RIG RATE FORMATIONS IN THE NORTH SEA

Axel Roshauw Tidemann 93406
Henrik Borgen Nordby 93629

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CBS COPENHAGEN BUSINESS SCHOOL
HANDELSHØJSKOLEN

ABSTRACT

This paper seeks to understand the offshore drilling market and specifically the formation of the contracted day rates on drilling operations. An industry analysis and a strategic analysis form the basis for an econometric model explaining day rates. The model is used to build forecasts on the day rates, which are used in a valuation of Odfjell Drilling, in order to illustrate a potential use case of the research.

Drilling Rig Supply and Demand

The supply of rigs is found to be fixed in the short-term but is adjusted in the medium- to long-term with drilling companies stack, scrap, and build rigs in order to meet the expected demand of the exploration and production (E&P) companies. We also see that rigs are principally purpose-built, where geo-specific regions demand different needs, mainly for water depths and the need for harsh weatherproofing. These geo-specific needs also create sub-markets where drilling rates vary with the technical specifications and capabilities of the rigs. The drilling demand comes from the exploration and production companies. Their need for drilling rigs fluctuates with their profitability, where the price of oil dictates their wish for exploratory spending. We also uncover a bargaining relationship between the drilling companies and the E&P companies. Here it seems that rig fleet availability dictates the pricing power of the drilling companies. Rig hires move from a spot-like market in times of high availability, where drilling companies could be viewed to be close to price takers, to a tight contract market where the E&P companies move close to becoming price takers.

Modeling and Forecasting Day Rates

Based on the analysis, we consider a multiple linear regression model explaining average rig rates, with smoothed Brent oil prices, a cross product of smoothed Brent oil prices and capacity utilization, average contract length, average contract lead times, average wage of petroleum workers in Norway and Real Interest rates (U.S. 10 year T-bills), as explanatory variables. We forecast a base case using Brent futures and a slight increase in utilization. Given these inputs, rig rates decrease slightly in the five-year forecast period. The paper also presents four alternative scenarios to test the rig rate forecast given its inputs. Here we test for an increase in Brent spot prices, increasing utilization, a combination of increasing Brent spot prices and utilization, as well as simulating a relatively large reservoir discovery.

Rig Rate Forecast – Applied Use Case

Finally, to further test and showcase the usefulness of the model, our findings are applied in a calculation of Odfjell Drilling’s future free cash flows. Here, we apply the model as a tool for valuating the fair value of Odfjell Drilling. The model allows for future analysis of the industry to be translated into rig rates and further into share price calculations.

CONTENTS

1 MOTIVATION

The purpose of this paper is to examine and analyze the offshore drilling industry in order to model and forecast day rates for rigs on contract with E&P companies in North West Europe (NW Europe). Our findings will be modeled and forecasted in a base case and sceanrios, and futhers utilized in a valuation case of Odfjell Drilling, a floater pure play drilling company with the majority of its operations in the NW Europe area. Our motivation for choosing this theme and structuring our thesis in this way is founded in several ways.

By modeling and forecasting day rates in the offshore industry and further utilizing our findings in a valuation case, we capture our motivation for entering into the master's program *Applied Economics and Finance* in a good way. Here, we get to utilize economic thinking and econometrics in order to model and forecast day rates in a multivariate regression. Furthermore, we are able to apply our findings in the field of finance, through the valuation of Odfjell Drilling. Both authors are also personally involved in the industry.

The offshore drilling industry is a volatile, complex and capital intensive industry. It is also highly influenced by the macro-economic environment. Thus, both supply and demand for drilling rigs are influenced by numerous factors. Offshore investments from petroleum companies are often seen as the main driver of the industry, which again is influenced by the macro environment, through oil prices. This is another reason why looking at drilling companies is becoming more interesting at the moment. The harsh decline in oil prices that begun in the second half of 2014 and continued until the entrance of 2015 sent the industry into a rough patch, with little activity and low day rates. Now, however, the industry is beginning to recover, creating a very clear business cycle. This environment is therefore interesting to analyze.

The offshore drilling industry is highly globalized with its main players holding a geographically spread fleet of drilling units. One drilling company, Transocean, has in recent years sold off its ground-based fleet and reinvested to become a pure-play floater company. Seadrill has in contrast to Transocean diversified their rigs, adding all types of rigs through mergers in recent years. Odfjell Drilling is chosen as the subject of our valuation case, as it is a pure-play floater company on the global market. However, their rigs operations are centeres in NW Europe, which will be the geographical focus of this paper.

2 PROBLEM STATEMENT AND CHAPTER GOALS/QUESTIONS

For oil companies to establish production of an offshore oil license, a preliminary step is exploration and appraisal drilling of these areas. Even though modern seismic technology has made this process simpler and more accurate, it is still complex and with large elements of uncertainty. Operators can consequently not be certain of the reservoir until actual drilling has provided hard evidence. These drilling operations are therefore contracted to third party drilling companies that provide the rigs and expertise to drill the preferred wells to the operators' specifications.

The contracts have specified terms from the involved parties, but are also standardized to some degree. A daily rate is charged to the oil company for the use of the rig. This day rate is dependent on deal specifics, such as rig type and environmental conditions, but are also a part of a market where supply and demand is prominent. This thesis therefore seeks to explain how day rates are created and provide a tool for predicting future day rats. The first research question reads as follows:

- *What are the most important factors influencing the formation of drilling day rates and what is their effect on the future rates?*

Furthermore, this paper will showcase how our findings could be used as a tool for valuating a drilling company. This paper, therefore, seeks to utilize our learnings from modeling and forecasting day rates, in order to present a set of future potential earnings of a drilling company's fleet and subsequently calculate the implied value of the firm. The second research question reads as follows:

- *How can the expected day rates be applied in valuation models for offshore drilling companies?*

Our chosen company for the applied case of this thesis is the offshore drilling company, Odfjell Drilling. The final research question reads as follows:

- *What is the effect of different forecasted day rate scenarios, on the share price of Odfjell Drilling?*

2.1 THE OFFSHORE DRILLING INDUSTRY

In order to accurately answer the problem statements, it is essential to structure the paper in a way that provides the reader with the necessary insights to the industry. A comprehensive introduction to the offshore drilling industry is therefore necessary. We will analyze and explain the overall structure of the industry, its assets, players, trends, and historical developments.

- What characterizes the offshore drilling market and how is the value chain composed?
- How has the offshore drilling market developed?
- Who are the main competitors in the market?

2.2 STRATEGIC ANALYSIS

This section of the paper seeks to examine the strategical industry factors influencing the value creation of the companies in the offshore drilling industry. This is predominantly done by analyzing the relationship between its supply and demand using an adapted version of Martin Stopford's (2009) Shipping Market Model. We will examine the industry structure as well as its bargaining frictions through the economic deductions presented by Skjerpen, Storrøsten, Rosendahl and Osmundsen (2018).

- What are the most influential external factors of the companies in the industry?
- How does the supply and demand relation affect the day rate mechanism?
- How does the industry bargaining power structure affect future day rates?

2.3 MODELING AND FORECASTING DAY RATES

This section builds on the approach of Skjerpen et al. (2018) "Modelling and Forecasting Day Rates on the Norwegian Continental Shelf," in order to explain day rates of a segment of the offshore drilling market. Combining our findings from the industry and strategic analysis, with comprehensive data on the NW European drilling market.

- What are the most important factors of the day rates in the drilling industry?
- Given our model, what are potential outlooks of day rates on floaters in NW Europe?
- Which uncertainties are tied to our model and forecasts?

2.4 ODFJELL DRILLING

In this section, we introduce a practical use case for our findings on day rates, a valuation of the drilling company Odfjell Drilling. This section introduces the company and conducts an internal analysis as well as a financial analysis of the firm. The internal analysis is meant to uncover if Odfjell Drilling is in fact a good entity for testing our findings. The financial analysis seeks to evaluate Odfjell Drilling's historical performance and uncover the reasons for this development. This section also provides crucial information for building estimates, by reviewing their going concern.

- Does Odfjell Drilling hold a specific strategic advantage over its competitors?
- Is Odfjell Drilling's profitability and liquidity healthy?

2.5 WACC

Here we will estimate the weighted average cost of capital of Odfjell Drilling. This will be done through the process described by Petersen et al. (2012), utilizing the CAPM theory for the cost of equity.

- What is WACC associated with an investment in Odfjell Drilling?

2.6 FORECASTING AND VALUATION

This section ties in our findings on day rates and the analysis of Odfjell Drilling in order to perform forecasts on the future cash flows to the company. The forecasted free cash flows are reported for each of the scenarios presented under the modeling and forecasting chapters in order to see how the different movements would affect the fair value pricing of a drilling company. The implied share price of Odfjell Drilling can be deducted through countless valuation models. As this valuation is meant to showcase the usefulness of our day rate forecasts, we will utilize the discounted cash flow model. A valuation will be done on the different future day rate scenarios.

- How will the market outlook affect the future free cash flows of Odfjell Drilling?
- What is the fair value share price of Odfjell Drilling?
- How sensitive are the values to variations in the DCF discount rates?

3 LITERATURE

The purpose of this chapter is to introduce the applied literature and to familiarize the reader with the main academic theories used in this paper, as well as how they are interpreted. Bitsch Olsen and Pedersen (2018) argue that it is of paramount importance that the scientific quality is safeguarded through reviewing the applied literature and data. To review the applied theories, Saunders, Lewis, and Thornhill (2009) state that the reviewer should apply critical thinking and to understand that the data or literature may contain bias. According to Saunders et al. (2009), there are three classes of literature sources; primary, secondary, and tertiary. Figure 3.1 illustrates the nature between the three. As the figure illustrates, sources of information are overlapping and do not exclusively belong to one class, as is the case with *government publications.* Saunders et al. (2009) point out that as sources move from primary to tertiary, their detail deteriorates, but they become more easily reachable.

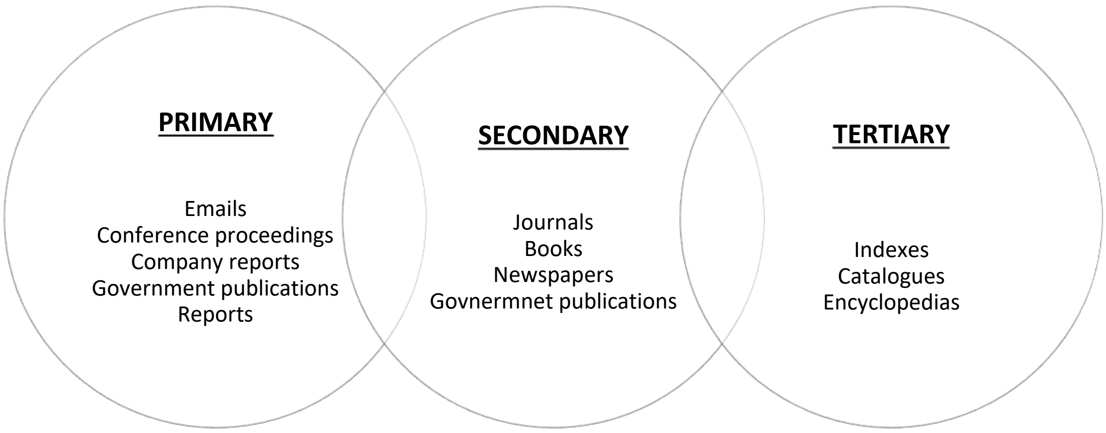

Figure 3.1 - Available literature sources. Source: Saunders, Lewis & Thornhill (2009)

The qualitative sources and input for this paper are gathered from both the academic community and the industry itself. Academic papers are carefully chosen and consist of peer-reviewed articles from known institutes and published in acknowledged journals. That being said, the academic community researching offshore drilling is limited and is dominated by a few researchers. In order to avoid bias, these academic sources are cross-checked with industry analysis from well-known and acknowledged banks and brokerage firms; e.g., SEB, Clarksons Platou Research, DNB Markets, Arctic Securities, IHS Markit, and Bassoe Analytics. Also, by selecting peer-reviewed academic articles, we can be more certain of the information, as these articles have been subject to information verification prior to publication (Saunders, Lewis, & Thornhill, 2009). These articles belong to the secondary literature source. Other academic literature not published in journals, yet belonging to the secondary source class, is according to Saunders et al. (2009) books written for specific audiences, i.e., academics or professionals. This paper applies theories from a variety of books, predominantly written for professionals where the books' approach is more practical than theoretical.

We have also gathered primary information from face-to-face contact with industry leaders and analysts at the DNB Oil, Offshore & Shipping Conference in Oslo (March 6, 2019), through direct contact with equity analysts from the firms listed above, as well as our own first-hand professional experience working in the industry. The possible industry-bias in the information received at the oil and offshore conference is acknowledged, and thus, the information is interpreted with the utmost care. The combination of peer-reviewed articles, cross-checking with industry analysts, industry leaders, as well as our critical thinking, create a basis of information that can be regarded as trustworthy.

In order to build a thorough analysis, our quantitative sources are primarily gathered from subscription-based industry databases that are produced in direct communication with the drilling- and the E&P companies. We have obtained raw data from the renowned offshore intelligence services RigLogix, Clarksons Platou Research (Offshore Intelligence Network), and IHS Markit. In addition to the industry-specific databases, we have collected data from official databases such as Statistics Norway, the Norwegian Petroleum Directorate, the Central Bank of Norway, the U.K. Office for National Statistics, the Organization for Economic Cooperation and Development, the U.S. Federal Reserve, and the U.S. Energy Information Administration. These datasets should be without bias. Finally, data from British Petroleum and the Organization of the Petroleum Exporting Countries are deemed reliable, though we acknowledge that there are subjective forecasts implemented in the datasets which might add an element of bias to our findings. Reassuringly, the British Petroleum database is used by academics in published papers. The combined result is a dataset that we regard as credible.

Other sporadic sources are applied where needed. These are gathered from credible media or industry publications, such as Bloomberg, RigZone, and Rystad Energy. The sources are interpreted critically and applied with care to avoid information inconsistency or bias.

The research area and problem statements derived from the motivation (section 1) constitute a relatively narrow academic field, as mentioned above. In the search for relevant literature on the topic, CBS Library assisted in identifying the applicable published models and theories. An inevitable result of researching a constrained field is the limited availability of peer-reviewed academic publications on the topic of the objective; how day rates are formed and the underlying variables' effect on its future outlook.

This paper will as briefly introduced in section 2.3, be based on the published article *Modeling and forecasting rig rates on the Norwegian Continental Shelf* by Skjerpen et al. (2018). As for the rig market analysis, Stopford's (2009) published book *Maritime Economics*, and particularly the *Shipping Market Model* will be applied to uncover the macro-economic factors influencing the industry. As we will apply our findings to a use case, in the valuation of Odfjell Drilling, we will apply *Financial Statement Analysis* (Petersen, Plenborg, & Kinserdal, 2012) to uncover the rig rates' effect on the company value. The following pages will review the central literature, and in the succeeding subsection, we will review our methodology for interpreting the literature with a critical perspective, as Saunders et al. (2009) stress the importance of doing. The objective of this literature review is to provide the reader with knowledge of the most important sources of information applied to the paper and to draw parallels between them.

3.1 LITERATURE REVIEW

This paper wants to contribute to the field of offshore drilling research. It was evident from the initial exploration of the academic literature within the field that academic research on the topic is somewhat sparse. Despite its vital role in the overall oil industry, it consists mainly of research papers from a few researchers affiliated with national institutions. The rig rate is the mechanism that controls the cash flows between the drilling companies and the E&P companies. There are different characteristics to offshore drilling units, and their day rates depend on the complexity of the operation. We want to explore the formation of rig day rates for the NW European market, characterized by harsh environment operations.

Kaiser & Snyder (2013) showed that there are separate regional markets within the global offshore drilling industry. According to their research, these markets are only weakly interacting. They studied the interaction between the separate regions and found that the two primary market indicators are the day rates at which the rigs a contracted on and the utilization of the marketed rig capacity. They found that rig contractors move rigs between markets to balance the different demand, to increase their utilization. However, the process of moving the drilling units may take years, and according to their research, it does not happen fast enough to create an interregional correlation in day rates and utilization (Kaiser & Snyder, 2013). The offshore drilling industry has over the past several years experienced a significant amount of consolidation, leaving a few large players that are affected mainly by the current oil price through increasing or decreasing day rates (Kaiser & Snyder, 2013). They found that as the price of oil increase, E&P companies' demand for drilling operations increase, leading to higher rig rates and higher utilization. Although arguing for separate regions that are weakly interacting with each other, Kaiser and Snyder (2013) suggest that, since the price of oil is set through global mechanisms, it provides similar signals to E&P companies regardless of their regional base, thus affecting the regions similarly.

In an effort to uncover the relationship between the gas reserves in West Virginia and the wellhead price of the gas, Iledare (1995) created a model that suggested that the drilling cost in mature markets would need to show a much more rapid decline than the wellhead price in order for companies to engage in new contracts. This result was in contrast to the paper's hypothesis, which believed that as long as the reduction in cost was more significant than the wellhead price reduction, the investments would be maintained. Similarly to Iledare (1995), in an effort to confirm or reject if oil rig activity is reacting to changes in the oil price, Ringlund, Rosendahl & Skjerpen (2008) found that the price of oil significantly impacts the rig activity. Their research showed that, for Europe, it takes four months from a change in the oil price to that change having an impact on the rig activity. However, the lagging factor experienced on the rig activity from the oil price differs between geographical regions. For example, the rig activity reacts much more rapidly in the U.S. than in Europe. Ringlund et al. (2008) explain this phenomenon by the predominance of longer contracts in Norway and the U.K. partly due to higher tax rates and the large, more complex, offshore installations present in the NW European region. Their findings are in line with those of Kaiser & Snyder (2013) that expose different regional markets within the global offshore drilling industry.

In contrast to Ringlund et al. (2008) and Kaiser & Snyder (2013), Kellogg (2011) focused on the relationship between the drilling companies and the E&P companies. He emphasizes the importance of firms' consideration of interpersonal industry-specific relationships between supplier and client. According to his research, firms should consider being closer to their customers in order to deepen the relationships between their workers on a personal level. This should be carefully deliberated as it might provide the underlying companies an advantage in a bargaining situation, in addition to enhancing the efficiency at which the bargaining and the work are committed.

Kellogg (2011) finds that a drilling rig that accumulates experience with one E&P company increases its efficiency by more than double that of a rig which changes clients regularly. The accumulation of experience also increases the likelihood of an E&P company to award contracts to rig operators. This should be an incentive for rig contractors to enhance their relationship to current and potential customers. Data indicates that E&P companies does not exclusively award contracts to operators with field-specific technical knowledge, but rather base their decision largely on how close their inter-personal relationships are with the rig operators (Kellogg, 2011). These findings should result in longer contracts for companies exploiting this opportunity, and is therefore a possible addition to Ringlund et al.'s (2008) findings of longer contracts in Europe relative to the U.S.

Building on Kellogg's (2011) findings, and Kaiser and Snyder's (2013) explanations regarding regional market correlations, Osmundsen, Rosendahl & Skjerpen (2015) narrow their researching area to the Gulf of Mexico and seek to uncover and understand the rig rate formation for jack-up rigs in this region. They find that the relative bargaining power of the rig contractors and the E&P companies are a significant factor in the formation of rig rates. They suggest that it is the factors affecting the companies' relative bargaining power, which are the factors determining the rig rates. Osmundsen et al. (2015) state that the utilization rates are a key determinant for who holds the bargaining power, and finds that higher utilization rates lead to higher rig rates, as rig contractors hold the bargaining advantage. In addition to the utilization rates, the price of oil is a major determinant for E&P companies' willingness to engage in rig contracts. These findings are supported by Kaiser and Snyder (2013; 2012). Osmundsen et al.'s (2015) research suggest that the E&P companies generally wait for some months after a change in the price of oil before engaging in contracts to be confident that the change is permanent. Interestingly, their research suggests that contract length and lead times play a significant role in determining the rig rates. Kaiser and Snyder (2013) fail to mention these contract-specific metrics. Nonetheless, lead-time and contract lengths increase in periods with high demand, which enhance the bargaining power of the rig companies, increasing rig rates (Osmundsen, Rosendahl, & Skjerpen, 2015).

Furthermore, Osmundsen et al. (2015) recognize that in some instances, rigs are moved between regions to meet demand; however, this practice is slow and costly. They argue that the effect of these movements is of minor importance to region-specific day rate formation, hence neglecting to incorporate interregion rig movements does not deteriorate the findings in their paper. Additionally, Osmundsen et al. (2015) put forward a notion that the rig rates for the floater segment, are formed similarly as jack-up day rates, but leaves this for future research.

As a prolongation to Osmundsen et al.'s (2015) research on jack-up rig formation in the Gulf of Mexico, Skjerpen, Storrøsten, Rosendahl & Osmundsen (2018) explores the rig rate formation for floaters on the Norwegian Continental Shelf (NCS), in effect continuing their previous research of jack-ups. Both papers are constructed with the same fundamental belief; that the rig rates are formed as a result of the relative bargaining power between the rig operators and the E&P companies, a theory supported by Kellogg (2011) and unsurprisingly, Osmundsen et al. (2015).

In contrast to Kellogg (2011), Skjerpen et al. (2018) develops a simple bargaining model for the rig markets and examines the empirically most essential drivers of the rig rate formation of floaters on the Norwegian Continental Shelf. They then use a reduced form time series model and report conditional point- and interval forecasts for rig rates in a base case and other scenarios. Skjerpen et al. (2018) limit their research to the NCS and seek to provide and apply a model that can explain the rig rate formation in the region to a satisfactory degree.

Skjerpen et al. (2018) suggest that the most critical determinants of rig rate formation are the price of oil, the rig capacity utilization, the remaining reserves in the area at which the rigs are operating, the contract length and their lead times, the labor cost, i.e., the workers' wages, and the real interest rate. These determinants are partially in line with Kaiser and Snyder (2013). They find that all determinants except wages have a positive effect on the rig rates. The paper seeks to fill the literature gap for the area of research which Skjerpen et al. (2018) find to be relatively scarce.

The overall purpose of Skjerpen et al.'s (2018) paper is to strengthen the understanding of the offshore rig markets for floaters, and the determinants that play a role in defining the daily rates. Skjerpen et al. (2018) forecast a slight increase in the rig rates of approximately $20,000 over the four-year forecast period for their base case. They also present specific scenarios and test the effect of an increase in the price of oil, utilization and the remaining reserves. They manage to prove their hypotheses, showing a positive effect on the rig rates in all three scenarios. The paper presents evidence that the oil price has to show stability before companies trust it to represent a lasting change; this is in line with observations made by Osmundsen et al. (2015).

There is little doubt that there are region-specific peculiarities in the drilling market, and it seems to be general agreement in the academic literature that the price of oil is a significant factor for determining the rig rates, regardless of region. Kaiser and Snyder (2013) suggest that the price of oil is formed in the global market, and Osmundsen et al. (2015) and Skjerpen et al. (2018) indicate that the global rig market is connected to the regional markets. It is therefore interesting to explore the day rate formation mechanisms on the global scale in order to obtain a fundamental understanding of the macro-economic mechanisms.

Martin Stopford (2009) developed the *shipping market model* with the traditional shipping market in mind. He simplifies the demand and supply factors for the industry into five elements within each group. According to Stopford (2009), the drivers for demand in the shipping industry are the world economy, the seaborne commodity trades, the average haul, random shocks, and the transport costs. The mechanics behind the factors involved in the demand function are relatively simple. Stopford (2009) finds that activities from industries, derived from the world economy, create goods which require transport from its origin port to the market at which it will be sold, thus being a factor for the demand for sea transport.

The supply factors are on the other hand the world fleet, the fleet's productivity, the shipbuilding production, scrapping and losses, and freight revenue. The combination of the factors in the supply function creates and regulates the fleet at any given point in time (Stopford, 2009). The supply of ships is cumbersome, like in the rig market (Kaiser & Snyder, 2013), and once a shipowner has ordered a new-build from the shipyard, it may take several years before he receives it. As a result, the supply of ships responds to increased demand with a time-lag of several years (Stopford, 2009). Similarly, once a shipowner receives a new ship with a life span of up to 30 years, it can be even more dawdling to reduce the supply when the industry experiences a reduction in demand (Stopford, 2009).

In a situation where there is an imbalance between the supply function and the demand function of the model, the freight rate market is the mechanism that controls the cash flow going from shippers to shipowners (Stopford, 2009). In periods with reduced supply, freight rates rise as shippers bid the price up. Shipowners start to order new ships, consequently adding capacity to the fleet, which in turn leads to a reduction of freight rates and decreased revenue for shipowners (Stopford, 2009). This mechanism is in line with relevant research (Kaiser & Snyder, 2013; Osmundsen, Rosendahl, & Skjerpen, 2015; Skjerpen T. , Storrøsten, Rosendahl, & Osmundsen, 2018; Kellogg, 2011).

Finally, following the understanding of modeling and presenting forecast scenarios for floater day rates, this paper seeks to add insights to the existing research by testing our findings in a valuation case of Odfjell Drilling in order to exemplify the consequences of different rig rates. To do so, we therefore apply the valuation methodology outlined by Petersen, Plenborg & Kinserdal (2012), *Financial Statement Analysis.* The book describes the financial analysis and valuation approaches needed to apply our findings to gain fresh insights to uncover the rig rate scenarios' effect in a use case.

Petersen et al. (2012) approach the financial statement analysis by developing a framework with a wide area of use cases. They stress the importance of gathering additional information beyond what is derived from the company as a premise for an adequate understanding of the markets and future outlooks for a valuation to be sufficient. By gathering information about the surrounding market, Petersen et al. (2012) say that it is possible to analyze a company's financials more intelligently, thus enabling the analyst to generate a more robust analysis. Their approach and literature were chosen as it is widely utilized, especially at Copenhagen Business School. These are familiar methods widely taught, and use financial models that are applicable to our intended purposes. That being said, Financial Statement Analysis, 4th edition is from 2012 and could be outdated in some aspects. We have therefore also utilized other sources to check the relevance of the information, as well as to supply the literature with additional information and guidelines, whenever deemed necessary.

Adding to Petersen et al.'s (2012) financial analysis, we seek to uncover if there are characteristics to the company that allow them to obtain a competitive advantage. Barney & Clark (2007) propose a framework for analyzing a company's resources; the VRIO-framework. According to their research, there are four requirements for a resource to provide a sustainable competitive advantage. They suggest that a resource has to be *valuable*, *rare*, *imperfectly imitable,* and that the *organization* must be able to utilize it. They argue that a resource may indeed provide an advantage to the firm, although it cannot be sustainable in the long-term if it does not fulfill all four criteria (Barney & Clark, 2007).

In summary, the reviewed literature seems to be in general agreement over the determinants of the rig rate formation. It has become evident that there are regional differences within the global market, and that the regional markets to some extent react differently to the same changes in non-region-specific input like the price of oil, but that they experience the same trajectories, i.e., it appears that they react similarly, though with different strength.

We seek to add an element to the existing literature by expanding the research to the NW European region. We have failed to identify academic literature or studies concerning the rig rate formation for this region in its entirety, and wish to contribute to the consisting literature by exploring an area that hosts one-third of the world's semisubmersibles. We will build a foundation based on Stopford's (2009) shipping market model that will allow for further investigation into the rig- and region-specific mechanisms that take part in determining the rig rate formation in NW Europe. We will base this investigation on Skjerpen et al.'s (2018) model for forecasting day rates on the NCS. Furthermore, we seek to add context to our findings by implementing our forecasted rig rate scenarios in a discounted cash flow valuation for Odfjell Drilling, where their operational exposure is viewed as ideal for testing our results.

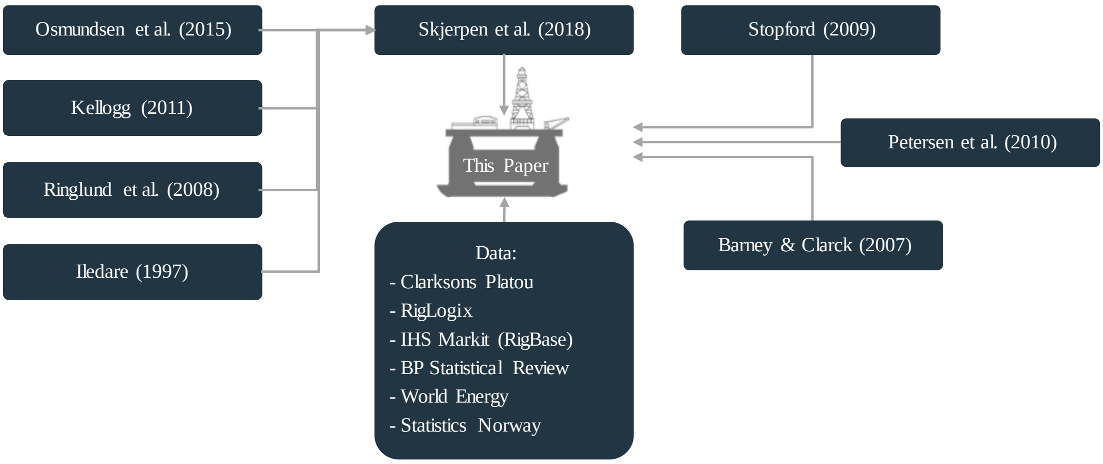

Figure 3.2 - Academic fundament of this paper. Authors' creation

3.2 METHODOLOGY AND DATA

In narrowing down our methodology, we find it important to review the methods applied by the literature on which this paper is built. The following will therefore elaborate on their methodology and how their approaches influence our approach. As the offshore drilling industry is highly influenced by macro-economic factors (National Petroleum Council, 2011), a framework for analyzing their effects on the market supply and demand is advantageous. The shipping market model presents theories that are derived from both external and objective data and from factors that to a large extent are socially constructed, i.e., the world economy and the decision-makers psychological aspect of business cycles, respectively. Stopford (2009) combines research approaches. He argues that the economy of the shipping industry is extremely complex and to grasp all aspects of the economic relations, he combines both a deductive and an inductive approach to his research. On the demand side of the model, he focuses on quantitative data, while on the supply side, he allows for interpretations of human psychology and partly explains mechanisms through behavioral action, like Kellogg (2011). Although unlikely, Martin Stopford has a stake in some of the shipping industry's leading companies, which may have put his model at risk for observer bias (Saunders, Lewis, & Thornhill, 2009).

The offshore drilling industry is a global business, with competing companies offering comparable products (Bassoe Analytics, 2019). By this definition, the offshore drilling market can be categorized as a commodity-driven industry. The offshore industry is in many ways similar to the shipping industry, but also somewhat different. Therefore, for the shipping market model to be effective, we need to alter the original model. We do this by excluding shipping-specific factors and replacing them with offshore drilling-specific factors. These are presented in Figure 3.3.

Potentially, another framework, like PESTEL could be utilized to analyze the same environment. However, the shipping market model is chosen as it is created for the maritime economy and is therefore more tailored for the offshore drilling industry. The shipping market model presents a framework for analyzing the structure of the maritime industry. However, in its broad nature, it might fail to highlight the nuances of a specific maritime sector, such as the offshore drilling industry. We therefore apply industry-specific literature in order to single out these nuances from the model in a more precise way.

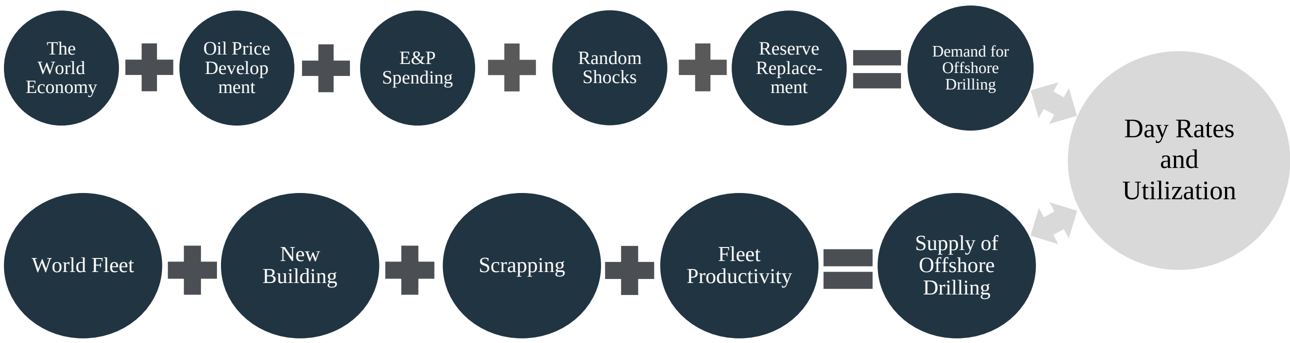

Figure 3.3 - Adjusted Shipping Market Model. Authors' creation

After examining the offshore rig market through Stopford's (2009) shipping market model, we apply Skjerpen et al.'s. (2018) model for a more focused and narrow area of the academia than what Stopford (2009) provides. The paper has a structured approach to the research area and applies a deductive methodology building on a quantitative dataset. According to Saunders et al. (2009), an adequate number of observations is a factor categorizing a deductive methodology, as induction puts more emphasis on the collection of qualitative data.

In contrast to Martin Stopford's (2009) methodology, Skjerpen et al.'s (2018) predominant approach of the paper is a positivist philosophy which implies that they are what Saunders et al. (2009) refer to as the 'resource' researchers. Our paper takes the stance of the positivist philosophy when interpreting Skjerpen et al. (2018). This means that we embrace data from real life observations and that the ontology is external and objective. Similarly to Skjerpen et al. (2018), we obtain data from the sources listed above, including Clarksons Platou Research. By not being currently employed in the industry, our role as independent researchers is in sum complied with.

Notably, as a result of taking the stance of the positivist philosophy, it is possible that Skjerpen et al. (2018) fails to acknowledge or recognize the subjective interventions from the market players within the industry. The complimenting broader approach of Stopford (2009) is therefore used to account for these potential shortcomings, and the two models must be seen in relation to each other.

As Petersen et al. (2012) stress the importance of understanding the surrounding market to better understand and analyze a company's financials, we include finding from both the shipping market model and Skjerpen et al.'s. (2018) model when interpreting Odfjell's financials, as well as peer-benchmarking. Petersen et al.'s (2012) approach resemble that of Stopford (2009) in the sense that they are guidelines to digest information on a non-specific industry or company basis. We must therefore adapt and apply these methods as seen fit for the industry. The book argues for both a positivist and interpretivist approach. As we value Odfjell Drilling, we are external observers of the truth in the form of gathering information from Odfjell Drilling's financial reporting and applying them to set mathematical models. That being said, as the valuation model moves to future estimates, the concept of a single external reality fades, and the methodology seeks to understand the company value from the context of the different interpretations of future economic scenarios.

The valuation process, therefore, relies on a less clear distinction of facts and judgments, where the preciseness of the model relies on our ability to predict the development of the industry and Odfjell's role herein. This part of the research paper, therefore, does not seek to answer a single external truth about the value of Odfjell Drilling, but rather to distinguish between the different realities' effect of the company value.

Skjerpen et al. (2018), Stopford (2009), and Petersen et al. (2012) form the backbone of our academic base. They are reliable sources in that they are all peer-reviewed and, particularly Stopford (2009), is broadly cited. Other articles reviewed in the literature review are also peer-reviewed, and as a result, we are confident that the literature and models we apply to our research are reliable. By establishing an academic foundation from these three pieces of literature, and implementing our constructive arguments, grounded in other sources, we are left with a robust and academically sound base on which we build our understanding of the offshore market. We will continue in our pursuit to understand and answer how rig day rates are formed in the NW European area and explore an academic area with little explicit literature.

We obtain a fundamental understanding of the macro-economic drivers for demand and supply for the resources in the industry on a global scale with the help of Stopford's (2009) framework. It is crucial to obtain a thorough understanding of these factors to be able to provide an answer to our research questions. It forms the fundament on which we subsequently narrow the area of research. Where we seek to explain and model how rig rates are formed in NW Europe, based on Skjerpen et al.'s (2018) model. This methodology will provide us with a structure on which we are able to answer how rig rates are formed. Lastly, we apply our forecasted findings to Odfjell Drilling. Here we combine both Stopford (2009), Skjerpen et al. (2018), and Petersen et al. (2012) to scenario-based forecasts of company revenue, and ultimately a share prices. By doing so, we illustrate how the expected day rates can be applied in a valuation model, and particularly how it impacts Odfjell Drilling.

3.3 STRUCTURE OF THE PAPER

The structure of the paper is illustrated in Figure 3.4 below. It is based on the selected models presented in this chapter and illustrates the causal structure of the paper. Each analyze and enlighten a subject that is deemed crucial to the following chapter, to create a consistent and reader-friendly paper.

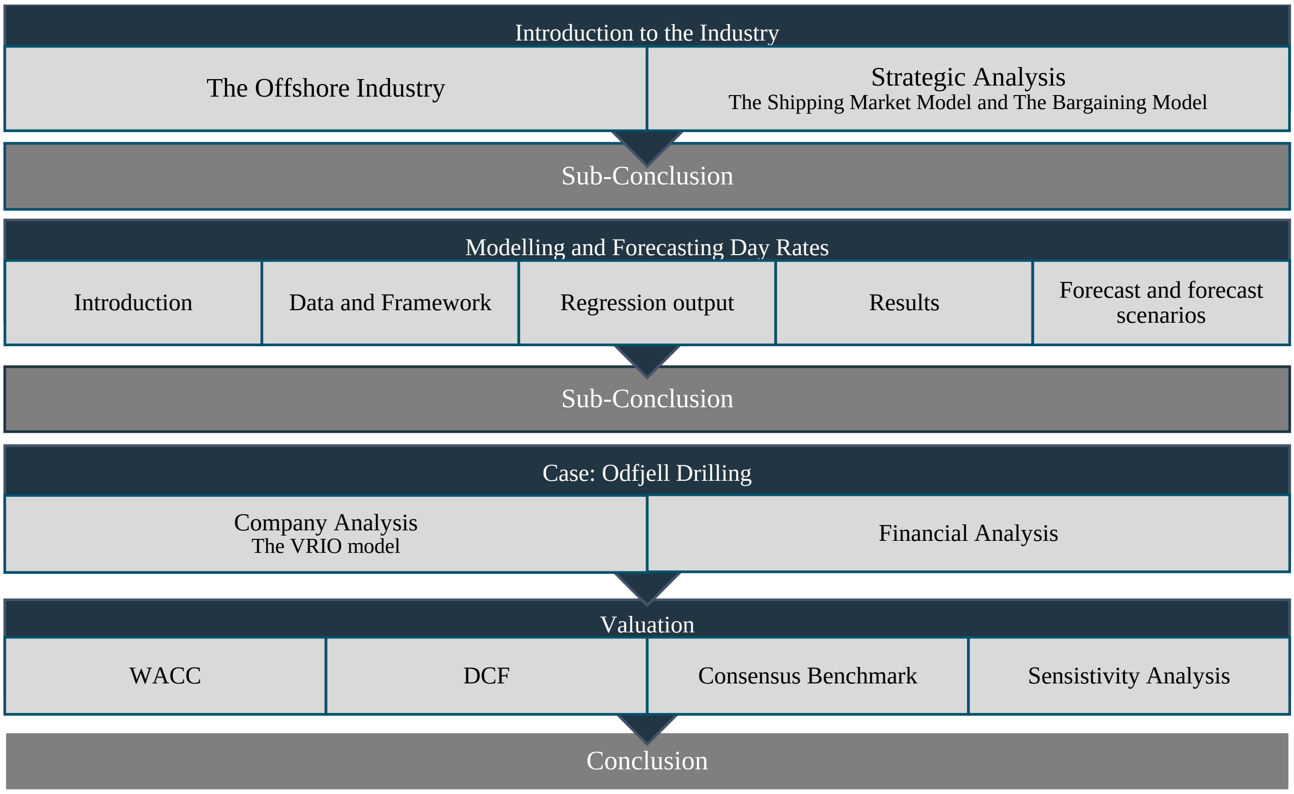

Figure 3.4 - Structure of the paper. Authors' creation

3.4 LIMITATIONS

In order to reach an academically robust response to the research questions, the following limitations have been set

- The cut-off date for the valuation is set to April 30, 2019
- No data prior to 2000 is used for modeling offshore drilling day rates
- Any information not available to the public is obtained for the valuation of Odfjell Drilling with regards to its financials
- All financials and prices are expressed in United States Dollars unless stated otherwise, e.g. share prices

Further assumptions made will be explicitly stated as they are made in their appropriate chapter.

4 THE OFFSHORE DRILLING INDUSTRY

In order to provide a deeper understanding of the key factors in the rig market, an analysis will be provided in the following subchapters. Here the aim is to provide a foundation of knowledge on which we can build a regression model to explain the rig rates. The research questions we seek to answer are the following:

- What characterizes the offshore drilling market and how is the value chain composed?
- How has the offshore drilling market developed?
- Who are the main competitors in the market?

This analysis will primarily be based on the Kaiser & Snyder (2013a) article, “A Primer on the Offshore Drilling Industry” and Olesen’s (2015) “Offshore Supply Industry Dynamics.”

4.1 DRILLING COMPANIES IN THE OIL AND GAS VALUE CHAIN

Offshore drilling rigs are a vital part of the oil and gas industry value chain. The following subchapter seeks to explain the drilling companies’ position herein. At the top level, the oil and gas industry can be divided into three main parts. Upstream, midstream and downstream (Olesen, 2015).

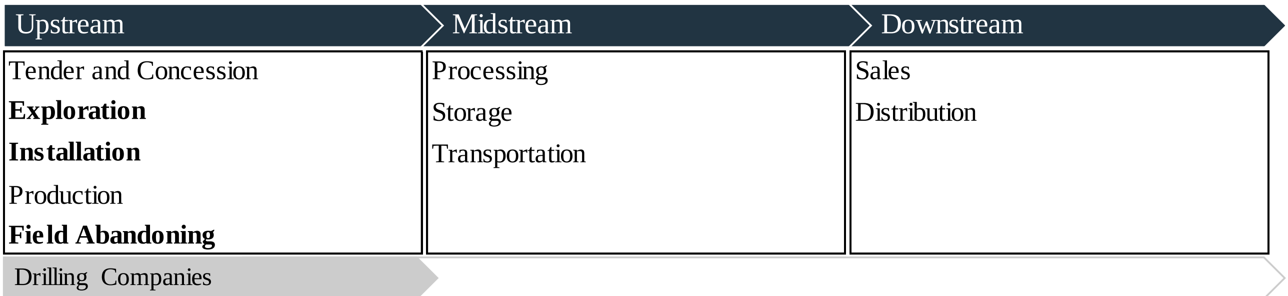

Figure 4.1 - Oil and gas value chain.Source: Olesen (2015). Authors' creation

As seen in Figure 4.1 above, drilling companies are considered to perform an upstream activity. The focus lies around exploration, installation, and field abandoning. This breakdown analysis will be centered around these three phases.

4.1.1 Exploration

The exploration phase is made up of three consecutive activities (Olesen, 2015):

1. Seismic surveys
2. Exploratory Drilling
3. Commercial Evaluation

We will focus on the exploratory drilling stage, as the other two are not directly relevant for this paper.

4.1.1.1 Exploratory drilling

In areas that - after seismic surveys - show promising geological signs, such as hydrocarbons and the correct topography for oil development, a hypothesis is made of possible oil in the field. To test this hypothesis, E&P companies must contract a drilling company to drill exploration wells. Drilling companies then charge daily rates for the use of their equipment, personnel, and expertise, in order to drill to the oil company and oil fields required specification. Variables include, but are not limited to rig types, fluids, water depths, and weather conditions. See section 4.2 for a comprehensive breakdown of rig types.

As these wells seek to confirm the hypothesis of the presence of oil, core samples from the wells are extracted for the E&P company to evaluate. This phase often requires several wells to be drilled around the field, in order to build a more precise understanding of the area.

Once the drilling companies can produce a positive core sample, proving oil, additional wells are drilled in the vicinity of the reservoir in order to evaluate its extent. These wells are called appraisal wells.

4.1.2 Installation

The installation phase is made up of four different phases (Olesen, 2015):

1. Building a production platform
2. Transport and logistics
3. Installation of the production platform
4. Drilling of production wells

Only the final phase of thos stage is done by drilling companies. However, an overall walkthrough is presented, as we argue that it is important to see the difference between drilling rigs and production platforms.

4.1.2.1 Production platforms

When oil discoveries are confirmed, the reservoir is sized up and thoroughly evaluated with the necessary studies. At this stage installation of production equipment can begin (Olesen, 2015). Production platforms are different from drilling rigs, as platforms are permanent installments that are stationary on location for many years. Similar to drilling rigs, there are a variety of different platform solutions, depending mainly on the water depths and the environment in which they operate. The platforms are designed and produced by suppliers, but are owned and operated by the E&P companies themselves and are therefore not charged a daily rate, as is the case with drilling rigs. The differences of platform designs can be viewed in Figure 4.2, below.

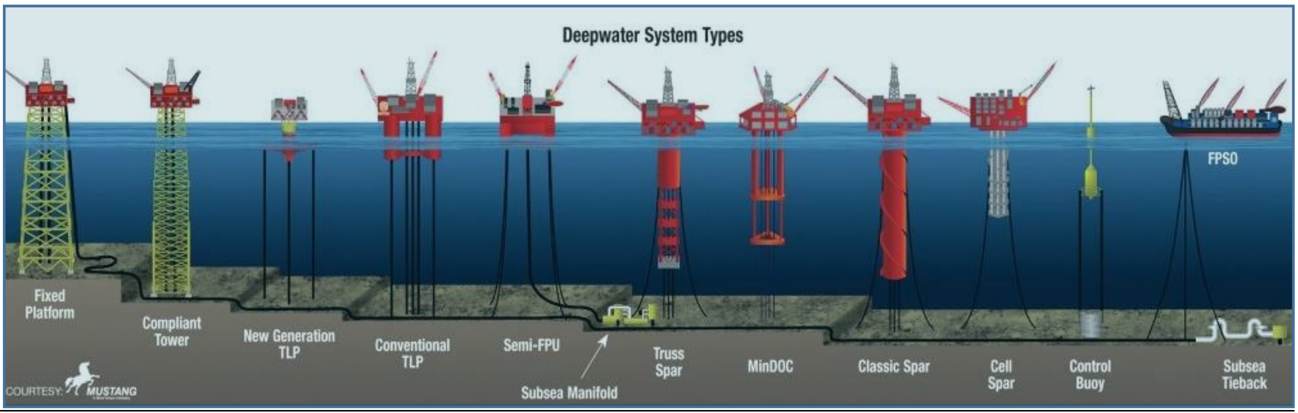

Figure 4.2 - Deepwater System Types. Source: Mahoney & Supan (2012)

4.1.2.2 Drilling of Production Wells

When the production platform is complete, drilling companies assist by drilling production wells to be used by the platform. These wells are drilled similarly to the exploration wells but differ in that they require more technical engineering because they have to be prepared for operation. During production, new wells are sometimes needed to continue the productivity of the platform. This keeps the drilling companies partly involved throughout the reservoir extraction.

4.1.3 FIELD ABANDONING

The final stage of an oil field operation is the field abandoning. This closing stage is made up of two phases (Olesen, 2015):

1. Well Plugging
2. Decommissioning

Drilling companies are involved in the well plugging.

4.1.3.1 WELL PLUGGING

To prevent leakages from remaining hydrocarbons from the well upon abandonment, it needs to be plugged. Before the equipment is disassembled (either on-site or transported away, depending on their possible environmental threat or disturbance to the local fishing industry), the drilling companies perform a well-plugging job, as their final role in the value chain. This is done by placing several cement plugs into the well in order to create a permanent seal. (Vrålstad, et al., 2019)

4.2 THE RIG TYPES

Oil drilling rigs (also referred to as Mobile Offshore Drilling Units, MODUs), is the main tool for accessing offshore oil and gas reserves. The oil rig is a marine vessels but comes in different sizes and shapes for different environments (Kaiser & Snyder, 2013a). The many different shapes of rigs are ordered into different categories and subcategories mainly according to whether they are bottom supported or floating. These categories can be explained in the following.

Figure 4.3 - Rig types. Source: Transocean Ltd.

4.2.1 FLOATERS

A floater is an umbrella term for all rig types that are not directly grounded to the sea floor, but float and are kept aligned with the well using anchors and/or dynamic positioning propeller and navigation systems (Kaiser & Snyder, 2013a). There are primarily two categories of floaters; semisubmersibles and drillships.

4.2.1.1 SEMISUBMERSIBLES

Semisubmersible drilling rigs is the most popular subcategory within floaters in NW Europe. The rigs are capable of drilling at water depths up to 3,000 meters (Maersk Drilling, 2019). These rigs have decks that are supported by two styles of submerged floating systems. Namely, the bottle-type and the column-type (RigZone, 2019a). The bottle style has large pillars that can be filled with ballast water in order to submerge parts of the rig, and the column-type has submerged pontoons that are connected by half-submerged pillars. In the column-type rigs, these pontoons are filled with ballast water. The column-type semisubmersible drill rig is the most common rig of this subcategory (RigZone, 2019a). It is a highly stable floater and is therefore often preferred for harsh environmental conditions, as the stability enables them to withstand the many hurdles of continuous rough waters (RigZone, 2019a).

Semisubmersible designs are mainly standardized and built in heavy-industry shipyards in Asia, such as the three Korean giants, Samsung Heavy Industries, Hyundai Heavy Industries and Daewoo Shipbuilding & Marine Engineering Co. Ltd. (Olesen, 2015). To differentiate the build designs from each other, a ranking is assigned in the form of a generation. Figure 4.4 below explains the generations and their main differences.

Generations of Semisubmersibles		
Generation	Build Year	Max Water Depth
1st	1962 – 1959	800 ft.
2nd	1970 – 1981	1 500 ft.
3rd	1982 – 1986	2 500 ft.
4th	1986 – 1997	3 000 ft.
5th	1997 – 2004	7 500 ft.
6th	2005 – Onwards	10 000 ft.
7th	2015 – Onwards	12 000 ft.

Figure 4.4 - Generations of Semisubmersibles. Source: Kaiser & Snyder (2013b)

4.2.1.2 DRILLSHIPS

Drillships are large ships constructed or converted to drilling vessels. They take on the form of tankers and other large ships but have a drilling derrick above a hole in the hull called a moon pool, from which the drilling arm is lowered (RigZone, 2019b). Drillships are held in position with satellite controlled dynamic positioning systems and can drill on ultra-deepwater depths, usually between 2,000 to12,000 feet (RigZone, 2019b; Schuler, 2016). While its ship-based design makes for a highly mobile and deep sea capable driller, the drillship is more exposed to harsh waters and does not handle waves, winds, and currents as well as its semisubmersible floater-counterpart (RigZone, 2019b).

Floater Specifications by Water Depth		
Mid-water	*Deep*	*Ultra-deep*
< 4000 ft.	*4001 - 7500 ft.*	*> 7500 ft.*

Figure 4.5 - Floater specification by water depth. Source: Kaiser & Snyder (2013b)

4.2.2 Bottom Supported

Bottom supported rigs are fixed to the sea bed. The most common type of bottom-supported rigs are jack-ups (Kaiser & Snyder, 2013a), which is also the most common rig of all categories. These rigs are barges with legs that can be lowered to the seafloor and are capable of drilling in water depths of around 400 ft. (Kaiser & Snyder, 2013a). Being bottom supported, jack-ups are stable but constrained to shallower waters.

Jack-up specifications by water depth		
TYPE	*Depth*	*Hook Load Capacity*
HIGH SPECIFICATION	400+ ft.	2 000 Kips
PREMIUM	350+ ft.	0-1999 Kips
STANDARD	> 350+ ft.	0
MAT CANTILEVER/SLOT	Any jack-up that not has an independent cantilever (ILC) sub-type	

Figure 4.6 - Jack-up specifications by water depth. Source: Kaiser & Snyder (2013b)

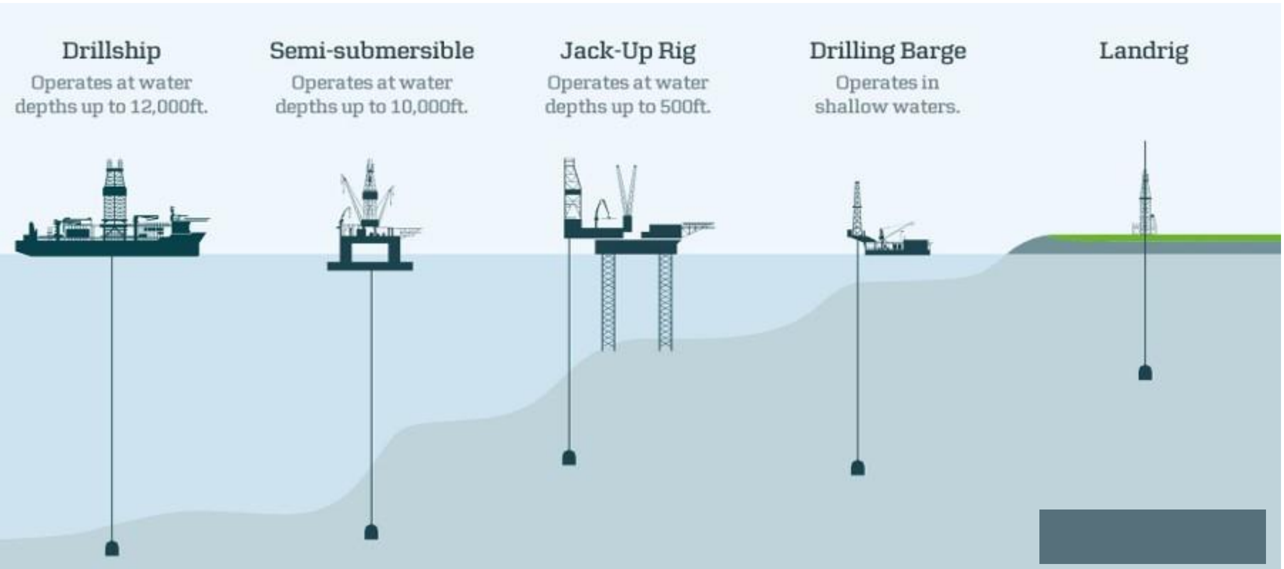

Figure 4.7 - Rig types. Source: Maersk Drilling. Retrieved from (Deep Trekker, 2019)

4.3 RIG STATES OF ACTIVITY

Drilling rigs can shift from one state of activity to another. As shown in the figure below, a rig is not merely on a contract or off contract. This chapter, therefore, seeks to explain the differences in rig activity, in order to build a picture of how this might affect the competitiveness of a company's fleet.

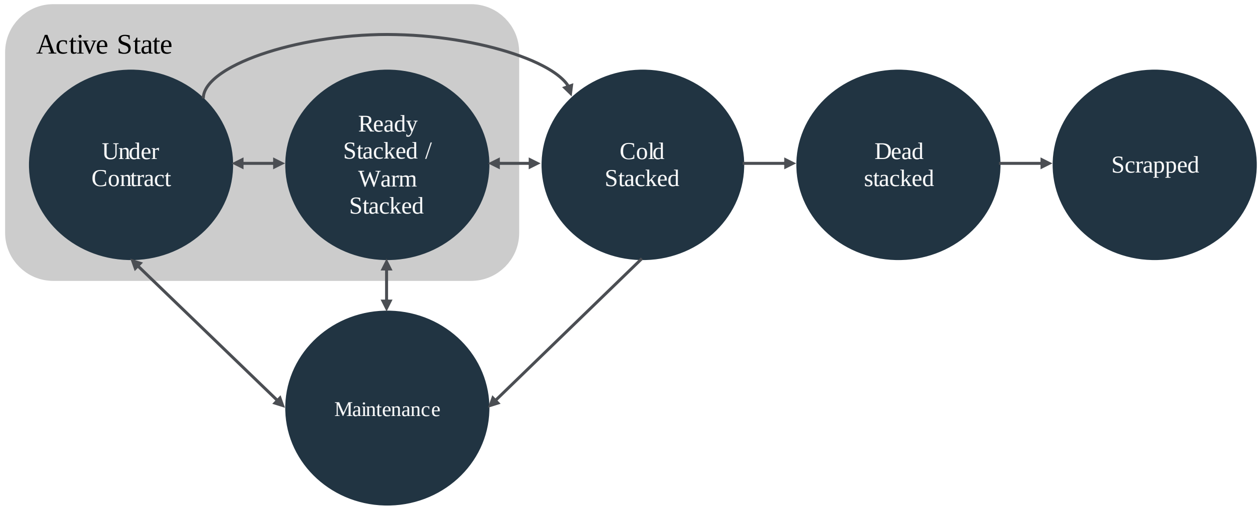

Figure 4.8 - Rig states of activity. Source: Kaiser & Snyder (2013)

As the illustration in Figure 4.8 shows, we can divide the rigs into an active state or an inactive state.

4.3.1 ACTIVE RIGS

Active rigs are rigs that are currently on contract, or that are ready/warm stacked. Being warm stacked means that the rig operator keeps the rig on normal maintenance operations, on a similar level to what happens when a rig is on contract (Kaiser & Snyder, 2013a). This means that the rig is work-ready on very short notice and is marketed accordingly.

4.3.2 INACTIVE RIGS

Inactive rigs are rigs that are not expected to be contacted in the near future. As opposed to being warm stacked, these rigs are considered to be cold stacked. These are idle for months to even years and is not considered a marketable supply (Kaiser & Snyder, 2013a). The cold stacked rigs are stored in wet docks and require reactivation investments in order to be brought back to the market. If rigs are cold stacked for too long, reactivation costs will be so high that they transition to be labeled dead-stacked and are often used for parts before being retired/scrapped (Kaiser & Snyder, 2013a). When scrapping a rig, it is either sold to recycling firms (recycling), or for alternative use cases, e.g., production services (conversion).

4.4 INDUSTRY DEVELOPMENT AND TRENDS

The drilling industry has experienced many mergers over the past decades, and the consolidations continue today (Kaiser & Snyder, 2013). NW Europe has been relatively stable in terms of rig count over the past two decades, whereas the West Coast of Africa has experienced an increase in activity during the same period, particularly off the coast of Angola and Ghana. Figure 4.9 illustrates the rig count for the major market regions and provides a good overview of where the world demand resides. The table includes every jack-up, semisubmersible, and drillships in the world including newbuilds, but excluding those that are cold stacked. The Far East and Southeast Asia region might be misrepresentative for where the demand is due to the high number of newbuilds being constructed there, especially in South Korea, Singapore, and China.

World rig count, excl. cold stack March 18 2019	**Jack-up**	**Semi**	**Drill ship**	**Total**
Canada/Greenland	1	3	0	4
Caspian	7	4	0	11
Far East	93	22	17	132
India/Subcontinent	37	4	7	48
Mediterranean/Black Sea	13	3	9	25
Mexico	34	4	2	40
Middle East	157	0	0	157
North Sea/Barents	39	32	0	71
Oceania	3	5	0	8
South America	8	13	22	43
Southeast Asia	68	10	7	85
US GoM	15	4	21	40
West Africa	16	3	27	46
Total	**491**	**107**	**112**	**710**

Figure 4.9 - World rig count, excluding cold stacked rigs. Source: Bassoe Analytics (2019)

As one might expect, the Middle East has the highest number of jack-ups due to shallower waters, while almost one-third of all semisubmersible rigs in the world are operating in the North Sea and the Barents Sea region. Nearly all of the available drillships are in the Americas and West Africa, working on deep-water and ultra-deep-water contracts. The distribution of rigs have been relatively stable over the past 20 years, except a slight decrease in the North Sea after 2001, yet stable for the past decade. West Africa has seen an increase in recent years and has the highest rig count volatility (Kaiser & Snyder, 2013). The political environment in the African West coast countries can be a contributor to the high volatility in MODUs due to uncertainties for oil companies. In addition, there are mostly deep-water E&P operations, hence utilizing drillships which are mobile and moved all over the world, as opposed to harsh-environment semi-submersibles in the North Sea, which are often exclusively operating in their designated area.

4.5 UTILIZATION

Rig utilization is the share of contracted rigs to the marketed supply. Although the rig market is highly international, there are regional differences in capacity utilization. There are several reasons for this, but the three most clear explanations are the environment, distance, and political; all explained under.

The environment is important because the different rig classifications are not interchangeably useable, i.e., to operate in the North Sea, the rig needs to be able to withstand harsh environment operations. Distance plays a role because of the costs related to moving a drilling unit from point A to point B. The oil company carries this cost, and as mentioned in section 3.1, this can be timely and costly. Political environments are region specific with regards to health, safety, and emergency preparedness, as well as environmental regulations. Some areas enforce stricter environmental policies on rigs and other equipment in its waters (Thune, Engen, & Wicken, 2019). Consequently, the barriers reduce the number of rigs allowed to operate in certain areas.

However, this does not imply that none of the rigs on the world market are useable outside of their initial operational region. When one region experiences high utilization, contractors respond by marketing idle rigs from other regions or rigs being constructed, to the high-utilization market (Kaiser & Snyder, 2013). As a result, the high-utilization market will experience a fall in utilization rates due to the larger fleet size and the process of stacking and redistributing rigs to other regions will repeat itself (Kaiser & Snyder, 2013). Figure 4.10 illustrates the development in capacity utilization for MODUs in a selection of key markets between 2000 and 2018. It is evident that the market cannot distribute its fleet perfectly. However, the rates appear to mostly react to the same macroeconomic factors, depicted in their similar development.

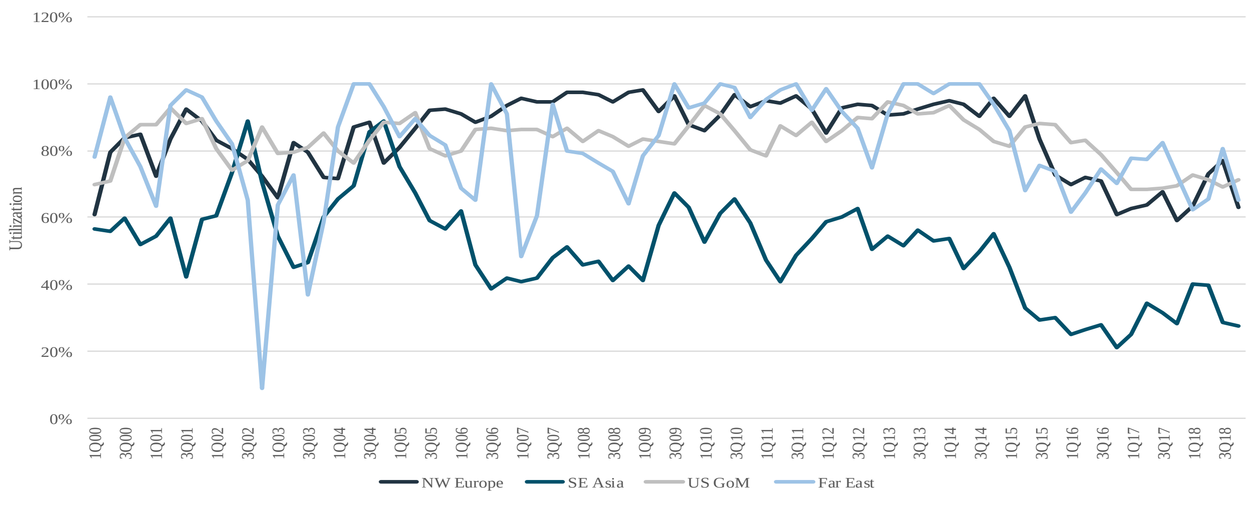

Figure 4.10 - Offshore rigs capacity utilizations in key markets. Source RigLogix

4.6 MARKET PLAYERS

Since the industry has experienced a substantial degree of consolidation, there are a handful of prominent market players. Many of the companies are publically traded stocks such as Seadrill, Transocean, and Odfjell Drilling, yet some are privately held. Additionaly, some operators are governemnt owned and might be subsidiaries of national oil companies such as COSL (owned by China National Offshore Oil Company) (Kaiser & Snyder, 2013). From Figure 4.11 and Figure 4.12 below, shows that when focusing on the semisubmersible market segment, the market share increases further. There are a total of 829 floaters in the world as of March 2019, including stacked rigs and units under construction, of which are 2010 semi-submersibles.

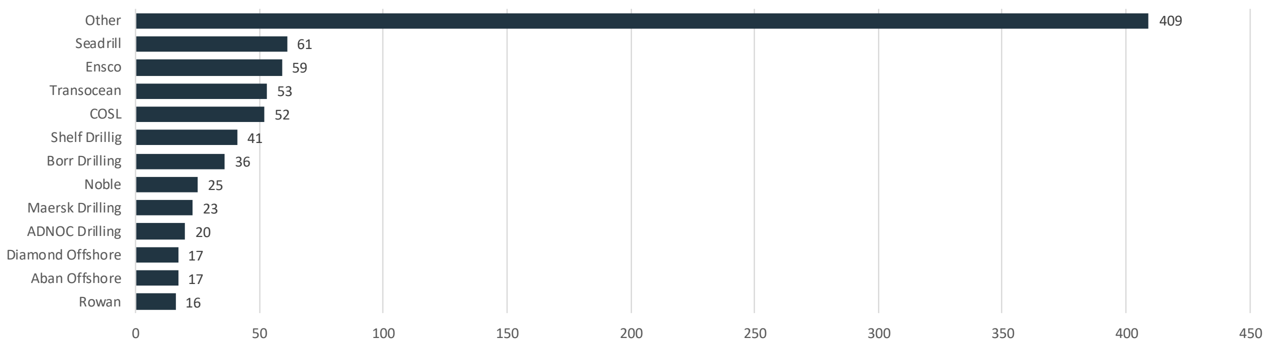

Figure 4.11 - Owners of the total world fleet. Source: Bassoe Analytics (2019)

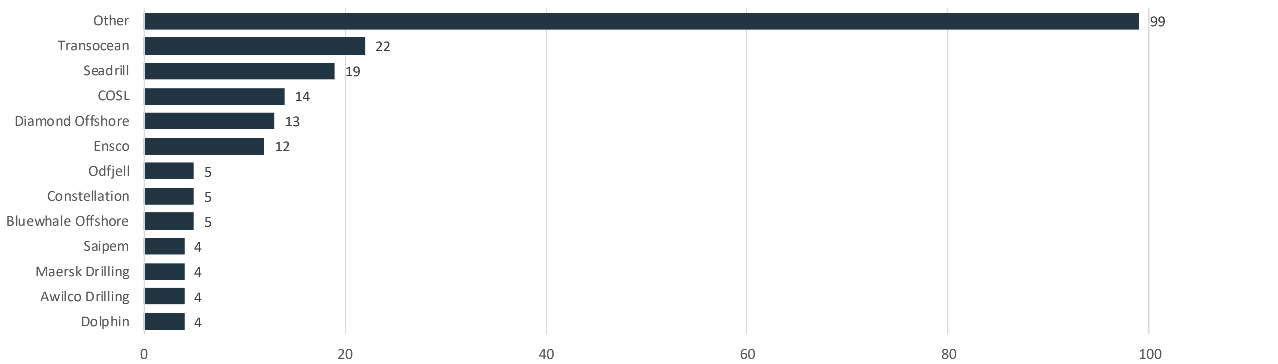

Figure 4.12 - Owners of the world's semisubmersible fleet. Source: Bassoe Analytics (2019)

In total, there are more than 100 rig owners in the world (74 with active rigs), and some only own one or two rigs (Shinn, 2018). Some companies choose to become specialized operators, i.e., pure players such as Transocean which have reduced their jack-up fleet to zero, and instead acquired companies with only drillships and semisubmersible rigs (Transocean, 2019). While other large players have a different philosophy with a fleet spanning all segments, e.g., Seadrill which as of March 2019 has the largest fleet of any drilling contractor with 61 rigs; 19 semisubmersibles, 29 jack-ups, and 13 drillships. Much of the contractors' motivation behind consolidation in the industry is the asset diversification it provides and the inherent economies of scale (Kaiser & Snyder, 2013). When a company obtains a larger fleet, they benefit from better liquidity from a larger backlog, i.e., Transocean's backlog as of December 31, 2018 was $12.5 billion (Transocean Ltd., 2019). The sheer size of the most significant players allows them to idle and stack rigs to force the market in a more favorable direction. For example, they can idle ten semi-submersibles, a substantial portion of the world fleet, to force an increase in day rates. According to Kaiser & Snyder (2013), the merger trend in the contractor industry has been a critical growth strategy for larger companies.

4.7 CONCLUSION

Overall, the industry resides mostly upstream of the oil production value chain, and are therefore directly dependent on the petroleum (E&P) companies. The rigs are use-specific in that different designs are useful for different environments, where depth is the dominant decider. For deeper waters, floaters are used and for shallower waters, bottom-supported units are preferred. The rigs are also taken on and off the marketed supply, by stacking – either for the long run (cold) or for shorter periods of time, between contracts (warm). This creates a heavy asset industry that is both international and regional, depending on the time horizon and the region-specific requirements. The market has in later years seen consolidation, where a few, international firms have emerged with a substantial holding of the world fleet. Despite ownership consolidation, the distribution of the world fleet has been fairly stable, highlighting the fact that rigs are more specified towards certain geographical regions – creating sub-markets.

5 STRATEGIC ANALYSIS

In this section, we seek to analyze the strategic environment surrounding the drilling companies. This is done in order to form a basis for understanding the frictions of the drilling industry, both internally and externally. By building on the knowledge of the characteristics of the industry gained in the previous chapter, we can now analyze the drivers of the industry. The following questions are used to pilot the analysis.

- What are the most influential factors of the companies in the industry?
- How does the supply and demand relation affect the day rate mechanism?
- How does the industry bargaining power structure affect future day rates?

5.1 SHIPPING MARKET MODEL

In order to explain the market powers affecting the pricing in the offshore drilling industry, this model seeks to build a thorough analysis of both the supply and demand side of the market. It is essential to know these factors before establishing an econometric model for forecasting the day rates in the next chapter, as they provide insights into the underlying critical mechanisms of the global and regional markets. Although we focus on the NW European area, the global macroeconomic forces are those that drive the industry regardless of geographical area. It is therefore necessary to analyze the world as a whole, as well as NW Europe. Our approach to the shipping market model is deductive. We formulate a set of hypotheses based on the model's theory and seek to analyze them in the next chapter.

The shipping market model by Martin Stopford is, as the name states, a shipping focused model. However, the similarities between the shipping market and the offshore rig market are plentiful; they are highly globalized industries, they work on a day rate basis, a few significant factors are affecting it such as oil price, and both industries are subject to a cyclical market, to name a few. On the following pages, the Shipping Market Model will be presented, and in the following subchapter, we will apply our empirical data to the model and analyze these through Stopford’s (2009) model.

The shipping industry is characterized by business cycles, and shipowners’ cash flows can be dramatically affected by these cycles in just a few months (Stopford, 2009). It is therefore a need to recognize the peaks and trenches in the cycles (Stopford, 2009). We want to expand our understanding of the market cycles and what drives them. Stopford (2009) argues that analyzing the supply and demand through his model allows for an explanation of the day rate formation through the mechanisms which determine them.

Because the maritime industry and its economy is complex, Stopford (2009) simplifies the model by emphasizing the most important factors influencing the market. Figure 12 states these factors according to theory, as well as an alternative which this paper argues to be more suitable for the offshore drilling market. These alternative factors are based on elements affecting the day rate formation in the rig market, recognized from existing literature, such as Skjerpen et al. (2018). The Shipping Market Model is adapted in order to better capture the complexities of the industry we analyze, and expectantly attain a more accurate depiction of the drilling market than would be the case should we exclusively utilize Stopford's (2009) key factors for the shipping industry.

Demand		Supply	
Shipping industry	**Offshore industry**	**Shipping industry**	**Offshore industry**
The world economy	The world economy	World fleet	World fleet
Seaborne commodity trades	Oil trade (oil demand)	Fleet productivity	Fleet productivity
Average haul	E&P spending	Shipbuilding production	New-building
Random shocks	Reserve replacement	Scrapping and losses	Scrapping and losses
Transport costs	Random shocks	Freight revenue	

Figure 5.1 - Shipping market model. Source: Stopford (2009) and Authors' adaptation

5.1.1 DEMAND THEORY

5.1.1.1 WORLD ECONOMY

Stopford (2009) lists the world economy as the first demand-factor and unquestionably is the single most crucial factor affecting the market. It becomes evident in his theory that there is a close relationship between the world economy, which he measures in OECD industrial production, and the seaborne trade. According to Stopford (2009), the world economy and the seaborne trade connects through three separate aspects. These are the business cycles, the trade elasticity, and the development cycle.

There are many explanations to business cycles, and most economists seem to agree that there is a combination of both demand and supply factors affecting them (Stopford, 2009). These are separated into external and internal factors. According to Stopford (2009), external factors may include events such as war or unexpected sudden changes to commodity prices, e.g., crude oil, both of which cause changes to the demand side of the model. Internal factors relate to the dynamic structure of the world economy itself, and one can argue that this naturally leads to a cyclical growth path (Stopford, 2009).

Stopford (2009) argues that some theories explaining the business cycles are more frequently applied than others.

The multiplier and accelerator effect are two separate factors that relate to the relationship between consumption and investment. This theory says that when income is invested in for example infrastructure, demand is created from the hired labor workers as they will spend their salaries, which again will create new demand in the area in which they are deployed. This occurrence is called the investment multiplier because the initial investment creates more demand than one can expect from the isolated investment itself. Sequentially, the consumption created from the investment multiplier leads to growth in the economy, in turn leading to even more demand for investment. This is referred to as the income accelerator. At one point, the economy over-heats because the labor and capital are fully utilized (Stopford, 2009). When this happens, the investments fall, and both the multiplier and the accelerator goes into reverse.

Time-lags may make the business cycles more volatile because there is a delay between the investment decision and their implementation (Stopford, 2009). Time-lags are especially true for the offshore market which is characterized as a capital-intensive industry with long lead times.

Mass psychology is argued by some economists to intensify the cycles because business decisions are not made independently from one another. Thus, they do not cancel each other out (Stopford, 2009). When times are rough, and the market players are pessimistic, the very fact that they become pessimistic grows into a self-fulfilling prophecy and further drives the market’s downturn even more than what it would have been if the players acted independently. The same is true in up-turns. In consequence, the effect of mass psychology can be argued to be canceled out over long periods, though still being a significant contributor to the business-cycle volatility in the shorter term.

Trade elasticity is the second aspect Stopford (2009) argues to cause interrelations between the world economy and the seaborne trades. It is a measure of a longer term relationship than business cycles and is essentially a beta-estimate of the seaborne trades. That is, how fast it grows relative to the industrial output (OECD industrial production). Stopford (2009) suggested a trade elasticity of 1.4 for the years between 1963 and 1996, indicating that the sea trade grew faster than the world industry on average in the measured period.

Lastly, the trade development cycle is an acknowledgment of changes to countries’ trade as it enters new economic stages and the domestic economy evolves (Stopford, 2009). When a country advances through these economic stages, their demand for raw materials such as iron ore and oil increase. The growth rate of the raw material import is then, possibly over 50 years, transitioning to become more stable as it reaches its mature level and the country enters a production stage where less raw material intensive activities are required (Stopford, 2009).

Since the business cycles in the shipping market model are argued to be closely related to the economic cycles of the world economy, we assume that the world economy and indirectly its cycles are closely related to the development in the offshore rig market. These business cycles are only good at illustrating the short-term developments in the economy. Thus, we also assume that the demand for oil and subsequently drilling activities are closely related to the economic developments in the world and especially emerging markets, as they will require an increase in the import of oil. That is, we hypothesize that the world demand for oil will to a large extent follow the world demand for energy.

Hypothesis 1.1

The demand for oil is to a large extent related to the development in the world economy

5.1.1.2 Trades

The second factor on the demand side of the Shipping Market Model is seaborne commodity trades. Stopford (2009) separates the trades into short-term and long-term trades. His theory states that short-term trade and its volatility comes from the seasonality of certain commodities such as agricultural products. The seasonalities are challenging to plan, and the result is that shippers rely on the spot market; consequently resulting in a disproportionately high influence on the spot market prices. The seasonalities are not exclusive to agricultural products, as the transport of oil experiences seasonal increases of transportation to the northern hemisphere in the winter months (Stopford, 2009).

However, the long-term trends, which likely is more relevant when analyzing the rig market, are identified by examining the economics of the industries which are receiving or producing the traded cargoes. In the 1960s, the demand for crude oil increased significantly and outpaced the growth in the general economy by a factor of almost four because western countries substituted their coal power stations with oil as their primary energy source (Stopford, 2009). Though more critical for the shipping trade than for the rig market, the change in the supply source is an essential part of rate formation. Because once the source is closer to the market it serves, it leads to less demand for shipping haul, i.e., NW Europe not relying on the Middle East for oil production after reservoirs were discovered in the North Sea in the 1960s and 1970s (Stopford, 2009).

In our analysis, we substitute this factor with oil trade, which essentially is the oil demand. We adopt Stopford's theory and utilize his arguments for changes in seaborne commodity trades to justify changes to the demand in oil. Seaborne commodity trade and the demand for oil is related because according to Stopford (2009), crude oil was the single largest commodity transported at sea (measured in tons) at the time of writing the model (1996). We build on Stopford's (2009) assumptions regarding the identification of long-term trends through the industry that needs oil.

Hypothesis 1.2

An increase in the demand for oil will positively influence offshore rig rates

5.1.1.3 Exploration spending

The third demand factor outlined by Stopford is the average haul and ton miles which are industry-specific metrics that relate to the average distance the freight moves and the tonnage multiplied by the average distance it is moved, respectively (Stopford, 2009). Changes in the ton miles are naturally affecting the shipping market, and the industry has been through periods where this has been intensely proven (Stopford, 2009).

The average haul and ton miles factors are industry-specific to the shipping market and do not translate to the offshore drilling industry. The factors must therefore be replaced. Skjerpen et al. (2018) indicate that remaining reserves, being the remaining reserves profitable for extraction at the given economic environment, is an essential factor in the rig market and for the rig rate formation. Since the remaining reserves are related to how much companies spend on exploring, we adapt Stopford's (2009) model and analyze the effect of exploration spending to the offshore rig market.

Hypothesis 1.3

Exploration spending is driven by factors such as the price of oil

5.1.1.4 Reserve replacement

In addition to exploration spending, another industry-spesific metric we deem fitting to the Shipping Market Model adaption is the reserve replacement ratio. The metric is a natural prolongation to the exploration spending, and its effect builds on the same reasoning.

Hypothesis 1.4

Reserve replacement is driven by factors such as the price of oil

5.1.1.5 Random Shocks

Stopford (2009) highlights random shocks as a potential driver of changes to demand. An example of a random shock was the closure of the Suez Canal due to the Angelo-French and Israeli invasion of Egypt in 1956. The following consequence was a doubling in the average distance between the Arabian Gulf to Europe (Stopford, 2009). Events such as the invasion of Egypt and the Iran revolution in 1979 is what Stopford (2009) calls political disturbances and is applied to the model as random shocks. These happenings does not always directly affect the market, but their indirect effects are often significant contributors to the shipping market (Stopford, 2009).

Consequently, we expect random shocks to affect the rig rates indirectly. Stopford (2009) indicates that random shocks might be too complicated for analysts to predict, which results in very few market forecasts where the factor is taken into account. For the period we analyze, we hypothesize that there will be a significant effect on rig rates as an indirect result of the financial crisis in 2008 and possibly the oil price drop in 2014.

Hypothesis 1.5

Random shocks affect the rig market in 2008 and 2014

5.1.2 Supply theory

5.1.2.1 The Fleet

In the short-term, the sum of the total marketed fleet creates the world capacity. The degree to which this fleet is being utilized or is cold stacked depends on the current demand. The fleet regulates its size by stacking and scrapping; a process that can be slow and cumbersome. A few decision-makers control the current supply of the total fleet; the shipowners, the bankers, the authorities and the charterers (Stopford, 2009). These groups have various tasks, all affecting the supply to the market.

The shipowners are the primary decision-makers because they are the ones ordering newbuilds and deciding when to scrap old ships. The authorities make and enforce legislation which may affect the supply, i.e., IMO 2020. The banks are the ones influencing the investments, and according to Stopford (2009), they are often applying financial pressure on shipowners that lead to the scrapping of a ship.

A consequence of the relatively few decision-makers is according to Stopford (2009) a behavioral relationship in the supply side of the model. The fact that there are behavioral relationships in the decision-making process is a warning to analysts. There is no guarantee that high freight rates have increased the number of newbuilds as it has proven to be the case in the past (Stopford, 2009).

In the long-term, fleet growth is adjusted by scrapping and shipbuilding production (Stopford, 2009). These adjustments may be measured in years as there are relatively few ships scrapped each year relative to the total fleet. The world's fleet of ships and the world's fleet of MODUs are assumed to be similar with regards to the factors affecting them where relatively few players influence the supply. We will analyze the fleet of rigs in alignment with Stopford's (2009) ship supply theory; through scrapping and new-building.

Hypothesis 1.6

The fleet size is related to the historical price of oil

5.1.2.2 Fleet Productivity

Stopford (2009) formulates fleet productivity as a second supply factor. Although the fleet in the short-run is fixed in size, the utilization of the supply adds a component of flexibility. Stopford (2009) looks at different types of ships, i.e., tankers and bulk ships and notes that the tankers were more exposed to fluctuations in productivity. He argues that the productivity of a given fleet is determined by both the physical performance and the market forces. We assume this to be true for the rig market. In other words, we assume that there are differences between the varieties of rigs available to the market. We also assume that the market forces driving productivity are derived mainly from the price of crude oil.

Hypothesis 1.7

Rig utilization is derived from the price of oil

5.1.2.3 New-building

As explained, the world fleet is regulated in size through shipowners ordering new ships or scrapping old ships. These two essential factors are the third and fourth market supply drivers in the Shipping Market Model. The shipbuilding process is timely, with construction taking up to four years from placing an order to ship delivery (Stopford, 2009). Therefore, shipowners are forced to order their ships based on predictions and forecasts of the demand for the product hauled (Stopford, 2009). Unfortunately, Stopford points out that such forecasts have time and again proven to be incorrect which has led to the delivery of ships for years after the demand in the market halted.

Furthermore, the type of ship must be considered when assessing the data for new-builds. As with offshore rigs, there are different types of ships, and the differences are considerably more significant to the industry than it might appear because a purpose-built ship may cost three times as much as a bulk carrier to produce (Stopford, 2009). That is, it might cost three times as much to produce a deadweight ton, an industry-specific measure in the shipping industry, for a ferry than for a dry bulk carrier. We see this as a parallel to the rig industry where we in the industry description explained that different types of rigs, such as harsh-environment semisubmersible and jack-ups serve different purposes.

Hypothesis 1.8

Purpose-specific rigs create nuances in the market, where supply only increases in its given sub-division

5.1.2.4 Scrapping

The scrapping process reduces the number of available ships or rigs on the market (Stopford, 2009). According to Stopford, age is the foremost determinant of a scrapping decision, yet earnings and technical obsolescence also plays a role in the decision-making process. The main takeaway is that the scrapping decision depends on the ship- or rig owner's predictions regarding the future profitability of the asset. As age is the central determinant in selling an asset for scrapping, it is the oldest ships that are discontinued from service first as the repair costs grow in tandem with its age (Stopford, 2009).

Hypothesis 1.9

There are a higher number of rigs being scrapped in areas where the rigs are older

5.1.3 HYPOTHESES

In the following subsections, we will use the demand and supply model to analyze the rig market. The purpose of conducting this fundamental analysis is to explain the mechanisms which determine the price development in the industry (Stopford, 2009) and use the findings as a foundation on which it is possible to build the model for explaining and forecasting day rates. We expect to see a number of the same market factors apply to the offshore rig market as Stopford (2009) theorize in his model. In the following, we apply empirical data to analyze the features discussed above through our modified Shipping Market Model, testing the following hypotheses:

- The demand for oil is to a large extent related to the development in the world economy.
- An increase in demand for oil will positively influence offshore rig rates.
- Exploration spending is driven by factors such as the price of oil.
- Reserve replacement is driven by factors such as the price of oil.
- Random shocks affect the rig market in 2008 and 2014.
- The fleet size is related to the historical price of oil.
- Rig utilization is derived from the price of oil.
- Purpose-specific rigs create nuances in the market, where supply only increases in its given sub-division
- There are a higher number of rigs being scrapped in areas where the rigs are older

5.1.4 DEMAND

5.1.4.1 WORLD ECONOMY

In the following sub chapeter, we test Stopford's (2009) theory that the development in the world economy creates a higher demand for goods and energy, further driving the price of oil. To test this, we must look at the OECD industrial production as a measure of world economy, and the world GDP outlook as a measure for the development of the production.

According to OPEC (2018), the world GDP is expected to grow by approximately 3.4% annualy over the two next decades and Figure 5.2 provides an overview of which regions that are expected to realize the most considerable economic improvements.

Long-term expected annual real GDP growth rate	2017-2023	2023-2030	2030-2040	2017-2040
OECD America	2.20	2.10	2.00	2.10
OECD Europe	2.00	1.60	1.60	1.70
OECD Asia Oceania	1.60	1.40	1.20	1.40
OECD	2.00	1.80	1.70	1.80
Latin America	2.40	2.40	2.40	2.40
Middle East & Africa	3.30	3.70	3.60	3.60
India	7.20	6.80	5.90	6.50
China	6.00	4.90	3.70	4.70
Other Asia	4.50	4.10	3.70	4.00
OPEC	2.60	3.20	3.10	3.00
Developing countries	5.00	4.60	4.00	4.50
Russia	1.80	2.00	2.00	2.00
Eurasia	2.90	2.90	2.60	2.80
World	**3.60**	**3.40**	**3.20**	**3.40**

Figure 5.2 - Long-term expected annual real GDP growth. Source: OPEC (2018)

Asia and developing countries are predicted to move hundreds of millions of people out of poverty and into the middle class, in effect allowing them to become prosperous consumers, thus driving the demand for energy (OPEC, 2018). The nominal world GDP will increase by 75% in the reference period in the table above from nearly \$100 trillion in 2019 to \$175 trillion in 2040. When emerging markets undergo economic development – as Stopford (2009) indicates as the development cycle – they increase their demand for raw materials like oil. Based on the data represented in Figure 5.2, we expect emerging markets to undergo these changes in the foreseeable future and thus adding value to the assumption that the demand for oil will increase.

To investigate if there is a relationship between the world economy and the price of oil, we graph the change in the OECD industrial production and the change in the price of Brent crude between 1990 and 2018. According to Stopford (2009), there is a link between the world economy and the seaborne trade. In order to translate this link to oil prices, we lean of the finding of Marbuah (2017) who in an attempt to model the oil demand in Africa, used the GDP as an indicator of the oil demand growth. Building on this theory, we see it likely that the positive change in the GDP of the world can be translated to increases of the demand for oil. Figure 5.3 depicts a relationship between the world economy and the oil price.

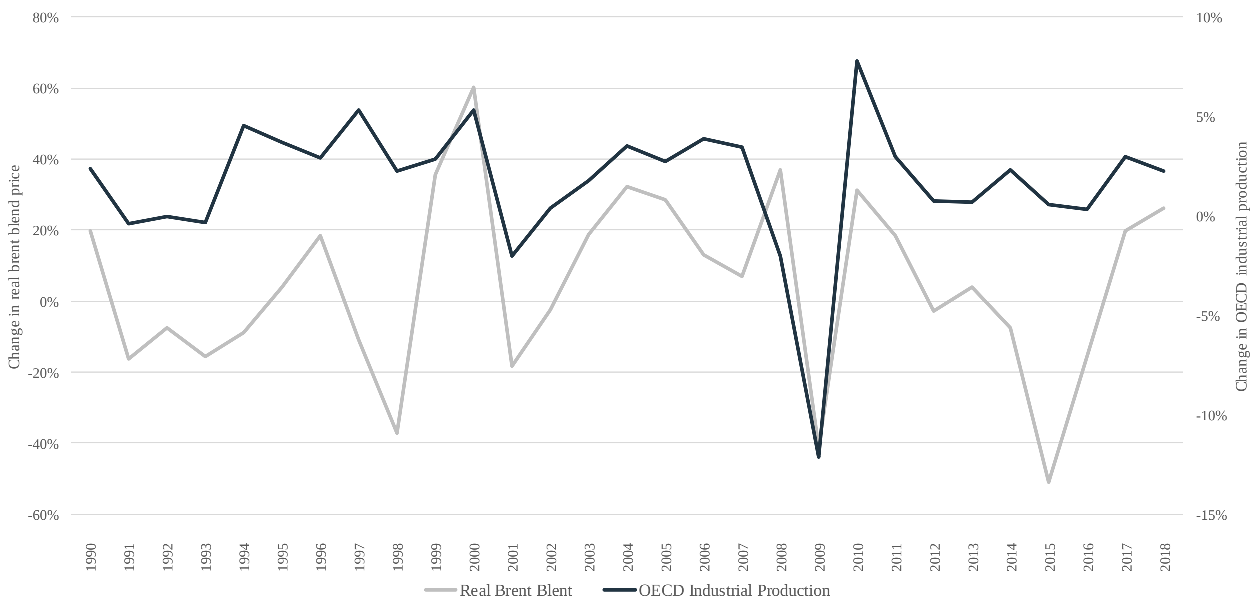

Figure 5.3 - Change OECD Industrial Production and Brent blend. Source: International Monetary Fund (2019)

By testing their movements in a cross-correlation plot (CCF-plot) in R, we find that although moving at different rates, they have a statistically significant correlation that is strongest with no time-lag, suggesting that they move simultaneously, or at least within the same year (Appendix 3). Judging from the long-term expected annual growth rate for the world; we expect the demand to increase in the coming decades.

Furthermore, Stopford (2009) argues that the trade elasticity, effectively the beta between the seaborne trades and the economy is positive. That is, his findings suggest that there is more volatility in the seaborne trade than in the OECD production. The suggestion seems to be in line with our data depicting the price of oil and the world economy, cf., Figure 5.3.

Based on our data obtained from the OECD, we have a positive outlook for the future world economy and implicitly the demand for oil. These findings seem to be in line with hypothesis 1.1; the demand for oil is related to the development in the world economy.

5.1.4.2 Demand for oil

As the world population is set to increase to 9.21 billion people by the year 2040, the future demand for petroleum is argued by OPEC (2018) to be substantial. According to the organization, the total world demand for energy will increase by nearly 96 million barrels of oil equivalents per day (mboe/d) between 2015 and 2040. Of this increase, crude oil accounts for almost 16.8 million barrels per day (mbbl./d). Figure 5.4 illustrates the steady increase in the global demand for oil as the world population grows. It is evident that population growth and the following requirement for energy, and subsequently for oil, will be one of the main drivers for demand in the industry.

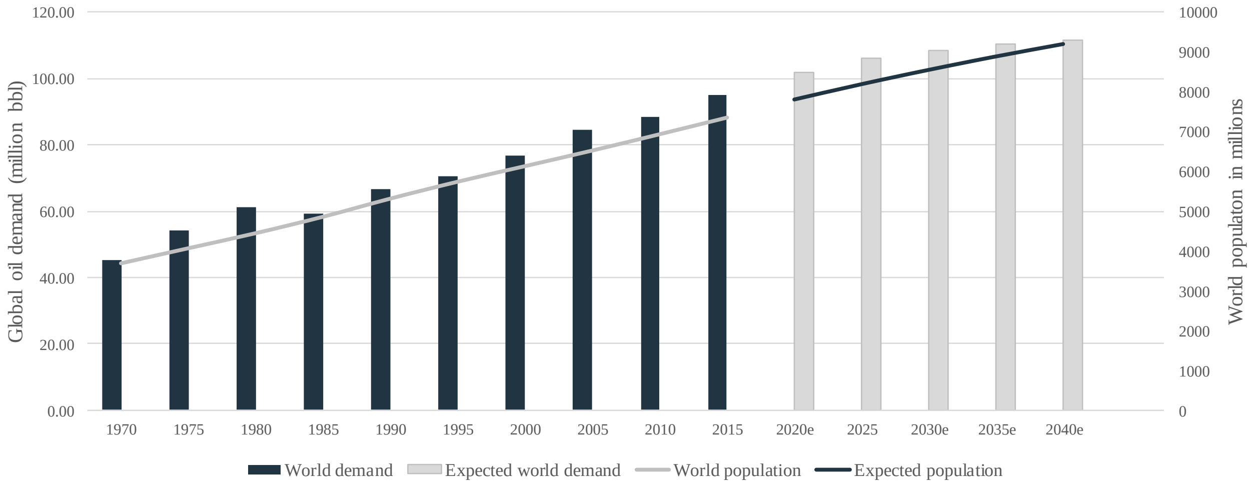

Figure 5.4 - World demand for oil and world population, including forecast. Source OPEC (2018)

Renewable energy is a direct competitor to petroleum and other fossil fuels and is in a position to disrupt this expected development. However, renewable energy is expected to gain only four percentage points of the market share in the same period (Figure 5.5). This still leaves oil and gas as the dominant supplier of energy in the foreseeable future, contributing to more than 50% of the world's energy in 2040.

As briefly discussed in the world economy section, the developing countries in Asia and Africa will need the highest amount of added energy in the coming decades. The nations of the Organization of Economic Cooperation and Development, will only experience an aggregated increase in the demand for energy of 0.1 percent annualy. India, on the other hand, is expected to need 3.5% annualy and developing nations is expected to need 1.9% more energy annualy between and 2040. See Appendix 10 for more details.

World primary energy demand by fuel type	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2015	2020	2030	2040	2015-2040	2015	2020	2030	2040
Oil	86.5	92.3	97.9	100.7	0.6	31.3	30.9	28.8	27.1
Gas	59.2	65.2	79.9	93.2	1.8	21.5	21.9	23.5	25.1
Coal	78.0	80.7	85.8	86.2	0.4	28.3	27.0	25.3	23.2
Nuclear	13.5	15.8	20.1	23.8	2.3	4.9	5.3	5.9	6.4
Hydro	6.8	7.5	9.0	10.3	1.7	2.5	2.5	2.6	2.8
Bio	28.0	30.1	34.0	37.3	1.2	10.1	10.1	10.0	10.0
Other renewables	3.8	6.6	12.9	20.0	6.8	1.4	2.2	3.8	5.4
Total	**276.0**	**298.2**	**339.4**	**371.6**	**1.2**	**100**	**100**	**100**	**100**

Figure 5.5 - World primary energy demand by fuel type. Source: OPEC (2018)

When analyzing the demand for all energy sources, there is little to indicate a decline in either fossil or renewables. That being said, the world is changing where international agreements, particularly in the western world seem to be more focused on investing and consuming energy from renewable sources. This change might be the reason the renewable's market share is expected to increase in the coming two decades, cf., Figure 5.5.

Although the focus on non-fossil fuel sources in the coming years likely will rise, there is an increased demand for energy, regardless of source (Figure 5.4). This forms the basis of the assumption that the green shift is not immediately an external threat to the offshore industry. Therefore, the need for energy, especially for non-OECD Asian and African countries, will be a considerable driver for the demand in the global market.

A substantial factor for the relationship between the increase in world population and its oil consumption is as mentioned partly caused by people moving out of poverty. This is the main driver for the transportation sector, which is expected to account for two-thirds of the additional barrels consumed in the forecasted period (OPEC, 2018). In 2016, this sector accounted for approximately 45% of the global demand for oil, according to OPEC (2018). The substantial expected increase in the transportation sector and its consumption of the available supply indicates a strengthened increase in demand for oil. That being said, in order to confirm or reject our hypothesis that an increase in oil demand is positive for rig day rates, we need to investigate if indeed there is a relationship between the demand for oil and its price.

Since this paper is focused on the offshore rig rates, we will apply findings from peer-reviewed academic papers to determine if there is a relationship between the two. It appears to be a consensus among the academics that demand is a driver for the price; that is, an increase in demand leads to an increase in price (Miao, Ramchander, Wang, & Yang, 2017; Wang & Sun, 2017; Kilian, 2009).

The graph below (Figure 5.6) presents the average day rates for NW Europe and the price of oil. The real Brent appears to be leading the rig rates, in accordance with our hypothesis that the price of oil is a determinant of the rig rates. By testing the cross-correlation, it is immediately evident that there is a significant correlation, where the real Brent leads the rig rates by six periods, i.e., 1.5 years (Appendix 4). This is also in accordance with the findings of Ringlund et al. (2008), who suggested a causality between changes in oil price and rig activity. Ringlund et al. (2008) found a four-month lag between oil price changes and activity changes. Intuitively, more activity (higher demand for rigs) should equal higher rig rates (Kaiser & Snyder, 2013a). The research by Osmundsen et al. (2015) also suggests the same tendency, yet finding that E&P companies only partly react to sudden positive changes in oil prices, waiting some months to see if the changes are permanent before awarding drilling contracts at higher rates. Our findings, and the coherence with intuitive thinking and the alignment with existing literature should suggest causality. Conclusively, if the price of oil increases, rig rates should experience an increase some time later, where our data suggest one and a half years.

Figure 5.6 - Historic rig rates and real Brent blend. Source: U.S. EIA (2019) and RigLogix (2019)

Based on the above discussion, we have uncovered that there is likely to be an increase in demand for energy – including oil and gas – in the coming years. Because it appears to be a positive relationship between the demand for oil and its price, as well as our findings of oil price leading the rig day rates, we are confident in hypothesis 1.2; an increase in demand for oil will positively influence the rig day rates.

5.1.4.3 Exploration spending

The E&P companies such as ExxonMobil, Equinor, BP, Shell, and Chevron which, as illustrated in the value chain analysis (Figure 4.1), are the rig contractors' customers are the direct demand driver for the rig industry. When the oil price fell in 2014, the industry experienced a decline in exploration and production spending, and the companies responded by cutting operating costs which decreased the cash flow breakeven point from approximately $110/bbl. to $55/bbl. (SEB, 2016).

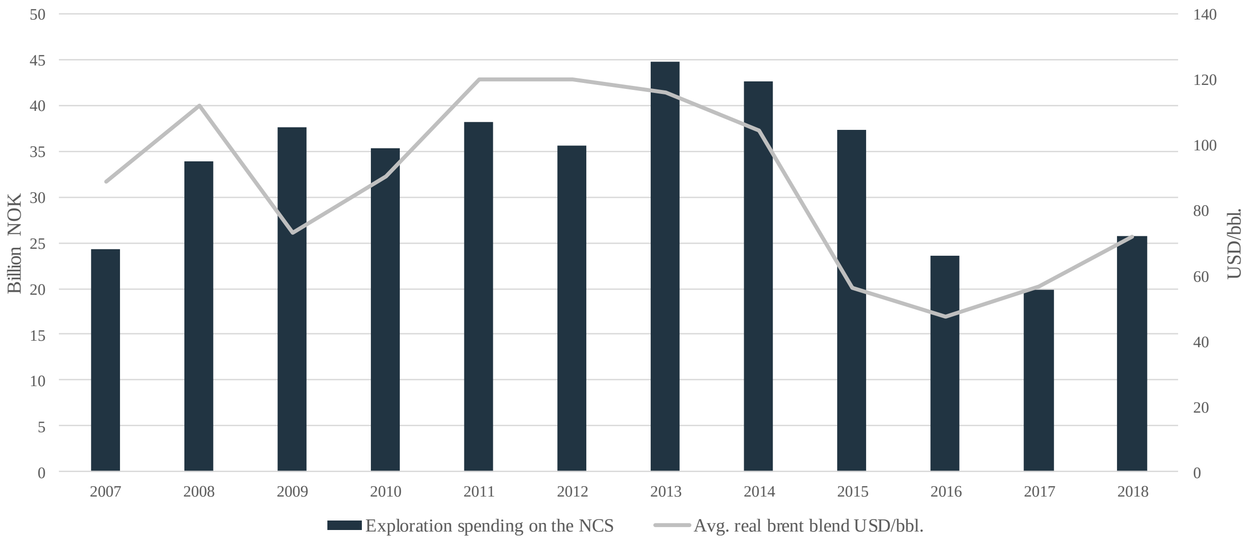

Figure 5.7 - Exploration spending and real Brent. Source: Norwegian Petroleum (2019c) and U.S. EIA (2019)

The substantial cut in operating costs is astounding and in need of further explanation. According to the World Economic Forum (2016), companies like British Petroleum cut their costs by negotiation with second and third tier suppliers, in addition to internal cuts, i.e., job cuts. The renegotiated prices with drilling contractors should therefore directly affect the rig rates. Figure 5.9 indicates a reduction in the day rates for the drilling units in the years after 2014 of more than 50%, mirroring the E&P companies' dramatic reduction in breakeven costs.

The exploration spending on the Norwegian Continental Shelf seems to mirror the global offshore spending, which increases and decreases in tandem with the price of oil, cf., Figure 5.7. Intuitively, companies want to sell oil when the price is high, thus allocate more money for exploration to accumulate greater revenues from sale in good times. According to Rystad Energy (2019), offshore exploration investments are expected to increase, allowing E&P companies to keep their reserve replacement ratio at a sustainable rate, which will be discussed next. Appendix 6 depicts the relationship between the two variables, and although just below the statistical significance level, hypothesis 1.3 is affirmed with a correlation between the two, and the price of oil leading the exploration spending with a one-year lag.

5.1.4.4 Reserve Replacement

Reserve replacement is an industry-specific measure and a metric which purpose is to unveil how much oil the underlying company, or in this specific analysis, NW Europe, is discovering during a certain period compared to how much it has produced in the same period. In effect, if the reserve-replacement ratio is less than 100%, the production will eventually come to a halt because new proven reserves are being discovered at a slower rate than what is being extracted. The same is true for companies. Thus, this measure is being used for analysis to determine a company's operating performance (Stockman, 2012). The reserve replacement is a natural extension to the exploration spending discussed above and will be affected by many of the same factors.

The columns in Figure 5.8 represent the average reserve replacement ratio between both the Norwegian and the United Kingdom continental shelves. This is based on what is classified as 2P reserves which are reserves that are yet to be proven, but which are estimated to have more than 50% likelihood of containing reserves which are both technically and commercially viable (UK Oil & Gas Authority, 2018).

By analyzing the reserve replacement ratio and comparing it to the Brent spot price in Figure 5.8, we can test if there is a relationship between the demand for exploration and the reserve replacement. We know that the world's petroleum is a finite resource and that the reserve replacement ratio is below its sustainable level in NW Europe. Given current estimates, the United Kingdom will run out of oil in approximately 40 years (UK Oil & Gas Authority, 2018), and one could assume that this trend applies to the Norwegian Continental Shelf as well. There is an underlying incentive for the exploration and production companies to allocate more resources to exploration to increase known reserves; in effect extending their core business lifetime. This is positive for the drilling contractors as they will receive an increased number of contracts, at least within the foreseeable future.

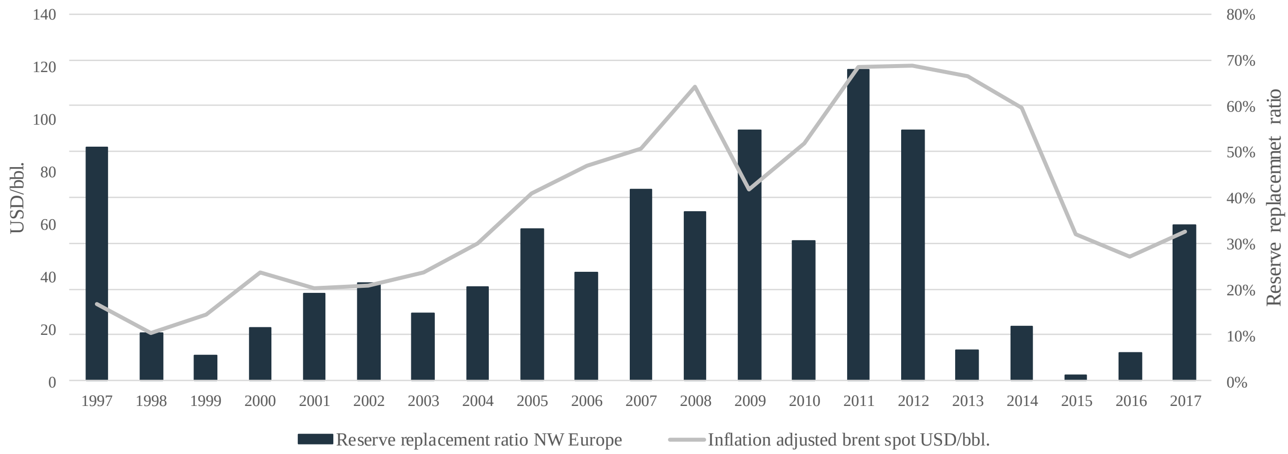

Figure 5.8 - Reserve replacement ratio NW Europe and Brent spot. Source: Norwegian Petroleum (2019a) and U.K. Oil and Gas Authority (2018)

It appears from Figure 5.8 that the two variables are linked. When the price per barrel falls, the exploration companies need to cut costs, and one way they do this is to decrease their engangement with drilling contractors, ultimately pushing day rates down as explained above. E&P companies know that oil prices fluctuate as a result of its cyclical nature. This allows them to postpone the issuance of exploratory drilling contracts when revenue streams are low to increase their spending after the oil prices increases. The notion that the E&P's increase and decrease their exploration spending is related to the price of oil is solidified by Figure 5.7. This figure illustrates a tendency of a change in reserve replacement approximately two years after a significant change in the price of oil. This observation relates to contract lengths for drilling contractors, as they are often around two years (RigLogix, 2019). To further strengthen the argument of a two-year lag, we produce a CCF plot, which confirms that the reserve replacement ratio lags the price of oil with a significant correlation by two years (Appendix 5). The test endorses hypothesis 1.4 that exploration spending should be related to the price of oil.

5.1.4.5 Random shocks

Unexpected or sudden changes in the geopolitical environment can have considerable consequences for the demand for a commodity like oil (Stopford, 2009), and subsequently to rig rates. The rates for semisubmersibles in NW Europe is illustrated in Figure 5.9. From the graph, there appears to be a sudden reduction in the day rates at the beginning of 2010 and the beginning of 2016. Both these periods are approximately 1.5 – 2 years after the financial crisis in 2008 and the oil price fall in 2014. In section 5.1.4.2, we confirmed that the rig rates lag the oil price by one and a half years, and in section 5.1.4.1 we confirmed that the oil price moves simultaneously, or at least within one year, to the world economy. The graph therefore signalizes that our hypothesis of rig rates being target to random shocks from the 2008 financial crisis and the 2014 oil price fall, holds. To confirm or reject hypothesis 1.5 on whether or not the rig rates are subject to random shocks in these periods, we analyze these disturbances as structural breaks in the rig rates in section 6.4.2, where the oil price fall in 2014 did not seem to cause a structural break, but the financial crisis in 2008 might have.

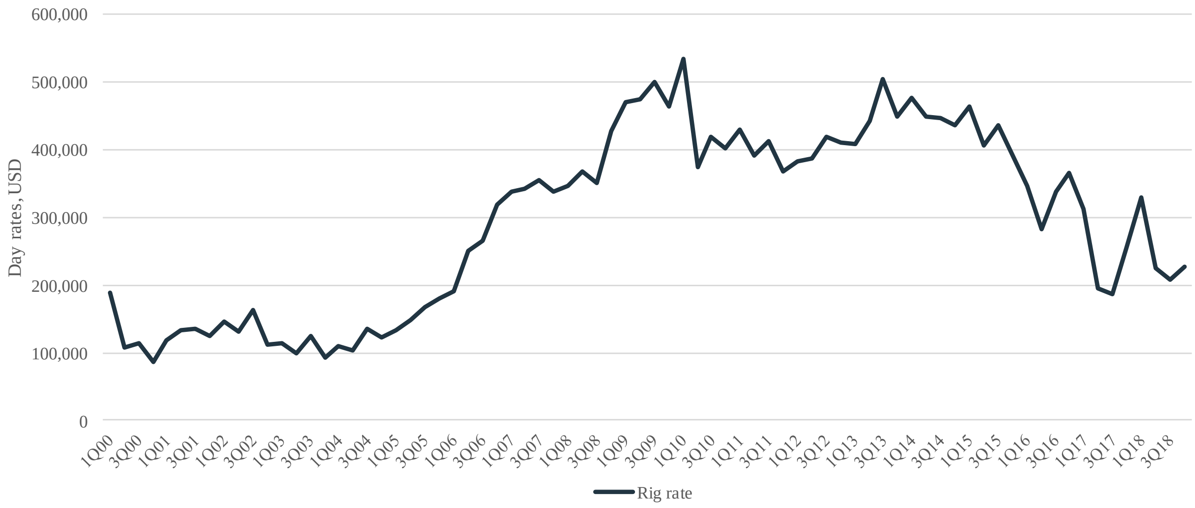

Figure 5.9 - Historic rig rates for floaters in NW Europe. Source: RigLogix (2019)

5.1.5 SUPPLY

5.1.5.1 THE FLEET

The fleet of rigs is directly translatable to the current supply of rigs. The fleet can either viewed as the total fleet on a world basis or as the rig count in a given region. All rig types described and analyzed in this paper are mobile. However, drillships are the only units that do not have to be transported by third party large heavy-lift vessels to be moved to a new market (Cosco Shipping, 2019). Transporting a rig is a large-scale operation, and a new rig produced in Singapore will take around 90 days to reach the Gulf of Mexico (Roach, 2014). The longer transport times make them somewhat anchored in the region that they currently operate in, as Kaiser & Snyder (2013a) also stressed. To create a more specific analysis of the relevant market, it is therefore interesting to look at the fleet development of the NW Europe region.

As seen by Figure 5.10, since the oil price downturn in 2014, the number of marketable rigs in the North Sea was reduced by around 12. It is not immediately apparent from the graph if the price of oil leads or lags the current supply of rigs. In order to test this, we produce a CCF plot. By examining the output it appears to be a lagged correlation between oil price and fleet size. Fleet size follows the price of oil with 5 periods. In other words, nearly 1.5 years after a drop in the price of oil, the number of rigs was reduced (Appendix 2). This difference is approximately the same lag as we saw in testing the rig rates relative to the oil price, discussed in section 5.1.4.2.

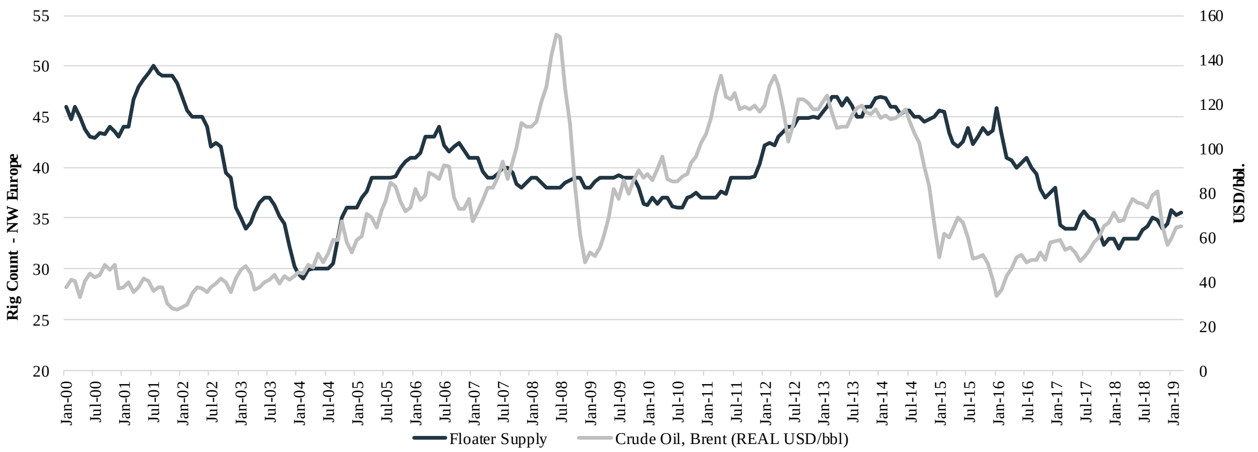

Figure 5.10 - Rig count and real Brent price. Source HIS Markit (2019) and U.S. EIA (2019)

The marketed fleet in the NW European area is therefore currently on a low level compared to times of higher activity, as described in the E&P spending section of the demand analysis. The significant lagged relationship between the price of oil and the supply of rigs builds confidence in hypothesis 1.6; rig supply is related to the price of oil with a lag of approximately 1.5 years.

5.1.5.2 Fleet Productivity

Although the fleet of rigs available is fixed in the short run, there is some flexibility to the degree of which the fleet is being utilized. Utilization can be explained as "a system measure defined by the proportion of rigs working to the available fleet at a specific time and place" (Kaiser & Snyder, 2013a). It is a critical part of the rig industry analysis, as it – in other words – describes the unused capacity in a given area. Osmundsen et al. (2015) also identified utilization as an essential determinant for rig rate formations, as it was a vital element of the bargaining power relationship between the drilling contractors and the E&P companies. They suggested that higher utilization would lead to higher rig rates as few unused rigs in the market forced oil companies to compete in order to land contracts with the drilling companies. Kaiser & Snyder (2013a) also stressed that high utilization on a global scale signals a need for a new building, and high regional utilization can indicate a need for drilling companies to relocate parts of their fleet.

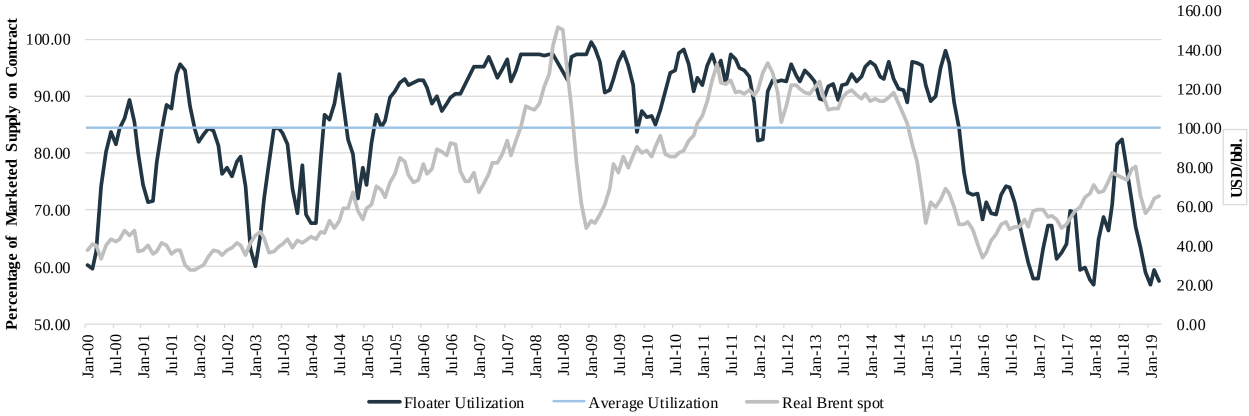

Figure 5.11 - Rig Utilization and real Brent crude. Source: IHS Markit (2019) and U.S. EIA (2019)

Figure 5.11 above, illustrates the utilization of floaters in the NW European market, as well as the average since 2000. The graph shows that utilization also fell in turn-of-the-year 2014/2015, as the oil price plummeted. Ringlund et al. (2008) suggested a theory that utilization is to some extent kept up by lower day rates when the oil price is reduced. Our data illustrated in the graph above does not seem to support this theory. It instead gives the impression that there is a positive relationship between the two. Though appearing to be correlated, we do not know which variable leads the other. Therefore, as with previous relationships, we produce a CCF plot. It appears to be no significant correlation, other than what must be regarded as noise (Appendix 1). Therefore, we see little evidence in the data to support hypothesis 1.7 that the oil price alone is a statistically significant driver of the utilization. This can be attributed to the reduced number of available rigs on the market when the industry experiences a downturn and takes rigs off the marketed supply, e.g., cold stacking. If more rigs are being cold stacked relative to how many newbuilds are being added to the global or regional fleet, there is a net reduction in available capacity, and the utilization rate will increase. Therefore, the utilization rate alone cannot say if the market is good or bad. Nevertheless, the low utilization of floaters in the NW European market indicates that there is spare capacity in the fleet.

As Osmundsen et al. (2015) argued, utilization could be viewed as an indication of the bargaining power of the drilling companies. Therefore, we test this statement by comparing utilization to another measure indicating bargaining power, namely the average contract lengths. When analyzing the utilization rates in the observed period, we see a positive relationship between the average contract length and utilization. The relationship implies that there is an element of bargaining power being displayed by the two variables, as previously suggested. The relationship can intuitively be explained as E&P companies want to secure rigs when the market is tight. Figure 5.12, illustrates the two variables where we observe a correlation between the two factors of 0.5213 – suggesting that utilization and contract lengths move together positively. The correlation's alignment with the intuitive argumentation, would also suggest causality.

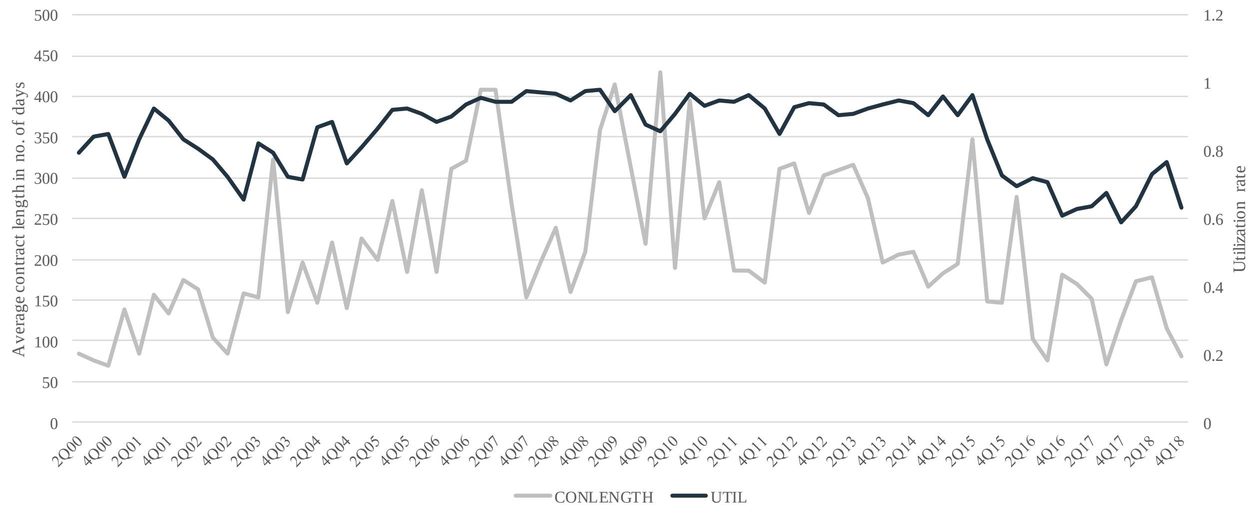

Figure 5.12 - NW Europe average contract length and rig utilization. Source: RigLogix (2019) and IHS Markit (2019)

5.1.5.3 NEW-BUILDING

We saw in Stopford's (2009) adapted theory that rig production is one way drilling companies regulate their ability to meet their demand. As seen in Figure 5.13, rig production is relevant, even though a substantial portion of the rigs are cold stacked. It is therefore interesting to analyze why rig owners commission newbuilds instead of reactivating cold stacked rigs which is a less time-consuming task. The basic economic mechanism of rig production is that more rigs equal lower day rates as E&P companies have more drilling units available for contracts. However, rig production is often a result of drilling companies wanting to acquire newer rigs with better specifications in order to appear more attractive to E&P companies (Shinn, 2018a).

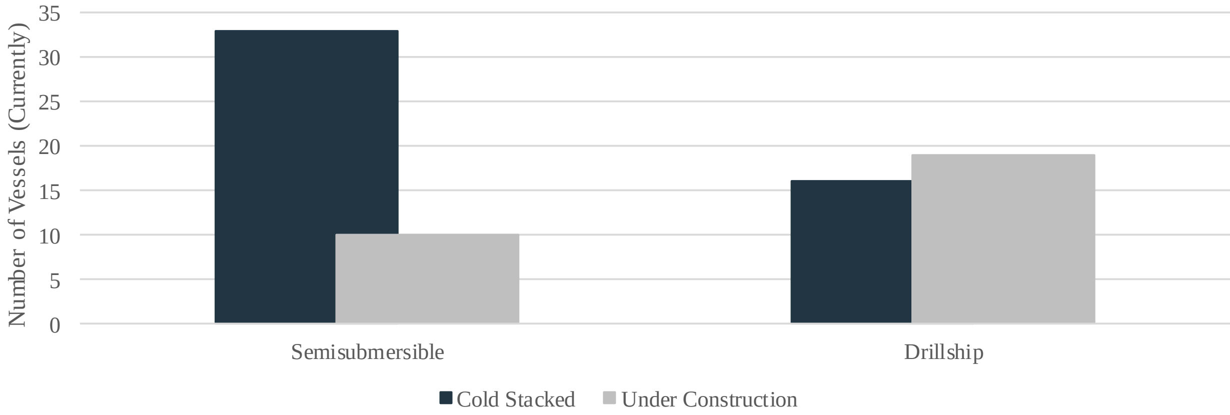

Figure 5.13 - Number of vessels cold stacked and under construction. Source: Bassoe Analytics (2019)

Figure 5.14 displays the movement of day rates on floaters in specific segments since 2000. Here the harsh environment rigs in Norway stand out in comparison with the NW European average, exemplifying Skjerpen et al.'s (2018) theory that as drilling operations become more environmentally complex, they also become more costly. We observe higher rates for the HE rigs in Norway than for the HE rigs in the U.K. Additionally, almost all semi-submersibles in Norway are committed through 2019 (Shinn, 2018a). Interestingly, of the 15 rigs on contract, only two were built before 2000 allowing for a further claim that the climb in HE rig rates in Norway is a direct result of a fleet with a higher specification, which is in line with Osmundsen et al.'s (2015) findings that rig rates are steered by rig specifications. As E&P companies will look to improve their efficiency and lower their carbon emissions, newer generations of semisubmersibles should therefore become preferred when issuing new contracts.

Conversely, of the 13 contracted semisubmersibles in the UK, only three were built after 2000. As evident from the development in Norway, newer harsh environment rigs can generate higher day rates, and rig analyst, David Shinn (2018a) argues that based on this trend, it seems likely that the old semisubmersibles in the UK will be replaced by newer more efficient rigs when their contracts expire. This is also in line with Stopford's (2009) theories regarding differences within the segments, which was explained in section 5.1.2.3.

The alternative to ordering a new-build is to upgrade an existing rig. Upgrades can be carried out as part of a reactivation process of a cold stacked unit or on available rigs that are still considered marketed. Reactivating cold stacked rigs is a costly operation in itself. Les Van Dyke, head of investor relations in Diamond Offshore was quoted in the Oil and Gas Journal (2005) saying that newbuilds often take between 36-40 months and about $425 million, while an upgrade from 4th to 5th generation capacity would require around 24 months and $250 million. However, upgrades are more likely to happen to fairly modern rigs to become state of the art, than to rigs that have operated for decades (Shinn, 2018a). The decision to newbuild or upgrade is predominantly decided by the company's fleet and business strategy, as well as their investors. Because technology evolves and the standards of efficient drilling operations become stricter, new-building will likely be a natural part of the drilling industry. It indeed seems to exist nuances to the rig market due to purpose-specific rigs within the floater segment, supporting hypothesized 1.8.

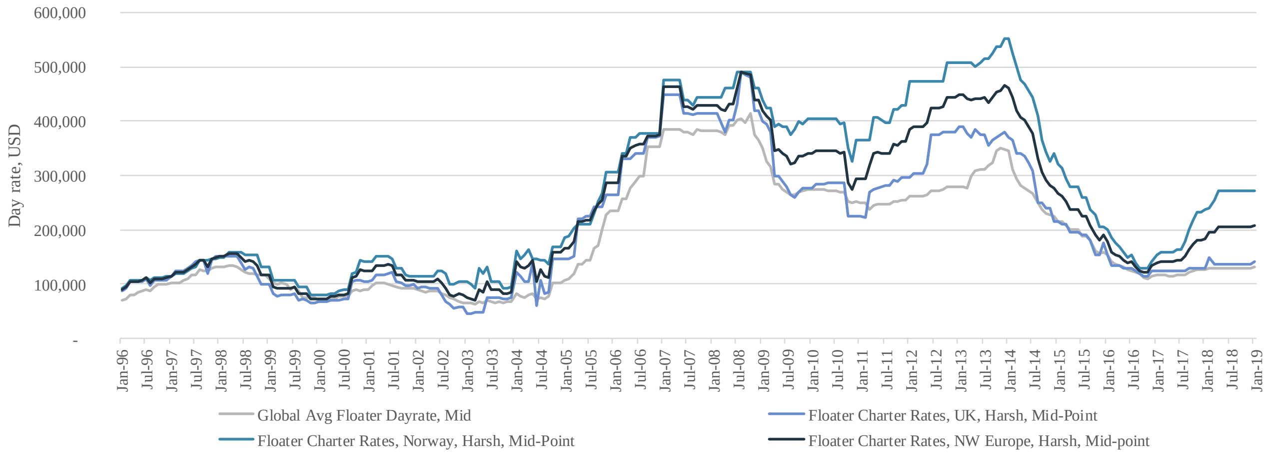

Figure 5.14 - Rig rate comparison: Source: Clarksons Platou Offshore Intelligence Network (2019)

5.1.5.4 Scrapping

Alongside newbuilding and stacking, scrapping is another factor that allows for control of the supply of rigs in the industry. However, as we saw in section 4.3.2 rigs are often stacked for some time before being moved towards scrapping. Of the 48 floaters currently in NW Europe, only 36 are considered to be marketed, meaning that 12 rigs are cold stacked.

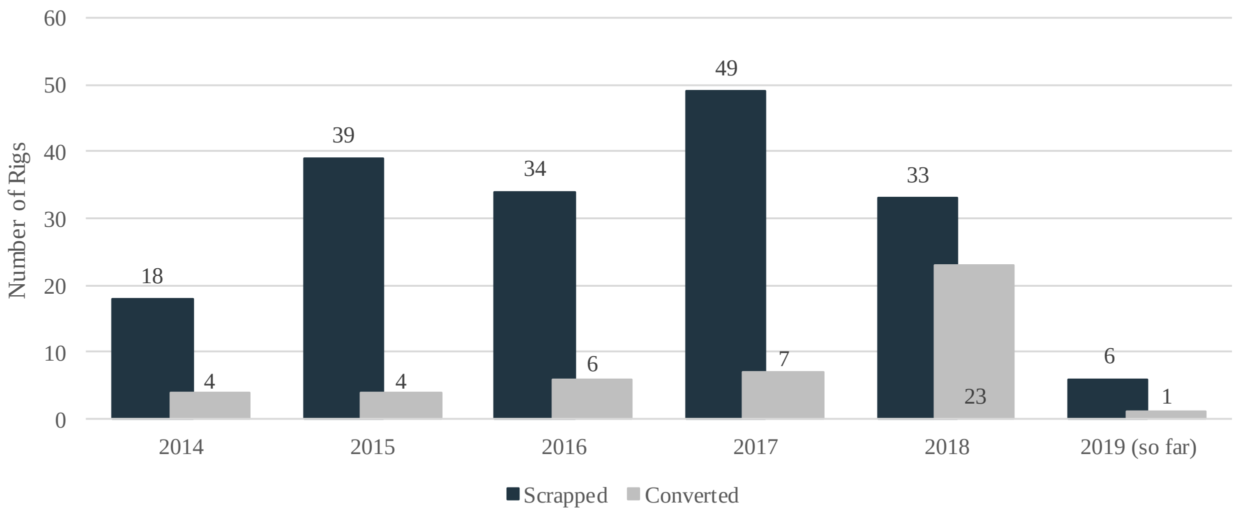

Figure 5.15 - Scrapped and converted rigs. Source: Bassoe Analytics (2019)

Nordea Markets rig analyst Janne Kvernland was quoted by Pico (2018) in ShippingWatch, saying that *"Many of the rigs have been stacked for so long now that they will never return. With every day that passes, it is likely getting more expensive to reactivate them"*, many of the rigs therefore seems dead stacked. This statement is also in line with the argument of E&P spending rewarding more efficient operations in the previous chapter. Equinor, for example, has in just a few years cut its rig fleet average age from 22 to 4.5 years (Pico, 2018). It seems likely that hypothesis 1.9 is correct in that scrapping will occur on older generation rigs first, somewhat limiting the supply of units in the NW European market, in particular due to the many old rigs in the U.K., discussed in 5.1.5.3 above.

5.2 The Rig Day Rate Mechanism

The Shipping Market Model illustrates how the contracted rig rates can be explained as a balance between rig supply and demand. This analysis has shown that both demand and supply could be considered as somewhat fixed in the short-term, but that it gains some flexibility with mechanisms such as cold stacking, moving markets and eventually scrapping/newbuilding when moving into the long-term.

Demand for petroleum will to a large extent follow the demand for energy by countries emerging through the economic stages in the coming decades. This does indeed seem positive for the demand for oil. Although the demand is expected to increase, its future price is complex and therefore uncertain. The analysis has shown that there is a historically positive relationship between the oil price and the rig rates and that the rig rates lags the oil price with around one and a half years. Also, the demand for offshore rigs has been low partly due to low oil prices which in turn has made oil companies reluctant to engage in exploration and appraisal well contracts with rig operators. The exploration spending is positively correlated to the oil price and is expected to increase as the companies have cut costs, and the oil price has to some degree recovered from the low levels in the wake of the 2014 collapse.

The current offshore rig fleet can be viewed as both in oversupply and undersupply. The current fleet sees both low utilization and high numbers of cold stacking of older generation rigs, which should point towards an oversupply. Nevertheless, new-building is also underway, and E&P companies show signs of preferring newer rigs, with their more efficient specifications. As oil companies are set to increase their activity and issue new contracts, the newer oil rigs should gain the best contracts. At least as the marketed capacity allows for it.

Finally, the industry is also currently looking to pressure day rates and drilling company CEOs seek to avoid contracts at lower rates. As we heard during DNB's 12th Oil, Offshore and Shipping Conference, the common theme among the management of the larger drilling companies like Transocean, Ensco and Diamond Offshore was that day rates at the current levels were below the companies breakeven points and that they would need to rise for the industry to survive. The larger companies express their desire to stay disciplined, keeping rigs cold stacked and not engaging in unsustainable contracts – even if tempting (DNB Oil, Offshore and Shipping, 2019). These messages suggest that, while the Shipping Market Model theory begins to introduce bargaining as a vital part of the pricing relationship of the industry, the model to a certain degree fails to explain the non-market power forced movements such as the game theoretical suggestions seen here. Inquiries into the market power frictions between the drilling companies and the E&P companies must therefore be analyzed further.

5.3 THE BARGAINING MODEL

The Shipping Market Model allowed for a breakdown of the industry's critical value drivers and provided useful insights into which parameters that could be used to explain the day rate movements. However, as we uncovered, some of the underlying tensions in bargaining power between the E&P companies and the drilling companies were not satisfactorily addressed by the model.

As made clear by the first part of this paper, rigs are hired in a somewhat standardized contract market. The contracts are signed on different durations, where we in section 5.1.5.2 saw a relation between contract lengths and utilization rates in the observed period. These findings were in line with the discoveries of other literature, such as Osmundsen et al. (2015) and Skjerpen et al. (2018) that suggested a changing bargaining power relationship between the drilling companies and the E&P companies when the rig supply tightened. Skjerpen et al. (2018) argue that there is a need for traditional market analysis as well as bargaining theory, supported by Kellogg (2011) in order to explain and evaluate this phenomenon. The following chapter seeks to further address this, by adding the economic deduction that Skjerpen et al. (2018) used as the foundation for the development of the econometric model for explaining the day rates.

5.3.1 RIG SUPPLY

1. E&P companies seeking new projects and drilling companies owning i rigs, negotiate in a period $t-1$ and, where $t \in T = \{1,2,\dots\}$
2. The rigs are indexed $i \in I = \{1,2,\dots,\bar{\iota}\}$
3. A simplification is made in that all contracts signed prior to period *t*, starts operations in period *t* and continue for the agreed number of periods into the future.
4. $I_t^a \subseteq I$ and $I_t^n \subseteq I$ denotes the subsets of rigs available for hire and the rigs that are on contract and not available for hire, in period *t*, respectively.
    a. This gives us the supply of marketed rigs denoted as: $I_t^a \cup I_t^n = I$

5.3.2 CONTRACT RESERVE

The contract reserve is defined as q_t^n and describes the previously negotiated contracts which is set to be terminated in period *t* or further into the future.

1. The contract reserve at the end of period $t-1$ is $q_t^n = \Sigma_{i \in I_t^n} q_{it}$, where $q_{it} > 0$ for all I_t^n

A simplification is made as q_{it} originally is defined as $q_{it} = \sum_{s=t}^{\infty} m^{is}$, where $m^{is} = 0$ if rig i is idle in period s and $m^{is} = 1$ if otherwise. For simplicity, it is assumed that q^{it} can be approximated by a continuous function.

2. The contract volume agreed on over the subset of available rigs (I_t^a) between periods $1-t$ and t is defined as $q_t^a = \sum_{i \in I_t^a} q_{it}$. Here $q_{it} = 0$ for several rigs.
3. The total contract volume when entering a period, after the negotiations have taken place, is the contract reserve plus new agreements $q_t = q_t^n + q_t^a$

5.3.3 BARGAINING POWER OF THE E&P COMPANIES

The relative bargaining power of E&P companies is denoted $\theta_t = \theta(q_t) \in (0,1)$.

1. The theory then assumes that the relative bargaining power of E&P's, θ_t, decreases with the number of contracted periods such that $\theta_{q_t} < 0$

This is based on the fact that E&P companies' option to hire a rig from another company increases with the availability of rigs today and in the future. Intuitively, as the availability of rigs on the market decrease, the E&P companies' bargaining power deteriorates and rig contractors might have more offers to consider.

As we analyzed in section 5.1.5.2, the overall trend in our observed period shows a positive relationship between the contract length and the utilization rate, however suggesting only a correlation, not explicitly a causality. Skjerpen et al. (2018) argues this to be true, as the contracts are relatively standardized. Therefore, the market approaches a spot market for new closures as utilization bottoms out.

1. p_t^a is the weighted average rig rate for contracts signed in period *t*.
   a. $p_t^a = \frac{\sum_{i \in I_t^a} p_{it} q_{it}}{\sum_{i \in I_t^a} q_{it}}$. This analysis therefore considers the negotiation of the variables q_t^a and p_t^a.

The standard bargaining solution presented in Watson (2002) is used to solve for the two variables. Here, the players first determine the contract volume q_t^a that maximizes the joint value of the agreement, denoted as ω^t. The rig owner and the E&P company share this joint value, which is divided between them based on their relative bargaining power.

This implies that q_t^a is independent of the rig rate p_t^a. Skjerpen et al. (2018) also notes that any contract that does not maximize ω^t with respect to q_t^a can be renegotiated to reach a Pareto-optimal solution.

2. Let x_1 *and* x_2 denote vectors of exogenous variables that determine the petroleum company's profits from drilling and the rig contractor's drilling costs, respectively.
3. The functions $\pi(q^t, x_{1t})$ and $c(q^t, x_{2t})$ refers to the present value of profits and costs associated with the number of hired rig periods ($q_t = q_t^n + q_t^a$).
4. $\tilde{x}_{1t}$ and $\tilde{x}_{2t}$ refers to particular variables in x_{1t} and x_{2t}.

5. It is assumed that the profit, $\pi(q^t, x_{1t})$, and the cost, $c(q^t, x_{2t})$, are monotonic in all $\tilde{x}_{1t}$ and $\tilde{x}_{2t}$.
6. To simplify the explanation, x_{1t} and x_{2t} are defined such that $\frac{\partial \pi}{\partial \tilde{x}_{1t}} = \pi_{\tilde{x}_{1t}} > 0$ and $\frac{\partial c}{\partial \tilde{x}_{2t}} = c_{\tilde{x}_{2t}} > 0$
7. For example, assuming that capital costs reduce the petroleum company's profits, we let $\tilde{x}_{1t}$ denote the negative capital cost. We also assume that the cross-derivatives satisfy $\pi_{q^t \tilde{x}_{1t}} > 0$ and $c_{q^t \tilde{x}_{2t}} > 0$.

For the profit function, this means that an additional hired rig period is more profitable for the E&P company if a variable that increases profits obtains a higher value. E&P companies will gain more from an additional hired rig period if the oil price increases.

8. It is assumed that E&P companies prioritize the most promising remaining projects so that profits will increase concavely in q^t.
9. Rig supply costs increase convexly in q^t, for example, as maintenance requirements increase as older rigs to a larger extent are put to use when demand picks up. Or because the average competence of the personnel is likely to decrease when rig capacity expands and use of less suitable rigs become necessary as the number of available rigs decreases. More formally, $\pi_{q^t}, c_{q^t}, -\pi_{q^t q^t}, c_{q^t q^t} > 0$, where all derivatives are assumed to be finite.
10. The joint profit of the standard bargaining agreement is subject to $q_t = q_t^n + q_t^a$, and is:

$$\boldsymbol{\omega_t \equiv \max q_t^a \left[\pi(q^t, x_{1t}) - c(q^t, x_{2t})\right]} \tag{1}$$

11. Since the joint profit is concave in q_t^a, this equation implicitly yields the optimal contract volume q_t^{a*} as characterized by the first order condition $\pi_{qt}\,(q_t^*, x_{1t}) = c_q^t(q_t^*, x_{2t})$, assuming $\omega_t > 0$ to ensure interior solution.

The profit share form the agreement accruing to the petroleum company and the rig contractor and the rig contractor are, respectively:

$$\boldsymbol{\theta_t \omega_t = \pi(q^t, x_{1t}) - p_t^a q_t^{a*}} \text{ and } \boldsymbol{(1-\theta_t)\omega_t = p_t^a q_t^{a*} - c(q^t, x_{2t})} \tag{2}$$

Using eqution (1) and (2), we get the rig rate (q_t^{a*} is given from (1) and independent of p_t^{a*} and θ_t):

$$\boldsymbol{p_t^{a*} = \frac{1}{q_t^{a*}}\Big(\pi(q_t^*, x_{1t}) - \theta_t\big(\pi(q_t^*, x_{1t}) - c(q_t^*, x_{2t})\big)\Big)} \tag{3}$$

12. Then, using equation (1) and (3) to solve the bargaining game.

$$\boldsymbol{\frac{dq_t^{a*}}{d\tilde{x}_{1t}} = \frac{\pi_{q\tilde{x}_1}}{c_{qq}-\pi_{qq}} \qquad \frac{dq^{a*}}{d\tilde{x}_{2t}} = \frac{c_{q\tilde{x}_2}}{\pi_{qq}-c_{qq}}}$$

$$\boldsymbol{\frac{dp_t^{a*}}{d\tilde{x}_{1t}} = \frac{1}{q_t^{a*}}\left((1-\theta)\pi_{\tilde{x}_{1t}} + \left(\pi_q - \theta_q(\pi - c) - p_t^{a*}\right)\frac{\partial q_t^{a*}}{\partial \tilde{x}_{1t}}\right), \frac{dp_t^{a*}}{d\tilde{x}_{2t}} = \frac{1}{q_t^{a*}}\left(\theta c_{\tilde{x}_{2t}} + \left(\pi_q - \theta_q(\pi - c) + p_t^{a*}\right)\frac{\partial q_t^{a*}}{\partial \tilde{x}_{2t}}\right)} \tag{4}$$

13. The rig rate p_t^{a*} depends on $q_t^* = q_t^n + q_t^{a*}$, since q_t^* affects the bargaining power $\theta(q_t)$, rig contractors' cost and E&P companies' profits.

The following assumes that the direct effect on the rig rate from a change in an exogenous variable, $\pi_{\tilde{x}_1}$ or $c_{\tilde{x}_2}$, dominates the indirect effect of these variables via adjustments of q_t^*.

14. $\frac{dp_t^{a*}}{d\tilde{x}_{1t}}, \frac{dp_t^{a*}}{d\tilde{x}_{2t}} > 0$ in equation (4), because the E&P companies' bargaining power decline as the capacity utilization increase.

Equation (4) implies that the direct effects on rig rates caused by oil price changes, (which would be an element of vector x_{1t}), increases as capacity utilization grows. In other words, the rig contractor captures more of the shared profit from new projects, whenever the rig market is tight, because E&P companies have fewer outside options, deteriorating their bargaining power.

This deduction exemplifies that there is a definite need for the variables representing the tightening of the drilling market to be represented in the changes in rig rates. This is because, as both the bargaining model and the Shipping Market Model suggest, the drilling companies gain more control of the pricing as the market tightens – capturing more of the joint value. Higher utilization, as discussed in the fleet productivity section of the Shipping Market Model, represents such a tight market where E&P companies might prove to have less control.

Figure 5.16 shows Skjerpen et al.'s (2018) hypothesized direct effects of exogenous variables in the analytical model.

Variable x_{1t}, x_{2t}	E&P company profit $\pi(q_t, x_{1t})$	Rig contractor cost $c(q_t, x_{1t})$	Contract volume q_t^a	Rig rate p_t^a
Oil price	Positive		Positive	Positive
Remaining reserves	Positive		Positive	Positive
Capital costs (Real interest rates)	Negative	Positive	Negative	Ambiguous
Labor cost (real wage)	Negative	Positive	Negative	Ambiguous

Figure 5.16 - Hypothesized effects of exogenous variables. Source: Skjerpen et al. (2018)

The average rig rate among all operating rigs in period t is $p^t = \frac{\sum_{i \in I} p_{it} q_{it}}{\sum_{i \in I} q_{it}}$, and the contract reserve in period t and the associated rig rates are negotiated prior to period t. We can deduce directly that changes in (q_t^{a*}, p_t^{a*}), changes the optimal contract volume and price. This provides the following result:

15. Lemma 1: Assume $\omega_t > 0$ so that $q_t^{a*} > 0$. Then we have:
    b. An increase in E&P companies' marginal profits or a decrease in the rig contractors' marginal cost, caused by a change in x_{1t} or x_{2t}, increases the optimal contract volume q_t^{a*}.
    c. An increase in E&P companies' marginal profits or the rig contractors' marginal costs, caused by a change in x_{1t} or x_{2t}, increases the rig rate p_t^{a*}.
16. Proof: The lemma follows directly from equation (4):
    d. If $\omega \leq 0$ in lemma 1, we have zero contracts ($q_t^{a*} = 0$ and no rig rates). Figure 5.16 lists some important exogenous variables in x_{1t} and x_{2t}, and their probable effect on the E&P companies' profit $\pi(q_t, x_{1t})$ and the rig contractor costs $c(q_t, x_{2t})$, as well as their implied effects on contract volume and rig rates according to lemma 1.

Skjerpen et al. (2018) also provides some notes on Figure 5.16:

1. Several variables affect the costs and benefits of the agreement after contract signing, for example, oil prices or real interest rates. Therefore, it is the future value of these variables that matter.
2. Drilling operations in harsh environments or ultra-deep waters are more demanding than others. The cost of operating in these areas are typically higher in demanding waters, but it is unreasonable to expect it to induce shorter contract length for a given operation. That being said, higher costs due to operational complexity will imply that fewer projects are developed as profits net of rig costs decrease.

3. Declining oil prices induced a dramatic drop in rig activity and rig rates. This can be explained by the model, as lower oil prices reduce expected profits from rig activity (ω). Some of this loss was taken by the rig contractors as rig rates fell. In addition, projects that would have been profitable with high oil prices are no longer profitable ($\omega \leq 0$). This also reduces rig activity.

5.4 CONCLUSION

Through the Shipping Market Model, we uncovered that the most influential external factor to the industry is the world economy, which in turn affects the demand for oil and thus the oil price. The price of oil then affects the E&P companies' decision-making concerning reserve replacement and exploration spending, which both lags the price of oil by, in respective order, two and one year. The drilling companies are mainly focused on their fleet; its size and its productivity. Their adaption to a change in rig demand is driven by stacking and to some degree scrapping in the short-term, and through ordering new rigs and in the long-term. We suggest a positive relationship between the price of oil and the rig rates, and found that the rig rates lags the price of oil by approximately two years.

Furthermore, we saw that there is a shifting power dimension in the market, where the dominant player is highly dependent on the total fleet utilization, representing the availability of the firms. It seems as though drilling companies quickly gain a market power advantage when E&P companies begin to struggle to find contractors for their exploration or appraisal campaigns. Similarly, when rig utilization is low, the market power advantage transitions from the rig contractors to the E&P companies.

6 MODELING AND FORECASTING DAY RATES

6.1 INTRODUCTION

The overall purpose of this section is to forecast the day rates in the offshore rig market and apply them to a valuation case, namely a valuation of Odfjell Drilling. In this chapter, the rig rates for semisubmersible rigs in NW Europe will be modeled and point forecasted. The model is based on the same model as published by Skjerpen et al. (2018) in *Modelling and forecasting rig rates on the Norwegian Continental Shelf.*

6.2 DATA

Variable	Description	Type of variable (original)	Type of variable (manipulated)	Source	Denomination
rigrate	Mean of log rig rates, constant prices	Varies across observational unit and time	Time series	Clarksons Platou Offshore Intelligence Network, RigLogix	USD(2015)/day
sbrent	Log-transformed smoothed BRENT spot, constant prices	Time series	Time series	U.S. Energy Information Administration	USD(2015)/bbl.
expUTIL	The exponential of capacity utilization, marketable fleet	Time series	Time series	RigLogix	$0 \leq UTIL \leq 1$
remres	Log of remaining reserves	Time series	Time series	British Petroleum	Million standard cubic meter o.e
conlength	Mean of log contract durations	Varies across observational unit and time	Time series	RigLogix	Number of days
LEADTIME	Mean of lead time	Varies across observational unit and time	Time series	RigLogix, HIS Markit	Number of days
wage	Log of the real hourly wage for petroleum workers	Time series	Time series	Statistics Norway	USD(2015)/hr.
RIR	U.S. 10-year government yield	Time series	Time series	U.S. Federal Reserve	Annual rate (%)

Figure 6.1 - Description of variables included in the model. Source: Authors' creation

Figure 6.1 illustrates our dataset. The observed units are both semisubmersibles and drillships, bundled together as the umbrella category floaters. This grouping is based on our findings from the first sections of this paper, where we have noted that these two rig types are similarly complex and specialized and that their rig rates should move similarly.

Furthermore, by analyzing our data, it is evident that drillships are far outnumbered by semisubmersibles in this region. Drillships at its peak in our observed period only account for 8% of the total fleet in NW Europe. This therefore allows for adding more data points to our analysis, where the potential differences should be dwarfed by its relative contribution to the total rig count.

The data is collected from highly reliable sources within the industry, mainly RigLogix, Clarksons Platou Research, Statistics Norway and U.S. Energy Information Administration (EIA). The following subchapters will summarize the specific variables as well as the explanation of their inclusion. These variables were uncovered in the Shipping Market Model and the Bargaining Model, as important factors to the offshore market and thus important to rig rate formation. The findings from the strategic analysis therefore creates the foundation of which we produce our hypotheses on the independent variables' effect on rig rates.

The dataset reports observations from Q1 2000 trough Q4 2018, as this is the full extent of our combined dataset for the area, we must therefore forecast from Q1 2019 and on, although this quarter is encompassed by our information stop at 30 April, 2019.

6.2.1 RIG RATES

First and foremost, rig rates is our dependent variable. Our rig rate data is retrieved from RigLogix and consists of every contract in NW Europe from the beginning of 2000.

We construct a quarterly time series from the rig rate dataset starting in the 1st quarter of 2000 and ending in the 4th quarter of 2018. A contract is assigned to its specified quarter based on the contract start date. The total number of contract fixtures in NW Europe in this period was 1182. Of these contracts, we have 1035 observations of day rate data, due to certain cases where the day rates were not disclosed. The number of observations is not evenly distributed throughout the quarters, as the data set did not suggest such a pattern.

Quarterly data is therefore constructed from a varying number of observations, i.e., the 3rd quarter of 2001 has 24 observations while the 1st quarter of 2000 has 3. The rig rate representing each quarter is the arithmetic mean of the rig rates within the given quarter. We deflate the rig rates with quarterly U.S. producer price index numbers retrieved from the U.S. Bureau of Labor Statistics.

In order to better see the pattern of the development of rig rates and the relatively large variance in the data set, Skjerpen et al. (2018) suggests logarithmically transforming them individually for each quarter. We mean log-transform the time series as the quarterly data is constructed from the mean of the corresponding observations in each specific quarter.

6.2.2 CRUDE OIL PRICE

Oil price is a natural inclusion to the model, as the rig market is a support function of the underlying oil commodity market and our strategic analysis strongly suggest its inclusion. There are two internationally recognized varieties of traded crude oil prices, Brent blend and WTI (Chen, 2018). The oil price used for this analysis is the Brent blend index, taken at quarterly observations in our observed period. The West Texas Intermediate (WTI) is also highly traded and a good indication of oil price movements, however, the oil from this index is considered to be a less sweet, heavier oil that requires more refining, affecting the pricing slightly (Chen, 2018). The Brent blend is built on oil from NW Europe and is, therefore, a natural choice when analyzing the observed period.

The oil prices are denominated in United States Dollars (USD) and are deflated using the US producer price index (PPI), which both matches its currency and the denomination of rig rates.

Since oil companies and their investments often are subject to long time horizons, they need to make assumptions on future oil prices reflecting expectations of current market developments. To depict this in our analysis, Aune, Osmundsen and Rosendahl (2010) suggest assuming that the E&P companies' expectation of future oil prices and its trajectory is based on the current price, $BRENT_s$, and that it is continuously adjusted in conjunction with historically assumed prices, $BRENT_{s-j}$.

In order to reflect the companies' price expectations, we create a new variable, $SBRENT_s$, which is the smoothed real price of Brent blend at time s. When assuming that oil companies update their expectation continuously, we imply that the weight of which their expectations are updated is not evenly distributed on the previous price observations. In other words, $BRENT_{s-1}$, is exponentially heavier weighted than $BRENT_{s-2}$, and so on. To calculate $SBRENT_s$, we run an exponential moving average simulation on $BRENT_s$, with $s = 12$, in R, which in effect means that expectations are based on assumed prices from 12 periods back, translating to 3 years in our dataset. The exponential moving average is in practice a moving average that reduces the applied weight of the data further from time period s. R uses a reduction factor calculated as $\frac{2}{(1+s)}$, which means that $SBRENT_{s-12}$, affects $SBRENT_s$ with $\approx 15.38\,\%$. Figure 6.2 illustrates the real Brent blend price, $BRENT_s$ and the smoothed real Brent blend, $SBRENT_s$.

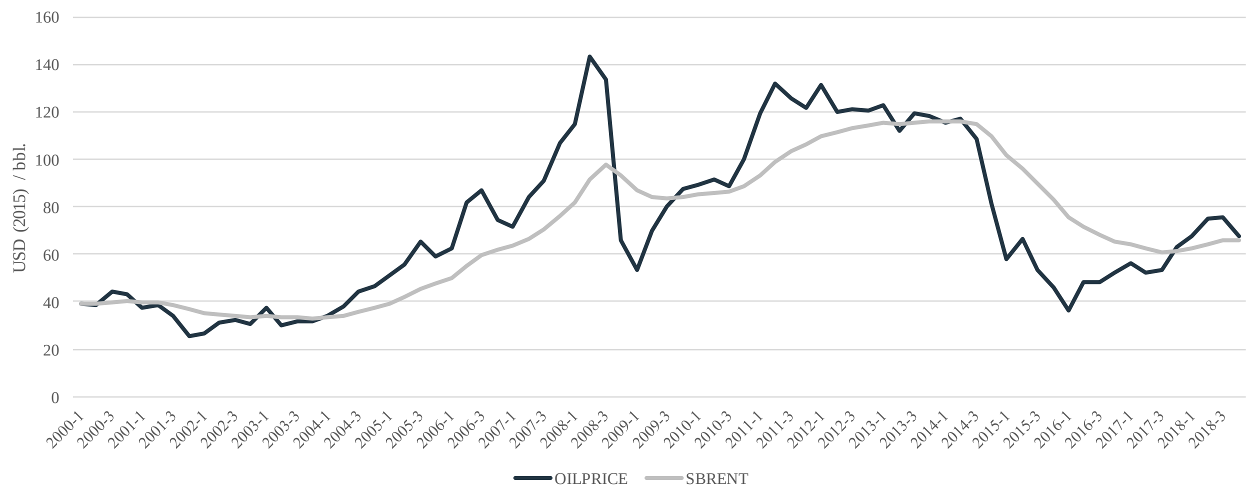

Figure 6.2 - Real Brent price and smoothed Brent. Source: U.S. EIA (2019)

In the data analysis, the $SBRENT_s$ variable is log-transformed and denoted with lower case letters as $sbrent_s$.

Hypothesis 2.1

sbrent will enter the model positively, as a higher oil prices makes E&P companies more profitable and thereby increased E&P spending is more attractive.

6.2.3 Capacity utilization and Oil Price

The capacity utilization represents the utilized capacity at a given point in time, which is the number of hired rig days divided by the number of available rig days. The capacity utilization data is obtained from IHS Markit's RigBase and includes monthly supplied and contracted semisubmersibles and drill ships for NW Europe. The monthly observations are aggregated to quarterly data, and each data point is between 0 and 1 : $0 \leq UTIL \leq 1$. The utilization is added to the model as a result of our findings in both the Shipping Market Model and the Bargaining Model, where we found evidence to believe that the utilization can be viewed as an indication of drilling companies growing bargaining power in a tightening market. Skjerpen et al. (2018) suggests that this could be tested by setting utilization as a cross-product with the oil price parameter, in order to see whether the elasticity of the rig rates with respect to oil prices increases, when utilization increases. Before entering the model, *UTIL* is set to the exponential.

Hypothesis 2.2

Utilization will enter the model positively, as higher utilization indicates a market where the drilling companies have a higher bargaining power.

6.2.4 REMAINING RESERVES

Remaining reserves are included in the model and were one of the highlighted important factors in the Shipping Market Model through exploration spending and reserve replacement. The data for remaining reserves is an annual time series of known petroleum resources where both geological and engineering information indicates with reasonable certainty that the reserves can be recovered under existing economic and operating conditions (British Petroleum, 2018).

There are certain differences between the countries' reserve classifications, and the numbers for 2018 are retrieved directly from the respective countries' governments, as the British Petroleum Statistical Review of World Energy is not yet published with 2018 data. We use reserves in classifications matching those of the reported reserves in the BP dataset, translating to category *1, 2A, 2F, 3A* and *3F,* for Norway. For Denmark, the numbers obtained belongs to development pending, a sub-classification to contingent resources. The Danish Government reported its 2018 numbers for gas in bn. Nm^3, which is the normalized cubic meter as opposed to the traditionally used standardized cubic meter (Sm^3). The measurements differ slightly due to different temperatures at which the mass is measured. The normalized standard cubic meter is measured at 0°C, while the standard cubic meter is measured at 15°C (sometimes 20°C), both at standard atmospheric pressure; 1.01325 barA. The conversion rate is 1.0549 going from Sm^3 to Nm^3 (Goodier, 2018). With regards to the remaining reserves of the U.K., Germany and the Netherlands, official numbers for 2018 is not yet publicly available. Therefore, we have used the last three years' average, assuming the numbers for 2018 is within reasonable proximity to the last years' reserves.

In order to deconstruct the yearly time series into a quarterly time series, we have divided the nominal difference for year $REMRES_n$ and $REMRES_{n-1}$ by 4 and evenly added the difference between each quarter within each year. This implies the assumption that the production and exploration of reserves occurs at an equal pace throughout the year. The remaining reserves is given by December 31st. That is, year 2000 equals Q4 2000, not Q1. Our first observation, 1Q00, is therefore equal to the end of the year 1999 plus one fourth of the change between 1999 and 2000**.** Before entering the model, *REMRES* is log-transformed to become *remres*.

Hypothesis 2.3

Remaining reserves enters the model positively, as a higher reserve creates more demand for drilling activity.

6.2.5 CONTRACT LENGTHS

Contract lengths describe the difference between the start and end date of a contract, meaning the date from which the rig operator assigns the asset to the company hiring it on the underlying contract. The variable is measured in number of days and is aggregated to quarterly data in the same way as rig rates. Before entering the model, *CONLENGTH* is log-transformed forming the variable *conlength.*

Hypothesis 2.4

Contract lengths enters the model positively, as longer contract lengths indicate that the drilling operators have a higher bargaining power.

6.2.6 LEAD TIME

As opposed to contract length, lead time is the number of days from the fixture date to the contract start date. Our data set lacks fixture dates for some contracts, especially at the beginning of the observed period. This means that we have six observations with no data points: 1Q00, 1Q01, 1Q, 2Q, and 3Q 2002 and 1Q04. These observed periods have therefore been omitted from the dataset. The remaining quarters have at least one fixture date observation, and the number representing the quarter is an average of the fixture days within each given period. By way of explanation, if a quarter has 15 contracts but there are only ten fixture dates in the data set, the mean of the ten fixture days and contract start date for those ten is used to represent all 15 contracts.

Hypothesis 2.5

Lead time enters the model positively, as longer contract lengths indicate that the drilling operators have a higher bargaining power.

6.2.7 REAL WAGES

Wages are a substantial part of rig contractors cost (see Appendix 11 for Odfjell Drilling analytical income statement). Based on the Bargaining Model's explanation of the importance of drilling contractors costs, we therefore hypothesize that real wages of workers in the industry will be an important explanatory variable. Real wages of petroleum workers are calculated from total wages and salaries paid out in the petroleum industry, including services, and divided by the full-time-equivalent number of workers. Numbers are gathered from the Norwegian Annual National Accounts and were originally posted as quarterly time series data. The hourly wage is then converted to USD, by a USD/NOK quarterly time series and finally deflated to USD 2015 prices using the same US producer price index as before. It is assumed that the hourly wage for workers in the oil and gas industry in NW Europe is reflected in the wages of the workers in Norway. The data is log-transformed, forming the variable *wage*.

Hypothesis 2.6

Real wages enters the model positively, as the cost component should drive rig rates.

6.2.8 Real interest rate

As with the real wage of petroleum workers, the interest rates are important for the drilling companies, holding substantial debt financed assets, as further explored in the financial analysis of Odfjell Drilling. We therefore hypothesize that real interest rates hold an explanatory variable to drilling rigs cost of capital, that again translate to the rig rate formation.

Real interest rates are a time series explaining the development of capital costs in the observed period. In order to measure this, we use US 10-year government bonds with a quarterly frequency which is deflated using the U.S. PPI to ensure equal terms for all deflated variables.

Hypothesis 2.7

Real Interest Rates will enter the model positively, as higher interest rates translate to higher costs of capital. The drilling companies will therefore seek compensation accordingly.

6.3 FRAMEWORK

The equation below formulates the econometric reduced form model we use to estimate $rigrate_s$. This model is the result of the hypotheses from both the strategic analysis and the subsequent explanations of the variables that enter the model. The framework is also influenced by the existing literature, chief of which is Skjerpen et al. (2018).

$$\begin{aligned} &rigrate_s \\ &= \beta_0 + \beta_1 * sbrent \; + \beta_2 * \exp(UTIL_{s-1}) * sbrent + \beta_3 * remres_{s-1} \\ &+ (\beta_4 * conlength_s) + (\beta_5 * LEADTIME_s) + (\beta_6 * wage_{s-1}) + (\beta_7 * RIR_{s-1}) + \varepsilon_s \end{aligned}$$

Where $\varepsilon_s \sim NIID(0, \sigma^2_{\varepsilon\varepsilon})$.

6.4 ESTIMATION RESULT

Figure 6.3 displays the output of the regression. The model is tested for heteroscedasticity with a white robustness test and corrected for autocorrelation using time clustering. The ordinary least squares estimates assign an estimate to the parameters, which we now specify by adding a hat. All variables expect *wage* and *RIR* are significant at a 5% level. Nonetheless, *RIR* is significant at the 10% level.

Regression output			
	Variable	Coefficient	Standard error
$\hat{\beta}_0$	*Constant*	16.374***	(2.348)
$\hat{\beta}_1$	*sbrent*	0.552**	(0.219)
$\hat{\beta}_2$	*sbrent:expUTIL*	0.070**	(0.033)
$\hat{\beta}_3$	*remres*	-0.980***	(0.214)
$\hat{\beta}_4$	*conlength*	0.222***	(0.053)
$\hat{\beta}_5$	*LEADTIME*	0.029***	(0.010)
$\hat{\beta}_6$	*wage*	0.032	(0.212)
$\hat{\beta}_7$	*RIR*	3.303*	(1.925)
	Observations		70
	R2		0.929
	Adjusted R2		0.921
	Residual Std. Error		0.151 (df=62)
	F - statistic		115.472***(df=7; 62)
	Note:		*p<0.1; **p<0.05; ***p<0.02

Figure 6.3 - Regression output

Parameter 1: Oil price

The Brent blend price is smoothed with an exponential weighted average and log-transformed before being added to the model. The parameter enters positively, where $\hat{\beta}_1 = 0.552$. Unsurprisingly, as oil prices increase, rig rates increase in a positive relationship. This is in line with the arguments presented in the first parts of this paper and provides confirmation to the hypothesis 2.1.

Parameter 2: Oil price and Capacity Utilization

The oil price also enters the model in a cross-product with capital utilization. Here, the logged smoothed oil price is interacting with the exponential of one-period-lagged capital utilization. The parameter, $\hat{\beta}_2$ is estimated to 0.070 and confirms that rig rates in fact increase more with oil prices as capital utilization increases, or that oil prices have a greater effect on rig rates as the rig market tightens and availability decreases. This confirm hypothesis 2.2 that as capacity utilization increases, drilling companies gain more bargaining power and are able to more heavily influence day rates. The elasticity of rig rates concerning smoothed oil prices is higher, the higher the capacity utilization. Explained intuitively, the drilling companies gain stronger bargaining power as utilization increases.

Parameter 3: Remaining Reserves

The log-transformed remaining reserves enter the model negatively with $\hat{\beta}_3$ estimated to -0.980. Surprisingly, our model estimates that more available resources imply lower rig rates. This is in stark contrast with the findings of Skjerpen et al. (2018) that see a positive relationship in their data. Hypothesis 2.3 is declined, and the intuitive explanation of this variable dictates that a higher remaining reserve causes a higher demand for drilling services by the E&P companies, does not find evidence in the data. Higher demand should then ceteris paribus translate to higher rig rates.

However, remaining reserves fall as oil prices fall, because the variable is dependent on whether or not the oil is profitable to collect, not just whether or not the oil is in the reservoir. As seen by Figure 6.4, the remaining reserve has fallen steadily over the observed period as the rig rates have both gone up and down. A negative coefficient on the *remres* parameter is therefore not unsurprising for our data.

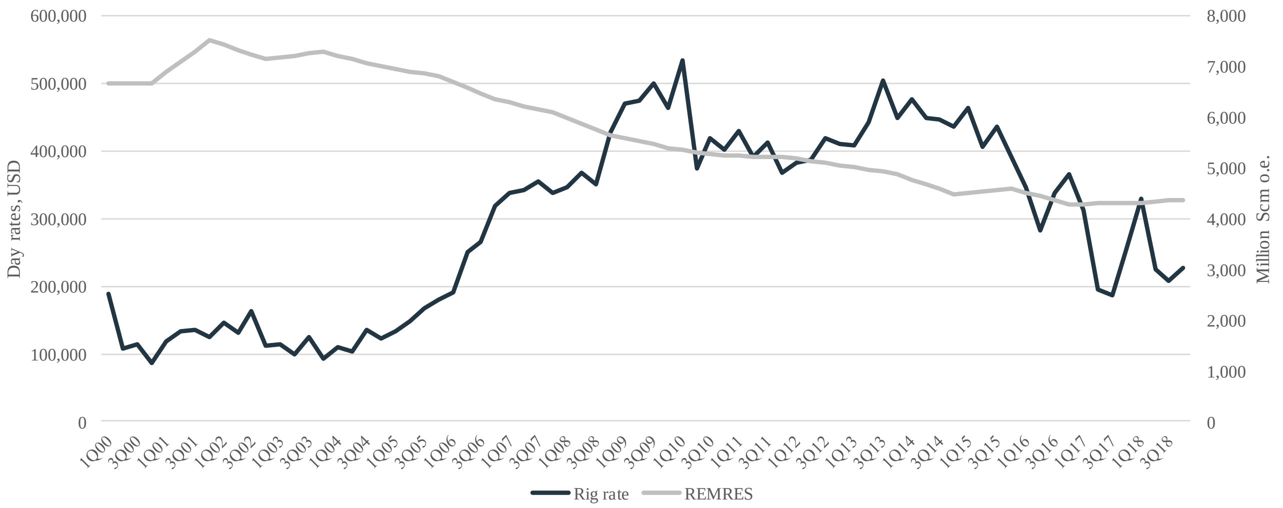

Figure 6.4 - Rig rate and remaining reserves. Source: RigLogix (2019) and British Petroleum (2018)

Nevertheless, as seen by Appendix 23, excluding the *remres* variable deteriorates the model's explanatory abilities, as well as tampering with the other variables' signs and significance. Because the model does not seem to improve by omitting this variable, it is kept, with recognition of its potential shortcomings.

An alternative explanation can be that *remres* enters negatively, because as larger discoveries are made, E&P companies do not need maintain a high E&P spending in order to uphold their reserve replacement ratio. In a sense saturating their exploration demand, which could lower rig rates.

Parameter 4: Contract Length

The contract length enters the model positively, with an estimated coefficient, $\hat{\beta}_4 = 0.222$. Increased contract lengths leads in other words to increasing rig rates. This is also in line with the suggested effect of increasing rig rates in markets where the bargaining power shifts towards the rig companies, seeing as longer contract lengths usually are considered better for the rig companies as they get more days on the E&P companies' payroll. This therefore confirms hypothesis 2.4.

Parameter 5: Contract Leadtime

Lead time enters the model positively, with a coefficient $\hat{\beta}_5 = 0.029$. Similarly to the contract length it again, confirms the theory of bargaining power of the rig companies. Intuitively, the fact that they are able to sign contracts further away from work start would be considered as positive for the rig contractors' future operations. The coefficient therefore confirms hypothesis 2.5.

Parameter 5: Wage of Petroleum Workers

The real wage of the petroleum workers enters the parameter positively, although without statistical significance. Nevertheless, the coefficient $\hat{\beta}_6 = 0.032$ indicates that the wage of workers enters with a positive effect on rig rates. We cannot confirm hypothesis 2.6 with statistical significance, yet intuitively it is in line with our suggestion that higher wages create higher costs for the rig contractor, which they seek to be compensated for by pushing it over on the E&P companies through the day rate.

Parameter 6: Interest Rates

The final parameter of the model is real interest rates. The coefficient $\hat{\beta}_7 = 3.303$ is only significant at the 10% level. Yet, the parameter enters positively, suggesting that the increases in rig contractors' cost of capital is translated to their price for supplying rig services, partly confirming hypothesis 2.7. Additionally, this discovery overshadows the potential explanation that higher interest rates make the E&P companies less willing to pay for rigs.

6.4.1 WITHIN-SAMPLE FIT

The different parameters combine to create the final model that estimates the logged rig rates. When applying the model to the observed period, we can gauge the effectiveness of the model. By comparing the within-sample fit with the observed values we see that the model captures most of the fluctuations and the trends in the rig rate development with a satisfying accuracy.

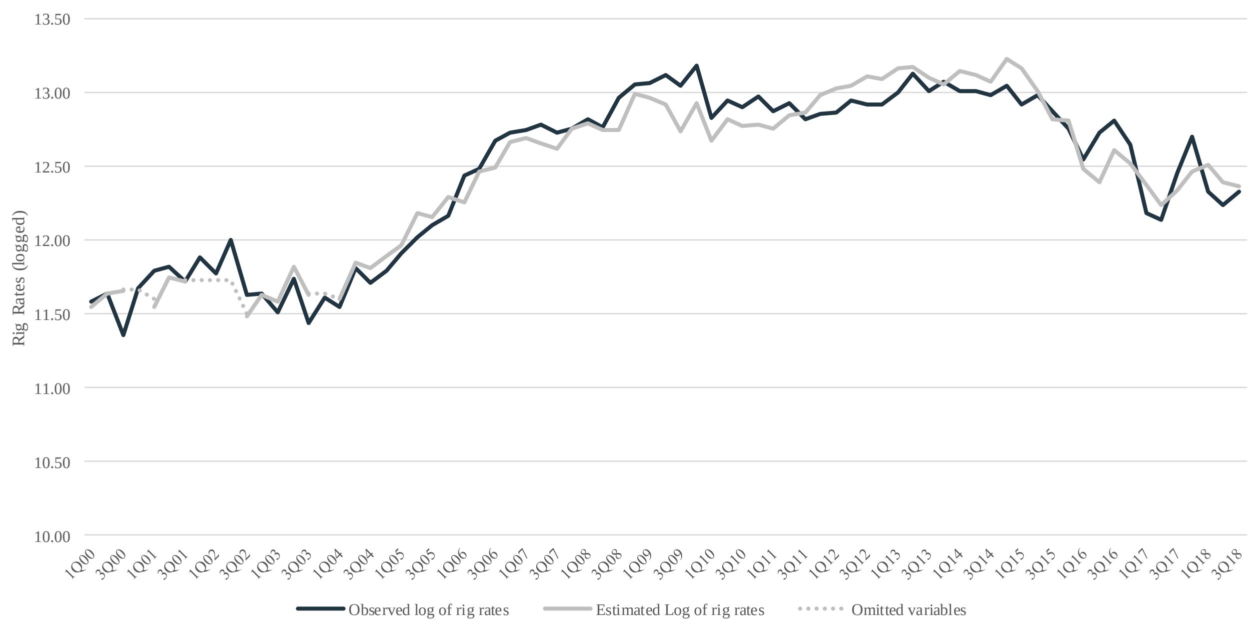

Figure 6.5 - Rig rate within-sample fit. Source: RigLogix (2019)

6.4.2 TESTING FOR STRUCTURAL BREAKS

Walter Enders (2014), argues that in some circumstances, there are reasons to expect that a structural break could appear in a data set. For our purpose, it therefore seems natural to test for structural breaks at the time of the financial crisis of 2008 and the oil price fall in 2014, introduced in section 5.1.4.5. These were two cases of changes in the macroeconomic environment surrounding the industry, presenting a need to test our model for structural breaks.

In testing a model's usefulness Walter Enders (2014), argues that it is important that the structure of the data-generating process does not change. A structural break is a permanent jump in the time series, due to a permanent shift in its construction. If there is some permanent structural change in the time series, it becomes an element of non-stationarity. Intuitively, if there is a permanent change in the formation of the time series, the information prior to the break will become un-suited to predicting the future.

In 2014 the United States flooded the oil market with their introduction of shale oil. The sharp shift in supply sent the world oil prices (WTI and Brent) crashing. This fall is shown in our dataset with a long drop in Brent spot from around 107 USD/bbl. to a bottom of 37 USD/bbl., over the course of around three years. It is reasonable to believe that this could cause a structural break in our dataset. Moreover, the financial crisis of 2008 had a major impact on the world economy, and sent among other things, the oil prices into a massive drop. As the oil price enters our model (smoothed and logged), we therefore want to test for a structural break in our model.

Enders (2014) outlines the following methodology for testing a model for structural breaks:

In an estimated model, using a sample size of T observations, denote the sum of the squared residuals as SSR. With a reason to suspect a structural break immediately following t_m, perform a Chow test by dividing the T observations into two subsamples with t_m observations in the first sample and $t_n = T - t_m$ observations in the second. Then test each subsample by estimating two separate models.

Setting the sum of the squared residuals to SSR_1 and SSR_2, test whether all coefficients are equal with an F-test and form:

$$F = \frac{\frac{SSR_{total} - SSR_1 - SSR_2}{n}}{\frac{SSR_1 + SSR_2}{(T - 2n)}}$$

Where,

- $n = number\ of\ parameters\ estimated$
- $degrees\ of\ freedom = T - 2n$

Since the sum of $SSR_1 + SSR_2$ should equal the SSR of the entire sample, given no breaks – F should be close to 0. The larger the calculated F, the more restrictive the assumption of equal coefficients are. A critical value is set at the 5% level and is calculated based on the degrees of freedom in the two subsamples. The null hypothesis is then built

$$H_o = No\ structural\ break \qquad H_1 = Structural\ break$$

If the F value exceeds the critical value, we must reject the null of no structural break.

The first test is done to check if there is a structural break on the rig rates because of the oil price fall post U.S. shale oil entering the market in 2014. In order to test this, a dummy variable is set up with DUMMY = 1, when $s \geq 2014 - 12 - 31$, and 0 otherwise.

We run a regression, with a subset specifying whether to include the variable or not, depending on the dummy value – this way the data is split into two subsamples. See Appendix 24 for R script

$$F = \frac{\frac{1.419436 - 0.9104367 - 0.2424926}{7}}{\frac{0.9104367 - 0.2424926}{(70 - 2 * 7)}} = 1.320892$$

Critical Value using a 5% level = 2.813149

As the $F < 2.813149$ we fail to reject the null of no structural break. In other words, the oil price drop of 2014 does not cause a structural break in our rig rate model.

The second test is done to see if there is a structural break in Q2 2010 when we see that the financial crisis hit the observed rig rates used in our data set. Using the same methodology as explained above, but with a new dummy variable adjusted for the appropriate timeline, we obtained a $F = 4.762834$ and critical value = 1.914209. Since $F > 1.914209$, we reject the null of no structural break. In other words, there is evidence to believe that there in fact is a structural break in the model, caused by the 2008 financial crisis.

Figure 6.6 and Figure 6.7 below illustrates the regression outputs and the subsamples split by time. Figure 6.6 explains which period the rig rate regression belongs to, and Figure 6.7 communicates its properties.

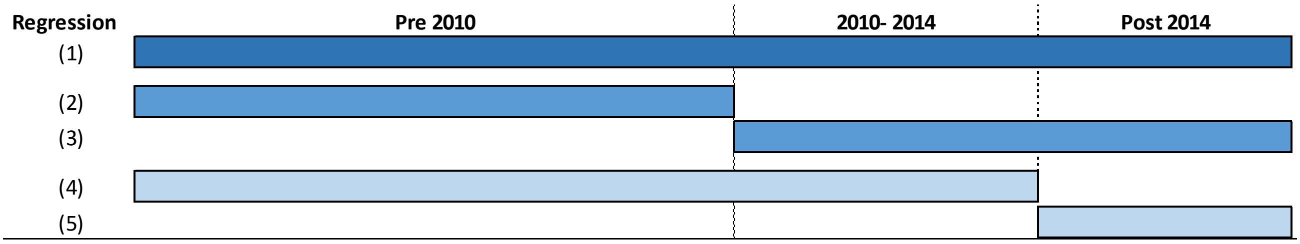

Figure 6.6 - Time intervals for sub-sample testing of structural breaks. Source: Authors' creation

Break-Test Regressions

	Dependent variable:				
	Rig rate				
	(1)	(2)	(3)	(4)	(5)
sbrent	0.552**	0.612*	-0.084	0.472	0.084
	(0.277)	(0.351)	(0.402)	(0.370)	(1.052)
remres	-0.980***	-1.941***	0.871	-1.023**	2.506
	(0.245)	(0.524)	(0.664)	(0.475)	(3.374)
conlength	0.222***	0.223***	0.056	0.245***	0.087
	(0.052)	(0.054)	(0.081)	(0.057)	(0.151)
LEADTIME	0.029***	0.030	0.043***	0.022	0.048
	(0.011)	(0.021)	(0.013)	(0.015)	(0.031)
wage	0.032	0.020	-0.505	0.089	-0.471
	(0.212)	(0.217)	(0.324)	(0.241)	(0.669)
RIR	3.303*	2.944	-0.891	4.649*	-9.976
	(2.314)	(2.359)	(4.376)	(2.467)	(13.386)
sbrent:expUTIL	0.070**	0.045	0.117**	0.098*	0.086
	(0.042)	(0.047)	(0.049)	(0.050)	(0.114)
Constant	16.374***	24.895***	6.333	16.411***	-7.992
	(2.711)	(5.491)	(5.302)	(5.200)	(26.617)
Observations	70	36	34	53	17
R^2	0.929	0.968	0.844	0.950	0.832
Adjusted R^2	0.921	0.961	0.802	0.942	0.701
Residual Std. Error	0.151 (df = 62)	0.118 (df = 28)	0.121 (df = 26)	0.142 (df = 45)	0.164 (df = 9)
F Statistic	115.472*** (df = 7; 62)	122.804*** (df = 7; 28)	20.072*** (df = 7; 26)	122.021*** (df = 7; 45)	6.364*** (df = 7; 9)
Note:					*p<0.1; **p<0.05; ***p<0.01

Figure 6.7 - Break-test regression

Comparing the entire sample (1) to subsample (2) and especially (3), we see that the structural break does not help explaining rig rates more accurately. The coefficient of the *sbrent* enters negatively after 2010, which goes strongly against the economic intuition of our findings, as well as the findings of the literature. Also, the significance levels drop in the new models and the adjusted R^2 drop in the post 2008 (3) model compared to the entire sample (1). While a structural break is an interesting observation that indeed needed to be addressed, the potential changes of the model by excluding the data are not improving the model in a way that is deemed worthy of the loss of observations. As we strive to reach a model that has the highest explanatory abilities, we choose to stick with the original model.

6.5 FORECASTING

The estimates of the systematic part of the model, together with the estimated variance of the errors allows us to forecast the untransformed variable *RIGRATE* for the period of 2019Q1, …, 2023Q4. The forecast method is described as follows:

$$z_s = \hat{\beta}_0 + \hat{\beta}_1 * sbrent_s + \hat{\beta}_2 * \exp(UTIL_{s-1}) * sbrent_s + \hat{\beta}_3 * remres_{s-1} + \hat{\beta}_4 * conlength_s + \hat{\beta}_5 * LEADTIME_s + \hat{\beta}_6 * wage_{s-1} + \hat{\beta}_7 * RIR_{s-1}$$

As the *RIGRATE* is conditional log-normal distributed, the point forecast is given as:

$$\widehat{RIGRATE}_s = \exp(z_s) * \exp(0.5 * \sigma^2_{\varepsilon\varepsilon})$$

In this forecast, the estimated variance is then given by:

$\widehat{Var}\left[\widehat{RIGRATE}_s - RIGRATE_s\right] = [\exp(z_s)]^2 \exp(\sigma^2_{\varepsilon\varepsilon} - 1)\exp(\sigma^2_{\varepsilon\varepsilon})$, and the forecast interval is given by

$$\{\widehat{RIGRATE}_s - 2z_{1-\frac{p}{2}} * \sqrt{\widehat{Var}\left[\widehat{RIGRATE}_s - RIGRATE_s\right]},$$
$$\widehat{RIGRATE}_s + 2z_{1-\frac{p}{2}} * \sqrt{\widehat{Var}\left[\widehat{RIGRATE}_s - RIGRATE_s\right]}\}$$

Where $z_{1-p/2}$ denotes the $100 * \left(1 - \frac{p}{2}\right)$ percent fractile of the standard normal distribution.

6.5.1 VARIABLES IN THE FORECASTED PERIOD

In order to apply our estimated exogenous variables and their corresponding parameters to the forecast of rig rates, we first have to make assumptions on the variables affecting the regression. On the following pages, we will briefly discuss all seven variables, as well as the deflation factor; the U.S. PPI, and how they are expected to behave in the period Q1 2019 through Q4 2023. Skjerpen et al. (2018) argues that forecasts intervals should be in the 50% range. This is based on Granger's (1996) argument of 50% forecast intervals being more interesting from a practical point of view compared to 90% as the latter yields too wide estimates, and that lower intervals are more likely to be believable. Therefore, we apply 50% forecast intervals for our five-year prediction.

Brent blend price

Assumptions regarding the real Brent blend price, and its smoothing is necessary to make as we both in our strategic analysis, as well as the evidence from the regression model, see it as a variable of great importance. The forecasted Brent blend prices are therefore gathered from the Brent crude futures traded on the Intercontinental Exchange (ICE), retrieved from a Bloomberg Terminal at April 13, 2019. Thus, our base case forecast for Brent blend is simply the market's expectation of its future prices. Because we use the market's expectations, we will not deflate the prices for the reason that it is assumed that inflation is accounted for in future transactions. The same exponential weighted average explained in section 6.2.2 is applied to the smoothing.

Capacity utilization

The offshore drilling industry experienced a relatively low capacity utilization towards the end of the observed period, cf. Figure 4.10. The NW European historic average is approximately 85%, which we set as the starting point for the base case forecast. The following periods will be increased by 0.25 percentage points, and as a result the final forecasted period will obtain a capacity utilization of 90%. This utilization level has been observed over longer periods of time in in the past, and is in line with Skjerpen et al.'s (2018) forecast developments, although their choice of forecasted levels are not explicitly communicated. The assumed development is also based on the industry outlook inferred by the DNB Oil Offshore and Shipping Conference, where leaders expressed a wish for tightening the marketed supply.

Remaining reserves

The historic data confirms a slight downward trajectory for the remaining reserves. It is expected to continue its downward path in the forecast period, although at a somewhat slower pace than seen in the observed period. E&P companies are starting to recover from the price fall in 2014, and as discussed in the strategic analysis, they have made permanent cost savings. We expect the exploration spending to pick up, consequently halting the decrease in the reserve replacement ratio. The remaining reserves are defined as reserves that are economically viable to extract given the current price of oil. Therefore, the remaining reserves increases and decreases in correlation with Brent. Since the variable Brent is expected to decrease, the remaining reserves should per definition decrease as well.

Since the future values of remaining reserves are quite complex to obtain and have multiple uncertain but important factors such as politics, we follow the suggested method of Skjerpen et al. (2018) simply keeping the values fixed for the forecasting period. The fixed value of remaining reserves which will be used in the model is 5,700 million Sm^3 o.e., implying a *remres* of 8.6482 after log-transformation. This is also close to the observed mean.

Lead time and contract length

These variables are kept constant in line with the suggestions from Skjerpen et al. (2018) throughout the forecast period and are based on a simple arithmetic mean of observed data. The contract length will be constant at 215.88 days and the lead time is 434 days. In the model, the contract length is log-transformed the lead time is scaled by 100, which is the suggested method of Skjerpen et al. (2018). Though being a noticeable increase in the values going from the last observed period to the first forecast period, it does not seem unreasonable as both the lead time and the contract lengths are varying considerably throughout our dataset. As an example, the two variables are observed to have values within [812; 1098] and [146; 374], respectively, in just one year.

Hourly Wage

The assumptions regarding the change in the real hourly wage of petroleum workers are based on the mean of the forecasted change in the yearly wage of all Norwegian workers from Statistics Norway, the Norwegian Ministry of Finance, and the Central Bank of Norway (Statistisk Sentralbyrå, 2019). The wage is converted from NOK to USD with a fixed exchange rate equal to the mean of the last three years, i.e., the last 12 observed periods. The applied exchange rate is 8.2685 NOK per USD.

The hourly wage in USD is deflated to 2015-prices to ensure continuity in the model. The deflator is an extension of the historical U.S. PPI with an applied change of OECD's forecast of the U.S. economy.

Real interest rate

The 10-year U.S. government bond yield rate is based on forecasts from Trading Economics (2019) for Q2 2019 through Q1 2020. The following periods are fixed at 2.54% which is the mean of Trading Economics' forecast. The rates are deflated with the same predicted PPI as the *wage* variable, and the fixed-rate period Q2 2020 through Q4 2023 obtains a constant *RIR* of 2.0191%.

Forecasted Model Inputs – Base Case										
Period	*BRENT*	*SBRENT*	*sbrent*	*UTIL*	*remres*	*CONLENGTH*	*LEADTIME*	*WAGE*	*RIR*	*PPI*
1Q19	65.0000	66.2549	4.1935	0.6306	8.3815	215.8829	4.3400	78.3111	0.0210	107.0954
2Q19	71.5500	67.0695	4.2057	0.8525	8.6482	215.8829	4.3400	78.5146	0.0190	107.6796
3Q19	70.6683	67.6232	4.2140	0.8550	8.6482	215.8829	4.3400	78.7187	0.0194	108.2670
4Q19	69.6517	67.9353	4.2186	0.8575	8.6482	215.8829	4.3400	78.9233	0.0198	108.8576
1Q20	68.7750	68.0645	4.2205	0.8600	8.6482	215.8829	4.3400	79.1537	0.0201	109.4782
2Q20	67.9467	68.0463	4.2202	0.8625	8.6482	215.8829	4.3400	79.3848	0.0197	110.1024
3Q20	67.1467	67.9079	4.2182	0.8650	8.6482	215.8829	4.3400	79.6166	0.0197	110.7301
4Q20	66.3133	67.6626	4.2145	0.8675	8.6482	215.8829	4.3400	79.8491	0.0197	111.3614
1Q21	65.5467	67.3371	4.2097	0.8700	8.6482	215.8829	4.3400	80.1405	0.0199	111.9689
2Q21	64.9000	66.9621	4.2041	0.8725	8.6482	215.8829	4.3400	80.4329	0.0199	112.5797
3Q21	64.2600	66.5464	4.1979	0.8750	8.6482	215.8829	4.3400	80.7264	0.0199	113.1938
4Q21	63.6300	66.0977	4.1911	0.8775	8.6482	215.8829	4.3400	81.0210	0.0199	113.8113
1Q22	63.1233	65.6401	4.1842	0.8800	8.6482	215.8829	4.3400	81.2971	0.0199	114.4322
2Q22	62.7000	65.1878	4.1773	0.8825	8.6482	215.8829	4.3400	81.5741	0.0199	115.0564
3Q22	62.3200	64.7466	4.1705	0.8850	8.6482	215.8829	4.3400	81.8520	0.0199	115.6841
4Q22	61.9800	64.3210	4.1639	0.8875	8.6482	215.8829	4.3400	82.1309	0.0199	116.3152
1Q23	61.7700	63.9285	4.1578	0.8900	8.6482	215.8829	4.3400	82.4143	0.0202	116.9211
2Q23	61.6200	63.5734	4.1522	0.8925	8.6482	215.8829	4.3400	82.6987	0.0202	117.5301
3Q23	61.4900	63.2528	4.1471	0.8950	8.6482	215.8829	4.3400	82.9841	0.0202	118.1424
4Q23	61.3700	62.9632	4.1426	0.8975	8.6482	215.8829	4.3400	83.2704	0.0202	118.7578

Figure 6.8 - Base case inputs for forecasted model

6.5.2 THE BASE CASE FORECAST

Figure 6.9 presents the forecast based on the assumptions discussed above. The rig rates are expected to decrease by approximately $38,000 between 2019 and 2023. However, the majority of the nominal change in the forecast occurs in the very first period, 1Q19. This is due to the lagged variables being integrated into the first forecast period with observed values, resulting in a rapid change in the value of the remaining reserves between 1Q19 and 2Q19. As we saw from the regression, *remres* has a negative coefficient. The rig rates, therefore, drop when *remres* is assumed to increase in the second forecast period. Most of the variables are presumed to either be fixed or show little fluctuation throughout the forecast horizon. In consequence, it is not surprising that the development in future rig rates looks relatively stable. In addition to the forecasted rig rate, Figure 6.10 illustrates the development of the smoothed Brent blend oil price on the right axis, as well as 50% forecast intervals, calculated as explained in section 6.5 and illustrated by the dotted lines.

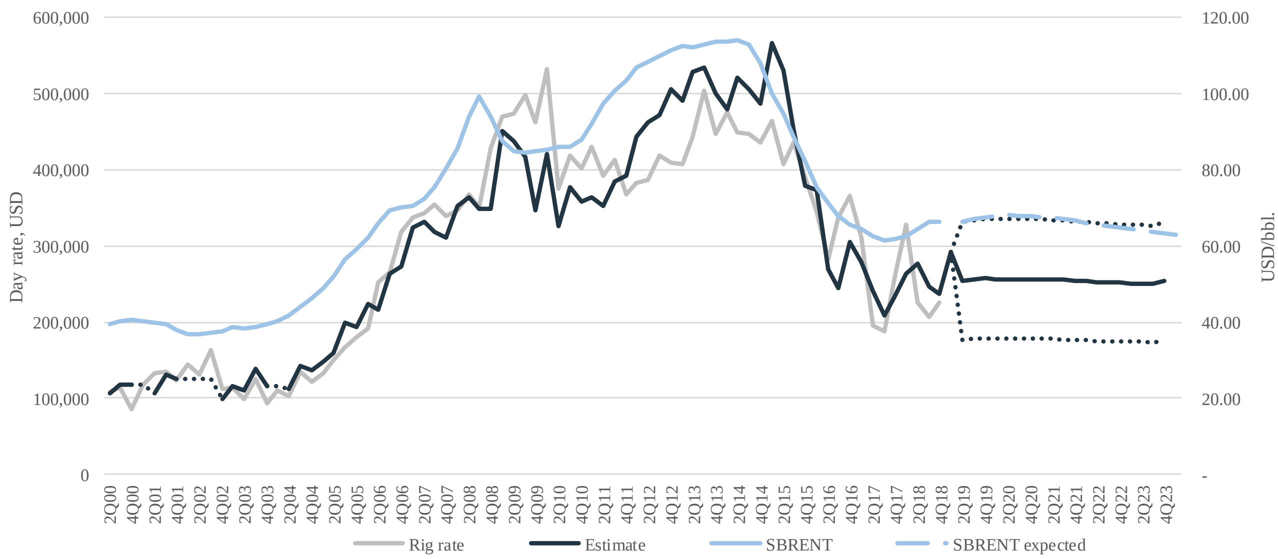

Figure 6.9 - Estimated and historic rig rates, and forecasted rig rates. Smoothed real Brent price. Source: RigLogix (2019), U.S. EIA (2019) and authors' creation

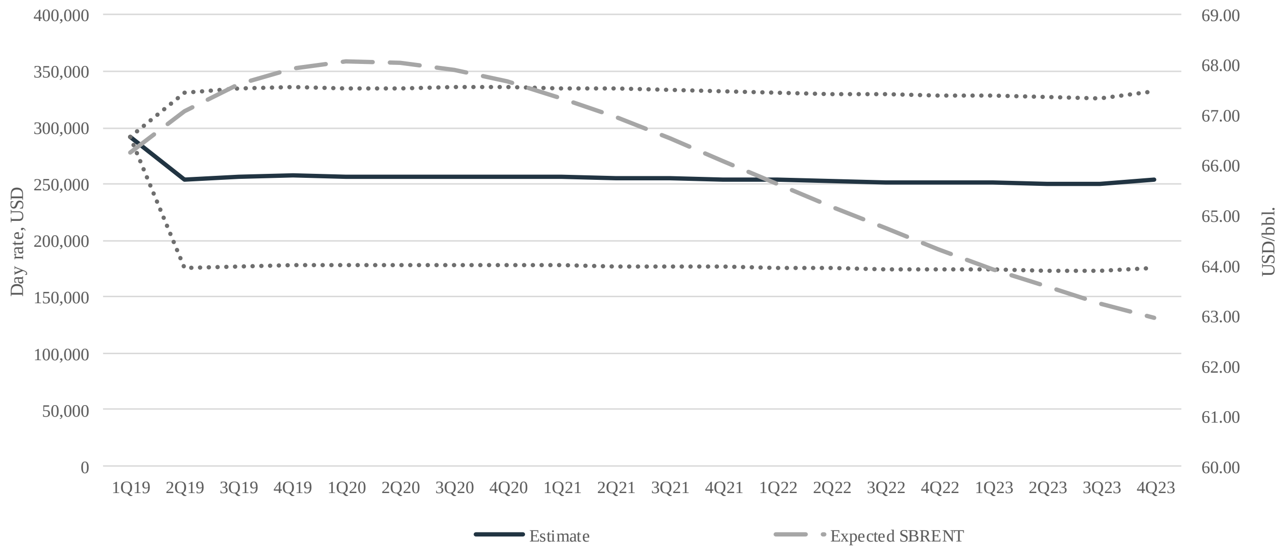

Figure 6.10 - Forecasted rig rates with 50% forecast intervals and expected smoothed real Brent price. Authors' creation

6.5.3 FORECAST SCENARIOS

In order to explore and further test the effects of model inputs, we create four alternative scenarios to illustrate the effect of how an increase in the Brent blend, capacity utilization, and remaining reserves affect the rig rates. We also analyze the effect of a combined increase in *sbrent* and *UTIL*. Below is an illustration of the four forecast scenarios including our reference forecast. The forecast scenarios are set to the ones suggested by Skjerpen et al. (2018). As our coefficient estimates differ from Skjerpen's, particularly the remaining reserves variable which entered their model with a positive effect, but with our data and model has a coefficient of -0.98, it will be interesting to see its effect on day rates, holding all else equal.

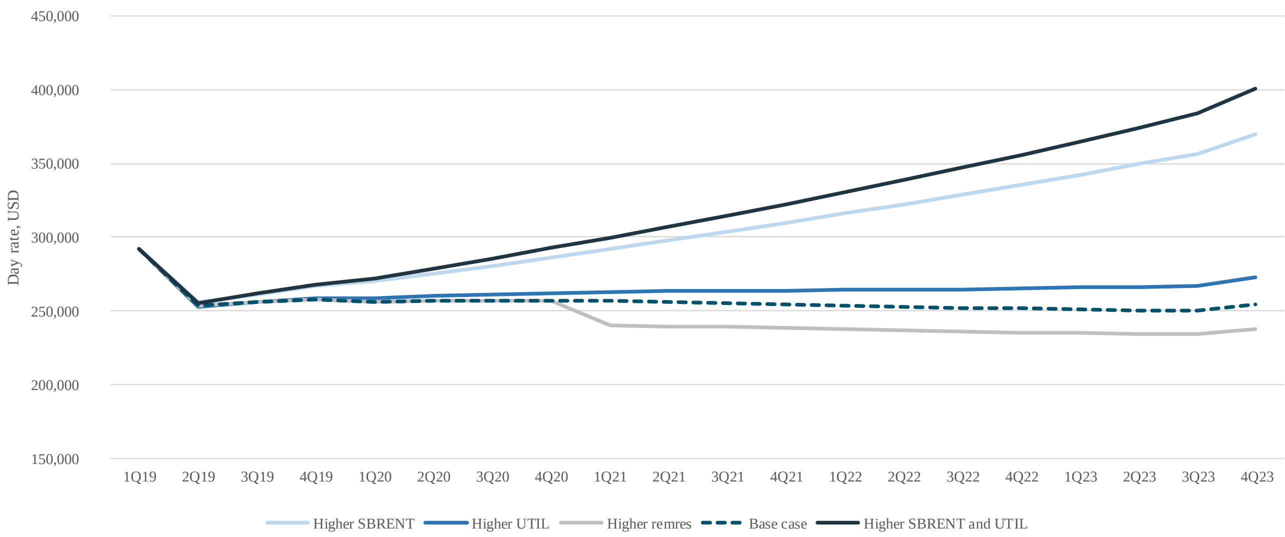

Figure 6.11 - Rig rate forecasted scenarios. Authors' creation

In *scenario 1*, we increase the variable *SBRENT* to induce a change in the rig rates. *SBRENT* is increased by 2.5% per quarter. As opposed to our predicted decrease in *SBRENT*, the incremental increase in higher *SBRENT* means that the smoothed oil price for 4Q23 reaches nearly 106 USD/bbl. According to Bloomberg (2018), some analysts have suggested the Brent blend price potentially moving towards USD 100/bbl. It seems within reason that we include an oil price that illustrates this potential outcome and what it does for the rig rates. *Scenario 1* results in a positive change in rates and an estimated rig rate of nearly $370,000 at the end of the forecast period. Further complementing our previous findings on this variable.

Scenario 2 tests for higher rig utilization. As confirmed in section 5.1.5.2, the *UTIL* variable is not statistically dependent on *BRENT*. This allows us to disregard any potential change in the *BRENT* variable when modifying the capacity utilization. We apply a quarterly incremental increase of 0.8

percentage points in the variable *UTIL* until it reaches 99% capacity utilization in the fourth quarter of 2023. Keeping all other variables equal, *scenario 2* does not affect the rig rate to the extent seen in *scenario 1*. This is expected as the variable enters the model indirectly through the oil price. However, the test is positive and shows that oil price becomes more important with an increasing utilization, increasing the rig rates to $272,000 at the end of 2023.

In *scenario 3*, we run a simulation where we combine *scenario 1* and *scenario 2*, causing the steepest increase in rig rates relative to the base case. Should the assumptions in *scenario 3* materialize, the forecasted rig rates will increase and approach approximately $400,000, equaling the rig rates of late 2015, a 60% increase from the base case. Interestingly, the effects of scenario 1 and 2 are larger when entering the model at the same time. This again exemplifies that an increasing bargaining power shifts the joint value creation towards the drilling companies.

In the fourth scenario, we intend to simulate an oilfield discovery. Therefore, we keep the *REMRES* stationery at 5,700 million Sm^3 o.e. until 4Q20, when our simulated discovery takes place. The *REMRES* will from 1Q21 be fixed at 6,100 Sm^3 o.e. When the Johan Sverdrup field was discovered on the Norwegian Continental Shelf in 2010, it had expected recoverable resources of between 2.1 and 3.1 billion boe (334 – 493 million Sm^3) (Equinor, 2019). Therefore, a sudden increase of 400 million Sm^3 o.e is possible, as history has shown. Skjerpen et al. (2018) simulate a 973 million Sm^3 o.e one-period increase in the remaining reserves variable. Again, we note that the reserves in this paper is related to the current price of Brent because they are measured at economic viability. Thus, by keeping the *BRENT* variable in *scenario 4* equal to the *BRENT* in the base case, we acknowledge that the *REMRES* cannot be fixed in practice. From Figure 6.11, it becomes visually apparent that *scenario 4* is the least favorable for rig companies, as the rig rates are set to be roughly $16,000/day lower than in the base case in the terminal period. Due to the negative coefficient and the notion that there is a reduced need to drill exploratory wells when remaining reserves increases, as was discussed in section 6.4, the resulting decrease in the modelled rig rates is expected. Should *scenario 4* materialize, offshore drilling companies will suffer from unsustainable rates, cf., section 5.2. Figure 6.12 lists the assumptions included in the model for *scenario 1*, *2*, and *4*, and the forecasted rig rates can be found in Appendix 9.

Assumptions in *scenario 1*, *scenario 2*, and *scenario 4*									
Period	**Assumed SBRENT**	**Higher SBRENT**	**Higher REMRES**	**Higher UTIL**	**Period**	**Assumed SBRENT**	**Higher SBRENT**	**Higher REMRES**	**Higher UTIL**

1Q19	66.25	66.25	4366	0.63	**3Q21**	66.55	84.81	6100	0.92
2Q19	67.07	67.91	5700	0.85	**4Q21**	66.10	86.93	6100	0.93
3Q19	67.62	69.61	5700	0.86	**1Q22**	65.64	89.11	6100	0.94
4Q19	67.94	71.35	5700	0.86	**2Q22**	65.19	91.33	6100	0.94
1Q20	68.06	73.13	5700	0.87	**3Q22**	64.75	93.62	6100	0.95
2Q20	68.05	74.96	5700	0.88	**4Q22**	64.32	95.96	6100	0.96
3Q20	67.91	76.84	5700	0.89	**1Q23**	63.93	98.36	6100	0.97
4Q20	67.66	78.76	5700	0.90	**2Q23**	63.57	100.81	6100	0.98
1Q21	67.34	80.73	6100	0.90	**3Q23**	63.25	103.34	6100	0.98
2Q21	66.96	82.74	6100	0.91	**4Q23**	62.96	105.92	6100	0.99

Figure 6.12 - Assumptions for scenarios 1, 2, and 3. Authors' creation

6.6 CONCLUSION

This part of the paper has concerned itself with modeling and forecasting rig rates for floaters in the NW European market. Adapting the methodology of Skjerpen et al. (2018), as well as our findings from the strategic and industry analysis from the first part of this paper, the forecast is based on a bargaining model and an empirical test of important drivers for rig rate formation in the observed period. The result is a model that allowed for predictions in a five-year forecast of rig rates given input assumptions in the explanatory variables.

The econometric analysis, using a multiple linear regression on a manipulated data set resulted in a robust model with both statistical significance in most coefficients and a strong within-sample fit. The results from the econometric analysis were mostly in-line with our hypothesized effects, and make intuitively sense with the theory and lessons learned in the first part of this paper and existing literature. Here, we saw that especially oil prices played an essential role in the rate formations. We also saw that the supply, represented by utilization, contract lengths and lead times had positive effects on the rig rates, however at a lower levels compared to the oil price. These findings were in line with the arguments of the Shipping Market Model and existing literature. Furthermore, we saw that with rising utilization and a tightening market, pricing power shifted towards the rig contractors, allowing them to pressure rig rates to a greater degree. The latter was explicitly showcased when applying our model on a set of bullish future oil prices and utilization values, where we saw that the rig rates grew at a steeper level than at low oil prices. This was also in line with the analysis from the Shipping Market Model and the Bargaining Model, as well as existing literature.

7 ODFJELL DRILLING

This chapter will analyze Odfjell Drilling in order to uncover any potential irregularities of the company that makes Odfjell unsuited to be the company valuated in the use case of the rig rates. We also want to see if Odfjell Drilling holds a strategic advantage over its peers, potentially awarding them a premium in the market. We also analyze their financials in order to evaluate their going concern.

- Does Odfjell Drilling hold a specific strategic advantage over its competitors?
- Does Odfjell Drilling have a strong financial position compared to its peers?

Odfjell Drilling Ltd. (hereafter, “Odfjell,” “the company,” or “they”/”their”) is a leading offshore drilling contractor in the harsh environment and ultra-deep-water segment. The company’s drilling operations is based in Norway and the United Kingdom and is listed on the Oslo Stock Exchange under the ticker ODL. However, Odfjell is incorporated in Bermuda and is therefore subject to Bermuda law (Odfjell Drilling, 2018). Today, Odfjell has more than 2,400 employees and operates in 20 countries worldwide (Odfjell Drilling, 2019c). The company’s primary business is drilling operations. However, their mission is to provide a complete service with high value to their customers, they have organized their business activities into three main segments: MODUs, drilling and technology, and well services (Odfjell Drilling, 2019c).

The company is owned by Odfjell Partners Ltd., which controls 71.45% of the nearly 200 million outstanding shares. Other large investors are Deutsche Bank AG (3.27%), J.P. Morgan Chase Bank N.A. London (2.95%), and State Street Bank and Trust Co. (1.54%).

7.1 HISTORY

Odfjell’s history dates back to 1914 when the Odfjell family formed several companies primarily focusing on timber transportation and dry cargo vessels (Odfjell Drilling, 2019a). Gradually, they adopted a new focus, moving from their main operating area of dry cargo to more specialized cargoes such as chemicals. About 30 years after having begun transporting chemicals, Odfjell moved into the offshore drilling market in 1970. They took part in the construction and design of the prominent Aker H-3 semisubmersible rig design which earned a highly successful reputation, proven by the realization of 28 rigs with its design. In 1973, Odfjell Drilling was established and began drilling operations one year later with its first Aker H-3 semisubmersible deep-sea driller (Odfjell Drilling, 2019a). Since then, the company has operated more than 30 rigs around the world.

As one of the pioneers on the NW European area, Odfjell has experienced several firsts. In 1978, they were awarded a drilling contract on Statfjord B. The contract was the largest ever recorded in Norway at the time, as well as the first contract awarded to a Norwegian company on the NCS. They were awarded an extensive contract with Statoil (now Equinor) on the Mariner field on the U.K. shelf, which was Statoil's first development project on the UKCS (Odfjell Drilling, 2019a). Odfjell engaged in activities in Asia and Africa in the 1980s and 1990s but changed their strategy to exclusively focus on the NW European market in 1995.

2013 was a milestone year for the company. They were listed on the Oslo Stock Exchange under the ticker ODL. Their market capitalization is approximately NOK 6.8 bn. as of April 2019, and in 2018 their revenue was NOK 6.1 bn.

7.2 FLEET

Odfjell's fleet consists of five semisubmersibles which are 100% owned and operated by Odfjell. Their fleet was recently expanded, with the semisubmersible, Deepsea Nordkapp, being delivered from the Samsung Heavy Industries shipyard in South Korea (Odfjell Drilling, 2019b) in January of 2019.

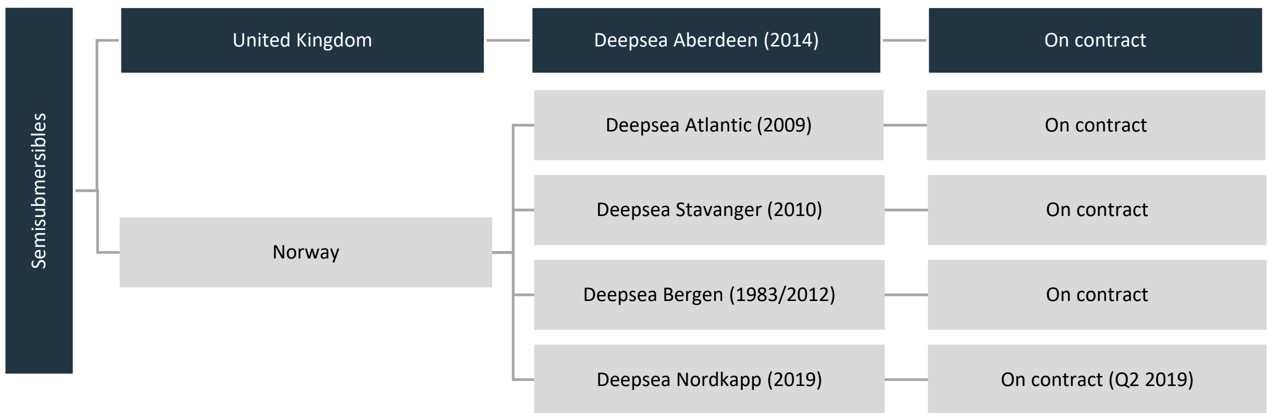

Figure 7.1 - Odfjell Drilling's semisubmersible rigs. Source: Odfjell Drilling (2019b)

Figure 7.1 displays Odfjell's fleet. Deepsea Bergen went through an upgrade in 2012, but the hull and rig design is the Aker H-3(.2), mentioned in the previous section. If counting its age from the year of the upgrade, Odfjell has a young fleet with an average age of just over six years. Since all the rigs are operating in NW Europe, namely on the UK continental shelf and the Norwegian continental shelf, they are equipped for harsh environment operations with what they describe as the highest safety standards and modern technology (Odfjell Drilling, 2019a).

7.3 ORGANIZATION AND MANAGEMENT

Mentioned in the introduction, Odfjell is owned by various investment banks and funds. This indicates that the company is thoroughly examined by analysts that in turn have concluded that there is an investment opportunity in the company, which may suggest a well-run business. The company has adopted a corporate governance system that satisfies the regulatory bodies of Norway through the *Norwegian Code of Practice for Corporate Governance* (Odfjell Drilling, 2019d). The code of practice's main objective is that publically listed companies in Norway ensure the division of roles between the management, the board of directors and the shareholders beyond what is required by the law (Oslo Stock Exchange, 2019).

The company seek to create profitability and increased shareholder value through good corporate governance by having sound systems for communication, monitoring, and allocation of responsibility throughout its international operations (Odfjell Drilling, 2018). Although focusing on the NW European marked for their MODUs, the company is involved in global activities through their well services, which is engaging over 450 people in operations in nearly 20 countries worldwide (Odfjell Drilling, 2018).

7.4 INTERNAL ANALYSIS

7.4.1 CHOICE OF MODEL

The purpose of the internal analysis is to uncover Odfjell's competitive advantages by looking at the company's unique qualities and which characteristics make them different from their competition. Competitive advantages on the firm level have roots in different parts of the value chain, and most research on its sources have, according to Barney (2007), been focused on the underlying firm's opportunities and threats, or by describing its strengths and weaknesses, i.e., through a SWOT-analysis. A critical limitation to the SWOT-model is that it only focuses on finding the company's strengths or weaknesses and suggests that companies make strategic decisions based on its strengths, but lacks a framework for identifying the underlying mechanisms describing these strengths (Barney & Clark, 2007). Furthermore, Porter's five forces presented in *How competitive forces shape strategy* (1979), assumes that all companies within an industry are essentially homogeneous concerning aspects of operation and resources except their size (Barney & Clark, 2007).

In section 4.2 we described the different offshore rig classifications and what made them different from one another. It became evident that the market players do not have the same type of assets, i.e., homogenous products as would be assumed should we analyze Odfjell through Porter's five forces. Based on the reasoning above, we apply the methodology of the resource-based value analysis based on Jay B. Barney and Delwyn N. Clark's book *Resource-based Theory* (2007). Thus, in this section of the paper, we will uncover and asses Odfjell's internal resources that enable them to gain and sustainable competitive advantages in the market in which they operate.

7.4.2 THE VRIO-FRAMEWORK

The resource-based theory assumes that firms within a competitive market may indeed be heterogeneous concerning the strategic assets they control, while simultaneously being able to prevent these assets from becoming entirely transferrable to competitors within the industry (Barney & Clark, 2007). This framework will assess the implications regarding the assumption concerning the analysis of the competitive advantages, being the sustainability of their resources (Barney & Clark, 2007).

By implementing the VRIO-framework, the following pages will analyze whether Odfjell's resources meet the criteria for sustainable competitive advantage, which according to Barney (2007) are as follows:

Valuable	**Rare**
Is the resource enabling the firm to conceive strategies that allow them to increase their effectiveness	Is the resource rare relative to the competition, both current and potential?
Imperfectly imitable	Organization
The resource cannot be perfectly imitable. In other words, it must not be transferrable to competitors	It must be able to be utilized by an organizational process

Figure 7.2 - VRIO-framework. Source: Barney and Clark (2007)

7.4.2.1 THE FLEET

Their five semi-submersible rigs make up the majority of Odfjell's physical assets and are fundamental to the value creation in the company. They have one of the youngest fleets of any player in the market and operate harsh-environment drilling units with the latest technological advancements available in the market (Odfjell Drilling, 2019a). As Odfjell is taking part in the development of new technologies through their research and development department, they can implement the latest advancements to their fleet. They state in their annual report (2018) that they shall remain the leading and preferred drilling contractor on the market through continuous technological improvements and implementations. By focusing on this, they can provide their customers with best-in-class operations. It is assumed that this is increasing customer willingness to pay for their product (rigs), and thus increasing the value of the resource. By reviewing our dataset, we saw that in the observed period, Odfjell Drilling held rig rates at a 15.44% premium to the average NW European rates. Hence allowing us to conclude that their fleet is valuable in the context of the resource-based theory and the VRIO-model (Barney & Clark, 2007).

The research and development go beyond rig-specific improvements, and it is vital for Odfjell to manage the latest and most efficient equipment, shall they stay true to their objectives. Since Odfjell's primary market is NW Europe, where harsh-environment operations are the norm, the fact that they only operate harsh-environment rigs is not rare, as their competitors are required to have the same general specifications to their fleets. Though they have a modern fleet, it is not unique for the area in which they operate (Bassoe Analytics, 2019). Seadrill operates a slightly older fleet of rigs in NW Europe (Seadrill, 2019), and Transocean is constantly "high-grading" their fleet to make sure they can take on the most challenging operations (Transocean, 2019a). It can be argued that Odfjell acquires an advantage through their cutting-edge technological improvements and their young fleet so that their fleet is rare due to these constant developments. However, their competitors make every effort to develop new technology, and thus, it is unjust to claim Odfjell's fleet as either rare or imperfectly imitable.

Though the fleet is likely rarer than imperfectly imitable, it is not hard to argue that their modern fleet is gaining Odfjell a competitive advantage. However, it does not meet the criteria necessary to sustain this advantage, because their competitors can obtain these very asset specifications. It is therefore up to the management to extract the most value from the resources they control at any given time, and it is only when a resource meets all these criteria it can be characterized as a potential source to sustainable competitive advantage (Barney & Clark, 2007).

Based on the discussion above, Odfjell has a competitive advantage in their modern fleets, but however competitive, it is unlikely to be a sustainable competitive advantage as other players may essentially acquire the same fleet over time.

7.4.2.2 BACKLOG AND FINANCIAL RESOURCES

By having financial resources that allow the company to withstand a downturn in the offshore rig market when the rig rates are low, they are better positioned for the future and will likely be considered a good investment option by investors. Therefore, we will look at Odfjell's financial resources to unveil if they have a potential advantage should the day rates significantly decrease as they did in 2015, cf. Figure 5.9. Odfjell's financial resources is a potential source to competitive advantage if they have managed to obtain interest rates lower than their competitors and better terms for their financing. In recent years, banks and other financial institutions providing debt to companies in the industry have altered their criteria. As the volatility in the share prices of offshore companies and service providers has increased as a result of the market crash in 2014, financing institutions now consider company backlog as an important financing criterion (Odfjell Drilling, 2018). Odfjell did not expand their backlog in 2018, but had at year-end $2.4 billion (Odfjell Drilling, 2019). One of their competitors, Transocean, had a backlog of approximately $12.5 billion at the same time (Transocean Ltd., 2019). Transocean is a company with a comparable fleet in terms of asset-class, however larger by a factor of 10, cf. Figure 4.12. Odfjell's backlog may indeed be a valuable resource when seeking financing.

Although their backlog is substantial and a guarantee for future cash-flow where day rates play a significant role, and where there is potential for a day rate premium to the global average due to higher specification rigs as discussed on the previous page, it may not affect their likelihood of gaining proper debt financing. The debt financing market is challenging, and other sources of funding other than what is already accessible to the company may not be available in the future (Odfjell Drilling, 2018). These new challenges regarding debt financing are not unique to Odfjell and is not regarded as a disadvantage.

Odfjell's backlog is a valuable resource for the company. It is not imperfectly imitable as competitors can, and are, increasing their backlog as well, but it is rare in the sense that they have a solid utilization outlook in the coming years as a result of their backlog.

At the end of 2018, Odfjell had an equity ratio of 45% with $1,025 million in equity (Odfjell Drilling, 2019). This is within their goal of maintaining at least 30% equity (Odfjell Drilling, 2018), also indicating that the organization is managing the financial resources in a way that satisfies their criteria. The equity ratio will be analyzed further in the financial analysis in section 7.5.4.2. Odfjell is likely to be able to withstand a downturn in the day rates given their current backlog and their equity ratio. However, we do not expect day rates in NW Europe to change considerably throughout the forecast period, c.f. section 6.5.2, thus having a backlog at the current rates is valuable to the company.

Odfjell's backlog and financial resources appear to give them an advantage in a market where the current average utilization rate is at around 80%, but we do not consider it a sustainable competitive advantage as all four criteria in the VRIO-framework are not fulfilled.

7.4.2.3 Brand

The purpose of looking at the brand is to analyze if there are advantages related to its brand reputation. Odfjell Drilling is a known company in the NW European market and a pioneer on the Norwegian Continental Shelf (Odfjell Drilling, 2019c). They have a modern, harsh-environment suited fleet as previously discussed, and they market themselves as "The safe choice*"*. Odfjell Drilling is a trusted supplier by the world's leading energy companies (Odfjell Drilling, 2019e), and with that, their brand represents a reliable and professional organization that fulfills their contract engagements on time (Odfjell Drilling, 2019). They have a publically expressed "zero fault" philosophy which includes striving to not harming the environment (Odfjell Drilling, 2019). However, according to Barney and Clark (2007), having a good reputation is advantageous, but hardly sustainable in the long-run. That being said, Odfjell Drilling's long standing position in the market and relationship with the conglomerate, Aker ASA, has earned them a strategic alliance with the E&P company Aker BP (Odfjell Drilling, 2019). This alliance ensures a close relationship with an important petroleum company in the region. While an alliance in itself is not inimitable, it must be regarded as a strong advantage as it omits some of the company's operational risk. Odfjell's brand cannot be regarded a sustainable competitive advantage, yet the company's reputation is of operational importance.

7.4.3 Concluding remarks – VRIO

Odfjell Drilling is in a competitive market where the players offer similar products. Nevertheless, the company is in a position that might allow them to charge a premium on day rates due to high specification units with up-to-date in-house developed technology. As none of their advantages are inimitable, the company fails to hold a sustaining competitive advantage, as described by Barney & Clark (2007). The company has secured contracts worth $2.4 billion and have a strong position in the NW European market with resilient focus on strengthening their brand through their attention to health, safety and technology. This is believed to be an advantage; however, not sustainable in the long term.

In the following chapter, we will uncover Odfjell's financials and compare them to the peer-group to uncover if it has potential to represent the market in order to understand the rig rates effect on companies' values.

7.5 FINANCIAL ANALYSIS

The methodology utilized in this chapter is extracted from Petersen et al.'s (2012) *Financial Statement Analysis*. The analysis is split into two parts; a profitability analysis, and a liquidity analysis.

The profitability analysis is built on the DuPont model outlined in Petersen et al. (2012). The DuPont model breaks down financial ratios to more specific ratios in order to see their development based on the data. The conclusions are made by comparing data to industry standards, which in this paper is represented by a peer average.

The liquidity analysis is built on Petersen et al.'s (2012) own methodology but resembles the DuPont model in that financial ratios are used to analyze a firm's situation. Here, financial ratios are used to measure liquidity risk on both the short- and long-term.

As the methodology of this chapter is based on the evaluation of existing data and comparing them to peers, the approach is done inductively.

Petersen et al. (2012) argue that financial ratio analysis is "a useful tool for mapping a firm's economic well-being, and uncovering different aspects of its performance and financial position." Its usefulness is explained as its ability to allow for the development of assumptions about future profitability. It is further argued that understanding the profitability of a firm's operations is fundamentally important as the level of profitability of a firm communicates information regarding the sustainability of a firm's operation. Especially analyzing whether the value of a firm is primarily driven by the level and growth in a firm's operational activities. To value Odfjell Drilling with the forecasted rig rates and the scenarios from section 6.5.3 it is therefore necessary to establish that these earnings, in fact, stem from operational activity.

In order to explore this, we will look at their profitability and liquidity. The results will be compared to peers, as this forms a basis for benchmarking our findings. This is done in order to evaluate whether or not Odfjell Drilling has any financial reasons to over or underperform relative to these peers. Our analysis is based on analytical income statements and balance sheets, which we have reformulated from the firm's financial reports. As we mentioned in the introduction to this part of the paper, the company went publicly in 2013, hence publishing its financials from 2012 the same year. We apply all available public information related to the companies from annual reports for 2012 through 2018.

7.5.1 Peers

The chosen peers for Odfjell Drilling, is Diamond Offshore and Dolphin Drilling. The two companies are chosen, as they are both pure-play floater companies with similarities to Odfjell Drilling. However, there are some dissimilarities in fleet size as well as Diamond drilling being more international in its fleet placement. That being said, the companies within the industry are all diversified within the boundaries of the industry and the two companies are seen as the closest to Odfjell.

7.5.2 Notes on the Reformulation

A firm consists of operating, investing and financing activities. Calculation of financial ratios is done in order to further understand the firm's profitability; in turn, this provides a better understanding of where the value-drivers of the firm originate. It is therefore beneficial to separate operations and investment in operations from financing activities (Petersen, Plenborg, & Kinserdal, 2012). Publicly traded companies are required to account and report earnings and expenses within the rules and regulations (IAS/IFRS). However, when conducting financial analysis, you seek to unveil a company's actual value-drivers. The analytical (or sometimes referred to as a reformulated) income statement and balance sheet (found in Appendix 11 and Appendix 12) singles out the operating activities of the firm. Most accounting posts are seen as obviously operational or financial; however, whenever it is deemed necessary, notes on certain posts are provided in order to justify our classification. We also note that if an item is considered operational in the income statement, this needs to be reflected in the balance sheet.

Investments in a joint venture

These joint ventures are within drilling operations and related to their core business and are therefore considered to be a part of Odfjell's operational activity (Petersen, Plenborg, & Kinserdal, 2012).

Derivative financial instruments

These instruments are in part hedging decisions and are measured at fair value. There are subtle differences between what is considered financial and operational within this post. This, combined with the fact that it is communicated a financial decision, makes the argument that it should be considered a financial activity (Petersen, Plenborg, & Kinserdal, 2012).

7.5.3 PROFITABILITY ANALYSIS

Through the profitability analysis, we target the drivers of Odfjell Drilling's viability. This is done because a detailed understanding of the company's profitability forms a crucial basis for considering future earnings (Petersen, Plenborg, & Kinserdal, 2012). The following subchapter will therefore break down the company's profitability by decomposing its return on equity, beginning with a decomposition of its return on invested capital.

7.5.3.1 RETURN ON INVESTED CAPITAL

Return on invested capital (ROIC) is an overall profitability measure for operations. It measures the return on capital invested in the firm's net operating assets (Petersen, Plenborg, & Kinserdal, 2012). ROIC allows us to better determine how the company is able to implement its net operating assets to create profit (Sørensen, 2012).

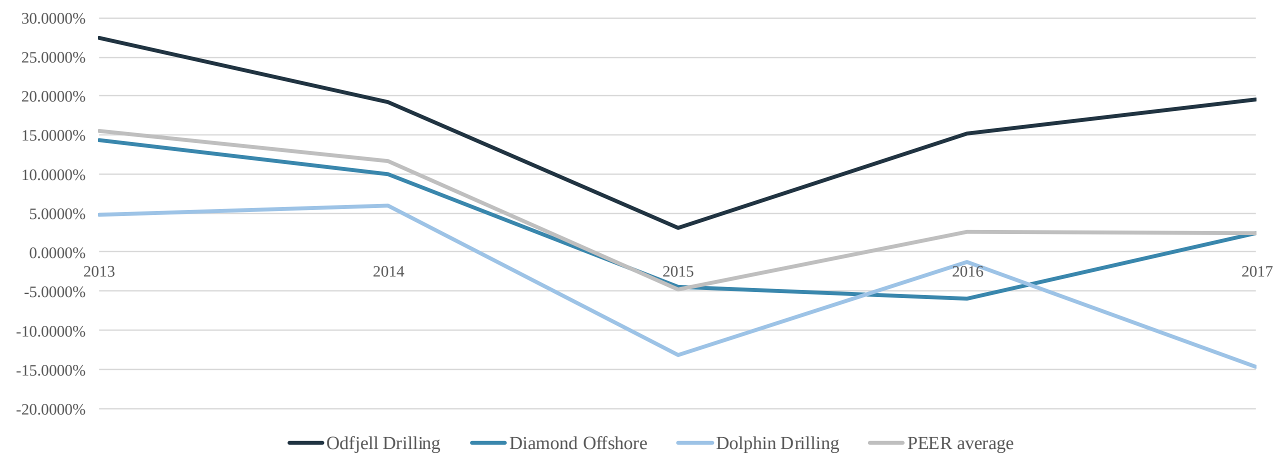

Figure 7.3 - Peer group return on invested capital

As visually observed from Figure 7.3, the industry has moved similarly over the later years. Odfjell Drilling moves in parallel with the peer average, but at a sustained higher level.

ROIC is a useful tool for measuring how well a company implements operating assets in order to create profit. Nevertheless, it fails to offer any explanations as to whether the profitability is driven by a better revenue-to-expense relation or improved capital utilization (Petersen, Plenborg, & Kinserdal, 2012). In order to answer this, it is therefore necessary to decompose the ratio into the profit margin and the turnover rate of invested capital (Petersen, Plenborg, & Kinserdal, 2012).

Profit Margin

The profit margin is, as the ROIC, based on the firm's earnings before interests and taxes (EBIT). The profit margin describes the company EBIT, relative to its net revenue. Figure 7.4 describes the profit margin of Odfjell Drilling and the peer group. The margin moves in accordance with the industry, but as we also saw with the ROIC, the company manages to outperform its peers. This suggests that one of the reasons behind Odfjell Drilling's superior ROIC comes from their profit margin. It would seem that Odfjell manages the costs of their operations well.

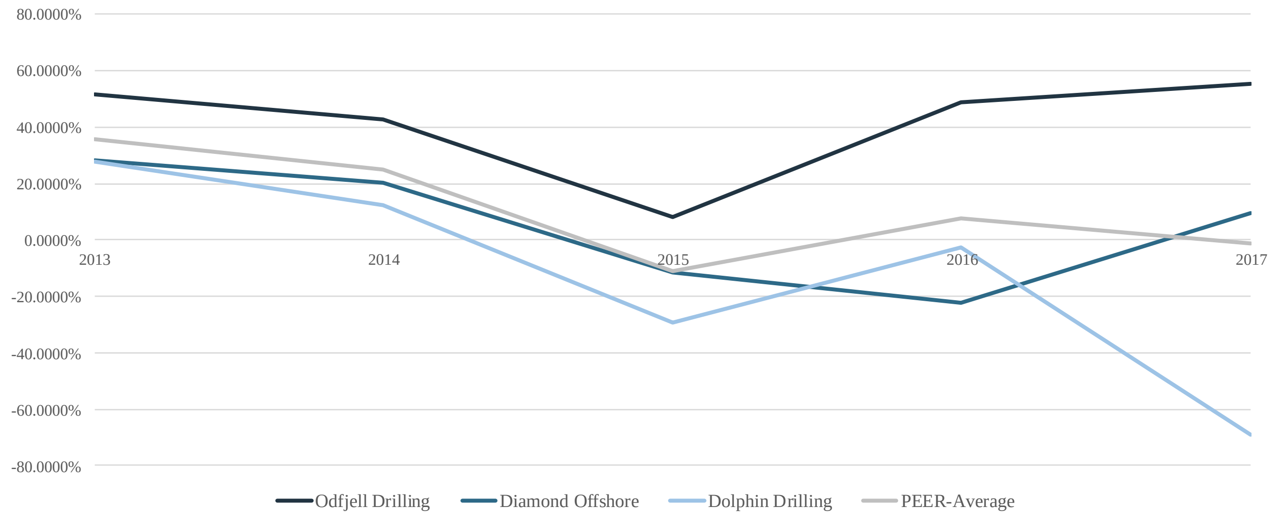

Figure 7.4 - Peer group operating profit margin

Turnover Rate of Invested Capital

The turnover rate of invested capital describes the company's ability to utilize its invested capital (Petersen, Plenborg, & Kinserdal, 2012). Odfjell Drilling's turnover rate of invested capital seems to be consistently close to the peer average. There seems to be little evidence that Odfjell is able to generate more revenue from its invested capital (rigs), than the other rig companies.

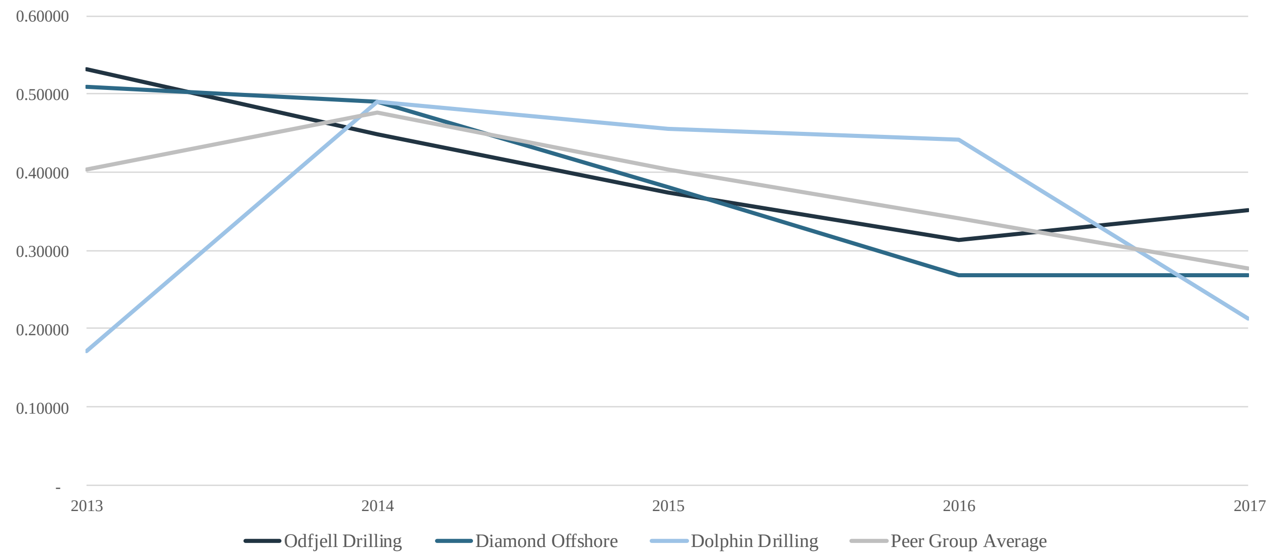

Figure 7.5 - Peer group turnover rate of invested capital

Concluding remarks – ROIC

Odfjell Drilling's ROIC has in the observed period moved close to the group average, with a slight upturn in later years. By decomposing the ROIC, it seems that the primary reason for this upturn is based on its operating profit margin. It also seems that the turnover rate of the invested capital is on par with its peers. These findings suggest that Odfjell Drilling is a good candidate for testing our forecast scenarios, as the firm is close to average in terms of operational performance, suggesting that the firm moves in line with exogenous inputs.

7.5.3.2 Return on Equity

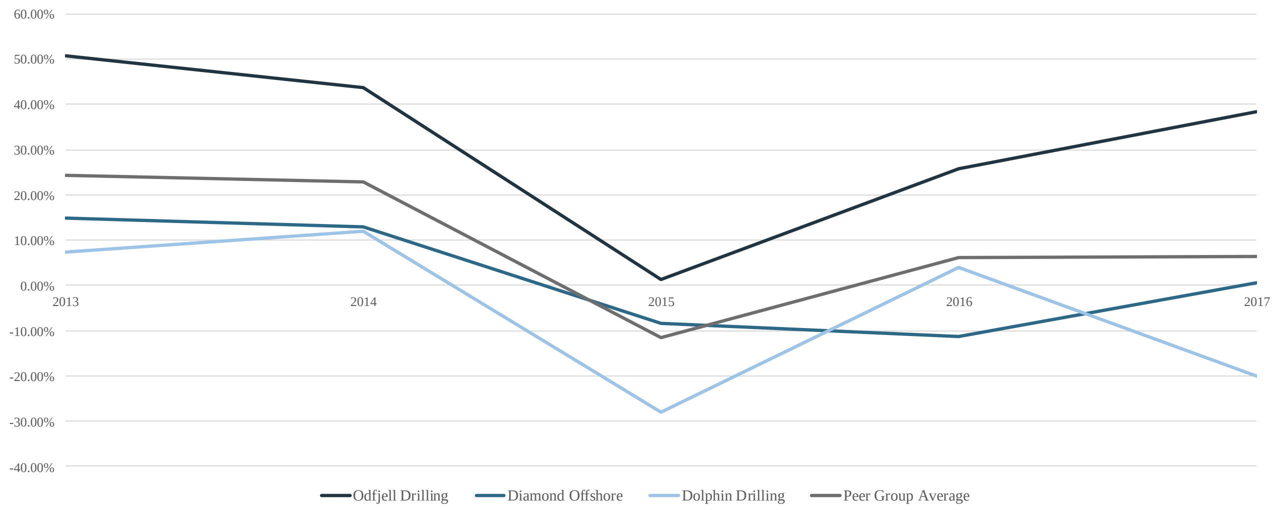

Figure 7.6 - Peer group return on equity

Figure 7.6 shows that the return on equity (ROE) fell for the entire industry around the time of the fall in oil prices. Again, Odfjell Drilling is outperforming its peers.

In order to further interpret the development of the ROE, this section will decompose this ratio into financial gearing and spread. The total equation of ROE is as following:

$$Return\ on\ Equity = ROIC + Spread * Financial\ Gearing$$

Financial Leverage

The first part of the decomposition is to find the effect the financial leverage of the firm has on its overall profitability. Odfjell Drilling is as seen by Figure 7.7 more levered than its peers. This can partly explain the higher variations in the ROE (Petersen, Plenborg, & Kinserdal, 2012). The high leverage makes it interesting to review whether this has a positive or negative effect on the ROE. In order to evaluate this, we must look at the spread between ROIC and net borrowing costs.

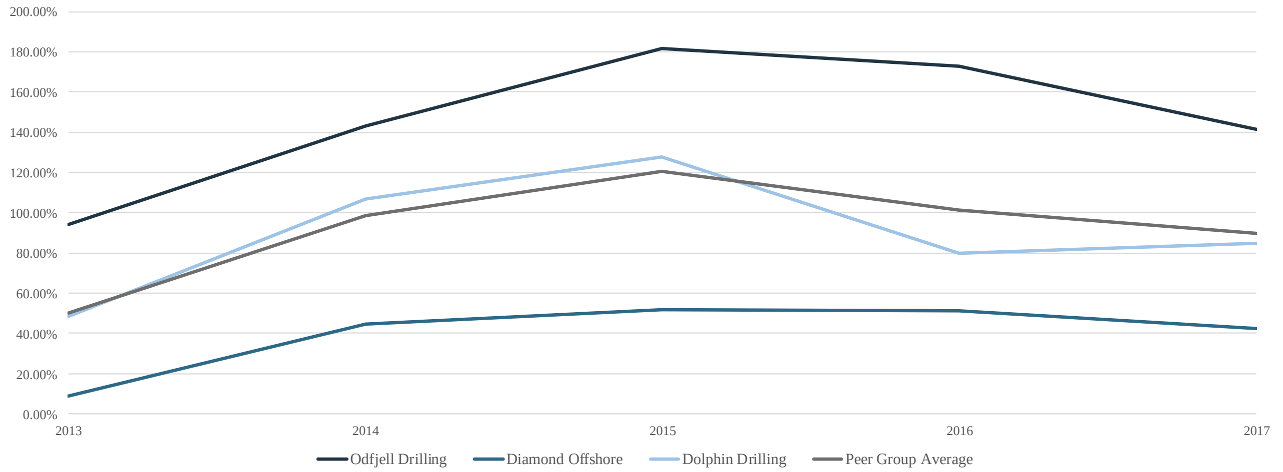

Figure 7.7 - Peer group financial leverage

Spread

The difference between a firms ROIC and its Net Borrowing Cost is by Petersen et al. (2012) called the spread. If a company has a positive spread, its ROE should increase by adding financial leverage. Inversely, a negative spread will decrease the ROE, as the cost of borrowing consumes the added benefit of leverage (Petersen, Plenborg, & Kinserdal, 2012). Odfjell Drilling had a positive spread until 2015 when it became negative as a result of a decrease in the ROIC. Since 2015, the firm's financial leverage has failed to add value, bearing in mind that the oil price collapse of 2014 made it harder to generate returns due to lower day rates, cf. section 5.1.4.5, Figure 5.9. That being said, Odfjell Drilling's spread is still higher than its peers for most of the observed period.

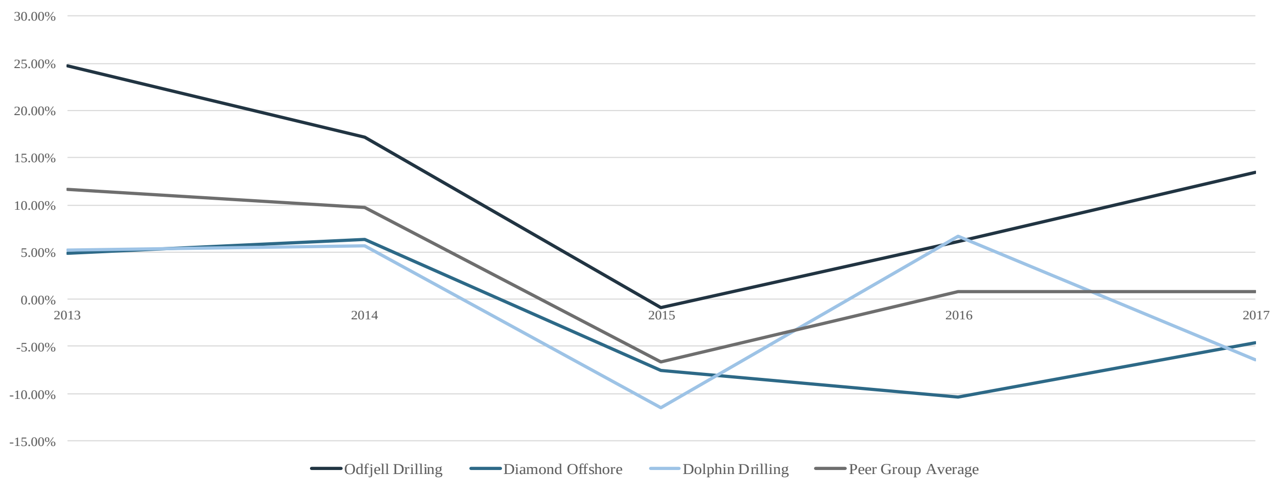

Figure 7.8 - Peer group spread

Concluding remarks – ROE

Odfjell Drilling has had a higher ROE in the observed period compared to its peers, which can be explained by its high financial leverage that is enhanced by a comparatively larger spread.

7.5.4 LIQUIDITY ANALYSIS

This section will analyze Odfjell Drilling's short- and long-term liquidity risk. Liquidity is a key element of a firm, as their going concern depends on remaining solvent and ability to invest in profitable projects (Petersen, Plenborg, & Kinserdal, 2012). This is an important reflection when applying our model in a valuation use case, as future earnings and their attached value is dependent on the firms going concern. The long-term analysis seeks to uncover Odfjell's financial health and ability to meet all future obligations. The short-term analysis looks at the firm's risk of default within a yearly perspective. Our primary tool for the analysis is financial ratios based on historical numbers from the same analytical reporting as earlier in this chapter. Again, Odfjell Drilling's results will be compared to its peers, as a comparison is necessary in order to interpret the results in a meaningful way.

7.5.4.1 SHORT TERM

The analysis starts with the short-term liquidity risk using both the liquidity cycle and the current ratio, in order to create a complete picture of the company's ability to meet its short-term liabilities.

Current Ratio

By looking at the relationship between current operating assets and current operating liabilities, the current ratio is a financial ratio that allows the analyst see to what degree the current assets can cover the current liabilities in the event of a default. A rule of thumb states that a current ratio of above 2, should indicate low short-term liquidity risk (Petersen, Plenborg, & Kinserdal, 2012). Nevertheless, the standard for what is considered normal differs from industry to industry, and the ratio must therefore be viewed in comparison to the peers.

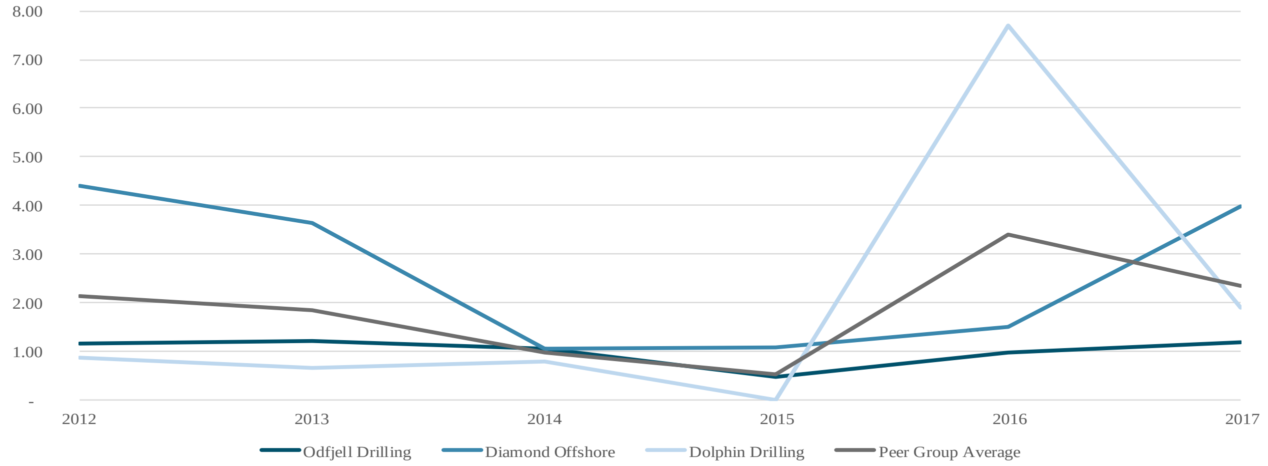

Figure 7.9 - Peer group current ratio

Figure 7.9 illustrates that Odfjell Drilling has a low current ratio compared to its peers. Not only is the ratio low in comparison to the rule of thumb, but more importantly it is lower than its peers – suggesting some liquidity risk in the short-term.

However, Petersen et al. (2012) argue that the usefulness of the current ratio is limited, as it does not consider continuous refinancing and because it is difficult to estimate when current ratios are at a satisfactory level. Therefore, we will analyze the short-term risk with a second ratio which they argue to be more suited.

Cash Flow from Operations to Short-term financial debt ratio

The CFO to short-term financial debt ratio serves the same purpose as the current ratio but differs in that it uses actual cash flows generated from operations, not potential cash flow resources (Petersen, Plenborg, & Kinserdal, 2012).

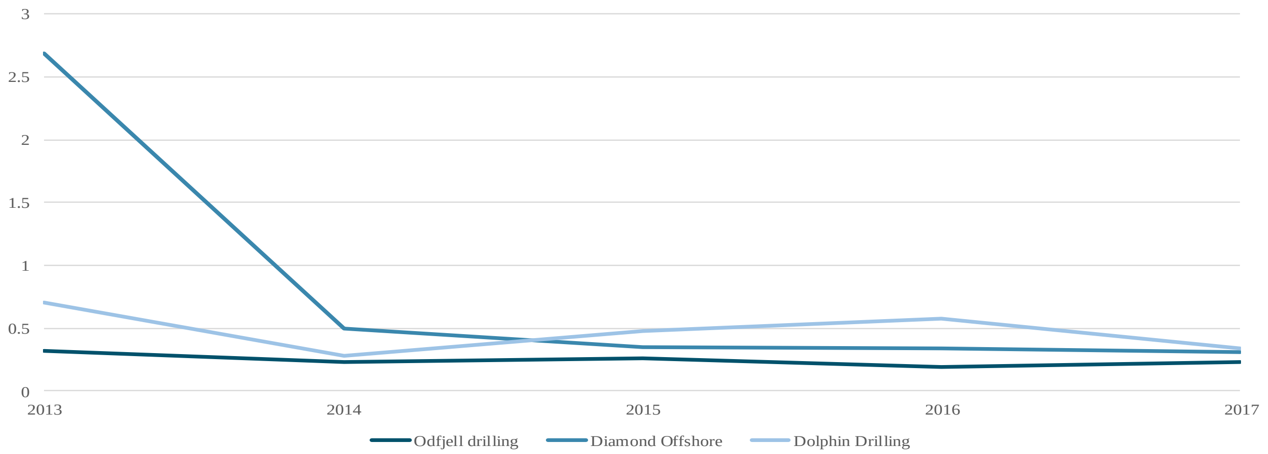

Figure 7.10 - Peer group cash flow from operations to short-term financial debt ratio

Still, with what Petersen et al. (2012) argue is a more precise measurement, Odfjell Drilling seems to be the worst performer among the peers. That being said, the three companies are at more stable levels in this analysis, where Odfjell does not deviate from the others to a substantial degree.

Conclusively, there is a potential for some short-term liquidity risk, but the CFO to short-term financial debt ratio illustrate that the companies show a similar trend arguing that this risk is not as substantial as it first appeared.

7.5.4.2 Long Term

The long-term liquidity risk analysis is focused on a firm's long-term financial stability and their ability to meet future liabilities. This analysis is done by analyzing their equity ratio, as well as scrutinizing their company policy.

Equity Ratio

In order to evaluate whether the firm is at any long-term liquidity risk, we begin by assessing their financial structure. Petersen et al. (2012) argue that the firm should have a good balance between equity and long-term and short-term financing that also corresponds to the nature of the assets and the risk of the operation. If this is not the case, a firm should at some point run into liquidity and going concern problems.

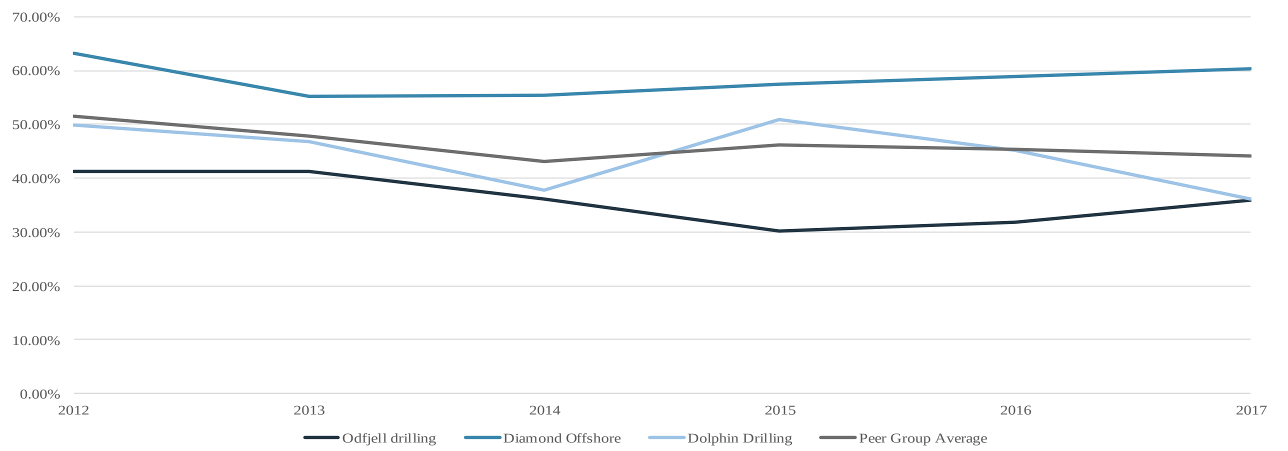

Figure 7.11 - Peer group equity ratio

Odfjell has the lowest equity ratio in the peer group, seen in Figure 7.11. However, it is not at an alarming level, considering the capital-intensive nature of the industry. Petersen et al. (2012) argue that firms in danger of default often experience a falling equity ratio in the years leading up to default, and even suggest that such a trend gives the equity ratio some predictive power. Odfjell Drilling, and indeed the entire peer group has had a reasonably stable equity ratio over the last years, suggesting a low long-term liquidity risk.

Company Policy

Another way of assessing a company's liquidity risk is by reading into the company's statements around the subject. While there is a definitive risk of bias in these statements, they are still important to evaluate. Odfjell communicates through their annual report that liquidity risk management is of high importance to the firm (Odfjell Drilling, 2018). Their overall goal within this area is to "maintain a balance between continuity of funding and flexibility through the use of credit facilities and to have sufficient cash and cash equivalents at any time to be able to finance its operations and investments in accordance with the Group's strategic plan" (Odfjell Drilling, 2018, p. 90). More specifically, The Odfjell Drilling Group has agreed to covenants of total liquidity of minimum 5% of the interest-bearing debt as well as maintaining an equity ratio of minimum 30% (Odfjell Drilling, 2018). These covenants are within the previously considered healthy levels, and therefore functions as a reassurement that their long-term liquidity risk is accounted for.

Concluding remarks – Liquidity risk

Overall, Odfjell Drilling's liquidity is deemed on par with the industry trends. The current ratio showed initial tendencies of short-term risk. However, a further analysis using the CFO to short-term financial debt ratio showed that the actual cash flows from the companies created little differences between the peers. On the long-term, the company has a sound and stable equity ratio that follows the trend of its peers.

8 WACC

In applying our model and forecasted scenarios, Odfjell Drilling's earnings at the different rig rates will be used as input in a discounted cash flow model (DCF). In this method, future cash flows to the firm are discounted to present value. This requires a discount rate, which Petersen et al. (2012) argues is best represented by a weighted average cost of capital (WACC). This is the weighted average cost of debt and cost of equity. WACC is often regarded as a good discount rate, as it considers the fact that future cash flows are shared between both debt- and equity holders (Petersen, Plenborg, & Kinserdal, 2012). Nevertheless, the methods for determining the input of the WACC might differ. This chapter seeks to answer the question:

- *What WACC is associated with an investment in Odfjell Drilling?*

After inquiries with equity analysts from research divisions in Norwegian banks covering maritime companies, especially in the shipping industry and the offshore drilling industry, we concluded that analysts usually take two approaches in determining the discount rate in their valuations of maritime companies.

Analysts often set a discount rate on what they describe as an educated judgment call. Here, the analysts estimate a WACC of around 8 – 9% for the shipping stocks and defend their method with general market knowledge and a critical view on the correctness of the assumptions and methodology of traditional WACC calculations. That being said, the same analysts said that they sometimes also calculate WACC with traditional methods and that it varies on a case-by-case basis.

The WACC is estimated using the traditional method outlined by Petersen et al. (2012).

$$WACC = \frac{MVE}{(NIBD + MVE)} * r_e + \frac{NIBD}{(NIBD + MVE)} * r_d * (1 - T_c)$$

Where,

- NIBD is the market value of net interest-bearing debt
- MVE is the market value of equity
- r_e is the cost of equity
- r_d is the cost of NIBD
- T_c is the tax rate

8.1 CAPITAL STRUCTURE

Petersen et al. (2012) argue that the capital structure must be based on market values as these values represent the true opportunity costs of investors and lenders. Odfjell Drilling is, as a consequence of being listed on the Oslo Stock Exchange traded in NOK, but report their financials in USD. We have therefore used the average yearly spot NOK/USD exchange rates for the years 2012 through 2018 to calculate Odfjell's share price in USD. The market value is then estimated by multiplying the average yearly share price by the number of outstanding shares at year-end. However, although arguing that the capital structure should be based on market values, Petersen et al. (2012) suggest that the net interest-bearing debt (NIBD) is applied to the equation, as market values on debt is difficult to estimate precisely. We calculate the NIBD by averaging the debt in year *t* and year *t*-1.

CAPITAL STRUCTURE (USD 000')	2013	2014	2015	2016	2017	2018	Average
Avg. Share price USD	6.62	4.62	0.80	0.93	2.90	4.06	**3.321**
Shares outstanding/1000	200,000	200,000	198,730	198,737	198,737	222,600	**203,134**
Avg. NIBD	1,104,989	1,329,401	1,518,765	1,343,596	1,166,443	1,007,171	**1,245,061**
MVE	1,323,000	924,185	159,366	184,071	576,025	904,437	**678,514**
NIBD/MVE	0.84	1.44	9.53	7.30	2.02	1.11	
NIBD+MVE	2,427,989	2,253,586	1,678,130	1,527,667	1,742,468	1,911,608	**1,923,574**
MVE/(NIBD+MVE)	0.54	0.41	0.09	0.12	0.33	0.47	**0.33**
NIBD/(NIBD+MVE)	0.46	0.59	0.91	0.88	0.67	0.53	**0.67**

Figure 8.1 - Odfjell Drilling capital structure

8.2 SYSTEMATIC RISK ON EQUITY (LEVERED BETA (β_e))

When the systematic risk of an asset increases, the owners required rate of return increases in order to compensate for the riskier investments (Petersen, Plenborg, & Kinserdal, 2012). In order to capture this systematic risk, an estimation of Odfjell's historical beta is computed. Petersen et al. (2012) argue that it can be estimated using historical data, as all value-relevant information should be priced and reflected in the stock returns. A number of factors can affect the equity beta (β_e) of a company. Liquidity of a stock, time perspective and possible misrepresentations of the market are mentioned by Petersen et al. (2012) as important. Therefore, in a perfect world, estimations on beta should be done on every asset in the market. It is however argued that using returns from publicly listed companies should provide enough information to represent the market (Petersen, Plenborg, & Kinserdal, 2012). In choosing the market benchmark index, it would be immediately natural to use the Oslo Stock Exchange Benchmark Index (OSEBX), as Odfjell Drilling is listed in Oslo. However, the OSEBX is relatively small and exceedingly weighted by the maritime- and oil industries, while also containing stocks at risk of being non-liquid due to low trading volumes, potentially skewing the market image. By using the S&P 500, we believe that we get a more diversified alternative and we also avoid problems from potentially non-liquid stocks on the OSEBX. Still, we recognize the potential issues of currency differences and other cross-market factors.

In our regression, we use monthly data, which Koller et al. (2010) stress to be important, as it removes potential noise in more frequent data. We also adjust the raw beta as statistically, betas exhibit mean reverting properties. This is done with the same formula as Bloomberg terminals:

$$\beta_{adjsted} = 0.67 * \beta_{raw} + 0.33 * 1$$

SUMMARY OUTPUT - ODL on S&P500

Regression Statistics	
Multiple R	0.2670
R Square	0.0713
Adjusted R Square	0.0568
Standard Error	0.1496
Observations	66.0000

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95,0%*	*Upper 95,0%*
Intercept	-0.0109	0.0191	-0.5695	0.5710	-0.0489	0.0272	-0.0489	0.0272
X Variable 1	1.2882	0.5812	2.2166	0.0302	0.1272	2.4492	0.1272	2.4492

Raw beta	1.2882
Adjusted beta	1.1934

Figure 8.2 - Odfjell Drilling historic beta to S&P 500

8.3 RISK-FREE INTEREST RATE, r_f

The idea of a completely risk-free rate of return is an elusive concept in the context of the real world. However, some interest rates are usually considered to be close to risk-free. A normal assumption is that government treasury bills from socially and economically stable countries, often the United States, are close to risk-free. The interest rate of the annual 10-year US treasury bills is 2.91% (2018 average).

That being said, these interest rates are particularly low. The consultancy firm Duff & Phelps (Grabowski, Nunes, & Harrington, 2019) argues that the risk-free rate should therefore be normalized, and suggests utilizing a rate of 3.5%, which this paper adopts.

8.4 RETURN ON THE MARKET PORTFOLIO, r_m

In estimating the risk premium on the market portfolio, we apply an ex-ante approach. Here we attempt to infer the market portfolio's implicit risk premium from analyst consensus on earnings forecast (Petersen, Plenborg, & Kinserdal, 2012).

In a KPMG report (Groenendijk, Engelbrecht, & van BaardWijk, 2018) on the equity market risk premium, the company concludes that the market risk premium should be around 5.5%. Aswath Damodaran's (2019) NYU Stern web page reports an April 1, 2019 market risk premium of 5.08%. Finally, simultaneously with reporting the 3.5% risk-free rate (Grabowski, Nunes, & Harrington, 2019), Duff & Phelps updated their market risk premium in early 2019 to 5.5%. As they argue that the two rates should be used in conjunction, we move forward with a market risk premium of 5.5%.

8.5 COST OF DEBT, r_d

Petersen et al. (2012), argues that the cost of debt should reflect actuals or be calculated with the following formula:

$$r_d = \left(r_f + r_s\right) * (1 - t)$$

Where,

- r_f = the risk-free interest rate
- r_s = Credit spread (the risk premium on NIBL)
- t = Corporate tax rate

Unfortunately, the company does not have outstanding bonds and does not report on any current specific interest rates. Therefore, we adjust the formula by replacing the risk-free rate and the credit spread with a calculation of actual debt costs form the financial reporting. This is done with the following calculation:

$$\left(\frac{Net\ Financial\ Expenses, Before\ Tax}{Net\ Interest\ Bearing\ Debt}\right) * (1 - t)$$

Because Odfjell Drilling is incorporated in Bermuda, the corporation's marginal tax rate is 0%. However, the company still incurs tax expenses, as a result of being an international company. Therefore, the average of the effective tax rate in the reported period is used as a proxy.

This methodology equals a cost of debt of $\approx 4.8\%$.

Professor Aswath Damodaran (2019) calculates, on the same tax basis, an Oil and Gas (Production and Exploration) industry after-tax cost of debt of 4.22%. He argues that the industry cost of debt is a good measure for gauging whether your calculations are within reason. As the industry description also includes production companies, we believe higher cost of debt must be applied.

Interestingly, in an investor presentation from April 19, 2019 Odfjell Drilling reports on a potential acquisition of the EX. Stena Midmax drilling rid, and its intended financing structure (Odfjell Drilling, 2018b). Here, the Company reports that they have received term sheets subject to final agreements, from leading Nordic banks for a term loan with an interest of LIBOR + 375/350 bps. With a USD LIBOR of around 2.72% in writing, this constitutes an interest rate of 6.47%. As this represent current demands from debtors, we consider this to be the best sign of the cost of debt possible and therefore choose to continue using this as our cost of debt.

8.6 COST OF EQUITY, r_e

In order to estimate the cost of equity, the capital asset pricing model is utilized, which is widely used by the industry. The CAPM formula is as follows:

$$r_e = r_f + \beta_e * (r_m - r_f)$$

Where

- r_f is the risk-free interest rate
- β_e is the systematic risk on equity
- r_m is the return on the market portfolio

Estimation of Owners' Required Rate of Return	
Risk-free interest rate	3.50%
Systematic risk on equity (β_e)	1.1934
Return on the market portfolio	9.00%
Cost of equity, r_e	10.06%

Figure 8.3 - Odfjell Drilling estimation of owners' required rate of return

8.7 CONCLUSION, WACC

As initially stated, the WACC is used as a discount rate for future cash flows from the firm. This chapter has accounted for the different elements of the WACC, and in Figure 8.4, the final calculation is displayed.

ESTIMATION OF WACC	
NIBD/(MVE+NIBD)	0.67
MVE/(MVE+NIBD)	0.33
R_e	10.06%
R_d	6.47%
Average effective tax rate	11.75%
WACC, before tax	8.8804%
WACC, after tax	**8.6303%**

Figure 8.4 - Odfjell Drilling estimation of weighted average cost of capital

Going forward, the paper uses an after-tax WACC of 8.63% as the discount rate. This WACC lies around what the analysts said in regards to shipping companies, making the case for a reasonable calculation.

9 FORECASTING ODFJELL DRILLING EARNINGS

The valuation scenarios build on the forecasted scenarios from section 6.5.3 and we do this in order to exemplify how different potential economic environments will affect the value of an actual rig company when holding other variables constant. The modeling and forecasting of the rig rates are therefore being utilized in a practical use case that allows us to compare the theoretical findings of this paper with the corresponding valuation outcomes, to further test the theories and results we have gathered. This chapter seeks to answer the following question:

- How will the market outlook affect the future free cash flows of Odfjell Drilling?

A valuation allows us to compare our forecasting scenarios with current market expectations as well as analysts' market predictions. This provides indirect insights to how the market and analysts value the current rig market as we can see their estimates in relation to how our forecast scenarios estimate the share price.

Odfjell Drilling also has a smaller fleet consisting mostly of 6th generation harsh environment semisubmersibles in a geographical area where this is considered an optimal fleet. Understanding how the forecast scenarios affect the fair value estimates of the company allows us to gauge whether the market believes that the company should be priced with a premium.

Based on the theories outlined in the Shipping Market Model and Skjerpen et al.'s (2018) framework for modelling and forecasting of rig rates, as well as our company analysis, we formulate the following hypotheses:

Hypothesis 3.1: Odfjell Drilling's share value moves in direct relation with the rig rates.

Hypothesis 3.2: Investors and analysts price Odfjell Drilling with a premium.

9.1 ASSUMPTIONS

In order to estimate different market values of Odfjell Drilling, we must create a pro forma statements of the free cash flows to the firm based on the forecast scenarios on rig rates and utilization, presented in section 9.3. These forecasted future cash flows form the basis for the fundamental valuation using the discounted cash flow model. The forecast follows Petersen et al.'s (2012) framework.

As this paper has shown, the rig rates are cyclical. This complicates a forecasting process and makes accurate predictions tougher. Our rig rate forecast scenarios follow Skjerpen et al. (2018) argument for a forecast period of five years. In our pro forma statements, we therefore choose not to extend the forecast period beyond this period, as this exercise seeks to exemplify the effects of the scenarios.

Following the forecasting period, a terminal period should reflect a steady state environment and assumes all inputs to remain constant. In the terminal state, we need to set a growth rate of the firm (Petersen, Plenborg, & Kinserdal, 2012). Firstly, in setting the growth rate, Damodaran (2019) stresses that it cannot exceed the growth rate of the overall economy. According to the IMF (2019), the world GDP in 2018 is expected to grow about 3.3% in 2019. This is much caused by a strong growth in the developing and emerging markets, as well as growth rates in advanced economics above being above historical averages. As the terminal value represent perpetuity, we consider a growth of advanced economies, as macroeconomic theory suggests that economic growth slows down as they advance. This paper therefore uses a terminal growth rate of 2.5%, which is slightly above the historic mean of 2.433% of advanced economies from 1980 to 2018 (IMF, 2019).

9.2 Cash Flows

In order to test the different forecasted scenarios of potential future rig rates, we must calculate different free cash flows to the firm (FCFF); varying the two inputs, day rate and utilization. The calculations and further assumptions required for the FCFF are presented below, and the cash flows are presented in the discounted cash flow model in Figure 9.1 for the base case. The calculations for the other scenarios are found in Appendix 13, Appendix 14, Appendix 15, and Appendix 16.

9.2.1 Operating Revenue

When calculating operating revenue, we return to Martin Stopford’s (2009) theory. He proposes that the operating revenue of shipping companies should be calculated with the following formula:

$$\begin{aligned}&\boldsymbol{Operating\ revenue}\\&\quad = \boldsymbol{Utlilization * Time\ Charter\ Equivalent * Available\ Days * Fleet\ Size}\\&\quad + \boldsymbol{Voyage\ Expenses * Fleet\ Size}.\end{aligned}$$

As with the Shipping Market Model, we convert this formula to one better suited for the offshore drilling industry.

$$\begin{aligned}&\boldsymbol{Operating\ Revenue}\\&\quad = \boldsymbol{Utilization * Day\ Rate * Available\ Days * Fleet\ Size}\\&\quad + \boldsymbol{Drillng\ \ and\ Other\ Operating\ expenses * Fleet\ size}\end{aligned}$$

Utilization of Odfjell's fleet

To predict the future utilization of Odfjell's fleet, we look at its previous contracts including those reported from the joint ventures where Odfjell had an ownership stake in the unit. Between 2014 and 2018, the total fleet's utilization was just over 80%. However, when excluding rigs from joint ventures the average utilization exceeded 90%. Since Odfjell does not engage in joint ventures on rigs in the forecast period, and their fleet is 100% owned by the company, we apply a utilization rate closer to that of their historic fully owned rigs. That being said, we expect the utilization for 2020 to be 100% as all rigs are on contract. For 2021 and 2022 we expect a utilization similar to the historic average. Furthermore, subsequently after selling Deepsea Bergen, we expect the utilization to increase to 100%, before staying at a constant 85% in the terminal period. This effectively means that on average, there is one rig not on contract for approximately 0.5 years per year.

Fleet Size

Odfjell Drilling has a rig fleet consisting of 100% owned rigs, in addition to having been involved in joint ventures. Here, they have reported an ownership stake of a certain percentage of the rig. However, as of 2017, the company is no longer involved in any joint ventures concerning MODUs. We therefore only budget on their fully owned rig fleet. Here, keeping in mind the delivery of the new 6th generation harsh environment semisubmersible, Deepsea Nordkapp in January 2019. The rig Deepsea Bergen is a 3rd generation semisubmersible built in 1983. It is currently on contract; however, we have chosen to expect it to go off the marketed supply after its contract. This is based on the analysis from section 5.1.5.3, where it is stressed that newer rigs are more likely to gain contracts in the coming years.

Drilling and other expenses

Operating and other expenses consist of Personnel and other expenses directly linked to drilling operations. In the budget period we therefore break down the operating expenses for each year to a per rig basis. The forecast is then done at an average of this historical data.

Share of profit from joint ventures

As mentioned in the fleet size paragraph, Odfjell previously reported income from operational joint ventures. These JVs were however, discontinued as of 2017. The budgeting therefore sets this value to zero.

Depreciation, amortization and taxes

As mentioned, Odfjell Drilling is incorporated in Bermuda, and as a result they do not follow conventional taxation laws. Odfjell has reported income tax expenses throughout their reported period, which have fluctuated significantly. As a result, we choose to forecast income tax based on the average level of the observed period, which is 11.75%.

Depreciation varies across the assets, and Odfjell Drilling does not report on any specific rate. However, they state that the assets are depreciated linearly in periods ranging from 5-37.5 years. Between 2012 and 2018, Odfjell drilling has reported an average depreciation rate of around 10% on its depreciable property. We therefore set a fixed depreciation rate of 10% throughout the forecast period.

9.2.2 INVESTED CAPITAL AND EQUITY

Net working capital

Net Working Capital should reflect the difference between a company's current assets and current liabilities. Petersen et al. (2012) suggest that the net working capital in the budget period is estimated based on the historic net working capital as a percentage of revenue. Odfjell had an average NWC of approximately 4.3% of revenue between 2012 and 2018. We therefor estimate the net working capital to be 4.3% of the future revenue.

Tangible and intangible assets

This item is forecasted irrespective of the company revenue, but rather based on the book values of assets and their expected development over time. In order to capture the effect of a potential sale or purchase of a rig, we separate the asset value of the total fleet and other assets. We assume an average rig value of approximately $464 million, derived from the last two years' fleet value divided by the number of rigs. This rig value is supported by Bassoe Analytics (2019b; 2019c) that estimates a rig values between $380 million and $520 million.

We expect Deepsea Bergen to be discontinued from service in 2023, effectively reducing Odfjell's fleet size from five to four drilling units. There has been no indication from the company regarding a potential expansion of their fleet after the delivery of Deepsea Nordkapp. Therefore, we keep the terminal fleet size at four units. However, as we have mentioned earlier, Deepsea Bergen is a 3rd generation rig and its value has deteriorated throughout its lifespan. As a result, if it is taken off the market in 2023, as we assume, Odfjell's rig assets will not decrease by one-fifth. Deepsea Bergen's asset value is according to Bassoe Analytics (2019a) approximately $50 million. We will therefore reduce Odfjell's fleet value by $50 million, not $460 million which would have been the case should we have assumed an equal value between the rigs. Deepsea Bergen's value is added to the revenue for 2023 as a scrapping income.

Dividends

In their annual report Odfjell Drilling (2018) reports on a long-term goal of dividend payouts of around 30-40% of net income. That being said, throughout the reported period, Odfjell Drilling has communicated this goal, yet only paid an extraordinary dividend in 2014. As a result, we will not forecast any dividend payouts until the terminal period, where it is set to 30% of the net income.

Earnings from non-MODU operations

As we saw from the company analysis, Odfjell Drilling is involved in other operations not related to the drilling activities of the fleet. These activities are considered irrelevant for showcasing the forecast scenarios of rig rates, but is a vital part of the company value and must therefore be included, The non-MODU NOPAT is therefore added to the pro forma cash flows with the historical average of $15.5 million for each period.

9.3 Firm Value

USD thousands	2019E	2020E	2021E	2022E	2023E	TERMINAL
Operating revenue	**1,117,365**	**1,153,094**	**1,103,037**	**1,098,207**	**963,624**	**864,686**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	264	257	255	253	251	256
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	433,959	469,688	419,630	414,801	416,899	317,961
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	166,849	202,578	152,520	147,691	154,788	55,851
Tax	(19,607)	(23,806)	(17,924)	(17,356)	(18,190)	(6,563)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**162,741**	**194,271**	**150,097**	**145,835**	**152,098**	**64,788**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	48,047	49,583	47,431	47,223	41,436	37,182
ΔNWC	54,016	1,536	(2,152)	(208)	(5,787)	(4,254)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**611,514**	**195,808**	**147,944**	**145,627**	**96,311**	**60,533**

	2019E	2020E	2021E	2022E	2023E	TERMINAL
FCFF	611,514	195,808	147,944	145,627	96,311	60,533
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	562,931	165,931	115,410	104,578	63,668	
Terminal value						987,446
Growth rate	0.025					
PV forecast period	1,012,519					
PV terminal period	652,767					
EV	1,665,286					
NIBD	929,203					
Market value of equity	736,083					
Shares outstanding	222,600					
Share price USD	3.307					
USD/NOK 30 April, 2019	8.618					
Share price NOK	28.50					
Share price NOK, April 30, 2019	**29.30**					

Figure 9.1 - Discounted cash flow model for Odfjell Drilling with base case rig rates forecast

Scenario	Share Price / NOK
Base case	29.30
Scenario 1	60.97
Scenario 2	34.42
Scenario 3	68.23
Scenario 4	26.67

Figure 9.2 - Summary of implied stock price with rig rates from scenario 1, 2, 3, and 4

Figure 9.2 summarizes the different scenarios implied stock price. The findings show that the base case fair value assessment of the company lies around 29 NOK per share.

The FCFF of Odfjell Drilling moves in line with the forecasted rig rate scenarios. This was made evident, as the oil prices increase in scenario 1 gave the stock price a substantial jump. The stock price also rose as the fleet utilization grew. Extra noteworthy is scenario 3, which showed that when there is a growth in utilization as well as in the oil prices, the effect from the utilization growth on stock value increases more than with growth in just the utilization. This is in line with the theories presented section 5.1.5.2 and 5.3, where we discussed the possibilities of the bargaining power relationship shifting as the industry tightens.

The fourth scenario that simulated a large reservoir discovery in the NW European, and will cause the share price of Odfjell Drilling to fall. The fall is again arguing towards the market power relationship between the drilling companies and the E&P players. The previously discussed effect of less interest in sporadic drilling activity after a large field discovery might cause the demand to lower and therefore move bargaining power towards the E&P companies, allowing them a larger share of the joint value.

As the share price estimations are seen to move in parallel to the rig rates of the forecast scenarios, we conclude that hypothesis 3.1 appear to hold and the rig rate model and subsequent forecasts might therefore be viewed as a functioning tool in the valuation process of a drilling company.

The share price of Odfjell Drilling on April 30, 2019 was 29.86 NOK per share. The market consensus from investment bank stock reports from April at the latest, have an average target price of 44.50 NOK per share. Compared to the base case estimation presented above, the base case value and the market value are similar. The analyst consensus, however, is well above this price. According to our model, this price difference communicates analyst optimism with regards to rig rates, where our findings should indicate that these analysts are predicting a rise in oil prices, utilization or both. Another explanation could be that analysts calculate Odfjell Drilling's share price with a premium to the market.

Investment Bank	Lead Analyst	Investment Recommendation	Date	Target Price	Currency
Pareto Securities	Bard Rosef / Christopher Mo Dege	Buy	13-02-2019	48.00	NOK
DNB Markets	Martin Huseby Karlsen	Buy	22-02-2019	43.00	NOK
Arctic Securities	Stian Malterudbakken	Buy	12-04-2019	45.00	NOK
Morgan Stanley Research	Lillian Starke	Overweight	21-02-2019	42.00	NOK
Min				42.00	NOK
Max				48.00	NOK
Average				44.50	NOK

Figure 9.3 - Analyst consensus of the share price of Odfjell Drilling

Since our base case share price for Odfjell Drilling is based on the average forecasted rig rate for NW Europe, it may not represent the true fair value of the company. We argued in section 5.1.5.37.4.2.2 that newer and higher specification rigs are able to obtain a premium to the average. Later, in section 7.4.2.2, we suggested that Odfjell may have this potential. Therefore, as a final scenario, we have calculated Odfjell's historic rig rate premium to the average for the region. Based on our data from RigLogix and Clarksons Platou, we have found that Odfjell was able to charge a 15.44% premium on average, compared to the market between 2000 and 2018. By assuming that the company is able to obtain the same premium in the forecast period, the model calculate a share price of 56.77 NOK per share. If this assumption holds true, our rig rate model and base case estimate predicts future rig rates for Odfjell Drilling, constituting a fair value of Odfjell, which is closer to the market consensus. This might provide evidence for hypothesis 3.2, yet the deduction is not seen as sufficiently rigid for fully confirming the hypothesis.

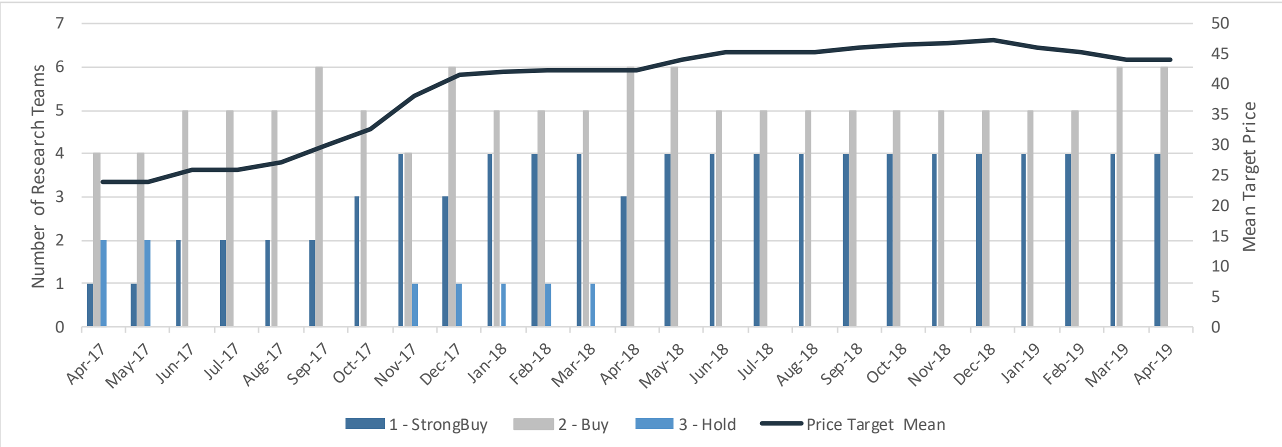

Figure 9.4 - Analyst recommendations for Odfjell Drilling

Our interpretation is also confirmed by the comments in the analysts estimates. Arctic Securities (Malterudbakken & Grindheim, 2019) states in their bull case that higher oil price and retirements of older harsh environment units should provide support to the fundamentals. This is further supported by DNB Markets (Karlsen, Masdal, & Knudsen, 2019) and Morgan Stanley (Starke, Pulleyn, & Rats, 2019), who also ads a potential catalyst in merger and acquisition activity, both in Odfjell internally as well as on a sector level. Market consolidation is also in alignment with the argument of bargaining power movements and tighter markets being able to move day rates.

9.4 Sensitivity Analysis

A valuation based on present values and a steady state is sensitive to changes in the discount rate and the terminal value. It is therefore argued by Petersen et al. (2012), that the DCF model should include a sensitivity analysis. The sensitivity analysis is therefore performed on the base case in order to see how much changes in the WACC and terminal growth rates have on the stock price assessment. Figure 9.5 illustrates how the fundamental value of the firm changes as the inputs vary. Within a reasonable span of both WACC and terminal growth, the stock price in the base case values fluctuate between 22.05 and 41.21 NOK per share.

A key take away from this sensitivity analysis is the importance of testing the results of the DCF. Here we uncover that the fundamental value of the firm can fluctuate with the assumptions of the model. As these inputs are held constant in the different scenarios, the comparison of the scenarios is still valid. That being said, this sensitivity is important to keep in mind when comparing the calculations to the market value of the stock and to consensus estimates.

		Terminal Growth								
		2.10%	**2.20%**	**2.30%**	**2.40%**	**2.50%**	**2.60%**	**2.70%**	**2.80%**	**2.90%**
WACC	**7.430%**	35.66	36.26	36.88	37.53	38.21	38.91	39.65	40.41	41.21
	7.730%	33.37	33.91	34.46	35.03	35.62	36.24	36.88	37.55	38.24
	8.030%	31.31	31.78	32.27	32.78	33.30	33.84	34.41	35.00	35.60
	8.330%	29.43	29.85	30.28	30.74	31.20	31.68	32.19	32.70	33.24
	8.630%	27.70	28.08	28.47	28.88	29.30	29.73	30.17	30.63	31.11
	8.930%	26.12	26.46	26.82	27.18	27.55	27.94	28.34	28.75	29.17
	9.230%	24.66	24.97	25.29	25.62	25.95	26.30	26.66	27.03	27.41
	9.530%	23.31	23.59	23.88	24.17	24.48	24.79	25.12	25.45	25.79
	9.830%	22.05	22.30	22.57	22.84	23.11	23.40	23.69	23.99	24.31

Figure 9.5 - Sensitivity analysis for changes in terminal growth and weighted average cost of capital

9.5 CONCLUSION

It is clear that the different scenarios all point towards day rates having a direct and positive relationship with the market value of a drilling company such as Odfjell Drilling. Using the oil futures as a base case for the day rate forecast created a slight downside in the stock, as the day rates fell over the budgeted period. However, when testing for rising oil prices the fundamental value of Odfjell Drilling rose sharply. Additionally, the case also affirmed the findings on utilization having a positive effect on stock prices and that this positive effect became stronger as the oil prices increased.

Comparing our scenarios to the market price and consensus of Odfjell Drilling's share value, allowed us to deduct that analysts have a positive outlook on Odfjell Drilling. This was based on an expectation of higher day rates, as well as analysts possibly calculating a premium on the modern and relevant fleet of the company.

Figure 9.6 below illustrates the different valuation scenarios, as well as the market consensus and the true share price of Odfjell Drilling as of April 30, 2019. From the illustration, it is evident that rates are in fact a highly important driver of a drilling company and that the value of the firm moves in relation to the rates' expected value. This perfectly illustrates the point of this case, namely to show that rig rate modelling has applicable use cases and that this specific case further illustrates the solidity of the model.

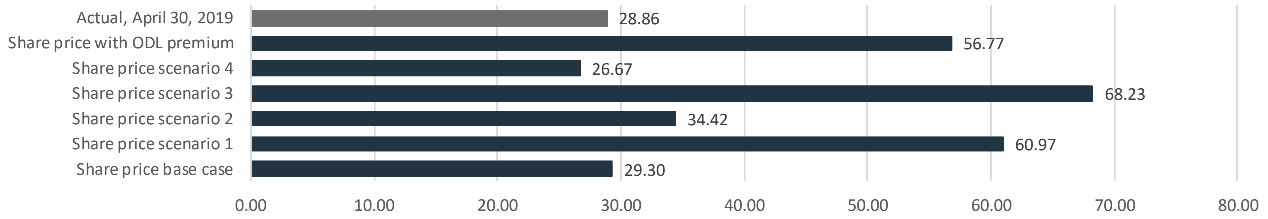

Figure 9.6 - Summary comparison of estimated share prices including premium

10 THESIS CONCLUSION

The following section will provide a summary of the research conducted in this paper, as well as its findings. The main objective of the paper has been to investigate how day rates on drilling contracts are formed, and what its future outlook is. Also, this paper has shown how the forecasted day rates could be applied in a valuation case of an offshore drilling company and found that the expected share prices of Odfjell Drilling mimic the expected day rates. Following the conclusion, we will provide propositions for areas of possible future research relating to day rate formation not covered by this paper. The problem statements of this thesis were as following:

- *What are the most important factors influencing the formation of drilling day rates and what is their effect on the future rates?*
- *How can the expected day rates be applied in valuation models for offshore drilling companies?*
- *What is the effect of different forecasted day rate scenarios, on the share price of Odfjell Drilling?*

First, in order to create a knowledge base of the industry, we provided a description of the industry and its specific assets and mechanisms. Then, in order to answer how day rates are formed, we uncovered the macro-economic demand- and supply factors affecting the day rate mechanism on the global market through an analysis using a modified Shipping Market Model originally created by Stopford (2009). Analysis through the framework uncovered the value drivers of the industry through the supply and demand of MODUs. We saw that the main driver of the demand in the industry is the E&P companies and their profit driven need for drilling services. Here, it is evident that the oil price and its effect on E&P's willingness to spend, is the key element. We saw that changes in the oil price induce a lagged change in the exploration spending and further leading to lagged change in the rig rates. The lagging factors were related to exploration and production companies' willingness to engage in new contracts after a substantial change in the price of oil. We suggest, with backing from the relevant literature, that this is partly due to E&P companies' uncertainty concerning whether the change is permanent or temporary.

The supply was shown to be mostly represented by the available fleet and therefore fixed in the short-term. Nevertheless, the rig fleet was able to adapt in the medium- to long-term. The analysis also showed that the purpose built nature of rigs created sub-markets, categorized by geo-specific needs. Furthermore, as the fleet size is fixed, utilization becomes a determinant for bargaining power in the industry. As the availability of rigs decrease, drilling operators quickly gain bargaining power and are able to obtain higher day rates. Similarly, when competition between rig operators increase, the E&P companies gain bargaining power, resulting in decreased day rates. The notion of a changing bargaining power relationship was supported by previous literature, and it was further confirmed through an economic bargaining theory deduction from Skjerpen et al. (2018).

Second, in modeling the future day rates in NW Europe, we applied our findings and the corresponding suggestions from Skjerpen et al. (2018) in an econometric model for determining the rig rate formation. The econometric analysis suggested that rig rates are formed in conjunction with the price of oil, the utilization, the remaining reserves, contract duration, and the contract lead time, petroleum workers' wage and the real interest rate. By running a multiple linear regression on a manipulated data set, we found that all variables have a positive effect of varying degree on the contract rig rates, with the exception of remaining reserves, and that most variables entered the model with statistical significance. We believe this could be explained by reservoirs discoveries, shifting E&P companies' investment focus from drilling broader exploration and appraisal wells to more specified reservoir development, thus decreasing the demand for drilling contractors. The negative effects remaining reserves has on rig rates was not in accordance with our hypothesis, nor existing literature. Yet, our model was improved with its inclusion, and able to accurately explain the observed rig rates, with a satisfactory within-sample fit.

Subsequently, to further test the model on day rate formation, we present four forecast scenarios in addition to the base case. The base case forecast presents a slight decrease in rig rates, ending at approximately $254,000/day in 2023. The decrease is caused by using the decreasing Brent crude futures as the expected oil price. In our scenarios we also test to what degree an increase in the price of Brent crude, the utilization and a combination of both, have on the rig rates. Finally, we also test a simulated discovery and its effect on rig rates. As was expected; all scenarios, except the simulated discovery, had a positive effect on the rig rates.

Third, to test the day rate model's logic as well as adding to the existing literature, we wanted to test its usefulness in a practical use case. We therefore tested the forecast scenarios in a company valuation. Here, we applied the forecasted rates to a DCF valuation model on Odfjell Drilling, as an internal and financial analysis of the firm ensured us that Odfjell is in fact day rate driven and hold no financial obstacles or going concern issues, skewing the valuation results. When applying the scenarios to the free cash flow input of the DCF, the scenarios produced outcomes in line with rig rate movements. Higher rig rates showed a positive effect on the company's value, and a higher capacity utilization in the market drove the price of Odfjell drilling, irrespective of the company's own utilization development. Based on the internal analysis, we tested if analysts add a premium to Odfjell Drilling because of their modern operations and optimal rig composition. When accounting for its historical premium, we saw that the value of Odfjell rose to a substantial overweight compared to current pricing. This higher price is in line with analyst consensus. Our analysis, could then propose that the analysts in fact see a premium in Odfjell Drilling, or expect an increase in oil prices, not reflected in the Brent futures, an increase in utilization, or a combination.

10.1 PROPOSITIONS FOR FURTHER RESEARCH

This paper has provided insights into an area of research with limited previous literature despite its crucial role in the petroleum industry. We have, based on existing literature, found the key determinants for oil rig day rates in NW Europe. Fundamental in our finding is a dataset with rig- and contract-specific information between 2000 and 2018. The limited period of data might fail to capture any long-term economic cycles. Therefore, extending its time-span may provide a more accurate model, and improve the fundament upon which the model and forecast is built.

We also argued for a crucial bargaining relationship between the drilling contractors and the E&P companies. Both the findings of this paper, as well as previous literature suggest a shift in this relationship when the available fleet capacity drops. It would therefore be interesting to further analyze the bargaining relationships of the firms, and how it materializes. Such research would need to include behavioral analysis as well as an interpretive methodology, with close access to primary sources such as decision makers from both E&P's and drilling companies. An analysis of this sort could provide crucial insight to a not yet explored part of the industry, as well as potentially uncovering new business segments ripe for exploitation.

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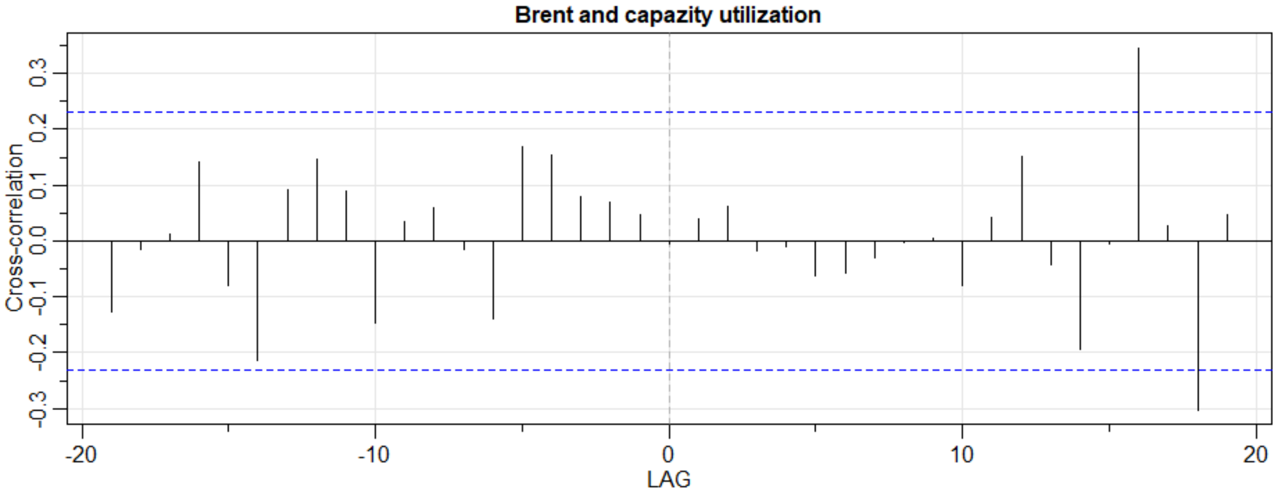
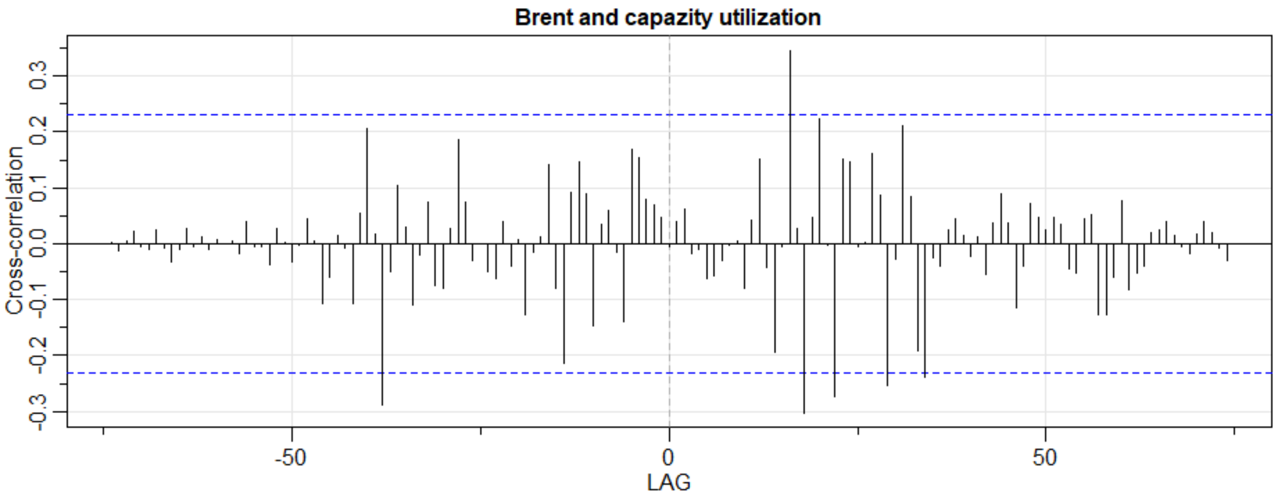
12 TABLE OF FIGURES

13 APPENDICES

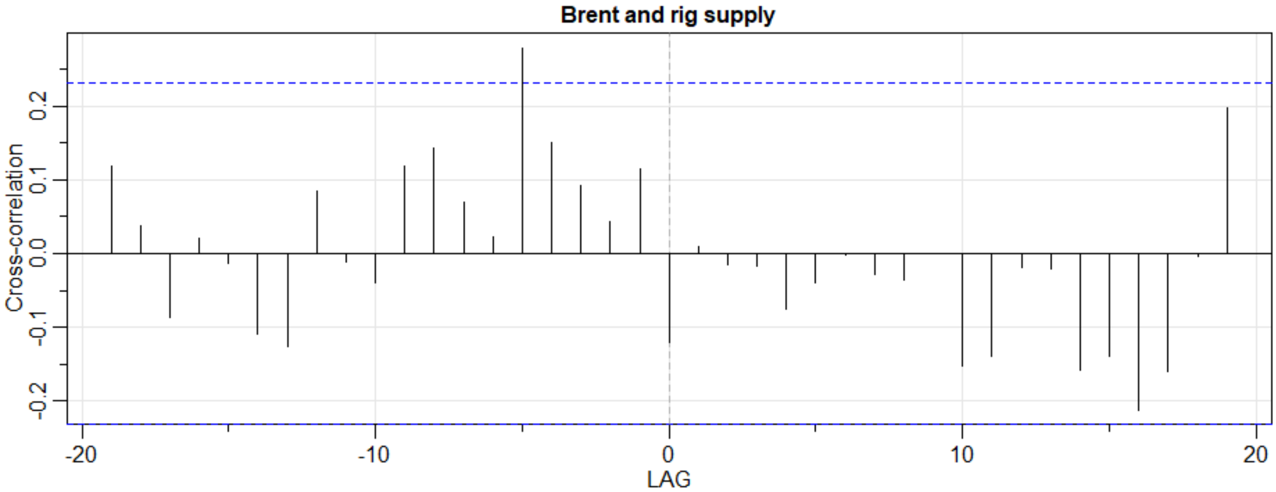
Appendix 1 - Cross-correlation Brent and capacity utilization





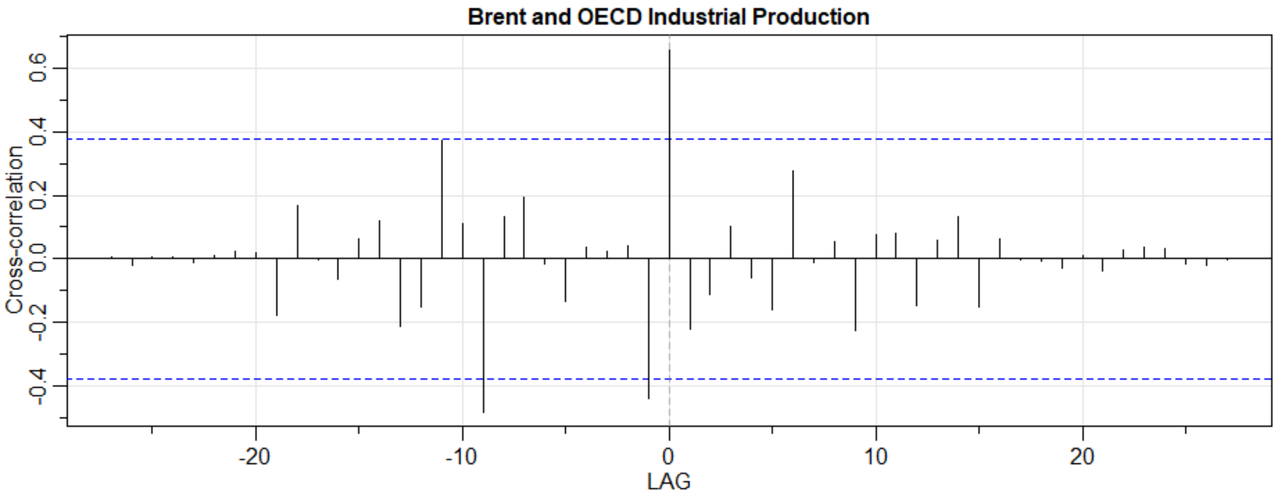
The cross-correlation plots indicates that the brent both lags and leads the capacity utilization. However, there is no significant correlation near *time = 0*, and the volatility in the potitive/negative correlations may indicate noise in the data. Based on the reviewed literature, and our understanding of the market, we believe the significant correlations in face is noise.

Appendix 2 - Cross-correlation Brent and rig supply (count)



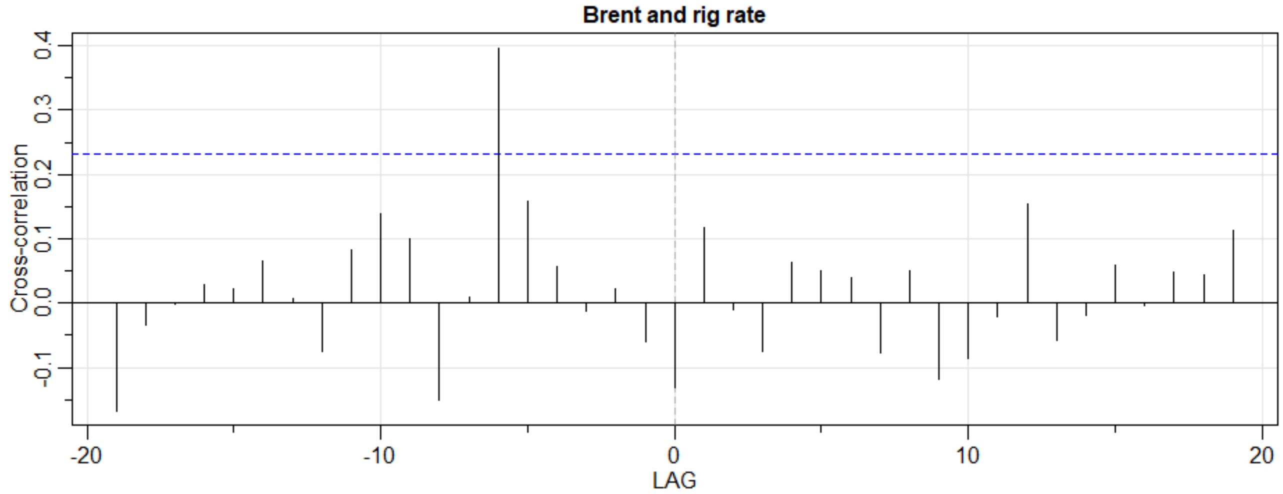
It appears that the rig supply lags the price of Brent with six periods, i.e., one and a half years.

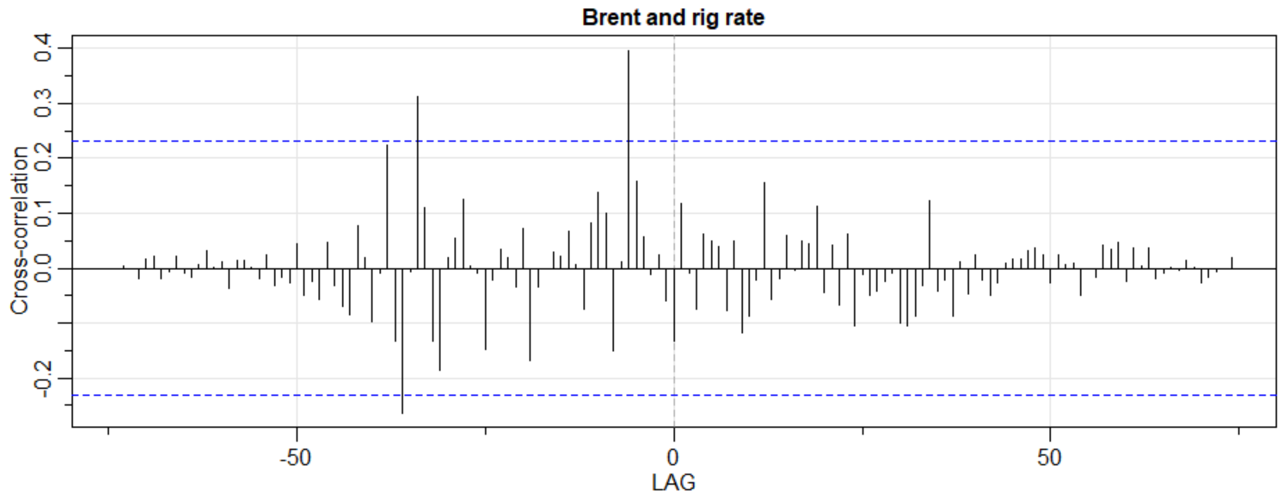
Appendix 3 - Cross-correlation Brent and OECD Industrial Production



The cross-correlation tests in R indicates that the correlation is strongest with zero lags.

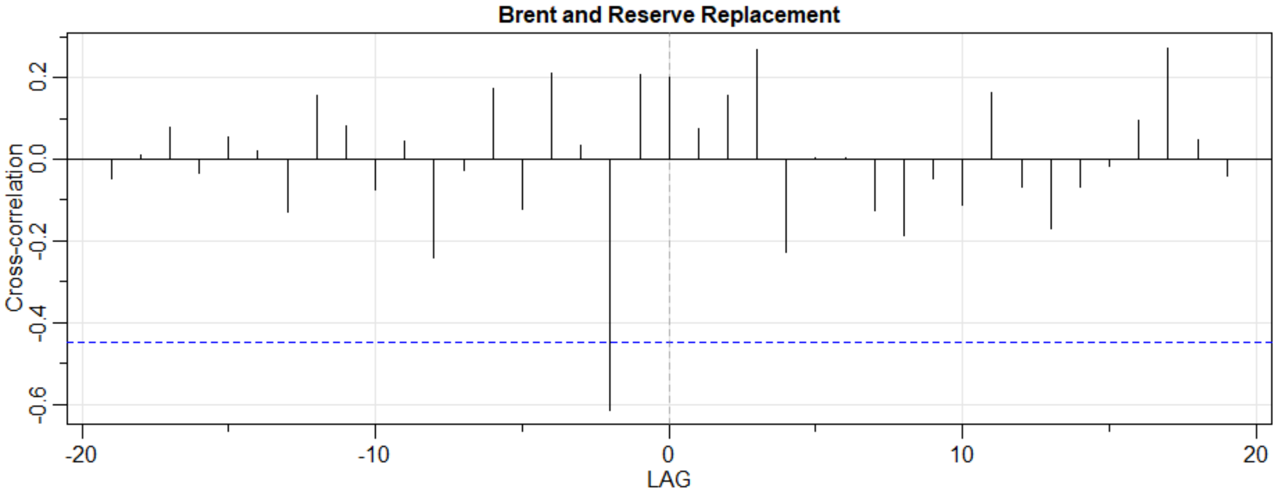
Appendix 4 - Cross-correlation Brent and rig rate





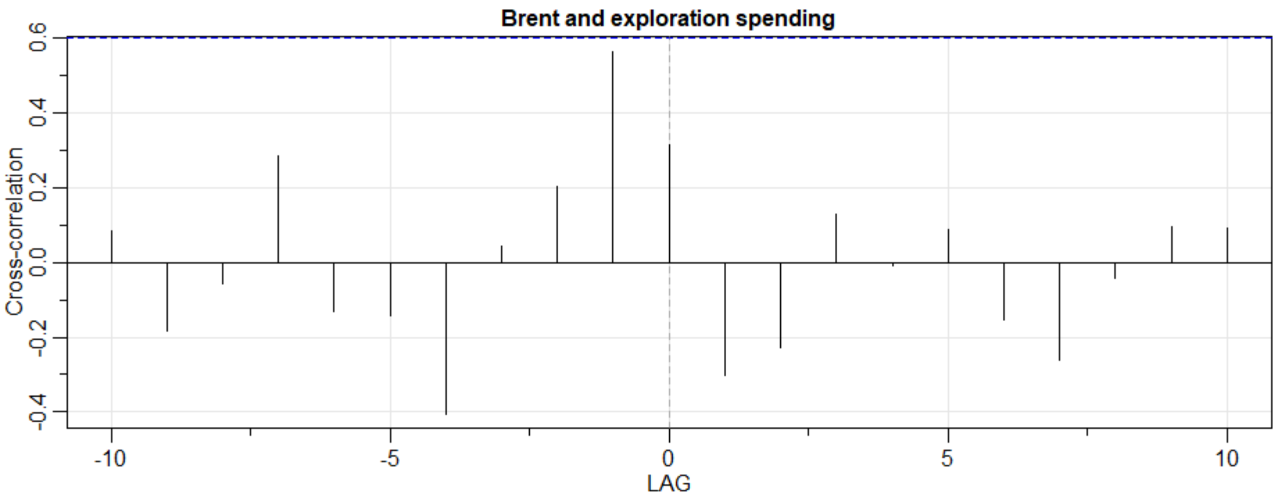
It is evident from the R output that the Brent leads the rig rates by six periods, corresponding to one and a half years. When extending the cross-correlation to maximum lag, it appears that the rig rates lag the Brent price both positively and negatively with 35 and 37 periods, respectively. Nonetheless, the six-period lag has the strongest statistical correlation and is closest to *time=0*. Thus, the spikes at *time = -34* and *time = -36* is considered noise.

Appendix 5 - Cross-correlation Brent and reserve replacement



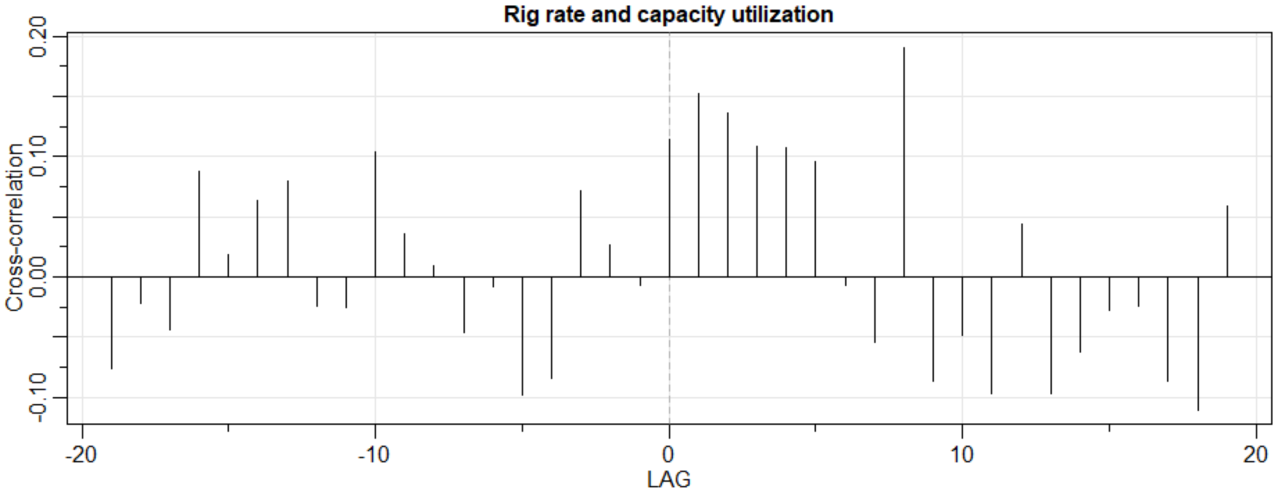
There is a statistically significant correlation between the price of Brent and the reserve replacement. The reserve replacement lags the price of Brent with two periods, e.g., two years.

Appendix 6 - Cross-correlation Brent and exploration spending



There is no statistical significance in the cross-correlation table above. However, there is a positive correlation with one lag from *time = 0*.

Appendix 7 - Cross-correlation rig rate and capacity utilization



The cross-correlation test shows no significant correlation between the rig rates and capacity utilization.

Appendix 8 - Rig rates in scenario 1, 2, 3, and 4

	Scenarios				
Period	***Base case***	***Scenario 1***	***Scenario 2***	***Scenario 3***	***Scenario 4***
1Q19	291,567	291,567	291,567	291,567	291,567
2Q19	253,599	255,874	252,813	255,079	253,675
3Q19	255,897	261,260	256,075	261,443	255,974
4Q19	257,342	266,550	258,513	267,777	257,419
1Q20	256,213	269,761	258,381	272,083	256,290
2Q20	256,636	275,099	259,826	278,598	256,713
3Q20	256,734	280,550	260,957	285,302	256,811
4Q20	256,749	286,349	262,016	292,437	256,826
1Q21	256,341	292,044	262,653	299,549	239,928
2Q21	255,793	297,860	263,154	306,870	239,415
3Q21	255,127	303,800	263,541	314,407	238,793
4Q21	254,365	309,866	263,833	322,168	238,079
1Q22	253,570	316,058	264,095	330,158	237,335
2Q22	252,782	322,383	264,372	338,386	236,598
3Q22	252,019	328,843	264,680	346,863	235,884
4Q22	251,498	335,713	265,250	355,885	235,396
1Q23	250,860	342,458	265,706	364,892	234,799
2Q23	250,323	349,348	266,279	374,174	234,296
3Q23	249,881	356,385	266,964	383,741	233,882
4Q23	253,853	369,883	272,399	400,435	237,600

Appendix 9 - Model input for base case, scenario 1, 2, 3, 4, and premium rig rates

Year		**2019**	**2020**	**2021**	**2022**	**2023**
Base case	Coefficient*					
Intercept	16.374					
σ^2	0.023					
sbrent	0.552	4.21	4.22	4.20	4.17	4.15
expUTIL	0.070	2.23	2.37	2.40	2.42	2.44
remres	-0.980	8.58	8.65	8.65	8.65	8.65
conlength	0.222	5.37	5.37	5.37	5.37	5.37
leadtime	0.029	4.34	4.34	4.34	4.34	4.34
wage	0.032	4.33	4.38	4.39	4.40	4.42
RIR	3.303	0.02	0.02	0.02	0.02	0.02
Implied rig rate		**$264,206**	**$256,660**	**$255,483**	**$252,543**	**$251,300**
Scenario 1						
Higher sbrent		4.23	4.33	4.43	4.53	4.63
Implied rig rate		**$268,472**	**$277,951**	**$300,906**	**$325,761**	**$354,476**
Scenario 2						
Higher expUTIL		2.24	2.42	2.50	2.58	2.66
Implied rig rate		**$264,346**	**$260,371**	**$263,377**	**$264,681**	**$267,906**
Scenario 3						
Higher sbrent		4.23	4.33	4.43	4.53	4.63
Higher expUTIL		2.24	2.42	2.50	2.58	2.66
Implied rig rate		**$268,615**	**$282,076**	**$310,714**	**$342,777**	**$380,682**
Scenario 4						
Higher remres		8.49	8.65	8.72	8.72	8.72
Implied rig rate		**$289,430**	**$256,660**	**$239,054**	**$236,303**	**$235,140**
Share price with ODL premium						
Base case rig rate		264,206	256,660	255,483	252,543	251,300
Odfjell premium		15.44%	15.44%	15.44%	15.44%	15.44%
Implied rig rate		**$305,000**	**$296,288**	**$294,929**	**$291,535**	**$290,101**

** The coefficient of UTIL in represented by the coefficient of sbrent:expUTIL*

Appendix 10 - World primary energy demand by region

World primary energy demand by region	Levels *mboe/d*				Growth *% p.a.*	Share of demand *%*			
	2015	2020	2030	2040	2015-2040	2015	2020	2030	2040
OECD America	56.0	57.5	58.0	57.6	0.1	20.3	19.3	17.1	15.5
OECD Europe	35.7	36.9	36.2	35.3	0.0	12.9	12.4	10.7	9.5
OECD Asia Oceania	18.3	19.0	19.3	19.2	0.2	6.6	6.4	5.7	5.2
OECD	110.0	113.5	113.6	112.0	0.1	39.9	38.0	33.5	30.1
China	62.7	69.0	79.7	84.9	1.2	22.7	23.1	23.5	22.9
India	16.8	20.6	30.4	39.7	3.5	6.1	6.9	9.0	10.7
OPEC	19.8	21.5	26.9	31.3	1.9	7.2	7.2	7.9	8.4
Other DCs	44.5	50.3	62.8	75.7	2.1	16.1	16.9	18.5	20.4
DCs	143.8	161.5	199.9	231.7	1.9	52.1	54.2	58.9	62.4
Russia	13.9	14.3	15.6	16.5	0.7	5.0	4.8	4.6	4.4
Other Eurasia	8.3	9.0	10.3	11.4	1.3	3.0	3.0	3.0	3.1
Eurasia	22.2	23.3	25.9	27.8	0.9	8.0	7.8	7.6	7.5
Total	**276.0**	**298.2**	**339.4**	**371.6**	**1.2**	**100**	**100**	**100**	**100**

Appendix 11 - Odfjell Drilling analytical income statement

Analytical Income Statement - Odfjell Drilling *USD Thousansd*	2012	2013	2014	2015	2016	2017	2018
Operating Revenue	1,093,754	1,173,605	1,087,960	926,827	657,392	662,158	698,476
Of which is non-MODU	400,364	411,930	340,429	306,202	219,487	181,111	222,026
Other gains/losses	3,438	22,288	11,344	1	629	11,215	2,211
Total Revenue	**1,097,192**	**1,195,893**	**1,099,304**	**926,828**	**658,021**	**673,373**	**700,687**
	340,963	370,228	341,079	347,668	284,168	262,505	256,936
Shares of profit (loss) from joint venture	(13,399)	436	(80,488)	(269,186)	20	0	0
Personnel expenses	(486,182)	(547,039)	(501,188)	(381,736)	(232,561)	(260,815)	(303,669)
Other operating expenses	(266,609)	(256,338)	(245,693)	(197,423)	(140,663)	(138,838)	(137,871)
Share of profit/ (loss) from joint ventures	0	0	(1,790)	(28,405)	1,399	(1,485)	0
EBITDA	**671,965**	**763,180**	**611,224**	**397,746**	**570,384**	**534,740**	**516,083**
Depreciation, amortisation and impairment loss	(147,318)	(145,180)	(141,235)	(320,806)	(250,722)	(161,436)	(160,630)
EBIT	**524,647**	**618,000**	**469,989**	**76,940**	**319,662**	**373,304**	**355,453**
EBIT (NON MODU)	21,438	42,923	(33,151)	(261,609)	23,982	791	5,004
Income tax (expense)/ income	(31,176)	(102,323)	(36,262)	15,741	(25,141)	(1,335)	(3,789)
Profit before tax	**493,471**	**515,677**	**433,727**	**92,681**	**294,521**	**371,969**	**351,664**
Effective tax rate	(0.2106)	(0.5985)	(0.4606)	(0.0470)	0.6521	(0.0364)	(0.1217)
NOPAT all segments	**414,156**	**248,136**	**253,496**	**73,327**	**528,124**	**359,720**	**312,203**
NOPAT non modu	**16,923**	**17,234**	**(17,881)**	**(249,323)**	**39,621**	**762**	**4,395**
Net financial expenses, before tax	(35,650)	(76,802)	(50,188)	(64,445)	(74,046)	(74,111)	(67,377)
Tax Shield	7,508	45,965	23,118	3,027	(48,288)	2,697	8,198
Net financial expenses, after tax	**(28,142)**	**(30,837)**	**(27,070)**	**(61,418)**	**(122,334)**	**(71,414)**	**(59,179)**
Net Earnings	**386,014**	**217,299**	**226,427**	**11,908**	**405,790**	**288,306**	**253,024**
NIBD	1,149,260	1,060,717	1,598,085	1,439,444	1,247,748	1,085,138	929,203
avg		1,104,989	1,329,401	1,518,765	1,343,596	1,166,443	1,007,171
Invested Capital	2,303,563	2,191,068	2,713,960	2,230,967	1,969,835	1,852,196	1,952,876
Invested Capital	2,303,562	2,191,066	2,713,959	2,230,968	1,969,833	1,852,194	1,952,876
avg		2,247,314	2,452,513	2,472,464	2,100,401	1,911,014	1,902,535
NBC	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	(0)	(0)	(0)	(0)	(0)	(0)	(0)
NIBD	1,149,260	1,060,717	1,598,085	1,439,444	1,247,748	1,085,138	929,203

Appendix 12 - Odfjell Drilling analytical balance sheet

Analytical Balance Sheet - Odfjell Drilling *USD Thousansd*		2012	2013	2014	2015	2016	2017	2018
Financial Assets								
Current								
Cash and cash equivalents		200,636	200,902	191,201	201,626	181,623	165,970	174,761
	Total	*200,636*	*200,902*	*191,201*	*201,626*	*181,623*	*165,970*	*174,761*
Non-Current								
Subordinated loan to related parties		52,069	79,273	0	0	0	0	0
Derivative financial instruments		0	3,221	688	386	235	318	599
Other non current assets		38,387	12,065	506	360	287	233	170
	Total	*90,456*	*94,559*	*1,194*	*746*	*522*	*551*	*769*
Total Financial Assets		**291,092**	**295,461**	**192,395**	**202,372**	**182,145**	**166,521**	**175,530**
Operational Assets								
Current								
Spare parts		2,960	3,666	3,428	2,818	1,782	1,680	1,574
Trade receivables		242,055	247,793	213,158	178,481	111,090	137,438	103,056
Other current receivables		35,289	44,420	27,543	45,195	12,097	13,775	36,971
	Total	*280,304*	*295,879*	*244,129*	*226,494*	*124,969*	*152,893*	*141,601*
Non-Current								
Goodwill		29,091	26,618	21,785	18,383	18,786	19,736	18,638
Deferred income tax asset		835	0	0	8,397	2,498	3,566	1,271
Software		0	6,109	15,211	15,417	14,223	13,119	11,173
Property, plant and equipment		1,871,897	1,773,615	2,312,214	2,131,364	1,912,754	1,782,393	1,928,132
Investments in joint ventures		331,144	338,480	306,763	14,419	8,217	0	0
Avaliable-for-sale financial assets		22	3	3	0	0	0	0
	Total	*2,232,989*	*2,144,825*	*2,655,976*	*2,187,980*	*1,956,478*	*1,818,814*	*1,959,214*
Total Operational Assets		**2,513,293**	**2,440,704**	**2,900,105**	**2,414,474**	**2,081,447**	**1,971,707**	**2,100,815**
Total Assets		**2,804,385**	**2,736,165**	**3,092,500**	**2,616,846**	**2,263,592**	**2,138,228**	**2,276,345**
Net investment			76,960	497,570	(154,848)	(102,532)	36,072	298,747
Net investmet as % of rec			0.06	0.45	(0.17)	(0.16)	0.05	0.43
Financial Liabilities								
Current								
(Current) Borrowings		211,270	180,178	233,764	718,360	204,058	157,472	782,980
	Total	*211,270*	*180,178*	*233,764*	*718,360*	*204,058*	*157,472*	*782,980*
Non-Curent								
(Non current) Borrowings		1,140,544	1,092,170	1,470,723	878,664	1,208,180	1,076,103	311,819
Derivative financial instruments		26,390	16,383	9,367	2,156	101	0	0
Post employment benefits		62,148	67,447	76,626	42,636	17,554	18,084	9,934
	Total	*1,229,082*	*1,176,000*	*1,556,716*	*923,456*	*1,225,835*	*1,094,187*	*321,753*
Total Financial Liabilities		**1,440,352**	**1,356,178**	**1,790,480**	**1,641,816**	**1,429,893**	**1,251,659**	**1,104,733**
Net financial liabilities		1,149,260	1,060,717	1,598,085	1,439,444	1,247,748	1,085,138	929,203
Operational Liabilities								
Current								
Trade payables		36,033	33,492	29,335	25,150	17,233	35,214	42,047
Current income tax		26,021	42,036	18,679	9,567	12,357	298	178
Social security and other taxes		32,746	31,851	25,929	16,697	13,337	16,163	18,047
Other current liabilities		110,324	123,896	107,850	130,433	67,163	62,505	87,298
	Total	*205,124*	*231,275*	*181,793*	*181,847*	*110,090*	*114,180*	*147,570*
Non-Current								
Deferred income tax liability		0	17,911	2,401	0	0	0	0
Other non current liabilities		4,606	450	1,951	1,660	1,522	5,331	369
	Total	*4,606*	*18,361*	*4,352*	*1,660*	*1,522*	*5,331*	*369*
Total Operational Liabilities		**209,730**	**249,636**	**186,145**	**183,507**	**111,612**	**119,511**	**147,939**
Total Liabilities		**1,650,082**	**1,605,814**	**1,976,625**	**1,825,323**	**1,541,505**	**1,371,170**	**1,252,672**
Total Equity		**1,154,302**	**1,130,349**	**1,115,874**	**791,524**	**722,085**	**767,056**	**1,023,673**
Total Liabilities and Equity		**2,804,384**	**2,736,163**	**3,092,499**	**2,616,847**	**2,263,590**	**2,138,226**	**2,276,345**

Appendix 13 - FCFF and DCF scenario 1

Scenario 1 *USD thousands*	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
Operating revenue	**1,124,372**	**1,192,057**	**1,177,644**	**1,218,468**	**1,114,260**	**925,867**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	268	278	301	326	354	306
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	440,965	508,651	494,237	535,062	567,535	379,142
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	173,855	241,540	227,127	267,952	305,425	117,032
Tax	(20,431)	(28,385)	(26,691)	(31,489)	(35,892)	(13,753)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**168,924**	**228,655**	**215,936**	**251,963**	**285,032**	**118,778**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	48,348	51,258	50,639	52,394	47,913	39,812
ΔNWC	54,317	2,910	(620)	1,755	(4,481)	(8,101)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**617,999**	**231,566**	**215,316**	**253,719**	**230,551**	**110,678**

	2019E	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
FCFF	617,999	231,566	215,316	253,719	230,551	110,678
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	568,901	196,233	167,967	182,200	152,410	
Terminal value						1,805,418
Growth rate	0.025					
PV forecast period	1,267,711					
PV terminal period	1,193,501					
EV	2,461,212					
NIBD	929,203					
Market value of equity	1,532,009					
Shares outstanding	222,600					
Share price USD	6.882					
USD/NOK 30 April, 2019	8.618					
Share price NOK	59.31					
Share price NOK, April 30, 2019	**60.97**					

Appendix 14 - FCFF and DCF scenario 2

Scenario 2						
USD thousands	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
Operating revenue	**1,117,595**	**1159884.641**	**1,116,002**	**1118145.419**	**987,868**	**874518.1455**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	264	260	263	265	268	264
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	434,189	476,478	432,596	434,739	441,143	327,793
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	167,079	209,368	165,486	167,629	179,033	65,683
Tax	(19,634)	(24,604)	(19,447)	(19,699)	(21,039)	(7,719)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**162,944**	**200,264**	**161,538**	**163,430**	**173,494**	**73,464**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	48,057	49,875	47,988	48,080	42,478	37,604
ΔNWC	54,026	1,818	(1,887)	92	(5,602)	(4,874)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**611,727**	**202082.4124**	**159,652**	**163521.9431**	**117,892**	**68590.03571**

	2019E	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
FCFF	611,727	202,082	159,652	163,522	117,892	68,590
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	563,127	171,248	124,543	117,428	77,934	
Terminal value						1,118,869
Growth rate	0.025					
PV forecast period	1,054,282					
PV terminal period	739,647					
EV	1,793,928					
NIBD	929,203					
Market value of equity	864,725					
Shares outstanding	222,600					
Share price USD	3.885					
USD/NOK 30 April, 2019	8.618					
Share price NOK	33.48					
Share price NOK, April 30, 2019	**34.42**					

Appendix 15 - FCFF and DCF scenario 3

Scenario 3 *USD thousands*	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
Operating revenue	**1,124,607**	**1199605.576**	**1,193,754**	**1246417.112**	**1,152,521**	**940088.3395**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	269	282	311	343	381	317
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	441,200	516,199	510,348	563,011	605,796	393,363
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	174,090	249,089	243,238	295,901	343,686	131,253
Tax	(20,458)	(29,272)	(28,584)	(34,773)	(40,389)	(15,424)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**169,132**	**235,317**	**230,153**	**276,627**	**318,797**	**131,329**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	48,358	51,583	51,331	53,596	49,558	40,424
ΔNWC	54,327	3,225	(252)	2,264	(4,038)	(9,135)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**618,216**	**238541.992**	**229,902**	**278891.9494**	**264,759**	**122194.1217**

	2019E	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
FCFF	618,216	238,542	229,902	278,892	264,759	122,194
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	569,101	202,145	179,345	200,277	175,024	
Terminal value						1,993,281
Growth rate	0.025					
PV forecast period	1,325,892					
PV terminal period	1,317,691					
EV	2,643,583					
NIBD	929,203					
Market value of equity	1,714,380					
Shares outstanding	222,600					
Share price USD	7.702					
USD/NOK 30 April, 2019	8.618					
Share price NOK	66.37					
Share price NOK, April 30, 2019	**68.23**					

Appendix 16 - FCFF and DCF scenario 4

Scenario 4 *USD thousands*	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
Operating revenue	**1,158,795**	**1,153,094**	**1,076,052**	**1,071,533**	**940,030**	**858,610**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	289	257	239	236	235	251
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	475,389	469,688	392,646	388,127	393,305	311,885
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	208,279	202,578	125,536	121,017	131,195	49,775
Tax	(24,476)	(23,806)	(14,753)	(14,221)	(15,418)	(5,849)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**199,302**	**194,271**	**126,283**	**122,296**	**131,277**	**59,425**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	49,828	49,583	46,270	46,076	40,421	36,920
ΔNWC	55,797	(245)	(3,313)	(194)	(5,655)	(3,501)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**649,857**	**194,026**	**122,970**	**122,101**	**75,623**	**55,924**

	2019E	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
FCFF	649,857	194,026	122,970	122,101	75,623	55,924
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	598,228	164,422	95,928	87,683	49,992	
Terminal value						912,260
Growth rate	0.025					
PV forecast period	996,253					
PV terminal period	603,065					
EV	1,599,317					
NIBD	929,203					
Market value of equity	670,114					
Shares outstanding	222,600					
Share price USD	3.010					
USD/NOK 30 April, 2019	8.618					
Share price NOK	25.94					
Share price NOK, April 30, 2019	**26.67**					

Appendix 17 - FCFF and DCF for Odfjell Drilling with premium rig rates

ODL premium day rates *USD thousands*	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
Operating revenue	**1,184,369**	**1,225,614**	**1,167,828**	**1,162,253**	**1,020,273**	**913,528**
Fleet utilization	90%	100%	90%	90%	100%	85%
Available days	365	366	365	365	365	365
Fleet size	5	5	5	5	4	4
Day rate	305	296	295	292	290	296
Drilling and other opex (per rig)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)	(136,681)
EBITDA	500,962	542,208	484,421	478,846	473,548	366,803
Depreciation /Amortization	267,110	267,110	267,110	267,110	262,110	262,110
EBIT	233,852	275,097	217,311	211,736	211,438	104,693
Tax	(27,481)	(32,328)	(25,538)	(24,882)	(24,847)	(12,303)
NOPAT (NON MODU)	15,500	15,500	15,500	15,500	15,500	15,500
NOPAT	**221,871**	**258,269**	**207,274**	**202,354**	**202,090**	**107,890**
Rig assets, per rig	463,816	463,816	463,816	463,816	463,816	463,816
Other assets	352,024	352,024	352,024	352,024	352,024	352,024
Intangible and Tangible Assets	2,671,102	2,671,102	2,671,102	2,671,102	2,621,102	2,621,102
NWC	50,928	52,701	50,217	49,977	43,872	39,282
ΔNWC	56,897	1,774	(2,485)	(240)	(6,105)	(4,590)
Net Investments	127,647	(267,110)	(267,110)	(267,110)	(312,110)	(262,110)
FCFF	**673,525**	**260,043**	**204,789**	**202,114**	**145,985**	**103,300**

	2019E	**2020E**	**2021E**	**2022E**	**2023E**	**TERMINAL**
FCFF	673,525	260,043	204,789	202,114	145,985	103,300
WACC	8.63%	8.63%	8.63%	8.63%	8.63%	8.63%
Discount factor	1.086	1.180	1.282	1.393	1.513	
PV FCFF	620,015	220,365	159,754	145,142	96,506	
Terminal value						1,685,072
Growth rate	0.025					
PV forecast period	1,241,782					
PV terminal period	1,113,944					
EV	2,355,727					
NIBD	929,203					
Market value of equity	1,426,524					
Shares outstanding	222,600					
Share price USD	6.408					
USD/NOK 30 April, 2019	8.618					
Share price NOK	55.23					
Share price NOK, April 30, 2019	**56.77**					

Appendix 18 - Dolphin Drilling analytical income statement

Analytical Income Statement - Dolphin Drilling

USD Thousansd	2012	2013	2014	2015	2016	2017	2018
Revenue	6,876,823	1,194,369	1,184,066	1,116,445	825,031	279,101	145,480
Total Revenue	**6,876,823**	**1,194,369**	**1,184,066**	**1,116,445**	**825,031**	**279,101**	**145,480**
Materials	(185,686)	(17,028)	(11,824)	(2,188)	(2,558)	(7,576)	(29,268)
Salaries and other personnel costs	(1,659,536)	(323,687)	(318,691)	(254,767)	(152,846)	(68,842)	(85,397)
Other operating expenses	(1,503,421)	(281,075)	(337,338)	(222,475)	(171,235)	(97,813)	(102,054)
EBITDA	**3,528,180**	**572,579**	**516,213**	**637,015**	**498,392**	**104,870**	**(71,239)**
Depreciation	(1,350,657)	(242,308)	(329,418)	(354,108)	(290,403)	(222,478)	(210,395)
Impairment	0	0	(42,702)	(607,940)	(230,782)	(75,000)	(191,089)
EBIT	**2,177,523**	**330,271**	**144,093**	**(325,033)**	**(22,793)**	**(192,608)**	**(472,723)**
Income tax (expense)/ income	(81,264)	(17,981)	(30,228)	(2,602)	(25,973)	(19,434)	1,242
Profit before tax	**2,096,259**	**312,290**	**113,865**	**(327,635)**	**(48,766)**	**(212,042)**	**(471,481)**
Effective tax rate	(0)	(0)	(0)	0	0	0	(0)
NOPAT	**2,084,456**	**311,601**	**114,777**	**(327,463)**	**(30,246)**	**(208,339)**	**(471,565)**
Net financial expenses, before tax	(276,152)	(12,191)	4,484	(22,993)	(56,642)	(45,341)	(34,121)
Tax Shield	11,803	689	(912)	(172)	(18,520)	(3,703)	84
Net financial expenses, after tax	**(264,349)**	**(11,502)**	**3,572**	**(23,165)**	**(75,162)**	**(49,044)**	**(34,037)**
Net Earnings	**1,820,107**	**300,099**	**118,349**	**(350,628)**	**(105,408)**	**(257,383)**	**(505,602)**
NIBD	3,886,645	696,087	1,398,271	1,231,573	679,812	502,938	684,063
avg		2,291,366	1,047,179	1,314,922	955,693	591,375	593,501
Invested Capital	11,782,814	2,133,001	2,706,200	2,197,101	1,533,055	1,096,247	752,672
Invested Capital	11,782,814	2,133,001	2,706,200	2,197,101	1,533,055	1,096,247	752,672
avg		6,957,908	2,419,601	2,451,651	1,865,078	1,314,651	924,460
NBC	(0)	(0)	0	(0)	(0)	(0)	(0)
NIBD	3,886,645	696,087	1,398,271	1,231,573	679,812	502,938	684,063

Appendix 19 - Dolphin Drilling analytical balance sheet

Analytical Balance Sheet - Dolphin Drilling

USD Thousansd		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Financial Assets								
Current								
Cash and cash equivalents		1,386,764	222,086	203,425	214,098	290,362	434,969	136,947
	Total	*1,386,764*	*222,086*	*203,425*	*214,098*	*290,362*	*434,969*	*136,947*
Non-Current								
Other non-current assets		1,310	26	205	197	673	357	10,973
	Total	*1,310*	*26*	*205*	*197*	*673*	*357*	*10,973*
Total Financial Assets		**1,388,074**	**222,112**	**203,630**	**214,295**	**291,035**	**435,326**	**147,920**
Operational Assets								
Current								
Consumable spare parts		430,965	102,953	115,165	120,030	113,126	103,056	62,466
Prepayments and tax refunds		188,878	31,684	31,085	207,712	13,642	13,928	32,240
Trade and other receivables		964,502	189,707	172,657	135,097	94,590	14,440	12,589
	Total	*1,584,345*	*324,344*	*318,907*	*462,839*	*221,358*	*131,424*	*107,295*
Non-Current								
Property, plant and equipment		12,684,546	2,476,237	2,901,586	1,862,393	1,360,951	1,073,397	689,823
Intangible assets		98,577	16,203	13,262	11,190	0	0	0
Deferred tax assets		56,365	26,970	31,237	22,712	16,686	1,284	162
	Total	*12,839,488*	*2,519,410*	*2,946,085*	*1,896,295*	*1,377,637*	*1,074,681*	*689,985*
Total Operational Assets		**14,423,833**	**2,843,754**	**3,264,992**	**2,359,134**	**1,598,995**	**1,206,105**	**797,280**
Total Assets		**15,811,907**	**3,065,866**	**3,468,622**	**2,573,429**	**1,890,030**	**1,641,431**	**945,200**
Financial Liabilities								
Current								
Interest bearing loans and borrowings (current)		730,312	131,200	95,455	325,658	0	190,909	748,444
Financial instruments		47,746	179	7,510	17,826	396	0	121
	Total	*778,058*	*131,379*	*102,965*	*343,484*	*396*	*190,909*	*748,565*
Non-Curent								
Interest bearing loans and borrowings		4,196,873	662,158	1,359,937	1,002,088	879,611	686,244	0
Employee benefits		263,221	121,276	133,899	97,463	88,919	60,263	83,418
Financial instruments		36,567	3,386	5,100	2,833	1,921	848	0
	Total	*4,496,661*	*786,820*	*1,498,936*	*1,102,384*	*970,451*	*747,355*	*83,418*
Total Financial Liabilities		**5,274,719**	**918,199**	**1,601,901**	**1,445,868**	**970,847**	**938,264**	**831,983**
Operational Liabilities								
Current								
Trade and other payables		206,274	43,564	58,346	31,825	16,683	10,081	16,119
Tax payable		17,648	7,578	15,219	6,597	13,486	8,422	590
Other accrued expenses and deferred revenue		2,417,097	659,611	485,227	123,611	35,771	91,355	27,899
	Total	*2,641,019*	*710,753*	*558,792*	*162,033*	*65,940*	*109,858*	*44,608*
Non-Current		0	0	0	0	0	0	0
	Total	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total Operational Liabilities		**2,641,019**	**710,753**	**558,792**	**162,033**	**65,940**	**109,858**	**44,608**
Total Liabilities		**7,915,738**	**1,628,952**	**2,160,693**	**1,607,901**	**1,036,787**	**1,048,122**	**876,591**
Total Equity		**7,896,169**	**1,436,914**	**1,307,929**	**965,528**	**853,243**	**593,309**	**68,609**
Total Liabilities and Equity		**15,811,907**	**3,065,866**	**3,468,622**	**2,573,429**	**1,890,030**	**1,641,431**	**945,200**

Appendix 20 - Diamond Offshore analytical income statement

Analytical Income Statement - Diamond Offshore

USD Thousansd	2012	2013	2014	2015	2016	2017	2018
Contract Drilling	2,936,066	2,843,584	2,737,126	2,360,184	1,525,214	1,451,219	1,059,973
Other gains/losses	50,442	76,837	77,545	59,209	75,128	34,527	23,242
Total Revenue	**2,986,508**	**2,920,421**	**2,814,671**	**2,419,393**	**1,600,342**	**1,485,746**	**1,083,215**
Contract drilling, excluding depreciation	1,537,224	1,572,525	1,523,623	1,227,864	772,173	801,964	722,834
Reimbursable expenses	48,778	74,967	76,091	58,050	58,058	33,744	22,917
General and administrative	64,640	64,788	81,832	66,462	63,560	74,505	85,351
Loss (gain) on disposition of assets	(80,844)	(4,070)	(5,382)	(2,290)	3,795	(10,500)	241
EBITDA	**1,416,710**	**1,212,211**	**1,138,507**	**1,069,307**	**702,756**	**586,033**	**251,872**
Depreciation	392,913	388,092	456,483	493,162	381,760	348,695	331,789
Impairment of assets	62,437	0	109,462	860,441	678,145	99,313	27,225
EBIT	**961,360**	**824,119**	**572,562**	**(284,296)**	**(357,149)**	**138,025**	**(107,142)**
Income tax (expense)/ income	(197,604)	(225,554)	(128,180)	107,063	95,796	39,786	46,353
Profit before tax	**763,756**	**598,565**	**444,382**	**(177,233)**	**(261,353)**	**177,811**	**(60,789)**
Effective tax rate	(0)	(0)	(0)	(0)	(0)	(2)	(0)
NOPAT	**754,441**	**584,034**	**430,108**	**(204,480)**	**(284,090)**	**(118,107)**	**(85,228)**
Bad debt recovery	(1,018)	22,513	0	0	(265)	0	0
Restructuring and separation costs	0	0	0	9,778	0	14,146	5,041
Tax on specials	219	(6,559)	0	(2,745)	54	(26,251)	(1,031)
Special Items	**(799)**	**15,954**	**0**	**7,033**	**(211)**	**(12,105)**	**4,010**
Net financial expenses, before tax	(44,297)	(27,366)	(57,371)	(87,274)	(111,415)	(145,319)	(114,442)
Tax Shield	9,534	7,972	14,274	24,502	22,791	269,667	23,408
Net financial expenses, after tax	**(34,763)**	**(19,394)**	**(43,097)**	**(62,772)**	**(88,624)**	**124,348**	**(91,034)**
Net Earnings	**720,477**	**548,686**	**387,011**	**(274,285)**	**(372,503)**	**18,346**	**(180,272)**
NIBD	10,476	397,079	1,994,832	2,135,821	1,928,816	1,596,188	1,520,000
avg		203,778	1,195,956	2,065,327	2,032,319	1,762,502	1,558,094
Invested Capital	4,586,870	5,034,337	6,446,395	6,248,591	5,678,950	5,370,449	5,104,653
Invested Capital	4,586,870	5,034,337	6,446,395	6,248,591	5,678,950	5,370,449	5,104,653
avg		4,810,604	5,740,366	6,347,493	5,963,771	5,524,700	5,237,551
NBC	3	(0)	(0)	(0)	(0)	0	(0)
NIBD	**10,476**	**397,079**	**1,994,832**	**2,135,821**	**1,928,816**	**1,596,188**	**1,520,000**

Appendix 21 - Diamond Offshore analytical balance sheet

Analytical Balance Sheet - Diamond Offshore								
USD Thousansd		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Financial Assets								
Current								
Cash and cash equivalents		335,432	347,011	233,623	119,028	156,233	376,037	154,073
Marketable securities		1,150,158	1,750,053	16,033	11,518	35	0	299,849
	Total	*1,485,590*	*2,097,064*	*249,656*	*130,546*	*156,268*	*376,037*	*453,922*
Non-Current		0	0	0	0	0	0	0
	Total	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Total Financial Assets		**1,485,590**	**2,097,064**	**249,656**	**130,546**	**156,268**	**376,037**	**453,922**
Operational Assets								
Current								
Accounts Receivables, net of bad debt		499,660	469,355	463,862	405,370	247,028	256,730	168,620
Prepaid expenses and other current assets		136,099	143,997	185,541	119,479	102,111	157,625	163,396
Assets held for sale		11,594	7,694	0	14,200	400	96,261	0
	Total	*647,353*	*621,046*	*649,403*	*539,049*	*349,539*	*510,616*	*332,016*
Non-Current								
Drilling, property and equipment, net of acc depreciation		4,864,972	5,467,227	6,945,953	6,378,814	5,726,935	5,261,641	5,184,222
Other assets		237,371	206,097	176,277	101,485	139,135	102,276	65,534
	Total	*5,102,343*	*5,673,324*	*7,122,230*	*6,480,299*	*5,866,070*	*5,363,917*	*5,249,756*
Total Operational Assets		**5,749,696**	**6,294,370**	**7,771,633**	**7,019,348**	**6,215,609**	**5,874,533**	**5,581,772**
Total Assets		**7,235,286**	**8,391,434**	**8,021,289**	**7,149,894**	**6,371,877**	**6,250,570**	**6,035,694**
Financial Liabilities								
Current								
Current portion of long-term debt		0	249,954	249,962	286,589	104,200	0	0
	Total	*0*	*249,954*	*249,962*	*286,589*	*104,200*	*0*	*0*
Non-Curent								
Long-term debt		1,496,066	2,244,189	1,994,526	1,979,778	1,980,884	1,972,225	1,973,922
	Total	*1,496,066*	*2,244,189*	*1,994,526*	*1,979,778*	*1,980,884*	*1,972,225*	*1,973,922*
Total Financial Liabilities		**1,496,066**	**2,494,143**	**2,244,488**	**2,266,367**	**2,085,084**	**1,972,225**	**1,973,922**
Operational Liabilities								
Current								
Accounts payable		96,631	94,151	138,444	70,272	30,242	38,755	43,933
Accrued liabilities		324,434	370,671	426,592	253,769	182,159	154,655	172,228
Taxes payable		64,481	30,806	41,648	15,093	23,898	29,878	20,685
	Total	*485,546*	*495,628*	*606,684*	*339,134*	*236,299*	*223,288*	*236,846*
Non-Current								
Deferred tax liability		490,946	525,541	530,394	276,529	197,011	167,299	104,380
Other liabilities		186,334	238,864	188,160	155,094	103,349	113,497	135,893
	Total	*677,280*	*764,405*	*718,554*	*431,623*	*300,360*	*280,796*	*240,273*
Total Operational Liabilities		**1,162,826**	**1,260,033**	**1,325,238**	**770,757**	**536,659**	**504,084**	**477,119**
Total Liabilities		**2,658,892**	**3,754,176**	**3,569,726**	**3,037,124**	**2,621,743**	**2,476,309**	**2,451,041**
Total Equity		**4,576,394**	**4,637,258**	**4,451,563**	**4,112,770**	**3,750,134**	**3,774,261**	**3,584,653**
Total Liabilities and Equity		**7,235,286**	**8,391,434**	**8,021,289**	**7,149,894**	**6,371,877**	**6,250,570**	**6,035,694**

Appendix 22 - Model regression without RIR

	Dependent variable:
	rigrate
sbrent	0.440*
	(0.231)
remres	-0.986***
	(0.221)
conlength	0.225***
	(0.054)
LEADTIME	0.030***
	(0.010)
wage	-0.126
	(0.177)
sbrent:expUTIL	0.097***
	(0.034)
Constant	17.403***
	(2.362)
Observations	70
R2	0.926
Adjusted R2	0.919
Residual Std. Error	0.153 (df = 63)
F Statistic	132.198*** (df = 6; 63)
Note:	*p<0.1; **p<0.05; ***p<0.01

Appendix 23 - Model regression without remres

	Dependent variable:
	rigrate
sbrent	1.398***
	(0.163)
conlength	0.143***
	(0.052)
LEADTIME	0.034***
	(0.012)
wage	-0.019
	(0.199)
RIR	3.480
	(2.242)
sbrent:expUTIL	-0.048*
	(0.027)
Constant	6.121***
	(0.840)
Observations	70
R2	0.910
Adjusted R2	0.902
Residual Std. Error	0.168 (df = 63)
F Statistic	106.647*** (df = 6; 63)
Note:	*p<0.1; **p<0.05; ***p<0.01

Appendix 24 - Model in R script

```r
## ------------------------------   Loading Data --------------------------------------------------------------------
library(tidyverse); library(AER); library(stargazer)
library(readxl)
RIGMASTER <- read_excel("RIGMASTER.xlsx",
                        col_types = c("date", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric",
                                      "numeric", "numeric", "numeric"))
View(RIGMASTER)
data.frame(RIGMASTER)
RIGMASTER <- na.omit(RIGMASTER)

model.rigrates <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
                     data =RIGMASTER)
se.model.rigrates <- sqrt(diag(vcovHC(model.rigrates, cluster="time", type ="HC0")))
stargazer(model.rigrates, se=list(se.model.rigrates), type="text", out="finalmodel.html")


## ------------------------------ Testing for a structural break in observation 54 ------------------------------
data.frame(RIGMASTER)
print(RIGMASTER
      )



regPOOLED <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
        data =RIGMASTER)

summary(regPOOLED)

regPRE <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
             data =subset(RIGMASTER, DUMMY=="0"))
summary(regPRE)

regPOST <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
             data =subset(RIGMASTER, DUMMY=="1"))
summary(regPOST)

regPRE$df
regPOOLED$df
regPOST$df

rssPRE <- sum(residuals(regPRE)^2)
rssPOOLED <- sum(residuals(regPOOLED)^2)
rssPOST <- sum(residuals(regPOST)^2)
rssPRE
rssPOOLED
rssPOST

fcrit <- qf(.95, df1=regPRE$df, df2=regPOST$df)
fcrit
k=7

Chow_Statistic <- ((rssPOOLED-(rssPRE+rssPOST))/k)/((rssPRE+rssPOST)/(regPRE$df+regPOST$df-(2*k)))
Chow_Statistic


## ------------------------------ Testing for a structural break in observation 30 ------------------------------
RIGMASTER$DUMMY2 <- ifelse(RIGMASTER$date > "2010-06-30", 1, 0)

regPRE2 <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
             data =subset(RIGMASTER, DUMMY2=="0"))
summary(regPRE2)

regPOST2 <- lm(rigrate ~ sbrent + expUTIL:sbrent + remres + conlength + LEADTIME + wage + RIR,
              data =subset(RIGMASTER, DUMMY2=="1"))
summary(regPOST2)

regPRE2$df
regPOOLED$df
regPOST2$df

rssPRE2 <- sum(residuals(regPRE2)^2)
rssPOOLED <- sum(residuals(regPOOLED)^2)
rssPOST2 <- sum(residuals(regPOST2)^2)
rssPRE2
rssPOOLED
rssPOST2

fcrit <- qf(.95, df1=regPRE2$df, df2=regPOST2$df)
fcrit
k=7

Chow_Statistic <- ((rssPOOLED-(rssPRE2+rssPOST2))/k)/((rssPRE2+rssPOST2)/(regPRE2$df+regPOST2$df-(2*k)))
Chow_Statistic

Break.Regressions <- list(regPOOLED,regPRE2, regPOST2, regPRE, regPOST)
stargazer(Break.Regressions, title="Break-Test Regressions", type="text", out = "break.html")
```