Anders Vika Hansen

An Offshore Rig Design and Deployment Model Using Stochastic Contract Scenarios

Master's thesis in Marine Technology
Supervisor: Stein Ove Erikstad
June 2020

Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Marine Technology

NTNU
Kunnskap for en bedre verden

NTNU
Det skapende universitet

Master's Thesis in Marine Systems Design

Stud. techn. Anders Vika Hansen

An Offshore Rig Design and Deployment Model Using Stochastic Contract Scenarios

Spring 2020

Background

Offshore rig owners experience a significant portion of their fleet stand without work due to a low oil price and an oversupply in the market. This creates financing problems and the mass accumulation of debt. The modelling of feasible market states may enable owners to evaluate which rig designs are better positioned for future work opportunities. It may provide insight into which candidates should remain in fleet and which should be scrapped. In addition, owners could evaluate the overall fleet performance and determine ideal fleet mix.

Overall aim and objective

The primary objective is to develop a method for comparing offshore rig design options for different market states. If possible, the model should allow for the presence of an existing fleet to enable evaluation of optimal fleet composition.

Scope and main activities

The candidate should presumably cover the following main points:

1. Provide a review of the offshore drilling industry, highlighting relevant technical and economic aspects of offshore rigs and drilling contracts.
2. Develop a method for modelling feasible realisations of future market states. Present relevant theory and methodological concepts for model formulation.
3. Develop a linear optimisation model that determines the performance of a rig design for a given market state. Evaluate a portfolio of rig design candidates to compare results.
4. Consider introducing stochastic elements to account for market uncertainty. Perform Monte Carlo simulation to generate expected values.
5. Consider different modes of analysis, e.g., consider rig designs as individual competitors and as complementary entities of a fleet. Develop case scenarios to highlight model applications.
6. Discuss the results and present main conclusions.

Modus operandi

At NTNU, Professor Stein Ove Erikstad will be the responsible advisor. The work shall follow the guidelines given by NTNU for the MSc Project work

Stein Ove Erikstad
Professor/Responsible Advisor

Sammendrag

Offshore riggeiere må bestemme i dag hvordan flåtestørrelse og sammensetning skal se ut for fremtiden. For mange rigger i markedet og en lav oljepris gjør at det er utfordrende å tiltrekke seg arbeid. Dette leder til finansielle problemer ettersom rigger er kapitalintensive ressurser. Valg av riggdesign, antall enheter i flåte og flåtesammensetning påvirker hvor egnet et selskap er til å utnytte fremtidige markedsmuligheter.

En lineær optimeringsmodell er utviklet for å evaluere egnethet til riggdesignalternativer for forskjellige markedstilstander. En markedstilstand er realisert ved generering av et endelig sett med kontrakter. Antall kontrakter og deres karakteristiske egenskaper bestemmes av stokastiske funksjoner som tar hensyn til markedsusikkerhet. Offshore rigger kan betjene de kontraktene der riggens spesifikasjon imøtekommer kontrakts kravene. Problemet er formulert som en nettverksmodell der rigger blir tildelt det settet med kontrakter som maksimerer inntjening. Flere kontraktscenarioer evalueres for å danne en fordeling av resultater og beregne forventningsverdier.

Tre analysemoduser ble utført. Modus 1 evaluerer rigger individuelt, modus 2 hensyntar tilstedeværelse av andre rigger, mens modus 3 evaluerer forskjellige flåtekomposisjoner for å identifisere best mulig sammensetning. Resultatene viser at høyspesifikasjon rigger (harsh environment, ultradypvanns) oppnår høyere profitt, gitt at det er tilstrekkelig med kontrakter tilgjengelig. De tiltrekker seg mer gunstige kontrakter og er derfor mer lønnsomme. Likevel så er de mer risikable og går på høyere underskudd i markeder der det er få kontrakter.

Jackupper har lavere operasjonskostnader og inntektspotensial enn flytere. Ved evaluering av forskjellige flåtekomposisjoner så er jackupper å foretrekke for et scenario med lav oljepris, mens flytere er foretrukket for et scenario med høy oljepris. Grunnen til dette er at kostnader får høyere påvirkning når det er få kontrakter tilgjengelig. En sannsynlighetsvektet beregning viser at en jevn flåtesammensetning av jackupper og flytere er ideell. Dette resultatet er spesifikk for den beskrevne markedstilstanden og bør ikke tolkes som en generell anbefalning.

Abstract

Offshore rig owners have to make a decision today of how their fleet size and mix should be in the future. An oversupply of rigs in the market and a low oil price has made it difficult to attract work. With rigs being capital intensive assets, this leads to significant financial problems. Choices of rig design, number of units and fleet composition influence how well positioned a company is to capitalise on future work opportunities.

A linear optimisation model is developed to evaluate performance of rig design options for different market states. A market state is realised by the generation of a finite set of contracts. The number of contracts and their characteristic properties are determined by use of stochastic functions to account for market uncertainty. Offshore rigs may service contracts as long as their specification satisfy minimum requirements. The problem is formulated as a network model with rigs being allocated the set of contracts that maximise total revenue. Multiple contract scenarios are evaluated to obtain a range of results and compute expected values.

Three modes of analysis were performed. Mode 1 evaluate rigs individually, mode 2 accounts for the presence of other rigs, whilst mode 3 consider different fleet compositions to identify optimal mix. The results show that high specification rigs (harsh environment, ultra-deepwater) generate greater profits, given that there is a sufficient amount of contracts available. They attract higher paying contracts and are therefore more profitable. However, they are also more risky and have a higher deficit in markets when the number of contracts is sparse.

Jackups have lower operating costs and earnings potential than flytere. When considering different fleet compositions, jackups were preferred for a low oil price scenario, whilst floaters were preferred for a high price scenario. The reason for this is that costs become more influential when there are few contracts available. A probability weighted computation yielded an even composition of jackups and floaters as optimal. However, this result is specific for the stated market case and should not be interpreted as a general recommendation.

Preface

The following master thesis culminates five years of studies in Marine Technology at the Norwegian University of Science and Technology. The work was carried out in spring 2020, in part at home due to national restrictions following the Covid-19 outbreak. It is valued as 30 ECTS (one tenth of degree total).

Having chosen a specialisation in Marine Systems Design, I am interested in developing models that say something about reality. I wanted to learn more about the offshore drilling industry and found this a golden opportunity to apply theoretical tools accumulated over five years, such as optimisation methods, marine system modelling and programming skills, to a market of which I have limited preliminary knowledge. I have learnt to work structurally, consistently and with determination to achieve results. Specifically, the task has provided me with insight into the use of optimisation methods to derive information from real world systems. It has also made me aware of how setbacks can be channeled for identifying key problems and areas of valuable insight.

I would like to thank my supervisor Stein Ove Erikstad for providing valuable guidance on a weekly basis. Also, a fundamental part of the method applies a framework proposed in a 2011 paper by Erikstad, Fagerholt and Solem.

To the reader: the aim has been to write a thesis that is readable without specific domain knowledge of marine industry. It is assumed a general appreciation of mathematical notation, which is applied in the methodology.

Table of Contents

List of Tables

List of Figures

Abbreviations

Terms and Definitions

b/d	=	barrels per day
BIP	=	Binary Integer Programming
CAPEX	=	Capital Expenditures
DP	=	Dynamic Positioning
E&P	=	Exploration and Production
LPP	=	Longest Path Problem
MODU	=	Mobile Offshore Unit
OPEX	=	Operating Expenditures
R/P	=	reserves-to-production ratio

Organizations

BP	=	British Petroleum
EIA	=	US Energy Information Administration
GOM	=	Gulf of Mexico
GOP	=	Gulf of Persia
NPD	=	Norwegian Petroleum Directorate
OPEC	=	Organization of Petroleum Exporting Countries
UNEP	=	United Nations Environment Programme

Chapter 1

Introduction

1.1 Motivation

We are consuming more energy every year. According to a report by British Petroleum (BP), global energy consumption (comprised of commercially traded fuels, including renewables) amounted to 13.865 billion tonnes oil equivalent in 2018 (BP Energy Economics, 2019). This is growth of 2.9% relative to 2017 - the annual average growth from 2007 to 2017 was 1.5%. Spencer Dale, chief economist in BP, writes that there is a ”mismatch between hopes and reality” as there is growing societal demand for action on climate change, followed by a continued growth in energy consumption (BP Energy Economics, 2019).

Of total energy consumption, oil and natural gas account for 57.5% - 4.66 and 3.31 billion tons oil equivalents respectively. Offshore oil industry contributes around 30% of this production (Manning, 2016b). Oil production companies makes use of mobile offshore drilling units (MODU) to search for and recover fossil resources located deep below the seabed. They are capital intensive and often listed under separate rig companies to reduce associated risk for oil operators.

Rig owners tender for drilling contracts announced by the operator. This can be challenging since the contract requirements, number of competitors and general market state cause contract payments to be highly varying. With capital and operating costs being relatively constant, there is significant uncertainty concerning the rig owner’s expected return on investment. This uncertainty results in cyclic trends. When the payment rates are high and most rigs are employed, there is an increased stream of newbuild rigs to market, which may result in the market being oversaturated. Such was the case in 2014 when the price of oil halved, which led to oil companies cancelling a large portion of their contracts. Drilling companies then struggled to find work for their newly acquired rigs.

We suggest that there is potential to reduce uncertainty by analysing fleet robustness in light of potential market states. Although we acknowledge that the future is inherently uncertain, it may be of significant value to evaluate the performance of a rig fleet for different market scenarios. Each scenario should be not be viewed as an interpretation of what will happen, but as a feasible realisation that capture market behaviour. This may be considered as a form of stress testing, or 'what if' analysis, and can be balanced by the perceived probability of any particular market realisation.

Limited research exist regarding analysis prospects of future rig performance. This may be in part due to the monumental challenge of finding a way to model market dynamics in a way that satisfactory generates feasible market states. Some literature on historic trends exist (Osmundsen et al., 2015; Kaiser, 2014), which cast light on proficient factors and correlation patterns. A way of modelling future market states by use of contract scenarios for service vessels was proposed (Erikstad et al., 2011). Network optimisation was applied by computing the potential revenue generated from a vessel by servicing a set of feasible contracts. The method proposed in this thesis is based on this framework.

1.2 Contribution of Thesis

The main contribution of this thesis is a method for evaluating performance and robustness, of offshore rigs and fleets, for different market states. Rigs are differentiated based on design/specification. A market state is realised by a finite set of contracts, defined by a set of characteristic properties. Stochastic elements are introduced to model inherent market uncertainty. A set of offshore rigs are evaluated for a given contract scenario. Rigs are awarded contracts by a linear optimisation model, with the objective being to maximise total revenue of the serviced contracts. The main constraints are that rigs must satisfy the operating requirements of the contract and contracts that overlap in time may not both be serviced by the same unit.

Three different modes of analysis are developed. Rigs are evaluated for individual comparison (mode 1), as a collective fleet (mode 2). Finally, changes in fleet composition is made to consider fleet mix (mode 3). We analyse expected value and variance of profit and rig utilisation as quantitative measures of performance.

The model may be used for decision support for rig owners. Examples of application include choice of rig design when procuring another unit, identifying candidates that should be removed from fleet and determining ideal fleet composition/mix.

1.3 Structure of Thesis

The main objective of this thesis is to develop a tool that allow for rig owners to evaluate the robustness of their fleet size and mix. That includes expected future earnings and amount of work the rigs will be able to attract. The task is broken down into separate parts. The main activities are as follows,

1. Literature review of the offshore drilling industry - chapter 2
2. Theory and methodological concepts - chapter 3
3. Methodology of market realisation, optimisation and simulation - chapter 4
4. Results for three modes of application - chapter 5
5. Discussion of findings of results and evaluation of method - chapter 6
6. Conclusions - chapter 7

In chapter 2, we provide an introduction to the offshore drilling industry. The aim is to understand the global effects that influence strategic decision making in terms of rig management. Significant focus will be placed on identifying causal relationships that describe market behaviour. Our perspective is that there is irreducible market uncertainty present. To effectively model future market states we will therefore include stochastic effects and aim to create feasible realisations that reflect market behaviour.

The proposed method makes use of realising the future state of the market by use of contract scenarios. This method was first proposed by Erikstad et al. for ship deployment. We will present their work and other theoretical principles in chapter 3.

We dedicate chapter 4 to a detailed explanation of the proposed method. The primary activities may be identified as a stochastic market generation based on initial conditions, network optimisation of each rig unit in fleet and repeated simulation. The last step acknowledges that any particular instance of results is uncertain and a range of results is computed, which will have a distribution and expected value. Three modes of operation have been identified. Mode 1 evaluates rigs individually by assuming that no other rigs are present. Mode 2 evaluates rigs collectively and serviced contracts are removed from set once any given rig has been chosen. Finally, mode 3 consider the fleet mix problem, of which we vary the fleet composition to evaluate the difference in expected earnings.

We present results from the three modes of application in chapter 5. Mode 1 provides a unit comparison of individual rigs, which may be useful when choosing design options. Mode 2 concern the overall fleet performance and aims to provide insight into expected earnings and associated risk. Mode 3 consider the optimal composition of rigs in fleet. This is relevant for fleet renewal.

In chapter 6, we discuss the main findings from the results. We also dedicate a portion of the chapter to evaluate the methodological framework presented. We have not found literature that makes similar effort to simulate the rig market by use of stochastic modelling, therefore a discussion of its utility is relevant. We conclude with a summary of our findings in chapter 7.

Chapter 2

Literature Review

In this chapter

An introduction of the offshore drilling industry from a systems approach is provided. We identify offshore drilling units as the main entities operating within a market. section 2.1 features a presentation of offshore rigs with emphasis their function and distinctive characteristics. A market overview is presented in section 2.2. We will quantify market sizes by historic production levels, thus enabling us to deduce activity levels in different regions. Finally, section 2.3 describes offshore drilling contracts and their properties. We aim to show that both rigs and contracts may be mathematically modelled as discrete entities operating within a market.

2.1 Offshore Drilling Units

Oil companies are awarded licenses from national governments to operate in a certain geographical area. To search for - and extract hydrocarbons, the companies charter MODUs from a rig owner. This is more common than the oil company taking direct ownership of the rig itself - due to the risk of a capital intensive asset being left without work for an extended period of time. Different types of drilling units exist and they serve different purposes. During a tendering process the payment and duration of the contract is agreed between oil company and rig owner. Duration may be time-specific or given as a number of wells that are to be drilled.

2.1.1 Types of Drilling Units

There are three main MODUs, which we will focus on in this thesis. These are drillships, semi-submersibles and jackups. Other units exist as well, although they are typically not mobile. Common examples are platform rigs and barges. Platform rigs are permanently installed to produce oil in fields that are expected to be productive over a long period of time. Barges are floating decks with drilling equipment that may be used in calm, shallow waters.

Drillships are vessel-shaped (sometimes they are converted from an oil tanker or similar), which gives them great transit speed. They are well suited for exploration drilling since they can easily change location. Drillships are however less stable and therefore not suitable for drilling in harsh environments (Infield Rigs, 2020). Semi-submersibles are more stable and capable of operating in both benign and harsh environments. Many are self-propelled and can therefore be used for exploration drilling. Modern drillships and semi-submersibles are capable of drilling at a water depth of up to 3000 meters, which is classified as ultra-deepwater.

A jackup is a barge with three or four legs that are extended and rooted to the seabed once in position. They are only capable for drilling in shallow waters - depth up to around 150 meters. Jackups are commonly not mobile and therefore is less applicable for exploration drilling that require coverage of large areas. An illustration is provided in fig. 2.1 [1].

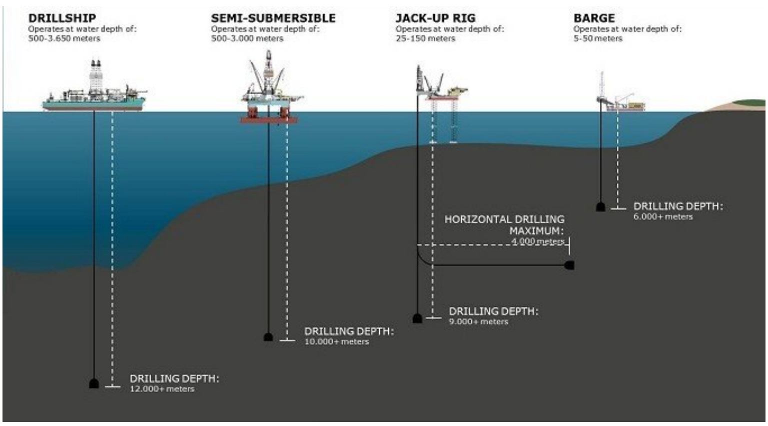


Figure 2.1: Different Rig Types

Source: subsea.org

A note on terminology: throughout this thesis we frequently will use ”rig” or ”drilling unit” when discussing MODUs (drillships, semisubmersibles and/or jackups). Although

[1] https://www.subsea.org/maersk-rig-61-rig-owned-by-maersk-contractors/

less precise this offer more pleasant reading. In addition, we will use the term ”floater” as a shared notion of drillships and semisubmersibles when they are discussed in dual relation.

2.1.2 Types of Drilling Wells

The Norwegian Petroleum Directorate (NPD) distinguishes in their database between the drilling of exploration- and development wells (Oljedirektoratet, 2020a). Exploration comprises either the search of new prospects (termed wildcats) or determining the characteristics and boundaries of discovered reservoirs (appraisal). This often require the drilling unit to move from one place to another for drilling different wells. Development drilling comprises of different types of drilling concerned with readying a reservoir for production. Examples are injection wells, production wells and observation wells.

Historic data from NPD show that almost 74% of all wells drilled are related to development and production of fields, 17% are exploration wells and 9% are appraisal wells (Oljedirektoratet, 2020b). However, it is worth noting that this changes over time. Well data of the Barents Sea states that around 75% of wells drilled are classified as exploration or appraisal. The Barents Sea is a less developed area and it is in recent time that activity has picked up. This suggest that exploration contracts will be over represented in less mature fields whilst development contracts will increase in frequency as fields mature.

2.1.3 Rig Specifications

The design and fitted equipment onboard rigs define in large what type of work they qualify for executing.

Environment Classification

There is a distinction between harsh environment and benign environment rigs, which describe in what areas they are eligible to operate. Harsh environments are areas which are subject to more extreme weather in terms of temperature, wave height and wind. This is descriptive for the North Sea and other far north areas such as the east Canadian coastline. There are stricter design criteria for rigs to be able to operate in harsh environments and this makes them more expensive to construct. An indicator often specify whether or not a certain rig qualify for operating in harsh environments.

Water Depth

Water depth is a key limiting factor to what areas a rig may operate. Advances in technology has enabled modern floaters to drill in areas with a depth of more than 3000 meters.

This has opened a range of new areas, which may ensure that offshore production levels is upheld as shallow water reservoirs are depleted.

Station Keeping

Whilst drilling, the rig needs to maintain its position relative to the seabed. Jackups are anchored by its legs, which are rooted to the seafloor. For floating structures the same is achieved either by mooring systems or dynamic positioning (DP). DP systems utilise thrusters to counter environmental loads and maintain the rig's position by use of GPS signals. Mooring systems consist of normally 8 or 12 point anchor lines (Diamond Offshore, 2020b). Combination systems do also exist.

DP systems allow for drilling in deeper waters. When water depth exceed 1500 meter it is no longer technically feasible to use mooring lines [2]. Therefore, rigs with DP systems are more flexible. It is however also more costly - both from an economic and environmental perspective. DP rigs have greater fuel consumption as they require constant use of thrusters, moored rigs require no effort to stay in place. To highlight this, moored a semi-submersible rebuilt in 1999 was declared by Rystad Energy as the "greenest" on the Norwegian Continental Shelf (NCS) [3]. The rig emits between 30-40 tonnes CO_2 per day. Worst on the list is a DP rig built in 2009, which emits up to 120 tonnes per day.

2.1.4 Rig Utilisation

An important indicator of the state of the rig market is what percentage of rigs are currently working under contracts. This is known as rig utilisation rate. A high utilisation rate means that fever rigs are available, which increases the bargaining power of rig owner relative to oil companies when negotiating new contracts. In contrast when utilisation is low, the oil companies will have more rigs to choose from and may therefore decide terms more easily.

Rigs that are not under contract are typically either labelled as idle (warm-stacked) or stacked (cold-stacked). Both groups are actively marketed as available for new work, but there is a difference in operating cost. Idle rigs are running most systems as if under contract and most of the crew is employed. This means that operational costs are almost as high as when active even though there are no earnings. The benefit is that the rig will have a low reactivation cost and response time to be ready for a new potential contract.

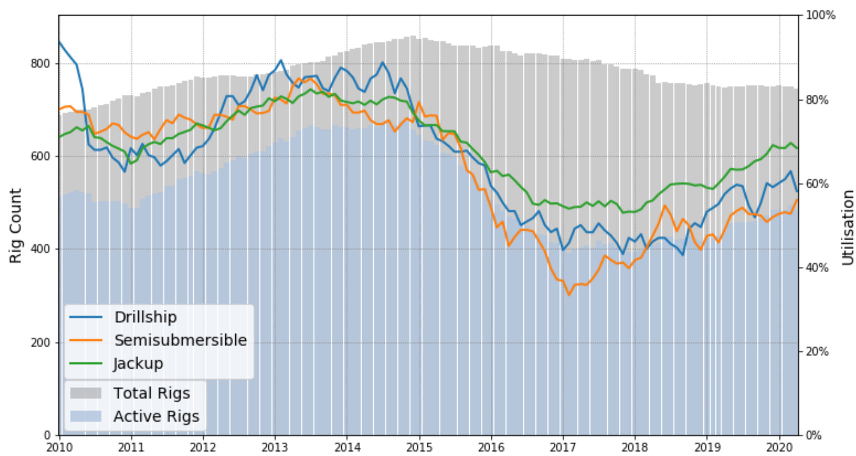
In contrast, stacked rigs are stationed quayside with most systems switched off and crew let go. This significantly lowers operating costs, but there will be a higher reactivation cost and longer response time to mobilise the rig for work. In short, operation costs, reactivation costs and expected prospects of attracting future work determine whether a

[2] https://www.offshore-mag.com/rigs-vessels/article/16756374/dynamic-positioning-versus-mooring-debate-continues-as-technology-evolves

[3] https://finansavisen.no/nyheter/oljeservice/2019/10/24/7466207/dolphin-drilling-har-de-gronneste-riggene-i-norge

rig owner will leave its rig stacked or idle. Rigs that are not expected to be awarded new contracts are normally sold for recycling (scrapping).

Utilisation by rig type for 2010-20 is presented in fig. 2.2. The total number of rigs in market have been plotted as well. We observe that as utilisation was in an upward trend from 2010-15, there was an increasing rigs brought to market, moving from almost 700 to a peak of 860 units. In 2014 the oil price plunged from $115 to $45 per barrel (Macrotrends LLC, 2020). We observe a downward trend in utilisation as the gap between active and total rigs increase. This translates reduced pay in new drilling contracts, which we will return to. Many rig companies have yet to recover from the market downturn in 2014-15.



The figure shows utilisation rate of drillships, semisubmersibles and jackups (right axis), as well as total count of employed and unemployed rigs (left axis). Data on number of working rigs are retrieved from Westwood Global Energy Group (RigLogix, 2020).
Utilisation rate represent the number of working rigs, divided by the total listed amount of rigs in market. By ”working” we mean all rigs that are assigned to a paid contract. The total rig fleet includes rigs that are either idle, stacked or under construction - awaiting to enter market.
The data counts the number of rigs employed each month. That is, if a rig is only employed part of a certain month, it will be registrars as employed throughout the month. Some variation is expected if one counts on a day basis.

Figure 2.2: Utilisation by Rig Type, 2010-20

2.1.5 Capital Cost of Rig Units

Offshore rigs are capital intensive assets. According to Ensco, since 2000, the average building cost for floaters was $665 million and $ 200 million for jackups (Ensco, 2019). This is fairly consistent with construction costs of current rigs on order from shipyards, displayed in table 2.1 (RigLogix, 2020). The high cost of purchase means there is a significant risk of loss if the owner is not able to attract sufficient work.

Rig Type	Avg. cost $ million	Number of rigs
Drillship	620	17
Semisubmersible	737	9
Jackup	225	28

Table 2.1: Construction Cost of Current Newbuilds, 2020
The table shows the average construction cost by rig type. Variation can be found by rated water depth and other rig capacity parameters. However, due to limited sample size, these are ignored.

2.1.6 Operating Cost of Rig Units

Attempts have been made to find reliable data on rig operating costs. This has proven challenging and there are limited sources available. One reason for this might be that companies consider this information sensitive and want to protect their intellectual property rights.

It is however clear that there are significant differences in operating cost based on rig type and level of specification. In an investor presentation, Valaris (formerly Ensco) estimates average OPEX of $150,000 per day for floaters and $50,000 per day for jackups (Ensco, 2019). To investigate operating costs we have reviewed financial statements from a selection of prominent companies, for the calendar year 2019. We have included the documented number of rigs in their portfolio to compute average operating expenses per rig. The results are presented in table 2.2.

Company	OPEX ($million)*	Number of rigs†		OPEX per rig ($/day)
		Jackup	Floater	
Borr Drilling	308	34	1	24,110
Diamond Offshore	793	0	15	144,840
Maersk Drilling	710	14	8	88,418
Seadrill	770	16	19	60,274
Shelf Drilling	367	36	0	27,930
Transocean	2140	0	43	134,349
Valaris	1806	51	26	64,259

Table 2.2: Operating Expenses by Company, 2019
* Includes only operating expenses related to contract drilling activities. Excludes costs related to depreciation, reimbursable, administrative and general loss from impairments.
† Includes only rigs of which the company is listed as owner. It is common that some rig companies manage rigs that have a different registered owner. The numbers include rigs independent of operating status. Some rigs may be stacked and will have lower operating expense.
Sources are company financial statements (Borr Drilling, 2020; Diamond Offshore, 2020a; Maersk Drilling, 2020; Seadrill, 2019; Shelf Drilling, 2020; Transocean, 2020a; Valaris, 2020).

It is of particular interest to note the companies that almost exclusively focus on one rig type. Borr- and Shelf Drilling owns almost exclusively jackups and report a unit operating cost of $24-28,000 per day. Diamond Offshore and Transocean has a fleet of only drillships and semisubmersibles, and a unit cost of $134-144,000 per day. Most of Transocean's rigs are classified as either harsh environment, ultra-deepwater or both. One would expect that they are more costly than traditional benign environment or midwater floaters. The figures are suggestive as to what the unit operating cost of rigs might be.

2.2 Overview of the Offshore Drilling Market

Oil is the most traded commodity in the world [4]. It is estimated that global oil consumption in 2018 was around 4.66 billion tonnes (BP Energy Economics, 2019). That is more than 34 billion barrels per year - close to 100 million barrels per day (Mb/d) [5]. Given a an oil price of $50 per barrel the market size is around $1.8 trillion per year. In comparison, the combined market size of the most traded metals is around $600 billion - gold, iron, copper, aluminium and more included [6].

There are different benchmarks that indicate the price of oil per barrel, the most common being Brent- and WTI Crude. This is an important indicator on the state of the market. A high oil price increases revenue per unit of oil, and allow for oil producers to pursue more projects. This translates into added work for oil service companies, such as the offshore drilling sector. Now, if the price of oil is low, oil companies are forced to reduced costs. The easiest way of doing this is to stop searching for new oil and focus on maintaining current production. This has a major impact on downstream companies that are based on delivering services to the oil companies (as shown with utilisation rate in fig. 2.2).

2.2.1 Offshore Oil Production

From 2005 to 2015 offshore crude oil and gas production remained stable at around 30% of total production (27 Mb/d in 2015) (Manning, 2016b). Five countries produced 43% of total global offshore production in 2015, listed in table 2.3.

[4] https://www.ig.com/au/trading-strategies/top-10-most-traded-commodities-180905

[5] https://www.rystadenergy.com/newsevents/news/press-releases/covid-19-demand-update-oil-seen-down-9point6-jet-fuel-down-31-road-fuel-down-9point6-in-20202/

[6] https://oilprice.com/Energy/Crude-Oil/The-Oil-Market-Is-Bigger-Than-All-Metal-Markets-Combined.html

Country	**Production Mb/d**	**Rate of total offshore** (%)
Saudi Arabia	3.7	13
Brazil	2.5	9.5
Mexico	2	7
Norway	2	7
United States	1.8	6.5

Table 2.3: Top Five Offshore Oil Producing Countries in 2015
Data is retrieved from the US Energy Information Administration (Manning, 2016b).

2.2.2 Production by Water Depth

Of the 27 Mb/d oil produced offshore in 2015, around 69% came from shallow water (less than 125m), 25% from deepwater (125-1500m) and 6% from ultra-deepwater projects (more than 1500m) (Manning, 2016a). Brazil and USA contributed to more than 80% of ultra-deepwater projects. An overview of distribution of oil production by depth is provided in table 2.4.

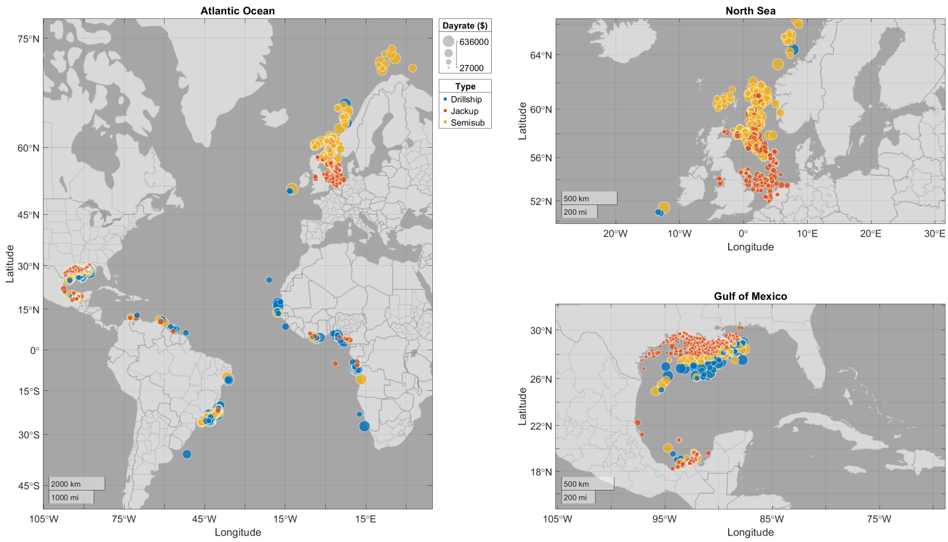
Country	**Shallow water** 0-125m	**Deepwater** 125-1500m	**Ultra-deepwater** over 1500m
Brazil	0.1 Mb/d	1.4 Mb/d	0.8 Mb/d
United States	0.4 Mb/d	0.9 Mb/d	0.5 Mb/d
Angola	0.3 Mb/d	1.3 Mb/d	0.2 Mb/d
Norway	0.5 Mb/d	1.5 Mb/d	0.0 Mb/d
Rest of world	18 Mb/d	2 Mb/d	0.1 Mb/d
Total	19.3 Mb/d	7.1 Mb/d	1.6 Mb/d

Table 2.4: National Production by Water Depth, 2015
The table shows distribution of oil production by depth in four proficient countries and rest of the world. Shallow water is categorised as up to 125 meter, deepwater is from 125-1500 meter and ultra-deepwater is above 1500 meter. Numbers are retrieved from figures in an article by EIA (Manning, 2016a).

There is a tendency for companies to move production towards deeper waters as technologies mature and shallow water reservoirs run out of oil. In Brazil and Angola, deep- and ultra-deepwater production has nearly doubled from 2005 to 2015 Manning (2016a). McKinsey suggest that new offshore production growth up to 2035 will in large come from ultra-deepwater projects (McKinsey, 2019).

2.2.3 Production by Market Region

In this thesis we will focus on offshore oil production in the Atlantic Ocean. This is to reduce complexity by only considering markets within a fixed geographical region. The Atlantic Ocean may be traversed fairly easily, and consist of no channels or straits that may at some point be expected to be closed by a nation for political reasons. An illustration of regional awarded contracts, from 2010 to 2020, illustrates the level of activity fig. 2.3. Interestingly, the contracts awarded in Gulf of Mexico indicate a pattern of jackups being located closer to shore than floaters, signifying a difference in depth.



The figure provides an illustration of historically awarded contracts and their spatial distribution. 1357 contracts between 2010-20 are plotted. The size of the markers represent different published dayrates, whilst the colour scheme is differentiated by rig type.
Source: Riglogix (RigLogix, 2020).

Figure 2.3: Awarded Contracts in the Atlantic Region, 2010-20

We identify four markets defined by region. USA and Mexico are in close proximity and make up the biggest producers in the Gulf of Mexico. Similarly, Norway and UK are dominant in the North Sea (and Europe). In addition, a number of oil producing countries make up a significant cluster in West Africa. The biggest are Nigeria and Angola (BP Energy Economics, 2019). Lastly, Brazil is left as a separate market due to its interesting high share of ultra-deepwater drilling projects. Other oil-producing countries in Latin America such as Venezuela and Colombia are located more north and closer to the Caribbean and Gulf of Mexico.

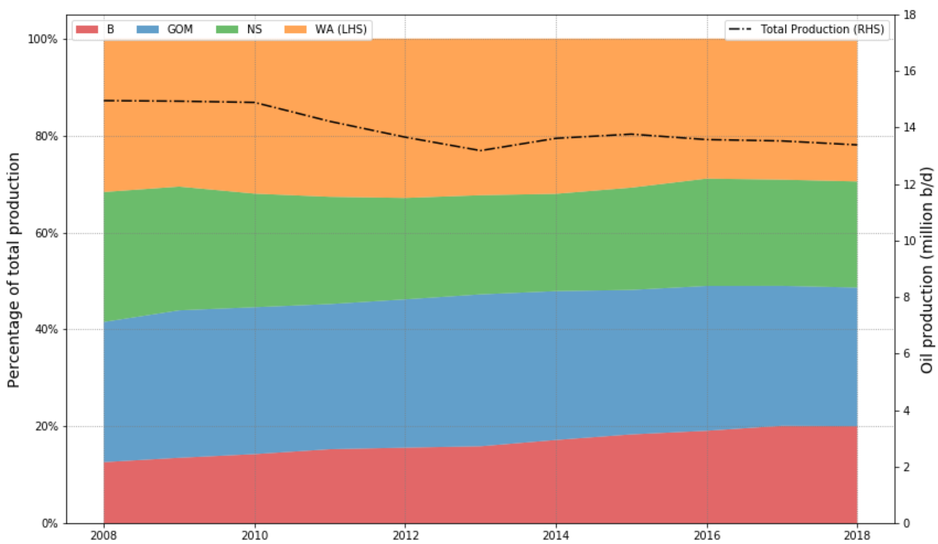
Regional production for 2018 is provided in table 2.5. In addition, the relative market sizes measured by production are given. This is illustrative and useful when considering the level of activity that may be expected for each region.

Region	**Production** (1000 b/d)	**Rate of total** (%)
Brazil∗	2683	20
USA† and Mexico	1758 and 2068	28
Norway and UK∗	1844 and 1085	22
West Africa⋄	3969	30
Total	**13407**	**100**

Table 2.5: Offshore Oil Production by Region, 2018

∗ The main source of data is BP's Statistical Review of World Energy, however it does not distinguish between onshore and offshore production (BP Energy Economics, 2019). By comparing with data from table 2.3 it seems fair to assume that approximately all production in Brazil and the North Sea is offshore.
† Since USA is a significant onshore oil producer we use published offshore production rate in GOM from EIA (US Energy Information Administration, 2020).
⋄ For West Africa we have included production rates from Angola, Equatorial Guinea, Gabon and Nigeria. We assume all production is offshore, although confirmation on this has proven difficult to find.

To evaluate whether it is fair to assume that the relative market sizes remain constant, we have reviewed production rates for the past ten years. In figure fig. 2.4 offshore production is given in percentage relative to total market size(left-hand axis). In addition, we have plotted the total production of all four regions (right-hand axis).



The figure shows the relative amount of offshore production for each market, from 2008 to 2018 (left-hand axis). Total offshore production for these markets in this period is shown by the black line (right-hand axis). The method of data collection and sources are identical as documented in table 2.5, (BP Energy Economics, 2019; US Energy Information Administration, 2020).

Figure 2.4: Offshore Production by Region, 2008-18

Total production has decreased somewhat during the last ten years. We observe that there are variations in market size over time. Brazil has seen an increased market share from around 13% in 2008 to 20% in 2018. This can be explained by the increased economic feasibility of deepwater drilling projects. The North Sea region has experienced a 5% reduction in market share. This is accounted for by the fact that Norway and UK has seen a production drop of around one million barrels of oil per day (BP Energy Economics, 2019). There are many mature fields in the region and therefore it is natural that production is reduced over time. It may be of interest to consider case scenarios of which relative market shares change over time.

2.2.4 Changes in Regional Production

There is ground to believe that market shares in the Atlantic Ocean will change with time. This depend on remaining available resources in respective regions, as well as national and international policies.

BP has produced numbers that documents proven oil reserves by region (BP Energy Economics, 2019). They compare this to current production and provides a reserves-to-production ratio (R/P), which returns the number of years a country can still produce oil, given that they maintain a 2018 production rate, and no new reserves are discovered. R/P is useful when considering the outlook for each region. Remaining proven oil reserves for a selection of countries is provided in table 2.6.

Region	**Reserves (1000 Mb)**	**Share of total**	**R/P (years)**
Brazil	13.4	0.8 %	13.7
United States	61.2	3.5 %	11.0
Mexico	7.7	0.4 %	10.2
Norway	8.6	0.5 %	12.8
United Kingdom	2.5	0.1 %	6.3
Angola	8.4	0.5 %	15.0
Equatorial Guinea	1.1	0.1 %	15.8
Gabon	2.0	0.1 %	28.2
Nigeria	37.5	2.2 %	50.0

Table 2.6: Golobal Oil Reserves By Region

Proven reserves by a select number of countries (BP Energy Economics, 2019).
Column three show the estimated share of total proven oil reserves both onshore and offshore. This is dominated by countries such as Venezuela, Saudi Arabia and Canada, which combined account for more than 44 % of proven oil reserves. Column four gives reserves-to-production (R/P) ratio, which show the amount of years a country may produce oil at current rate before running out of proven reserves.
Europe is almost exclusively dominated by Norwegian and UK production. The majority of USA production is onshore, numbers on offshore reserves were not given.

Table 2.6 suggest that many countries will be able to produce between 10-15 years at current levels. Now, if all exploration activity were to cease today, we may expect that market shares in the North Sea, and potentially the Gulf of Mexico, will decline. A change in market shares will change the distribution of contracts by depth and may therefore favor other rig types.

2.2.5 Risk Factors and Climate Change

Future states of the rig market may depend on global politics and extraordinary events. An ongoing example is the outbreak of the Covid-19 pandemic. To reduce transmission rate, many countries has issued travel restrictions and national lockdowns, encouraging people to stay at home. These measures reduce the demand for energy. Rystad Energy reports that global oil consumption April 2020 was reduced by 27% (71.8), compared to the daily 2019 average of 99.5 Mb/d (Rystad Energy, 2020). They forecast an annual average production for 2020 of 89 Mb/d, an 11% reduction from 2019.

It is debatable whether we should search for new oil and if it is justifiable to maintain current production levels. A recent report by the United Nations Environment Programme (UNEP) states that "governments are planning to produce about 50% more fossil fuels by 2030 than (what) would be consistent with a 2°C pathway and 120% more than would be consistent with a 1.5°C pathway" (UNEP et al., 2019). This is measured by the amount of carbon dioxide released per year and referred to as the "Production Gap". It is worth noting that the largest production gap (difference in allowed versus scheduled CO_2 emission) is found in coal, however oil and gas are also exceeding their carbon budgets.

Many nations are struggling to deal with conflicting interests in meeting climate goals and energy demand. The case of Norway has been described as a sort of "paradox" as the country has been very ambitious in international discussions of climate action. Simultaneously Norway is a significant oil and gas producer with the industry providing around a quarter of government revenue (Lahn, 2019). Such a conflict of interest was illustrated when, in 2018, the largest national oil producer changed its name from Statoil to Equinor, signifying an itention to become a "broader energy company" [7].

In 2016, Greenpeace and "Nature and Youth" brought a lawsuit the Norwegian government based on a licensing of arctic areas for oil exploration (Lahn, 2019). The argument was that a "failure to consider climate impacts of further licensing" violates article 112 of the Norwegian constitution, which grants citizens a right to a healthy environment. The trial ruled in favour of the Norwegian government in January 2018.

Changes in national and global energy strategies, financial crises, pandemics and catastrophes are difficult to predict. They may fundamentally change market dynamics, which influence all involved parties. Actual realisation of such events may be, for example, in the form of the closure of an existing market (or the opening of a new), a redistribution of the payment rates of contracts or the number of contracts available. All events represent a form of risk that the rig owner has accepted.

[7] https://www.equinor.com/no/news/15mar2018-statoil.html

2.3 Drilling Contracts

Rig companies make their earnings by attracting contracts for their offshore drilling units. The scope of work and expected time is agreed between oil company and rig owner.

Payment of drilling contracts often follow a dayrate model, which means that the well cost is a function of time it takes complete (Maersk Drilling, 2020). Dayrate is the daily payment a rig owner is expected to receive for a contracted rig unit. This is usually disclosed as the full operating dayrate, which means that the rig will be drilling all the time. In reality, the rig will have variable operating status with scheduled maintenance, sailing time, and potentially downtime. It is common that dayrate varies dependent on operating status (Osmundsen et al., 2005; Transocean, 2020b).

The duration of a contract is also subject to change. An initial agreement is often based on the amount of work that is to be performed and the expected time it will take. An oil producer may also simply define a set number of wells they want to be drilled. However, significant lead time between contract agreement and commencement is to be expected. During this time the conditions may change and the client may want to postpone, shorten, lengthen or even cancel the contract. This means that there will always be uncertainty attached to what the actual contract duration will be.

2.3.1 Historic Contract Data

In chapter 4 we propose a method for evaluating offshore rigs performance for different market conditions. A fundamental assumption is that the future can be reasonably represented by a set of available contracts that form a base of earnings for the rig owner. Now, in order to generate these contracts we need to understand their inherent characteristics. It is therefore of interest to consult historic contracts to obtain insight. Some published papers exist, most notably by Osmundsen et al. and Kaiser.

Most rig contract databases require paid subscription, however we were generously provided with access to historic data from Westwood Global Energy Group (RigLogix, 2020). Based on search criteria outlined below, a set of 2161 unique contract entries were obtained. This enables analysis of important trends and correlations that characterise the offshore drilling market.

Analysis of contract characteristics in between 2000 and 2010 are well documented (Kaiser, 2014; Osmundsen et al., 2015). Therefore, only contracts from 2010 to 2020 are considered in the dataset. Contracts from regions Brazil, Gulf of Mexico, North Sea and West Africa have been sampled. In addition, we are only concerned with drillships, semisubmersibles and jackups. Contracts for other rigs (e.g. platform rigs) are not included.

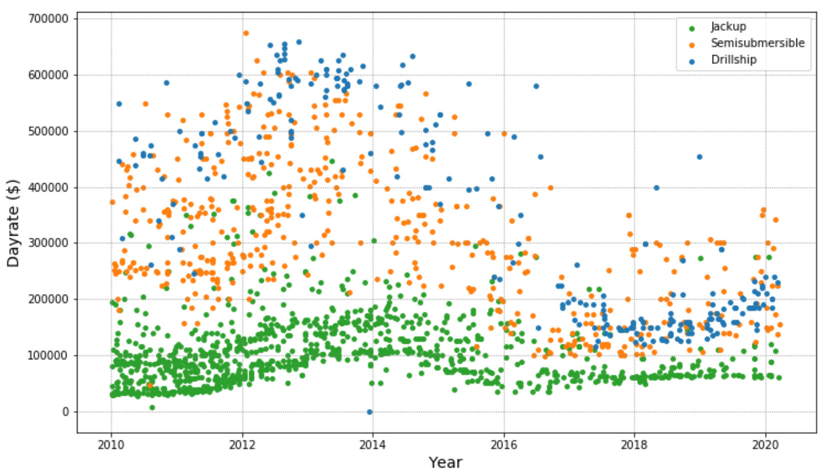
Note that caution should be exercised when considering to what extent historic data provides foresight. However, awareness of specific causal relationships may be useful. This will be the objective in the following sections.

2.3.2 Payment of Drilling Contracts

It is common to estimate expected earnings by multiplying the disclosed dayrate by the stated contract duration. This will be an approximation as it is uncommon that rig units maintain full operating status. Contract revenues are stochastic by nature and therefore difficult to predict. Nevertheless it is of interest for rig owners to be able to understand and predict what current and future earnings will be as this is crucial for deciding how their rig portfolio should look like. If one were able to accurately model future earnings this would be a major business advantage.

Dayrates by Rig Type

In fig. 2.5 we have plotted dayrate for each contract by date signed - categorised by rig type. From inspection it is clear that dayrate earned for jackups is, on average, lower than that of floaters. Although multiple outliers are spotted, dayrate for jackups is by and large concentrated between $50-200,000. The average dayrate for floaters is significantly higher, however for semisubmersibles there seem to be a greater spread as well. Also, note a dip in the average dayrates as the market worsened in 2014.



Scatter plot of leading edge dayrate and date of contract signing, by rig type. Leading edge dayrate is the dayrate agreed upon time of contract signing, as opposed to the time of commencement. This will have a faster response since it reflects the current market conditions at the time.

Figure 2.5: Leading Edge Dayrate by Rig Type, 2010-20

Table 2.7 shows the expected value and standard deviation of dayrate by rig type, per year. It is interesting to note that the average ratio of standard deviation over expected value is greater for jackups (49%) compared to floaters (32%).

Year	**Jackups**			**Floaters**		
	μ ($)	σ ($)	σ/μ	μ ($)	σ ($)	σ/μ
2010	78,542	52,177	0.66	340,696	101,306	0.29
2011	88,709	61,668	0.69	350,704	113,656	0.32
2012	124,378	66,700	0.53	452,428	124,820	0.27
2013	147,833	59,555	0.40	482,131	120,590	0.25
2014	138,136	43,613	0.31	409,030	109,694	0.26
2015	105,283	48,772	0.46	318,334	112,174	0.35
2016	89,749	54,365	0.60	231,461	111,553	0.48
2017	83,770	40,875	0.48	161,632	56,096	0.34
2018	68,862	15,233	0.22	178,779	70,690	0.39
2019	87,731	49,794	0.56	193,145	54,634	0.28
Mean	**101,299**	**49,277**	**0,49**	**311,834**	**97,521**	**0.32**

Table 2.7: Expected Value and Standard Deviation of Dayrate by Rig Type, 2010-20

Dayrate and Oil Price

Osmundsen et al. used econometric analysis to examine the formation of rig rates on jackups in the Gulf of Mexico (Osmundsen et al., 2015). They had access to a dataset consiting of 6801 contracts from 204 rig units, between 2000-10. It was found that average dayrates increased proportional to oil and gas prices - a 10% increase in price would lead to around 12% increase in dayrate (assuming other factors remain constant).

Kaiser analysed global dayrate factors on jackups and floaters (Kaiser, 2014). With set of 7123 rig contracts between 2000-10, a range of parameters' influence on dayrate was investigated using regression analysis. It was found that moving average oil price was a strong indicator on dayrates. Explicit equations for jackups and floaters both yielded quality of fit (R^2) above 0.9. Denote dayrate, DR, and oil price, P_{oil}, and the expression is given in (2.1). The author experienced greater success with 12 month moving average oil price for jackups and 24 month for floaters. It was reasoned that floaters are preferred for more capital intensive projects (e.g. deepwater) and contracts tend to be longer - therefore a higher inertia.

$$ln(DR) = \beta_0 + \beta_1 * ln(P_{oil}) \tag{2.1}$$

Attempts were made to replicate Kaiser's findings by using data from 2010-20 - with limited success. We conducted simple regression using oil price as explanatory variable of dayrate. Quality of fit for different rig types, with various transformation of variables, are displayed in table 2.8.

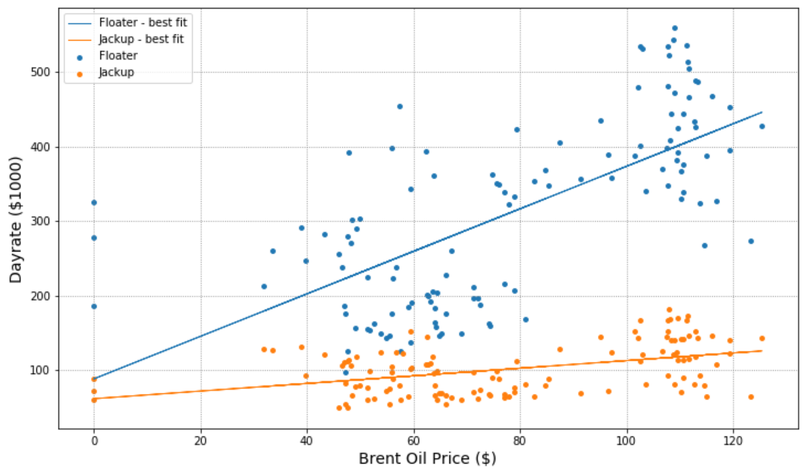
Transformation Dayrate ($)	Transformation Oil Price ($)	Drillship R^2	Semisubmersible R^2	Jackup R^2
y	x	0.57	0.71	0.33
ln(y)	x	0.42	0.64	0.26
ln(y) - Kaiser	ln(x)	0.47	0.68	0.30

Table 2.8: Quality of Fit of Dayrate by Oil Price, 2010-20

Simple regression was conducted to investigate the explainable power of oil price on dayrates (the simple linear regression equation has form $y = \beta_0 + \beta_1 x$). Transformation of variables was attempted to increase quality of fit, unsuccessfully however.

A word of caution is due. Raw data was applied without filtering outliers or conducting other form of pre-processing. In addition, the results in table 2.8 were obtained using yearly average values. Kaiser used 12 month and 24 month moving average oil prices to predict dayrate for any given period, thus a direct comparison is unfair.

The most illustrative example of the effect of oil price and dayrates is shown in fig. 2.6. Monthly average dayrate and oil price is plotted - distinguishing between floaters and jackups. Regression lines were fitted with different transformation of variables. The linear transformation yield the highest quality of fit for each dataset and is the one displayed in the figure. Although oil price does not explain dayrates in a satisfactory way, there is a clear positive trend.



Best fit lines are computed for floaters and jackups. The quality of fit was 0.52 for floaters and 0.18 for jackups. This can be in part explained by the fact that jackups have a higher variance relative to expected value, as shown in table 2.7.

Figure 2.6: Monthly Average Dayrates by Oil Price, 2010-20

It would be of interest to spend more time investigating the effect of oil price on dayrate, in particular by introducing other explanatory variables. However, this is outside the scope of this thesis. For now, we accept that oil price has a positive correlation with dayrates, which must be accounted for in the model.

Contract Duration

Osmundsen et al. states that oil companies pay a premium on longer contracts since rig owners are not able to take advantage of potentially increasing rates during this period (Osmundsen et al., 2015). Kaiser found that contracts that were longer than average awarded a premium of 20-30% dependent on region (Kaiser, 2014).

Rig Utilisation

Osmundsen found that higher rig utilisation had a positive impact on dayrates (Osmundsen et al., 2015). It was however concluded that utilisation is indirectly influenced by oil price so this may be considered a second hand effect. Kaiser found a correlation, but not statistically significant relationship between rig utilisation and dayrate (Kaiser, 2014). This reinforces the impression that utilisation is a weak indicator and secondary to oil price.

Premiums Based on Rig Specification

Rig specification, on the other hand was considered a significant indicator, both for jackups and floaters. Jackups with independent leg cantilever received a premium of 40% on dayrates relative to mat or slot rigs (Kaiser, 2014).

Between 2000-10, floaters capable of operating at waters deeper than 1500 meter were paid an average premium of 35% (Kaiser, 2014). In general, more specialised rigs attract higher rates. This is reflected for winterised rigs that are able to operate in harsh environments and rigs that utilise dynamic positioning for station keeping - as opposed to mooring systems. Floaters equipped with DP systems were on average paid 40% more than moored rigs. We caution that not all premiums are independent - a rig operating in ultra-deepwater is necessarily also dynamically positioned.

Premium by Well Type

It was found that higher than average dayrate was paid for appraisal drilling contracts, relative to development and exploration drilling (Kaiser, 2014). Appraisal drilling concern the determination of size and characteristics of discovered reservoirs. It is considered technically more challenging and awards an average premium of 20%.

Regional Differences

Dayrates differ dependent on region although it was not proven to be systematic. Regional differences may in part be explained by drilling environment and water depth since conditions vary. In addition, Kaiser suggest that national oil companies pay higher dayrates than independent companies. The reason for this is that whilst stock enlisted companies mainly answer to shareholder expectations of return on investment, national companies have economic and political agendas that may increase their willingness to pay higher rates (Kaiser, 2014). National oil companies is more prominent in certain regions compared to others (for example Petrobas in Brazil and Equinor in the North Sea) and this may lead to a regional difference in pricing.

Market Power

Since there is a limited number of rigs in the world one may expect that the biggest rig owners are able to exercise market power and obtain higher rates. This argument was rebutted. Although a market leader such as Transocean was found to receive higher than average rates, this can be explained by the fact that they own high capacity rigs, thus companies were not able to exercise market power (Kaiser, 2014).

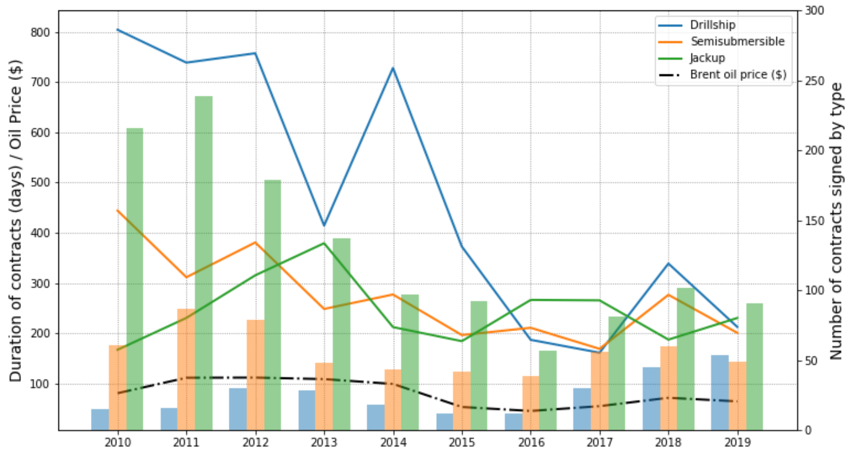
2.3.3 Duration of Drilling Contracts

Revenue generated from a contract is decided by dayrate and duration. It is of interest to observe historic duration of contracts to get an impression of how long contracts are to be expected. Historic average duration of contracts by rig type, as well as yearly Brent oil price, is plotted in fig. 2.7 (left-hand axis). To give an impression of the state of the market, a bar chart of the number of contracts signed every year is shown (right-hand axis).

The timestamp for each contract is the date when the contract was signed, not when drilling is scheduled to commence. This is an important difference since contracts may be signed years before work is scheduled to begin. Using the date of contract signing will have a more realistic response to current market conditions. However, contracts may be postponed, shortened or even terminated and this is not shown in the data.

In addition awarding lower dayrates (see fig. 2.5), contracts for floaters have become significantly shorter. Drillships and semisubmersibles had an average planned contract duration of around 800 and 440 days in 2010, whilst in 2019 both had an average duration of just above 200 days. Contract lengths for jackups has been fluctuating - in most part between 150 and 400 days. The number of contracts awarded have also decreased, in particular from 2011-14.

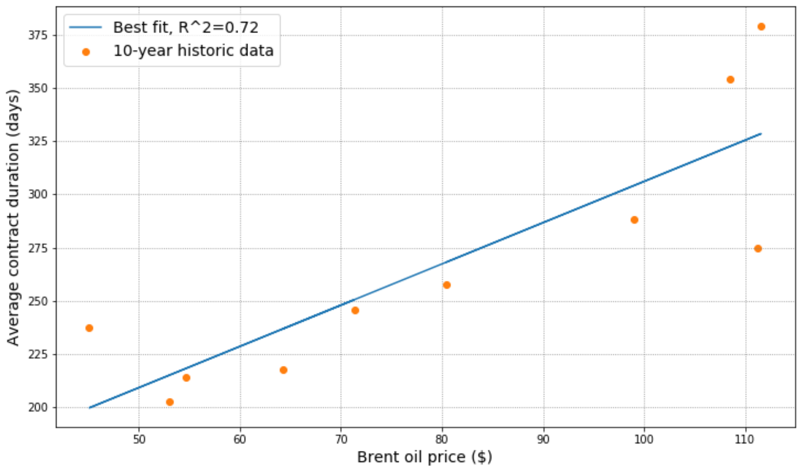
It is of interest to consider the exact relation between length of contracts and oil price. In fig. 2.8, yearly average contract duration is plotted against Brent Crude. A simple linear regression line is fitted, which yields a quality of fit pf 0.72. This suggest that indeed



12 month average duration of contracts signed is plotted by rig type (left-hand axis). To compare with market conditions, a bar chart of the number of contracts signed each year is shown as well (right-hand axis).
The date is taken as when the contract is signed, not when it is executed. This date will have a more appropriate response to market conditions since the date of commencement of drilling is set in the future.
Data is provided by Westwood Global Energy Group (RigLogix, 2020). Historic Brent Crude oil prices are retrieved from Macrotrends (Macrotrends LLC, 2020).

Figure 2.7: Mean Contract Duration by Rig Type, 2010-19

contracts tend to be longer as oil price is higher.



Twelve month average duration of contracts signed is plotted by average price of Brent Crude. A positive correlation is suggestive from scatter plot. A best fit line with intercept 112.5, gradient 1.9 and $R^2 = 0.72$ was found.

Figure 2.8: Twelve Month Average Contract Duration by Oil Price, 2010-19

Chapter 3

Theory of Methodology

In this chapter

The objective of this thesis is to create a model that enable rig owners to evaluate performance and robustness of offshore drilling units in face of uncertain future market states. We present a method for generating feasible realisations of the market in section 3.1, based on previous work (Erikstad et al., 2011). This realisation may be quantitatively evaluated by linear optimisation in the form of a network model, which is shown in section 3.2. Finally, in section 3.3 we argue that use of stochastic modelling allow for useful modelling of irreducible market uncertainty.

3.1 Market Representation by Use of Contract Scenarios

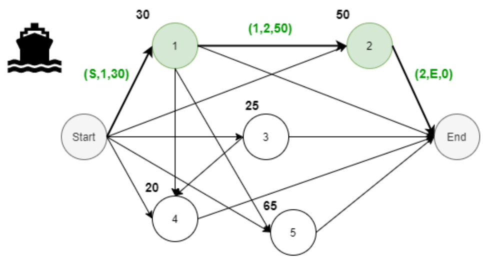
Any generated market representation should provide a feasible, quantitative realisation of a market state that reflects its dynamics. Erikstad et al. propose use of contract scenarios as a way of realising a market state for a limited period of time (Erikstad et al., 2011). A contract scenario consist of a finite set of contracts (as shown in table 3.1), which are described by a set of parameters such as revenue, start time, duration and specific requirements. The investigated ship will be eligible for service if the vessel's capacities meet the requirements specified in the contract. For example, an offshore construction vessel would require a specific minimum hook load capacity for lifting a subsea module.

	Period	Revenue
Contract 1	2020-22	30
Contract 2	2022-25	50
Contract 3	2021-23	25
Contract 4	2024-26	20
Contract 5	2022-26	65

Table 3.1: Example of Contract Scenario

3.2 Network Optimisation

Based on a set of contract entities, a BIP model may be formulated to maximise total revenue generated by a vessel (Erikstad et al., 2011). A network model is formulated, which consist of nodes and arcs (Lundgren et al., 2012). The contracts represent the nodes and the arcs form pathways between the nodes (fig. 3.1). A start node and end node is added, thus the total number of nodes will be the number of contracts, plus two. The investigated vessel have to traverse the network, beginning from the start node and finishing at the end node. The arcs are unidirectional and represent the legal paths that the vessel may take. The optimisation algorithm form a subclass of network problems, called the longest path problem.



The network consist of the contracts in table 3.1, represented as nodes. Arcs are drawn from one contract to another. The prerequisite is that the start date of the new contract is after the end date of the previous. For this example, the optimal solution is shown in bold. This is the combination of contracts that yields the largest combined revenue. Arcs for the optimal solution are shown in green - labelled from-node, to-node and revenue for to-node.

Figure 3.1: Example of Network

Two constraints define the network structure. First, the contracts in the network are a subset of the total, making up the *feasible* contracts for a given vessel. This set is found by comparing the capacities of the vessel against the requirements of the contracts. Second, arcs between two nodes can only exist between contracts that are non-overlapping temporally. If two contracts overlap in time, both may not be serviced by the same vessel. After the set of feasible nodes and arcs have been properly defined, the network may be solved by Ford's algorithm, which is detailed in section 3.2.1 (Lundgren et al., 2012).

By applying this method to offshore rigs we may form a framework of which an individual rig unit may be evaluated if the set of available contracts are known. One advantage with this method is that the problem formulation guarantee finding the global optimum solution, thus we are not required to evaluate the influence of choice of optimisation algorithm. One major challenge is to develop realistic contract scenarios since dayrates, durations and frequency of contract releases are difficult to predict (as discussed in chapter 2).

3.2.1 Ford's Algorithm

Ford's algorithm is presented in full (Lundgren et al., 2012). This is applied to determine the longest path of a network. The "length" of each arc will be measured by contract revenue, which we will return to in chapter 4.

1. Given a set of N nodes and A arcs that make up a network structure.. All nodes have attributes $(n_i, p_i, y_i) =$ (node id, predecessor node, value). All arcs have attributes $(i, j, c_{ij}) =$ (from node, to node, cost).
2. Divide N into two subsets: searched nodes $S = \varnothing$ and unsearched nodes $U = N$. Initial node values are set to negative infinite - except for start node, which is set to zero.
3. Select node from U with highest value, $n_i = \max(y_i, n_i \in U))$. First iteration will be start node.
4. For selected node, n_i, search all arcs going from current node, $(i, j) \in A_v$.
   - If $y_i + c_{ij} > y_j$, then a longer path from start node n_s to n_j (going through n_i) has been found. Update for n_j, $(p_j, y_j) = (i, y_i + c_{ij})$.
   - If n_j was in searched set S, move to unsearched set U.
5. Move n_i from U to S.
6. Termination of algorithm is obtained when all nodes are in searched set - $U = \varnothing$ and $S = N$.

3.3 Stochastic Modelling

A fundamental assumption for the above described method is that all market opportunities (contracts) are known beforehand for any given time period. This may be true short term where new projects from oil companies have been announced and tendering processes are due to commence. However investment decisions regarding fleet composition have to be made before such information is available. A more long term perspective is therefore more useful.

From our review of the offshore drilling industry it is clear that there are irreducible elements of uncertainty for future market conditions. However, modelling different potential scenarios may provide insight and enable quantification of decision making under uncertainty. Now, programmes may be modelled either as deterministic or stochastic. Deterministic programmes can be developed by use of mean values from historic data, although it is not given that historic values have predictive qualities. It is not certain if such a model will reflect market behaviour when conditions change.

A stochastic formulation incorporates degrees of uncertainty by use of (pseudo) random number generators. These models may yield different results for each iteration. By running a stochastic programme multiple times one may obtain a range of results comprised of a mean value and variance, thus converting uncertainty to risk.

Literature suggest that stochastic programmes offer added value. Pantuso et al. compared deterministic and stochastic programmes for a maritime fleet renewal problem (Pantuso et al., 2015). Binary decision variables indicate whether or not a specific vessel, newbuild or second-hand, should be purchased. They found that the solutions of the stochastic model were significantly better.

For our purposes, this approach means that the generation of any given contract scenario should not be interpreted in a literal sense. The set of contracts should represent the opportunity space for the investigated rig unit to generate revenue. By a repeated scenario generation and optimisation, we may identify how rigs perform on average, for different market assumptions. This will provide rig owners with information of performance potential and risk exposure of their assets.

A stochastic contract scenario may be developed by use of random number generators and probability distributions for uncertain parameters (e.g. oil price and dayrates). In addition, causal relationships between parameters should be reasonably incorporated according to evidence. A specific parameter will have different properties (such as mean value, variance and correlation coefficients). The quality of property estimates may have different degrees of influence on the results. In one paper, stochastic programmes was formulated with different erroneous parameter values and compared with a correct baseline. It was found that inaccurate modelling of mean values may lead to significantly worse results, whilst inaccurate correlation coefficients had limited effect (Pantuso et al., 2016). Although this was related to a specific problem case, a final statement bear relevance. The objective of stochastic programming is not to develop correct estimators, but to ”suggest good decisions”, and the quality of some estimators may have limited impact on final results.

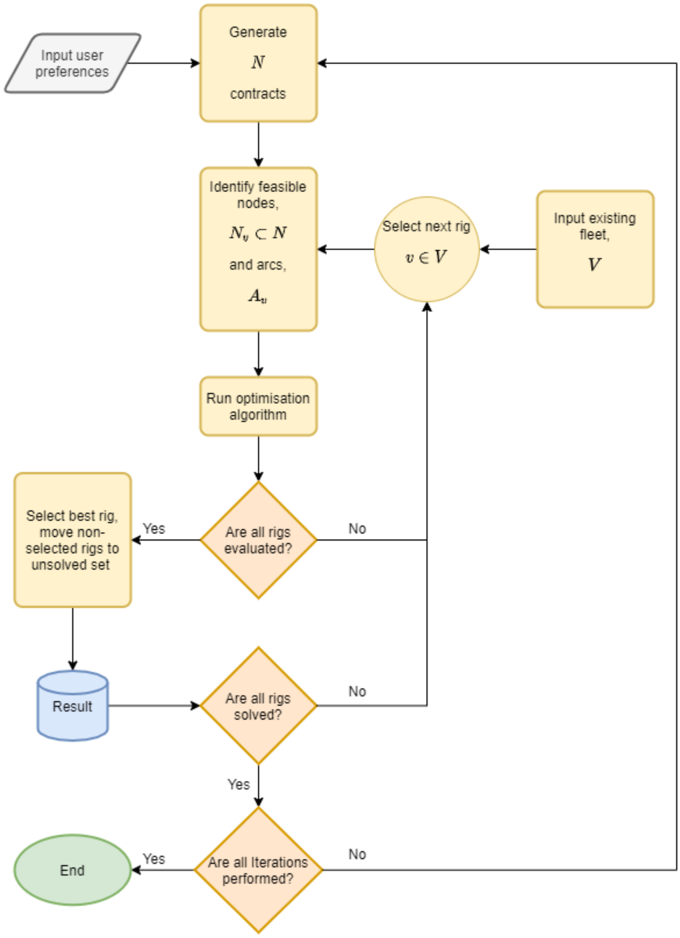
Chapter 4

Method

In this chapter

A network optimisation model is presented to enable rig owners to evaluate offshore rig performance and robustness. Figure 4.1 illustrates the main steps performed, which are covered in this chapter. A system description, including boundaries and fundamental assumptions, is presented in section 4.1. Representation of future market states is realised by the application of contract scenarios. This consist of a set of N contracts defined by exogenous parameters - presented in section 4.2, and contract attributes, which are outlined in section 4.3.

A theoretical or existing rig fleet, consisting of V entities, is modelled according to principles discussed in section 4.4. The rigs are evaluated individually, looping over the fleet, for the generated contract scenario. The linear optimisation model is given in section 4.5. Due to inherent stochasticity of contract scenarios, results are recorded and the procedure is repeated for a specified number of iterations. Important points regarding the simulation procedure is given in section 4.6. Section 4.7 concludes this chapter with a presentation of case studies, which will be analysed in the following chapters. Different modes of use are discussed and results shown in chapter 5 are based on these.



User preferences consist of market assumptions in form of exogenous parameters, as well as specifying time period and number of iterations desired. The processes shown are presented in sequence through this chapter. In short, the program generate a set of contracts, compute the potential revenue for each rig unit by use of an optimisation algorithm, and selects the best rig. The algorithm loops until a solution for all rigs have been selected.
Some notation is included in the figure and are defined in section 4.5. N make up a set of contract and V a set of rigs. N_v and A_v are the set of nodes and arcs that describe a network.

Figure 4.1: Flowchart of Methodology

4.1 System Description

The system is comprised of four distinct markets identified by geography: Brazil, Gulf of Mexico, North Sea and West Africa. There are two types of entities, contracts and offshore rigs. The contracts generated are imagined offered by an arbitrary oil producer. Each are described by a set of attributes, outlined in section 4.3. Rig units are, unlike contracts, defined by an input file. This represent the current fleet we want to investigate. Similar to contracts, each rig will have a set of attributes, described in section 4.4.

4.1.1 Assumptions

Throughout this chapter we make assumptions of the described system that enable its modelling, to the level of our understanding. It is more meaningful to present these as they occur, however some general assumptions are in place.

- The number of contracts available, for a specified time period, is known today. This means that scheduling is planned with full market information - new information is not added during simulation.
- We assume no tendering process - of which the contract issuer selects the rig making the best offer. The algorithm simply assign the contracts that form part of optimal solution for the evaluated unit.
- It is assumed that contracts and offshore rigs may be reasonably modelled by a set of attributes. Multiple modelling choices for these have been made and will be explained in the following sections.
- Market sizes are modelled with data based on oil production and reserves. Natural gas production is ignored.
- Contracts are generated on a yearly basis. That is, for each year a certain market state is generated and a number of contracts with set attributes is created based on this. Note that all contracts are created at the start of the simulation and the contract scenario make up all contracts over the simulation period.

4.1.2 Period and Time Step

A definition of time period, T, and time step of simulation have to be made. The time period is the planning horizon of which rig performance is evaluated. The step size determine the resolution of the data. A small step size may allow for greater detail at the expense of added computational time. A large step size may leave out important effects.

Due to the stochastic nature of the rig market it is of limited utility to simulate over a 30-40 year period, which is a common scheduled lifetime of a rig unit. From review of historic data it was wound that contracts typically range from several months to a few years. A simulation period of ten years will allow for a satisfactory number of contracts to commence and conclude, whilst a time step of one month seem sufficient. This yields a total of 120 points in time.

4.2 Exogenous Parameters

Exogenous parameters influence model behaviour, but is not evaluated within the model. They represent external factors that influence the system and are specified from input. For now, oil price is the main external parameter model. In section 2.2 oil price was found to have the most profound effect on market activity and literature suggest a certain causal influence on dayrates (see section 2.3.2). Since it is not realistic to predict future oil prices, rig performance may be evaluated for different price scenarios. To allow for varying oil price over the simulation period, it is generated on a yearly basis drawn from a normal distribution. Expected value and variance is set as input parameters.

A second parameter is the fleet size, that is the number of rigs evaluated. This is important since the number of contracts available should be generated relative to fleet size. If not, then the number of design options considered will influence results.

4.3 Contract Attributes

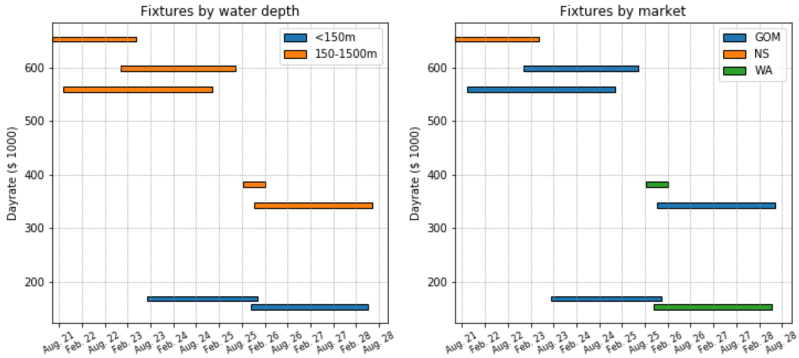
Use of contract entities is a way of representing a potential realisation of a future market state. A set of N contracts with different attributes is generated. The attributes are listed below.

1. Market region, M - section 4.3.2
2. Set of requirements, $\Psi = (\psi_1, \psi_2, \psi_3)$ - section 4.3.3
   (a) Environment, ψ_1 - classified as either harsh or benign
   (b) Water depth, ψ_2 (m) - shallow, mid- or deepwater
   (c) Well type, ψ_3 - exploration, appraisal or development drilling contract
3. Start date, T_s, and duration, D - section 4.3.4
4. Revenue, R ($) - section 4.3.5

An example of a contract scenario realisation is given in fig. 4.2. The contract period is represented by the stretch along the x-axis. Dayrates are given from the y-axis. The contracts are colour coded in two subplots to display water depth specification and market region.

4.3.1 Number of Contracts

A stochastic number of contracts is generated using a normal distribution. The expected value of this distribution dependent on exogenous parameters. Contracts are generated on



The figure displays temporal and dayrate attributes for a set of contracts. In addition, the legend indicates which market the contracts belong to and their respective water depths. The abbreviations are short for Gulf of Mexico, North Sea and West Africa.

Figure 4.2: Contract Schedule by Requirement

a yearly basis, and the total generated over period T, make up the the set N.

The more contracts available, the higher the likelihood that rigs will be able to find work. The number of contracts generated is normalised by the current fleet size, V, to make the size of the fleet independent of results. The expected number of contracts generated per year will be the size of the fleet multiplied by a ratio, r_t, which depend on that year's oil price, P_{oil_t}. Table 4.1 present these ratio values, whilst eq. (4.1) show how N is computed.

P_{oil_t} (\$)	< 30	< 60	< 100	≥ 100
r_t	0.5	1	2	3

Table 4.1: Ratio for Number of Contracts

$$
\begin{aligned}
\mu_{N_t} &= V r_t(P_{oil_t}) \\
N_t &\sim N(\mu_{N_t}, \sigma_N) \\
N &= \sum_{t \in T} N_t
\end{aligned}
\tag{4.1}
$$

4.3.2 Market Region

Each contract will be located in a specific market region. Region is assigned at random draw from a probability distribution, which is determined based on two assumptions. First, the number of contracts awarded by region is consistent with oil production levels. Second, production levels are in steady state, which means there is no temporal changes in market sizes. Regional production shares shown in table 2.5 may therefore be interpreted as the probability of any given contract being located in the respective regions. The probability array is provided in table 4.2.

Region	Brazil	Gulf of Mexico	North Sea	West Africa
P(region)	0.20	0.28	0.22	0.30

Table 4.2: Distribution of Contracts by Region

Estimated distances between markets are shown in table 4.3 [1]. Market distances were applied to compute the time it would take a given rig to sail between markets. To illustrate, examples of a jackup being transported at 1 kts and a floater sailing at 10 kts, is provided. Effects from currents, waves and wind are ignored, thus it is assumed that the sailing direction is irrelevant.

Route	**Distance** (nm)	**Transit Time** (months)	
		Jackup (1 kts)	Floater (10 kts)
B - GOM	5200	7.1	0.7
B - NS	5700	7.8	0.8
B - WA	2900	4.0	0.4
GOM - NS	4600	6.3	0.6
GOM - WA	5700	7.8	0.8
NS - WA	5100	7.0	0.7

Table 4.3: Distance and Sailing Time Between Markets

4.3.3 Requirements

Requirements specify what capacities are required for a rig to be eligible for service. The process of assignment of requirements for each contract is described in the next paragraphs.

Environment

A binary indicator ($\psi_1 \in [0, 1]$) is used to describe whether a contract is harsh or benign environment. This is decided by the market category for the contract. Currently, the North Sea is the only harsh environment market. Remaining markets are classified as benign environment.

[1] `https://www.google.no/maps/`

Water Depth

For each market there will be drilling activities for a range of depths. Water depth is divided into three groups; shallow water (0-125 meter), midwater (125-1500 meter) and deepwater (more than 1500 meter). A categorical variable ($\psi_2 \in [0, 1, 2]$) is used to identify depth category each contract.

In table 2.4, an overview of offshore production by depth in 2015, was provided. Similar to production by region, this data may be applied to derive the depth distribution of contracts within different market regions. This follows from the assumption that USA, Angola and Norway are representative for their respective regions. This may of course be challenged, but it is simple to alter these probabilities at a later stage, given appropriate data. Table 2.4 is therefore utilised to develop a probability matrix for any contract with a given market being within a specific depth range. The probability matrix is given in table 4.4

Region	**Shallow water,** less than 150 m	**Midwater,** 150-1500 m	**Deepwater,** more than 1500 m
Brazil	0.04	0.61	0.35
Gulf of Mexico	0.22	0.50	0.28
North Sea	0.25	0.75	0
West Africa	0.17	0.72	0.11

Table 4.4: Relative Production Rate by Depth
The table shows the rate of production by depth, over the total production in eac market. The numbers are based on 2015 data (Manning, 2016a). By assuming that the relative rate of production does not change we may instigate this as the probability of a certain depth for each contract in a given market.

Well Type

A variable ($\psi_3 \in [0, 1, 2]$) specify the type of well for each contract - exploration, appraisal or development. It was suggested in chapter 2 that appraisal contracts tend to be more expensive. A criteria for exploration drilling is rig mobility, which render jackups unsuitable for such contracts.

The NPD has published data on the category of every well drilled on the NCS since 1966 (Oljedirektoratet, 2020b). We assume that the relative distribution of wells is representative for all markets, thus we can determine the probability of a contract falling into a certain category (see table 4.5).

Well Type	**Number of wells**	**Amount of total**
Development	4961	0.74
Exploration	1164	0.17
Appraisal	605	0.09

Table 4.5: Distribution of Well Type on the NCS, 1966-2020

4.3.4 Contract Period

Start time (T_S) and duration (D) is assigned for each contract. Assuming no seasonality, the start month may be randomly drawn from a uniform distribution. The start year is the year of which the contract is generated.

In section 2.3.3 it was shown that the variance of contract durations is high - sometimes higher than expected values. Therefore it is not suggested that it is realistic to predict contract lengths on an individual basis. However, a reasonable estimated value may be generated based on the current oil price. In fig. 2.8, a best fit line with $R^2 = 0.72$ was found. Expected value may be determined from this linear curve and the actual contract duration may be drawn from a normal distribution. A standard deviation of 80% of mean value is used, which is close to what was found from historic data.

Denote duration for contract i D_i, and oil price P_{oil}. Then the expected duration of contract i is found by eq. (4.2). Duration for each contract is computed by eq. (4.3).

$$\begin{aligned} \mu_D &= \beta_0 + \beta_1 P_{oil} \\ &= 112.5 + 1.9 P_{oil} \end{aligned} \tag{4.2}$$

$$D_i \sim N(\mu_D, 0.8\mu_D^2) \tag{4.3}$$

4.3.5 Revenue

The revenue (R) of each contract is determined by dayrate (DR) multiplied with the contract length. Dayrate is generated from a normal distribution with expected value μ_{DR} and variance σ_{DR}^2. The expected dayrate is set to depend on oil price - which describes the state of the market, and contract specifications, which account for contract complexity and cost. A standard dayrate is generated by eqs. (4.4) and (4.5). Different coefficients are applied for jackups and floaters (subscripts j and f) - which are retrieved from fitted lines in fig. 2.6.

$$\begin{aligned} \mu_{DR_j} &= \beta_{0j} + \beta_{1j} P_{oil} \\ &= 58605 + 546 P_{oil} \end{aligned} \tag{4.4}$$

$$\begin{aligned} \mu_{DR_f} &= \beta_{0f} + \beta_{1f} P_{oil} \\ &= 38853 + 3423 P_{oil} \end{aligned} \tag{4.5}$$

Given the requirements of each contract, premiums are awarded to account for increasing revenue due to complexity. These rates are based on findings in section 2.3.2. The premiums are as follows:

1. Harsh environment contracts are awarded additional 15% of standard dayrate.
2. Deepwater contracts (above 1500 m) are awarded additional 40% of standard dayrate.
3. Longer than 18 month contracts are awarded additional 30% of standard dayrate.
4. Appraisal drilling contracts are awarded additional 20% of standard dayrate.

Variance is determined as a percentage of expected value based on table 2.7. For jackups, the ten year average standard deviation was around 50% of expected value, whilst for floaters it was just above 30%. It is expected that part of this variance is explained by differences in rig capacities, therefore the relative variance is somewhat lower. The standard deviation for jackups is set to 40% and 25% for floaters. Finally, DR of contract i is computed by eq. (4.6).

$$DR_i \sim N(\mu_{DR}, \sigma_{DR}^2) \tag{4.6}$$

4.4 Rig Attributes

A set of N rig entities are constructed with their own set of attributes. These are listed below.

1. Name
2. Type - classified as drillship, semisubmersible or jackup
3. CAPEX, C_v ($) - section 4.4.1
4. OPEX, O_v ($/month) - section 4.4.2
5. Set of capacities, $\Phi = (\phi_1, \phi_2, \phi_3)$
   (a) Environment class, ϕ_1
   (b) Water depth, ϕ_2 (m)
   (c) Transit speed, ϕ_3 (kts)

Rigs are predefined as input and represent the set of design options to be evaluated. The different attributes serve different purposes. The rig name works as a unique identifier, useful for programming purposes. Rig capacities Φ have to satisfy contract requirements Ψ to be eligible for service. Transit speed determines the time required to move between markets. If one contract is located in Brazil whilst the other is in the North Sea, a transit time need to be added to identify the earliest start of new contract.

4.4.1 Capital Expenditure

The price a rig is purchased may vary depending if it is bought second hand or directly from a construction yard. When there are many rigs in market these may also be purchased at a discount. However, for now it is assumed that the cost of purchasing a rig is similar to the listed construction cost, presented in section 2.1.5.

Instead of assigning the purchase cost as a lumped sum, it is useful to model apply a constant depreciation rate. Most rigs have an expected lifetime of 30-40 years and it is unrealistic that a ten year period will be adequate to give a return on investment. By imagining a fixed depreciation rate, the actual capital cost for ten years will be around one third of total expenditure.

4.4.2 Operating Expenditure

Operating cost is the fixed cost related to daily rig operations. This may depend on operating status - for example the rig being idle, drilling or sailing. Costs may be significantly different depending on rig type and specification.

It has proven difficult to obtain sufficient data for comparable rigs, as discussed in section 2.1.6. Estimates are therefore generated based on review of financial reports from industry rig owners (see table 2.2). Homogeneous fleets provide reasonable estimates of unit rig cost by type. It is reasonable to assume that accurate cost data will be available to rig owners and it is therefore relatively simple to update the model. Singular and periodic costs, such as those related maintenance and surveys, are ignored. Due to insufficient data, operating costs are assumed constant independent of operating status.

4.4.3 Fleet Input

In table 4.6, a set of rigs is present. This represent the required input specifications of a fleet to be investigated. Results in chapter 5 are based on this fleet.

Type	CAPEX ($ million)	OPEX ($ million)	HE/BE	Water depth (m)	Transit speed (kts)
JU 1	70	1	HE	150	1
JU 2	57	0.8	BE	150	1
DS 1	185	4.5	BE	3600	12
S 1	185	4.5	BE	3000	7
S 2	200	4.5	HE	3000	8
S 3	157	3	HE	1500	4

Table 4.6: Set of Rigs

4.5 Formulation of Optimisation Problem

For a given set of contracts (N) and offshore rigs (V), the objective is to maximise profit. A network model, consisting of nodes and arcs, is developed. Nodes represent contracts, whilst each arc represent a pathway between two contracts. Mathematically, the arcs are realised as binary variables, x_{ijv}. Networks will have different forms for each rig since the set of nodes and arcs will change. Rigs are solved in a loop with appropriate termination statements based on preference.

4.5.1 Modes of Analysis

Three different model applications are identified. In comparison of design alternatives, it is sufficient to determine the optimal solution for each rig and compare results. However, when evaluating an existing fleet, it is desirable to establish total fleet performance. Similar rigs may have the same optimal solution, which means that the same contract may be awarded multiple times. This is not realistic, therefore serviced contracts are removed from set before the next rig is solved.

In mode 1, contracts are not removed from set and remain available for all rigs. In mode 2, serviced contracts are removed from set whenever a rig has been selected. The problem is then resolved before the next rig is chosen. Later we will also introduce mode 3, which consist of changes being made to the rig fleet, thus enabling comparison of different fleet options.

4.5.2 Compatible Contracts

The first step is to identify the subset of contracts that may be serviced by the investigated rig unit, $N_v \subset N$. This is done by comparing the requirements of each contract i, Ψ_i, with the capacities of rig v, Φ_v. An example is provided in table 4.7

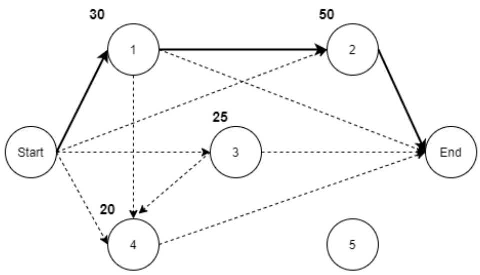
	Period	Revenue R ($Million)	Environment ψ_1	Depth ψ_2 (m)	Well Type ψ_3
Contract 1	2020-22	30	HE	500	Appraisal
Contract 2	2022-25	50	BE	1500	Development
Contract 3	2021-23	25	BE	150	Exploration
Contract 4	2024-26	20	BE	500	Development
Contract 5	2022-26	65	HE	2500	Appraisal
Semisubmersible	-	-100	HE	1500	-

Table 4.7: Example of Compatibility Evaluation of Contracts for Rig
The table shows a comparison between the requirements of a set of contracts against the capacities of a rig unit. The rig satisfy requirements for contracts 1-4, but do not meet the water depth criterion for contract 5. Therefore, the set of feasible contracts is $N_v \in [1, 2, 3, 4]$. Note that well type is only a limiting requirement for jackups since both semisubmersibles and drillships are assumed to be mobile (self-propelled).

The requirements are specified as categorical variables. The feasibility check is formalised as a constraint in eq. (4.11).

4.5.3 Network Optimisation

After defining N_v we the set of feasible arcs, A_v, is identified. The arcs represent all possible combinations of contracts that may be serviced. The pathways are defined by contracts that are non-overlapping in time, which is later realised as a constraint in eq. (4.12). Continuing with the previous example, a network is presented in fig. 4.3.



An example of a simple network model. There are four compatible contracts for the current rig unit. Arcs are represented by unidirectional arrows. Contract pairs $(1, 3)$, $(2, 3)$ and $(2, 4)$ overlap in time and therefore no arc between them exist. We denote the starting node as 0 and the end node as -1. The set of feasible arcs is: $A_v \in [(0, 1), (0, 2), (0, 3), (0, 4), (1, 2), (1, 4), (1, -1), (2, -1), (3, 4), (3, -1), (4, -1)]$. Each entry in A_v contain information about the revenue generated for traversing the arc (node it is moving to). The rig cost is added to the arcs moving to the end node. This cost component is identical no matter which contract is the last to be serviced. For this simple example, the optimal solution is highlighted by arrows in bold.

Figure 4.3: Example of Network Model

In section 4.5.4 the general BIP problem is formulated. This is expanded in section 4.5.5 of which an existing rig fleet is incorporated. Each rig will have to traverse its own network model - from start to end node, in order to maximise profit. This is achieved by use of Ford's algorithm, presented in section 3.2.1.

4.5.4 General Problem Formulation

The most general problem is to identify the most profitable rig amongst a selection, given a specific contract scenario. The problem formulation is based on the work of Erikstad et al (see chapter 3), although some variations are made.

Sets and indices

1. N - set of contracts, denoted by indices i and j.
2. V - set of offshore rigs, denoted by index v.
3. $N_v \subset N$ - subset of contracts compatible with rig v.
4. A_v - subset of arcs in network that can be traversed by rig v. These are denoted as (i, j) to indicate the contract it is moving from and contract it is moving to.

Note from fig. 4.3 that there will be N plus two nodes. This is because the network algorithm makes use of a start and end node. The start and end node is denoted by subscripts $i = S$ and $i = E$ respectively.

Parameters

- Contract parameters
  1. M_i - market indicator
  2. R_i - revenue of contract i in USD
  3. Ts_i - start date
  4. D_i - duration of contract i in months
  5. $\Psi = (\psi_1, \psi_2, \psi_3)$ - set of requirements
     (a) ψ_1 - environment (binary: equal one if harsh environment, else zero)
     (b) ψ_2 - water depth (categorical: shallow-, mid- or deepwater)
     (c) ψ_3 - well type (categorical: development, exploration or appraisal)
  6. L_{ij} - distance between markets for contract i and j in nautical miles.
- Offshore rig parameters

1. C_v - total cost of rig v
2. $\Phi = (\phi_1, \phi_2, \phi_3)$ - set if capacities
   (a) ϕ_1 - environment (binary: equal one if harsh environment class, else zero)
   (b) ϕ_2 - water depth (categorical: shallow-, mid- or deepwater)
   (c) ϕ_3 - transit speed in knots

Variables

- x_{ijv} - binary variable equal to 1 if rig v is servicing contracts i and j, else 0

Objective Function

The objective function of the optimisation problem is formulated in eq. (4.7). Revenue is maximised and rig costs are subtracted from arcs connected to the end node.

$$max \sum_{v \in V} (\sum_{(i,j) \in A_v} R_j x_{ijv} - \sum_{i \in N_v} C_v x_{iEv}) \tag{4.7}$$

Constraints

$$\sum_{v \in V} \sum_{j \in N_v} x_{Sjv} = 1 \tag{4.8}$$

Equation (4.8) ensures that exactly one rig is selected and moving from start node to first contract.

$$\sum_{v \in V} \sum_{i \in N_v} x_{iEv} = 1 \tag{4.9}$$

Equation (4.9) ensures that exactly one arc is active to end node.

$$\sum_{i \in N_v \cup [E]} x_{ijv} - \sum_{i \in N_v \cup [S]} x_{jiv} = 0, \qquad v \in V, j \in N_v \cup [S, E] \tag{4.10}$$

Equation (4.10) ensures continuity of flow through all contract nodes. Note that the indices for the binary variables are switched. Combined with eq. (4.8) and eq. (4.9), these constraints ensure flow of exactly one rig from start node to end node.

$$\phi_{kv} \geq \psi_{kj} - (\psi_{kj} - \phi_{kj})(1 - \sum_{i \in N} x_{ijv}), \qquad v \in V, j \in N, k \in \Psi \tag{4.11}$$

Equation (4.11) ensures that the capacity of requirement k for rig v is greater than or equal to requirement k for contract j. These constraints define subset N_v. Specifically, the constraint is set on all arcs moving to each contract. A second constraint is implemented in practice on all arcs moving from each contract to limit the number of arcs (variables) to evaluate.

$$\begin{aligned} Ts_j \geq Ts_i + D_i + \frac{L_{ij}}{\phi_{3v}} - Y(1 - \sum_{v \in V} x_{ijv}), \qquad i, j \in N_v \\ Y = (Ts_i + D_i + \frac{L_{ij}}{\phi_{3v}} - Ts_j) \end{aligned} \tag{4.12}$$

Equation (4.12) ensures that only arcs between sequential contracts are allowed - that the start time of contract j is after the end date of contract i, plus potential sailing time between contracts. Dates are described by integer numbers in the program. These constraints define subset A_v.

$$x_{ijv} \in [0, 1], \qquad v \in V, (i, j) \in A_v \tag{4.13}$$

Equation (4.13) are binary constraints for the decision variables. In addition, it is stated that (i, j) pairs must form pair of subset A_v. This statement is redundant because of constraints eqs. (4.11) and (4.12), but included for consistency.

4.5.5 Existing Fleet

The problem formulated in section 4.5.4 selects the best rig in set V. This is useful when comparing different rig designs against each other. However, in other cases one may want to evaluate rig units in light of an existing fleet. This will allow evaluation of multiple rigs individually, or as a whole. It may also help identify rig additions that complement the fleet. We add this functionality to by adjusting constraints in eqs. (4.8) and (4.9).

$$\sum_{v \in V} x_{Sjv} \leq 1, j \in N_v \tag{4.14}$$

$$\sum_{v \in V} x_{iEv} \leq 1, i \in N_v \tag{4.15}$$

Equations (4.14) and (4.15) states that, for each contract compatible with rig V, at most one rig may service that contract. The algorithm is no longer fixed to only selecting one rig unit.

However, one additional constraint is required to ensure that if eq. (4.14) equal one for rig v, then eq. (4.15) equal one for that rig as well. A flow of one from start node require a flow of one to the end node, for each rig unit. This is achieved by eq. (4.16).

$$x_{Siv} - x_{iEv} \leq 0, i \in N_v, v \in V \tag{4.16}$$

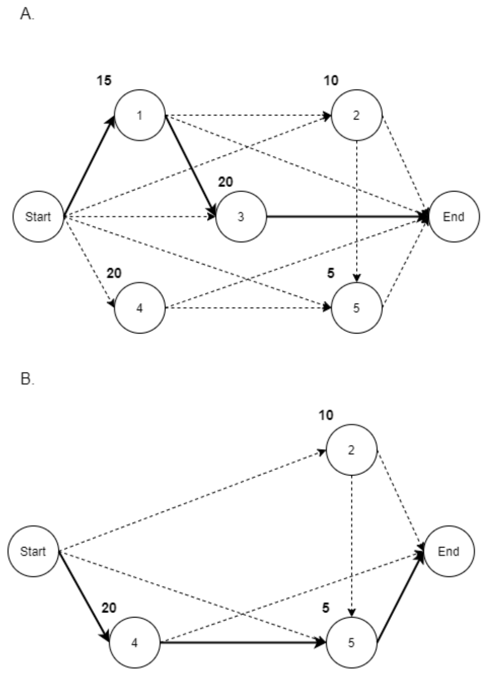
4.5.6 Optimisation Algorithm

Ford's algorithm is used for finding the longest path in a network problem (presented in section 3.2.1). It is more commonly used for finding the shortest path between two nodes through a set of intermittent nodes, the variation being called Dijkstra's algorithm (Lundgren et al., 2012). The algorithmic steps is formalised below and implemented with a computer by use of Python programming language.

1. Input contract data and rig data.
   (a) Set of N contracts with attributes (M, R, T_s, D, Ψ).
   (b) Set of V rigs with attributes (C, Φ).
2. Divide rigs into solved set, $V_s = \varnothing$ and unsolved set $V_u = V$
3. Find subset N_v - set of contracts compatible with rig $v \in V_u$.
4. Find subset A_v - set of arcs containing only non-overlapping contracts.
5. Execute Ford's algorithm for each candidate $v \in V_u$
6. Select rig v^* that yields the best solution from selection criteria (section 4.5.7), move v^* from V_u to V_s.
7. **If** we have an existing fleet (mode 2),
   (a) Remove serviced contracts by v^* from set N.
8. Repeat until all rigs have been solved, $V_u = \varnothing$.

4.5.7 Selection Criteria for Best Solution

The described algorithm is looping over a set of rig options to find each candidate's longest path (max revenue from set of contracts). When evaluating an existing fleet, the best rig is chosen and serviced contracts are removed from set N. We then repeat the process for all non-selected rigs to choose the second candidate. This is repeated until all rigs have been removed from the unsolved set. The process is illustrated in fig. 4.4 and it shows how the network is different each time a rig is chosen as the 'best candidate'.



The figure illustrates two iterative solutions to the network problem, A and B - for two identical rig candidates. Both rigs will have the optimal solution shown in A since the longest path is shown to be through contracts 1 and 3. These contracts are removed and allocated to the selected rig. For the second rig a new network B is available - of which the allocated contracts have been removed. The longest path have to be computed once again. Therefore rig 1 is awarded contracts 1 and 3 for a net revenue of 35, whilst rig 2 is awarded contracts 4 and 5 for a net revenue of 25.

Figure 4.4: Looping Solution to Longest Path Problem for a Set of Rigs

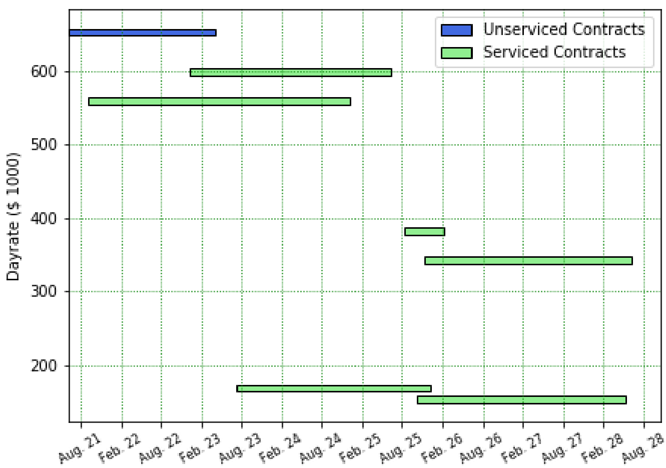
To accomplish this, an unambiguous selection criterion is required, which defines the best rig. The obvious option would be to simply select the rig that yields the largest revenue, since this is consistent with the objective function. However, this raises an issue of rig specification. High specification rigs will always have a larger network than low capacity rigs, therefore a greater (and in many cases definite) likelihood of being selected first. One specific consequence is that floating rig units designed for ultra-deepwater contracts are awarded a great amount of shallow water contracts, which are in reality serviced by jackups. Jackups are not able to compete with such a selection criteria and will end up with unrealistic results.

A more viable option is to start by allocating contracts for low specification rigs first and then move upwards towards higher capacity. The benefit from this is that low requirement contracts are awarded to low specification rigs and high requirement contracts for high specification rigs. This is especially useful in scenarios when the number of available contracts is sparse, which means that some rigs will be left idle for extended periods of time.

There is an issue of given precedence to different types of specification, for example water depth and environment class (harsh versus benign). We choose to give midwater rigs precedence over benign environment rigs since there is only one market that exclude these (the North Sea). This gives a hierarchical solution order to rigs based on specification.

4.5.8 Example of Output

A visual representation of the output from the optimisation algorithm is given in fig. 4.5. This is the same contract scenario as illustrated in fig. 4.2. The contracts are distinguished between those that are being serviced by a rig and those that are not.



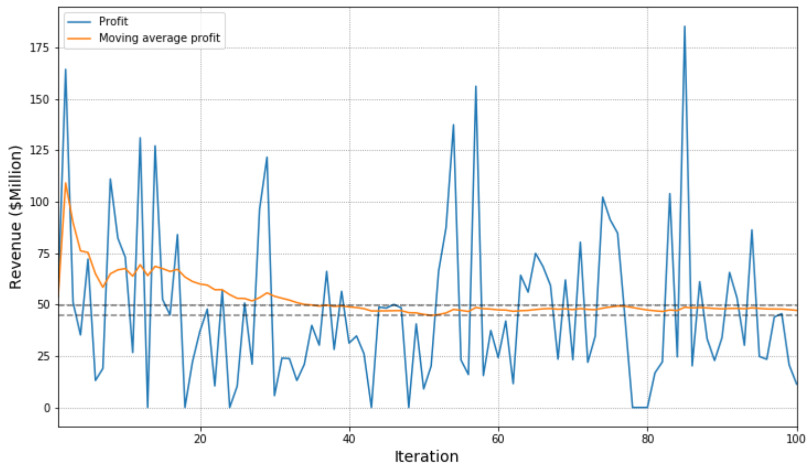
The figure illustrates temporal and profit attributes of contracts for market scenario. The colour coding is distinguishing between contracts that are being serviced by a rig and those that are not. The figure does not show which rig is servicing a specific contract, although there must be different rigs servicing contracts that overlap in time.

Figure 4.5: Serviced Contracts by Dayrate

4.6 Simulation

A degree of model stochasticity is introduced to account for market uncertainty. Any individual results may therefore offer limited insight. A Monte Carlo approach is therefore suitable, of which repeated runs are performed to record a range of results and expected values computed.

To determine what would be a sufficient set of iterations, a test run is performed to determine when the difference in compounded average value, from one iteration to the next, is satisfactory small. Figure 4.6 show the profit generated from an arbitrary rig unit over 100 iterations. The two horisontal lines indicate a 5% tolerance and it is observed that the average value converges to around \$50 million after 50 iterations. It is therefore concluded that 50 runs is sufficient to generate satisfactory expected values.



The profit of an arbitrary rig is plotted for 100 iterations. The moving average profit is plotted to establish when there is a sufficient convergence of results. Note that there is significant variation of profit from one iteration to the next.

Figure 4.6: Convergence Study of Mean Profits

4.7 Case Studies

No attempt has been made to predict future oil prices, but the actual price has a profound effect on the model. A method of analysing different market states is to develop case scenarios of average price values and perform repeated simulations. One may then evaluate what insight can be retrieved from different price levels.

Three cases of different oil price are developed and are presented in table 4.8. In addition, the distribution of contracts by water depth is set to be different depending on price scenario. The rationale is that there will be an increased rate of deepwater projects when oil price is high since these tend to be more expensive. When the oil price is low, projects are postponed, in particular on the exploration side.

Results for all three cases will be presented in chapter 5 and discussed in chapter 6. Note that other market case studies may be highly relevant and of interest. This depends on user preference, but the method has been developed to allow for flexibility of input assumptions.

Scenario	**Oil price**		**Distribution of water depth**		
	$\mu(\$)$	$\sigma(\$)$	$< 150m$	$150 - 1500m$	$> 1500m$
1	30	10	0.85	0.10	0.05
2	60	15	0.60	0.25	0.15
3	100	25	0.4	0.35	0.25

Table 4.8: Different Oil Price Cases

4.8 Computer Implementation

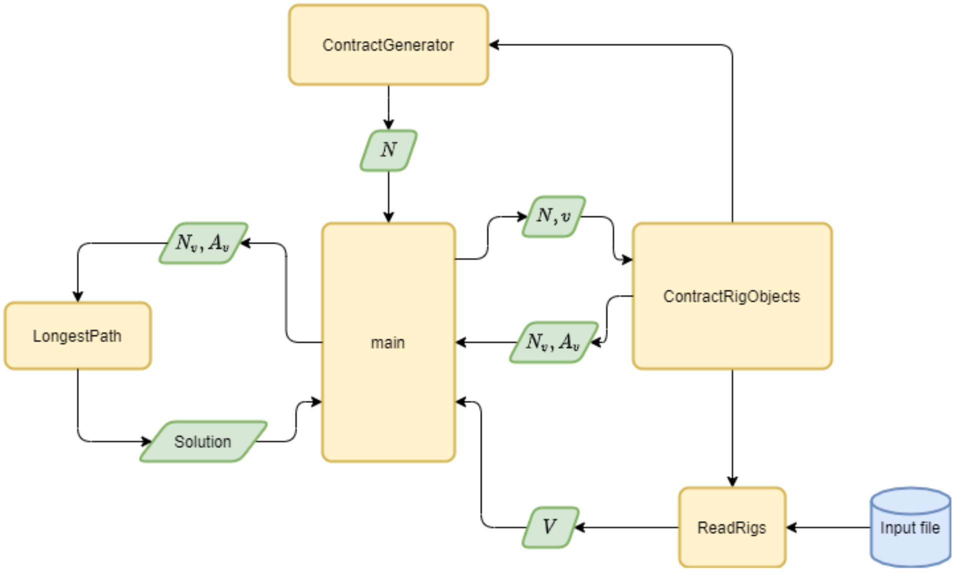
The method was implemented by use of Python programming language. Instead of using a commercial optimisation solver, Ford's algorithm is explicitly written, as shown in section 3.2.1. This solves in a satisfactory amount of time for our applications, however a study has not been performed by comparing other solver options. The main libraries used are listed below.

- Numpy - used for most mathematical computations in model
- Pandas - used for processing data, writing and reading comma separated value (.csv) files
- Matplotlib - used for generating plots and figures

The program is submitted along with this thesis. The main executing files and their function are briefly described.

- main - run this file to execute program
- ContractGenerator - returns a set of contracts from input
- ContractRigObjects - develops objects (rig and contract) with corresponding attributes

- ReadRigs - reads file with rig data and creates a set of rig objects
- LongestPath - develops network and runs optimisation algorithm



The most important files are shown in yellow. Inter-dependencies and flow of information is illustrated by green boxes.

Figure 4.7: Schematic Overview of Main Files

Chapter 5

Results

In this chapter

Results for three different applications, for different oil price scenarios, are presented. In section 5.1, rigs are evaluated on an individual basis for comparison. This may be a useful approach for comparing design options or purchasing of an existing rig unit. In section 5.2, rig performance is analysed in presence of an existing fleet. The difference is that serviced contracts are consecutively removed from feasible set and therefore one contract cannot be allocated to multiple rigs. This enables performance evaluation of the whole fleet, as well as the individual contributions of each unit.

Finally in section 5.3, we compare different fleet compositions to develop the optimal mix of a fleet of fixed size, given a specific market scenario. Specifically we vary the number of bottom-fixed rig types in fleet as an illustrative case study of how ideal fleet composition may be evaluated.

5.1 Mode 1: Individual Rig Analysis

In mode 1, simulation is run independently for all rigs. Contracts are not removed from set once allocated and different rigs can therefore service the same contract. The interpretation is that the market opportunities of one rig does not influence that of the next one. The simulation consist of fifty iterations that are run for different oil price scenarios, described in table 4.8. Mean results for each rig unit are presented in tables 5.1 to 5.3. Illustrations of rig profit and utilisation are provided in figs. 5.1 and 5.2.

Rig Name	Profit ($Million)		Contracts served	Utilisation rate (%)		Number of relocations	Number of HE contracts
	μ	σ		μ	σ		
JU1	-43.12	27.91	7.66	47	7	2.96	1.56
JU2	-23.24	26.94	7.34	43	8	2.04	0
DS1	-326.47	83.73	12.86	70	7	7.62	0
Semi 1	-275.09	82.86	12.36	67	7	6.98	0
Semi 2	-289.57	75.39	13.74	74	7	9.42	3.26
Semi 3	-156.09	54.9	12.04	67	7	7.68	3.88

Table 5.1: Rig Results for Case 1 - Oil Price $30 p/b

JU is short for jackup and DS is short for drillship. The mean value and standard deviation of profit is given in columns two and three. Column four shows the average number of contracts served. Columns five and six gives the mean and standard deviation of utilisation, in percentage. The average number of relocations from one geographic market to another is shown in column seven. Note that the more mobile floaters are more inclined to change location. Finally, in column eight, the number of harsh environment contracts serviced is shown.

Rig Name	Profit ($Million)		Contracts served	Utilisation rate (%)		Number of relocations	Number of HE contracts
	μ	σ		μ	σ		
JU 1	45.65	55.11	6.7	54	9	2.28	2.02
JU 2	54.41	54.85	6.42	51	11	1.56	0
DS 1	488.34	183.61	11.08	84	6	6.28	0
Semi 1	513.98	178.9	10.44	81	6	5.36	0
Semi 2	543.73	176.78	11.36	86	6	7.48	1.84
Semi 3	478.26	162.59	9.62	78	7	6.08	3.16

Table 5.2: Rig Results for Case 2 - Oil Price $60 p/b

Rig Name	Profit ($Million)		Contracts served	Utilisation rate (%)		Number of relocations	Number of HE contracts
	μ	σ		μ	σ		
JU 1	254.85	89.83	5.86	70	15	1.82	1.72
JU 2	243.01	93.37	5.84	68	16	1.4	0
DS 1	1936.9	380.96	9.14	90	6	5.3	0
Semi 1	1946.37	373.33	8.7	88	6	4.48	0
Semi 2	2014.12	411.84	9.18	92	6	5.92	1.64
Semi 3	1613.89	371.73	8.08	85	8	4.64	3.68

Table 5.3: Rig Results for Case 3 - Oil Price $100 p/b

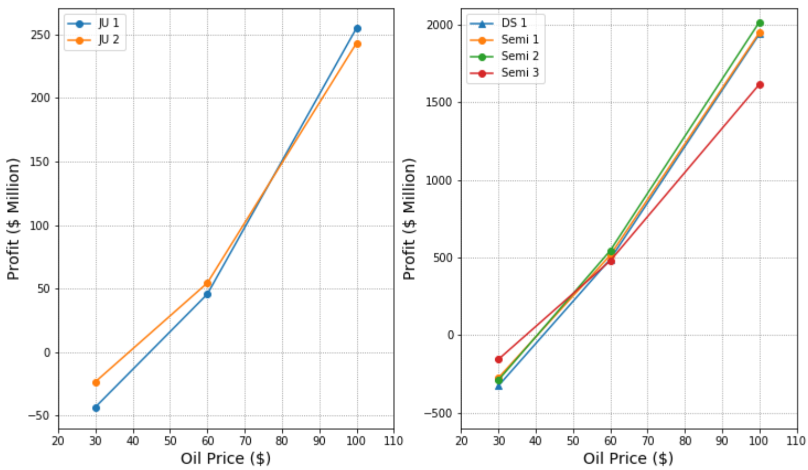


Figure 5.1: Mode 1: Rig Profit at Different Oil Price Scenarios

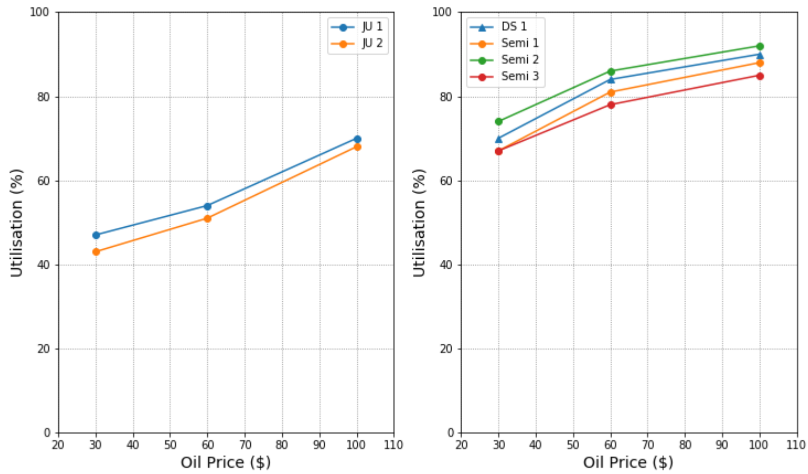


Figure 5.2: Mode 1: Rig Utilisation at Different Oil Price Scenarios

Close to one order of magnitude difference in gradient of profit, for floating rigs and jackups, is observed (we therefore found it reasonable to create separate plots). All rigs generate a net loss in the low price scenario - \$20-40 million for jackups and \$150-325 million for floaters. The loss is greater for floaters due to higher costs (constant for all scenarios). Profits turn positive and utilisation increases in the medium price scenario. Both jackups generate a profit of around \$50 million whilst floaters obtain around \$500 million. Utilisation is around 50% for jackups and 75-85% for floaters. The high price scenario returns a net profit of \$250 million for jackups and \$1.6-2 billion for floaters.

Although utilisation increases for higher price scenarios, the average number of contracts served decreases, as shown in tables 5.1 to 5.3. This is because contracts will be longer for higher priced markets. The utilisation rate is also expected to increase as the number of contracts are reduced since each transition impose a risk of downtime.

The gradient in fig. 5.1 of Semi 3 is somewhat lower than for the other floaters. Semi 3 has a certified water depth of 1500 meter, which means it is unable to service to service ultra-deepwater contracts. In the high price scenario, there will be more such contracts available, thus eligible rigs will be able to generate greater earnings. Semi 3 has lower capital and operating cost, which explains a lower net loss for the low price scenario.

Drillship 1 has the second highest utilisation rate and slightly higher than Semi 1, which is of equal specification. This suggest that a higher transit speed between markets enable some improvement in network paths, although the significance is limited. However mobile floaters do have a higher rate of market relocations compared to jackups. Jackups are therefore to a greater extent constrained to one market.

Jackup 1 has a higher utilisation than Jackup 2 since it is harsh environment classified. This effect is marginal and Jackup 1 yields higher profit for the low and medium price scenario due to lower costs. Semi 2 is both ultra-deepwater and harsh environment classified, and therefore has the highest overall utilisation. Semi 3 is harsh environment, but not ultra-deepwater class, and has a lower utilisation than Semi 1 - which is ultra-deepwater, but not harsh environment class.

5.2 Mode 2: Fleet Allocation Problem

In mode 2, price scenarios are repeated, however the rigs are now included as part of an existing fleet. Contracts that have been awarded to a specific rig unit are now removed from the feasible set. Results for all three price scenarios are given in tables 5.4 to 5.6. In figs. 5.3 and 5.4, we have plotted profit and utilisation similar to previous results. Finally, in fig. 5.5, a boxplot is generated for total fleet values. This gives an impression as to the spread of the results.

Rig Name	**Profit** ($Million)		**Contracts served**	**Utilisation rate** (%)		**Number of relocations**	**Number of HE contracts**
	μ	σ		μ	σ		
JU1	-27.68	27.85	8.72	53	7	2.68	1.7
JU2	-58.09	23.36	6.38	35	8	1.74	0
DS1	-511.88	78.8	9.58	48	12	5.72	0
S1	-593.87	39.88	4.12	20	10	2.22	0
S2	-271.82	68.61	14.48	76	6	10.22	3.28
S3	-279.51	70.88	10.66	55	10	6.94	3.76
Total Fleet	-1742.84	309.38	53.94	48	9	29.52	8.74

Table 5.4: Fleet Result for Case 1 - Oil Price $30 p/b

Rig Name	**Profit** ($Million)		**Contracts served**	**Utilisation rate** (%)		**Number of relocations**	**Number of HE contracts**
	μ	σ		μ	σ		
JU 1	60.05	57.42	6.64	56	10	2.52	2.02
JU 2	-7.49	45.89	5.74	40	11	1.62	0
DS 1	211.9	221.04	10.54	76	9	6.24	0
Semi 1	4.51	191.46	8.92	62	12	4.88	0
Semi 2	463.88	169.37	11.5	84	6	8	2.42
Semi 3	188.79	154.74	9.08	67	10	5.32	4.08
Total Fleet	921.63	839.92	52.42	64	9	28.58	8.52

Table 5.5: Fleet Result for Case 2 - Oil Price $60 p/b

Rig Name	**Profit** ($Million)		**Contracts served**	**Utilisation rate** (%)		**Number of relocations**	**Number of HE contracts**
	μ	σ		μ	σ		
JU1	233.42	78.25	5.8	68	10	1.92	1.76
JU2	144.09	73.61	5.68	57	10	1.4	0
DS1	1535.13	326.8	9.04	87	5	5.48	0
S1	1235.86	287.96	8.44	82	6	4.56	0
S2	1920.9	380.82	9.04	91	6	6.3	1.94
S3	1250.63	273.38	8.1	81	7	4.38	4.4
Total Fleet	6320.02	1420.82	46.1	78	7	24.04	8.1

Table 5.6: Fleet Result for Case 3 - Oil Price $100 p/b

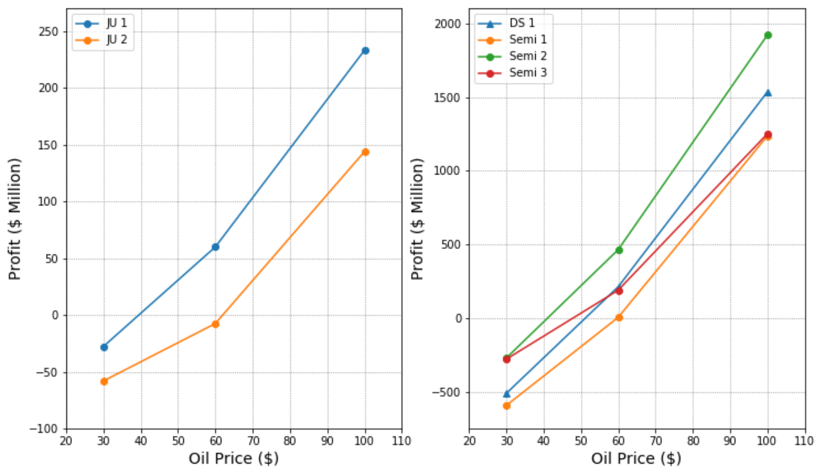


Figure 5.3: Mode 2: Rig Profit by Oil Price

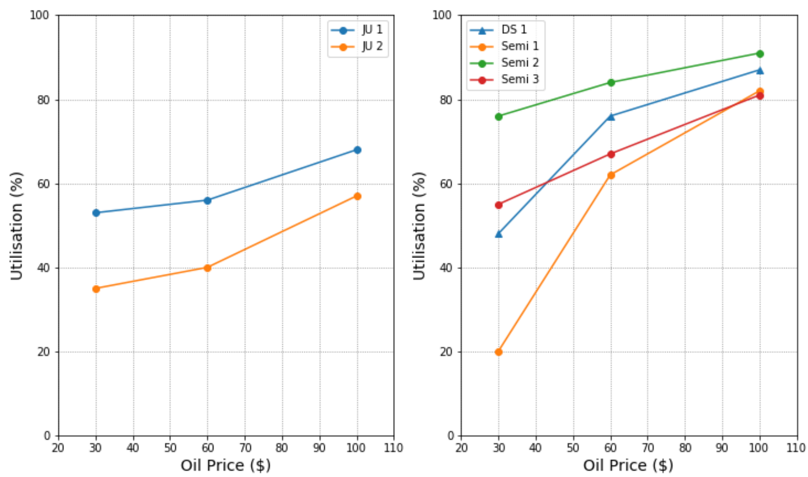


Figure 5.4: Mode 2: Rig Utilisation by Oil Price

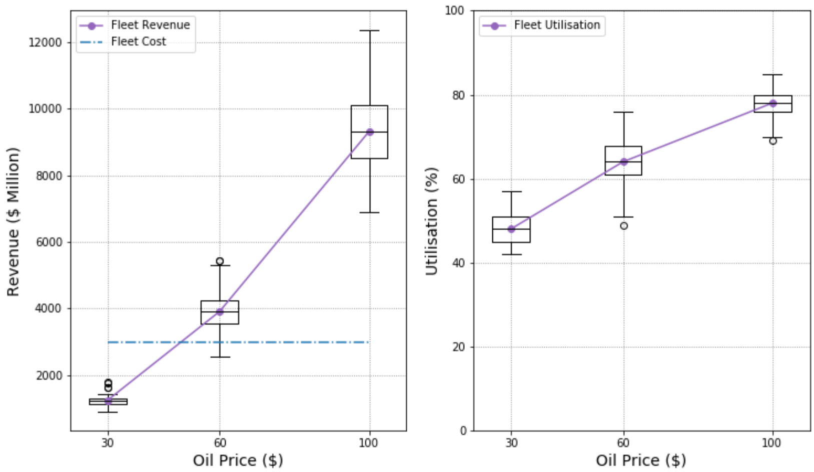


Figure 5.5: Mode 2: Fleet Results by Oil Price

The overall trend is similar as in section 5.1, however there is a greater spread between individual rigs. This is reasonable - when contracts are removed from set rigs cannot follow the same network paths.

In contrast to previous results, a floater now has the lowest utilisation in the low oil price scenario. Jackup 1 and 2 has a utilisation of 53% and 35%, whilst utilisation for Semi 1 is 20%. This is because jackups are awarded contracts before floaters and therefore have precedence on shallow water contracts (see section 4.5.7). There are too few remaining contracts available for Semi 1 (and most other floaters), therefore a low utilisation is obtained. Semi 2 is the only rig that remains relatively unaffected.

The fleet generates an expected deficit of $1.7 billion for the low price scenario. A net profit is recorded for the medium and high price scenarios - $0.9 and $6.3 billion respectively (fig. 5.5). Fleet also utilisation increases for each scenario, from 48% to 78%.

5.3 Mode 3: Optimal Fleet Mix

We have seen how the model may be applied to compare rigs on an individual basis, with and without competition, as well as the performance of the fleet. In this section we consider what would fleet mix would be ideal. Again, we use the oil price scenarios described in table 4.8. Since the number of contracts generated depends on the fleet size, the number of rigs in fleet is fixed to six units.

It was found that there is a major difference in results between jackups and floaters, however they may complement each other in a shared fleet. By varying the number of jackups and floaters, a comparison may be made for different fleet compositions. Seven fleet candidates - each with a size of six units, are created and the number of floaters in fleet range from zero to six. The simulation is repeated as previously. For a set of seven fleets and three price scenarios this yields 21 different simulations.

In figs. 5.6 to 5.8 results are presented for all fleets, each figure shows a different price scenario. Each point represent a unique fleet and the x-axis indicates the number of floaters present - fleet revenue, costs and profit are plotted. The utilisation of each fleet is plotted in the right window, for each figure. The figures illustrate what will happen if you make a unit change in fleet mix, for different price scenarios. The individual rig properties are similar to the ones described in table 4.6.

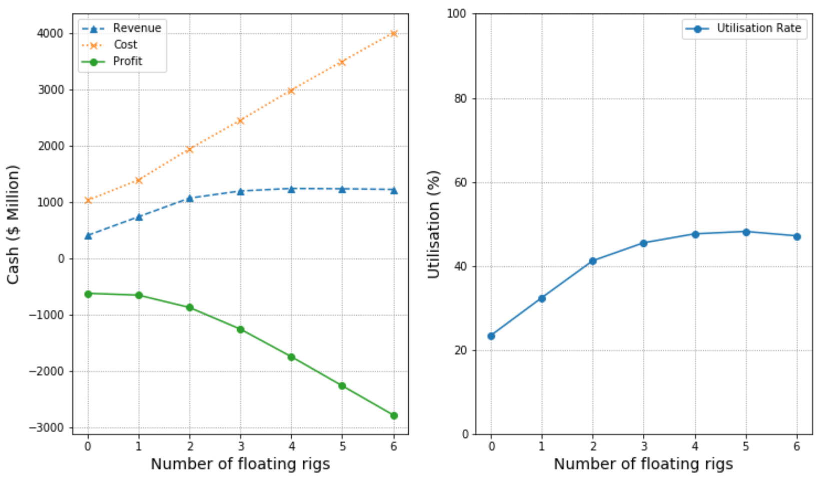


Figure 5.6: Mode 3: Revenue for $30 Oil Price, Different Fleets

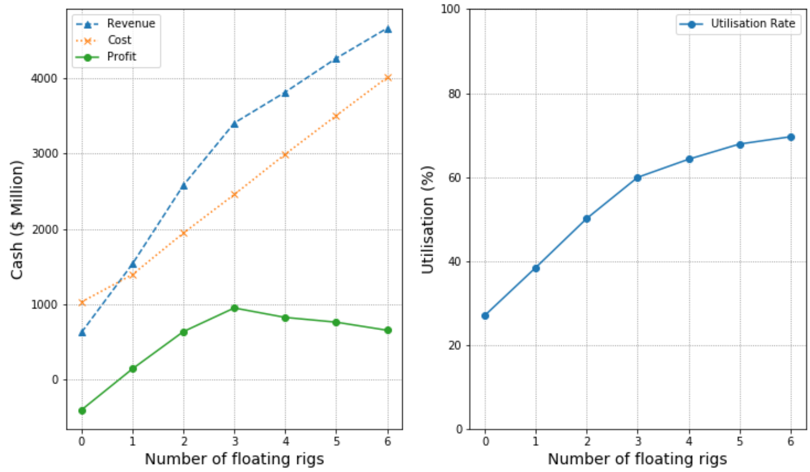


Figure 5.7: Mode 3: Revenue for \$60 Oil Price, Different Fleets

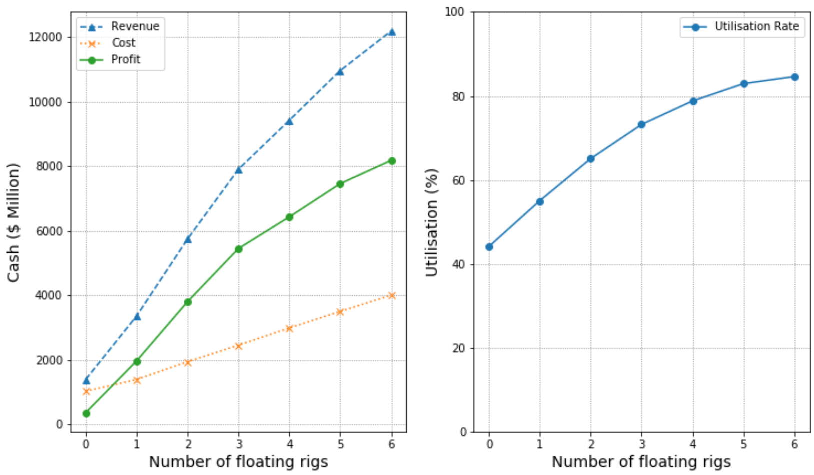


Figure 5.8: Mode 3: Revenue for \$100 Oil Price, Different Fleets

For the low price scenario, no fleets manage to obtain a net profit (fig. 5.6). Note that the fleet with zero floaters has the lowest deficit and is therefore the best choice. There is a small increase in deficit when moving from zero to one floater in fleet. When number of floaters are further increased the gain in revenue become smaller. Since cost increase is fairly constant, a linear downward trend in profit become apparent. Utilisation is increased until the fleet consist of four floaters. Further addition of floaters do not result in greater utilisation, which suggest that most contracts are already being serviced and the market is saturated.

We observe a maximum net positive profit of $950 million in the medium price scenario. The optimal fleet consists of three floaters and three jackups, with an overall utilisation of 60%. There is a continued increase in revenue and utilisation as you add more floaters, however the gradient is lower. The the unit increase in cost is higher than the unit increase in revenue.

For the high price scenario, there is also a marked reduction in gradient of revenue when more than three floaters are introduced. However, there is an increase in profit each time a new floater replaces a jackup. The optimal fleet composition consist exclusively of high specification floaters, with a profit of $8.2 billion and an utilisation of 85%. This indicates that the market has not been saturated and that there are more ultra-deepwater, high yielding contracts available.

5.3.1 Probability Weighted Results

The optimal fleet composition differ for each scenario. For the low price scenario the optimal fleet consist of six jackups and zero floaters, an equal distribution is optimal for the medium scenario, whilst for the high price scenario a fleet consisting exclusively of floaters is ideal. Naturally, the rig owner will have to determine a fleet mix before new information of correct market scenario is available.

To determine what fleet mix a rig owner should choose, one may assign probability weights for each scenario occurring. These probabilities should be based on market analysis and one should also have a sense of understanding of the likelihood of being right (confidence intervals). Although beyond the scope of this thesis, an example is provided for illustrative purposes.

We assume that the future can take a finite set of P manifestations. Let p_i be the probability of future scenario i occurring. We define a set of Y fleets. The expected profitability of fleet y is the expected revenue, minus the constant operating and capital costs $(R_{iy} - C_{iy})$. The weighted expected profitability of fleet y is then given in eq. (5.1).

$$w_y = \sum_{i \in P} p_i (R_{iy} - C_{iy}), \qquad y \in Y \tag{5.1}$$

We assume for this example that the three case scenarios completely describe set P. The probability of each scenario is given in table 5.7.

Case	**Oil Price**	**Probability** (p_i)
1	$30	35 %
2	$60	50 %
3	$100	15 %

Table 5.7: Probability of Future Oil Price Scenarios

The weighted profitability of all fleets are given in table 5.8.

Fleet	**Case 1**		**Case 2**		**Case 3**		**Weighted**
	p_1	Profit ($M)	p_2	Profit ($M)	p_3	Profit ($M)	**mean** ($M)
6 JU	0.35	-623	0.5	-403	0.15	364	-365
5 JU	-	-655	-	141	-	1966	136
4 JU		-874		635		3803	582
3 JU		-1259		950		5451	852
2 JU		-1748		823		6432	765
1 JU		-2266		760		7463	707
0 JU		-2784		653		8182	580

Table 5.8: Probability Weighted Results for Different Oil Price Scenarios

According to this method, the fleet consisting of three jackups and three floaters is most robust. It has an estimated profitability of $852 million. The second best fleet consist of two jackups and four floaters and have a profitability of $765 million. The worst fleet consist exclusively of jackups and have an expected deficit of $365 million. This should not come as a surprise given the low utilisation rate shown earlier.

Chapter 6

Discussion

In this chapter

Section 6.1 consist of a discussion of the main findings from the different modes presented in chapter 5. We will highlight how the model provides rig and fleet performance insight and suggest different applications. In section 6.2 we evaluate the methodology by reviewing relevant strengths and weaknesses.

6.1 Main Findings From Results

6.1.1 Mode 1: Individual Rig Selection

Given a set of design options, the model computes estimated revenue for different price scenarios. This may provide a recommendation of selection of rig design for new investments. The results show that both profit and utilisation is greater for high specification rig units of the same type.

The recommendation is to select the highest specification floating rig in a high price scenario and the low specification jackup in the low price scenario. This is explained by increased earnings potential when oil price is high - there are more contracts available, a greater rate of them are deepwater and more specified rigs are suited for capitalising on this. Oppositely, when market opportunities are scarce, the operating cost of the rig units become crucial as most rigs will lose money. This highlights the extra risk associated with more costly floaters.

One important observation is that there is a great deal of homogeneity for rigs of the same type. Rig type is therefore the dominant specification identifier. Both profit and utilisation follow similar trendlines, some which non-overlapping for different price scenarios. This suggest that certain rigs will be preferable independent of price scenario. For example, Semi 2 outperform Drillship 1 in all three scenarios.

Utilisation for both floating rigs and jackups follow similar trendlines. They are sorted according to specification, which means that high specification rigs have highest utilisation. There are two primary reasons for this. First, rigs will not reject a contract even though they are over-qualified and second, multiple rigs may service the same contract. Since high specification rigs satisfy more constraints, they are able to select more profitable network paths. However, the finding that jackups have on overall lower utilisation is not an accurate description of reality.

6.1.2 Mode 2: Fleet Allocation Problem

In mode 2, emphasis is on rig performance in presence of competition, as well as total fleet profit and utilisation for different price scenarios. A fleet of six units was investigated and allocated contracts were removed from set, thus forcing each rig to take different network paths.

The most apparent observation is increased differentiation between rigs. Substantial differences in profit and utilisation were observed, compared with results in section 5.1. For example, Semi 1 and 2 had a $322 million difference in profit and 56% difference in utilisation for the low price scenario. In table 6.1 we compare results for modes 1 and 2 by showing the difference in profit generated by Semi 1 and Semi 2.

Oil Price ($)	30	60	100
Mode 1	-14.48	29.75	67.75
Mode 2	322.05	459.37	685.04

Table 6.1: Difference in Profit between Semi 1 and Semi 2, by Modes 1 and 2
Computation of the difference in profit generated by Semi 1 and Semi 2, for results in sections 5.1 and 5.2. The difference is computed as the profit of Semi 2 minus the profit of Semi 1.

Semi 1 and 2 are marginally different in terms of specification - Semi 2 is harsh environment certified, Semi 1 is not, and Semi 2 is $75 million more costly in total. Yet Semi 2 outperform Semi 1 in all price scenarios in mode 2 by a significant margin. Relative to mode 2, the differences in mode 1 are less than one tenth.

These findings suggest that high specification rigs tend to dominate the market. They are more flexible, which results in shorter periods of time being without work. When there is competition this may result in low specification rigs performing significantly worse. The rig owner should therefore accept the extra costs and prioritise a modern fleet.

Jackups perform consistently worse, except when all rigs are generating a net loss. They also have a lower utilisation rate, however it is argued that this offer limited practical insight. Rather it seems that one should not generally compare jackups and floaters for the same market scenario. Shallow water contracts are, to our knowledge, dominated by jackups since they are relatively inexpensive.

6.1.3 Mode 3: Fleet Mix Problem

The fleet mix problem enable the rig owner to evaluate the current composition of rigs in inventory. The expected profit for different price scenarios give an impression of the level of risk associated with a certain fleet. By varying rig properties one may consider alternative fleet compositions and their performance implications. However, it would be useful to develop this method further such that different parameters may be altered without manually changing the fleet input, thus enabling effective identification of optimal fleet mix for any given case study. This would require a reformulation of the optimisation problem by replacing rig properties with variables.

The recommendation from the weighted estimated profits is a fleet consisting of an equal number of jackups and floaters (table 5.8). This is seem to be a case of balancing risk and reward since the earnings potential is very diffferent for the three price scenarios. However, we already noted that it may be unrealistic to compare rig types since jackups and floaters are radically different.

On a final note, the results are specific for the actual defined market scenario, which is based on a specific geographic region. This may not be applicable for all companies since they have different strategies. There are examples of companies that focus on one rig type and it is inaccurate to suggest that an equal composition of rig units is universally optimal.

6.1.4 Applications

These illustrative cases suggest that the model can be applied as a tool for analysis of both existing rigs and design alternatives. It is relevant for rig owners and market analysts interested in comparing different fleet compositions. By comparing rigs on an individual basis we found that rig type dominate other specification criteria due to differences in cost. It was also found that high specification rigs have a greater earnings potential, but high costs make them more risk exposed. These findings were amplified on a competitive fleet basis, of which some rigs were outperformed and resulted in a very low utilisation. Such insight may prove valuable when making investment decisions.

Comparing different fleet compositions may be used for rig owners to identify their ideal mix based on market strategy. It may also enable analysts to compare different companies and how well suited they are to take advantage of future market opportunities.

6.2 Evaluation of Methodology

The model is versatile and have potential for different applications. However, development and testing have shown that there is room for improvement. Some points of reflection are worth making and presented in this section.

6.2.1 Realisation of Market States

It seem reasonable to model future market states by a set of contracts since this show the level of demand rig owners will experience. Parameters such as contract payments and duration are effectively generated by use of stochastic functions since they are uncertain and difficult to predict. Investigating casual relationships were to some extent able to provide realistic expected values.

Determination of the number of contracts for any given scenario has proven challenging. Contracts are generated based on oil price working as a market indicator and fleet size as a normalising factor. The number of contracts need to be normalised per rig unit, else a smaller fleet input will result in more contracts per rig unit and a difference in results. This gives flexibility when considering fleet performance (mode 2) since the size of the fleet is arbitrary. However, it is problematic when evaluating rigs individually (mode 1) since there will be an increased number of contract opportunities for larger fleet sizes. When contracts are not being removed from set once serviced, all rigs will generate longer network paths. Mode 1 is therefore only valid for evaluating rigs relative to each other and not in terms of real values. For that, mode 2 is recommended.

6.2.2 Added Constraints for Rig Design

Constraints were developed to differentiate rigs based on design, however identifying key design properties proved challenging. Certified water depth, environment class and rig type are clear identifiers, but there might be others that have not been included. Consulting domain experts to identify other key technical aspects of rig units is advised. An increased level of specification of contract requirements will only improve the results. Some points of interest are listed:

1. Station keeping system
2. Deck area (m^2)
3. Accommodation capacity
4. Drilling speed (m/s)
5. Drilling depth (m)

The use of DP systems require continuous burning of fuel to power thrusters. Isolated, this will have a higher cost than the use of passive mooring systems, although installation cost by use of service vessels should be included. DP systems are not constrained by water depth and may therefore be a requirement for ultra-deepwater rigs.

Operating efficiency may be affected by the ability to perform multiple operations simultaneously. Factors influencing this are deck area, outfitting and the number of workers available. Therefore, given that efficiency is a priority, deck area and accommodation capacity may influence the dayrate is willing to pay for the drilling unit. Efficiency will also be influenced by drilling speed, which may be an interesting measure to consider. The time required to drill a particular well of satisfactory quality may to a great extent differentiate rig units.

The drilling depth restricts how far below the seabed one is able to drill and extract oil. If reservoirs are located outside the specified drilling depth of a certain rig, the rig will not be eligible for service. Evaluating this will require information of the required drilling depth of contracts, for example from historic data.

6.2.3 Precedence and Competition for Rig Units

When more than one rig unit qualifies for a contract, the program will select the rig of highest specification, since it will higher revenue streams (the set of feasible contracts, N_v, will be greater and therefore longer network paths may be found). In some cases, this means that floaters may ”steal” shallow water contracts that will in reality be awarded to jackups. In reality one would expect that contracts on an individual basis will be awarded to the rig that makes the best offer, which is related to operating costs. Qualified rigs with low operating costs will therefore be preferred.

To remedy this effect, a hierarchical selection criterion based on rig specification was developed (explained in section 4.5.7). Low specification rigs were awarded contracts first and this was helpful in particular to ensure that jackups were the preferred option for shallow water contracts. However, this method requires an explicit prioritisation of which specification has precedence (e.g. water depth versus environment class). If one were to add specifications to improve rig descriptions, this method will be increasingly complicated.

The model does not account for competition. Contracts are generated with a fixed revenue, which depend on the contract requirements and not the servicing rig unit. In turn, it is assumed that rigs are automatically awarded contracts if they are selected as part of the optimal solution. To account for this one may assign a probability value of rig v being selected for contract i. This likelihood estimate may depend on the number of rigs in fleet that meet contract requirements. It may also depend on the level of over-specification (penalising or awarding parameter) and cost of the rig unit.

A simple way of realising this is to identify a subset of awarded contracts before solving the network model. After identifying the set of feasible contracts (N_v) for each unit in fleet, we know the number of rigs that are compatible with each contract. Then, let N'_v be the set of compatible contracts that are awarded to rig v through a tendering process - controlled by a probability function. This gives us an impression of relative competition and rigs are no longer guaranteed winning all contracts. A network is formulated from a set of N'_v contracts and optimisation proceeded as before.

6.2.4 Simulation Approach

A simulation approach may offer an alternative to use of network optimisation. If we assume that contracts randomly occur as a Poisson process, they may be generated sequentially over a simulation period. At every instance in time there will be a set of unemployed rigs. The rigs that meet the contract requirements will make offers to service the contract and allocation will be determined by a selection criterion. Once a contract has been awarded, the rig is removed from the unemployed set for the contract period.

The main difference is that we no longer assume that the number of contracts available for the whole period will be known today. New information is added during simulation by the generation of new contracts. It may also enable more accurate modelling of the tendering process since the unemployed rigs have to compete for each contract. The number of unemployed rigs may also be regarded as a measure of utilisation, thus influencing the dayrate of the contract.

6.2.5 Capital and Operating Costs

Obtaining sufficient quality data has at times been difficult. Historic contract data was generously provided by Westwood Energy through the RigLogix platform. Information on specific operating and capital costs of rig units have not been obtained and thus estimates were determined from financial reports. In turn, we are not able to verify results or consider model uncertainties since we do not have a comparable baseline. It is clear however, that rig owners have such information readily available and thus a simple change in input would suffice to address this.

Given that accurate measures of operating and capital costs are in place, it is of interest to estimate the marginal value of any given specification. For example, one may compare rig units of which one is harsh environment certified whilst the other is not. For different market scenarios, the performance of these rigs may help quantify the value of added specification.

It will also be insightful to review operating costs depending on rig status. We assumed that costs are constant independent of whether the rig is either drilling, sailing or idle.

6.2.6 User-Specified Market Scenario

Different markets were classified by region and local conditions assimilated by water depth distribution and environment category. The user should be able to develop customised market scenarios by turning off and on certain market segments (by region or specification or both), thus making it easier to create different case scenarios. Added model flexibility will be welcomed since rig owners have different market strategies and do not compete equally in all segments.

6.2.7 Transit Speed of Jackups

To compute the required transit time between markets, each market was represented by single point coordinates and their respective distances computed. The speed of the floaters were given by comparison of relevant rigs. Since jackups are not self propelled, we assumed that they are less likely to change markets and therefore assigned a low transit speed. Jackups are in reality transported by use of heavy lift vessels, or dragged by use of service vessels. It seem reasonable to include the cost and transit speed of these vessels for more accurate modelling.

Chapter 7

Conclusion

In this thesis, a method for evaluating performance and robustness of offshore rig units was proposed. Stochastic market states were realised by generation of contract scenarios. The interpretation of a contract scenario is a feasible representation of the opportunity space, which differ based on rig design/specification. This is advantageous since it does not require the identification of any individual future contract prospects.

A linear optimisation model was applied to determine the optimal set of contracts serviced for each rig unit. When considering presence of existing rigs, contracts were removed from set once allocated since they cannot be awarded multiple times. A selection criterion based on specification was developed to determine which rig should have precedence for contract selection.

The results show that rigs of higher specification were able to service a more profitable set of contracts and consistently outperform low specification rigs. These are preferable, given that there is a sufficient number of contract opportunities. When there are too few contracts available, rigs that have low operating costs are less risky and yield a lower net loss.

When evaluating the ideal fleet composition by type, it was found that an equal mix of jackups and floaters is optimal. This is however specific to the stated market scenario and should not be considered a general recommendation. Different market scenarios may be defined by changing input parameters, which will enable users to perform relevant case studies.

Bibliography

Borr Drilling, 2020. 4th Quarter 2019 Results. Technical Report. Borr Drilling.

BP Energy Economics, 2019. BP Statistical Review of World Energy - 2019 — 68th edition. Technical Report. BP.

Diamond Offshore, 2020a. 2019 Annual Report. Technical Report. Diamond Offshore.

Diamond Offshore, 2020b. Offshore rig basics. URL: http://www.diamondoffshore.com/offshore-drilling-basics/offshore-rig-basics.

Ensco, 2019. Investor Presentation, February 2019. Technical Report. Ensco.

Erikstad, S.O., Fagerholt, K., Solem, S., 2011. A ship design and deployment model for non-cargo vessels using contract scenarios. Ship Technology Research .

Infield Rigs, 2020. Infield Rigs Data Portal. Technical Report. Infield Systems Ltd.

Kaiser, M.J., 2014. Empirical analysis of dayrate factors in offshore contract drilling, 2000–2010. Taylor & Francis .

Lahn, B., 2019. Norwegian petroleum policy in a changing climate. CICERO .

Lundgren, J., Ronnqvist, M., Varbrand, P., 2012. Optimization. Studentlitteratur.

Macrotrends LLC, 2020. Brent crude oil prices - 10 year daily chart. URL: https://www.macrotrends.net/2480/brent-crude-oil-prices-10-year-daily-chart.

Maersk Drilling, 2020. 2019 Annual Report. Technical Report. Maersk Drilling.

Manning, M., 2016a. Offshore oil production in deepwater and ultra-deepwater is increasing. URL: https://www.eia.gov/todayinenergy/detail.php?id=28492.

Manning, M., 2016b. Offshore production nearly 30% of global crude oil output in 2015. URL: https://www.eia.gov/todayinenergy/detail.php?id=28492.

McKinsey, 2019. Offshore Drilling Outlook to 2035. Technical Report. McKinsey & Company.

Oljedirektoratet, 2020a. Faktasider oljedirektoratet - brønnbane. Oljedirektoratet .

Oljedirektoratet, 2020b. Lete og utvinningsbrønnbaner - sortert etter år boringen startet. URL: https://factpages.npd.no/no/wellbore/statistics/entryyear.

Osmundsen, P., Rosendahl, K.E., Skjerpen, T., 2015. Understanding rig rate formation in the gulf of mexico. Elsevier Ltd .

Osmundsen, P., Toft, A., Dragvik, K.A., 2005. Design of drilling contracts — economic incentives and safety issues. Elsevier Ltd .

Pantuso, G., Fagerholt, K., Wallace, S.W., 2015. Which uncertainty is important in multistage stochastic programmes? a case from maritime transportation. IMA Journal of Management Mathematics .

Pantuso, G., Fagerholt, K., Wallace, S.W., 2016. Uncertainty in fleet renewal: A case from maritime transportation. Transportation Science .

RigLogix, 2020. Historic Contract Data 2010-20. Technical Report. Westwood Global Energy Group.

Rystad Energy, 2020. COVID-19 Report 10th Edition. Technical Report. Rystad Energy.

Seadrill, 2019. Seadrill Limited - Fourth quarter 2019 results. Technical Report. Seadrill Ltd.

Shelf Drilling, 2020. 2019 Annual Report. Technical Report. Shelf Drilling.

Transocean, 2020a. 2019 Annual Report. Technical Report. Transocean Ltd.

Transocean, 2020b. Fleet Status Report Feb 20. Technical Report. Transocean.

UNEP, IISD, ODI, Analytics, C., CICERO, SEI, 2019. The production gap: The discrepancy between countries' planned fossil fuel production and global production levels consistent with limiting warming to 1.5 °C or 2 °C. United Nations Environment Programme .

US Energy Information Administration, 2020. Federal Offshore–Gulf of Mexico Field Production of Crude Oil. Technical Report. U.S. Department of Energy.

Valaris, 2020. 2019 Annual Report. Technical Report. Valaris.

NTNU

Kunnskap for en bedre verden