Norwegian School of Economics

Bergen, Fall 2015

Petroleum fiscal system design and cost-related incentives in oil and gas projects

A comparative study of UK, Norway, Indonesia and China

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Master thesis

MSc in Economics and Business Administration

Major in Energy, Natural Resources and the Environment

NORWEGIAN SCHOOL OF ECONOMICS

Abstract

In recent years, the oil and gas industry has been facing unprecedented cost and time overruns while delivering megaprojects both in Norway and internationally. Combined with a dramatic oil price drop, cost overruns became a hot topic in both academic and business worlds. Whilst the project management aspects were in the spotlight, external factors, such as government policies, were paid much less attention.

Although, oil companies are cost minimizers, in a situation of a moral hazard presented in the oil and gas industry, certain petroleum fiscal designs can create incentives for cost inflation. Thus, the focus of the current master thesis is to understand how different fiscal designs affect cost consciousness of the companies on the examples of Norway, UK, Indonesia and China.

According to the comparative study, petroleum fiscal design that incorporates high marginal rates on the profits rather than revenues, i.e. more back-end loaded, in combination with additional capital allowances and uplifts, tends to create higher incentives for operators to inflate their costs. However, such a design is also referred to as neutral and provides additional incentives for investments. Therefore, the optimal balance in risk sharing between the company and the host government in petroleum fiscal designs is crucial.

Acknowledgments

I would like to take this opportunity to say thank you to people who have been helping me in one way or another throughout this long and challenging journey of completing my master thesis.

I wish to express my gratitude to my supervisor, Linda Nøstbakken, for sharing her knowledge and ideas, as well as for encouraging and motivating me in the times of struggle. I would also like to say thank you to my family and friends for their participation and assistance, valuable feedbacks, endless support and unceasing encouragement.

Without you the completion of this master thesis would not have been possible. Thank you.

Dina Serova

Bergen, June 2015

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Introduction

1.1 Motivation for the thesis topic

In recent years, the oil and gas industry is facing unprecedented cost and time overruns while delivering megaprojects both in Norway and internationally. The failure to deliver the projects within predefined time and budget frames could cost energy companies trillions of dollars in lost investments. The estimated overspend across the whole capital budget of the energy industries could be approximately 13%, which translates to US$5 trillion overspend on the US$38 trillion IEA forecast for global investments (Accenture 2012).

Therefore, over the last three years the researchers tried to identify the factors responsible for cost overruns and time delays. Most of the studies are devoted to the internal factors related mainly to project management aspects. Not only scholars, but also practitioners devote most of their attention to this field. In fact, the author of the current thesis took part in a collaborative project with a Norwegian Oil and Gas Department of one of the largest international consulting firms. The task assigned by the company was directly connected to poor performance of oil and gas field development projects. According to the company representatives, consulting services in the area of oil and gas project management are high in demand, which reflects the topicality of the chosen problem. This collaborative project was a start of idea development process for the current master thesis topic.

Whilst the project management aspects were in the spotlight, external factors, such as regulatory challenges and government policies, were paid much less attention, despite the fact, that petroleum industry is one of the most governmentally controlled sectors, a subject to special taxation, subsidies and allowances. Thus, the topic of this thesis is not only highly important due to the large scale of cost overruns, but also quite novel due to relatively low coverage in the literature.

1.2 Research question

Multiple studies devoted to deliberate cost underestimation in capital projects by Bent Flyvbjerg[1] in combination with studies devoted to incentives provided by the petroleum taxation systems for low cost consciousness by Petter Osmundsen[2] were the main source of justification and formulation of the final research question:

How does different petroleum fiscal systems affect the cost-related behavior of oil companies before and after the contract award?

The answer to the part of the question related to the behavior *before* the contract award implies a rather theoretical approach, which is mainly based on assumptions. The answer to the part related to the incentives provided by the taxation policy *after* the contract award can in fact be computed and contrasted for various fiscal regimes.

1.3 Structure of the thesis

The structure of the thesis clearly represents the process of the idea development, starting from a broad understanding of the problem and then narrowing down to the least studied topic.

The first chapter devoted to the background research is intended to answer the question '*why should one study cost overruns in oil and gas industry*?' It provides the evidence and significance of cost overruns in the industry.

'Literature review' chapter provides an analysis of relevant studies devoted to various factors responsible for cost overruns. Thus, it helps to answer the question: '*what has already been done in this field of research?* This answer also implies an analysis of the gap, which is intended to fulfil with the current paper.

The next chapter presents a theoretical overview of petroleum fiscal regimes as well as includes a comparative analysis from the research question perspective – cost-related incentives. In this chapter a theory of moral hazard is applied to the oil and gas industry, which justifies the reasoning behind this thesis.

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[1] Professor at Oxford University

[2] Professor University of Stavanger

The rest of the thesis presents an individual research, which includes modelling incentives for deliberate cost underestimation, qualitative analysis of the four chosen petroleum fiscal regimes, computing incentives for low or high cost consciousness and contrasting the results across different regimes.

The conclusion summarizes the results of the research, present its implications, as well as provides an outlook for the future research potential.

2 Background research

2.1 Megaprojects in oil and gas industry

Projects across different process industries have become significantly larger and more complex over the past ten years. Megaprojects (also used term 'mega-project' or 'mega project') – projects requiring huge physical and financial recourses, typically more than US$1 billion (Altshuler & Luberoff, 2003; Flyvberg, 2008). However, the cost of a project and its complexity are not the only characteristics that are considered. Moreover, in many developing countries projects that cost less than US$1 can still be considered as megaprojects as contrasted with the country's gross national product (Greiman, 2013).

There are over 25 common megaproject attributes summarised and presented by Greiman (2013). A short overview of the main features can be found in Appendix 1. In summary, large investment projects take long time to plan and operate, they are relatively common in various sectors including *oil and gas*, transport and infrastructure, chemicals, minerals and power and always imply complex technical integration and design. These projects usually play a strategic role for society, satisfying its demand for different urban developments, energy, chemicals, metals, and other products. Thus, they always attract public attention or political interest due to its significant direct and indirect impacts on the community, environment and budget. Increased technical and commercial complexity of such projects together with its commercial, environmental and political cost and risk made the stakeholder scrutiny even stricter.

Greiman (2013) also names *consistent cost underestimation and poor performance* one of the main attributes. The characteristics mentioned above explain the challenge to make a precise cost estimation before the operation starts and cope with the stretching of available resources to the limit. The scholars and practitioners made multiple attempts to identify the reasons behind significant cost overruns (see Chapter 3), however, cost overruns tend to be "a distinguishing characteristic of megaprojects" (Greiman, 2013).

The underlying reason why megaprojects in oil and gas industry is the main object of the current research is the last mentioned characteristic – consistent cost underestimation and poor performance, which is thoroughly researched further in the paper.

The large-scale projects are broadly presented in petroleum sectos. As it was mentioned above, projects in this industry are almost always considered as megaprojects regardless of the size. The nature of this industry is unique and requires managing science, technology and engineering aspects. The oil and gas extraction projects have always been associated with high risks and complexity due to extensive engineering effort. Besides that there is no assurance that expenditures will result in commercial quantities of hydrocarbons or any quantities at all.

On top of the traditional risks and complexity, the time of easy extraction and procession of natural resources has been coming to an end, and the world is facing an issue of progressively more difficult circumstances. The reserves of natural resources are spread unevenly across the world, which means that the largest resource-holding countries have a power to make an influence on the industry by restricting or delaying the development of some easier accessible reservoirs pursuing their own interests (Merrow, 2012). Moreover, apart from unexploited conventional reserves, energy companies are looking into emerging opportunities in unconventional oil and gas areas, such as shale gas, coal seam gas, light tight oil, LNG, oil sands, ultra-deep water and the Arctic. This is the underlying reason for increasing size and difficulty of the projects (EY, 2014). The Yamal project in Russia, Ichthys LNG plant in Australia, Kashagan project in Kazakhstan are just few examples of recent challenging megaprojects.

2.2 Present and future investment projections in oil and gas industry

The oil and gas industry was always a subject to significant capital spending, which more than doubled in real terms since 2000 and amount to about $900 billion (IEA, 2014). According to International Energy Agency (2014), the estimated market value of the oil and gas produced globally in 2012 was around $4.2 trillion, which is almost double the estimated $2.3 trillion generated in 2005. Moreover, the generated value is four times bigger than the capital expenditures in oil and gas sector in 2012, which was mainly underpinned by consistently higher oil prices and enriched the resource-holding countries.

The investment projections in oil and gas sector made by IEA in June 2014 suggest that the wave of capital spending is going to continue, amounting to $22.4 trillion cumulative oil and gas investment between 2014 and 2035, which means that there will be more than $1 trillion annual spending globally, with North America, Europe and Asia-Pacific being the major investment regions (Figure 2.1). It is expected that about 77% of this capital spending ($17.4 trillion) will be made in the upstream oil and gas segment.

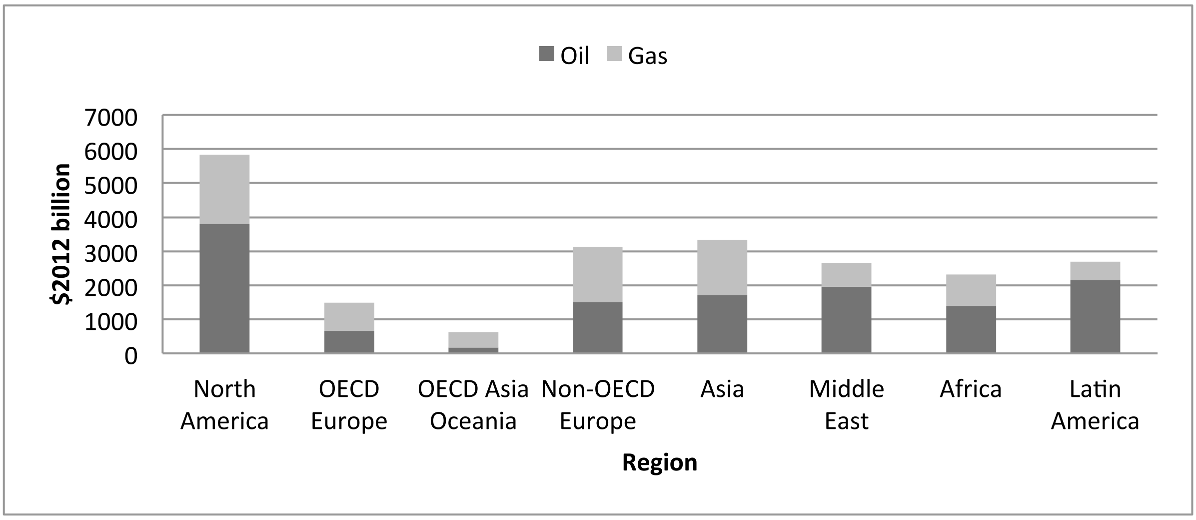


Figure 2.2 Regional cumulative oil and gas investment between 2014 and 2035. Source: IEA 2014

However, the investment projections were made by the International Energy Agency, NPD and oil companies before the dramatic fall in oil prices as much as 50% that took place in the end of 2014. According to the oil minister of Qatar, "the degree of investment cuts is substantial due to the oil price of today" (Critchlow, 2015). The low oil price has significantly threatened the investments into new field developments globally and especially in the regions where the oil exploration activities are the most expensive, such as the North Sea in the UK and Norway. The energy companies in the S&P500 have already announced $8.3 billion spending cut, whilst a 25% fall is expected in capital spending globally (Timiraos, 2015).

The low oil price, expected investment cuts and, thus, decreased expected number of field development projects globally, however, do not understate the importance of the present research. On the contrary, cost control is moving to the forefront as profit margins decreasing.

2.3 Performance of oil and gas mega-projects

As the previous subchapter showed, the investments in upstream oil and gas sector increased significantly before the oil price drop. It doubled and, in some cases, tripled the annual capital budgets of companies in the last eight years aimed to increase their exploration and production (E&P) activities. However throughout this period companies failed to enhance their production by the same degree, decreasing their capital efficiency since 2005 (see Figure 2.2) (PwC, 2014).

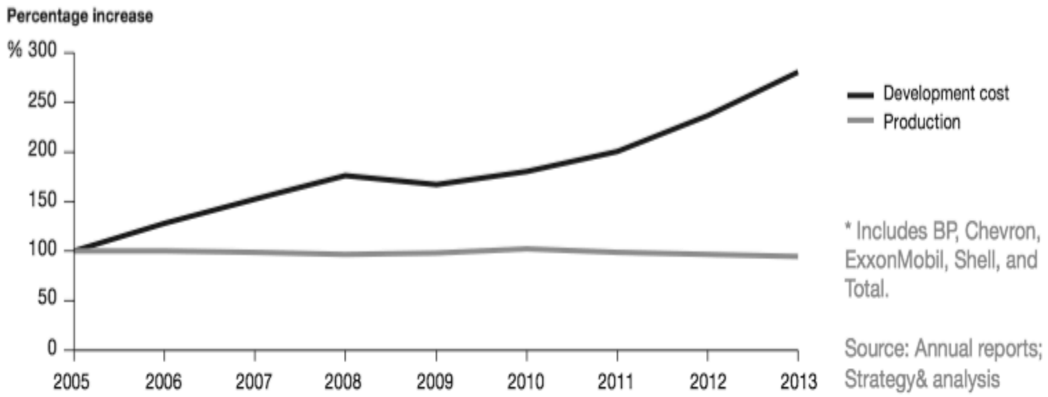


Figure 2.2 Oil and Gas Production and Development Costs (PwC, 2014)

The lowered capital efficiency is typically explained by four factors (PwC, 2014):

- more challenging exploration conditions;
- harder terms of collaboration with resource-owner;
- increased construction input costs;
- poor project planning and delivery.

Decreasing oil prices make the situation even more problematic for investors. While the first three factors are mostly out of E&P companies' control, they do take responsibility for the project planning and delivery. However, the oil and gas industry is facing unprecedented cost overruns while delivering megaprojects both in Norway and internationally.

Cost overruns are commonly understood as actual costs exceeding estimated costs, where actual costs are defined as real construction costs determined at the time of project completion, and estimated costs are defined as budgeted or forecasted construction costs at the time of decision to build (Flyvbjerg, Buhl, & Holm, 2002).

The failure to deliver the projects within predefined time and budget frames could cost energy companies trillions of dollars in lost investments. The estimated overspend across the whole capital budget of the energy industries is approximately 13%, which translates to US$5 trillion overspend on the US$38 trillion (Accenture, 2012). Another research of 365 megaprojects conducted for oil and gas industry (EY, 2014) shows that nearly 64% of the projects experienced cost overruns and 73% reported schedule delays globally.

However, other studies show that this trend is a not a curse of the petroleum sector alone. Poor performance of large capital projects is common in other industries, where mega-projects tend to appear, such as infrastructure and urban development, chemicals, power and utilities, mining and metals. A global cross-industrial study conducted by A.T.Kearney (2012) shows that 63% of capital projects are delivered over budget, and nearly 70% behind schedule, very similar figures to oil and gas industry. Other studies (Flyvbjerg, Buhl, & Holm (2002), Booz Allen Hamilton (2006), Accenture (2012)) also draw an attention to this increasing concern globally.

While capital project performance seems to be similar across the countries and even industries, the size of the project itsleft makes a difference in meeting its budget and schedule goals. An interesting pattern was discovered by Independent Project Analysis (Merrow, 2012): success of the offshore projects declines rapidly with project size. The success of the project in this context is defined as meeting its targets stated at the time of the financial investment decision (FID). While projects in the range $300-600 million were mainly successful, only half of the offshore megaprojects in the range more than $1 billion managed to deliver within the budget. Merrow (2012) also mentions that the same rates of success and failure is seen across industrial sectors. It draws a conclusion that the larger and more complex the project is, the higher chances of exceeding the initial budget are, where cost overruns are estimated in billions of dollars.

Summing up Chapter 2, lowered capital intensity and constant costoverruns is a common trend across capital intensive industries. The larger the project is, the more chances it has to overrun the intitial budget. The vast majority of projects in oil and gas industry is characterized as a megaproject, or a large-capital project, and the recent treck record of oil and gas project has shown that companies experience major problems with cost control which can be measured in millions of dollars. Finally, taking into account the current market conditions, the cost control becomes a main priority when the margins are cut by the oil price decrease.

3 Literature review

As it was mentioned in Chapter 2, capital-intensive projects draw a lot of attention of the society and increase stakeholder scrutinity. Thus, such constant poor performance of the companies in the upstream oil and gas sector and other industries has become an important topic in the business and academic worlds. Different factors causing cost overruns are discussed further in Part 2 of this chapter.

According to the definition of cost overruns given in Chapter 2, actual costs are compared to estimated costs. While most of the studies focus on why the actual costs keep escalating over the time of the project, less researches focus on the first parameter – estimated costs. It is important to study cost underestimation as it leads to two problems: (1) the project may be started despite the fact that it is not economically viable; (2) the project may be started instead of another project that would have yielded higher returns if the actual costs and benefits of both projects been know (Flyvbjerg et al., 2009). Hence, Chapter 3 Part 3 is devoted to cost underestimation.

The following structure allows to look at the problem from both sides of cost overruns, i.e. actual and estimated costs.

3.1 Cost overruns in large capital projects

The problem of cost overruns drew attention of various researchers from different fields, including engineering, economics and project management, as well as of major professional services corporations and governmental institutions, such as Norwegian Petroleum Directorate. The analysed articles and studies used different data collection methods, including interviews and surveys of managers, obtaining the data from Independent Project Analysis (IPA) database and from the project documentation provided by the companies or reported to the state institutions. The majority of the examined projects was characterised by large scale and international profile. While some researches focused only on cost overruns and delays in oil and gas projects (Emhjellen et al., 2003; Jergeas, 2008; Booz Allen Hamilton, 2006; EY, 2014; NPD, 2013), others studied overruns and delays using the data from other industries, where the capital projects tend to take place, such as infrastructure and urban development (Flyvbjerg et al., 2002; Flyvbjerg, 2005; Flyvberg, 2008; A.T. Kearney, 2012; Merrow, 2012).

Table 3.1 Overview of literature sources devoted to cost overruns in capital projects

Focus of the studies	*Various categories of projects including construction and infrastructure projects*	*Oil and gas projects*
Broad focus (poor performance)	Hall (1980) Morris (1990) Chan et al. (2004) Arvan & Leite (1990) Le-Hoai et al. (2008) Kaming et al. (1997) Kaliba et al. (2009) Assaf & Al-Hejji (2006)	Merrow (2012) Jergeas (2008) Abdullah et al. (2011)
Narrow focus (cost underestimation)	Lovallo & Kahneman (2003) Flyvbjerg, Buhl & Holm (2002, 2004, 2005) Flyvbjerg (2005, 2006) Flyvbjerg, Garbuio, & Lovallo (2009) Wachs (1982, 1987, 1989)	Emhjellen et al. (2003)

In addition, the studies addressing poor project performance in general (broad focus) as well as studies focusing only on initial cost underestimation (narrow focus) are considered. The literature with a broad focus presents a set of potential explanations why companies fail to deliver projects on time and within the budget. While few studies include inequaquate or unrealistic cost estimates as one of the potential explanations of failures to meet the targets, the majority of studies focuses on various issues regarding project management such as poor front-end loading, inappropriate contract strategy, insufficient project follow-up or human resource problems. Table 3.1 presents the analysed studies classified by the focus (broad or narrow) and projects (various types or oil and gas exclusively). This overview emphasizes the exisitng gap between studies in various indsutries and oil and gas sector in specific, where the latter is lacking studies with both, broad and narrow focuses.

The findings devoted to the consequate cost escalation and initial cost underestimation are presented below. The consequence and volume of the subchapters is explained by a higher significance of cost underestimation part, as it has not been widely covered in the literature before. While a separate chapter (Chapter 4) includes the studies devoted to fiscal policy design implications on project costs.

3.2 Explanations of consequent cost escalation

The table presented above illustrates that the majority of studies were conducted either within infrastructure and construction industries or across various capital-intensive industries. As oil and gas projects are always capital-intensive, require a substantial engineering effort and have a similar project development phases, most of the conclusions from the studies are applicable to petroleum sector as well.

3.2.1 Findings from construction and infrastructure projects

One of the most common general reasons mentioned by the authors is inefficent or ineduaquate planning. According to Morris (1990), 25-30% of cost increase can be explained by inflation, while the remaining 70-75% can be attributed to delays inefficiencies, scope changes and etc. The author concludes that inedequte project preparation is perhaps the most important reason for cost overruns. Kaming et al. (1997) has similar findings, adding poor labour productivity and resource shortage to factors responsible for delays and high project complexity, inflation and inaccurate material estimating to factors responsible for cost overruns.

Chan et al. (2004) devides factors into two categories – project management and project-participants related factors. The former group includes communication system, control mechanism, feedback capabilities, planning effort, organization structure and overall managerial actions; the latter – client's experience and ability, client contribution to the project, project team leader's experience and skills, commitment on time, cost and quality and project team leader's adaptability and working relationship.

More attention to team management and communication was drawn in later studies. For example, Abdullah (2011) concludes, "lack of communication has been noted to be the main reason for the failure of many project, hence, effective communication is needed so as to reduce non-productive effors, avoid duplication and help eliminate mistakes.

Exteranal factors, such as different aspects of the environement (ex. bad weather conditions) as well as inflation, price and exchange rates fluctuations are also mentioned by the authors.

3.2.2 Findings from oil and gas projects

The findings are similar to the previously discussed ones. There are also two main groups of factors that can be identified – internal and external factors. External factors are commonly presented by regulatory and geopolitical challenges. Internal factors usually refer to such project management elements as inadequate planning, poor procurement and contract management and human resource capital deficit (EY, 2014). By nature external factors are outside of companies' control area. Therefore, the major studies in the industry are focused on project management elements. While there is a wide set of elements affecting the performance of the oil and gas upstream projects, the four main categories can be selected based on the literature review: front-end loading, contract management and team management. A short summary of the three categories is presented below.

Front-end loading

Front-End Loading (FEL) is a project phase aimed to secure a detailed definition of the scope needed to satisfy the project's business objectives for capital investment (Deloitte, 2014). A well-defined and thoroughly performed FEL phase, leads to less unexpected problems and more competitive and predictable project outcomes (Deloitte, 2014), thus, more chances to meet the budget and avoid cost overruns. This point of view is supported by both, scholars (Jergeas, 2008; Merrow, 2012; Weijde, 2008) and practitioners (NPD, 2013; Accenture, 2012; Booz Allen Hamilton, 2006; EY, 2014).

Contract management

There are few topics within general contract management, where oil and gas projects experience problems, that resulted in cost and time overruns: inadequate prequalification of contractors; unclear contract strategy and insufficient follow-ups of suppliers by the operator (Schramm, Meißner, & Weidinger, 2010). Insufficient experience of executing complex and multidiscipline projects may have detrimental effects on both schedules and costs (Stangeland, 2011). Moreover, a poorly constructed contract that does not clearly state the scope of work and responsibilities over each step of project realization may lead to disputes between the operator and the contractor, leading to time and cost overruns. Last but not least, the follow-up of contractors is an important reason for exceeding the time frames and budgets (Investeringsutvalget, 1999; NPD, 2013).

Team management

The crucial element in team management category is the team composition. While the size of team can vary depending on the complexity of the project, the lack of sufficient experience of the team members was an issue mentioned in multiple industrial studies. It is important to that the opinions presented in the literature may vary. For example, Accenture (2012) after interviewing 61 executives from different countries concluded that availability of leadership talents in general is one of the reasons of project failures. While A.T.Kearney (2012) and Booz Allen Hamilton (2009) emphasised the shortage of technical and engineering talents in specific. The projects on the Norwegian Continental Shelf often experience delays and overruns due to underestimated task complexity and, hence lack of allocation of employees with relevant knowledge, according to NPD (2013).

3.3 Explanations of initial cost underestimation

There had been written a numerous amount of works devoted to the issue of complex projects implementation, i.e. coping with the mentioned-above risk factors and overcoming geological, technological and other uncertainties. The literature review revealed that these factors do contribute to the cost overruns and time delays. The purpose of the current chapter is, however, an attempt to understand why planners and forecasters, on average, fail to anticipate the greater costs of complex projects. Therefore, the following chapter is devoted to the potential explanations of initial cost underestimation.

The literature related to this topic is also mainly presented by the researches focusing on the infrastracture industry (Flyvbjerg, Buhl, & Holm (2002); Flyvbjerg, Garbuio, & Lovallo (2009); Flyvbjerg, Cantarelli, & Bert van Wee (2010)). In the previous part of the chapter the insights from the infrastructure industry could be transferred to oil and gas industry easily, as the project design is quite similar. However, the insights relating to cost underestimation from the infrastructure industry may not always be applicable in the oil and gas sector due to differences in the allocation of funds and production rights, which is taken into consideration in the further literature review.

There are three categories of underlying reasons that are applicable for all forecasting errors across the industries: honest mistakes (delusions), strategic manipulation (deceptions) or bad luck (Flyvbjerg, Garbuio, & Lovallo, 2009). By *bad luck* the authors mean “the unfortunate resolution of one of the major project uncertainties”, which is a salient explanation, but presents little research interest. *Honest mistakes or delusions* imply that planners underestimate costs and overestimate benefits due to delusional optimism, or what phychologists call ‘the planning fallacy’. The tendency of executives to consider a project or a problem as unique and thus disregard the knowledge from other unsucceful experiences is called an adoptation of the 'inside view' in referance class forecasing (Lovallo & Kahneman, 2003). This way, unrealistic plans are a result of a delusion rather than rational weighting of gains and losses. The third group of underlying reasons, *strategic manipulation or deceptions,* refer to what economist call a "Principal-Agent" problem, when actors have different preferences and incentives in the system. In this case, planners and executives deliberatly underestimate costs and overestimate benefits in order to increase the chances of project approval.

Categories 'delusion' and 'deception' can further be divided into four groups: technical, physocological, political and economical (Flyvbjerg et al., 2003). Where technical and physocological refer to 'delusion' and political and economical to 'deception' (Figure 3.1).

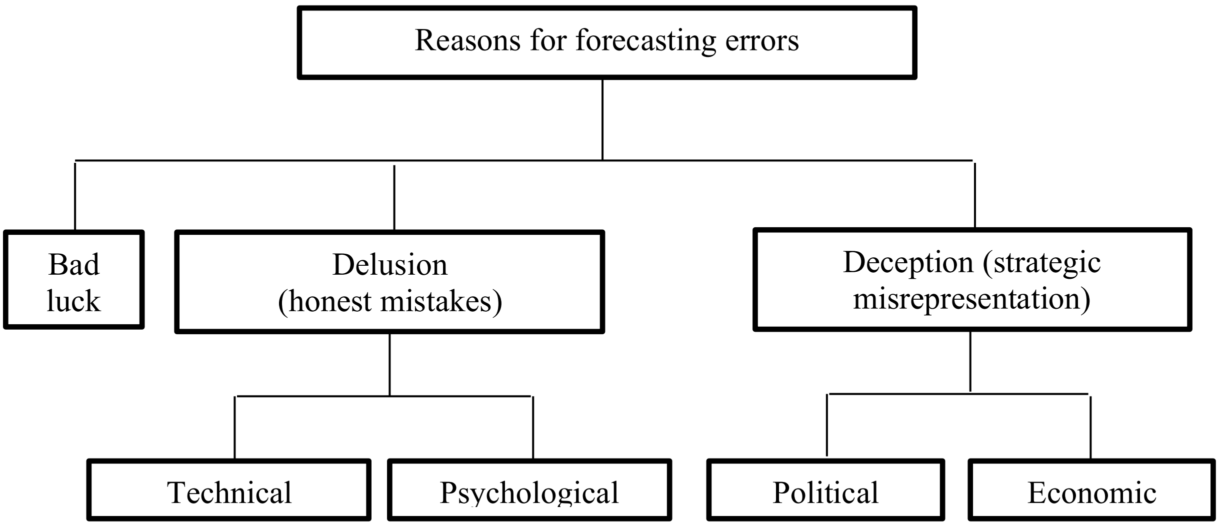


Figure 3.1 Underlying reasons for forecasting errors (Flyvbjerg et al. 2002, 2009)

Technical explanations

Technical categoty combines different forecasting errors, including imperfect techniques, inadequate, unreliable and outdated data, 'honest mistakes', inherent problems in predicting the future, lack of experience on the part of forecasters or simply the use of inappropriate forecasting models (Flyvbjerg, Buhl, & Holm, 2002; Flyvbjerg, 2006; Emhjellen et al., 2003). For example, Emhjellen et al. (2003) explained part of cost overruns by the use of 50/50 (median) CAPEX estimate instead of expected CAPEX cost estimate. Although, data and methods have been improved over several decades, as well as the possibility to predict the risk, based on wider experience from previous projects, the accuracy of cost estimations did not follow the same pattern (Flyvbjerg, Cantarelli, & Bert van Wee, 2010).

Psychological explanations

Psychological explanations attempt to explain cost underestimation by planning fallacy and optimism bias in the mental makeup by project promoters and forecasters. Over-optimism is a commonly known problem across projects of various scales and industries. Kahneman and Tversky (1979), Kahneman and Lovallo (2003), Son and Rojas (2011) argue that the high number of business failures is a consequence of executives' planning fallacy, when they make decisions based on delusional optimism, which leads to overestimating benefits and underestimating costs. However, Bent Flyvbjerg (2008) suggests that strategic misrepresantation could be the chief reason for inaccuracy, i.e. the mistake is delibarate rather than 'honest' and, therefore, is better explained by economical and political factors.

3.3.1 Political explanations

Both political and economical factors explain deliberate (intentional) underestimation of project costs. The difference between both types of explanation is rather small as they use utility as a basis to understand behavior. In both types, costs are intentionally underestimated in order to increase the chance of project acceptance. However, economical explanations refer to economic rationality, while political explanations construe cost underestimation in terms of interest and power (Flyvbjerg, Buhl, & Holm, 2002).

Supporting political explanations of cost overruns, Wachs (1989) argues that planning often refers to the considerations of advocacy, rather than objectivity. As one may expect, due to legal, moral and economic reasons, planners and forecasters are unlikely to reveal to researchers that the cost estimates were intentionally fabricated. However, while interviewing public officials, consultants, and planners who were involved in transportation projects in the U.S., Wachs (1990) discovered that the constant cost underestimates are best explained by deliberated falsification rather than technical errors.

3.3.2 Economic explanations

Flyvbjerg et al. (2002) found a statistical evidence of the systematic underestimation of costs in data derived from infrastructure projects. The authors conclude that the costs are "highly, systematically, and significantly deceptive" and depict the underestimation as delibarate and economically rational. After this conclusion has been studied in more details, Flyvbjerg, Cantarelli, & Bert van Wee (2010) comprise economical explanations group with such causes as lack of incentices, lack of resources, inefficient use of resourses, dedicated funding process, poor financing/contract management and strategic behavior.

Lack of incentives to provide accurate estimates is a common problem in large megaprojects across industries, including oil and gas sector. The authors argue that forecasters and promoters tend to underestimate the costs in order to make a project to look more attractive for decision-makers and, therefore, increase a chance of being awarded a licence or selected for financing. Moreover, inaccurate cost estimates can result in a situation, where an inferior project is implemented. In this case, the *resources are spent inefficiently* and cannot be recovered. Finally, Flyvbjerg et al. (2010) denotes *strategic behavior* as an economic explanation of its own as underestimating costs increases the chance of getting the project started. It seems applicable in the oil and gas industry, as international oil companies have to compete for the right to develop a specific oil field, where one of the top criteria is the cost-benefit ratio. Therefore, the most basic explanation offered by Flyvbjerg et al. (2005): "lying pays off, or at least political or economic agents believe it does", could potentially be related to oil and gas projects.

As a result, companies, that have lack of incentives to deliver accurate cost estimates and believe that underestimated costs and overestimated benefits increase their chances of starting a project, provide an artificially high cost-benefit ratio, which leads to two problems, named by Flyvbjerg et al. (2009). First, a project that is not economically viable can be approved. Second, a project that yields higher returns can be rejected, i.e. it leads to Pareto-inefficient allocation of resources. If this is the case in the oil and gas industry, this means that the host government does not reach its major policy objective – maximisation of the economic rent.

Economic explanations are mainly based on neoclassical economics and rational choice theories, where incentives and costs play an important role in making decisions. The neoclassical economics theory is used by Flyvbjerg et al. (2010) to explain the lack of incentives for the planners in their role as 'advocates', while the rational choice theory assumes that individuals calculate the costs and benefits of an action before the decision, which means, it is economically rational to underestimate costs because it will increase the likelihoood of revenue and profit. For this reason rational choice theory "is considered to have considerable potential in explaning cost overruns, not only for economic explanations, but also for psychological and political explanations" (Flyvbjerg, Cantarelli, & Bert van Wee, 2010).

The rational choice theory is also applicable in the oil and gas indsutry for both sides – international oil companies and the host governement. While it is clear that the main objective of the oil companies is profit maximization, the host governemnts aim at a variaty of objectives over time. However, the maximization of the net present value of the economic rent is among the most common ones. That means, that the governments are motivated to allocate the mineral rights to the most efficient operator, i.e. the lowest-cost bidder, which will lead to decreased costs and increased economic rent (Tordo, Johnston, & Johnston, 2010).

Concluding the chapter, the literature related to both sides of cost overruns problem was analysed. Despite various studies, reports and services aimed at improving the performance of the project, the scale of overspendings is increasing. Flyvbjerg et al took a different approach. By applying rational choice theory he attempts to explain initial cost underestimation as an intentional choice that is expected to bring economic befenits.

4 Petroleum fiscal systems and economic incentives

The previous chapter outlined various reasons that could be responsible for cost overruns. However, little if any attention was devoted to special petroleum policies from the perspective of providing incentives for intentional cost inflation. In order provide some explanation to why an economically rational oil company and, thus, a cost minimiser would be willing to inflate its costs, the theory of moral hazard is introduced below.

4.1 Moral hazard and petroleum taxation

In order to explain why petroleum taxation regimes are the main focus of the current master thesis devoted to cost underestimation and overruns, the theory of moral hazard has been applied to the oil and gas industry.

It has long been recognized that a problem of moral hazard may arise when individuals engage in risk sharing under conditions such that their privately taken actions affect the probability distribution of the outcome (Holmstrom, 1979). In other words, Principal-Agent theory is considered in a situation of imperfect information, in which outcomes conditional on the agent's actions are uncertain, and the agent's behaviour, therefore, unobservable (Mirrlees, 1999).

Principal-Agent theory is often used to demonstrate the design of petroleum taxation (Lovas & Osmundsen, 2009). The ownership over the national petroleum reserves is shared by all residents of the host government in most of the cases. On behalf of the population, the government acts as a 'principal' and attracts private companies, i.e. 'agents', to participate in petroleum extraction. In theory, the government's main objective is to maximise the net total take from the industry and use it for public expenditures and investments, i.e. maximise the social benefits. In this case, both, the principal and the agents, aim at reward maximization and shifting risks to the other parties. Lovas and Osmundsen (2009) states that, "an ideal tax and licensing system captures the petroleum rent, attracts the most efficient companies, and induces all socially profitable fields to be exploited in an optimal way". Moreover, an ideal tax system implies optimal risk sharing between the two parties.

In order to identify if the problem of moral hazard is important in the relationship between the government as a 'principal' and the company as an 'agent', two questions should be answered: (1) if there is an existence of hidden actions in the oil and gas industry and (2) whether the outcomes are the joint product of uncertainty and actions known only to the agent.

Regarding the first question, the host government has imperfect means for observing the company's effort to increase output and reduce costs. By company's effort to increase output, exploration and production efforts are assumed. The government gets access to the information about the amount of seismic data collected, the number of exploration, appraisal and production wells drilled, but the government has imperfect monitor over the amount of internal resources allocated to the exploration process. Another observability problem is that the government cannot perfectly monitor the efforts to reduce costs. Osmundsen (1999) emphasized the development stage, as the investment goods at this stage are not standard commodities with established market prices, therefore, the observability over company's efforts to reduce the costs decreases.

In regards to the second question, the outcome in this case is the output in tons of oil equivalent and costs for a given production, where both, the output and costs, are considered as stochastic in petroleum industry due to various uncertainties. Hence, in the case of high costs and low production, it is often not possible for the government to observe whether it could be explained by exogenous factors or simply by a low effort on the part of the firm.

As a result, moral hazard is presented in petroleum industry due to the existence of opportunities for hidden action that impacts the outcome due to imperfect government's control and, most importantly. Having said that, the next two questions aroused: (1) how petroleum taxation can actually incentivise cost increase and (2) why would a company, traditionally a cost minimiser, intentionally increase its costs.

A simple answer to the first question is the higher the marginal tax rate, the more incentives it provides to write off costs against it. Here it is important to understand that it does not actually encourage incurring additional costs, but instead it incentivise allocation of costs to the activities attracting high tax. This also explains why a company would intentionally increase its costs. In the presence of moral hazard and a high marginal tax rate, the international oil company (1) may not report the accurate costs incurred in the project, which is an accounting monitoring aspect; (2) may allocate costs of not relevant activities with the purpose of writing it off against a high marginal tax rate and get benefits for it elsewhere (Osmundsen, 1999).

In the situation of a neutral tax system, incentives of the company and the government are aligned, i.e. makes the operator to expand output and reduce costs. However in the situation of higher marginal rates these incentives are eroded and the issue of the company inflating claimed costs is emphasized. Osmundsen (1999) provides an example of cost inflating in Norway, which has a high marginal tax for petroleum industry (78%) as well as additional cost allowances and investment incentives. The author suggests that Norwegian petroleum taxation system makes it attractive to multinational companies to transfer the training of personnel to the Norwegian petroleum sector, while the resulting benefits may occur in other sectors with lower marginal rates. This way, costs on the Norwegian continental shelf can be high as a result of hidden actions.

To sum up, the objective of this part was to explain with the use of moral hazard theory why the taxation is studies in the perspective of cost overruns in oil and gas projects. The next step is to study how different petroleum fiscal regimes may differ in providing incentives described above, starting with a theoretical introduction to petroleum fiscal regimes.

4.2 Theoretical introduction of petroleum fiscal regimes

States have sovereign jurisdiction over their natural resources and are responsible for maintaining a legal regime for regulating petroleum operations, which is normally set in a constitution. While the abundance of hydrocarbons in a state is a gift of nature, it requires large investments and efforts to translate it into saleable crude oil. Despite the choice of a government to invest directly or through private companies, its primary task is to maximize the social benefits derived from the exploitation of this natural resource.

Petroleum taxation is the principal mechanism for sharing petroleum wealth between host governments and investors, or in other words, "it is to acquire for the state in whose legal territory the resource in question lie, a fair share of the wealth accruing from their extraction, whilst encouraging investors to ensure optimal economic recovery for those hydrocarbon resources" (Nakhle, 2008). Thus, the state has two competing rather than complementary objectives: (1) to ensure a fair share of revenues for itself (2) to provide sufficient incentives to encourage investments. To find a balance between the two objectives is the major challenge, especially in a situation of volatile oil prices. In order to overcome this challenge, the governments of petroleum-rich nations introduce various taxation techniques and relationships with the oil companies, which in combination represent the country's fiscal system design.

The petroleum fiscal system is a combination of *the taxation structure* established by legislation and *the contractual framework* under which an oil company operates with the government (Mazeel, 2010). Fiscal terms and conditions can include bonuses, rentals, royalties, carried interest provisions, corporate income and special taxes and production sharing arrangements. In other words, all kind of payments to the government that are required under the petroleum arrangement can be called a “fiscal system” (Khelil, 1995).

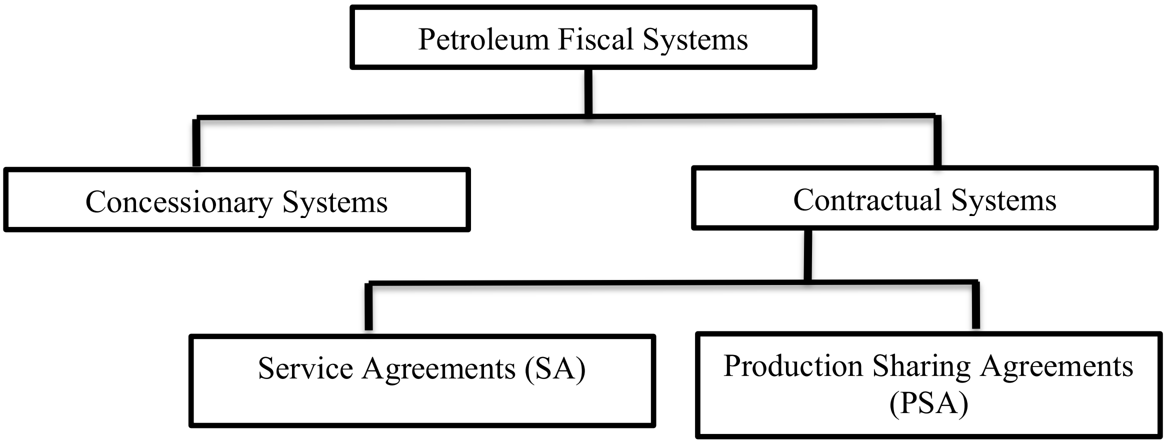


Figure 4.1 Classification of petroleum fiscal systems (Mazeel, 2010)

There are two main classes of petroleum fiscal systems as illustrated in Figure 4.1. A system is called *concessionary* when a host government grants a license or a permit to explore and produce on a specific field to an oil company. The producing company is imposed net tax and/or royalty. A system is called *contractual* when a host government either self-produce or share the production and marketing with private oil companies. The private oil companies receive a share of production or revenues in accordance with a *production sharing agreements* (PSA) or a *service agreement* (SA) (Mazeel, 2010). The main difference between a PSA and a SA is the type of compensation an oil company receives. In case of a production sharing agreement, the contractor has a right over a share of production, i.e. receives its compensation in crude oil. While under a service agreement, the contractor gets a share of profits, i.e. receives its compensation in cash. There are more subclasses under each of the contractual system. Despite the variation used, the bottom line of the fiscal design system is a financial issue, i.e. how costs are recovered and profits divided. Both systems, contractual and concessionary, are discussed in more details later in the chapter.

As theory “Principal-Agent” implies, there is no universal optimal contract or tax system. An optimal system is rather ‘tailored’ to the specific situation of the contracting parties and the transaction. Thus, such *transaction-related characteristics*, as economic attractiveness of the geological area, the oil price, business cycle, presence of infrastructure and competent supplies, in combination with such *contracting parties-related characteristics*, as ability and willing to carry risks and level of impatience for revenue, define a state contingent optimal tax policy (Lovas & Osmundsen, 2009).

In practice, there are more petroleum fiscal systems in the world than there are countries, as each country may use more than one system (Johnston, 1994). As there are no identical characteristics of *the transaction* and *the contracting parties* across different countries, there are no identical fiscal system designs. They vary largely from country to country. Moreover, the use of more than one fiscal system can be explained by the transition period when government uses two different systems at once, or simply by using different contract terms applied for different contractors. However, despite such a great variability of the fiscal systems around the world, there are basic elements used for design construction.

4.3 Concessionary petroleum fiscal system

Many governments decide on engaging private companies with an aim to increase the efficiency of the resource exploitation. In this case, one of the most important processes is the allocation of the exclusive rights to explore, develop and produce the resources. There are various terms such as “permit”, “license”, “concession”, “acreage position”, “contract area”, “lease” or “block” that can be used interchangeably most of the times when talking about rights for exploration, development and production (E&P).

Under a concessionary system, the host government grants a license to an international oil company (IOC) or a group of companies, which gives a right to explore, develop and produce hydrocarbons for a fixed period within a certain lease area (Mazeel, 2010). The host government may require the IOC to pay a signature bonus to secure the license. Thereafter, the rest of the government’s compensation comes from royalty and tax payments when hydrocarbons are produced. As collecting royalties and a combination of taxes is the most common way for the government to collect their share of the economic rent within this system, it is also called a Royalty/Tax System or R/T.

Concessionary systems are used by around half of the countries including the US, UK, Russia, Norway, France, Argentina, South Africa and Australia (EY, 2014). According to Johnston (2003), the percentage of these countries may reach 44% of all oil-producing countries. While all these countries have the same type of the fiscal system, the system design varies widely in terms of royalty and tax rates, tiers of taxation and other elements such as incentives to promote investments. A short summary of main element of the system is present below.

Royalties have historically been the most common method used by governments to gain revenue from oil exploration. Royalties are paid to the government only when the production starts, however long before the actual profit generation. Thus, it can be seen as a regressive form of taxation. Royalties may distort long-term behaviour and decision-making, for example high royalties may lead to early termination of production. The use of progressive royalties, i.e. where royalty rates are linked to certain parameters that usually closely reflect project profitability, is a possible way to eliminate such risks.

The Corporate Income Tax (CIT) is levied on oil and gas companies as well as on all other companies operating in the country. The tax is paid when annual revenues exceed a certain measure of costs and allowences. Therefore, it is important to understand the taxable income structure. Many countries provide incentives for exploration and development by allowing exploration costs to be recovered immediately and development costs recovery to be accelerated, for example over 5 years. Moreover, the governemnt can allow additional uplift for capital costs, so the company could in fact deduct more than 100% of costs, in order to make the fiscal system more neutral. In order to secure that the company does not deduct exploration and development costs from one project against the income of the other project that already generates taxable income, a *ring-fencing* practices are implemented by some countries. However, in a situation where moral hazard is taken into account, hidden actions of companies may not be limited by such practicies.

Additional taxes may be imposed on the petroleum sector. *The Brown Tax (BT) and Resource Rent Tax (RRT)* are the cash-flow taxes. RRT is a modified form of BT and is collected only when a rate of return that represent normal profits has been reached. Although both, BT and RRT captures a share of the economic rent and make the tax system less distortive in theory, it has not been proven to be a significant revenue raiser in practice (Sunley, Baunsgaard, & Simard, 2002; Nakhle, 2008).

To sum up, the two main elements of this system are royalties and corporate income tax. In addition, the capital allowences, depreciation and deducutions could be incorporated in order to provide investment incentives and encourage expoliration of marginal fields. Incorporation of a special petroleum tax increases the marginal tax across various industries, including oil and gas E&P rights.

4.3.1 Winner's Curse

The concessionary petroleum fiscal system implies allocation of E&P rights, which is often performed through an auction. Thus, the winner's curse is a relevant theory that can be applied in the oil and gas industry.

The economic theory behind auctions used by the government is that "the market participants are much better informed than the government about the true economic values of the goods offered". However, a crucial element of an auction problem is asymmetries of information, when one party has relevant information about the transaction that the other party does not have. In fact, the key element of oil and gas exploration is uncertainty. The mineral rights, which the participants are bidding for, have a value, which is worth the amount of oil lying under the ground. However, no one knows the true value. The bidders have access to different information and different estimates and predictions about how much the rights are objectively worth. This is called the *common-value model*. When the product (the resource rights) being bid has a common value, the phenomenon named the *winner's curse* may arise (McAfee & McMillan, 1987).

This phenomenon was first presented in the literature by petroleum engineers Capen, Clapp and Campbell (1971). The logic of the winner's curse is simple: "the lease winner tends to be the bidder who most overestimates reserves potential" (Capen, Clapp, & Campbell, 1971). Given that it is a common value action and the difficulty to estimate the true value of the reserves, the estimates of the experts will vary substantially. It occurs that the company that wins the auction will be the one whose experts provided the highest estimates, i.e. no one else was willing to bid as much for the item (Thaler, 1988).

Porter, Wilson, & Hendricks (1994) incorporated the role of information by assuming that one bidder has better informtaiton than others. The results of the study has revealed that the percentage rate of increase in the distribution of the uninformed bid is always smaller than the one of the informed bid and that the informed buyer is more likely to submit low bids. This demonstrates that in the auctions the lower costs submitted may be explained by simply information assymetry rather than strategic misrepresentation (as suggested in Chapter 3.3. Based on this, certain assumptions are made whilst modeling economic incentives in Chapter 7.

4.4 Contractual petroleum fiscal system

The main principle of this system and also the main difference from the concessionary system implies the host government's ownership over the resource, while the oil companies have a role of "*contractors*" who develop and extract in return for a compensation. Contractors are required to submit a programme and a budget to be approved by the national company of the host government. The contract as a rule depends on the amount of petroleum reserves and political and economic aims of the government.

There are two categories within the contractual system. Different terms are used in the literature, such as "production-sharing arrangement", "production sharing contract (PSC)" or "service contract". In the current paper the terms "Production Sharing Agreement" or "PSA" and "Service Agreement" or "SA" are used.

The main difference between the two systems is the compensation received by an oil company: under a PSA system the oil company receives its compensation. In a PSA system a host government or a national oil company (NOC) enters a contract with an oil company or an international oil company (IOC) directly, which implies that the IOC finances and carries out the E&P operations and receives certain amount of produced oil to recover the costs as well as a certain share of profit. In some cases, the host government requires additional payments apart from the share of production, such as royalties, corporate income taxes, windfall profit taxes and other (EY, 2014). Under a SA system, an oil company receives a fee for the service it provides – financing and carrying out projects. The fee usually permits the recovery of all or part of costs and a profit component. Moreover, under some service agreements, the contractor has the right to purchase crude oil from the host government at a discount. Despite the discussed differences, the same economic results under the two types are achieved (Mazeel, 2010).

With an aim to understand better the contractual system, the two main elements are described below.

4.4.1 "Cost oil"

Even though all the oil extracted belongs to the government under the contractual regime, the oil company bears all the costs and risks of exploration and development. In the event when discovery of oil does not occur, the company has no right to be paid. However, if the discovery does occur, the company is entitled to recover the costs, which is known as "cost recovery" or "cost oil", which is one of the main elements in the contractual system design.

Typically, a pre-determined share of production is annually allocated for cost recovery. According to Nakhle (2008), a general limit for cost recovery ranges from 30-60% of gross revenue, which means, for any given period the maximum level of costs recovered is 60% of revenue. The limit on cost recovery can be seen as an alternative to royalties in concessionary regime, as it ensures that there is "profit oil" and the government obtains its share as soon as production starts. Thus, royalties are usually not applied within PSA regimes.

Moreover, as a rule, contractual regimes offer some investment incentives such as unrecovered costs carried forward or an uplift factor to compensate for the delay in cost recovery. Similar ring-fencing practices as discussed in concessionary system are also applied under the PSA regime, which means that costs inccured in a particular block can be recovered only from revenues generated within this block.

4.4.2 "Profit oil"

After all costs have been recovered, the "profit oil" or "production split" is devided between the host government and the company. The split shares are predifined in the contract and can be either a sole split or a progressive split. The share of the profit oil that the oil company obtains can also be a subject to the income tax. The most typicall share that goes to the governemnt is 50-60% of profit oil, however, some countries apply higher shares (Johnston D. , 2003).

The list of countries using contractual regimes includes China, Angola, Algeria, Oman, Azerbaijan, Indonesia, Malaysia, Kazakhstan, Iraq, Argentina and others. As it can be noticed, contractual basis is presented mainly among developing countries. The potential explanation behind it is that contractual system implies a government's ownership title over the resource and facilities (Johnston D. , 2003), a higher government control and, last but not least, a larger share of the oil, which can be sold and the revenue used for the government's development programmes and economic needs (Mazeel, 2010). Glomsrød & Lindholt (2004) also suggested an alternative idea, "it is not surprising that the PSA contract was selected in developing countries such as Indonesia, where production sharing under the name of "sharecropping" has been a traditional way of subcontracting in agriculture".

The two types of contracts are not equally spread across different countries. According to Johnston (2003) and International Petroleum Fiscal Systems Data Base, only 8% of all oil producing countries implemented a SA system, while PSAs are used in 48% of the countries. As the economic results are similar under both types of agreements, only Production Sharing Agreement, as the most widely used system in the world, is chosen for the further analysis and research. Moreover, the majority of studies devoted to evaluation and analysis of different fiscal regimes include only one single contract agreement, a PSA, in their research (Sunley, Baunsgaard, & Simard, 2002; Lovas & Osmundsen, 2009; Glomsrød & Lindholt, 2004; Nakhle, 2008, Johnston, 1994, 2001, 2004).

Moreover, a PSA regime can have a variety of designs even within one country. The scheme can vary from contract to contract. Besides that, it is not uncommon to have hybrid revenue schemes containing both, PSA and R/T elements. Examples of countries with hybrid systems are Nigeria, Brazil, India, Argentina, Libya and others (EY, 2014).

4.5 Comaparative analysis of R/T and PSA regimes

There are different opinions about the similarity of economic results of concessionary and contractual regimes. For example, Johnston (2006) states that there is no particular fundamental difference between the two systems from a mechanical and financial point of view. The main difference is only from a legal point of view, i.e. in the *ownership structure* or, in other words, where, when and if the ownership over hydrocarbons is transferred to the oil company. While the concessionary scheme implies the transfer of the title at the wellhead, when the IOC gains a right over gross revenue less royalty; the PSA allows the transition only at the export point, when the company takes title to ‘cost oil’ and ‘profit oil’. However, as it was mentioned, under PSA regime the company still bears all the costs and risks of exploration, development and productions, therefore, the title of ownership does not affect the economics of the project and, hence, does not provide specific economic incentives.

Johnston (2003) emphasizes the design elements of the fiscal system, rather than the type of the system itself, arguing that, “governments can achieve their fiscal objectives with any fiscal system they choose as long as the system is designed properly”. Moreover, according to Sunley et al. (2002), the fiscal terms of R/T regime can be replicated in a PSA regime, and vice versa (Table 4.1).

Table 4.1 Replication of R/T elements in a PSA regime (Sunley et al. 2002)

Reward trade-off/Risk	*Concessionary regime*	*PSA regime*
Low risk to government	Royalty	Explicit royalty or a limit on cost oil that functions as an implicit royalty
Medium risk	Income tax	Income tax, which may be paid out of the government's share of production
High risk	Resource Rent Tax	The determination of the amount of profit oil can imitate the RRT

This means that no conclusion can be made about superiority of one regime over another in terms of efficiency or neutrality based only on the type of the system and the presence of certain elements in the design. Instead, the specific terms fiscal and the total marginal effect should be analysed.

4.5.1 Analysis from a cost consciousness perspective

Without taking moral hazard into consideration and, thus, assuming symmetric information, optimal risk sharing would mean equal marginal rates for the two parties. By optimal risk sharing it is assumed that the company's incentives are aligned with the resource owner's. However, as it was shown earlier, moral hazard does take place in petroleum sector, therefore, the government should provide economic incentives to induce effort of the companies.

Depending on what are the term the governemnt uses within the R/T or PSA system, it can provide more or less incentives for *cost consciouss* behavior of international oil companies. High cost conscioussness means that a company has a stricter cost control and is more careful about its spendings. Under the R/T system, the higher the marginal tax, the higher incetives it provides to write off additional costs. Following the same logic, high capital allowences provoke the same behavior if governement's monitoring effors are imperfect, which is the case in petroleum industry. Besides that, if the marginal tax is high, which means a high government take, then the company is less motivated to save costs.

Under the PSA regime, the development and operation cost overruns as well as cost savings are shared according the cost recovery terms between the host government and the oil company. Thus, larger government share means lower benefits from cost savings and lower income risks in case of cost overruns for the company.

There is no identical fiscal system in the world. However, there are terms that are more typical for one regime or another. World average fiscal terms generalised by Johnston (2003) and Tordo (2007) are presented in Table 4.2. Based on generalisation of the terms, a common comparison of R/T and PSA regimes can be made.

Table 4.2 World Average Fiscal Terms (Johnston, 2003; Tordo, 2007)

	R/T regime	*PSA regime*
Number of systems	64	72
Government Take	59%	70%
Governement Participation	Less likely	More likely
Royalty Rate	8%	5%
Lifting Entitlement	92%	63%
Saving Index	56%	39%
Cost Recovery Index	N/A	65%

Typically but not always, the oil company would benefit from cost reductions. The degree to which the company would benefit depends on profit-based fiscal terms. The Savings Index (SI) (see Chapter 9.1) is used to quantify to a certain extent the incentives companies have to keep their costs down (Johnston, 2003).

The world average terms illustrate that R/T regime typically implies less government control and participation, as well as less government take and a higher lifting entitlement by the contractor. With such terms, a higher saving index is expected under R/T regime. While the PSA system incorporates a higher government take and control, the saving index is lower.

However, there is no such thing as a world average petroleum fiscal system. Each country's case should be considered separately and no generalization or conclusions about its fiscal regime's neutrality or incentives it provides for cost savings based purely on the fiscal regime type could be made. Thus, the next step of the thesis is an analysis of real fiscal terms of four petroleum-producing countries.

5 Hypothesis

By hypothesis the author of the thesis understands "a supposition or proposed explanation made on the basis of limited evidence as a starting point for further investigation" as it is simply and clearly defined in the Oxford Dictionaries.

According to Flyvbjerg (2008) and Flyvbjerg et al. (2002, 2005, 2009, 2010), cost overruns in a project can be explained by a strategic misrepresentation of initial cost estimates provided by a company to the authorities in order to increases the chances of the project approval. This logic can be applied to the realities of oil and gas industry as well as the companies have to compete in order to obtain the license. Answering the reseach question, therefore, it is assumed that:

H1. Petroleum fiscal systems provide more incentives for cost underestimation by allocating larger shares of profits to the company.

The second and the major part of the research topic is about the incentives that the fiscal regimes provide after the contract is awarded and the project started. The reasoning presented by Osmundsen (1999) is that in the presence of moral hazard and a high marginal tax rate, the international oil company may be incentivised to report inaccurate costs incurred in the project. Therefore, it is assumed that:

H2. Petroleum fiscal systems that imply higher marginal tax rates provide more incentives for low cost consciousness among the oil companies

It is important to mention that the hypothesis does not intend to generalise all PSAs or R/Ts and draw common conclusions based on the research. The research question is answered based on the evidence received from the analysis performed further in the paper.

6 Methodology

It was outlined in Chapter 1.2 that the answer to the part of the research question related to the behavior *before* the contract award implies a rather theoretical approach and conceptual research, which is mainly based on assumptions. The answer to the part related to the incentives provided by the taxation policy *after* the contract award can in fact be computed and contrasted for various fiscal regimes.

The research design of the both parts is based on a hypothetical oil project data. Thus, the primary step for both researches is:

0) Defining sample project assumptions

The reasons behind using a hypothetical oil project are (1) data availability: it is rare when the net cash flow data from a real asset is available outside the firm, as cash flow and cost information is proprietary; (2) project specifics: even if data is available for a specific field, it include pecularities that are not widely presented among other fields, which may partly distort the analysis and (3) the purpose of the study: the conclusions are mainly to be made based on comparative analysis, this, relative values rather than actual values are important. Using a standart petroleum project type in evaluating petroleum taxation policies is a typical approach among scholars as well as such institusions as World Bank and International Monetary Fund.

6.1 Research related to cost underestimation incentives

This part is performed as a conceptual research. By 'conceptual' the author of the thesis understands 'analytical' research, that provides an underlying understanding of the subject of the reserch. It is recognized that this research type is recommended to used in combination with empirical analysis. However, the legal, moral and economic limitations associated with data collection about deliberate and true cost estimates, as well as probability distribution of chances of award is hard or imporssible to obtain. Thus, only a conceptual research could be performed in this secton, which nontheless is intented to provide a better understanding of economic benefits for the company and losses for the government.

The concepual research implies a constraction of a model for economic incentives for deliberate cost underestimation based only on assumptions, derived from economics theories, such as “Principal-Agent” and others. The model development process follows the following steps (given the identified sample project assumptions):

1) *The fiscal regime assumptions are defined*
   For this model constraction, specific fiscal terms do not provide additional value, therefore, for the sake of avoidance of unnecessary complication, standard assumptions of R/T and PSA regimes are made.
2) *Scenario of honest estimates is described*
3) *Scenario of deliberate cost underestimation is described*
4) *Decision-tree with both scenarios is constructed*
5) *Economic incentives for the company are calculated*
6) *Opportunity costs for the government are calcualted*

The model and analysis is presented in Chapter 8.

6.2 Research related to fiscal incentives for cost consiousness

This is the main research of the thesis. The research focuses on only four fiscal regime examples (two under each of the system) and, thus, can be considered as a case study analysis, which implies the following steps.

1) Qualitative analysis of the modern fiscal terms of a chosen fiscal regime (Chapter 8)

Qualitative assessment of the system is important for understanding the true incentives the government provides.

2) Identification of the relevant economic figures and indecies to be computed

As a full evaluation of a petroleum fiscal regime from cost consioussness point of view is relatevly novel, the relevant economic indicators have to be chosen or, in other words, a framework for evaluation should be developed.

3) Computation of cash flows and NPVs for each of the taxation systems for each of the sides – the host government and the oil company

This step requires an understanding of all nuances of the taxation system, as well as accounting specifics. The spread sheets of calculations are to be provided in Appendix 11, 12, 13, 14.

4) Calculations of the economic figures and indices

5) Running a One-at-a-time (OAT) sensitivity analysis

Three costs categories, CAPEX, OPEX and R&D (in this study – exploration and appraisal costs) as an input variable and NPV for the host government and the oil company as an output. i.e. values where there is a 50% chance of the actual outcome exceeding the base value and a 50% chance of the outcome being below the value.

7) *Comparative analysis of outcomes*

The calculated figures are to be compared and discussed from the government and the company perspectives. This analysis is undertaken in order to study in more details the difference in the terms within each group of systems. The main insights about fiscal terms and difference are to be obtained.

The thesis proceeds with modelling economic incentives for cost underestimation, which is then followed by the main research of the master thesis focusing on fiscal terms and their economic incentives.

7 Modeling economic incentives for cost underestimation

Two out of four groups of explanations – political and economic – imply deliberate cost underestimation. The underlying assumption for both groups is "costs are intentionally underestimated in order to increase the chance of project acceptance" (Flyvbjerg, Cantarelli, & Bert van Wee, Cost Overruns in Large-scale Transportation Infrastructure Projects: Explanationa and Their Theoretical Embeddedness, 2010). The economic group of explanations presents the main interest focus of the current master thesis. Therefore, the problem of deliberate cost underestimation will be analysed from the perspective of economical rationality to underestimate costs.

The purpose of the current step is to identify if there are any incentives in deliberate cost underestimation and what is the impact on the host government if underestimation takes place. Based on the rational choice theory, individuals calculate the costs and benefits of an action before the decision. In the given context, it means that an increase in the likelihood of revenue and profit makes it economically rational to underestmate costs. Based on this theory and Flyvbjerg et al. (2002, 2005, 2008, 2010) studies, first thesis statement was developed.

7.1 Project assumptions

A deterministic approach is used to calculate the level of production, costs and prices, which does not imply random variations of the variables. An alternative approach could be statistical or stochastic methods to determine possible value distribution. It would have provided valuable information for the optimization of the fiscal system. However, the objective of the modelling is not fiscal system optimization in a particular country, but a demonstration of economic incentives to underestimate costs and an analysis how different fiscal terms influence consequent cost consciousness of an oil company.

In relative terms, different field sizes generate different levels of economic rent. Hence, different tax regimes have a varying impact on field profitability given the individual specific characteristics of each oil field. According to findings in Merrow (2012), success of the offshore projects declines rapidly with project size. Thus, it is interesting to analyse a field of a medium or larger size.

In order to avoid unnecessary complications, the modelling is based on a standard project, where a single company operates on a single oil field. Besides that, it is assumed that a field is guaranteed to have a commercial discovery. An inclusion of determined probabilities of exploration (usually 30% discovery and 70% dry hole) and discovery outcomes (80% commercial and 20% not) would make a model more realistic, however, it would decrease the value of expected NPV but would not provide valuable insights in relative terms.

The sample project is a standard type of an upstream petroleum project that was also used by Lovas and Osmundsen (2009) witihin the study devoted to evaluation of petroleum taxation. The project has following details:

- Total production of the field equals 400 million barrels, which is the upper limit for a "medium" field size according to Sem and Ellerman (1998), Watkins (2000) and Ruairidh (2003) and is a "large" field according to Robinson and Morgan (1978) classification.
- Exploration phase starts in 2015 followed by apprasal in 2016 and installation the production wells in 2019. The production phase lasts for 15 years starting from 2023.
- Production profile represents a typical depletion scenario for a large field. It starts with a steep rise followed by a production plateau at 40 millions barrels per year and a slow decline spread over nine years. There are no The profile is presented in Table 8.1.

Table 7.1 Production profile for a sample field

	2023	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*	*2031*	*2032*	*2033*	*2034*	*2035*	*2036*	*2037*
Production, mm bbl	20	40	40	40	40	40	37	33	27	22	18	15	12	9	7

- Exploration, appraisal and development costs are presented in Table 8.2.

Table 7.2 Exploration, appraisal and development expenditures of a sample project

	2015	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
Exploration costs	(150)							
Appraisal costs		(75)	(150)	(75)				
New facilities costs					(200)	(1500)	(2000)	(3000)

- The annual operation costs (OPEX) in production phase are equal to $400 mn.
- The base case oil price is $80. In the shadow of the current price drop, the base case price seems optimistic, however, the production of the hypothetical field starts in 2023, when, according to The World Bank forecast, the price will exceed $80 in real terms (The World Bank, 2015).
- Discount rate for company and society is 10%, which is a traditional rate for oil and gas industry and is applied in the major studies devoted to evaluation of petroleum fiscal regimes;

Other assumptions:

- The oil company applies the full cost (FC) method, where all exploration expenditures are allowed to be capitalized.
- There is no distinction made between intangible and tangible costs, thus, all capital costs are treated as tangible.
- Abandonment procedures and costs are not included.

7.2 8.2 Fiscal regime assumptions

These simplified assumptions were made based on the most common terms under each of the regimes provided by Johnston (2003).

Table 7.3 R/T regime assumptions for modelling incentives

Terms	*Values*
r	10%
Oil price	80
Royalty	12%
CIT	30%
βinv	0.166666667
uplift	10.00%

Table 7.4 PSA regime assumptions for modelling incentives

Terms	*Values*
r	10%
Oil price	80
Tg(Royalty)	0%

Tn	30%
βinv	0.166666667
up	10.00%
βco	40%
βpo	40%

The notations are explained in Appendix 2.

7.3 Modeling incentives and effects of cost underestimation

In the simulated situation a company has two decision alternatives: (1) to deliver honest cost estimates; (2) to deliver lower cost estimates. We assume that choice (2) increases the probability of receiving the rights to produce in concessionary systems or the contract in contractual system.

7.3.1 Scenario 1. Honest cost estimates

Under this scenario an oil company submits "honest" cost estimates. "Honest" cost estimates means that the forecasters or project promoters did not intend to underestimate the costs with the purpose to make the project look more attractive for the decision-makers and, therefore, applied relevant data sets and assumptions for the given location and time in technical reports, used statistical and mathematical models as well as forecasting techniques with a little subject to error.

The size of the sample project (400 mm barrel) is considered to be large. Thus, the competition for the production license on the upstream oil market is also assumed to be high, due to the lack of recent big hydrocarbon reserves discoveries. The variance of the production costs in the specific location of the different oil companies is assumed to be relatively small. The competing companies do not hold the information about cost estimates and bids of each other. Therefore, at the considered moment of time – application for a production right – the given oil company, submitting honest estimates, equally evaluates the chances of winning (50%) and loosing (50%) in the license or contract award round.

It is assumed that the host government's main policy objective from an economic perspective is the maximization of the net present value of the economic rent. Under this condition, the most cost efficient oil operator is awarded the E&P right. Once the right is obtained, the potential subsequent cost overruns are explained by a set of various external and/or internal factors (see Part 2). In the simplified model, the awarded company is expected to successfully complete the project with no or minimum deviation from the initially claimed cost estimates.

7.3.2 Scenario 2. Deliberate cost underestimation

Under this scenario the oil company submits cost estimates that are deliberately underestimated with a purpose to increase the chances of being awarded a production license or a contract and, therefore, to increase the likelihood of revenues and profit. The company intentionally underestimates costs by applying false assumptions in the technical and commercial reports; applying irrelevant data – out dated or for a different location; falsification of data sets and other.

The same conditions as in Scenario 1 are applied to Scenario 2, i.e. there is a high competition between the companies with similar cost structures on the upstream oil market and the government seeks to maximize the value of economic rent obtained from the hydrocarbon reserves. This means that a little change in costs provided can increase a chance of obtaining a license, i.e. a linear relation between a cost variable and a probability to win variable is assumed. Underestimated costs by 10% lead to 15% higher probability of obtaining the license. In this case the company would evaluates a chance of license award as 65% probability.

Assuming that the oil company knows initially the true estimates of costs that are going to occur throughout the project, it uses the true values for the project evaluation. Therefore, the expected NPV is the same as under Scenario 1.

7.3.3 Company's perspective analysis

A decision tree is built to depict the scenarios where the value associated with each outcome is the net present value of the project. The values located above the uncertainty nodes are the expected value of the project taking into consideration different probabilities of the events. In order to make the decision tree more realistic, high, medium and low price scenarios were added. However, a general simplifying assumption is made that the commercial amount of oil would be found once the exploration process starts.

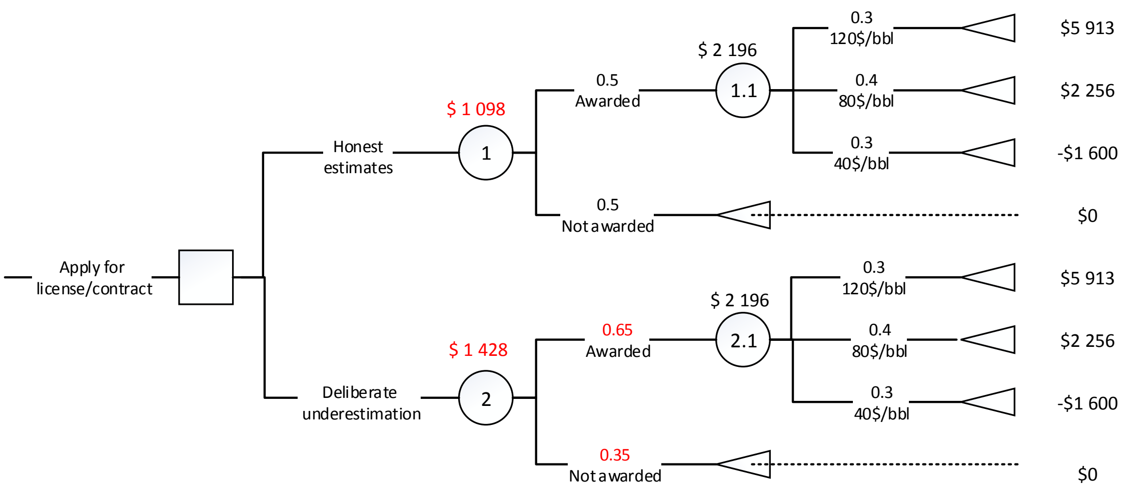
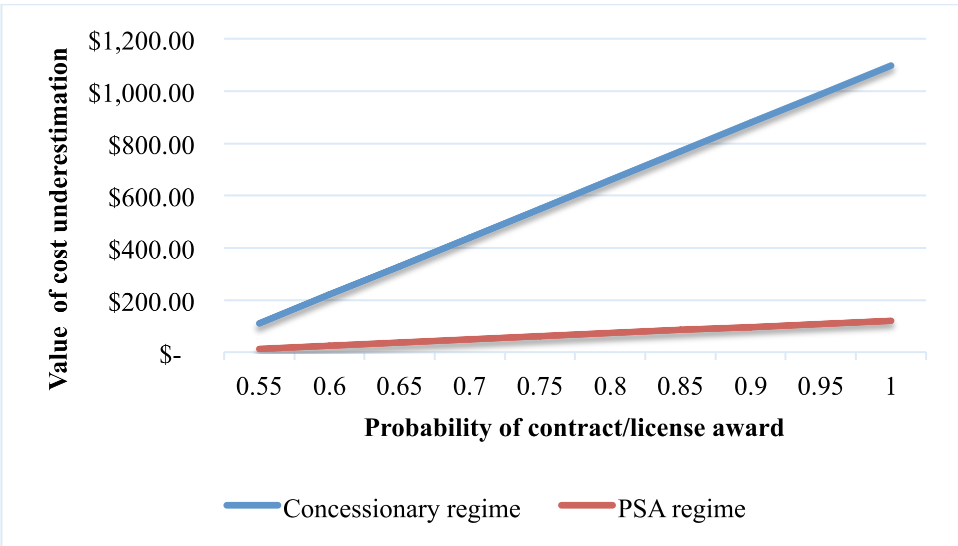


Figure 7.1 The value of cost underestimation under R/T regime

The difference between the expected values of nodes 1 and 2 is the value of the deliberate cost underestimation for the company. Under the concessionary regime, the value is $330 million. The same calculations were made for the PSA regime (see Appendix 6), where the value of 'lying' amounts to $36 million. The linear relation between the probability of contract award and the value of cost falsification is illustrated at Figure I below.

Table 7.5 Probability of contract award and value of cost underestimation



The purpose of this example is to illustrate that the company has economic incentives to significantly underestimate costs as it constantly increases the chance of project approval, and therefore brings the expected value up. If there were no incentives provided by the government to deliver honest estimates or 'punishments' for delivering false estimates, oil companies, that act as economically rational players and have a positive NPV (calculated with consideration of the true expected costs) for the awarded project, would constantly be encouraged to underestimate their costs. The fact that subsequent cost escalation can be explained by a various set of factors makes it easier for the oil companies to disguise the initial intentional underestimation.

7.3.4 Analysis from the government's perspective

While the logic behind the oil company's behaviour is clear, it is more interesting to look at the situation from the host government's perspective. Under Scenario 2 (Deliberate cost underestimation) it is important to understand that a government in fact does not choose the actual most cost efficient operator. Assuming that there is a company that can be more cost efficient in developing the field, the government incurs opportunity costs by not awarding this operator. The opportunity cost in this case is the difference between the government's potential NPV when the actual cost leader is awarded and the government's real NPV when the company with false cost estimates is awarded.

As it was originally assumed, the oil company decreases its cost estimates by 10% in order to increase the chance of contract approval. The government's expected net present value is then calculated taking into consideration the decreased operating costs that equal to \$360 mm annually. The potential government's expected value is also calculated when the truly cost efficient operator wins the license/contract with annual operation costs equal to \$380 mm (which is lower than the real costs of the winning operator - \$400 mm and higher than the claimed costs of the same operator - \$360 mm). The expected value for the government is calculated based on the annual government's share of all economic profits or 'government take', which was discounted in order to consider the timeframe for payments as well as weighted in order to consider the three price scenarios. The annual 'government take' under Concessionary regime equals to the sum of royalties and a CI tax, and under PSA regime - government's share of 'profit oil' and a CI tax.

Table 7.6 Government's opportunity costs

Opex, mm \$	*Expected Government take under Concessionary*	*Expected Government take under PSA*
\$380.00	\$2,248.39	\$3,993.73
\$400.00	\$2,231.72	\$3,971.97
Opportunity costs, mm\$	**\$16.67**	**\$21.76**

The results show that the government could have potentially gained $17 million and $22 million more under a concessionary and a production sharing agreement respectively, if the truly most cost efficient operator was chosen. As the PSA regime implies a larger government take, it is expected the opportunity cost to be larger than under concessionary regime, which is true for the sample project calculated above.

Table 7.7 Sensitivity analysis of expected government's share

Opex, mm $	*300*	*320*	*340*	*360*	*380*	*400*
%	75%	80%	85%	90%	95%	100%
EV Gov. PSA	$4,098.96	$4,071.72	$4,044.91	$4,019.08	$3,993.73	$3,971.97
%	96.9%	97.6%	98.2%	98.8%	99.5%	100.0%

Calculation of the expected value of the government's share under the PSA regimes for different cost scenarios shows that every 5% operation costs increase decreases the government's share by approximately 1%. Similar results were obtained for Concessionary regime and could be found in Appendix 7.

7.4 Discussion

As one of the purposes of the modelling was to demonstrate if there are any incentives for the company to provide deliberate cost underestimates and how it differs under the two most common regimes, the following conclusion can be made.

Under a condition that the government pursues a goal of economic rent maximization and does not impose any cost on delivering false estimation, there is an economic incentive for an oil company to deliberately underestimate the costs, which was demonstrated by using a decision-tree. While it is hard to compute how much the chance of getting a contract increases in the case of cost underestimation in a real business setting, certain assumptions were made to demonstrate the calculations of the economic value of underestimation.

As the concessionary regime yields higher profits, the value of cost underestimation increases. Thus, the hypothesis made in the beginning reflects the core of the model: "*Petroleum fiscal systems provide more incentives for cost underestimation by allocating larger shares of profits to the company*".

Secondly, the government's opportunity costs were also explained and demonstrated. While the government's takes differ largely across the regimes, the opportunity costs were increasing by approximately the same relative value under both Concessionary and PSA systems, when only change in operation costs was considered. Finally, the benefits for the company who underestimates costs are significantly larger than the opportunity costs for the government that chose a less cost efficient operator.

The hypothesis (H1) that was made prior the research is right.

Petroleum fiscal systems provide more incentives for cost underestimation by allocating larger shares of profits to the company.

8 Qualitative analysis of international petroleum fiscal regimes

Fiscal regimes were chosen for a detailed analysis in the following countries: Norway, UK, Indonesia and China. Fiscal policies of these countries are often a subject of evaluation in research papers. However, only Norwegian system has been analysed from the perspective of incentives it creates for cost inflation. All of the countries are important oil producers in the world. Norway and UK represent concessionary fiscal regime. Both of the countries extract oil from the North Sea, where the capital costs are infamously high. Moreover, both of the countries experience major problems with poor project performance. China and Indonesia represent production sharing agreement regime. However, China incorporates more progressive tools of taxation, which makes it more interesting for comparison.

8.1 Norwegian concessionary regime

In 2012, Norway was 14th largest oil producer and 5th largest natural gas producer in the world. Based on its daily petroleum production in 2014, Norway is 15th largest producer in the world (IEA, 2015). It is also a significant oil exporter due to small internal oil consumption. Hydrocarbons are extracted on the Norwegian continental shelf in the North Sea, where the costs of exploration and production are traditionally high. Norwegian petroleum taxation system belongs to the concessionary group and is an example of a simple but yet close to neutral fiscal regime (Lund, 2014). The state receives its revenues partly through direct participation and partly through taxation of the participants in the industry.

In order to explore and produce oil, a license should be obtained from the Ministry of Petroleum and Energy. Although governmental standards are set high, projects on the Norwegian Continental Shelf experienced major quality and cost overruns (Table 5.1).

Table 8.1 Cost overruns on various field development projects approved between 2007-2012 (NPD, 2013)

Project	*PDO appr.*	*PDO est.*	*New est.*	*Change*	*Change %*
Brynhild	2011	4277	4579	352	8%
Goliat	2009	30942	37142	6200	**20%**
Hyme	2011	4593	4780	187	4%
Jette	2012	2590	2909	319	12%
Knarr	211	11437	11527	90	1%
Marulk	2010	4162	4476	314	8%

Oselvar	2009	4937	5120	183	4%
Skarv	2007	35632	47162	11530	**32%**
Skuld	2012	9895	10147	253	3%
Valemon	2011	26329	26880	551	2%
Valhall	2007	25163	46727	21564	**86%**
Vigdis	2011	4194	4467	273	7%
Yme	2007	4894	14114	9220	**188%**
Asgard	2012	15660	17693	2031	13%

Relative neutrality, high government participation and poor performance of oil companies makes Norwegian petroleum fiscal regime an interesting case to consider.

8.1.1 Norwegian petroleum fiscal regime details

The Norwegian petroleum fiscal regime is mainly based on corporate income tax (CIT) and special petroleum tax (SPT).

Table 8.2 Norwegian petroleum fiscal terms at a glance (EY, 2014)

Terms	*Values*
Bonuses	None
Royalties	None
Income tax rate	27%
Resource rent tax (or SPT)	51%
Capital allowances	Yes: depreciation over 6 years and an additional uplift 22%
Investment incentives	Loss carry forward with interest

The royalty was abolished in 1986 (Nakhle, 2008). An ordinary CIT with a rate equal to 27% is applied. Due to the extraordinary profitability, SPT was introduced, which current rate is 51% (Deloitte, 2015). This amounts to a marginal tax rate of 78%. Capital expenditures are a subject to depreciation on a linear basis over six years. The company can write off all relevant expenditures for exploration, appraisal, net finance, operation, decommissioning and etc. This is applicable for taxable income calculation for both CIT and SPT taxes. A special deduction, uplift, is allowed in taxable income calculation for SPT.

Currently total amount of 22% of investment can be deducted over 4 years (5.5% annual deduction). This means 89.2%[3] of offshore investments are eventually deductible. If a company does not have a taxable income, it has an option to carry forward losses with interest; hence no tax is paid until all losses have been absorbed. Moreover, oil companies can receive a refund of the fiscal value for exploration costs (78%) in their tax return from the Norwegian state annually. There are no expected significant changes in the tax system in the near future.

8.1.2 Analysis from a company's cost consciousness perspective

The system is considered to be close to neutral, i.e. it does not distort investment decisions and induces companies to maximize their pre-tax values, but it is costly and risky for the government (Lund, 2014).

The distinctive feature of Norwegian petroleum tax regime - high marginal tax rate (78%), according to Osmundsen (1999), may provoke low consciousness among international oil companies, due to (1) high benefits of deducting additional costs and (2) low fraction of cost savings received by the operator.

Moreover, neutrality of a tax system usually implies higher risks for government. Risk sharing has been moved to the government through: (1) abolishing of low marginal tax rate and the regulation that required foreign companies to carry Statoil's exploration costs (2) a shift of the tax level closer to economic conditions also implies additional risk transfer to the government and (3) high direct government participation through the national oil company. The behaviour of oil companies on the Norwegian continental shelf is often described as risk seeking (Osmundsen, 1999) and is explained by high direct state participation.

In response to such behaviour the government imposed incentives to induce the optimal level of unobservable effort by increasing the equity share of the operator. This feature provides incentives to refund the true costs in the internal accounting and makes the fiscal system close to neutral. However, the petroleum fiscal terms still bear too little risk on the companies. Low saving index makes it clear that this system may cause low cost consciousness and excessive testing of new technology.

[3] 51% + 27% + 22%*51%

8.2 United Kingdom concessionary regime

United Kingdom used to be a major non-OPEC oil and gas producer. The production rate was in decline since 1999 with 5-10% rate. However, in 2011 UK the decline accelerated and reached an unprecedented decline rate 17.9%, which was partly explained by an increase in North Sea taxation, which added fiscal uncertainty. UK is ranked 50th by its daily production in the list of global oil producing countries (EIA, 2015). On the contrary, capital, exploration, appraisal costs for the UK continental shelf in the North Sea had significantly increased over the last decade. Starting in 2004, total OPEX for oil and gas nearly doubled by 2012, whilst the production had more than halved (Mearns, 2013).

The current situation alone makes UK continental shelf an interesting subject for analysis. The Norwegian regime has often been compared with the UK petroleum fiscal regime (Nakhle, 2008). Therefore, the two countries present an interesting case for comparison.

8.2.1 UK petroleum fiscal regime details

The UK fiscal regime is a concessionary regime with a combination of corporate income tax and supplementary charge rate (32%). Petroleum resource revenue tax (50%) is also applied for fields that received the development permission before March 1993. The royalty was abolished on all fields in 2002 (Nakhle, 2008)

Table 8.3 UK petroleum fiscal terms at a glance (EY, 2014)

Terms	*Values*
Bonuses	None
Royalties	None
Income tax rate	30% ring-fence (20% non-ring fence)[4]
Supplementary charge rate	32%
Petroleum resource rent tax	50% for fields received development before April 1993

[4] Starting since April 1st 2015 (EY, 2014)

Capital allowances	Immediate write-off for exploration costs
Investment incentives	Loss carry forward, R&D incentive

The corporate income tax differs based on ring-fencing. Profits from oil and gas exploration and production are subject to the ring-fence rate. CIT was initially set at 52% but was reduced to 30%. Supplementary charge is an additional tax on profits from oil production. Taxable income is calculated in the same manner as for CIT but without any deduction for finance costs. This means that a total marginal tax rate for fields approved before 1993 – 81% (as PRT is deductible for IT and supplementary charge) and after 1993 - 62%.

The system incorporates investment incentives for certain high-pressure high-temperature, ultra-heavy-oil, deep-water gas fields and other, as a rule, marginal fields. It involves a special field allowance (reduces a company's ring-fenced profits for supplementary charge), oil allowance (certain amount of production is allowed to be earned free of PRT), and safeguard (allows to earn a specific return before being subject to PRT). For other fields an additional uplift 35 % for capital expenditures is available to reduce PRT taxable income.

Exploration and appraisal expenditures are a subject for 100% R&D allowances. Additional allowance are available for R&D costs not related to exploration and appraisal at a rate of 130% for large companies and 200% for small and medium-sized companies.

The loss can be carried forward and be offset against any chargeable gains. A 100% first-year allowance (FYA) is available for most capital expenditures incurred.

8.2.2 Analysis from a company's cost consciousness perspective

There is a significant difference in fiscal terms that are applied to oilfields that were approved before and after 1993. While profit from the recent fields is a subject to CIT and SC, an additional petroleum tax is applied to more mature fields. Firstly, it means a larger government take. Secondly, UK government offers generous tax reliefs in order to prevent petroleum revenue tax from being an undue burden on marginal fields. Thirdly, it makes a taxation system quite complicated. In an industry where moral hazard is presented and the government as an 'agent' does not have perfect control over company's effort, all of the three characteristics reduce the company's incentives to cut costs.

Abolishing of PRT for the new fields clearly reduces the marginal tax rate and hence, government take and overall simplifies the petroleum taxation. Reduced total marginal rate from 81% to 62%, given the maturity of oil province, is necessary to sustain oil production. Moreover, an immediate depreciation of the costs increases the faction of every cost saved if the time value is considered. Overall, the government has undertaken certain actions in order to induce companies' effort in terms of costs and production.

8.3 Indonesian production sharing agreement

Indonesia is one of the most active countries in South-East Asia for nearly 130 years after the first oil discovery in North Sumatra and continues to be a significant player in the global oil and gas sector (PwC, 2012). Indonesia is ranked 22nd among world oil producers by its daily production in 2014 (EIA, 2015). Indonesia is also a pioneer of the production sharing agreements, as the first contract was signed in the early 1960s (Nakhle, 2008).

The issue that the industry is facing is declining oil production over the last decade. The decline is explained by mainly a lack of exploration and other investments due to weak government management, bureaucracy, an unclear regulatory framework and legal uncertainty regarding contracts. The petroleum fiscal regime is often referred as one of the most punitive in the world.

8.3.1 Indonesia's petroleum fiscal regime details

The petroleum fiscal regime consists of production sharing agreements that are contracted between oil companies and the executive body for oil and gas upstream activities on behalf of the Indonesian government.

Table 8.4 Indonesian petroleum fiscal regime at a glance (EY,2014)

Terms	*Values*
Bonuses	Depends on PSA terms
Royalties	None
Corporate income tax	25%
Branch profits tax (BPT)	20%
Government profit oil share	64%

Cost recovery limit	No limit stipulated in the contract, but actual 80%[5]
Capital allowances	Declining-balance depreciation
Investment incentives	Loss carry forward

The income tax rates for CIT and BPT depend on the year the contract was entered. Ring-fencing rule is applied, restricting companies to offset working interest in one area against income of another area. The CIT has been reduced to 25% for 2010 onwards (Deloitte, 2013).

Indonesian PSA system does not charge a royalty, but instead includes fiscal term 'first tranche production' (FTP) or 'branch profits tax' (BPT). First tranche production is imposed on gross revenue and is equal to 20%, which means that 20% of gross revenues is split between the government (64%) and the contractor (36%). Government's FTP is a part of total government take, while contractor's FTP is a part of its taxable income.

The next term is 'domestic market obligation' (DMO). After 60 months of production it requires the contractor to sell 25% of oil to the domestic market, i.e. to the national oil company Pertamina. The price set as 25% of the market price.

There is no limit for cost recovery, however, 20% FTP act as a cap by reducing the available gross revenue for recovery. Hence, in fact, 80% of gross revenue is the actual cost recovery limit.

Contractors are allowed to carry forward their losses. Contractor are also permitted an investment credit 15.5% after tax. Annual depreciation on capital expenditures is 25% using the declining balance method with undepreciated amount written off in year five.

8.3.2 Analysis from a company's cost consciousness perspective

Indonesia's PSA was famous for its split 85/15, where a national oil company Pertamina would receive 85% and a contractor 15%. However, the policy has been changed towards allocation of more share of profits to contractors. Currently, the general split of profit oil and FTPs between the government and the contractor is 64/36 respectively. That means that the company gets 36 cents more on every dollar saved in costs before tax and 27

[5] There is no recovery limit stipulated in the PSA, however, BPT limits the gross revenues for cost recovery by 20%

cents after the tax. Even though this figure is much higher now, in combination with no limit for cost recovery, it may be still seen as a potential incentive for companies to inflate costs.

Declining balance method for depreciation allows receiving a higher post-tax cash flows in the beginning, thus, increasing the net present value for a contractor. However, this increase is insignificant and does not provide noticeably different incentives.

8.4 Chinese PSA regime

China is 4th largest oil producing company in the world with daily production of 4.5 million barrels per day in 2014 (EIA, 2015). China used to be a net oil exporter, however it changed in 1993. China, being a second largest energy consumer and forth largest oil producer, is one of the major players in world oil markets.

China adopts a production sharing agreement system combining it with a corporate income tax and royalties. Moreover, the sliding scales applied in sharecropping of profit oil make it an interesting regime to study.

8.4.1 Chinese petroleum fiscal regime details

The Chinese fiscal regime consists of PSAs, special oil gain levies, VAT, resource tax and CIT.

Table 8.5 Chinese petroleum fiscal regims at a glance (EY,2014)

Terms	*Values*
Bonuses	Depends on PSA terms
Royalties	None[6]
Income tax rate	25%
Resource tax	5%
Special oil gain levy	Depending on oil price
VAT	17%
Cost recovery limit	62.5%

[6] For projects approved after November 1st 2011 (EY, 2014)

Capital allowances	100% straight line depreciation of capital expenditures
Investment incentives	R&D costs deduction at 150%

Royalties are only applied to projects approved before 1 November 2011. The rate has a sliding scale depending on the daily oil production, with a maximum rate being 12.5%. The new projects are exempted from this payment. However, an additional resource rent tax 5% was introduced in 2011. Besides that, a special oil gain levy is used, which is petroleum special profit tax levied on all oil companies selling crude oil in China. The revenue windfall is charged when the weighted-average price of crude oil sold in any month exceeds $55 per barrel. A sliding scale is also used where a price increase leads to a higher tax.

Profit oil is also split on a sliding rate, depending on the annual level of production. Cost oil or cost recovery limit varies from offshore and onshore projects from 50% to 62.5% respectively. All exploration, development and operating expenses are to be covered. After profit oil has been split, the contractors are taxed corporate income tax at 25%. Special allowances include 5 years loss carry forward, 150% deduction of qualified R&D. It is allowed to carry forward the loss for 5 years.

8.4.2 Analysis from a company's cost consciousness perspective

China has abolished royalties, however, it still has a large share of front-end loaded taxation instruments, such as VAT, newly introduced recourse rent tax at 5%, which is going to be raised after 2015 by 1%. This emphasises that most probably less government share of profit oil can be expected, and, hence, a higher incentives for cost control are to be provided for oil companies, as they can receive a larger fraction of benefits form saved costs.

The main different from Indonesia is that China incorporates progressive forms of taxation. The preliminary conclusion can be made that the sliding scale in profit oil share adds flexibility to the contract, but could also provide additional disincentives in cost efficiency. The Chinese regime, however, by applying a sliding scale based on the production, rather than profit, eliminates the potential disincentives. Loss carry forward and additional R&D cost deduction transfers a certain share of risk to the government.

The analysis in Chapter 9 is intended will include calculation of what the government take and other indices are, and then certain conclusions about incentives.

9. Comparative analysis of incentives under international petroleum fiscal systems

9.1 Framework for evaluating fiscal incentives

When the project and fiscal regime assumptions are made and all cash flows are calculated, the petroleum fiscal regimes are to be evaluated on the subject of cost-related incentives. There is no specific framework available for such evaluation. However, different studies were evaluating fiscal regimes from a general economic perspective. Few of the criteria used in these studies are presented in Table 9.1.

Table 0.1 Economic evaluation parameters of petroleum fiscal regimes

Study	Evaluation figures
The World Bank (Tordo, 2007)	NPV, IRR, PR, Operating Leverage, Government Take, Saving Index
The International Monetary Fund (IMF, 2012)	NPV, IRR, Effective Marginal Rate, Coefficient of variation, Profitability Index
David Johnston (2003)	Government take Effective Royalty Rate Government Participation Saving Index Progressive – Regressive Systems Exposure to Exploration Risk
Daniel Johnston (2003)	Effective Royalty Rate Saving Index Entitlement Index Cost recovery limits Progressive – Regressive System

Some of these criteria are relevant for making conclusions about cost-related incentives it provides. According to Osmundsen (1999), such figures as marginal rates, government take, equity shares and fractions received by the contractor from every saved monetary unit, may identify if the tax regime promote low cost conscious behaviour of the oil company. Based on the author’s reasoning, the following evaluation figures and indices were chosen.

Government take and government NPV

The division of profits between companies and government is often referred to as “take”. Thus, government take is defined as “the government’s percentage of pre-tax project net cash flow adjusted to take into account any form of government participation" (Tordo, 2007). In other words, government take include all of the means by which government economically benefits from the project (bonuses, royalties, taxes, profit oil and etc.). The government take can also be calculated in discounted or undiscounted values.

In order to incorporate the value of time, the annual government take, i.e. government's net cash flow, is discounted and summed up. The method of Discounted Cash Flow (DCF) is the most common form of project evaluation in the oil and gas industry (Nakhle, 2008). The majority of economic studies uses this traditional technique to evaluate the profitability of an oil field. Moreover, it was found that 99 per cent of oil and gas companies utilize this method (Siew, 2001). Net Present Value (NPV) is an analysis tool that measures the economic profit of an investment.

IOC take is a complement parameter to government take. NPV of IOC is the decision-making criteria used to evaluate a project by contractors.

Effective royalty rate (ERR)

As a single measure, government take fails to provide information about the timing of payments (Johnston, 2003). The ERR is a statistic that shows how quickly a government takes its share. This index is a common metric used in the industry and it calculated as share of revenue that the host government expects to receive from royalties and profit oil (Tordo, 2007). If the system does not have a recovery limit, then the royalty rate is the ERR. If royalties are absent as well, then ERR equals to zero. In a situation of large capital-intensive projects, the government may experience cash flow problems, as the taxable income may stay negative for a long time due to long cost recovery, which means zero government take. The lower ERR is, the more back-end loaded the system is and the more patient the government is. This is expected to be more common among developed countries.

The drawback of ERR is excluding the effects of depreciation or amortization due to its focus on gross revenues. It also excludes the effects of government participation.

The Saving Index (SI)

SI is defined by the World Bank as, "the part of an additional one dollar in profit (arising from a one-dollar saving in cost) that accrues to the contractor" (Tordo, 2007) or, in other words, it measures how much a company gets to keep if it saves one dollar. It is important to note that only the profit-based fiscal elements influence this index.

The index can be explained by the following example. Let us consider an R/T system with a 60% Special Petroleum Tax and a 30% Income Tax. When the company saves one dollar in costs and therefore adds it to the taxable income, the government first takes 60% of that, leaving the company with 40 cent, and then another 30% of these 40 cent, so the company only get's to keep 28 cent on the dollar saved. The SI is 28%. Under a PSA regime, the saving index corresponds to the company's share of profit oil (Johnston, 2003).

8.5 Comparative analysis of four fiscal regimes

8.5.1 Comparative analysis of the evaluation parameters

The calculations of the net cash flows can be found in Appendix 11, 12, 13 and 14. Fiscal regime assumptions are also presented in Appendix 10. Fiscal terms that are relevant only for the new fields for the sample field were applied, i.e. the modern design of the systems was evaluated.

Table 0.2 Comparative analysis of chosen parameters of the chosen fiscal regimes

	Norway	UK	Indonesia	China
NPV Gov	$3,184.22	$2,755.28	$3,333.13	$3,671.77
NPV IOC	$182.12	$611.06	$33.20	$-305.43
Government take	73%	62%	73%	72%
IOC take	27%	38%	27%	28%
IRR IOC	11%	13%	10%	9%
Cost recovery	N/A	N/A	80%	62.5%
Cost deduction	89%	62%	N/A	N/A
ERR	0%	0%	34%	23%
Saving Index	**22%**	**38%**	**27%**	**65%**

First of all, the main economic indicators used for decision-making processes and ranking of the project, i.e. NPV and IRR makes the sample project more attractive for investors under the UK regime and the least attractive under the Chinese PSA regime. Overall, the project has higher profitability under the two concessionary regimes.

Norwegian petroleum fiscal has the lowest Saving Index. Its design incorporates high marginal rates 78% on the profits in combination with additional cost uplifts, which allows 89% of the costs to be deducted. On the contrary, China has the highest SI. Its design incorporates high rate based on the gross profits and low participation in the profit oil sharing, which allows the contractors to obtain more of the benefits from cost saving.

Government take figure is almost the same in Norway, Indonesia and China. At the same time, the saving index varies across all presented regimes. Therefore, this figure does not necessarily determine incentives for any specific cost-related behaviour. For example, Norway has 73% of government participation, the project profitability is much higher, whilst saving index is the lowest. The explanation can be found in looking at ERR rate, which means how front- or back-end loaded the regime is, i.e. how fast the government obtains its profits. In both PSA regimes, the front-end load is quite significant. China imposes a marginal tax of 22% on gross revenues though collecting VAT and a new Resource Rent Tax. Indonesia uses FTP and DMO as front-ending loading elements to secure earlier revenue collection.

From the company's cost consciousness perspective, the ERR would not effect the behaviour following the logic of the saving index, when only an additional dollar saved on costs and added to the profit considered. However, by looking from the perspective of total tax allocation, high ERR would often mean lower income tax rate or government share of profit oil. In the situation where the tax is only based on gross revenues, i.e. the ERR is expected to be relatively high, the fraction of costs saved is 100%, which leads, on the one hand, to a distortive and non-neutral taxation system, but on the other, to a maximum induce of company's efforts to save costs.

This, in fact, can be observed in China, where the government share of profit oil is calculated at a sliding scale and the average government share of profit oil is 4.5%, which is considered to be extremely low. Despite the fact that the contractor's income is then taxed at 33% CIT, the SI is the highest – 65%. However, the distortion of this system is quite clear, as it is the only regime that made the sample project, which is profitable before tax and after tax under UK, Norwegian and Indonesian regimes, unprofitable.

This shows that such parameters as government and contractor take are not sufficient for drawing any conclusions as it fails to provide information about the timing of the payment. Thus, the ERR and Saving Index should be considered in combination. While the ERR measures the front-end load of the taxation system, the Saving Index in a way measures the back-end load. Thus, the concessionary regimes presented in Norway and UK, both developed countries that are patient for the petroleum economic rent, charge only income based taxes, which automatically decreases the fraction of every dollar saved in costs received by contractor, i.e. the SI.

All in all, the evaluation of the systems supports the results of qualitative analysis obtained in Chapter 5.

8.5.2 Sensitivity analysis to cost change

Sensitivity analysis was performed in order to analyse how project profitability changes with the change in the input variables, i.e. increase or decrease of capital, operation and appraisal and development costs. The spread sheets with the analysis can be found in Appendix.

OPEX -/+50% Change

By comparing NPV sensitivity analysis to OPEX change of different regimes, the following conclusion can be made. NPVs of the oil companies and the governments under UK, Norwegian and Indonesian regimes slowly decrease with an OPEX change at the same rate. Thus, the NPV of the company is reduced by the same rate as the NPV of the government, which means that the risk of an OPEX increase is shared equally. However, under Chinese PSA regime the net present value of 'government take' is less sensitive to the changes than the IOC under the same regime. It means that the risk of OPEX increase is more levied on the company.

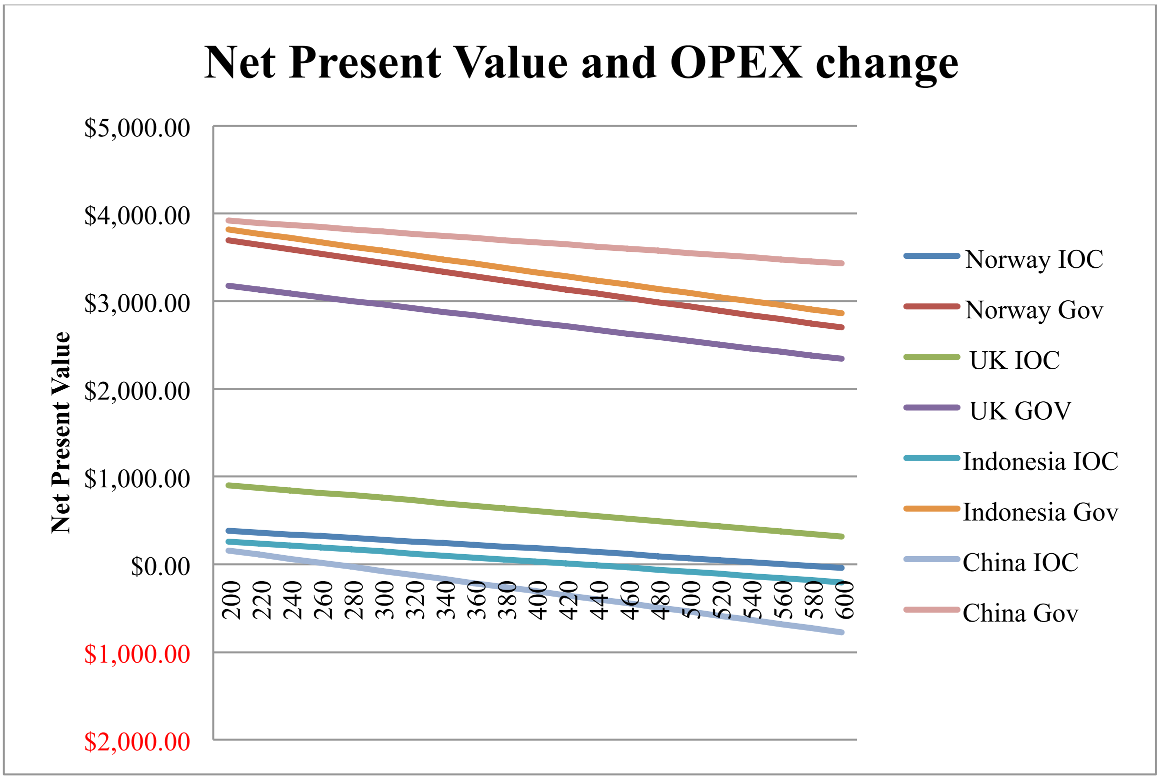


Figure 0.1 NPV Sensitivity Analysis to OPEX Change

This can be seen in comparison with other regimes as an incentive to induce company's efforts on cutting costs, as with every operation cost increase/decrease, the company is loosing/gaining higher profit shares. This insight is correlated with high saving index of this PSA regime.

CAPEX -/+50% Change

Sensitivity analysis to the change of the capital costs is one of the most important ones, as the capital costs are a subject of special capital allowance and depreciation terms.

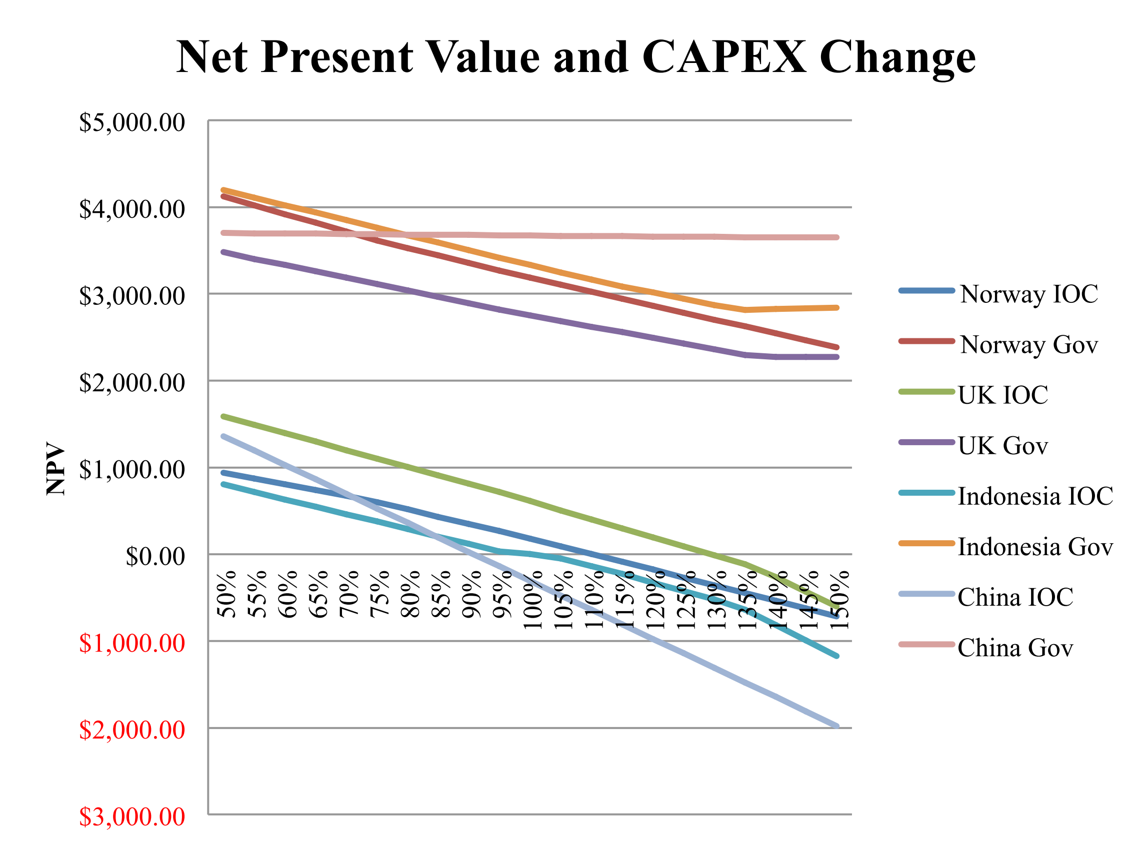


Figure 0.2 NPV Sensitivity Analysis to CAPEX Change

Similar results are observed for Chinese PSA regime. Most of the risk is levied on the company, while the Chinese government secures its share with front-end fiscal tools and, thus, is almost neutral to CAPEX change risk. A common characteristic among UK and Indonesian regimes is that once the CAPEX increase exceeds 30-35%, more risk is transferred to the companies. This is, however, not the case of Norway, which continues to have the same risk share ratio.

R&D -/+50% Change

This sensitivity analysis is mostly interested due to Norwegian fiscal regime, as it allows companies to claim 75% of all exploration expenditures.

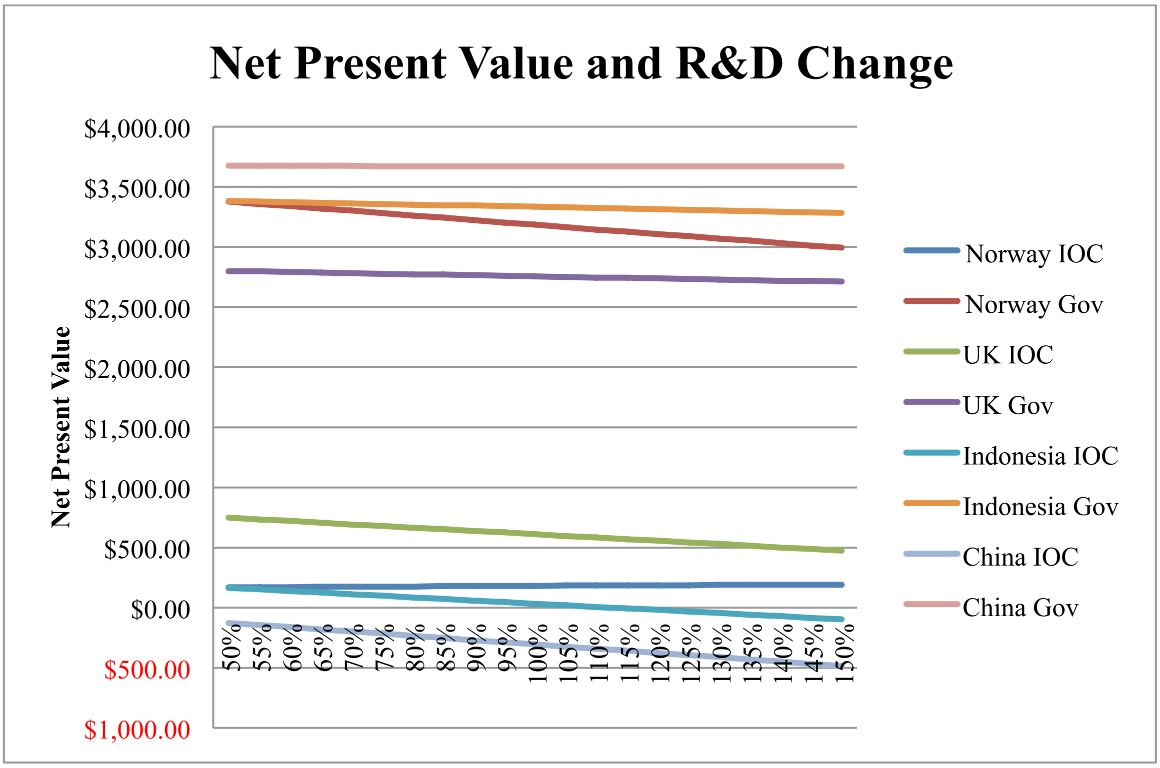


Figure 0.3 NPV Sensitivity Analysis to R&D Change

Figure 9.3. clearly illustrates this fiscal term, as with exploration and appraisal cost increase, the government NPV decreases. Governments under other systems are fairly neutral to this risk, even taking into consideration the Total Cost method applied, which treats exploration and development costs as capital costs. The main explanation is that this group of costs present only 6% of the total project costs.

8.6 Discussion

The analysis performed in Part 9.2. presents the following interesting insights regarding country's fiscal regimes.

The hypothesis made before the analysis was undertaken: '*Petroleum fiscal systems that imply higher marginal tax rates provide more incentives for low cost consciousness among the oil companies'*, reflects the main findings, as the saving index is calculated based on the marginal tax rate on profits. However, additional parameters should always be taken into account.

It is interesting to see that the most neutral system among all, Norwegian R/T, implies the lowest incentives to keep the costs low. This makes the neutrality of the Norwegian system relatively expensive. This also in fact means, that the Norwegian government by trying to provide as least distortions in the investments as possible, left too little risk for the oil companies. In order to find the balance in risk sharing, an option is to introduce front-end payments, such as bonuses or royalties.

Moreover, in a situation of a moral hazard, countries with low Saving Index, such as Norway and Indonesia should consider investing in monitoring and increase the observation means. This is an alternative for a Norwegian government to consider instead of incorporating distortive elements into the design. The investment in monitoring means would decrease possibilities for oil companies to perform hidden actions.

In fact, none of the systems incorporates a 'gold plating' risk, i.e. does not create incentives to incur real costs that, in the absence of taxation, would be unprofitable. Thus, the interests of saving costs of the 'principal' and the 'agent' are, in fact, aligned. However, with an introduction of a moral hazard to the oil and gas industry, the incentives could be created through excessive capital allowances, high marginal rates and high government participation. Thus, the calculation of the relevant indicators that make an attempt to explain how the fiscal regime influences the behavior of the company, i.e. how it provides incentives for low or high cost consciousness.

Another point that is worth discussion is that the figure 'government take' failed to determine incentives for cost efficiency. In the Chinese system the government take was calculated to be over 72%, which is relatively high. At the same time, Chinese PSA SI was the highest among all four presented cases – 65%. The reasoning behind 'government take' and its affect on cost efficiency fails to explain these figures. As the analysis showed, the timing of government take is more important, and thus, ERR, as an indicator that measures it, should always be included into the evaluation of petroleum fiscal regimes.

The sensitivity analysis clearly reflected the effect of additional risk the Norwegian government incorporates by allowing claiming part of the exploration costs. At the same time, Chinese government, which obtains its take from mainly gross revenues, secures itself from the risk of CAPEX change.

A comparative analysis of four regimes provide valuable incentives regarding not only the tax terms that influence the most, but also what economic parameters are the best in explaining high or low saving index. Besides that, calculation of indices together with NPV sensitivity analysis to the costs proved itself as a good combination for this kind of analysis, as the sensitivity report provides additional sense of how treatment of different costs, i.e. depreciation, allowances, and uplifts, impacts the risk sharing between the oil company and the government.

9 Conclusion

The research question of the current master thesis was formulated as follows.

How does different petroleum fiscal systems affect the cost-related behavior of oil companies before and after the contract award?

In attempt to answer this question, two types of research were conducted. A general conclusion is presented in this chapter, while expanded conclusions could be found after the relevant research.

Thus, a model that explains economic incentives of providing deliberate cost underestimates under certain assumptions was created to illustrate that the higher the expected value of the project is, the most economic incentives there are created. Taking into consideration the fiscal system terms, the main parameter that should be looked at is the net present value of the oil company.

The second research provided several important insights related to the ways the petroleum fiscal design create incentives for less or more cost conscious behavior of the contractor. However, the main conclusion can be drawn – petroleum fiscal design that incorporates high marginal rates on the profits rather than revenues, i.e. more back-end loaded, in combination with additional capital allowances and uplifts, tends to create higher incentives for operators to inflate their costs. However, such a design is also referred to as neutral and provides additional incentives for investments. Therefore, the optimal balance in risk sharing between the company and the host government in petroleum fiscal designs is crucial.

Additional insights for the fiscal evaluation are also provided. The saving index dependable on the marginal rate, levied on the taxable income in the case of R/T or profit oil share in the case of PSA, and the contractor's equity share is the major parameter that should be considered while evaluating regimes on the subjects of cost-related incentives.

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Appendices

Appendix 1. Megaprojects attributes

There are over 25 common attributes of megaprojects summarized and presented by Virginia A. Greiman (2013), which, among others, include:

- *Long duration*: minimum duration is 3-15 years, whereas it can reach 20-40 years for oil and gas concessions;
- *Scale and dimension*: typical megaproject size exceeds US$1. However, most definitions of the scale of a megaproject are imprecise and depend on the specific project type. Moreover, the cost of a project needs to be contrasted with the location or country. Greiman (2013) also specifies: "*oil and gas projects are almost always characterized as megaprojects regardless of the size*";
- *Type of industry and purpose*: besides oil and gas projects, other typical types are: infrastructure projects (bridges, roads, tunnels and etc.), production industries (agriculture, rubber plantations), research and development (biotechnology, aerospace innovation), consumption (film festivals, Olympic games);
- *Design and construction complexity:* there is an extensive number of design phases that are to be completed, such as conceptual, environmental feasibility and sustainability, geotechnical, structural, tendering, operational and maintenance. Construction complexity is defined by technical integration and organizational complexity;
- *Long, complex and critical front end:* front end, or an exploratory/formulation phase of a project takes seven years on average. Complexity and importance of the front end are explained by high level of ambiguity, design complexity, a significant number of variables, multiple stakeholders and an extended impact assessment required in order to get the approval. Front end loading is considered to be one of the crucial success factors (See Chapter 2.3.1).
- *Consistent cost underestimation and poor performance:* the characteristics mentioned above explain the challenge to make a precise cost estimation before the operation starts and cope with the stretching of available resources to the limit. The scholars and practitioners made multiple attempts to identify the reasons behind significant cost overruns (see Chapter 3), however, cost overruns tend to be "a distinguishing characteristic of megaprojects" (Greiman, 2013).

Appendix 2. Net Revenue calculation under R/T and PSA tax regimes

Net Revenue under concessionary regime:

(Glomsrød & Lindholt, 2004).

$$\pi_t = p_t q_t - C_{INV} - C(Q_t, R_{t-1}) - w_t x_t - B - \{\tau_{Gt} p_t q_t + \tau_{Nt}[p_t q_t - \beta_{INV} C_{INVt} - \beta_{EXT} C(Q_t, R_{t-1}) - up w_t x_t]\}$$

Where:

C_{INV} - is the development or capital costs (CAPEX);

$C(Q_t, R_{t-1})$ – is the extraction costs (OPEX), which vary positively with the rate of extraction Q_t and negatively with the level of remaining reserves R;

x_t – is the rate of exploratory effort at unit cost w_t in period t;

B - is the bonus bid in auction licensing or a signature bonus in discretionary licensing;

τ_{Gt} - is the royalty in period t;

τ_{Nt}- is the net income tax, including corporate tax, special petroleum tax, petroleum revenue tax, resource rent tax and etc.

β_{INV} and β_{EXT}- are the correction factors or a share by which capital costs C_{INV} and operation costs $C(Q_t, R_{t-1})$ respectively can be deducted;

up - is an uplift on exploration costs $w_t x_t$.

Net Revenue under Production Sharing Agreement (PSA):

(Glomsrød & Lindholt, 2004)

$$\pi_t = \beta_{COt} p_t q_t - C_{INVt} - C(q_t, R_{t-1}) - w_t x_t - B + \beta_{POt}(p_t q_t - \beta_{COt} p_t q_t) - \tau_{Nt}\{\beta_{POt}(p_t q_t - \beta_{CO} p_t q_t) + \beta_{COt} p_t q_t - \beta_{INVt} C_{INVt} - \beta_{EXT} C(q_t, R_{t-1}) - up w_t x_t\}$$

Where:

β_{COt} – is the share of the production that goes to the contractor to cover costs, so $\beta_{COt} p_t q_t$ is often referred to as "cost oil".

β_{POt} - is the share of production value left after the cost oil is recovered, so $\beta_{POt}(p_t q_t - \beta_{COt} p_t q_t)$ is contractor's part of "profit oil".

Appendix 3. Life cycle phases of an oil field and

Understanding the basics of the physical nature of oil operations is vital for the analysis of the economics of petroleum projects. Therefore, a short description of six life cycle phases of a typical oil field is presented below. (Nakhle, 2008)

1) *The acquisition of a license or concession*

   Before the exploration stage starts, an oil company has to obtain a legal access to perform exploration and development activities in a part of a potentially oil rich territory.
2) *Exploration*

   Throughout this phase seismic surveys are undertaken to identify the prospect. The decision whether to proceed further is taken based on the obtained technical data. If the conditions are favourable, an exploration well is drilled. If the well proves dry the costs of exploration are written-off, while in either case, i.e. the oil is found, the company proceeds to the testing phase. The given phase can cost over tens of million dollars and involves high risk. While the modern seismic technologies help to identify potential traps, only one in ten exploration wells find oil, and only one in four of those finds proves commercial (Nakhle, 2008)
3) *Appraisal*

   Appraisal of the reservoir follows the successful exploration. Development wells are drilled to define the main characteristics of the reservoir, such as size, structure and quality. The elements of risk are also presented in this phase even if the exploration phase was classified as successful: the quantity of oil or gas may not be enough to make the field commercially viable; or filed development may require technologies that are too expensive.
4) *Development*

   If the appraisal phase proved the field to be commercially attractive, a decision regarding the field development is taken. It is a common practice among host governments to require a submission of a detailed development plan for their approval.
5) *Production*

The production phase starts with drilling the first production wells. The operating revenues and operating costs occur. All costs incurred prior this stage are generally considered as capital expenditures.

6) *Abandonment phase*

When the field reaches the point where production levels fall to a level, which ceases to cover operating costs, it is decommissioned. Abandonment costs occur and generally include plugging of wells, removal of equipment, production tanks and installations. These costs of decommissioning can represent the second most significant financial event in the business cycle, after installation of facilities themselves.

However, an oil project is not only about the technology and engineering. Laws, regulations, leases, auctions and permits is an essential part of the initial phases of the project and is the starting point of the value chain of an upstream project.

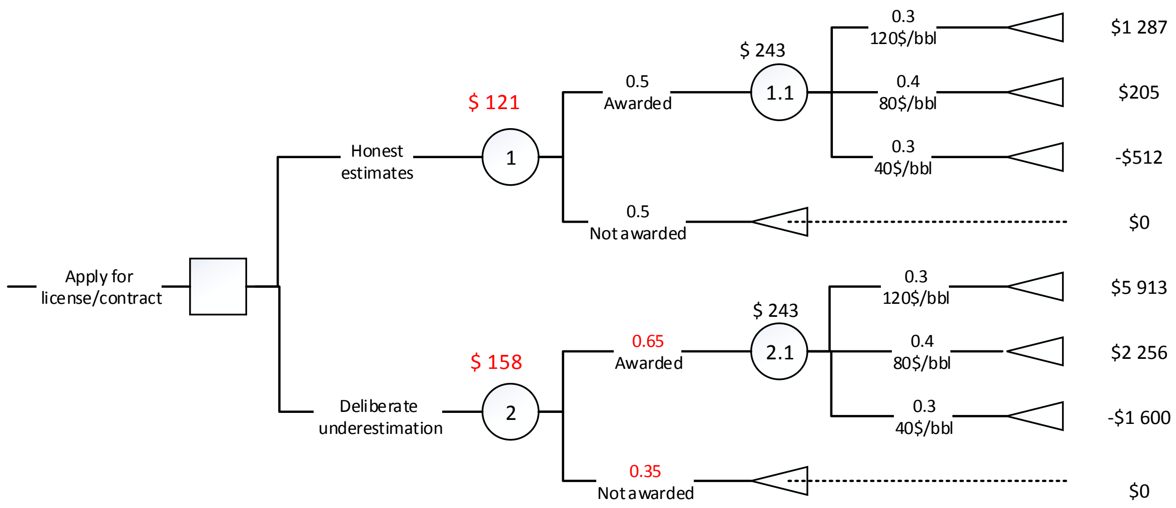
Other important unique characteristics of petroleum projects: long time profile, high risk and uncertainty in exploration activities, capital intensity (high operating and developing costs), volatility of oil prices and maturity of certain oil provinces.

The physical nature of petroleum operations explains the long time profile of oil and gas projects. It may take ten or more years from the initial discovery to first production, while the production itself may last over thirty years before the recoverable reserves are depleted (Nakhle, 2008). Moreover, most of investment and costs are incurred upfront and there may be significant delays of obtaining a return on investments. Besides that, oil and gas industry is capital intensive. It requires substantial amounts to be spent annually on exploration to discover reservoirs that are large enough to be commercially attractive. Natural reservoir depletion implies that an oil company has a limited number of years to realise a competitive rate of return.

As it was mentioned in the description of phases, each step in petroleum projects presents a set of risks, which gives oil industry a high-risk profile relatively to other sectors. Nakhle (2008) names various risks including political, exploratory (chance of failure), technical (reserves and cost estimation), economic (oil and gas prices), or commercial (fiscal risks). In comparison with other industry, oil industry provides substantially less certainty regarding return on investment, as large investments are necessary before it is known what returns to be expected.

The oil and gas industry implies a wide range of decisions with different complexities, where some can determine the direction and course of billions of dollars each year. Summing up all the challenges mentioned above – a long time horizon, capital intensity, a wide set of uncertainties and a high risk profile – adding multiple alternatives and complex value issues, it becomes clear the challenge of making decisions.

Appendix 6. Decision-tree model under PSA regime



Appendix 7. Expected government take under the concessionary regime

Opex, mm $	*75%*	*80%*	*85%*	*90%*	*95%*	*100%*
%	300	320	340	360	380	400
EV Gov. PSA	$2,315.22	$2,298.38	$2,281.72	$2,265.05	$2,248.38	$2,231.72
%	96.4%	97.1%	97.8%	98.5%	99.3%	100.0%

Appendix 8. NCFs under simplified concessionary regime

Year	*Prod*	*Rev*	*R&D costs*	*CAPEX*	*OPEX*	*Royalty*	***Pre-Tax CF***	*Depr.*	*Uplift*	*Taxable Income*	*CIT*	***NCFs***	***Government take***
2015	0	0	150	0	0	0	-150	0	0	-150	0	-150	0
2016	0	0	75	0	0	0	-75	0	0	-75	0	-75	0
2017	0	0	150	0	0	0	-150	0	0	-150	0	-150	0
2018	0	0	75	0	0	0	-75	0	0	-75	0	-75	0
2019	0	0	0	200	0	0	-200	0	0	-200	0	-200	0
2020	0	0	0	1500	0	0	-1500	0	0	-1500	0	-1500	0
2021	0	0	0	2000	0	0	-2000	0	0	-2000	0	-2000	0
2022	0	0	0	3000	0	0	-3000	0	0	-3000	0	-3000	192
2023	20	1600	0	0	400	192	1008	1116.67	45	-153.67	0	1008	760.3
2024	40	3200	0	0	400	384	2416	1116.67	45	1254.33	376.3	2039.7	760.3
2025	40	3200	0	0	400	384	2416	1116.67	45	1254.33	376.3	2039.7	760.3
2026	40	3200	0	0	400	384	2416	1116.67	45	1254.33	376.3	2039.7	760.3
2027	40	3200	0	0	400	384	2416	1116.67	45	1254.33	376.3	2039.7	760.3
2028	40	3200	0	0	400	384	2416	1116.67	45	1254.33	376.3	2039.7	1016.4
2029	37	2960	0	0	400	355.2	2204.8	0	0	2204.8	661.44	1543.36	893.76
2030	33	2640	0	0	400	316.8	1923.2	0	0	1923.2	576.96	1346.24	709.44
2031	27	2160	0	0	400	259.2	1500.8	0	0	1500.8	450.24	1050.56	555.84
2032	22	1760	0	0	400	211.2	1148.8	0	0	1148.8	344.64	804.16	432.96
2033	18	1440	0	0	400	172.8	867.2	0	0	867.2	260.16	607.04	340.8
2034	15	1200	0	0	400	144	656	0	0	656	196.8	459.2	248.64
2035	12	960	0	0	400	115.2	444.8	0	0	444.8	133.44	311.36	156.48
2036	9	720	0	0	400	86.4	233.6	0	0	233.6	70.08	163.52	95.04
2037	7	560	0	0	400	67.2	92.8	0	0	92.8	27.84	64.96	8443.1
Total	**400**	**32000**	**450**	**6700**	**6000**	**3840**	**15010**	**6700**	**270**	**8040**	**4603.1**	**10406.9**	**16886.2**

Appendix 9. NCFs under simplified PSA regime

Year	*Production*	*Gross Revenue*	*R&D costs*	*CAPEX*	*Total CAPEX*	*OPEX*	*Total costs*	*DD&A*	***Pre-Tax CF***
2015	0	0	150	0	150	0	150	0	-150
2016	0	0	75	0	75	0	75	0	-75
2017	0	0	150	0	150	0	150	0	-150
2018	0	0	75	0	75	0	75	0	-75
2019	0	0	0	200	200	0	200	0	-200
2020	0	0	0	1500	1500	0	1500	0	-1500
2021	0	0	0	2000	2000	0	2000	0	-2000
2022	0	0	0	3000	3000	0	3000	0	-3000
2023	20	1600	0	0	0	400	400	1430	1200
2024	40	3200	0	0	0	400	400	1430	2800
2025	40	3200	0	0	0	400	400	1430	2800
2026	40	3200	0	0	0	400	400	1430	2800
2027	40	3200	0	0	0	400	400	1430	2800
2028	40	3200	0	0	0	400	400	0	2800
2029	37	2960	0	0	0	400	400	0	2560
2030	33	2640	0	0	0	400	400	0	2240
2031	27	2160	0	0	0	400	400	0	1760
2032	22	1760	0	0	0	400	400	0	1360
2033	18	1440	0	0	0	400	400	0	1040
2034	15	1200	0	0	0	400	400	0	800
2035	12	960	0	0	0	400	400	0	560
2036	9	720	0	0	0	400	400	0	320
2037	7	560	0	0	0	400	400	0	160
Total	**400**	**32000**	**450**	**6700**	**7150**	**6000**	**13150**	**7150**	**18850**

(Continued)

Year	*Cost amort*	*Cost oil available*	*Cost oil*	*Profit oil*	*IOC profit oil*	*Gov profit oil*	***Tax***	***After-tax income***	***FCFs***	*Gov take*
2015	0	0		0	0	0	0	0	-150	0
2016	0	0		0	0	0	0	0	-75	0
2017	0	0		0	0	0	0	0	-150	0
2018	0	0		0	0	0	0	0	-75	0
2019	0	0		0	0	0	0	0	-200	0
2020	0	0		0	0	0	0	0	-1500	0
2021	0	0		0	0	0	0	0	-2000	0
2022	0	0		0	0	0	0	0	-3000	0
2023	1830	640	640	960	384	576	115.2	268.8	1698.8	691.2
2024	3020	1280	1280	1920	768	1152	230.4	537.6	1967.6	1382.4
2025	3570	1280	1280	1920	768	1152	230.4	537.6	1967.6	1382.4
2026	4120	1280	1280	1920	768	1152	230.4	537.6	1967.6	1382.4
2027	4670	1280	1280	1920	768	1152	230.4	537.6	1967.6	1382.4
2028	3790	1280	1280	1920	768	1152	230.4	537.6	537.6	1382.4
2029	2910	1184	1184	1776	710.4	1065.6	213.12	497.28	497.28	1278.72
2030	2126	1056	1056	1584	633.6	950.4	190.08	443.52	443.52	1140.48
2031	1470	864	864	1296	518.4	777.6	155.52	362.88	362.88	933.12
2032	1006	704	704	1056	422.4	633.6	126.72	295.68	295.68	760.32
2033	702	576	576	864	345.6	518.4	103.68	241.92	241.92	622.08
2034	526	480	480	720	288	432	86.4	201.6	201.6	518.4
2035	446	384	384	576	230.4	345.6	69.12	161.28	161.28	414.72
2036	462	288	288	432	172.8	259.2	51.84	120.96	120.96	311.04
2037	574	224	224	336	134.4	201.6	40.32	94.08	94.08	241.92
Total	**31222**	**12800**	**12800**	**19200**	**7680**	**11520**	**2304**	**5376**	**5376**	**13824**

Appendix 10. Petroleum fiscal terms assumptions for Norway, UK, Indonesia and China

Norway	
CIT	27%
SPT	51%
Depreciation (6 years)	0.167
Uplift (4 years)	5.50%
Exploration refund	75.00%

UK	
SCT	32%
CIT	30%

Indonesia	
CIT	25%
BPT	20%
GOV FTP	64%
IOC FTP	36%
DMO (75%*25%*36%)	7%
Depreciation (decline)	25%
Investment credit	16%

China	
VAT	17%
Recovery limit	63%
CIT	33%
Resource tax	5%
R&D	150%

Appendix 11. NCFs under Norway's concessionary regime

Year	*Production, mm bbl*	*Revenue, mm$*	*R&D costs, mm$*	*Capex, mm$*	*Total Capex, mm$*	*Opex, mm$*	***Pre-Tax CF**, mm$*	*Depreciation, mm$*	*Taxable Income, mm$*	*CIT, mm$*	*Expl. uplift, mm$*
2015	0	0	150	0	150	0	-150	0	-150	0	
2016	0	0	75	0	75	0	-75	0	-75	0	
2017	0	0	150	0	150	0	-150	0	-150	0	
2018	0	0	75	0	75	0	-75	0	-75	0	
2019	0	0	0	200	200	0	-200	0	-200	0	
2020	0	0	0	1500	1500	0	-1500	0	-1500	0	
2021	0	0	0	2000	2000	0	-2000	0	-2000	0	
2022	0	0	0	3000	3000	0	-3000	0	-3000	0	
2023	20	1600	0	0	0	400	1200	1191.67	8.33	2.25	393.2
2024	40	3200	0	0	0	400	2800	1191.67	1608.33	434.25	393.2
2025	40	3200	0	0	0	400	2800	1191.67	1608.33	434.25	393.2
2026	40	3200	0	0	0	400	2800	1191.67	1608.33	434.25	393.2
2027	40	3200	0	0	0	400	2800	1191.67	1608.33	434.25	
2028	40	3200	0	0	0	400	2800	1191.67	1608.33	434.25	
2029	37	2960	0	0	0	400	2560	0	2560	691.2	
2030	33	2640	0	0	0	400	2240	0	2240	604.8	
2031	27	2160	0	0	0	400	1760	0	1760	475.2	
2032	22	1760	0	0	0	400	1360	0	1360	367.2	
2033	18	1440	0	0	0	400	1040	0	1040	280.8	
2034	15	1200	0	0	0	400	800	0	800	216	
2035	12	960	0	0	0	400	560	0	560	151.2	
2036	9	720	0	0	0	400	320	0	320	86.4	
2037	7	560	0	0	0	400	160	0	160	43.2	
Total	**400**	**32000**	**450**	**6700**	**7150**	**6000**	**18850**	**7150**	**11700**	**5089.5**	**157**

(Continued)

Year	*SPT taxable income, mm$*	*SPT, mm$*	*Exploration Refund, mm$*	***IOC**, mm$*	***Government take**, mm$*
2015	-150.00	0.00	112.50	-37.50	-112.50
2016	-75.00	0.00	56.25	-18.75	-56.25
2017	-150.00	0.00	112.50	-37.50	-112.50
2018	-75.00	0.00	56.25	-18.75	-56.25
2019	-200.00	0.00	0.00	-200.00	0.00
2020	-1500.00	0.00	0.00	-1500.00	0.00
2021	-2000.00	0.00	0.00	-2000.00	0.00
2022	-3000.00	0.00	0.00	-3000.00	0.00
2023	-384.92	0.00	0.00	1197.75	2.25
2024	1215.08	619.69	0.00	1746.06	1053.94
2025	1215.08	619.69	0.00	1746.06	1053.94
2026	1215.08	619.69	0.00	1746.06	1053.94
2027	1608.33	820.25	0.00	1545.50	1254.50
2028	1608.33	820.25	0.00	1545.50	1254.50
2029	2560.00	1305.60	0.00	563.20	1996.80
2030	2240.00	1142.40	0.00	492.80	1747.20
2031	1760.00	897.60	0.00	387.20	1372.80
2032	1360.00	693.60	0.00	299.20	1060.80
2033	1040.00	530.40	0.00	228.80	811.20
2034	800.00	408.00	0.00	176.00	624.00
2035	560.00	285.60	0.00	123.20	436.80
2036	320.00	163.20	0.00	70.40	249.60
2037	160.00	81.60	0.00	35.20	124.80
Total	**10127.00**	**9007.58**	**337.50**	**5090.42**	**13759.58**

Appendix 12. NCFs under UK concessionary regime (same pre-tax CFs)

Year	*Pre-Tax CF, mm$*	*Net Profit1, mm$*	*Cummulative loss, mm$*	*Loss set-off, mm$*	*Taxable income, mm$*	*CIT and SCT*	*NPV IOC, mm$*	*NPV Gov, mm$*	*Project Cash Flow, mm$*
2015	-150	-150	0	0	0	0	-150	0	-150
2016	-75	-75	-225	0	0	0	-75	0	-75
2017	-150	-150	-375	0	0	0	-150	0	-150
2018	-75	-75	-450	0	0	0	-75	0	-75
2019	-200	-200	-650	0	0	0	-200	0	-200
2020	-1500	-1500	-2150	0	0	0	-1500	0	-1500
2021	-2000	-2000	-4150	0	0	0	-2000	0	-2000
2022	-3000	-3000	-7150	0	0	0	-3000	0	-3000
2023	1200	1200	-5950	1200	0	0	1200	0	1200
2024	2800	2800	-3150	2800	0	0	2800	0	2800
2025	2800	2800	-350	2800	0	0	2800	0	2800
2026	2800	2800	0	350	2450	1519	1281	1519	2800
2027	2800	2800	0	0	2800	1736	1064	1736	2800
2028	2800	2800	0	0	2800	1736	1064	1736	2800
2029	2560	2560	0	0	2560	1587.2	972.8	1587.2	2560
2030	2240	2240	0	0	2240	1388.8	851.2	1388.8	2240
2031	1760	1760	0	0	1760	1091.2	668.8	1091.2	1760
2032	1360	1360	0	0	1360	843.2	516.8	843.2	1360
2033	1040	1040	0	0	1040	644.8	395.2	644.8	1040
2034	800	800	0	0	800	496	304	496	800
2035	560	560	0	0	560	347.2	212.8	347.2	560
2036	320	320	0	0	320	198.4	121.6	198.4	320
2037	160	160	0	0	160	99.2	60.8	99.2	160
Total	**18850**	**18850**	**-24600**	**7150**	**18850**	**11687**	**7163**	**11687**	**18850**

Appendix 13. NCFs under Indonesia's PSA regime

Year	*Production*	*Gross Revenue, mm$*	*Total FTP, mm$*	*Gov FTP, mm$*	*IOC FTP, mm$*	*Net Revenue, mm$*	*DMO, mm$*	*R&D costs, mm$*	*Capex, mm$*	*Total Capex, mm$*
2015	0	0	0	0	0	0	0	150	0	150
2016	0	0	0	0	0	0	0	75	0	75
2017	0	0	0	0	0	0	0	150	0	150
2018	0	0	0	0	0	0	0	75	0	75
2019	0	0	0	0	0	0	0	0	200	200
2020	0	0	0	0	0	0	0	0	1500	1500
2021	0	0	0	0	0	0	0	0	2000	2000
2022	0	0	0	0	0	0	0	0	3000	3000
2023	20	1600	320	204.8	115.2	1280	0	0	0	0
2024	40	3200	640	409.6	230.4	2560	0	0	0	0
2025	40	3200	640	409.6	230.4	2560	0	0	0	0
2026	40	3200	640	409.6	230.4	2560	0	0	0	0
2027	40	3200	640	409.6	230.4	2560	0	0	0	0
2028	40	3200	640	409.6	230.4	2560	216	0	0	0
2029	37	2960	592	378.88	213.12	2368	199.8	0	0	0
2030	33	2640	528	337.92	190.08	2112	178.2	0	0	0
2031	27	2160	432	276.48	155.52	1728	145.8	0	0	0
2032	22	1760	352	225.28	126.72	1408	118.8	0	0	0
2033	18	1440	288	184.32	103.68	1152	97.2	0	0	0
2034	15	1200	240	153.6	86.4	960	81	0	0	0
2035	12	960	192	122.88	69.12	768	64.8	0	0	0
2036	9	720	144	92.16	51.84	576	48.6	0	0	0
2037	7	560	112	71.68	40.32	448	37.8	0	0	0
Total	**400**	**32000**	**6400**	**4096**	**2304**	**25600**	**1188**	**450**	**6700**	**7150**

(Continued)

Year	*DD&A and Investment Credit*	*Investment credit*	***Pre-Tax CF***	***Total cost recovery***	***Cost recovery limit***	***Cost Carry forward***	***Cost Recovery Allowed***	*Total Profit Oil*	*Gov. PO*	*IOC PO*
2015	0	0	-150	0	0		0	0	0	0
2016	0	0	-75	0	0	0	0	0	0	0
2017	0	0	-150	0	0	0	0	0	0	0
2018	0	0	-75	0	0	0	0	0	0	0
2019	0	0	-200	0	0	0	0	0	0	0
2020	0	0	-1500	0	0	0	0	0	0	0
2021	0	0	-2000	0	0	0	0	0	0	0
2022	0	0	-3000	0	0	0	0	0	0	0
2023	1787.50	1675	1200	3862.5	1280	0	1280	0	0	0
2024	1340.63	0	2800	1740.6	2560	2582.5	2560.0	0	0	0
2025	1005.47	0	2800	1405.5	2560	1763.1	2560.0	0	0	0
2026	754.10	0	2800	1154.1	2560	608.6	1762.7	797.30	510.275	287.029
2027	2262.30	0	2800	2662.3	2560	0.0	2560.0	0	0	0
2028	0	0	2800	400	2560	102.3	502.3	2057.69	1316.925	740.77
2029	0	0	2560	400	2368	0.0	400.0	1968	1259.52	708.48
2030	0	0	2240	400	2112	0.0	400.0	1712	1095.68	616.32
2031	0	0	1760	400	1728	0.0	400.0	1328	849.92	478.08
2032	0	0	1360	400	1408	0	400	1008	645.12	362.88
2033	0	0	1040	400	1152	0	400	752	481.28	270.72
2034	0	0	800	400	960	0	400	560	358.4	201.6
2035	0	0	560	400	768	0	400	368	235.52	132.48
2036	0	0	320	400	576	0	400	176	112.64	63.36
2037	0	0	160	400	448	0	400	48	30.72	17.28
Total	**7150**	**1675**	**18850**	**14825**	**25600**		**14825**	**10775**	**6896**	**3879**

(Continued)

Year	*Taxable*	*Income*	*Gov.*	*Contractor's*	*Projects*

	Income	*tax*	*take*	*NCF*	*NCF*
2015	0	0	0	-150	-150
2016	0	0	0	-75	-75
2017	0	0	0	-150	-150
2018	0	0	0	-75	-75
2019	0	0	0	-200	-200
2020	0	0	0	-1500	-1500
2021	0	0	0	-2000	-2000
2022	0	0	0	-3000	-3000
2023	1790.2	447.6	652.4	547.7	1200
2024	230.4	57.6	467.2	2332.8	2800
2025	230.4	57.6	467.2	2332.8	2800
2026	517.4	129.4	1049.2	1750.8	2800
2027	230.4	57.6	467.2	2332.8	2800
2028	755.2	188.8	2131.3	668.7	2800
2029	721.8	180.5	2018.7	541.4	2560
2030	628.2	157.1	1768.9	471.2	2240
2031	487.8	122.0	1394.2	365.9	1760
2032	370.8	92.7	1081.9	278.1	1360
2033	277.2	69.3	832.1	207.9	1040
2034	207.0	51.8	644.8	155.3	800
2035	136.8	34.2	457.4	102.6	560
2036	66.6	16.7	270.1	50.0	320
2037	19.8	5.0	145.2	14.9	160
Total	**6670.0**	**1667.5**	**13847.5**	**5002.5**	**18850**

Appendix 14. NCFs under China's PSA regime

Year	*Production, mm bbl*	*Prod/day, bbl*	*Gross Rev*	*VAT*	*Resource Rent Tax*	*Net Rev*	*R&D costs*	*Capex*	*Total Capex*	*Opex*	*Total costs*
2015	0	0.00	0	0	0	0	150	0	150	0	150
2016	0	0.00	0	0	0	0	75	0	75	0	75
2017	0	0.00	0	0	0	0	150	0	150	0	150
2018	0	0.00	0	0	0	0	75	0	75	0	75
2019	0	0.00	0	0	0	0	0	200	200	0	200
2020	0	0.00	0	0	0	0	0	1500	1500	0	1500
2021	0	0.00	0	0	0	0	0	2000	2000	0	2000
2022	0	0.00	0	0	0	0	0	3000	3000	0	3000
2023	20	54794.52	1600	272	80	1248	0	0	0	400	400
2024	40	109589.04	3200	544	160	2496	0	0	0	400	400
2025	40	109589.04	3200	544	160	2496	0	0	0	400	400
2026	40	109589.04	3200	544	160	2496	0	0	0	400	400
2027	40	109589.04	3200	544	160	2496	0	0	0	400	400
2028	40	109589.04	3200	544	160	2496	0	0	0	400	400
2029	37	101369.86	2960	503.2	148	2308.8	0	0	0	400	400
2030	33	90410.96	2640	448.8	132	2059.2	0	0	0	400	400
2031	27	73972.60	2160	367.2	108	1684.8	0	0	0	400	400
2032	22	60273.97	1760	299.2	88	1372.8	0	0	0	400	400
2033	18	49315.07	1440	244.8	72	1123.2	0	0	0	400	400
2034	15	41095.89	1200	204	60	936	0	0	0	400	400
2035	12	32876.71	960	163.2	48	748.8	0	0	0	400	400
2036	9	24657.53	720	122.4	36	561.6	0	0	0	400	400
2037	7	19178.08	560	95.2	28	436.8	0	0	0	400	400
Total	**400**	**1095890.41**	**32000**	**5440**	**1600**	**24960**	**450**	**6700**	**7150**	**6000**	**13150**

(Continued)

Year	*DD&A*	*Pre-Tax CF*	*Total cost recovery*	*Cost recovery limit*	*Cost Carry forward*	*Cost Recovery Allowed*	*Total Profit Oil*	*Government share of profit oil*	*Gov. PO*	*IOC PO*
2015	225	-150	150	0		0	0	0	0	0
2016	112.5	-75	75	0	150	0	0	0	0	0
2017	225	-150	150	0	225	0	0	0	0	0
2018	112.5	-75	75	0	375	0	0	0	0	0
2019	200	-200	200	0	450	0	0	0	0	0
2020	1500	-1500	1500	0	650	0	0	0	0	0
2021	2000	-2000	2000	0	2150	0	0	0	0	0
2022	3000	-3000	3000	0	4150	0	0	0	0	0
2023	0	1200	400	1000	7150	1000	248	1	2.48	245.52
2024	0	2800	400	2000	6550	2000	496	4.5	22.32	473.68
2025	0	2800	400	2000	4950	2000	496	4.5	22.32	473.68
2026	0	2800	400	2000	3350	2000	496	4.5	22.32	473.68
2027	0	2800	400	2000	1750	2000	496	4.5	22.3	473.7
2028	0	2800	400	2000	150	550	1946	4.5	87.6	1858.4
2029	0	2560	400	1850	0	400	1908.8	4.1625	79.5	1829.3
2030	0	2240	400	1650	0	400	1659.2	2.31	38.3	1620.9
2031	0	1760	400	1350	0	400	1284.8	1.89	24.3	1260.5
2032	0	1360	400	1100	0	400	972.8	1.54	15.0	957.8
2033	0	1040	400	900	0	400	723.2	0.9	6.5	716.7
2034	0	800	400	750	0	400	536	0.75	4.0	532.0
2035	0	560	400	600	0	400	348.8	0.45	1.6	347.2
2036	0	320	400	450	0	400	161.6	0.3375	0.5	161.1
2037	0	160	400	350	0	350	86.8	0.14	0.1	86.7
Total	**7375**	**18850**	**13150**	**20000**	**32050**	**13100**	**11860**	**35.98**	**349.1**	**11510.9**

(Continued)

Year	*Taxable Income*	*Income tax*	*Gov. take*	*Contractor's NCF*	*Projects NCF*
2015	-225.00	0.00	0.00	-150.00	-150
2016	-112.50	0.00	0.00	-75.00	-75
2017	-225.00	0.00	0.00	-150.00	-150
2018	-112.50	0.00	0.00	-75.00	-75
2019	-200.00	0.00	0.00	-200.00	-200
2020	-1500.00	0.00	0.00	-1500.00	-1500
2021	-2000.00	0.00	0.00	-2000.00	-2000
2022	-3000.00	0.00	0.00	-3000.00	-3000
2023	845.52	279.02	633.50	566.50	1200
2024	2073.68	684.31	1410.63	1389.37	2800
2025	2073.68	684.31	1410.63	1389.37	2800
2026	2073.68	684.31	1410.63	1389.37	2800
2027	2073.68	684.31	1410.63	1389.37	2800
2028	2008.43	662.78	1454.35	1345.65	2800
2029	1829.35	603.68	1334.34	1225.66	2560
2030	1620.87	534.89	1154.02	1085.98	2240
2031	1260.52	415.97	915.45	844.55	1760
2032	957.82	316.08	718.26	641.74	1360
2033	716.69	236.51	559.82	480.18	1040
2034	531.98	175.55	443.57	356.43	800
2035	347.23	114.59	327.36	232.64	560
2036	161.05	53.15	212.09	107.91	320
2037	36.68	12.10	135.43	24.57	160
Total	**11235.86**	**6141.58**	**13530.72**	**5319.28**	**18850**

Appendix 15. Sensitivity analysis of NPV to OPEX change

OPEX	*Norway IOC*	*Norway Gov*	*UK IOC*	*UK GOV*	*Indonesia IOC*	*Indonesia Gov*	*China IOC*	*China Gov*
200	$381.50	$3,694.49	$901.11	$3,174.88	$256.60	$3,819.40	$156.45	$3,919.54
220	$361.56	$3,643.46	$872.80	$3,132.23	$234.45	$3,770.57	$110.28	$3,894.75
240	$341.63	$3,592.44	$844.49	$3,089.58	$212.31	$3,721.75	$64.10	$3,869.96
260	$321.69	$3,541.41	$816.17	$3,046.92	$190.17	$3,672.93	$17.93	$3,845.17
280	$301.75	$3,490.38	$787.86	$3,004.27	$168.03	$3,624.10	$28.25	$3,820.38
300	$281.81	$3,439.35	$758.55	$2,962.61	$145.84	$3,575.32	$74.43	$3,795.59
320	$261.87	$3,388.33	$729.06	$2,921.14	$123.31	$3,526.89	$120.60	$3,770.80
340	$241.93	$3,337.30	$699.56	$2,879.68	$100.79	$3,478.45	$166.78	$3,746.01
360	$222.00	$3,286.27	$670.06	$2,838.21	$78.26	$3,430.01	$212.96	$3,721.22
380	$202.06	$3,235.24	$640.56	$2,796.74	$55.73	$3,381.57	$259.18	$3,696.48
400	$182.12	$3,184.22	$611.06	$2,755.28	$33.20	$3,333.13	$305.43	$3,671.77
420	$160.85	$3,134.52	$581.56	$2,713.81	$10.68	$3,284.69	$351.69	$3,647.06
440	$138.62	$3,085.79	$552.06	$2,672.35	$11.85	$3,236.25	$398.07	$3,622.47
460	$116.39	$3,037.05	$522.56	$2,630.88	$35.36	$3,188.79	$445.07	$3,598.51
480	$94.16	$2,988.31	$493.06	$2,589.41	$59.51	$3,141.99	$492.07	$3,574.54
500	$71.93	$2,939.57	$463.56	$2,547.95	$83.67	$3,095.18	$539.07	$3,550.58
520	$49.70	$2,890.84	$434.06	$2,506.48	$107.83	$3,048.37	$586.07	$3,526.61
540	$27.47	$2,842.10	$404.56	$2,465.01	$131.99	$3,001.56	$633.07	$3,502.65
560	$5.25	$2,793.36	$375.06	$2,423.55	$156.14	$2,954.75	$680.07	$3,478.68
580	$18.72	$2,746.37	$344.18	$2,383.47	$180.66	$2,908.30	$727.83	$3,455.48
600	$42.69	$2,699.37	$313.29	$2,343.39	$206.72	$2,863.40	$775.65	$3,432.32

Appendix 16 Sensitivity analysis of NPV to CAPEX change

CAPEX	*Norway IOC*	*Norway Gov*	*UK IOC*	*UK Gov*	*Indonesia IOC*	*Indonesia Gov*	*China IOC*	*China Gov*
50%	$939.95	$4,124.75	$1,584.02	$3,480.69	$802.91	$4,193.97	$1,362.40	$3,702.30
55%	$872.49	$4,022.37	$1,491.32	$3,403.54	$717.39	$4,107.69	$1,195.78	$3,699.09
60%	$805.04	$3,919.99	$1,394.28	$3,330.74	$631.86	$4,021.41	$1,029.16	$3,695.87
65%	$737.58	$3,817.61	$1,297.24	$3,257.95	$546.34	$3,935.13	$862.54	$3,692.65
70%	$670.12	$3,715.23	$1,200.21	$3,185.15	$460.82	$3,848.85	$695.92	$3,689.43
75%	$599.72	$3,615.80	$1,103.17	$3,112.35	$375.29	$3,762.57	$529.24	$3,686.28
80%	$516.20	$3,529.48	$1,006.13	$3,039.55	$289.77	$3,676.29	$362.33	$3,683.35
85%	$432.68	$3,443.17	$909.09	$2,966.76	$204.25	$3,590.01	$195.42	$3,680.43
90%	$349.16	$3,356.85	$812.05	$2,893.96	$118.73	$3,503.73	$28.51	$3,677.50
95%	$265.64	$3,270.53	$714.71	$2,821.46	$33.20	$3,417.44	$138.40	$3,674.57
100%	$182.12	$3,184.22	$611.06	$2,755.28	$6.31	$3,333.13	$305.43	$3,671.77
105%	$93.16	$3,103.34	$507.40	$2,689.10	$52.39	$3,248.89	$472.61	$3,669.11
110%	$3.25	$3,023.41	$403.74	$2,622.92	$137.98	$3,164.64	$639.79	$3,666.45
115%	$86.66	$2,943.49	$300.09	$2,556.74	$229.27	$3,086.09	$806.96	$3,663.79
120%	$176.58	$2,863.56	$196.43	$2,490.56	$327.49	$3,014.47	$974.14	$3,661.13
125%	$266.49	$2,783.64	$92.77	$2,424.38	$425.71	$2,942.86	$1,141.60	$3,658.75
130%	$356.40	$2,703.72	$10.89	$2,358.20	$523.93	$2,871.24	$1,309.20	$3,656.52
135%	$446.31	$2,623.79	$114.54	$2,292.02	$636.80	$2,814.28	$1,476.80	$3,654.28
140%	$536.23	$2,543.87	$263.64	$2,271.28	$815.52	$2,823.16	$1,644.40	$3,652.04
145%	$626.14	$2,463.94	$433.47	$2,271.28	$994.23	$2,832.04	$1,812.38	$3,650.19
150%	$716.05	$2,384.02	$603.31	$2,271.28	$1,172.95	$2,840.92	$1,981.09	$3,649.06

Appendix 17 Sensitivity analysis of NPV to R&D change

R&D	*Norway IOC*	*Norway Gov*	*UK IOC*	*UK Gov*	*Indonesia IOC*	*Indonesia Gov*	*China IOC*	*China Gov*
50%	\$169.43	\$3,378.04	\$747.74	\$2,799.73	\$164.88	\$3,382.59	\$126.14	\$3,673.61
55%	\$170.70	\$3,358.66	\$734.07	\$2,795.28	\$151.71	\$3,377.65	\$144.06	\$3,673.42
60%	\$171.97	\$3,339.28	\$720.41	\$2,790.84	\$138.54	\$3,372.70	\$161.98	\$3,673.22
65%	\$173.24	\$3,319.89	\$706.74	\$2,786.39	\$125.38	\$3,367.75	\$179.90	\$3,673.02
70%	\$174.51	\$3,300.51	\$693.07	\$2,781.95	\$112.21	\$3,362.81	\$197.82	\$3,672.84
75%	\$175.77	\$3,281.13	\$679.40	\$2,777.50	\$99.04	\$3,357.86	\$215.76	\$3,672.66
80%	\$177.04	\$3,261.75	\$665.73	\$2,773.06	\$85.87	\$3,352.92	\$233.69	\$3,672.48
85%	\$178.31	\$3,242.36	\$652.06	\$2,768.61	\$72.71	\$3,347.97	\$251.63	\$3,672.30
90%	\$179.58	\$3,222.98	\$638.39	\$2,764.17	\$59.54	\$3,343.02	\$269.56	\$3,672.13
95%	\$180.85	\$3,203.60	\$624.73	\$2,759.72	\$46.37	\$3,338.08	\$287.50	\$3,671.95
100%	\$182.12	\$3,184.22	\$611.06	\$2,755.28	\$33.20	\$3,333.13	\$305.43	\$3,671.77
105%	\$183.39	\$3,164.83	\$597.39	\$2,750.83	\$20.04	\$3,328.18	\$323.37	\$3,671.59
110%	\$184.66	\$3,145.45	\$583.72	\$2,746.39	\$6.87	\$3,323.24	\$341.30	\$3,671.41
115%	\$185.59	\$3,126.40	\$570.05	\$2,741.94	\$6.30	\$3,318.29	\$359.24	\$3,671.23
120%	\$186.43	\$3,107.45	\$556.38	\$2,737.50	\$19.47	\$3,313.35	\$377.17	\$3,671.05
125%	\$187.27	\$3,088.49	\$542.71	\$2,733.05	\$32.63	\$3,308.40	\$395.11	\$3,670.88
130%	\$188.11	\$3,069.54	\$529.05	\$2,728.61	\$45.80	\$3,303.45	\$413.04	\$3,670.70
135%	\$188.95	\$3,050.59	\$515.38	\$2,724.16	\$58.97	\$3,298.51	\$430.98	\$3,670.52
140%	\$189.79	\$3,031.64	\$501.71	\$2,719.72	\$72.14	\$3,293.56	\$448.91	\$3,670.34
145%	\$190.63	\$3,012.68	\$488.04	\$2,715.27	\$85.30	\$3,288.62	\$466.85	\$3,670.16
150%	\$191.47	\$2,993.73	\$474.37	\$2,710.83	\$98.47	\$3,283.67	\$484.78	\$3,669.98