Universitetet i Stavanger

FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study programme/specialisation: Industrial Economics / Contract administration	Spring semester, 2017 Confidential
Author: Bjørnar Tomassen	…………………………………………… (signature of author)
Programme coordinator: Petter Osmundsen Supervisor(s): Nils Frode Foldnes, Ross Offshore	
Title of master's thesis: Turnkey Contracts in Production Drilling	
Credits: 30 points	
Keywords: Turnkey contracts Incentives Drilling Industry	Number of pages: …63…… + supplemental material/other: 0 Stavanger, 15.06.2017 date/year

This page is left intentionally blank

1 ABSTRACT

Over the past few years, the drilling industry on the Norwegian Continental Shelf (NCS) and worldwide has faced a significant change. With declining oil prices, the margins for both oil companies and service contractors are under pressure and the companies now focus on reducing costs and increasing efficiency.

The NCS is considered a mature drilling area, where the cost of extracting oil is high, due to increasing complexity, high operational costs, smaller fields, tail end production, and decreasing drilling efficiency.

In response, the oil service industry is looking for new approaches to contracts and incentive designs that can gain market share in a declining market. This thesis reviews a case presented by an alliance of service providers to VNG Norge for the field development on the Pil & Bue field. The proposed format is unique to the NCS and is categorized as a turnkey drilling contract. The thesis investigates the proposed contract's format and compares it with the theory of optimal incentive design to find areas of potential conflict, risk, and uncertainty.

2 TABLE OF CONTENTS

1 Abstract ... 3

3 Terminology and Abbreviations ... 7

4 Introduction ... 8

5 Theoretical foundation ... 10

5.1 Contracts ... 10

5.2 The individual's utility ... 11

5.3 Opportunistic behavior ... 12

5.4 Risk-sharing and incentives in contracts ... 13

5.5 Agency theory – The principal-agent model ... 16

5.5.1 Challenges in agency theory ... 18

5.5.2 Adverse Selection ... 20

5.5.3 Responses to the moral hazard and adverse selection problems ... 22

5.5.4 Non-Verifiability ... 24

5.5.5 Other challenges ... 25

5.5.6 Specific challenges in drilling ... 26

6 Contract Design in the Norwegian Drilling Industry ... 27

6.1 Operator – contractor relationship ... 27

6.2 Contract strategies in drilling ... 28

6.2.1 Conventional contract situation ... 28

6.2.2 Bundle service contract ... 29

6.3 Risks relating to drilling ... 30

6.3.1 Blowout ... 30

6.3.2 Well control ... 31

6.3.3 Weather ... 31
6.3.4 Equipment failure ... 31
6.3.5 Formation problem ... 32
7 Case Study ... 33
7.1 Introduction ... 33
7.1.1 About the companies ... 33
7.1.2 Pil & Bue field development ... 34
7.2 Contract Model ... 35
7.2.1 Incentive models in the contract ... 36
7.3 Time and cost estimates ... 37
7.3.1 Drilling campaign time estimates ... 37
7.3.2 Cost estimate for "top hole" sections ... 37
7.3.3 Cost estimation reservoir section ... 38
7.3.4 Cost estimation completion ... 39
7.3.5 Cost not included in alliance deliveries ... 40
7.3.6 Further possible efficiency increases ... 40
7.3.7 Total cost and cost savings ... 41
7.4 Risk sharing in the alliance ... 42
8 Discussion ... 43
8.1 Contract design ... 43
8.2 How the players will benefit from the contract ... 43
8.2.1 Drilling efficiency: ... 44
8.3 Risk ... 45
8.3.1 Risk allocation ... 45
8.3.2 Risk exposure ... 46

8.4 Possible areas of conflict ... 47

8.4.1 Transitioning between wells and sections ... 47

8.4.2 Organization and monitoring ... 47

9 References ... 49

10 Appendices ... 54

10.1 Appendix A, Detailed time estimate ... 55

10.2 Appendix B, Field cost summary ... 63

3 TERMINOLOGY AND ABBREVIATIONS

Agent - a person or entity who can make decisions on behalf of, or that impact, another person or entity. Typically a contractor, employee, sales persons, politician etc.

Principal - a person or entity who hires an agent to act on his behalf or to perform a service or work.

Operator - The oil company responsible for the exploration and production of petroleum resources in a license

Supermajors – a name used to describe the world’s seven biggest publicly owned oil and gas companies.

NCS - The Norwegian Continental Shelf.

GOM – The Gulf of Mexico

MWD – Measurement While Drilling

LWD – Logging While Drilling

ROV – Remote Operated Vehicle

MODU – Mobile Offshore Drilling Units

KPI – Key Performance Indicators

AFE – Authorization for Expenditures

WOW – Waiting On Weather

CAPEX – Capital Expenditure

HSEQ – Health, Safety, Environment and Quality

WOCS – Work Over Control System

BOP – Blow Out Preventer

4 INTRODUCTION

In 2014 the price of oil declined rapidly from over 100$/bbl to less than 30$/bbl. With this decline in price followed a reduction in investments, spending don the Norwegian Continental Shelf (NCS) have declined from 224 mrd NOK in actual spending in 2014 [1] to 147 mrd NOK forecast for 2017 [2]. The reduction in investments is dramatic compared with the peak years of 2010-2014. For example, the number of exploration wells dropped from 42 to 28 from 2014 to 2016 [3]. When the price of crude, and by extension, the value of oil in the ground and field value, drops below the average cost per barrel, the rational thing is to stop exploring for oil and instead develop a strategy for reserve replenishment either by acquiring fields or licenses directly, or indirectly by acquiring smaller companies. Smaller exploration companies with a business strategy to explore and find oil and then sell the proven recourses in the licenses before the field is developed, no longer have a profitable business model. They now face the choice of either selling their resources with a loss, or to shift their focus from exploration to production.

This shift from exploration to acquisition and development has resulted in a sharp decline in drilling activity that has hit the oil service industry and the rig market in particular. The rig market was near 100% utilization of its fleet and day rates upwards of $600,000 per day during the peak years. As of January 1, 2017, 27 of 44 rigs were in cold storage or out of contract according to the Norwegian Ship-owner Association [4], and approximately 40,000 people lost their jobs in the industry [5]. The competition for the remaining jobs is fierce amongst both rig owners and service companies.

This thesis focuses on turnkey drilling contracts as a tool for the service industry to gain market share by differentiating from their competitors, take on more risk, and increase the drilling efficiency, primarily for production drilling. Responding to the declining market, Ross Offshore, Schlumberger, and Transocean entered into an alliance with a goal of developing a different contract model than what is common on the NCS. By transferring risk from the operator to the contractors and giving the operators predictability in economic estimates for field development, the alliance is hoping for a competitive edge when bidding for work. The turnkey contract model also has strong incentives for increasing drilling efficiency.

The contract model is not formalized, and currently it is dynamic and subject to change. In this thesis, I will initially lay out some of the theories and challenges related to contract and, in particular, incentive design. Then, the general situation in the industry is presented before I review of the proposed format in Section 7 and see if the contract format is in line with the theory on contracts, competition, and incentives. Finally I will identify the most important risks for in the model and identify possible gains and losses for both sides.

5 THEORETICAL FOUNDATION

The following sections explain the basic theory and assumptions for agency and contract theory.

5.1 CONTRACTS

In its simplest form, a contract is a binding agreement between two parties with roots in the early beginnings of civilization, as human interaction in groups is largely about sharing labor. “I do this, while you do that, so we can both benefit.”

From these early agreements, a more formal contract theory developed and today, Oxford Dictionary defines a contract as:

> *“A written or spoken agreement, especially one concerning employment, sales, or tenancy, that is intended to be enforceable by law.”*

The Business Dictionary defines a contract as [6]:

> *“A voluntary, deliberate, and legally binding agreement between two or more competent parties. Contracts are usually written but may be spoken or implied, and generally have to do with employment, sale or lease, or tenancy.”*

The definition of a contract as we know it today contains law, economics, and psychology, and theories on this interaction are studied and were developed in all these fields.

All trades are in principle mediated by some form of contract, some more explicit than others [7]. In a perfect world, all contracts would be complete contracts [8]**.** Complete contracts are complete in the sense that they cover all possible variations, changes, and contingencies, and determine all the corresponding actions and compensation. Such contracts are accurate to the point that they cannot be misunderstood and the parties must abide by the terms, even though doing so induces losses.

However, the world is not a perfect place and contracts are, with very few exceptions, always incomplete. The real world and its people are restrained by what Milgrom describes as bounded rationality [8], meaning that humans lack the ability and capacity to evaluate and process all available information and unable to predict all possible outcomes or contingencies. Furthermore, the design, planning, negotiation and construction of a complete contract would be exceedingly costly, and the transaction's cost would be too large [9].

5.2 THE INDIVIDUAL'S UTILITY

The perceived outcome of a situation or the overall satisfaction that an outcome brings to an individual depends on the pay or on the consumption of goods, and on psychological factors such as values, self-worth, or morale. The expression of an individual's welfare in any given situation is their utility and is represented by the Von Neumann – Morgenstern utility function [10].

Utility = U(X1, X2, X3,….,Xn)

Where X refers to the quantity of the possible factors influencing the total satisfaction.

A common illustration is an individual's utility of income and disutility of work. If income is a linear function of effort, and income is the only factor affecting the utility, the rational choice is to work as hard and long as possible to maximize the utility. However, there are other factors at play, which are difficult to evaluate in monetary terms, such as stress or free time. The "pleasure" of working from hour 0 to hour 1 to earn the first 100 NOK is larger than working from hour 23 to hour 24 and making 2400 NOK instead of 2300 NOK. The individual's marginal utility of income decreases.

This way of measuring utility also holds true for companies. Just as an individual a company can allocate resources in many ways, dividends, investments, labor conditions, etc. in a way which maximizing the specific company's utility.

For example, an oil company's utility of a contractor's performance depends on the contract price, speed, safety aspects, quality, and risk sharing.

Many factors influencing the utility are perceived differently by the parties. Goodwill and reputation will affect one party more than the other and the quantification of these factors is subjective. Thus, the outcome of the contract will be evaluated differently for the two parties and a conflict of interest may result.

Economic theory commonly assumes that any rational player acts to maximize their personal utility [11]. When choosing from multiple possible actions, the individual or company tries to reach the outcome that maximizes utility. This maximization of utility also comes into consideration when assessing how much risk a contractor will carry in a contract and compensation for the risk.

5.3 OPPORTUNISTIC BEHAVIOR

The possible conflicts between contractual partners was recognized by Adam Smith in his work on economic theory as early as the late 18th century in his description of the relationship between landowners and workers. In the "Wealth of Nations", he wrote:

> *"What are the common wages of labor, depends everywhere upon the contract usually made between those two parties, whose interests are by no means the same. The workmen desire to get as much, the masters to give as little as possible. The former are disposed to combine in order to raise, the latter in order to lower the wages of labor." [12]*

This recognition or assumption of the self-interested behavior of persons is one of the cornerstones of economic and contractual theory, and the theories of marginal utility and utility maximization build on this postulation. People and organizations try to maximize their perceived outcome from a transaction and are assumed to be amoral in their maximization of the outcome. This assumption leads to useful predictions that often hold up, even if the assumption is relaxed [13].

When a contract is incomplete, there are many possible unforeseen circumstances not covered in the contract. When these situations occur, the parties must adapt and settle on a fair compensation or mitigation. This opens the possibility of opportunistic behavior, when the parties try to turn the situation in their favor, which may be a problem in situations where the two parties have different levels of information. If one party has private information, i.e., relevant information the other part has no knowledge of, according to utility theory, the party with the private information would try to take advantage of this information to get the maximum possible compensation.

Problems of opportunism can be reduced by the threat of damage to a party's reputation and by creating contractual commitments. The goal for the principal is to design the contract to maximize the utility (compensation) to act in the best interest of the other party, to incentivize improving performance and mitigate opportunistic behavior.

The maximization of utility is the foundation for agency theory, which describes the relationship between principals and agents in business.

5.4 RISK-SHARING AND INCENTIVES IN CONTRACTS

How will the contractor be paid for their services, and who bears the responsibility for cost overruns? These are important aspects of any contract and the compensation format depends on the degree of risk allocated to each of the parties.

General economic theory dictates that risk is rewarded. The size of the required compensation from taking on risk depends on a party's degree of risk aversion. If an agent is extremely risk averse, he or she might not want to take on any risk unless the resulting compensation is extremely good. If the principal is less risk averse than the agent, it might be beneficial for the principal to take on the risk himself.

We consider the example of a salesperson selling some product. The salesperson has the option of either being paid a fixed amount per month and no commission or a commission for each sale he makes, but no fixed income.

In the first situation, the salesman has no monetary incentive to sell. If he is not concerned with reputation or by being penalized, he can choose to not do anything and sell no units. His income is fixed and he carries no risk.

The other extreme is a pure commission salary, where the salesperson has strong incentives to sell as many units as possible. If one month, he sells no units due to some uncontrollable situation, he will not be paid that month. Even if the prospect of making a larger sum of money is present, the salesperson may decline such a commission-based remuneration scheme if he, depending on his degree of risk averseness, sees that his utility from the potential extra income is less than the disutility of the extra risk.

These scenarios represent the two extremes, but there is also a possibility of combining fixed and commission-based income. The salesperson could be paid a smaller fixed income and a smaller commission per unit sold. Then the salesperson would have incentives for selling units while not taking on a risk he is unable to bear. This same principle is also valid for contractor-operator relationships. The compensation format defined in the contract may transfer all, nothing, or some of the risk from the operator to the contractor, and through that shift in risk, change the incentives for various parameters in the contract.

When designing contracts and the incentive schemes in a contract, the two parties must agree on the optimal trade-off between optimal incentives and risk-sharing. There are several sources describing optimal incentive schemes in various settings and Hart extended the basic principal-agent problems to include variables such as repeated relationships, multiple agents, multiple principals, careers concerns, and reputational effects [9].

Disregarding the variables mentioned by Hart and focusing on compensation type as the main incentivizing mechanism, there are several options, each with benefits and drawbacks. The most common forms of compensation plans are fixed price/lump sum, unit rate, time rate, or a reimbursable format.

Fixed price, also called all-inclusive, lump sum or turnkey, is an arrangement where the operator pays a fixed amount for a specified piece of performed work. For example, a contractor is paid a fixed sum to build a house with certain specifications. The contractor bears all the risk of delays in the process, weather, and sub-contractors. The customer has no risk of overruns, but in this type of contract, it is important that the degree of specification is high. If the customer wishes to make changes to the specifications, the cost to the customer could be high. A risk with this structure is that the contractor might be tempted to sacrifice quality for speed to increase profits, so quality control either during or after the work is performed is important.

In unit rate contracts, the contractor is paid per delivered unit. The contractor carries the risk of productivity and for the cost in production, while the customer carries the risk of quantity.

In time rate contracts, the contractor is paid a specific amount per unit time, day, hour, or month. The contractor carries the risk of salary and overhead increases; the customer carries the risk of productivity and quantity.

Reimbursable is a contract form where the contractor is reimbursed for all costs plus a fee. Here, the customer carries all the risk. These contract formats are suitable when the type of work requires little specification and the need for flexibility is high.

Theory postulates that risk should be placed on the party who is most able to carry the risk, usually the “largest” company. Large companies usually have a portfolio of projects to divide the risk amongst and are generally better at absorbing unfavorable outcomes than a company with a limited number of projects.

In the drilling industry, the supermajors are more capable of carrying the risk than the contractors. But given the size of the three largest service contractors, Baker Hughes, Halliburton, and Schlumberger, and some rig contractors, compared with the size of some of the smaller operators, the service contractors may be better suited to take on risk than small operator companies.

Table 1 summarizes the distribution of risk for the different contract formats, where Q = Quantity - Risk for quantity changes, N = Norm – Risk for productivity, R = Rate – Risk of labor cost increase.

	Contractor	Operator
Fixed price	Q * N * R	
Unit rate	N * R	Q
Time Rate	R	Q * N
Reimbursable		Q * N * R

Table 1 Distribution of risk for contract formats

Regardless of compensation format, incentives can alter the basis of the format. For example, the threat of penalties to a contractor working under a fixed price regime can ensure a sufficient level of quality and profit sharing incentives, such as bonuses, can increase efficiency in a time compensation regime. Designing incentives to fit the customers’ needs can be challenging as introducing incentives also introduces a need for control and the potential for the contractor to manipulate the incentive model for a higher yield. Osmundsen states that well-functioning incentives in a contract should be [14]:

1. Measurable: the result must be possible to measure. The quality of products, the number of units, etc. must be quantitatively measurable, and subjectivity in the measurement

should be avoided. For example, quality can be measured against a reference product, units can be counted, or time ahead of schedule.

2. Observable for both parties: both principal and agent must be able to observe, verify, or control the outcome.
3. Within the agent's control: the agent must be able to influence the outcome. If the agent is unable to effect the outcome, the incentive will not have an effect on the agent's actions.
4. Verifiable: it must be possible to verify the realization of a specific outcome. If the outcome produced by the agent is unverifiable, the work is worthless, and by contract, the principal can deny compensation.

5.5 AGENCY THEORY – THE PRINCIPAL-AGENT MODEL

The principal-agent model describes the relationship between the principal and the agent, where the agent performs some task on the principal's behalf. Typical examples of this model include employer-employee or customer-supplier relationships.

This theory recognizes that, in general, the agent and the principal have different objectives and it refers to the individual's utility and opportunistic behavior. Each party, principal and agent, seeks to combine the variables of pay, effort, and risk to maximize individual utility.

The first general theory of incentives is explained by Chester Barnard in his book, "The Function of the Executive." He described incentives as a process of changing subjective attitudes to achieve goal congruence, such as aligning the goals of the organization with the goals of the worker. He also introduced the importance of non-material incentives, which were almost exclusively considered in economic theory, and some of the problems seen in agency theory such as moral hazard. [15]

Building on the writings of Smith and Barnard, the theories on incentives and agency have developed and are studied with great interest. In the following subsections, I outline some of the main features and problems of incentives and agency, along with their proposed solutions.

With the background in opportunistic behavior and the individual's utility, there is a separation in goals for any whenever a job or task is to be done. The principal wants as much effort, amount, or quality for as little price as possible, while the agent wants to deliver as little as possible for as high a price as possible. The theory postulates that for the principal to get what he wants, he must motivate or incentivize the agent in a matter to increase the agent's effort and align the goals of the agent with the goals of the principal to achieve goal congruence. As described in the following sections, this can be achieved by material goods (money) or non-material methods (reputation or feeling), either positive or negative.

The assumptions creating the foundation for the agency theory may seem extreme, but they are consistent with accepted economic theory and yield predictions that are consistent with observed behavior. Agency theory is complex and by making extreme and simplified assumptions, we can make these complex problems manageable [13].

In the drilling industry, the almost exclusively used remuneration scheme for rigs is day rates. A drilling contractor (the agent) is paid a fixed amount per day by the operator (the principal), who leases the rig. The work is performed exclusively by the agent and the principal controls the work performed. This payment scheme is commonly used for service providers, such as cementing, mud system, MWD, or testing, but rate per meter drilled is also common for drilling equipment.

This example raises several problematic issues:

- How does the principal ensure that the agent does not deliberately delay the work? The agent benefits from working slowly as they are paid by the day, and an increase in the time spent on the project means an increase in revenue for the agent. There is a conflict of interest between the rig or service provider (agent) and the operator (principal).
- How does the operator ensure that they receive correct information about the performance of the rig when sourcing a rig? And how does the operator ensure that they get the correct information about progress and the operation? The rig contractor has more information than the operator on both earlier and current performance, and this asymmetric distribution of information can be exploited by the contractor.
- How should uncertainty and risk be shared? When the rig is idle due to bad weather, who should pay? When something breaks or causes delays, who bears the cost?

Incentives try to solve the problems described above and others that occur when assigning a task to an agent. One must be careful when designing the incentives because implementing incentives on one variable may adversely affect another variable. For example, when a company is given a large bonus for drilling speed or if the remuneration scheme is changed from day-rate to paid by meter drilled, the incentives change from quality to speed. As a result, a company may end up with a borehole of insufficient quality that will later induce extra costs.

The subsequent sections present the most core problems in incentive design, solutions to those design problems, and then the most common forms of contracts for companies operating on the NCS.

5.5.1 Challenges in agency theory

As mentioned above, there are several challenges and pitfalls to consider when designing an incentive scheme or a contract. In this section, the major challenges from the theory are presented along with illustrative examples from the general theory and from the drilling industry specifically.

When two parties enter into a contract, either for employment, a purchase, or to perform a service, one of the parties normally has more relevant information than the other. Delegating work to an agent with differing objectives from the principal and assumed self-interested behavior becomes problematic when information about the agent is imperfect. If there was perfect symmetry in the information about the agent's skills or performance levels, the principal could, in theory, design a contract to perfectly control the agent's output. The difference in objectives and asymmetric information are the two basic variables in incentive theory, and the consequences of this difference in knowledge and information can be complex [15].

The asymmetry in information can go both ways, either the agent or the principal can be the un-informed party, or they can have different types of relevant information unknown to the other party.

Consider a job interview situation. The principal, the employer, has no real information about the agent's, the applicant's, ability to perform. The principal will try to uncover this information through *screening* for the agent's type. The applicant does not have information about other applicants, but probably assumes that the company wants to employ the best qualified person. The applicant then will *signal* pieces of information about his or her abilities to the company.

For the drilling industry, asymmetry in information is a relevant problem. In the tendering process for a rig or a service provider, the oil company has more information about the reservoir, while the rig contractor or service company has more information about the rig or tool performance. The oil company wants to screen the information from the agents to find the best suited rig or service, while the contractors will try to signal to the oil company that they are the best qualified for the job.

Generally, we divide asymmetric information problems into two types:

- the agent can take an action that is unobserved by the principal, which is defined as moral hazard or hidden action; or
- the agent has some information about cost or valuation which is hidden from the principal, as in the case of adverse selection or hidden knowledge.

A third type of information problem is also raised in the literature, non-verifiability, where the principal and agent both have the same information, but the information is not possible to verify via a third-party.

5.5.1.1 Moral Hazard

The term moral hazard has its origin in insurance. An insured customer transfers risk from himself to the insurance company and has a reduced incentive to avoid damage and a tendency to act less careful than he otherwise would if he was uninsured. This same type of behavior applies in other situations. An employee with fixed pay will, in theory, work less if the effort he puts in has no effect on the reward, positive or negative.

Even if a contract is fully specified, all aspects of the work might not be observable by the principal. For example, a contractor's experience and qualifications can be controlled by the principal, but the contractor's selection of staff for the project is beyond the principal's control. A principal with a time rate or cost-reimbursable contract might worry that the agent assigns inexperienced or poorly qualified personnel to their contract while assigning the experienced and more capable team to its fixed price contracts. The interests of the two parties are not aligned because the principal wishes to complete the task with sufficient quality, within the timeframe and for as little cost as possible, while the agent wishes to have as large a profit margin as possible and to train the less experienced personnel at a low cost to the contractor. This potential self-interested behavior after contract is awarded is referred to as moral hazard, and it refers to situations where the principal knows the agent, but the principal is unable to observe or control the agent's actions and choices after contracting. Moral hazard situations are divided into two sub-categories, hidden action and hidden information, depending on what the agent keeps from the principal [16].

When the agent hides their actions, the principal is unable to control the actions performed to reach an observable outcome. For example, a product with inferior quality. Is the poor quality a result of the contractor's (agent's) work, or is it poor specifications provided to the agent by the company (principal) that is to blame? If the principal is not able to control the work performed this fact can be difficult to establish.

With hidden information, the principal observes both outcome and the actions performed, but due to the principal's lack of information, the principal is unable to assess if the actions are proper, or if there was some other possible action to produce the same result faster, cheaper, or with better quality.

In a turnkey drilling situation, the agent receives payment only after the well is drilled and has no claims on revenues from future oil production. The drilling company has no incentives to ensure that the well is drilled to achieve the highest possible net present value. In production drilling, it is common to optimize the mud-system prior to drilling the reservoir section and to properly clean the well before completion to avoid adverse reservoir damage. An oil company might also wish to geo-steer the well in order to optimize production. These are steps that take time and are costly. Because the effects of these steps only are seen after the well is finished and producing, the work needs to be monitored to ensure compliance by the contractor.

5.5.2 Adverse Selection

As with moral hazard, adverse selection is a term that originated in the insurance industry. A typical example of adverse selection is that when a customer seeks insurance, he or she will try to look better than his or her true nature and be extra vigilant, or careful, to lower the price of the insurance premium, or to be able to get insurance at all. Another typical example is the overrepresentation of people with some sort of illness buying health insurance.

The term refers the selection of agents *prior* to contracting without knowing the agent's type in advance. Some agents are more efficient, valuable, or represent better quality than others, and if information about the agent type is not observed prior to the creation of the contract, adverse selection occurs.

The principal also faces the risk of adverse selection of an entire pool of agents. This means that the agents offered to him are less attractive than the true mean. A classic example of this is Akerloff's example of the trade of used cars. The seller knows whether a car is a good or bad car, a "peach" or a "lemon," while the buyer does not have this information prior to the transaction. The buyer knows there is some probability that the car he is buying is a lemon and expects the average price of the cars for sale to be lower than the price of a peach. The seller determines that he is not getting the price he wants for the peaches and withdraws the peaches from the market. Thus, the only cars for sale are lemons, which reduces the buyer's expected value further. This situation, where inferior product drives away the more valuable product, is called Gresham's law [17] [18].

Oil companies hiring drilling contractors face the same problem as described in Gresham's law. They know that some contractors are more cost-efficient and capable than others. Therefore, the oil company expects the average price of hiring a contractor to be lower than the price of hiring an effective one. The "good" contractor might find that they are not paid according to the potential value they represent and may refrain from bidding on certain contracts. This leaves the oil company with only inferior rigs.

To solve this problem the principal wants to know if the agents is more or less capable before signing the contract. He wants the agent to reveal if he is a good or bad agent so the principal can determine appropriate compensation. In this identification lies a potential for opportunistic behavior, and the agent profits from stating that he is better than he is. This type of adverse selection is regarded as a combination of adverse selection and moral hazard, and it is important to create incentives that motivate the agent to reveal his true type [18].

5.5.3 Responses to the moral hazard and adverse selection problems

The responses to the moral hazard problem seek to control the conditions for the problem's existence: lack of goal congruence and difficulties in determining if the contracts terms are fulfilled. From these two conditions, two primary control mechanisms arise: monitoring and incentives [13].

For the problem of adverse selection, there are two main responses: screening and signaling. The agent can signal his true type to the principal, or the principal can screen the characteristics of the potential agents. This process is typical in a job application scenario. The applicant signals his type to the company through his education and the job application itself, while the company screens the applicant by checking his references and grades or merits.

5.5.3.1 Performance monitoring as response to moral hazard

One method of preventing a moral hazard is performance monitoring. This implies that the principal verifies and monitors the work as it is performed. This can take many forms, such as when an employee is required to punch in and out of work by using a time clock. In the drilling industry, the company man on the rig monitors and supervises the drilling contractor and service companies and ensures that the contractors provide accurate information and that the contract requirements are fulfilled.

The method of direct monitoring as is the normal practice on the NCS, but having a representative present in the agent's offices is resource consuming for the principal and the principal should seek to reduce these costs. The principal can seek information from other sources or through benchmarking. Also, contracts can be constructed so that they award coordination and cooperation between the sub-contractors and through aligning with the goals of the principal.

5.5.3.2 Performance incentives as response to moral hazard

Incentives are tools to align the interests of the principal and agent, and the method bases compensation on results that are important to the principal. The simplest form of such incentives is a bonus for each item sold. If the only thing that matters to the principal is the number of items sold, it is sensible to base the compensation directly on sales volume.

However, the principal should be careful when creating such incentives. Altering incentives might adversely affect variables like quality, and by basing pay on performance, the risk is transferred from principal to agent. The agent's output is a function of internal variables such as effort, quality, staff, and management, and external variables such as weather, supplier problems, owner technology, and specifications. The variation of performance due to external factors represents an exogenous risk for which the agent should charge a risk premium.

The principal should also consider the agent's attitude towards risk. If an agent is risk averse, they would charge a higher price to perform work with a given income, even if the long run deviation is zero, and it might be financially beneficial for the principal to carry this risk on his own.

Generally, small companies are more sensitive to fluctuations in income and more risk averse than big companies with large portfolios to divide the risk amongst. Economic theory assumes that agents consider their degree of risk aversion when bidding on contracts, and balancing risk and incentive effects are of great importance when designing contracts.

5.5.3.3 Signaling as response to adverse selection

If the principal is unable to distinguish between good and bad agents, he will pay less for the agent's service, and the good agent's price will not represent their true value. Therefore, a good agent should communicate to the principal that he is a good agent and increase his price. The classic model is the Spence's [19] job signaling model, where able workers gain education to separate themselves from less able colleagues.

The agent's signal must be in a format that only the good agent will find profitable to provide the signal. The signaling cost must be negatively correlated with productive capability. If not everyone would invest in a signal in the same way and distinguishing the applicant would not be possible on the basis of the signal.

In the example with the peach versus lemon cars, the car salesman, or agent, signals to the buyer that the car is a peach by offering a warranty. If the car turns out to be a lemon and suffers frequent breakdowns, the agent incurs costs for repair. By offering a long and extensive warranty the car salesman signals to the buyer that the car is a good one and warrants a higher sales price.

In the drilling industry, under the assumption of balance in supply and demand, a good contractor signals their cost efficiency level s_g, which is their previous cost efficiency record. The compensation will be V_g giving the contractor the total utility of U_g. A bad contractor finds it unprofitable to provide the same signal, s_g, giving him V_g, because the disutility of increasing efficiency is larger than the increased utility from the increased income. The bad agent benefits by sending the lowest possible signal, s_0, and receiving $V_b < V_g$. The good contractor could signal a lower cost efficiency and still be the optimal choice. All signal values from s* to s_g inform the oil company that the best contractor is cost efficient. This creates a separating equilibrium [18] and sending their "correct" signal and revealing their true type will be optimal for both contractors.

5.5.3.4 Screening as response to adverse selection

As a response to the adverse selection problem, the principal can screen agents to determine their actual type. He can offer a selection of contracts and the agent, based on what he thinks best, will choose a contract which fits his type. The analogy in insurance terms is considering choosing a low premium with a high deductible or a high premium with a low deductible. A customer who is likely to claim the insurance is willing to pay a higher premium to avoid the high deductible on his claim and vice versa. Based on their choice of contract, the insurance company gets information about their type.

5.5.4 Non-Verifiability

Non-verifiability is the problem that arises when both parties have access to the same information before contracting. This prior information may lead to the parties having uncertainties about variables that will influence either of the parties' performance, and this ex-ante information is not verifiable by a third party.

In the case of the drilling industry, there is always significant uncertainty about variables that affect the contract. This is a problem when trying to create incentives in the contract. This problem amplifies the importance of linking incentives to observable, measurable, and verifiable variables.

5.5.5 Other challenges

5.5.5.1 Free-rider problem

If the incentive scheme is not designed to reflect every participant's effort on the outcome, some of the participants may increase their utility by not maximizing effort. If one party can reduce effort without seeing any effect on the outcome, based on the assumptions of self-interested and amoral behavior, it makes sense for the party to reduce its efforts.

Collective bonuses in a large company are one example of the free-rider problem. A worker might determine that his or her effort has no effect on the annual company bonus, and will then reduce his or her effort, but receive the same bonus. If this line of thinking is adopted by large parts of the workforce in a company, the company will suffer.

Osmundsen points to a similar problem in the drilling industry when drilling a well. A typical well will take anywhere from 20-180 days to drill, depending on the result and type of well. It takes several drilling crew shifts working in a rotation to complete the well. One shift could produce very little and still receive the same bonus as other shifts, due to the fact that the incentives are tied to the whole well and not to the performance of each shift [20].

The same applies to overall incentives for the sub-contractors. If there are several service providers serving the well or operation and all are tied to the same incentive, one or more of these providers might benefit from the extra effort of others.

5.5.5.2 The ratchet effect

The ratchet effect is an incentive problem that is very relevant to the drilling industry. The problems occur whenever a contract is re-negotiated, frequently with repeated or long-term commitments between principal and agent. In these situations, the agent must consider how the principal assessed future performance based on current performance.

When the principal has learned the agent's true productivity or level of performance, the principal increases the level of effort needed to obtain the incentive, and reduces the agent's compensation for similar future performance. This is termed ratcheting [21] and results in reduced effort from the agent to avoid raising future standards. There are also limits to how efficiently a service can be delivered, and crossing this threshold may not be possible or have adverse effects on other aspects like safety or long term results. Especially if linked to positive incentives and penalties, the ratcheting effect may be damaging for the under-informed principal. If a contractor with a long contract history delivers a performance close to the technical limit, well above the principal's expectation, but due to the several rounds of toughening of bonus criteria, the contractor runs the risk of being penalized for delivering excellent service. In the next round, the contractor may decline bidding on the contract and a less efficient service provider wins the bid, resulting in an allover loss for the oil company.

One solution to the ratcheting effect is that the principal does not let results in one period affect the compensation in subsequent periods. This allows the agent keep all profits from the actual efficiency increase in the project. An alternative mechanism is the "New Soviet Incentive Mechanism," where the agent is compensated for both the change in performance indicators and the actual performance [21].

5.5.6 Specific challenges in drilling

Is the agency theory relevant for the drilling industry?

The theories presented in the previous sections are the foundations of the theory and are often simplified and one-dimensional for illustrative purposes. Scholars have developed and revised the agency theory over the last 20 to 30 years and proposed solutions to complex and multidimensional problems.

The drilling industry is complex. There are a multitude of service contractors, or agents, that are interdependent. The competition is fierce, but limited to mainly very large international corporations. Often contracts are repeated and one company has active contracts with several competing contractors performing on different fields.

On the principal side, there are a range of actors from true supermajors such as Exxon and Shell to small independent oil companies and everything in between. This variety of companies creates a multitude of different attitudes to risk and incentive design.

6 CONTRACT DESIGN IN THE NORWEGIAN DRILLING INDUSTRY

The traditional rig contract on the NCS is a day rate contract, often for the duration of a particular operation. This contract model gives the operator great flexibility regarding the operation, but offers little incentive for efficiency. Oil companies rely on control mechanisms as key performance indicators and the presence of company men to ensure efficiency in the operation. The rig owners face few penalties for downtime on the rig. The same is true for service contractors because personnel and equipment are usually contracted on a day rate basis and consumables are purchased. Service companies face small penalties in rate for downtime, but this penalty is linked to reliability, not efficiency.

When the market is good, one may argue that this compensation scheme works, but in a declining market where at the end of contract, the rig goes into storage the incentive for the rig and service companies is to be slow, but good. Rig and service companies want to maximize the measured KPIs, but reduce efficiency. For example, a rig owner usually has a certain amount of maintenance time included in the contract, but with the prospect of going off contract after the end of the job, the rig owner is incentivized to spend all its allocated time for maintenance on location, rather that maintaining what is necessary and then do the rest on the quayside.

6.1 OPERATOR – CONTRACTOR RELATIONSHIP

The NCS is divided into numbered blocks. Normally every second year, the Norwegian government holds concession rounds where it opens some of these blocks for bidding. Oil companies, who are qualified as either operators or license owners, can apply for the rights to explore and develop petroleum resources from these blocks. The licenses are not confined to the blocks and can contain multiple blocks or parts of blocks. Almost without exception, the licenses are shared among several license owners with one company assigned as the operator, which is the company responsible for the execution of the exploration and development. The license owners share the financial risks and profit depending on their stake in the license.

The core business of the oil companies is typically upstream activities such as exploration and production. Some of the larger companies also operate in mid- and downstream markets, but for the majority of the companies on the NCS, exploration and production are the core of their business. Within the drilling industry, the market can be divided in two sections, fixed platform drilling and mobile offshore drilling units (MODU). The fixed drilling platforms are an integrated part of a production facility and handles simultaneous production and drilling. These platforms are owned by the oil companies, but the drilling operation itself is contracted to a separate drilling company. The MODU's on the NCS are owned by a rig contractor and the oil companies lease the use of the rig for drilling or other purposes.

The rig contractors provide the rig and the drilling crew, but in a well project, there are many other activities and roles which need to be filled: directional drilling, MWD/LWD, ROV, logistics, casing running, testing, plugs, drill-bits, mud services, cementing services, etc. These services are provided by contractors or service companies, of which Baker Hughes, Halliburton, and Schlumberger are the three dominant companies.

In recent years, several smaller oil companies have entered the NCS. While exploration for oil and gas are considered the core activities of an oil company, these companies are often too small and do not have the resources to employ a permanent drilling department capable of executing a drilling project. There is a market supplying these operators with project management services and personnel capable of projecting and executing a well project. When a contractor is hired and tasked with planning and executing a well project, it is termed well-management.

6.2 CONTRACT STRATEGIES IN DRILLING

6.2.1 Conventional contract situation

Although the NCS has many small players, much of the activity is done by the large oil companies such as Statoil, Lundin, Aker BP, and ConocoPhillips. These companies have generally tendered all the different services they might need through independent contracts. This practice of tendering encourages competition and increases innovation by decentralizing competence and opening up the market for smaller service providers. The oil companies can also choose the best service provider, based on cost, quality, or technology, relative to the task to be performed. This method of contracting carries large costs because each contracted service-provider requires a separate contract, which must be managed and controlled. Cooperation and coordination between the service providers is also challenging if they are separate entities. The parts of the puzzle of drilling a well are interlinked and dependent and the tradeoffs that need to be managed are difficult if the service companies have no common incentive. In addition, the oil companies often have multiple ongoing drilling campaigns and if they were to contract independently on all projects the contract administration workload would be too large to handle efficiently.

Given these parameters, offshore contracting is moving towards bundling of services.

6.2.2 Bundle service contract

The three big service companies all have large portfolios of services they can provide and supply services for nearly all operations in a well project. The common way the operators award work on the NCS for the past decade is to bundle the main services and award those to one company. Mud services, cementing, LWD/MWD, and directional drilling were awarded in one big contract and the interface between company and service provider was moved from the service level to a project level. This way of contracting is increasingly popular amongst the operators and recent tenders required contractors to bundle services, even past the point of services originally provided by each contractor. The most recent consultancy framework agreements for Statoil included a tendering requirement that the contractor must deliver services for all multi-technical and project management disciplines, forcing the construction of alliances among the bidders.

So, the question is: How big a bundle can you make? Within the construction industry, this type of contracting is referred to as Engineering, Procurement, Construction, and Implementation (EPCI) or turnkey contracts, and is quite common.

Even if the operators lose detail control and are no longer able to pick and choose the best services available for each individual task, there are several advantages in using EPCI contracts:

- Cost prediction because of simplified project financing;
- Single point of contact. The risk of delays is reduced, when one contractor may delay other contractors;
- Speed of procurement;
- Defect liability; and,

- Efficiency, since the contractor is responsible for design, construction, and implementation, he no longer needs to take the time between phases to understand the design and familiarize with the task.

While the format is used in the oil industry on platform construction, the drilling industry has not yet used EPCI contracts to a large extent on the NCS. In the Gulf of Mexico and on land in the US, about 15% of contracts are for turkey contract drilling [22]. The reason for this difference is not clear, but the differences in petroleum law and the “see to it” duty in Norway can explain part of the difference.

6.3 RISKS RELATING TO DRILLING

This section presents some of the risks to consider during a drilling project. The risks mentioned are general and there are other risks that can cause delays and increase cost. The following are the major risks related to probability of occurrence and possible consequences.

6.3.1 Blowout

The nature of oil production is to drill and puncture a pressurized body of oil hydrocarbons and deliver this pressurized fluid in a controlled manner to the surface through a number of barriers and control mechanisms. A double barrier standard is required for all critical equipment, but even if a control mechanism is in place, sometimes the flow of hydrocarbons to the surface becomes uncontrolled by design, equipment failure, or for other reasons. This is called a blowout and is considered one of the biggest risks in drilling because of the huge consequences they represent. Although rare, blowouts are always serious because of the potential for loss of life, damage to the environment, damage to the company’s reputation, and economic impacts.

The 2010 Deepwater Horizon/Macondo disaster in the Gulf of Mexico where the operator BP and the drilling contractor Transocean lost control of a deep water well off the coast of Louisiana due to a failing cement barrier. The well gushed hydrocarbons uncontrolled onto the platform and the oil was ignited. In the explosion and subsequent fire, 11 people lost their lives. The rig capsized and sank within days leaving with the well still pouring oil into the sea. It took 87 days to stop the flow of oil, and approximately 5 million barrels of crude oil were spilled to the environment.

The consequences were huge, not only for the people whose lives were lost, the operator BP, and rig contractor Transocean, but also for the cement vendor Halliburton. BP set aside $42.2 billion so far and the BBC estimates that the total bill may increase to over $90 billion. The costs for the people along the coast and for the industry itself are difficult to quantify, but those costs are large.

6.3.2 Well control

Although not quite as serious as a blowout, which is a total loss of well control, a well control incident has the potential to develop into a blowout. Well control incidents are always treated seriously and can cause serious delays in the operation. Oil companies must report this type of incident to the petroleum authorities and the occurrence of these incidents are considered an important performance indicator for the companies.

A well control incident occurs when there is loss of control of fluid levels in the well. It can be an unintended influx of fluid into the wellbore due to higher than predicted pressure or severe losses in the formation, resulting in a loss-kick situation.

6.3.3 Weather

The weather on the NCS is harsh, especially during the winter season, with frequent winter storms. Fair weather is a prerequisite for operating offshore. Boats must be able to sail and cargo must be lifted from the boat to the platform and down to the boat again. Helicopters must be able to fly and land on the platform. The rigs, particularly the jack-up rigs, require the sea to be calm to move from location to location. There are also limits on drilling operation itself for the type of weather for safe operation.

Good logistical and equipment planning can avoid the delays caused by no-boat or no-fly weather, but when it comes to the operation, little can be done and waiting for the weather to settle is the only option. During the winter on the NCS, an estimated 10 to 20% of the time spent drilling a well is waiting on weather, which is a significant economic risk.

6.3.4 Equipment failure

The drilling industry utilizes equipment ranging from simple mechanical tools without moving parts, dumb-iron, to high tech computer-like tools. Regardless of the tool's complexity, they are subject to failure. Cement and drilling fluid are also necessary equipment, which can be unreliable in its operation. Mud can be contaminated and cement can fail. In addition, the equipment used for drilling wells is exposed to harsh treatment, high pressure, high temperatures, and high mechanical stress for extended periods of time.

When tools fail or break down, either topside or downhole, these failures cause delays. In a "normal" factory setting, there might be several production lines and redundancy, but in drilling most tools failing need immediate repair or replacement, which causes delays or downtime and incurs costs.

6.3.5 Formation problem

When drilling through the subsurface strata, the wellbore penetrates various geological formations that have different properties due to composition, age, and deposition environment. On the NCS, there are sand, clay, and limestone formations. The unknown parameters and characteristics of different formations are challenging to drill. Sandstone can be either abrasive or very loose, clay or shale can be stable or unstable, and limestone can be hard and tough to drill. The formation and the deposition environment is hard to anticipate, especially in un-explored areas. The formation can respond differently than anticipated and can cause a variety of problems. The drill-string or other downhole tubulars can get stuck and be difficult to free. The hole can collapse and sections can be lost. Fluid pressure is hard to predict before the formation is actually drilled. As wells are drilled in the blocks and surrounding areas with similar depositional environment, the uncertainty of these parameters decreases and the cumulative experience in an area can act as a proxy for specific knowledge about a field.

7 CASE STUDY

7.1 INTRODUCTION

Ross Offshore, Schlumberger Norway, and Transocean Ltd. have entered into an informal alliance. The business case is to offer turnkey contracts on drilling of production wells. The model proposed is primarily aimed at VNG Norge and their upcoming development of the Pil and Bue Field development, but is also intended to be used to bid for work on selected exploration wells and for other operators that fit the model.

7.1.1 About the companies

7.1.1.1 Ross Offshore AS

Ross Offshore is a project management and consultancy company aimed at the upstream oil and gas industry. Besides the consultancy business unit, which offers in-house consultants on a project to project basis, the company's core competency is well management services. Well management is a business model aimed at small oil and gas companies without the internal capacity or competence to carry out the planning and operation of a well project. Ross Offshore offers a full suite of services including third party contracts, logistics, marine operations, HSEQ planning and follow-up, drilling, and well construction. Ross Offshore describes themselves as "the operator's operator" and has all the capabilities that regular licenses operator has, but does not own any assets. In 2015, Ross Offshore had an equity of 106.523 million NOK [23].

7.1.1.2 Schlumberger Ltd.

Schlumberger is the world's largest oil service company and employs around 100,000 people worldwide. They offer a wide range of services to the upstream oil and gas industry, ranging from seismic acquisition and modeling to drilling, completion, and processing. Schlumberger offers drilling tools and drilling-related services for practically all potential operations in a well project. In 2015, Schlumberger had an equity of $41.078 million [24].

7.1.1.3 Transocean Ltd.

Transocean is one of the world's largest rig companies with offices worldwide and about 21,000 employees. Up until recently, Transocean had six rigs operating in Norwegian waters. In early

2017, only Transocean Arctic was under contract. One rig was scrapped and the two older rigs, Polar Pioneer and Transocean Searcher, are stacked. Transocean's two new sixth generation rigs with double derrick capabilities are idle and awaiting contracts. In 2015, Transocean had an equity of $15.9 billion [25].

7.1.2 Pil & Bue field development

The Pil & Bue discovery is located in license PL 586 in blocks 6406/11 and /12 in the Norwegian Sea, approximately 32 kilometers southeast of Njord. The partners in the discovery are the operators VNG Norge (30%), Faroe Petroleum (25%), and Point Resources (45%). The total resources are estimated to 90-200 Mboe. The discovery is being developed as a subsea development from two templates with six to eight wells tied to the Njord platform for processing.

The Phase 1 drilling schedule for the Pil & Bue field development is three oil producers and two water injectors drilled from two subsea templates, which are used for the development of the contract model proposal.

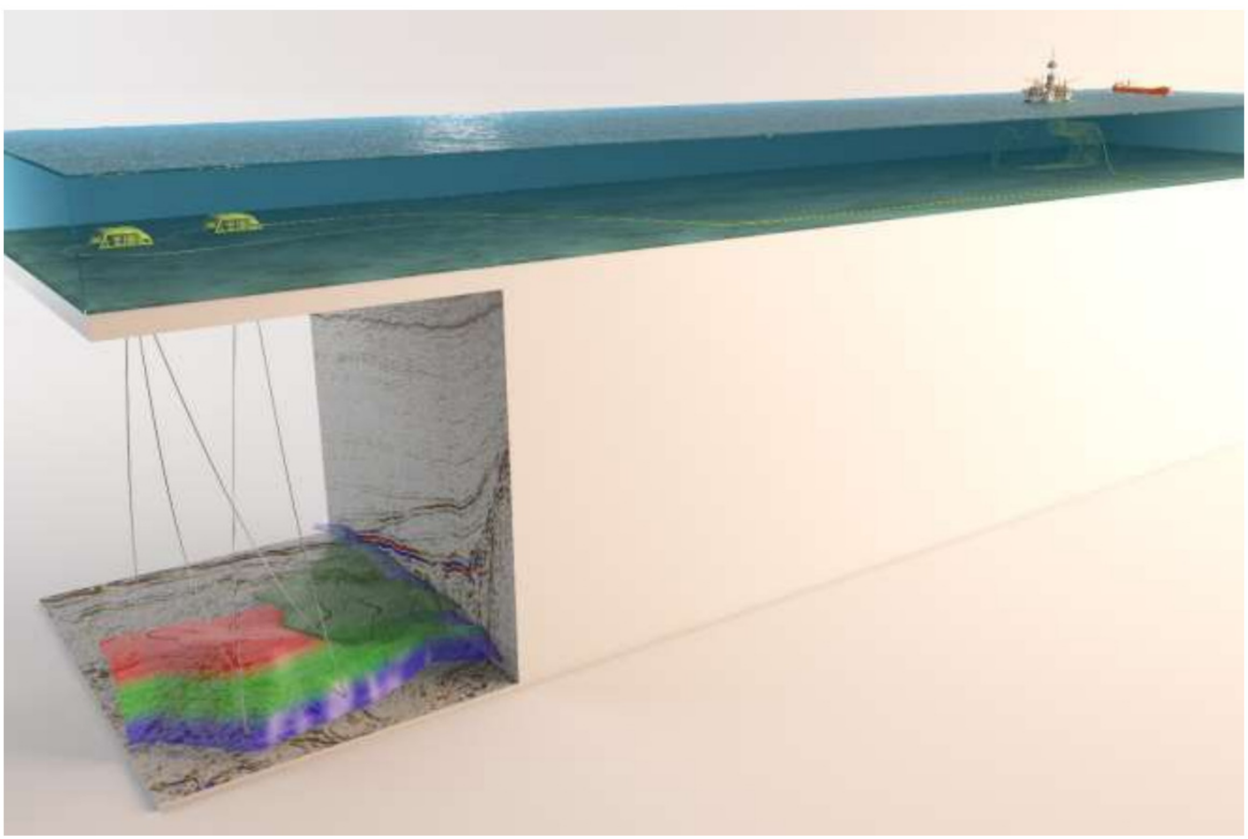


Figure 1 Illustration of proposed field development solution for Pil & Bue

7.2 CONTRACT MODEL

The model proposed for VNG Norge in the Pil & Bue field development is a combined fixed price and day rate contract. The contract model is not formalized and subject to negotiations and discussion.

The goal is to develop an innovative commercial model in cooperation with the operator that will reward efficiency and offer an acceptable risk profile.

- The fixed price given is for all activities down to the 9 5/8" casing shoe.
- Reservoir drilling is performed under a traditional day rate regime, and includes lump sum service and well management operational cost.
- Completion is performed on a fixed price, not including consumables.
- There is a bonus for delivery below the P50 estimate on a well to well basis.
- There is a bonus for delivery below the P50 estimate for the complete campaign.

Included in the fixed price model is:

- Schlumberger's fixed costs for planning, included drilling, completion, and subsea.
- Schlumberger's service costs including consumables, drilling tools, slop treatment, mud system and associated services, cement systems and associated services, offshore service engineers for all disciplines, and logistical costs.
- Ross Offshore's costs for well construction planning, including drilling, completion, HSEQ, and subsea.
- Ross Offshore's costs for operational follow-up, drilling superintendent, drilling and completion engineers, and HSEQ.
- Transocean's costs for the drilling rig, including personnel, planning, catering, etc.
- The costs for vessels and vessel management.

Items not delivered by one of the three companies or related to reservoir evaluation and characterization are not included in the fixed price or all-inclusive day rate.

Examples of such items include, but not limited to:

- Tubulars, casing, liners, tubing, etc.
- Helicopter services

- Vessel chartering
- Well site geologists
- ROV and related services
- Coring
- Medical and emergency preparedness services
- Special studies
- Wellhead
- Wireline services for reservoir evaluation
- Base and logistics services

7.2.1 Incentive models in the contract

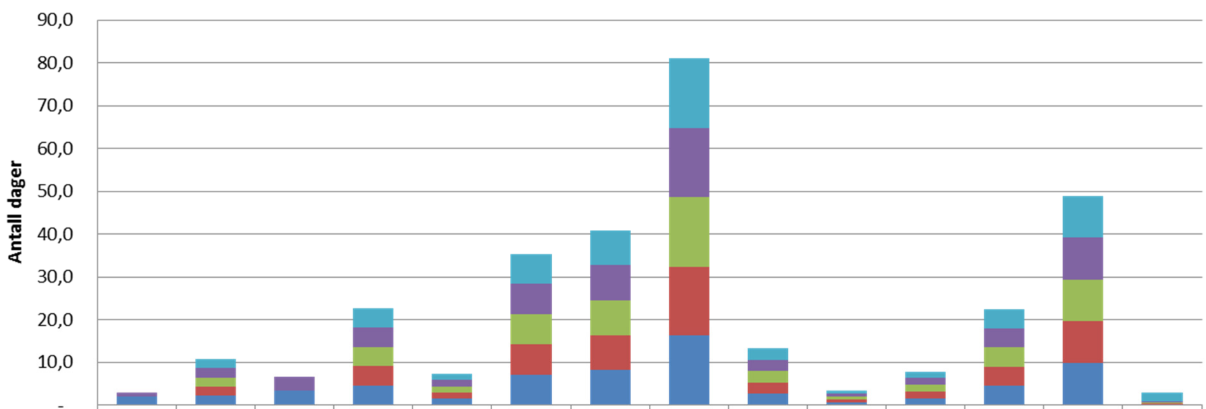
The contract proposes additional incentives in form of a bonus:

1. A bonus when the well is completed ahead of budget.
2. A bonus after project execution, if it is better than AFE.

7.3 TIME AND COST ESTIMATES

7.3.1 Drilling campaign time estimates

Ross Offshore developed a time estimate for the proposed drilling schedule presented by VNG. The time estimate is based on a sixth generation rig time database from Transocean. The total scope of the campaign is 306 days, including contingencies.



	Rig mobilization	36" Hole section	9 7/8" pilot hole	26" Section	Run BOP	17 1/2" Section	12 1/4" Section	8 1/2" Section	Lower Completion	Install TP&A plug	Install HXT	Clean up well bore	Top Completion	Marine Activities
WI2	-	2,2	-	4,5	1,5	7,1	8,2	16,2	2,6	0,7	1,6	4,5	9,8	2,1
WI1	0,9	2,2	3,3	4,5	1,5	7,1	8,2	16,2	2,6	0,7	1,6	4,5	9,8	0,2
OP3	-	2,2	-	4,5	1,5	7,1	8,2	16,2	2,6	0,7	1,6	4,5	9,8	0,2
OP2	-	2,2	-	4,5	1,5	7,1	8,2	16,2	2,6	0,7	1,6	4,5	9,8	0,2
OP1	2,1	2,2	3,3	4,5	1,5	7,1	8,2	16,2	2,6	0,7	1,6	4,5	9,8	0,2

Figure 2 Pil & Bue Drilling schedule time estimate

This time estimate was presented to VNG and compared with their Phase 2 time estimate. The time estimate for the campaign presented by the alliance was significantly lower than the preliminary time estimate from VNG. See Appendix A, Detailed time estimate for a full breakdown.

7.3.2 Cost estimate for "top hole" sections

"Top hole" sections are the sections down to the top of the reservoir, including the conductor, surface casing, intermediate, and production casing sections, as opposed to just the surface casing sections, which is the normal naming convention for boreholes.

Based on the time estimates, an example well cost equal to the bid was developed for the top hole sections. Ross Offshore estimated that it will take a total of 25 days to drill down to the top reservoir, including running and cementing the 9 5/8" production casing, and the cost is estimated at 66 million NOK.

The service cost, including consumables, tools, and waste handling is estimated at 43 million NOK.

Operational management is estimated at 75,000 NOK per day during operation.

The contingency cost is estimated at approximately 20 million NOK.

The total of the alliance costs, including contingency costs, is estimated at 130 million NOK.

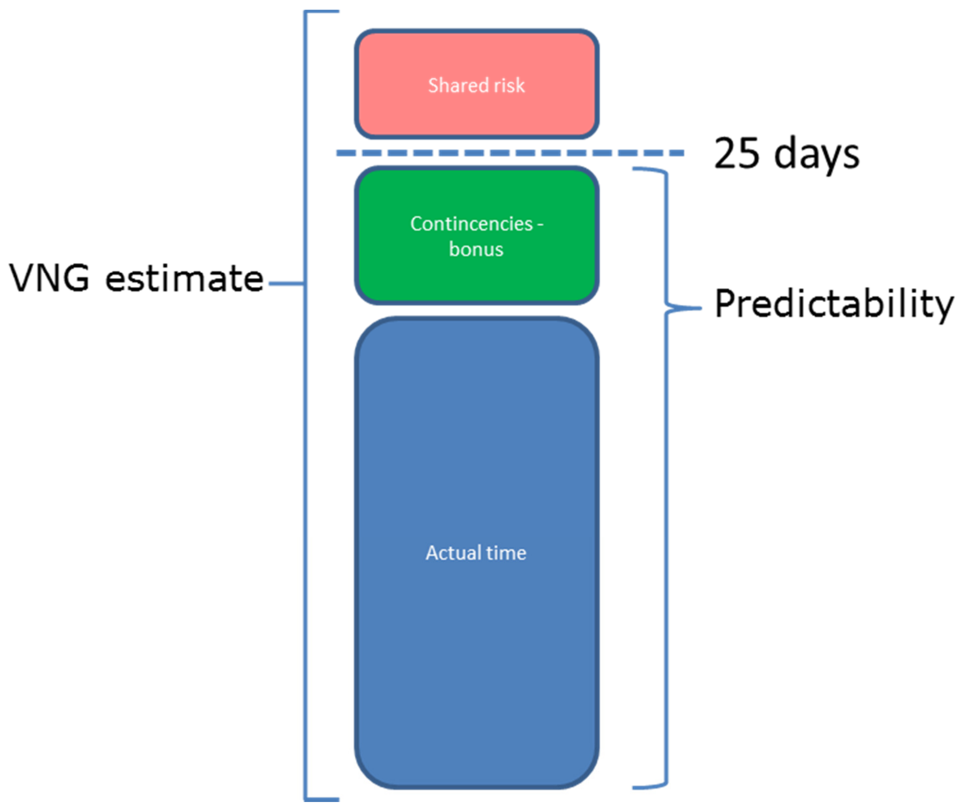


Figure 3 Cost and bonus scheme top-hole sections

7.3.3 Cost estimation reservoir section

Drilling in mature areas like the NCS is associated with relatively low risk. Knowledge of the various formations in the overburden is considered good. The best practice drilling methods for the various formations encountered in the overburden are well known amongst the operators. In addition, VNG has operated both exploration wells and appraisal wells on the field with documentation of the various features such as formation type, composition, consolidation, and pressure regime. Many of the formational uncertainties of drilling the top hole sections down to the reservoir are known, and contract can specify much of the well program.

When drilling into the reservoir, the uncertainty increases as the degree of wellbore placement accuracy increases. Parameters other than speed and efficient take priority. Placement, geo-steering, pressure sampling, petrochemical and petrophysical logging quality of the borehole, and length are parameters that are often optimized as drilling progresses. The specification of drilling the reservoir section changes, and it is natural for oil companies to have a larger degree of control over decisions made. For these reasons, drilling the reservoir section is not practical under a turnkey contract regime.

The alliance partners offered the drilling of the reservoir section on a fixed price day rate contract. This contract format is close to the contract format used as normal practices with the exception that the service cost is based on a day rate, not meter rate, which is the common model.

The time estimation is based on the same parameters as the top-hole estimate and is estimated to 16 days drilling, including wellbore cleanup and reservoir liner running.

The rates are the same as for the top hole with a 15 million NOK contingency cost added. The total estimate for drilling the reservoir section is 75 million NOK.

The summed total of the alliance cost for reservoir section including contingency cost is estimated to 75 million NOK.

7.3.4 Cost estimation completion

The completion program for the Pil & Bue field is not yet finalized, but assuming running upper and lower completion separately, a wellbore cleanup, and running of a horizontal standard X-mas tree, the estimate for completing a well using the same parameters is 19 days.

The estimated cost for the drilling rig is 50 million NOK.

The service costs, including consumables, tools and waste handling are estimated at 43 million NOK.

Operational management is estimated to 75,000 NOK per day during operation.

The contingency cost is estimated to approximately 15 million NOK.

The total costs of the alliance for completion, including contingency cost, is estimated to 98 million NOK.

7.3.5 Cost not included in alliance deliveries

There are a number of services needed to drill a typical well on the NCS that are not included in the alliance's scope of work. Below is a summary of the services representing the largest expected expenditures for a typical well. The costs are an estimate average cost based on previous wells managed by Ross Offshore.

Service	Cost (million NOK)
ROV services incl. personnel	4
Helicopter services	15
Special studies	3
Infernal cost	15
Casing and tubulars	20
Emergency preparedness, medical services and area emergency	10
Wellhead	5
Marine operations, positioning, vessels, etc.	4
Base services	8
Supply vessels	20
Sum	104

Table 2 Service costs not included in SoW

In addition to the above-mentioned equipment and services, X-mas trees, WOCS, and subsea production facilities will be needed. These costs are not included in the reported drilling cost of a well and are exempt from the estimate.

7.3.6 Further possible efficiency increases

The estimate does not include the possibility of batch-drilling the sections on each template. When batch drilling all the similar sections are drilled consecutively, so first all 36" section, then all 20" sections and so on.

By utilizing this method, the rig increases efficiency and reduces operational risk. The same equipment is used for all sections, which saves logistical costs and logistics in general, and tubular handling is simplified. By drilling the well conventionally, the BOP must be installed after drilling the 20" section on every well. By batch-drilling, the BOP can jump once and then the rig can skid between well locations while the BOP is in the water, saving days in rig time.

7.3.7 Total cost and cost savings

The total of the alliance's costs for completion, including contingency cost, is estimated to 407 million NOK.

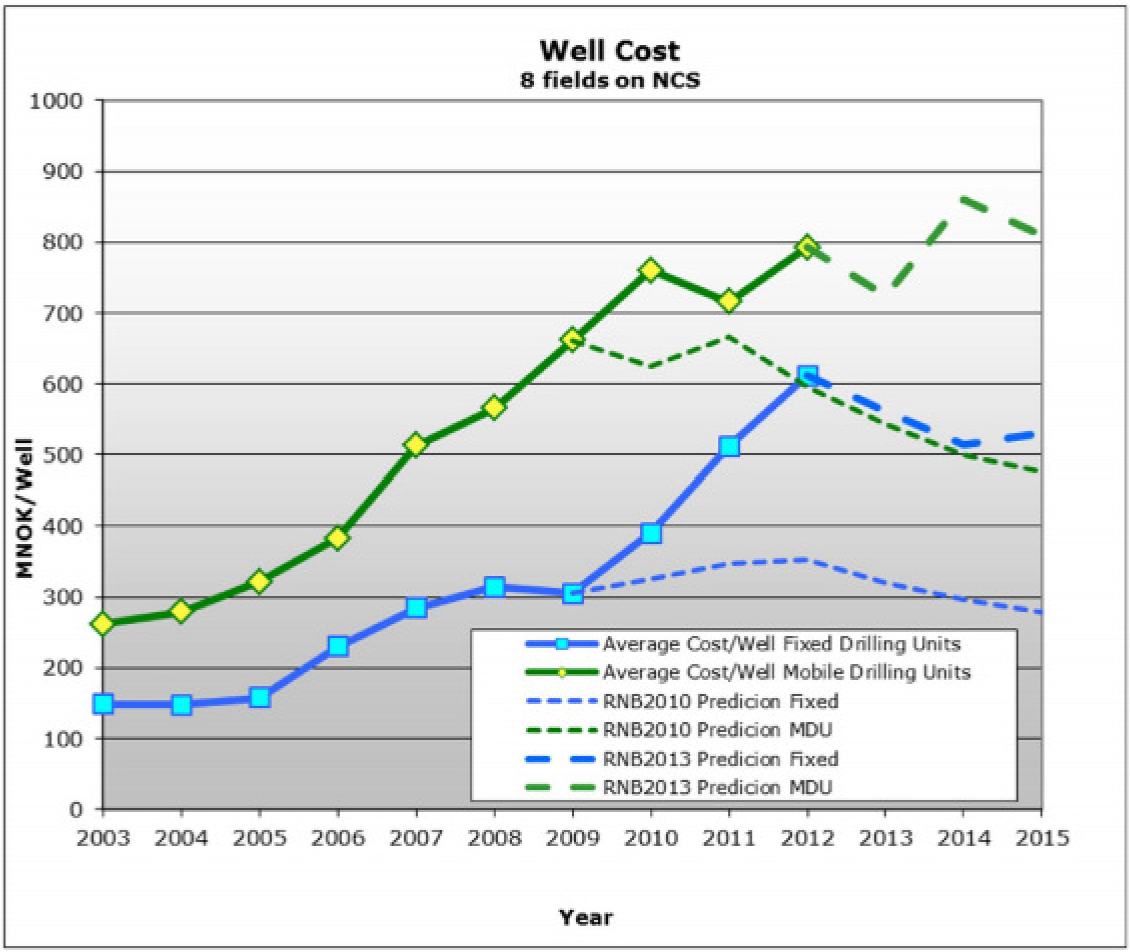


Figure 4 Well costs NCS [26]

In 2014, the cost of a production well drilled with a MODU averaged around 800 million NOK. The dataset used does not specify rig-rates, maturity level of the field, and complexity of the wells. A direct comparison between the two costs should be done with care, but the numbers do indicate significant possible savings for the operator.

Summed for the 6 wells, see 10.2Appendix B, Field cost summary for details, about 53% of the well cost will be under a lump sum regime, while 19% will be drilled under a traditional day-rate regime. The remaining 28% are cost for items not included in the alliance delivery.

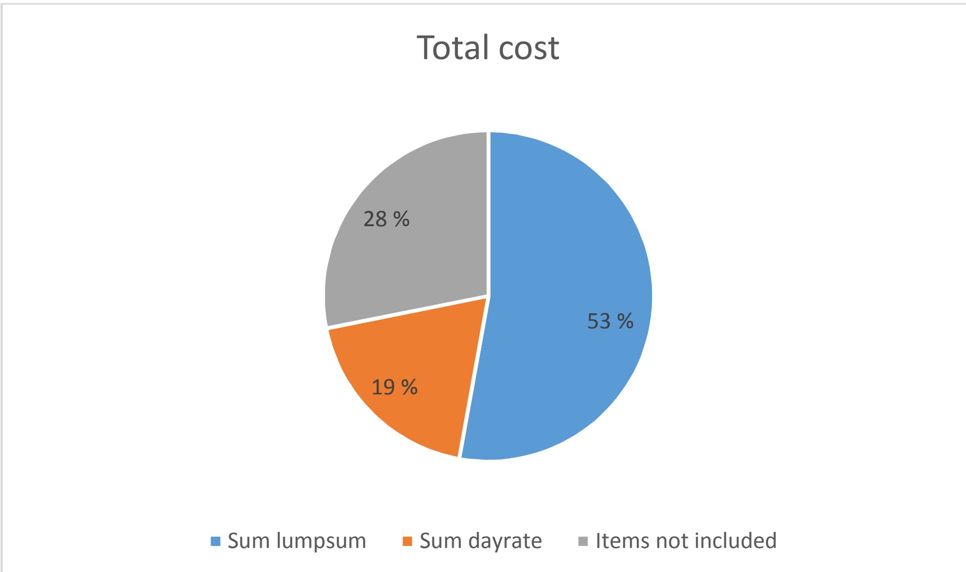


Figure 5 Total well cost distribution

7.4 RISK SHARING IN THE ALLIANCE

The risk allocation in the alliance is based on the knock for knock principle. A knock for knock agreement means that each of the parties in the alliance agrees to protect and indemnify the other parties in the alliance against losses to that party. Fault or reason for the loss is irrelevant. In practical terms, this allocates risk within the alliance and provides incentives for each of the parties to reduce potential loss. The potential for loss is also indirectly dependent on potential revenue and exposure.

8 DISCUSSION

8.1 CONTRACT DESIGN

The contract format is sensible and considers the different requirements of the operator. The contract awards speed and efficiency in the sections down to the reservoir, while allowing for flexibility and uncertainty during drilling of the reservoir. The format transfers much of the responsibilities and risk to the contractor that were traditionally carried by the operator. This will motivate early integration, focus, and planning on the contractor side.

By taking on the drilling down to the reservoir section and the completion in a turnkey contract format, the drilling contractors take on added risks, some of which are controlled by the contractor and some which are not. Of the major drilling risks listed in section 6.3, weather, formation problems, and reservoir uncertainty are uncontrolled by the contractor. The reservoir risk is removed by opting for a day-rate regime in the reservoir section drilling. Formation problem risks are related to the subsurface knowledge and are uncontrollable only to a certain extent. Formation problem risks are reduced in mature areas with established practices for drilling the various geological formations. In the early phase drilling of a subsea development, well paths and template placement is optimized and this also reduces risk by keeping well path angles, dogleg severity, and section lengths low. By design, the contract can reduce the risks, and drilling strategy and drainage strategy should be included in the evaluation of template placement.

8.2 HOW THE PLAYERS WILL BENEFIT FROM THE CONTRACT

In contrast to 2010 to 2014, the rig fleet, equipment, and personnel in the oil services sector are underutilized and the contractors seek to increase utilization of their resources. The prices in the sector are significantly reduced from the high 2014 levels. This reduction is due to efficiency increases, but also significantly reduced profit margins. The prices are now at a point where further reduction in price under a traditional contract regime is not possible without losses. The alliance contractors are attempting to differentiate by offering drilling of the Pil & Bue fields under the described contract scheme, signaling that they are capable of better and more efficient drilling. By offering this contract format, the alliance contractors effectively transfer risk from the operator under the assumption that the alliance are more capable of handling the risk and can do so at a lower risk-premium than the operator. Some of the risks, like the weather, are not controllable, but statistics on WOW during different seasons on the NCS are good and are included in the price given.

Although the contract format presented in this thesis is not a “true” turnkey as the operator still is responsible for items listed in section 7.3.5 and the use of day-rate remuneration in the reservoir section, the format is closer to an all-inclusive contract than before seen on the NCS. Turnkey and day-rate contracts each have their strengths and weaknesses and trade-offs are inevitable. A turnkey contract gives the operator greater predictability on cost and gives the drilling contractor an intense incentive for efficient operation. The operator loses some control and flexibility over the operation down to the 9 5/8” shoe, and the degree of specification of the well increases to some extent. However, this should be relatively uncomplicated because a drilling program will always have specifications for placement of the 9 5/8” shoe. A common target specification with error margin, and well integrity to a specified pressure would be sufficient. These parameters can be controlled and documented through methods common in the industry and specified by NORSOK D-010 and are performed regardless of contract format.

8.2.1 Drilling efficiency:

The cost of drilling new production wells has multiplied over the last decade. Drilling new wells in not only the main driver to increase the recoverable reserves from a field, but is also the main cost driver. The recent growth in drilling costs are making large volumes in mature fields unprofitable.

With rising in oil prices, oil companies concentrated on increasing volumes without thinking too much about the costs. [27] Much of the cost increases can be attributed to the rise in service costs and rig costs in particular, which together account for 60-70% of a well cost. In addition to the increase in CAPEX cost of a well, there was also a significant inefficiency creep on the NCS. The reasons for the reduction in efficiency are complex. Osmundsen argues that reasons for the decline are longer wells, technologically more challenging wells (multilaterals, MPD, UBD, ERD, etc.), and new technology with a higher risk of downtime, suboptimal maintenance, and high capacity utilization [14]. Mature fields are also more challenging to drill due to the variations in pore and fracture pressure from depletion and injection.

The incentive scheme in service and rig contracts was also suboptimal. Contracts and attention were placed on efficiency, but limited to minimizing downtime. By penalizing downtime, attention is directed to creating fault-free processes where everything carries equal weight. A comparison reveals that 23 of 25 sub-operations take longer now than they did in the 1990s [27]. By implementing risk portfolio thinking or by transferring the risk and making incentives for efficiency measured by progress, not downtime, the operators may reverse some of the efficiency loss. The same applies if a turnkey model is used, as the use of a fixed price creates incentives for progress and downtime is not penalized, as long as overall efficiency is high.

8.3 RISK

8.3.1 Risk allocation

Traditionally, the drilling contractor is more risk averse than the oil companies, but the degree of risk averseness is related to size and number of projects in a company's portfolio. Oil companies are generally good in carrying and taking on risk through diversified project portfolios, license partnership and high financial capacity. It is worth noting that both Schlumberger and Transocean are significantly bigger in terms of equity and number of projects than VNG Norge and the other partners in the license. Assuming that the operator is more risk averse than the contractor alliance, based on size, both controllable and uncontrollable risk are transferred from the operator to the contractor alliance.

Osmundsen [28] point to some important aspects experiences when the petroleum sector moved towards EPCI (Engineering, Procurement, Construction & Implementation) contracts. The main contractors are reported to have been too optimistic when bidding on development contracts and to not have sufficient project management and coordination competence, resulting in financial problems for the contractors. Experience gained indicates that there should be more focus on developing better technical specifications prior to the award of EPCI contract. Ross Offshore have through their well management service specialized in planning and execution drilling operations and have considerable experience in offshore drilling. Early integration of the Ross Offshore planning team and the VNG project team should be considered important and would reduce the risk for both parties.

Within the contractor alliance, the relative sizes of the companies are uneven with Schlumberger and Transocean dwarfing Ross Offshore. The knock for knock principle in the alliance allows the companies to take on the risk as the companies are only liable for their own equipment and personnel, but the financial risk is relative to the revenue from the project. In this particular project, the alliance will drill several wells, which reduces the total risk of overruns for the portfolio.

Importantly, under Norwegian petroleum law, the operator cannot legally transfer the risk to the alliance. The operator has final responsible for all aspects of the operation. When addressing the risk allocation in the contract, the parties should pay special attention to the allocation of consequential well control risks, reservoir damage, and third-party liabilities as the reciprocal indemnities in the alliance relate only to the alliance members. The allocation of risk by the knock for knock principle will limit the risk exposure for the contractors to a level that is manageable. The operator will be responsible, and to some extent insured against, the big catastrophic events, while the contractors are responsible for delays and efficiency in the operation. Given the relative size of the companies and the operational costs the exposure will be bearable.

8.3.2 Risk exposure

The most common drilling risk, waiting on weather (WOW), non-productive time (NPT) and changing drilling bits are included in cost estimate as contingencies. The NPT contingency is set to 20% and covers more than the ordinary equipment failures, the 20% NPT included also covert event such as hole problems and section re-drill.

It is difficult to quantify the risk exposure. The profit in the project is based on performance above expected and WOW and NPT below expected. As the variance in the statistical data is unknown and the break-even rates for the three alliance companies vary with activity and also are unknown there are too many parameters to properly quantify the risk at present time.

Based on the proposed profit model with earnings based on above average performance on could argue that the risk exposure is high. The contingency WOW and NPT are the statistical expected values and if the earning margin is solely based on performance above expected there is a 50/50 chance of profit/loss. The bonus scheme presented in section 7.2.1 with a bonus on performance better than the AFE will increase the risk /reward ratio.

It is also worth noticing that the market situation today with underutilized rig-fleet, equipment and personnel makes the picture even more complicated. The alternative for the companies may be no work at all which also carries (significant) cost. Considering the alternatives of a guaranteed loss (leaving equipment un-used) and a 50/50 chance of profit with risk/reward ratio >1, the alternative of taking the risk could be worth it.

8.4 POSSIBLE AREAS OF CONFLICT

8.4.1 Transitioning between wells and sections

The remuneration scheme changes when reservoir section drilling commences. The industry definition of the start of a new section is when the bit has drilled out of the shoe and a successful formation integrity test or a leak-off test is performed. By keeping the transition time as is, the contractors have strong incentives to perform this test as soon as possible, and this might cause potential contractual conflicts. If a batch-drilling solution is chosen, the wells will be cased and cemented, but not drilled out directly, and a small section of each well will remain on a lump sum regime when reservoir drilling commences. The operation code reporting system can address this situation, but can carry the potential for conflicts and moral hazard. For contractual purposes, the reservoir section should start when the 9 5/8" casing cement is verified and the logging tools are out of the hole.

8.4.2 Organization and monitoring

Under the well management model proposed for the campaign, Ross Offshore will supply operational personnel during the execution of the drilling. This includes offshore drilling supervisors and an onshore drilling superintendent. In a normal contract setting, the superintendent and the drilling supervisor or company man has the role of monitoring and verifying the drilling contractor and service companies. This applies even if the well is drilled under a well management regime, as the well management company is independent of the drilling contractor and their allegiance is to the operator. Monitoring and verification of the well management contractor is moved outside the operational organization and is often a single point project manager. In an alliance organization, the foundation for this model is changed and there is an increased danger of opportunistic behavior. By operating in an alliance with the drilling contractor and the major service company, there is a risk that the well management company could change focus from controlling and monitoring the contractors to cooperation with the contractors to achieve the best possible performance indicators. The cost risk is reduced in the turnkey format, but there are other parameters that are important too, including future contracts. A common performance indicator on the NCS is downtime, and it is the company man offshore who assigns and reports the downtime. In this new contract format, it would be in the well management company's best (short-term) interest to tweak the downtime reporting to a minimum to achieve a better performance score. There is also a potential for moral hazard when going from the turnkey rate to the day rate, as reporting the proper handover time when the well goes from turnkey to day-rate impacts the revenue for the company doing the reporting and existing control mechanisms will not capture this.

Finally, the proposed contract model transfers risks to the contractors, which under a traditional day-rate regime the operator bears. General economic theory states that there should be compensation for this increase in risk. This is not the case in the current climate. The oil companies have become extremely price sensitive and to win contracts the contractors have lowered their prices substantially. For many contractors, cost reduction has reached a level where it is close to unsustainable and it is impossible to decrease prices further without losses. The transfer of risk from the operator to the contractor without the risk premium can be considered a lowering of the price. How sustainable this strategy is in the long run can be discussed, but in the current market, it may be a survival strategy.

9 REFERENCES

[1] Statistisk Sentralbyrå, "Investeringer i olje og gass, industri, bergverk og kraftforsyning," 2014. [Online]. Available: https://www.ssb.no/statistikkbanken/selectvarval/saveselections.asp. [Accessed 03 January 2017].

[2] Statistisk Sentralbyrå, "Investeringer i olje og gass, industri, bergverk og kraftforsyning, 4. kvartal 2016," 2016. [Online]. Available: https://www.ssb.no/energi-og-industri/statistikker/kis/kvartal/2016-11-23. [Accessed 03 January 2017].

[3] Norwegian Petroleum, "Exploration Activity," 3 April 2017. [Online]. Available: http://www.norskpetroleum.no/en/exploration/exploration-activity/.

[4] Norges Rederiforbund, "Konjunkturrapprt 2016," Norges Rederiforbund, Oslo, 2016.

[5] NTB, "Aftenposten.no," Aftenposten, 01 November 2016. [Online]. Available: http://www.aftenposten.no/okonomi/40000-farre-jobber-i-oljenaringen-608023b.html. [Accessed 03 January 2016].

[6] Business Dictionary, "www.businessdictionary.com," Web Finance Inc, [Online]. Available: http://www.businessdictionary.com/definition/contract.html. [Accessed 03 MAy 2017].

[7] O. Hart and B. Holmström, "The theory of contracts," in *Advances in Economic Theory, Fifth World Congress*, Cambridge, 1985.

[8] P. Milgrom and j. Roberts, Economics, organization and management, Englewood Cliffs: Prentice Hall, 1992.

[9] O. Hart, Firms Contracts and Financial Structure, New York: Oxford University Press, 1995.

[10] J. v. Neumann and O. Morgenstern, Theory of Games and Economic Behaviour, Princeton: Princeton University Press, 1953.

[11] W. Nicholson, Microeconomic Theory: Basic Principles and Extensions, Hinsdale, Illinois: Dryden Press, 1978.

[12] A. Smith, Wealth of Nations, London, 1776.

[13] W. E. Howard and L. C. Bell, "Innovative strategies for contractor compensation," Clemson University, Clemson, 1998.

[14] P. Osmundsen, T. Sørenes and A. Toft, "Drilling Contracts and incentives," *Energy Policy 36,* pp. 3138-3144, 2008.

[15] J.-J. Laffont and D. Martimort, The theory of Incentives I: The Principal-Agent Model, Princeton university press, 2001.

[16] E. Rasmussen, Games and information. An introduction to game theory, London: Basil Blackwell, 1989.

[17] G. Akerloff, "The Market for Lemons: Quality Uncertainty and the Market Mechanism," *Quarterly Journal of Economics,* pp. 488-500, 1970.

[18] D. M. Kreps, A Course in Microeconomic Theory, New York: Harvester Wheatsheaf, 1990.

[19] M. Spence, "Job Market Signaling," *The Quarterly Journal of Economics,* vol. 87, no. 3, pp. 355-374, 1973.

[20] P. Osmundsen, T. Sørenes and A. Toft, "Offshore oil service contracts new incentive schemes to promote drilling efficiency," *Journal of Petroleum Science and Engineering,* vol. 72, pp. 220-228, 2010.

[21] M. L. Weitzman, "The nre Soviet incentive model," *BELL Journal of Economics,* pp. 251-257, 1976.

[22] K. S. Corts, *Fixed price vs. Cost-Plus: The Determinants of Contractual Form in Offshore Drilling,* Boston, MA: Harvard, 2002.

[23] Proff.no, "Proff, The business finder," Proff.no, 11 05 2017. [Online]. Available: https://www.proff.no/regnskap/ross-offshore-as/stavanger/offshoretjenester/PN4824028I10078/. [Accessed 11 05 2017].

[24] Stock Analysis on Net, "www.stck-analysis-on.net," [Online]. Available: https://www.stock-analysis-on.net/NYSE/Company/Schlumberger-Ltd/Financial-Statement/Liabilities-and-Stockholders-Equity. [Accessed 11 05 2017].

[25] Morningstar, "www.morningstar.com," Morningstar, [Online]. Available: http://investors.morningstar.com/ownership/shareholders-overview.html?t=RIG. [Accessed 11 05 2017].

[26] G. Moen, "www.petoro.no," 24 March 2017. [Online]. Available: https://www.petoro.no/The%20cost%20challenge%20on%20the%20NCS.pdf.

[27] A. I. Molde, "Turning the tide for drilling," *Norwegian Continantal Shelf,* vol. No 1, pp. 24-30, 2014.

[28] P. Osmundsen and T. E. Olsen, "Sharing og endogenous risk in construction," *Journal of Bahaviour & Organization,* vol. 58, pp. 511-526, 2005.

[29] K. E. Baum, J. R. Munson, J. A. Marshall and D. K. Vrooman, "Turnkey Drilling: Bringing Cost Predictability to a Risky Business," in *IADC/SPE Drilling Conference*, Texas, 1998.

[30] P. Bajari and S. Tadelis, "Incentives versus transaction costs: a theory of procurement contracts," *RAND Journal of Economics,* vol. 32, no. 3, pp. 387-407, 2001.

[31] P. Osmundsen, K. H. Roll and R. Tveterås, "Exploration Drilling Productivity at the Norwegian Shelf," *Journal of Petroleum Science and Engineering,* vol. 73, pp. 122-128, 2010.

[32] P. Osmundsen, "Innovative og robuste strategier for rigganskaffelse," *Praktisk økonomi & finans,* vol. 1, pp. 64-79, 2015.

[33] P. Osmundsen, T. Aven and J. E. Vinnem, "Safety, economic incentives and insurance in the Norwegian petroleum industry," *Reliability Engineering and system safety,* vol. 93, pp. 137-143, 2008.

[34] K. S. Corts and J. Singh, "The effect of REpeated Interaction on Contract Choice: Evidence from Offshore Drilling," *The Journal of Law, Economics & Organization,* vol. 20, no. 1, pp. 230-260, 2004.

[35] C. A. Moomjian, "Contractual insurance and risk allocation in the offshore drilling industry," *Drilling Contractor,* pp. 26-29, May/June 1999.

[36] P. Osmundsen, A. Toft and K. A. Dragvik, "Design of drilling contracts - Economic incentives and safety issues," *Energy Policy,* vol. 34, pp. 2324-2329, 2006.

[37] K. S. Corts, "Stacking the Deck: Idling and Reactivation of Capacity in Offshore Drilling," *Journal of Economics & Management Strategy,* vol. 17, no. 2, pp. 271-294, 2008.

[38] P. Osmundsen, "Collaboration in Norway's offshore sector, Contracts and Incentives," University of Stavanger, Stavanger.

[39] C. R. Erickson, "Risk Allocation in a Turnkey Drilling Contract¨," in *SPE/IADC 18643*, New Orleans, 1989.

[40] L. B. Brown and H. J. Flanagan, "Onshore Drilling Contracts: Avoiding the Pitfalls of Form Drilling Contracts," Liskow & Lewis, New Orleans, 2014.

[41] J. Greenberg, "Turnkey management allows operators to manage drilling risks," *Oil and Gas Journal,* vol. 96, no. 38, 09 September 1998.

[42] J. P. Hull, "Turnkey drilling model bucks declining trend, An "insurance policy for drilling budgets"," *Offhore,* pp. 50-52, January 2004.

[43] D. Sparling, "TURNKEY DRILLING, Drilling responding to changes in management philosopy," *Offshore,* 02 January 1995.

[44] C. A. Moomjian, "Contractual insurance and risk allocation in the offshore drilling industry," *Drilling Contractor,* pp. 14-17, March/April 1999.

[45] P. Osmundsen, "Risikodeling og anbudsstrategier ved utbyggingsprosjekter i Nordsjøen; en spillteoretisk tilnærming," *Praktisk Økonomi & Finans,* vol. 1, pp. 94-103, 1999.

[47] Oljedirektoratet, "npd.no," 21 March 2017. [Online]. Available: http://www.npd.no/no/Publikasjoner/Ressursrapporter/2014/Kapittel-2/.

10 APPENDICES

10.1 APPENDIX A, DETAILED TIME ESTIMATE

		Wells				
Section	**Operations**	**OP1**	**OP2**	**OP3**	**WI1**	**WI2**
Rig mobilization	Sail rig from Kr.Sund Approx 100 nM	25,0				
Rig mobilization	DP arrival test/Debalast rig	12,0				
Rig mobilization	Move rig to next template				4,0	
Rig mobilization	DP arrival test				12,0	
Rig mobilization	Install Cuttings transport sys	0,0			0,0	
36" Hole section	Stab in w/x36" BHA	0,5	0,5	0,5	0,5	0,5
36" Hole section	Drill 36" hole (+/- 420 m)	12,0	12,0	12,0	12,0	12,0
36" Hole section	Circulate clean & displace to mud	2,5	2,5	2,5	2,5	2,5
36" Hole section	Wipertrip to seabed and check for fill	2,5	2,5	2,5	2,5	2,5
36" Hole section	Circulate clean & displace to mud	2,0	2,0	2,0	2,0	2,0
36" Hole section	PO to seabed	2,0	2,0	2,0	2,0	2,0
36" Hole section	Run and land 30" conductor	3,0	3,0	3,0	3,0	3,0
36" Hole section	Circulate, mix and pump foam cement. Displace cement with seawater	4,5	4,5	4,5	4,5	4,5
36" Hole section	Keep conductor in tension while WOC	8,5	8,5	8,5	8,5	8,5
36" Hole section	Release RT. Pull stinger 10 m above PGB.	1,0	1,0	1,0	1,0	1,0
26" Section	Stab 26" BHA	0,5	0,5	0,5	0,5	0,5
26" Section	Drill 30" Shoe and clean rat hole	3,0	3,0	3,0	3,0	3,0
9 7/8" pilot hole	Flow check	0,5			0,5	
9 7/8" pilot hole	PO to seabed	1,0			1,0	
9 7/8" pilot hole	RIH / 9 7/8" BHA	1,0			1,0	
9 7/8" pilot hole	Drill 9 7/8" pilot hole to TD (+/- 1250 m, 28 m/hrs)	40,0			40,0	
9 7/8" pilot hole	Pump 2 x 15 m3 Hi-vis sweeps at TD and circulate.	3,0			3,0	
9 7/8" pilot hole	Flow check. Perform 5 stand wipertrip and ran back to bottom.	2,0			2,0	
9 7/8" pilot hole	Set a 100 m balanced cement plug	2,0			2,0	

9 7/8" pilot hole	Pull above cement and circulate BHA clean. Displace to 1.35 sg mud.	3,5			3,5	
9 7/8" pilot hole	POOH seabed	3,5			3,5	
9 7/8" pilot hole	Stab 26" BHA, RIH	2,0			2,0	
26" Section	Drill 26" hole to TD (+/- 1240m, 25 m/hrs)	40,0	40,0	40,0	40,0	40,0
26" Section	Circulate hole clean. Displace to (1.35 sg mud)	4,0	4,0	4,0	4,0	4,0
26" Section	POOH to inside 30" shoe. Top up hole. POOH	3,0	3,0	3,0	3,0	3,0
26" Section	Run 20" casing joints	10,0	10,0	10,0	10,0	10,0
26" Section	M/U 18 3/4" Wellhead Housing. RIH on DP landing string and land in 30" Wellhead Housing.	7,5	7,5	7,5	7,5	7,5
26" Section	Release and pull running tool free.	1,0	1,0	1,0	1,0	1,0
26" Section	M/U cement stand. Pressure test hose	2,0	2,0	2,0	2,0	2,0
26" Section	RIH, P/U drill pipe. Stab into wellhead. Sting into receptacle	1,0	1,0	1,0	1,0	1,0
26" Section	Establish circulation and circulate prior to cement job	2,0	2,0	2,0	2,0	2,0
26" Section	Pressure test surface lines	1,0	1,0	1,0	1,0	1,0
26" Section	Mix & pump foam cement, displace with SW.	5,0	5,0	5,0	5,0	5,0
26" Section	Release RT, POOH	1,0	1,0	1,0	1,0	1,0
Run BOP	Run BOP / Riser	20,0	20,0	20,0	20,0	20,0
Run BOP	Land BOP, Take Overpull, Test WH connector	2,0	2,0	2,0	2,0	2,0
Run BOP	R/D BOP Equipment	4,0	4,0	4,0	4,0	4,0
17 1/2" Section	Run BOP special test tool. Pressure test WH connector to 550 bar.	4,0	4,0	4,0	4,0	4,0
17 1/2" Section	M/U & RIH with 17 1/2" BHA RIH, wash to tag TOC.	8,0	8,0	8,0	8,0	8,0
17 1/2" Section	Perform choke drill	1,0	1,0	1,0	1,0	1,0
17 1/2" Section	Displace to new 1,45 Sg OBM mud.Drill out shoetrack. Clean rat hole	4,5	4,5	4,5	4,5	4,5
17 1/2" Section	Drill 3m of new formation, circulate even mud and perform FIT to 1,70 sg.	3,0	3,0	3,0	3,0	3,0
17 1/2" Section	Drill 17 1/2" hole to +/-2260 m MD. (25 m/hr)	50,0	50,0	50,0	50,0	50,0
17 1/2" Section	Circulate hole clean and flowcheck	4,0	4,0	4,0	4,0	4,0

17 1/2" Section	POOH and, rack back BHA	6,0	6,0	6,0	6,0	6,0
17 1/2" Section	Pull nominal bore protector (jet BOP when washing down). MU and rack cmt head in advance.	6,0	6,0	6,0	6,0	6,0
17 1/2" Section	R/U to run 13 3/8" casing	0,5	0,5	0,5	0,5	0,5
17 1/2" Section	P/U shoetrack and test	2,0	2,0	2,0	2,0	2,0
17 1/2" Section	Run 13 3/8" casing	12,0	12,0	12,0	12,0	12,0
17 1/2" Section	M/U casing hanger	1,5	1,5	1,5	1,5	1,5
17 1/2" Section	RIH on landing string	2,0	2,0	2,0	2,0	2,0
17 1/2" Section	M/u cmt head. Establish circulation and land 13 3/8" casing. Circulated BU+	2,0	2,0	2,0	2,0	2,0
17 1/2" Section	Mix, Pump & Displance cement	4,0	4,0	4,0	4,0	4,0
17 1/2" Section	Pressure test casing. 300 bar	0,5	0,5	0,5	0,5	0,5
17 1/2" Section	Set seal assembly and pressure test BOP, incl release of RT and retesting of seal assy.	6,0	6,0	6,0	6,0	6,0
17 1/2" Section	Release RT and POOH. L/d RT.	3,0	3,0	3,0	3,0	3,0
17 1/2" Section	Install wearbushing.	4,0	4,0	4,0	4,0	4,0
17 1/2" Section	Pressure test IBOP, Kelly cock and mud hose (surface equipment)	2,5	2,5	2,5	2,5	2,5
12 1/4" Section	M/U 12 1/4" BHA (incl. change out of APX, 1 ea hr), incl. MWD plug-in/verification, and inst. radioactive sources	4,5	4,5	4,5	4,5	4,5
12 1/4" Section	RIH w/12 1/4" BHA to 1050 m, running DP stands, filled string and function tested MWD	5,0	5,0	5,0	5,0	5,0
12 1/4" Section	Function test BOP and perform choke drill.	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	Drill out plugs, landing collar, cement in shoetrack and shoe. Clean out rat hole.	5,0	5,0	5,0	5,0	5,0
12 1/4" Section	Drill 4 m of new formation and perform LOT	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	Drill 12 1/4" hole to TD @ +/- 3450 m MD ROP 24 m/hr	50,0	50,0	50,0	50,0	50,0
12 1/4" Section	Circulate hole clean	4,0	4,0	4,0	4,0	4,0
12 1/4" Section	POOH with 12 1/4" BHA	8,5	8,5	8,5	8,5	8,5
12 1/4" Section	Rack back BHA and clear rig floor.	2,0	2,0	2,0	2,0	2,0
12 1/4" Section	Pull wearbushing, wash wellhead	6,0	6,0	6,0	6,0	6,0
12 1/4" Section	R/U to run 9 5/8" casing	1,0	1,0	1,0	1,0	1,0

12 1/4" Section	P/U shoetrack and test	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	Run 9 5/8" casing	20,0	20,0	20,0	20,0	20,0
12 1/4" Section	M/U casing hanger	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	RIH 9 5/8" casing on landing string	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	M/U cement head. Establish circulation. Land 9 5/8" csg hanger in WH	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	Establish full circulation and circulate btm's up prior to cement job	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	Pressure test surface lines	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	Mix, Pump & Displance cement	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	Pressure test casing to 70 bar above final circulation pressure. Press test casing to xx bar	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	Set seal assy. Press test . Pressure test BOP- except for BSR .	6,0	6,0	6,0	6,0	6,0
12 1/4" Section	Release running tool and POOH	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	L/D running tool	1,0	1,0	1,0	1,0	1,0
12 1/4" Section	Install wearbushing. Pressure test annular BOP's	5,0	5,0	5,0	5,0	5,0
12 1/4" Section	Pressure test DDM hose, drilling pup and IBOP.	3,0	3,0	3,0	3,0	3,0
12 1/4" Section	Pressure test casing against BSR to xxx bar	2,0	2,0	2,0	2,0	2,0
8 1/2" Section	M/U 8 1/2" BHA	2,0	2,0	2,0	2,0	2,0
8 1/2" Section	RIH	8,0	8,0	8,0	8,0	8,0
8 1/2" Section	Perform choke drill	1,0	1,0	1,0	1,0	1,0
8 1/2" Section	Drill out shoetrack. Displace to 1.74 sg OBM while drilling shoe track. Take new SCR and CLF	6,0	6,0	6,0	6,0	6,0
8 1/2" Section	Drill 3 m of new formation and perform LOT	3,0	3,0	3,0	3,0	3,0
8 1/2" Section	Drill 8 1/2" hole to TD (+/- 5000 m, 25 /hrs)	80,0	80,0	80,0	80,0	80,0
8 1/2" Section	Optional, Bit Trip	48,0	48,0	48,0	48,0	48,0
8 1/2" Section	Circulate hole clean	6,0	6,0	6,0	6,0	6,0
8 1/2" Section	POOH and L/D MWD tools	15,0	15,0	15,0	15,0	15,0
8 1/2" Section	Hold prejob meeting and R/U wireline	0,5	0,5	0,5	0,5	0,5
8 1/2" Section	Log 1	20,0	20,0	20,0	20,0	20,0
8 1/2" Section	Log 2	20,0	20,0	20,0	20,0	20,0
8 1/2" Section	Log 3	20,0	20,0	20,0	20,0	20,0

8 1/2" Section	Log 4	20,0	20,0	20,0	20,0	20,0
8 1/2" Section	R/D wireline logging	0,5	0,5	0,5	0,5	0,5
8 1/2" Section	Wipertrip	15,0	15,0	15,0	15,0	15,0
8 1/2" Section	Circulate hole clean	6,0	6,0	6,0	6,0	6,0
8 1/2" Section	Displace well to Completion Fluid	4,0	4,0	4,0	4,0	4,0
8 1/2" Section	POOH	12,5	12,5	12,5	12,5	12,5
8 1/2" Section	R/B BHA	2,0	2,0	2,0	2,0	2,0
Lower Completion	BOP test	6,0	6,0	6,0	6,0	6,0
Lower Completion	R/U screen handling equipment	4,0	4,0	4,0	4,0	4,0
Lower Completion	Make up screen, blank pipe, barrier plug assy and packer. Run in hole 1200 m	14,0	14,0	14,0	14,0	14,0
Lower Completion	Run screen on landing string 3800 m.	12,0	12,0	12,0	12,0	12,0
Lower Completion	Set Packer acc.to supplier proceed. Close BOP ram to mark white std.	3,0	3,0	3,0	3,0	3,0
Lower Completion	Pull out LS to above PBR and test barrier to 345 bar	4,0	4,0	4,0	4,0	4,0
Lower Completion	Pull out with the landing string	4,0	4,0	4,0	4,0	4,0
Install TP&A plug	Pick up and RIH with plug at 800 m	5,0	5,0	5,0	5,0	5,0
Install TP&A plug	Set plug and pick up to above same	2,0	2,0	2,0	2,0	2,0
Install TP&A plug	Test plug from above and POOH	5,0	5,0	5,0	5,0	5,0
Install HXT	RI w/BOP Jump tool	6,0	6,0	6,0	6,0	6,0
Install HXT	Pull BOP Above wellhead, Move rig of well	3,0	3,0	3,0	3,0	3,0
Install HXT	Position rig / Land XT in Aux rig	2,0	2,0	2,0	2,0	2,0
Install HXT	Test XT conn. and test flowline conn.	5,0	5,0	5,0	5,0	5,0
Install HXT	Barrier test connection. POOH with landing string (Offline)	2,0	2,0	2,0	2,0	2,0
Install HXT	Move rig, move BOP above XT	2,0	2,0	2,0	2,0	2,0
Install HXT	Land, lock and pressure test WH conn to 345 bar	4,0	4,0	4,0	4,0	4,0
Install HXT	POOH w/ BOP Jump tool	4,0	4,0	4,0	4,0	4,0
Clean up well bore	Make up PT to retrieve TP&A plug. RIH to plug	5,0	5,0	5,0	5,0	5,0

Clean up well bore	Retrieve plug and POOH, prepare for running clean up string	6,0	6,0	6,0	6,0	6,0
Clean up well bore	Pick up 2 7/8 DP stinger for clean above barrier plug	2,0	2,0	2,0	2,0	2,0
Clean up well bore	P/U and M/U landing sub for PBR (inflow test packer)	2,0	2,0	2,0	2,0	2,0
Clean up well bore	P/U and M/U scrapers, magnets etc for clean up well	3,0	3,0	3,0	3,0	3,0
Clean up well bore	RIH with clean up tools while scraping packer setting area.	14,0	14,0	14,0	14,0	14,0
Clean up well bore	Land on top liner PBR. Mark white painted stand.	2,0	2,0	2,0	2,0	2,0
Clean up well bore	Set and test inflow test packer, unset same and prepare for inflow test well.	4,0	4,0	4,0	4,0	4,0
Clean up well bore	Pump base oil (0,75 sg) from cmt unit down DP. 40 m3 ?	3,0	3,0	3,0	3,0	3,0
Clean up well bore	Set inflow test packer, test same in annulus. Wait to let temperature effect level out.	7,0	7,0	7,0	7,0	7,0
Clean up well bore	Bleed down U-tube pressure stepwise to 10 bar, inflow test barrier 30 min	3,0	3,0	3,0	3,0	3,0
Clean up well bore	Increase pressure in DP to U-tube pressure and un-set packer.	2,0	2,0	2,0	2,0	2,0
Clean up well bore	Pump wash train as per program. Displace well to base oil (0,85 sg)	8,0	8,0	8,0	8,0	8,0
Clean up well bore	POOH with clean up string	14,0	14,0	14,0	14,0	14,0
Clean up well bore	Lay down equipment and clean drill floor, prepare for running top completion	5,0	5,0	5,0	5,0	5,0
Top Completion	Pull 10 3/4" WB, wash BOP/WH/DR	5,0	5,0	5,0	5,0	5,0
Top Completion	Make up the umbilical to THRT	3,0	3,0	3,0	3,0	3,0
Top Completion	R/U for running tubing.	6,0	6,0	6,0	6,0	6,0
Top Completion	Make up speed stands and rack back	4,0	4,0	4,0	4,0	4,0

Top Completion	Run Sealstem, 2 joints 5 1/2" tbg, prod. Packer, 2 joints 5 1/2" tbg.	4,0	4,0	4,0	4,0	4,0
Top Completion	Make up CIV assy's, M/U and pressure test control line. M/U 2 joints 5 1/2" tbg.	4,0	4,0	4,0	4,0	4,0
Top Completion	Make up DHG assy and terminate cable, test same.	5,0	5,0	5,0	5,0	5,0
Top Completion	Make up GLV assy and X-over assy from 5 1/2" to 7" tbg.	3,0	3,0	3,0	3,0	3,0
Top Completion	Run 7" tubing to DHSV at 10 jnts/hr. 3800 m	36,0	36,0	36,0	36,0	36,0
Top Completion	Make up DHSV, pressure test line	4,0	4,0	4,0	4,0	4,0
Top Completion	Run tubing below TH	3,0	3,0	3,0	3,0	3,0
Top Completion	P/U and M/U TH, lay out TH handling pup	4,0	4,0	4,0	4,0	4,0
Top Completion	Terminate control lines through TH and test same	12,0	12,0	12,0	12,0	12,0
Top Completion	Make up THRT, connect to TH and test THRT	4,0	4,0	4,0	4,0	4,0
Top Completion	Run in hole with TH on SLS	4,0	4,0	4,0	4,0	4,0
Top Completion	Make up pre-build landing stand. Orientate TH.	2,0	2,0	2,0	2,0	2,0
Top Completion	While pumping through top drive, Sting into PBR, land and lock TH	3,0	3,0	3,0	3,0	3,0
Top Completion	Rig up hose to be able to pump from cmt unit to tubing.	2,0	2,0	2,0	2,0	2,0
Top Completion	Low pressure test tubing to 35 bar to confirm proper sting in	2,0	2,0	2,0	2,0	2,0
Top Completion	Low pressure test annulus to 35 bar to confirm GLV closed	2,0	2,0	2,0	2,0	2,0
Top Completion	Pres. up tbg to set prod. Packer (345 bar) pres. test tbg.	2,0	2,0	2,0	2,0	2,0
Top Completion	Inflow test DHSV, low and high pressure test	3,0	3,0	3,0	3,0	3,0
Top Completion	Pressure test annulus against prod. Packer and TH seals to 345 bar	2,0	2,0	2,0	2,0	2,0
Top Completion	Disconnect THRT, POOH lay out or rack back landing stand.	4,0	4,0	4,0	4,0	4,0
Top Completion	Pressure test production cross and annulus cross to 345 bar	4,0	4,0	4,0	4,0	4,0
Top Completion	Connect horizontal el. Couplers w/ROV (parallel)	0,0	0,0	0,0	0,0	0,0

Top Completion	RIH with lower XT plug, set same and test from above to 345 bar.	4,0	4,0	4,0	4,0	4,0
Top Completion	RIH with upper XT plug set same and test in between plugs to 345 bar	4,0	4,0	4,0	4,0	4,0
Top Completion	Line up to pressure up down tubing to cycle open barrier plug. (optional)	2,0	2,0	2,0	2,0	2,0
Top Completion	Cycle open barrier plug (optional)	6,0	6,0	6,0	6,0	6,0
Top Completion	Prepare for pulling marine riser and BOP	4,0	4,0	4,0	4,0	4,0
Top Completion	Pull marine riser and BOP	24,0	24,0	24,0	24,0	24,0
Top Completion	Run and land XTC, test same.	2,0	2,0	2,0	2,0	2,0
Top Completion	Release TCRT and pull same	2,0	2,0	2,0	2,0	2,0
Marine Activities	Replace guidewires, and move to next well	2,0	2,0	0,0	2,0	0,0
Marine Activities	Move cuttings transport system	2,0	2,0		2,0	
Marine Activities	Pull Cuttings transport system (offline)					0,0
Marine Activities	Pull guidewires, close roof (Offline)			4,0		0,0
Marine Activities	De-balast rig / move out of 500 zone					12,0
Marine Activities	Move rig to Kristiansund					25,0
Contingency	WOW (10%)	114,9	105,4	105,4	112,8	108,7
Contingency	NPT (20%)	229,8	210,7	210,7	225,6	217,3
Contingency	Additional bit Run	48,0	48,0	48,0	48,0	48,0
Contingency						
Contingency						

Hours	1541,7	1417,6	1417,6	1514,4	1460,5
Days	64	59	59	63	61

10.2 APPENDIX B, FIELD COST SUMMARY

Transocean Spitsbergen - Cost summary

Total	**kr 5 200 000,00**
Rig rate pr day	kr 2 630 000,00
Ross rate pr day	kr 75 000,00
Schlum rate pr day	kr 2 263 000,00

Sum lumpsum	Sum dayrate	Items not included
kr 1 171 433 450,99	kr 421 488 918,79	kr 624 000 000,00

	Number of days									Schlumberger cut	Transocean cut	Ross cut
Description	**OP1**	**OP2**	**OP3**	**WI1**	**WI2**	**Sum**	**Incl cont**	**Price NOK**	**Unit**			
Rig mobilization	1,5	-	-	0,7	-	**2,2**	**3,0**	15 432 755	Lumpsum	kr 4 997 458,33	kr 5 807 916,67	kr 165 625,00
36" Hole section	1,6	1,6	1,6	1,6	1,6	**8,0**	**10,8**	56 052 930	Lumpsum	kr 18 151 145,83	kr 21 094 791,67	kr 601 562,50
9 7/8" pilot hole	2,4	-	-	2,4	-	**4,9**	**6,6**	34 068 534	Lumpsum	kr 11 032 125,00	kr 12 821 250,00	kr 365 625,00
26" Section	3,4	3,4	3,4	3,4	3,4	**16,9**	**22,7**	117 929 542	Lumpsum	kr 38 188 125,00	kr 44 381 250,00	kr 1 265 625,00
Run BOP	1,1	1,1	1,1	1,1	1,1	**5,4**	**7,3**	37 853 927	Lumpsum	kr 12 257 916,67	kr 14 245 833,33	kr 406 250,00
17 1/2" Section	5,3	5,3	5,3	5,3	5,3	**26,4**	**35,4**	184 173 914	Lumpsum	kr 59 639 479,17	kr 69 311 458,33	kr 1 976 562,50
12 1/4" Section	6,1	6,1	6,1	6,1	6,1	**30,4**	**40,9**	212 564 360	Lumpsum	kr 68 832 916,67	kr 79 995 833,33	kr 2 281 250,00
8 1/2" Section	12,1	12,1	12,1	12,1	12,1	**60,3**	**81,1**	421 488 919	Day-rate	kr 136 487 187,50	kr 158 621 875,00	kr 4 523 437,50
Lower Completion	2,0	2,0	2,0	2,0	2,0	**9,8**	**13,2**	68 428 253	Lumpsum	kr 22 158 541,67	kr 25 752 083,33	kr 734 375,00
Install TP&A plug	0,5	0,5	0,5	0,5	0,5	**2,5**	**3,4**	17 471 043	Lumpsum	kr 5 657 500,00	kr 6 575 000,00	kr 187 500,00
Install HXT	1,2	1,2	1,2	1,2	1,2	**5,8**	**7,8**	40 765 768	Lumpsum	kr 13 200 833,33	kr 15 341 666,67	kr 437 500,00
Clean up wellbore	3,3	3,3	3,3	3,3	3,3	**16,7**	**22,4**	116 473 622	Lumpsum	kr 37 716 666,67	kr 43 833 333,33	kr 1 250 000,00
Top Completion	7,3	7,3	7,3	7,3	7,3	**36,5**	**49,0**	254 786 048	Lumpsum	kr 82 505 208,33	kr 95 885 416,67	kr 2 734 375,00
Marine Activities	0,2	0,2	0,2	0,2	1,5	**2,2**	**3,0**	15 432 755	Lumpsum	kr 4 997 458,33	kr 5 807 916,67	kr 165 625,00
Contingency	16,4	15,2	15,2	16,1	15,6	**78,4**				kr 177 376 768,75	kr 206 142 687,50	kr 5 878 593,75
Sum incl contingency	64	59	59	63	61	**306**	**306**	**1 592 922 370**	See above	kr 693 199 331,25	kr 805 618 312,50	kr 22 973 906,25
Sum excl contingency	48	44	44	47	45	**228**	**228**	**1 132 393 500**	See above	kr 515 822 562,50	kr 599 475 625,00	kr 17 095 312,50
Contingency percent	34,2 %	34,6 %	34,6 %	34,3 %	34,4 %	34,4 %						

Revenue	kr 1 818 000 000,00	
Profit best case	kr 685 606 500,00	38 %
Profit contingency used	kr 225 077 630,21	12 %