is the goal, but can never be fully achieved.

The ontology under the post-positivistic paradigm is known as critical realism. Critical realism assumes that one truth does exist, but that the researcher can never fully find the truth. In our thesis, we strive to value the Detnor shares correctly, but acknowledge that the subjectivity of our estimates and tools can bring us a step away from the truth. The epistemology of the post positivistic paradigm is modified objectivism; the researcher might be influenced by whatever he or she researches. Hence, our thesis seeks to find the truth,

[8] Guba, Egon; The Paradigm Dialog (1990)

but we acknowledge the subjectivity of our measures, and thus replicating the research would depend on making the same assumptions.

Our valuation techniques are prone to subjective measures in which econometric testing is not always possible, nor applicable. Whereas some chapters in this thesis use econometric approaches, these are put in a valuation context in which their inherent objectivity might be transformed to subjectivity. Our methodology strives to use econometrics where possible, decreasing the subjectivity aspect as much as possible.

1.3.2 Thesis structure and theoretical framework

In order to understand the industry in which Detnor operates, the thesis will initially give a short presentation of the oil and gas industry, with special attention to exploration and production. With this background in mind, we will look at the core assets of Detnor; the oil fields, and the general classifications of these. Following the introduction to *Det Norske Oljeselskap ASA* and the industry, we will address the main drivers of the oil price, and discuss its prior and recent movements.

Whereas the introductory chapter is vital for understanding the comprehensive nature of oil production, finding a comparable peer group is equally important to evaluate the relative performance of Detnor in an industry context. The peer group will be our reference point in the subsequent financial statement analysis, in which Detnor's profitability and liquidity will be analyzed thoroughly within the framework of Stephen Penman[9].

Following an introduction to the industry, peer companies, and the oil price, as well as a financial statement analysis, we will analyze the strategic environment of Detnor with appropriate theory. In the external strategic analysis, we apply Porters Five Forces[10], and PESTEL analysis[11], whereas the internal analysis is based on a resource analysis. With this comprehensive strategic analysis, we will be able to depict the strategic environment of Detnor today, and how we predict that it will evolve in the future.

In our valuation, we apply several models, that all paint alternative and complementary pictures of the same object. The shortfalls of one model can be addressed by another, and vice versa, hence an important part of our valuation is discussing the background and implications of our choice of models. The first model applies Penman's framework[12], with specific reference to the residual operating income model. The second model is known as a net asset value (NAV) model, which can be considered as a version of an Asset-based valuation

[9] Penman (2003):" Financial Statement Analysis and Security Valuation"
[10] Fjeldstad & Lunnan (2014): "Strategi"
[11] Fjeldstad & Lunnan (2014): "Strategi"
[12] Penman (2003):" Financial Statement Analysis and Security Valuation"

model[13]. Penman's asset-based valuation model does not involve forecasting[14], but in order to find the market value of each oil field in the NAV model, we are required to forecast its future cash flows, in lack of a market place for oil fields.

The latter model is furthermore extended into a real option valuation model[15], partially based on some of the input from the NAV. The real options valuation pays special attention to determining a fitting stochastic process for the oil price, and the econometric techniques needed to perform the valuation. The framework for valuing oil fields using real options mainly relies on papers by Eduardo Schwartz[16], supplemented with other accompanying studies.

1.3.3 Data sources

The reliability of the data is important to perform a high quality analysis. This might however be complicated if the creator of the source is biased or don't have the required knowledge. Even information from Detnor or from publications could be biased, but the error is likely to be less from both the company itself, and accredited sources. This chapter will discuss the reliability of data.

Market and asset data – Our preferred market data agencies in this thesis are primarily Bloomberg and Thomson Reuters, and secondarily Quandl. Bloomberg is considered a reliable source in all our market data, being one of the most acknowledged financial platforms in the world. Thomson Reuters is a similar service.

Other data – Whereas the previously introduced data is readily available from reliable sources, data related to other external sources include noise and thus it can be difficult to disentangle true values. As we described in the introduction, information can often be colored by the author. Hence, sources in this thesis are kept to a small cluster of what we consider to be reliable sources of information. These sources of information are mainly governmental, stock exchanged corporations and large organizations (the term of large will be a subjective measure), accredited journal articles, academic books and information from Detnor. These sources will unfortunately not give us all the information we require, and information from newspapers and unlisted companies will have to be used.

[13] Penman (2003):" Financial Statement Analysis and Security Valuation" page 73
[14] Penman (2003):" Financial Statement Analysis and Security Valuation" page 18
[15] Schwartz (2013): "The Real Option Approach to Valuation: Challenges and Opportunities"
[16] Cortazar & Schwartz (1998): "Monte Carlo Evaluation of an Undeveloped Oil Field"

The strength in governmental information is the independence. The Norwegian Petroleum Directorate's (NPD), which answers to the Ministry of Petroleum and Energy[17] and The U.S. Energy Information Administration (EIA)[18] are the two governmental sources mostly used.

Stock exchange companies are subject to regulation and strict rules regarding reporting. Hence, the reliability of the information presented is considered satisfactory. Detnor is a stock exchanged company and considered as one of our most important sources of information. With regards to the respective companies' financial statements, we rely on the annual reports to depict a reliable picture.

Data from large organizations are used to assess the large trends in the supply and demand in the oil market. The two main organizations sourced in this thesis are the International Energy Agency (IEA) and the Organization of the Petroleum Exporting Countries (OPEC). These organizations have data and information from various member countries, as well as supporting data from other economies.

For a research paper to be published in a well-known journal there are certain requirements that have to be met. The same applies for publishing a book through a well-known publisher. Published research articles and books in accredited journals will we therefore define as reliable sources.

Newspapers and unlisted companies are affected by many factors, for example political angles. Unlisted companies are not prone to the same regulations as listed companies. Therefore, information from these companies can for example be overly positive, since it is unlikely to have any negative regulatory consequences for the company.

1.4 Limitations

- The thesis is purely based on external, secondary information. Primary data in the shape of interviews with key personnel in the company could enhance our analysis. This was unfortunately not possible. However, this mirrors the reality of many investors' access to information, and is therefore a realistic approach.
- We have set a cut-off date for our valuation of 31.03.2016, and thus all information released after this date will be disregarded.
- We assume that the reader possesses knowledge about the most commonly applied valuation models and financial statement analysis. The real option valuation on the other hand will be elaborated more than the other models, but requires the reader to have a basic knowledge about stochastic processes and the application of these in an option context.

[17] The Norwegian Petroleum Directorate: "About us"
[18] U.S. Energy Information Administration: "About us"

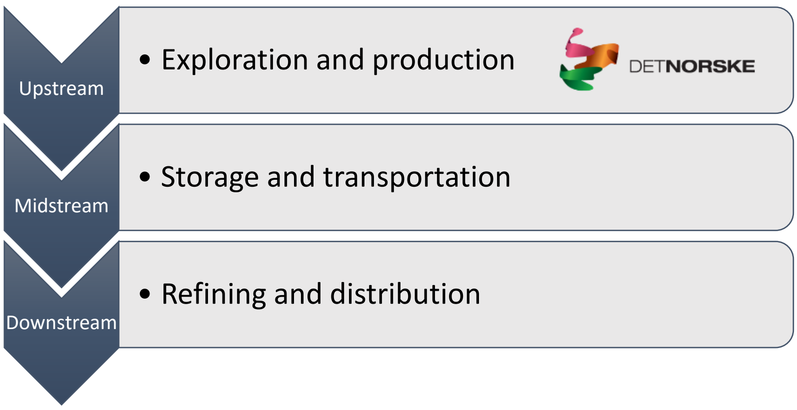
- In order to understand certain chapters of the appendices, a basic knowledge of programming (preferably R) is necessary.
- The intention of this thesis is to develop a tool for valuing *Det Norske Oljeselskap*, which excludes technical aspects of oil production.

2 Detnor and the E&P industry

2.1 Introduction to the E&P Industry

Oil production can be divided into onshore- and offshore activities. Despite some minor discoveries of onshore oil in Norway[19], Norwegian oil production is currently exclusively happening offshore[20]. Detnor's operations are only conducted on the Norwegian Continental shelf, and consequently their production is offshore. The offshore and onshore production of oil requires different processes, knowledge and costs. Generally, onshore infrastructure is less complex and cheaper than offshore infrastructure[21]. This thesis will mainly analyze the offshore industry in which Detnor operates, whereas the onshore industry will be shortly introduced through the sections dealing with the global supply of oil.

The value chain of oil production can be divided into upstream, midstream and downstream activities, going from the exploration phase until delivery of crude- or refined products.



The upstream sector, where Detnor operates, of the value chain is the part of the process concerned with the exploration and production (E&P) of oil. This is a time consuming and rigorous process involving governmental approvals, exploration of petroleum resources, and eventually the production of oil[22]. Typically, the upstream sector is a high risk game[23]. Finding the needle in the haystack is difficult; discovering

[19] Norwegian Petroleum Directorate: «Disappointed on land»
[20] Deutsche Bank (2013): "Oil & Gas for Beginners"
[21] The World Bank Group (2009): "The Petroleum Sector Value Chain"
[22] PSG Dover: "Defining Upstream Oil & Gas"
[23] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 57

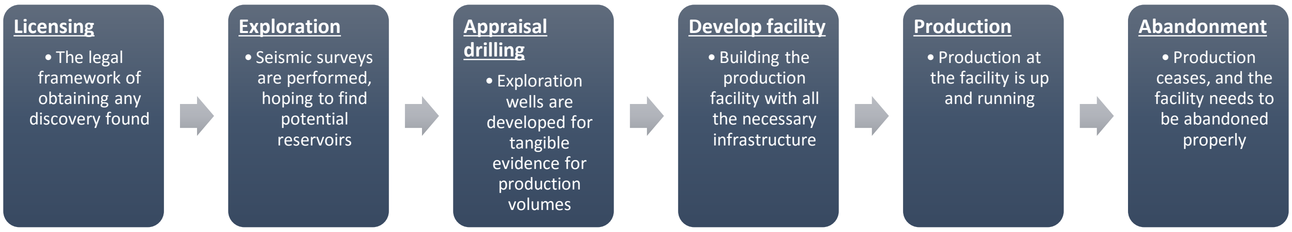
a potential oil reservoir is very challenging, and the feasibility of the project cannot be fully assessed until the exploration wells show positive results.

The midstream sector is in the grey zone between upstream and downstream, and can contain parts of both. Typically, midstream refers to the storage and transportation between the upstream and downstream sector, that is; an intermediary between the produced oil and the refinery[24]. In offshore oil production it might be necessary to transport the oil produced to a refinery onshore, meaning that emphatic pipelines need to be built in order to transport the oil.

Once the oil is produced in the upstream sector, a company in the midstream sector will transport the oil to a refinery belonging to the downstream sector[25]. The refineries typically process and refine the crude oil. Due to its low return, low growth and a capital-intensive nature, the downstream sector has been described as one of the least attractive industries in the world[26].

2.2 Value activities in the E&P industry

The following figure shows value activities in the industry, from legal ownership of a geographic area, until production and abandonment.



Licensing – In order for the production process to be profitable, the producers need assurance that they have exclusive rights to any discoveries in a specified area[27]. A license provides this necessary legal framework. Under §1-1 in the Norwegian Law of Petroleum Activities (*"Petroleumsloven"*), the Norwegian State has the proprietary rights to all subsea deposits[28], and licenses to operate on these are offered to the public once or twice a year. There are two types of licenses awarded in Norway[29]:

[24] PSG Dover: "Defining Upstream Oil & Gas"
[25] PSG Dover: "Defining Upstream Oil & Gas"
[26] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 163
[27] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 48
[28] The Norwegian Petroleum Directorate: "Act 29 November 1996 No. 72 relating to petroleum activities"
[29] Det Norske Oljeselskap: "Success for Det norske in license round"

1. *Awards in Predefined Areas (APA)* – Also known as “Tildelingen I forhåndsdefinerte områder” (TFO) in Norway. These licenses are awarded once a year, and are geographically tied to an area where there is already a solid foundation of infrastructure.
2. *The ordinary licensing round* – These licenses are awarded every other year, and are located in areas where there is less or no existing infrastructure. The Barents Sea is a typical example of geographic area where these licenses can be awarded.

Exploration – Once a license is awarded, the oil company needs to perform a seismic survey in which it can create an artificial picture of the subsurface, using sound waves from specially constructed seismic vessels[30]. Detnor’s prospects are purely based on 3D seismic that can be applied to all oil field sizes, graphing a 3D image of the subsurface[31]. When the seismic survey is done, the attractiveness of the reservoirs is determined, and viable options are considered for drilling[32]. There is high risk inherent in the exploration phase, but it only accounts for approximately 15% of the total capital expenditures of a project[33].

Drilling – Once a license is awarded, and a seismic survey has shown potential reserves, the company needs to gather tangible evidence of recoverable reserves[34]. Firstly, one or more exploration wells are drilled to test the results of the seismic survey[35], before moving on to an appraisal drilling, if the exploration wells give positive answers. The results of the appraisal drilling will determine whether the reservoir has commercial value, and is the last step before the capital demanding development phase can begin[36].

Develop Production Facility – Even though a company has been granted a license for a specified area, the Norwegian government has strict rules about how the field should be operated. In what is called a Plan for Development and Operation of the Petroleum Deposit (PDO), the company needs to create a detailed plan of how the resource will be managed and the impact on society and environment[37]. If the PDO is accepted, the process of putting in place all necessary platforms, wells, infrastructure, pipelines, export terminals, etc., begins[38]. Together, the drilling and development of production facilities account for approximately 85% of the total capital expenditures of the project[39]. As the exploration and appraisal drilling has shown positive

[30] Deutsche Bank (2013): “Oil & Gas for Beginners”. Page 56
[31] Det Norske Oljeselskap: Ordbok
[32] Deutsche Bank (2013): “Oil & Gas for Beginners”. Page 48
[33] Deutsche Bank (2013): “Oil & Gas for Beginners”. Page 87
[34] Deutsche Bank (2013): “Oil & Gas for Beginners”. Page 57
[35] SOTS: “Exploration and appraisal drilling”
[36] SOTS: “Exploration and appraisal drilling”
[37] The Norwegian Petroleum Directorate: “Plans and processes for PDOs and PIOs”
[38] Deutsche Bank (2013): “Oil & Gas for beginners”. Page 49
[39] Deutsche Bank (2013): “Oil & Gas for beginners”. Page 87

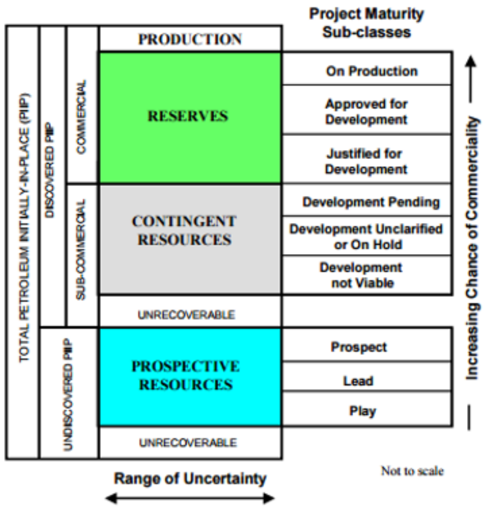
results at this stage, the possibility of a successful project increases, and thus the risk at this phase is significantly lower[40].

Production – Once the production facilities and the surrounding infrastructure is built, the resources can start generating revenue for the company. At this stage, it is crucial that the company maximizes the recovered volumes, as this is the only time in which the project generates revenues. With maximizing recovered volumes in mind, management seek to prolong the lifetime of the oil field, in order to get as much out of the existing infrastructure as possible[41]. The previous phases are highly capital intensive, and require huge upfront costs before the project pays off during production, and thus prolonging the production at an already existing facility is considered very attractive. Hence, new oil fields attached to existing fields (tie-ins) can be very attractive.

Abandonment – As production comes to an end, or production is no longer economically viable, the company needs to shut down and abandon the facility. However, abandoning a project of such size is costly, and requires careful planning[42].

2.3 Reserves classification

The high uncertainty in proving the size of a resource demands a system that is comparable across the industry. The classifications are based on the degree of certainty in the recovered oil volume from the reservoir[43], and are divided into three main categories. Detnor's classifications comply with Oslo Stock Exchange and the Society of Petroleum Engineers (SPE), and thus use SPE's Petroleum Resources Classification Framework[44].



Source: Society of Petroleum Engineers (2007): "Petroleum Resources Management System"

- *1P* – Proved reserves – There is a 90% chance of exceeding the 1P estimate.
- *2P* – Proved + probable reserves – There is a 50% chance of exceeding the 2P estimate.
- *3P* – Proved + probable + possible reserves – There is a 10% chance of exceeding the 3P estimate.

[40] Deutsche Bank (2013): "Oil & Gas for beginners". Page 57
[41] Deutsche Bank (2013): "Oil & Gas for beginners". Page 49
[42] Deutsche Bank (2013): "Oil & Gas for beginners". Page 53
[43] Mitchell, John (2004): "Petroleum Reserves in Question"
[44] Detnor Annual Report 2015 – Page 39

From the figure[45], we see that the classification scheme is based on whether a resource is discovered, commercial or sub-commercial, and the project stage in the project maturity sub-classes. In the company's reports, classifications are based on a third party and in-house assessment of the resources[46], in order to mitigate the risk of subjectivity of measures.

Within the *reserves* category, we find the previously introduced 1P, 2P and 3P classifications, that are either on production, approved for development or justified for development. Detnor's assessments of recoverable reserves are based on proved and probable (2P) reserves[47], and are next to perfectly consistent[48] with the Norwegian Petroleum Directorate estimates[49]. Hence, we will apply the NPD estimated reserve sizes for the remainder of this thesis, unless otherwise stated.

The second level of discovered petroleum concerns sub-commercial discoveries, which are classified as development pending, development unclarified or on hold, or development not viable. These volumes are less certain, and are not recognized in the financial statements[50]. However, we do not rule out the possibilities of these resources having an effect upon the share price, even though they are contingent upon an uncertain occurrence[51]. Resources can be re-classified at a later date; hence contingent resources need to be considered in assessing our value to Detnor's equity.

2.4 About Det Norske Oljeselskap ASA

2.4.1 History of Detnor[52]

Detnor ASA was created in 2007, when Pertra and Det Norske Oljeselskap (DNO) decided to merge Pertra and the Norwegian part of Det Norske Oljeselskap (previously DNO). The combined entity was named Det Norske Oljeselskap, more commonly called Det Norske or Detnor (which is also its ticker).

In 2009, Detnor continued to expand, as they merged with the Norwegian exploration and production company Aker Exploration ASA, owned by the Aker Group. The merged entity kept *Det Norske Oljeselskap*'s name. These two mergers strengthened Detnor's presence on the Norwegian Continental Shelf, and created a solid foundation for becoming one of the major fully fledged Norwegian oil companies, from exploration to production.

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[45] Society of Petroleum Engineers (2007): "Petroleum Resources Management System". Page 7
[46] Detnor Annual Statement of Reserves 2015 – page 17
[47] Detnor Annual Statement of Reserves 2015 – page 17
[48] Compare table in Detnor's annual report 2015, page 109, with NPD fact pages for verification
[49] Norwegian Petroleum Directorate: "Fact Pages"
[50] Detnor Annual Report 2015 – page 76
[51] Detnor Annual Report 2015 – page 76
[52] Det Norske Oljeselskap: "The history of Det Norske"

In order to finance what would become two of the main sources of revenue for the company, engagements on the Ivar Aasen and Johan Sverdrup fields, Detnor acquired Marathon Oil Norge AS, in June 2014[53]. The target held valuable E&P expertise in its employees, high quality assets, and positive incoming cash flows in the near future, meaning that they would fit perfectly into Detnor's strategy, both long and short term.

In the third quarter of 2015, Detnor decided to strengthen their portfolio further by increasing their ownership in currently owned oil fields, and increasing its presence in the North Sea. The former was carried out through the acquisition of the Norwegian subsidiary of Svenska Petroleum[54], whereas the latter was accomplished through the acquisition of Norwegian subsidiary of Premier Oil[55].

2.4.2 Detnor today

Detnor's headquarters are today in Trondheim, but they also have offices in Stavanger, Harstad and Oslo. They are currently organized according to the company structure below.

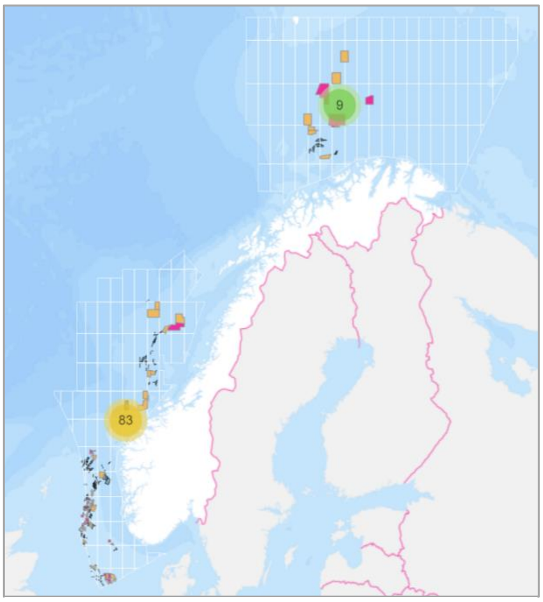
**Source: Authors' contribution in accordance with Detnor Annual Report 2015 (page 27)*

Except for Aker ASA's ownership share of 49.99% through Aker Capital AS, the shares are fragmented among institutional and private investors[56]. The chairman of the Aker ASA board is the well-known Norwegian business profile Kjell Inge Røkke, who is also a board member in Det Norske Oljeselskap ASA. The CEO of Det Norske Oljeselskap ASA is Karl Johnny Hersvik, who has extensive experience from other large Norwegian corporations such as Norsk Hydro and Statoil[57].

[53] Det Norske Oljeselskap (2014): «Det norske acquires Marathon Oil Norge AS»
[54] Det Norske Oljeselskap (2015): «Det Norske acquires Svenska Petroleum's Norwegian Subsidiary»
[55] Det Norske Oljeselskap (2015): "The acquisition of Premier Oil Norge is completed"
[56] See appendix 2 for the 10 largest shareholders
[57] Det Norske Oljeselskap: «About us»

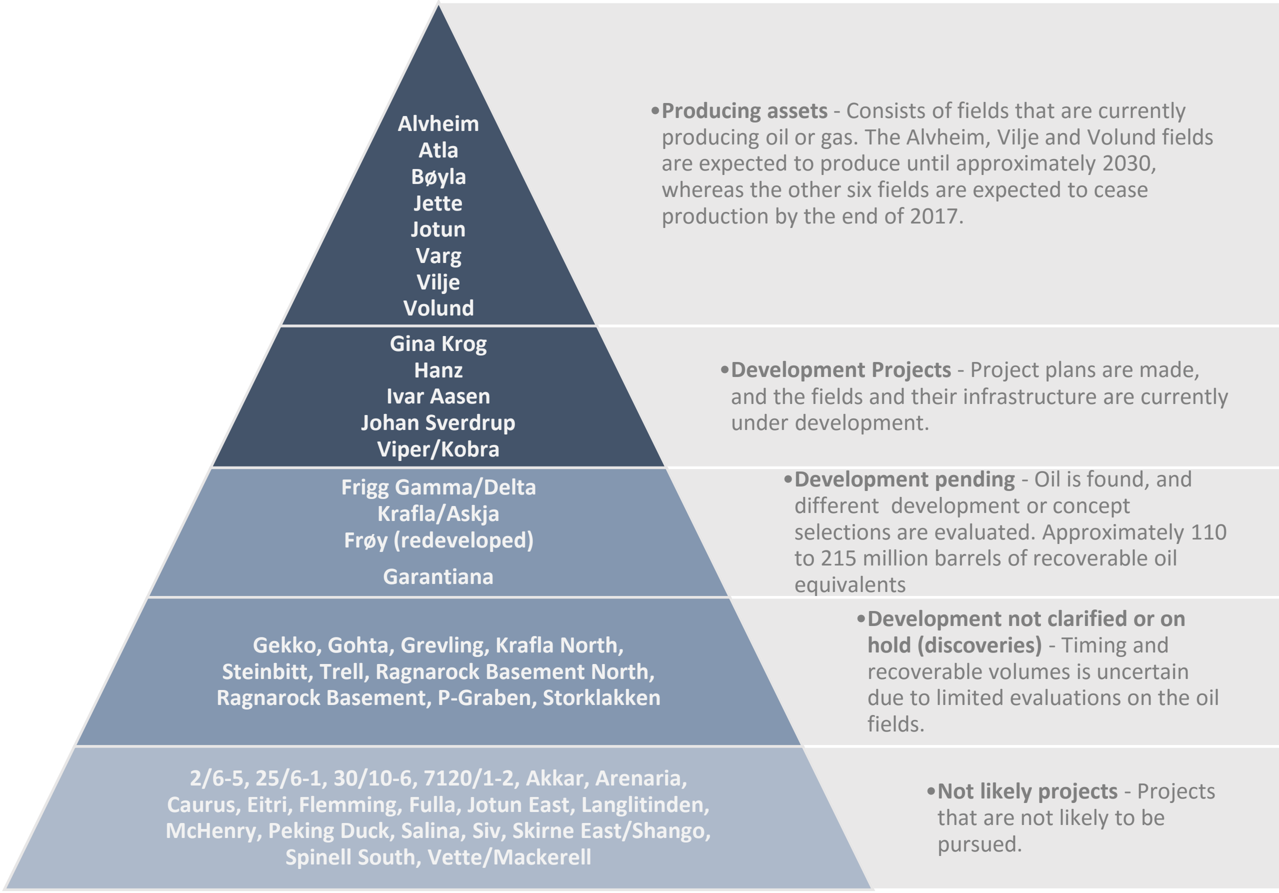
2.4.3 License geography and petroleum assets

The North Sea and Norwegian Sea has been the hub for Norwegian oil production since its inception in the 1960's. The lion's share of Detnor's licenses are situated in the North Sea and the Norwegian Sea (the yellow dot marked with 89), whereas the remaining licenses are in the Barents Sea (the green dot marked with 9). In accordance with Detnor's ambitious plan of continuous growth[58], an exploration office was built in Harstad, Norway, in 2007[59]. The office was intended to serve as an introductory stage of projects in the limitedly explored Barents Sea, where they could acquire better knowledge of the area. The license rounds are still highly concentrated around The North- and Norwegian Sea, with approximately 90% of the licenses concerning these areas in the 2016 license round, but as much as 10% of the licenses were situated in the Barents Sea[60]. Detnor's increased focus on exploring the more unknown potential resources in the Barents Sea shows that they are positioning themselves for future growth. Currently all of Detnor's producing assets are situated in the North Sea[61], with the Alvheim field being the flagship of the producing assets in the company[62]. The following figure shows Detnor's oil fields, according to their respective project maturity sub-classes:



Source: Detnor (2016): "Licenses"

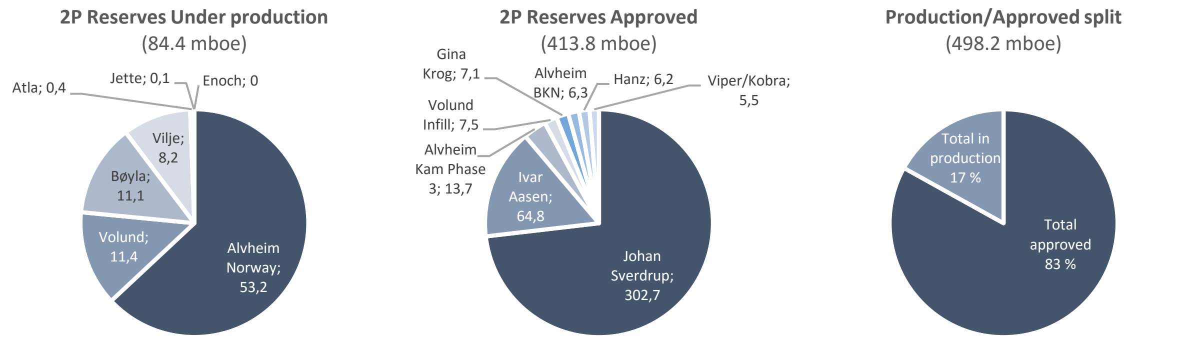
[58] Det Norske Oljeselskap: "Our assets"
[59] Det Norske Oljeselskap (2007): «Pertra Establishes Exploration Office»
[60] Det Norske Oljeselskap (2016): "Rewarded with ten new licenses – thereof six operatorship"
[61] Det Norske Oljeselskap: «Licenses»
[62] Det Norske Oljeselskap: «Production»



**Source: Authors' contribution, based on Detnor Annual Statement of reserves 2015, and NPD fact pages*

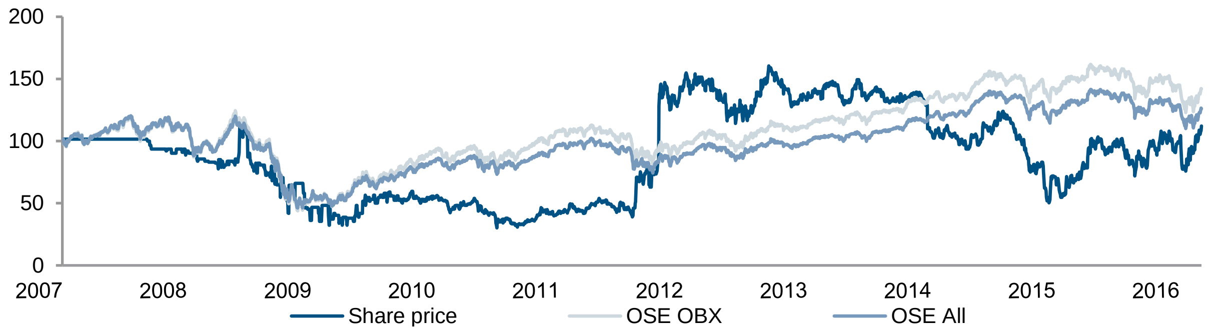
The following pie charts show Detnor's reported split of total recoverable volumes of oil equivalents (oil and gas), as of 31.12.2015, weighted by Detnor's ownership share[63]. From the first chart showing the currently producing fields, Alvheim is by far the largest with 53.2 million barrels of oil equivalents (mboe), with expansion by 6.3 mboe and 13.7 mboe in Kam Phase 3 and Boa Kam North respectively approved. However, the approved Johan Sverdrup field contains more than four times the amount of oil, even after the Alvheim expansion, and is thus the main source of revenue for Detnor in the future. The stock price jumped ≈75% as a result of a twofold increase in the previous estimates of Johan Sverdrup (previously known as Aldous Major)[64]. Hence, we expect the Johan Sverdrup field to have a significant impact on the share price breakdown. Evident from the third pie chart, the total production in currently operating fields accounts for as little as 17% of the total expected volumes in Detnor's portfolio of producing and approved assets. With the large capital expenditures related to the early stages of the exploration activities, we should expect low cash flows before the Johan Sverdrup and Ivar Aasen fields are ready for production.

[63] Detnor annual statement of reserves 2015
[64] Stangeland, Glenn (2011): "Nytt anslag: Aldous dobbel så stort"



2.4.4 Share price development

Equity holders of Detnor have experienced a roller coaster ride from the inception of *Det Norske Oljeselskap ASA.* Following the global financial crisis of 2008 there was an evident turmoil in the market, and both the Detnor stock and the Oslo Stock Exchange took a plunge. Both Oslo Stock Exchange and Detnor picked up the pace, and enjoyed a great upside in the aftermath of the crisis, with Detnor lagging behind Oslo Stock Exchange before the Johan Sverdrup oil field discovery in 2011 redeemed itself as one of the greatest of all time in Norway[65]. The Detnor share has performed better than the Oslo All Share Index and the OSE OBX (consisting of the 25 most liquid stock on Oslo Stock Exchange) from ultimo 2011 too ultimo 2013, but has been lagging behind ever since. As of 31.03.2016, the value of the Detnor share was NOK 62.00.



**Source: Bloomberg, Rebased at 100 (29.12.2006)*

2.5 Detnor's peer companies

In order to paint a nuanced picture of Detnor's performance and strategic positioning relative to the rest of the industry, we need to assess their main peers. When choosing peers, we have strived to find companies that are engaged in the same type of operations[66], that is; offshore oil E&P companies. However, these

[65] Det Norske Oljeselskap: «Johan Sverdrup feltet»
[66] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation"

companies vary vastly in both size and operations, and thus there are no perfectly fitted companies. The following table summarizes the gross peer group, focusing on similar operations[67]:

Name	Operations	Country (headquarter)	Offshore/onshore	Operating geography	Drawback as peer
Det Norske Oljeselskap ASA	E&P	Norway	Offshore	North Sea, Norwegian Sea, Barents Sea	
Cairn Energy	E&P	United Kingdom	Offshore and onshore	North West Europe, Atlantic Margin, Mediterranean	Many basins, onshore and offshore
Enquest Plc	D&P	United Kingdom	Offshore	North sea (and other)	Some production outside Norway
EP Energy	E&P	United States	Onshore	United States	Onshore shale production
Faroe Petroleum	E&P	United Kingdom (Faroe Islands)	Offshore	North Sea, Norwegian Sea, Barents Sea, Celtic Sea, West Shetland	Some production outside Norway
Ithaca Energy Inc.	D&P	Canada	Offshore	North Sea	Little exploration
KMG	Up-, mid-, downstream	Kazakhstan	Offshore and onshore	Kazakhstan	Fully fledged oil company
Lundin Petroleum	E&P	Sweden	Offshore and onshore	North Sea, Norwegian Sea, Barents Sea, Europe, South East Asia	Broad operating geography
Nostrum Oil & Gas Plc	E&P	United Kingdom (Netherlands)	Offshore	Pre-caspian Basin	Not matching operating geography
Novatek OAO	Up-, mid-, downstream	Russia	Onshore	Russia	Mainly onshore natural gas productic
PGNIG	Up-, mid-, downstream	Poland	Offshore and onshore	Norwegian Sea, Europe and Asia	Fully fledged oil company
Premier Oil Plc	E&P	United Kingdom	Offshore and onshore	UK, Asia, South America, Africa	Not matching operating geography
Rockhopper Exploration	E&P	United Kingdom	Offshore and onshore	South America, Mediterranean	Mainly exploration as core operation
Soco Intl	E&P	United Kingdom	Offshore and onshore	Africa, Asia	Not matching operating geography
Tullow Oil	E&P	United Kingdom	Offshore and onshore	Africa	Not matching operating geography

**D&P = development and production*

Evidently, a majority of the peers operates both onshore and offshore, all across the world and in all parts of the oil supply chain described in previous chapters. We choose to narrow down our peer group to the companies that:

1. Mainly operate in the same part of the value chain as Detnor (Upstream E&P)
2. Mainly operate offshore
3. Trade on a European Stock Exchange

A fourth criterion could include the geography of the peers' operations, but this would narrow down the search to very few candidates, leaving us with a very small peer group.

2.5.1 Peer Group

The following is a brief introduction[68] to the resulting peer group, which will be used as a benchmark towards Detnor in the remainder of the analysis.

[67] Table input from the respective companies' web pages. For URL's, see bibliography.
[68] Company descriptions from company home pages, and "key info" is as of 31.03.2016, using Bloomberg.

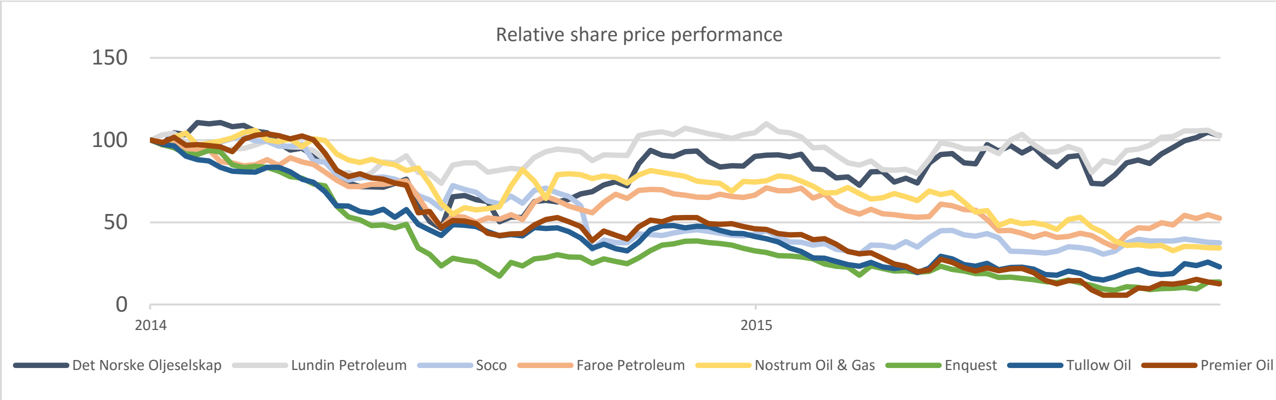
COMPANY	LOGO	COMPANY DESCRIPTION	KEY INFO	
LUNDIN PETROLEUM		Swedish E&P company mainly operating in Norway and South East Asia. Due to its similarity to Detnor, this is the main peer in the group	**Country** **Enterprise value** (SEK) **Market cap** (SEK)	Sweden 8,965 5,660
ENQUEST		Largest Brittish E&P company operating in the UK part of the North Sea. As opposed to Detnor, EnQuest has no exploration activity.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	United Kingdom 1,499 277
FAROE PETROLEUM		Faroese E&P company listed in the UK. Operations in the North-, Norwegian- and Barents Sea, as well as outside United Kingdom.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	Faroe Islands (UK) 186 252
NOSTRUM OIL & GAS		Dutch E&P company with main operations in the pre-Caspain Basin.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	Netherlands (UK) 1,343 644
SOCO INTERNATIONAL		UK based E&P company with main operations in Africa and Asia.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	United Kingdom 650 756
TULLOW OIL		UK based leading African E&P company mainly operating in Africa. Exploration licenses in Norway from acquiring Spring Energy Norway AS in 2013.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	United Kingdom 6,065 2,580
PREMIER OIL		UK based E&P company with operations in UK, Asia, Africa, and South America. Sold its Norwegian subsidiary to Detnor in 2015.	**Country** **Enterprise value** (GBP) **Market cap** (GBP)	United Kingdom 2,340 325

**Source: Bloomberg (key info) and company home pages (company description)*

2.5.2 Peer Comparison

Apparent from the graph, showing the relative share price performance of Detnor to its peer group, with 27.06.2014[69] being the base year (set equal to 100), the Detnor share has outperformed most of its peers. Unsurprisingly, as Lundin Petroleum and Detnor share the ownership of many of the same main assets, Lundin Petroleum (grey line) exhibits much of the same tendencies as the Detnor share.

[69] 27.06.2014 is chosen because this is the first day of trading after EnQuest's initial public offering. See Enquest press release as of April 9th 2010: "Unconditional Trading Expected to commence in shares of Enquest Plc on Nasdaq OMX Stockholm"



**Share prices obtained from Bloomberg*[70]

Even though the companies trade on European Stock Exchanges, they might enjoy different taxes due to operations in one or several other countries. In assessing the tax rates, we have used the corporate tax rate in the country of operation if they only operate in one country, and if operations are conducted in several countries, we use a weighted average of the corporate tax rates. The latter is given in the annual reports of the respective companies of which this is applicable. Tax rates and their origin is given in the respective companies' financial reports in appendix 5.3.

3 Financial Statement Analysis

3.1 Introduction

3.1.1 General

Our financial statement analysis is mainly based on Stephen H. Penman's (2003) book *Financial Statement Analysis and Security Valuation*, with elaborations from other sources when necessary. The chapter includes a brief discussion of how financial statements might differ between industries, before applying Penman's framework of reformulating the income statement and balance sheet for further analysis. In order to achieve an in-depth knowledge of Detnor's operations we will apply the same framework to Detnor's previously introduced peers, and analyze them accordingly. The chapter will discuss the rationale of our Detnor analysis thoroughly, whereas the peer analysis is merely used as a benchmark with regards to the bullet points in the analysis. An elaborated peer analysis can be found in appendix 5.3.

Both Detnor and our chosen peer group use IFRS accounting standards, hence adjustments related to accounting standards have not been necessary. Furthermore, it has not been necessary to adjust for leasing when analyzing and comparing the companies in our peer group with Detnor, as consensus seems to be

[70] **Bloomberg tickers**: Det Norske Oljeselskap – *DETNOR:NO*, Lundin Petroleum – *LUPE:SS*, EnQuest – *ENQ:LN*, , Faroe Petroleum: *FPM:LN*, Nostrum Oil & Gas – *NOG:LN*, Soco Intl. – *SIA:LN*, Tullow Oil – *TLW:LN*, Premier Oil – *PMO:LN*

smaller sized operating leasing of what can be classified as office premises and IT services. There are however certain aspects of the analysis of financial statements of an E&P company that are industry specific, and will be important when discussing Detnor's debt covenants later.

3.1.2 Special features of the oil industry

Exploration and EBITDAX – The financial reporting in the oil and gas industry is very similar to that of other industries, with a few exceptions. Later in this chapter, we will analyze the income statement and balance sheet closely, where it will be evident that Detnor incur large exploration costs. These costs are very typical to resource-based industries, where there is large uncertainty associated with a potential discovery. Most of the large upstream participants use what is known as the *successful efforts* method, in which exploration that leads to proven resources will be capitalized, whereas exploration that does not lead to proven resources will be charged as an expense in the income statement[71]. The alternative to the successful efforts is the full cost method, in which all exploration costs are capitalized, regardless of the outcome of the exploration. In our peer group, all companies, including Detnor themselves, apply the successful efforts method[72], hence we do not need to adjust the financial statements according to this.

The exploration aspect of the oil and gas industry has further implications on the perception of profitability across companies, as there may be lack of consistency in this estimate from year to year. Exploration is crucial for an upstream company, but is not only affected by management strategy, but also the government. Hence, it may be beneficial to adjust EBITDA by adding back exploration expenses, creating the earnings before interest, tax, depreciation, amortization and exploration (EBITDAX) measure.

3.1.3 Currency reported

As of October 15th 2014, the functional currency of Detnor changed from Norwegian Kroner (NOK) to U.S. Dollars (USD), due to the acquisition of Marathon Oil Norge AS. Former Marathon Oil Norge AS had a majority of its income denoted in USD, and thus the functional currency of Detnor was shifted towards USD. In accordance with IAS 21, this triggered a change from reporting in NOK to USD. The effects of this change on the income statement and balance sheet are as follows[73]:

- **Income statement** – Revenues and expenses are translated using the average exchange rate over the period, as long as this estimate is representative of the exchange rate at the date of the transaction. If this is not the case, the exchange rate on the transaction date is used.
- **Assets and liabilities** –Translated using the exchange rate at the balance sheet date.

[71] Deloitte (2008): "International Financial Reporting Standards: Considerations for the Oil & Gas Industry"
[72] See annual reports of the respective companies
[73] Det Norske Oljeselskap ASA: "Annual Report 2014"

- **Equity transactions** –Translated using the exchange rate at the transaction date.

In this analysis of Detnor we will however use NOK as our choice of currency, as Detnor is a Norwegian company listed on Oslo Stock Exchange, and thus has a stock price denoted in NOK. The following exchange rates are based on the above discussion[74]:

USDNOK	2010	2011	2012	2013	2014	2015
Income Statement	6.04477	5.60588	5.81838	5.87817	6.30827	8.06948
Balance Sheet	5.82180	5.97510	5.56480	6.07130	7.45200	8.84310

3.1.4 Tax

E&P companies operating on the NCS are prone to two different tax rates; ordinary petroleum tax rate/corporate tax rate and the special tax rate[75]. The Norwegian corporate tax rate was 28% until 2013[76], before changing to 27% from 2014[77] and lately changed to 25% in 2016[78], and applies to interest costs and other financial items. The special tax rate is 53%, making the effective tax rate 78%. The tax system for oil and gas taxation is however more complex than a flat corporate tax rate, with tax depending upon the rate of success in the exploration phase. The corporate tax rate however does apply to those operations not subject to the special tax, and thus we can separate the tax on core-operations, non-core operations and tax on net financial expenses (NFE) by acknowledging that:

$$Total\ tax = Tax\ on\ core\ operations + Tax\ on\ non\ core\ operations + Tax\ on\ NFE$$

Where, in the case of Detnor, the tax on non-core operations typically includes adjustments related to special impairments etc., which will be discussed later. NFE is taxed at the corporate tax rate.

3.2 Reformulation

3.2.1 Accounting standards

Both Detnor and the presented peer group follow IFRS accounting standards, meaning that we do not have to make adjustments to obtain comparable results. We have previously introduced the successful efforts method, and the effect of using this method relative to full cost. According to IFRS 6, a company can choose between the full cost and successful efforts method in the exploration and evaluation phase[79], but all of the studied companies apply the latter method. Hence, all companies in our research capitalize their exploration

[74] Bloomberg estimate: exchange rate for USDNOK (NOK BGN Currency)
[75] Deloitte (2014): "Oil and Gas Taxation in Norway"
[76] KPMG: "Corporate Tax Rate Tables"
[77] Deloitte (2014): "Oil and Gas Taxation in Norway"
[78] Ministry of Finance: "Skattesatser 2016"
[79] Ernst & Young (2009): "US GAAP vs. IFRS, the basics: Oil and gas". Page 2

after the same principles, and no adjustments are necessary. Adjustments are thus solely made as to reflect the core and non-core operations of the company and create clean and comparable results across the chosen peer group.

Furthermore, some items related to exchange differences on translation from NOK to USD, and actuarial gain/loss on pension plans are reported in the statement of comprehensive income. Penman argue that income must be calculated on a clean surplus basis[80], hence we have added these items back to the income statement, as non-core items.

3.2.2 Transitory items

2012 – Due to technical challenges with one of the wells in the planned Jette field, the development plan had to be revised, which resulted in higher drilling costs and lower recoverable reserves. We acknowledge that impairments generally are a non-transitory part of an oil company's operations, and Detnor is no exception with impairments occurring in all of the periods analyzed. However, we choose to differentiate between transitory and non-transitory impairments, in which the transitory impairments include internal errors and shortcomings that do not happen on a daily basis, such as with Jette. What we define as non-transitory impairments are those that are directly affected by macroeconomic variables. Producing licenses and development licenses are prone to impairment testing in which cash flows are discounted based on expected oil prices (using forward curve), foreign exchange rates, inflation, and a discount rate[81]. The before tax effect of the impairment adjustment with regards to Jette is 1,880 NOKm, and 477 NOKm after tax.

2014 – With the 2014 acquisition of Marathon Oil, Detnor incurred several expenses such as consulting fees that would not otherwise occur. However, keeping in mind Detnor's previously discussed M&A activity, with three acquisitions since the Marathon Oil acquisitions, the transitory nature of this type of activity is questionable. Due to Detnor's ambitious growth plans and recent acquisitions, we choose to classify M&A activity as non-transitory.

3.3 Profitability analysis

When choosing Detnor's peer group our selection criteria were mainly based on industry and geography. Even though the selected peer group is more or less comparable within these frames, there are drawbacks related to project timing. As previously introduced, the first stages of an oil field project are associated with heavy capital expenditures and no revenue, whereas the production phase is mainly associated with operating income and expenses. This issue has at least two implications:

[80] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 357
[81] Detnor Q3 2012 report

1. *Inconsistency across time* – The return on net operating assets (RNOA) of a company can vary vastly over time due to an increased asset value in the early phases (exploration and development), with revenue lagging behind until the field under development is re-classified as a production facility[82]. Hence all else equal, the RNOA of a company that relies on a few large oil fields, such as Detnor, will necessarily vary greatly across time, starting of as negative before hopefully recovering as production begins.
2. *Inconsistency across companies* – The same argument as above is applicable to comparing profitability across companies; profitability varies greatly across the life of a project, and thus comparing a company that is relatively heavier on development phase projects than production phase projects, can cause the latter to appear more profitable.

There is no evident alternative to mitigating this drawback on our profitability analysis, but it is increasingly important to analyze why the profitability measure yields the result it does. We will start out by discussing Detnor's profitability, before turning to the peers for a broader understanding of the industry's profitability.

3.3.1 Detnor

For the profitability analysis of Detnor we seek to find the underlying profitability drivers through a breakdown of the return on common equity, also known as ROCE[83]. Special attention is also dedicated to the return on net operating assets (RNOA), because of its inherent dependence upon the company as a whole, and not only equity. This feature is very nifty when comparing the profitability across peers later, as we obtain a measure of the company's operation as a whole. In accordance with Penman's approach[84], balance sheet measures are an equally weighted average of last year and current year.

First level breakdown – Leverage effect

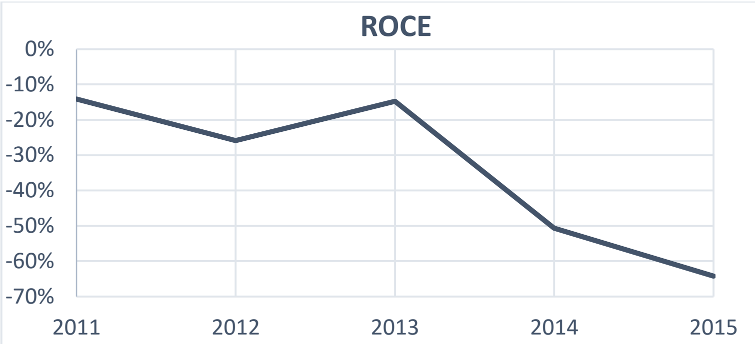
The first level breakdown separates the operating activities and financing activities, and consists of return on net operating assets (RNOA), financial leverage (FLEV) and operating spread between net operating assets and the net borrowing cost (SPREAD).

$$ROCE = RNOA + [FLEV * SPREAD] = \frac{OI}{NOA} + \left[\frac{NFO}{CSE} * (RNOA - NBC)\right]$$

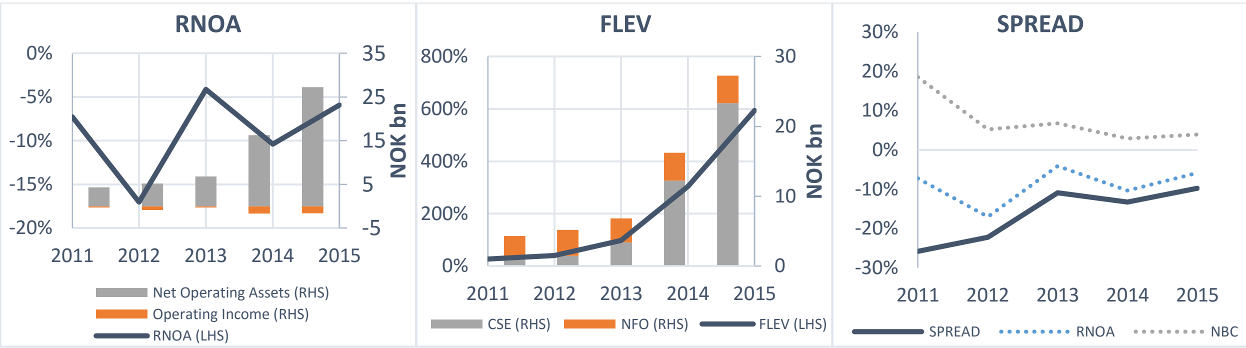
From the following graph we can conclude that Detnor have experienced a negative and falling return on common equity (ROCE) for the last five years. From 2011 to 2013 Detnor experienced a negative ROCE, meaning that the company destroyed shareholder value, assuming that required rate of return is positive.

[82] Detnor annual report 2014
[83] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 351
[84] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 302

After 2013 this value destruction was enhanced even further, ending up at a ROCE of -64%, in 2015, destroying shareholder value at an increasing pace.



However, as pointed out in the previous sub-chapter, we expected some inconsistency across time for the profitability, thus we need to break down the ROCE measures according to the formula presented:



Looking at the first element of the ROCE formula, the return on net operating assets (RNOA) fluctuate between negative approximately 5% and 17%. In our RNOA breakdown, we will however see that the core RNOA is less negative in the extreme year, 2012. The operating income was increased by approximately 10% in 2013, and though still negative, Detnor managed to increase their RNOA in the period. In 2014 however, the acquisition of Marathon Oil Norge AS brought substantial operating assets in oil fields such as the producing Alvheim FPSO[85]. The increased fixed operating assets were accompanied by a core operating loss after tax more than three times the size of that of 2013, leading the RNOA to take a plunge in 2014. The Marathon Oil acquisition was financed by a reserve based lending (RBL) facility, which alone accounted for an increase in interest bearing debt of 15.2 billion NOK, increasing net financial obligations (NFO) by 240% from 2013 to 2014, using average numbers. With a negative spread (RNOA – NBC) of -13.3% in the same year, the multiplying effect dragged Detnor's ROCE down to -50.7% in 2014. With an increasing level of debt through the reserve based lending facility and other bonds, the financial leverage alongside a stable negative

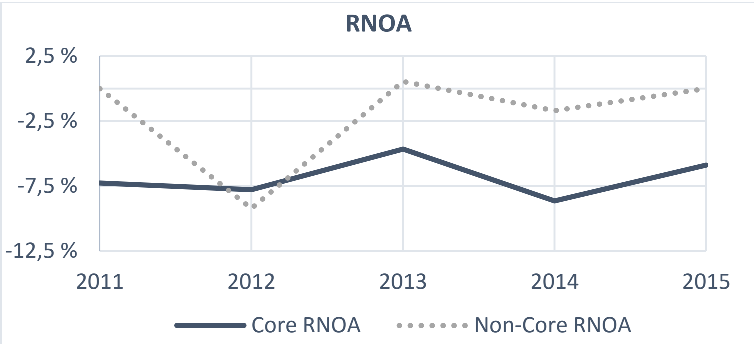
[85] Det Norske Oljeselskap (2014): «Det norske acquires Marathon Oil Norge AS»

spread had an overall negative impact on the ROCE. The positive impact of the RNOA was inadequate to prevent the ROCE to drop further down, to -64.2% in 2015.

In analyzing the operating liability leverage, we use the following breakdown:

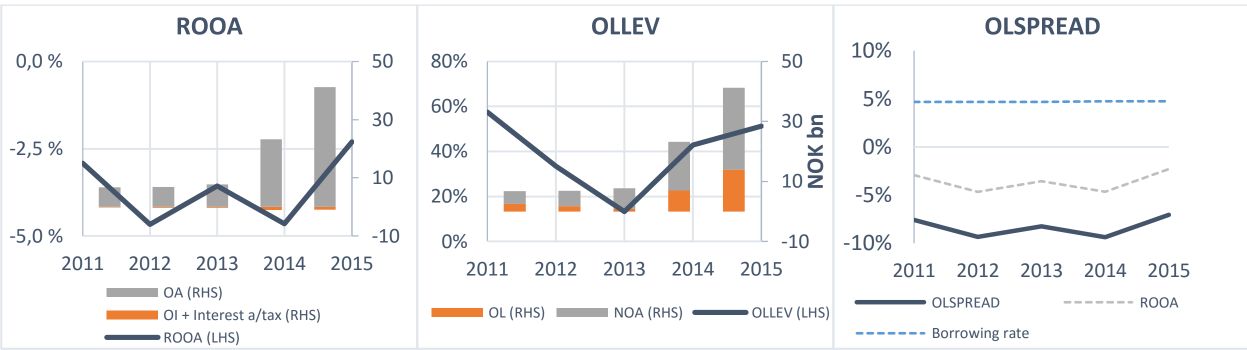
$$RNOA = ROOA + (OLLEV * OLSPREAD)$$

Where we focus explicitly on the core operations, hence the breakdown is only based on this. The background material for the breakdown and analysis can be found in appendix 5.2.3.



The core RNOA is shown to have a negative pull on the total RNOA, whereas non-core has a positive effect. Hence, with the exception of 2012, Detnor's non-core operations have had a positive effect on the total ROCE, which is not a positive sign going forward. The remainder of the profitability chapter is dedicated to analyzing the core operations, as these are most interesting for our forecasting.

When breaking down the RNOA, we assume that the short-term borrowing rate is equal to that of the revolving credit facility (RCF), as this line of credit is independent of reserves etc., and hence is considered as the line of credit drawn upon in the short-term. The interest on the RCF facility is LIBOR + 5.5%, where LIBOR as of March 31.03.2016 is 1%. The pre-tax interest rate is thus 6.50%. Assuming a tax rate of 28% until 2013, and 27% in 2014 and 2015, we obtain an interest rate after tax of 4.68% and 4.745%, respectively.



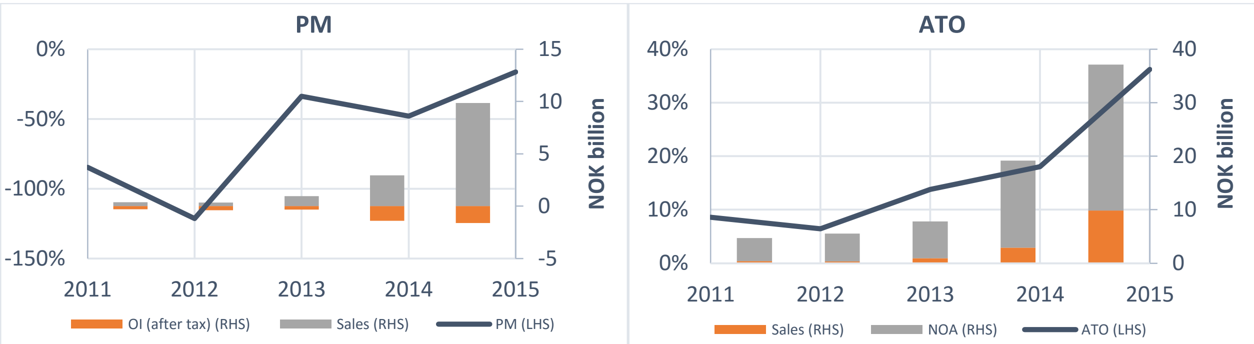
With a negative operating liability leverage spread (OLSPREAD) in the whole period, the increased operating leverage has a multiplying effect that has significant impact upon RNOA. In the year of the Marathon Oil purchase, 2014, the operating leverage (OL) increased significantly, non-proportionally to the increase in net operating assets. Hence, the leverage premium given by the last two factors of the breakdown had a large effect on the RNOA. The return on operating assets (ROOA) had enhanced the negative development in RNOA in 2014 as well, due to an operating loss more than three times the size of the equivalent 2013 figures.

Second level breakdown: Operating profitability – In the second level breakdown we dig deeper into the first element of the first level breakdown, the return on net operating assets (RNOA), explicitly focusing on the core operations. The two drivers of the second level breakdown are:

1. Profit margin (PM), given by: $PM = OI(after\ tax)/Sales$
2. Asset turnover (ATO), given by: $ATO = Sales/NOA$

This breakdown is more commonly referred to as the Du Pont Model[86]. The breakdown tells us that (1) RNOA is higher for each dollar from revenue that is remained in operating income and (2) the share of sales generated by net operating assets. The breakdown can be described through the following relation:

$$ROCE = (PM * ATO) + [FLEV * (RNOA - NBC)]$$



Evidently, the profit margin (PM) has been through a roller coaster ride since 2011, fluctuating between negative 122% in 2012 and negative 16.3% in 2015. One of the main drivers of the profit margin development has been the Marathon Oil Acquisition in 2014. Detnor's sales have increased substantially after the acquisition, with operating income following but not in the same proportion. Before 2013 Detnor only had producing assets in Enoch, Varg, Jotun, Glitne and Atla, which were all relatively small oil fields with declining production volumes. In 2013 the Jette field, of which Detnor owns 70%, started production, and thus sales increased substantially. With the Marathon Oil acquisition 2014, Detnor took control of the largely profitable

[86] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 360

Alvheim field (and all of its tie-in fields), explaining the improvement in sales and profit margin from 2014 to 2015.

Asset turnover varies between 0.06 and 0.36, in 2012 and 2015 respectively. These findings indicate that Detnor have been able to utilize their net operating assets more efficiently in recent years. This comes as no surprise as fields as Jette have started production, whereas the asset was capitalized at an earlier stage. Thus the early investments are beginning to bear fruits, hence asset turnover has increased.

Third level breakdown: Profit margin drivers – The third level breakdown is based on the two first components of the second level breakdown, profit margin (PM) and asset turnover (ATO). The EBITDAX margin is predominantly driven by relatively high production costs, but evidently the highest costs are clearly related to exploration. Recalling that the Norwegian tax system incentives exploration through large tax deductions, should the exploration deem worthless, the EBITDA and EBIT margins might be prone to subjective managerial decisions. In the years when exploration is relatively high (2010 and 2012), we see that tax refunds are equally larger, as a result of this incentive program.

COMMON SIZE **Income Statement**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Total operating revenue	100 %	100 %	100 %	100 %	100 %	100 %
Production costs	-42 %	-49 %	-63 %	-26 %	-14 %	-12 %
Payroll expenses	-4 %	-9 %	-3 %	-4 %	4 %	1 %
Other operating expenses	-24 %	-16 %	-25 %	-12 %	-11 %	-5 %
EBITDAX	**29 %**	**26 %**	**8 %**	**58 %**	**79 %**	**84 %**
Exploration expenses	-486 %	-272 %	-484 %	-173 %	-34 %	-6 %
EBITDA	**-456 %**	**-246 %**	**-476 %**	**-116 %**	**45 %**	**78 %**
Depreciation and amortization	-43 %	-21 %	-34 %	-50 %	-35 %	-39 %
Impairments	-47 %	-53 %	-81 %	-71 %	-75 %	-35 %
EBIT	**-546 %**	**-320 %**	**-590 %**	**-236 %**	**-64 %**	**3 %**
Tax on EBIT	394 %	235 %	469 %	202 %	16 %	-20 %
Operating income	**-152 %**	**-85 %**	**-122 %**	**-34 %**	**-48 %**	**-16 %**

Third level breakdown: Turnover drivers – From the reciprocal asset turnover table, we see that property, plant, and equipment, as well as capitalized exploration expenditures represent a big part of the total asset turnover. This is no wonder, as the major operating assets of Detnor are its oil fields, at different stages of the life cycle. Detnor can increase its RNOA by increasing ATO, which in return can be addressed by keeping net operating assets low while increasing sales. However, increasing sales is almost tantamount with obtaining a higher oil price, which we will discuss is next to impossible to do in a competitive market.

Increasing sales without increasing the operational assets in the form of oil fields is thus very difficult, hence improving the ATO will rely on other factors than PP&E.

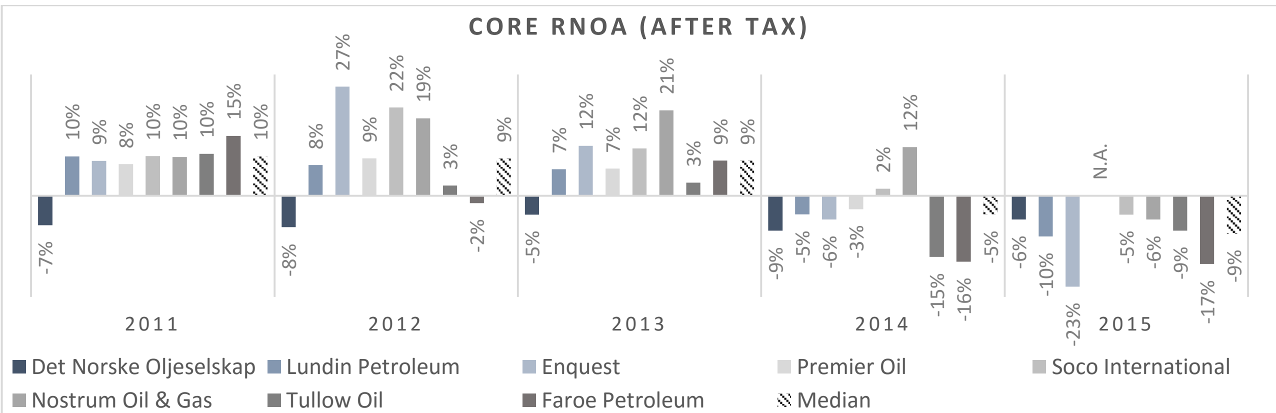
Reciprocal asset turnover - operating assets	**2011**	**2012**	**2013**	**2014**	**2015**
Inventories	0.06	0.09	0.03	0.04	0.02
Accounts receivable	0.28	0.37	0.13	0.26	0.11
Other short-term receivables	1.32	1.32	0.45	0.32	0.12
Tax receivables	5.03	4.02	1.42	0.24	0.06
Goodwill	1.51	1.37	0.38	1.56	0.79
Capitalized exploration expenditures	5.63	6.86	2.24	0.72	0.24
Other intangible assets	2.71	2.36	0.69	0.94	0.54
Deferred tax asset	0.00	0.00	0.33	0.11	0.00
Property, plant and equipment	1.76	4.35	2.46	3.70	2.30
Long-term receivables	0.00	0.05	0.08	0.03	0.01
Operating assets	**18.29**	**20.80**	**8.22**	**7.92**	**4.18**

Reciprocal asset turnover - operating liabilities	**2011**	**2012**	**2013**	**2014**	**2015**
Accrued public charges and indirect taxes	0.05	0.06	0.03	0.01	0.01
Tax payable	0.00	0.00	0.00	0.24	0.07
Other current liabilities	1.52	1.89	0.87	0.48	0.24
Deferred taxes	5.11	3.26	0.07	1.64	1.09
Operating liabilities	**6.68**	**5.22**	**0.97**	**2.37**	**1.42**

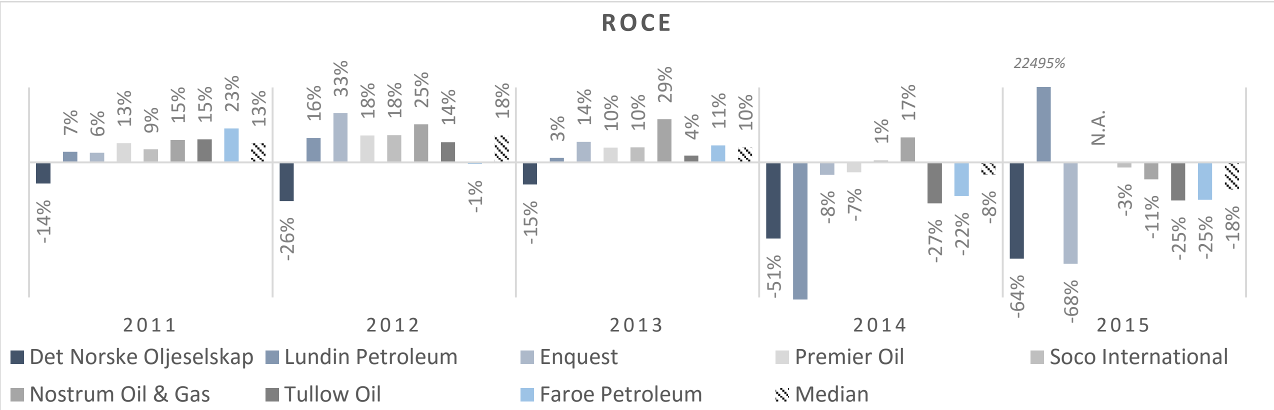
3.3.2 Peers

In the peer comparison we will use the same three-level breakdown framework as we did for Detnor, but we will merely present the major findings of these. The peers' reformulated financial statements and their respective profitability analyses can be found in appendix 5.3.

$$ROCE = (PM * ATO) + [FLEV * (RNOA - NBC)]$$



There was a very coinciding return on net operating assets in 2011, when the oil price was still above 110 USD/barrel, with the exception of Detnor. Detnor's subsequent poor performance seems special to the industry, but is of course affected by the fact that the company had low production in the period analyzed. As the oil price plunged in 2014 and 2015 all companies evidently performed poorly, whereas Detnor kept their steady track of poor performance. Turning to the return on common equity, the story is denominated by the same pattern of Detnor underperforming relative to peers in the analyzed period. The high return on common equity in Lundin in 2015 is due to a negative equity and the measure does not paint the right picture, but rather the opposite, and should not be considered comparable to Detnor and the remaining peers.



Noteworthy in both RNOA and ROCE is that Detnor performs worse than the peer group median in almost all years, where adverse market conditions generally has lowered profitability across the industry substantially. Recent acquisitions have not borne fruit, and the lag between investments and return on investments is what we believe is the case in Detnor in 2014 and 2015, and thus a natural extension to the recent negative profitability should be a near-term profitability comeback.

3.4 Analysis of credit risk

In this chapter, we will discuss the short term as well as the long-term aspect to credit risk in Detnor, and subsequently compare it with our peer group, under the framework presented by Penman[87]. This means that we do not use average balance sheet figures, but the actual figures in the respective years. The short-term liquidity ratios will discuss the companies' ability to pay their near future debt obligations, and see whether these findings are industry standard, or if Detnor can be considered an outlier. The second part of the credit analysis relates to the long-term solvency ratios that incorporate the long-term assets and liabilities, in order to understand both the short and long-term ability.

[87] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation"

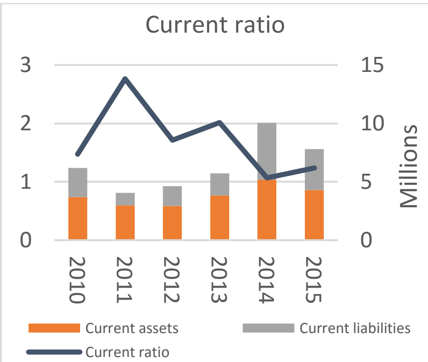
3.4.1 Detnor

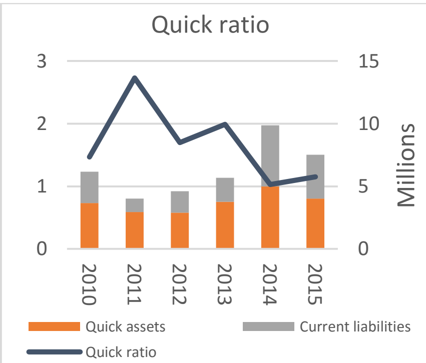
3.4.1.1 Short-term liquidity stock ratios

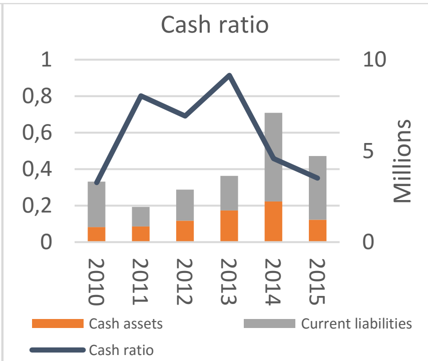
The current ratio[88] of a company measures the degree to which current assets are able to cover all near-term liabilities[89]. This measure assumes that all current assets can be converted into cash, but does not take into account the time it takes for the assets to be converted. 26% (2015) to 64% (2010) of Detnor's total current assets consist of tax receivable in the analyzed period, with the exception of 2014 where they had a tax payable. The inventories are mainly equipment for drilling and exploration wells or spare parts, and can considered fairly liquid in a functioning market. The latter is however not an assumption to take for granted in a struggling oil and oil service market, and thus the subsequent ratio's might have a better explanatory power in the short term liquidity analysis of Detnor.

By subtracting inventories from the Detnor's current assets, the numerator yields assets that are easily converted to cash in the short run, and yields a ratio known as the quick ratio[90]. This ratio mitigates the risk of not being able to convert the asset to cash, but still, there is a risk inherent in the accounts receivable. However, the lion's share of the numerator in Detnor consists of tax receivable, which we consider a fairly safe item in Norway, and thus the quick ratio may indeed paint a fair picture of Detnor's liquidity in the short run. Taking short-term liquidity measures to the extreme, we can look at the cash ratio[91], which limits the inherent risk to contain risk associated with the financial system. The short-term derivatives are considered secure as they are traded with financial institutions, and not over the counter (OTC)[92]. The same argument applies for cash and short-term investments.

The following graphs summarizes the previous discussion applied to Detnor's financial statements. Specifications can be found in the appendix.

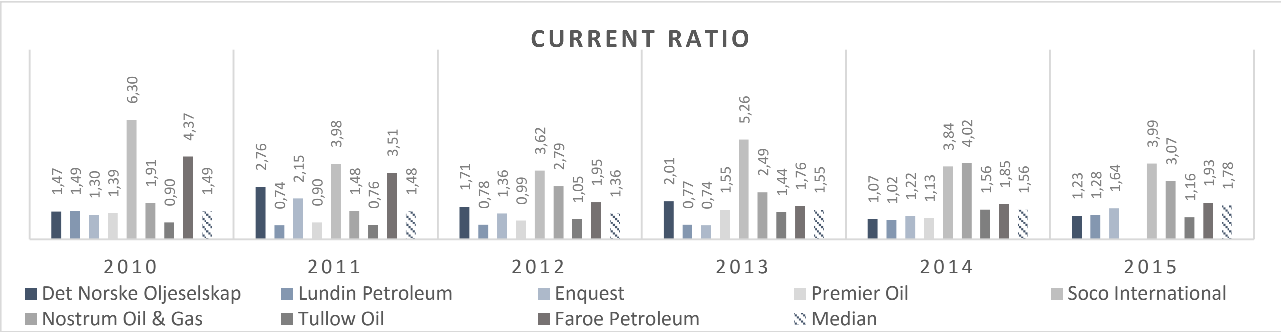






[88] Current ratio = Current assets / Current liabilities
[89] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 686
[90] Quick ratio = (Cash + short term investments + receivables) / Current liabilities
[91] Cash ratio = (Cash + short term investments) / Current liabilities
[92] Detnor Annual Report 2015. Page 106

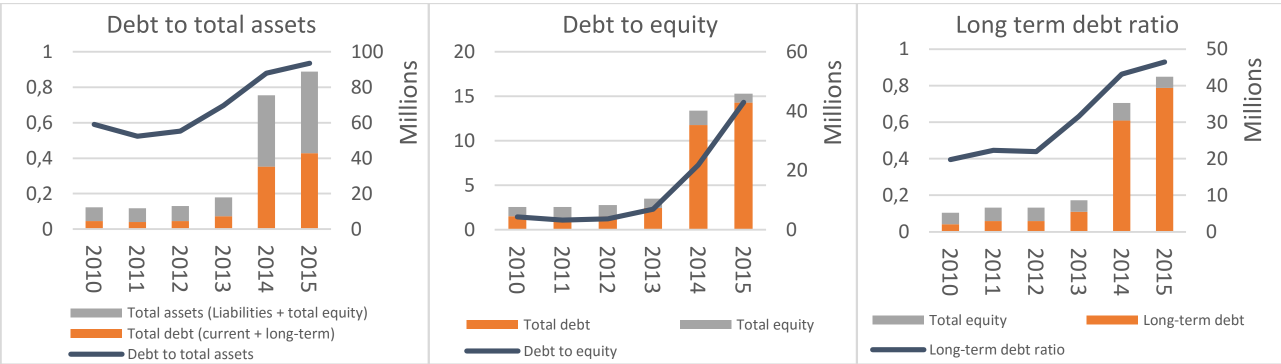
Evidently, both current, quick, and cash ratios have incurred high volatility over the last six years, with a peak in 2011 for the current and quick ratio. The peak comes from a sudden drop in current liabilities due to lower short-term borrowings related to an Exploration Facility (overdraft facility) in 2011.



Comparing Detnor with its peers, we identify that the current ratio is, and has been since 2010, fairly low compared to the peer group. With a current ratio hovering between approximately 1.1 and 1.7, Detnor have experienced a lower current ratio than the median (Detnor excluded) in the peer group for three out of a total of 6 years. Detnor's high accounts receivables would otherwise increase the ratio, but its already high level relative to peers might indicate lower liquidity.

3.4.1.2 Long term solvency stock measures

In assessing the long-term solvency measures, we look at the debt level relative to the assets and equity[93], respectively. Debt to total assets and debt to equity[94] tell the same story from a different angle[95], where a higher level indicates higher long-term liquidity risk. The long-term debt ratio[96] however, shows long-term debt relative to long-term debt and equity.

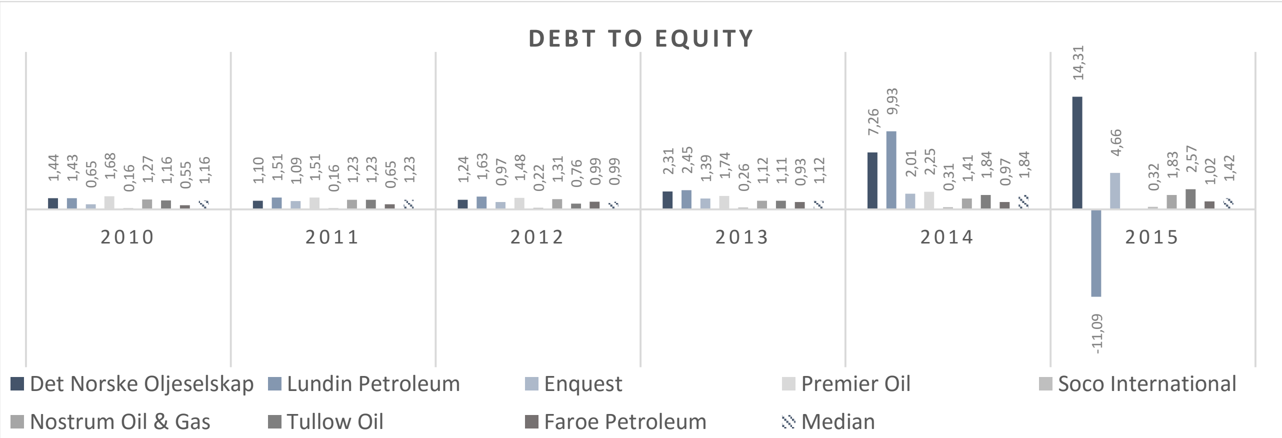


The debt to total assets ratio shows us that debt has grown to become almost the same size as the total assets, which in return indicates that Detnor has an increasing long-term liquidity risk. As previously

[93] Debt to total assets = Total debt / Total assets
[94] Debt to equity = Total debt / Total equity
[95] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 686
[96] Long term debt ratio = Long term debt / (Long term debt + total equity)

introduced, with the acquisition of Marathon Oil in 2014, the total assets increased substantially, alongside an increase in the credit facilities. The same findings are applicable to the long-term debt ratio, where it is evident that the long-term debt has increased substantially, whereas the book value of equity is much more stable.

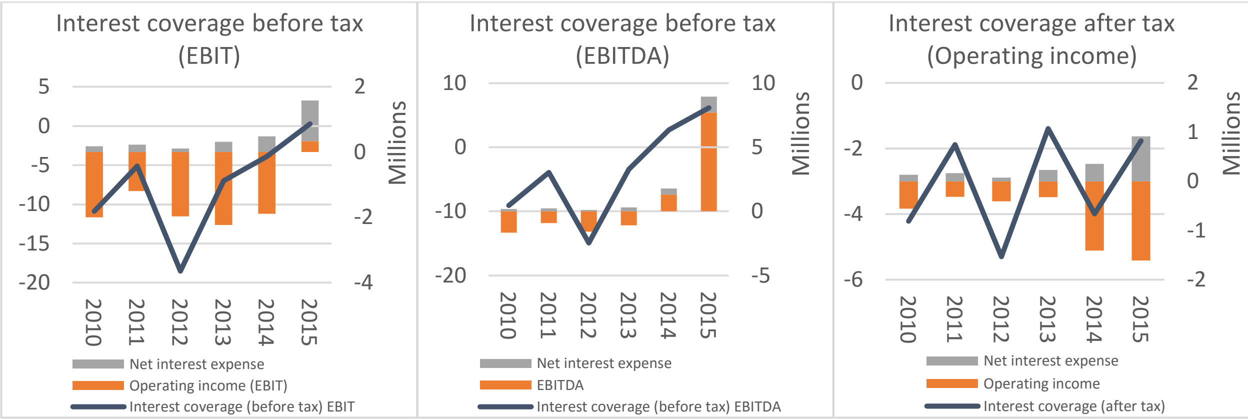
Comparing Detnor to its peers, we see that Detnor has been in the upper half of the table in most years in the analyzed period, with the debt equity ratios generally increasing across the peer group after the oil price plunge in 2014. Comparing Detnor to Lundin with regards to the debt equity ratio, there is evidently some sort of correlation between the two. Lundin's negative debt equity ratio is driven by a negative book value of equity driven by negative earnings, and thus this measure in 2015 is not very useful. The debt side of the story however tells the same tale as for Detnor; debt has increased significantly during the past two years.



3.4.1.3 *Long term solvency flow measures*

For the flow measures of long-term liquidity risk assessment, we will analyze the interest coverage ratio[97]. The interest coverage ratio tells us whether the company is able to meet its financial obligations in a given year, based on its profits. It can be argued that operating income should be on a before tax basis, but also after tax[98]. Furthermore, separating core and non-core operations can be beneficial to analyze whether main operations are enough to cover the interests. We will thus rely on before tax, after tax, and core operating income in the numerator, with the appropriate denominator. Where operating income refers to the core business of Detnor. EBITDA is included in the analysis due to the non-cash effect of depreciation and amortization.

[97] Interest coverage before tax = Operating income / Net interest expense
[98] Penman, Stephen H. (2003): "Financial Statement Analysis and Security Valuation". Page 687



From the graphs we see that the interest coverage has increased significantly in the last few years, due to a positive development in operating profits. The operating income after tax (right hand graph) does however not display any clear pattern, and is much more volatile. All in all, we can expect that due to the revenue enhancement from producing fields, either developed or acquired, the operating profits should increase. Assuming a stable LIBOR, the interest expenses should stay at the same level, hence interest coverage ratios should increase.

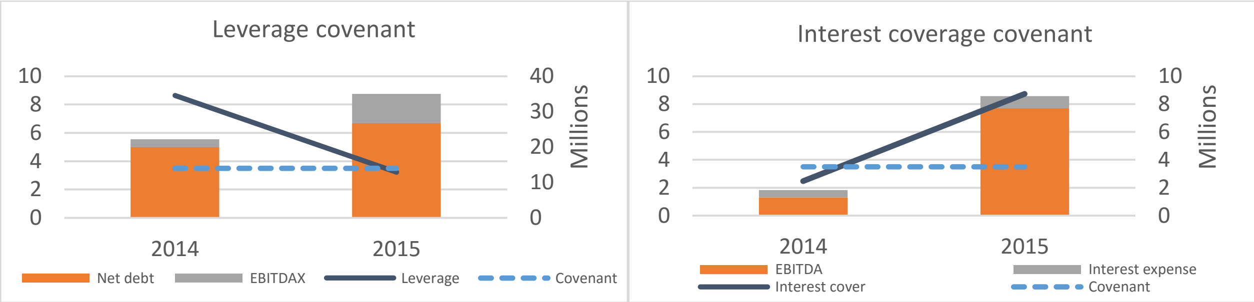
3.4.1.4 Covenant analysis

As mentioned, the Marathon Oil acquisition required a significant increase in Detnor's credit facilities. Attached to the credit facilities there were covenants related to both leverage, interest cover and operating cash flow[99]. The latter is related to short- and long-term projections made by Detnor, which is beyond the scope of this thesis, and thus only the two former will be analyzed here.

- Leverage covenant: Net debt / EBITDAX < 3.5x
- Interest cover covenant: EBITDA / Interest expense > 3.5x

Apparent from the following graphs, we see that in 2015, Detnor satisfied both of their covenants. Detnor's leverage (Net debt / EBITDAX) was 3.2, whereas the interest coverage (EBITDA / Interest expense) was 8.7, both inside the required range.

[99] Detnor Annual Report 2015. Page 100



3.4.2 Liquidity analysis summary

The 2014 acquisition of Marathon Oil brought with it both assets and liabilities. The short-term liquidity risk defined by the current ratio and quick ratio shows a negative trend over the analyzed period, and from 2014, current assets are barely sufficient to cover the current liabilities. The liquidity of the current assets items is considered fairly high, which enhances Detnor's otherwise downward facing liquidity story, with mediocre short-term liquidity assessments compared to peers.

In the long-term, we see that debt levels are not surprisingly increased, due to the financing needs of the Marathon Oil acquisition. Debt levels across the industry are similarly increasing, though at a lower rate. The main driver of the increased debt are the credit facilities introduced in 2014 and 2015 related to the acquisition activity, and thus the effect on debt from organic growth itself would probably be lower. We consider the higher level of debt to be a normal effect of a struggling oil market. However long term solvency is under pressure, should the market downturn persist.

Detnor is currently able to sustain an acceptable level of leverage and interest coverage related to the covenants on their credit facilities. With production facilities in place from 2014, revenue should increase in the next years, hence these covenants should not be breached as long as LIBOR and NIBOR do not increase significantly, but could potentially come under pressure at low oil prices[100].

4 Strategic analysis

4.1 Internal analysis

In the internal analysis, we will look at Detnor's resources and its abilities of utilizing these resources. Resources include all assets, processes, routines, relations, networks, information and knowledge the firm possess[101]. The petroleum assets are the main resource for the E&P company. The other resources dictate the utilization of the petroleum assets.

[100] Detnor Annual Report 2015. Page 100
[101] Fjeldstad, Øystein D; Lunnan, Randi (2014):" Strategi"

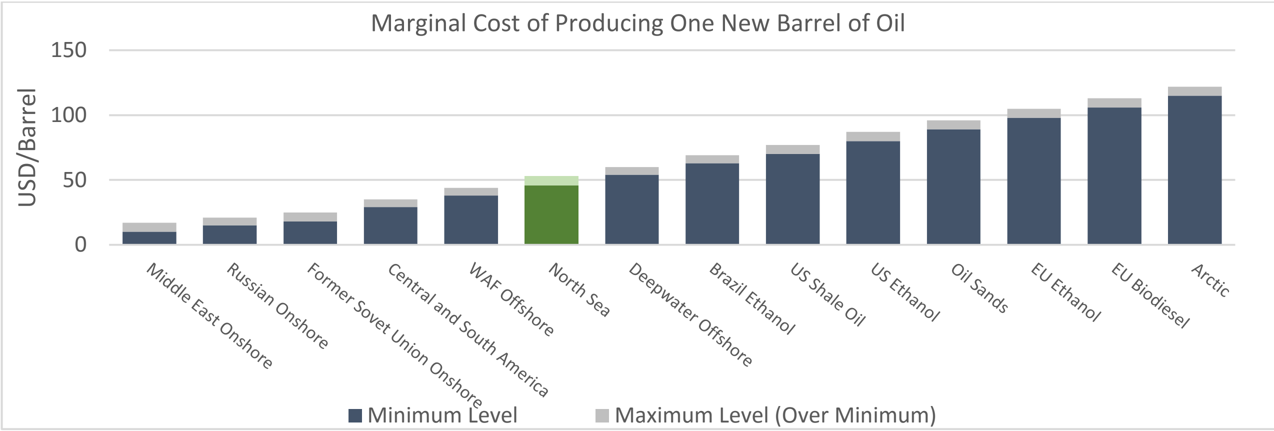
4.1.1 Resource analysis

Petroleum assets are not entirely homogenous since they differ in production output and characteristics associated with field productivity (determining the break-even costs). Petroleum assets produce either natural gas liquids, natural gas or crude oil. Crude oil has the highest price per oil equivalent, and is therefore regarded as the most valuable asset. Detnor's producing and developing assets are mainly oil fields.

The Alvheim area is Detnor's most important production area. All other producing fields are expected to shut down within 2 years[102]. Alvheim has a high quality crude oil, which sells at a $3-6 per barrel premium above the Brent Crude Oil[103]. Combined with high operating and production efficiency performance[104], the field is the reason for Detnor's overall low operational expenses (OPEX). Several tie-in projects are planned in the area[105]. These are projects where fields are tied to existing infrastructure, which often yields a lower CAPEX per barrel.

Detnor's assets in development can mainly be classified in two categories: large oil fields and tie-ins. The tie-in developments are mainly associated with the Alvheim area. The larger developments are Johan Sverdrup, Ivar Aasen and Gina Krog. With only 3.3% working interest in Gina Krog, Ivar Aasen and Johan Sverdrup are the cornerstones of Detnor's future operations. Both fields have estimated low breakeven oil prices[106]. The size of the reserves, especially for Johan Sverdrup, is the main reason for the low breakeven prices. Economies of scale gives lower capital expenditures (CAPEX) per barrel of oil equivalent (boe), but also operational expenditures (OPEX) per boe. The low oil prices have also reduced CAPEX costs on Johan Sverdrup[107], and the expected breakeven cost for the field is under $40 dollars per barrel[108]. Johan Sverdrup is one of the largest oil fields in the history of the NCS, with several possibilities for tie-in developments. Ivar Aasen has lower reserves than Johan Sverdrup does, but with a larger share and role as operator, the field is a very important asset. Detnor's producing and development assets outperform the North Sea marginal cost of producing one new barrel of oil.

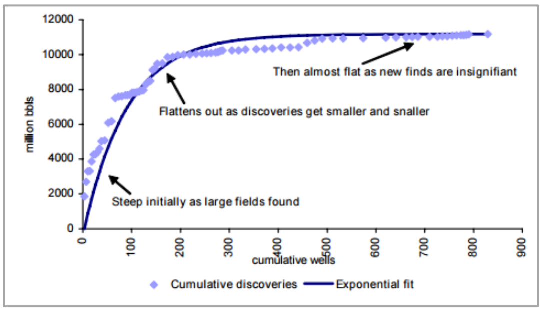
[102] Detnor (2016): "Annual Statements of Reserves"
[103] Detnor (2016): "Acquisition of Marathon Norge: Press & Analyst conference"
[104] Det Norske Oljeselskap (2016) "Capital Market Day 2016 Presentation". Page 67
[105] Detnor (2016): "Capital Market day 2016 Presentation"
[106] E24 (2015): "Så lønnsomme er de neste årenes oljeproduksjon i Norge nå"
[107] Detnor (2016): "Capital Market day 2016 Presentation"
[108] E24.no (2015): "Så lønnsomme er de neste årenes oljeproduksjon i Norge nå"



**Source: Authors' contribution and Reuters (2014): "Oil prices below most OPEC producers' budget needs"*

For petroleum assets classified as *development pending* the uncertainties around the value of the assets are greater. Breakeven costs are currently not possible to comment about these fields. Many of these assets are located in the same area, called North of Alvheim[109]. Krafla/Askja is described as the main assets for this area, just as Alvheim is for the Alvheim Area. Gohta is the only asset in the development pending category located in the Barents Sea. As with Krafla/Askja this is an important field for establishing a production area. The petroleum assets described as discoveries are mainly tie-in fields for Johan Sverdrup, Alvheim area and possibly North of Alvheim.

Licenses for exploration are also important for the E&P company, but the outcome is very uncertain. The graph on the right hand side shows what is known as a creaming curve for the Northern North Sea[110]. The curve explains that as the number of wells increase, the total barrels produced increase, but at a diminishing rate. Assuming that this graph is representative for the North Sea as a whole, we can expect that discoveries in the North Sea will become smaller in years to come, and that the discovery of giant fields may be a rarer occurrence. The Barents Sea on the other hand is much less explored, and thus Detnor consider this area of huge potential[111]. Should the creaming curve apply to this area as well, we could expect the discovery of larger fields in the years to come, as these are easier to spot on seismic[112], before the size of discoveries decline as the oil province matures. The Barents



**Source: Deutsche Bank (2013). "Oil & Gas for Beginners"*

109 Detnor (2016): "Capital Market day 2016 Presentation"
110 Deutsche Bank – "Oil & Gas for beginners". Page 50
111 Det Norske Oljeselskap (2007): "Pertra establishes exploration office"
112 Deutsche Bank – "Oil & Gas for beginners". Page 50

Sea is prone to political uncertainty near the Russian borders, and environmental restrictions[113]. Detnor has been active in acquiring licenses in the Barents Sea. In addition to acquiring and exploring in the Barents Sea, exploration around Alvheim Area, North of Alvheim, Johan Sverdrup and Ivar Aasen is also a priority for Detnor[114]. Possible tie-in fields are the reason for this activity.

The organization design and abilities are important factors for utilizing the resources[115]. The ability to acquire licenses has been successful the past years. This has been done through license rounds and M&A activity. Especially during the past two years, the M&A activity has risen, and so far, in 2016 Detnor has acquired 3 companies with total of 27 licenses[116][117].

Year	2015	2014	2013	2012	2011	2010
Licenses	84	79	80	67	65	66
Operator	34	35	33	26	28	30

**Licenses, Source: Own Production. Data from Annual reports 2015, 2014, 2013, 2012, 2011, and 2010.*

It is difficult to assess past performance of the exploration department, because lack of data. Detnor's goal for the future is to become a leading explorer on the NCS by 2020[118].

Jette was Detnor's first development finished in 2013. This was a small development, where Detnor encountered several difficulties[119]. With the acquisition of Marathon Oil Norge in 2014, an organization with experienced personnel for developing oil fields were brought into the organization. With several development projects, the knowledge acquired in the transaction is important for successfully developing the discoveries. The future goal in the development entity is "*to sanction stand-alone projects at a breakeven price below 40 USD/bbl*"[120], through standardization.

An experienced staff with production knowledge was also acquired through Marathon Petroleum Norge. Low risk of operations is important for the operating division. Health, safety and environment (HSE) are commitments Detnor take extremely seriously with no major incidents the past year[121]. The operational performance on Alvheim has been excellent[122], and transferring this knowledge to Ivar Aasen should create

[113] Store Norske Leksikon: "Barentshavet"
[114] Detnor (2016): "Capital Market day 2016 Presentation"
[115] Fjeldstad, Øystein D; Lunnan, Randi (2014):" Strategi"
[116] Detnor (2015): "Det norske kjøper Svenska Petroleum i Norge"
[117] Detnor (2016): "Det norske overtar Norecos portefølje i Norge"
[118] Det Norske Oljeselskap (2016) "Capital Market Day 2016 Presentation"
[119] Detnor: "Our Assets"
[120] Det Norske Oljeselskap (2016): "Capital Market Day 2016 Presentation". Page 59
[121] Det Norske Oljeselskap (2016): "Capital Market Day 2016 Presentation". Page 46
[122] Det Norske Oljeselskap (2016): "Capital Market Day 2016 Presentation". Page 67

internal synergies. In the operations department there are several improvement initiatives to increase efficiency.

Important for Detnor's organization is relational and network resources. Being owned by Aker ASA gives Detnor a unique relation to one of the most powerful industrial conglomerates in Norway. After the merger between Aker Exploration and Detnor, the company has grown, especially through M&A activity. This rapid expansion can partially be accredited to Detnor's relation to Aker, which has its own investment team that supports the different portfolio companies. Aker also creates possibilities through financial resources. When Marathon Oil Norge was acquired, Detnor was forced to do a cash placement. Aker gave a guarantee to participate and guaranteed 50% of the placement[123]. The companies within the Aker group also cooperates and are great network resources. The group has several companies in the oil service industries and which could benefit Detnor. The largest partner and operator on the Johan Sverdrup field is the most experienced company on the NCS, Statoil. Being in cooperation on Statoil on this asset could prove to be valuable. Mainly because of the size of the project. In general, Detnor is focusing on reducing costs. The ambition is to reduce CAPEX by 50% and OPEX by 20%[124]. The viability of doing this is definitely there, where Detnor has shown ability to obtain low breakeven costs on projects. We will analyze this further in the external analysis, since many of these costs are dependent on suppliers.

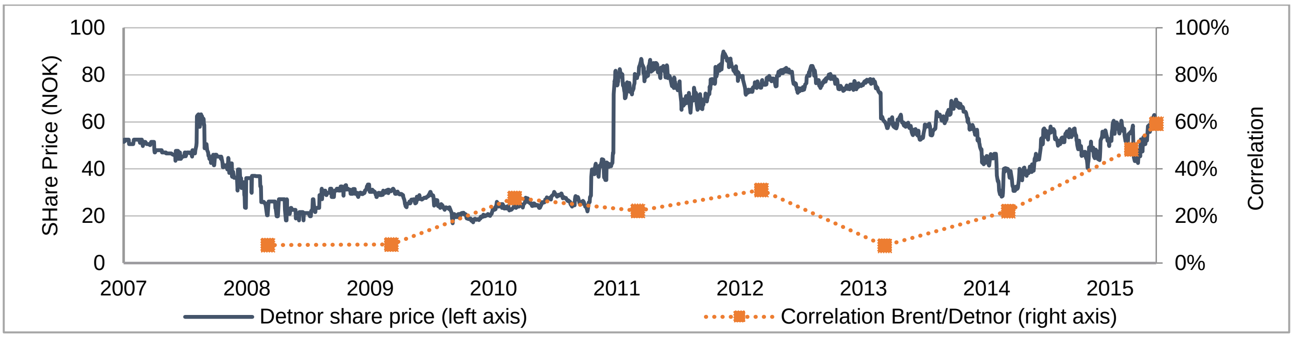
Detnor have shown that they have a strong organization, which is able to exploit the resources. This is based on the opportunities that has been presented to Detnor, with successful discoveries of fields, acquisitions of key assets and effectively developing assets. Relational resources have been a huge contributor for this success. The petroleum assets are valuable in the sense that they produce the preferred Brent crude oil with low breakeven prices. Especially the Johan Sverdrup field will be a valuable asset with large amounts of oil equivalents. Detnor's remaining portfolio of discoveries are also promising, but the value has higher uncertainty. The Johan Sverdrup field is a rare asset, since there are not many companies on the NCS that possess fields with these amounts of oil. Johan Sverdrup is the fifth largest oil discovery throughout the history of the NCS[125].Resources like Ivar Aasen and Alvheim are not as rare as the Johan Sverdrup field, and in size, there are several similar oil fields on the NCS. The extraordinary aspects of these fields, which makes them somewhat rare, is the low breakeven costs for the production of oil.

[123] Det Norske Oljeselskap (2014): "Det norske kjøper Marathon Oil Norge AS"
[124] Detnor: "Capital Market Day 2016"
[125] Aftenposten (2015):" Seks grafer som forklarer hvor viktig Johan Sverdrup-feltet er for Norge"

The risk for Detnor's strategy regarding its resources is the dependence on very few large oil fields. This means that if something goes wrong on a field development, the share price will be extremely affected. As mentioned, this has happened to Detnor previously with the development of Jette, proving it to be viable.

4.2 Oil Price Analysis

Detnor's sales mainly relate to crude oil, hence, we expect the variance in the share price to be somewhat coherent with the variance in the oil price. The following graph shows Detnor's share price development (solid line corresponding to the primary/left axis), as well as the correlation between the return in the share price and the return in Brent Spot measured at the end of year for the current year (dashed line corresponding to secondary/right axis).



**Source: Thomson Reuters quoted Brent Crude Oil spot price*

From the graph, we see that in the period from 2008 to 2013 the correlation between the return share price and the return on spot oil price is in the range between approximately 7.5% and 30%, before experiencing a very positive trend ending up at approximately 60% in 2016. Evidently, there is a positive relationship between Detnor's share price and the spot price of Brent Crude Oil; hence, this chapter is dedicated to understanding what drives the oil price, and how it affects Detnor.

4.2.1 Introduction to Crude Oil

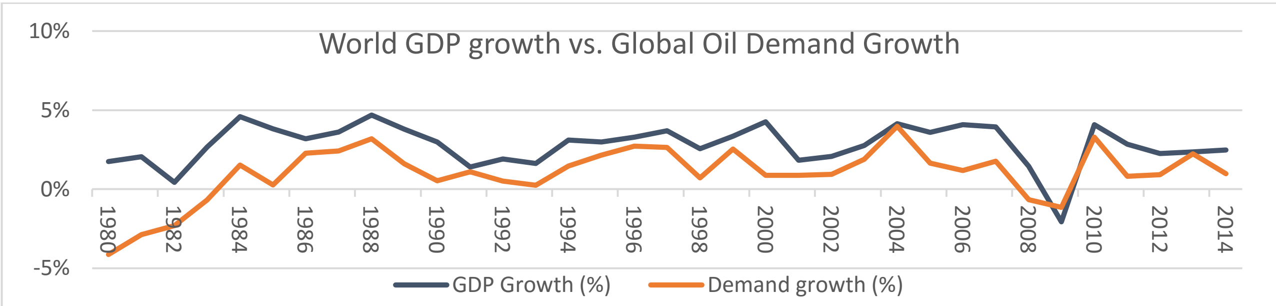
Crude oil is produced all over the world, and the different types are sold at different prices, both according to indices and regional specifications, as previously shown in the Alvheim field. The classifications of crude oil are by geographic location where the three most quoted crude oil types are West Texas Intermediate (WTI), Brent Blend and Dubai-Oman. These three are the main reference indexes for the global oil price, and differs in price due to quality differences, but remain in the same price range due to arbitrage conditions[126]. The different types of crude oil are traded internationally, and are easily transported at low costs. By extension, the international feature of crude oil means that the price is determined by global supply and

[126] U.S Energy Information Administration: "What drives crude oil prices?"

demand, hence it can be determined by an abundance of factors. This in return means that Detnor is affected by both local and global factors, and competition can be both local and international, which is reflected in our peer group. Detnor is producing Brent blend crude, which is sold as North Sea Brent Crude. The North Sea Brent Crude oil futures are traded on the Intercontinental Exchange (ICE)[127].

4.2.2 Oil demand

From the following graph, we see that even though the price has plunged the past year, the demand for oil has grown steadily, with the exception of the period in the aftermath of the global financial crisis in 2008.



GDP vs Demand Growth, Graph: Own production, Source: EIA[128] & World Bank World Development Indicators[129] (through Quandl)

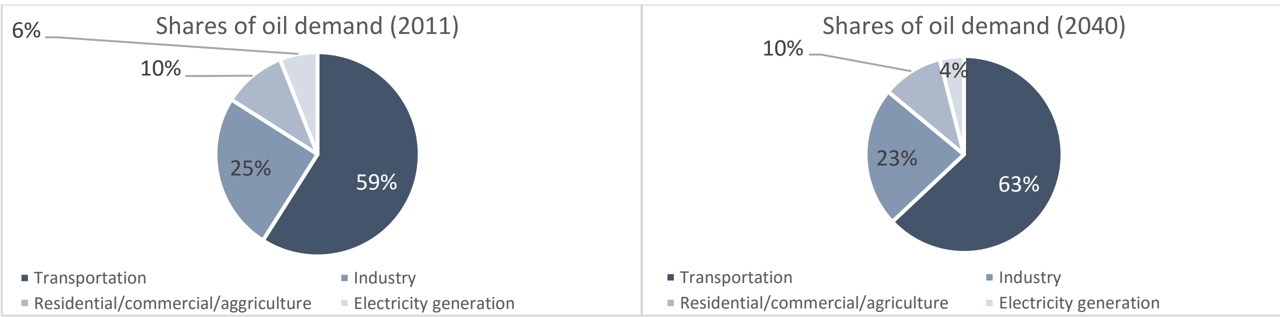
The fact that demand growth is mainly positive from 1980 until today might suggest that oil demand is somewhat inelastic[130], hence oil might be considered a necessary good, with few substitutionary products. However, for this to be true we need to assume stationarity in consumption of oil, which we will reject as a plausible assumption when looking at historical data in this chapter. There are many different factors that affect the demand for crude oil. A key driver for the long-term demand is the world GDP, which is discussed next.

The world GDP measures the market value of products and services produced in one year, worldwide. It gives an indication of the economic activity in the world. Crude oil is often more demanded when there is high economic activity[131]. World GDP is also affected by the oil price, where a low oil price often yields a higher world GDP growth. Furthermore, the world GDP growth is affected by growth in emerging economies, and so is the oil demand. China, for example is the world's second largest consumer of oil[132]. The steep positive income elasticity of demand in China versus a more or less flat income elasticity of oil in the US suggests that income growth in emerging economies will increase demand for oil more than growth in developed

[127] Intercontinental exchange (2016): Home pages
[128] U.S. Energy Information Administration (2016): "International Energy Statistics"
[129] Quandl (2016): "World Development Indicators"
[130] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 134
[131] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 135
[132] Oilprice.com (2015): "Top five factors affecting oil prices in 2015"

countries[133]. These findings are coherent with the fact that mature economies tend to see an increase in service related industries, which are less energy demanding, whereas developing economies are lagging behind and still depend on energy intensive industries[134].

An explanation to this phenomenon is that sectors that demand oil are growing when there is economic growth, as industries develop and more energy-intensive goods are consumed, such as cars and other transportation vehicles[135]. Furthermore, bearing in mind that price and quantity exhibits a negative relationship for most goods, at a certain point the quantity of oil demanded should decrease with an increase in the price of oil. As the oil price spiked well above 100 dollars per barrel in 2008, US and OECD Europe witnessed a decreasing demand for oil, proving the inverse relationship between oil demand and oil price[136]. Even though the general demand for oil decreased, the demand for transportation oil exhibited a much smaller decrease in demand, suggesting that the price of transportation fuel is more inelastic, much due to low threat of substitution products[137]. Looking at a demand split between major consumption groups, transportation accounted for 59% of total demand in 2011, and is expected to grow by 4% until 2040, resulting in a total demand of 63% of global oil. Hence, the lion's share of the total demand for oil is at least moderately inelastic as long as transportation is dependent on oil, and alternative sources of energy is yet to become fully implemented.



**Percentage shares of oil demand sector. Figure from OPEC (2014): "World Oil Outlook"*

Forecasting the world's economic growth is difficult since many factors affect it, but substantial empirical research is conducted on the subject. In OPEC's "World Oil Outlook 2014" and Exxon "The Outlook for Energy:

133 Deutsche Bank (2013): "Oil & Gas for Beginners". Page 135
134 Deutsche Bank (2013): "Oil & Gas for Beginners". Page 135
135 Deutsche Bank (2013): "Oil & Gas for Beginners". Page 135
136 Deutsche Bank (2013): "Oil & Gas for Beginners". Page 134
137 Deutsche Bank (2013): "Oil & Gas for Beginners". Page 134

A view to 2040" they expect a continuation of the economic growth, mainly due to the global population growth, urbanization[138], growing middle class and globalization[139].

On the other hand, oil has substitute products that also could affect the demand. Coal, nuclear energy, ethanol, wind power and sun power are other energy sources that in some sectors could perform the same activities as oil. Within transportation however, other energy sources are not as efficient as oil, and therefore the threat of substitutes has not been equally relevant for the oil price[140]. The technologic changes that we are seeing today could change the demand. For example, the electrification of car motors has created a threat against the demand for oil in transportation, which is a major demand driver for oil. However, the platform on which the alternative energy cars rely is yet to become fully operational, as gas stations are still more than a common sight in many countries. Even though the development in vehicles is developing quickly, technology is lagging behind on alternative energy sources for shipping and larger transportation vehicles, where we still see larger vessels being dependent on oil. This gives rise to a continuous demand for oil in these industries.

Apart from substitute products, the environmental focus also affects the demand for oil. Energy policies making the oil more expensive or other technologies cheaper could change the demand. People's attitude towards fossil fuels could also make them more aware of what energy sources they use. It is important to bear in mind that the environmental focus and negative attitudes are mainly in the westernized world and due to the discussions about global warming, whereas emerging markets do not always share the same focus[141]. In emerging markets, oil is a necessity to continue high economic growth rates. Growth in energy demand looks certain for the next decades, where British Petroleum's Energy Outlook expects a total growth of 34% between 2014 and 2035[142].

4.2.2.1 Concluding remarks on oil demand

Despite an increased focus on renewable sources of energy in parts of the world, developing countries are still heavily dependent upon oil in the future. This is a good sign for Detnor who's only source of operating revenue is from oil or oil related products. Furthermore, with over 50% of total demand being fairly inelastic, oil is still demanded at high prices, which in return is positive for Detnor. However, as we will see later, Detnor are not able to set prices, as prices are dependent on a few strong market participants, and we would assume

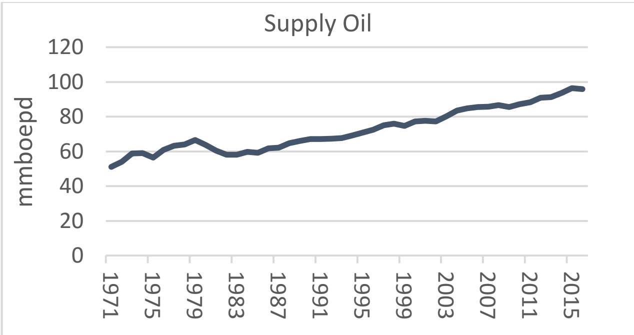
[138] OPEC (2014): "World Oil Outlook"
[139] ExxonMobil (2015): "The Outlook for Energy: A view to 2040"
[140] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 134
[141] Hermes Investment Management (2015): "ESG in Emerging Markets: Challenging the Dominant Investment Paradigm"
[142] British Petroleum: "Outlook to 2035 – "Energy use to rise by a third"

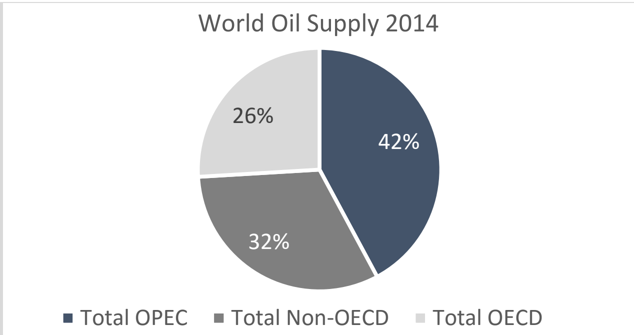
that in an effective globalized market they would not be able to sell their oil at a higher premium than they do today.

4.2.3 Oil Supply

In this section we will describe the major suppliers of oil in the world, and how they affect oil production and the price of oil. Furthermore, we will elaborate on possible explanations for the recent oil price plunge.

The supply for oil has grown looking at data from 1971-2016[143] [144]. Despite certain spikes, there is a close to linear positive trend in the oil supply in the analyzed period, ending up at approximately 96 million barrels of oil equivalents per day (mmboepd) in 2016.





**Source (Left hand graph): Authors' contribution and Quandl: "Organisation for Economic Co-Operation and Development" and EIA: "International Energy Statistics"*

**Source (Right hand graph): Authors' contribution and OPEC "World Oil Outlook 2014"*

The Organization of Petroleum Exporting Countries (OPEC) was in 2014 the largest producer of oil, whereas the remaining market participants are runners up in the ranking when deducing the member countries in the "Organisation for Economic Co-operation and Development" (OECD). OECD members are spread across the world, but the lion's share of production stems from USA and European countries. Non-OECD consists of countries that are neither in OPEC nor in OECD, hence, it is evident that power lies within the hands of a few large players. It is important to bear in mind that supply is only the barrels that are produced, whereas the actual production capacity is much higher. Hence, in the long term an increase in demand will not necessarily result in significantly higher oil prices, because suppliers can easily increase volumes.

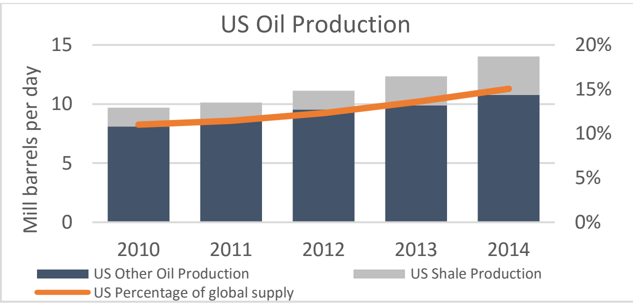
For a long time, the OPEC cartel has influenced the price through setting a specific production level, which has been very effective since they contribute to a large share of the world's oil production[145]. There have

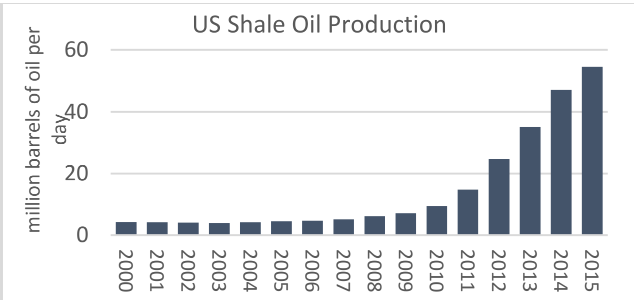
[143] Quandl: "Organisation for Economic Co-operation and development"
[144] U.S Energy Information Administration: "International Energy Statistics"
[145] Deutsche Bank (2013): "Oil & Gas for Beginners". Page 27

often been disputes between the member countries and accusations of breaches in the agreements by members of the cartel, but the organization has been effective over a longer period in achieving a high oil price. Price fixing at a higher level can be beneficial to Detnor. Since Norway is not part of the OPEC, they only reap the benefits of OPEC's initiatives, but are not bound to follow OPEC specified production limits.

Geopolitics is a key driver for the supply, where many of the highest producing countries are in non-democratically governed states. In these countries, the income from oil sales is substantial for the government, and lower prices will give deficits on their national budget. Hence, predicting these countries' political strategy regarding oil production is difficult, constituting a significant source of uncertainty for future oil production and oil price.

OPEC's price setting power has however recently been challenged by US Shale Oil. The big change that disrupted the balance in the market was the enormous growth in production from the United States of America[146], leading up to the oil price plunge in 2014.





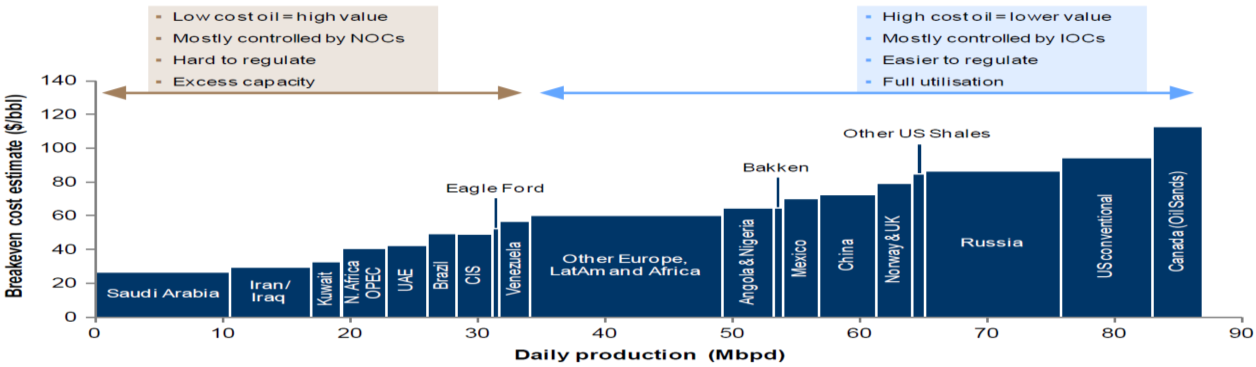
**Source: EIA (2014): "Today in Energy", and EIA (2016): "Energy in Brief: Shale Oil in the United States"*

The technological innovations that created the shale oil industry will have a huge impact on the worldwide production of oil also in a long-term perspective. When the sanctions were lifted against Iran, even more oil was brought to the market with a monthly compound growth rate of production equal to approximately 6%, from the beginning of 2016[147].

Additionally, also other technological innovations could give new oil fields. Technology that enables production further at sea and at deeper levels will open up vast new areas for oil production. In addition, creating technology that works in colder environments is an important enabler for oil production further north. Technology does not only target new ways to find and develop oil, but also improve cost efficiency. The lower the capital expenditure for developing a field, the easier it will be for a field to become commercially viable.

[146] DN (2016): "Oljekrisen"
[147] Quandl: "Crude Oil Production, Iran, Monthly"

For a company valuation, both the short- and the long-term oil price is very important. Analyzing today's situation, it is clear that the oil price cannot be sustained at today's low level with the current technology. Breakeven prices are important measures in the oil industry, because they give a floor for the possible oil price over a longer period of time. The break-even prices could decrease in the future due to technological innovations. In this area, there are many innovations in Norway, mainly through the biggest market participant on the Norwegian Continental Shelf, Statoil[148].



**Source: Global breakeven prices source (Alliance Bernstein, October 2014 via[149])*

4.2.3.1 Concluding remarks on oil supply

The political play between established and newly entered market participants, have shook the oil markets significantly lately, and these frictions seems to continue further into 2016. In the short-term, this turmoil causes instability when predicting the oil price, and could potentially contribute to an error in our thesis. In the long-term it is hard to see a production level that gives an oil price below the global break even prices, where supply meets demand, but with technological innovations we could see a general negative shift in production costs for E&P companies.

4.2.4 Gas Prices

Gas is also an important commodity for Detnor, constituting 9.57% of the revenue in 2015. The natural gas market has traditionally been regional, because of the high costs associated with transports. Pipelines have been the main transportation method. Pipelines are costly to build and therefore global connected supply networks are not seen. The three largest regional gas markets are North America, Europe (including Russia and North Africa) and Asia[150]. Norway is, together with Russia, the biggest gas producer in the European market. Demand for gas in Europe is highly seasonal, since its major use is for heating[151]. The European

[148] Statoil (2016): "Statoil Technology Invest"
[149] Zero Hedge (2016): Why Oil Under $30 Is a Major Problem"
[150] Antill & Arnott (2000): "Valuing Oil and Gas Companies: A Guide to the Assessment and Evaluation of Assets, Performance and Prospects". Page 75
[151] EIA (2014): "Today in Energy: Oil and natural gas import reliance of major economies projected to change rapidly"

market is known for having lower volatility in prices than the North American because of long-term purchase contracts and monopolistic positions for the gas/utility companies[152].

The market for shipping gas with vessels, where the gas is liquefied, has boomed in recent years[153]. Liquid Natural Gas (LNG) vessels are often chartered on long-term contracts to minimize risk. The risk of the LNG market is the high costs associated with building the LNG terminals. The trend of more LNG vessels could create a gas market similar to the crude oil market.

Natural Gas is also traded on the ICE, where the sales price that is most relevant to Detnor is the National Balancing Point (NBP). All gas from Alvheim is transported to St. Fergus Scotland, where the price is determined by the local market[154]. If the gas is exported to Germany, which is the case for the Atla field, then the European Union Natural Gas Import Price index is a better measurement. We will not spend much time analyzing the gas price, as revenue from oil production is the company's largest source of income, and Detnor's future strategy is mainly to produce oil[155].

4.2.5 Oil Price Scenarios

Forecasting the oil price is an extremely difficult task, and even the so-called experts have difficulties with getting the projections correct. The Norwegian asset manager Holberg Fondene showed how the futures price, which is often used as an estimate for oil price in the future, differs from the actual spot price[156].

**Brent spot vs 2-year future from Holberg Fondene, Source: Holbergfondene (2015): "Holberggrafene"*

This graph shows that even the broader market view, which should be embedded in the futures price[157] (red line), is having difficulty forecasting the oil price (blue line). If the current situation continues, producers will go bankrupt, eventually leading to balance in the market. It is, however, not certain that the oil price will go

[152] Antill & Arnott (2000): Valuing Oil and Gas Companies: "A Guide to the Assessment and Evaluation of Assets, Performance and Prospects".
[153] International Gas Union (2015): "World LNG Report - 2015 edition"
[154] Det Norske Oljeselskap ASA (2015): "Produksjon"
[155] Det Norske Oljeselskap ASA (2016): "Capital Markets Day Presentation 2016"
[156] Holbergfondene (2015): "Holberggrafene"
[157] 2 years futures price in the graph

to the previous levels above $100 per barrel. If OPEC agrees on lowering the supply to achieve higher prices, this may happen.

The revenue stream of Detnor, depends on the oil, which again is linked to several global factors complicating correct forecasting. We have obtained oil price forecasts from both Detnor, the World Bank, the forward curve, and the joint diffusion process on which we will elaborate later, in order to understand the variation and suggest a future oil price. The findings are summarized in the following table:

Oil prices	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forward curve[158]	39.38	43.32	46.36	48.92	51.07	52.87	54.16	54.16	54.16	54.16
Detnor estimates[159]	42.53	49.58	53.90	56.75	58.54	85.00	85.00	85.00	85.00	85.00
Joint diffusion future prices	41.30	42.63	44.17	45.74	47.42	49.19	51.07	53.06	55.19	57.51
World Bank[160]	41.00	50.00	53.30	56.70	60.40	62.90	67.30	72.00	77.10	82.60
Average	41.05	46.38	49.43	52.03	54.36	62.49	64.38	66.05	67.86	69.82
Median	41.15	46.45	49.83	52.81	54.81	57.89	60.73	63.08	66.15	70.05

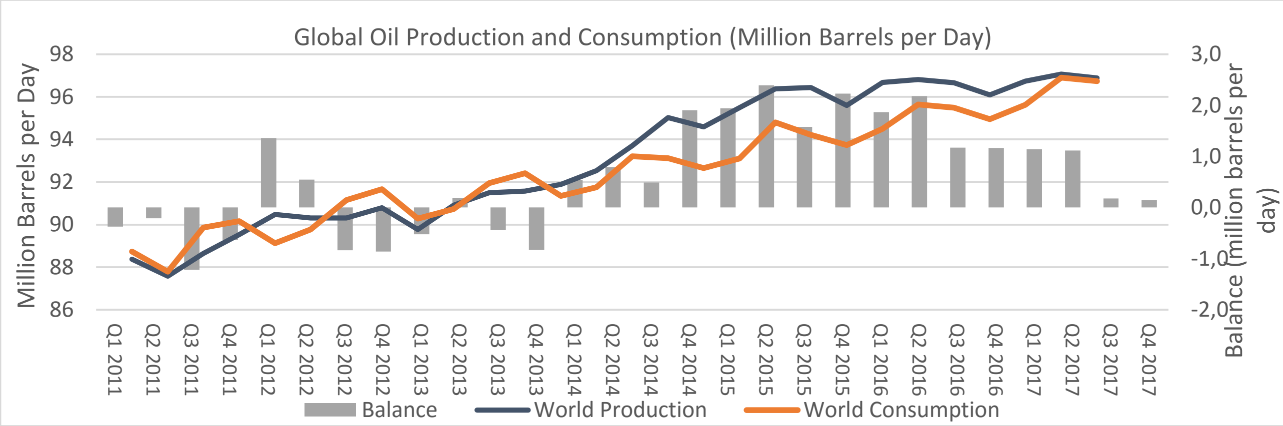
The table shows that there are large discrepancies among the forecasts, enhancing our statement of the difficulties of forecasting the oil price. Estimating the future price of oil is evidently anyone's guess, hence, we need to apply a series of scenario analyses in order to further understand the implications of a highly volatile and uncertain oil price on the final value of Detnor's equity. The choice of natural gas price on the other hand is based on the relationship between the forward curve of oil and gas, which is applied to the other three oil price scenario's presented. Hence, the resulting gas price estimates are:

GAS PRICES	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Oil gas relationship	*5.92 %*	*6.52 %*	*6.26 %*	*6.03 %*	*5.90 %*	*5.98 %*	*6.13 %*	*6.13 %*	*6.13 %*	*6.13 %*
Gas forward curve[161]	2.33	2.82	2.90	2.95	3.02	3.16	3.32	3.32	3.32	3.32
Detnor estimates	2.52	3.23	3.37	3.42	3.46	5.09	5.21	5.21	5.21	5.21
Joint diffusion future prices	2.44	2.78	2.76	2.76	2.80	2.94	3.13	3.25	3.38	3.52
World Bank	2.43	3.26	3.33	3.42	3.57	3.76	4.12	4.41	4.73	5.06
Average	2.43	3.02	3.09	3.14	3.21	3.74	3.95	4.05	4.16	4.28
Median	2.44	3.03	3.12	3.18	3.24	3.46	3.72	3.87	4.05	4.29

[158] Bloomberg quoted forward curve, averaged over the respective years
[159] Det Norske Oljeselskap ASA: "Annual report 2015"
[160] Knoema (2016): "Crude Oil Forecast: Long Term 2016 to 2025"
[161] Bloomberg quoted forward curve of natural gas traded on NYMEX, averaged over the respective years

4.2.6 Concluding remarks on oil price analysis

In the previous section, we have briefly introduced the dynamics of the oil price, and how it is affected by macroeconomic and political factors. The following graph better shows the effect of these discussions on the balance between demand and supply[162], which has been nothing but a roller coaster ride for the last 5 years. The over-supply in the market have created a positive balance, which has contributed to a plummeting oil price in the last years.



**Source: U.S. Energy Administration: "Global petroleum and other liquids "*

Despite stable and positive outlooks for oil demand, the fact that power over oil supply lies within the hands of a few people and countries that enjoy low breakeven prices is fairly frightening. The OPEC cartel's overwhelming market share combined with price setting at a low level possesses a threat to Detnor's profitability, in a time where production volumes are low until Ivar Aasen and Johan Sverdrup commence production. According to market research, both demand and supply should continue to grow in the future, which poses the question of whether consumption will catch up with supply, which might lead to a higher oil price. The question depends upon an abundance of factors, but the fact that certain parts of the world are still dependent on oil is positive for Detnor, who already enjoys low breakeven prices, and can sell some of their oil at a premium to the market.

4.3 External Strategic Analysis

4.3.1 PESTEL

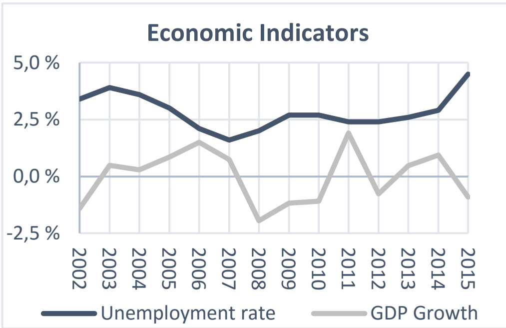
PESTEL is an analysis of the macro factors that affect the company's strategy. Through this analysis we seek to discover other factors that are not directly related to the oil price. These are most often factors that the company cannot affect, but should be taken into account when deciding future strategy.

[162] U.S. Energy Administration: "Global petroleum and other liquids"

Political – Politics have historically had a huge impact on oil companies' profits[163], where many of the largest oil producing countries have unstable political systems. Detnor operates solely on the NCS and have to answer to the Norwegian government, which we consider a stable political system where sudden changes rarely occur. The government incentivizes companies to explore on the NCS by refunding 78% of all exploration expenses when oil is not found; hence, the potential downside risk of exploration is severely mitigated. Probably the most interesting aspect when looking at political influence on Detnor is the disputed discussion about exploration and development in the Lofoten area. A possible concession of oil exploration and development in the area would open many new opportunities to find reserves on the NCS, which would be positive for Detnor.

As previously mentioned, licenses on the NCS are allocated through allocation rounds. The allocation process is open for everyone, but it requires an upfront payment of 119 000 NOK. New licenses are crucial for an E&P company like Detnor, since current oil fields in the North Sea are maturing, with reference to the creaming curve. To summarize; the political stability on the NCS is a huge advantage for the companies operating here, with large incentive programs, and a stable political environment.

Economic – Nationally the Norwegian economic situation determines the availability and price of qualified labor, interest rates, and partly the foreign exchange rates. The oil price turmoil has damaged Norway severely, where the west coast with high employment rates in oil, or oil related businesses, has experienced the largest shock. The Rogaland region in Western Norway, where much of Norwegian petroleum companies are situated, experienced an increase in unemployed skilled workers of approximately 90%, from November 2014 to November 2015[164]. A lower production level in Norway (measured in GDP), has made many oil jobs redundant, leading to an excess number of unemployed qualified personnel, which naturally has been positive for Detnor. Especially, the exploration department of Detnor is heavily dependent on knowledge intensive human capital. Hence, the oil turmoil has ripple effects that are not necessarily uniformly negative for Detnor.



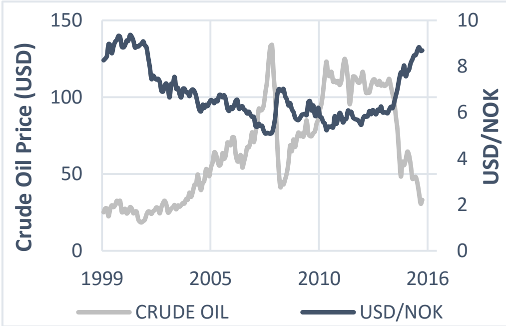
*Source: Quandl: "Normalized GDP Norway", and Eurostat

[163] Yergin (2008): "The Prize: The Epic Quest for Oil, Money & Power"
[164] Statistisk Sentralbyrå (2016): "Registrerte arbeidsledige 2015"

To stimulate the economy, the Norwegian Central Bank has led an expansive monetary policy, decreasing the key policy rate, which has led to a low Norwegian Interbank Offering Rate (NIBOR). This is as positive for Detnor which has a lot of debt, where the bond DETNOR02 interest payments are decided as NIBOR (1% floor) + 6.5%. For interest payments the London Interbank Offered Rate (LIBOR) is also important where the reserve based lending (RBL) facility is decided on the level of LIBOR plus a spread.

*Source: Bloomberg quoted 3month NIBOR and LIBOR

The depreciation of the Norwegian Kroner (NOK) against the United States Dollar (USD) has mitigated the effect of a decreasing oil price. From the graph, we see this evident effect, where it seems like there is a negative correlation between the oil price and the USD/NOK exchange rate. Looking at recent monthly data from 31.01.2000 to 29.02.2016, we observe a correlation of -0.796. This works as a natural hedge for the company. The depreciation of the NOK has also been favorable for Detnor since they are currently developing many fields that have a high percentage of its expenses in NOK. Interest rates are in the same way as FX rates subject to the oil price, since it dictates the economic activity in Norway. So this could also be seen as a hedge against low oil prices. The Norwegian Central Bank has an inflation goal of 2.5%, and we have used this inflation goal in the thesis.



*Source: Quandl: "Currency Exchange Rates – USD/NOK" and Brent Crude Oil Price

Sociocultural – In the oil price analysis, we introduced a sociocultural factor through the generally increased environmental focus, especially in the westernized world. In order to maintain a good reputation to all stakeholders, it is increasingly important for Detnor to keep focusing on health, safety, and environment, to mitigate the potential risks involving oil spill and work related injuries.

Technological – Technological advances are especially important for an E&P company in times with low oil prices. The low oil price today is also partly explained by technological advances. The productivity output on the NCS has been criticized from several sources[165], and will probably be on the agenda for most companies

[165]Regjeringa (2015): "Vi må auke produktiviteten på norsk sokkel"

in the future. Detnor's technological advances can be internal, through the exploration department or through general processes improvements, or external, through improvements made by subcontractors.

Oil extraction at sea is costly and technological advances could lower the breakeven costs for new fields. Detnor's focus on tie-in fields has shifted focus to innovations, known as fast track development. Fast track development is standardized development solutions that decreases the time of development and costs[166]. Of the remaining potential oil fields, 3 out of 4 are classified as smaller findings[167]. Hence, fast track development is important for Detnor since operations are solely on the increasingly mature NCS. Technological developments in subsea installations are also important for Detnor's future strategy. It is in this exact area the largest company on the NCS, Statoil, allocates a lot of resources. Statoil's goal by 2020 is to develop subsea operations that could replace the traditional platforms/FPSOs that are required today[168], making it possible to extract oil further from land, deeper and in colder areas, such as the Barents Sea. Many of the new licenses on the NCS are further north and these new technologies could open up many new areas to develop oil, which is indisputably interesting for Detnor's new additions to the exploration license portfolio. Alongside technological improvements in reservoir utilization, both Detnor and the industry as a whole can enjoy lower costs and better asset utilization in the future.

Environmental and Legal – A promising area on the NCS which is not yet open for the oil companies is the Lofoten area. This area is today not open for exploration and production since the government has been afraid of what an oil spill might do to the nature and environment. There are many large environmental organizations[169] working against petroleum activity in this area, and we do not see it as likely to be open for oil extraction in the near future.

The legal factors affecting Detnor are especially related to the ownership rights of the oil fields. A discovery can typically stretch over several license areas, with different owners, which could potentially create tension when deciding on the ownership shares in the oil field. This was the case in Johan Sverdrup, where Detnor considered a trial against the other owners of the field, as they felt unfairly treated[170].

4.3.2 Industry analysis – Porter's Five Forces

We map the external players that could affect Detnor's strategic possibilities and analyze what Detnor could do to improve its position amongst these players through an industry analysis. Detnor's value creation

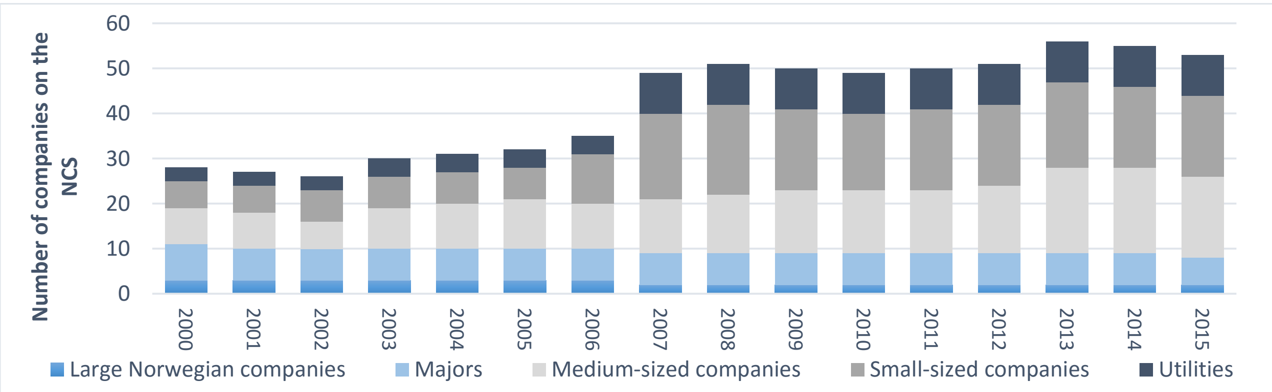
[166] Statoil: "More Fast-Track Developments on The Norwegian Continental Shelf"
[167] Statoil: "Flere utbygginger på Norsk sokkel"
[168] Statoil (2011): "Havbunnsfabrikken"
[169] Norges Naturvernforbund: "Lofoten, Vesterålen, og Senja"
[170] Dagens Næringsliv (2015): "Det Norske vurderer rettssak om Johan Sverdrup-fordelingen»

process is highly dependent on several external actors, including the customers, suppliers, competitors and the government.

Threat of new entrants – Michael Porter (1980) argues that low entry barriers are favorable for potential market entrants[171]. In recent years the growing number of actors is much due to low barriers to enter the NCS. The Norwegian Government (NOG) have historically focused on maintaining a high exploration activity, which will lower their dependency on a few large players. In order to make this possible, the Norwegian Government have therefore taken several measures to create incentives for companies to explore on the NCS. Here we identify the three most important ones[172]:

1. In 2000 the NOG created a scheme to help new companies acquire a license to explore and produce on the NCS, called prequalification[173]. Hence, new companies can mitigate the risk of not obtaining a license if the process is undertaken, making the application for exploration licenses more attractive.
2. The TFO license distribution gives the market participants a constant stream of licenses every year and favors diversity amongst companies since there is no bidding for licenses. This enhances the possibilities for smaller actors to compete against majors.
3. Probably one of the measures that has incentivized smaller companies to explore on the NCS most is the exploration refund, which was introduced in 2005. The refund is 78%, and can be claimed by companies if exploration deems unsuccessful[174]. These incentives have first and foremost created a threat for the exploration department to acquire the best exploration licenses.

The following graph summarizes the above discussion; the number of small- and medium sized companies has increased significantly during the past years:



[171] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors"
[172] Norwegian Petroleum: "Number and Diversity of Companies"
[173] Petroleum Safety Authority Norway: "Prequalification"
[174] KPMG (2016): "Petroleumsbeskatning"

**Source: data from the Norwegian Petroleum Directorate (2016) "Number and diversity of companies"*

Economies of scale are present when developing fields with oil discovery, but are to a lesser extent present in the exploration face. Hence, the threat of new entrants is primarily related to acquiring exploration licenses that also in the long run will affect the company's strategy for acquiring licenses, like Detnor has done through acquisitions lately. The low oil prices will most likely lower the threat of new entrants, as the industry becomes less attractive due to lower profits. This was indeed the case last year where there was only one prequalification on the NCS[175].

The high development cost poses a high entry barrier to the production industry. The costly production facilities might not permit the companies that might have entered the exploration part of the value chain to exploit their identified resources; hence, the threat of new entrants in Detnor's operating environment with regards to production remains fairly low.

Threat of substitute products or services – The threat of substitute products of oil was briefly covered in the oil price section, where we explained how petroleum products might be substituted by electric cars, etc. According to Porter, a substitution product is a product that can perform the same function as the original product[176], but we argued that substitution from petroleum products was not very likely in the short run, but might indeed pose a threat as technology develops.

Bargaining power of the customers – Detnor's customers are midstream and downstream companies that refine oil, but the demand from downstream companies is heavily dependent on the demand from their customers, hence there's a dual source of demand. The mid- and downstream companies should only be interested in Detnor's petroleum products if there is a demand for refined products by the end consumers.

- *Mid- and downstream* – The price of which these companies can buy Detnor's products is, as previously explained, defined by a global market for standardized petroleum products. However, the quoted crude oil price is merely an index of which the actual trade price of crude oil tends to follow, and prices can vary, such as for the Alvheim field that sells oil at a premium. With full information about the world oil prices, we would expect that an E&P company cannot raise their oil price to a significantly higher level than the spot index price, as buyers can change their suppliers. This statement alongside the previously presented low profits of downstream companies suggest that E&P customers would not accept a higher price of oil, hence, with respect to these aspects, their bargaining power should be high[177]. On the other hand, Detnor's buyers are not able to negotiate

[175] Norwegian Petroleum Directorate (2016): "Pre-qualification"
[176] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors". Page 23
[177] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors". Page 25

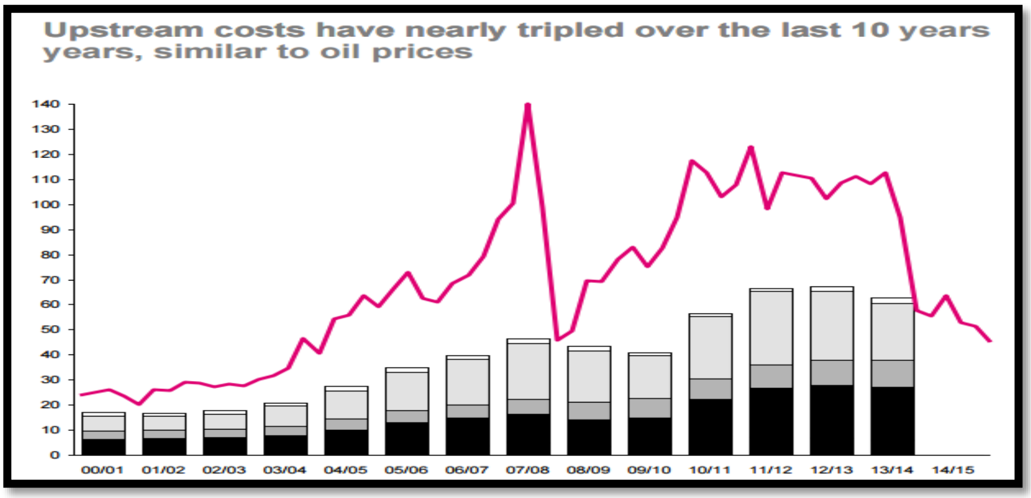
the price of oil, because of the broad customer group. Secondly, a threat of backward integration does not seem credible in this case, as both obtaining licenses and explore and develop, as well as producing oil is far from a trivial process. Hence, based on Porter (1998)[178], we conclude that the standardized products and high degree of information are not sufficient to counteract the high switching costs and Detnor's ability to sell to a wide customer base. Hence, the mid- and downstream companies are considered to have low bargaining power over Detnor.

- *End consumers* – We covered parts of this discussion in the oil price analysis, where we concluded that the lion's share of end consumers were insensitive to the price. Hence, based on Porter (1998)[179] we conclude that this part of the industry, which mainly consisted of transportation, has a low bargaining power as long as technology stays the same. Secondly, end consumers can be considered as price takers, as you for example would not be able to bargain over the price of gas a gas station, which depicts the same conclusion as before; consumers have low bargaining power. On the other hand, the consumers are free to choose their supplier in a competitive market. Hence, downstream companies can't raise their prices significantly, pushing for low price from the upstream companies.

Bargaining power of suppliers – Detnor's main suppliers are what we have previously called oil service companies, which mainly consist of seismic suppliers and rig suppliers. Even though, as we saw in the financial statement analysis, exploration costs constituted a large share of the total costs of Detnor, although they do not perform the exploration themselves. Detnor hire companies for seismic surveys as well as rig specialists. Hence, they are significantly affected by price fluctuations in these industries.

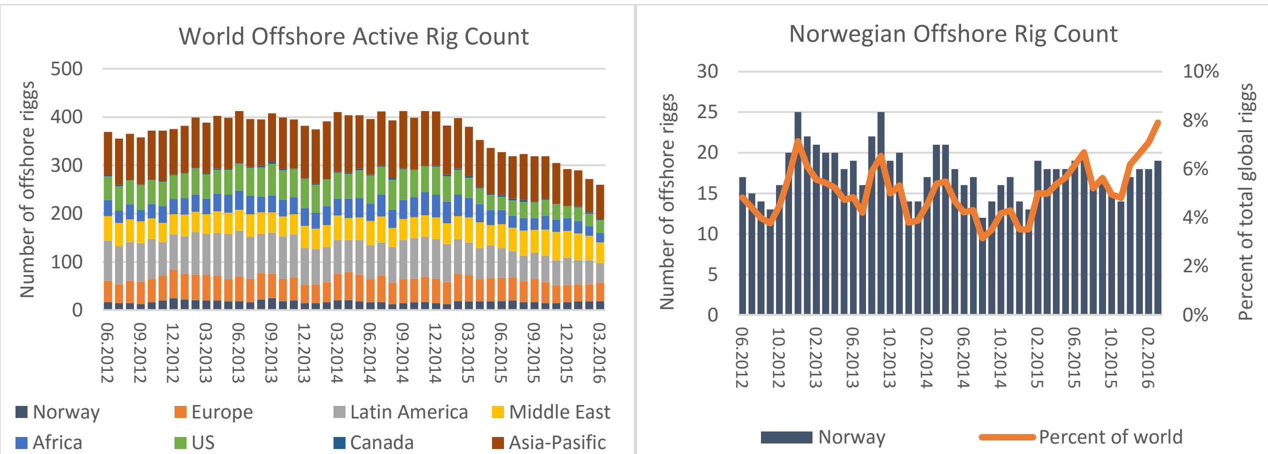
The supplier's power depends mainly on the activity in the industry, which is highly driven by the oil price. Upstream costs have nearly tripled over the last 10 years according to Detnor CEO Karl Johnny Hersvik[180], and is, evident from the presented graph, highly correlated with the oil price. This correlation could be explained by the increased activity in the industry when prices are high, increasing prices from suppliers. Breakeven prices are only determined by costs and could dictate the pace of new developments.

[178] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors". Page 25
[179] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors". Page 25
[180] Detnor (2016): "Capital Market Day Presentation 2016"



**Source: Figure from Det Norske Oljeselskap ASA: "Capital market day presentation 2016"*

Costs have grown because of the high bargaining power of suppliers when the oil price rose after the financial crisis. This situation has now changed and the suppliers are desperate in securing contracts with E&P firms. The different suppliers for the E&P firms are geophysical services, drilling, construction, shipyards, supply vessels, engineering, oilfield services, subsea services, accommodation vessels, pipelines etc. Many of these are now having difficulties because of the low activity combined with the high gearing these companies normally have. This has created a buyer's market, and Detnor is expecting to lower its capex cost by 50% and OPEX with 20%[181]. From the graph, we see that the active rig count has decreased significantly from 2014, which could suggest that the number of idle rigs has increased, which in return can increase Detnor's bargaining power over suppliers. This would represent a potential of higher profit margins in the future.



**Sources: Baker Hughes (2016): "Rig Count"*

[181] Detnor (2016): "Capital Markets day presentation 2016"

Intensity of competitive rivalry – As introduced, the rivalry in the E&P industry arises from two different sources: exploration and production. The exploration part of the company is prone to both small and large market participants, which is in accordance with the programs initiated by the Norwegian Government to promote diversification in market participants.

Turning to the production part of the company, there is rivalry in all comparable E&P companies worldwide, as is clearly represented in our chosen peer group. The international aspect of oil production means that rivalry has become larger in the globalized world, and the growth of the oil industry in the time leading up to the oil price plunge has furthermore provoked growth stagnation. In accordance with Porter, these effects alongside high fixed costs related to development and production induces a very high intensity of rivalry among existing competitors[182].

4.4 Concluding remarks

The previous discussions have given a broad and comprehensive understanding of both the internal and the external environment in which Detnor operates. In this chapter, we will conclude the previous chapters in a SWOT matrix, summing up the key takeaways:

STRENGTHS

- Valuable asset portfolio with large resources, such as Johan Sverdrup
- Strong cash flow from the Alvheim field in the short term, and significant production growth in the future
- Low breakeven prices on oil fields, both relative to the NCS and globally, coupled with selling oil at a premium to the market
- Strong and experienced organization after the acquisition of Marathon Oil Norge, with outstanding knowledge about the NCS
- AKER ASA owns approximately 50% of the company, and is a solid owner with M&A capabilities
- Stable political conditions on the NCS, and favorable governmental incentives, specially related to tax (specific to all NCS companies)

WEAKNESSES

- Highly levered company, on the brink of breaching covenants related to debt, limiting potential future debt funding
- Solely dependent upon non-renewable petroleum resources
- Operates solely on the NCS where the current areas are becoming increasingly saturated
- Low diversification of assets, and highly dependent on a few cash generators in the short run (Alvheim), and future stars (Johan Sverdrup)

OPPORTUNITIES

- The oil price plunge has reduced CAPEX and OPEX, leading some previously considered negative NPV projects to become positive (or less negative)
- New technology makes development of (primarily smaller) fields viable at low oil prices, increasing the profitability potential even further
- New exploration areas in the Barents Sea are a main opportunity for further expansion for Detnor
- Increased unemployment rate of knowledge intensive human capital gives rise to a large pool of potential (and cheap) hires

THREATS

- Long term low oil prices will keep profitability low and threatens the debt covenants
- A lower world GDP can trigger a lower demand for oil
- NCS could become increasingly saturated
- New sources of energy, and a changed consumer behavior can have a substitution effect away from oil and petroleum related products
- The Norwegian Government's aims to increase the number of license holders on the NCS, potentially increasing industry rivalry
- Global oil production is dictated by a few large players with OPEC being one of the largest participants. Detnor has no possibility to affect the price, and is thus implicitly threatened by political turmoil in the middle east, as well as the US
- Technological advances could move demand away from oil

[182] Porter (1998): "Competitive Strategy: Techniques for Analyzing Industries and Competitors". Page 17

5 Valuation Theory

5.1 Introduction and motivation

In the following chapter, we will apply a set of models to assess the value of Detnor, based on the previous discussions. We believe an E&P company valuation should reflect its current operations, but also its qualities in acquiring, discovering and developing new oil fields. All the operating income in the pure E&P Company stems from the producing assets. These assets are depleting and the importance of replacing the reserves is important for long-term operations for the E&P Company. Hence, the firm's capabilities in obtaining new oil are also important. The optimal valuation model for an E&P company should cover both these value driving operational activities.

Residual operating income model (ReOI) – The first valuation model we will look at is the accounting based Residual Operating Income model (ReOI). Both exploration and production are accounted for using the ReOI model, and thus includes both of the main value adding activities in Detnor.

Net asset value (NAV) – Not all the models used in practice cover both value drivers. The most popular model used by analysts valuing E&P companies is the Net Asset Value (NAV) method[183], which is also known as an asset-based valuation[184]. NAV only values the company's assets, and therefore omits the exploration activities in the firm, hence it can be considered a method under the liquidation valuation method. This model is performed using a version of a discounted cash flow method, but without terminal values, and further exploration is neglected. Hence, the model implicitly states that the company value is equal to zero as the assets are fully depleted. Exploration is naturally an important part of both present operations and future value creation, which was further elaborated on in the introduction, thus this assumption might be questionable in the real world setting. The NAV model can thus be regarded as a model driven by ceteris paribus assumptions, where value creation only occurs if input variables in the assets such as costs and oil prices change.

Real option Valuation (ROV) – The last valuation method used in this paper is the real option valuation (denoted as ROV in our thesis). The ROV is dependent upon the same asset base as the NAV, but does not require a risk-weighing of oil fields, because the model incorporates the risk-weighing through the stochastic process of the oil price. As previous models, ROV is heavily dependent upon the oil price development, but if a field is not yet developed, management has the option of developing or abandoning the development project. This feature is very neat as it is highly relevant in the decision making process of oil field

[183] Pareto Securities (2016), Fondsfinans (2015), and SEB (2016)
[184] Penman (2003) "Financial Statement Analysis and Security Valuation" page 73

development, where licenses are conditional upon development until a pre-specified relinquishment date. The framework is based on the same estimation techniques as the NAV model, but is heavily dependent upon the optionality and underlying oil price. The ROV is based on stochastic processes for the oil price and cash flows, and the optionality elements limits the potential down side, increasing the value of the oil field, which will be elaborated further under the real option chapter.

Model comparison – Applying a different set of valuation techniques based on heavy assumptions regarding the future of the company enlightens our analysis, and makes us able to understand how the choice of model affects the final valuation. Since models such as discounted cash flow models that are based on the same set of assumptions as the residual operating would yield the same final value as the residual operating income model, we also chose to look at models that differ widely in their assumptions, motivating the choice of net asset value and real option valuation. As long as the valuation methods are based on the same pro forma statements, the results of the valuation will be the same[185]. Hence, as long as we apply a clean surplus valuation, we should be indifferent in choosing between accounting based valuation models and cash flow based models, when assessing the final value. By applying valuation methods that have dispersed assumptions, we hope to enlighten the positive and negative sides of the different models, applied to an E&P company.

5.2 Accounting Based Valuation Models

In accounting based valuation models, the previously recognized balance sheet measures work as a basis on which the additional value is added[186]. The additional value added is positive if future earnings have a higher rate of return than the required rate of return. Some of the main advantages of the accounting based methods are[187]:

- **Focus on value drivers** – Investments are considered as positive value drivers as long as they earn a higher return than the cost capital.
- **Financial statement** – The method is based on financial statements reported by the companies, and what analysts use when they are looking at companies, hence it is not necessary to convert analysis forecast to valuation.
- **Accrual accounting** – Accrual accounting uses the matching principle, where we match the value added to the value expensed, which better captures the value creation of the period. Furthermore, investments are cause of higher asset values, whereas in a discounted cash flow model investments

[185] Plenborg & Petersen (2012): “Financial Statement Analysis”. Page 225
[186] Penman (2003):”Financial Statement Analysis and Security Valuation”. Page 432
[187] Penman (2003):”Financial Statement Analysis and Security Valuation”. Page 161

are cause of negative cash outflow, and hence have a negative effect in the investment period. In the accounting based model, investments are expensed when the equipment is used, through depreciation.

- **Versatility** – The framework is easily adapted to a range of accounting principles.
- **Validation** – Since the companies report financial statements, it is easy to validate the quality of our past forecasts, and update them accordingly.

There are also shortfalls with using residual earnings models, especially related to the following:

- **Subjectivity –** While cash flow measures are objective, it is possible to manipulate accounting measures, which can be a problem if past earnings are used for forecasting future earnings.
- **Complexity** – Accrual accounting could also be complexed, and it's important to understand its dynamics.
- **Forecast horizon** – The forecast horizon can be fairly short because value is recognized earlier, but this makes the framework even more dependent on quality of the matching. This is typically what is expected from exploration in Detnor, where we can't be certain of when the value is eventually created.

5.2.1 Residual Operating Income Model (ReOI)

In our accounting based model, we choose to focus on the operating activities of Detnor, while keeping forecasting rather simple, making the residual operating income model (ReOI) an obvious choice[188]. The Residual operating income (ReOI) is the residual amount of the operating income (OI) after the required return on Net Operating Assets (NOA) is subtracted. ReOI shows the additional value creation to this booked value. The value of operations in the firm is the value of the firm, and is often referred to as enterprise value:

$$Enterprise\ value\ (V_0^{NOA}) = Value\ of\ equity\ (V_0^{E}) + Value\ of\ debt\ (V_0^{NFO})$$

Net financial obligations (NFO) that are recorded at mark-to-market on the balance sheet, hence should not yield a residual return, which gives an expected residual net financial expense (ReNFE) of zero[189]. This assumption is assumed adhered here. Operating activities are therefore valued acknowledging that the equity value is equal to the value of net operating assets less net financial obligations:

$$V_0^{E} = V_0^{NOA} - V_0^{NFO}$$

[188] Penman (2003):"Financial Statement Analysis and Security Valuation". Page 432
[189] Penman (2003):"Financial Statement Analysis and Security Valuation". Page 434

Where Penman[190] defines value of equity as:

$$V_0^E = CSE_0 + \frac{ReOI_t}{\rho_F} + \frac{ReOI_t}{\rho_F^2} + \cdots + \frac{ReOI_T}{\rho_F^T} + \frac{CV_T}{\rho_F^T}$$

Following the same Penman framework, the drivers for ReOI model is (1) the net operating assets and (2) the return on net operating assets (RNOA). Combining these two drivers gives us the ReOI:

$$ReOI_t = (RNOA_t - (\rho_F - 1))NOA_{t-1}$$

Which can be rewritten in terms of operating income:

$$ReOI_t = \ OI_t - (\rho_F - 1)NOA_{t-1}$$

Despite its shortcomings[191], which we will discuss later, in accordance with Penman, we will apply a weighted average cost of capital (WACC) to our ReOI valuation, but with accompanying analysis' addressing the shortcomings of the method. The last term in the residual operating income is the continuing value which captures the value of the operating activities after the forecasting horizon T[192]. We introduce four main approaches to calculating this last term:

1. Through assuming that the residual operating income will grow by the same percentage as the cost of capital of the firm, effectively leading a continuing value of zero.
2. Through assuming that ReOI remains at the same level as the last year of the forecast for all eternity
3. Through assuming that the company will grow at a constant rate (g) after the forecast horizon, and all eternity.
4. The last approach is related to using exit multiples, such as a market-to-book approach.

The first three approaches[193] are cases of the Gordon's growth formula[194], and can potentially have a significant and dominating impact on the final valuation. Hence, large uncertainties depend on few input that are difficult to assess due to their distant nature. A last approach is assessing the continuation value through multiples[195]. We have chosen not to use this approach, as we find the former three sufficient to explain the continuing value for Detnor. The appropriateness of these values is discussed later.

$$(1)\ CV_T = 0 \qquad (2)\ CV_T = \frac{ReOI_{T+1}}{\rho_F - 1} \qquad (3)\ CV_T = \frac{ReOI_{T+1}}{\rho_F - g}$$

[190] Penman (2003) "Financial Statement Analysis and Security Valuation"
[191] Penman (2003) "Financial Statement Analysis and Security Valuation" page 691
[192] Penman (2003) "Financial Statement Analysis and Security Valuation" page 435
[193] Penman (2003) "Financial Statement Analysis and Security Valuation" page 435
[194] Penman (2003) "Financial Statement Analysis and Security Valuation"
[195] Penman (2003) "Financial Statement Analysis and Security Valuation" page 457

5.3 Net Asset Value

The NAV method was originally used for investment companies, where the NAV per share is treated as the share price for the investment company[196]. The whole idea of the method is to base the value of the firm on a sale at fair market value for the assets. Had the assets been traded often, it would be a trivial case to find the market value of these, but since oil fields are neither exchange traded nor regularly traded off the market, we cannot use comparable transactions as a proxy for the market value. Such an approach would also require markets to be perfectly efficient and the asset to have the same value added for all firms[197].

As previously stated, the lion's share of the assets of an E&P company consists of tangible assets, in the form of oil fields in different parts of the life cycle, which are depleted over time. Applying a continuing value to the valuation would assume that the company to some extent are able to replace the reserves into perpetuity, for example through exploration or further acquisitions. The NAV method values the company as if it did not acquire more assets, and only produce its existing assets until full depletion. Implicit in the model, is that when there is no more recoverable oil to produce, the company will shut down its business. All assets that, at the moment of the valuation, have some sense of commerciality will be evaluated. This means that we will evaluate the producing fields, developing fields, fields under planning and non-developed proven assets. These fields have different risk weighing, since it is not sure that all the fields will be developed or produce the amount of oil that is reported as recoverable. The risk weighing can be considered a subjective process and there is no clear framework on how it should be done. The risk weighting scale goes from 0% to a 100%, where a 100% is considered least risky. The most important criteria for the risk weighting is what category the field is currently in. All producing fields have a risk weighting of 100%, since the likelihood that the reported amount will be produced is high. Projects under development also have a high risk weighting, since developments that have started seldom are cancelled. Our final risk weightings will be elaborated further, and can be found in appendix 8.

Since liquidation value models assume that the value of the company is equal to the net proceeds from selling of all assets, and paying off all debt[198], we need to consider all assets relevant for this purpose. Here it is important to remember that licenses are considered as intangible assets[199], whereas exploration is capitalized and fields under development as well as producing fields are classified as property, plant, and equipment on the balance sheet. Goodwill will not be recorded in the NAV model.

[196] U.S. Securities and Exchange Commission (2013): "Net Asset Value"
[197] Penman (2003) "Financial Statement Analysis and Security Valuation" page 73
[198] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 211
[199] Det Norske Oljeselskap: "Annual report 2015". Page 89

Each field will be valued separately in the NAV model, using the discounted cash flow method, and finding the value per share of the respective fields. By doing the analysis on a field-by-field basis we are able to analyze capital expenditures, operating costs and revenue for each field, concluding in a sensitivity analysis where we can identify potential future scenarios for the breakeven price of the field. All though production and direct costs are easily separated on fields, whereas there are certain indirect costs that cannot in a sensible manner be allocated to the respective fields. These costs include for example general and administrative costs and other operating costs, and are based on a separate discounted cash flow valuation under the same methodology as before, but on a company basis. From the sum of the discounted cash flows from each field and companywide costs we can then deduct net financial obligations at time zero to obtain the market value of equity, and furthermore the share price value by dividing by the number of shares.

Mainly we have identified four main advantages of using the NAV model for oil field valuation:

+ The model is easy to understand and follows a standardized setup for each oil field, but requires specific information on each oil field.
+ *What you see is what you get*: Finding new commercial oil fields is not necessarily an obviously true assumption, as the resource is non-renewable. Furthermore, Detnor's current oil field portfolio is considered of high quality, and replicating this portfolio in the future might not be a trivial task.
+ We don't have to calculate the continuing value when using the NAV model. This is positive since the continuing value is highly dependent on input variables, and could yield highly volatile results with only minor changes in input variables.
+ Another important feature is the time value of money, where fields that are discovered in the future will not be developed until the current development program is finished. The NPV of future projects will therefore be low, since they will not realistically come to life before 2030. This is not necessarily true if future discoveries are very large, but with smaller discoveries this will be the case.

Even though the model seems applicable in many aspects of oil field valuation, as with any other models it is heavily dependent upon the input, and is based on assumptions that might be questionable. Hence, we have identified four negative aspects of the model:

÷ Since there might be large deviations with regards to costs and production between each field, the model is less applicable if there is low information flow between authorities, the company and investors, which might indeed be the case in less developed countries in the world. Since the information flow is very high in Norway, and Detnor exclusively operates on the Norwegian Continental Shelf, we consider our forecasts explained in the NAV model highly reliable.

- ÷ Using the NAV valuation violates a couple of important aspects of the firm's operations, which we identified earlier. We argued that the company might not be able to find commercial oil in the future, but it is likely that the company will explore or acquire new assets in the future, and then develop more reserves than the NAV will take into account. The extent to which we can conclude whether this or the opposing argument is true, is difficult to assess, but it is likely that the rate of which commercial discoveries will be made is declining in the long-term, recalling the creaming curve.
- ÷ Another disadvantage is the applicability of the risk weighing of each field. Even though we use an external framework for risk weighing, this is not necessarily applicable to the NCS in 2016. The model is deterministic and forecasting far into the future gives uncertain measures. The last field producing in the NAV model is Johan Sverdrup, which reaches the final production stage in 2056, and it is difficult to make good forecasts this far into the future.
- ÷ The model yields a value based on a long forecast horizon which follows a pre-defined plan of which deviation could potentially be very high. There is uncertainty in both oil price, production volumes, and costs in the long term.

As mentioned, we will rely on a cash flow based method in our NAV. The weighted average cost of capital method is one of the most commonly used discounted cash flow models. This valuation method builds on discounting the free cash flow to the firm (FCFF) with the weighted average cost of capital (WACC)[200]. Since we are valuing each field separately we include only field specific items that are necessary to operate the fields before aggregating on firm level. The items that can be tracked to each field are summarized in the following formula for free cash flow to the firm, from each field:

$$FCFF_t = Operating\ Income_t - Capital\ expenditures_t + Depreciation_t$$

This formula deviates from the commonly known free cash flow formula including change in net working capital, because it is not field specific. It is rather accounted for when arriving at the *net* asset value, after discounting the field specific cash flows. The valuation yields the total value of the firm, which is the value, divided among the claimants – the debtholders and shareholders[201]. When doing this valuation in the NAV model, we will only value the finite horizon, and discharge the continuing value.

$$V_0^F = \frac{FCFF_1}{\rho_F} + \frac{FCFF_2}{\rho_F^2} + \cdots + \frac{FCFF_T}{\rho_F^T}$$

[200] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 216
[201] Penman (2003)" Financial Statement Analysis and Security Valuation". Page 112

DCF valuations are advantageous as they rely on cash flows measures, which are reliable since they only track money and cannot easily be manipulated. With Brent Crude Oil prices as one of the most important inputs for the free cash flow, it is clear that cash flows can vary widely, due to a very volatile oil price.

DCF methods are not the preferred model to use when we are looking at value creation in a firm. Capital expenditures are considered negative in the DCF model due to lower cash flows[202], whilst this could actually be value creating if the return on the investment is higher than the required return. This last statement shows how value creation is difficult to track and analyze in a DCF model.

5.4 Cost of capital of the firm

As a part of valuing Detnor, we need to consider at which rate the cash flows should be discounted. This section will discuss our preferred method of calculating required returns, as well as the shortcomings in our choices. As for the financial statement analysis, the discussion in this section is motivated by concepts introduced in Penman's book[203], but is extended by other theories. For this thesis, we will focus on the required return on equity, as well as how it fits into the cost of capital of the firm through the weighted average cost of capital relation[204], where the latter term is after tax:

$$\rho_F = \frac{V_0^E}{V_0^{NOA}}\rho_E + \frac{V_0^D}{V_0^{NOA}}\rho_D$$

The relation shows that the cost of capital to invest in the operations is a weighted average of the shareholders' required rate of return and the cost of net financial obligations. The model relies on input that are shown to be rather noisy, which will be elaborated on further later, but by applying several frameworks on the noisiest input we hope to mitigate the risk of estimation error.

5.4.1 Required return of shareholders

The intricate notion of required return has been simplified by several models in the past, whereas one of the most commonly used is known as the capital asset pricing model (CAPM). This model indicates that the required rate of return to the shareholders can be described through the relation of risk-free return and risk premium, respectively:

$$\rho_E = \rho_{RF} + \beta(\rho_M - \rho_{RF})$$

[202] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 216
[203] Penman (2003): "Financial Statement Analysis and Security Valuation"
[204] Penman (2003): "Financial Statement Analysis and Security Valuation". Page 652

Where ρ_{RF} is the return of a risk-free asset, β is the measure of unsystematic risk of the asset and $(\rho_M - \rho_{RF})$ is the market premium or the expected return from holding all risky assets less the risk-free asset[205]. This model has however been heavily criticized and new models originating from the CAPM has evolved over time, but these are still prone to estimation errors present in the CAPM. Multifactor models have been introduced with factors explaining the required return, but these still require identification of factors and estimation of risk premiums. This thesis does not seek to find the most proper required rate of return on equity, hence we will apply the CAPM as the benefit from applying a more emphatic model will probably be offset by estimation errors.

5.4.1.1 CAPM

Firstly, we will introduce the two main sources of estimation error[206], namely the beta and the market risk premium, before turning to the discussion of the risk-free rate.

5.4.1.1.1 Beta

The beta of the investment yields the risk of the asset relative to the market[207], but there are several methods of estimating it. We will introduce three different methods in this chapter, which all refer to ReOI:

Method 1 – Penman introduces an approximation of beta as the covariance between the market and the asset relative to the variance of the market. The definition of the market might however depend on the nationality of securities in the portfolio, and whether or not all of these securities can easily be included in an index. Damodaran[208] introduces the Morgan Stanley Capital Index (MSCI) as a better approximation than the commonly applied S&P 500 index for U.S. firms, because it is more comprehensive in terms of number of traded securities. The same argument can be applied to Oslo Stock Exchange, where the OBX index consists of the 25 most liquid stocks on Oslo Stock Exchange[209], and can be considered a Norwegian equivalent to the S&P 500 in the U.S. The Oslo All Share Index (OSEAX) and OBX do however only contain Norwegian stocks, which in a globalized world seems rather unrepresentative of the actual choices of investment opportunities of an investor. Hence, we apply the MSCI World, which is an index of selected equities from 23 different developed countries[210], which better reflects an investors' range of potential investments, while securing a high liquidity that will make our beta estimate more robust[211].

[205] Penman (2003): "Financial Statement Analysis and Security Valuation". Page 107
[206] Penman (2003): "Financial Statement Analysis and Security Valuation". Page 107
[207] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 249
[208] Damodaran: "Estimating Risk Parameters"
[209] Oslo Børs: "OBX Total Return Index"
[210] MSCI (2016): "MSCI World"
[211] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 252

$$\beta_{DETNOR} = \frac{Cov(R_{DETNOR}; R_{MSCI})}{Var(R_{MSCI})}$$

We use excess returns based on a 3-month Norwegian Treasury bill[212], with corresponding excess returns on the MSCI world index[213]. This gives a levered beta of 1.3996 based on last 12 months.

Method 2 – The second beta estimate we use is the industry beta. This beta is not observable, but is based on estimates of the betas of 1029 global Oil & Gas (exploration and production) companies, presented by Damodaran[214]. we obtain an estimate of the industry beta. The reported unlevered and levered industry betas are 1.1282 and 1.9336, respectively.

Method 3 – The third assessment method of the beta is based on our peer group, of which we create a weighted portfolio of unlevered betas, and re-lever it to Detnor. The risk profile may however vary across our peer group, but we consider the portfolio to be sufficiently diversified, making the peer group a better estimate than comparable single stocks. We base our estimation of the previously introduced method 1, and the following formula for un-levering beta[215]:

$$\beta_U = \frac{\beta_L}{1 + (1 - t_c) * \frac{NFO}{CSE}}$$

Where β_U is the unlevered beta and $\beta_L$is the levered beta, and we assume that the beta of debt is zero. The unlevered betas and their respective weights are given in the following table:

Company	Market cap (GBP)	Weight	Unlevered beta	Weighted beta (unl.)
Lundin	483.96	7.6 %	0.8468	0.064
Enquest	406.40	6.4 %	0.7575	0.048
Premier Oil	515.40	8.1 %	0.7244	0.058
Soco International	630.30	9.9 %	1.3303	0.131
Nostrum Oil & Gas	854.20	13.4 %	0.3836	0.051
Tullow Oil	3,298.70	51.6 %	1.3309	0.687
Faroe Petroleum	199.80	3.1 %	1.2211	0.038
Total	**6,388.76**	**100 %**	**0.8468**	**1.079**

[212] Norges Bank (2016): "Treasury Bills Daily Observations"
[213] Data from Thomson Reuters, with ticker: .WORLD
[214] Damodaran: "Total Beta by Industry Sector (Global)"
[215] Hillier, Ross, Westerfield, Jaffe & Jordan (2013): "Corporate Finance". Page 481

We then re-lever the beta according to the structure we have found later in the chapter, where this beta is also included as a parameter in finding the correct leverage ratio. This gives us a beta of 2.1955 in the peer group.

Summary – The large variation in the presented betas confirms our hypothesis that there is a large uncertainty in the estimate. We choose to put largest emphasis on method 2, with a 50% weighting, and method 1 and 3 is equally weighted at 25% each, in order to place largest emphasis on Detnor's own share price movements relative to the market, but still incorporating the industry consensus. Hence our resulting beta is 1.7321 for the ReOI. We will show later in the chapter that this is different for the NAV model, as, but for now accept that the NAV equivalent beta is 1.8530. The methodology is the same, and the calculations are shown in appendix 6.2 and 6.3.

5.4.1.1.2 Market risk premium

The second main source of error in the estimation of the CAPM is the market risk premium, which is difficult or impossible to observe. One way of estimating the risk premium could be to find its implicit value through the CAPM relation from other analysts, but the noise of the beta estimate would distort our analysis and could lead to biased estimates. Aswath Damodaran has estimated risk premiums for different countries, where the resulting market risk premium for Norway is 6%[216]. An alternative to using such analytical measures is through surveys of investors that have explicit knowledge of the Norwegian market. PwC publish a yearly report[217] based on surveys on applied market risk premiums amongst analysts[218] in the Norwegian market, which might give a more practical approach to the valuation techniques applied in relevant industries. According to the study, the market risk premium has been very stable from 2011 to 2015 with a median of 5% every year, and average ranging from 5% to 5.2%, suggesting a slightly positively skewed distribution. Even though this measure might be noisy due to a fairly low sample size (n=151), and none of the respondents have the actual solution to explaining the risk premium, we accept that the market risk premium measure might be noisy, regardless of the estimation method. Hence we choose to rely on the estimate of Norwegian analysts in the PwC report, and use a market risk premium equal to the median of 5%.

[216] Damodaran (2016): "Country Default Spreads and Risk Premiums"
[217] PwC (2015): "Risikopremien i det norske markedet 2015"
[218] Analysts include respondents working within the following industries: Bank, Asset Management, Corporate Finance, Securities Trading, Private Equity, Accounting and Auditing, Financial Consulting, and Other.

5.4.1.1.3 Risk-free rate

The risk-free rate should represent an investor's return on a risk-free asset. Penman[219] suggests the use of a U.S. Government bond as a proxy for the risk-free asset, with the same duration as the investment. From an investor angle, we believe it's important to emphasize that since Detnor is listed on the Oslo Stock Exchange investors are mainly Norwegian (see appendix 2). A risk-free investment of a Norwegian investor should thus be a Norwegian Government bond.

However, Detnor's income is mainly in USD, leading to a change of functional currency to USD in 2014, thus U.S. Treasury Bills might appropriate in the CAPM derivation. Plenborg and Petersen (2012)[220] argue that local government bonds should be applied, much due to the fact that Government Bond should be denominated in the same currency as the cash flow of the firm. Detnor's cash flows are both in USD and NOK, thus this specific argument is not directly applicable to Detnor.

Hence, there are arguments in favor of both the estimates, and once more we choose to analyze the consensus in the market. The previously introduced PwC report on market risk premiums in Norway also includes a survey of the choice of risk-free rate, based on the same investors as in the previous survey. Consensus over the last 5 years is to use a 10-year Government Bond, in a close race with a normalized long term risk free rate in 2015. The latter is not standardized and observable, but has a median of 3.5% according to the respondents. The uncertainty surrounding the assessment of the latter risk free rate, leads us to preferring the Norwegian Governmental bonds as a proxy for the risk-free rate. In our beta calculation for the peer group we applied a 3-month treasury bill, effectively sharing the same characteristics of a government bond[221]. Hence, in order to minimize the mismatches in terms of risk free rate in the set of applied models in this thesis, we use the same risk free rate here as before. As of 31.03.2016, the risk-free rate on a 3-month treasury bill was 0.4439459%[222].

Adding up the components of the capital asset pricing model, we obtain a cost of equity of 10.37%:

$$\rho_E = \rho_{RF} + \beta(\rho_M - \rho_{RF}) = 0.44\% + 1.8322 * 5\% = 10.37\%$$

5.4.2 Cost of debt

As of 31.03.2016, Detnor has a portfolio of four interest bearing loans, all with different interest rates. In order to find the total cost of debt, we weigh the four components according to their size, and find a portfolio cost of debt, which we will consider Detnor's cost of debt.

[219] Penman (2003): "Financial Statement Analysis and Security Valuation"
[220] Plenborg & Petersen (2012): "Financial Statement Analysis". Page 251
[221] DNB (2016): "Hva er sertifikater og obligasjoner?"
[222] Norges Bank (2016): "Treasury bills daily observations"

We previously introduced the Reserve Based Lending (RBL) facility and the Revolving Credit Facility (RCF), which together represents approximately 80% of Detnor's portfolio of loans (the RCF is currently undrawn), and were issued in 2014 and 2013, respectively[223]. The remainder of the portfolio consists of two unsecured bonds, DETNOR02 and DETNOR03, which were issued in 2013 and 2015 respectively. We have summarized the credit specifications as well as our main calculations in the following table, where *base* refers to 3-month LIBOR for the RBL and RCF, and 3-month NIBOR for DETNOR02.

Credit type	Size (NOKm)	Weight	Base	Margin	Rate	Weighted Rate
RBL	18,030	80.41 %	0.63 %	2.75 %	3.38 %	2.72 %
RCF	0	0.00 %	0.63 %	5.50 %	6.13 %	0.00 %
DETNOR02	1,900	8.47 %	1.00 %	6.50 %	7.50 %	0.64 %
DETNOR03	2,493	11.12 %	n.a.	n.a.	10.25 %	1.14 %
Total	22,422	100 %				4.49 %
Tax rate						25 %
Cost of debt after tax						**3.37 %**

According to our estimates the pre-tax weighted cost of debt is 4.49%. As DETNOR02 is the only loan denoted in NOK, arguments can be made for applying the U.S. corporate tax rate of 40%[224]. Nonetheless, Detnor is registered and operates exclusively in Norway, hence arguments can also be made for applying the Norwegian corporate tax rate of 25%. In compliance with previous discussions, we apply the Norwegian tax rate, and thus apply a tax rate of 25%. This returns an after tax cost of debt of 3.37%.

5.4.3 Leverage through iterations

Thus far the parameters of the cost of capital formula have seemed easily estimated through a set of commonly known relations. However, it should be evident that the leverage ratio drives the valuation through the weighted average cost of capital of the firm, which in return results in a new leverage ratio (denominated in market values). This is a circular process that requires us to update the estimates of leverage ratio for each time the valuation is concluded. Hence, we need to find the leverage ratio resulting from our valuation, in order to use it as an input for the weighted cost of capital of the firm. Using the solver function in excel, with the objective of minimizing the discrepancies between the leverage ratio in the WACC formula and the resulting leverage ratio, we obtain a leverage ratio and weighted average cost of capital of 1.74 and 5.46%, respectively, for the NAV model:

$$\rho_F = \frac{V_0^E}{V_0^{NOA}}\rho_E + \frac{V_0^D}{V_0^{NOA}}\rho_D = \frac{15\ 319\ 897}{42\ 048\ 901} * (1 + 9.10\%) + \frac{26\ 729\ 003}{42\ 048\ 901} * (1 + 3.37\%) = 105.46\%$$

223 Detnor: "Debt and bonds"
224 KPMG (2016): "Corporate Tax Rates Table"

And for the ReOI model we get a leverage ratio of 1.42 and WACC of 5.74%.

$$\rho_F = \frac{V_0^E}{V_0^{NOA}}\rho_E + \frac{V_0^D}{V_0^{NOA}}\rho_D = \frac{18\ 846\ 507}{45\ 575\ 510} * (1 + 9.10\%) + \frac{26\ 729\ 003}{45\ 575\ 510} * (1 + 3.37\%) = 105.74\%$$

Since the company has not disclosed their target leverage ratio, we believe this measures are better than any approximation from historical data. Due to large changes in the company in the recent years, the time after the Marathon Oil acquisition would be most applicable to our forecast, which gives a very small sample size. Hence, the implicit relation presented here is considered a better method for the leverage ratio.

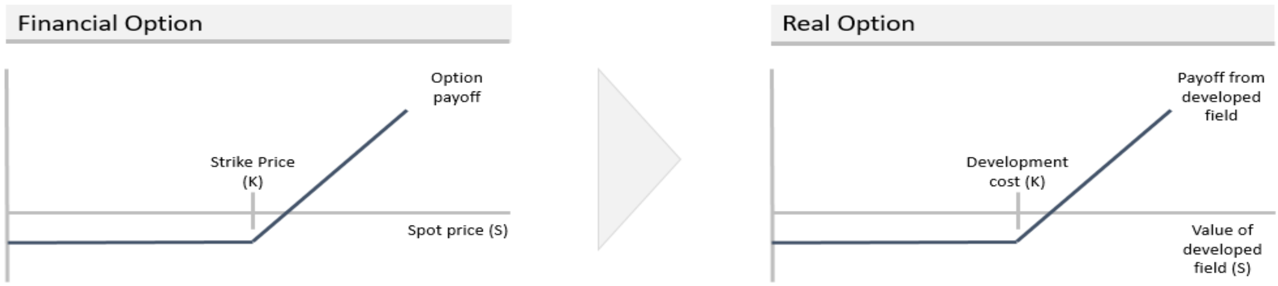
5.5 Real options

In the previously introduced models, we have implicitly assumed that the company will develop new oil fields no matter what happens to the oil price. However, this assumption seems rather strict. As a criticism to the commonly applied DCF models, Siegel, Smith and Paddock (2010) claimed that calculating expected cash flows for a company that relied heavily on operating options was very difficult[225]. Operating options refer to the management's ability delay a decision until a later date, which might indeed be applicable for managers of an E&P company. The article is based on a study by the same authors in 1985, and has been heavily debated ever since. The acknowledged Eduardo Schwartz has joined the debate, arguing that the value of real options is dependent upon a firm's flexibility to respond to uncertainty[226], supporting Siegel, Smith and Paddock's article. The use of real options is however heavily dependent on the fact that there is uncertainty present, and the company has an option to react to the uncertainty. Recalling Detnor's CEO argument about the development flexibility in recently acquired licenses[227], it is natural to assume an investment flexibility in these development projects. The method used to evaluate flexibility in investment decisions for real assets are real options valuation (ROV).

To understand ROV better it is also important to possess general knowledge about financial options. Financial options are the most famous type of options. A financial option contract is either the right to buy (call) or sell (put) an asset during a certain time period or at a specific date (exercise date) at a specific price (strike price)[228]. Options can be either American, which can be exercised at any time before or at the exercise date, or European, which can only be exercised on the exercise date[229]. The principle of financial options can be directly translated to real options, if we consider the option as a variation of a net present value (NPV) project. If the sum of discounted future income exceeds the development cost of the project, the project yields a

[225] Siegel, Smith, and Paddock (2010): "Valuing Offshore Oil Properties with Option Pricing Models"
[226] Schwartz (2013): "The Real Options Approach to Valuation: Challenges and Opportunities"
[227] Detnor (2016): "Capital Markets Day"
[228] Hull (2012): "Options, Futures, and Other Derivatives".
[229] Hull (2012): "Options, Futures, and Other Derivatives". Page 194

positive net present value. The following stylized graph shows the relation between a financial option, and a real option applied to oil field development.



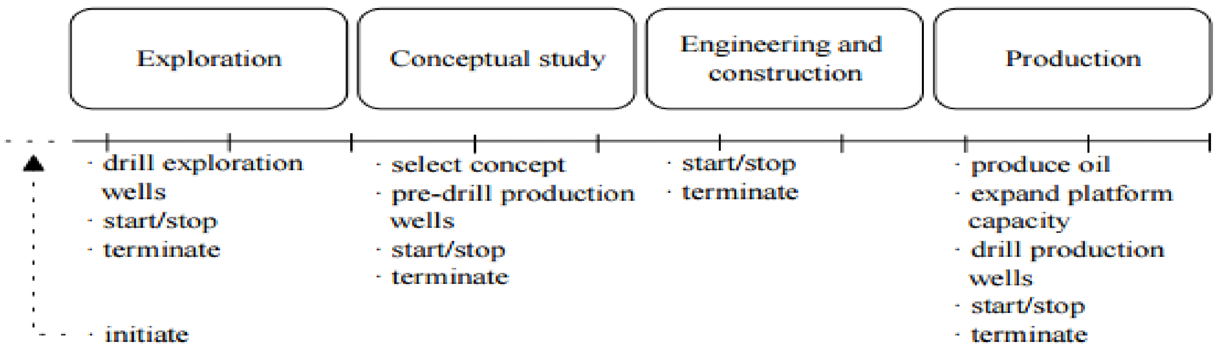
**Source: Authors' contribution and Hull (2012): "Options, Futures, and Other Derivatives". Page 771*

Obvious from the graph, is that the real option is a call option, whose payoff increases as the value of the developed field increases. Furthermore, as the decision to conduct a project can be taken at several occasions until the option expires, we classify the option as American.

The exploration cost is considered a sunk cost as it is incurred regardless of the choice of developing, and is not incorporated in the model. Furthermore, once the plan to develop an oil field is undertaken, the optionality seizes to exist, and the production plan is followed accordingly[230]. In financial option theory this is similar to holding the underlying asset.

5.5.1 Real options in the E&P industry

The focus on flexibility that real options introduce is very relevant in valuing petroleum assets. Options in the E&P industry are related to the different stages in the lifetime of the oil field. The different options are sequential. Morten W. Lund[231], who at the time worked at The Norwegian University of Science and Technology and later at Statoil, mapped the different options which are summarized in the graph below.



[230] Cortazar & Schwartz (1998): "Monte Carlo Evaluation Model of an Undeveloped Oil Field"
[231] Lund (1999): "Real options in Offshore Oil Field Development Projects"

**Decision space related to phases in the oil field development project. Source: Lund (1999): "Real options in Offshore Oil Field Development projects"*

Options in these stages are similar to options types in other investment decision. Schwartz advocates four main types: option to expand, to postpone, to abandon and to temporarily suspend[232]. The type of options to use depends on the investment decision, and in which stage of the sequence we are currently at.

When evaluating a license, sequential options has to be used. Paddock, Siegel and Smith (1988) did this in their study of valuation hydrocarbon leases[233]. They identified three stages the holder of the offshore petroleum lease has complete before producing hydrocarbons: exploration, development and extraction. The payoff from the exploration phase is the undeveloped reserves, where the lease holder again has the decision to develop. The payoff from development is the developed reserves, where the lease holder has the decision to extract the oil. The payoff from extracting the oil is obviously the income from oil production. The article does not include the option to abandon the project. Lund argues that ignoring the connections and dependencies between the sequential investment decisions will not capture the flexibility value of a petroleum lease[234].

From the Paddock, Siegel and Smith (1988)[235] article there are compounded options in all the different stages, except from the extraction stage. Many sequential flexibilities seem good in theory, but to implement this in a valuation is difficult. Therefore, most studies on real option valuation in the E&P industry are focused on one type of flexibility. This has mainly been flexibility of the investment decision developing the field or postponing. Performing this valuation neglects the options of extraction and abandonment. It seems unlikely that a company will choose not to extract oil once the production facility is up and running, nor have we heard of any occurrences where this is the case. Ignoring this option therefore seems somewhat reasonable. The few abandoned fields on the NCS does not give sufficient data to assess if the abandonment option is valuable. In theory, there are real options in every decision made in a corporation, but it is important to bear in mind that the option does not necessarily contain much value. As mentioned earlier, Schwartz argued that the value of the real option depends on the firm's flexibility to respond to uncertainty[236].

The different uncertainties that are related to the investment decision are also important to take into account. Uncertainties related to the different stages could either be market related or technical related[237]. This means that a number of stochastic variables could be included assessing the value of the petroleum

[232] Schwartz (2013): "The Real Options Approach to Valuation: Challenges and Opportunities"
[233] Paddock, Siegel, & Smith (1988): "Option Valuation of Claims on Real Assets: The case of offshore Petroleum Leases"
[234] Lund (1999): "Real Options in Offshore Oil Field Development Projects"
[235] Paddock, Siegel, & Smith (1988): "Option Valuation of Claims on Real Assets: The case of offshore Petroleum Leases"
[236] Schwartz (2013):" The Real Options Approach to Valuation: Challenges and Opportunities"
[237] Lund (1999): "Real Options in Offshore Oil Field Development Projects"

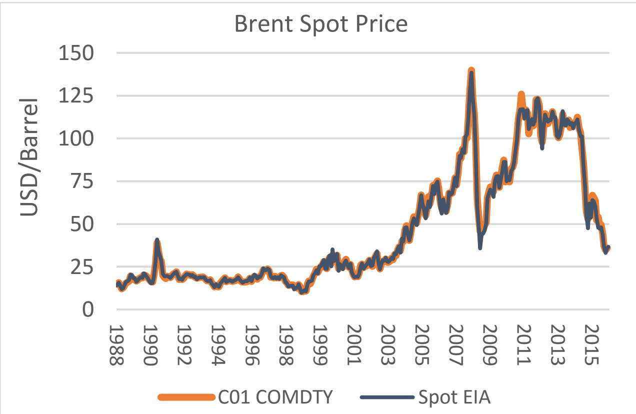
asset. Both uncertainties are important for the value of all the options. Obtaining data to assess technical related uncertainties in the E&P industry is difficult, as this requires internal information.

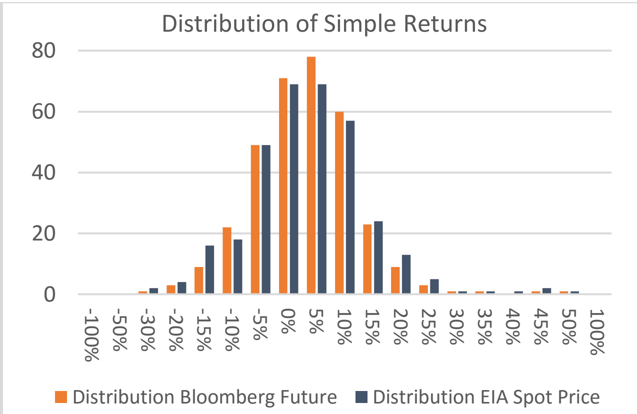
The relevant investment decision we will value is the option to develop at the current date or to postpone the investment decision. We have mainly used the articles by Cortazar and Schwartz, which focuses on evaluating the undeveloped oil field[238] [239]. This article does not include the option to extract or abandon, and we will not include these. This is of course a weakness of the model, and should create a downward bias to the final share price.

5.5.2 Data Analysis for real options

5.5.2.1 Introduction to the data

In this chapter we will mainly test whether the oil price and convenience yield are mean reverting, and whether the log returns of the oil price are normally distributed. Since the spot oil price is not directly observable[240]. The choice of oil price is between using Bloomberg's estimated spot price, which for all practical purposes is known as the spot price, but is truly a 1-month futures contract Brent Spot traded on The Intercontinental Exchange[241], and the EIA quoted spot price. Since futures contracts tend to behave erratically during their delivery month[242], using a futures contract with maturity one month ahead eliminates the risk of incorporating this element in our time series testing, and creates more reliable results. The graph shows a close relationship between the Bloomberg quoted 1 month futures contract and the European Brent Spot Price quoted by EIA[243], with only a few exceptions. However, since there are some deviations, we will test both time series in this chapter.





[238] Cortazar & Schwartz (1998): "Monte Carlo Evaluation Model of an Undeveloped Oil Field"
[239] Cortazar & Schwartz(1997) "Implementing a Real Option Model for Valuating an Undeveloped Oil Field"
[240] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[241] Bloomberg quote: C01:COM (Generic 1st 'CO' Future)
[242] Hull (2012): "Options, Futures, and Other Derivatives". Page 55
[243] U.S. Energy Information Administration (2016): "Europe Brent Spot Price FOB, Daily"

Before having analyzed data quantitatively we see that the distribution of returns yields a nice bell shape, but with heavy tails, suggesting that returns might not be normally distributed for the whole period from 1988 until 2016. Furthermore, we observe that the oil price has experienced spikes in the past, and it seems like the oil price, despite its recent plunge, is higher than what we have seen in the past. In their 1990 paper on Stochastic Convenience Yield and the Pricing of Oil Contingent Claims, Gibson and Schwartz estimated their parameters over a four to five year period, with a split in the middle due to extreme values of the convenience yield[244]. Hence, we acknowledge that our tests should include both a shorter and longer time series, which captures current a long-term price developments, respectively. The long period will contain monthly oil prices from January 1990 until February 2016, whereas the shorter periods will contain monthly oil prices from January 2000 until February 2016, and January 2010 until February 2016. The R code for this chapter can be found in appendix 7.3.

5.5.2.2 *Testing oil price processes*

Despite its neat features of being easy to incorporate in a wide range of models, the Black-Scholes Merton model falls short to mean reversion models, which have been considered more appropriate for commodity prices[245]. Since commodities are determined by supply and demand, it is not unlikely that as commodity prices increase the relative interest in producing the commodity increases, and thus the price should decrease with the increased supply[246]. Following our previous discussions in this thesis, this might be exactly what we have seen; the high oil prices have attracted further suppliers, leading the oil price to plummet. Based on this reasoning, the oil price might follow a mean reversion, in which it tends to revert to a level, according to supply and demand in the market. The Black-Scholes Merton model however assumes that the drift is constant, hence the oil price can potentially drift of. Hence, we need to test whether this is true or not.

5.5.2.2.1 Test of stationarity

The testing procedure is based on a stationarity test where we test for a unit root based on an Augmented Dickey-Fuller (ADF) Test as well as a Kwiatkowski-Phillips-Schmidt-Shin (KPSS) test. All tests in this chapter are based on 95% confidence. We will test the AR (1) process of the log returns on the oil price, as suggested by Schwarz (1990)[247]:

$$\ln(S_{t+1}/S_t) = a + b\ln(S_t/S_{t-1}) + \varepsilon_t$$

[244] Schwartz and Gibson (1990): “Stochastic Convenience Yield and the Pricing of Oil Contingent Claims”
[245] Hull (2012): “Options, Futures, and Other Derivatives”. Page 753
[246] Hull (2012): “Options, Futures, and Other Derivatives”. Page 749
[247] Schwartz and Gibson (1990): “Stochastic Convenience Yield and the Pricing of Oil Contingent Claims”

Where we test $H_0\text{: b} = 0$ and $H_1\text{: b} < 0$, and rejecting H_0 yields stationarity in data. The KPSS test is based on the same AR-process, but has stationarity under the null hypothesis; $H_0\text{: b} < 0$ and $H_1\text{: b} = 0$. The KPSS test has the large drawback of being unreliable with small sample sizes[248], thus if the two tests yield contradicting results we will rely on the ADF-test.

	ADF test					KPSS test			
Time series	Period	Test stat	P-value	N	Time series	Period	Test stat	P-value	N
Bloomberg	Jan'90 - Feb'16	-8.10020	0.010	315	Bloomberg	Jan'90 - Feb'16	0.10946	0.100	315
	Jan'00 - Feb'16	-5.83090	0.010	195		Jan'00 - Feb'16	0.26719	0.100	195
	Jan'10 - Feb'16	-4.95920	0.010	75		Jan'10 - Feb'16	0.52832	0.035	75
EIA	Jan'90 - Feb'16	-8.16130	0.010	315	EIA	Jan'90 - Feb'16	0.10440	0.100	315
	Jan'00 - Feb'16	-6.10360	0.010	195		Jan'00 - Feb'16	0.26719	0.100	195
	Jan'10 - Feb'16	-4.07830	0.011	75		Jan'10 - Feb'16	0.53920	0.035	75

Based on both tests we evidently reject that the time series contain a unit root for all the tested time series', hence the returns are stationary. Furthermore, we do the same tests by applying the ADF-test to an AR (1) on spot oil prices to test the mean reversion, where the null hypothesis is the same as above:

$$P_t = a + bP_{t-1} + \varepsilon_t$$

	ADF test					KPSS test			
Time series	Period	Test stat	P-value	N	Time series	Period	Test stat	P-value	N
Bloomberg	Jan'90 - Feb'16	-1.99490	0.579	315	Bloomberg	Jan'90 - Feb'16	4.81420	0.010	315
	Jan'00 - Feb'16	-1.32740	0.858	195		Jan'00 - Feb'16	3.06670	0.010	195
	Jan'10 - Feb'16	-1.83180	0.644	75		Jan'10 - Feb'16	1.51420	0.010	75
EIA	Jan'90 - Feb'16	-1.87620	0.629	315	EIA	Jan'90 - Feb'16	4.75320	0.010	315
	Jan'00 - Feb'16	-1.61490	0.737	195		Jan'00 - Feb'16	3.00380	0.010	195
	Jan'10 - Feb'16	-1.11420	0.914	75		Jan'10 - Feb'16	1.54270	0.010	75

The tests evidently fail to reject H_0 for the ADF-tests, and reject H_0 in the KPSS-test, and we can dismiss that a mean reverting process is applicable to the oil price.

5.5.2.2.2 Test of normality

Secondly, the BSM model assumes that log returns are normally distributed[249], which will be tested by applying a Jarque-Bera (JB) test. The JB-test is Chi-square distributed with 2 degrees of freedom and normality under the null[250]:

$$JB = \frac{T}{6}\left(\hat{S}^2 + \frac{1}{4}\left(\hat{K} - 3\right)^2\right) \;\;,\;\; JB \overset{a}{\sim} X^2(2)$$

[248] Brooks (2008): "Introductory Econometrics for Finance". Chapter 7.
[249] Ross (1999): "An Introduction to Mathematical Finance". Page 148
[250] The University of British Columbia: "A test of normality"

Jarque-Bera test				
Time series	Period	Test stat	P-value	N
Bloomberg	Jan'90 - Feb'16	82.042	2.20E-16	315
	Jan'00 - Feb'16	34.013	4.11E-08	195
	Jan'10 - Feb'16	1.947	0.3777	75
EIA	Jan'90 - Feb'16	61.896	3.63E-14	315
	Jan'00 - Feb'16	33.229	6.61E-08	195
	Jan'10 - Feb'16	4.849	0.0885	75

Evidently, and in accordance with our visual analysis in the beginning of the chapter, we strongly reject our null hypothesis of normality for the long and medium term period, but we fail to reject normality for the short-term period. Further specifications of formulas can be found in appendix 7.2.

5.5.2.2.3 Test of mean reversion in convenience yield

As introduced in the theory on oil price and convenience yield processes, Gibson & Schwartz (1990)[251] argue that the convenience yield is mean reverting, and points to empirical evidence from their own studies in 1989. As evident from the oil price development in the beginning of the chapter, changes have occurred since they conducted the study, hence we need to check the validity of this statement as well.

We have used the relationship between 2 month futures[252] and a proxy for the spot price of oil[253], as well as the rate of return on a risk-free investment to find the implicit convenience yield. Schwartz and Gibson[254] argue that the spot crude oil price can be defined as the closing price of the nearest possible futures contract. Furthermore, we apply the rate of return on return on U.S. treasury bills[255] in assessing the implied convenience yield. The 1 month US Treasury Bills are not quoted before 2001, hence we need to use 3 month US T-bills instead, adjusted as to represent a 1-month investment. The U.S. treasury bills are chosen based on the inherent choice of investment for a U.S. investor of a risk-less and risky asset, denominated in the same currency, USD. Furthermore, we assume that the relation between the futures price and the proxy for the spot in the past is best represented by the US T-bill, rather than the Norwegian equivalent. The previous discussion can be summarized with the following relation:

$$F(S,T) = Se^{(r-\delta)(T-t)} \rightarrow F(S,T) = F(S,T-1)e^{(r-\delta)(T-t)}$$

Where isolating convenience yield results in the following relation:

$$\delta_{T-1,T} = r_{T-1,T} - 12\ln\left[\frac{F(S,T)}{F(S,T-1)}\right]$$

[251] Gibson & Schwartz (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[252] Bloomberg quoted CO1:COM futures, which are 1 month futures of crude oil on the ICE
[253] Bloomberg quoted CO2:COM futures, which are 2 month futures of crude oil on the ICE
[254] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[255] U.S. Department of the Treasury: "Daily Treasury Yield Rates"

The log return is multiplied by 12 to annualize the convenience yield. The return on a T-Bill of the same maturity as the futures contract is annualized as well. As before, we use the ADF- and KPSS-tests for testing the mean reversion of the convenience yield. A graphic illustration of the convenience yield over time is given in appendix 7.1.

ADF test

Test	Period	Test stat	P-value	N
ADF	Jan'90 - Feb'16	-4.2454	0.010	315
	Jan'00 - Feb'16	-3.3567	0.063	195
	Jan'10 - Feb'16	-1.5499	0.759	75
KPSS	Jan'90 - Feb'16	0.9688	0.010	315
	Jan'00 - Feb'16	1.0799	0.010	195
	Jan'10 - Feb'16	1.4340	0.010	75

Evidently, the ADF-test shows mean reversion in the long-run, but clearly not in the short-run, and on the borderline for the medium-run at 95% confidence. The KPSS test displays a non mean-reverting conenience yield for all periods, but we acknowledged earlier that with small sample sizes, the ADF outperforms the KPSS. Hence, we accept mean reversion in convnenience yield in the long-run, and a process that incorporates this phenomenon might be applicable in assessing the future oil price.

5.5.2.3 Concluding remarks

This chapter has shown some of the basic dynamics of the oil price. Most interestingly we observed two phenomena in the analysis, that might show a general tendency for the pricing of oil in the future;

1. The oil price is not mean reverting
2. The convenience yield is mean reverting

In the next chapter, we will introduce the two-factor model by Gibson and Schwartz (1990)[256], which is consistent with these two findings.

5.5.3 Schwartz' two factor model

5.5.3.1 Introduction and motivation of the process

The previously introduced Black-Scholes and Merton model can more precisely be described through the process[257]:

$$dS = \mu S dt + \sigma S dz$$

Where μ is and σ is constant. As previously discussed, according to Hull[258] the futures price of an asset can be explained by the spot price, the continuously compounded risk free interest rate, storage cost and

[256] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[257] Hull (2012): "Options, Futures, and Other Derivatives". Page 291
[258] Hull (2012): "Options, Futures, and Other Derivatives". Page 120

convenience yield, where the latter has a negative effect upon the futures price, and the former have a positive effect[259]. Schwartz however refers to the convenience yield as *net* convenience yield, in which storage costs (and all other empirically significant input) will be accounted for. Furthermore, Schwartz concludes that the net convenience yield can't be considered constant, but rather stochastic with mean-reversion and a volatility independent of the spot oil price. In accordance with the above discussion, we can present the basis for Schwartz's pricing equation for contingent claims on oil fields. The following is the joint diffusion process for the spot oil price(S) and net convenience yield(δ):

$$dS/S = \mu dt + \sigma_S dz_S$$

$$d\delta = k(\alpha - \delta)dt + \sigma_\delta dz_\delta$$

Where dz_1 and dz_2 are correlated Brownian motion increments, $dz_1 dz_2 = \rho dt$. Here, and only here, ρ is the correlation between the Brownian increments. Evidently the first of the two processes is well-known from Black, Scholes and Merton's model as a process with constant μ and σ_S, and dz_S is the Brownian increments[260]. The second process is a mean reverting Ornstein-Uhlenbeck process where k is the reversion rate (a constant)[261], α is the mean convenience yield, δ is the convenience yield, σ_δ is the volatility of the convenience yield, and dz_δ are the Brownian increments of the process.

This true process is however not appropriate for the pricing of derivatives, as we need to obtain a risk-neutral process[262]. Furthermore, in the absent of arbitrage, the risk adjusted drift of the spot price can be re-written as $r - \delta$ [263]. Hence, under the risk-neutral framework, we can re-define our joint diffusion process as:

$$dS/S = (r - \delta)dt + \sigma_S dz_S$$

$$d\delta = k(\hat{\alpha} - \delta)dt + \sigma_\delta dz_\delta$$

Where

$$\hat{\alpha} = \alpha - \frac{\lambda}{k}$$

The last term is the mean convenience yield when we have adjusted it for the market price of convenience yield risk λ. This term is necessary because convenience yield risk cannot be hedged away, hence there will be an associated market price of this risk under the risk-neutral measure[264]. dz_1 and dz_2 are still correlated.

[259] $F_0 = S_0 e^{(r+u-y)T}$
[260] Hull (2012): "Options, Futures, and Other Derivatives". Page 300
[261] Hull (2012): "Options, Futures, and Other Derivatives". Page 757
[262] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"
[263] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[264] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"

Defining the price of the contingent claim as a function of the spot oil price, convenience yield and risk-free rate $B(S, \delta, r)$, we can use Itô's Lemma to obtain the instantaneous change in the price of the oil contingent claim as:

$$dB = \frac{\partial B}{\partial S}(r-\delta)S + \frac{\partial B}{\partial \delta}(\hat{\alpha}-\delta)k - \frac{\partial B}{\partial \tau} + \frac{1}{2}\left[\frac{\partial^2 B}{\partial S^2}\sigma_S^2 S^2 + \frac{\partial^2 B}{\partial \delta^2}\sigma_\delta^2 + 2\frac{\partial^2 B}{\partial S \partial \delta}\rho\sigma_S\sigma_\delta S\right]dt + \frac{\partial B}{\partial S}\sigma_S S dz_s + \frac{\partial B}{\partial \delta}\sigma_\delta dz_\delta$$

The future price for a contract with maturity T is given by[265]:

$$F(S, \delta, T) = S\ exp\left[-\delta\frac{(1-e^{-kT})}{k} + A(T)\right]$$

Where

$$A(T) = \left(r - \hat{\alpha} + \frac{1}{2}\frac{\sigma_\delta^2}{k^2} - \frac{\sigma_S\sigma_\delta\rho}{k}\right)T + \frac{1}{4}\sigma_\delta^2\frac{1-e^{-2kT}}{k^3} + \left(\hat{\alpha}k + \sigma_S\sigma_\delta\rho - \frac{\sigma_\delta^2}{k}\right)\frac{1-e^{-kT}}{k^2}$$

However, this closed form solution is only applicable if there is no inherent optionality in the cash flows, and other methods are more applicable if we consider management to make the decision to develop a field at discrete points in time[266]. We consider management to make such decisions at only few occasions, and not continuously, hence alternative methods should be considered. Nevertheless, the choice to exercise the option (develop the field) or to hold on to the option (wait) can be conducted until the relinquishment date of the oil field, hence the option is classified as American (or Bermudian if we draw an analogy to financial options)[267]. Other suggested methods to solve real option problem, in the light of the issues shown here are discussed next.

5.5.3.2 The Two-Factor Oil Contingent Claim Pricing Model

Schwartz argue that there are different ways to solve the real option problems[268]:

1. We could use a dynamic programming approach, where the binominal method is mainly used. The model shows possible future outcomes and we derive the value of the option today by discounting the values using the risk neutral distribution. Dynamic programming is not preferable when there are many state variables or path dependencies[269].
2. The second approach is solving the partial differential equation (PDE) using numerical methods. It is a more technical model than the dynamic programming and definition of boundaries are required.

[265] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"
[266] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"
[267] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"
[268] Eduardo Schwartz "The Real Options Approach to Valuation: Challenges and Opportunities"
[269] Eduardo Schwartz "The Real Options Approach to Valuation: Challenges and Opportunities" May 2012

3. The last approach is the simulation approach where the Monte Carlo simulation is a popular method[270]. Simulation approaches are powerful since they look at as many outcomes as desired, and are easy easily extended to several factors. Here we can use a Least Square Monte Carlo (LSM) method to solve the contingent claim problem[271]. This involves a Monte Carlo method to simulate the future oil price, coupled with a least square regression to approximate optimal exercise of the option. We will use this method for our real option valuation.

In this calculation we introduce three different time and space sequences, time in years (t,T), number of simulated paths (n,N), and production lifetime for a field (γ,Γ), respectively. This first procedure is to simulate paths of the convenience yield and spot oil price. We have denoted T as the total number of time periods simulated forward and N as total number of paths simulated. The convenience yield simulation is based on a Euler-Maruyama method[272], which is an approximation of the previously introduced process for the convenience yield. The spot oil price is based on the simulation method presented by Hull for Geometric Brownian Motions[273].

$$\delta_{t+1,n} = \delta_{t,n} + k\left(\hat{\alpha} - \delta_{t,n}\right)\Delta t + \sigma_2 \Delta W_{\delta t,n} \qquad \Delta W_{\delta t} \sim N(0,\Delta t) = \sqrt{\Delta t} * N(0,1)$$

$$S_{t+1,n} = S_{t,n} e^{\left((\mu-\delta_{t,n})-\frac{\sigma_1^2}{2}\right)*\iota+\sigma_1 \Delta W_{St,n}} \qquad \Delta W_{St} \sim N(0,\Delta t) = \sqrt{\Delta t} * N(0,1)$$

To get the correct historical correlations between the increments the Cholesky decomposition is applied[274]. Each of the simulated values of $\delta_{t,n}$ are then used to find the spot price $S_{t,n}$. These values are stored in an I x N matrix[275].

The spot prices will then be used to calculate the value of starting production of the oil field at different points in time. Deciding time steps is difficult since in reality the decision to develop could be taken on a next to continuous basis. For the sake of simplicity, have we have chosen a time step of 1 year. Every decision is taken at the 31st of March and if one decides to start the project, development will commence immediately. For each year of the options lifetime we need to calculate the value of the underlying of the option and the payoff from exercising. Recalling our discussion of the payoffs of the real option introduced earlier in the chapter, we argued that real option equivalent of the spot price of the financial option was the cash flows to the firm from developing the field. The same argument can be represented through the formula:

[270] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"
[271] Schwartz, Eduardo S.; Longstaff, Francis A. (2001)"Valuing American Options by Simulation: A Simple Least-Squares Approach"
[272] Sauer: "Numerical Solution of Stochastic Differential Equations in Finance"
[273] Hull (2012): "Options, Futures, and Other Derivatives". Page 300
[274] The R function "Chol" is used to implement the decomposition which creates the wanted correlations between the increments
[275] Cortazar & Schwartz (1998):"Monte Carlo Evaluation of an Undeveloped Oil Field"

$$VD(S) = \sum_{\gamma=1}^{\Gamma} e^{-\rho_{RF}\gamma}\left(\left(P_\gamma S_\gamma - C_\gamma\right) - Tax_\gamma\right)$$

$VD(S)$: $Value\ of\ the\ developedfield$

P_γ: $Barrels\ produced\ in\ year\ \gamma$

S_γ: $Simulated\ spot\ price\ in\ each\ production\ year$

C_γ: $Total\ cost\ of\ production\ year\ \gamma$

Tax_γ: $Tax\ paid\ year\ \gamma$ (described in section 6.1.6)

ρ_{RF}: $The\ risk\ free\ interest\ rate$

The S_γ is the only input parameter that changes in the equation. The S_γ values are drawn from the simulated spot price matrix. The input spot price for every year depends on which year the option of the field is exercised. This formula is repeated for every option year and for every path. This creates a matrix of dimensions TxN for $VD(S)$.

We see each field as a standalone project, where the VD is the present value at time t future cash flow. This is the cash flow obtained after investing. The only input that changes the equation is the spot price. The strike price of the project is the total development costs (D). The development time of an oil field varies, but is normally over several years. Therefore, the development cost is discounted to a present value at time t, using the risk free interest rate. This value will be the same over all the time periods, t.

$$D = \sum_{\gamma=1}^{\Gamma} e^{-\rho_{RF}\gamma}\left(D_\gamma\right)$$

The lag time between decision to develop and first oil is also accounted for in the calculation of VD. The value of the developed field subtracted from the strike price yields the value of exercising the option at time t.

Calculating the value of exercising the option is subsequently done through Least Square Method (LSM). Standard Monte Carlo approaches are forward looking while the LSM procedure works backwards. At the horizon of the option the value of the option will be the payoff from exercising. If at option maturity (T), the value of exercising is negative, the option holder will not exercise and the value is zero.

$$\Omega_{t,n} = \max(VD_{t,n} - D, 0)$$

However, this is only applicable to the maturity date of the option, but the choice of exercising or waiting will have to be defined at each point in time. Working backwards, we could apply the equation that determines optimal decision at each time step, by implementing the following general equation for optimal choice between exercising and waiting, which is based on the Bellman optimality principle[276]:

$$F_t(x_t) = \underset{u_t}{max}\left(\pi_t(x_t, u_t) + \frac{1}{1+\rho}E[F_{t+1}(x_{t+1})]\right)$$

Which states that optimal decisions are taken so as to maximize the immediate profit π_t and the continuation value $\frac{1}{1+\rho}E[F_{t+1}(x_{t+1})]$. Next, we expand the general optimality principle to include the previously introduced optionality aspect. We re-define the immediate profit plus continuation value (not to be mixed with continuing value in the ReOI) as CV, and include the option to develop a field Ω, where we can consider optimal stopping[277]. The decision to continue or develop (exercise the option) is whichever of the two that yields the highest value, and the condition can be de described through the simple relation:

$$F(x) = \max(\Omega(x), CV(x))$$

More specifically, we can define the function according to simulation path (n) and time (t):

$$F^n(x_t^n, t) = \max\{\Omega(x_t^n, t); CV(x_t^n, \{u(x_\tau, \tau)\}, t\}$$

We define x_t^n as the value of the developed field at time t, in path n: $VD_{t,n} - D$. The u parameter refers to the optimal decision rule. CV is a generalized one path function of continuing value, which we will re-define for several paths through the simple conditional expectation function introduced by Longstaff and Schwartz (2001)[278]. The LSM is performed through calculating conditional expectations of the next periods payoff based on the value of this period's underlying asset. When using Monte Carlo methods this conditional estimation can be calculated cross-sectional using the least squares[279].

$$E[Y|X] = \alpha + bX + cX^2$$

Where Y represents the next period discounted (risk-free) payoff from the option cash flows. The way of choosing Y introduces the recursive way of calculating options. Y is not necessarily the payoff from the option in the next period but could be drawn from periods further back, if the option has been exercised at this time period. The continuation value calculated at each path is not used when we calculate Y, since this could lead to upward biases[280]. This means that there are only real payoff values when we are calculating Y. X represents the value of the underlying asset, being the value of the developed field, without taking into account the

[276] Dixit & Pindyck (1994): "Investment Under Certainty". Page 100
[277] Dixit & Pindyck (1994): "Investment Under Certainty". Page 103
[278] Schwartz & Longstaff (2001)"Valuing American Options by Simulation: A Simple Least-Squares Approach"
[279] Schwartz & Longstaff (2001)"Valuing American Options by Simulation: A Simple Least-Squares Approach"
[280] Schwartz & Longstaff (2001)"Valuing American Options by Simulation: A Simple Least-Squares Approach"

development cost. We only use positive values of Ω in the expectation function, since we assume that an option will not be exercised if its payoff is negative[281].

$$\underset{1\,x\,N}{Y} = \begin{bmatrix} \mathrm{e}^{-\rho_{\mathrm{RF}}}\Omega_{\mathrm{t+1,n}} \\ \mathrm{e}^{-\rho_{\mathrm{RF}}}\Omega_{\mathrm{t+1,n+1}} \\ \ldots \end{bmatrix} \; for\ \Omega_{\mathrm{t,n}} \in <0, \rightarrow>$$

$$\underset{3\,x\,N}{X} = \begin{bmatrix} 1 & VD_{t,n} & {VD_{t,n}}^2 \\ 1 & VD_{t,n+1} & {VD_{t,n+1}}^2 \\ \ldots & \ldots & \ldots \end{bmatrix} for\ \Omega_{\mathrm{t,n}} \in <0, \rightarrow>$$

Using a least square regression, we can estimate the coefficients a, b, and c, in order to calculate the continuing value at time t. Based on this assumption, the continuation value can thus be defined as:

$$CV_{t,n} = a_t + b_t VD_{t,n} + c_t VD_{t,n}^2$$

Hence, the re-defined Bellman equation applied to our oil field analysis, with several simulations (n), at time t, can be written as:

$$F_{t,n}(VD_t) = \max(\Omega_{t,n}; CV_{t,n})$$

Now we have the continuation value $CV_{t,n}$ and the exercise value $\Omega_{t,n}$ for each path (n) at time t, hence we can decide whether it is optimal to continue or exercise at this period in time. With this derivation as a basis, we can go backwards through the paths, in order to obtain the optimal stopping at every time step of the path. As we reach the optimal stopping, we find the option value of each path by discounting the value at the stoppage time by the risk-free rate.

The resulting real option value comes from the arithmetic average of the discounted payoffs at stoppage time for each path, which concludes the value of the analyzed undeveloped oil field. This process is conducted for all undeveloped oil fields under the previously introduced condition of the oil field having an embedded option. The Monte Carlo Simulation is based on 10 000 iterations. We are not able to do any more simulations because of lack of computational power.

5.5.3.3 Certainty Equivalent Approach

Thus far in the chapter we have focused on assets with inherent optionality, disregarding producing fields without optionality. The risk in these cash flows are the same as in the real options, where we assume that the production plan is followed accordingly, and the full production cycle is carried out. Hence, we apply the risk-free rate for discounting the cash flows of the certain cash flows in currently producing fields and fields under development. This approach is known as the certainty equivalent approach (CEQ)[282], and allows us to

[281] Schwartz & Longstaff (2001)"Valuing American Options by Simulation: A Simple Least-Squares Approach"
[282] Cortazar & Schwartz (1998): "Monte Carlo Evaluation of an Undeveloped Oil Field"

aggregate all the relevant oil fields in Detnor's portfolio, under the same assumptions as the real options framework.

Based on this discussion we can apply much of the same framework as in the real option valuation, by eliminating the optionality:

$$CEQ = VD_{Tn} - D = \sum_{\gamma=1}^{\Gamma} e^{-\rho_{RF}\gamma} \left(P_\gamma F(S,\delta,\iota)_{t-1+\gamma,n} - C_\gamma\right) - Tax_\gamma) - D$$

In the ReOI and NAV model we applied the weighted average cost of capital, representing the required return on equity and debt. The models for real options and certainty equivalent approach do however not incorporate these required returns, but argue that the cash flows are risk-free because the risk can be diversified away[283].

5.5.3.4 Expectations of share price assessment

Our model is a discrete version with annual steps, thus each time series will have a fairly small sample size of 30 to 50 observations. Recall that for simplicity we assumed annual steps in our previous valuation models, hence we accept this noise in the data. Specific implications of a low sample size are that the correlation between our generated error terms deviate from the target correlation previously introduced.

According to Schwartz and Gibson[284] this model works best for short periods, as it tends to over value long term contracts. The model can however be enhanced by using monthly updated estimates of the market price of convenience yield risk. This is beyond the scope of this thesis, but we acknowledge that the resulting valuation using real options would, all else equal, yield an optimistic estimate with respect to time horizon.

The option element in oil fields that are under development or not yet developed should have a positive impact on the share price, as the option not to develop a project at low oil prices is apparent. Hence, at a low price, the optionality element should be more valuable than at high oil price. That is; at oil prices that would yield negative payoffs without optionality, the real option payoff is zero or above, and negative for models without the option of not conducting a project (recall the Bellman optimality principle and payoff never being negative). The probability of the oil price ending up in the money makes the option valuable, and hence at low oil prices, we would expect that, ceteris paribus, the real option would be more valuable. For an analysis of how the final share price value would develop for different values of the oil price, we would calculate the option delta, representing the change of the option price as a response to the change in the underlying asset[285]. This type of analysis would require substantial computational power, as the response to incremental

[283] Cortazar & Schwartz (1998): "Monte Carlo Evaluation of an Undeveloped Oil Field". Page 84
[284] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"
[285]Hull (2012): "Options, Futures, and Other Derivatives"

changes of the oil price would have to be calculated, which is beyond the scope of this thesis. Instead, we will identify how the final equity values differ in our conducted valuation methods, and why, under the currently assumed oil prices and processes.

6 Forecasting

In this chapter will we forecast the different parameters used in the three valuation models. The model that requires most parameters forecasted is the NAV model, and we will therefore start with the parameters for this model. Next, we will look at the parameters used in the ReOI model. The advantage with the ReOI model is that it requires less forecasting of both parameters and years. Relying on fewer pieces of information to solve the problem, is something that Penman advocates[286]. At last we will look at the different input parameters in the ROV valuation. Here the estimation of the process is important, where we have used the parameters from a Schwartz paper[287].

6.1 Net Asset Valuation (NAV) model forecasting

For closer field specific details, underlying the tables and graphs in this chapter, see appendix 8.

6.1.1 Revenue

The revenue for an E&P company depends on the amount of the petroleum produced and the price it is sold at. Therefore, we have to estimate the future production and the future prices.

6.1.1.1 Production Forecasting

Forecasting of production is one of the most important parameters in the cash flow. To know how production is going to be in the future we need to know how much reserves there are, and when these are going to be produced.

The recoverable reserves say a lot about the production profile. Lifetime of the field, length of the plateau production[288] and depletion are all characteristics that the recoverable reserves could help us understand. The recoverable reserves depend on many different factors, which are all hard to predict. These could be geological factors, production mechanism, number of wells and economic consideration. E&P companies also experience trouble estimating recoverable reserves, where the recoverable reserves tend to increase over time[289]. This phenomenon is called reserves growth. We will rely on the Norwegian Petroleum Directorate's estimates and Detnor's own estimates for the reserves forecasting. The most recent update of the two

[286]Penman (2003) "Financial Statement Analysis and Security Valuation"
[287] Schwartz (1997) "The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging"
[288] The time period of which the oil field reaches its top production amount of barrels per day
[289] Morehouse (1997): "The Intricate Puzzle of Oil and Gas "Reserves Growth""

sources will be chosen. The ratio between oil and gas will also be given by these sources. Not accounting for any reserves growth in the NAV model is a weakness, which could give a downward bias for the final share price.

To get the correct value of the oilfield it is not only important to estimate the total amount of petroleum reserves, but also when the petroleum is extracted. The production profile, as for the reserves, is determined by several factors, but is unclear in what way they affect. Factors could be techniques used to extract reserves, field-development programs, reservoir management practices, geology, national production policies, field-maintenance programs and external factors[290]. Here it is clear that the technical aspects of production are constraints of production, while other factors are mainly decision making from the E&P company. In general, the confidence level in a production forecast is low[291].

The preferred estimates for production profiles are the E&P companies' own forecasts. The company is the decision maker for the oilfield production and has the most geological knowledge about the field. Information about production is possible to find in PODs, annual reports, capital market day presentations and press releases.

For producing fields which are in the decline phase, will we use a constant decline rates that fully depletes the oil fields. Five of nine producing fields are closing in 2016, and their last year production will not impact the total value of the company substantially. The future production from the Alvheim area is very important for the company. The four fields included in this area are all in the decline phase and the last year of production of the field is reported by the company. Alvheim is estimated to produce until 2032[292]. We will therefore assume a decline rate that gives full depletion on these fields.

For oil fields that haven't started production we have to use comparable oil fields to forecast production. Finding criterions for good comparable oil fields is conducted by looking at studies that introduce similarities of production profiles for different oil fields. Höök (2009)[293] explains the *standard* production profile of an oil field, which is depicted in the figure below:

[290] International Energy Agency (2008): World Energy Outlook 2008. Page 223
[291] Antill & Arnott (2000): "Valuing Oil and Gas Companies: A Guide to the Assessment and Evaluation of Assets, Performance and Prospects". Page 125
[292] Lundin Petroleum: "Norway – Alvheim & Volund"
[293] Mikael Höök (2009): "Depletion and Decline Curve Analysis in Crude Oil Production"

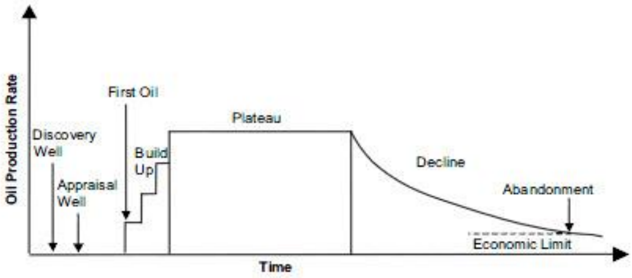


**Figure 1- The lifetime of an oil field Source: Mikael Höök (2009): "Depletion and Decline Curve Analysis in Crude Oil Production"*

From the first oil there is normally a buildup phase of production until peak production or a plateau production. For smaller oilfields the plateau phase is often very short, while it could be very long for larger oil fields[294]. After the plateau phase there is typically a decline phase until the abandonment of the oilfield hits when the economic limit is reached. Höök distinguishes between sizes of fields and argues that this is a major determinant of the production profile.

From looking at these studies, we have identified the two most important variables in explaining the shape of production as:

1. The size of reserves
2. The physiographic situation (onshore/offshore)

Therefore, we have only chosen fully depleted oil fields from the NCS where size of reserves is known and physiographic situation is similar with Detnor's undeveloped fields. It is also important that comparable fields are as new as possible so the current production technology is accounted for. Last criteria are that the comparable oil fields should have the production profile descried by Höök (2009).

Lille-Frigg is the comparable for oil fields under 20 mbbl. The oil field was situated in the North-Sea and was a subsea field. This is perfect for modelling Detnor's assets since they will most likely be developed with subsea solutions. The disadvantage of using Lille-Frigg to explain Detnor's oil fields today is that it was shut down in 2001, making it a fairly old comparable field. There are only 18 fields that has shut down on the NCS (21.02.2016) according to the NPD[295], and of the small fields Lille-Frigg is the best comparable.

Glitne was recently shut down in 2013 and is the comparable for fields between 20-100 mbbl. The oil field was situated in the North Sea and developed with subsea installations.

[294] Cambridge Energy Research Association (2007): "CERA-IHS: Global Oil Field Decline Rate at 4.5%/Year"
[295] Norwegian Petroleum Directorate: "Fact Pages"

Jotun is expected to shut down in 2016 and is the comparable for fields between over 100 mbbl. The oil field is situated in the North Sea and developed with an FPSO and a wellhead facility. The following table summarizes this analysis of production profiles for the fields. For field-by-field production details, see appendix 8.1.

Year	Reserves (mbbl)	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Lille-Frigg	8.3	2.4	2.7	1.8	0.8	0.4	0.1	0.0	0.0									
% of res	100%	29%	33%	21%	10%	5%	1%	0%	0%									
Glitne	55.8	4.7	13.6	10.6	6.1	5.2	3.7	2.9	3.2	2.3	1.6	1.2	0.6	0.0				
% of res	100%	8%	24%	19%	11%	9%	7%	5%	6%	4%	3%	2%	1%	0%				
Jotun	145.1	5.4	45.1	34.5	16.3	14.1	6.9	4.8	4.2	3.2	2.4	2.0	1.6	1.3	1.1	0.9	0.7	0.6
% of res	100%	4%	31%	24%	11%	10%	5%	3%	3%	2%	2%	1%	1%	1%	1%	1%	1%	0%

6.1.1.2 Sales prices

Detnor sells Crude Oil and Natural Gas. Crude oil has historically been the main revenue driver with approximately 90% of sales, and looking forward their assets base is also mainly crude oil. Hence, emphasis has been placed on estimating the crude oil price. We have chosen not to focus on production of NGL since this is often omitted from Detnor's own reports and include these reserves in the Natural Gas reserves. The input for Brent Crude Oil prices are taken from the forecasted estimates in section 7.4, where we have chosen the Detnor estimates as our base case. We have taken into account that the Alvheim Crude sells at a premium of 3-6 USD/bbl to Brent Blend[296], where we have used 3 USD/bbl as a cautious estimate.

6.1.2 Operational expenses (OPEX)

The operational expenses are costs that are associated with the daily operations of the company and tied to the production volume of the company. These costs are typically production costs, transportation costs and maintenance costs. These costs will vary from asset to asset and also company to company[297]. These costs are not reported on each field, but in the guidance for 2016, Detnor have estimated an average production cost of 8-9 USD per boe (including shipping & handling costs). This is above previous years' OPEX per boe, but previous years have not included the shipping & handling costs. In the strategic analysis we discussed Detnor's goal to reduce OPEX by 20%, and how the low oil prices could give lower procurement costs for Detnor. We will therefore assume a long term OPEX per barrel cost of USD 8 for Detnor's current producing fields. For future producing fields we have estimated an OPEX of $ 6-8 per barrel, where larger development projects have lower OPEX per barrel costs. From the financial statements we see varying production costs,

[296]Detnor (2014): Acquisition of Marathon Norge: Press & Analyst conference
[297] Antill & Arnott (2000): "Valuing Oil and Gas Companies: A Guide to the Assessment and Evaluation of Assets, Performance and Prospects". Page 129

but these have decreased with the increase in Detnor's production level. This indicates the economies of scale in producing oil. Following is the result of calculations from the financial statements[298].

Date	2010	2011	2012	2013	2014	2015
OPEX/boe (USD)	34.89	55.52	69.59	25.24	9.91	5.87

6.1.3 Other operating expenses

Other operating expenses are typically general and administrative expenses (G&A), rent and consultancy costs[299]. These costs do not vary with the production level in the same matter as OPEX, within certain ranges. When estimating future other operating expenses, we will use previous income statements and forecast it based on the relationship *other operating expenses/total operating revenue*.

Year	2010	2011	2012	2013	2014	2015
Other operating / revenue	28%	21%	28%	16%	14%	4%

From the strategic analysis we know that these costs are subject to economies of scale, which we have depicted in the table above. With Detnor's plans of future production their size will increase further and even more economics of scale will be possible. As this measure is in percentage of revenue, we would expect the ratio to drop as sales increase when oil fields under development are reclassified, and starts production. However, 2015 was still a year of solid production volumes, hence keeping in mind that the ratio most likely exhibits decreasing returns to scale at this point, we assume that other operating costs will decrease to 2% of revenue.

6.1.4 Capital Expenditure (CAPEX)

When the decision that discovery could be developed commercially the development phase begins. On the NCS no E&P company could start developing before getting the" Plan for Production and Development" (POD) approved. CAPEX are costs associated with production wells, injection wells, subsea costs, Floating production, Storage and Offloading Unit (FPSO)/Platform costs, engineering costs, pipeline costs and contingency costs[300]. Most costs for CAPEX are payments to external companies, and as stated in the industry analysis; these costs are correlated with the oil price. This means that CAPEX occurring in the near future will decrease, because of lower oil prices. Detnor's ambition is to reduce CAPEX with 50%, presented at the Capital Market Day (2016)[301]. For fields not yet approved for development we have assumed a 30% CAPEX decrease. This is mainly based on the argument for CAPEX decrease in the future on the NCS stated in the

[298] OPEX is defined as production cost in the financial statements
[299] Det Norske Oljeselskap: «Annual report 2015»
[300] Antill & Arnott (2000): "Valuing Oil and Gas Companies: A Guide to the Assessment and Evaluation of Assets, Performance and Prospects". Page 128
[301] Det Norske Oljeselskap ASA: "Capital Market Day 2016"

strategic analysis. In forecasting future development CAPEX, we have used a set of different methods, tailored to the specific oil fields of Detnor:

- **Fields under production –** For fields under production, the estimated future development CAPEX is listed on the NPD homepage, hence these estimates are considered realistic and reliable. CAPEX on the NPD is listed in 2015 NOK, where we use the inflation to adjust for CAPEX occurring in the future.
- **Oil fields approved for development –** As for the fields under production, the estimated future development CAPEX is reported by NPD. The NPD only reports the total expected future CAPEX, and not when it will actually occur. For Ivar Aasen, Hanz and Johan Sverdrup we use the CAPEX profiles presented in the PDO, but with updated total CAPEX estimates. We assume that Gina Krogh, which is a similar field as Ivar Aasen, to have the same CAPEX profile as Ivar Aasen.
- **Fields not yet approved for development –** For discoveries and fields that are yet to be approved for development there is a lack of public information, thus we have to use CAPEX estimates based on comparable fields. Similarly, to the forecasting of production profiles, it's vital to apply appropriate comparable fields, with similar characteristics. The basis for our estimation, and determinant of CAPEX profiles, is the size of the field, and operatorship. Hence, we have only used new developments where Detnor is the operator, in order to take company specific input into account.

CAPEX is a process going over several years and we have therefore made "CAPEX profiles". The classification system is the same used for the production profiles. The Viper/Kobra field is a proxy for fields with recoverable volumes of less than 20 mbbl, Bøyla for fields between 20-100 mbbl and Ivar Aasen for the fields above 100 mbbl.

The fields with recoverable volumes of less than 20 mbbl are mostly tie-in developments. The Viper/Kobra development is a tie-in to the Alvheim field and finished development in 2016. Detnor is operator on the field, and the field is developed with subsea installations.

Bøyla is a development tied to the Alvheim FPSO. The development was finished in 2015. The field will be the comparable for fields between 20-100 mbbl. Detnor is operator on the field. The field is developed with subsea installations.

Ivar Aasen is the comparable for the fields above 100 mbbl. The field is expected to start production in Q4 2016. Detnor is operator on the field.

CAPEX Profiles (NOK)	Total	1	2	3	4	5	Per barrel
VIPER/KOBRA	1,800,000,000	600,000,000	1,200,000,000				200.0
% Of total Capex	100%	33%	67%				

BØYLA	5,538,000,000	85,000,000	414,000,000.0	1,276,000,000	3,260,000,000	503,000,000	244.6
% Of total Capex	100%	2%	7%	23%	59%	9%	
IVAR AASEN	25,786,200,000	2,305,000,000	5,167,000,000	11,008,000,000	7,306,200,000	0.0	139.4
% Of total Capex	100%	9%	20%	43%	28%	0%	

6.1.5 Decommission costs

The decommission costs are all the costs related to the abandonment of an oil field. There is a lack of empirical data and information about decommission costs on the NCS. Decommission costs are typically costs associated with removing subsea structures, platforms and shutting down wells, and is highly dependent on the production structure of the oil field. Details about number of platforms/FPSO, wells and pipelines give good indications on what the decommission costs would be.

Our Decommission estimates is forecasted using the existing facilities at the production site and looking at decommission costs that have occurred to similar production sites. The UK government has detailed decommission plans available for oil fields shutting down[302]. From this information we have done a study on what decommission on Detnor's fields will cost. The following results have been obtained from the study:

	Orwell	Wissey	Gawain	Arthur	Rose	Stamford	Schiellion and Loyal	Average Subsea	Average FPSO
Subsea and pipeline installations	63.39	38.03	79.87	87.47	11.65	160.43	1,534.20		
Per subsea installment	63.39	38.03	79.87	21.87	11.65	160.43	28.41	62.54	709.46
Well abandonment	177.48	63.39	316.93	418.35	116.55	112.07	709.46		
Per Well	59.16	63.39	105.64	104.59	116.55	112.07	709.46	93.57	28.41
Continuing liability	6.34	6.34	6.34	2.54	11.65	11.80	26.60	7.50	26.60

When looking at the decommissioning cost of Detnor's oil fields, we use the averages according to the relevant production facility. For the larger fields where the POD is available we have used the reported decommissioning costs in these, as these measures are considered more reliable than our estimated proxies. For undeveloped fields where the choice of development facility is yet to be made, we have used past field decommission cost per barrel as a proxy. The measure proxy is from the Varg field where a thorough decommission plan with cost estimates is available[303]. This proxy yields a decommissioning cost of $ 16.5 per barrel. As with the CAPEX we will adjust the decommission costs with the inflation rate.

[302] Gov.UK (2016): "Oil and Gas: Decommissioning of Offshore Installations and Pipelines"

[303] Talisman Energy (2014): "Avslutning av virksomheten og disponering av innretninger på Varg-feltet"

6.1.6 Tax

Exploration and operating activates on the NCS are subject to the "Norwegian Oil and Gas Taxation code", which is a set of special tax rules. The Norwegian petroleum tax system is based on the taxation of the entity rather than the specific petroleum asset[304]. Most of the value created on NCS falls in the hands of the Norwegian state, where the effective tax rate is 78% as of 1.2.2016[305].

6.1.6.1 Depreciation (tax)

CAPEX on the NCS are allowed to be depreciated linearly over 6 years with a maximum of 16.67% per year. In Finnmark and four municipalities in Troms the depreciation could be 33.3% in the future, which could potentially be relevant to some of Detnor's discoveries in the Barents Sea[306]. The start of the depreciation is immediately after the costs have occurred. If the production is less than for three years, the depreciation can be accounted as a direct expense.

6.1.6.1.1 Corporate tax

As discussed, the corporate tax in Norway is 25% and is the same for all companies operating in Norway. The amount of corporate tax is for a year is calculated as:

$$EBIT_t = EBITDA_t - depreciation_t$$

$$Calculated\ tax_t = 0{,}25 * EBIT_t$$

$$Balance_t = \min(Balance_{t-1} + Calculated\ tax_t, 0)$$

$$Corporate\ tax_t = if(Balance_t < 0{,}0, Calculated\ tax_t + Balance_t)$$

The tax loss carry forward here is reflected in the balance, where the tax advantage with a deficit is taken into account. The tax carry forward has no restriction on how long it can be carried forward. Interest should be added to the tax loss carry forward, with a fixed rate set by the Ministry of Finance. In the NAV model any tax carry forward not used when the field shuts down, will be refunded.

6.1.6.2 Special tax

Special tax is the other direct tax which is under the "Norwegian Oil and Gas Taxation Code"[307]. Unlike the corporate tax, special tax is a distinctive tax for oil companies, and amounts to 53%[308]. Special tax is paid on EBIT but deducted for a tax free allowance, called uplift. The uplift is based on the development costs and is

[304] Deloitte (2014): "Oil and Gas Taxation in Norway"
[305] Finansdepartementet (2016): "Skattesatser 2016"
[306] KPMG (2016): "Petroleumbeskatning"
[307] Deloitte: "Oil and Gas Taxation in Norway"
[308] Ministry of Finance (2016): "Skattesatser 2016"

granted for 5.5% annually for four years, making the total uplift 22%. For costs incurred before 05.05.2013 the annual uplift is 7.5%.

$$Uplift_t = sum(CAPEX_{t-15}: CAPEX_t) * 0.075/4$$

$$Tax\ base\ for\ Special\ Tax_t = EBIT_t - Uplift_t$$

$$Calculated\ tax_t = 0.53 * Tax\ base\ for\ Special\ Tax_t$$

$$Balance_t = \min(Balance_{t-1} + Calculated\ tax_t, 0)$$

$$Special\ tax_t = if(Balance_t < 0{,}0, Calculated\ tax_t + Balance_t)$$

6.1.6.3 Refunds

Tax loss carryforwards can be claimed by a company if they do not have any petroleum activity left on the NCS. When we are performing the NAV, these tax loss carryforwards will not be transferred to other fields but rather create value through a refund on the field when it closes down. This will typically happen to our fields in the NAV model where the last decommissions will create a tax loss carryforward which will be refunded, at an effective tax rate of 78%.

6.1.7 Macroeconomic variables

6.1.7.1 USD/NOK

For simplicity we will not estimate the future exchange rates applicable to the respective years in the future, but rather rely on the forward curve of USD/NOK. Hence, we will use the 12 month average forward curve for each year as an estimation of the USD/NOK exchange rate. The exchange rate is taken from Bloomberg, and are averaged over the respective years as we assume that sales are spread evenly over the year. See appendix 8 for future foreign exchange rates.

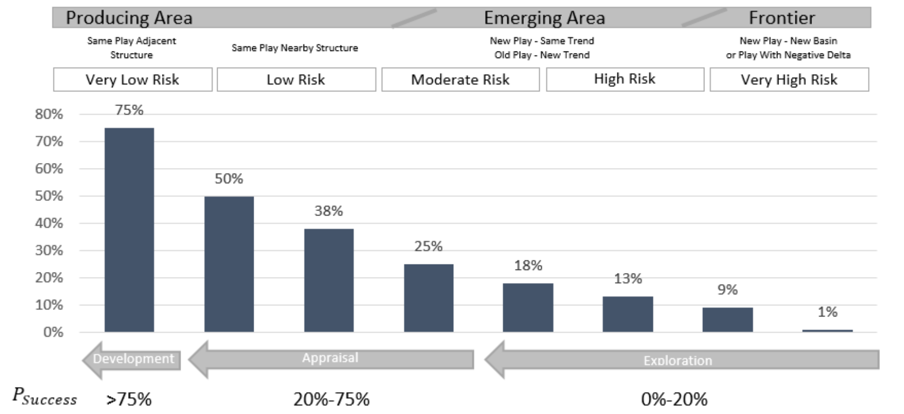
6.1.7.2 Inflation

Similarly, to the USD/NOK argument, we will not estimate the inflation in this thesis. Furthermore, we consider the Norwegian Central Banks inflation goal of 2.5% to be a reliable and realistic estimation for the future inflation, even though inflation has fluctated around 2.0% in the last 10 years[309].

[309] Norges Bank (2016): "Inflation"

6.1.8 Risk Weighing

In the NAV model, as previously introduced, we need to include a risk-weighing, as fields in different life cycles are typically associated with different risks. Currently producing fields are associated with very low risk, as both production volumes and costs are fairly certain at this point in the life cycle, whereas exploration projects are considered very highly risky due to large uncertainties of volumes, commercial viability, etc. Recalling the SPE classification scheme, early exploration phase projects have a low chance of commerciality, reinforcing our argument of not including these in an asset valuation. Looking at the following graph from Deutsche Bank (2013), we obtain a framework in which we can appropriately risk weigh Detnor's oil fields. The Resulting risk weights for each oil field will appear in valuation chapter.



*Source: Original figure taken from Deutsche Bank (2013): "Oil & Gas for Beginners". Page 57

6.2 Residual Operating Income (ReOI) model forecasting

Since we rely heavily on Penman's frameworks in previous chapters, it is tempting to apply Nissim and Penman's time series analysis of ratios to forecast ratios in the future[310]. However, as discussed in the financial statement analysis, upstream oil companies tend to exhibit high cyclicality because they are heavily dependent upon the development of fields. Hence, a time series analysis of the past, across the industry, would most probably yield ratios that would not coincide with our expectations of the future.

Penman suggests a full information forecast model when performing the ReOI model. The forecasting method builds up pro forma financial statements from forecasts of drivers[311]. The key drivers are the ratios that drives the return on net operating assets (RNOA), which are asset turnover (ATO) and profit margin (PM).

The process starts with a thorough analysis of sales and a resulting forecast, before analyzing and forecasting the profit margin and asset turnover in the similar manner. According to Penman, this type of forecasting has a high degree of validity since it requires forecasting of very few items, minimizing forecasting error. Sales, ATO and PM are value drivers in most firms and focusing mainly on these will show if the firm is creating

310 Nissim & Penman (2001): "Ratio Analysis and Equity Valuation: From Research to Practice"
311 Penman (2003): "Financial Statement Analysis and Security Valuation".

value. The forecasting horizon is often shorter using the ReOI model, since value creation is often acknowledged earlier.

When forecasting parameters for the residual operating income model, we have chosen to use the same input as the NAV model in the years from 2016 to 2019. This argument is based on the identification of three main sources of generalizability difficulties of forecasting measures, namely company specific, industry specific, and market specific:

1. The underlying reasoning is that Detnor is a company in growth with high M&A activity, where operating income has been negative for the past five years, due to a historically very volatile ATO and PM. Hence, the future and past are not necessarily coinciding. Detnor has invested heavily in the past years, resulting in a growth in net operating assets (NOA). Some of these investments have borne fruits instantaneously as the production facilities were already in place, such as for the Alvheim field. However, for investments in which production is yet to start, there is a lag time before sales are generated from the investments. This has led us to base our forecast horizon on the end of the development process of Johan Sverdrup, which is finished in 2019, as this point in time marks a change from certainty to uncertainty in full information forecasting. The high degree of information transparency from both Detnor and the Norwegian Petroleum Directorate, makes forecasts in developing and under development fields very reliable, hence our time horizon.
2. For E&P companies with continuous investments and sales from several assets, basing the forecast on the PM and ATO ratios are more applicable, but often this is not the case for Detnor nor its peers. The E&P industry is generally in a turmoil because of low oil prices. Hence, forecasting the correct ATO and PM from year to year is difficult for more established producers as well. This situation is well summarized in the table below, where it is clear is that on an industry basis there is a downward trend in both ATO and PM, where Detnor are experiencing a countervailing effect from their previous investments[312].

	2011	2012	2013	2014	2015
ATO					
Peer median	0.34	0.71	0.52	0.40	0.29
Peer mean	0.57	0.66	0.53	0.41	0.29
Detnor	0.09	0.06	0.14	0.18	0.36
PM					
Peer median	23 %	21 %	17 %	-15 %	-38 %

[312] ATO (Asset turnover) = Sales / Net Operating Assets, and PM (Profit Margin) = Operating income (a/tax) / Sales, where we only use core operating figures

Peer mean	23 %	18 %	18 %	-15 %	-41 %
Detnor	-85 %	-122 %	-34 %	-48 %	-16 %

3. The third source of generalizability issues comes from the uncertainty of the oil price, which has a highly significant effect on the sales, profit margin and asset turnover. Looking at previous figures, it is difficult to separate the effect from oil price changes and operational improvements/ deteriorations, hence the historical profit margin is highly volatile and might yield a misleading basis for the forecast. From the strategic analysis we concluded that the current level of global production could not be sustained at this oil price, due to a high marginal cost, leading us to expect a higher oil price in future.

As the huge Johan Sverdrup field commences production in 2020, Detnor's sales and asset turnover is fairly pre-determined, with oil price still being an uncontrollable and vital external factor. Johan Sverdrup is estimated to reach peak production in 2023, and the development plan stretches only until 2022, hence production will most probably decline steadily after 2023. Estimating the continuing value from the peak point in 2023 will be misleading for how the development will be in the future, as a field of the size and profitability of Johan Sverdrup is a rare occurrence. As a result, we have chosen 2026 as the last year of our forecast horizon, as production has stabilized at a lower, more sustainable level, after which we apply a continuing value, which is discussed later.

Our forecast in the 2016 to 2019 period is based on most of the same input as the NAV, but differs in terms of exploration expenses, accounting depreciation and accounting tax. Exploration expenses are not accounted for in the NAV model. Recall that the NAV implicitly assumed that Detnor will not obtain further oil fields than those they currently have, and thus exploration is redundant. Depreciation is treated differently by the company and by the government, which affects taxes. Furthermore, in the ReOI model we also need to forecast balance sheet items and sales, which is based on input from the NAV model.

6.2.1 Sales, ATO and PM

6.2.1.1 Sales

Detnor's sales are forecasted with the same methods as in the NAV, where we assume that the company will produce and sell according to the production plan. Since the Marathon Oil acquisition was motivated by its near term cash flows required for the Johan Sverdrup development phase, with covenants already on the brink of being breached, we see it as highly unlikely that more new projects will occur before this field reaches peak production, and development seizes. Hence, the production plan until 2023 seems very reliable, and sales will be based on the production plans from assets during these periods.

6.2.1.2 Asset turnover

The table presented earlier showed that the median ATO in our peer group varied from 0.34 to 0.71 before the sudden drop in the oil price. The mean ATO varied from 0.41 to 0.66. Detnor reached its highest ATO when the rest of the industry hit their lowest ATO, due Marathon acquisition, and shows how Detnor became a totally different company when acquiring working interest in the Alvheim Area. Whether Detnor is able to sustain the historical level of growth is difficult to assess, but based on assets that are currently under development, we remain positive to the previous trend. As introduced earlier in the thesis, Detnor has been very successful in recent licensing rounds, receiving an abundance of both operating and partner licenses, which shows faith in Detnor's efforts to successfully extract oil from Norwegian resources. Coupled with lower costs than what is seen in other North Sea oil fields, which was analyzed in the oil price chapter, and a higher oil price in the future, we consider the growth potential of new assets to Detnor to be substantial. Several new oil fields are in the development process, and as the resource base has the potential to grow, we can expect the asset turnover to be less cyclical over the long term. Hence, in the long term we would expect that the asset turnover should converge to a higher and more stable level. Whether sales will increase relatively more than net operating assets relies on the efficiency of the use of assets, which we believe will grow as the company obtains more knowledge through learning, as the company is still relatively young.

6.2.1.3 Profit margin

The profit margin has naturally gone down in 2016 because of the low oil prices. OPEX will often also decrease with lower oil prices looking long-term, but not at the same rate as the oil price decreases in the short-term. Detnor has also created several initiatives reducing operational costs and exploration costs to get a higher profit margin. Lower OPEX is also important for sanctioning projects under $40 per barrel and will naturally be lower in the future when the margins in the business are getting squeezed, as explained in the strategic analysis. The median PM for Detnor's peers was between 23% and -15% before the worst drop in the oil price occurred. The mean PM had the same range, while Detnor varied from -122% to -48%. The consensus before the oil price drop in the peer group seem to be 17% to 23%, in a more normalized market. We believe that with the estimated higher oil prices and Detnor's initiative in lowering costs, the profit margin should be 16% from 2020, and in eternity. This is slightly lower than the peer group historically, but this is justified in a lower oil price, coupled with a lower operating cost.

The following table summarizes the previous discussion on sales, asset turnover and profit margin, where we have included historical figures from 2011 to 2015[313]:

[313] For coherence in comparing the future and the past, we have used end of year figures when looking at the balance sheet.

	Historical					Forecast Horizon (NAV-based)				Forecast Horizon (Ratio-based)						Continuing value
	2011	2012	013	2014	2015	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Sales (in mill NOK)	372.1	332.4	943.9	2,928.5	9,859.3	6,356.5	11,704.0	13,415.5	13,318.1	14,839.9	23,622.6	29,022.8	44,874.0	38,146.3	33,117.7	30,109.3
Asset turnover	0.09	0.08	0.16	0.38	0.4	0.21	0.34	0.38	0.36	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Profit margin (after tax)	-85 %	-122 %	-34 %	-48 %	-16 %	9 %	10 %	10 %	9 %	16 %	16 %	16 %	16 %	16 %	16 %	16 %

6.2.2 Forecasting from 2016-2019

As previously mentioned, near term forecasts are based on the net asset value model, but this is not sufficient to capture all of the forecast elements of the ReOI model. This chapter is dedicated to forecast the remaining items for the near-term forecast horizon, namely 2016 to 2019.

6.2.2.1 Net Operating Assets

When we forecast the net operating assets for the period 2016-2019 we mainly look at the changes in the Non-Current Assets, since these are the main constituents of Detnor's net operating assets (NOA). The changes in tangible non-current operating assets are dependent on the investments, acquisitions and expensed exploration cost subtracted of depreciation and impairments. All these measures are previously calculated in the NAV valuation, except from the accounting depreciation. The intangible assets are more difficult to estimate because assessing key drivers is difficult. Detnor has had a decreasing trend of the multiple intangible assets/Non-current operating assets. The main driver for this item is goodwill from acquisitions, where we believe Detnor will be less active in the future, because of little available capital. We have assumed a level of 20% of total Non-current operating assets which is substantially lower than the previous years. Intangible assets are deferred tax liabilities and also calculated by looking at the changes in accounting tax and payable tax. We have estimated both these items. The non-current operating assets less the non-current operating liabilities yields the non-current operating assets. Net Working Capital (NWC) has decreased the past years in both percentages of the NOA and in absolute terms. In 2015 NWC amounted to 1% of net operating assets, which we consider to be a plausible estimate going forward.

	2016E	2017E	2018E	2019E
Ingoing balance	28,945,200	35,675,735	35,906,450	36,840,265
+ Investments	8,618,366	3,495,568	4,469,719	4,712,017
- Depreciation	1,887,831	3,264,852	3,535,905	3,457,469
Tangible assets	35,675,735	35,906,450	36,840,265	38,094,813
% Percentage of non-current operating assets	*80 %*	*80 %*	*80 %*	*80 %*
Intangible	8,918,934	8,976,613	9,210,066	9,523,703
% Percentage of non-current operating assets	*20 %*	*20 %*	*20 %*	*20 %*
Non-current operating assets	**44,594,668**	**44,883,063**	**46,050,331**	**47,618,516**

Deferred tax balance	-10,799,894	-10,292,161	-9,656,769	-8,212,026
Net operating working capital	348,399	356,607	375,191	406,252
Net operating assets	**34,839,972**	**35,660,723**	**37,519,135**	**40,625,246**

6.2.2.2 Exploration expenditures (EXPEX)

EXPEX are all the costs associated with exploring licenses for petroleum reserves. These costs are typically made up of acreage, seismic, geological and geophysical (G&G), drilling and completion costs. Detnor have their own exploration department which works with the G&G and as project managers for exploration projects. The costliest parts of EXPEX are on the other hand services delivered by external companies. This is especially shooting seismic surveys and drilling for exploration wells (wildcat wells). From this we could see that EXPEX main driver is how much exploration activity Detnor is initiating, and at what prices they could get seismic and drilling. These prices often follow the activity in the industry which is dictated by the oil price. The day rates/contracts for contracting rigs and seismic vessels has decreased since the oil price also have decreased. The EXPEX is on the NCS held by the companies, but the Norwegian Government have favorable rules where 78 percent of exploration expenditures could be claimed the following year. As previously introduced, Detnor uses the "Successful efforts" accounting method, where EXPEX is first put in the balance, and only expensed if the exploration is not successful (failure of finding commercially viable resources).

Estimating future exploration capex is done through looking at the past year's exploration capex, and also taking into account Detnor's ambition to be a leading explorer on the NCS by 2020 seen in the strategic analysis. Between 2016 and 2020 the company aims to discover 150 mboe net to Detnor[314]. Detnor expect to explore for a value of 1.496 billion NOK in 2016[315], and since this is part of the ambitious exploration program, we assume that they are able to obtain the same amount of exploration in the years between 2016 and 2019.

6.2.2.3 Capitalized exploration costs

We previously introduced the successful efforts method, in which only exploration that leads to proven resources will be capitalized on the balance sheet. Detnor firstly recognize all exploration costs on the balance sheet, and if the exploration is proved worthless, the amount related to the exploration is charged as an expense[316]. The choice of charging exploration as an expense is however made by Detnor themselves, and since it has a positive tax refund effect, the item might be subject to subjectivity. Even though we expect

[314] Det Norske Oljeselskap ASA: "Capital Market Day 2016"
[315] Det Norske Oljeselskap ASA: "Capital Market Day 2016"
[316] Det Norske Oljeselskap ASA: "Annual Report 2015». Page 67

Detnor not to manipulate their financial statements, the exploration capitalization/expense ratio is non consistent over time, making forecasting challenging.

Detnor has optimistic exploration plans in the year to come, meaning that capitalized exploration costs should increase every year. However, since unsuccessful explorations are expensed, and some explorations will be reclassified to development projects, there will be an opposing effect on the balance sheet following the capitalization. Our assumption is that Detnor will seek to sustain their exploration portfolio over time, and the capitalized exploration will be offset by an equal portion of expensed capitalization and reclassification (total), resulting in a net change in capitalized exploration equal to zero.

6.2.2.4 Accounting depreciation

In the income statement, tax is treated differently than in tax accounting. When Detnor depreciate their assets, it is done through the units of production method[317].

$$Depreciation_t = \frac{Number\ of\ units\ produced_t}{Life\ in\ number\ of\ units} * (Cost - Salvage\ value)$$ [318]

6.2.2.5 Accounting tax

Accounting tax is measured:

$$EBIT_t = EBITDA_t - depreciation\ accounting_t$$

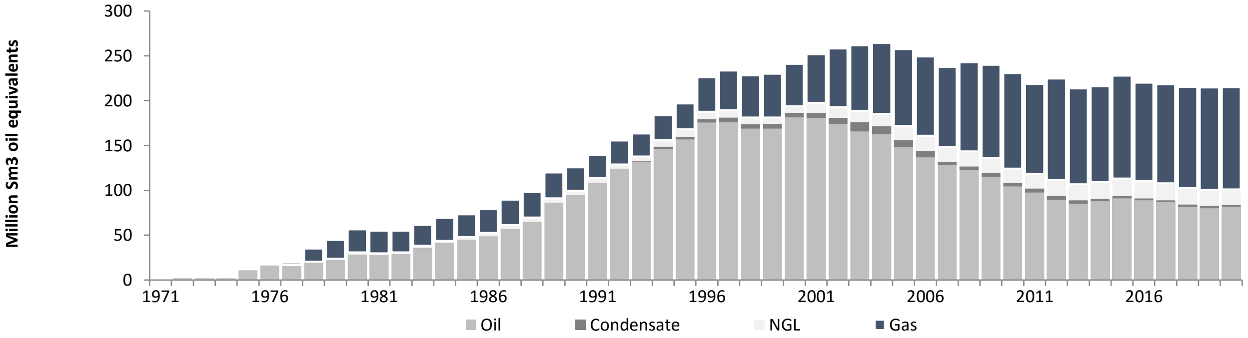
$$Calculated\ tax_t = 0{,}78 * EBIT_t - Uplift_t * 53\%$$

6.2.3 Continuing value

After the forecast horizon (2016-2026), we apply the previously discussed continuing value. We introduced three different methods of estimating this value. Estimating the value of the firm beyond the forecasting horizon is difficult since the strategy and operations of Detnor are influence by many external factors. One element that is important to take into account is that oil is a non-renewable resource, where it has been argued that peak production on the NCS is already reached[319]. The same argument can be made looking at the previously introduced creaming curve for the North Sea, where we concluded that oil field discoveries are most likely to become smaller in the future. At the year of the continuing value, most of the production stems from the elephant field Johan Sverdrup, which is a reserve that is difficult to replace. Growth in the ReOI is therefore not likely for the period beyond the forecasting horizon. We introduced alternative resources in the oil price analysis early in the thesis, where we saw that some of the demand in petroleum products could be replaced in the future. Hence, we are expecting a decrease in Detnor's eternal residual

[317] Det Norske Oljeselskap ASA: "Annual Statement of Reserves 2016". Page 76
[318] Accounting Explained: "Units of Production Method of Depreciation"
[319] Höök & Aleklett (2008): "A decline rate study of Norwegian oil production"

operating income, but emphasize that much of the oil demanded in the world is still highly inelastic, giving rise to two opposing effects on future growth.



**Source: Norwegian Petroleum (2016): "Historical and expected production in Norway, 1971-2020"*

From the graph we see that since the historic peak production point of Norwegian oil production in 2004, at 261.68 mill sm^3 of oil equivalents, until the projected 2020 level, at 215.11 mill sm^3, the compound annual growth rate (CAGR) can be assessed at -1.2%. As we have discussed thus far, the oil industry has been through a recent shock, and the current and near-term years is likely to be affected by the aftermath of this turmoil. Hence, in the long-run, we don't expect to see a linear trend in the presented forecast by Norwegian Petroleum, but rather an exponentially decreasing level of production. Coupled with the expectation of lower production costs, we will expect that profit margins should, all else equal, increase in the long term, even though this is a dangerous long run assumption for an otherwise volatile commodity. Furthermore, new technology might enhance the asset turnover in the long run, but as we have expected it to increase in the forecast horizon, we don't expect it to increase further, consistent with the industry standards previously discussed.

The question does however remain; are we bound to see a persistent shock, or will there be a reversion to a higher level? Based on our discussion, we expect a slight negative growth rate in the continuing value, but keeping in mind the positive effect of a Detnor undergoing large changes to costs and efficiency, the growth is expected to stay at approximately negative 0.6% in the future. This we consider a standardized CAGR, at half of what we have experienced in the studied period. Hence, we rely on formula 3 from the valuation theory chapter, for our continuing value:

$$CV_T = \frac{ReOI_{T+1}}{\rho_F - g}$$

6.3 Real Option Valuation (ROV) model forecasting

6.3.1 Parameters for futures oil price

Input variables for the futures oil price are taken from the paper "Monte Carlo Evaluation Model of an Undeveloped Oil Field" written by Cortazar and Schwartz[320]. The parameters are not necessarily the appropriate to use today, since they were calculated in 1997. The futures prices observed after 1997 may give different parameters, since these could change through time. The complexity of estimating new parameters and the time it takes to quality control the parameters, makes it better to use the already estimated parameters. Further studies should conduct such researches to find appropriate parameters for current market conditions.

The parameters in the presented paper we have used are actually taken from an earlier Schwartz paper[321], where he estimates parameters for three different models. Schwartz argues that there are difficulties in estimating the parameters since they are not directly observable. The procedure used is the space state form, and the Kalman filter is applied to estimate the parameters. The data set used in the paper are weekly observations of futures prices of oil, where there are ten futures contracts used. The data set is from the 1/15/1993 to 5/16/1996 and provided by Enron Capital. We have chosen to change one of the parameters which is the risk free interest rate. The interest rate (π) used in the model is the average risk-free interest rate over the time period considered. For the Enron data, the interest rate in this period was 5%, but we have chosen to use the same interest rate that we discount with in the field valuations. This is the 3-month Norwegian Treasury bill rate of 0.44%. Below are the parameters from the paper:

μ	κ	α	σ_S	σ_δ	ρ	λ	π
0.082	1.187	0.09	0.212	0.187	0.845	0.093	0.0044

**Parameters of the Stochastic Process. Source: Cortazar & Schwartz (1998): "Monte Carlo Evaluation of an Undeveloped field"*

The starting oil spot price and convenience yield has to be calculated. As a proxy for the oil spot price we use the futures contract closest to maturity[322]. The starting convenience yield is calculated as we did when analyzing the mean reversion of the convenience yield, using the futures price equation:

$$F(S,T) = Se^{(r-\delta)(T-t)}$$

Where we can rearrange and get the following relation:

[320] Cortazar & Schwartz (1997): "Monte Carlo Evaluation Model of an Undeveloped Oil Field"
[321] Schwartz (1997) "The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging"
[322] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"

$$\delta_{T-1,T} = r_{T-1,T} - 12\ln\left[\frac{F(S,T)}{F(S,T-1)}\right]$$

Calculating the starting spot oil price and convenience yield using the methods above yields:

Spot oil price (S_0)	39.60	Convenience yield (δ_0)	-21.90%

6.3.2 Parameters Calculating Oil Field Value

When calculating the value of the oil field do we use many of the same variables as we forecasted in the NAV model. The main difference is the oil price calculated through the two-factor model. For the gas price will we use the relation calculated in chapter 4.2.5. The discount rate used will be the 3-month Norwegian Treasury Bill rate of 0.44%. We will use the current USD/NOK rate as a proxy for the foreign exchange rate in the future. This rate is 8.28 USD/NOK. When calculating the final value of the firm do we also need to calculate the NPV of other operating costs. This will be done in the same manner described in chapter 6.1.3. All other parameters will be equal to the ones in the NAV valuation. For further detailed input variables for each field, see appendix 9.

6.3.3 Oil fields included

As stated will only fields where development has not started be valuated using real options. Detnor do not have majority share in most fields, and we have therefore made an assumption that all companies in the oil field consortium thrive to create value for their respective shareholders, aligning the interest of all decision makers in the process of producing oil. There is not any development optionality where the development process already is initiated. These fields are then valued through the certainty equivalent (CEQ) approach. The expiration date of the option is taken from the expiration date of the licenses. These details are available at NPD fact pages[323]. Below are the relevant fields with the expiration date of the option.

Field	Attic Oil	BoaKam SW	Caterpillar	Frigg GD	Frøy	Garantiana	Gekko	Gohta	
Relinquishment	2029	2029	2029	2017	2019	2022	2029	2018	
Option years	14	14	14	2	4	7	14	3	
Field	Grevling	Krafla/Askja	P-Graben	Ragnarock	Ragnarock B.	Steinbit	Storklakken	Skalle	Trell
Relinquishment	2021	2022	2037	2037	2037	2022	2018	2017	2025
Option years	6	7	22	22	22	7	3	1	10

[323] Norwegian Petroleum Directorate: “Factpages”

6.4 Concluding remarks on forecasting

The NAV and ROV models evidently bear many similarities in terms of production levels and associated costs, but naturally deviate widely in oil price forecasting, and inherent optionality. The ReOI model is based on the same input as the NAV for near term forecasts, but relies heavily on simplicity through ratios in long term forecasting. Stephen Penman (2013)[324] states that forecasting vague notions will give wrong estimates of the value of the firm. Forecasts should be of items that can be audited and reported in the firm's future financial statements[325]. Penman also advocates being parsimony, which for forecasting means being straightforward and relying on fewer pieces of information. Hence, our choices of forecasting in the ReOI and NAV/ROV is implicitly also a discussion of the balance between simplicity and rigorousness.

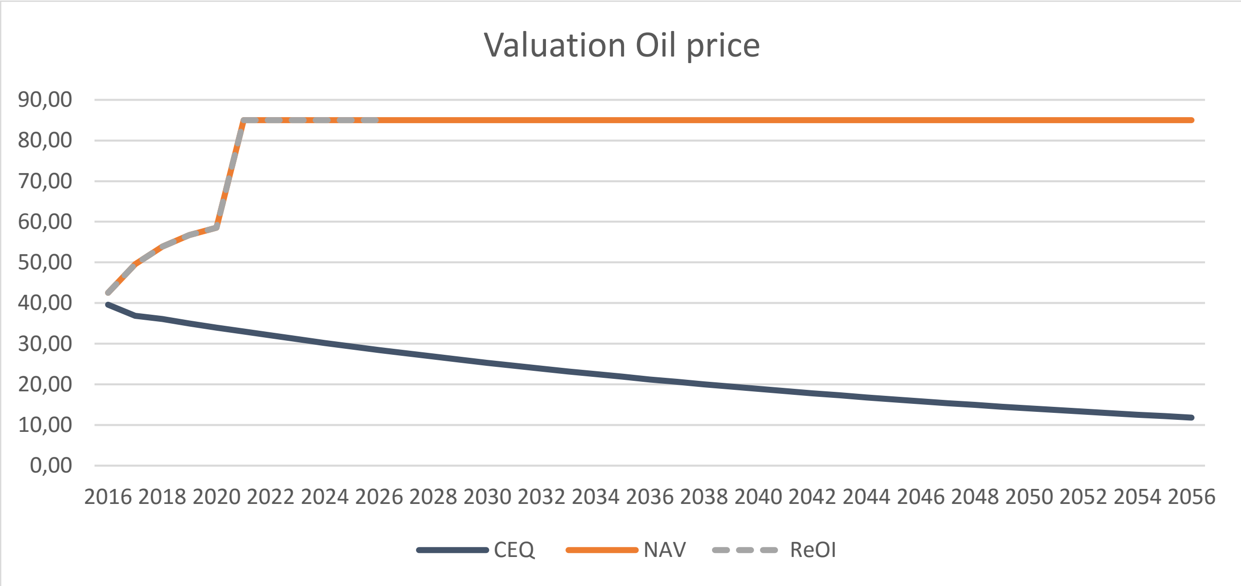
This chapter has shown that either model is bound to be affected by an investor's subjectivity. Even though the NAV and ROV models are more rigorous, they are not necessarily more precise. The length of forecast horizon demands high transparency in future revenue and costs, and requires stability in these measures over time. This is however a very vague assumption, as both the revenue and cost aspects in the oil industry are shown to fluctuate widely. In the ReOI we rely on fewer parameters in the long term, but are still dependent on stability, especially related to the continuing value. Under the law of large numbers, we assume that our estimators are fairly stable when computing the continuing value, whereas both the NAV and the ROV require very precise yearly estimations.

7 Valuation

Based on previous discussions, this chapter will conclude the final values for each of our presented valuation models, accordingly. As emphasized throughout this thesis, assumptions regarding key input has been necessary to obtain a final value, hence a natural extension to the valuation is a sensitivity analysis. The valuations methods can naturally yield deviating equity values and share prices, since they are based on different assumptions. Hence, the analysis is concluded with a discussion on how to assess a final value for Detnor's equity.

The following graph shows the oil prices used in the different valuation models. The oil prices in the NAV and ReOI are both deterministic, and are equal for all future years. Evidently, it is upward sloping, and is based on the previous discussion of future oil price. The stochastic process of the oil price in the ROV on the other hand, gives a negatively sloped oil price in the future. We will discuss the underlying reason for this later in the chapter.

[324] Penman (2003): "Financial Statement Analysis and Security Valuation"
[325] Penman (2003): "Financial Statement Analysis and Security Valuation" page 84



7.1 Residual Operating Income Valuation (ReOI)

Our residual operating income model was based on the assumption that the company will continue to exist in the future, and assets would be replaced over time. Furthermore, this allowed us to incorporate exploration of new assets in the future, in accordance with what we saw historically in Detnor.

Summing up our previous discussions, we apply a cost of capital of the firm of 5.74% for both the forecast horizon and continuing value, and a negative perpetual growth rate of 0.06% in calculating the continuing value. The following table shows a valuation summary from the ReOI model, where we emphasize the main elements included in the analysis:

(NOK'000)	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	Continuing value
Revenues	**6,356,570**	**11,704,843**	**13,415,544**	**13,381,101**	**14,839,904**	**23,622,200**	**29,022,877**	**44,874,700**	**38,146,228**	**33,117,790**	**30,109,298**
Production costs	-1,420,506	-2,029,006	-2,066,527	-1,901,507							
Other operating costs	-127,131	-234,097	-268,311	-267,622							
EBITDAX	**4,808,933**	**9,441,740**	**11,080,705**	**11,211,972**							
Exploration expenses	-1,496,000	-1,496,000	-1,496,000	-1,496,000							
EBITDA	**3,312,933**	**7,945,740**	**9,584,705**	**9,715,972**							
Depreciation and amortization	-1,887,831	-3,264,852	-3,535,905	-3,457,469							
EBIT	**1,425,102**	**4,680,888**	**6,048,800**	**6,258,503**							
Tax on EBIT	-849,095	-3,471,453	-4,675,397	-5,009,619							
Profit margin	*9%*	*10%*	*10%*	*9%*	*16%*	*16%*	*16%*	*16%*	*16%*	*16%*	*16%*
Operating Income	**576,007**	**1,209,435**	**1,373,404**	**1,248,885**	**2,374,385**	**3,779,552**	**4,643,660**	**7,179,952**	**6,103,397**	**5,298,846**	**4,817,488**
Asset turnover	0.21	0.34	0.38	0.36	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Net operating assets (t-1)	29,727,036	34,839,973	35,660,723	37,519,135	29,679,807	47,244,401	58,045,754	89,749,399	76,292,456	66,235,580	60,218,597
Firm cost of capital %	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%	5.74%
Firm cost of capital NOK	1,706,499	2,000,010	2,047,126	2,153,809	1,703,788	2,712,094	3,332,153	5,152,120	4,379,616	3,802,295	3,456,886
Residual operating income (ReOI)	**-1,130,492**	**-790,575**	**-673,723**	**-904,925**	**670,597**	**1,067,458**	**1,311,508**	**2,027,832**	**1,723,780**	**1,496,552**	**1,360,602**
PV ReOI	-1,069,118	-707,066	-569,844	-723,846	507,287	763,662	887,318	1,297,475	1,043,055	856,398	
PV forecast horizon	2,285,321										
PV Continuing value	12,279,680										
Book value of common equity (CSE0)	2,998,041										
Equity value	**17,563,042**										
Shares outstanding (millions)	202.62										
Per share value	**86.68**										

Evident from the table, our ReOI model yields an equity of approximately NOK 17.6 billion, which at 202.62 million shares outstanding yields a per share equity value of NOK 86.68. This is based upon the assumptions made along the way, and the presented estimates refer to our *base case* in the ReOI; the case which we consider most likely.

With Detnor being reborn because of the Marathon Oil Norge acquisition in 2014, the company as we know it today is fairly young, with small volumes produced until 2020. This results in negative residual operating income from 2016 to 2019, counteracting the positive residual operating income from 2020 when the Johan Sverdrup field enters the production phase. Hence, even though we have a forecast horizon of 10 years, 70% of the equity value lies within the continuing value, which is highly sensitive to its input.

As seen in the oil price analysis, the oil price is highly volatile, and can change by small or large increments in a short time span. Hence, the following sensitivity analysis is based on a range of oil price scenarios, rather than a fixed oil price scenario, as well as a range of capital costs, that together yield a share price.

		Flat USD/bbl							
		30	40	50	60	70	80	90	100
WACC	4,0 %	74,63	109,54	144,29	178,84	213,34	247,80	282,27	316,73
	5,0 %	35,78	59,61	83,25	106,65	130,00	153,30	176,59	199,89
	6,0 %	8,37	24,83	41,07	57,03	72,92	88,76	104,59	120,42
	7,0 %	-12,06	-0,76	10,30	21,04	31,70	42,31	52,91	63,51
	8,0 %	-27,93	-20,35	-13,04	-6,08	0,79	7,60	14,40	21,20
Growth rate	-2,0 %	10,80	27,62	44,24	60,59	76,87	93,10	109,32	125,55
	-1,0 %	13,41	31,10	48,58	65,79	82,94	100,03	117,12	134,21
	0,0 %	16,93	35,79	54,43	72,81	91,12	109,38	127,63	145,89
	1,0 %	21,93	42,45	62,75	82,78	102,75	122,67	142,58	162,50
	2,0 %	29,61	52,67	75,52	98,10	120,61	143,07	165,52	187,98
OPEX	-20,0 %	16,52	34,61	52,46	70,08	87,64	105,15	122,66	140,18
	-10,0 %	15,60	33,70	51,58	69,21	86,77	104,28	121,80	139,31
	0,0 %	14,68	32,80	50,70	68,33	85,90	103,41	120,93	138,44
	10,0 %	13,76	31,89	49,81	67,46	85,03	102,55	120,06	137,57
	20,0 %	12,85	30,98	48,93	66,58	84,16	101,68	119,19	136,70
ATO	0,30	-38,31	-37,70	-37,31	-37,19	-37,14	-37,14	-37,14	-37,14
	0,40	-5,19	6,36	17,69	28,76	39,76	50,71	61,65	72,60
	0,50	14,68	32,80	50,70	68,33	85,90	103,41	120,93	138,44
	0,60	27,93	50,42	72,70	94,71	116,66	138,55	160,44	182,33
	0,70	37,39	63,01	88,42	113,56	138,63	163,65	188,67	213,69
PM	10,0 %	-26,86	-22,47	-18,29	-14,39	-10,55	-6,76	-2,98	0,81
	12,0 %	-13,01	-4,05	4,70	13,18	21,60	29,96	38,32	46,68
	14,0 %	0,84	14,37	27,70	40,76	53,75	66,69	79,63	92,56
	16,0 %	14,68	32,80	50,70	68,33	85,90	103,41	120,93	138,44
	18,0 %	28,53	51,22	73,70	95,90	118,05	140,14	162,23	184,32

Referring to the oil price analysis chapter, both a USD 30 per barrel scenario and USD 100 per barrel is highly likely in the short term. USD 30 per barrel was indeed a fact earlier inn 2016, and oil prices hovered around USD 100 dollar per barrel between 2011 and 2014. Hence, recalling the previously presented graph of correlation between the return on share price and crude oil at 60% thus far in 2016, the sensitivity analysis confirms this positive relationship. The WACC components, including for example the risk-free rate and market risk premium (through the CAPM relation), we consider less sensitive on a daily basis, which is supported by a stable historic market risk premium considered by Norwegian investors[326], and assuming a fairly stable capital structure. The former was presented in the cost of capital chapter. The capital structure

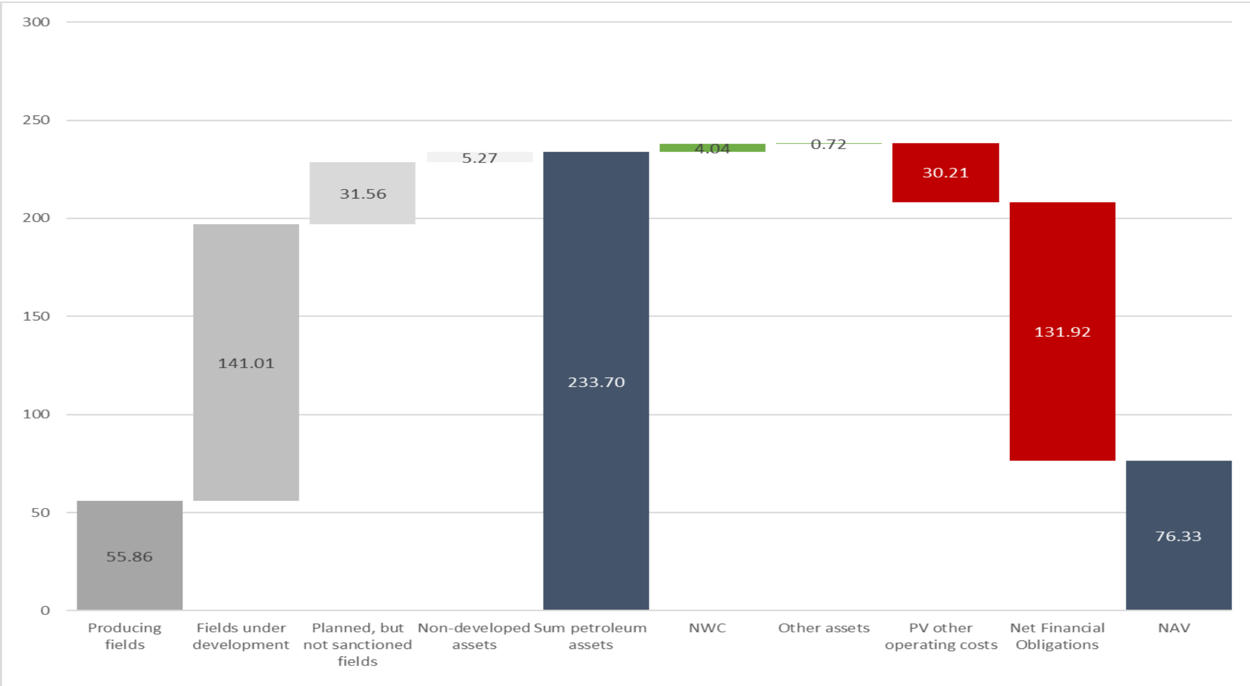
[326] PwC (2015): «Risikopremien i det norske markedet»

was found through iterations, and is of course subject to change over time, especially considering Detnor's aggressive M&A activity. As explained in the financial statement analysis, we do however consider the debt to be kept at the current level, since the company is already on the brink of breaching its current debt covenants.

7.2 Net Asset Valuation (NAV)

Whereas the ReOI model assumed replacement of old assets, as well as exploration, for all eternity, the net asset value (NAV) model is solely based on the assets in Detnor's portfolio of oil fields. Hence, in this sum of the parts analysis, we have aggregated the oil fields in each of the respective four asset groups, according to where they are in the field development process. The NAV takes no continuing value.

Summarizing our previous discussions, we apply a WACC of 5.46%, differing slightly from the ReOI valuation, because they are based on separate iterative process. The four oil field categories are *producing fields* (8 fields excluding the currently non-producing Enoch field), *fields under development* (4 fields counting Johan Sverdrup Phase 1 and 2 as one), *planned but not sanctioned fields* (5 fields), and lastly *non-developed assets* (12 fields). The total values to the company for each field per share is NOK 55.86, 141.01, 31.56, and 5.27, respectively, which net after accounting for net operating working capital, other operating costs, and net financial obligations, yields a share price of NOK 76.33. Most of the value in Detnor's assets comes from the *fields under development* category. Fields like Johan Sverdrup (Phase 1 and 2) and Ivar Aasen have low breakeven prices, and at the same time large reserves. The two account for 58% of the petroleum assets value and are together with the Alvheim area the most valuable assets in the portfolio. See appendix 8 for detailed field values.



This means that the NAV model estimates a lower value of Detnor's equity, relative to the ReOI model. A significant portion of the equity value in the ReOI model lies within the continuing value, because the forecast horizon is much shorter in the ReOI than the NAV. The NAV model and ReOI uses the same input for the near term forecast, but deviates in the long term when we expect production, asset turnover and profit margins to stabilize for the ReOI, and the NAV model risk weighs the oil fields according to their respective project phases. The two valuation models do however only deviate in share price by approximately NOK 10.4 (≈13.6% higher for the ReOI), hence the results are somewhat conforming.

The inability to value future production and value creation arising from the exploration department could also make the final value of the model differ from the stock price in the market. Investors can appreciate a well driven exploration department with discoveries like Johan Sverdrup.

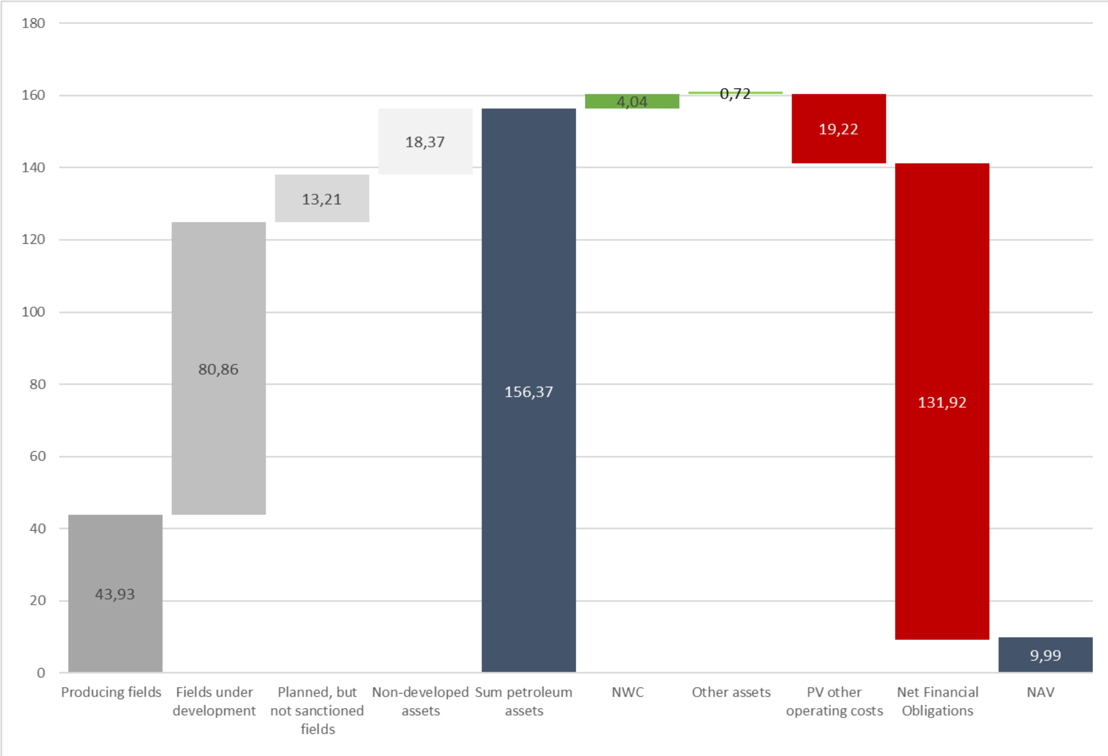
Despite these short comings, we don't have to assume stability in sales, profit margins and asset turnover, as we did in the ReOI. Each oil field is treated as a separate entity with variations in these parameters across the life time of the oil field according the development and production plan, at the cost of uncertainty in these measures. The NAV is deterministic which means that factors like reserves and date of production start for new developments are decided when the model is performed and managerial flexibility in the form of optionality in developed projects is not valued.

		Flat USD/bbl							
		30	40	50	60	70	80	90	100
WACC	4,0 %	-58,98	-19,36	15,89	50,38	84,67	118,75	152,77	186,76
	5,0 %	-67,80	-30,10	2,98	35,17	67,13	98,86	130,51	162,13
	6,0 %	-75,62	-39,64	-8,49	21,67	51,58	81,22	110,79	140,31
	7,0 %	-82,55	-48,14	-18,70	9,65	37,73	65,52	93,23	120,90
	8,0 %	-88,72	-55,74	-27,83	-1,09	25,37	51,51	77,57	103,58
OPEX	-20,0 %	-64,40	-29,09	2,86	34,03	64,99	95,71	126,37	156,99
	-10,0 %	-67,73	-31,83	0,21	31,41	62,39	93,11	123,77	154,40
	0,0 %	-71,50	-34,61	-2,44	28,78	59,77	90,51	121,18	151,80
	10,0 %	-75,75	-37,41	-5,10	26,16	57,16	87,91	118,58	149,21
	20,0 %	-80,07	-40,24	-7,78	23,53	54,54	85,30	115,99	146,62
CAPEX uncommenced fields	-30,0 %	-14,11	17,96	48,64	79,12	109,58	140,04	170,51	200,97
	-15,0 %	-19,03	13,09	43,80	74,28	104,75	135,21	165,67	196,14
	0,0 %	-24,28	7,89	38,63	69,11	99,59	130,06	160,53	191,00
	15,0 %	-30,05	2,33	33,11	63,61	94,08	124,55	155,02	185,49
	30,0 %	-36,07	-3,55	27,35	57,96	88,48	118,95	149,43	179,90

Similar to the ReOI model, the share price is very sensitive to both the capital cost and the oil price in the NAV model, suggesting that our estimated share price can change significantly with oil price changes.

7.3 Real Option Valuation (ROV)

Even though the NAV and ROV are based on same input with regards to production volumes and costs, they are largely deviating in terms of final share price. As previously explained, the ROV model assumes that production plans and associated costs are followed exactly as planned, and hence the only risk adjustment needed is with the future price of oil, which is created under the risk-neutral framework. The resulting share price from the ROV is summarized in the following waterfall graph, which shows the same split on oil field type as the NAV.



Evidently, the ROV yields a much lower value than the NAV and ReOI at NOK 9.99[327]. The option not to develop a field pulls the share price from the ROV in the positive direction relative to the NAV, but is opposed by a lower oil price. Recall our risk-neutral stochastic process for the oil price and convenience yield, respectively:

$$dS/S = (r - \delta)dt + \sigma_S dz_S$$

$$d\delta = k(\hat{\alpha} - \delta)dt + \sigma_\delta dz_\delta$$

Where $\hat{\alpha}$ is 0.01165, meaning that the convenience yield, δ, is reverting to this level. This is coherent with similar mean-reversion models, such as the Vasicek model[328]. This in return means that the drift term of the oil price, $r - \delta$, becomes negative for $r < \delta$. With a risk free rate of 0.44% and $\hat{\alpha}$ at 0.01165 the drift term in the oil price becomes negative, and hence, the oil price is decreasing with time.

Schwartz argued that the model tends to overvalue long-term contracts[329], but this is evidently only true if there is a positive drift term in the oil price process. We experience a very low oil price in the long-term, resulting in a low per share value of long-term contracts. The ROV however yields a higher value of the *non-developed assets* category than the NAV, which we largely accredit to the severe risk weighing of 10-20% in

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[327] We denote the share price as core NAV per share as in the NAV model, as a large amount of the input data and underlying principles are the same.
[328] Hull (2012): "Options, Futures, and Other Derivatives". Page 684
[329] Schwartz and Gibson (1990): "Stochastic Convenience Yield and the Pricing of Oil Contingent Claims"

the NAV. For *producing fields* and *fields under development*, the oil price is also lower in the ROV than in the NAV. The higher discount rate in the NAV is not sufficient to pull the NAV beneath the ROV level for these fields.

With an increased risk-free rate, the drift will be increasingly positive, but on the other hand, the discount rate is higher, yielding an ambiguous effect on the final share price. The following table shows that a higher risk-free rate, and as a result a higher oil price in the future, has a negative effect on Detnor's share price.

Risk free rate	0.0044	0.02	0.04	0.06	0.08	0.10
Detnor Value	9.99	3.39	-2.68	-6.53	-8.31	-11.18
Contingent Assets Value	31.58	28.42	25.75	24.75	25.17	25.95

Evidently, the risk-free rate and the share price are negatively correlated, but the share price is not very sensitive to the parameter. The ROV framework uses the risk-free rate for discounting, whereas the NAV uses the weighted average cost of capital, hence the NAV cash flows are discounted harder than those in the ROV. Adjusting the discount rate for risk, using for example the WACC, would require us to use the actual drift of the oil price (which is large and positive if we use a long horizon); hence, the lowered share price from the higher discount rate is opposed by an increased oil price. We leave the discussion here, concluding that the effect is two-fold, and opposing. The previous findings might suggest that the convenience yield specific parameters or the oil price might possibly better explain the development in Detnor's share price. The following table shows the sensitivity of both the share price, and the value of the share price accredited to the field with inherent optionality, with respect to the oil price:

Oil price	30	39.6	50	60	70	80
Detnor Value	-42.90	9.99	60.58	111.42	159.97	208.42
Contingent Assets Value	10.20	31.58	53.16	75.88	96.47	116.93

Evidently, and expectedly, the oil price has significant impact on the final share price. Furthermore, the contribution from the fields with optionality are not zero, even at low oil prices. The optionality of not starting a project that deems negative under current market conditions will necessarily be valuable. This is for example clear in the Gekko field, which is valued at NOK zero using ROV, and NOK -0.2 per share in the NAV. The ROV will thus yield a higher share price for such oil fields, comparing to the NAV, all else equal. See appendix 8 and 9 for further examples. Turning to the convenience yield in the next table, we see that the starting point of the convenience yield has a positive effect on the share price, but not at all to the same degree as the oil price. This strengthens our hypothesis of the Detnor share price being highly dependent on the oil price, as is the case for both of the other models.

Convenience yield	-0.3	-0.219	-0.1	0	0.1	0.2
Detnor Value	7.28	9.99	13.62	16.70	20.93	23.21
Contingent Assets Value	30.31	31.58	33.23	34.67	36.19	37.57

Based on the discussion in this chapter, we conclude that with coinciding oil prices in the future, the ROV valuation with the chosen process should yield a higher value than the NAV (and to some extent the ReOI). This is however not the case, as the future oil price in the ROV is very low due to a negative drift term in the oil price process. Recalling our discussion on breakeven prices in the E&P industry, it seems unlikely that prices should drop to the levels suggested by the ROV in the current market. Furthermore, we acknowledge that minor changes to the oil price will have critical effect on the Detnor share price, and thus with a volatile oil price, the Detnor share price will necessarily also be volatile under the ROV framework.

7.4 Valuation summary

The valuations in this chapter is summarized in the following table, with the upside column referring to the estimated upside on the observed market share price relative to the respective valuation models.

Model	Share price (NOK)	Upside
Residual Operating Income	86.68	39.8 %
Net Asset Value	76.33	23.1 %
Real Options	9.99	-83.9 %
Current share price	62.00	

Even though the results of the valuation models deviate, there are many common denominators. From the sensitivity analyses, we can conclude that the Detnor share is highly sensitive to the oil price. In our oil supply analysis, we concluded that the oil price was determined by an abundance of macroeconomic and political factors, and as a price taker, Detnor is highly dependent on these. Hence, the Detnor share is highly dependent on both internal abilities in exploring and producing oil, as well as external factors of which the company has no significant influence.

The **ReOI valuation** showed a high dependence upon the very sensitive continuing value measure, hence a valuation using this model is highly prone to subjectivity. We do however expect the production level, asset turnover and profit margins to stabilize in the long term, which could potentially lead to less dependence upon the continuing value. Implicit in this statement is that currently producing oil fields are replaced by new oil fields at the amount depleted. Detnor’s current recoverable oil volumes are dependent on a few large oil fields, and the findings of such oil fields are distorting the stabilizing assumption in the future. Hence, only as the portfolio of oil fields grows sufficiently large, and production (and by extension; depletion) happens at a higher rate than today, this assumption will be true. This in return means that the ReOI can be considered very neat for E&P companies with high production volumes and continuous replacement of existing oil fields, by discovering or acquiring new oil fields. This assumption is questionable for Detnor at the moment, hence a valuation using ReOI will necessarily yield a high continuing value. As discussed, Detnor's aggressive acquisition strategy and high exploration levels leads us to believe that the stabilizing assumption can be true in the future, making the ReOI model less subjective in terms of continuing value in the future.

The gift and the curse of the **NAV model** and the **ROV model** is that replacement of assets does not occur. Petroleum is also a non-renewable resource, meaning that at some point in time, the resource will be fully depleted. This means that we cannot take for granted that E&P companies could have a sustainable reserves replacement rate for all eternity. Since Detnor operates solely on the NCS, we consider the probability of running out of potential resources to be even higher than for a global E&P company. Furthermore, the ROV allows for managerial flexibility, but might in return undervalue the share price under the current interest rate regime, and overvalue the share price at more normalized interest rate levels.

7.5 Share price assessment

All of the presented models are applied according to the theories upon which they are based, and we have stated the explicit as well as implicit assumptions behind them, in the context of valuing Detnor. The models are however largely based on subjective views of the petroleum market in the future, hence an investor should choose his or her model accordingly:

- *Future exploration* – An investor should focus on whether the company will put efforts in exploration of new resources in the future, or if the value of the share lies within its current portfolio of assets. This point is closely tied to the next consideration.
- *Continuing value* – As a scarce resource, petroleum resources will at some point in time be fully depleted. Whether this will happen in the near or distant future should be considered when choosing between a model that emphasizes the oil fields that the company currently holds (NAV), and whether these will be replaced by new assets in the future.
- *Optionality in development projects* – The implications of optionality are evidently very large, and the extent to which this is realistic needs to be considered.

The expectations of future oil price could also be a determining factor for the choice of model, but either model could be adjusted for the desired stochastic process, or a deterministic approach. In our analysis we applied both a deterministic oil price (ReOI and NAV) and a stochastic oil price (ROV), hence there should necessarily be differences in the final value for these models, with respect to this choice. Applying the stochastic joint diffusion process for the oil price in the ReOI and NAV, we obtain share prices of NOK 26.86 and-22.7, respectively, when applying the respective iterative processes explained in chapter 5.4.3.

We consider all of the models to have neat features, in terms of applicability to an E&P company. However, we consider the managerial flexibility in the ROV model to be superior to the more static NAV model, as it better captures the day-to-day operations in an E&P company. The ROV is however not coherent with our strategic analysis, where the long term oil price should lie at or above the marginal cost, which is roughly USD 50 per barrel for the North Sea, and ranging from USD 20 to 120, globally. At low oil prices, much of the global oil supply will be eliminated in the long run. We do however need to emphasize that the ROV could potentially be a superior model under different market conditions, or by applying a different input variables or processes.

The ROV is argued to have an inherent upward bias for long-term contracts, hence the final share price is higher than it should be in this model, should the drift term in the oil price be positive. The ReOI on the other hand does not account for managerial flexibility, and relies on a continuing value that is highly sensitive to its input. Adding managerial flexibility (optionality) to the ReOI would yield a higher final share price, which we have argued to be preferable for an E&P company. During this thesis, we have encountered several sources of error that can drive the final share price of Detnor to unrealistic levels, either high or low. Even though we argued that the oil price was impossible to forecast deterministically, the stochastic process is not suitable for long term contracts, and the high oil prices in the future when the drift term is positive are unrealistically high, and vice versa when the drift term is negative (as it is now). Both due to model specifics and by looking at previous peak levels, way below what we encounter when using the joint diffusion process.

The NAV (and ROV) depends on the current portfolio of fields in the company, and being widely used in the industry, we might draw some empirical conclusions from the model. The focus is exclusively on the current portfolio of assets in the company; hence, we are tempted to believe that the consensus among analysts is that exploration of new assets is not very important in assessing the share price. Our NAV and ROV both showed that the estimated share price consisted mainly of producing or developing fields, hence the value of fields that are far out in time is relatively small. Thus, even though the ReOI includes the feature of exploring new oil fields, the value from the near term producing or developing assets is the main share price driver. As previously argued, the NAV does not allow for reserves growth, which should cause the NAV to be downward biased.

Summarizing this chapter's discussion, we conclude that the concept of the real option valuation model is most suitable for the E&P industry. However, we consider the shortfalls discussed throughout the thesis as too large in the case of assessing our estimate of the true value of Detnor. The model could however deem superior, despite being more technically challenging than the other presented models, if the shortfalls assessed in this thesis are accounted for, and the market behaves differently.

Based on this reasoning, we rely on the NAV and the ReOI for our main range of share prices, where the NAV is considered our slightly conservative case, and the ReOI is considered our upside case. The NAV is considered to have the lowest degree of uncertainty, and is fairly precise in countries where external information is transparent and reliable, and is used for our final share price assessment. We set our target share price for *Det Norske Oljeselskap ASA* to the NAV level, at NOK 76.33.

8 Conclusion

This thesis was aimed at estimating the value of the equity of *Det Norske Oljeselskap ASA*, as of 31.03.2016, by relying on a range of valuation models. The equity of *Det Norske Oljeselskap ASA* was estimated at NOK 15 320 million, resulting in a share price of NOK 76.33, applying a net asset value (NAV) method. This represents a 23.1% upside to the current share price in the market, at NOK 62. In supporting our final equity value, it was necessary to understand historic performance through a financial statement analysis of both Detnor and its peers, internal competences, external influence, and future outlook.

The financial statement analysis showed inconsistency in profitability over time both for Detnor and the peer group, meaning that finding a pattern was difficult. Furthermore, the acquisition of Marathon Oil Norge in 2014 marked the start of a new Detnor, with an increased asset base, higher leverage, and near-term income. Despite the difficulty of comparing Detnor to itself historically and to some extent to its peers, the consensus seems to be a relatively low profitability in the past, with the potential of profitability improvements in the future.

The internal analysis focused extensively on the greatness of Detnor's current portfolio of oil fields, but also concluded that relations with the Aker Group and Detnor's ability to utilize its assets enhanced their potential to create organic growth, and acquisition related growth in the future.

The external strategic analysis showed that the lion's share of petroleum products demanded globally came from industries that had inelastic demand for these products, where especially industrializing economies were highly dependent on petroleum products. Hence, as long as disruptive innovations are kept at a low, the demand for oil should be sustained in the future. Furthermore, we concluded that Detnor were severely affected by international politics and a few large market participants, giving rise to an uncertain future in terms of oil supply.

From the financial statement analysis, we saw that the recent turmoil in the oil market had a clear negative effect on the revenues of E&P companies, but also that the bargaining power over suppliers had gone up during the same period. Hence, Detnor's bargaining powers over suppliers are high in the current market, and coupled with ambitious plans of higher profit margins through cost cutting, we see an opposing effect on the declining revenue in the long term.

The valuation frameworks are shown to have significant effect on the final target share price, and the assumptions behind the models should be aligned with the analyst's expectation of the future development of the oil E&P market. The ReOI relies on few input parameters, making it very applicable on a day-to-day basis, and minimizes estimation errors in parameters. Penman's suggested forecasting method does however not seem to recognize the dynamics of the E&P industry, which is prone to large variations in sales, profits and asset turnover, dependent on the assets that are employed. Our ReOI model could use the NAV specific input for a longer period, but in the lack of development plans after 2020 we would assume that projects might plausibly be undertaken at this point in time. Hence, in order to comply with the stated assumptions, there will necessarily arise deviations between the models in the long term.

The attractive feature of managerial flexibility, and applying a widely acknowledged joint-diffusion process for the future oil price motivated our use of the real option model. The model did however display several flaws in terms of assessing the option value of distant oil field development projects, with parameters that might not be well suited for the current oil price movements. Furthermore, the ROV requires substantial computational power, limiting our possibilities of running further sensitivity analyses. The amount of input needed for forecasting production and costs in the future, coupled with ever changing parameter estimators made it an inconvenient model to handle on a day-to-day basis. Should a future model however manage to adjust for the pricing of far-term oil field development projects, and maybe also the exploration part of an E&P company, we could potentially see a far superior model, in terms of mimicking the real circumstances of an E&P company. This would however be more time consuming in terms of computational power and continuous model updates, than the ReOI and NAV model presented in this thesis.

9 Perspective

During the process of writing this thesis, we have strived to maintain objectivity, in order to secure robust and reliable results. A valuation is however prone to subjective measures, making this our personal belief of the target share price of Detnor.

Since our thesis depends heavily upon present value methods and extensions to these, a natural addition to the thesis could be a relative valuation, based on multiples. Due to restrictions regarding length of the thesis, we were unable to perform such a study, even though it might serve as a sanity check to how the shares of comparable companies' trade.

Furthermore, this study has relied heavily upon previous studies performed by acknowledged authors, but these do however in some cases refer to completely different market conditions than what we see today, as is the case for the oil price. In further studies it could be beneficial to conduct extensive research and testing of the best fitted process for the oil price. This could severely enhance a real option valuation of a company's assets under current market conditions. An extension to this research would be to estimate new parameters for the model, better fitted to the market conditions that are experienced today, applying for example a Kalman Filter.

Even though our suggested real option method is flexible in terms of whether or not it is optimal to commence a project, it lacks flexibility after the development well is drilled. Our model assumes that production will be carried out as planned if the decision to produce is made, whereas in real life, this assumption might indeed be relaxed as severe market movements can make a project unprofitable also after production start. This would require non-trivial modifications to the Least Square Monte Carlo method because of an added dimension, and would be a master thesis in itself.

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11 APPENDIX

Contents

1 Words and explanations

1.1 Financial statement analysis

ATO = Asset turnover

CSE = Common shareholders' equity

FLEV = Financial leverage

NBC = Net borrowing cost

NFA = Net financial assets

NFE = Net financial expenses

NFO = Net financial obligations

NOA = Net operating assets

NOWC = Net operating working capital

NWC = Net working capital

OI = Operating income

OL = Operating liabilities

OLLEV = Operating liability leverage

OLSPREAD = Operating liability leverage spread

PM = Profit margin

RNOA = Return on net operating assets

SPREAD = Operating spread

1.2 Oil Specific

Mboe = Thousand barrels of oil equivalents

MMboe = Million barrels of oil equivalents

MMboed (or MMboepd) = Million barrels of oil equivalents per day

2 Ownership

Top 10 largest owners	Share
Aker Capital AS	49.99 %
Folketrygdfondet	5.57 %
Verdipapirfondet DNB Norge (IV)	2.02 %
VPF Nordea Kapital	1.42 %
Verdipapirfondet DNB Norge Selekti	1.36 %
Verdipapirfondet KLP Aksjenorge	1.34 %
VPF Nordea Avkastning	1.23 %
Clearstream Banking S.A.	1.08 %
Danske Invest Norske Instit. II.	1.00 %
JP Morgan Chase Bank. NA	0.93 %

3 World oil production and supply

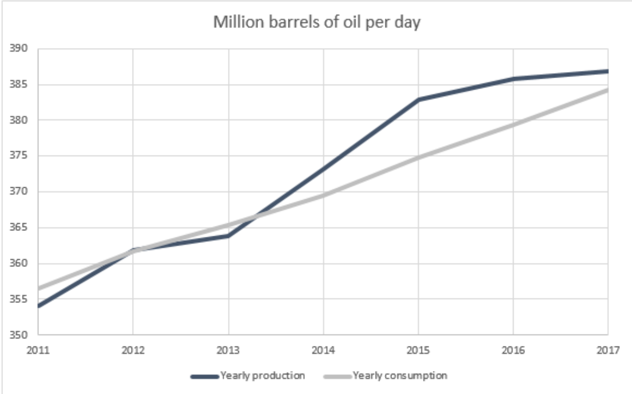
3.1 Total volumes per day

Category	Implied stock change and balance (right axis) (million barrels per day)	World production (left axis) (million barrels per day)	World consumption (left axis) (million
Q1 2011	-0.372112782	88.36706145	88.73917423
Q2 2011	-0.209490797	87.58296451	87.79245531
Q3 2011	-1.215344492	88.64481351	89.86015801
Q4 2011	-0.634588898	89.53261055	90.16719944
Q1 2012	1.363136583	90.48074469	89.11760811
Q2 2012	0.549274447	90.31255106	89.76327661
Q3 2012	-0.833947653	90.31076515	91.1447128
Q4 2012	-0.863575884	90.79337369	91.65694958
Q1 2013	-0.524640226	89.76259579	90.28723602
Q2 2013	0.189219853	90.91448316	90.72526331
Q3 2013	-0.442858074	91.49765293	91.94051101
Q4 2013	-0.82821319	91.57851872	92.40673191
Q1 2014	0.542731474	91.89266278	91.34993131
Q2 2014	0.788237186	92.5395993	91.75136212
Q3 2014	0.493389657	93.70032648	93.20693683
Q4 2014	1.907416055	95.03246872	93.12505267
Q1 2015	1.939565234	94.5958152	92.65624996
Q2 2015	2.390631718	95.49803462	93.10740291
Q3 2015	1.577650462	96.38382969	94.80617923
Q4 2015	2.2275926	96.43746364	94.20987104
Q1 2016	1.869039611	95.59618994	93.72715033
Q2 2016	2.18217853	96.67990338	94.49772485
Q3 2016	1.173354751	96.81950642	95.64615167
Q4 2016	1.165135998	96.66352001	95.49838401
Q1 2017	1.138546884	96.08627764	94.94773075
Q2 2017	1.117094629	96.74104104	95.62394641
Q3 2017	0.176442676	97.0741285	96.89768582
Q4 2017	0.149251515	96.89447943	96.74522792

Source: https://www.eia.gov/forecasts/steo/report/global_oil.cfm

Year	Yearly production	Yearly consumption	Over supply	Return production	Return consumption
2011	354.13	356.56	-2.43		
2012	361.90	361.68	0.21	2.2 %	1.4 %
2013	363.75	365.36	-1.61	0.5 %	1.0 %
2014	373.17	369.43	3.73	2.6 %	1.1 %
2015	382.92	374.78	8.14	2.6 %	1.4 %
2016	385.76	379.37	6.39	0.7 %	1.2 %
2017	386.80	384.21	2.58	0.3 %	1.3 %

	Production CAGR	Consumption CAGR
2011-2015	2.0 %	1.3 %



3.2 World oil production by region

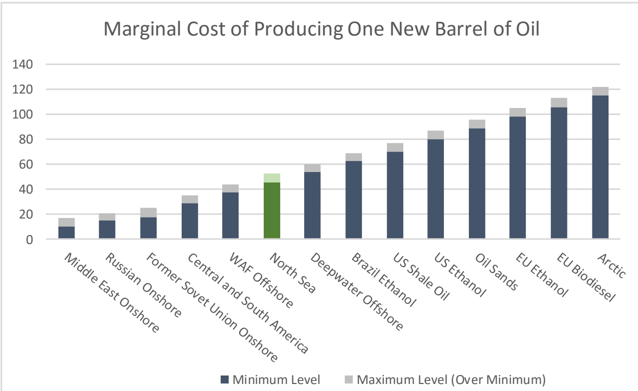
Table: Total Oil Supply (Thousand Barrels Per Day)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	CAGR ('10-'14)	Horizon (years)
North America	15,271	15,343	15,545	15,687	15,710	15,205	15,318	15,418	15,099	15,450	16,116	16,685	17,915	19,331	21,216	7.12 %	4
Central & South Am	7,313	7,218	6,928	6,685	7,026	7,243	7,296	7,271	7,510	7,726	7,892	8,064	8,004	8,120	8,408	1.60 %	4
Europe	7,166	7,226	7,171	6,963	6,591	6,166	5,777	5,445	5,225	4,983	4,656	4,300	3,989	3,813	3,870	-4.52 %	4
Eurasia	8,185	8,774	9,429	10,424	11,347	11,766	12,214	12,688	12,639	13,025	13,366	13,493	13,608	13,782	13,905	0.99 %	4
Middle East	23,484	22,793	21,571	22,992	25,070	26,092	25,774	25,286	26,764	25,326	26,221	27,674	27,880	27,472	27,836	1.51 %	4
Africa	7,990	8,028	8,136	8,606	9,321	10,089	10,195	10,485	10,574	10,425	10,669	9,268	9,918	9,296	8,707	-4.95 %	4
Asia & Oceania	8,316	8,290	8,321	8,250	8,337	8,538	8,560	8,537	8,703	8,768	9,179	9,048	9,152	9,199	9,258	0.21 %	4
World	77,725	77,672	77,101	79,606	83,402	85,099	85,135	85,130	86,515	85,703	88,099	88,532	90,466	91,014	93,201	1.42 %	4

4 Marginal cost of oil by region

Marginal cost of producing one new barrel of oil in US dollars per barrel ($/bbl)

Region	Minimum Level	Max level	Maximum Level (Over minimum)	Average
Middle East Onshore	10	17	7	13.50
Russian Onshore	15	21	6	18.00
Former Sovet Union Onshore	18	25	7	21.50
Central and South America	29	35	6	32.00
WAF Offshore	38	44	6	41.00
North Sea	**46**	**53**	**7**	**49.50**
Deepwater Offshore	54	60	6	57.00
Brazil Ethanol	63	69	6	66.00
US Shale Oil	70	77	7	73.50
US Ethanol	80	87	7	83.50
Oil Sands	89	96	7	92.50
EU Ethanol	98	105	7	101.50
EU Biodiesel	106	113	7	109.50
Arctic	115	122	7	118.50



5 Financial statement analysis

5.1 Classifications

Classifications are made according to chapter 9 (The Analysis of the Balance Sheet and Income Statement) in "Financial Statement Analysis and Security Valuation" by Stephen H. Penman unless otherwise stated.

5.1.1 Non-current assets

Goodwill – Detnor's acquisitions are related to their operating activities, and companies are not regarded as investment objects. The most recent acquisition, and cause of the spike in goodwill in 2014 is the acquisition of Marathon Oil Norge AS (now Det Norske Oljeselskap AS), with operations closely related to that of the former Detnor. Goodwill is thus considered an *operating asset*.

Capitalized exploration expenditures – This item is related to the early phases of the oil production process, later re-classified to "fields under development" and further on "production facilities", should the asset reach these stages. As a vital part of Detnor's operations, capitalized exploration expenditures are defined as an operating asset.

Other intangible assets – Mainly consists of licenses and software used in Detnor's operations, and is thus defined as an operating asset.

Deferred tax asset/liability – Arises from differences between the accounting values and tax base values, and is directly related to Detnor's operations, and is thus regarded as an operating asset.

Property, plant, and equipment – Consists of "fields under development", "Production facilities, including wells", and "Fixtures and fittings, office machinery etc.". These assets are solely held for operational purposes, and this item is classified as an *operating asset.*

Long-term receivables (prepayment) – Detnor classifies long-term receivables as a financial asset, thus so do we[1].

Other non-current assets – Consists of:

- 2012 and 2013
    - Shares in Sandvika Fjellstue AS – Conference center used by Detnor. *Operating asset*
    - Debt service reserve. Required for the multi-currency facility, and is part of the debt covenants. *Operating asset.*
    - Tenancy deposit. *Operating asset*

[1] Det Norske Oljeselskap ASA: «Annual Report 2015». Page 62

- 2014 and 2015
    - All of the above in 2013
    - Alvheim AS. Legal owner of MST Alvheim (FPSO). *Operating asset.*
    - Det Norske Oljeselskap AS (previously Marathon Oil Norge AS). *Operating asset.*

5.1.2 Current assets

Inventories – Consists of equipment for drilling or spare parts, directly related to the operations. *Operating asset.*

Accounts receivable – Is related to petroleum sales and license transactions. We assume that this asset does not bear any rent, and is explicitly used as a sort of trade note. *Operating asset.*

Other short-term receivables – VAT receivable, underlift, etc., directly related to operations. *Operating asset*.

Other current financial assets (short term deposits) – Undefined in the annual reports, but we consider it safe to assume that this is a financial asset.

Tax payable/receivable – Arises as a result of operations. *Operating asset.*

Cash and cash equivalents – Consists of bank deposits and short-term investments, of which the company receive interest. Assumed to be explicitly a *financial asset*.

5.1.3 Liabilities

Pension obligations – Earns interest and is thus classified as a *financial liability*.

Provisions – Provisions are discounted using a proper discount rate that reflects the time value and risk associated with the provisions[2], and are re-evaluated each year. We classify provision liabilities as *financial.*

Bonds – Earns interest, and is naturally a *financial liability.*

Other interest-bearing debt – Consists of the interest bearing Reserve Based Lending Facility (RBL) and Revolving Credit Facility (RCF). *Financial liability*.

Short-term loan – Earns interest, and is naturally a *financial liability*

Trade creditors – This item is classified by the company as a financial asset in a similar way as other interest bearing debt. We follow the company's classification and assume that this credit is interest bearing, and we classify trade creditors as a *financial liability.*

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[2] Detnor Annual Report 2014 – page 100

Accrued public charges and indirect taxes – Lacks specifications in the annual report, but is assumed to cover charges that occur as a result of operations, and is classified as *operating liability.*

Derivatives – Consists of interest rate swaps, foreign currency contracts and put options that are marked to market. *Classified as financial assets*.

Other current liabilities – Liabilities arising from overlift of petroleum, overcall in licenses, unpaid wages, and vacation pay. These liabilities don't pay interest, and are thus considered *operating liabilities.*

5.2 Detnor

5.2.1 Detnor Income Statement

REPORTED INCOME STATEMENT (NOK 1000)						
(NOK 1000)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
USDNOK	6.04477	5.60588	5.81838	5.87817	6.30827	8.06948
Petroleum revenues	362,115	361,774	325,093	933,162	2,598,982	9,349,971
Other operating revenues	3,855	10,332	7,351	10,719	329,512	509,338
Total operating revenues	**365,970**	**372,106**	**332,444**	**943,881**	**2,928,494**	**9,859,309**
Exploration expenses	(1,777,337)	(1,012,191)	(1,609,314)	(1,637,063)	(994,044)	(616,541)
Production costs	(154,960)	(181,888)	(210,962)	(249,619)	(421,102)	(1,137,797)
Payroll epenses	(14,763)	(31,732)	(11,000)	(38,025)	107,506	98,722
Depreciation and amortization	(159,049)	(78,518)	(111,687)	(470,529)	(1,010,925)	(3,881,090)
Impairments	(170,508)	(197,673)	(2,149,653)	(666,135)	(2,185,311)	(3,473,654)
Other operating expenses	(88,977)	(60,721)	(82,799)	(109,886)	(310,323)	(515,172)
Total operating expenses	*(2,365,594)*	*(1,562,723)*	*(4,175,415)*	*(3,171,257)*	*(4,814,200)*	*(9,525,531)*
Operating profit/loss (EBIT)	**(1,999,624)**	**(1,190,617)**	**(3,842,971)**	**(2,227,376)**	**(1,885,706)**	**333,778**
Interest income	51,255	69,900	54,997	40,750	44,215	24,999
Other financial income	89,431	26,825	68,399	80,567	122,601	527,623
Interest expenses	(218,647)	(305,969)	(128,250)	(301,834)	(528,917)	(880,582)
Other financial expenses	(105,844)	(23,111)	(101,050)	(137,435)	(121,724)	(922,568)
Net financial items	*(183,805)*	*(232,355)*	*(105,904)*	*(317,952)*	*(483,825)*	*(1,250,528)*
Profit/loss before tax (EBT)	**(2,183,429)**	**(1,422,972)**	**(3,948,875)**	**(2,545,328)**	**(2,369,531)**	**(916,750)**
Taxes	1,493,075	940,594	2,991,624	1,996,727	608,653	(1,606,190)
Net profit/loss	**(690,354)**	**(482,378)**	**(957,251)**	**(548,601)**	**(1,760,878)**	**(2,522,940)**
Weighted average number of shares outstanding	*111,111,111*	*115,058,944*	*128,649,729*	*140,707,363*	*165,811,098*	*202,618,602*
Exchange Differences on translation to USD	0	0	0	0	(271,691)	0
Actuarial gain/loss pension plan	0	0	(6,834)	40,064	(5,659)	137
Other	0	0	5,331	(3,170)	0	0
Comprehensive Income	**(690,354)**	**(482,378)**	**(958,754)**	**(511,707)**	**(2,038,227)**	**(2,522,802)**

REFORMULATED INCOME STATEMENT (NOK 1000)

Reformulated Income Statement (NOK 1000)	2010	2011	2012	2013	2014	2015
Petroleum revenues	362,115	361,774	325,093	933,162	2,598,982	9,349,971
Other operating revenues	3,855	10,332	7,351	10,719	329,512	509,338
Total operating revenues	**365,970**	**372,106**	**332,444**	**943,881**	**2,928,494**	**9,859,309**
Production costs	(154,960)	(181,888)	(210,962)	(249,619)	(421,102)	(1,137,797)
Payroll expenses	(14,763)	(31,732)	(11,000)	(38,025)	107,506	98,722
Other operating expenses	(88,977)	(60,721)	(82,799)	(109,886)	(310,323)	(515,172)
EBITDAX	**107,270**	**97,765**	**27,683**	**546,351**	**2,304,575**	**8,305,062**
Exploration expenses	(1,777,337)	(1,012,191)	(1,609,314)	(1,637,063)	(994,044)	(616,541)
EBITDA	**(1,670,067)**	**(914,426)**	**(1,581,631)**	**(1,090,712)**	**1,310,530**	**7,688,521**
Depreciation and amortization	(159,049)	(78,518)	(111,687)	(470,529)	(1,010,925)	(3,881,090)
Impairments	(170,508)	(197,673)	(268,700)	(666,135)	(2,185,311)	(3,473,654)
EBIT	**(1,999,624)**	**(1,190,617)**	**(1,962,018)**	**(2,227,376)**	**(1,885,706)**	**333,778**
Tax on EBIIT	1,441,610	875,535	1,558,018	1,907,700	478,020	(1,943,832)
Tax %	*-72.09 %*	*-73.54 %*	*-79.41 %*	*-85.65 %*	*-25.35 %*	*-582.37 %*
Operating income (OI)	**(558,014)**	**(315,082)**	**(404,000)**	**(319,676)**	**(1,407,685)**	**(1,610,054)**

Financial expenses (USDm)	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(183,805)	(232,355)	(105,904)	(317,952)	(483,825)	(1,250,528)
Tax rate	28 %	28 %	28 %	28 %	27 %	27 %
Tax on Net financial expenses	51,465	65,059	29,653	89,027	130,633	337,642
Net financial expenses after tax	**(132,340)**	**(167,296)**	**(76,251)**	**(228,925)**	**(353,192)**	**(912,885)**
Core operations after tax	(558,014)	(315,082)	(404,000)	(319,676)	(1,407,685)	(1,610,054)
Net income	**(690,354)**	**(482,378)**	**(480,251)**	**(548,601)**	**(1,760,878)**	**(2,522,940)**

Non-Core Operations (USDm)	2010	2011	2012	2013	2014	2015
Comprehensive income	0	0	(1,503)	36,894	(277,349)	137
Jette Impairment before tax	0	0	(1,880,953)	0	0	0
Tax on non-core	0	0	1,403,953	0	0	0
Other non-core after tax	0	0	(478,503)	36,894	(277,349)	137

Tax allocation (USDm)	2010	2011	2012	2013	2014	2015
Tax on EBIT	1,441,609.6	875,534.6	1,558,017.9	1,907,700.4	478,020.5	(1,943,832.4)
Tax on Jette	0.0	0.0	1,403,953.0	0.0	0.0	0.0
Tax on NFE	51,465.4	65,059.4	29,653.1	89,026.6	130,632.8	337,642.4
Total tax	1,493,075.0	940,594.0	2,991,624.0	1,996,727.0	608,653.3	(1,606,190.0)

Adjustments	
Jette (Q3 2012)	2012
Impairments of fixed tangible assets	1,799,650
Impairments of intangible assets	112,800
Impairments of goodwill	56,487
Impairment deferred tax	-87,984
Total before tax	1,880,953
Tax	1,403,953
Total after tax	477,000

5.2.2 Detnor Balance Sheet

ORIGINAL BALANCE SHEET						
NOK 1000	2010	2011	2012	2013	2014	2015
USDNOK	5.82180	5.97510	5.56480	6.07130	7.45200	8.84310
ASSETS						
TOTAL NON-CURRENT ASSETS						
Goodwill	596,506	525,870	387,551	321,120	8,843,318	6,787,707
Capitalized exploration expenditures	1,802,234	2,387,360	2,175,492	2,056,100	2,173,145	2,564,322
Other intangible assets	1,107,693	905,726	665,542	646,299	4,834,768	5,730,594
Deferred tax asset	0	0	0	630,423	0	0
Property, plant and equipment	406,834	902,071	1,993,269	2,657,566	18,997,167	26,347,433
Long-term receivables	0	0	31,995	125,432	65,570	33,445
Prepayments	106,269	0	0	0	0	0
Other non-current assets	18,210	18,423	193,934	285,399	26,812	111,671
Total non-current assets	**4,037,746**	**4,739,450**	**5,447,783**	**6,722,340**	**34,940,774**	**41,575,171**
TOTAL CURRENT ASSETS						
Inventories	10,249	37,039	21,209	40,880	186,360	278,849
Accounts receivable	60,719	146,188	101,839	134,221	1,389,507	756,492
Other short-term receivables	448,221	532,538	342,566	499,419	1,375,580	930,206
Other current financial assets (short term deposits)	22,568	21,750	23,138	24,075	24,510	25,707
Tax receivables	2,344,753	1,397,420	1,273,737	1,411,251	0	1,117,688
Short-term derivatives	6,033	0	0	0	0	399,858
Cash and cash equivalents	789,330	841,599	1,154,182	1,709,166	2,207,610	801,176
Total current assets	**3,681,872**	**2,976,534**	**2,916,670**	**3,819,011**	**5,183,566**	**4,309,985**
Total assets	**7,719,619**	**7,715,984**	**8,364,453**	**10,541,352**	**40,124,340**	**45,885,157**
TOTAL EQUITY						
Equity and liabilities						
Share capital	111,111	127,916	140,707	140,707	279,674	331,882
Share premium reserve	1,167,312	2,083,271	3,089,542	3,089,542	7,672,706	9,105,006
Other paid in capital	17,715	0	0	0	0	0
Other equity	1,864,035	1,465,364	505,926	(41,780)	(3,096,194)	(6,438,847)
Total equity	**3,160,173**	**3,676,551**	**3,736,175**	**3,188,470**	**4,856,185**	**2,998,041**
TOTAL PROVISION FOR LIABILITIES						
Pension obligations	32,070	46,944	65,258	66,512	15,060	14,485
Deferred taxes	1,757,481	2,042,051	126,604	0	9,585,932	11,992,252
Abandonment provision	268,227	285,201	798,057	828,529	3,601,723	3,650,476
Provisions for other liabilities	2,429	1,643	647	780	89,752	0
Total provision for liabilities	**2,060,207**	**2,375,839**	**990,566**	**895,821**	**13,292,468**	**15,657,213**
TOTAL NON-CURRENT LIABILITIES						
Bonds	0	587,011	589,078	2,473,582	1,886,407	4,451,970
Other interest-bearing debt	0	0	1,299,733	2,036,907	15,181,952	18,737,954
Long-term derivatives	0	0	45,971	49,453	42,074	548,378
Total non-current liabilities	**0**	**587,011**	**1,934,782**	**4,559,942**	**17,110,433**	**23,738,303**
TOTAL CURRENT LIABILITIES						
Bonds	421,668	0	0	0	0	0
Short-term loan	1,110,652	379,550	567,075	478,050	0	0
Trade creditors	219,984	274,308	258,596	452,435	1,134,627	451,688
Accrued public charges and indirect taxes	20,013	18,568	24,536	23,579	50,361	80,118
Tax payable	0	0	0	0	1,409,158	0
Short-term derivatives	0	0	0	0	187,969	119,435
Abandonment provision	0	0	0	147,375	42,685	93,029
Other current liabilities	726,921	404,156	852,722	795,680	2,040,454	2,747,330
Total current liabilities	**2,499,238**	**1,076,582**	**1,702,929**	**1,897,119**	**4,865,254**	**3,491,601**
Total liabilities and provision for liabilities	**4,559,446**	**4,039,432**	**4,628,277**	**7,352,882**	**35,268,155**	**42,887,116**
Total equity and liabilities	**7,719,619**	**7,715,984**	**8,364,453**	**10,541,352**	**40,124,340**	**45,885,157**

Reformulated balance sheet (in NOK 1000)	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	10,249	37,039	21,209	40,880	186,360	278,849
Accounts receivable	60,719	146,188	101,839	134,221	1,389,507	756,492
Other short-term receivables	448,221	532,538	342,566	499,419	1,375,580	930,206
Tax receivables	2,344,753	1,397,420	1,273,737	1,411,251	0	1,117,688
Total current operating assets	**2,863,942**	**2,113,185**	**1,739,351**	**2,085,771**	**2,951,447**	**3,083,235**
CURRENT OPERATING LIABILITIES						
Accrued public charges and indirect taxes	20,013	18,568	24,536	23,579	50,361	80,118
Tax payable	0	0	0	0	1,409,158	0
Other current liabilities	726,921	404,156	852,722	795,680	2,040,454	2,747,330
Total current operating liabilities	**746,934**	**422,724**	**877,258**	**819,259**	**3,499,973**	**2,827,449**
NON-CURRENT OPERATING ASSETS						
Goodwill	596,506	525,870	387,551	321,120	8,843,318	6,787,707
Capitalized exploration expenditures	1,802,234	2,387,360	2,175,492	2,056,100	2,173,145	2,564,322
Other intangible assets	1,107,693	905,726	665,542	646,299	4,834,768	5,730,594
Deferred tax asset	0	0	0	630,423	0	0
Property, plant and equipment	406,834	902,071	1,993,269	2,657,566	18,997,167	26,347,433
Long-term receivables	0	0	31,995	125,432	65,570	33,445
Total non-current operating assets	**3,913,267**	**4,721,027**	**5,253,849**	**6,436,940**	**34,913,969**	**41,463,501**
NON-CURRENT OPERATING LIABILITIES						
Deferred taxes	1,757,481	2,042,051	126,604	0	9,585,932	11,992,252
Total non-current operating liabilities	**1,757,481**	**2,042,051**	**126,604**	**0**	**9,585,932**	**11,992,252**
NET OPERATING ASSETS	4,272,794	4,369,437	5,989,338	7,703,452	24,779,510	29,727,036
Average		4,321,116	5,179,388	6,846,395	16,241,481	27,253,273
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	111,111	127,916	140,707	140,707	279,674	331,882
Share premium reserve	1,167,312	2,083,271	3,089,542	3,089,542	7,672,706	9,105,006
Other paid in capital	17,715	0	0	0	0	0
Other equity	1,864,035	1,465,364	505,926	(41,780)	(3,096,194)	(6,438,847)
Total equity	**3,160,173**	**3,676,551**	**3,736,175**	**3,188,469**	**4,856,185**	**2,998,041**
INTEREST BEARING ASSETS						
Prepayments	106,269	0	0	0	0	0
Other non-current assets	18,210	18,423	193,934	285,399	26,812	111,671
Other current financial assets (short term deposits)	22,568	21,750	23,138	24,075	24,510	25,707
Short-term derivatives	6,033	0	0	0	0	399,858
Cash and cash equivalents	789,330	841,599	1,154,182	1,709,166	2,207,610	801,176
Total interest bearing assets	**942,410**	**881,772**	**1,371,254**	**2,018,640**	**2,258,932**	**1,338,412**
INTEREST BEARING DEBT						
Pension obligations	32,070	46,944	65,258	66,512	15,060	14,485
Abandonment provision	268,227	285,201	798,057	828,529	3,601,723	3,650,476
Provisions for other liabilities	2,429	1,643	647	780	89,752	0
Bonds	0	587,011	589,078	2,473,582	1,886,407	4,451,970
Other interest-bearing debt	0	0	1,299,733	2,036,907	15,181,952	18,737,954
Long-term derivatives	0	0	45,971	49,453	42,074	548,378
Bonds	421,668	0	0	0	0	0
Short-term loan	1,110,652	379,550	567,075	478,050	0	0
Trade creditors	219,984	274,308	258,596	452,435	1,134,627	451,688
Short-term derivatives	0	0	0	0	187,969	119,435
Abandonment provision	0	0	0	147,375	42,685	93,029
Total interest bearing debt	**2,055,030**	**1,574,657**	**3,624,415**	**6,533,623**	**22,182,249**	**28,067,416**
NET FINANCIAL OBLIGATIONS	1,112,620	692,885	2,253,161	4,514,983	19,923,317	26,729,004
Average		902,753	1,473,023	3,384,072	12,219,150	23,326,160
EQUITY	3,160,173	3,676,551	3,736,175	3,188,469	4,856,185	2,998,041
Average		3,418,362	3,706,363	3,462,322	4,022,327	3,927,113
NET OPERATING ASSETS	4,272,793	4,369,436	5,989,336	7,703,452	24,779,502	29,727,045
Average		4,321,115	5,179,386	6,846,394	16,241,477	27,253,273
TOTAL OPERATING ASSETS	6,777,209	6,834,212	6,993,200	8,522,711	37,865,415	44,546,736
Average		6,805,711	6,913,706	7,757,956	23,194,063	41,206,076
TOTAL INTEREST BEARING ASSETS	942,410	881,772	1,371,254	2,018,640	2,258,932	1,338,412
Average		912,091	1,126,513	1,694,947	2,138,786	1,798,672
TOTAL ASSETS	7,719,619	7,715,984	8,364,454	10,541,351	40,124,348	45,885,148
Avereage		7,717,802	8,040,219	9,452,903	25,332,849	43,004,748
TOTAL EQUITY	3,160,173	3,676,551	3,736,175	3,188,469	4,856,185	2,998,041
Average		3,418,362	3,706,363	3,462,322	4,022,327	3,927,113
TOTAL LIABILITIES	4,559,445	4,039,432	4,628,277	7,352,882	35,268,155	42,887,116
Average		4,299,439	4,333,855	5,990,580	21,310,518	39,077,635
NOWC (Net operating working capital)	2,117,008	1,690,461	862,093	1,266,512	(548,527)	255,787
Average		1,903,735	1,276,277	1,064,303	358,993	(146,370)
NWC (Net working capital)	1,182,634	1,899,952	1,213,741	1,921,892	318,312	818,385
Average		1,541,293	1,556,847	1,567,817	1,120,102	568,348

** Deviations are due to rounding errors*

5.2.3 Detnor profitability

Profitability analysis	2010	2011	2012	2013	2014	2015
First level breakdown	2010	2011	2012	2013	2014	2015
FINANCIAL LEVERAGE						
Return on common equity (ROCE)		-14.1 %	-25.9 %	-14.8 %	-50.7 %	-64.2 %
Core Return on Net Operating Assets (Core RNOA)		-7.3 %	-7.8 %	-4.7 %	-8.7 %	-5.9 %
Operating income		(315,082)	(404,000)	(319,676)	(1,407,685)	(1,610,054)
Net operating assets		4,321,115	5,179,386	6,846,394	16,241,477	27,253,273
Financial leverage (FLEV)		26.4 %	39.7 %	97.7 %	303.8 %	594.0 %
Net financial obligations (NFO)		902,753	1,473,023	3,384,072	12,219,150	23,326,160
Common shareholders equity (CSE)		3,418,362	3,706,363	3,462,322	4,022,327	3,927,113
Operating spread (SPREAD=RNOA-NBC)		-25.8 %	-13.0 %	-11.4 %	-11.6 %	-9.8 %
RNOA		-7.3 %	-7.8 %	-4.7 %	-8.7 %	-5.9 %
NBC		18.5 %	5.2 %	6.8 %	2.9 %	3.9 %
NFE after tax		167,296	76,251	228,925	353,192	912,885
NFO		902,753	1,473,023	3,384,072	12,219,150	23,326,160
Non-core Operating Income		0	(478,503)	36,894	(277,349)	137
Non-Core Return on Net Operating Assets (Non-Core RNOA)		0.0 %	-9.2 %	0.5 %	-1.7 %	0.0 %
OPERATING LIABILITY LEVERAGE						
Return on net operating assets (RNOA)		-7.29 %	-7.80 %	-4.67 %	-8.67 %	-5.91 %
RNOA		-7.29 %	-7.80 %	-4.67 %	-8.67 %	-5.91 %
Return on operating assets (ROOA)		-2.92 %	-4.67 %	-3.57 %	-4.65 %	-2.30 %
Operating assets average		6,805,711	6,913,706	7,757,956	23,194,063	41,206,076
Implicit interest on operating liabilities		116,279	81,166	42,661	329,900	662,061
Short term borrowing rate (a/tax)		4.680 %	4.680 %	4.680 %	4.745 %	4.745 %
Operating liabilities (OL) average		2,484,595	1,734,319	911,561	6,952,582	13,952,803
Operating liability leverage spread (OLSPREAD)		-7.60 %	-9.35 %	-8.25 %	-9.39 %	-7.05 %
Operating liability leverage (OLLEV)		0.57	0.33	0.13	0.43	0.51
Operating liabilities (OL) average		2,484,595	1,734,319	911,561	6,952,582	13,952,803
Net operating assets (NOA)		4,321,115	5,179,386	6,846,394	16,241,477	27,253,273
Seccond level breakdown (Du Pont) AFTER TAX	2010	2011	2012	2013	2014	2015
Return on common equity (ROCE)		-14.1 %	-13.0 %	-15.8 %	-43.8 %	-64.2 %
PM = OI (after tax) / Sales		-84.7 %	-121.5 %	-33.9 %	-48.1 %	-16.3 %
ATO = Sales / NOA		0.09	0.06	0.14	0.18	0.36
FLEV		26 %	40 %	98 %	304 %	594 %
RNOA		-7.29 %	-7.80 %	-4.67 %	-8.67 %	-5.91 %
NBC		19 %	5 %	7 %	3 %	4 %
Seccond level breakdown (Du Pont) BEFORE TAX	2010	2011	2012	2013	2014	2015
Return on common equity (ROCE)		-41.6 %	-55.8 %	-73.5 %	-58.9 %	-23.3 %
PM = OI (after tax) / Sales		-320.0 %	-590.2 %	-236.0 %	-64.4 %	3.4 %
ATO = Sales / NOA		0.09	0.06	0.14	0.18	0.36
FLEV		26 %	40 %	98 %	304 %	594 %
RNOA		-27.55 %	-37.88 %	-32.53 %	-11.61 %	1.22 %
NBC		26 %	7 %	9 %	4 %	5 %

5.2.4 Detnor Liquidity

Liquidity analysis	2010	2011	2012	2013	2014	2015
Short term liquidity stock measures	2010	2011	2012	2013	2014	2015
Current ratio	**1.47**	**2.76**	**1.71**	**2.01**	**1.07**	**1.23**
Current assets	3,681,872	2,976,534	2,916,670	3,819,011	5,183,566	4,309,985
Current liabilities	2,499,238	1,076,582	1,702,929	1,897,119	4,865,254	3,491,601
Quick ratio	**1.47**	**2.73**	**1.70**	**1.99**	**1.03**	**1.15**
Cash	789,330	841,599	1,154,182	1,709,166	2,207,610	801,176
Short term investments	22,568	21,750	23,138	24,075	24,510	25,707
Short term derivatives	6,033	0	0	0	0	399,858
Receivables	508,940	678,726	444,405	633,640	2,765,087	1,686,698
Tax receivables	2,344,753	1,397,420	1,273,737	1,411,251	0	1,117,688
Current liabilities	2,499,238	1,076,582	1,702,929	1,897,119	4,865,254	3,491,601
Cash ratio	**0.33**	**0.80**	**0.69**	**0.91**	**0.46**	**0.35**
Cash	789,330	841,599	1,154,182	1,709,166	2,207,610	801,176
Short term investments	22,568	21,750	23,138	24,075	24,510	25,707
Short term derivatives	6,033	0	0	0	0	399,858
Current liabilities	2,499,238	1,076,582	1,702,929	1,897,119	4,865,254	3,491,601
Long term solvency stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.59**	**0.52**	**0.55**	**0.70**	**0.88**	**0.93**
Total debt (current + long-term)	4,559,446	4,039,432	4,628,277	7,352,882	35,268,155	42,887,116
Total assets (Liabilities + total equity)	7,719,619	7,715,984	8,364,453	10,541,352	40,124,340	45,885,157
Debt to equity	**1.44**	**1.10**	**1.24**	**2.31**	**7.26**	**14.31**
Total debt	4,559,446	4,039,432	4,628,277	7,352,882	35,268,155	42,887,116
Total equity	3,160,173	3,676,551	3,736,175	3,188,470	4,856,185	2,998,041
Long-term debt ratio	**0.39**	**0.45**	**0.44**	**0.63**	**0.86**	**0.93**
Long-term debt	2,060,207	2,962,850	2,925,348	5,455,763	30,402,901	39,395,515
Total equity	3,160,173	3,676,551	3,736,175	3,188,470	4,856,185	2,998,041
Long term solvency flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**(10.88)**	**(5.12)**	**(18.53)**	**(7.01)**	**(3.90)**	**0.27**
Operating income (EBIT)	(1,999,624)	(1,190,617)	(1,962,018)	(2,227,376)	(1,885,706)	333,778
Net interest expense	183,805	232,355	105,904	317,952	483,825	1,250,528
Interest coverage (after tax)	**(4.22)**	**(1.88)**	**(5.30)**	**(1.40)**	**(3.99)**	**(1.76)**
Operating income	(558,014)	(315,082)	(404,000)	(319,676)	(1,407,685)	(1,610,054)
Net interest expense	132,340	167,296	76,251	228,925	353,192	912,885
Interest coverage (before tax) EBITDA	**(9.09)**	**(3.94)**	**(14.93)**	**(3.43)**	**2.71**	**6.15**
EBITDA	(1,670,067)	(914,426)	(1,581,631)	(1,090,712)	1,310,530	7,688,521
Net interest expense	183,805	232,355	105,904	317,952	483,825	1,250,528
Covenants	2010	2011	2012	2013	2014	2015
Leverage	**10.37**	**7.09**	**81.39**	**8.26**	**8.65**	**3.22**
Net debt	1,112,620	692,885	2,253,161	4,514,983	19,923,317	26,729,004
EBITDAX	107,270	97,765	27,683	546,351	2,304,575	8,305,062
Covenant					*3.5*	*3.5*
Interest cover	**(7.64)**	**(2.99)**	**(12.33)**	**(3.61)**	**2.48**	**8.73**
EBITDA	(1,670,067)	(914,426)	(1,581,631)	(1,090,712)	1,310,530	7,688,521
Interest expense	218,647	305,969	128,250	301,834	528,917	880,582
Covenant					*3.5*	*3.5*

5.3 Peers

5.3.1 Peer Income Statements

LUNDIN PETROLEUM

Reported income statement						
USDm	2010	2011	2012	2013	2014	2015
Total revenue	**798.6**	**1,269.5**	**1,375.8**	**1,195.8**	**785.2**	**569.3**
Production costs	(157.1)	(193.1)	(203.2)	(195.8)	(66.5)	(150.3)
Depletion and decommissioning costs	(145.3)	(165.1)	(191.4)	(174.2)	(131.6)	(260.6)
Depletion of other assets	0.0	0.0	0.0	0.0	0.0	(23.7)
Exploration costs	(127.5)	(140.0)	(168.4)	(287.8)	(386.4)	(184.1)
Impairment costs of oil and gas properties	0.0	0.0	(237.5)	(123.4)	(400.7)	(737.0)
Gross profit	**368.7**	**771.2**	**575.3**	**414.6**	**(200.0)**	**(786.4)**
Gain on sale of assets	66.1	0.0	0.0	0.0	0.0	0.0
General, administration and depreciation expenses	(41.0)	(67.0)	(31.8)	(43.6)	(52.2)	(39.5)
Operating profit (EBIT)	**393.9**	**704.2**	**543.5**	**371.0**	**(252.2)**	**(825.9)**
Financial income	21.0	46.5	27.3	3.3	1.8	7.4
Financial expenses	(33.5)	(21.0)	(48.5)	(86.3)	(421.8)	(617.9)
Net financial expenses	*(12.5)*	*25.4*	*(21.2)*	*(83.0)*	*(420.0)*	*(610.5)*
Share of the result of joint ventures accounted for	0.0	0.0	0.0	0.0	(12.9)	0.0
Profit before tax (EBT)	**381.3**	**729.7**	**522.3**	**288.0**	**(685.1)**	**(1,436.4)**
Income tax	(251.9)	(574.4)	(418.4)	(215.1)	253.2	570.1
Net income (continuing operations)	**129.5**	**155.2**	**103.9**	**72.9**	**(431.9)**	**(866.3)**
Result from discontinued operations	369.0	0.0	0.0	0.0	0.0	0.0
Net income	**498.5**	**155.2**	**103.9**	**72.9**	**(431.9)**	**(866.3)**
Other comprehensive income (net of tax)	7.0	(82.5)	84.6	(36.0)	(360.3)	(78.5)
Total Comprehensive Income	**505.5**	**72.7**	**188.5**	**36.9**	**(792.2)**	**(944.8)**

Analytical income statement						
Core operations (USDm)	2010	2011	2012	2013	2014	2015
Revenue	**798.6**	**1,269.5**	**1,375.8**	**1,195.8**	**785.2**	**569.3**
Share of the result of joint ventures	0.0	0.0	0.0	0.0	(12.9)	0.0
Net revenue	**798.6**	**1,269.5**	**1,375.8**	**1,195.8**	**772.3**	**569.3**
Production costs	(157.1)	(193.1)	(203.2)	(182.3)	(115.6)	(123.8)
SG&A	(41.0)	(67.0)	(31.8)	(43.6)	(52.2)	(39.5)
EBITDAX	**600.6**	**1,009.4**	**1,140.8**	**969.9**	**604.5**	**406.0**
Exploration costs	(127.5)	(140.0)	(168.4)	(287.8)	(386.4)	(184.1)
EBITDA	**473.0**	**869.4**	**972.4**	**682.1**	**218.1**	**221.9**
Depletion and decommissioning costs	(145.3)	(165.1)	(191.4)	(174.2)	(131.6)	(260.6)
Depletion of other assets	0.0	0.0	0.0	0.0	0.0	(23.7)
Impairment costs of oil and gas properties	0.0	0.0	(237.5)	(123.4)	(400.7)	(737.0)
EBIT	**327.7**	**704.2**	**543.5**	**384.5**	**(314.2)**	**(799.4)**
Tax on EBIT	(158.9)	(568.8)	(423.1)	(236.3)	171.6	430.0
Operating income (OI)	**168.8**	**135.4**	**120.4**	**148.2**	**(142.6)**	**(369.4)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Brynhild production costs	0.0	0.0	0.0	(13.5)	49.1	(26.5)
Sale of assets	66.1	0.0	0.0	0.0	0.0	0.0
Result from discontinued operations	369.0	0.0	0.0	0.0	0.0	0.0
Non-core operations before tax	435.1	0.0	0.0	(13.5)	49.1	(26.5)
Tax rate	22 %	22 %	22 %	22 %	22 %	22 %
Tax on non-core	(95.7)	0.0	0.0	3.0	(10.8)	5.8
Non-core operations after tax	339.4	0.0	0.0	(10.5)	38.3	(20.7)
Other Comprehensive Income (net of tax)	7.0	(82.5)	84.6	(36.0)	(360.3)	(78.5)
Total non-core operations after tax	**346.4**	**(82.5)**	**84.6**	**(46.5)**	**(322.0)**	**(99.2)**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(12.5)	25.4	(21.2)	(83.0)	(420.0)	(610.5)
Tax on NFE	2.8	(5.6)	4.7	18.3	92.4	134.3
NFE after tax	**(9.8)**	**19.8**	**(16.5)**	**(64.7)**	**(327.6)**	**(476.2)**

Tax allocation (USDm)	2010	2011	2012	2013	2014	2015
Tax on EBIT	(158.9)	(568.8)	(423.1)	(236.3)	171.6	430.0
Tax on NFE	2.8	(5.6)	4.7	18.3	92.4	134.3
Tax on Non-core operations	(95.7)	0.0	0.0	3.0	(10.8)	5.8
Total tax	(251.9)	(574.4)	(418.4)	(215.1)	253.2	570.1

** Tax rate: Swedish tax rate*

ENQUEST PLC

Reported income statement

USDm	2010	2011	2012	2013	2014	2015
Total revenue	**583.5**	**936.0**	**889.5**	**955.2**	**1,028.5**	**908.5**
Cost of sales	(223.6)	(291.6)	(241.7)	(301.5)	(467.3)	(445.9)
Gross profit	**359.8**	**644.4**	**647.9**	**653.8**	**561.2**	**462.7**
Depletion of oil and gas assets	(177.2)	(217.2)	(216.8)	(225.7)	(244.5)	(302.7)
Exploration costs	(80.9)	(37.0)	(23.2)	(8.6)	(156.0)	(9.4)
Impairment costs of oil and gas assets	(2.1)	0.0	(143.9)	0.0	(678.8)	(1,224.5)
Impairment of investments	0.0	(12.5)	(4.4)	(0.3)	(1.3)	(0.6)
General and administration expenses	(27.2)	(13.8)	(6.7)	(25.0)	(16.5)	(18.0)
Other income / expenses	1.5	(3.3)	(6.4)	(26.4)	27.2	(12.3)
Negative goodwill	0.0	0.0	0.0	0.0	28.6	0.0
Gain on disposal of intangible oil and gas assets	0.0	0.0	0.0	0.0	2.0	(2.3)
Gain on disposal of PPE	0.0	0.0	175.9	0.0	0.0	(8.5)
Gain on disposal of asset held for sale	0.0	8.6	0.0	0.0	0.0	0.0
Well abandonment	(8.2)	8.2	0.0	0.0	0.0	0.0
Operating profit (EBIT)	**65.8**	**377.5**	**422.5**	**367.7**	**(478.1)**	**(1,115.4)**
Financial income	1.2	4.0	2.2	2.0	1.8	1.0
Financial expenses	(11.2)	(18.6)	(21.2)	(38.8)	(102.4)	(226.5)
Net financial expenses	*(10.0)*	*(14.6)*	*(19.1)*	*(36.8)*	*(100.6)*	*(225.5)*
Profit before tax (EBT)	**55.8**	**362.8**	**403.4**	**330.9**	**(578.7)**	**(1,340.9)**
Income tax	(28.7)	(301.8)	(41.2)	(141.3)	402.3	581.5
Net income (continuing operations)	**27.1**	**61.0**	**362.2**	**189.6**	**(176.4)**	**(759.5)**
Result from discontinued operations	0.0	0.0	0.0	0.0	0.0	0.0
Net income	**27.1**	**61.0**	**362.2**	**189.6**	**(176.4)**	**(759.5)**
Other comprehensive income (net of tax)	0.0	(2.6)	2.6	0.4	59.0	74.8
Total Comprehensive Income	**27.1**	**58.4**	**364.8**	**190.0**	**(117.4)**	**(684.7)**

Analytical income statement

Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**583.5**	**936.0**	**889.5**	**955.2**	**1,028.5**	**908.5**
Production costs	(223.6)	(291.6)	(241.7)	(301.5)	(467.3)	(445.9)
General and administration expenses	(27.2)	(13.8)	(6.7)	(25.0)	(16.5)	(18.0)
Well abandonment	(8.2)	8.2	0.0	0.0	0.0	0.0
EBITDAX	**324.5**	**638.9**	**641.2**	**628.7**	**544.7**	**444.7**
Exploration costs	(80.9)	(37.0)	(23.2)	(8.6)	(156.0)	(9.4)
EBITDA	**243.6**	**601.9**	**618.0**	**620.1**	**388.7**	**435.3**
Depletion of oil and gas assets	(177.2)	(217.2)	(216.8)	(225.7)	(244.5)	(302.7)
Impairment costs of oil and gas assets	(2.1)	0.0	(143.9)	0.0	(678.8)	(1,224.5)
EBIT	**64.3**	**384.7**	**257.4**	**394.4**	**(534.6)**	**(1,091.9)**
Tax on EBIT	(32.4)	(311.3)	22.3	(169.0)	383.1	473.1
Operating income (OI)	**31.9**	**73.3**	**279.7**	**225.5**	**(151.5)**	**(618.7)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Negative goodwill	0.0	0.0	0.0	0.0	28.6	0.0
Gain on disposal of intangible oil and gas assets	0.0	0.0	0.0	0.0	2.0	(2.3)
Impairment of investments	0.0	(12.5)	(4.4)	(0.3)	(1.3)	(0.6)
Other income / expenses	1.5	(3.3)	(6.4)	(26.4)	27.2	(12.3)
Gain on disposal of PPE	0.0	0.0	175.9	0.0	0.0	(8.5)
Gain on disposal of asset held for sale	0.0	8.6	0.0	0.0	0.0	0.0
Non-core operations before tax	1.5	(7.2)	165.1	(26.7)	56.5	(23.6)
Tax rate	43.5 %	43.5 %	43.5 %	43.5 %	43.5 %	43.5 %
Tax on non-core	(0.7)	3.1	(71.8)	11.6	(24.6)	10.3
Non-core operations after tax	0.8	(4.1)	93.3	(15.1)	31.9	(13.3)
Other Comprehensive Income (net of tax)	0.0	(2.6)	2.6	0.4	59.0	74.8
Total non-core operations after tax	**0.8**	**(6.7)**	**95.8**	**(14.6)**	**90.9**	**61.5**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(10.0)	(14.6)	(19.1)	(36.8)	(100.6)	(225.5)
Tax on NFE	4.4	6.4	8.3	16.0	43.7	98.1
NFE after tax	**(5.7)**	**(8.3)**	**(10.8)**	**(20.8)**	**(56.8)**	**(127.4)**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	(32.4)	(311.3)	22.3	(169.0)	383.1	473.1
Tax on NFE	4.4	6.4	8.3	16.0	43.7	98.1
Tax on Non-core operations	(0.7)	3.1	(71.8)	11.6	(24.6)	10.3
Total tax	(28.7)	(301.8)	(41.2)	(141.3)	402.3	581.5

** Tax rate: Weighted average of countries in which they operate (annual report)*

PREMIER OIL

Reported income statement

USDm	2010	2011	2012	2013	2014	2015
Sales revenue	763.6	826.8	1,408.7	1,501.0	1,629.4	
Other operating revenue	0.0	0.0	0.0	38.7	0.0	
Profit on disposal of non-current assets	0.0	0.0	0.0	3.6	2.7	
Total revenue	**763.6**	**826.8**	**1,408.7**	**1,543.3**	**1,632.1**	
Cost of sales (excl. D&A)	(266.9)	(234.8)	(369.6)	(472.3)	(530.2)	
Gross profit	**496.7**	**592.0**	**1,039.1**	**1,071.0**	**1,101.9**	
Depreciation & Amortization PPE	(198.3)	(206.0)	(352.1)	(383.8)	(456.4)	
Impairment charge on oil and gas properties	(65.3)	25.9	(20.7)	(178.7)	(784.4)	
Exploration expense	(68.2)	(187.5)	(157.7)	(106.2)	(58.5)	
Pre-license exploration cost	(18.9)	(23.0)	(29.2)	(30.1)	(25.3)	
General and administration costs	(18.3)	(25.8)	(24.2)	(20.2)	(25.4)	
Operating profit (EBIT)	**127.7**	**175.6**	**455.2**	**352.0**	**(248.1)**	
Share of profit in associate	0.0	0.0	(1.9)	0.0	1.9	
Gain/Loss on commodity derivative financial instruments	38.6	34.0	14.2	(1.2)	0.0	
Financial income	2.5	5.5	3.2	33.0	58.5	
Financial expenses	(68.0)	(73.6)	(110.8)	(98.4)	(196.3)	
Net financial expenses	*(65.5)*	*(68.1)*	*(107.6)*	*(65.4)*	*(137.8)*	
Profit before tax (EBT)	**100.8**	**141.5**	**359.9**	**285.4**	**(384.0)**	
Income tax	29.0	29.7	(107.9)	(51.4)	173.7	
Net income (continuing operations)	**129.8**	**171.2**	**252.0**	**234.0**	**(210.3)**	
Result from discontinued operations	0.0	0.0	0.0	0.0	0.0	
Net income	**129.8**	**171.2**	**252.0**	**234.0**	**(210.3)**	
Other comprehensive income (net of tax)	(15.6)	(15.2)	41.7	(35.1)	78.1	
Total Comprehensive Income	**114.2**	**156.0**	**293.7**	**198.9**	**(132.2)**	

Analytical income statement

Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**763.6**	**826.8**	**1,408.7**	**1,543.3**	**1,632.1**	**0.0**
Cost of sales (excl. D&A)	(266.9)	(234.8)	(369.6)	(472.3)	(530.2)	0.0
General and administration costs	(18.3)	(25.8)	(24.2)	(20.2)	(25.4)	0.0
EBITDAX	**478.4**	**566.2**	**1,014.9**	**1,050.8**	**1,076.5**	**0.0**
Exploration expense	(68.2)	(187.5)	(157.7)	(106.2)	(58.5)	0.0
Pre-license exploration cost	(18.9)	(23.0)	(29.2)	(30.1)	(25.3)	0.0
EBITDA	**391.3**	**355.7**	**828.0**	**914.5**	**992.7**	**0.0**
Impairment charge on oil and gas properties	(65.3)	25.9	(20.7)	(178.7)	(784.4)	0.0
Depreciation & Amortization PPE	(198.3)	(206.0)	(352.1)	(383.8)	(456.4)	0.0
EBIT	**127.7**	**175.6**	**455.2**	**352.0**	**(248.1)**	**0.0**
Tax on EBIT	16.4	13.7	(152.7)	(82.7)	109.8	0.0
Operating income (OI)	**144.1**	**189.3**	**302.5**	**269.3**	**(138.3)**	**0.0**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Gain/Loss on commodity derivative financial instruments	38.6	34.0	14.2	(1.2)	0.0	0.0
Share of profit in associate	0.0	0.0	(1.9)	0.0	1.9	0.0
Non-core operations before tax	38.6	34.0	12.3	(1.2)	1.9	0.0
Tax rate	47 %	47 %	47 %	47 %	47 %	47 %
Tax on non-core	(18.1)	(16.0)	(5.8)	0.6	(0.9)	0.0
Non-core operations after tax	20.5	18.0	6.5	(0.6)	1.0	0.0
Other Comprehensive Income (net of tax)	(15.6)	(15.2)	41.7	(35.1)	78.1	0.0
Total non-core operations after tax	**4.9**	**2.8**	**48.2**	**(35.7)**	**79.1**	**0.0**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(65.5)	(68.1)	(107.6)	(65.4)	(137.8)	0.0
Tax on NFE	30.8	32.0	50.6	30.7	64.8	0.0
NFE after tax	**(34.7)**	**(36.1)**	**(57.0)**	**(34.7)**	**(73.0)**	**0.0**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	16.4	13.7	(152.7)	(82.7)	109.8	0.0
Tax on NFE	30.8	32.0	50.6	30.7	64.8	0.0
Tax on Non-core operations	(18.1)	(16.0)	(5.8)	0.6	(0.9)	0.0
Total tax	29.0	29.7	(107.9)	(51.4)	173.7	0.0

** Tax rate: Weighted average of countries in which they operate (annual report)*

SOCO INTERNATIONAL

Reported income statement						
USDm	2010	2011	2012	2013	2014	2015
Sales revenue	**48.4**	**234.1**	**621.6**	**608.1**	**448.2**	**214.8**
Cost of sales (excl. D&A)	(6.3)	(48.4)	(115.8)	(124.3)	(93.6)	(67.2)
Gross profit	**42.0**	**185.7**	**505.8**	**483.8**	**354.6**	**147.6**
Depletion and depreciation	(6.0)	(19.4)	(45.3)	(44.8)	(50.2)	(99.2)
Impairment of property, plant, and equipment	0.0	0.0	0.0	0.0	(60.5)	0.0
Exploration cost written off	0.0	0.0	0.0	(92.0)	(79.5)	(35.6)
General and administration costs	(6.9)	(9.4)	(12.3)	(13.2)	(11.8)	(10.0)
Operating profit (EBIT)	**29.1**	**156.9**	**448.2**	**333.8**	**152.6**	**2.8**
Investment revenue	1.3	1.1	1.0	1.0	0.7	0.4
Other gains and losses	0.9	3.3	1.5	1.3	1.6	7.4
Financial income	0.0	0.0	0.0	0.0	0.0	0.0
Financial expenses	(0.5)	(2.7)	(5.1)	(2.8)	(2.2)	(2.2)
Net financial expenses	*(0.5)*	*(2.7)*	*(5.1)*	*(2.8)*	*(2.2)*	*(2.2)*
Profit before tax (EBT)	**30.9**	**158.6**	**445.6**	**333.3**	**152.7**	**8.4**
Income tax	(18.5)	(70.0)	(238.6)	(229.2)	(138.7)	(42.0)
Net income (continuing operations)	**12.3**	**88.6**	**207.0**	**104.1**	**14.0**	**(33.6)**
Result from discontinued operations (net of tax)	89.1	0.0	0.0	0.0	0.0	0.0
Net income	**101.4**	**88.6**	**207.0**	**104.1**	**14.0**	**(33.6)**
Other comprehensive income (net of tax)	(5.5)	4.2	(0.2)	9.3	(1.8)	1.8
Total Comprehensive Income	**95.9**	**92.8**	**206.8**	**113.4**	**12.2**	**(31.8)**

Analytical income statement						
Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**48.4**	**234.1**	**621.6**	**608.1**	**448.2**	**214.8**
Cost of sales (excl. D&A)	(6.3)	(48.4)	(115.8)	(124.3)	(93.6)	(67.2)
General and administration costs	(6.9)	(9.4)	(12.3)	(13.2)	(11.8)	(10.0)
EBITDAX	**35.2**	**176.3**	**493.5**	**470.6**	**342.8**	**137.6**
Exploration cost written off	0.0	0.0	0.0	(92.0)	(79.5)	(35.6)
EBITDA	**35.2**	**176.3**	**493.5**	**378.6**	**263.3**	**102.0**
Impairment of property, plant, and equipment	0.0	0.0	0.0	0.0	(60.5)	0.0
Depletion and depreciation	(6.0)	(19.4)	(45.3)	(44.8)	(50.2)	(99.2)
EBIT	**29.1**	**156.9**	**448.2**	**333.8**	**152.6**	**2.8**
Tax on EBIT	(17.7)	(69.2)	(239.9)	(229.5)	(138.7)	(39.2)
Operating income (OI)	**11.4**	**87.8**	**208.3**	**104.4**	**14.0**	**(36.4)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Investment revenue	1.3	1.1	1.0	1.0	0.7	0.4
Other gains and losses	0.9	3.3	1.5	1.3	1.6	7.4
Non-core operations before tax	2.2	4.4	2.5	2.3	2.3	7.8
Tax rate	50 %	50 %	50 %	50 %	50 %	50 %
Tax on non-core	(1.1)	(2.2)	(1.3)	(1.2)	(1.2)	(3.9)
Non-core operations after tax	1.1	2.2	1.3	1.2	1.2	3.9
Other Comprehensive Income (net of tax)	(5.5)	4.2	(0.2)	9.3	(1.8)	1.8
Result from discontinued operations (net of tax)	89.1	0.0	0.0	0.0	0.0	0.0
Total non-core operations after tax	**84.7**	**6.4**	**1.1**	**10.5**	**(0.7)**	**5.7**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(0.5)	(2.7)	(5.1)	(2.8)	(2.2)	(2.2)
Tax on NFE	0.3	1.4	2.6	1.4	1.1	1.1
NFE after tax	**(0.3)**	**(1.4)**	**(2.6)**	**(1.4)**	**(1.1)**	**(1.1)**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	(17.7)	(69.2)	(239.9)	(229.5)	(138.7)	(39.2)
Tax on NFE	0.3	1.4	2.6	1.4	1.1	1.1
Tax on Non-core operations	(1.1)	(2.2)	(1.3)	(1.2)	(1.2)	(3.9)
Total tax	(18.5)	(70.0)	(238.6)	(229.2)	(138.7)	(42.0)

** Tax rate: Weighted average of countries in which they operate (annual report)*

NOSTRUM OIL & GAS

Reported income statement

USDm	2010	2011	2012	2013	2014	2015
Total revenue	**178.2**	**300.8**	**737.1**	**895.0**	**781.9**	**448.9**
Cost of sales (excl. DD&A)	(38.7)	(51.4)	(136.9)	(167.3)	(111.5)	(78.9)
Gross profit	**139.5**	**249.5**	**600.2**	**727.7**	**670.4**	**370.0**
Depreciation, depletion and amortization	(15.2)	(19.4)	(101.4)	(119.0)	(110.5)	(107.7)
General and administration expenses	(27.3)	(36.4)	(64.9)	(56.0)	(54.9)	(49.3)
Selling and transportation expenses	(17.0)	(35.4)	(103.6)	(121.7)	(122.3)	(93.0)
Foreign exchange gain/loss	0.0	(0.4)	0.8	(0.6)	(4.2)	(21.7)
Other expenses	(1.1)	(7.9)	(6.6)	(25.6)	(49.8)	(30.6)
Other income	3.3	3.4	3.9	4.4	10.1	11.3
Operating profit (EBIT)	**82.3**	**153.4**	**328.5**	**409.3**	**338.8**	**79.1**
Employee share option plan fair value adjustment	0.0	0.0	0.0	(4.4)	3.1	2.165
Interest income	0.2	0.3	0.7	0.8	1.0	0.5
Gain on derivative financial instruments	(0.5)	0.0	0.0	0.0	60.3	37.1
Finance costs - reorganization	0.0	0.0	0.0	0.0	(29.6)	(1.1)
Finance costs	(21.3)	(4.7)	(46.8)	(43.6)	(61.9)	(46.0)
Profit before tax (EBT)	**60.8**	**149.0**	**282.4**	**362.0**	**311.7**	**71.8**
Income tax	(37.9)	(67.3)	(120.4)	(142.5)	(165.3)	(166.6)
Net income (continuing operations)	**22.9**	**81.6**	**162.0**	**219.5**	**146.4**	**(94.8)**
Result from discontinued operations	0.0	0.0	0.0	0.0	0.0	0.0
Net income	**22.9**	**81.6**	**162.0**	**219.5**	**146.4**	**(94.8)**
Other comprehensive income (net of tax)	0.0	0.0	0.0	0.0	0.0	0.0
Total Comprehensive Income	**22.9**	**81.6**	**162.0**	**219.5**	**146.4**	**(94.8)**

Analytical income statement

Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**178.2**	**300.8**	**737.1**	**895.0**	**781.9**	**448.9**
Cost of sales (excl. DD&A)	(38.7)	(51.4)	(136.9)	(167.3)	(111.5)	(78.9)
General and administration expenses	(27.3)	(36.4)	(64.9)	(56.0)	(54.9)	(49.3)
Selling and transportation expenses	(17.0)	(35.4)	(103.6)	(121.7)	(122.3)	(93.0)
Foreign exchange gain/loss	0.0	(0.4)	0.8	(0.6)	(4.2)	(21.7)
Other expenses	(1.1)	(7.9)	(6.6)	(25.6)	(49.8)	(30.6)
Other income	3.3	3.4	3.9	4.4	10.1	11.3
EBITDA	**97.5**	**172.8**	**429.8**	**528.3**	**449.3**	**186.8**
Depreciation, depletion and amortization	(15.2)	(19.4)	(101.4)	(119.0)	(110.5)	(107.7)
EBIT	**82.3**	**153.4**	**328.5**	**409.3**	**338.8**	**79.1**
Tax on EBIT	(42.2)	(68.2)	(129.6)	(152.0)	(170.7)	(168.1)
Operating income (OI)	**40.1**	**85.1**	**198.9**	**257.3**	**168.1**	**(89.0)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Gain on derivative financial instruments	(0.5)	0.0	0.0	0.0	60.3	37.1
Employee share option plan fair value adjustment	0.0	0.0	0.0	(4.4)	3.1	2.2
Non-core operations before tax	(0.5)	0.0	0.0	(4.4)	63.4	39.2
Tax rate	20 %	20 %	20 %	20 %	20 %	20 %
Tax on non-core	0.1	0.0	0.0	0.9	(12.7)	(7.8)
Non-core operations after tax	(0.4)	0.0	0.0	(3.5)	50.7	31.4
Other comprehensive income (net of tax)	0	0	0	0	0	0
Total non-core operations after tax	**(0.4)**	**0.0**	**0.0**	**(3.5)**	**50.7**	**31.4**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses before tax	(21.1)	(4.4)	(46.1)	(42.9)	(90.5)	(46.5)
Tax on NFE	4.2	0.9	9.2	8.6	18.1	9.3
NFE after tax	**(16.8)**	**(3.5)**	**(36.9)**	**(34.3)**	**(72.4)**	**(37.2)**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	(42.2)	(68.2)	(129.6)	(152.0)	(170.7)	(168.1)
Tax on NFE	4.2	0.9	9.2	8.6	18.1	9.3
Tax on Non-core operations	0.1	0.0	0.0	0.9	(12.7)	(7.8)
Total tax	(37.9)	(67.3)	(120.4)	(142.5)	(165.3)	(166.6)

Netherlands and Khazakhstan weighted average (annual report)

TULLOW

Reported income statement

USDm	2010	2011	2012	2013	2014	2015
Sales revenue	**1,089.8**	**2,304.2**	**2,344.1**	**2,646.9**	**2,212.9**	**1,606.6**
Cost of sales (excl. D&A)	(212.5)	(363.4)	(406.1)	(561.9)	(494.9)	(435.2)
Gross profit	**877.3**	**1,940.8**	**1,938.0**	**2,085.0**	**1,718.0**	**1,171.4**
Depletion and amortization of oil and gas assets	(355.9)	(513.6)	(536.7)	(565.1)	(572.2)	(551.2)
Depreciation of other fixed assets	(11.4)	(20.2)	(25.2)	(26.8)	(49.6)	(28.9)
Administrative expenses	(89.6)	(122.8)	(191.2)	(218.5)	(192.4)	(193.6)
Restructuring costs	0.0	0.0	0.0	0.0	0.0	(40.8)
Gain/loss on disposal of assets and subsidiaries	0.5	2.0	702.5	29.5	(482.4)	(56.5)
Goodwill impairment	0.0	0.0	0.0	0.0	(132.8)	(53.7)
Exploration cost written off	(154.7)	(120.6)	(670.9)	(870.6)	(1,657.3)	(748.9)
Impairment of property, plant and equipment	(4.3)	(33.6)	(31.3)	(52.7)	(595.9)	(406.0)
Provision for onerous service contracts	0.0	0.0	0.0	0.0	0.0	(185.5)
Operating profit (EBIT)	**261.9**	**1,132.0**	**1,185.2**	**380.8**	**(1,964.6)**	**(1,093.7)**
Gain/Loss on hedging instruments	(27.7)	27.2	(19.9)	(19.7)	50.8	(58.8)
Finance revenue	15.1	36.6	9.6	43.7	9.6	4.2
Finance costs	(70.1)	(122.9)	(59.0)	(91.6)	(143.2)	(149.0)
Net financial expenses	*(55.0)*	*(86.3)*	*(49.4)*	*(47.9)*	*(133.6)*	*(144.8)*
Profit before tax (EBT)	**179.2**	**1,072.9**	**1,115.9**	**313.2**	**(2,047.4)**	**(1,297.3)**
Income tax	(89.7)	(383.9)	(449.7)	(97.1)	407.5	260.4
Net income (continuing operations)	**89.5**	**689.0**	**666.2**	**216.1**	**(1,639.9)**	**(1,036.9)**
Result from discontinued operations (after tax)	0.0	0.0	0.0	0.0	0.0	0.0
Net income	**89.5**	**689.0**	**666.2**	**216.1**	**(1,639.9)**	**(1,036.9)**
Other comprehensive income (net of tax)	(40.3)	(23.1)	15.5	21.5	348.7	124.7
Total Comprehensive Income	**49.2**	**665.9**	**681.7**	**237.6**	**(1,291.2)**	**(912.2)**

Analytical income statement

Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**1,089.8**	**2,304.2**	**2,344.1**	**2,646.9**	**2,212.9**	**1,606.6**
Cost of sales (excl. D&A)	(212.5)	(363.4)	(406.1)	(561.9)	(494.9)	(435.2)
Administrative expenses	(89.6)	(122.8)	(191.2)	(218.5)	(192.4)	(193.6)
EBITDAX	**787.7**	**1,818.0**	**1,746.8**	**1,866.5**	**1,525.6**	**977.8**
Exploration cost written off	(154.7)	(120.6)	(670.9)	(870.6)	(1,657.3)	(748.9)
EBITDA	**633.0**	**1,697.4**	**1,075.9**	**995.9**	**(131.7)**	**228.9**
Depletion and amortization of oil and gas assets	(355.9)	(513.6)	(536.7)	(565.1)	(572.2)	(551.2)
Depreciation of other fixed assets	(11.4)	(20.2)	(25.2)	(26.8)	(49.6)	(28.9)
Impairment of property, plant and equipment	(4.3)	(33.6)	(31.3)	(52.7)	(595.9)	(406.0)
Goodwill impairment	0.0	0.0	0.0	0.0	(132.8)	(53.7)
EBIT	**261.4**	**1,130.0**	**482.7**	**351.3**	**(1,482.2)**	**(810.9)**
Tax on EBIT	(109.4)	(397.6)	(297.7)	(106.2)	271.9	143.7
Operating income (OI)	**152.0**	**732.4**	**185.0**	**245.1**	**(1,210.3)**	**(667.2)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Restructuring costs	0.0	0.0	0.0	0.0	0.0	(40.8)
Gain/loss on disposal of assets and subsidiaries	0.5	2.0	702.5	29.5	(482.4)	(56.5)
Provision for onerous service contracts	0.0	0.0	0.0	0.0	0.0	(185.5)
Gain/Loss on hedging instruments	(27.7)	27.2	(19.9)	(19.7)	50.8	(58.8)
Non-core operations before tax	(27.2)	29.2	682.6	9.8	(431.6)	(341.6)
Tax rate	24 %	24 %	24 %	24 %	24 %	24 %
Tax on non-core	6.5	(7.0)	(163.8)	(2.4)	103.6	82.0
Non-core operations after tax	(20.7)	22.2	518.8	7.4	(328.0)	(259.6)
Other comprehensive income (net of tax)	(40.3)	(23.1)	15.5	21.5	348.7	124.7
Total non-core operations after tax	**(61.0)**	**(0.9)**	**534.3**	**28.9**	**20.7**	**(134.9)**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses	(55.0)	(86.3)	(49.4)	(47.9)	(133.6)	(144.8)
Tax on NFE	13.2	20.7	11.9	11.5	32.1	34.8
NFE after tax	**(41.8)**	**(65.6)**	**(37.5)**	**(36.4)**	**(101.5)**	**(110.0)**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	(109.4)	(397.6)	(297.7)	(106.2)	271.9	143.7
Tax on NFE	13.2	20.7	11.9	11.5	32.1	34.8
Tax on Non-core operations	6.5	(7.0)	(163.8)	(2.4)	103.6	82.0
Total tax	(89.7)	(383.9)	(449.7)	(97.1)	407.5	260.4

** Tax rate: Weighted average of countries in which they operate (annual report)*

FAROE PETROLEUM

Reported income statement						
GBPm	2010	2011	2012	2013	2014	2015
Sales revenue	**15.1**	**80.2**	**158.8**	**129.4**	**129.2**	**113.0**
Cost of sales (excl. D&A)	(9.1)	(39.4)	(62.5)	(49.2)	(68.4)	(61.8)
Gross profit	**6.0**	**40.9**	**96.3**	**80.1**	**60.8**	**51.2**
Depreciation, depletion and amortization - development productio	(5.0)	(12.9)	(34.5)	(27.2)	(34.4)	(38.0)
Asset impairment	(5.9)	0.0	0.0	(2.1)	(38.5)	(45.1)
Other income	0.0	0.0	0.0	0.0	4.6	13.9
Net gain on disposal of exploration and evaluation assets	0.0	40.0	1.7	0.1	0.8	0.0
Exploration and evaluation expenses	(13.7)	(42.3)	(79.7)	(22.2)	(139.4)	(89.5)
Administrative expenses	(6.6)	(9.9)	(9.3)	(7.7)	(6.6)	(3.7)
Operating profit (EBIT)	**(25.2)**	**15.8**	**(25.6)**	**21.0**	**(152.6)**	**(111.4)**
Finance revenue	1.5	2.3	2.7	1.2	0.7	0.9
Finance costs	(2.4)	(3.8)	(6.1)	(12.2)	(13.8)	(11.9)
Net financial expenses	*(0.9)*	*(1.5)*	*(3.4)*	*(10.9)*	*(13.2)*	*(10.9)*
Profit before tax (EBT)	**(26.0)**	**14.3**	**(29.0)**	**10.0**	**(165.8)**	**(122.3)**
Income tax	5.7	33.2	23.8	4.1	110.8	69.4
Net income (continuing operations)	**(20.4)**	**47.4**	**(5.2)**	**14.1**	**(55.0)**	**(52.9)**
Result from discontinued operations (after tax)	0.0	0.0	0.0	0.0	0.0	0.0
Net income	**(20.4)**	**47.4**	**(5.2)**	**14.1**	**(55.0)**	**(52.9)**
Other comprehensive income (net of tax)	0.5	(0.7)	2.7	12.4	1.2	(1.5)
Total Comprehensive Income	**(19.8)**	**46.7**	**(2.5)**	**26.4**	**(53.7)**	**(54.4)**

Analytical income statement						
Core operations (USDm)	2010	2011	2012	2013	2014	2015
Total revenue	**15.1**	**80.2**	**158.8**	**129.4**	**133.8**	**126.8**
Cost of sales (excl. D&A)	(9.1)	(39.4)	(62.5)	(49.2)	(68.4)	(61.8)
Administrative expenses	(6.6)	(9.9)	(9.3)	(7.7)	(6.6)	(3.7)
EBITDAX	**(0.6)**	**31.0**	**87.0**	**72.4**	**58.9**	**61.3**
Exploration and evaluation expenses	(13.7)	(42.3)	(79.7)	(22.2)	(139.4)	(89.5)
EBITDA	**(14.3)**	**(11.3)**	**7.3**	**50.2**	**(80.5)**	**(28.2)**
Depreciation, depletion and amortization - development productio	(5.0)	(12.9)	(34.5)	(27.2)	(34.4)	(38.0)
Asset impairment	(5.9)	0.0	0.0	(2.1)	(38.5)	(45.1)
EBIT	**(25.2)**	**(24.2)**	**(27.2)**	**20.9**	**(153.4)**	**(111.4)**
Tax on EBIT	5.5	41.2	23.4	1.8	108.2	67.1
Operating income (OI)	**(19.7)**	**17.0**	**(3.8)**	**22.7**	**(45.2)**	**(44.3)**

Non-core operations (USDm)	2010	2011	2012	2013	2014	2015
Net gain on disposal of exploration and evaluation assets	0.0	40.0	1.7	0.1	0.8	0.0
Non-core operations before tax	0.0	40.0	1.7	0.1	0.8	0.0
Tax rate	21 %	21 %	21 %	21 %	21 %	21 %
Tax on non-core	0.0	(8.4)	(0.3)	(0.0)	(0.2)	0.0
Non-core operations after tax	0.0	31.6	1.3	0.1	0.6	0.0
Other comprehensive income (net of tax)	0.5	(0.7)	2.7	12.4	1.2	(1.5)
Total non-core operations after tax	**0.5**	**30.9**	**4.0**	**12.4**	**1.9**	**(1.5)**

Financial expenses	2010	2011	2012	2013	2014	2015
Net financial expenses	(0.9)	(1.5)	(3.4)	(10.9)	(13.2)	(10.9)
Tax on NFE	0.2	0.3	0.7	2.3	2.8	2.3
NFE after tax	**(0.7)**	**(1.2)**	**(2.7)**	**(8.6)**	**(10.4)**	**(8.6)**

Tax allocation	2010	2011	2012	2013	2014	2015
Tax on EBIT	5.5	41.2	23.4	1.8	108.2	67.1
Tax on NFE	0.2	0.3	0.7	2.3	2.8	2.3
Tax on Non-core operations	0.0	(8.4)	(0.3)	(0.0)	(0.2)	0.0
Total tax	5.7	33.2	23.8	4.1	110.8	69.4

** Tax rate: UK tax rate*

5.3.2 Peer Balance Sheets

LUNDIN PETROLEUM

Reported balance sheet						
USDm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Oil- and gas properties	1,999.0	2,329.3	2,864.4	3,851.9	4,182.6	4,015.4
Other tangible fixed assets	15.3	16.1	49.4	85.0	200.3	204.3
Financial assets	0.0	0.0	0.0	0.0	31.0	5.5
Deferred tax assets	15.1	15.3	13.3	22.4	12.9	13.4
Derivative instruments	0.0	0.0	0.0	3.0	0.0	0.0
Other shares and participations	68.6	17.8	20.0	22.0	4.7	4.1
Long-term receivables	23.8	0.0	0.0	0.0	0.0	0.0
Other financial assets	22.5	11.0	10.8	11.8	1.3	1.1
Total non-current assets	**2,144.2**	**2,389.4**	**2,957.9**	**3,996.1**	**4,432.8**	**4,243.8**
Current assets						
Inventories	20.0	31.6	18.7	22.8	41.6	45.6
Trade and other receivables	113.9	168.0	166.2	172.4	163.5	159.3
Prepaid expenses and accrued income	6.4	4.5	32.9	62.1	0.0	0.0
Current tax assets	0.0	0.0	0.0	0.0	373.6	264.7
Derivative instruments	0.0	0.0	9.1	3.2	0.0	0.0
Joint venture debtors	21.4	20.3	11.5	25.2	0.0	0.0
Cash and cash equivalents	48.7	73.6	97.4	92.7	80.5	71.9
Short term loan receivables	74.5	0.0	0.0	0.0	0.0	0.0
Total current assets	**285.0**	**298.0**	**335.8**	**378.4**	**659.2**	**541.5**
Total assets	**2,429.1**	**2,687.4**	**3,293.7**	**4,374.5**	**5,092.0**	**4,785.3**
EQUITY AND LIABILITIES						
EQUITY						
Share capital	0.5	0.5	0.5	0.5	0.5	
Additional paid in capital	483.6	483.6	474.9	454.8	445.0	
Other reserves	(66.1)	(145.8)	(63.8)	(96.7)	(436.2)	
Retained earnings	(9.4)	502.5	662.6	770.8	849.4	
Net result	511.9	160.1	108.2	77.6	(427.2)	
Shareholders's equity	**920.4**	**1,000.9**	**1,182.4**	**1,207.0**	**431.5**	**-498.2**
Non-controlling interest	77.4	69.4	67.7	59.8	34.2	24.1
Total equity	**997.8**	**1,070.3**	**1,250.1**	**1,266.8**	**465.7**	**-474.1**
LIABILITIES						
Non-current liabilities						
Financial liabilities	458.8	204.5	384.2	1,239.1	2,654.0	3,834.8
Provisions	113.0	184.5	262.4	282.0	288.0	379.9
Deferred tax liabilities	650.7	803.5	942.2	1,067.6	973.3	542.6
Derivative instruments	0.0	0.0	0.0	1.6	33.9	48.4
Other non-current liabilities	17.8	21.8	22.6	24.9	29.1	32.2
Total non-current liabilities	**1,240.3**	**1,214.3**	**1,611.4**	**2,615.2**	**3,978.3**	**4,837.9**
Current liabilities						
Deferred revenue	0.0	0.0	0.0	0.0	0.0	20.2
Trade payables	16.0	16.5	15.7	19.4	23.9	23.1
Joint operations creditors and accrued expenses	100.9	88.4	209.6	334.5	383.5	271.5
Other accrued expenses	7.7	16.2	12.7	41.0	46.1	23.7
Derivative instruments	6.9	0.2	0.0	4.0	101.4	66.1
Other liabilities	13.8	29.2	15.4	42.6	37.9	11.4
Current tax liabilities	39.7	240.1	170.0	4.7	1.8	0.7
Provisions	6.0	12.2	8.8	46.2	53.4	4.8
Total current liabilities	**191.0**	**402.8**	**432.2**	**492.4**	**648.0**	**421.5**
Total liabilities	**1,431.4**	**1,617.1**	**2,043.6**	**3,107.6**	**4,626.3**	**5,259.4**
Total equity and liabilities	**2,429.1**	**2,687.4**	**3,293.7**	**4,374.4**	**5,092.0**	**4,785.3**

LUNDIN PETROLEUM

Analytical balance sheet

USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	20.0	31.6	18.7	22.8	41.6	45.6
Trade and other receivables	113.9	168.0	166.2	172.4	163.5	159.3
Prepaid expenses and accrued income	6.4	4.5	32.9	62.1	0.0	0.0
Current tax assets	0.0	0.0	0.0	0.0	373.6	264.7
Joint venture debtors	21.4	20.3	11.5	25.2	0.0	0.0
Current operating assets	**161.7**	**224.4**	**229.3**	**282.5**	**578.7**	**469.6**
CURRENT OPERATING LIABILITIES						
Deferred revenue	0.0	0.0	0.0	0.0	0.0	20.2
Trade payables	16.0	16.5	15.7	19.4	23.9	23.1
Joint operations creditors and accrued expenses	100.9	88.4	209.6	334.5	383.5	271.5
Other accrued expenses	7.7	16.2	12.7	41.0	46.1	23.7
Other liabilities	13.8	29.2	15.4	42.6	37.9	11.4
Current tax liabilities	39.7	240.1	170.0	4.7	1.8	0.7
Current operating liabilities	**178.1**	**390.4**	**423.4**	**442.2**	**493.2**	**350.6**
NON-CURRENT OPERATING ASSETS						
Oil- and gas properties	1,999.0	2,329.3	2,864.4	3,851.9	4,182.6	4,015.4
Other tangible fixed assets	15.3	16.1	49.4	85.0	200.3	204.3
Deferred tax assets	15.1	15.3	13.3	22.4	12.9	13.4
Long-term receivables	23.8	0.0	0.0	0.0	0.0	0.0
Non-current operating assets	**2,053.1**	**2,360.7**	**2,927.1**	**3,959.3**	**4,395.8**	**4,233.1**
NON-CURRENT OPERATING LIABILITIES						
Deferred tax liabilities	650.7	803.5	942.2	1,067.6	973.3	542.6
Non-current operating liabilities	**650.7**	**803.5**	**942.2**	**1,067.6**	**973.3**	**542.6**
NET OPERATING ASSETS	**1,386.0**	**1,391.2**	**1,790.8**	**2,732.0**	**3,508.0**	**3,809.5**
Average		1,388.6	1,591.0	2,261.4	3,120.0	3,658.8
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	0.5	0.5	0.5	0.5	0.5	
Additional paid in capital	483.6	483.6	474.9	454.8	445.0	
Other reserves	(66.1)	(145.8)	(63.8)	(96.7)	(436.2)	
Retained earnings	(9.4)	502.5	662.6	770.8	849.4	
Net result	511.9	160.1	108.2	77.6	(427.2)	
Shareholders's equity	**920.4**	**1,000.9**	**1,182.4**	**1,207.0**	**431.5**	**(498.2)**
Non-controlling interest	77.4	69.4	67.7	59.8	34.2	24.1
Total equity	**997.8**	**1,070.3**	**1,250.1**	**1,266.8**	**465.7**	**(474.1)**
INTEREST BEARING ASSETS						
Financial assets	0.0	0.0	0.0	0.0	31.0	5.5
Derivative instruments	0.0	0.0	0.0	3.0	0.0	0.0
Other shares and participations	68.6	17.8	20.0	22.0	4.7	4.1
Other financial assets	22.5	11.0	10.8	11.8	1.3	1.1
Derivative instruments	0.0	0.0	9.1	3.2	0.0	0.0
Cash and cash equivalents	48.7	73.6	97.4	92.7	80.5	71.9
Short term loan receivables	74.5	0.0	0.0	0.0	0.0	0.0
Interest bearing assets	**214.3**	**102.3**	**137.3**	**132.7**	**117.5**	**82.6**
INTEREST BEARING DEBT						
Financial liabilities	458.8	204.5	384.2	1,239.1	2,654.0	3,834.8
Provisions	113.0	184.5	262.4	282.0	288.0	379.9
Derivative instruments	0.0	0.0	0.0	1.6	33.9	48.4
Other non-current liabilities	17.8	21.8	22.6	24.9	29.1	32.2
Derivative instruments	6.9	0.2	0.0	4.0	101.4	66.1
Provisions	6.0	12.2	8.8	46.2	53.4	4.8
Interest bearing debt	**602.5**	**423.2**	**678.0**	**1,597.8**	**3,159.8**	**4,366.2**
NET FINANCIAL OBLIGATIONS	**388.2**	**320.9**	**540.7**	**1,465.1**	**3,042.3**	**4,283.6**
Average		354.5	430.8	1,002.9	2,253.7	3,663.0
NET OPERATING ASSETS	**1,386.0**	**1,391.2**	**1,790.8**	**2,731.9**	**3,508.0**	**3,809.5**
Average		1,388.6	1,591.0	2,261.4	3,120.0	3,658.8
EQUITY	**997.8**	**1,070.3**	**1,250.1**	**1,266.8**	**465.7**	**(474.1)**
Average		1,034.0	1,160.2	1,258.5	866.3	(4.2)

ENQUEST

Reported balance sheet						
USDm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Property, plant and equipment	1,134.2	1,273.6	1,816.6	2,871.2	3,116.4	2,436.7
Goodwill	107.8	107.8	107.8	107.8	189.3	189.3
Intangible oil and gas assets	9.6	24.3	97.5	130.9	65.7	46.5
Asset held for sale	9.8	1.3	0.0	0.0	0.0	0
Investments	0.0	6.7	2.3	2.4	0.7	0.1
Deferred tax assets	13.2	12.6	23.1	14.7	40.4	138.5
Other financial assets	0.0	0.0	19.4	21.9	18.8	15.3
Total non-current assets	**1,274.6**	**1,426.3**	**2,066.8**	**3,148.9**	**3,431.3**	**2,826.4**
Current assets						
Inventories	12.4	11.8	15.3	46.8	89.4	67.6
Trade and other receivables	132.6	126.6	239.7	267.2	286.2	351.9
Current tax receivable	0.0	2.6	2.0	6.3	11.2	3.7
Cash and cash equivalents	41.4	378.9	124.5	72.8	176.8	269.0
Other financial assets	0.0	2.5	96.5	8.5	100.9	258.7
Total current assets	**186.4**	**522.4**	**478.0**	**401.5**	**664.5**	**950.9**
Total assets	**1,461.0**	**1,948.7**	**2,544.8**	**3,550.5**	**4,095.9**	**3,777.3**
EQUITY						
Share capital	113.2	113.4	113.4	113.4	113.4	113.4
Merger reserve	662.9	662.9	662.9	662.9	662.9	662.9
Cash flow hedge reserve	0.0	(2.6)	(0.0)	0.0	59.4	134.2
Available for sale reserve	0.0	0.0	0.0	0.4	0.0	0.0
Share-based payment reserve	2.5	(6.0)	(11.1)	(10.3)	(17.7)	(12.0)
Retained earnings	104.3	166.5	528.7	718.3	541.9	(231.3)
Total equity	**882.9**	**934.2**	**1,293.9**	**1,484.7**	**1,359.9**	**667.2**
LIABILITIES						
Non-current liabilities						
Borrowings	0.0	0.0	34.6	199.4	227.0	907.1
Bonds	0.0	0.0	0.0	254.5	882.6	870.3
Obligations under finance leases	0.0	0.0	0.1	0.1	0.0	0.0
Provisions	140.1	181.2	233.0	308.4	556.4	686.6
Other financial liabilities	0.0	0.3	0.0	0.8	23.7	7.7
Current tax payable	294.7	590.0	632.2	761.0	503.0	59.2
Total non-current liabilities	**434.8**	**771.6**	**899.9**	**1,524.2**	**2,192.7**	**2,530.8**
Current liabilities						
Bonds	0.0	0.0	0.0	4.3	12.7	12.3
Trade and other payables	135.7	234.3	329.7	363.3	429.1	543.5
Obligations under finance leases	0.0	0.0	0.0	0.0	0.0	0.0
Other financial liabilities	0.0	6.9	17.6	169.9	101.5	19.3
Current tax payable	7.6	1.7	3.8	4.0	0.0	4.1
Total current liabilities	**143.3**	**242.9**	**351.0**	**541.5**	**543.3**	**579.3**
Total liabilities	**578.1**	**1,014.5**	**1,250.9**	**2,065.7**	**2,736.0**	**3,110.1**
Total equity and liabilities	**1,461.0**	**1,948.7**	**2,544.8**	**3,550.5**	**4,095.9**	**3,777.3**

ENQUEST

Analytical balance sheet

USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	12.4	11.8	15.3	46.8	89.4	67.6
Trade and other receivables	132.6	126.6	239.7	267.2	286.2	351.9
Current tax receivable	0.0	2.6	2.0	6.3	11.2	3.7
Current operating assets	**145.0**	**141.0**	**257.0**	**320.3**	**386.8**	**423.2**
CURRENT OPERATING LIABILITIES						
Trade and other payables	135.7	234.3	329.7	363.3	429.1	543.5
Current tax payable	7.6	1.7	3.8	4.0	0.0	4.1
Current operating liabilities	**143.3**	**236.0**	**333.4**	**367.3**	**429.1**	**547.7**
NON-CURRENT OPERATING ASSETS						
Property, plant and equipment	1,134.2	1,273.6	1,816.6	2,871.2	3,116.4	2,436.7
Goodwill	107.8	107.8	107.8	107.8	189.3	189.3
Intangible oil and gas assets	9.6	24.3	97.5	130.9	65.7	46.5
Deferred tax assets	13.2	12.6	23.1	14.7	40.4	138.5
Non-current operating assets	**1,264.8**	**1,418.3**	**2,045.0**	**3,124.6**	**3,411.8**	**2,811.0**
NON-CURRENT OPERATING LIABILITIES						
Current tax payable	294.7	590.0	632.2	761.0	503.0	59.2
Non-current operating liabilities	**294.7**	**590.0**	**632.2**	**761.0**	**503.0**	**59.2**
NET OPERATING ASSETS	**971.8**	**733.2**	**1,336.4**	**2,316.6**	**2,866.5**	**2,627.4**
Average		852.5	1,034.8	1,826.5	2,591.6	2,747.0
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	113.2	113.4	113.4	113.4	113.4	113.4
Merger reserve	662.9	662.9	662.9	662.9	662.9	662.9
Cash flow hedge reserve	0.0	(2.6)	(0.0)	0.0	59.4	134.2
Available for sale reserve	0.0	0.0	0.0	0.4	0.0	0.0
Share-based payment reserve	2.5	(6.0)	(11.1)	(10.3)	(17.7)	(12.0)
Retained earnings	104.3	166.5	528.7	718.3	541.9	(231.3)
Total equity	**882.9**	**934.2**	**1,293.9**	**1,484.7**	**1,359.9**	**667.2**
INTEREST BEARING ASSETS						
Asset held for sale	9.8	1.3	0.0	0.0	0.0	0.0
Investments	0.0	6.7	2.3	2.4	0.7	0.1
Other financial assets	0.0	0.0	19.4	21.9	18.8	15.3
Cash and cash equivalents	41.4	378.9	124.5	72.8	176.8	269.0
Other financial assets	0.0	2.5	96.5	8.5	100.9	258.7
Interest bearing assets	**51.2**	**389.4**	**242.8**	**105.6**	**297.2**	**543.1**
INTEREST BEARING DEBT						
Borrowings	0.0	0.0	34.6	199.4	227.0	907.1
Bonds	0.0	0.0	0.0	254.5	882.6	870.3
Obligations under finance leases	0.0	0.0	0.1	0.1	0.0	0.0
Provisions	140.1	181.2	233.0	308.4	556.4	686.6
Other financial liabilities	0.0	0.3	0.0	0.8	23.7	7.7
Bonds	0.0	0.0	0.0	4.3	12.7	12.3
Obligations under finance leases	0.0	0.0	0.0	0.0	0.0	0.0
Other financial liabilities	0.0	6.9	17.6	169.9	101.5	19.3
Interest bearing debt	**140.1**	**188.4**	**285.3**	**937.5**	**1,803.9**	**2,503.3**
NET FINANCIAL OBLIGATIONS	**88.9**	**(201.0)**	**42.5**	**831.9**	**1,506.7**	**1,960.2**
Average		(56.0)	(79.2)	437.2	1,169.3	1,733.4
NET OPERATING ASSETS	**971.8**	**733.2**	**1,336.4**	**2,316.6**	**2,866.5**	**2,627.4**
Average		852.5	1,034.8	1,826.5	2,591.6	2,747.0
EQUITY	**882.9**	**934.2**	**1,293.9**	**1,484.7**	**1,359.9**	**667.2**
Average		908.6	1,114.0	1,389.3	1,422.3	1,013.5

PREMIER OIL

Reported balance sheet						
USDm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Intangible exporation and evaluation assets	310.8	315.5	658.0	701.0	825.7	
Property, plant and equipment	1,732.8	2,257.8	2,692.9	2,885.9	2,430.0	
Goodwill	0.0	0.0	240.8	240.8	240.8	
Investment in associate	0.0	0.0	6.1	6.2	7.6	
Long-term employee benefit plan surplus	0.0	0.0	4.2	1.0	0.8	
Long-term receivables	0.0	0.0	2.5	198.1	494.1	
Deferred tax assets	285.3	500.8	568.9	762.4	971.7	
Total non-current assets	**2,328.9**	**3,074.1**	**4,173.4**	**4,795.4**	**4,970.7**	**0.0**
Current assets						
Inventories	18.6	27.7	34.6	49.5	26.1	
Trade and other receivables	245.5	389.9	351.3	421.8	411.0	
Tax recoverable	67.5	39.5	87.1	82.4	57.9	
Derivative financial instruments	65.7	49.1	9.8	15.9	273.4	
Cash and cash equivalents	299.7	309.1	187.4	448.9	291.8	
Asset held for sale	0.0	0.0	0.0	0.0	56.7	
Total current assets	**697.0**	**815.3**	**670.2**	**1,018.5**	**1,116.9**	**0.0**
Total assets	**3,025.9**	**3,889.4**	**4,843.6**	**5,813.9**	**6,087.6**	**0.0**
EQUITY						
Share capital	98.3	98.8	110.5	110.5	106.7	
Share premium account	254.8	649.2	649.2	649.6	649.7	
Retained earnings	738.7	922.9	1,150.1	1,342.1	1,142.3	
Other reserves	38.4	27.4	43.7	22.2	(26.5)	
Total equity	**1,130.2**	**1,698.3**	**1,953.5**	**2,124.4**	**1,872.2**	**0.0**
LIABILITIES						
Non-current liabilities						
Convertible bonds	218.1	226.5	219.6	223.8	228.1	
Other long-term debt	466.4	626.5	1,064.4	1,665.4	1,858.1	
Deferred tax liabilities	183.7	219.1	297.1	306.8	254.2	
Long-term provisions	473.2	565.4	613.3	824.6	864.0	
Long-term employee benefit plan deficit	15.2	18.6	18.2	13.1	18.3	
Deferred revenue	35.9	0.0	0.0	0.0	0.0	
Total non-current liabilities	**1,392.5**	**1,656.1**	**2,212.6**	**3,033.7**	**3,222.7**	**0.0**
Current liabilities						
Trade and other payables	314.0	381.2	450.0	512.4	544.5	
Current tax payable	56.4	146.5	114.9	92.0	84.2	
Provisions	23.7	35.1	68.8	13.1	14.1	
Derivative tax liabilities	109.1	154.8	43.8	38.3	48.1	
Short-term debt	0.0	183.7	0.0	0.0	300.0	
Liabilities directly associated with asset held for sale	0.0	0.0	0.0	0.0	1.8	
Deferred revenue	0.0	8.4	0.0	0.0	0.0	
Total current liabilities	**503.2**	**909.7**	**677.5**	**655.8**	**992.7**	**0.0**
Total liabilities	**1,895.7**	**2,565.8**	**2,890.1**	**3,689.5**	**4,215.4**	**0.0**
Total equity and liabilities	**3,025.9**	**4,264.1**	**4,843.6**	**5,813.9**	**6,087.6**	**0.0**

PREMIER OIL

Analytical balance sheet						
USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	18.6	27.7	34.6	49.5	26.1	0.0
Trade and other receivables	245.5	389.9	351.3	421.8	411.0	0.0
Tax recoverable	67.5	39.5	87.1	82.4	57.9	0.0
Current operating assets	**331.6**	**457.1**	**473.0**	**553.7**	**495.0**	**0.0**
CURRENT OPERATING LIABILITIES						
Trade and other payables	314.0	381.2	450.0	512.4	544.5	0.0
Current tax payable	56.4	146.5	114.9	92.0	84.2	0.0
Deferred revenue	0.0	8.4	0.0	0.0	0.0	0.0
Current operating liabilities	**370.4**	**536.1**	**564.9**	**604.4**	**628.7**	**0.0**
NON-CURRENT OPERATING ASSETS						
Intangible exporation and evaluation assets	310.8	315.5	658.0	701.0	825.7	0.0
Property, plant and equipment	1,732.8	2,257.8	2,692.9	2,885.9	2,430.0	0.0
Goodwill	0.0	0.0	240.8	240.8	240.8	0.0
Deferred tax assets	285.3	500.8	568.9	762.4	971.7	0.0
Non-current operating assets	**2,328.9**	**3,074.1**	**4,160.6**	**4,590.1**	**4,468.2**	**0.0**
NON-CURRENT OPERATING LIABILITIES						
Deferred tax liabilities	183.7	219.1	297.1	306.8	254.2	0.0
Deferred revenue	35.9	0.0	0.0	0.0	0.0	0.0
Non-current operating liabilities	**219.6**	**219.1**	**297.1**	**306.8**	**254.2**	**0.0**
NET OPERATING ASSETS	**2,070.5**	**2,776.0**	**3,771.6**	**4,232.6**	**4,080.3**	**0.0**
Average		2,423.3	3,273.8	4,002.1	4,156.5	2,040.2
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	98.3	98.8	110.5	110.5	106.7	0.0
Share premium account	254.8	274.5	649.2	649.6	649.7	0.0
Retained earnings	738.7	922.9	1,150.1	1,342.1	1,142.3	0.0
Other reserves	38.4	27.4	43.7	22.2	(26.5)	0.0
Total equity	**1,130.2**	**1,323.6**	**1,953.5**	**2,124.4**	**1,872.2**	**0.0**
INTEREST BEARING ASSETS						
Investment in associate	0.0	0.0	6.1	6.2	7.6	0.0
Long-term employee benefit plan surplus	0.0	0.0	4.2	1.0	0.8	0.0
Long-term receivables	0.0	0.0	2.5	198.1	494.1	0.0
Derivative financial instruments	65.7	49.1	9.8	15.9	273.4	0.0
Cash and cash equivalents	299.7	309.1	187.4	448.9	291.8	0.0
Asset held for sale	0.0	0.0	0.0	0.0	56.7	0.0
Interest bearing assets	**365.4**	**358.2**	**210.0**	**670.1**	**1,124.4**	**0.0**
INTEREST BEARING DEBT						
Convertible bonds	218.1	226.5	219.6	223.8	228.1	0.0
Other long-term debt	466.4	626.5	1,064.4	1,665.4	1,858.1	0.0
Long-term provisions	473.2	565.4	613.3	824.6	864.0	0.0
Long-term employee benefit plan deficit	15.2	18.6	18.2	13.1	18.3	0.0
Provisions	23.7	35.1	68.8	13.1	14.1	0.0
Derivative tax liabilities	109.1	154.8	43.8	38.3	48.1	0.0
Short-term debt	0.0	183.7	0.0	0.0	300.0	0.0
Liabilities directly associated with asset held for sale	0.0	0.0	0.0	0.0	1.8	0.0
Interest bearing debt	**1,305.7**	**1,810.6**	**2,028.1**	**2,778.3**	**3,332.5**	**0.0**
NET FINANCIAL OBLIGATIONS	**940.3**	**1,452.4**	**1,818.1**	**2,108.2**	**2,208.1**	**0.0**
Average		1,196.4	1,635.3	1,963.2	2,158.2	1,104.1
NET OPERATING ASSETS	**2,070.5**	**2,776.0**	**3,771.6**	**4,232.6**	**4,080.3**	**0.0**
Average		2,423.3	3,273.8	4,002.1	4,156.5	2,040.2
EQUITY	**1,130.2**	**1,323.6**	**1,953.5**	**2,124.4**	**1,872.2**	**0.0**
Average		1,226.9	1,638.6	2,039.0	1,998.3	936.1

SOCO

Reported balance sheet						
USDm	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
ASSETS						
Non-current assets						
Intangible assets	144.3	193.1	199.7	215.7	209.1	211.5
Property, plant, and equipment	693.0	793.6	816.6	801.3	790.0	760.5
Investments	0.0	0.0	0.0	0.0	0.0	0.0
Financial assets	37.4	40.6	42.1	43.4	45.0	0.0
Other receivables	0.0	0.0	0.0	15.0	24.6	29.5
Total non-current assets	**874.7**	**1,027.3**	**1,058.4**	**1,075.4**	**1,068.7**	**1,001.5**
Current assets						
Inventories	16.4	10.2	11.1	7.3	6.1	3.1
Trade and other receivables	24.4	79.8	72.2	68.9	39.6	19.5
Tax receivables	0.3	0.5	0.6	0.9	1.1	0.7
Assets classified as held for sale	0.0	0.0	36.3	0.0	0.0	0.0
Liquid investments	0.0	0.0	50.0	80.1	40.2	0.0
Cash and cash equivalents	260.4	160.1	208.5	129.9	126.2	103.6
Financial asset	0.0	0.0	0.0	0.0	0.0	52.7
Total current assets	**301.6**	**250.6**	**378.7**	**287.1**	**213.2**	**179.6**
Total assets	**1,176.2**	**1,277.9**	**1,437.1**	**1,362.5**	**1,281.9**	**1,181.1**
EQUITY						
Share capital	27.5	27.5	27.6	27.6	27.6	27.6
Share premium account	72.6	72.7	73.0	11.1	0.0	0
Other reserves	149.2	140.8	105.5	226.5	239.5	242.3
Retained earnings	763.9	857.1	970.5	815.6	708.0	622.6
Total equity	**1,013.2**	**1,098.1**	**1,176.6**	**1,080.8**	**975.1**	**892.5**
LIABILITIES						
Non-current liabilities						
Deferred tax liablities	24.1	37.5	113.3	184.2	200.2	183.7
Long term provisions	13.1	32.7	42.7	42.9	51.1	59.9
Convertible bonds	78.0	46.6	0.0	0.0	0.0	0.0
Total non-current liabilities	**115.1**	**116.8**	**156.0**	**227.1**	**251.3**	**243.6**
Current liabilities						
Trade and other payables	45.9	49.5	34.3	36.1	43.9	37.2
Tax payable	2.0	13.5	21.4	18.5	11.6	7.8
Convertible bonds	0.0	0.0	47.2	0.0	0.0	0.0
Liabilities associated with assets classified as held for sale	0.0	0.0	1.6	0.0	0.0	0.0
Total current liabilities	**47.9**	**63.0**	**104.5**	**54.6**	**55.5**	**45.0**
Total liabilities	**163.0**	**179.8**	**260.5**	**281.7**	**306.8**	**288.6**
Total equity and liabilities	**1,176.2**	**1,277.9**	**1,437.1**	**1,362.5**	**1,281.9**	**1,181.1**

SOCO

Analytical balance sheet						
USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	16.4	10.2	11.1	7.3	6.1	3.1
Trade and other receivables	24.4	79.8	72.2	68.9	39.6	19.5
Tax receivables	0.3	0.5	0.6	0.9	1.1	0.7
Current operating assets	**41.1**	**90.5**	**83.9**	**77.1**	**46.8**	**23.3**
CURRENT OPERATING LIABILITIES						
Trade and other payables	45.9	49.5	34.3	36.1	43.9	37.2
Tax payable	2.0	13.5	21.4	18.5	11.6	7.8
Current operating liabilities	**47.9**	**63.0**	**55.7**	**54.6**	**55.5**	**45.0**
NON-CURRENT OPERATING ASSETS						
Intangible assets	144.3	193.1	199.7	215.7	209.1	211.5
Property, plant, and equipment	693.0	793.6	816.6	801.3	790.0	760.5
Non-current operating assets	**837.2**	**986.7**	**1,016.3**	**1,017.0**	**999.1**	**972.0**
NON-CURRENT OPERATING LIABILITIES						
Deferred tax liablities	24.1	37.5	113.3	184.2	200.2	183.7
Non-current operating liabilities	**24.1**	**37.5**	**113.3**	**184.2**	**200.2**	**183.7**
NET OPERATING ASSETS	**806.4**	**976.7**	**931.2**	**855.3**	**790.2**	**766.6**
Average		891.5	954.0	893.3	822.8	778.4
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	27.5	27.5	27.6	27.6	27.6	27.6
Share premium account	72.6	72.7	73.0	11.1	0.0	0.0
Other reserves	149.2	140.8	105.5	226.5	239.5	242.3
Retained earnings	763.9	857.1	970.5	815.6	708.0	622.6
Total equity	**1,013.2**	**1,098.1**	**1,176.6**	**1,080.8**	**975.1**	**892.5**
INTEREST BEARING ASSETS						
Investments	0.0	0.0	0.0	0.0	0.0	0.0
Financial assets	37.4	40.6	42.1	43.4	45.0	0.0
Other receivables	0.0	0.0	0.0	15.0	24.6	29.5
Assets classified as held for sale	0.0	0.0	36.3	0.0	0.0	0.0
Liquid investments	0.0	0.0	50.0	80.1	40.2	0.0
Cash and cash equivalents	260.4	160.1	208.5	129.9	126.2	103.6
Financial asset	0.0	0.0	0.0	0.0	0.0	52.7
Interest bearing assets	**297.9**	**200.7**	**336.9**	**268.4**	**236.0**	**185.8**
INTEREST BEARING DEBT						
Long term provisions	13.1	32.7	42.7	42.9	51.1	59.9
Convertible bonds	78.0	46.6	0.0	0.0	0.0	0.0
Convertible bonds	0.0	0.0	47.2	0.0	0.0	0.0
Liabilities associated with assets classified as held for sale	0.0	0.0	1.6	0.0	0.0	0.0
Interest bearing debt	**91.1**	**79.3**	**91.5**	**42.9**	**51.1**	**59.9**
NET FINANCIAL OBLIGATIONS	**(206.8)**	**(121.4)**	**(245.4)**	**(225.5)**	**(184.9)**	**(125.9)**
Average		(164.1)	(183.4)	(235.5)	(205.2)	(155.4)
NET OPERATING ASSETS	**806.4**	**976.7**	**931.2**	**855.3**	**790.2**	**766.6**
Average		891.5	954.0	893.3	822.8	778.4
EQUITY	**1,013.2**	**1,098.1**	**1,176.6**	**1,080.8**	**975.1**	**892.5**
Average		1,055.7	1,137.4	1,128.7	1,028.0	933.8

NOSTRUM

Reported balance sheet

USDm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Exploration and evaluation assets	0.0	0.0	0.0	20.4	24.4	36.9
Goodwill	0.0	0.0	0.0	30.4	32.4	32.4
Property, plant and equipment	955.9	1,120.5	1,222.7	1,330.9	1,442.2	1,605.8
Restricted cash	2.7	3.1	3.7	4.2	5.0	5.4
Advances for non-current assets	6.5	3.4	25.3	10.0	134.4	130.7
Derivative financial instruments	0.0	0.0	0.0	0.0	60.3	43.0
Non-current investments	0.0	0.0	0.0	30.0	0.0	
Total non-current assets	**965.1**	**1,126.9**	**1,251.6**	**1,426.0**	**1,698.6**	**1,854.1**
Current assets						
Inventories	5.6	14.5	25.0	22.1	25.4	29.0
Trade receivables	1.6	12.6	54.0	66.6	30.1	31.3
Prepayments and other current assets	16.8	23.3	24.4	31.2	39.6	27.4
Income tax prepayment	3.2	3.5	0.0	5.0	13.9	26.9
Current investments	0.0	0.0	50.0	25.0	25.0	54.1
Cash and cash equivalents	144.2	125.4	197.7	184.9	375.4	165.6
Restricted cash	1.0	0.0	0.0	0.0	0.0	0.0
Total current assets	**172.4**	**179.3**	**351.1**	**334.8**	**509.6**	**334.3**
Total assets	**1,137.6**	**1,306.2**	**1,602.7**	**1,760.8**	**2,208.2**	**2,188.4**
EQUITY AND LIABILITIES						
EQUITY						
Share capital		0.0	0.0	0.0	3.2	3.2
Treasury capital		0.0	0.0	(30.8)	(1.9)	(1.9)
Partnership capital	366.9	368.2	371.1	380.9	0.0	0.0
Additional paid-in capital	0.0	1.7	6.1	8.1	0.0	0.0
Retained earnings and reserves	133.7	215.4	317.9	474.2	916.4	772.4
Total equity	**500.7**	**585.2**	**695.1**	**832.5**	**917.7**	**773.8**
LIABILITIES						
Non-current liabilities						
Long-term borrowings	434.9	438.1	615.7	621.2	930.1	936.5
Abandonment and site restoration provision	4.5	8.7	11.1	13.9	20.9	15.9
Due to Government of Kazakhstan	6.3	6.2	6.1	6.0	5.9	5.8
Deferred tax liability	100.8	146.7	148.9	152.5	206.8	347.8
Total non-current liabilities	**546.6**	**599.7**	**781.9**	**793.6**	**1,163.7**	**1,305.9**
Current liabilities						
Current portion of long-term borrowings	9.5	9.5	7.2	7.3	15.0	15.0
Employee share option plan liability	10.1	11.7	9.8	12.0	6.4	4.3
Trade payables	49.2	81.9	58.4	58.5	49.6	41.5
Advances received	11.7	3.2	0.0	0.0	2.7	0.2
Income tax payable	0.0	0.0	11.8	1.2	1.5	1.7
Current portion of Due to Government of Kazakhstar	1.0	1.0	1.0	1.0	1.0	1.0
Other current liabilities	8.4	14.0	37.6	54.6	50.6	45.0
Derivative financial instruments	0.4	0.0	0.0	0.0	0.0	0.0
Total current liabilities	**90.3**	**121.3**	**125.7**	**134.7**	**126.9**	**108.7**
Total liabilities	**636.9**	**720.9**	**907.6**	**928.3**	**1,290.5**	**1,414.7**
Total equity and liabilities	**1,137.6**	**1,306.2**	**1,602.7**	**1,760.8**	**2,208.2**	**2,188.4**

NOSTRUM

Analytical balance sheet						
USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	5.6	14.5	25.0	22.1	25.4	29.0
Trade receivables	1.6	12.6	54.0	66.6	30.1	31.3
Prepayments and other current assets	16.8	23.3	24.4	31.2	39.6	27.4
Income tax prepayment	3.2	3.5	0.0	5.0	13.9	26.9
Current operating assets	**27.2**	**53.9**	**103.3**	**124.9**	**109.1**	**114.6**
CURRENT OPERATING LIABILITIES						
Trade payables	49.2	81.9	58.4	58.5	49.6	41.5
Advances received	11.7	3.2	0.0	0.0	2.7	0.2
Income tax payable	0.0	0.0	11.8	1.2	1.5	1.7
Current operating liabilities	**60.9**	**85.1**	**70.2**	**59.8**	**53.7**	**43.4**
NON-CURRENT OPERATING ASSETS						
Exploration and evaluation assets	0.0	0.0	0.0	20.4	24.4	36.9
Goodwill	0.0	0.0	0.0	30.4	32.4	32.4
Property, plant and equipment	955.9	1,120.5	1,222.7	1,330.9	1,442.2	1,605.8
Advances for non-current assets	6.5	3.4	25.3	10.0	134.4	130.7
Non-current operating assets	**962.4**	**1,123.8**	**1,247.9**	**1,391.8**	**1,633.3**	**1,805.8**
NON-CURRENT OPERATING LIABILITIES						
Deferred tax liability	100.8	146.7	148.9	152.5	206.8	347.8
Non-current operating liabilities	**100.8**	**146.7**	**148.9**	**152.5**	**206.8**	**347.8**
NET OPERATING ASSETS	**827.9**	**946.0**	**1,132.2**	**1,304.3**	**1,481.9**	**1,529.2**
Average		886.9	1,039.1	1,218.3	1,393.1	1,505.6
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Share capital	0.0	0.0	0.0	0.0	3.2	3.2
Treasury capital	0.0	0.0	0.0	(30.8)	(1.9)	(1.9)
Partnership capital	366.9	368.2	371.1	380.9	0.0	0.0
Additional paid-in capital	0.0	1.7	6.1	8.1	0.0	0.0
Retained earnings and reserves	133.7	215.4	317.9	474.2	916.4	772.4
Total equity	**500.7**	**585.2**	**695.1**	**832.5**	**917.7**	**773.8**
INTEREST BEARING ASSETS						
Restricted cash	2.7	3.1	3.7	4.2	5.0	5.4
Derivative financial instruments	0.0	0.0	0.0	0.0	60.3	43.0
Non-current investments	0.0	0.0	0.0	30.0	0.0	0.0
Current investments	0.0	0.0	50.0	25.0	25.0	54.1
Cash and cash equivalents	144.2	125.4	197.7	184.9	375.4	165.6
Restricted cash	1.0	0.0	0.0	0.0	0.0	0.0
Interest bearing assets	**147.9**	**128.5**	**251.4**	**244.1**	**465.8**	**268.0**
INTEREST BEARING DEBT						
Long-term borrowings	434.9	438.1	615.7	621.2	930.1	936.5
Abandonment and site restoration provision	4.5	8.7	11.1	13.9	20.9	15.9
Due to Government of Kazakhstan	6.3	6.2	6.1	6.0	5.9	5.8
Current portion of long-term borrowings	9.5	9.5	7.2	7.3	15.0	15.0
Employee share option plan liability	10.1	11.7	9.8	12.0	6.4	4.3
Current portion of Due to Government of Kazakhstar	1.0	1.0	1.0	1.0	1.0	1.0
Other current liabilities	8.4	14.0	37.6	54.6	50.6	45.0
Derivative financial instruments	0.4	0.0	0.0	0.0	0.0	0.0
Interest bearing debt	**475.2**	**489.2**	**688.5**	**716.0**	**1,030.0**	**1,023.5**
NET FINANCIAL OBLIGATIONS	**327.2**	**360.7**	**437.1**	**471.9**	**564.2**	**755.5**
Average		344.0	398.9	454.5	518.0	659.8
NET OPERATING ASSETS	**827.9**	**946.0**	**1,132.2**	**1,304.3**	**1,481.9**	**1,529.2**
Average		886.9	1,039.1	1,218.3	1,393.1	1,505.6
EQUITY	**500.7**	**585.2**	**695.1**	**832.5**	**917.7**	**773.8**
Average		543.0	640.2	763.8	875.1	845.7

TULLOW

Reported balance sheet						
USDm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Goodwill		0.0	0.0	350.5	217.7	164.0
Intangible exploration and evaluation assets	4,001.2	5,529.7	2,977.1	4,148.3	3,660.8	3,400.0
Property, plant and equipment	2,974.4	3,580.3	4,407.9	4,862.9	4,887.0	5,204.4
Investments	1.0	1.0	1.0	1.0	1.0	1.0
Other non-current assets	0.0	313.5	696.7	68.7	119.7	223.4
Derivative financial instruments	0.0	0.0	0.0	6.8	193.9	218.7
Deferred tax assets	100.4	39.0	4.9	1.1	255.0	295.3
Total non-current assets	**7,077.0**	**9,463.5**	**8,087.6**	**9,439.3**	**9,335.1**	**9,506.8**
Current assets						
Inventories	183.0	225.7	163.7	193.9	139.5	107.2
Trade receivables	158.9	272.4	238.7	308.7	87.8	80.8
Other current assets	655.3	360.2	416.6	944.4	902.3	763.2
Current tax assets	0.0	7.0	28.6	226.2	221.6	127.6
Derivative financial instruments	0.0	0.0	0.0	0.0	280.8	406.5
Cash and cash equivalents	338.3	307.1	330.2	352.9	319.0	355.7
Assets classified as held for sale	0.0	0.0	116.4	43.2	135.6	0.0
Total current assets	**1,335.5**	**1,172.4**	**1,294.2**	**2,069.3**	**2,086.6**	**1,841.0**
Total assets	**8,412.5**	**10,635.9**	**9,381.8**	**11,508.6**	**11,421.7**	**11,347.8**
EQUITY AND LIABILITIES						
EQUITY						
Called-up share capital	143.5	146.2	146.6	146.9	147.0	147.2
Share premium	251.5	551.8	584.8	603.2	606.4	609.8
Other reserves	574.2	551.1	566.6	588.1	936.8	1,061.5
Retained earnings	2,873.6	3,441.3	3,931.2	3,984.7	2,305.8	1,336.4
Shareholders' equity	**3,842.8**	**4,690.4**	**5,229.2**	**5,322.9**	**3,996.0**	**3,154.9**
Non-controlling interest	60.6	75.6	92.4	123.5	24.3	19.8
Total equity	**3,903.4**	**4,766.0**	**5,321.6**	**5,446.4**	**4,020.3**	**3,174.7**
LIABILITIES						
Non-current liabilities						
Trade and other payables	354.0	2.4	30.6	29.4	85.1	99.3
Borrowings	1,890.0	2,858.1	1,173.6	1,995.0	3,209.1	4,262.4
Provisions	278.6	440.8	531.6	989.2	1,260.4	1,065.1
Deferred tax liabilities	465.5	1,030.8	1,076.3	1,588.0	1,507.6	1,164.5
Derivative financial instruments	35.3	4.2	19.3	28.3	0.0	0.0
Total non-current liabilities	**3,023.4**	**4,336.3**	**2,831.4**	**4,629.9**	**6,062.2**	**6,591.3**
Current liabilities						
Trade and other payables	1,008.2	1,119.6	848.1	1,041.1	1,074.9	1,110.6
Provisions	0.0	0.0	0.0	0.0	0.0	187.0
Borrowings	309.8	217.8	0.0	159.4	131.5	73.8
Current tax liabilities	120.6	153.8	292.4	165.5	115.9	208.3
Derivative financial instruments	47.1	42.4	39.4	48.1	3.3	2.1
Liabilities directly associated with assets clasified as held for sale	0.0	0.0	48.9	18.2	13.6	0.0
Total current liabilities	**1,485.7**	**1,533.6**	**1,228.8**	**1,432.3**	**1,339.2**	**1,581.8**
Total liabilities	**4,509.1**	**5,869.9**	**4,060.2**	**6,062.2**	**7,401.4**	**8,173.1**
Total equity and liabilities	**8,412.5**	**10,635.9**	**9,381.8**	**11,508.6**	**11,421.7**	**11,347.8**

TULLOW

Analytical balance sheet						
USDm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	183	225.7	163.7	193.9	139.5	107.2
Trade receivables	158.9	272.4	238.7	308.7	87.8	80.8
Other current assets	655.3	360.2	416.6	944.4	902.3	763.2
Current tax assets	0	7	28.6	226.2	221.6	127.6
Current operating assets	**997.2**	**865.3**	**847.6**	**1,673.2**	**1,351.2**	**1,078.8**
CURRENT OPERATING LIABILITIES						
Trade and other payables	1,008.2	1,119.6	848.1	1,041.1	1,074.9	1,110.6
Current tax liabilities	120.6	153.8	292.4	165.5	115.9	208.3
Current operating liabilities	**1,128.8**	**1,273.4**	**1,140.5**	**1,206.6**	**1,190.8**	**1,318.9**
NON-CURRENT OPERATING ASSETS						
Goodwill	0.0	0.0	0.0	350.5	217.7	164.0
Intangible exploration and evaluation assets	4,001.2	5,529.7	2,977.1	4,148.3	3,660.8	3,400.0
Property, plant and equipment	2,974.4	3,580.3	4,407.9	4,862.9	4,887.0	5,204.4
Other non-current assets	0.0	313.5	696.7	68.7	119.7	223.4
Deferred tax assets	100.4	39.0	4.9	1.1	255.0	295.3
Non-current operating assets	**7,076.0**	**9,462.5**	**8,086.6**	**9,431.5**	**9,140.2**	**9,287.1**
NON-CURRENT OPERATING LIABILITIES						
Trade and other payables	354.0	2.4	30.6	29.4	85.1	99.3
Deferred tax liabilities	465.5	1,030.8	1,076.3	1,588.0	1,507.6	1,164.5
Non-current operating liabilities	**819.5**	**1,033.2**	**1,106.9**	**1,617.4**	**1,592.7**	**1,263.8**
NET OPERATING ASSETS	**6,124.9**	**8,021.2**	**6,686.8**	**8,280.7**	**7,707.9**	**7,783.2**
Average		7,073.1	7,354.0	7,483.8	7,994.3	7,745.6
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Called-up share capital	143.5	146.2	146.6	146.9	147.0	147.2
Share premium	251.5	551.8	584.8	603.2	606.4	609.8
Other reserves	574.2	551.1	566.6	588.1	936.8	1,061.5
Retained earnings	2,873.6	3,441.3	3,931.2	3,984.7	2,305.8	1,336.4
Shareholders' equity	**3,842.8**	**4,690.4**	**5,229.2**	**5,322.9**	**3,996.0**	**3,154.9**
Non-controlling interest	60.6	75.6	92.4	123.5	24.3	19.8
Total equity	**3,903.4**	**4,766.0**	**5,321.6**	**5,446.4**	**4,020.3**	**3,174.7**
INTEREST BEARING ASSETS						
Investments	1.0	1.0	1.0	1.0	1.0	1.0
Derivative financial instruments	0.0	0.0	0.0	6.8	193.9	218.7
Derivative financial instruments	0.0	0.0	0.0	0.0	280.8	406.5
Cash and cash equivalents	338.3	307.1	330.2	352.9	319.0	355.7
Assets classified as held for sale	0.0	0.0	116.4	43.2	135.6	0.0
Interest bearing assets	**339.3**	**308.1**	**447.6**	**403.9**	**930.3**	**981.9**
INTEREST BEARING DEBT						
Borrowings	1,890.0	2,858.1	1,173.6	1,995.0	3,209.1	4,262.4
Provisions	278.6	440.8	531.6	989.2	1,260.4	1,065.1
Derivative financial instruments	35.3	4.2	19.3	28.3	0.0	0.0
Provisions	0.0	0.0	0.0	0.0	0.0	187.0
Borrowings	309.8	217.8	0.0	159.4	131.5	73.8
Derivative financial instruments	47.1	42.4	39.4	48.1	3.3	2.1
Liabilities directly associated with assets clasified as held for sale	0	0	48.9	18.2	13.6	0
Interest bearing debt	**2,560.8**	**3,563.3**	**1,812.8**	**3,238.2**	**4,617.9**	**5,590.4**
NET FINANCIAL OBLIGATIONS	**2,221.5**	**3,255.2**	**1,365.2**	**2,834.3**	**3,687.6**	**4,608.5**
Average		2,738.4	2,310.2	2,099.8	3,261.0	4,148.1
NET OPERATING ASSETS	**6,124.9**	**8,021.2**	**6,686.8**	**8,280.7**	**7,707.9**	**7,783.2**
Average		7,073.1	7,354.0	7,483.8	7,994.3	7,745.6
EQUITY	**3,903.4**	**4,766.0**	**5,321.6**	**5,446.4**	**4,020.3**	**3,174.7**
Average		4,334.7	5,043.8	5,384.0	4,733.4	3,597.5

FAROE PETROLEUM

Reported balance sheet

GBPm	2010	2011	2012	2013	2014	2015
ASSETS						
Non-current assets						
Intangible assets	102.7	99.6	145.1	185.8	128.3	73.5
Property, plant and equipment: development a	9.5	104.7	133.4	139.1	138.4	110.6
Property, plant and equipment: other	0.3	0.4	0.8	0.8	0.8	0.5
Financial assets	0.0	0.0	0.0	0.0	0.0	0.0
Deferred tax asset	0.0	0.0	0.0	0.0	30.0	32.4
Total non-current assets	**112.5**	**204.7**	**279.2**	**325.7**	**297.5**	**217.0**
Current assets						
Inventories	0.6	4.4	4.9	4.9	4.3	5.9
Trade and other receivables	7.5	59.9	55.4	60.7	36.5	28.0
Current tax receivable	28.1	0.0	48.5	23.9	45.8	35.2
Financial assets	0.0	0.0	0.0	0.0	6.1	10.6
Cash and cash equivalents	132.2	111.6	72.9	40.6	92.6	91.5
Total current assets	**168.4**	**175.8**	**181.6**	**130.1**	**185.4**	**171.2**
Total assets	**280.9**	**380.5**	**460.9**	**455.8**	**482.9**	**388.2**
EQUITY						
Equity share capital	21.2	21.2	21.2	21.3	26.8	26.8
Share premium account	205.9	206.0	206.0	206.3	262.4	262.5
Cumulative translation reserve	6.3	5.3	8.1	(3.8)	(2.6)	(4.1)
Retained earnings	(52.3)	(1.7)	(3.6)	11.8	(41.1)	(92.9)
Total equity	**181.1**	**230.8**	**231.7**	**235.6**	**245.5**	**192.4**
LIABILITIES						
Non-current liabilities						
Deferred tax liabilities	52.5	64.3	87.0	98.2	58.8	19.9
Provisions	8.3	35.0	48.6	47.5	77.7	87.1
Defined benefits pension plan deficit	0.4	0.3	0.4	0.6	1.0	0.0
Total non-current liabilities	**61.2**	**99.6**	**136.0**	**146.2**	**137.4**	**107.0**
Current liabilities						
Trade and other payables	20.9	36.8	41.9	53.0	34.3	32.4
Financial liabilities	17.6	0.0	51.2	21.0	65.7	55.8
Tax payable	0.0	13.3	0.0	0.0	0.0	0.7
Total current liabilities	**38.5**	**50.1**	**93.2**	**74.0**	**100.0**	**88.9**
Total liabilities	**99.7**	**149.7**	**229.2**	**220.2**	**237.4**	**195.9**
Total equity and liabilities	**280.9**	**380.5**	**460.9**	**455.8**	**482.9**	**388.2**

FAROE PETROLEUM

Analytical balance sheet

GBPm	2010	2011	2012	2013	2014	2015
OPERATING ASSETS AND LIABILITIES						
CURRENT OPERATING ASSETS						
Inventories	0.6	4.4	4.9	4.9	4.3	5.9
Trade and other receivables	7.5	59.9	55.4	60.7	36.5	28.0
Current tax receivable	28.1	0.0	48.5	23.9	45.8	35.2
Current operating assets	**36.2**	**64.2**	**108.8**	**89.5**	**86.7**	**69.1**
CURRENT OPERATING LIABILITIES						
Trade and other payables	20.9	36.8	41.9	53.0	34.3	32.4
Tax payable	0.0	13.3	0.0	0.0	0.0	0.7
Current operating liabilities	**20.9**	**50.1**	**41.9**	**53.0**	**34.3**	**33.1**
NON-CURRENT OPERATING ASSETS						
Intangible assets	102.7	99.6	145.1	185.8	128.3	73.5
Property, plant and equipment: development a	9.5	104.7	133.4	139.1	138.4	110.6
Property, plant and equipment: other	0.3	0.4	0.8	0.8	0.8	0.5
Deferred tax asset	0.0	0.0	0.0	0.0	30.0	32.4
Non-current operating assets	**112.5**	**204.7**	**279.2**	**325.7**	**297.5**	**217.0**
NON-CURRENT OPERATING LIABILITIES						
Deferred tax liabilities	52.5	64.3	87.0	98.2	58.8	19.9
Non-current operating liabilities	**52.5**	**64.3**	**87.0**	**98.2**	**58.8**	**19.9**
NET OPERATING ASSETS	**75.3**	**154.6**	**259.0**	**264.0**	**291.1**	**233.1**
Average		114.9	206.8	261.5	277.5	262.1
EQUITY AND INTEREST BEARING ASSETS AND LIABILITIES						
EQUITY						
Equity share capital	21.2	21.2	21.2	21.3	26.8	26.8
Share premium account	205.9	206.0	206.0	206.3	262.4	262.5
Cumulative translation reserve	6.3	5.3	8.1	(3.8)	(2.6)	(4.1)
Retained earnings	(52.3)	(1.7)	(3.6)	11.8	(41.1)	(92.9)
Total equity	**181.1**	**230.8**	**231.7**	**235.6**	**245.5**	**192.4**
INTEREST BEARING ASSETS						
Financial assets	0.0	0.0	0.0	0.0	0.0	0.0
Financial assets	0.0	0.0	0.0	0.0	6.1	10.6
Cash and cash equivalents	132.2	111.6	72.9	40.6	92.6	91.5
Interest bearing assets	**132.2**	**111.6**	**72.9**	**40.6**	**98.7**	**102.1**
INTEREST BEARING DEBT						
Provisions	8.3	35.0	48.6	47.5	77.7	87.1
Defined benefits pension plan deficit	0.4	0.3	0.4	0.6	1.0	0.0
Financial liabilities	17.6	0.0	51.2	21.0	65.7	55.8
Interest bearing debt	**26.3**	**35.3**	**100.2**	**69.0**	**144.3**	**142.9**
NET FINANCIAL OBLIGATIONS	**(105.9)**	**(76.3)**	**27.3**	**28.4**	**45.6**	**40.7**
Average		(91.1)	(24.5)	27.9	37.0	43.2
NET OPERATING ASSETS	**75.3**	**154.6**	**259.0**	**264.0**	**291.1**	**233.1**
Average		114.9	206.8	261.5	277.5	262.1
EQUITY	**181.1**	**230.8**	**231.7**	**235.6**	**245.5**	**192.4**
Average		206.0	231.3	233.7	240.5	218.9

5.3.3 Peer profitability

LUNDIN PETROLEUM

PROFITABILITY - After tax							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Core profit margin (PM)	OI (after tax) / Sales		10.67 %	8.75 %	12.39 %	-18.46 %	-64.89 %
Non-core profit margin	NCI / Sales		-6.50 %	6.15 %	-3.89 %	-41.69 %	-17.42 %
Asset turnover (ATO)	Sales / NOA		0.91	0.86	0.53	0.25	0.16
Financial leverage (FLEV)	NFO / CSE		0.34	0.37	0.80	2.60	(872.13)
Core RNOA	OI (after tax) / NOA		**9.75 %**	**7.57 %**	**6.55 %**	**-4.57 %**	**-10.10 %**
Non-Core RNOA	NCI (after tax) / NOA		**-5.94 %**	**5.32 %**	**-2.06 %**	**-10.32 %**	**-2.71 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		5.60 %	-3.84 %	-6.46 %	-14.54 %	-13.00 %
ROCE			**7.03 %**	**16.25 %**	**2.93 %**	**-91.45 %**	**22495.24 %**

OI (after tax)	168.83	135.41	120.44	148.17	-142.60	-369.44
Non core income (after tax)	346.40	-82.51	84.60	-46.53	-322.00	-99.17
Sales	798.60	1,269.52	1,375.80	1,195.80	772.30	569.30
NOA		1,388.59	1,590.99	2,261.35	3,119.95	3,658.75
NFO		354.54	430.79	1,002.90	2,253.70	3,662.95
CSE		1,034.04	1,160.20	1,258.45	866.25	-4.20
NFE (before tax)	-12.51	25.43	-21.20	-83.00	-420.00	-610.50
NFE (after tax)	-9.76	19.84	-16.54	-64.74	-327.60	-476.19

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Profit margin (PM)	EBIT / Sales		55.47 %	39.50 %	32.15 %	-40.68 %	-140.42 %
Asset turnover (ATO)	Sales / NOA		0.91	0.86	0.53	0.25	0.16
Financial leverage (FLEV)	NFO / CSE		0.34	0.37	0.80	2.60	-872.13
RNOA before tax	EBIT/NOA		50.72 %	34.16 %	17.00 %	-10.07 %	-21.85 %
Net borrowing cost	NFE / NFO		7.17 %	-4.92 %	-8.28 %	-18.64 %	-16.67 %
ROCE			**70.56 %**	**45.02 %**	**23.96 %**	**-84.76 %**	**33569.05 %**

Operating income before tax (EBIT)	327.72	704.22	543.50	384.50	-314.20	-799.40
Sales	798.60	1,269.52	1,375.80	1,195.80	772.30	569.30
NOA		1,388.59	1,590.99	2,261.35	3,119.95	3,658.75
NFO		354.54	430.79	1,002.90	2,253.70	3,662.95
CSE		1,034.04	1,160.20	1,258.45	866.25	-4.20
NFE (before tax)	-12.51	25.43	-21.20	-83.00	-420.00	-610.50
NFE (after tax)	-9.76	19.84	-16.54	-64.74	-327.60	-476.19

*All balance sheet figures are averaged

ENQUEST PLC

PROFITABILITY - After tax							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Core profit margin (PM)	OI (after tax) / Sales		7.83 %	31.45 %	23.60 %	-14.73 %	-68.11 %
Non-core profit margin	NCI / Sales		-0.71 %	10.77 %	-1.53 %	8.84 %	6.77 %
Asset turnover (ATO)	Sales / NOA		1.10	0.86	0.52	0.40	0.33
Financial leverage (FLEV)	NFO / CSE		(0.06)	(0.07)	0.31	0.82	1.71
Core RNOA	OI (after tax) / NOA		**8.60 %**	**27.03 %**	**12.35 %**	**-5.85 %**	**-22.52 %**
Non-Core RNOA	NCI (after tax) / NOA		**-0.78 %**	**9.26 %**	**-0.80 %**	**3.51 %**	**2.24 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		14.77 %	13.58 %	-4.76 %	-4.86 %	-7.35 %
ROCE			**6.43 %**	**32.74 %**	**13.68 %**	**-8.26 %**	**-67.55 %**

	2010	2011	2012	2013	2014	2015
OI (after tax)	31.89	73.33	279.72	225.48	-151.52	-618.75
Non core income (after tax)	0.85	-6.67	95.82	-14.64	90.92	61.49
Sales	583.47	935.97	889.51	955.25	1,028.50	908.51
NOA		852.54	1,034.81	1,826.47	2,591.56	2,746.96
NFO		-56.01	-79.23	437.18	1,169.27	1,733.42
CSE		908.55	1,114.04	1,389.29	1,422.29	1,013.54
NFE (before tax)	-10.01	-14.64	-19.05	-36.80	-100.55	-225.52
NFE (after tax)	-5.66	-8.27	-10.76	-20.79	-56.81	-127.42

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Profit margin (PM)	EBIT / Sales		41.10 %	28.94 %	41.29 %	-51.98 %	-120.18 %
Asset turnover (ATO)	Sales / NOA		1.10	0.86	0.52	0.40	0.33
Financial leverage (FLEV)	NFO / CSE		-0.06	-0.07	0.31	0.82	1.71
RNOA before tax	EBIT/NOA		45.12 %	24.87 %	21.60 %	-20.63 %	-39.75 %
Net borrowing cost	NFE / NFO		26 %	24 %	-8 %	-9 %	-13 %
ROCE			**40.73 %**	**21.39 %**	**25.74 %**	**-44.66 %**	**-129.98 %**

	2010	2011	2012	2013	2014	2015
Operating income before tax (EBIT)	64.29	384.66	257.38	394.44	-534.64	-1,091.85
Sales	583.47	935.97	889.51	955.25	1,028.50	908.51
NOA		852.54	1,034.81	1,826.47	2,591.56	2,746.96
NFO		-56.01	-79.23	437.18	1,169.27	1,733.42
CSE		908.55	1,114.04	1,389.29	1,422.29	1,013.54
NFE (before tax)	-10.01	-14.64	-19.05	-36.80	-100.55	-225.52
NFE (after tax)	-5.66	-8.27	-10.76	-20.79	-56.81	-127.42

*All balance sheet figures are averaged

PREMIER OIL

PROFITABILITY - After tax							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Core profit margin (PM)	OI (after tax) / Sales		22.89 %	21.47 %	17.45 %	-8.47 %	
Non-core profit margin	NCI / Sales		0.34 %	3.42 %	-2.32 %	4.85 %	
Asset turnover (ATO)	Sales / NOA		0.34	0.43	0.39	0.39	
Financial leverage (FLEV)	NFO / CSE		0.98	1.00	0.96	1.08	
Core RNOA	OI (after tax) / NOA		**7.81 %**	**9.24 %**	**6.73 %**	**-3.33 %**	
Non-Core RNOA	NCI (after tax) / NOA		**0.12 %**	**1.47 %**	**-0.89 %**	**1.90 %**	
Net borrowing cost (NBC)	NFE (after tax) / NFO		-3.02 %	-3.49 %	-1.77 %	-3.38 %	
ROCE			**12.71 %**	**17.92 %**	**9.76 %**	**-6.62 %**	
OI (after tax)		144.06	189.27	302.51	269.30	-138.27	
Non core income (after tax)		4.86	2.82	48.22	-35.74	79.11	
Sales		763.60	826.80	1,408.70	1,543.30	1,632.10	
NOA			2,423.25	3,273.80	4,002.10	4,156.45	
NFO			1,196.35	1,635.25	1,963.15	2,158.15	
CSE			1,226.90	1,638.55	2,038.95	1,998.30	
NFE (before tax)		-0.53	-68.10	-107.60	-65.40	-137.80	
NFE (after tax)		-0.28	-36.09	-57.03	-34.66	-73.03	

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Profit margin (PM)	EBIT / Sales		21.24 %	32.31 %	22.81 %	-15.20 %	
Asset turnover (ATO)	Sales / NOA		0.34	0.43	0.39	0.39	
Financial leverage (FLEV)	NFO / CSE		0.98	1.00	0.96	1.08	
RNOA before tax	EBIT/NOA		7.25 %	13.90 %	8.80 %	-5.97 %	
Net borrowing cost	NFE / NFO		-5.69 %	-6.58 %	-3.33 %	-6.39 %	
ROCE			**8.76 %**	**21.21 %**	**14.06 %**	**-19.31 %**	
Operating income before tax (EBIT)		127.70	175.60	455.20	352.00	-248.10	
Sales		763.60	826.80	1,408.70	1,543.30	1,632.10	
NOA			2,423.25	3,273.80	4,002.10	4,156.45	
NFO			1,196.35	1,635.25	1,963.15	2,158.15	
CSE			1,226.90	1,638.55	2,038.95	1,998.30	
NFE (before tax)		-0.53	-68.10	-107.60	-65.40	-137.80	
NFE (after tax)		-0.28	-36.09	-57.03	-34.66	-73.03	

*All balance sheet figures are averaged

SOCO INTERNATIONAL

PROFITABILITY - After tax							
Element	**Calculation**	2010	2011	2012	2013	2014	2015
Core profit margin (PM)	OI (after tax) / Sales		37.48 %	33.51 %	17.16 %	3.11 %	-16.95 %
Non-core profit margin	NCI / Sales		2.73 %	0.17 %	1.72 %	-0.15 %	2.65 %
Asset turnover (ATO)	Sales / NOA		0.26	0.65	0.68	0.54	0.28
Financial leverage (FLEV)	NFO / CSE		(0.16)	(0.16)	(0.21)	(0.20)	(0.17)
Core RNOA	OI (after tax) / NOA		**9.84 %**	**21.84 %**	**11.68 %**	**1.70 %**	**-4.68 %**
Non-Core RNOA	NCI (after tax) / NOA		**0.72 %**	**0.11 %**	**1.17 %**	**-0.08 %**	**0.73 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		0.82 %	1.39 %	0.59 %	0.54 %	0.71 %
ROCE			**8.79 %**	**18.18 %**	**10.05 %**	**1.19 %**	**-3.41 %**

OI (after tax)	11.45	87.75	208.30	104.35	13.95	-36.40
Non core income (after tax)	84.71	6.40	1.05	10.45	-0.65	5.70
Sales	48.39	234.10	621.60	608.10	448.20	214.80
NOA		891.55	953.95	893.25	822.75	778.40
NFO		-164.11	-183.40	-235.45	-205.20	-155.40
CSE		1,055.66	1,137.35	1,128.70	1,027.95	933.80
NFE (before tax)	-0.53	-2.70	-5.10	-2.80	-2.20	-2.20
NFE (after tax)	-0.26	-1.35	-2.55	-1.40	-1.10	-1.10

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	2010	2011	2012	2013	2014	2015
Profit margin (PM)	EBIT / Sales		67.02 %	72.10 %	54.89 %	34.05 %	1.30 %
Asset turnover (ATO)	Sales / NOA		0.26	0.65	0.68	0.54	0.28
Financial leverage (FLEV)	NFO / CSE		-0.16	-0.16	-0.21	-0.20	-0.17
RNOA before tax	EBIT/NOA		17.60 %	46.98 %	37.37 %	18.55 %	0.36 %
Net borrowing cost	NFE / NFO		2 %	3 %	1 %	1 %	1 %
ROCE			**14.61 %**	**38.96 %**	**29.33 %**	**14.63 %**	**0.06 %**

Operating income before tax (EBIT)	29.14	156.90	448.20	333.80	152.60	2.80
Sales	48.39	234.10	621.60	608.10	448.20	214.80
NOA		891.55	953.95	893.25	822.75	778.40
NFO		-164.11	-183.40	-235.45	-205.20	-155.40
CSE		1,055.66	1,137.35	1,128.70	1,027.95	933.80
NFE (before tax)	-0.53	-2.70	-5.10	-2.80	-2.20	-2.20
NFE (after tax)	-0.26	-1.35	-2.55	-1.40	-1.10	-1.10

*All balance sheet figures are averaged

NOSTRUM OIL & GAS

PROFITABILITY - After tax							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Core profit margin (PM)	OI (after tax) / Sales		28.30 %	26.98 %	28.75 %	21.50 %	-19.82 %
Non-core profit margin	NCI / Sales		0.00 %	0.00 %	-0.40 %	6.49 %	6.99 %
Asset turnover (ATO)	Sales / NOA		0.34	0.71	0.73	0.56	0.30
Financial leverage (FLEV)	NFO / CSE		0.63	0.62	0.60	0.59	0.78
Core RNOA	OI (after tax) / NOA		**9.60 %**	**19.14 %**	**21.12 %**	**12.07 %**	**-5.91 %**
Non-Core RNOA	NCI (after tax) / NOA		**0.00 %**	**0.00 %**	**-0.29 %**	**3.64 %**	**2.08 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		-1.02 %	-9.24 %	-7.54 %	-13.98 %	-5.64 %
ROCE			**15.03 %**	**25.31 %**	**28.74 %**	**16.73 %**	**-11.21 %**

	2010	2011	2012	2013	2014	2015
OI (after tax)	40.12	85.13	198.88	257.34	168.13	-88.97
Non core income (after tax)	-0.38	0.00	0.00	-3.54	50.71	31.38
Sales	178.16	300.84	737.07	895.01	781.88	448.90
NOA		886.93	1,039.08	1,218.25	1,393.11	1,505.56
NFO		343.98	398.92	454.48	518.05	659.85
CSE		542.95	640.17	763.78	875.07	845.72
NFE (before tax)	-21.06	-4.38	-46.09	-42.85	-90.53	-46.54
NFE (after tax)	-16.85	-3.50	-36.87	-34.28	-72.42	-37.23

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Profit margin (PM)	EBIT / Sales		50.98 %	44.56 %	45.73 %	43.34 %	17.63 %
Asset turnover (ATO)	Sales / NOA		0.34	0.71	0.73	0.56	0.30
Financial leverage (FLEV)	NFO / CSE		0.63	0.62	0.60	0.59	0.78
RNOA before tax	EBIT/NOA		17.29 %	31.61 %	33.60 %	24.32 %	5.26 %
Net borrowing cost	NFE / NFO		-1 %	-12 %	-9 %	-17 %	-7 %
ROCE			**27.44 %**	**44.11 %**	**47.98 %**	**28.38 %**	**3.85 %**

	2010	2011	2012	2013	2014	2015
Operating income before tax (EBIT)	82.30	153.35	328.46	409.30	338.83	79.14
Sales	178.16	300.84	737.07	895.01	781.88	448.90
NOA		886.93	1,039.08	1,218.25	1,393.11	1,505.56
NFO		343.98	398.92	454.48	518.05	659.85
CSE		542.95	640.17	763.78	875.07	845.72
NFE (before tax)	-21.06	-4.38	-46.09	-42.85	-90.53	-46.54
NFE (after tax)	-16.85	-3.50	-36.87	-34.28	-72.42	-37.23

*All balance sheet figures are averaged

TULLOW

PROFITABILITY - After tax							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Core profit margin (PM)	OI (after tax) / Sales		31.79 %	7.89 %	9.26 %	-54.70 %	-41.53 %
Non-core profit margin	NCI / Sales		-0.04 %	22.79 %	1.09 %	0.93 %	-8.40 %
Asset turnover (ATO)	Sales / NOA		0.33	0.32	0.35	0.28	0.21
Financial leverage (FLEV)	NFO / CSE		0.63	0.46	0.39	0.69	1.15
Core RNOA	OI (after tax) / NOA		**10.35 %**	**2.52 %**	**3.27 %**	**-15.14 %**	**-8.61 %**
Non-Core RNOA	NCI (after tax) / NOA		**-0.01 %**	**7.27 %**	**0.39 %**	**0.26 %**	**-1.74 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		-2.40 %	-1.63 %	-1.73 %	-3.11 %	-2.65 %
ROCE			**15.36 %**	**13.52 %**	**4.41 %**	**-27.28 %**	**-25.36 %**

OI (after tax)	151.97	732.40	184.97	245.06	-1,210.35	-667.24
Non core income (after tax)	-60.97	-0.91	534.28	28.95	20.68	-134.92
Sales	1,089.80	2,304.20	2,344.10	2,646.90	2,212.90	1,606.60
NOA		7,073.05	7,354.00	7,483.75	7,994.30	7,745.55
NFO		2,738.35	2,310.20	2,099.75	3,260.95	4,148.05
CSE		4,334.70	5,043.80	5,384.00	4,733.35	3,597.50
NFE (before tax)	-55.00	-86.30	-49.40	-47.90	-133.60	-144.80
NFE (after tax)	-41.80	-65.59	-37.54	-36.40	-101.54	-110.05

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Profit margin (PM)	EBIT / Sales		49.04 %	20.59 %	13.27 %	-66.98 %	-50.47 %
Asset turnover (ATO)	Sales / NOA		0.33	0.32	0.35	0.28	0.21
Financial leverage (FLEV)	NFO / CSE		0.63	0.46	0.39	0.69	1.15
RNOA before tax	EBIT/NOA		15.98 %	6.56 %	4.69 %	-18.54 %	-10.47 %
Net borrowing cost	NFE / NFO		-3 %	-2 %	-2 %	-4 %	-3 %
ROCE			**24.08 %**	**8.59 %**	**5.64 %**	**-34.14 %**	**-26.57 %**

Operating income before tax (EBIT)	261.40	1,130.00	482.70	351.30	-1,482.20	-810.90
Sales	1,089.80	2,304.20	2,344.10	2,646.90	2,212.90	1,606.60
NOA		7,073.05	7,354.00	7,483.75	7,994.30	7,745.55
NFO		2,738.35	2,310.20	2,099.75	3,260.95	4,148.05
CSE		4,334.70	5,043.80	5,384.00	4,733.35	3,597.50
NFE (before tax)	-55.00	-86.30	-49.40	-47.90	-133.60	-144.80
NFE (after tax)	-41.80	-65.59	-37.54	-36.40	-101.54	-110.05

*All balance sheet figures are averaged

FAROE PETROLEUM

PROFITABILITY - After tax							
Element	**Calculation**	2010	2011	2012	2013	2014	2015
Core profit margin (PM)	OI (after tax) / Sales		21.23 %	-2.39 %	17.51 %	-33.78 %	-34.90 %
Non-core profit margin	NCI / Sales		38.50 %	2.51 %	9.59 %	1.39 %	-1.18 %
Asset turnover (ATO)	Sales / NOA		0.70	0.77	0.49	0.48	0.48
Financial leverage (FLEV)	NFO / CSE		(0.44)	(0.11)	0.12	0.15	0.20
Core RNOA	OI (after tax) / NOA		**14.82 %**	**-1.84 %**	**8.67 %**	**-16.29 %**	**-16.89 %**
Non-Core RNOA	NCI (after tax) / NOA		**26.88 %**	**1.93 %**	**4.75 %**	**0.67 %**	**-0.57 %**
Net borrowing cost (NBC)	NFE (after tax) / NFO		1.31 %	11.00 %	-31.04 %	-28.09 %	-20.03 %
ROCE			**22.69 %**	**-1.08 %**	**11.31 %**	**-22.34 %**	**-24.86 %**

OI (after tax)	-19.67	17.04	-3.79	22.66	-45.21	-44.27
Non core income (after tax)	0.51	30.89	3.98	12.41	1.86	-1.50
Sales	15.09	80.23	158.79	129.39	133.81	126.85
NOA		114.91	206.79	261.51	277.54	262.09
NFO		-91.06	-24.47	27.86	37.01	43.18
CSE		205.98	231.26	233.66	240.54	218.91
NFE (before tax)	-0.86	-1.51	-3.41	-10.95	-13.16	-10.95
NFE (after tax)	-0.68	-1.19	-2.69	-8.65	-10.39	-8.65

*All balance sheet figures are averaged

PROFITABILITY - Before tax (Core operations only)							
Element	**Calculation**	2010	2011	2012	2013	2014	2015
Profit margin (PM)	EBIT / Sales		-30.16 %	-17.15 %	16.15 %	-114.66 %	-87.79 %
Asset turnover (ATO)	Sales / NOA		0.70	0.77	0.49	0.48	0.48
Financial leverage (FLEV)	NFO / CSE		-0.44	-0.11	0.12	0.15	0.20
RNOA before tax	EBIT/NOA		-21.06 %	-13.17 %	7.99 %	-55.28 %	-42.49 %
Net borrowing cost	NFE / NFO		2 %	14 %	-39 %	-36 %	-25 %
ROCE			**-12.48 %**	**-13.25 %**	**4.26 %**	**-69.25 %**	**-55.87 %**

Operating income before tax (EBIT)	-25.19	-24.20	-27.24	20.89	-153.42	-111.35
Sales	15.09	80.23	158.79	129.39	133.81	126.85
NOA		114.91	206.79	261.51	277.54	262.09
NFO		-91.06	-24.47	27.86	37.01	43.18
CSE		205.98	231.26	233.66	240.54	218.91
NFE (before tax)	-0.86	-1.51	-3.41	-10.95	-13.16	-10.95
NFE (after tax)	-0.68	-1.19	-2.69	-8.65	-10.39	-8.65

*All balance sheet figures are averaged

5.3.4 Peer Liquidity

LUNDIN PETROLEUM

LIQUIDITY - Short term	2010	2011	2012	2013	2014	2015
Current ratio	**1.49**	**0.74**	**0.78**	**0.77**	**1.02**	**1.28**
Current assets	285.0	298.0	335.8	378.4	659.2	541.5
Current liabilities	191.0	402.8	432.2	492.4	648.0	421.5
Quick ratio	**1.27**	**0.61**	**0.69**	**0.66**	**0.95**	**1.18**
Cash	48.7	73.6	97.4	92.7	80.5	71.9
Receivables	194.8	172.6	199.1	234.5	537.1	424.0
Short term investments	0.0	0.0	0.0	0.0	0.0	0.0
Current liabilities	191.0	402.8	432.2	492.4	648.0	421.5
Cash ratio	**0.25**	**0.18**	**0.23**	**0.19**	**0.12**	**0.17**
Cash	48.7	73.6	97.4	92.7	80.5	71.9
Current liabilities	191.0	402.8	432.2	492.4	648.0	421.5

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.59**	**0.60**	**0.62**	**0.71**	**0.91**	**1.10**
Total debt (current + long-term)	1431.4	1617.1	2043.6	3107.6	4626.3	5259.4
Total assets (Liabilities + total equity)	2429.1	2687.4	3293.7	4374.5	5092.0	4785.3
Debt to equity	**1.43**	**1.51**	**1.63**	**2.45**	**9.93**	**-11.09**
Total debt	1431.4	1617.1	2043.6	3107.6	4626.3	5259.4
Total equity	997.8	1070.3	1250.1	1266.8	465.7	-474.1
Long-term debt ratio	**0.55**	**0.53**	**0.56**	**0.67**	**0.90**	**1.11**
Long-term debt	1240.3	1214.3	1611.4	2615.2	3978.3	4837.9
Total equity	997.8	1070.3	1250.1	1266.8	465.7	-474.1

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-26.20**	**27.69**	**-25.64**	**-4.63**	**0.75**	**1.31**
Operating income (EBIT)	327.7	704.2	543.5	384.5	-314.2	-799.4
Net interest expense	-12.5	25.4	-21.2	-83.0	-420.0	-610.5
Interest coverage (after tax)	**1.28**	**1.28**	**1.28**	**1.28**	**1.28**	**1.28**
Operating income	168.8	135.4	120.4	148.2	-142.6	-369.4
Net interest expense	131.7	105.6	93.9	115.6	-111.2	-288.2
Interest coverage (before tax) EBITDA	**-37.82**	**34.18**	**-45.87**	**-8.22**	**-0.52**	**-0.36**
EBITDA	473.0	869.4	972.4	682.1	218.1	221.9
Net interest expense	-12.5	25.4	-21.2	-83.0	-420.0	-610.5

ENQUEST PLC

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**1.30**	**2.15**	**1.36**	**0.74**	**1.22**	**1.64**
Current assets	186.4	522.4	478.0	401.5	664.5	950.9
Current liabilities	143.3	242.9	351.0	541.5	543.3	579.3
Quick ratio	**1.21**	**2.10**	**1.32**	**0.66**	**1.06**	**1.52**
Cash	41.4	378.9	124.5	72.8	176.8	269.0
Receivables	132.6	129.2	241.7	273.5	297.4	355.5
Short term investments	0.0	2.5	96.5	8.5	100.9	258.7
Current liabilities	143.3	242.9	351.0	541.5	543.3	579.3
Cash ratio	**0.29**	**1.56**	**0.35**	**0.13**	**0.33**	**0.46**
Cash	41.4	378.9	124.5	72.8	176.8	269.0
Current liabilities	143.3	242.9	351.0	541.5	543.3	579.3

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.40**	**0.52**	**0.49**	**0.58**	**0.67**	**0.82**
Total debt (current + long-term)	578.1	1014.5	1250.9	2065.7	2736.0	3110.1
Total assets (Liabilities + total equity)	1461.0	1948.7	2544.8	3550.5	4095.9	3777.3
Debt to equity	**0.65**	**1.09**	**0.97**	**1.39**	**2.01**	**4.66**
Total debt	578.1	1014.5	1250.9	2065.7	2736.0	3110.1
Total equity	882.9	934.2	1293.9	1484.7	1359.9	667.2
Long-term debt ratio	**0.33**	**0.45**	**0.41**	**0.51**	**0.62**	**0.79**
Long-term debt	434.8	771.6	899.9	1524.2	2192.7	2530.8
Total equity	882.9	934.2	1293.9	1484.7	1359.9	667.2

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-6.42**	**-26.27**	**-13.51**	**-10.72**	**5.32**	**4.84**
Operating income (EBIT)	64.3	384.7	257.4	394.4	-534.6	-1091.9
Net interest expense	-10.0	-14.6	-19.1	-36.8	-100.6	-225.5
Interest coverage (after tax)	**1.77**	**1.77**	**1.77**	**1.77**	**1.77**	**1.77**
Operating income	31.9	73.3	279.7	225.5	-151.5	-618.7
Net interest expense	18.0	41.4	158.0	127.4	-85.6	-349.6
Interest coverage (before tax) EBITDA	**-24.33**	**-41.10**	**-32.44**	**-16.85**	**-3.87**	**-1.93**
EBITDA	243.6	601.9	618.0	620.1	388.7	435.3
Net interest expense	-10.0	-14.6	-19.1	-36.8	-100.6	-225.5

PREMIER OIL

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**1.39**	**0.90**	**0.99**	**1.55**	**1.13**	
Current assets	697.0	815.3	670.2	1018.5	1116.9	
Current liabilities	503.2	909.7	677.5	655.8	992.7	
Quick ratio	**1.35**	**0.87**	**0.94**	**1.48**	**1.10**	
Cash	299.7	309.1	187.4	448.9	291.8	
Receivables	313.0	429.4	438.4	504.2	468.9	
Short term investments	65.7	49.1	9.8	15.9	330.1	
Current liabilities	503.2	909.7	677.5	655.8	992.7	
Cash ratio	**0.60**	**0.34**	**0.28**	**0.68**	**0.29**	
Cash	299.7	309.1	187.4	448.9	291.8	
Current liabilities	503.2	909.7	677.5	655.8	992.7	

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.63**	**0.66**	**0.60**	**0.63**	**0.69**	
Total debt (current + long-term)	1895.7	2565.8	2890.1	3689.5	4215.4	
Total assets (Liabilities + total equity)	3025.9	3889.4	4843.6	5813.9	6087.6	
Debt to equity	**1.68**	**1.51**	**1.48**	**1.74**	**2.25**	
Total debt	1895.7	2565.8	2890.1	3689.5	4215.4	
Total equity	1130.2	1698.3	1953.5	2124.4	1872.2	
Long-term debt ratio	**0.55**	**0.49**	**0.53**	**0.59**	**0.63**	
Long-term debt	1392.5	1656.1	2212.6	3033.7	3222.7	
Total equity	1130.2	1698.3	1953.5	2124.4	1872.2	

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-1.95**	**-2.58**	**-4.23**	**-5.38**	**1.80**	
Operating income (EBIT)	127.7	175.6	455.2	352.0	-248.1	
Net interest expense	-65.5	-68.1	-107.6	-65.4	-137.8	
Interest coverage (after tax)	**-4.15**	**-5.24**	**-5.30**	**-7.77**	**1.89**	
Operating income	144.1	189.3	302.5	269.3	-138.3	
Net interest expense	-34.7	-36.1	-57.0	-34.7	-73.0	
Interest coverage (before tax) EBITDA	**-5.97**	**-5.22**	**-7.70**	**-13.98**	**-7.20**	
EBITDA	391.3	355.7	828.0	914.5	992.7	
Net interest expense	-65.5	-68.1	-107.6	-65.4	-137.8	

SOCO INTERNATIONAL

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**6.30**	**3.98**	**3.62**	**5.26**	**3.84**	**3.99**
Current assets	301.6	250.6	378.7	287.1	213.2	179.6
Current liabilities	47.9	63.0	104.5	54.6	55.5	45.0
Quick ratio	**5.95**	**3.82**	**3.52**	**5.12**	**3.73**	**3.92**
Cash	260.4	160.1	208.5	129.9	126.2	103.6
Receivables	24.7	80.3	72.8	69.8	40.7	20.2
Short term investments	0.0	0.0	86.3	80.1	40.2	52.7
Current liabilities	47.9	63.0	104.5	54.6	55.5	45.0
Cash ratio	**5.44**	**2.54**	**2.00**	**2.38**	**2.27**	**2.30**
Cash	260.4	160.1	208.5	129.9	126.2	103.6
Current liabilities	47.9	63.0	104.5	54.6	55.5	45.0

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.14**	**0.14**	**0.18**	**0.21**	**0.24**	**0.24**
Total debt (current + long-term)	163.0	179.8	260.5	281.7	306.8	288.6
Total assets (Liabilities + total equity)	1176.2	1277.9	1437.1	1362.5	1281.9	1181.1
Debt to equity	**0.16**	**0.16**	**0.22**	**0.26**	**0.31**	**0.32**
Total debt	163.0	179.8	260.5	281.7	306.8	288.6
Total equity	1013.2	1098.1	1176.6	1080.8	975.1	892.5
Long-term debt ratio	**0.10**	**0.10**	**0.12**	**0.17**	**0.20**	**0.21**
Long-term debt	115.1	116.8	156.0	227.1	251.3	243.6
Total equity	1013.2	1098.1	1176.6	1080.8	975.1	892.5

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-55.50**	**-58.11**	**-87.88**	**-119.21**	**-69.36**	**-1.27**
Operating income (EBIT)	29.1	156.9	448.2	333.8	152.6	2.8
Net interest expense	-0.5	-2.7	-5.1	-2.8	-2.2	-2.2
Interest coverage (after tax)	**-43.60**	**-65.00**	**-81.69**	**-74.54**	**-12.68**	**33.09**
Operating income	11.4	87.8	208.3	104.4	14.0	-36.4
Net interest expense	-0.3	-1.4	-2.6	-1.4	-1.1	-1.1
Interest coverage (before tax) EBITDA	**-67.02**	**-65.30**	**-96.76**	**-135.21**	**-119.68**	**-46.36**
EBITDA	35.2	176.3	493.5	378.6	263.3	102.0
Net interest expense	-0.5	-2.7	-5.1	-2.8	-2.2	-2.2

NOSTRUM OIL & GAS

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**1.91**	**1.48**	**2.79**	**2.49**	**4.02**	**3.07**
Current assets	172.4	179.3	351.1	334.8	509.6	334.3
Current liabilities	90.3	121.3	125.7	134.7	126.9	108.7
Quick ratio	**1.61**	**1.14**	**2.40**	**2.05**	**3.39**	**2.31**
Cash	144.2	125.4	197.7	184.9	375.4	165.6
Receivables	1.6	12.6	54.0	66.6	30.1	31.3
Short term investments	0.0	0.0	50.0	25.0	25.0	54.1
Current liabilities	90.3	121.3	125.7	134.7	126.9	108.7
Cash ratio	**1.60**	**1.03**	**1.57**	**1.37**	**2.96**	**1.52**
Cash	144.2	125.4	197.7	184.9	375.4	165.6
Current liabilities	90.3	121.3	125.7	134.7	126.9	108.7

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.56**	**0.55**	**0.57**	**0.53**	**0.58**	**0.65**
Total debt (current + long-term)	636.9	720.9	907.6	928.3	1290.5	1414.7
Total assets (Liabilities + total equity)	1137.6	1306.2	1602.7	1760.8	2208.2	2188.4
Debt to equity	**1.27**	**1.23**	**1.31**	**1.12**	**1.41**	**1.83**
Total debt	636.9	720.9	907.6	928.3	1290.5	1414.7
Total equity	500.7	585.2	695.1	832.5	917.7	773.8
Long-term debt ratio	**0.52**	**0.51**	**0.53**	**0.49**	**0.56**	**0.63**
Long-term debt	546.6	599.7	781.9	793.6	1163.7	1305.9
Total equity	500.7	585.2	695.1	832.5	917.7	773.8

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-3.91**	**-35.00**	**-7.13**	**-9.55**	**-3.74**	**-1.70**
Operating income (EBIT)	82.3	153.4	328.5	409.3	338.8	79.1
Net interest expense	-21.1	-4.4	-46.1	-42.9	-90.5	-46.5
Interest coverage (after tax)	**-2.38**	**-24.29**	**-5.39**	**-7.51**	**-2.32**	**2.39**
Operating income	40.1	85.1	198.9	257.3	168.1	-89.0
Net interest expense	-16.8	-3.5	-36.9	-34.3	-72.4	-37.2
Interest coverage (before tax) EBITDA	**-4.63**	**-39.44**	**-9.33**	**-12.33**	**-4.96**	**-4.01**
EBITDA	97.5	172.8	429.8	528.3	449.3	186.8
Net interest expense	-21.1	-4.4	-46.1	-42.9	-90.5	-46.5

TULLOW

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**0.90**	**0.76**	**1.05**	**1.44**	**1.56**	**1.16**
Current assets	1335.5	1172.4	1294.2	2069.3	2086.6	1841.0
Current liabilities	1485.7	1533.6	1228.8	1432.3	1339.2	1581.8
Quick ratio	**0.33**	**0.38**	**0.58**	**0.65**	**0.78**	**0.61**
Cash	338.3	307.1	330.2	352.9	319.0	355.7
Receivables	158.9	279.4	267.3	534.9	309.4	208.4
Short term investments	0.0	0.0	116.4	43.2	416.4	406.5
Current liabilities	1485.7	1533.6	1228.8	1432.3	1339.2	1581.8
Cash ratio	**0.23**	**0.20**	**0.27**	**0.25**	**0.24**	**0.22**
Cash	338.3	307.1	330.2	352.9	319.0	355.7
Current liabilities	1485.7	1533.6	1228.8	1432.3	1339.2	1581.8

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.54**	**0.55**	**0.43**	**0.53**	**0.65**	**0.72**
Total debt (current + long-term)	4509.1	5869.9	4060.2	6062.2	7401.4	8173.1
Total assets (Liabilities + total equity	8412.5	10635.9	9381.8	11508.6	11421.7	11347.8
Debt to equity	**1.16**	**1.23**	**0.76**	**1.11**	**1.84**	**2.57**
Total debt	4509.1	5869.9	4060.2	6062.2	7401.4	8173.1
Total equity	3903.4	4766.0	5321.6	5446.4	4020.3	3174.7
Long-term debt ratio	**0.44**	**0.48**	**0.35**	**0.46**	**0.60**	**0.67**
Long-term debt	3023.4	4336.3	2831.4	4629.9	6062.2	6591.3
Total equity	3903.4	4766.0	5321.6	5446.4	4020.3	3174.7

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**-4.75**	**-13.09**	**-9.77**	**-7.33**	**11.09**	**5.60**
Operating income (EBIT)	261.4	1130.0	482.7	351.3	-1482.2	-810.9
Net interest expense	-55.0	-86.3	-49.4	-47.9	-133.6	-144.8
Interest coverage (after tax)	**-3.64**	**-11.17**	**-4.93**	**-6.73**	**11.92**	**6.06**
Operating income	152.0	732.4	185.0	245.1	-1210.3	-667.2
Net interest expense	-41.8	-65.6	-37.5	-36.4	-101.5	-110.0
Interest coverage (before tax) EBITDA	**-11.51**	**-19.67**	**-21.78**	**-20.79**	**0.99**	**-1.58**
EBITDA	633.0	1697.4	1075.9	995.9	-131.7	228.9
Net interest expense	-55.0	-86.3	-49.4	-47.9	-133.6	-144.8

FAROE PETROLEUM

PROFITABILITY - After tax	2010	2011	2012	2013	2014	2015
Current ratio	**4.37**	**3.51**	**1.95**	**1.76**	**1.85**	**1.93**
Current assets	168.4	175.8	181.6	130.1	185.4	171.2
Current liabilities	38.5	50.1	93.2	74.0	100.0	88.9
Quick ratio	**4.35**	**3.42**	**1.90**	**1.69**	**1.81**	**1.86**
Cash	132.2	111.6	72.9	40.6	92.6	91.5
Receivables	35.6	59.9	103.9	84.6	82.4	63.2
Short term investments	0.0	0.0	0.0	0.0	6.1	10.6
Current liabilities	38.5	50.1	93.2	74.0	100.0	88.9
Cash ratio	**3.43**	**2.23**	**0.78**	**0.55**	**0.93**	**1.03**
Cash	132.2	111.6	72.9	40.6	92.6	91.5
Current liabilities	38.5	50.1	93.2	74.0	100.0	88.9

LIQUIDITY - Long term stock measures	2010	2011	2012	2013	2014	2015
Debt to total assets	**0.36**	**0.39**	**0.50**	**0.48**	**0.49**	**0.50**
Total debt (current + long-term)	99.7	149.7	229.2	220.2	237.4	195.9
Total assets (Liabilities + total equity)	280.9	380.5	460.9	455.8	482.9	388.2
Debt to equity	**0.55**	**0.65**	**0.99**	**0.93**	**0.97**	**1.02**
Total debt	99.7	149.7	229.2	220.2	237.4	195.9
Total equity	181.1	230.8	231.7	235.6	245.5	192.4
Long-term debt ratio	**0.25**	**0.30**	**0.37**	**0.38**	**0.36**	**0.36**
Long-term debt	61.2	99.6	136.0	146.2	137.4	107.0
Total equity	181.1	230.8	231.7	235.6	245.5	192.4

LIQUIDITY - Long term flow measures	2010	2011	2012	2013	2014	2015
Interest coverage (before tax) EBIT	**29.46**	**16.01**	**7.99**	**-1.91**	**11.66**	**10.17**
Operating income (EBIT)	-25.2	-24.2	-27.2	20.9	-153.4	-111.4
Net interest expense	-0.9	-1.5	-3.4	-10.9	-13.2	-10.9
Interest coverage (after tax)	**29.13**	**-14.27**	**1.41**	**-2.62**	**4.35**	**5.12**
Operating income	-19.7	17.0	-3.8	22.7	-45.2	-44.3
Net interest expense	-0.7	-1.2	-2.7	-8.6	-10.4	-8.6
Interest coverage (before tax) EBITDA	**16.70**	**7.48**	**-2.13**	**-4.58**	**6.12**	**2.58**
EBITDA	-14.3	-11.3	7.3	50.2	-80.5	-28.2
Net interest expense	-0.9	-1.5	-3.4	-10.9	-13.2	-10.9

6 Cost of capital

6.1 Cost of debt

DEBT

Credit facilities	Current	Max	Current (NOK)	Weight
RBL size (USDm)	2 170	2 900	18 030	80,41 %
RCF size (USDm)	0	550	0	0,00 %
DETNOR02	1 900	1 900	1 900	8,47 %
DETNOR03 (USDm)	300	300	2 493	11,12 %
Total	4 370	5 650	22 422	100 %
Available debt facilities (USDm)		1 280		
Available debt facilities (NOKm)		10 635		

Input figures	
USDNOK (31.03.2016)	8,3086
NIBOR 3m	1,0000 %
LIBOR 3m (ICE 3m)	0,6286 %

Pre-tax cost of debt	Base	Margin	Rate	Weighted rate
RBL cost	0,63 %	2,75 %	3,38 %	2,72 %
RCF cost	0,63 %	5,50 %	6,13 %	0,00 %
DETNOR02	1,00 %	6,50 %	7,50 %	0,64 %
DETNOR03	*Fixed at 10.25%*		10,25 %	1,14 %
	Pre-tax cost of debt			**4,49 %**
	Interest tax shield			25 %
	After-tax cost of debt			**3,37 %**

6.2 Beta ReOI

2) Damodaran beta

Industry Name	Number of firms	Levered Beta	D/E Ratio	Tax rate	Unlevered beta
US Oil/Gas (E&P)	351	1,6298	82,48 %	2,91 %	0,9050
Western Europe Oil/Gas (E&P)	133	2,0186	179,05 %	3,90 %	0,7419
Global Oil/Gas (E&P)	1029	1,8660			1,1282

1) Approximation from covariance with market (MSCI World)

Last 12 m	1,3996
Last 3 y	1,3693
Last 5 y	1,1424
Total	0,6626

3) Weighted portfolio beta of peers, relevered to Detnor

Company	**Market cap**	**Weight**	**Unlevered beta**	**Weighted beta (unl.)**
Lundin	483,96	7,6 %	0,8468	0,064
Enquest	406,40	6,4 %	0,7575	0,048
Premier Oil	515,40	8,1 %	0,7244	0,058
Soco International	630,30	9,9 %	1,3303	0,131
Nostrum Oil & Gas	854,20	13,4 %	0,3836	0,051
Tullow Oil	3 298,70	51,6 %	1,3309	0,687
Faroe Petroleum	199,80	3,1 %	1,2211	0,038
Total	**6 388,76**	**100 %**	**0,8468**	**1,079**

***) Summary**

Method	**Unlevered beta**	**D/E**	**Tax rate**	**Levered beta**	**Weighted**
Damodaran beta	0,95	142 %	27 %	1,9336	0,4834
Approximation from covariance with market (MSCI World)			27 %	1,3996	0,6998
Weighted portfolio beta of peers, relevered to Detnor	1,0787	142 %	27 %	2,1955	0,5489
					1,7321

6.3 Beta NAV

2) Damodaran beta

Industry Name	Number of firms	Levered Beta	D/E Ratio	Tax rate	Unlevered beta
US Oil/Gas (E&P)	351	1,6298	82,48 %	2,91 %	0,9050
Western Europe Oil/Gas (E&P)	133	2,0186	179,05 %	3,90 %	0,7419
Global Oil/Gas (E&P)	1029	1,8660			1,1282

1) Approximation from covariance with market (MSCI World)

Last 12 m	1,3996
Last 3 y	1,3693
Last 5 y	1,1424
Total	0,6626

3) Weighted portfolio beta of peers, relevered to Detnor

Company	Market cap	Weight	Unlevered beta	Weighted beta (unl.)
Lundin	483,96	7,6 %	0,8468	0,064
Enquest	406,40	6,4 %	0,7575	0,048
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Nostrum Oil & Gas	854,20	13,4 %	0,3836	0,051
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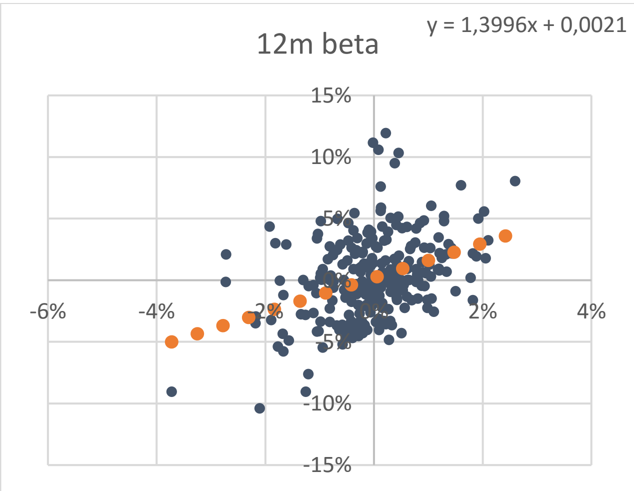
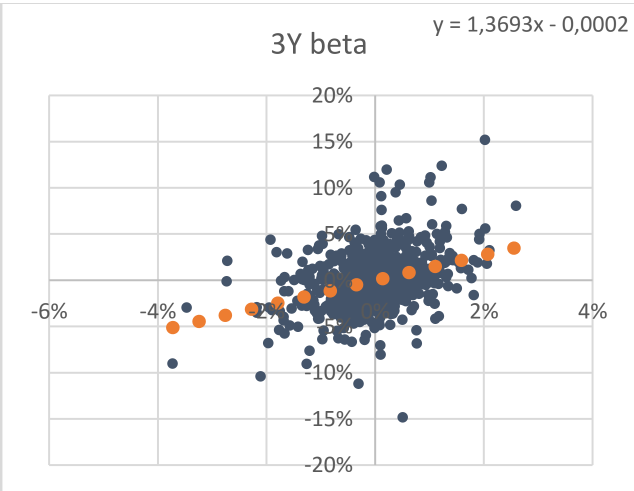
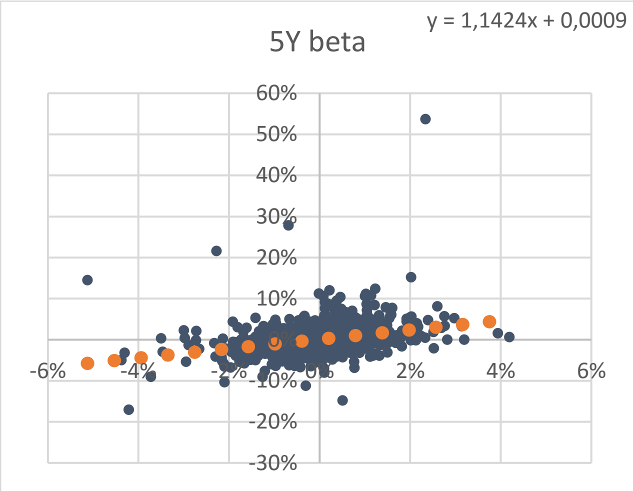
Faroe Petroleum	199,80	3,1 %	1,2211	0,038
Total	**6 388,76**	**100 %**	**0,8468**	**1,079**

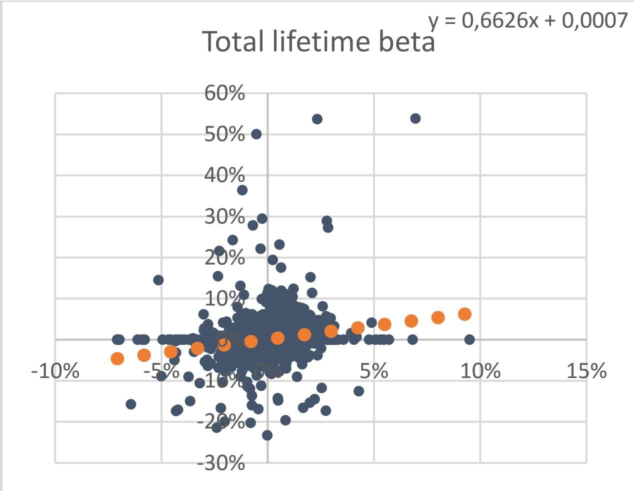
***) Summary**

Method	levered be	D/E	Tax rate	Levered beta	Weighted
Damodaran beta	0,95	174 %	27 %	2,1600	0,5400
Approximation from covariance with market (MSCI World)			27 %	1,3996	0,6998
Weighted portfolio beta of peers, relevered to Detnor	1,0787	174 %	27 %	2,4525	0,6131
					1,8530





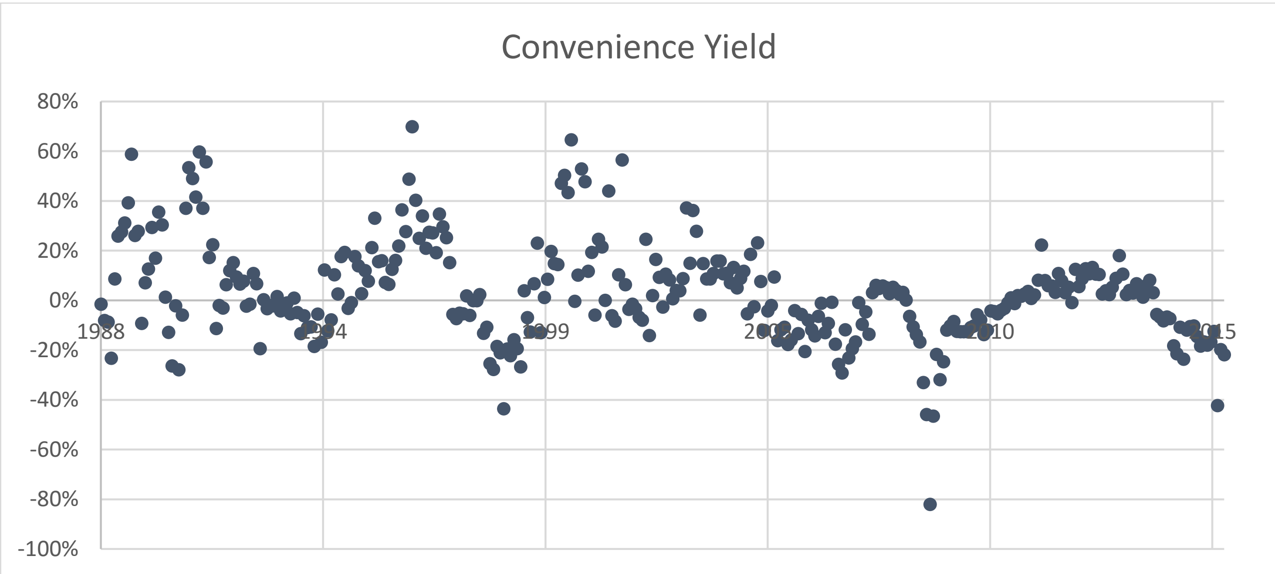




7 Testing of time series

7.1 Convenience yield

Convenience yield of oil price through the implicit relation between the futures price and the spot price of oil.



7.2 Testing for data analysis

Jarque-Bera test of normality

$$JB = \frac{T}{6}\left(\hat{S}^2 + \frac{1}{4}\left(\hat{K} - 3\right)^2\right) \quad , \quad JB \overset{a}{\sim} X^2(2)$$

Where as usual

$$\hat{S} = \frac{\frac{1}{T}\sum_{i=1}^{T}(R_i - \bar{R})^3}{\left(\frac{1}{T}\sum_{i=1}^{T}(R_i - \bar{R})^2\right)^{\frac{3}{2}}} \quad \text{and} \quad \hat{K}\,\frac{\frac{1}{T}\sum_{i=1}^{T}(R_i - \bar{R})^4}{\left(\frac{1}{T}\sum_{i=1}^{T}(R_i - \bar{R})^2\right)^{2}} \quad \text{and} \quad \bar{R} = \frac{1}{T}\sum_{i=1}^{T} R_i$$

And returns are defined as log returns.

7.3 R code for testing procedure

```
rm(list=ls())

'Required R packages for the analysis'

require(xlsx)

require(tseries)

require(car)

require(lmtest)

require(stats)

require(fBasics)

require(systemfit)

setwd("C:/Users/Gard/Dropbox/Master/Processes")

Long <<- read.xlsx("AllSeries.xlsx",1)

Medium<<-read.xlsx("AllSeries.xlsx",2)

Short<<-read.xlsx("AllSeries.xlsx",3)

TEST<<-read.xlsx("AllSeries.xlsx",4)

Daily<<-read.xlsx("DailySeries.xlsx",1)

"Testing mean reversion in oil prices"

#Oil prices - Long term

PriceL=Long[,8]

plot(PriceL)

adf.test(PriceL)
```

```
kpss.test(PriceL)

PriceEL=Long[,9]

plot(PriceEL)

adf.test(PriceEL)

kpss.test(PriceEL)

#Oil prices - Medium term

PriceM=Medium[,8]

plot(PriceM)

adf.test(PriceM)

kpss.test(PriceM)

PriceEM=Medium[,9]

plot(PriceEM)

adf.test(PriceEM)

kpss.test(PriceEM)

#Oil prices - Short term

PriceS=Short[,8]

plot(PriceS)

adf.test(PriceS)

kpss.test(PriceS)

PriceES=Short[,9]

plot(PriceES)

adf.test(PriceES)

kpss.test(PriceES)

"1: Testing stationarity of Log Return of spot prices"

#Long Series

BLogRetLong=Long[,2]
```

```
ELogRetLong=Long[,3]

plot(BLogRetLong)

plot(ELogRetLong)

adf.test(BLogRetLong)

adf.test(ELogRetLong)

kpss.test(BLogRetLong)

kpss.test(ELogRetLong)

#Medium Series

BLogRetMed=Medium[,2]

ELogRetMed=Medium[,3]

plot(BLogRetMed)

plot(ELogRetMed)

adf.test(BLogRetMed)

adf.test(ELogRetMed)

kpss.test(BLogRetMed)

kpss.test(ELogRetMed)

#Short Series

BLogRetShort=Short[,2]

ELogRetShort=Short[,3]

plot(BLogRetMed)

plot(ELogRetMed)

adf.test(BLogRetShort)

adf.test(ELogRetShort)

kpss.test(BLogRetShort)

kpss.test(ELogRetShort)

"2: Testing First Order Correlation in Residuals in log return spot prices"
```

```
#Long Series

dwt(BLogRetLong)

dwt(ELogRetLong)

pacf(BLogRetLong)

#Medium Series

dwt(BLogRetMed)

dwt(ELogRetMed)

#Short Series

dwt(BLogRetShort)

dwt(ELogRetShort)

"2: Testing Normality of Log Return of spot prices"

jarque.bera.test(BLogRetLong)

jarque.bera.test(BLogRetMed)

jarque.bera.test(BLogRetShort)

jarque.bera.test(ELogRetLong)

jarque.bera.test(ELogRetMed)

jarque.bera.test(ELogRetShort)

"3: Testing Mean Reversion of Convenience yield (Bloomberg Only)"

CYLong=Long[,4]

CYMed=Medium[,4]

CYShort=Short[,4]

plot(CYLong)

plot(CYMed)

plot(CYShort)

adf.test(CYLong)

adf.test(CYMed)
```

adf.test(CYShort)

kpss.test(CYLong)

kpss.test(CYMed)

kpss.test(CYShort)

8 NAV Valuation

Shares (million)	202,618602			Unrisked value				Risked value			
Assets	WI%	Prob./ valuation risk %	Implied risked value NOK/bbl	Reported net mmboe	Value NOKm	NOK per share	NOK/bbl	Reported net mmboe	Value NOKm	NOK per share	NOK/bbl
Producing fields											
Alvheim	65 %	100 %		85	6 506	32,11	76	85	6 506	32,11	76
Bøyla	65 %	100 %		11	2 450	12,09	216	11	2 450	12,09	216
Volund	65 %	100 %		19	1 697	8,38	90	19	1 697	8,38	90
Vilje	47 %	100 %		7	694	3,43	101	7	694	3,43	101
Varg	5 %	100 %		0	3	0,02	46	0	3	0,02	46
Enoch	2 %	100 %		0	0	0,00	0	0	0	0,00	0
Jotun	7 %	100 %		0	-61	-0,30	-1 572	0	-61	-0,30	-1 572
Atla	10 %	100 %		0	22	0,11	53	0	22	0,11	53
Jette	70 %	100 %		0	7	0,03	39	0	7	0,03	39
Sum producing fields				123	11 318	55,86	92	123	11 318	55,86	92
Fields under development											
Ivar Aasen	35 %	100 %		64	7 152	35,30	111	64	7 152	35,30	111
Gina Krog	3 %	100 %		7	889	4,39	122	7	889	4,39	122
Johan Sverdrup phase 1	12 %	100 %		215	13 568	66,96	63	215	13 568	66,96	63
Johan Sverdrup phase 2	12 %	100 %		130	6 656	32,85	51	130	6 656	32,85	51
Hanz	35 %	100 %		6	306	1,51	48	6	306	1,51	48
Sum fields under development				423	28 571	141,01	395	423	28 571	141,01	395
Planned, but not sanctioned fields											
Garantiana (34/6-2S)	30 %	70 %		34	2 423	11,96	71	24	1 696	8,37	50
BoaKamSouth/West	61 %	75 %		4	179	0,88	49	3	134	0,66	37
Attic Oil 1	62 %	75 %		4	188	0,93	43	3	141	0,70	32
Caterpillar	65 %	75 %		5	385	1,90	74	4	289	1,43	56
Krafla	50 %	70 %		100	5 907	29,15	59	70	4 135	20,41	41
Sum planned, but not sanctioned fields				113	9 083	44,83	296	80	6 395	31,56	216
Non-developed assets											
Frigg/Gamma/Delta	60 %	15 %		48	3 020	14,91	63	7	453	2,24	9
Frøy	100 %	15 %		25	2 015	9,94	80	4	302	1,49	12
Gekko	65 %	20 %		12	-619	-3,06	-50	2	-124	-0,61	-10
Grevling	30 %	10 %		15	646	3,19	44	1	65	0,32	4
Gohta	60 %	10 %		78	2 778	13,71	35	8	278	1,37	4
P-Grabben	20 %	15 %		3	97	0,48	37	0	14	0,07	5
Ragnarock basement	58 %	15 %		8	148	0,73	18	1	22	0,11	3
Ragnarock basement North	58 %	15 %		12	389	1,92	32	2	58	0,29	5
Steinbit	50 %	10 %		16	-103	-0,51	-6	2	-10	-0,05	-1
Storklakken	100 %	16 %		11	103	0,51	9	2	17	0,08	2
Skalle	10 %	10 %		1	-185	-0,91	-192	0	-18	-0,09	-19
Trell	50 %	10 %		5	111	0,55	23	0	11	0,05	2
Sum Non-developed assets				235	8 401	41,46	93	30	1 068	5,27	16
Sum petroleum assets					57 372	283,15			47 352	233,70	
NPV of NWC					818	4,04			818	4,04	
NPV of other operating costs					-6 122	-30,21			-6 122	-30,21	
Other assets					145	0,72			145	0,72	
Reserves and resources					52 069	257,70			42 049	208,24	
Net Financial Obligations					-26 729	-131,92			-26 729	-131,92	
Core NAV					25 340	125,78			15 320	76,33	
Price/Core NAV						**2,08**				**1,26**	

Alvheim:

We have incorporated the two tie ins ViperKobra[3] and BoaKamNorth[4] in the Alveim estimates.

Production: Alvheim reached peak production in Q1 2009[5] and have since had an average decline rate of -3,34% per quarter. We assume that the future decline rate will give full depletion when the field shuts down in 2032[6]. This gives a future decline rate of -3.3% which seems reasonable. The ViperKobra tie-in is expected to start up in late 2016 or early 2017[7], where we have used production start in 2017. We have used the same date for BoaKamNorth. We have used the production profile for Bøyla on these fields.

CAPEX: NPD estimate for Alvheim is 3978 mill NOK in 2015-kroner[8]. These capital expenditures include the development of Viper/Kobra and BoaKamNorth which will come in production Q1 2017. Therefore we assume that the CAPEX will occur before 2017. We know that total CAPEX for Alvheim field was 3,461 billion NOK in 2015[9] and forecasted for 2016 is 3,3 billion NOK[10]. The CAPEX for 2016 is only for Viper/Kobra, BoaKamNorth and Volund Infill. So we estimate 1/3 on each project. We also know that Viper/Kobra has an estimated total CAPEX of 1,8 billion NOK[11] so the rest occurred in 2015. We will handel all future CAPEX on the Alvheim fields from 2017 in separate project evaluations (tie-in projects).

OPEX: Detnor's guidance for 2016 gives a opex of 8-9 USD per boe, with an exchange rate of 8,8 USD/NOK. We will use a OPEX of 8 USD/boe.

ALVHEIM	2016	2017	2018	2019	2020	2021	2022	2023
Barrels (boe)	10 236 210	12 628 818	11 963 995	10 038 597	7 221 201	5 212 191	4 554 037	3 978 990
Revenue	3 359 243 599	4 818 075 197	4 945 232 519	4 354 463 791	3 215 732 275	3 306 447 564	2 889 168 647	2 524 503 164
OPEX	678 128 138	836 634 721	792 590 741	665 044 219	478 405 612	345 319 273	301 729 274	263 645 567
Tax	1 410 112 412	2 543 269 482	2 779 839 946	2 473 088 686	1 791 548 739	2 120 131 942	2 018 202 711	1 763 468 925
Capex	1 458 062 500	-	-	-	-	-	-	-
Decomission costs	-	-	-	-	-	-	-	-
Tax refund	-	-	-	-	-	-	-	-
FCF	(187 059 451)	1 438 170 995	1 372 801 831	1 216 330 886	945 777 924	840 996 349	569 236 662	497 388 671
NPV	**6 506 201 066**							
NPV per share	**32,11**							
EBITDA	2 681 115 460	3 981 440 476	4 152 641 777	3 689 419 572	2 737 326 663	2 961 128 291	2 587 439 373	2 260 857 596
CAPEX	1 458 062 500	-	-	-	-	-	-	-
Depreciation	763 410 972	616 727 639	489 977 639	464 302 639	440 469 306	243 010 417	-	-
Uplift	161 692 621	153 219 871	145 354 871	80 193 438	-	-	-	-
Corporate tax	479 426 122	841 178 209	915 666 035	806 279 233	574 214 339	679 529 469	646 859 843	565 214 399
Special tax	930 686 290	1 702 091 272	1 864 173 912	1 666 809 452	1 217 334 399	1 440 602 474	1 371 342 867	1 198 254 526
Total tax	1 410 112 412	2 543 269 482	2 779 839 946	2 473 088 686	1 791 548 739	2 120 131 942	2 018 202 711	1 763 468 925
Accounting depreciation	754 441 584	933 334 518	881 784 860	739 876 861	532 225 714	385 207 729	335 647 179	293 264 323
Tax accounting	1 417 108 535	2 296 316 116	2 474 230 314	2 258 140 792	1 719 978 740	2 009 218 039	1 756 397 911	1 534 722 753

[3] Detnor (2015): «To små funn tilknyttes Alvheim»
[4] Detnor (2015): «Videreutvikling i Alvheimområdet»
[5] NPD (2016): «Factpages»
[6] Lundin Petroleum «Norway – Alvheim & Volund»
[7] Detnor (2015): «To små funn tilknyttes Alvheim»
[8] NPD (2016): «Factpages»
[9] Detnor (2015): "Aker Investor Day"
[10] Detnor (2016): "Capital Markets Day 2016"
[11] Detnor (2015): "Aker Investor Day"

ALVHEIM	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Barrels (boe)	3 476 555	3 037 563	2 654 004	2 318 877	2 026 068	1 770 232	1 546 701	1 351 396	1 180 753	-
Revenue	2 206 187 310	1 927 898 847	1 684 420 080	1 471 724 910	1 285 887 194	1 123 515 587	981 646 975	857 692 402	749 389 828	-
OPEX	230 402 367	201 339 413	175 911 797	153 699 054	134 291 160	117 333 941	102 517 944	89 572 793	78 262 253	-
Tax	1 541 112 255	1 346 716 359	1 176 636 461	1 028 060 167	898 244 906	784 821 684	685 720 644	599 133 295	523 479 508	
Capex	-	-	-	-	-	-	-	-	-	
Decomission costs	-	-	-	-	-	-	-	-	-	1 178 240 233
Tax refund	-	-	-	-	-	-	-	-	-	919 027 382
FCF	434 672 687	379 843 076	331 871 822	289 965 688	253 351 127	221 359 962	193 408 387	168 986 314	147 648 066	(259 212 851)
NPV										
NPV per share										
EBITDA	1 975 784 943	1 726 559 434	1 508 508 283	1 318 025 856	1 151 596 034	1 006 181 646	879 129 031	768 119 609	671 127 574	-
CAPEX	-	-	-	-	-	-	-	-	-	-
Depreciation	-	-	-	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-	-	-	-
Corporate tax	493 946 236	431 639 859	377 127 071	329 506 464	287 899 008	251 545 412	219 782 258	192 029 902	167 781 894	-
Special tax	1 047 166 020	915 076 500	799 509 390	698 553 704	610 345 898	533 276 272	465 938 386	407 103 393	355 697 614	-
Total tax	1 541 112 255	1 346 716 359	1 176 636 461	1 028 060 167	898 244 906	784 821 684	685 720 644	599 133 295	523 479 508	-
Accounting depreciation	256 233 237	224 491 506	195 608 591	170 908 694	149 327 703	130 829 245	113 996 849	99 602 233	87 025 256	-
Tax accounting	1 341 250 331	1 171 612 984	1 024 061 760	894 751 386	781 769 298	682 774 873	596 803 102	521 443 553	455 599 809	-

Volund:

Production: The Volund field reached end of plateau production in Q2 2013[12] and has declined with an average of 11% since. A decline rate of 5,59 % will give 100% depletion taken into account previous production, and 2028 as abandonment year[13]. Volund Infill has total reserves of 12 mmboe[14]. The production profile is estimated using the Bøyla production profile.

CAPEX: NPD estimates that CAPEX on Volund in the future would be 1.835 billion NOK in 2015-kroner[15]. Since the Volund Infill has production start in 2017, we assume that this money has been used in 2015: 865.38 million NOK and 2016: 1,1 billion NOK.

OPEX: We assume that we have the same OPEX as the Alvheim field of 8 USD/boe.

VOLUND	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	2 126 475	4 016 907	3 963 067	3 094 370	1 640 307	673 090	534 756	424 853	337 537	268 166	327 773	260 409	206 889	-
Revenue	802 471 412	1 749 756 055	1 867 960 912	1 531 569 289	836 341 593	490 990 440	390 108 962	309 952 608	246 302 092	195 711 482	239 207 866	190 045 692	150 987 364	-
OPEX	155 239 881	277 525 163	271 612 585	212 201 926	114 394 018	49 141 008	39 043 347	31 021 044	24 650 697	19 587 428	23 940 685	19 020 378	15 111 296	-
Tax	232 770 259	881 416 460	1 016 766 625	828 129 253	391 336 079	249 868 494	273 831 180	217 566 621	172 888 088	137 376 762	167 908 401	133 399 745	105 983 333	-
Capex	729 031 250	-	-	-	-	-	-	-	-	-	-	-	-	
Decomission cost	-	-	-	-	-	-	-	-	-	-	-	-	-	265 241 281
Tax refund	(314 569 978)	590 814 431	579 581 702	491 238 110	330 611 496	191 980 937	77 234 435	61 364 944	48 763 307	38 747 292	47 358 780	37 625 569	29 892 735	206 888 200
FCF	(314 569 978)	590 814 431	579 581 702	491 238 110	330 611 496	191 980 937	77 234 435	61 364 944	48 763 307	38 747 292	47 358 780	37 625 569	29 892 735	(58 353 082)
NPV	**1 697 176 887**													
NPV per share	**8,38**													
EBITDA	647 231 531	1 472 230 891	1 596 348 327	1 319 367 363	721 947 575	441 849 432	351 065 615	278 931 565	221 651 395	176 124 054	215 267 181	171 025 314	135 876 068	-
CAPEX	729 031 250	-	-	-	-	-	-	-	-	-	-	-	-	
Depreciation	294 226 319	290 542 986	243 417 986	230 417 986	220 234 653	121 505 208	-	-	-	-	-	-	-	
Uplift	80 327 935	76 037 935	72 677 435	40 096 719	-	-	-	-	-	-	-	-	-	-
Corporate tax	88 251 303	295 421 976	338 232 585	272 237 344	125 428 230	80 086 056	87 766 404	69 732 891	55 412 849	44 031 013	53 816 795	42 756 329	33 969 017	-
Special tax	144 518 956	585 994 484	678 534 040	555 891 909	265 907 849	169 782 438	186 064 776	147 833 729	117 475 239	93 345 748	114 091 606	90 643 417	72 014 316	-
Total tax	232 770 259	881 416 460	1 016 766 625	828 129 253	391 336 079	249 868 494	273 831 180	217 566 621	172 888 088	137 376 762	167 908 401	133 399 745	105 983 333	-
Accounting depreciation	157 091 815	281 604 905	274 852 654	214 730 951	115 754 879	49 860 272	39 504 721	31 385 682	24 935 274	19 864 834	24 213 966	19 237 494	15 283 790	-
Tax accounting	339 735 173	888 388 164	992 247 584	840 365 140	472 830 303	305 751 545	243 017 498	193 085 789	153 438 574	121 882 191	149 021 508	118 394 500	94 061 976	

12 NPD (2016): «Factpages»
13 Lundin Petroleum «Norway – Alvheim & Volund»
14 Detnor (2016): "Capital Markets Day 2016"
15 NPD (2016): «Factpages»

Vilje:

Production: Estimated life of the field is 2030[16] and the production of the field is in decline. We will use a decline rate of 7.21% which yields full depletion in 2030.

CAPEX: No expected future CAPEX[17].

OPEX: We assume that we have the same OPEX as the Alvheim field of 8 USD/boe.

VILJE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Barrels (boe)	1 806 756	1 339 287	992 767	735 905	545 501	404 361	299 739	222 186	164 699	122 086	90 498	67 083	49 726	36 861	27 323	-
Revenue	658 469 486	563 700 119	452 176 572	351 971 643	268 724 911	284 855 535	211 165 255	156 539 256	116 061 320	86 045 298	63 780 965	47 278 653	35 046 052	25 978 443	19 256 933	-
OPEX	119 693 913	88 725 142	65 768 857	48 752 739	36 139 519	26 789 833	19 859 322	14 721 946	10 915 144	8 092 246	5 998 367	4 446 385	3 295 953	2 443 178	1 811 044	-
Tax	340 989 241	301 233 504	250 056 900	223 279 127	181 416 606	201 291 247	149 218 628	110 617 502	82 014 018	60 803 381	45 070 427	33 409 169	24 765 077	18 357 507	13 607 793	-
Capex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48 768 920
Tax refund																38 039 758
FCF	197 786 332	173 741 473	136 350 816	79 939 777	51 168 786	56 774 454	42 087 305	31 199 808	23 132 159	17 149 671	12 712 172	9 423 099	6 985 022	5 177 758	3 838 096	(10 729 162)
NPV	**694 151 821**															
NPV per share	**3,43**															
EBITDA	538 775 573	474 974 977	386 407 715	303 218 904	232 585 393	258 065 702	191 305 933	141 817 310	105 146 176	77 953 052	57 782 598	42 832 268	31 750 099	23 535 265	17 445 889	-
CAPEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	86 850 573	84 974 413	65 821 947	16 963 613	-	-	-	-	-	-	-	-	-	-	-	-
Uplift	21 721 242	5 597 992	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate tax	112 981 250	97 500 141	80 146 442	71 563 823	58 146 348	64 516 425	47 826 483	35 454 328	26 286 544	19 488 263	14 445 650	10 708 067	7 937 525	5 883 816	4 361 472	-
Special tax	228 007 991	203 733 363	169 910 457	151 715 304	123 270 258	136 774 822	101 392 145	75 163 174	55 727 473	41 315 118	30 624 777	22 701 102	16 827 552	12 473 690	9 246 321	-
Total tax	340 989 241	301 233 504	250 056 900	223 279 127	181 416 606	201 291 247	149 218 628	110 617 502	82 014 018	60 803 381	45 070 427	33 409 169	24 765 077	18 357 507	13 607 793	-
Accounting depreciation	64 987 986	48 305 358	35 709 280	26 470 071	19 621 360	14 584 493	10 781 449	7 991 920	5 924 138	4 403 392	3 255 166	2 412 944	1 788 633	1 329 485	982 809	-
Tax accounting	358 042 059	329 835 367	273 544 780	215 864 090	166 111 945	189 915 343	140 809 098	104 383 804	77 393 190	57 368 735	42 531 397	31 527 073	23 369 944	17 320 508	12 841 202	-

Bøyla:

Production: Bøyla has only produced for one year and reached a top production of 17 000 boepd[18]. Already the first year are 23% of the reserves depleted. We assume that this is peak year and that production declines from this point. We know that Bøyla is expected to produce until 2030[19] so we use a decline rate of -6.85% that gives full depletion and production until 2030.

CAPEX: All CAPEX associated with Bøyla has occurred before 2016[20].

OPEX: We assume that we have the same OPEX as the Alvheim field of 8 USD/boe.

BØYLA	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Barrels (boe)	2 843 551	2 141 090	1 612 162	1 213 899	914 022	688 225	518 208	390 192	293 800	221 221	166 571	125 422	94 438	71 108	53 542	-
Revenue	987 278 301	858 566 855	699 561 611	553 118 756	428 957 764	461 888 297	347 808 089	261 902 928	197 244 302	148 540 191	111 842 739	84 213 491	63 409 679	47 745 169	35 950 366	-
OPEX	188 379 463	141 843 051	106 802 526	80 419 270	60 554 070	45 596 431	34 334 058	25 853 885	19 471 075	14 663 223	11 040 615	8 313 179	6 259 520	4 713 189	3 548 859	-
Tax	59 703 642	31 495 534	22 497 084	50 732 099	244 851 381	324 707 655	244 509 744	184 118 254	138 663 117	104 424 035	78 625 657	59 202 244	44 577 124	33 564 944	25 273 175	-
Capex	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146 995 574
Tax refund																114 656 548
FCF	739 195 197	685 228 270	570 262 001	421 967 387	123 552 313	91 584 210	68 964 287	51 930 790	39 110 110	29 452 933	22 176 467	16 698 069	12 573 035	9 467 035	7 128 331	(32 339 026)
NPV	**2 450 151 756**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NPV per share	**12,09**															
EBITDA	798 898 838	716 723 804	592 759 085	472 699 486	368 403 694	416 291 866	313 474 031	236 049 043	177 773 227	133 876 968	100 802 124	75 900 313	57 150 159	43 031 980	32 401 507	-
CAPEX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	599 950 000	590 741 667	545 891 667	407 658 333	54 491 667	-	-	-	-	-	-	-	-	-	-	-
Uplift	180 144 250	134 527 250	17 982 250	-	-	-	-	-	-	-	-	-	-	-	-	-
Corporate tax	49 737 210	31 495 534	11 716 855	16 260 288	78 478 007	104 072 966	78 368 508	59 012 261	44 443 307	33 469 242	25 200 531	18 975 078	14 287 540	10 757 995	8 100 377	-
Special tax	9 966 432	-	10 780 230	34 471 811	166 373 375	220 634 689	166 141 237	125 105 993	94 219 811	70 954 793	53 425 126	40 227 166	30 289 584	22 806 949	17 172 799	-
Total tax	59 703 642	31 495 534	22 497 084	50 732 099	244 851 381	324 707 655	244 509 744	184 118 254	138 663 117	104 424 035	78 625 657	59 202 244	44 577 124	33 564 944	25 273 175	-
Accounting depreciation	694 919 332	524 682 398	393 987 237	296 657 979	223 372 608	168 652 202	126 641 975	95 356 775	71 800 164	54 211 015	40 707 384	30 651 171	23 079 211	17 425 412	13 084 849	-
Tax accounting	(14 372 437)	78 492 854	145 511 449	137 312 376	113 124 247	193 158 938	145 729 004	109 739 969	82 658 990	62 139 444	46 873 897	35 294 330	26 575 340	19 973 123	15 066 993	-

[16] Detnor (2014): «Styrets Årsberetning»
[17] NPD (2016): «Factpages»
[18] NPD (2016): «Factpages»
[19] Lundin Petroleum «Norway – Bøyla»
[20] NPD (2016): «Factpages»

<u>Atla:</u>

<u>Production</u>: In Detnor's annual report for 2015 it says that Alta is planning to shut down between 2018-2020[21]. We assume that the last year of production is 2017 and that the estimates recoverable also reflects this. We have therefore used a decline rate of 1.21% which yields full depletion.

<u>CAPEX</u>: In NPD it says that from 1.1.2015 that there are future CAPEX of 15 million in the Atla field[22]. We assume that these was in 2015 and there isn't any more CAPEX for the field.

<u>OPEX</u>: Detnor's guidance for 2016 gives a opex of 8-9 USD per boe, with an exchange rate of 8,8 USD/NOK. Atla is a subsea development[23], and we don't believe that OPEX will be any more than the estimated 8 USD/boe.

ATLA	2016	2017	2018
Barrels (boe)	16 462	15 678	-
Revenue	6 435 570	7 217 323	-
OPEX	13 843 042	13 184 246	-
Tax	-	-	-
Capex	-	-	-
Decomission cost	-	-	17 618 647
Tax refund			57 415 573
FCF	(7 407 472)	(5 966 923)	39 796 926
NPV	**21 542 397**		
NPV per share	**0,11**		
EBITDA	(7 407 472)	(5 966 923)	-
CAPEX	-	-	-
Depreciation	23 633 333	18 233 333	250 000
Uplift	-	-	-
Corporate tax	-	-	-
Special tax	-	-	-
Total tax	-	-	-
Accounting depreciation	1 356 793	1 295 761	-
Tax accounting	(6 836 127)	(5 664 894)	-

<u>Jette:</u>

<u>Production</u>: Jette is expected to shut down at the end of 2016 when the Jotun field also shut downs, since they are connected[24]. We assume that production continues to decline until full depletion.

<u>CAPEX</u>: There is no further expected CAPEX on Jette[25].

<u>OPEX</u>: Detnor's guidance for 2016 gives a opex of 8-9 USD per boe, with an exchange rate of 8,8 USD/NOK. We will use 8 USD/boe.

[21] Detnor (2016): "Årsrapport 2016"
[22] NPD (2016): «Factpages»
[23] NPD (2016): «Factpages»
[24] Detnor (2016): "Årsrapport 2016"
[25] NPD (2016): «Factpages»

JETTE	2016	2017
Barrels (boe)	170 830	-
Revenue	60 093 155	-
OPEX	11 317 169	-
Tax	-	-
Capex	-	-
Decomission cost		176 056 338
Tax refund		132 042 254
FCF	48 775 985	(44 014 085)
NPV	**6 675 648**	
NPV per share	**0,03**	
EBITDA	48 775 985	-
CAPEX	-	-
Depreciation	415 566 667	384 883 333
Uplift	-	-
Corporate tax	-	-
Special tax	(39 575 731)	-
Total tax	(39 575 731)	-
Accounting depreciation	12 512 779	-
Tax accounting	28 285 301	-

Jotun:

Production: Jotun is expected to shut down at the end of 2016[26]. We assume that production continues to decline until full depletion.

CAPEX: From 2015 NPD expects there to be 36 mill NOK in CAPEX[27], but we assume that this occurs in 2015 since 2016 is the last year of production. Therefore, there is no more CAPEX in 2016.

OPEX: Detnor’s guidance for 2016 gives a opex of 8-9 USD per boe, with an exchange rate of 8,8 USD/NOK. We will use 8 USD/boe.

JOTUN	2016	2017
Barrels (boe)	38 744	-
Revenue	13 645 136	-
OPEX	2 566 684	-
Tax	7 843 157	-
Capex	-	-
Decomission cost	-	294 175 000
Tax refund		223 042 519
FCF	3 235 294	(71 132 481)
NPV	**(60 891 687)**	
NPV per share	**(0,30)**	
EBITDA	11 078 451	-
CAPEX	-	-
Depreciation	840 000	
Uplift	269 500	
Corporate tax	2 559 613	-
Special tax	5 283 544	-
Total tax	7 843 157	-
Accounting depreciation	11 135	-
Tax accounting	8 489 672	-

Varg:

Production: Varg is expected to end production in second quarter of 2016[28]. We assume a decline rate which gives full depletion.

CAPEX: From 2015 NPD expects there to be 5 mill NOK in CAPEX[29], but we assume that this occurs in 2015 since 2016 is the last year of production. Therefore, there is no more CAPEX in 2016.

[26] Detnor (2016): “Årsrapport 2016”
[27] NPD (2016): «Factpages»
[28] Detnor (2016): “Årsrapport 2016”
[29] NPD (2016): «Factpages»

OPEX: Detnor's guidance for 2016 gives a opex of 8-9 USD per boe, with an exchange rate of 8,8 USD/NOK. We'll be careful and use 8 USD/boe.

VARG	2016	2017
Barrels (boe)	69 951	-
Revenue	19 434 865	-
OPEX	4 634 106	-
Tax	1 221 138	-
Capex	-	-
Decomission cost		86 000 000
Tax refund		75 227 480
FCF	13 579 622	(10 772 520)
NPV	**3 190 526**	
NPV per share	**0,02**	
EBITDA	14 800 760	-
CAPEX	-	-
Depreciation	12 200 000	
Uplift	1 523 500	
Corporate tax	650 190	-
Special tax	570 948	-
Total tax	1 221 138	-
Accounting depreciation	12 873	-
Tax accounting	10 727 097	-

Gina Krog:

Production: Since the Gina Krog field is developed at the same time as the Ivar Aasen development and we only have access to the Ivar Aasen PDO will we use Ivar Aasen as a comparable for Gina Krog. The two fields are also similar in reserves so we believe that this is a good approximation[30]. Production start for Gina Krog will be Q1 2017[31].

CAPEX: CAPEX will also be estimated using the Ivar Aasen PDO as an estimate. Inflation adjusted will this give a CAPEX of 5.652 billion NOK for all partners involved for 2016 before the field is producing in 2017.

OPEX: We assume that Detnor's reported OPEX for 2016 of 8 USD/boe will be a good estimate, but adjusted since the ambitions for new developments are lower production costs. Gina Krog is a larger field with economics of scale and we believe that an OPEX of 7 USD/boe is reasonable.

GINA KROG	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	-	1 082 449	1 167 409	1 217 755	1 179 995	855 890	560 104	361 865	242 292	213 972	179 359	144 746	94 400	-
Revenue	-	353 050 485	413 891 459	454 532 205	454 316 398	478 508 889	313 175 658	202 345 002	135 511 365	119 690 447	100 326 433	80 965 206	52 803 384	-
OPEX	-	62 746 377	67 671 186	70 590 369	68 402 995	49 616 519	32 471 168	20 979 851	14 050 301	12 409 932	10 402 202	8 394 761	5 474 843	-
Tax	-	-	27 931 898	142 640 630	192 866 420	310 286 814	218 949 502	141 464 818	94 739 629	83 678 801	70 140 900	56 604 947	36 916 262	-
Capex	186 532 575	-	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost	-	-	-	-	-	-	-	-	-	-	-	-	-	163 198 476
Tax refund														122 398 857
FCF	(186 532 575)	290 304 107	318 288 374	241 301 207	193 046 983	118 605 556	61 754 988	39 900 333	26 721 434	23 601 713	19 783 331	15 965 498	10 412 279	(40 799 619)
NPV	**889 219 722**													
NPV per share	**4,39**													
EBITDA	-	290 304 107	346 220 272	383 941 836	385 913 403	428 892 370	280 704 490	181 365 151	121 461 063	107 280 515	89 924 231	72 570 445	47 328 541	-
CAPEX	186 532 575	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	174 932 263	174 932 263	174 932 263	163 123 763	138 648 763	31 088 763	-	-	-	-	-	-	-	-
Uplift	57 727 647	53 830 842	45 754 092	10 259 292	-	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	27 931 898	55 204 518	61 816 160	99 450 902	70 176 123	45 341 288	30 365 266	26 820 129	22 481 058	18 142 611	11 832 135	-
Special tax	-	-	-	87 436 111	131 050 260	210 835 912	148 773 380	96 123 530	64 374 364	56 858 673	47 659 843	38 462 336	25 084 127	-
Total tax	-	-	27 931 898	142 640 630	192 866 420	310 286 814	218 949 502	141 464 818	94 739 629	83 678 801	70 140 900	56 604 947	36 916 262	-
Accounting depreciation	-	155 540 861	167 749 044	174 983 457	170 022 166	122 985 770	80 483 358	51 997 657	34 911 218	30 746 446	25 772 756	20 799 070	13 601 771	-
Tax accounting	-	76 584 986	114 957 889	157 550 111	168 395 165	238 607 148	156 172 483	100 906 646	67 508 879	59 696 574	50 038 151	40 381 673	26 306 880	-

Ivar Aasen:

Production: Production is taken from the Ivar Aasen POD[32].

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[30] NPD (2016): «Factpages»

[31] Detnor: «Gina Krog"

[32] Detnor (2012): «Plan for utbygging of drift av Ivar Aasen»

CAPEX: CAPEX is estimated from the Ivar Aasen PDO[33].

OPEX: We assume that Detnor's reported OPEX for 2016 of 8 USD/boe will be a good estimate, but adjusted since the ambitions for new developments are lower production costs. Ivar Aasen is a larger field with economics of scale and described as one of the fields with the lowest breakeven costs on the NCS. we believe that an OPEX of 6 USD/boe is reasonable.

IVAR AASEN	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	1 452 467	8 163 219	10 267 986	10 714 459	10 373 297	7 523 176	4 922 996	3 182 371	2 130 727	1 882 279	1 577 466	1 272 652	829 151	-
Revenue	449 498 957	2 829 699 247	3 919 410 095	4 419 043 521	4 127 293 053	4 303 783 018	2 804 393 554	1 896 006 722	1 266 114 552	1 146 458 429	945 549 726	744 667 508	446 116 181	-
OPEX	72 167 261	405 598 069	510 175 128	532 364 404	515 424 311	373 820 367	244 631 069	158 146 566	105 907 547	93 572 632	78 417 794	63 265 112	41 218 141	-
Tax	-	-	660 716 260	1 895 655 313	1 989 051 767	2 734 969 452	1 996 614 739	1 355 530 922	904 961 464	821 250 922	676 362 907	531 493 869	315 820 471	-
Capex	2 541 549 344	-	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost														1 720 319 648
Tax refund														1 290 239 736
FCF	(2 164 217 648)	2 424 101 178	2 748 518 708	1 991 023 804	1 622 816 974	1 194 993 198	563 147 747	382 329 234	255 245 541	231 634 875	190 769 025	149 908 527	89 077 569	(430 079 912)
NPV	**7 151 731 670**													
NPV per share	**35,30**													
EBITDA	377 331 697	2 424 101 178	3 409 234 968	3 886 679 117	3 611 868 742	3 929 962 650	2 559 762 485	1 737 860 156	1 160 207 005	1 052 885 797	867 131 932	681 402 397	404 898 040	-
CAPEX	2 541 549 344	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	1 495 006 517	1 495 006 517	1 495 006 517	1 361 369 532	1 061 802 373	423 591 557	-	-	-	-	-	-	-	-
Uplift	493 352 151	449 251 946	350 394 783	139 785 214	-	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	431 412 072	631 327 396	637 516 592	876 592 773	639 940 621	434 465 039	290 051 751	263 221 449	216 782 983	170 350 599	101 224 510	-
Special tax	-	-	229 304 187	1 264 327 916	1 351 535 175	1 858 376 679	1 356 674 117	921 065 883	614 909 713	558 029 473	459 579 924	361 143 270	214 595 961	-
Total tax	-	-	660 716 260	1 895 655 313	1 989 051 767	2 734 969 452	1 996 614 739	1 355 530 922	904 961 464	821 250 922	676 362 907	531 493 869	315 820 471	-
Accounting depreciation	202 496 312	1 141 196 332	1 431 515 217	1 493 760 516	1 446 197 249	1 051 720 109	686 341 423	443 671 538	297 056 102	263 137 659	219 922 987	177 427 234	115 596 427	-
Tax accounting	(125 105 040)	762 562 249	1 356 912 170	1 792 390 345	1 689 223 764	2 245 029 182	1 461 268 428	1 009 467 123	673 257 705	616 003 548	504 822 977	393 100 627	225 655 258	-

Hanz:

Production: Expected production start is in 2021[34]. The field is a tie-in to the Ivar Aasen development.

CAPEX: CAPEX is estimated from the Ivar Aasen PDO where Hanz Capex is also included[35]. The decision to develop Hanz is sanctioned.

OPEX: Since it is a tie-in field for Ivar Aasen will we use the same OPEX of 6 USD/boe.

HANZ	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	-	-	-	-	-	1 916 250	1 526 557	1 037 528	705 158	479 262	325 732	221 384	150 464	-
Revenue	-	-	-	-	-	1 163 981 786	927 349 713	630 314 215	428 483 496	291 263 788	197 953 504	134 539 546	91 440 106	-
OPEX	-	-	-	-	-	95 216 868	75 856 899	51 559 493	35 049 808	23 825 281	16 192 531	11 005 290	7 479 770	-
Tax	-	-	-	-	-	396 692 039	476 634 726	275 160 664	153 696 643	105 643 888	141 773 559	96 356 720	65 489 062	-
Capex	-	-	-	386 334 512	791 985 749	-	-	-	-	-	-	-	-	-
Decomission cost														80 910 172
Tax refund														60 682 629
FCF	-	-	-	(386 334 512)	(791 985 749)	672 072 878	374 858 089	303 594 057	239 737 045	161 794 619	39 987 414	27 177 536	18 471 274	(20 227 543)
NPV	**305 883 552**	-	-	-	-	-	-	-	-	-	-	-	-	-
NPV per share	**1,51**													-
EBITDA	-	-	-	-	-	1 068 764 918	851 492 814	578 754 722	393 433 688	267 438 507	181 760 973	123 534 256	83 960 336	
CAPEX	-	-	-	386 334 512	791 985 749	-	-	-	-	-	-	-	-	-
Depreciation	116 667	116 667	116 667	64 447 419	196 386 710	196 386 710	196 386 710	196 386 710	196 386 710	131 997 625	-	-	-	-
Uplift	38 500	19 250	-	21 248 398	64 807 614	64 807 614	64 807 614	43 559 216	-	-	-	-	-	-
Corporate tax	-	-	-	-	-	152 798 520	163 776 526	95 592 003	49 261 744	33 860 221	45 440 243	30 883 564	20 990 084	-
Special tax	-	-	-	-	-	243 893 520	312 858 200	179 568 662	104 434 898	71 783 668	96 333 316	65 473 156	44 498 978	
Total tax	-	-	-	-	-	396 692 039	476 634 726	275 160 664	153 696 643	105 643 888	141 773 559	96 356 720	65 489 062	-
Accounting depreciation	-	-	-	-	-	354 974 296	282 785 865	192 196 052	130 984 361	88 780 583	60 339 923	41 010 165	27 949 015	
Tax accounting	-	-	-	-	-	522 408 649	409 243 385	278 429 378	204 710 475	139 353 181	94 708 419	64 368 791	43 688 831	

Johan Sverdrup Phase 1:

Production: Production is taken from the Johan Sverdrup POD where we have divided between the two different phases[36].

[33] Detnor (2012): «Plan for utbygging of drift av Ivar Aasen»
[34] Detnor (2016): "Capital Markets Day 2016"
[35] Detnor (2012): «Plan for utbygging of drift av Ivar Aasen»
[36] Detnor (2014): «Johan Sverdrup Feltet»

CAPEX: CAPEX is estimated from the Johan Sverdrup PDO[37]. CAPEX estimates are updated for new estimates from Capital Markets Day 2016[38]

OPEX: Johan Sverdrup is the fifth largest field discovered on the NCS, and will therefore have huge economics of scale. Same argument as in Ivar Aasen do we believe that 6 USD/boe is a good estimate.

JOHAN SVERDRUP PHASE 1	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Barrels (boe)	-	-	-	-	8 465 862	15 756 662	16 167 830	15 589 163	15 584 884	15 592 204
Revenue	-	-	-	-	4 090 439 279	11 030 671 644	11 280 030 931	10 873 341 411	10 875 571 415	10 906 772 873
OPEX	-	-	-	-	420 648 415	782 935 409	803 403 759	774 696 706	774 644 992	775 125 973
Tax	-	-	-	-	-	1 486 348 464	6 996 354 990	7 103 140 106	7 557 454 308	7 783 049 918
Capex	3 499 350 000	2 918 207 595	3 365 058 133	1 532 970 927	517 218 003	80 528 879	122 437 450	141 009 423	-	-
Decomission cost										
Tax refund										
FCF	(3 499 350 000)	(2 918 207 595)	(3 365 058 133)	(1 532 970 927)	3 152 572 860	8 680 858 892	3 357 834 732	2 854 495 176	2 543 472 115	2 348 596 982
NPV	**13 567 693 500**									
NPV per share	**66,96**									
EBITDA	-	-	-	-	3 669 790 864	10 247 736 235	10 476 627 172	10 098 644 705	10 100 926 423	10 131 646 900
CAPEX	3 499 350 000	2 918 207 595	3 365 058 133	1 532 970 927	517 218 003	80 528 879	122 437 450	141 009 423	-	-
Depreciation	806 787 083	1 293 155 016	1 853 998 038	2 109 493 193	2 147 474 110	1 985 555 590	1 422 736 831	959 870 469	399 027 447	143 532 292
Uplift	266 239 738	426 741 155	595 906 065	622 357 266	458 340 006	302 267 677	123 923 539	47 365 657	18 918 666	14 489 578
Corporate tax	-	-	-	-	-	930 266 017	2 263 472 585	2 284 693 559	2 425 474 744	2 497 028 652
Special tax	-	-	-	-	-	556 082 446	4 732 882 405	4 818 446 547	5 131 979 564	5 286 021 266
Total tax	-	-	-	-	-	1 486 348 464	6 996 354 990	7 103 140 106	7 557 454 308	7 783 049 918
Accounting depreciation	-	-	-	-	543 339 042	1 014 033 205	1 037 651 410	1 000 512 537	1 000 237 911	1 003 449 389
Tax accounting	-	-	-	-	2 195 712 218	7 042 086 495	7 296 721 618	7 071 439 293	7 088 510 146	7 112 314 583

JOHAN SVERDRUP PHASE 1	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Barrels (boe)	15 471 303	15 071 003	13 862 464	11 909 366	10 180 940	8 731 494	7 491 833	6 448 546	5 522 459	4 744 094
Revenue	10 839 914 798	10 571 547 386	9 730 696 433	8 362 938 236	7 151 648 601	6 135 333 356	5 265 675 164	4 533 471 223	3 883 226 578	3 336 522 691
OPEX	769 097 888	749 198 466	689 120 474	592 029 513	506 107 278	434 053 497	372 428 393	320 565 316	274 528 371	235 834 853
Tax	7 806 409 917	7 585 072 715	6 991 986 674	6 019 197 454	5 141 410 883	4 412 600 077	3 782 334 269	3 286 066 607	2 814 784 601	2 418 536 514
Capex	-	264 601 631	-	-	-	-	-	-	-	-
Decomission cost										
Tax refund										
FCF	2 264 406 993	1 972 674 574	2 049 589 286	1 751 711 269	1 504 130 441	1 288 679 781	1 110 912 502	926 839 299	793 913 605	682 151 324
NPV										
NPV per share										
EBITDA	10 070 816 910	9 822 348 920	9 041 575 959	7 770 908 723	6 645 541 324	5 701 279 858	4 893 246 771	4 212 905 907	3 608 698 206	3 100 687 839
CAPEX	-	264 601 631	-	-	-	-	-	-	-	-
Depreciation	57 329 292	88 008 084	67 601 842	44 100 272	44 100 272	44 100 272	44 100 272	-	-	-
Uplift	7 755 518	14 553 090	14 553 090	14 553 090	14 553 090	-	-	-	-	-
Corporate tax	2 503 371 905	2 433 585 209	2 243 493 529	1 931 702 113	1 650 360 263	1 414 294 897	1 212 286 625	1 053 226 477	902 174 552	775 171 960
Special tax	5 303 038 013	5 151 487 506	4 748 493 144	4 087 495 341	3 491 050 620	2 998 305 181	2 570 047 644	2 232 840 130	1 912 610 049	1 643 364 554
Total tax	7 806 409 917	7 585 072 715	6 991 986 674	6 019 197 454	5 141 410 883	4 412 600 077	3 782 334 269	3 286 066 607	2 814 784 601	2 418 536 514
Accounting depreciation	992 948 319	967 257 055	889 693 013	766 437 252	653 412 757	560 387 303	480 825 852	415 001 608	354 431 457	304 475 964
Tax accounting	7 076 627 076	6 899 258 517	6 350 755 561	5 455 774 610	4 666 147 145	4 009 896 193	3 441 688 316	2 962 365 353	2 538 328 064	2 181 045 262

2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
4 076 856	3 514 196	3 013 570	2 592 071	2 230 109	1 924 417	1 651 939	1 422 225	1 224 695	1 057 680	908 611
2 867 724 177	2 472 298 504	2 120 369 954	1 824 005 295	1 569 452 930	1 354 438 129	1 162 752 630	1 001 131 591	862 137 027	744 603 970	639 688 958
202 665 619	174 695 114	149 808 361	128 855 110	110 861 513	95 665 159	82 119 939	70 700 610	60 881 109	52 578 598	45 168 191
2 078 745 675	1 792 130 644	1 537 038 043	1 322 217 144	1 137 701 305	981 842 916	842 893 499	725 736 165	624 979 616	539 779 790	463 726 199
-	-	-	-	-	-	-	-	-	-	-
586 312 883	505 472 746	433 523 551	372 933 041	320 890 112	276 930 053	237 739 192	204 694 816	176 276 302	152 245 582	130 794 569
2 665 058 558	2 297 603 390	1 970 561 594	1 695 150 185	1 458 591 416	1 258 772 970	1 080 632 691	930 430 981	801 255 918	692 025 372	594 520 768
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
666 264 640	574 400 848	492 640 398	423 787 546	364 647 854	314 693 242	270 158 173	232 607 745	200 313 980	173 006 343	148 630 192
1 412 481 036	1 217 729 797	1 044 397 645	898 429 598	773 053 451	667 149 674	572 735 326	493 128 420	424 665 637	366 773 447	315 096 007
2 078 745 675	1 792 130 644	1 537 038 043	1 322 217 144	1 137 701 305	981 842 916	842 893 499	725 736 165	624 979 616	539 779 790	463 726 199
261 652 631	226 159 068	193 410 959	166 359 143	143 128 404	123 847 444	106 021 427	91 278 435	78 600 911	68 067 883	58 314 657
1 874 656 623	1 615 726 571	1 386 177 495	1 192 457 013	1 026 061 149	885 241 910	760 196 786	654 538 986	563 670 905	486 686 841	418 240 767

2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
782 812	674 530	582 896	501 025	431 884	372 324	321 889	276 756	238 660	205 824	
551 145 147	474 924 288	410 419 536	352 783 196	304 106 209	262 173 384	226 663 641	194 911 860	174 466 127	150 462 135	
38 914 588	33 531 708	28 976 503	24 906 585	21 469 475	18 508 696	16 001 523	13 757 877	12 314 865	10 620 541	
399 539 836	344 286 212	297 525 566	255 743 757	220 456 652	190 058 457	164 316 452	141 300 107	126 477 984	109 076 443	
-	-	-	-	-	-	-	-	-	-	
									-	4 459 269 578
										3 478 230 270
112 690 723	97 106 368	83 917 467	72 132 854	62 180 081	53 606 231	46 345 666	39 853 876	35 673 278	30 765 151	(981 039 307)
512 230 559	441 392 580	381 443 033	327 876 611	282 636 733	243 664 688	210 662 117	181 153 983	162 151 262	139 841 594	
-	-	-	-	-	-	-	-	-	-	
-	-	-	-	-	-	-	-	-	-	
-	-	-	-	-	-	-	-	-	-	
128 057 640	110 348 145	95 360 758	81 969 153	70 659 183	60 916 172	52 665 529	45 288 496	40 537 815	34 960 398	
271 482 197	233 938 067	202 164 807	173 774 604	149 797 469	129 142 285	111 650 922	96 011 611	85 940 169	74 116 045	
399 539 836	344 286 212	297 525 566	255 743 757	220 456 652	190 058 457	164 316 452	141 300 107	126 477 984	109 076 443	
50 240 906	43 291 307	37 512 778	32 155 792	27 718 291	23 895 760	20 715 460	17 762 187	15 317 211	13 209 813	
360 351 930	310 518 993	268 265 599	230 662 239	198 836 385	171 419 764	148 158 393	127 445 601	114 530 559	98 772 789	

Johan Sverdrup Phase 2:

Production: Production is taken from the Johan Sverdrup POD where we have divided between the two different phases[39].

CAPEX: CAPEX is estimated from the Johan Sverdrup PDO[40]. CAPEX estimates are updated for new estimates from Capital Markets Day 2016[41].

[37] Detnor (2014): «Johan Sverdrup Feltet»
[38] Detnor (2016): "Capital Markets Day 2016"
[39] Detnor (2014): «Johan Sverdrup Feltet»
[40] Detnor (2014): «Johan Sverdrup Feltet»
[41] Detnor (2016): "Capital Markets Day 2016"

OPEX: We will use the same OPEX per barrel as in the Johan Sverdup 1. This is 6 USD/boe.

JOHAN SVERDRUP PHASE 2	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Barrels (boe)	-	-	-	-	-	-	-	10 068 520	12 692 423	16 391 641	15 779 258	15 075 540	12 612 422	9 884 285	8 377 993
Revenue	-	-	-	-	-	-	-	6 710 526 341	8 183 243 421	10 410 228 316	9 981 817 960	9 537 487 435	7 935 853 945	6 205 640 999	5 300 345 601
OPEX	-	-	-	-	-	-	-	500 350 736	630 875 535	814 867 926	784 406 689	749 424 005	626 979 317	491 360 194	416 480 527
Tax	-	-	-	-	-	-	-	476 524 533	4 284 727 935	6 055 369 954	6 071 506 496	6 130 567 468	5 403 956 366	4 306 822 984	3 809 414 758
Capex	-	-	224 337 209	766 485 464	1 833 177 734	2 657 453 008	3 026 543 703	1 128 075 380	1 156 277 265	-	-	-	-	-	-
Decomission cost															
Tax refund															
FCF	-	-	(224 337 209)	(766 485 464)	(1 833 177 734)	(2 657 453 008)	(3 026 543 703)	4 605 575 692	2 111 362 686	3 539 990 436	3 125 904 776	2 657 495 962	1 904 918 262	1 407 457 822	1 074 450 316
NPV	**6 656 095 270**														
NPV per share	**32,85**														
EBITDA	-	-	-	-	-	-	-	6 210 175 606	7 552 367 886	9 595 360 390	9 197 411 271	8 788 063 430	7 308 874 628	5 714 280 806	4 883 865 074
CAPEX	-	-	224 337 209	766 485 464	1 833 177 734	2 657 453 008	3 026 543 703	1 128 075 380	1 156 277 265	-	-	-	-	-	-
Depreciation	-	-	37 389 535	165 137 112	470 666 734	913 575 569	1 417 999 520	1 606 012 083	1 761 335 426	1 633 587 848	1 328 058 226	885 149 391	380 725 441	192 712 877	-
Uplift	-	-	12 338 546	54 495 247	155 320 022	301 479 938	455 601 295	475 488 740	438 259 215	292 099 299	125 639 395	63 595 250	-	-	-
Corporate tax	-	-	-	-	-	-	-	399 848 763	1 447 758 115	1 990 443 135	1 967 338 261	1 975 728 510	1 732 037 297	1 380 391 982	1 220 966 268
Special tax	-	-	-	-	-	-	-	76 675 770	2 836 969 820	4 064 926 819	4 104 168 234	4 154 838 958	3 671 919 069	2 926 431 002	2 588 448 489
Total tax	-	-	-	-	-	-	-	476 524 533	4 284 727 935	6 055 369 954	6 071 506 496	6 130 567 468	5 403 956 366	4 306 822 984	3 809 414 758
Accounting depreciation	-	-	-	-	-	-	-	832 152 615	1 049 015 471	1 358 463 647	1 304 139 139	1 245 977 617	1 042 403 486	819 163 950	692 432 337
Tax accounting	-	-	-	-	-	-	-	3 942 848 900	4 840 337 500	6 269 966 831	6 090 163 383	5 849 121 451	4 887 847 491	3 818 191 147	3 269 317 535

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
6 973 235	5 542 228	4 241 727	2 877 061	2 232 018	1 722 848	1 453 816	1 272 597	1 136 607	801 736	607 951	442 979	304 455	-
4 433 026 027	3 522 255 353	2 682 746 328	1 783 972 855	1 378 648 968	1 059 066 688	900 352 289	797 856 874	721 862 857	501 813 870	377 803 302	271 821 606	182 303 320	-
346 648 267	275 511 113	210 861 585	143 022 330	110 956 430	85 644 923	72 271 002	63 262 381	56 502 137	39 855 295	30 221 993	22 021 042	15 134 832	-
3 187 374 652	2 532 460 507	1 928 070 099	1 279 941 409	988 800 180	759 268 977	645 903 404	572 983 704	518 981 362	360 327 689	271 113 420	194 844 440	130 391 421	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
												-	3 315 716 137
													2 586 258 587
899 003 107	714 283 733	543 814 643	361 009 115	278 892 358	214 152 788	182 177 883	161 610 788	146 379 359	101 630 887	76 467 888	54 956 124	36 777 068	(729 457 550)
4 086 377 759	3 246 744 239	2 471 884 742	1 640 950 525	1 267 692 538	973 421 765	828 081 287	734 594 493	665 360 721	461 958 576	347 581 308	249 800 564	167 168 489	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
1 021 594 440	811 686 060	617 971 186	410 237 631	316 923 135	243 355 441	207 020 322	183 648 623	166 340 180	115 489 644	86 895 327	62 450 141	41 792 122	-
2 165 780 212	1 720 774 447	1 310 098 913	869 703 778	671 877 045	515 913 536	438 883 082	389 335 081	352 641 182	244 838 045	184 218 093	132 394 299	88 599 299	-
3 187 374 652	2 532 460 507	1 928 070 099	1 279 941 409	988 800 180	759 268 977	645 903 404	572 983 704	518 981 362	360 327 689	271 113 420	194 844 440	130 391 421	-
576 330 594	458 059 360	351 534 804	237 786 114	184 473 979	142 391 566	120 485 543	105 178 791	93 939 342	66 262 629	50 384 154	36 611 751	25 162 873	-
2 737 836 789	2 175 174 206	1 653 872 952	1 094 468 241	844 910 476	648 203 556	551 924 680	490 944 247	445 708 675	308 642 838	231 813 780	166 287 274	110 764 380	-

Attic oil:

Production: Attic Oil is expected to start up in 2017[42]. The field is a tie-in field to Alvheim and the production profile is therefore done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves, this is explained in section 6.1.4. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet[43].

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account[44], and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

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[42] Detnor (2016): “Capital Markets Day 2016”
[43] Detnor (2016): “Capital Markets Day 2016”
[44] Detnor (2016): “Capital Markets Day 2016”

ATTIC	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Barrels (boe)	-	1 278 148	1 439 258	932 623	435 537	232 769	42 854	5 453	1 358	-
Revenue	-	524 777 600	642 414 044	438 287 979	211 137 315	163 844 127	30 164 723	3 838 430	955 549	-
OPEX	-	74 090 497	83 429 489	54 061 953	25 247 574	13 493 759	2 484 402	316 157	78 721	-
Tax	-	221 771 397	338 684 545	202 372 892	53 612 526	37 775 687	-	-	-	-
Capex	203 840 000	407 680 000	-	-	-	-	-	-	-	-
Decomission cost										72 414 072
Tax refund										84 459 427
FCF	(203 840 000)	(178 764 293)	220 300 010	181 853 134	132 277 215	112 574 681	27 680 322	3 522 273	876 827	12 045 355
NPV	**188 146 226,76**									
NPV per share	**0,93**									
EBITDA	-	450 687 104	558 984 555	384 226 026	185 889 741	150 350 368	27 680 322	3 522 273	876 827	-
CAPEX	203 840 000	407 680 000	-	-	-	-	-	-	-	-
Depreciation	33 973 333	101 920 000	101 920 000	101 920 000	101 920 000	101 920 000	67 946 667	-	-	-
Uplift	11 211 200	33 633 600	33 633 600	33 633 600	22 422 400	-	-	-	-	-
Corporate tax	-	78 698 443	114 266 139	70 576 506	20 992 435	12 107 592	-	-	-	-
Special tax	-	143 072 954	224 418 406	131 796 386	32 620 091	25 668 095	-	-	-	-
Total tax	-	221 771 397	338 684 545	202 372 892	53 612 526	37 775 687	-	-	-	-
Accounting depreciation	-	178 891 746	201 440 967	130 531 470	61 125 445	32 578 680	5 997 938	763 231	190 521	-
Tax accounting	-	212 000 379	278 883 999	197 881 753	97 316 151	91 861 916	16 912 259	2 152 052	535 319	-

BoaKamSouthWest (BKSW):

Production: BKSW is expected to start up in 2018[45]. The field is a tie-in field to Alvheim and the production profile is therefore done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field[46], since contracts are not made yet. This is explained in section 6.1.4

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account[47], and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

BOA KAM SOUTH WEST	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Barrels (boe)	-	-	1 063 953	1 198 064	776 332	362 548	193 761	35 673	4 539	1 130	-
Revenue	-	-	474 896 290	563 032 380	376 346 305	255 195 168	136 386 732	25 109 646	3 195 176	795 416	-
OPEX	-	-	61 674 173	69 448 928	45 003 088	21 017 184	11 232 970	2 068 187	263 229	65 539	-
Tax	-	-	214 294 964	303 981 377	177 433 993	106 591 283	31 444 734	-	-	-	-
Capex	-	169 680 000	339 360 000	-	-	-	-	-	-	-	-
Decomission cost											59 902 005
Tax refund											70 011 803
FCF	-	(169 680 000)	(140 432 846)	189 602 075	153 909 224	127 586 700	93 709 028	23 041 459	2 931 947	729 877	10 109 799
NPV	**179 268 733,47**										
NPV per share	**0,88**										
EBITDA	-	-	413 222 117	493 583 452	331 343 217	234 177 984	125 153 762	23 041 459	2 931 947	729 877	-
CAPEX	-	169 680 000	339 360 000	-	-	-	-	-	-	-	-
Depreciation	-	28 280 000	84 840 000	84 840 000	84 840 000	84 840 000	84 840 000	56 560 000	-	-	-
Uplift	-	9 332 400	27 997 200	27 997 200	27 997 200	18 664 800	-	-	-	-	-
Corporate tax	-	-	75 025 529	102 185 863	61 625 804	37 334 496	10 078 441	-	-	-	-
Special tax	-	-	139 269 434	201 795 514	115 808 189	69 256 787	21 366 294	-	-	-	-
Total tax	-	-	214 294 964	303 981 377	177 433 993	106 591 283	31 444 734	-	-	-	-
Accounting depreciation	-	-	148 865 851	167 630 322	108 920 150	50 726 932	27 110 546	4 991 220	636 868	158 110	-
Tax accounting	-	-	206 197 888	254 243 441	173 489 992	143 091 820	76 473 708	14 079 186	1 790 162	445 978	-

Caterpillar:

[45] Detnor (2016): “Capital Markets Day 2016”
[46] Detnor (2016): “Capital Markets Day 2016”
[47] Detnor (2016): “Capital Markets Day 2016”

Production: Caterpillar is expected to start up in 2019[48]. The field is a tie-in field to Alvheim and the production profile is therefore done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account[49], and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

CATERPILLAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Barrels (boe)	-	-	-	1 521 605	1 713 403	1 110 266	518 496	277 106	51 017	6 492	1 616	-
Revenue	-	-	-	715 081 177	830 614 854	781 507 829	364 965 586	195 052 532	35 910 385	4 569 559	1 137 558	-
OPEX	-	-	-	88 203 846	99 324 034	64 362 872	30 058 991	16 065 745	2 958 418	376 513	93 728	-
Tax	-	-	-	334 482 719	454 545 639	443 511 866	152 439 678	44 969 694	-	-	-	-
Capex	-	-	242 666 667	485 333 333	-	-	-	-	-	-	-	-
Decomission cost												85 659 011
Tax refund												100 120 064
FCF	-	-	(242 666 667)	(192 938 720)	276 745 180	273 633 091	182 466 918	134 017 093	32 951 967	4 193 047	1 043 830	14 461 053
NPV	**385 128 759,16**											
NPV per share	**1,90**											
EBITDA	-	-	-	626 877 332	731 290 820	717 144 957	334 906 595	178 986 787	32 951 967	4 193 047	1 043 830	-
CAPEX	-	-	242 666 667	485 333 333	-	-	-	-	-	-	-	-
Depreciation	-	-	40 444 444	121 333 333	121 333 333	121 333 333	121 333 333	121 333 333	80 888 889	-	-	-
Uplift	-	-	13 346 667	40 040 000	40 040 000	40 040 000	26 693 333	-	-	-	-	-
Corporate tax	-	-	-	116 274 888	152 489 372	148 952 906	53 393 316	14 413 363	-	-	-	-
Special tax	-	-	-	218 207 830	302 056 268	294 558 960	99 046 362	30 556 331	-	-	-	-
Total tax	-	-	-	334 482 719	454 545 639	443 511 866	152 439 678	44 969 694	-	-	-	-
Accounting depreciation	-	-	-	212 826 876	240 310 189	155 292 827	72 522 035	38 758 741	7 155 275	908 014	226 043	-
Tax accounting	-	-	-	322 959 355	382 964 892	438 244 661	204 659 957	109 377 876	20 121 419	2 562 326	637 874	-

Garantiana:

Production: Garantiana is expected to start up in 2022[50]. The production profile is done through a comparable of Jotun. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Ivar Aasen with adjusting for reserves. This is explained in section 6.1.4. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet[51].

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account[52], and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

[48] Detnor (2016): "Capital Markets Day 2016"
[49] Detnor (2016): "Capital Markets Day 2016"
[50] Detnor (2016): "Capital Markets Day 2016"
[51] Detnor (2016): "Capital Markets Day 2016"
[52] Detnor (2016): "Capital Markets Day 2016"

GARANTIANA	2018	2019	2020	2021	2022	2023	2024	2025	2026
Barrels (boe)	-	-	-	1 279 351	10 621 433	8 122 484	3 834 674	3 312 300	1 634 978
Revenue	-	-	-	900 526 002	7 477 095 129	5 717 357 118	2 699 199 164	2 331 503 343	1 150 848 961
OPEX	-	-	-	74 164 887	615 760 775	470 917 250	222 369 102	192 106 113	94 822 938
Tax	-	-	-	-	4 360 923 046	3 589 315 115	1 509 324 635	1 360 617 011	700 782 893
Capex	298 297 357	668 677 850	1 424 580 178	945 518 504	-	-	-	-	-
Decomission cost									
Tax refund									
FCF	(298 297 357)	(668 677 850)	(1 424 580 178)	(119 157 390)	2 500 411 308	1 657 124 753	967 505 427	778 780 219	355 243 131
NPV	**2 422 797 352,13**								
NPV per share	**11,96**								
EBITDA	-	-	-	826 361 114	6 861 334 353	5 246 439 868	2 476 830 062	2 139 397 230	1 056 026 023
CAPEX	298 297 357	668 677 850	1 424 580 178	945 518 504	-	-	-	-	-
Depreciation	49 716 226	161 162 535	398 592 564	556 178 982	556 178 982	556 178 982	506 462 755	395 016 447	157 586 417
Uplift	16 406 355	53 183 636	131 535 546	183 539 064	167 132 709	130 355 427	52 003 518	-	-
Corporate tax	-	-	-	-	1 491 466 545	1 172 565 222	492 591 827	436 095 196	224 609 901
Special tax	-	-	-	-	2 869 456 501	2 416 749 893	1 016 732 808	924 521 815	476 172 991
Total tax	-	-	-	-	4 360 923 046	3 589 315 115	1 509 324 635	1 360 617 011	700 782 893
Accounting depreciation	-	-	-	124 794 703	1 036 070 796	792 310 142	375 079 257	323 099 241	159 484 406
Tax accounting	-	-	-	547 221 801	4 543 705 575	3 474 221 186	1 639 365 628	1 416 712 431	699 302 461

GARANTIANA	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Barrels (boe)	1 132 914	986 343	759 258	569 311	462 619	376 117	316 311	257 537	223 093	174 383	136 893	-
Revenue	797 450 185	694 279 423	534 436 131	400 733 544	325 634 152	264 746 250	222 649 107	181 278 136	157 033 779	122 747 165	96 357 677	-
OPEX	65 705 033	57 204 392	44 034 279	33 018 001	26 830 269	21 813 477	18 344 929	14 936 213	12 938 626	10 113 618	7 939 285	-
Tax	570 761 218	496 918 524	382 513 444	286 818 124	233 067 029	189 487 563	159 357 259	129 746 700	112 394 219	87 854 166	68 966 346	-
Capex	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost												563 372 728
Tax refund												-
FCF	160 983 933	140 156 507	107 888 407	80 897 419	65 736 854	53 445 210	44 946 919	36 595 223	31 700 934	24 779 380	19 452 046	(123 942 000)
NPV												
NPV per share												
EBITDA	731 745 151	637 075 031	490 401 852	367 715 543	298 803 883	242 932 773	204 304 178	166 341 923	144 095 153	112 633 547	88 418 392	-
CAPEX	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	-	-	-	-	-	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-	-	-	-	-	-
Corporate tax	182 936 288	159 268 758	122 600 463	91 928 886	74 700 971	60 733 193	51 076 044	41 585 481	36 023 788	28 158 387	22 104 598	-
Special tax	387 824 930	337 649 767	259 912 981	194 889 238	158 366 058	128 754 370	108 281 214	88 161 219	76 370 431	59 695 780	46 861 748	-
Total tax	570 761 218	496 918 524	382 513 444	286 818 124	233 067 029	189 487 563	159 357 259	129 746 700	112 394 219	87 854 166	68 966 346	-
Accounting depreciation	110 510 478	96 213 096	74 062 046	55 533 570	45 126 312	36 688 479	30 854 666	25 121 486	21 761 708	17 010 276	13 353 227	-
Tax accounting	484 563 045	421 872 310	324 745 048	243 501 939	197 868 505	160 870 549	135 290 619	110 151 941	95 420 087	74 586 151	58 550 829	-

Krafla/Askja:

Production: Garantiana is expected to start up in 2022[53]. The production profile is done through a comparable of Jotun. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Ivar Aasen with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field[54], since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account[55], and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

[53] Detnor (2016): "Capital Markets Day 2016"
[54] Detnor (2016): "Capital Markets Day 2016"
[55] Detnor (2016): "Capital Markets Day 2016"

KRAFLA	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Barrels (boe)	-	-	-	3 740 793	31 056 821	23 749 955	11 212 498	9 685 087	4 780 637	3 312 615	2 884 043	2 220 053
Revenue	-	-	-	1 851 063 951	15 367 910 205	11 752 248 678	5 548 311 763	4 792 497 845	2 365 615 809	1 639 190 569	1 427 118 965	1 098 554 721
OPEX	-	-	-	216 866 582	1 800 581 194	1 377 237 138	650 300 319	561 700 764	277 260 053	192 119 981	167 264 303	128 755 202
Tax	-	-	-	-	7 075 087 011	6 622 017 826	2 584 768 186	2 399 107 020	1 269 509 871	1 128 715 059	982 686 636	756 443 625
Capex	872 214 495	1 955 198 393	4 165 439 116	2 764 673 989	-	-	-	-	-	-	-	-
Decomission cost												
Tax refund												
FCF	(872 214 495)	(1 955 198 393)	(4 165 439 116)	(1 130 476 620)	6 492 242 000	3 752 993 715	2 313 243 259	1 831 690 061	818 845 885	318 355 529	277 168 026	213 355 894
NPV	**5 907 207 733,99**											
NPV per share	**29,15**											
EBITDA	-	-	-	1 634 197 369	13 567 329 011	10 375 011 541	4 898 011 445	4 230 797 081	2 088 355 756	1 447 070 588	1 259 854 662	969 799 520
CAPEX	872 214 495	1 955 198 393	4 165 439 116	2 764 673 989	-	-	-	-	-	-	-	-
Depreciation	145 369 083	471 235 481	1 165 475 334	1 626 254 332	1 626 254 332	1 626 254 332	1 480 885 250	1 155 018 851	460 778 998	-	-	-
Uplift	47 971 797	155 507 709	384 606 860	536 663 930	488 692 132	381 156 221	152 057 069	-	-	-	-	-
Corporate tax	-	-	-	-	2 541 734 455	2 187 189 302	854 281 549	768 944 558	406 894 190	361 767 647	314 963 665	242 449 880
Special tax	-	-	-	-	4 533 352 557	4 434 828 524	1 730 486 637	1 630 162 462	862 615 682	766 947 412	667 722 971	513 993 745
Total tax	-	-	-	-	7 075 087 011	6 622 017 826	2 584 768 186	2 399 107 020	1 269 509 871	1 128 715 059	982 686 636	756 443 625
Accounting depreciation	-	-	-	370 557 672	3 076 444 533	2 359 082 306	1 110 694 147	959 390 900	473 563 130	328 142 978	285 689 215	219 915 259
Tax accounting	-	-	-	985 638 963	8 182 889 893	6 252 424 803	2 954 107 493	2 551 696 821	1 259 538 248	872 763 536	759 849 048	584 909 724

KRAFLA	2031	2032	2033	2034	2035	2036	2037	2038	2039
Barrels (boe)	1 664 651	1 352 687	1 099 758	924 886	753 031	652 320	509 893	400 271	
Revenue	823 723 737	669 353 950	544 196 445	457 664 093	372 624 418	322 789 178	252 311 679	198 067 038	
OPEX	96 543 862	78 451 079	63 782 096	53 640 143	43 673 138	37 832 240	29 571 983	23 214 284	
Tax	567 200 302	460 904 240	374 723 192	315 138 681	256 581 998	222 266 412	173 736 963	136 385 148	
Capex	-	-	-	-	-	-	-	-	
Decomission cost									1 643 843 373
Tax refund									1 282 197 831
FCF	159 979 572	129 998 632	105 691 157	88 885 269	72 369 282	62 690 526	49 002 733	38 467 606	(361 645 542)
NPV									
NPV per share									
EBITDA	727 179 874	590 902 871	480 414 349	404 023 950	328 951 280	284 956 938	222 739 696	174 852 753	
CAPEX	-	-	-	-	-	-	-	-	
Depreciation	-	-	-	-	-	-	-	-	
Uplift	-	-	-	-	-	-	-	-	
Corporate tax	181 794 969	147 725 718	120 103 587	101 005 988	82 237 820	71 239 235	55 684 924	43 713 188	
Special tax	385 405 333	313 178 522	254 619 605	214 132 694	174 344 178	151 027 177	118 052 039	92 671 959	
Total tax	567 200 302	460 904 240	374 723 192	315 138 681	256 581 998	222 266 412	173 736 963	136 385 148	
Accounting depreciation	164 897 947	133 995 280	108 940 501	91 617 937	74 594 186	64 617 869	50 509 262	39 650 245	
Tax accounting	438 579 903	356 387 922	289 749 601	243 676 690	198 398 533	171 864 474	134 339 739	105 457 957	

Frigg/Gamma/Delta (FGD):

Production: FGD is expected to start up in 2020[56] by other sources than Detnor. In the article they mention that using the existing infrastructure from the Krafla development is one alternative. The Krafla field is not finished before 2022, so we believe FGD will start production in 2023. The production profile is done through a comparable of Jotun. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Ivar Aasen with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field[57], since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

[56] SyslaOffshore.no (2014): «Setter fart på ny milliardutbygging»
[57] Detnor (2016): "Capital Markets Day 2016"

FRIGG/GAMMA/DELTA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	-	-	-	1 795 581	14 907 274	11 399 978	5 381 999	4 648 842	2 294 706	1 590 055
Revenue	-	-	-	1 263 896 143	10 494 168 602	8 024 360 867	3 788 349 704	3 272 285 393	1 615 226 612	1 119 228 330
OPEX	-	-	-	104 091 070	864 225 650	660 936 491	312 096 985	269 622 615	133 084 825	92 217 591
Tax	-	-	-	-	6 120 593 748	5 037 635 249	2 118 350 365	1 909 637 910	983 554 937	801 068 376
Capex	418 662 958	938 495 229	1 999 410 775	1 327 043 515	-	-	-	-	-	-
Decomission cost										
Tax refund										
FCF	(418 662 958)	(938 495 229)	(1 999 410 775)	(167 238 442)	3 509 349 204	2 325 789 127	1 357 902 354	1 093 024 869	498 586 850	225 942 363
NPV	**3 020 219 113,34**									
NPV per share	**14,91**									
EBITDA	-	-	-	1 159 805 073	9 629 942 952	7 363 424 376	3 476 252 719	3 002 662 779	1 482 141 787	1 027 010 739
CAPEX	418 662 958	938 495 229	1 999 410 775	1 327 043 515	-	-	-	-	-	-
Depreciation	69 777 160	226 193 031	559 428 160	780 602 079	780 602 079	780 602 079	710 824 920	554 409 048	221 173 919	-
Uplift	23 026 463	74 643 700	184 611 293	257 598 686	234 572 224	182 954 986	72 987 393	-	-	-
Corporate tax	-	-	-	-	2 093 286 379	1 645 705 574	691 356 950	612 063 433	315 241 967	256 752 685
Special tax	-	-	-	-	4 027 307 369	3 391 929 675	1 426 993 415	1 297 574 477	668 312 970	544 315 692
Total tax	-	-	-	-	6 120 593 748	5 037 635 249	2 118 350 365	1 909 637 910	983 554 937	801 068 376
Accounting depreciation	-	-	-	176 661 861	1 470 700 706	1 121 609 975	529 518 910	457 385 703	225 769 293	156 440 828
Tax accounting	-	-	-	766 851 706	6 364 208 952	4 868 615 233	2 298 452 371	1 985 316 119	979 970 545	679 044 530

FRIGG/GAMMA/DELTA	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Barrels (boe)	1 384 341	1 065 625	799 032	649 290	527 884	443 945	361 455	313 113	244 749	192 130	
Revenue	974 427 260	750 085 797	562 433 044	457 030 389	371 573 684	312 489 974	254 425 454	220 398 286	172 276 722	135 238 845	
OPEX	80 286 866	61 802 497	46 341 054	37 656 518	30 615 406	25 747 269	20 963 106	18 159 475	14 194 552	11 142 856	
Tax	697 429 508	536 860 975	402 551 752	327 111 619	265 947 457	223 659 310	182 100 631	157 746 273	123 304 093	96 794 871	
Capex	-	-	-	-	-	-	-	-	-	-	
Decomission cost											790 163 855
Tax refund											592 622 892
FCF	196 710 887	151 422 326	113 540 238	92 262 252	75 010 821	63 083 395	51 361 717	44 492 538	34 778 078	27 301 118	(197 540 964)
NPV											
NPV per share											
EBITDA	894 140 395	688 283 301	516 091 990	419 373 871	340 958 278	286 742 705	233 462 348	202 238 811	158 082 171	124 095 989	
CAPEX	-	-	-	-	-	-	-	-	-	-	
Depreciation	-	-	-	-	-	-	-	-	-	-	
Uplift	-	-	-	-	-	-	-	-	-	-	
Corporate tax	223 535 099	172 070 825	129 022 998	104 843 468	85 239 569	71 685 676	58 365 587	50 559 703	39 520 543	31 023 997	
Special tax	473 894 409	364 790 149	273 528 755	222 268 152	180 707 887	151 973 634	123 735 044	107 186 570	83 783 550	65 770 874	
Total tax	697 429 508	536 860 975	402 551 752	327 111 619	265 947 457	223 659 310	182 100 631	157 746 273	123 304 093	96 794 871	
Accounting depreciation	136 201 170	104 843 704	78 614 425	63 881 704	51 936 940	43 678 478	35 562 474	30 806 306	24 080 085	18 903 093	
Tax accounting	591 192 596	455 082 886	341 232 501	277 283 891	225 436 643	189 590 097	154 361 901	133 717 354	104 521 627	82 050 459	

<u>Frøy:</u>

<u>Production:</u> Frøy is expected to start up in 2024, where we apply the same argument as we did with FGD. The production profile is done through a comparable of Glitne. This is explained in section 6.1.1.1.

<u>CAPEX:</u> CAPEX is estimated comparing the field with Bøyla with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

<u>OPEX:</u> We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

FRØY	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Barrels (boe)	-	-	-	-	2 099 556	6 074 079	4 748 315	2 728 453	2 328 356	1 637 439	1 319 727	1 434 019	1 044 168	730 178	554 613	283 750	17 347	
Revenue	-	-	-	-	1 017 812 161	4 275 499 701	3 342 304 355	1 920 538 060	1 638 912 682	1 152 581 275	928 946 162	1 009 395 266	734 982 006	513 966 959	390 387 884	199 729 574	12 210 459	
OPEX	-	-	-	-	121 708 887	352 118 598	275 276 082	158 187 513	135 019 137	94 967 871	76 539 500	83 168 016	60 558 036	42 347 744	32 165 582	16 456 499	1 006 067	
Tax	-	-	-	-	-	1 912 200 856	1 874 940 941	951 364 454	863 870 299	783 612 164	664 877 196	722 457 255	526 050 697	367 862 988	279 413 396	142 952 999	8 739 425	
Capex	53 719 754	261 646 804	806 428 313	2 060 310 581	317 894 547	-	-	-	-	-	-	-	-	-	-	-	-	
Decomission cost																		414 457 831
Tax refund																		323 277 108
FCF	(53 719 754)	(261 646 804)	(806 428 313)	(2 060 310 581)	578 208 727	2 011 180 247	1 192 087 331	810 986 094	640 023 247	274 001 240	187 529 465	203 769 995	148 373 273	103 756 227	78 808 906	40 320 077	2 464 966	(91 180 723)
NPV	**2 014 558 569,73**																	
NPV per share	**9,94**																	
EBITDA	-	-	-	-	896 103 274	3 923 381 102	3 067 028 273	1 762 350 548	1 503 893 545	1 057 613 404	852 406 661	926 227 250	674 423 970	471 619 215	358 222 302	183 273 075	11 204 391	
CAPEX	53 719 754	261 646 804	806 428 313	2 060 310 581	317 894 547	-	-	-	-	-	-	-	-	-	-	-	-	
Depreciation	8 953 292	52 561 093	186 965 812	530 350 909	583 333 333	583 333 333	574 380 041	530 772 240	396 367 521	52 982 424	-	-	-	-	-	-	-	
Uplift	2 954 586	17 345 161	61 698 718	175 015 800	189 545 414	175 154 839	130 801 282	17 484 200	-	-	-	-	-	-	-	-	-	
Corporate tax	-	-	-	-	-	718 496 651	623 162 058	307 894 577	276 881 506	251 157 745	213 101 665	231 556 813	168 605 993	117 904 804	89 555 576	45 818 269	2 801 098	
Special tax	-	-	-	-	-	1 193 704 205	1 251 778 883	643 469 877	586 988 793	532 454 419	451 775 531	490 900 443	357 444 704	249 958 184	189 857 820	97 134 730	5 938 327	
Total tax	-	-	-	-	-	1 912 200 856	1 874 940 941	951 364 454	863 870 299	783 612 164	664 877 196	722 457 255	526 050 697	367 862 988	279 413 396	142 952 999	8 739 425	
Accounting depreciation	-	-	-	-	294 600 160	849 958 644	664 441 744	381 798 162	326 704 376	229 130 274	184 672 173	200 665 254	146 112 584	102 175 346	77 608 135	39 705 740	2 427 409	
Tax accounting	-	-	-	-	469 172 428	2 397 269 517	1 874 017 492	1 076 830 861	918 207 552	646 216 842	520 832 901	565 938 357	412 082 881	288 166 218	218 879 051	111 982 522	6 846 046	

Gekko:

Production: Gekko has no announced start date. Looking at Detnors current development plan do we believe it can't start before 2025, so we will use this year as start of production. The field is a tie-in field to Alvheim and the production profile is therefore done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

GEKKO	2026	2027	2028	2029	2030	2031	2032	2033	2034
Barrels (boe)	-	-	-	-	1 037 181	3 000 595	2 345 668	1 347 856	1 150 208
Revenue	-	-	-	-	54 520 920	158 196 113	123 674 943	71 080 238	60 666 285
OPEX	-	-	-	-	60 126 078	173 954 758	135 994 775	78 160 869	66 709 534
Tax	-	-	-	-	-	-	-	-	-
Capex	32 451 201	158 056 439	487 149 797	1 244 599 011	192 034 755	-	-	-	-
Decomission cost	-	-	-	-	-	-	-	-	-
Tax refund									
FCF	(32 451 201)	(158 056 439)	(487 149 797)	(1 244 599 011)	(197 639 913)	(15 758 645)	(12 319 832)	(7 080 630)	(6 043 249)
NPV	**(619 174 801)**								
NPV per share	**(3,06)**								
EBITDA	-	-	-	-	(5 605 158)	(15 758 645)	(12 319 832)	(7 080 630)	(6 043 249)
CAPEX	32 451 201	158 056 439	487 149 797	1 244 599 011	192 034 755	-	-	-	-
Depreciation	5 408 534	31 751 273	112 942 906	320 376 075	352 381 867	352 381 867	346 973 334	320 630 594	239 438 961
Uplift	1 784 816	10 477 920	37 271 159	105 724 105	114 501 200	105 808 096	79 014 857	10 561 912	-
Corporate tax	-	-	-	-	-	-	-	-	-
Special tax	-	-	-	-	-	-	-	-	-
Total tax	-	-	-	-	-	-	-	-	-
Accounting depreciation	-	-	-	-	177 470 542	513 427 719	402 463 637	230 629 761	196 810 492
Tax accounting	-	-	-	-	(142 799 046)	(412 765 364)	(323 531 106)	(185 414 106)	(158 225 918)

GEKKO	2035	2036	2037	2038	2039	2040	2041	2042	2043
Barrels (boe)	808 895	651 945	708 405	515 819	360 708	273 979	140 173	8 569	-
Revenue	42 663 166	34 385 241	37 363 090	27 205 595	19 024 652	14 450 333	7 393 054	451 974	-
OPEX	46 913 041	37 810 513	41 085 000	29 915 670	20 919 786	15 889 797	8 129 511	496 997	-
Tax	-	-	-	-	-	-	-	-	-
Capex	-	-	-	-	-	-	-	-	-
Decomission cost	-	-	-	-	-	-	-	-	204 742 169
Tax refund									2 106 096 348
FCF	(4 249 875)	(3 425 272)	(3 721 910)	(2 710 075)	(1 895 133)	(1 439 464)	(736 456)	(45 023)	1 901 354 179
NPV									
NPV per share									
EBITDA	(4 249 875)	(3 425 272)	(3 721 910)	(2 710 075)	(1 895 133)	(1 439 464)	(736 456)	(45 023)	-
CAPEX	-	-	-	-	-	-	-	-	-
Depreciation	32 005 793	-	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	-	-	-	-	-	-	-
Special tax	-	-	-	-	-	-	-	-	-
Total tax	-	-	-	-	-	-	-	-	-
Accounting depreciation	138 408 892	111 553 442	121 214 255	88 261 060	61 720 244	46 880 125	23 984 729	1 466 305	-
Tax accounting	(111 273 838)	(89 683 398)	(97 450 208)	(70 957 485)	(49 619 994)	(37 689 280)	(19 282 524)	(1 178 836)	-

Grevling:

Production: Same argument with Grevling as Gekko. We expected it to start up in 2025. The production profile is done through a comparable of Glitne. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Bøyla and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

GREVLING	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Barrels (boe)	-	-	1 217 129	3 521 190	2 752 635	1 581 705	1 349 766	949 236	765 056	831 312	605 312	423 290	321 513	164 492	10 056	-
Revenue	-	-	856 844 467	2 478 885 566	1 937 829 651	1 113 505 926	950 222 784	668 253 408	538 592 333	585 235 802	426 134 140	297 992 149	226 342 419	115 800 917	7 079 484	-
OPEX	-	-	71 567 073	207 055 461	161 872 323	93 033 585	79 403 251	55 839 814	45 005 226	48 902 793	35 608 125	24 900 473	18 913 362	9 676 422	591 568	-
Tax	-	-	-	414 558 958	1 013 262 829	491 625 249	456 939 064	447 967 751	384 997 943	418 339 746	304 610 291	213 011 507	161 794 664	82 777 107	5 060 575	-
Capex	579 846 317	1 481 425 543	228 575 782	-	-	-	-	-	-	-	-	-	-	-	-	-
Decomission cost																242 457 831
Tax refund																189 117 108
FCF	(579 846 317)	(1 481 425 543)	556 701 613	1 857 271 146	762 694 498	528 847 093	413 880 470	164 445 842	108 589 164	117 993 262	85 915 723	60 080 169	45 634 392	23 347 389	1 427 342	(53 340 723)
NPV	**645 606 157**															
NPV per share	**3,19**															
EBITDA	-	-	785 277 395	2 271 830 104	1 775 957 328	1 020 472 342	870 819 533	612 413 594	493 587 107	536 333 008	390 526 015	273 091 676	207 429 057	106 124 496	6 487 916	-
CAPEX	579 846 317	1 481 425 543	228 575 782	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation	134 434 066	381 338 324	419 434 287	419 434 287	412 996 600	381 641 274	285 000 221	38 095 964	-	-	-	-	-	-	-	-
Uplift	44 363 242	125 841 647	136 288 878	125 941 620	94 050 073	12 571 668	-	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	-	414 558 958	340 740 182	159 707 767	146 454 828	143 579 408	123 396 777	134 083 252	97 631 504	68 272 919	51 857 264	26 531 124	1 621 979	-
Special tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total tax	-	-	-	414 558 958	340 740 182	159 707 767	146 454 828	143 579 408	123 396 777	134 083 252	97 631 504	68 272 919	51 857 264	26 531 124	1 621 979	-
Accounting depreciation	-	-	211 286 985	611 259 727	477 842 636	275 327 786	234 312 101	164 782 263	132 809 593	144 311 243	105 078 922	73 480 838	55 812 983	28 554 942	1 745 705	-
Tax accounting	-	-	447 712 520	1 295 244 895	1 012 529 460	581 212 754	496 475 797	349 152 438	281 406 461	305 776 977	222 648 732	155 696 453	118 260 538	60 504 252	3 698 925	-

Gohta:

Production: Gohta lies in the Barents Sea, a new area for oil production. We have no estimates when production will begin. Reviewing Detnors current development plan and the size of Gohta do we believe it to start up in 2024. The production profile is done through a comparable of Jotun. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Ivar Aasen with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

GOHTA	2021	2022	2023	2024	2025	2026	2027	2028	2029
Barrels (boe)	-	-	-	2 940 264	24 410 661	18 667 464	8 813 024	7 612 478	3 757 581
Revenue	-	-	-	1 456 612 280	12 093 092 028	9 247 908 299	4 365 996 643	3 771 242 569	1 861 515 922
OPEX	-	-	-	170 457 133	1 415 256 818	1 082 508 390	511 136 050	441 496 800	217 926 402
Tax	-	-	-	-	5 573 179 076	5 213 205 865	2 035 546 200	1 889 082 743	999 505 437
Capex	685 560 593	1 536 785 937	3 274 035 145	2 173 033 755	-	-	-	-	-
Decomission cost									
Tax refund									
FCF	(685 560 593)	(1 536 785 937)	(3 274 035 145)	(886 878 608)	5 104 656 134	2 952 194 044	1 819 314 393	1 440 663 026	644 084 083
NPV	**2 778 492 921,51**								
NPV per share	**13,71**								
EBITDA	-	-	-	1 286 155 147	10 677 835 210	8 165 399 909	3 854 860 593	3 329 745 769	1 643 589 520
CAPEX	685 560 593	1 536 785 937	3 274 035 145	2 173 033 755	-	-	-	-	-
Depreciation	114 260 099	370 391 088	916 063 612	1 278 235 905	1 278 235 905	1 278 235 905	1 163 975 806	907 844 817	362 172 292
Uplift	37 705 833	122 229 059	302 300 992	421 817 849	384 112 016	299 588 789	119 516 857	-	-
Corporate tax	-	-	-	-	2 001 700 937	1 721 791 001	672 721 197	605 475 238	320 354 307
Special tax	-	-	-	-	3 571 478 139	3 491 414 864	1 362 825 003	1 283 607 505	679 151 131
Total tax	-	-	-	-	5 573 179 076	5 213 205 865	2 035 546 200	1 889 082 743	999 505 437
Accounting depreciation	-	-	-	292 218 927	2 419 431 889	1 850 202 159	873 491 723	754 501 150	372 427 888
Tax accounting	-	-	-	775 270 252	6 441 554 590	4 925 854 245	2 325 467 718	2 008 690 803	991 506 073

GOHTA	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2040
Barrels (boe)	2 603 716	2 266 858	1 744 961	1 308 416	1 063 212	864 410	726 961	591 882	512 723	400 776	314 613	
Revenue	1 289 887 957	1 123 007 661	864 458 673	648 192 680	526 718 257	428 231 137	360 138 359	293 220 177	254 004 556	198 545 429	155 860 027	
OPEX	151 006 305	131 469 742	101 201 588	75 883 476	61 662 548	50 132 728	42 161 153	34 327 087	29 736 141	23 243 578	18 246 427	
Tax	888 327 689	773 399 576	595 340 526	446 401 179	362 743 453	294 916 759	248 022 221	201 936 611	174 929 364	136 735 444	107 338 608	
Capex	-	-	-	-	-	-	-	-	-	-	-	
Decomission cost												1 292 486 747
Tax refund												1 008 139 663
FCF	250 553 963	218 138 342	167 916 559	125 908 025	102 312 256	83 181 650	69 954 985	56 956 480	49 339 051	38 566 407	30 274 992	(284 347 084)
NPV												
NPV per share												
EBITDA	1 138 881 652	991 537 918	763 257 085	572 309 204	465 055 709	378 098 409	317 977 207	258 893 091	224 268 416	175 301 851	137 613 600	
CAPEX	-	-	-	-	-	-	-	-	-	-	-	
Depreciation	-	-	-	-	-	-	-	-	-	-	-	
Uplift	-	-	-	-	-	-	-	-	-	-	-	
Corporate tax	284 720 413	247 884 480	190 814 271	143 077 301	116 263 927	94 524 602	79 494 302	64 723 273	56 067 104	43 825 463	34 403 400	
Special tax	603 607 276	525 515 097	404 526 255	303 323 878	246 479 526	200 392 157	168 527 920	137 213 338	118 862 260	92 909 981	72 935 208	
Total tax	888 327 689	773 399 576	595 340 526	446 401 179	362 743 453	294 916 759	248 022 221	201 936 611	174 929 364	136 735 444	107 338 608	
Accounting depreciation	258 064 001	224 676 763	172 949 645	129 681 958	105 378 936	85 674 915	72 051 798	58 663 678	50 817 927	39 722 386	31 182 446	
Tax accounting	687 037 768	598 151 701	460 439 803	345 249 252	280 547 883	228 090 326	191 821 819	156 178 942	135 291 381	105 751 983	83 016 300	

P-Graben:

Production: P-Graben lies close to Johan Sverdrup. We have no estimates when production will begin. Reviewing Detnors current development plan and the possibility that P-Graben could be a tie-in field do we believe it to start up in 2028. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

PGRABEN	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Barrels (boe)	-	-	760 803	856 701	555 133	259 248	138 553	25 508	3 246	808	-
Revenue	-	-	323 815 566	376 125 628	353 893 262	165 272 843	88 328 571	16 261 843	2 069 303	515 138	-
OPEX	-	-	44 101 923	49 662 017	32 181 436	15 029 496	8 032 873	1 479 209	188 256	46 864	-
Tax	-	-	155 789 842	227 904 416	225 830 424	95 349 811	48 070 645	11 530 454	1 467 216	365 254	-
Capex	56 000 000	112 000 000	-	-	-	-	-	-	-	-	-
Decomission cost											43 518 072
Tax refund											33 944 096
FCF	(56 000 000)	(112 000 000)	123 923 802	98 559 194	95 881 402	54 893 536	32 225 054	3 252 179	413 830	103 020	(9 573 976)
NPV	**96 548 256,17**										
NPV per share	**0,48**										
EBITDA	-	-	279 713 643	326 463 611	321 711 826	150 243 347	80 295 698	14 782 634	1 881 047	468 274	-
CAPEX	56 000 000	112 000 000	-	-	-	-	-	-	-	-	-
Depreciation	9 333 333	28 000 000	28 000 000	28 000 000	28 000 000	28 000 000	18 666 667	-	-	-	-
Uplift	3 080 000	9 240 000	9 240 000	9 240 000	6 160 000	-	-	-	-	-	-
Corporate tax	-	-	53 595 077	74 615 903	73 427 956	30 560 837	15 407 258	3 695 658	470 262	117 068	-
Special tax	-	-	102 194 764	153 288 514	152 402 468	64 788 974	32 663 387	7 834 796	996 955	248 185	-
Total tax	-	-	155 789 842	227 904 416	225 830 424	95 349 811	48 070 645	11 530 454	1 467 216	365 254	-
Accounting depreciation	-	-	49 247 564	55 303 680	35 836 159	16 735 552	8 968 668	1 646 676	209 538	52 163	-
Tax accounting	-	-	179 763 542	211 504 746	222 983 020	104 136 080	55 635 084	10 246 047	1 303 777	324 566	-

Trell:

Production: We have no estimates when production on Trell will begin. We expect it to start in 2030. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

TRELL	2029	2030	2031	2032	2033	2034	2035	2036	2037	2037
Barrels (boe)	-	1 463 082	1 647 503	1 067 563	498 554	266 448	49 055	6 242	1 554	-
Revenue	-	600 706 960	735 364 061	501 703 273	241 686 487	187 550 512	34 529 216	4 393 807	1 093 806	-
OPEX	-	84 810 550	95 500 788	61 884 104	28 900 611	15 446 153	2 843 866	361 901	90 111	-
Tax	-	253 859 200	387 688 353	231 653 951	61 369 650	43 241 400	-	-	-	-
Capex	233 333 333	466 666 667	-	-	-	-	-	-	-	-
Decomission cost										79 265 060
Tax refund										93 851 073
FCF	(233 333 333)	(204 629 457)	252 174 920	208 165 217	151 416 226	128 862 959	31 685 350	4 031 906	1 003 694	14 586 013
NPV	**111 228 218,53**									
NPV per share	**0,55**									
EBITDA	-	515 896 410	639 863 273	439 819 169	212 785 876	172 104 359	31 685 350	4 031 906	1 003 694	-
CAPEX	233 333 333	466 666 667	-	-	-	-	-	-	-	-
Depreciation	38 888 889	116 666 667	116 666 667	116 666 667	116 666 667	116 666 667	77 777 778	-	-	-
Uplift	12 833 333	38 500 000	38 500 000	38 500 000	25 666 667	-	-	-	-	-
Corporate tax	-	90 085 214	130 799 152	80 788 125	24 029 802	13 859 423	-	-	-	-
Special tax	-	163 773 986	256 889 201	150 865 826	37 339 847	29 381 977	-	-	-	-
Total tax	-	253 859 200	387 688 353	231 653 951	61 369 650	43 241 400	-	-	-	-
Accounting depreciation	-	590 152 929	664 541 429	431 795 105	201 098 150	107 475 074	19 786 830	2 524 752	-	-
Tax accounting	-	(57 920 085)	(19 248 962)	6 258 770	9 116 426	50 410 842	9 280 846	1 175 580	782 882	-

Ragnarock Basement North:

Production: Ragnarock Basement North lies close to Johan Sverdrup. We have no estimates when production will begin. Reviewing Detnors current development plan and the possibility that Ragnarock Basement North could be a tie-in field do we believe it to start up in 2027. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

R-BASEMENT NORTH	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Barrels (boe)	-	-	-	-	1 022 904	2 959 291	2 313 379	1 329 302	1 134 375	797 760	642 971
Revenue	-	-	-	-	633 570 043	1 832 996 283	1 432 916 009	823 375 195	702 636 595	494 136 000	398 258 891
OPEX	-	-	-	-	59 298 432	171 560 239	134 122 782	77 084 970	65 791 265	46 267 275	37 290 045
Tax	-	-	-	-	-	643 470 499	704 843 497	329 936 314	312 547 786	324 716 729	281 555 700
Capex	32 004 505	155 880 763	480 444 091	1 227 466 879	189 391 362	-	-	-	-	-	-
Decomission cost											
Tax refund											
FCF	(32 004 505)	(155 880 763)	(480 444 091)	(1 227 466 879)	384 880 249	1 017 965 545	593 949 730	416 353 911	324 297 544	123 151 997	79 413 146
NPV	**389 352 517,43**										
NPV per share	**1,92**										
EBITDA	-	-	-	-	574 271 611	1 661 436 044	1 298 793 227	746 290 225	636 845 330	447 868 726	360 968 847
CAPEX	32 004 505	155 880 763	480 444 091	1 227 466 879	189 391 362	-	-	-	-	-	-
Depreciation	5 334 084	31 314 211	111 388 226	315 966 040	347 531 267	347 531 267	342 197 182	316 217 055	236 143 040	31 565 227	-
Uplift	1 760 248	10 333 690	36 758 115	104 268 793	112 925 070	104 351 628	77 927 203	10 416 525	-	-	-
Corporate tax	-	-	-	-	-	269 160 640	239 149 011	107 518 292	100 175 572	104 075 875	90 242 212
Special tax	-	-	-	-	-	374 309 859	465 694 486	222 418 022	212 372 214	220 640 854	191 313 489
Total tax	-	-	-	-	-	643 470 499	704 843 497	329 936 314	312 547 786	324 716 729	281 555 700
Accounting depreciation	-	-	-	-	175 002 215	507 673 861	395 781 688	227 422 076	194 073 178	136 483 849	110 001 915
Tax accounting	-	-	-	-	311 430 129	899 934 503	704 349 000	404 717 156	345 362 278	242 880 204	195 754 207

R-BASEMENT NORTH	2034	2035	2036	2037	2038	2039	2039
Barrels (boe)	698 654	508 719	355 743	270 207	138 243	8 451	-
Revenue	432 749 126	315 102 350	220 348 519	167 367 553	85 628 298	5 234 882	-
OPEX	40 519 457	29 503 875	20 631 821	15 671 071	8 017 606	490 156	-
Tax	305 939 141	222 766 811	155 779 025	118 323 255	60 536 339	3 700 886	-
Capex	-	-	-	-	-	-	-
Decomission cost							198 318 072
Tax refund							154 688 096
FCF	86 290 527	62 831 665	43 937 674	33 373 226	17 074 352	1 043 840	(43 629 976)
NPV							
NPV per share							
EBITDA	392 229 669	285 598 475	199 716 698	151 696 481	77 610 692	4 744 726	-
CAPEX	-	-	-	-	-	-	-
Depreciation	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-
Corporate tax	98 057 417	71 399 619	49 929 175	37 924 120	19 402 673	1 186 182	-
Special tax	207 881 724	151 367 192	105 849 850	80 399 135	41 133 667	2 514 705	-
Total tax	305 939 141	222 766 811	155 779 025	118 323 255	60 536 339	3 700 886	-
Accounting depreciation	119 528 361	87 033 492	60 861 815	46 228 099	23 651 140	1 445 911	-
Tax accounting	212 707 020	154 880 687	108 306 809	82 265 339	42 088 450	2 573 076	-

Ragnarock Basement:

Production: Ragnarock Basement lies close to Johan Sverdrup. We have no estimates when production will begin. Reviewing Detnors current development plan and the possibility that Ragnarock Basement could be a tie-in field do we believe it to start up in 2027. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

R-BASEMENT	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2034
Barrels (boe)	-	-	-	2 545 763	2 866 655	1 857 560	867 484	463 619	85 355	10 861	2 704	-
Revenue	-	-	-	806 146 189	936 311 089	881 003 443	411 472 024	219 907 532	40 486 381	5 151 853	1 282 516	-
OPEX	-	-	-	147 571 819	166 176 749	107 684 036	50 291 004	26 879 227	4 949 661	629 934	156 814	-
Tax	-	-	-	255 228 409	406 860 085	409 344 437	99 711 396	-	-	-	-	-
Capex	-	-	406 000 000	812 000 000	-	-	-	-	-	-	-	-
Decomission cost												138 822 651
Tax refund												189 495 804
FCF	-	-	(406 000 000)	(408 654 039)	363 274 255	363 974 969	261 469 624	193 028 305	35 536 720	4 521 919	1 125 702	50 673 154
NPV	**148 058 332,30**											
NPV per share	**0,73**											
EBITDA	-	-	-	658 574 370	770 134 339	773 319 407	361 181 020	193 028 305	35 536 720	4 521 919	1 125 702	-
CAPEX	-	-	406 000 000	812 000 000	-	-	-	-	-	-	-	-
Depreciation	-	-	67 666 667	203 000 000	203 000 000	203 000 000	203 000 000	203 000 000	135 333 333	-	-	-
Uplift	-	-	22 330 000	66 990 000	66 990 000	66 990 000	44 660 000	-	-	-	-	-
Corporate tax	-	-	-	96 976 926	141 783 585	142 579 852	39 545 255	-	-	-	-	-
Special tax	-	-	-	158 251 483	265 076 500	266 764 586	60 166 141	-	-	-	-	-
Total tax	-	-	-	255 228 409	406 860 085	409 344 437	99 711 396	-	-	-	-	-
Accounting depreciation	-	-	-	356 075 735	402 057 432	259 816 846	121 334 942	64 846 354	11 971 326	1 519 177	378 188	-
Tax accounting	-	-	-	235 948 936	287 099 988	400 531 998	187 079 940	99 981 921	18 381 007	2 342 139	583 061	-

Steinbit:

Production: Steinbit lies close to Johan Sverdrup. We have no estimates when production will begin. Reviewing Detnors current development plan and the possibility that Steinbit could be a tie-in field do we believe it to start up in 2030. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra and adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

STEINBIT	2026	2027	2028	2029	2030	2031	2032	2033
Barrels (boe)	-	-	-	-	1 385 707	4 008 892	3 133 888	1 800 779
Revenue	-	-	-	-	374 583 129	1 084 088 600	847 469 963	486 970 510
OPEX	-	-	-	-	80 330 388	232 409 191	181 693 424	104 425 452
Tax	-	-	-	-	-	-	-	-
Capex	43 355 856	211 168 521	650 847 907	1 662 824 589	256 564 653	-	-	-
Decomission cost								
Tax refund								
FCF	(43 355 856)	(211 168 521)	(650 847 907)	(1 662 824 589)	37 688 088	851 679 409	665 776 539	382 545 057
NPV	**(102 789 892,51)**							
NPV per share	**(0,51)**							
EBITDA	-	-	-	-	294 252 741	851 679 409	665 776 539	382 545 057
CAPEX	43 355 856	211 168 521	650 847 907	1 662 824 589	256 564 653	-	-	-
Depreciation	7 225 976	42 420 730	150 895 381	428 032 812	470 793 588	470 793 588	463 567 612	428 372 858
Uplift	2 384 572	13 998 841	49 795 476	141 250 828	152 977 312	141 363 043	105 566 408	14 111 056
Corporate tax	-	-	-	-	-	-	-	-
Special tax	-	-	-	-	-	-	-	-
Total tax	-	-	-	-	-	-	-	-
Accounting depreciation	-	-	-	-	237 106 392	685 956 062	537 704 454	308 128 831
Tax accounting	-	-	-	-	44 574 152	129 264 210	99 896 227	58 044 656

STEINBIT	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042
Barrels (boe)	1 536 715	1 080 710	871 020	946 452	689 151	481 918	366 044	187 275	11 449	-
Revenue	415 562 734	292 248 425	235 543 522	255 942 191	186 361 985	130 321 425	98 986 724	50 643 417	3 096 083	-
OPEX	89 126 098	62 677 342	50 516 070	54 890 891	39 968 304	27 949 511	21 229 284	10 861 290	664 004	-
Tax	-	-	27 631 848	50 262 825	36 598 420	25 592 979	28 266 081	31 030 059	1 897 021	-
Capex	-	-	-	-	-	-	-	-	-	-
Decomission cost			-	-	-	-	-	-	-	269 915 663
Tax refund										210 534 217
FCF	326 436 636	229 571 083	157 395 604	150 788 476	109 795 261	76 778 936	49 491 359	8 752 068	535 057	(59 381 446)
NPV										
NPV per share										
EBITDA	326 436 636	229 571 083	185 027 452	201 051 301	146 393 681	102 371 914	77 757 440	39 782 127	2 432 079	-
CAPEX	-	-	-	-	-	-	-	-	-	-
Depreciation	319 898 207	42 760 775	-	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	27 631 848	50 262 825	36 598 420	25 592 979	19 439 360	9 945 532	608 020	-
Special tax	-	-	-	-	-	-	8 826 721	21 084 527	1 289 002	-
Total tax	-	-	27 631 848	50 262 825	36 598 420	25 592 979	28 266 081	31 030 059	1 897 021	-
Accounting depreciation	262 945 192	184 918 762	149 039 012	161 946 170	117 919 635	82 460 245	62 633 365	32 044 374	1 959 031	-
Tax accounting	49 523 326	34 828 810	28 070 983	30 502 002	22 209 756	15 531 102	11 796 778	6 035 447	368 977	-

Storklakken:

Production: Storklakken is expected to start up after the Krafla development. We believe that 2023 is a good estimate. The production profile is done through a comparable of Lille-Frigg. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Viper/Kobra with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

STORKLAKKEN	2022	2023	2024	2025	2026	2027	2028	2029	2030	2030
Barrels (boe)	-	2 048 315	2 306 504	1 494 588	697 976	373 027	68 677	8 739	2 176	-
Revenue	-	840 981 416	1 029 498 496	702 384 582	338 368 354	262 584 604	48 345 730	6 152 324	1 531 894	-
OPEX	-	118 734 770	133 701 103	86 637 746	40 460 856	21 624 614	3 981 413	506 662	126 156	-
Tax	-	236 564 384	453 630 967	235 191 532	10 310 208	-	-	-	-	-
Capex	513 333 333	1 026 666 667	-	-	-	-	-	-	-	-
Decomission cost										180 289 157
Tax refund										140 625 542
FCF	(513 333 333)	(540 984 405)	442 166 426	380 555 304	287 597 291	240 959 990	44 364 317	5 645 662	1 405 738	(39 663 614)
NPV	**103 429 759,56**									
NPV per share	**0,51**									
EBITDA	-	722 246 646	895 797 393	615 746 836	297 907 499	240 959 990	44 364 317	5 645 662	1 405 738	-
CAPEX	513 333 333	1 026 666 667	-	-	-	-	-	-	-	-
Depreciation	85 555 556	256 666 667	256 666 667	256 666 667	256 666 667	256 666 667	171 111 111	-	-	-
Uplift	28 233 333	84 700 000	84 700 000	84 700 000	56 466 667	-	-	-	-	-
Corporate tax	-	95 006 106	159 782 682	89 770 042	10 310 208	-	-	-	-	-
Special tax	-	141 558 278	293 848 285	145 421 490	-	-	-	-	-	-
Total tax	-	236 564 384	453 630 967	235 191 532	10 310 208	-	-	-	-	-
Accounting depreciation	-	450 210 699	508 348 477	328 504 058	153 411 996	81 989 644	15 136 159	1 920 798	478 168	-
Tax accounting	-	212 188 039	302 210 154	224 049 367	112 706 492	123 996 870	22 797 963	2 905 394	723 504	-

Skalle:

Production: Combination of being a gas field and in the Barents Sea do we believe that Skalle won't start production before 2030. The production profile is done through a comparable of Glitne. This is explained in section 6.1.1.1.

CAPEX: CAPEX is estimated comparing the field with Bøyla with adjusting for reserves. We have also estimated that Detnor will achieve a cost reduction of 30% on this field, since contracts are not made yet. This is explained in section 6.1.4.

OPEX: We assume an OPEX of 7 USD/bbl. Detnors ambition to reduce OPEX with 20% are taken into account, and we believe that new fields where contracts are not already negotiated will benefit from these OPEX goals.

Skalle	2026	2027	2028	2029	2030	2031	2032	2033	2034
Barrels (boe)	-	-	-	-	260 345	753 186	588 791	338 328	288 716
Revenue	-	-	-	-	1 743 219	5 166 487	4 039 068	2 321 391	1 981 285
OPEX	-	-	-	-	15 092 376	43 664 757	34 136 340	19 619 327	16 744 903
Tax	-	-	-	-	-	-	-	-	-
Capex	8 145 646	39 674 086	122 280 516	312 409 468	48 203 056	-	-	-	-
Decomission cost									
Tax refund									
FCF	(8 145 646)	(39 674 086)	(122 280 516)	(312 409 468)	(61 552 212)	(38 498 271)	(30 097 272)	(17 297 936)	(14 763 619)
NPV	**(184 651 014,44)**								
NPV per share	**(0,91)**								
EBITDA	-	-	-	-	(13 349 156)	(38 498 271)	(30 097 272)	(17 297 936)	(14 763 619)
CAPEX	8 145 646	39 674 086	122 280 516	312 409 468	48 203 056	-	-	-	-
Depreciation	1 357 608	7 969 955	28 350 041	80 418 286	88 452 129	88 452 129	87 094 521	80 482 173	60 102 087
Uplift	448 011	2 630 085	9 355 514	26 538 034	28 741 192	26 559 117	19 833 689	2 651 168	-
Corporate tax	-	-	-	-	-	-	-	-	-
Special tax	-	-	-	-	-	-	-	-	-
Total tax	-	-	-	-	-	-	-	-	-
Accounting depreciation	-	-	-	-	44 547 261	128 876 594	101 023 261	57 890 871	49 401 824
Tax accounting	-	-	-	-	(45 159 206)	(130 552 394)	(102 274 016)	(58 647 270)	(50 049 045)

Skalle	2035	2036	2037	2038	2039	2040	2041	2042	2043
Barrels (boe)	203 042	163 646	177 818	129 477	90 542	68 772	35 185	2 151	-
Revenue	1 393 325	1 122 979	1 220 232	888 501	621 321	471 930	241 448	14 761	-
OPEX	11 775 743	9 490 898	10 312 834	7 509 197	5 251 120	3 988 532	2 040 606	124 752	-
Tax	-	-	-	-	-	-	-	-	-
Capex	-	-	-	-	-	-	-	-	-
Decomission cost							-	-	51 807 229
Tax refund							(1 799 158)	(109 991)	639 896 552
FCF	(10 382 418)	(8 367 919)	(9 092 602)	(6 620 696)	(4 629 799)	(3 516 602)	(1 799 158)	(109 991)	588 089 323
NPV									
NPV per share									
EBITDA	(10 382 418)	(8 367 919)	(9 092 602)	(6 620 696)	(4 629 799)	(3 516 602)	(1 799 158)	(109 991)	-
CAPEX	-	-	-	-	-	-	-	-	-
Depreciation	8 033 843	-	-	-	-	-	-	-	-
Uplift	-	-	-	-	-	-	-	-	-
Corporate tax	-	-	-	-	-	-	-	-	-
Special tax	-	-	-	-	-	-	-	-	-
Total tax	-	-	-	-	-	-	-	-	-
Accounting depreciation	34 742 313	28 001 269	30 426 250	22 154 598	15 492 531	11 767 481	6 020 458	368 060	-
Tax accounting	(35 197 290)	(28 367 967)	(30 824 705)	(22 444 729)	(15 695 417)	(11 921 585)	(6 099 301)	(372 880)	-

Commodity prices:

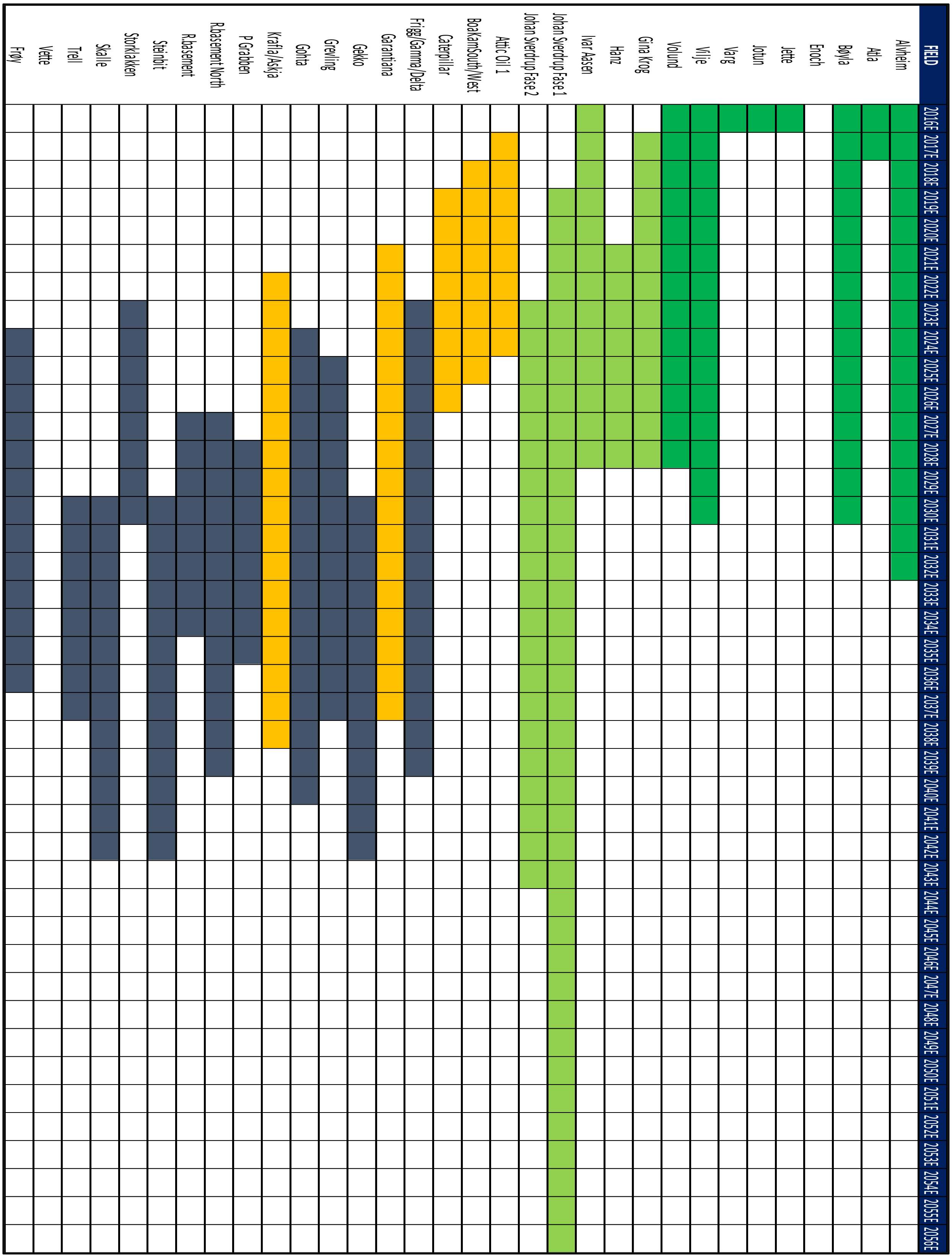
Prices in use	Unit	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Oil price	USD/bbl	42.53	49.58	53.90	56.75	58.54	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00
Gas	$/mmbtu	2.52	3.23	3.37	3.42	3.46	5.09	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21
USD/NOK	NOK	8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29

Prices in use	Unit	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056
Oil price	USD/bbl	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00	85.00
Gas	$/mmbtu	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21	5.21
USD/NOK	NOK	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29	8.29

8.1 Risk weighing

Assets	Prob./ valuation risk %	Comment
Producing fields	100	
Alvheim	100%	Stable historical production and no risk in estimates
Bøyla	100%	Stable historical production and no risk in estimates
Volund	100%	Stable historical production and no risk in estimates
Vilje	100%	Stable historical production and no risk in estimates
Varg	100%	Abandonment plan concluded, no estimation risk
Enoch	100%	Shut down
Jotun	100%	Abandonment plan concluded, no estimation risk
Atla	100%	Abandonment plan concluded, no estimation risk
Jette	100%	Abandonment plan concluded, no estimation risk
Sum producing fields		
Fields under development	75>%	
Ivar Aasen	100%	Starting production Q4 2016, no risk
Gina Krog	100%	Starting production Q1 2017, no risk
Johan Sverdrup phase 1	100%	Norway's biggest 5th biggest oil discovery, no risk
Johan Sverdrup phase 2	100%	Norway's biggest 5th biggest oil discovery, no risk
Hanz	100%	Tie-in development for Ivar Aasen, no risk
Sum fields under development		
Planned, but not sanctioned fields	20-75%	
Garantiana (34/6-2S)	70%	Large field in emerging area, low risk/very low risk
BoaKamSouth/West	75%	Tie-in development for Alvheim, very low risk
Attic Oil 1	75%	Tie-in development for Alvheim, very low risk
Caterpillar	75%	Tie-in development for Alvheim, very low risk
Krafla	70%	Large field in emerging area, low risk/very low risk
Sum planned, but not sanctioned fields		
Non-developed assets	0-20%	
Frigg/Gamma/Delta	15%	Emerging area (North of Alvheim), High risk
Frøy	15%	Emerging area (North of Alvheim), High risk
Gekko	20%	Tie-in development for Alvheim in early stage, high risk
Grevling	10%	No Detnor discoveries in the area, very high risk
Gohta	10%	Frontier area, High risk/Very high risk
P-Grabben	15%	Tie-in development for Johan Sverdrup, High risk
Ragnarock basement	15%	Tie-in development for Johan Sverdrup, High risk
Ragnarock basement North	15%	Tie-in development for Johan Sverdrup, High risk
Steinbit	10%	Emerging area, High risk
Storklakken	15%	Emerging area (North of Alvheim), High risk
Skalle	10%	Frontier area, High risk/Very high risk
Trell	10%	Gas field, high risk

8.2 Production start for the petroleum assets:



9 ROV Valuation

Shares	202,618602		
Assets	WI%	Value NOKm	NOK per share
Producing fields			
Alvheim	65 %	4 577 443 724	22,59
Bøyla	65 %	2 395 741 434	11,82
Volund	65 %	1 396 800 010	6,89
Vilje	47 %	566 343 787	2,80
Varg	5 %	2 548 231	0,01
Enoch	2 %	0	0,00
Jotun	7 %	-67 489 984	-0,33
Atla	10 %	25 471 824	0,13
Jette	70 %	4 863 000	0,02
Sum producing fields		8 901 722 026	43,93
Fields under development			
Ivar Aasen	35 %	6 037 120 744	29,80
Gina Krog	3 %	779 996 117	3,85
Johan Sverdrup phase 1	12 %	7 228 156 122	35,67
Johan Sverdrup phase 2	12 %	2 259 352 556	11,15
Hanz	35 %	78 998 225	0,39
Sum fields under development		16 383 623 765	80,86
Planned, but not sanctioned fields			
Garantiana (34/6-2S)	30 %	1 015 591 782	5,01
BoaKamSouth/West	61 %	116 807 456	0,58
Attic Oil 1	62 %	140 228 932	0,69
Caterpillar	65 %	167 051 581	0,82
Krafla	50 %	1 235 970 568	6,10
Sum planned, but not sanctioned fields		2 676	13,21
Non-developed assets			
Frigg/Gamma/Delta	60 %	1 425 498 665	7,04
Frøy	100 %	560 304 312	2,77
Gekko	65 %	0	0,00
Grevling	30 %	155 863 332	0,77
Gohta	60 %	1 311 725 490	6,47
P-Grabben	20 %	89 647 496	0,44
Ragnarock basement	58 %	0	0,00
Ragnarock basement North	58 %	0	0,00
Steinbit	50 %	0	0,00
Storklakken	100 %	15 243 601	0,08
Skalle	10 %	0	0,00
Trell	50 %	164 814 294	0,81
Sum Non-developed assets		3 723	18,37
Sum petroleum assets		25 285 352 190	156,37
NPV of NWC		818	4,04
NPV of other operating costs		-3 894	-19,22
Other assets		145	0,72
Reserves and resources		25 285 349 259	141,91
Net Financial Obligations		-26 729	-131,92
Core NAV		25 285 322 530	9,99
Price/Core NAV			**0,16**

Barrel production: bbl

Gas production: Mm3

Attic Oil:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	203 840 000	33 973 333	11 211 200
1 278 148	0	74 090 497	407 680 000	101 920 000	33 633 600
1 439 258	0	83 429 489	0	101 920 000	33 633 600
932 623	0	54 061 953	0	101 920 000	33 633 600
435 537	0	25 247 574	0	101 920 000	22 422 400
232 769	0	13 493 759	0	101 920 000	0
42 854	0	2 484 402	0	67 946 667	0
5 453	0	316 157	0	0	0
1 358	0	78 721	0	0	0
0	0	0	15 931 096	0	0

BoaKamSouthWest:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	169 680 000	28 280 000	9 332 400
1 063 953	0	61 674 173	339 360 000	84 840 000	27 997 200
1 198 064	0	69 448 928	0	84 840 000	27 997 200
776 332	0	45 003 088	0	84 840 000	27 997 200
362 548	0	21 017 184	0	84 840 000	18 664 800
193 761	0	11 232 970	0	84 840 000	0
35 673	0	2 068 187	0	56 560 000	0
4 539	0	263 229	0	0	0
1 130	0	65 539	0	0	0
0	0	0	13 178 441	0	0

Caterpillar:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	242 666 667	40 444 444	13 346 667
1 521 605	0	88 203 846	485 333 333	121 333 333	40 040 000
1 713 403	0	99 324 034	0	121 333 333	40 040 000
1 110 266	0	64 362 872	0	121 333 333	40 040 000
518 496	0	30 058 991	0	121 333 333	26 693 333
277 106	0	16 065 745	0	121 333 333	0
51 017	0	2 958 418	0	80 888 889	0
6 492	0	376 513	0	0	0
1 616	0	93 728	0	0	0
0	0	0	18 844 982	0	0

Frigg/Gamma/Delta:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	418 662 958	69 777 160	23 026 463
0	0	0	938 495 229	226 193 031	74 643 700
0	0	0	1 999 410 775	559 428 160	184 611 293
1 795 581	0	104 091 070	1 327 043 515	780 602 079	257 598 686
14 907 274	0	864 225 650	0	780 602 079	234 572 224
11 399 978	0	660 936 491	0	780 602 079	182 954 986
5 381 999	0	312 096 985	0	710 824 920	72 987 393
4 648 842	0	269 622 615	0	554 409 048	0
2 294 706	0	133 084 826	0	221 173 919	0
1 590 055	0	92 217 591	0	0	0
1 384 341	0	80 286 866	0	0	0
1 065 625	0	61 802 497	0	0	0
799 032	0	46 341 054	0	0	0
649 290	0	37 656 518	0	0	0
527 884	0	30 615 406	0	0	0
443 945	0	25 747 269	0	0	0
361 455	0	20 963 106	0	0	0
313 113	0	18 159 475	0	0	0
244 749	0	14 194 552	0	0	0
192 130	0	11 142 856	0	0	0
0	0	0	173 836 048	0	0

Frøy:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	53 719 754	8 953 292	2 954 586
0	0	0	261 646 804	52 561 093	17 345 161
0	0	0	806 428 314	186 965 812	61 698 718
0	0	0	2 060 310 581	530 350 909	175 015 800
2 099 556	0	121 708 887	317 894 547	583 333 333	189 545 414
6 074 079	0	352 118 599	0	583 333 333	175 154 839
4 748 315	0	275 276 082	0	574 380 041	130 801 282
2 728 453	0	158 187 513	0	530 772 240	17 484 200
2 328 356	0	135 019 137	0	396 367 521	0
1 637 439	0	94 967 871	0	52 982 424	0
1 319 727	0	76 539 500	0	0	0
1 434 019	0	83 168 016	0	0	0
1 044 168	0	60 558 036	0	0	0
730 178	0	42 347 744	0	0	0
554 613	0	32 165 582	0	0	0
283 750	0	16 456 499	0	0	0
17 347	0	1 006 067	0	0	0
0	0	0	91 180 723	0	0

Garantiana:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	298 297 357	49 716 226	16 406 355
0	0	0	668 677 850	161 162 535	53 183 636
0	0	0	1 424 580 178	398 592 564	131 535 546
1 279 351	0	74 164 887	945 518 504	556 178 982	183 539 064
10 621 433	0	615 760 775	0	556 178 982	167 132 709
8 122 484	0	470 917 250	0	556 178 982	130 355 428
3 834 674	0	222 369 102	0	506 462 755	52 003 518
3 312 300	0	192 106 113	0	395 016 447	0
1 634 978	0	94 822 938	0	157 586 417	0
1 132 914	0	65 705 033	0	0	0
986 343	0	57 204 392	0	0	0
759 258	0	44 034 279	0	0	0
569 311	0	33 018 001	0	0	0
462 619	0	26 830 269	0	0	0
376 117	0	21 813 477	0	0	0
316 311	0	18 344 929	0	0	0
257 537	0	14 936 213	0	0	0
223 093	0	12 938 626	0	0	0
174 383	0	10 113 618	0	0	0
136 893	0	7 939 285	0	0	0
0	0	0	123 942 000	0	0

Gekko:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0		0	32 451 201	5 408 534	1 784 816
0		0	158 056 439	31 751 273	10 477 920
0		0	487 149 797	112 942 906	37 271 159
0		0	1 244 599 011	320 376 075	105 724 105
68 236	154 045	60 126 078	192 034 755	352 381 867	114 501 200
197 408	445 658	173 954 758	0	352 381 867	105 808 096
154 320	348 386	135 994 775	0	346 973 334	79 014 857
88 675	200 188	78 160 869	0	320 630 594	10 561 912
75 672	170 832	66 709 534	0	239 438 961	0
53 217	120 140	46 913 041	0	32 005 793	0
42 891	96 829	37 810 513	0	0	0
46 606	105 215	41 085 000	0	0	0
33 935	76 611	29 915 670	0	0	0
23 731	53 573	20 919 786	0	0	0
18 025	40 692	15 889 797	0	0	0
9 222	20 819	8 129 511	0	0	0
564	1 273	496 997	0	0	0
0	0	0	45 043 277	0	0

Gohta:

Barrel production	Gas production	Production Cost	CAPEX/Depreciation	Depreciation	Uplift
0	0	0	457 040 395	76 173 399	25 137 222
0	0	0	1 024 523 958	246 927 392	81 486 039
0	0	0	2 182 690 097	610 709 075	201 533 995
2 060 589	139 853	170 457 133	1 448 689 170	852 157 270	281 211 899
17 107 424	1 161 087	1 415 256 818	0	852 157 270	256 074 677
13 082 489	887 913	1 082 508 390	0	852 157 270	199 725 860
6 176 323	419 189	511 136 050	0	775 983 871	79 677 904
5 334 959	362 086	441 496 800	0	605 229 878	0
2 633 379	178 728	217 926 402	0	241 448 195	0
1 824 730	123 845	151 006 305	0	0	0
1 588 654	107 823	131 469 742	0	0	0
1 222 900	82 999	101 201 588	0	0	0
916 961	62 234	75 883 476	0	0	0
745 118	50 571	61 662 548	0	0	0
605 794	41 115	50 132 728	0	0	0
509 467	34 578	42 161 153	0	0	0
414 802	28 153	34 327 087	0	0	0
359 326	24 388	29 736 141	0	0	0
280 871	19 063	23 243 578	0	0	0
220 486	14 964	18 246 427	0	0	0
0	0	0	284 347 084	0	0

Grevling:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	38 626 126	6 437 688	2 124 437
0	0	0	188 131 956	37 793 014	12 471 694
0	0	0	579 846 317	134 434 066	44 363 242
0	0	0	1 481 425 543	381 338 324	125 841 647
1 217 129	2 768	71 567 073	228 575 782	419 434 287	136 288 878
3 521 190	8 008	207 055 461	0	419 434 287	125 941 620
2 752 635	6 260	161 872 323	0	412 996 600	94 050 073
1 581 705	3 597	93 033 585	0	381 641 274	12 571 668
1 349 766	3 070	79 403 251	0	285 000 221	0
949 236	2 159	55 839 814	0	38 095 964	0
765 056	1 740	45 005 226	0	0	0
831 312	1 891	48 902 793	0	0	0
605 312	1 377	35 608 125	0	0	0
423 290	963	24 900 473	0	0	0
321 513	731	18 913 362	0	0	0
164 492	374	9 676 422	0	0	0
10 056	23	591 568	0	0	0
0	0	0	53 340 723	0	0

Krafla/Askja:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	872 214 495	145 369 083	47 971 797
0	0	0	1 955 198 393	471 235 481	155 507 709
0	0	0	4 165 439 116	1 165 475 334	384 606 860
2 618 555	178 416	216 866 582	2 764 673 989	1 626 254 332	536 663 930
21 739 775	1 481 247	1 800 581 194	0	1 626 254 332	488 692 132
16 624 968	1 132 748	1 377 237 138	0	1 626 254 332	381 156 221
7 848 749	534 777	650 300 319	0	1 480 885 250	152 057 069
6 779 561	461 928	561 700 764	0	1 155 018 851	0
3 346 446	228 011	277 260 053	0	460 778 998	0
2 318 831	157 994	192 119 981	0	0	0
2 018 830	137 554	167 264 303	0	0	0
1 554 037	105 885	128 755 202	0	0	0
1 165 256	79 395	96 543 862	0	0	0
946 881	64 516	78 451 079	0	0	0
769 831	52 453	63 782 096	0	0	0
647 421	44 112	53 640 143	0	0	0
527 122	35 916	43 673 138	0	0	0
456 624	31 112	37 832 240	0	0	0
356 925	24 319	29 571 983	0	0	0
280 189	19 091	23 214 284	0	0	0
0	0	0	361 645 542	0	0

P-Graben:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	56 000 000	9 333 333	3 080 000
688 345	11 519	44 101 923	112 000 000	28 000 000	9 240 000
775 111	12 971	49 662 017	0	28 000 000	9 240 000
502 263	8 405	32 181 436	0	28 000 000	9 240 000
234 558	3 925	15 029 496	0	28 000 000	6 160 000
125 357	2 098	8 032 873	0	28 000 000	0
23 079	386	1 479 209	0	18 666 667	0
2 937	49	188 256	0	0	0
731	12	46 864	0	0	0
0	0	0	9 573 976	0	0

Ragnarock Basement:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	406 000 000	67 666 667	22 330 000
1 708 196	119 142	147 571 819	812 000 000	203 000 000	66 990 000
1 923 513	134 160	166 176 749	0	203 000 000	66 990 000
1 246 415	86 934	107 684 036	0	203 000 000	66 990 000
582 078	40 598	50 291 004	0	203 000 000	44 660 000
311 086	21 697	26 879 227	0	203 000 000	0
57 273	3 995	4 949 661	0	135 333 333	0
7 288	508	629 934	0	0	0
1 814	127	156 814	0	0	0
0	0	0	30 540 983	0	0

Ragnarock Basement North:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	32 004 505	5 334 084	1 760 248
0	0	0	155 880 763	31 314 211	10 333 690
0	0	0	480 444 091	111 388 227	36 758 115
0	0	0	1 227 466 879	315 966 040	104 268 793
898 915	19 712	59 298 432	189 391 362	347 531 267	112 925 070
2 600 589	57 027	171 560 239	0	347 531 267	104 351 628
2 032 970	44 580	134 122 782	0	342 197 183	77 927 203
1 168 175	25 616	77 084 970	0	316 217 055	10 416 525
996 875	21 860	65 791 265	0	236 143 040	0
701 062	15 373	46 267 275	0	31 565 227	0
565 035	12 390	37 290 045	0	0	0
613 969	13 463	40 519 457	0	0	0
447 056	9 803	29 503 875	0	0	0
312 622	6 855	20 631 821	0	0	0
237 455	5 207	15 671 071	0	0	0
121 486	2 664	8 017 606	0	0	0
7 427	163	490 156	0	0	0
0	0	0	43 629 976	0	0

Steinbit:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	43 355 856	7 225 976	2 384 572
0	0	0	211 168 522	42 420 730	13 998 841
0	0	0	650 847 907	150 895 381	49 795 476
0	0	0	1 662 824 589	428 032 812	141 250 828
523 962	137 002	80 330 388	256 564 653	470 793 588	152 977 312
1 515 838	396 352	232 409 191	0	470 793 588	141 363 043
1 184 983	309 842	181 693 424	0	463 567 612	105 566 408
680 909	178 040	104 425 452	0	428 372 858	14 111 056
581 061	151 932	89 126 098	0	319 898 207	0
408 637	106 848	62 677 342	0	42 760 775	0
329 349	86 116	50 516 070	0	0	0
357 872	93 574	54 890 891	0	0	0
260 581	68 135	39 968 304	0	0	0
182 222	47 646	27 949 511	0	0	0
138 408	36 190	21 229 284	0	0	0
70 812	18 516	10 861 290	0	0	0
4 329	1 132	664 004	0	0	0
0	0	0	59 381 446	0	0

Storklakken:

Barrel production	Gas production	Production Cost	CAPEX/Decomission	Depreciation	Uplift
0	0	0	513 333 333	85 555 556	28 233 333
2 048 315	0	118 734 770	1 026 666 667	256 666 667	84 700 000
2 306 504	0	133 701 103	0	256 666 667	84 700 000
1 494 588	0	86 637 746	0	256 666 667	84 700 000
697 976	0	40 460 856	0	256 666 667	56 466 667
373 027	0	21 624 614	0	256 666 667	0
68 677	0	3 981 413	0	171 111 111	0
8 739	0	506 662	0	0	0
2 176	0	126 156	0	0	0
0	0	0	39 663 614	0	0

Skalle:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	8 145 646	1 357 608	448 011
0	0	0	39 674 086	7 969 955	2 630 085
0	0	0	122 280 516	28 350 041	9 355 514
0	0	0	312 409 468	80 418 286	26 538 034
0	41 390	15 092 376	48 203 056	88 452 129	28 741 192
0	119 743	43 664 757	0	88 452 129	26 559 117
0	93 607	34 136 340	0	87 094 521	19 833 689
0	53 788	19 619 327	0	80 482 173	2 651 168
0	45 901	16 744 903	0	60 102 087	0
0	32 280	11 775 743	0	8 033 843	0
0	26 017	9 490 898	0	0	0
0	28 270	10 312 834	0	0	0
0	20 585	7 509 197	0	0	0
0	14 395	5 251 120	0	0	0
0	10 934	3 988 532	0	0	0
0	5 594	2 040 606	0	0	0
0	342	124 752	0	0	0
0	0	0	11 397 590	0	0

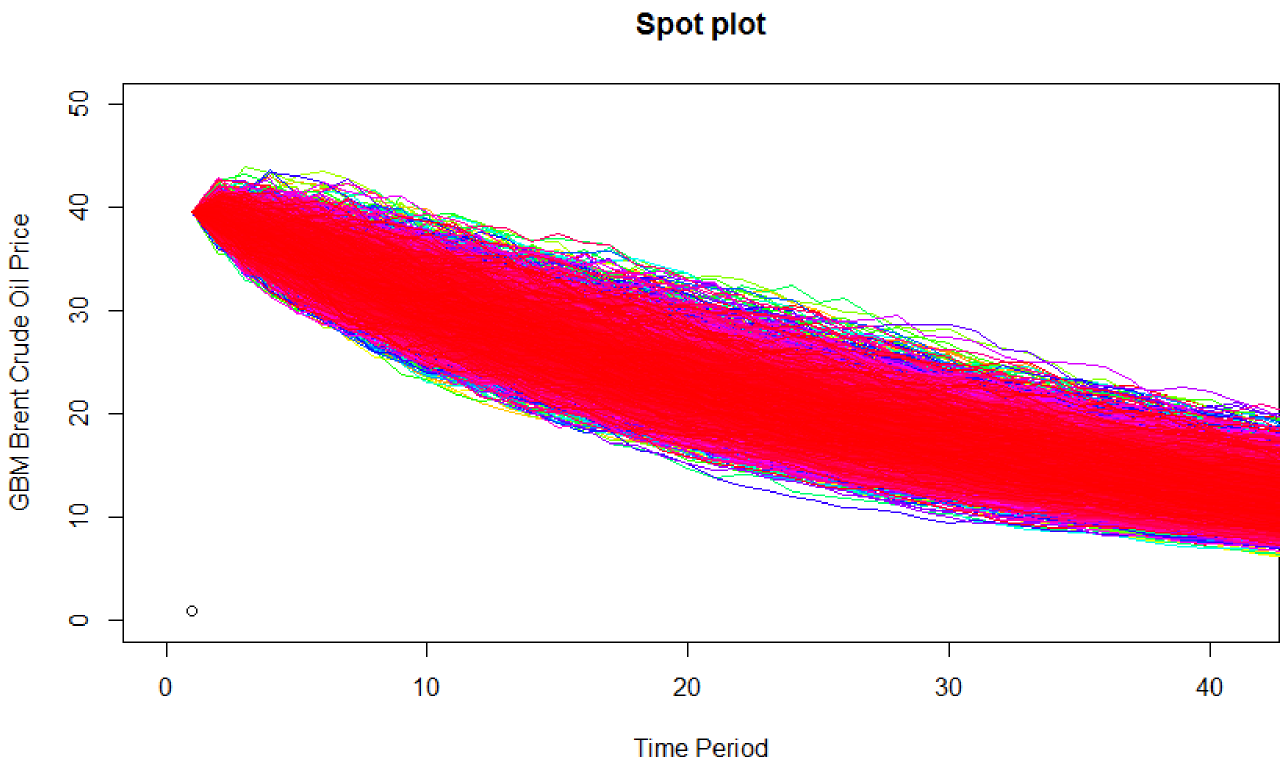
Trell:

Barrel production	Gas production	Production Cost	CAPEX	Depreciation	Uplift
0	0	0	233 333 333	38 888 889	12 833 333
1 463 082	0	84 810 550	466 666 667	116 666 667	38 500 000
1 647 503	0	95 500 788	0	116 666 667	38 500 000
1 067 563	0	61 884 104	0	116 666 667	38 500 000
498 554	0	28 900 611	0	116 666 667	25 666 667
266 448	0	15 446 153	0	116 666 667	0
49 055	0	2 843 866	0	77 777 778	0
6 242	0	361 901	0	0	0
1 554	0	90 111	0	0	0
0	0	0	13 725 538	0	0

Simulating the Joint Stochastic Process and averaging the futures price for each time step:

Spot oil price		S0					Rf					Conv. Yield				
Year	Base case	30	50	60	70	80	0,02	0,04	0,06	0,08	0,1	-0,3	-0,1	0	0,1	0,2
1	39.600000	30.000000	50.000000	60.00000	70.00000	80.00000	39.60000	39.60000	39.60000	39.60000	39.60000	39.600000	39.600000	39.600000	39.600000	39.600000
2	36.843188	27.906538	46.496193	55.78906	65.10545	74.41762	37.40445	38.17205	38.94883	39.71998	40.52826	36.276691	37.649489	38.378255	39.099842	39.825849
3	36.077268	27.325374	45.524640	54.62046	63.73361	72.85982	37.19148	38.72527	40.31518	41.92886	43.67446	35.627249	36.720867	37.288577	37.855397	38.426666
4	34.991994	26.493411	44.126556	52.96996	61.81672	70.66718	36.63774	38.91597	41.32190	43.85133	46.61217	34.534987	35.628589	36.189994	36.768279	37.363956
5	33.996401	25.731671	42.865725	51.46570	60.06545	68.62463	36.13953	39.17198	42.43213	45.94882	49.84270	33.538216	34.606763	35.145745	35.708803	36.284746
6	33.025816	24.996363	41.609860	49.95041	58.33400	66.64677	35.65426	39.41592	43.56105	48.09947	53.28764	32.574127	33.598263	34.132771	34.689646	35.245163
7	32.075266	24.269022	40.386411	48.52965	56.66104	64.71356	35.17810	39.67700	44.71167	50.40818	56.99395	31.639716	32.635159	33.140827	33.683461	34.222368
8	31.141921	23.563589	39.221442	47.10413	55.02854	62.83905	34.69185	39.92244	45.90314	52.80149	60.91056	30.726308	31.696056	32.193368	32.713003	33.226000
9	30.238270	22.889644	38.085033	45.74904	53.41547	61.01799	34.23019	40.16862	47.13398	55.29522	65.06769	29.843589	30.797529	31.264508	31.765827	32.260471
10	29.372003	22.225128	36.978184	44.41993	51.84470	59.28389	33.77727	40.41166	48.39587	57.91351	69.52440	28.978828	29.913137	30.356691	30.829765	31.329781
11	28.519693	21.580018	35.897942	43.12675	50.33474	57.58164	33.31333	40.66481	49.69343	60.64875	74.29961	28.142313	29.045951	29.460701	29.939866	30.427116
12	27.688987	20.948753	34.858949	41.89433	48.87122	55.90619	32.86157	40.92634	50.99481	63.52988	79.37819	27.333569	28.210551	28.612427	29.077993	29.552467
13	26.901060	20.350442	33.843638	40.68242	47.45137	54.28438	32.41494	41.19018	52.35413	66.52814	84.83011	26.529258	27.380659	27.775987	28.238006	28.688148
14	26.120158	19.761299	32.863500	39.50083	46.06505	52.70535	31.96609	41.46383	53.75871	69.68230	90.64674	25.761747	26.590768	26.965453	27.419362	27.863389
15	25.363474	19.190740	31.901926	38.36299	44.73324	51.17624	31.52741	41.71135	55.15654	72.97373	96.84584	25.017320	25.830246	26.187819	26.624967	27.063889
16	24.621294	18.644455	30.966691	37.23490	43.44100	49.70202	31.10132	41.97234	56.60966	76.42445	103.47523	24.290190	25.087666	25.425436	25.849791	26.281221
17	23.915226	18.110114	30.068681	36.17208	42.16052	48.28581	30.66758	42.24449	58.09722	80.04629	110.58255	23.594933	24.367994	24.694184	25.116487	25.515853
18	23.219722	17.592566	29.216843	35.13129	40.94246	46.87584	30.24229	42.52301	59.62817	83.80105	118.21221	22.914555	23.666404	23.980880	24.392799	24.769231
19	22.555842	17.085688	28.370427	34.10682	39.74619	45.50900	29.82657	42.79114	61.21877	87.80740	126.22887	22.249486	22.984453	23.273897	23.676254	24.053573
20	21.897321	16.593809	27.548523	33.11767	38.59903	44.19297	29.41899	43.05562	62.85662	91.98017	134.84625	21.601130	22.322787	22.617321	22.994361	23.357331
21	21.262335	16.113403	26.753256	32.15525	37.47887	42.91145	29.00551	43.32447	64.54093	96.33238	144.10520	20.973715	21.690663	21.965313	22.331896	22.673993
22	20.649048	15.650084	25.983035	31.23057	36.39331	41.67595	28.61033	43.59160	66.28310	100.86740	153.95281	20.367091	21.060884	21.331916	21.686500	22.015270
23	20.046593	15.197301	25.234549	30.32236	35.35543	40.45642	28.22644	43.84948	68.05702	105.64285	164.46734	19.776549	20.449473	20.725406	21.064695	21.377947
24	19.464521	14.768546	24.500529	29.43676	34.33376	39.28084	27.84237	44.13913	69.85281	110.64083	175.74643	19.200478	19.862010	20.131540	20.460095	20.753990
25	18.905237	14.341418	23.794607	28.59709	33.33901	38.15606	27.46119	44.41556	71.68742	115.88820	187.80532	18.638269	19.283351	19.548211	19.873339	20.154338
26	18.368122	13.923653	23.112126	27.77089	32.38139	37.04049	27.07677	44.68832	73.58038	121.37307	200.59890	18.093480	18.723349	18.977748	19.303672	19.570131
27	17.838417	13.524230	22.451719	26.96252	31.45074	35.98459	26.71327	44.97701	75.53612	127.07354	214.26887	17.567126	18.192881	18.427193	18.745153	19.001251
28	17.320571	13.127798	21.803065	26.18308	30.54529	34.93881	26.34009	45.24935	77.55919	133.14894	228.96137	17.061214	17.657306	17.903312	18.200552	18.448812
29	16.822819	12.749967	21.165760	25.42502	29.65740	33.92771	25.98618	45.52868	79.62663	139.44910	244.62401	16.568185	17.143668	17.379776	17.667123	17.912954
30	16.343872	12.384496	20.549470	24.69022	28.79977	32.93845	25.62447	45.80970	81.72534	146.07810	261.38761	16.092505	16.645661	16.882355	17.158723	17.394669
31	15.871634	12.025409	19.961055	23.98033	27.96379	31.97146	25.26844	46.09927	83.87960	153.00527	279.35482	15.621962	16.166937	16.397812	16.661806	16.899765
32	15.414266	11.675262	19.375323	23.27723	27.14514	31.05297	24.92976	46.38776	86.09850	160.24212	298.48834	15.166672	15.703891	15.920553	16.178265	16.405827
33	14.975019	11.341355	18.811386	22.60797	26.36379	30.16169	24.59279	46.65934	88.38122	167.85932	319.02262	14.731290	15.250707	15.455698	15.709166	15.929689
34	14.535043	11.014109	18.260203	21.95475	25.59916	29.28017	24.25987	46.97277	90.71499	175.80050	340.80069	14.304072	14.816006	15.005283	15.258146	15.469288
35	14.114930	10.699344	17.743753	21.31877	24.85565	28.43029	23.92618	47.24916	93.12386	184.08127	364.17496	13.890231	14.388927	14.570408	14.812663	15.024095
36	13.708025	10.393167	17.234593	20.69888	24.13067	27.60253	23.59813	47.54883	95.59775	192.73324	389.05846	13.492312	13.972969	14.150320	14.386925	14.585413
37	13.309276	10.090447	16.728814	20.09378	23.42466	26.80231	23.28266	47.85048	98.13587	201.81614	415.63923	13.102865	13.574993	13.738615	13.962270	14.161007
38	12.922134	9.799509	16.245549	19.50710	22.74784	26.03605	22.96251	48.16865	100.73045	211.35130	444.03813	12.729692	13.187751	13.344896	13.561917	13.752996
39	12.551204	9.516501	15.772242	18.94299	22.09390	25.28414	22.64625	48.48671	103.41458	221.32621	474.30489	12.363235	12.807971	12.963117	13.170840	13.355801
40	12.187905	9.239065	15.314173	18.39298	21.44868	24.54632	22.32825	48.80907	106.14257	231.79107	507.08949	11.999515	12.437903	12.587470	12.786635	12.967164
41	11.834213	8.973152	14.867016	17.86075	20.83008	23.82699	22.02307	49.08730	108.98347	242.82279	541.97511	11.652695	12.076885	12.228409	12.417498	12.591111
42	11.485937	8.715298	14.431546	17.35721	20.22893	23.15410	21.72727	49.40547	111.86968	254.29522	579.22287	11.313283	11.728228	11.875621	12.061321	12.225477
43	11.156284	8.464895	14.008085	16.85922	19.64990	22.48183	21.41474	49.71892	114.86777	266.32113	619.05090	10.982985	11.390873	11.532108	11.716152	11.868209
44	10.833250	8.221769	13.608792	16.36729	19.07342	21.84105	21.11334	50.03768	117.92277	278.80440	661.76978	10.666967	11.058625	11.197720	11.382396	11.527410
45	10.519169	7.982301	13.217714	15.89338	18.52063	21.21266	20.83388	50.34774	121.06747	291.98400	706.94468	10.355088	10.739998	10.876816	11.052701	11.195213
46	10.214473	7.751073	12.838777	15.43807	17.98643	20.60199	20.55266	50.66505	124.27477	305.65930	755.09203	10.053361	10.429201	10.560623	10.732321	10.870766
47	9.919316	7.526832	12.466135	14.98127	17.47433	20.00169	20.27202	50.98036	127.57814	320.02132	806.85629	9.761979	10.131704	10.251269	10.420354	10.558075
48	9.635274	7.309651	12.099057	14.55280	16.96743	19.42881	19.99354	51.29641	130.91990	335.08802	862.39343	9.476256	9.835510	9.953737	10.121046	10.257111
49	9.355803	7.099219	11.750975	14.13324	16.47873	18.87124	19.71820	51.63308	134.44339	350.76765	921.77223	9.197251	9.552553	9.664354	9.827436	9.960941
50	9.085627	6.893268	11.413056	13.72267	16.01036	18.32518	19.45168	51.96259	138.04603	367.37415	985.07947	8.930400	9.274715	9.387729	9.541886	9.674586
51	8.821990	6.694246	11.081599	13.31832	15.54706	17.79074	19.18099	52.29278	141.70481	384.70593	1052.23966	8.672784	9.009157	9.113159	9.262621	9.393914
52	8.565791	6.501074	10.760420	12.93055	15.09273	17.27847	18.91892	52.61124	145.59645	402.86754	1123.89054	8.419281	8.748078	8.847018	8.995352	9.121714
53	8.319636	6.315425	10.450368	12.55215	14.65957	16.78098	18.66592	52.93452	149.43860	421.70824	1201.22461	8.174979	8.494534	8.587765	8.734764	8.857263
54	8.074209	6.134575	10.144909	12.19017	14.23270	16.29156	18.40762	53.26390	153.42289	441.56077	1283.54286	7.935955	8.247074	8.339429	8.485035	8.595000
55	7.839965	5.955429	9.848551	11.83974	13.81930	15.82070	18.15121	53.59473	157.45073	462.61591	1371.38253	7.708687	8.005850	8.097876	8.242537	8.352226
56	7.613746	5.779762	9.567882	11.49939	13.41793	15.36530	17.89917	53.94997	161.65921	484.41405	1466.29619	7.488174	7.774328	7.861832	8.004755	8.111625
57	7.395871	5.613636	9.293037	11.17052	13.02518	14.91176	17.64598	54.26621	165.91504	507.16704	1566.66005	7.267413	7.546083	7.632596	7.776167	7.876318
58	7.184691	5.453425	9.026065	10.84625	12.65136	14.48374	17.40958	54.59543	170.28505	531.00488	1673.41946	7.059207	7.325186	7.412156	7.552130	7.647152
59	6.975896	5.294561	8.760028	10.53411	12.28201	14.06791	17.17094	54.94362	174.84011	556.21639	1788.86728	6.853703	7.115654	7.199135	7.333363	7.426324
60	6.769744	5.141749	8.508171	10.22886	11.92539	13.66186	16.93030	55.28205	179.48333	582.57497	1911.20283	6.652542	6.907916	6.992627	7.121351	7.212045

Plot of the base case simulation of the spot oil price



9.1 R code LSM

```
rm(list=ls())

#Simulation of paths

N=10000  #number of simulations

Y=60  #number of years simulating

#1 Input parameters

#Spot oil price

mu=0.004439459  #expected return holding crude oil

sigma1=0.212  #Volatility spot crude oil

spot=matrix(0,Y+1,N)

spot[1,]=39.6 #spot price year 0

#Convenience yield
```

```
kappa=1.187 #reversion rate convenience yield
alpha=0.09  #mean convenience yield
lamda=0.093 #market price of convenience yield risk
alphatilda=alpha-(lamda/kappa) #alpha adjusted for market price of conv. yield risk
convyield=matrix(0,Y+1,N)
convyield[1,]=-0.219 #convenience yield year 0
sigma2=0.187    #convenience yield volatility
#Other variables
rho=0.845  #correlation spot oil and conv yield error terms
r=0.004439459 #risk-free rate
#2 Simulating correlated error terms
covmatrix=matrix(c(sigma1^2,sigma1*sigma2*rho,sigma2*sigma1*rho,sigma2^2),nrow=2,ncol=2)
cholesky=t(chol(covmatrix)) #creating the cholesky decomposition
converror=matrix(0,Y,N) #matrix for storing convenience yield error terms
spoterror=matrix(0,Y,N) #matrix for storing spot crude oil error terms
for (i in 1:N){
errorterms=matrix(rnorm(Y*2),Y,2)
uncorr=matrix(errorterms%*%t(cholesky),Y,2)
spoterror[,i]=uncorr[,1]
converror[,i]=uncorr[,2]}
#3 Simulating convenience yield and spot
dt=1  #time step
for (i in 1:N){ for (n in 1:Y){
convyield[n+1,i]=convyield[n,i]+kappa*(alphatilda-convyield[n,i])*dt+sigma2*converror[n,i]*sqrt(dt)  }
```

```
for (n in 1:Y){

spot[n+1,i]=spot[n,i]*exp(((mu-convyield[n+1,i])-sigma1^2*0.5)*dt+sigma1*sqrt(dt)*spoterror[n,i])    }}

avg_spot_oil_price=matrix(0,Y,1)

for(i in 1:Y){ avg_spot_oil_price[i,]=mean(spot[i,])}

#4 Calculating payoffs

TaxRate1=0.25     #corporate tax rate

TaxRate2=0.53      #special tax rate

USDNOK=8.28       # Assumption: flat USD/NOK rate

rf=0.004439459    #wacc

gas=as.matrix(read.csv("gas.csv",stringsAsFactors=FALSE))

#FIELD NAME

Field=as.matrix(read.csv2("FIELDNAME.csv",stringsAsFactors=FALSE))

class(Field)="numeric"

optionyear= #years of the option

cyears=  #years of cash flow, including developing

Field_FCFF=matrix(0,cyears,1) #calculating every years free cash flow

Field_FCF_VD=matrix(0,cyears,1) #calculating free cash flow from developed field

Field_Balance1=matrix(0,1,cyears+1) #Calculating payable corporate taxes

Field_Balance2=matrix(0,1,cyears+1) #Calculating payable special taxes

Field_payoff=matrix(0,optionyear,N) #Storing the value of exercising the field

Field_VD=matrix(0,optionyear,N)     #Storing the value of developed field

# DCF of the field

for (i in 1:N){

for (n in 1:optionyear){
```

```
for (k in 1:cyears){

Field_EBITDA=Field[k,1]*spot[n-1+k,i]*USDNOK+Field[k,2]*spot[n-1+k,i]*USDNOK*gas[n-1+k,]-Field[k,3]

Field_EBIT=Field_EBITDA-Field[k,5]

Tax1=Field_EBIT*TaxRate1

Tax2=(Field_EBIT-Field[k,6])*TaxRate2

Field_Balance1[,k+1]=Field_Balance1[,k]+Tax1

Field_Balance2[,k+1]=Field_Balance2[,k]+Tax2

if (Field_Balance1[k+1]<=0){

Tax1=0 } else {

Tax1 = min(Field_Balance1[,k],0) + Tax1}

if (Field_Balance2[k+1]<=0){ Tax2=0} else {

Tax2 = min(Field_Balance2[,k],0) + Tax2}

Field_FCFF[k,]=(Field_EBITDA-Tax1-Tax2-Field[k,4])*exp(-rf*(k))

Field_FCF_VD[k,]=(Field_EBITDA-Tax1-Tax2)*exp(-rf*(k))}

Field_VD[n,i]=sum(Field_FCF_VD)

Field_payoff[n,i]=max(sum(Field_FCFF),0) }}


mean(Field_payoff)

# Least square MC

X=matrix(1,N,3)

Y=matrix(0,N,1)

decision=matrix(0,3,N)

decisiontree=matrix(0,optionyear,N)

Ystore=matrix(0,N,optionyear-1)
```

```
Xstore=matrix(0,N,optionyear-1)

parametere=matrix(0,N,optionyear-1)

continvalue=matrix(0,N,optionyear-1)

for (i in 1:(optionyear-1)){

for (n in 1:N){

if (Field_payoff[(optionyear-i),n]>0){

X[n,2]=t(Field_VD[(optionyear-i),n])

X[n,3]=t(Field_VD[(optionyear-i),n]^2)

#Find Y

if(i==1){

Y[n,1]=t(Field_payoff[optionyear+1-i,n]*exp(-rf*1))}

else{  for(j in 1:i){

if(decisiontree[optionyear-i+j,n]>0){

Y[n,1]=t(Field_payoff[optionyear-i+j,n]*exp(rf*(-j))) break}else{

Y[n,1]=t(Field_payoff[(optionyear+1-i),n])*exp(-rf*1) }}  }

decision[1,n]=Field_payoff[(optionyear-i),n]

decision[2,n]=Field_VD[(optionyear-i),n]   }else{

X[n,2]=0

X[n,3]=0

Y[n,1]=0

decision[1,n]=0

decision[2,n]=0}  }

Ystore[,i]=Y[,1]

Xstore[,i]=X[,2]
```

```
fit=lm.fit(X,Y)      # least square regression

intercept=as.numeric(fit$coefficients[1]) # intercept

slope=as.numeric(fit$coefficients[2]) # slope

slope2=as.numeric(fit$coefficients[3]) #slope 2

summary(lm(speed~dist, cars))$r.squared

summary(lm(speed~dist, cars))$adj.r.squared

parametere[1,i]=intercept

parametere[2,i]=slope

parametere[3,i]=slope2

#continuation value

for (k in 1:N){

decision[3,k]=intercept+(slope*decision[2,k])+decision[2,k]^2*slope2

continvalue[k,i]=decision[3,k]

if(i==1){

if (decision[3,k]>(Field_payoff[(optionyear-i),k])){

decisiontree[optionyear,k]=Field_payoff[optionyear,k]  }else{

decisiontree[optionyear-i,k]=Field_payoff[optionyear-i,k]  }}    if(i>1){

if (decision[3,k]<Field_payoff[(optionyear-i),k]){

decisiontree[optionyear-i,k]=Field_payoff[(optionyear-i),k]}}}}

optimalstop=matrix(0,optionyear,N)

for (n in 1:N){  for (i in 1:optionyear){

if(decisiontree[i,n]>0){

optimalstop[i,n]=1

break  }else""}}
```

```
# Calculating the option value

for (n in 1:N){

if (sum(optimalstop[,n]>0)){""    }

else optimalstop[optionyear,n]=decisiontree_continuation[optionyear-1,n]}

Valuematrix=matrix(0,optionyear,N)

for (i in 1:N){for (n in 1:(optionyear)){

Valuematrix[n,i]=exp(-rf*n)*optimalstop[n,i]*Field_payoff[n,i]}}

FieldName=sum(Valuematrix)/N
```

10 ReOI Valuation

Production 2016-2026:

Production	Working Interest	Unit	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Alvheim	65.00%	NOK	10,236,210	12,628,818	11,963,995	10,038,597	7,221,201	5,212,191	4,554,037	3,978,990	3,476,555	3,037,563	2,654,004
Atla	10.00%	NOK	208,958	199,013	-	-	-	-	-	-	-	-	-
Bøyla	65.00%	NOK	2,843,551	2,141,090	1,612,162	1,213,899	914,022	688,225	518,208	390,192	293,800	221,221	166,571
Enoch	2.00%	NOK											
Jette	70.00%	NOK	170,830	-	-	-	-	-	-	-	-	-	-
Jotun	7.00%	NOK	38,744	-	-	-	-	-	-	-	-	-	-
Varg	5.00%	NOK	69,951	-	-	-	-	-	-	-	-	-	-
Vilje	46.90%	NOK	1,806,756	1,339,287	992,767	735,905	545,501	404,361	299,739	222,186	164,699	122,086	90,498
Volund	65.00%	NOK	2,343,315	4,189,181	4,099,936	3,203,110	1,726,698	741,726	589,286	468,176	371,956	295,511	361,196
Sum Producing			**17,718,315**	**20,497,389**	**18,668,861**	**15,191,511**	**10,407,422**	**7,046,504**	**5,961,271**	**5,059,544**	**4,307,010**	**3,676,381**	**3,272,269**

Production	Working Interest	Unit	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Gina Krog	3.30%	NOK	-	1,082,449	1,167,409	1,217,755	1,179,995	855,890	560,104	361,865	242,292	213,972	179,359
Hanz	35.00%	NOK	-	-	-	-	-	1,916,250	1,526,557	1,037,528	705,158	479,262	325,732
Ivar Aasen	34.79%	NOK	1,452,467	8,163,219	10,267,986	10,714,459	10,373,297	7,523,176	4,922,996	3,182,371	2,130,727	1,882,279	1,577,466
Johan Sverdrup Fase 1	11.57%	NOK	-	-	-	-	8,465,862	15,756,662	16,167,830	15,589,163	15,584,884	15,592,204	15,471,303
Johan Sverdrup Fase 2	11.57%	NOK	-	-	-	-	-	-	-	10,068,520	12,692,423	16,391,641	15,779,258
Sum Developing			**1,452,467**	**9,245,667**	**11,435,394**	**11,932,214**	**20,019,154**	**26,051,978**	**23,177,487**	**30,239,447**	**31,355,484**	**34,559,359**	**33,333,118**

Production	Working Interest	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Attic Oil 1	62.40%	-	1,278,148	1,439,258	932,623	435,537	232,769	42,854	5,453	1,358	-	-
BoaKamSouth/West	60.60%	-	-	1,063,953	1,198,064	776,332	362,548	193,761	35,673	4,539	1,130	-
Caterpillar	65.00%	-	-	-	1,521,605	1,713,403	1,110,266	518,496	277,106	51,017	6,492	1,616
Frøy	100.00%									2,099,556	6,074,079	4,748,315
Frigg/Gamma/Delta	60.00%								1,795,581	14,907,274	11,399,978	5,381,999
Garantiana	30.00%						4,264,504	35,404,776	27,074,948	12,782,248	11,040,999	5,449,926
Gekko	65.00%										-	-
Grevling	30.00%										1,234,539	3,571,559
Gohta	60.00%	-	-	-	-	-	-	-	-	2,940,264	24,410,661	18,667,464
Krafla/Askja	50.00%	-	-	-	-	-	-	3,740,793	31,056,821	23,749,955	11,212,498	9,685,087
P Grabben	20.00%	-	-	-								
R.basement North	58.00%										-	-
R.basement	58.00%	-	-	-								
Steinbit	50.00%										-	-
Storklakken	100.00%	-							2,048,315	2,306,504	1,494,588	697,976
Skalle	10.00%										-	-
Trell	50.00%	-										
Sum not sanctioned		-	1,278,148	2,503,212	3,652,292	2,925,271	5,970,087	39,900,680	58,450,001	36,589,116	22,261,119	15,136,629

Total	**19,170,783**	**31,021,205**	**32,607,467**	**30,776,017**	**33,351,847**	**39,068,568**	**69,039,439**	**93,748,991**	**72,251,610**	**60,496,859**	**51,742,016**

Revenue 2016-2026:

Revenue	Working Interest	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Alvheim	65.00%	3,359,243,599	4,818,075,197	4,945,232,519	4,354,463,791	3,215,732,275	3,306,447,564	2,889,168,647	2,524,503,164	2,206,187,310	1,927,898,847	1,684,420,080
Atla	10.00%	6,435,570	7,217,323	-	-	-	-	-	-	-	-	-
Bøyla	65.00%	987,278,301	858,566,855	699,561,611	553,118,756	428,957,764	461,888,297	347,808,089	261,902,928	197,244,302	148,540,191	111,842,739
Enoch	2.00%											
Jette	70.00%	60,093,155	-	-	-	-	-	-	-	-	-	-
Jotun	7.00%	13,645,136	-	-	-	-	-	-	-	-	-	-
Varg	5.00%	19,434,865	-	-	-	-	-	-	-	-	-	-
Vilje	46.90%	658,469,486	563,700,119	452,176,572	351,971,643	268,724,911	284,855,535	211,165,255	156,539,256	116,061,320	86,045,298	63,780,965
Volund	65.00%	802,471,412	1,749,756,055	1,867,960,912	1,531,569,289	836,341,593	490,990,440	390,108,962	309,952,608	246,302,092	195,711,482	239,207,866
Sum Producing		**5,907,071,523**	**7,997,315,548**	**7,964,931,613**	**6,791,123,479**	**4,749,756,543**	**4,544,181,836**	**3,838,250,953**	**3,252,897,956**	**2,765,795,025**	**2,358,195,818**	**2,099,251,651**

Revenue	Working Interest	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Gina Krog	3.30%	-	353,050,485	413,891,459	454,532,205	454,316,398	478,508,889	313,175,658	202,345,002	135,511,365	119,690,447	100,326,433
Hanz	35.00%	-	-	-	-	-	1,163,981,786	927,349,713	630,314,215	428,483,496	291,263,788	197,953,504
Ivar Aasen	34.79%	449,498,957	2,829,699,247	3,919,410,095	4,419,043,521	4,127,293,053	4,303,783,018	2,804,393,554	1,896,006,722	1,266,114,552	1,146,458,429	945,549,726
Johan Sverdrup Fase 1	11.57%	-	-	-	-	4,090,439,279	11,030,671,644	11,280,030,931	10,873,341,411	10,875,571,415	10,906,772,873	10,839,914,798
Johan Sverdrup Fase 2	11.57%	-	-	-	-	-	-	-	6,710,526,341	8,183,243,421	10,410,228,316	9,981,817,960
Sum Developing		**449,498,957**	**3,182,749,731**	**4,333,301,554**	**4,873,575,726**	**8,672,048,730**	**16,976,945,337**	**15,324,949,857**	**20,312,533,691**	**20,888,924,248**	**22,874,413,853**	**22,065,562,421**

Revenue	Working Interest	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Attic Oil 1	62.40%	-	524,777,600	642,414,044	438,287,979	211,137,315	163,844,127	30,164,723	3,838,430	955,549	-	-
BoaKamSouth/West	60.60%	-	-	474,896,290	563,032,380	376,346,305	255,195,168	136,386,732	25,109,646	3,195,176	795,416	-
Caterpillar	65.00%	-	-	-	715,081,177	830,614,854	781,507,829	364,965,586	195,052,532	35,910,385	4,569,559	1,137,558
Frøy	100.00%									1,017,812,161	4,275,499,701	3,342,304,355
Frigg/Gamma/Delta	60.00%								1,263,896,143	10,494,168,602	8,024,360,867	3,788,349,704
Garantiana	30.00%	-	-	-	-	-	900,526,002	7,477,095,129	5,717,357,118	2,699,199,164	2,331,503,343	1,150,848,961
Gekko	65.00%										-	-
Grevling	30.00%										856,844,467	2,478,885,566
Gohta	60.00%									1,456,612,280	12,093,092,028	9,247,908,299
Krafla/Askja	50.00%	-	-	-	-	-	-	1,851,063,951	15,367,910,205	11,752,248,678	5,548,311,763	4,792,497,845
P Grabben	20.00%											
R.basement North	58.00%											
R.basement	58.00%											
Steinbit	50.00%										-	-
Storklakken	100.00%								840,981,416	1,029,498,496	702,384,582	338,368,354
Skalle	10.00%										-	-
Trell	50.00%	-	600,706,960	735,364,061	501,703,273	241,686,487	187,550,512	34,529,216	4,393,807	1,093,806	-	-
Sum not sanctioned		-	524,777,600	1,117,310,334	1,716,401,536	1,418,098,474	2,101,073,126	9,859,676,121	21,309,267,931	14,491,508,953	7,885,180,081	5,944,484,364

Total	**6,356,570,480**	**11,704,842,880**	**13,415,543,501**	**13,381,100,741**	**14,839,903,746**	**23,622,200,299**	**29,022,876,931**	**44,874,699,578**	**38,146,228,225**	**33,117,789,751**	**30,109,298,436**

Commodity prices 2016-2026:

Prices in use	Unit	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Oil price	USD/bbl		42.53	49.58	53.90	56.75	58.54	85.00	85.00	85.00	85.00	85.00	85.00
Gas	$/mmbtu		2.52	3.23	3.37	3.42	3.46	5.09	5.21	5.21	5.21	5.21	5.21
USD/NOK	NOK		8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.28	8.29	8.29

OPEX 2016-2019:

OPEX	Working Interest	2016E	2017E	2018E	2019E
Alvheim	65.00%	678,128,138	836,634,721	792,590,741	665,044,219
Atla	10.00%	188,379,463	141,843,051	106,802,526	80,419,270
Bøyla	65.00%	188,379,463	141,843,051	106,802,526	80,419,270
Enoch	2.00%				
Jette	70.00%	11,317,169	-	-	-
Jotun	7.00%	2,566,684	-	-	-
Varg	5.00%	4,634,106	-	-	-
Vilje	46.90%	119,693,913	88,725,142	65,768,857	48,752,739
Volund	65.00%	155,239,881	277,525,163	271,612,585	212,201,926
Sum Producing		**1,348,338,817**	**1,486,571,127**	**1,343,577,235**	**1,086,837,423**
Gina Krog	3.30%	-	62,746,377	67,671,186	70,590,369
Hanz	35.00%	-	-	-	-
Ivar Aasen	34.79%	72,167,261	405,598,069	510,175,128	532,364,404
Johan Sverdrup Fase 1	11.57%	-	-	-	-
Johan Sverdrup Fase 2	11.57%	-	-	-	-
Sum Developing		**72,167,261**	**468,344,446**	**577,846,314**	**602,954,772**
Attic Oil 1	62.40%	-	74,090,497	83,429,489	54,061,953
BoaKamSouth/West	60.60%	-	-	61,674,173	69,448,928
Caterpillar	65.00%	-	-	-	88,203,846
Frøy	100.00%				
Frigg/Gamma/Delta	60.00%				
Garantiana	30.00%	-	-	-	-
Gekko	65.00%				
Grevling	30.00%				
Gohta	60.00%	-	-	-	-
Krafla/Askja	50.00%	-	-	-	-
P Grabben	20.00%				
R.basement North	58.00%				
R.basement	58.00%				
Steinbit	50.00%				
Storklakken	100.00%				
Skalle	10.00%				
Trell	50.00%				
Sum not sanctioned		-	74,090,497	145,103,661	211,714,727
Total		**1,420,506,077**	**2,029,006,070**	**2,066,527,210**	**1,901,506,922**

CAPEX 2016-2019:

CAPEX	Working Interest	Unit	2016E	2017E	2018E	2019E
Alvheim	65.00%	NOK	1,458,062,500	-	-	-
Atla	10.00%	NOK	-	-	-	-
Bøyla	65.00%	NOK	-	-	-	-
Enoch	2.00%	NOK				
Jette	70.00%	NOK	-	-	-	-
Jotun	7.00%	NOK	-	-	-	-
Varg	5.00%	NOK	-	-	-	-
Vilje	46.90%	NOK	-	-	-	-
Volund	65.00%	NOK	729,031,250	-	-	-
Sum Producing			2,187,093,750	-	-	-
Gina Krog	3.30%	NOK	186,532,575	-	-	-
Hanz	35.00%	NOK	-	-	-	386,334,512
Ivar Aasen	34.79%	NOK	2,541,549,344	-	-	-
Johan Sverdrup Fase 1	11.57%	NOK	3,499,350,000	2,918,207,595	3,365,058,133	1,532,970,927
Johan Sverdrup Fase 2	11.57%	NOK	-	-	224,337,209	766,485,464
Sum Developing			**6,227,431,919**	**2,918,207,595**	**3,589,395,342**	**2,685,790,903**
Attic Oil 1		TRUE	203,840,000	407,680,000	-	-
BoaKamSouth/West		TRUE	-	169,680,000	339,360,000	-
Caterpillar		TRUE	-	-	242,666,667	485,333,333
Cliffhanger North		FALSE	-	-	-	-
Frigg/Gamma/Delta		FALSE				
Garantiana		TRUE	-	-	298,297,357	668,677,850
Gekko		FALSE				
Grevling		FALSE				
Gohta		FALSE	-	-	-	685,560,593
Krafla/Askja		TRUE	-	-	-	872,214,495
P Grabben		FALSE	-	56,000,000	112,000,000	-
R.basement North		FALSE				
R.basement		FALSE	-	-	406,000,000	812,000,000
Steinbit		FALSE				
Storklakken		FALSE	513,333,333	1,026,666,667	-	-
Skalle		FALSE				
Trell		FALSE	233,333,333	466,666,667	-	-
Sum not sanctioned			203,840,000	577,360,000	880,324,024	2,026,225,679
Total		**NOK**	**8,618,365,669**	**3,495,567,595**	**4,469,719,366**	**4,712,016,581**

Accounting depreciation 2016-2019:

Accounting Depreciation	Working Interest	Unit	2016E	2017E	2018E	2019E
Alvheim	65.00%	NOK	754,441,584	933,334,518	881,784,860	739,876,861
Atla	10.00%	NOK	1,356,793	1,295,761	-	-
Bøyla	65.00%	NOK	694,919,332	524,682,398	393,987,237	296,657,979
Enoch	2.00%	NOK				
Jette	70.00%	NOK	12,512,779	-	-	-
Jotun	7.00%	NOK	11,135	-	-	-
Varg	5.00%	NOK	12,873	-	-	-
Vilje	46.90%	NOK	64,987,986	48,305,358	35,709,280	26,470,071
Volund	65.00%	NOK	157,091,815	281,604,905	274,852,654	214,730,951
Sum Producing			**1,685,334,296**	**1,789,222,941**	**1,586,334,031**	**1,277,735,862**
Gina Krog	3.30%	NOK	-	155,540,861	167,749,044	174,983,457
Hanz	35.00%	NOK	-	-	-	-
Ivar Aasen	34.79%	NOK	202,496,312	1,141,196,332	1,431,515,217	1,493,760,516
Johan Sverdrup Fase 1	11.57%	NOK	-	-	-	-
Johan Sverdrup Fase 2	11.57%	NOK	-	-	-	-
Sum Developing			**202,496,312**	**1,296,737,193**	**1,599,264,261**	**1,668,743,973**
Attic Oil 1	62.40%	TRUE	-	178,891,746	201,440,967	130,531,470
BoaKamSouth/West	60.60%	TRUE	-	-	148,865,851	167,630,322
Caterpillar	65.00%	TRUE	-	-	-	212,826,876
Cliffhanger North	100.00%	FALSE				
Frigg/Gamma/Delta	60.00%	FALSE				
Garantiana	30.00%	TRUE	-	-	-	-
Gekko	65.00%	FALSE				
Grevling	30.00%	FALSE				
Gohta	60.00%	FALSE	-	-	-	-
Krafla/Askja	50.00%	TRUE	-	-	-	-
P Grabben	20.00%	FALSE	-	-	-	49,247,564
R.basement North	58.00%	FALSE				
R.basement	58.00%	FALSE	-	-	-	356,075,735
Steinbit	50.00%	FALSE				
Storklakken	100.00%	FALSE	-	450,210,699	508,348,477	328,504,058
Skalle	10.00%	FALSE				
Trell	50.00%	FALSE	-	590,152,929	664,541,429	431,795,105
Sum not sanctioned		**NOK**	**-**	**178,891,746**	**350,306,818**	**510,988,668**
Total		**NOK**	**1,887,830,608**	**3,264,851,880**	**3,535,905,111**	**3,457,468,504**

Tax 2016-2019:

Tax accounting	Working Interest	2016E	2017E	2018E	2019E
Alvheim	65.00%	1,417,108,535	2,296,316,116	2,474,230,314	2,258,140,792
Atla	10.00%	-6,836,127	-5,664,894	-	-
Bøyla	65.00%	-14,372,437	78,492,854	145,511,449	137,312,376
Enoch	2.00%				
Jette	70.00%	28,285,301	-	-	-
Jotun	7.00%	8,489,672	-	-	-
Varg	5.00%	10,727,097	-	-	-
Vilje	46.90%	358,042,059	329,835,367	273,544,780	215,864,090
Volund	65.00%	339,735,173	888,388,164	992,247,584	840,365,140
Sum Producing		**2,141,179,272**	**3,587,367,606**	**3,885,534,126**	**3,451,682,398**
Gina Krog	3.30%	-	76,584,986	114,957,889	157,550,111
Hanz	35.00%	-	-	-	-
Ivar Aasen	34.79%	-125,105,040	762,562,249	1,356,912,170	1,792,390,345
Johan Sverdrup Fase 1	11.57%	-	-	-	-
Johan Sverdrup Fase 2	11.57%	-	-	-	-
Sum Developing		**-125,105,040**	**839,147,235**	**1,471,870,060**	**1,949,940,457**
Attic Oil 1	62.40%	-	212,000,379	278,883,999	197,881,753
BoaKamSouth/West	60.60%	-	-	206,197,888	254,243,441
Caterpillar	65.00%	-	-	-	322,959,355
Frøy	100.00%				
Frigg/Gamma/Delta	60.00%				
Garantiana	30.00%	-	-	-	-
Gekko	65.00%				
Grevling	30.00%				
Gohta	60.00%		-	-	-
Krafla/Askja	50.00%	-	-	-	-
P Grabben	20.00%	-	-	-	179,763,542
R.basement North	58.00%				
R.basement	58.00%	-	-	-	235,948,936
Steinbit	50.00%				
Storklakken	100.00%	-	212,188,039	302,210,154	224,049,367
Skalle	10.00%				
Trell	50.00%	-	-57,920,085	-19,248,962	6,258,770
Sum not sanctioned		**-**	**212,000,379**	**485,081,886**	**775,084,550**
Group tax		**-99,162.50**	**-182,595.55**	**-209,282.48**	**-208,745.17**
Exploration tax		**-1,166,880,000.00**	**-1,166,880,000.00**	**-1,166,880,000.00**	**-1,166,880,000.00**
Total		**849,095,070**	**3,471,452,624**	**4,675,396,790**	**5,009,618,659**