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Optimal Investment Conditions for Electrification of Edvard Grieg

A Discrete Dynamic Programming Approach

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Preface

This thesis was written as a part of the Energy, Natural Resources and the Environment master profile at NHH. The idea of a real options analysis concerning use of power from shore on offshore platforms on the NCS sprang from the desire to apply a relatively common analysis to a new problem. The test field investigated in this thesis, Edvard Grieg, along with the rest of the Utsira High, is currently embroiled in controversy regarding the use of power from shore, making this problem not only a new application but also a very interesting one. Despite the relevance of PFS, there have been surprisingly few studies on the economic viability of PFS published, at least none that are publicly available.

I would like to thank my NHH advisor, Linda Nøstbakken, for her invaluable help in navigating me through the complex waters of dynamic programming and MATLAB, teaching me incredibly valuable skills I will keep through the rest of my career. Additionally, I would like to thank Lars Harald Hauge and the Business Risk Management department of DNV GL in Høvik, who supported my thesis and provided me with a fantastic work environment over the past 6 months.

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Abstract

This thesis investigates the optimal investment conditions for switching the Edvard Grieg field from traditional power generation methods (gas turbines) to electrical power from shore. By interpreting this problem as a cost-minimization problem, the wholesale electricity price is the main stochastic element. A discrete dynamic programming model, implementing backward recursion, is implemented to find the threshold wholesale electricity prices for choosing between gas turbines and PFS. Additionally, different future carbon prices and their effects on the threshold price are examined, given the criticality of carbon prices for the gas turbine solution's costs.

Upon running the dynamic programming model, the baseline model yielded a threshold wholesale electricity price of 295 NOK/MWh. This indicates that PFS would be the optimal choice when the wholesale electricity price is at or below 295 NOK/MWh. Upon completing a sensitivity analysis for the oil price and OPEX parameters, it is found that the threshold electricity price does not change, only the project value range changes. Thereafter, a 10% and 25% increase in the carbon emission tax is examined. A 10% increase in the carbon tax price yields a threshold electricity price of 320 NOK/MWh, while a 25% increase yields 360 NOK/MWh. Lastly, the critical carbon price was found to be 1003 NOK/ton, representing the level of carbon tax necessary to negate the gas turbine option.

This thesis finds the PFS solution economically viable in some cases, illustrating different levels of threshold electricity prices given the current environment. However, there are more concerns against PFS than just economic ones, such as electricity import, export of emissions, etc. Decisions concerning the fate of PFS at the Edvard Grieg platform are in discussion now, but it could be years before a final decision is made.

Contents

List of Figures

Abbreviations

AC	Alternating Current
BBL	barrel of oil
Btu	British Thermal Units
CAPEX	Capital Expenditures
CO_2	Carbon Dioxide
DC	Direct Current
EOR	Extended Oil Recovery
ETS	Emission Trading System
GBM	Geometric Brownian motion
GDP	Gross Domestic Product
KWh	Kilowatt-hour
MPE	Ministry of Petroleum and Energy
MW	Megawatt
MWh	Megawatt-hour
NBIM	Norges Bank Investment Management
NOK	Norwegian Kroner
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
OPEX	Operating Expenditures
OU	Ornstein-Uhlenbeck

PDO	Plan for Development and Operation
PFS	Power from Shore
R&D	Research and Development
SDFI	State Direct Financial Interest
Sm^3	Standard cubic meter
TSO	Transmission System Operator

1. Introduction

Despite Norway's efforts to be a world leader in sustainability and environmental policy, it is difficult to ignore that the largest part of Norway's modern economy and society is its booming oil and gas industry. In an effort to try and clean up one of the world's "dirtiest" industries, for years the Norwegian government has promoted the use of a new power generation solution for its offshore platforms: electrical power from shore, and there is no greater goal than to completely electrify the area known as the Utsira High, home to the Edvard Grieg, Ivar Åsen, and giant Johan Sverdrup fields. The electrification of this area could lead to a savings of more than a million tons of CO_2 emissions per year; however, power from shore comes at a high cost that the operators do not want to pay.

Before Johan Sverdrup was found, it was determined that it would not be economical for Edvard Grieg (who supplies Ivar Åsen with electrical power) alone to implement power from shore (hereafter, PFS), so a traditional gas turbine power solution was planned and implemented. Yet, after Johan Sverdrup and its enormous reserves were found, there seemed to be hope once again for a PFS solution. Edvard Grieg operator Lundin now stands at a fork in the road; once Johan Sverdrup is up and running, should Edvard Grieg connect to that platform and receive electrical power, or should it continue with the originally planned gas turbine generators?

Currently, there is large debate between the Norwegian government and the oil operators as to whether this PFS solution can actually be implemented for the Utsira High. Given that a major cost differential between the PFS and gas turbine solution is the cost of the electricity needed; this thesis aims to the approximate threshold electricity prices for which PFS can be implemented at Edvard Grieg. Furthermore, special attention will be given to identifying the effect of the Norwegian and European carbon taxes on the viability of a PFS versus a gas turbine solution for the Edvard Grieg field.

This thesis is split into four different parts. First, there is an in-depth look at the context of this problem, including the Norwegian petroleum industry and its contributions to Norwegian emissions, Norwegian power markets, and the specific case field, Edvard Grieg. Thereafter, the problem is narrowly defined and the chosen theory to evaluate the problem is introduced and elaborated on. Next, the results from the chosen methodology are presented, and lastly, the results are discussed in the context of the current environment, both economically and politically.

2. Background

2.1 Petroleum Industry in Norway

2.1.1 Overview

Since the beginning of oil production on the Norwegian Continental Shelf in the early 1970s, the petroleum industry has played a major role in the development of Norway as a whole. The NCS currently has more than 70 fields in operation, producing approximately 1.9 million barrels of oil and 111 billion Sm^3 of natural gas per day in 2012 (Oljedirektoratet, 2013). This put Norway as the seventh largest oil exporter and fourteenth largest oil producer as well as the third largest gas exporter and sixth largest gas producer in the world (Oljedirektoratet, 2013).

The revenues received from petroleum activities have been a crucial part in financing the Norwegian welfare state, as well as contributing to the economy's financial growth over the last decades. Since the first field started producing in 1971, production on the NCS has contributed more than NOK 9000 billion to the country's GDP and comprised more than 23 percent of the country's total value creation in 2012 (Oljedirektoratet, 2013). Not only does the industry contribute financially, but also socially, providing hundreds of thousands of jobs, both directly and indirectly.

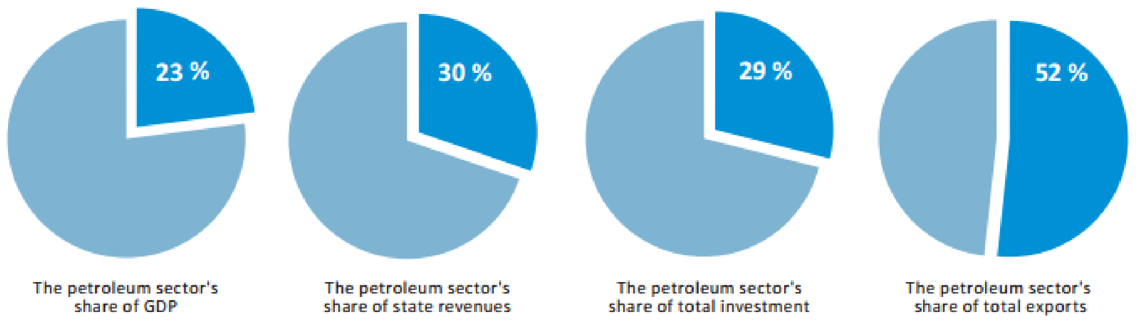

Figure 2-1: Macroeconomic indicators for the petroleum sector in 2012. Source: Oljedirektorat (2013).

The petroleum industry's impact on major parts of the Norwegian economy can be seen above in Figure 2-1.

2.1.2 Norwegian State in the Petroleum Industry

Framework

Since the beginning of oil production on the NCS, the Norwegian state has maintained a very involved role within the petroleum industry. The Norwegian parliament, the democratically elected legislative body, is at the head of the hierarchy for all decisions made surrounding the framework, operation and regulation of the industry. The parliament is responsible for deliberations on major development projects, financial/taxation systems and oversight of the industry as well as advisory to the Government and public offices (Oljedirektoratet, 2013). The parliament's primary instrument for directing the industry is legislation, as well as considerable influence over the intermediary decision-makers. Within the parliament, there is the Energy and Environment committee, which handles all cases related to oil, gas, waterways, the environment and regional planning (Stortinget, 2013).

Directly under the parliament is the Government. In this context, the Government refers to the "Council of State". The council consists of the Prime Minister and heads of the various ministries. The Prime Minister is normally the leader of the coalition receiving/maintaining the majority in Storting after national elections every 4 years. Changes in the council can have significant consequences for the petroleum industry depending on the incoming coalition's views on fossil fuel use and the environment. Primarily, the Government has "executive authority" over the petroleum industry through its various policies. This "executive authority" is divided among the different ministries, based on topic, as seen below in Table 2-1.

Table 2-1: Division of responsibilities among ministries. Source: Oljedirektoratet (2013).

Ministry	Responsibility
- **Petroleum and Energy**	Resource management and the sector as a whole
- **Labor**	Safety and working environment

- **Finance**	Petroleum taxation
- **Fisheries and Coastal Affairs**	Oil spill preparedness
- **Health and Care Services**	Health issues
- **Environment**	External environment

Lastly, under the different ministries, there are also a wide spectrum of public agencies, the most prominent being the Norwegian Petroleum Directorate, which work in cooperation with the ministries to ensure the best possible framework and operation of the industry.

In addition to the state's role as legislator and regulator, the Norwegian state is also an investor in petroleum activities on the NCS. The first role as investor is as the majority owner of Statoil Hydro ASA. Statoil was originally established as a state oil company by the parliament in 1972, in order to ensure Norwegian participation on the NCS (Statoil, 2013). Then in 2001, the company was partially privatized and listed on the Oslo stock exchange, with the government retaining 81.7% of its shares. Since then, the government has gradually reduced its shareholding, to its current level of 67%. Because of its ownership in Statoil, the government receives yearly dividends based on the company's performance. The second investor role held by the government is an arrangement called the State's Direct Financial Interest (hereafter, SDFI). In this role, the state is an actual investor, similar to other oil and gas operators holding shares in projects, which they do not directly operate. SDFI began in 1985 by splitting Statoil's share in its NCS licenses in half and contributing one-half to the SDFI. As of January 2012, the SDFI portfolio consists of direct financial interests in 158 production licenses and 15 joint ventures for pipelines and onshore facilities, with an approximate value of NOK 1.140 billion (Ministry of Petroleum and Energy, 2012).

Revenues to the State

As mentioned previously in Overview, the Norwegian state receives a large amount of money from the petroleum industry, mainly through the previously mentioned SDFI and the petroleum taxation system. The petroleum taxation system is based on two major arguments. The first argument is that the petroleum resources, in fact, belong to Norway, which should receive a sizeable portion of the created value from extraction. The second argument is that the petroleum tax will keep oil companies' returns at an ordinary level (Oljedirektoratet, 2013). The petroleum tax system is split between 2 different rates, the standard corporate tax rate (28%) and the special petroleum tax rate (50%). The corporate tax rate base is the operator's operating incomes less exploration and production-related expenses[1]. Additionally, there is a depreciation tax deduction, where the operator can deduct the full cost of its initial investments over the first six years. From the corporate tax base, there is an additional depreciation deduction, called "uplift", which at 5.5% over four years (previously, 7.5%), is meant to ensure that normal returns are not subjected to the special tax rate. The special tax base is the corporate tax base less the uplift. In beginning years of a field, the tax base can be negative, in which case the excess uplift can be carried over to the next year.

Alongside the SDFI and petroleum tax system, the state also receives revenues through area fees, environmental taxes and its stake in Statoil. Since 1990, all revenues the state receives from petroleum activities have been put into a separate, dedicated fund, the Government Pension Fund – Global, where it is managed by the Norges Bank Investment Management (hereafter, NBIM), on behalf of the Ministry of Finance, who decides on the investment strategy. The fund's investment strategy is based on discussions in the parliament and with advisors in NBIM. Two distinct characteristics of the fund are, first, that it is invested entirely outside of Norway and second, that the fund follows ethical guidelines concerning the companies in which they will invest. As of 2014, the fund's market value is approximately NOK 5 billion (Norges Bank Investment Management, 2014). The main role of the Government Pension Fund – Global is to preserve the wealth from the petroleum industry for future generations of Norwegians.

[1] Exploration and production-related expenses include all operating expenses, exploration expenses, research and development, decommissioning, CO_2 and NO_x taxes, area fees, etc.

2.1.3 Current State of the Industry

After having reached at peak in the early 2000s, total petroleum production on the NCS has started to decline. Although Norway still maintains its spot as the seventh largest exporter of oil and second largest of gas in 2010, new areas for discoveries and new methods for extending production are being explored.

New Exploration Areas

The NPD Resource Report indicated that there are still substantial resources available on the NCS, in the Norwegian, North and South Barents Seas (2011). While the North Sea has been relatively well developed, with 54% of its recoverable petroleum resources sold and delivered, there is still great potential in the Norwegian Sea, only 29% and the especially the Barents Sea, only 1% (Norwegian Petroleum Directorate, 2011). Many of the new finds on the NCS, for which operators have received licenses, are in challenging environments, from ultra-deep waters (>1500 meters) to difficult geological properties, and harsh conditions. These environments present a problem for operators to produce hydrocarbons in an economically feasible way, especially if the estimated reserves are of a small to medium quantity.

In addition to the currently explored areas, there are other areas, such as the North Barents Sea and the Arctic Ocean, which hold much promise in terms of possible petroleum resources, but are not open for petroleum activities. As the parliament makes most major decisions concerning the operation of the industry, the only way for exploration to begin in these areas is by political decision. However, no new areas have been opened for oil and gas activities since 1994, which indicates a political environment that wants to limit petroleum activities (Norwegian Petroleum Directorate, 2011). As mentioned above in Framework section, the coalition in charge of the government has the possibility to change every 4 years, meaning that there could be a shift in future policy regarding these unopened areas

Existing Fields

Many fields on the NCS are maturing and with that have had declining production. Declining production on oil and gas fields is a result of the pressure drop in the reservoir, which occurs when more and more hydrocarbons are extracted. The rate of decline is dependent on the individual reservoirs properties and the production rate of the facilities, decided by the operator. The NCS has some very large fields, like, Ekofisk, Statfjord, and Troll, which have been producing for a long time, but as Figure 2-2, below, shows, there will still be large amounts of resources left behind, if the current plan is followed. Because of this, many players in the industry, operators, service providers, and the government, are continuously working on finding a way to increase recovery factors, both on individual fields and for the shelf as a whole.

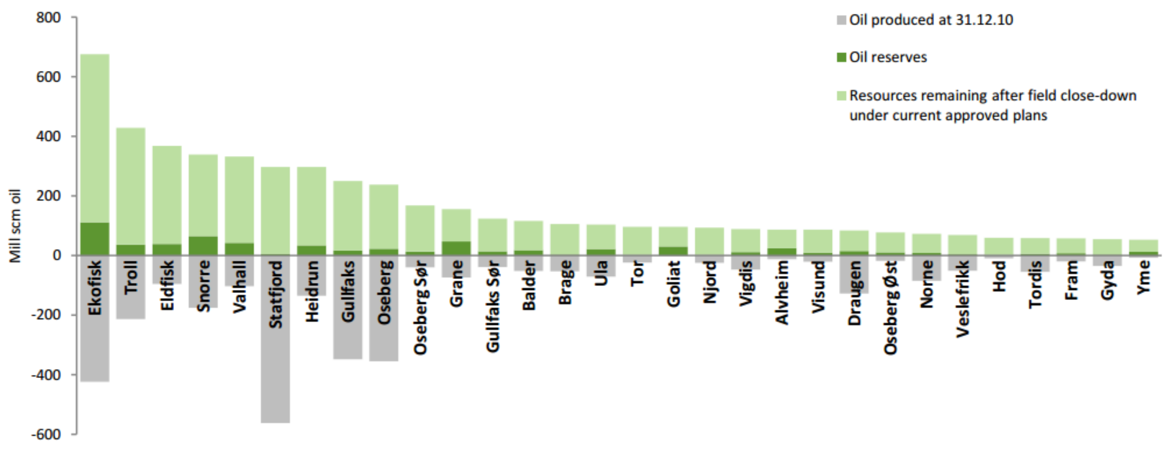

Figure 2-2: Distribution of produced oil, remaining oil reserves and oil resources, which will remain in the ground if fields follow the currently approved plans. Source: Norwegian Petroleum Directorate (2011).

In 2010, the NCS had an average recovery factor of 49% for oil and 70% for gas, well above the international average of 22% (Norwegian Petroleum Directorate, 2011). These recovery factors are bolstered by the very large fields like Ekofisk, Statfjord, and Oseberg, who have individual recovery factors of 49, 66 and 64%, respectively. The larger fields tend to have a higher recovery factor because they have very long production lifetimes and more flexibility, which allows the operator to implement different extended oil recovery (hereafter, EOR) techniques. The typical EOR methods employed on the NCS include mainly injection of different liquids or gases, such as polymers, surfactants, CO_2, low-saline water, into the reservoir to increase the pressure. In order to inject the chosen substance, additional wells need to be drilled into the reservoir and large compressors and pumps need to be installed on the platform. All of these activities, especially the compressors and pumps, will require additional power, potentially significantly increasing the field's total power requirement and and the field's emissions.

2.1.4 Contribution to Norwegian Emissions

Although the Norwegian petroleum industry is one of the largest contributors to the Norwegian economy, it is also one of the largest contributors to the country's total greenhouse gas emissions. In 2012, the offshore petroleum industry contributed 12.4 million tons of carbon dioxide emissions, a slight increase over 2011 (Norwegian Oil and Gas Association, 2013). These emissions comprise roughly 28% of Norway's total carbon emissions, second only to transportation (Statistics Norway, 2013).

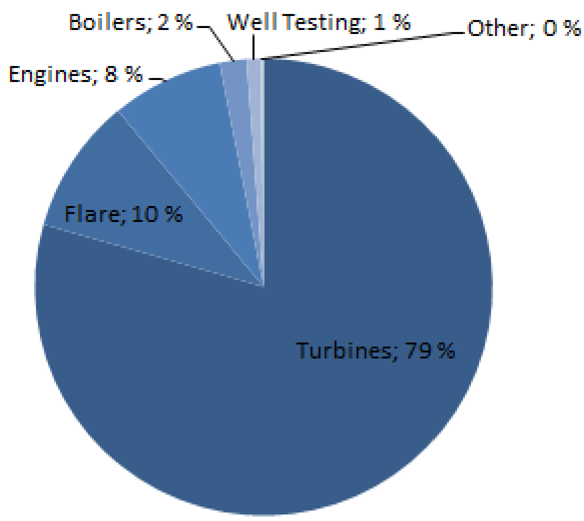

Figure 2-3: Petroleum production-related carbon emissions on the NCS. Source: Norwegian Oil and Gas Association (2013).

Figure 2-3 depicts the breakdown of associated carbon emissions by source, indicating that the overwhelming majority of petroleum-related carbon emissions are a result of the platform-based gas turbines used for power generation, contributing 79.4% in 2012. The platform-based gas turbines are a standard method of power generation on offshore platforms because of its practicality and cost-effectiveness. Most oil fields have a sizeable amount of associated gas, meaning gas that is trapped in the oil that is extracted from the well. After the separation process, where the gas and other unwanted parts of the well stream are removed from the oil, there are limited options for the operator as to what to do with the gas. If there is export infrastructure, it can be exported, but if not, it can either be used in the turbines or burned as flare gas. Since the platform needs power as well, it is easiest for the operator to use the associated gas as fuel.

Given the increased awareness and motivation to decrease overall greenhouse gas emissions, especially carbon dioxide emissions, the Norwegian government and several other industry and environmental agencies have investigated the different ways for the petroleum industry to decrease its carbon emissions. The main solutions supported by the parliament are carbon taxes on gas burned and the full or partial replacement of gas turbines by electrical power from shore.

2.1.5 Power from Shore

Although taxes on carbon emitted from offshore platforms can help mitigate emissions, the government-favored solution is supplying these platforms with power from the onshore grid. The power from shore (hereafter, PFS) solution can be either partial or full. A partial system would entail covering a portion of the platform's power supply, with a supplemental gas turbine supplying the rest. This would decrease emissions based on the amount of power covered by electrical power. A full solution entails that the platform's entire power requirement be covered by electrical power. In this case, the emissions savings are much greater. Collectively, PFS solutions could help significantly decrease the emissions of individual platforms, contributing to overall lower emissions on the NCS. The electricity is transported from the mainland Norwegian grid via a subsea power cable; alternating or direct current (hereafter AC and DC) depending on the distance from shore and power requirement. Since onshore power grids supply AC power, an AC PFS solution requires mainly the subsea cable and both onshore and offshore connection points. However, for distances further than 100 kilometers, AC cables suffer from some technical transmission limitations (Chokhawala, 2008). In the case of longer distances, a DC solution can be implemented. Due to onshore grids supplying AC power, a DC solution requires units on both the onshore and offshore ends to convert the power from AC to DC for transmission and then back for use on the platform (Chokhawala, 2008).

Since 1996, the Norwegian government has required operators to investigate the use of PFS when examining all new developments (Meld.St.28, 2010-2011). Although PFS solutions have the ability to decrease emissions from the NCS, it is not used very often because of the high investment costs, due to the required infrastructure for DC solutions and very new technology as well as power availability onshore. When considering a PFS solution, the main cost drivers are the distance from shore as well as the required load. The distance from shore contains two major components, whether it is AC or DC power, and the length of the cable. As mentioned briefly above, an AC system requires fewer components than DC, meaning a lower investment. Additionally, the subsea cables, regardless of the current type, are priced by the meter. Longer cables will not only cost more, but will also require longer installation times, adding to the capital expenditure. These concerns aside, there are some fields currently operating with a PFS solution, among which are Ormen Lange (A/S Norske Shell), Troll A (Statoil), and Valhall (BP). ABB, a Swedish power solutions manufacturer, asserts that the best case, economically, for implementing PFS is in completely new developments and large-scale renovations on major fields.

Despite its potential positive environmental impact, there are some large challenges with large-scale implementation of PFS on the NCS, namely, power availability. The amount of power platforms require is quite large, ranging from 15 to 200 MW and all of this power is supplied by the Norwegian grid, which is also responsible for the power demand on-shore (Chokhawala, 2008). Given increasing on-shore power demands, as well as, the possible implementation of PFS on the NCS, there is the potential for severe grid capacity issues, if no grid development occurs.

2.2 Norwegian Power Grid and Power Markets

2.2.1 Norwegian Power Grid

A power grid is a critical piece of infrastructure in modern society, responsible for the transport of electricity from producers to consumers. One of the main requirements of a power grid is instantaneous balance, which entails a math between total generation and total consumption of power at all times (Norwegian Ministry of Petroleum and Energy, 2013). In Norway, the electricity grid is divided into three different levels: main, regional and distribution/local. The different levels are divided based on both administrative and technical criterion. The main grid deals with the highest voltage power and constitutes the bulk of the transmission grid. Because of the high-voltage power, it is also responsible for international connectors. The regional grid transmits power throughout the country, serving as a connector between the main grid and the local/distribution grids, which primarily serves light industry and households with final distribution of low-voltage power.

Within Norway, Statnett is the main transmission system operator (TSO) of the Norwegian power system, as well as the national main grid owner, responsible, not for the production of electricity, but the distribution to end consumers and maintenance of the instantaneous balance (Statnett, 2013). Additionally, Statnett controls decisions regarding the utilization of the current grid and new infrastructure.

There are currently some major security of supply challenges in Norway, especially in Central and West Norway, where there are connections to offshore platforms. In Central Norway, the

Ormen Lange (both on- and off-shore) facilities require a large amount of power from the grid, which could jeopardize supply for commercial and residential power users. Additionally, in Western Norway, offshore projects, like Martin Linge, Troll A, and the subject of this thesis, the Utsira High, will put a large strain on the grid. Statnett, in its role as TSO and main grid owner, plans to increase grid capacity and strengthen transmission capabilities in order to meet these and other future grid challenges. According to the Statnett Grid Development Report, Statnett plans to spend roughly NOK 5-7 billion every year for the next ten years (2013).

2.2.2 Power Markets

The Norwegian grid is a part of the larger Nordic power market, comprised of Norway, Sweden, Denmark and Finland. Norway was the first Nordic power market to deregulate, serving as a catalyst for the rest of the Nordic countries, culminating in the formal establishment of Nord Pool Spot AS in 2002 (Nord Pool Spot, 2013). Figure 2-4 illustrates the expansion of Nord Pool Spot to the Baltic states of Estonia, Latvia and Lithuania, as well as further connection points to Russia, Poland, Germany and the Netherlands, encouraging further market integration with Europe. The major players in the power market are the power producers, power suppliers, brokers, energy companies and major consumers, who trade either on Nord Pool Spot, or bilaterally. In 2010, 74% of Nordic power generation was traded through Nord Pool Spot (Norwegian Ministry of Petroleum and Energy, 2013). As mentioned above, the TSO is responsible for maintaining instantaneous balance within its area, and the Nordic power market is an excellent tool for the countries to trade power based on their shifting power demand and supply. This market is especially important for Norway, where 98% of electricity comes from hydropower, making Norwegian power supply highly dependent on annual rainfall, snow and other inflows to the reservoirs. The power market

Figure 2-4: Nordic power market, Source: Nord Pool Spot (2013).

allows Norway to export power in especially "wet" years and import power in "dry" years, balancing out the previously extremely volatile electricity prices for Norwegian end-users.

Prices on Nord Pool Spot are calculated the day before for each hour of the coming day, with prices for each of the regions as well as the system price. The system price is representative of overall generation and consumption conditions at the given hour, as seen below in Figure 2-5. In Figure 2-5, part of the supply curve dips under the x-axis, indicating negative prices.

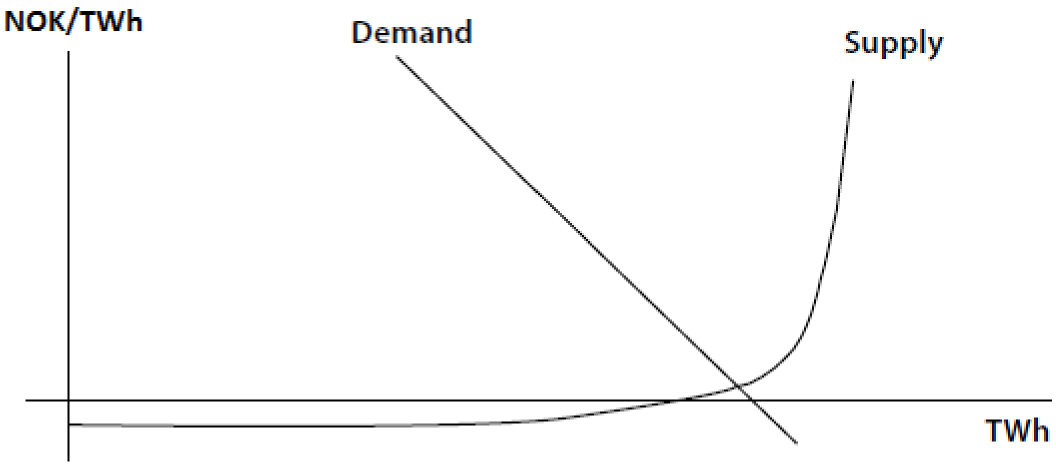

Figure 2-5: Nord Pool Spot system price formation. The system price arises at the market equilibrium, where the demand and supply curve intersect. Source: Nord Pool Spot (2013).

Negative prices are possible on the wholesale power market, due to high inflexible power generation and low power demand. If the power generation cannot be shut down and/or restarted in a cost-efficient manner, then producers could decide to sell their energy at a negative price. Additionally, the right-hand side of the supply curve is quite steep. This can be attributed to the marginal cost of different power generation methods. The increase occurs at high quantity (x-axis) because the cheapest power generation method will be used to its full capacity, in which case, then increasingly more expensive generation methods are used for surplus demand. Norwegian prices are mainly determined by the market conditions in the Nordic market, however there is some effect from market developments outside the Nordic region.

Very large power users, like oil and gas operators, tend to purchase their electricity from the wholesale market. One such operator, with much experience with PFS, is Norske Shell, who claimed that they operate an electricicty portfolio comprised of mainly spot positions and a few longer term contracts. In this case, however, none of the contracts lasted for longer than five years.

2.3 Current Carbon Taxes

For oil and gas operators on the NCS, there are two major taxes for the emissions originating at their platforms: first, the Norwegian carbon tax and second, the European Union Emission Trading System (hereafter, ETS).

2.3.1 Norwegian Carbon Tax

The Norwegian government levies a tax on each ton of CO_2 emitted on the NCS from offshore oil and gas installations. Up to 2013, the tax amounted to 210 NOK/ton CO_2 emitted, however in 2013, the government decided to almost double the tax, putting the rate at 410 NOK/ton (Norwegian Ministry of Petroleum and Energy, 2013). This new carbon tax gives Norway one of the strictest policies against carbon emissions in the world, especially when looking at taxation on industry.

2.3.2 European Union Emission Trading System

The EU ETS is the world's largest emissions trading system, spanning over 31 countries, the 28 EU member states, plus Iceland, Norway and Liechtenstein. The ETS follows a "cap and trade" principle (European Commission, 2014). The main intuition behind the system is that the carbon emitters will receive permits for their given amount of allowed emissions. The total number of permits is the maximum amount of emissions allowed. Thereafter, the emitters are allowed to trade the permits as needed. Gradually, the cap or maximum amount of permits will be reduced in order to reduce the total amount of CO_2 emissions. The system was rolled out in 2005 as the cornerstone in the EU's climate policy. The system covers all factories, power stations and other installations with a net heat excess of 20 MW (European Commission, 2014). Also included in this broad definition are aviation operators who fly within or between most of the member countries. In total, approximately 45% of all EU emissions are controlled by the EU ETS (European Commission, 2014).

Upon its launch, the EU ETS was split up into three different phases:

- 2005 – 2007: First Trading Period – This was the establishment of the system and the "learning period".
- 2008 – 2012. Second Trading Period – In this period, three extra countries joined the system (Iceland, Liechtenstein and Norway) and the number of allowances was reduced by 6.5%.
- 2013 – 2020: Third Trading Period – In this period, a major reform takes effect with an EU-wide cap on emissions to be reduced yearly.

Despite the planning, there have been many problems with the launch and operation of the system, which have limited the effectiveness of the system. First, the initial permits were allocated under the "grandfathering" system (European Commission, 2014). That means that permits would be allocated based on previous emissions. In this case, many participants increased their emissions in the years leading up to the ETS launch, in order to acquire as many permits as possible under the new system. Additionally, the financial crisis in Europe caused a decrease in demand as well as emissions, which led to an oversupply of carbon permits in the market. As of the start of Phase 3 in 2013, there was a surplus of approximately 2.1 billion carbon permits in the market (European Commission, 2014). These shortcomings have suppressed the carbon permit price, forcing the European Commission to take action in order to increase the effectiveness of the carbon permit market. The most notable action came in February 2014, where the European Commission voted to enact "backloading" measures (Garside, 2014). This law will enable the European Commission to freeze the auction sale of some carbon permits, up to 900 million until 2019-2020, thereby decreasing the supply in the market place and hopefully, placing upward pressure on the price. In addition, the maximum amount of carbon permits to be withdrawn from the market is increased from 300 million to 400 million permits. These actions seek to increase the price and suppress the supply of the permits until demand can pick up again.

2.4 Selected Case: Edvard Grieg Field

2.4.1 Area Description

After winning the production license PL338, Lundin petroleum discovered the Edvard Grieg field while drilling in block 16/1 in 2007. This area is situated off the west coast of Norway, 180 kilometers west of the city of Stavanger. The field sits on the Utsira High geological formation, at a depth of 109 meters. The Edvard Grieg reservoir is made up of alluvial, eolian and shallow marine conglomerates and sandstones from the Triassic to Lower Cretaceous ages and is located at a depth of approximately 1,900 meters (Lundin Petroleum, 2013). The estimated reserves at the field are 26.2 million Sm^3 of oil and 1.8 billion Sm^3 of natural gas, with an additional 0.6 million tons NGL (Oljedirektoratet, 2013). The geological make-up of the reservoir has excellent properties for extraction and Lundin predicts a recovery rate of more than 50% (2013).

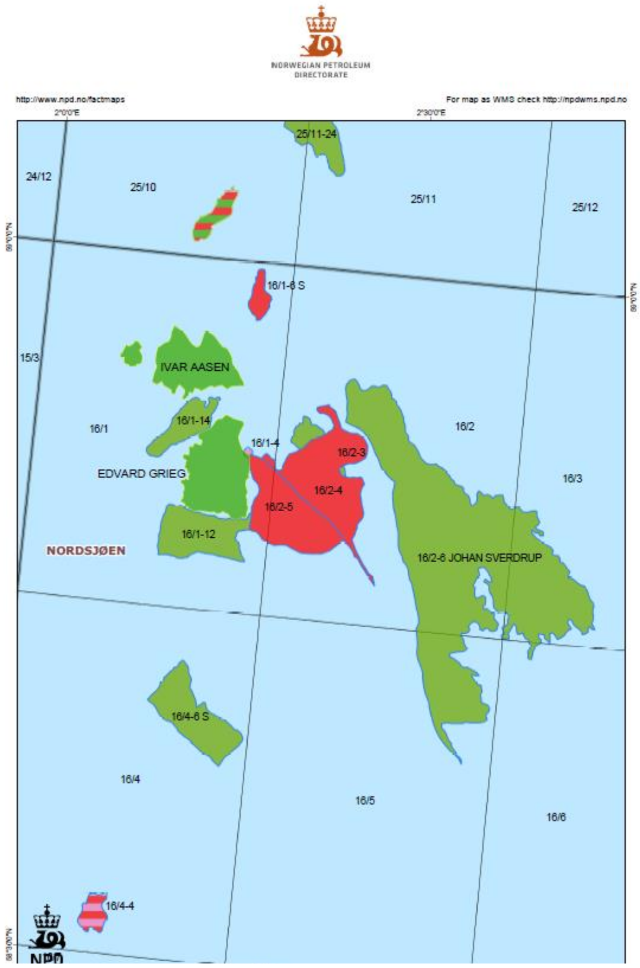

Figure 2-6: License Map of the Edvard Grieg, Ivar Åsen, Johan Sverdrup and Gina Krog fields. The green shading indicates an oil field, red gas fields, and red and green mixed oil and gas fields. Source: Oljedirektoratet (2013).

The discovery of the Edvard Grieg field spurred the further exploration of the area, leading to the finds of other fields, among which are Apollo, Luno South, Luno II and the exceptionally large Johan Sverdrup field, the fifth largest find on the Norwegian Continental Shelf to date (Lundin Petroleum , 2013). Other fields in the area are Ivar Åsen, which will be connected to the Edvard Grieg field and Gina Krog. Edvard Grieg, Ivar Åsen, Johan Sverdrup, and Gina

Krog (labelled on the map as 16/4-6) and their general proximity to each other can be seen above in Figure 2-6. In Figure 2-6, the Edvard Grieg field is labelled to the left of the Johan Sverdrup Field. The map does not mark that Johan Sverdrup is comprised, of not only block 16/2-6, but also 16/2-3, 16/2-4 and 16/2-5. In addition to Edvard Grieg, Lundin has operator rights on Johan Sverdrup as well, with other operators/license holders in the area being OMV Norge (Edvard Grieg), Wintershall Norge AS (Edvard Grieg), Det Norske Oljeselskapet (Ivar Åsen), and Statoil (Johan Sverdrup/Gina Krog) (Oljedirektoratet, 2013).

2.4.2 Field Development

Lundin submitted its plan for development and operation (hereafter, PDO) to the parliament in the first quarter of 2012. Since 1996, the parliament has required that every new field development consider a power from shore solution in their PDO, in order to encourage PFS and reduce future carbon emissions on the NCS (Oljedirektoratet, 2013). Since Edvard Grieg and Ivar Åsen were found in the same time span, a joint PFS solution was investigated but ultimately, found to be uneconomic. However, with the discovery of the large Johan Sverdrup field in 2010, a PFS solution for the entire area could be realized. An investigation into PFS solutions for the entire Utsira High southern region (Edvard Grieg, Ivar Åsen, Johan Sverdrup and Gina Krog) is underway by Statoil, but since both Edvard Grieg and Ivar Åsen are planned to come on-stream in late 2015-2016, the two fields need a power generation solution for the pre-Johan Sverdrup years. Edvard Grieg is planned to be the "field center", taking care of the bulk of processing and export of the extracted hydrocarbons from both fields. Additionally, the Ivar Åsen field will be electrified from the start, receiving power via a subsea AC cable from Edvard Grieg (Det norske oljeselskapet, 2013). The subsea cable and oil lines between the two facilities can be seen below in Figure 2-7.

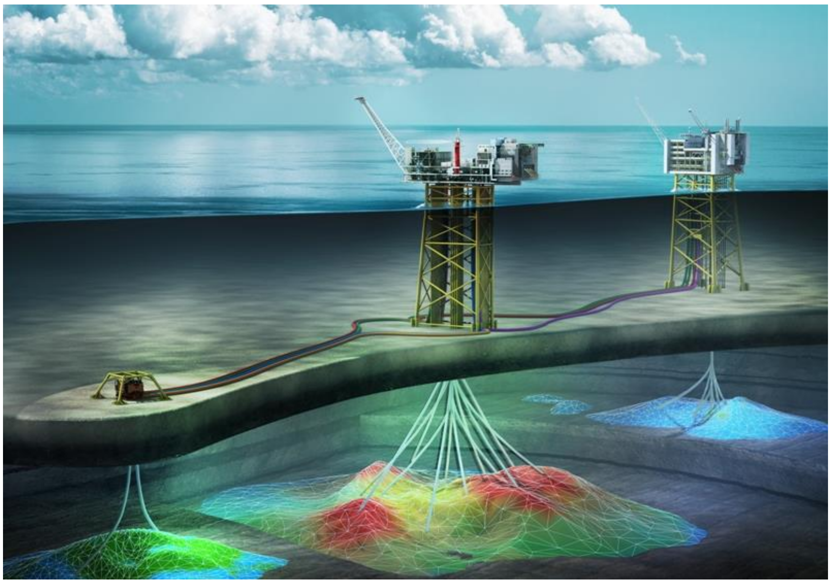

Figure 2-7: Planned development of the Ivar Åsen (left) and Edvard Grieg (right) fields. Source: Det norske Oljeselskapet (2013).

In order to power both Ivar Åsen and its own platform before Johan Sverdrup, Edvard Grieg will be powered initially by two 30MW GE LM2500+ gas turbines to power both platforms (add energy, 2012). However, the PDO detailing this solution was accepted by the parliament, contingent on the capability of connecting to a communal electrified power source once it becomes available (Prop.88 S, 2011-2012). Lundin has managed this by installing a hook-up point on the platform for a future AC power cable.

2.4.3 Current Controversy over Utsira High Electrification

As discussed above, given the discovery of Johan Sverdrup, the parliament approved the PDO (with gas turbines) for Edvard Grieg, contingent on the eventual switch to power from shore once Johan Sverdrup came on-stream. This entire arrangement, in turn, is dependent on Johan Sverdrup receiving enough power to cover the needs of all the platforms or on a separate power hub platform to power all the platforms in the area[2]. However, on February 13, 2014, Statoil, in charge of the design and development plans for Johan Sverdrup, revealed the phase one concept selection for the Johan Sverdrup development, including a PFS solution, but only for

[2] The power hub platform is a current project undertaken by Statoil called the Utsira High Power Hub Project, which consists of an on-shore substation convertor at Kårstø, with a DC subsea cable to an offshore hub platform convertor. The newly AC electricity would then be transported to the surrounding platforms (Johan Sverdrup, Edvard Grieg, and Gina Krog) via AC subsea cables.

Johan Sverdrup. Now there is a large debate both between the government and the parliament and between the state and the operators over whether (or not) the entire Utsira High area will be electrified, as previously believed.

Statoil, along with the operators and license-holders in the area, claims that the estimated capital expenditures for a full-area electrification solution have increased from approximately NOK 9 billion in December 2012 to over NOK 16 billion in December 2013 (Taraldsen, Her er Tord Leins forklaring på at Utsira-prisen gikk fra 9 til 16 mrd. på ett år, 2014). The NOK 7 billion increase comes from a variety of different factors both in the project and external that have changed over the last year. Internally, there have been varying estimates of the power requirement for the entire solution, from 250 MW initially, to 300 MW in summer 2013 and then 190 MW, more recently. Externally, the operators have made claims that major projects in the offshore wind industry in Europe is dominating the supplier industry, creating bottlenecks, as well as increasing prices and lead times. However, this argument has received strong criticism from NORWEA, the interest group for wind power in Norway, stating that it is unlikely that wind projects require so much installation capacity that it would affect the Utsira High project (Taraldsen, "Vennligst ikke forsøk å skylde på oss. Vennlig hilsen vinnkraften", 2014). It is also worth mentioning that most of the reports made by both the OED and media outlets are based primarily on data from Statoil.

Arguments and criticism aside, electrification of the Utsira High is primarily a political issue that the parliament strongly supports. Considering that operators must submit and receive approval on a PDO detailing development and operation plans to Storting, it is most likely the case that the Utsira High will receive a full electrification solution, based on requirement from the parliament, which serves as a main assumption for this thesis.

3. Methodology

3.1 Problem Formulation

The optimal investment condition problem centers on a switch option for the Edvard Grieg field, either to maintain its current power generation solution (gas-powered turbines) or to switch to a PFS solution from Johan Sverdrup. The real options technique chosen to investigate this problem is discrete-time stochastic dynamic programming. The structure of the analysis is as follows:

- determination of the appropriate stochastic price process,
- estimation of parameters based on historical data,
- definition of the profit function of the two power generation solutions,
- dynamic optimization of the solutions' expected net present values, through the real option approach, to identify the optimal conditions for investment.

In this thesis, "optimal conditions" will be characterized by threshold wholesale electricity prices, which will serve as the thresholds to indicate the optimal action of when to switch power generation solutions or not. Additionally, the results through real option analysis will be modified to explore the effect of the total carbon price on the threshold electricity prices and to find the critical carbon price, the price at which the gas turbine power generation solution is not viable.

3.2 Real Option Overview

Real option valuation is based on the logic of financial options, that a manager has the right but not the obligation to make certain investment. Before moving to real options, first the logic of financial options must be reviewed. According to Hull (2009), a financial option is a contract that gives the holder the right, but not the obligation, to buy or sell the underlying asset at a pre-determined price. The option itself has four important characteristics. First, there is the type of option, either a call or a put. A call option is the option to buy the underlying asset and a put option is to sell the underlying asset. Second, there is the time horizon or maturity, meaning the length of the time the option lasts before it expires. Third, is the exercise style. There is a wide variety of different exercise styles available, but the most common are

European and American options. A European option can be exercised only at maturity, while an American option can be exercised at any time leading up to and at maturity. Lastly, is the pre-determined price of the underlying asset, referred to as the strike price. As mentioned previously, the option holder is not obligated to exercise the option, so if current prices at the time of exercise are more favorable than the strike price, the holder can let the option expire and buy the underlying asset on the market. In letting the option expire, the option holder foregoes only the premium or the price of the option.

The main intuition of real option valuation is applying the structure of financial options to real investment decisions. In the case of real options, instead of the option holder deciding whether to buy or sell an underlying asset, it is the manager deciding whether to perform an action (Luenberger, 1998). The use of real options allows managers to take uncertainty in future project profitability into account, more so than with the traditional NPV method. Before discussing real option valuation, it is useful to see the different types of real options potentially available to managers. The six main types, as defined by Trigeorgis (1993), are explained below in Table 3-1.

Table 3-1: Real Options Types, Source: Trigeorgis (1993).

Category	Description	Application
Defer	The ability to wait to make an investment over a defined time horizon.	Natural resource extraction industries, real estate development, farming, etc.
Default	A generic project with a series of outlays, which consists of a construction stage and an operating stage. Each stage could be considered as an option on the value of the subsequent stages	All R&D intensive industries, particularly in pharmaceuticals, and long-term development projects, like infrastructure development.
Scaling	Depending on market conditions, the managers could expand production to take advantage of large demand or contract production. Additionally, the	Natural resources, such as mines, facilities and construction in cyclical industries, fashion industry, consumer good industry

	manager could temporarily shut-down and then re-start production	
Abandon	If the market conditions decline severely, the manager could abandon the project and salvage what is left of the investment through resale	Capital-intensive industries, new product launch in uncertain markets.
Switch (outputs or inputs)	Dependent on market conditions, the manager can change production outputs, or change production inputs for better profitability	Output shift: consumer goods, machine parts, etc. Input shifts: energy/power source, procurement
Corporate Growth	If the cash flow of an early project is lower than expected, corporate growth options open up a company's future growth opportunities, namely with a new product, oil reserves, access to a new market, etc.	Infrastructure-based industries, like high-tech, R&D, multinational options, etc.

For the purpose of this thesis, the option to switch an input is the focus. Slightly different from the explanation above, this option to switch provides the manager with the opportunity to investigate the economic viability of switching from one input to another, while still expecting positive future profits. In this particular application, the manager is considering electrical power from shore for power in comparison to the currently used gas-powered turbines.

At the heart of any real option valuation is the uncertainty that will be modeled, for example the electricity, as in this thesis. Although future electricity prices are not known, if the current price, the price volatility and other cost factors are known, the price can be modeled using a probability tree, as seen below in Figure 3-1 (Copeland & Antikarov, 2005). Figure 3-1 illustrates a binomial tree, which means that at each node, the price can either move upwards or downwards, with both probabilities equal to one. Typically, the factor of an upward movement is denoted by u, while the factor of a downward movement is denoted by d. Using the probabilities of an upwards or downwards movement, plus the *u* and *d* factors, the binomial tree can be easily calculated. This tree will then be used in finding the present value of the project at each node, represented below by the black dots at each intersection, just like with options.

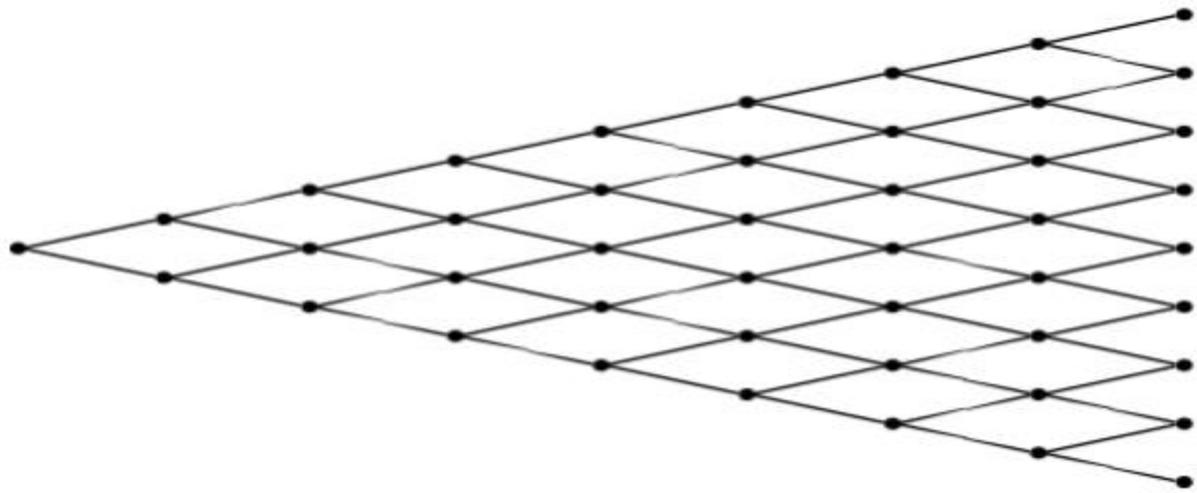

Figure 3-1: Example of probability tree construction. (Own illustration)

Then the present value at each of the nodes can be used to find the project's NPV at each of the nodes, which can be compared to the traditional NPV. Dependent on the node's NPV, the manager can decide either to invest, if the node NPV is greater than the initial NPV, or defer investment, if the node NPV is less than the initial NPV. The tree approach also allows the manager to find the "threshold" price, or the price at which the manager is indifferent between investing and deferring (Copeland & Antikarov, 2005).

The probability tree method is the most basic method for incorporating uncertainty into investment decisions. More sophisticated methods for modeling the chosen uncertain element include using a stochastic process, such as a Geometric Brownian Motion (hereafter, GBM) or a mean-reverting Ornstein-Uhlenbeck process. This thesis implements a stochastic process for the uncertain future electricity prices.

3.3 Data Analysis

As mentioned in the previous section, this thesis employs a stochastic process to model the uncertain electricity price. The first step is to analyze the historical wholesale electricity prices to determine the appropriate process, either GBM or Ornstein-Uhlenbeck.[3]

3.3.1 Geometric Brownian Motion

A GBM can also be described as a random walk with drift and its general form is expressed below in Equation (1):

$$dx = \alpha \, x \, dt + \sigma \, x \, dz \tag{1}$$

In this case, the change in the examined variable can be characterized by a constant drift term, α, a constant variance term, σ, and a Wiener increment process, *dz*. Dixit and Pindyck (1994) put forth three characteristics of GBMs and any Wiener processes that are important to their understanding:

- First, these processes are also *Markov processes*, which means that the probability distribution for all future values of the process depends only on the current value
- Second, the process has *independent increments*, meaning the probability distribution for the change in the process over any time interval is independent of any other time interval, so long as they do not overlap.
- Last, changes in the process over any finite time interval are *normally distributed*, with a variance that linearly increases over the time interval.

Following the third characteristic, the percent changes in x, $\Delta x/x$, are normally distributed. Because the percent changes are changes in the natural log of x, absolute changes in x, Δx, are log normally distributed (Dixit & Pindyck, 1994). By examining the relationship between x and its logarithm, the mean and the variance can be found. Using the GBM general form in Equation (1) above, $F(x) = log(x)$ can be expressed as a Brownian motion with drift:

[3] There are many other stochastic processes used in commodity price modelling, however, given the scope and intention of this thesis, only the GBM and Ornstein-Uhlenbeck processes are considered. The GBM and Ornstein-Uhlenbeck process are considered since they are the most commonly used processes in relevant literature.

$$dF = \left(\alpha - \frac{1}{2}\sigma^2\right)dt + \sigma dz \tag{2}$$

with mean of $\left(\alpha - \frac{1}{2}\sigma^2\right)t$ and variance of $\sigma^2 t$.

3.3.2 Mean-Reverting Ornstein-Uhlenbeck Process

An alternative process to the GBM is the Ornstein-Uhlenbeck process, a simplified mean reverting process. A main property of the OU process is a steady mean that the data oscillates around. In continuous time, the geometric Ornstein-Uhlenbeck process takes the following general form:

$$dP = \eta P(\bar{P} - P)dt + \sigma P dz \tag{3}$$

As with the GBM, this thesis uses the discretized form of this process, which translates to:

$$\frac{P_t - P_{t-1}}{P_{t-1}} = \eta(\bar{P} - P_t)\Delta t + \sigma\varepsilon_t\sqrt{\Delta t} \tag{4}$$

Although no formal test is used to determine the appropriateness of the mean-reverting model, many economists, including Insley (2002) and Metcalf & Hassett (1995), maintain that a mean-reverting process is more appropriate for minerals and other raw commodities, citing that the prices tend to return to a mean in the long-term. Dixit and Pindyck (1994) claim that mean reversion is a product of the tendency of long-term prices to move closely around the marginal cost of production. Additionally, some GBM properties, like increasing without bound, do not fit well with modelling commodities prices, due to the external effects of supply and demand. If prices were to increase without bound, then firms would most likely increase investment to expand, however, in equilibrium, the supply shift would lead to a fall in price, due to downward sloping demand curves (Metcalf & Hassett, 1995).

Based on the works of Insley (2002), Detert & Kotani (2013), and Metcalf & Hassett (1995), among others, as well as the economic intuition, the thesis implements a mean-reverting Ornstein Uhlenbeck process, as described above, as the stochastic process for wholesale electricity prices.

3.4 Parameter Estimation

After determination of the appropriate price process, the parameters, primarily the mean reversion rate and the volatility, must be estimated. Using Equation (4) from the previous section, a regression equation is formed to estimate these parameters.

$$\frac{P_t - P_{t-1}}{P_{t-1}} = c(1) + c(2)P_{t-1} + e_t \tag{5}$$

where $c(1) = \eta\bar{P}\Delta t$, $c(2) = -\eta\Delta t$, and $e_t = \sigma\varepsilon_t\sqrt{\Delta t}$. Here, η is the mean reversion rate, and σ is the volatility. Equation (5) is then used in a regression with historical monthly crude electricity prices. The resulting c(1) and c(2) estimates are then used to calculate the long-run mean, $\bar{P}$, the mean reversion rate, η, and the volatility, σ using the following formulas (Detert & Kotani, 2013):

$$\eta = \frac{-c(2)}{\Delta t} \tag{6}$$

$$\bar{P} = \frac{-c(1)}{c(2)} \tag{7}$$

$$\sigma = \frac{std(e_t)}{\sqrt{\Delta t}} \tag{8}$$

Once the parameters are calculated, the estimated Ornstein-Uhlenbeck process can be used to model potential future price diffusions, given an initial price point. The price diffusions are then used in the next step of determining the functional form of the profit function and the NPV calculations for the two alternative power generation solutions.

3.5 NPV Calculation

3.5.1 Profit Function

Before the NPVs of the two alternatives, gas turbines and PFS, can be calculated, first, each of the profit functions for the respective solutions must be defined. The two profit functions are quite similar, sharing the same revenue stream. The main difference lies in the cost of power generation under the expenditure stream. While the gas-powered turbine solution's costs include emission fees for the carbon emitted, the PFS solution's costs include the cost of electricity transported to the platform. Below, Equations (9) and (10)**Feil! Fant ikke referansekilden.** present the profit functions, before tax, for the gas-powered turbine solution and the PFS solution, respectively. Only the revenue section of the profit function is time dependent. The variables associated with the operating expenditures remain constant or time-independent for the purposes of simplifying the necessary modelling. The individual variables are then further elaborated on.

$$\pi_{G,t} = P_o * Q_t - (OPEX + E * B) \tag{9}$$

$$\pi_{P,t} = P_o * Q_t - \left(OPEX + P_{EL,t} * M\right) \tag{10}$$

Where:

- P_o: average annual oil price, with three possible regions: low, medium and high
- Q_t: annual quantity of oil extracted at time t
- $OPEX$: sum of approximate operating expenditures, excluding power generation costs
- E: annual carbon fees
- B: annual carbon emissions
- $P_{EL,t}$: estimated wholesale electricity price for the operators, realized by the mean-reverting stochastic process
- M: annual amount of electricity required by the platform

Production Profile

The annual quantity of oil is found by finding the production profile for the Edvard Grieg field. The production profile is the approximate distribution of annual extraction over the field's estimated lifetime. Since the Edvard Grieg field is not yet in production, a similar field already in production is chosen to estimate the production profile in this case. The strategy chosen to estimate the production profile is the Hubbert Curve. Under the Hubbert Curve, annual production follows approximately a bell-shaped function of time and is a function of cumulative production. Specifically, the relationship is as such:

$$q_t = rQ_t\left(1 - \frac{Q_t}{K}\right) \tag{11}$$

Since annual production can also be seen as the change in cumulative production over time, Equation (11) can be re-written like so:

$$q_t = \frac{dQ_t}{dt} = rQ_t\left(1 - \frac{Q_t}{K}\right) \qquad (12)$$

This relationship leads to:

$$\frac{Q_t}{K - Q_t} = e^{rt+c_0} \qquad (13)$$

$$Q_t = \frac{Ke^{c_0}}{e^{c_0} + e^{-rt}} \qquad (14)$$

$$\lim_{t\to\infty} Q_t = \frac{Ke^{c_0}}{e^{c_0}} = K \qquad (15)$$

Equations (13), (14) and (15) illustrate how the Hubbert Curve connects the three different factors, q_t, annual production, Q_t, cumulative production, and K, initial economic reserves and sets up the foundation for production profile estimation.

In order to estimate parameters, observations for annual production, q_t, are needed. From the observations of q_t, the corresponding Q_t, cumulative production values can be computed. By transforming Equation (11), the quadratic regression equation with no intercept is as follows:

$$q_t = rQ_t - \frac{r}{K}Q_t^2 \qquad (16)$$

From the regression, both r and K can be found. The coefficient on the Q_t term is the value for r, while K can be found by setting the Q_t^2 coefficient equal to $-\frac{r}{K}$ and solving for K. After determining r and K, a base year for the estimation is chosen to be set to year zero, giving the value of the constant e^{c_0} term, $e^{c_0} = \frac{Q_{base\ year}}{K - Q_{base\ year}}$ as seen from Equation (13)**Feil! Fant ikke referansekilden.**. Equation (17) uses the estimated r, K, and, e^{c_0}, to both forecast and "hindcast" values of Q_t.

$$Q_t = \frac{Ke^{c_0}}{e^{c_0} + e^{-r(t-base\ year)}} \qquad (17)$$

Additionally, the corresponding values of q_t can be calculated using Equation (11). This allows for an estimated production profile for an un-developed field, by using the production data from a similar field already in production.

Carbon Emissions

As stated previously, under the gas turbine solution, the main power generation cost is comprised of taxes paid on carbon emissions from the gas-turbine generators. The carbon emissions are relatively straightforward to calculate, requiring the heat rate for the generators, a carbon factor, and the power load. Since most of these values are given in differing units, they need to be converted, requiring only a few calculations. The heat rate is converted from Btu/KWh to sm^3/GWh, the CO_2 factor stays as is, and the power load is converted into energy, from MW to GWh. The annual carbon emissions amount typically expressed as a function of annual production, because the level of production would dictate the level of energy-intensiveness required for extraction, hence dictating the amount of emissions. However, in this case, the average annual energy demand is used in the analysis so that energy requirement is kept as a constant and the emissions are calculated from there.

Power Requirement

The annual energy requirement for the Edvard Grieg platform is the average energy needed for the platform's operations each year. In the PFS solution, the load required is necessary to the profit calculations because the electricity must be purchased from the on-land grid, before being sent via the subsea cable to the platform. Again, a relatively simple conversion is required, from the energy load in MW to the power requirement in GWh. This is calculated by multiplying the load by the number of hours in a year in order to find the power.

Operating Expenditures

The operating expenditures (hereafter, OPEX) include all the annual costs associated with the operation and maintenance of the Edvard Grieg platform. Normally, this would include the power generation costs, but, as mentioned above, in this case, the power generation costs are considered separately, since they are different in the two profit functions.

Taxes

Table 3-2: Breakdown of the tax base calculation in Norway. Source: Ministry of Petroleum and Energy (2012).

+	Operating Income
-	Operating costs (including search costs)
-	Depreciation (linear over 6 years from investment for production installations and pipelines
-	Exploration expenses, R&D, incurred plugging & abandonment (P&A) and removal
-	Allocated financial costs
=	General Income Tax Base (28%)
-	Uplift (7.5% of investment for 4 years)
=	Special Tax Base (50%)

Because Edvard Grieg is a field on the NCS, Norwegian law and its petroleum tax system govern its operators and their actions. All of the profits made by both Lundin and Statoil are subject to the Norwegian Petroleum Taxation System. The taxation system is comprised of two parts, the general corporate tax and the special petroleum tax. Table 3-2 illustrates the general calculation method for the general income tax base, as well as the special tax base.

3.5.2 NPV

Using the profit functions, as defined above, the NPV for the two different solutions can be found using the known electricity price. NPV_G and NPV_P represent the NPV for the gas turbine and PFS solution, respectively. The NPV formula makes use of the profit function after it is subjected to the Norwegian tax system. In order to simplify the formula in the paper, the character ξ represents the effect of taxes on the profit function, including tax deductions. The adjusted NPV formulas for both solutions are as follows:

$$NPV_G = \sum_{t=0}^{T} PV_{G,t} = \sum_{t=0}^{T} \rho^t \xi \pi_{G,t} \qquad (18)$$

$$\begin{aligned} NPV_P &= \sum_{t=0}^{7} PV_{G,t} + \sum_{t=8}^{T} PV_{P,t} - \rho^8 I \\ &= \sum_{t=0}^{7} \rho^t \xi \pi_{G,t} + \sum_{t=8}^{T} \rho^t \xi \pi_{P,t} \\ &\quad - \rho^8 I \end{aligned} \qquad (19)$$

In Equation (18), NPV_G is equal to the summation of the present values of the gas turbine solution in each timer period up until the terminal time period T. In both NPV calculations, ρ is the discount factor, which is equal to $\frac{1}{(1+r)}$, with r being the discount rate. In Equation (19), the NPV for the PFS solution, there is both the gas-turbine profit function and the PFS profit function, because the option to switch to the PFS solution occurs only after the seventh year, 2023, when the Johan Sverdrup installation has the capacity to supply power. Additionally, there is the one-time investment cost from installing the cable from Johan Sverdrup to Edvard Grieg.

3.6 Monte Carlo Simulation

Because a mean-reverting stochastic process governs the electricity price in the NPV calculations, the expected values for the NPV must be estimated through Monte Carlo simulations. This creates the transition matrix necessary for the final dynamic programming portion of the analysis. The first step in the process is the generation of a vector of possible electricity price realizations using the mean-reverting stochastic process from t = 0 to t = T. Specifically, Equation (3), using the discretized specification from Equation (4), is used as the underlying price generating process. Next, using the price realization vector and an initial price condition,$P_{o,0}$, the present values are summed according to $NPV_G = \sum_{t=0}^{T} PV_{G,t}$ and $NPV_P = \sum_{t=0}^{7} PV_{G,t} + \sum_{t=8}^{T} PV_{P,t} - \rho^8 I$. This process is repeated a sufficiently large number of times, J, to approximate the expected NPV estimation at each initial price node i by taking the average of $E(NPV_{G,t}|P_{o,0}) \approx \frac{1}{J}\sum_{j=1}^{J} NPV_{G,t}$ and $E(NPV_{P,t}|P_{o,0}) \approx \frac{1}{J}\sum_{j=1}^{J} NPV_{P,t}$. This process is repeated to find the NV at each of the terminal period price nodes. The terminal period price nodes range from $P_{EL,0} = 0$ to $P_{EL,0} = 1000$, with steps of 10. This serves as the foundation for the dynamic optimization to take place in the dynamic programming section of the model.

3.7 Dynamic Programming

The dynamic programming approach is inspired by Detert & Kotani (2013), who consider a similar real options problem when analyzing renewable energy investments in Mongolia. In this case, there is an option to switch from a coal-based energy infrastructure or to switch to a renewable energy-based infrastructure. The dynamic programming process is similar to valuation technique for American call options, using backward recursion from the terminal nodes to the initial node. The main intuition behind dynamic programming is to split the decision sequence into two parts: the immediate period and the whole continuation beyond that (Dixit & Pindyck, 1994). Three major characteristics of dynamic programming are the state and control variables, x_t and u_t, and the outcome or expected NPV, $V_t(x_t)$. The state variable describes the current state of the cash flows in time t. Although the current state variable is known, all future values are random numbers, in this case, following the chosen mean-reverting stochastic process. The control variable represents the choice available to the firm, in this case, the choice to switch power generation solutions. Due to the two options available to the firm, the control variable takes on a binary nature, $u_t = \{0,1\}$. The outcome represents the expected NPV, resulting from the chosen policies. The objective in dynamic programming is to choose the sequence of controls over time to maximize the expected NPV of the profits (Dixit & Pindyck, 1994).

In this thesis, the state variable is the wholesale electricity price, which will dictate the optimal value and policy function from the analysis. Although dynamic programming problems are typically characterized as profit-maximization problems, this particular problem could be seen as a cost minimization problem. Namely, what is the optimal value and policy for minimizing the project's operating costs, given the two alternative power generation options.

3.7.1 Bellman Optimality

The main principle behind the dynamic programming technique is the solution of Bellman's Principle of Optimality, which states:

> "*An optimal policy has the property that, whatever the initial action, the remaining choices constitute an optimal policy with respect to the sub problem starting at the state that results from the initial actions* (Dixit & Pindyck, 1994)*."*

Turning back to the previous section, the foundation of dynamic programming is to split the decision sequence into two parts, the immediate period and the whole continuation beyond that. Focusing now on the immediate period, when the manager chooses control variable u_t, they receive $\pi_t(x_t,u_t)$ immediately. Next, the continuation value must be found. In the next period, t+1, the state will be x_{t+1}, yielding the outcome of $V_{t+1}(x_{t+1})$. As mentioned previously, the current state is known, but the future values are random, requiring the expectation of the outcome, $E_t[V_{t+1}(x_{t+1})]$. This expectation is the continuation value. The resulting value, summing the immediate payoff and the discounted continuation value, yields:

$$\pi_t(x_t, u_t) + \rho E_t[V_{t+1}(x_{t+1})] \tag{20}$$

Equation (20) represents the value that the manager will want to maximize. Since the control variable, u_t, is the manager's choice, he will maximize this expression with respect to u_t, yielding the Bellman equation:

$$V_t(x_t) = \max_{u_t}\{\pi_t(x_t, u_t) + \rho E_t[V_{t+1}(x_{t+1})]\} \tag{21}$$

Returning to the Problem Formulation, this thesis models the problem as an American call option, and this problem implements the Bellman equation to work backwards from the terminal period, T, to find the initial value. In this case, the Bellman equation is formulated as such:

$$V_{T-1}(x_{T-1}) = \max_{u_t}\{\pi(x_{T-1}, u_{T-1}) + \rho E_{T-1}[\Omega_T(x_t)]\} \tag{22}$$

In Equation (22), $\Omega_T(x_t)$ is the termination payoff, or the amount that the firm will get at the end of the period. Using the simulated expected NPVs from the Monte Carlo simulations, the value of the previous period can be calculated and continued from T-1, to T-2, etc. all the way back to the initial period, t = 0.

In this application, the Bellman equation, Equation (22), must be modified to represent the optimal stopping or switching problem this thesis presents. The resulting equation is:

$$V(x) = max\{\Omega(x), \pi(x) + \rho E[V(x'|x)]\} \tag{23}$$

Equation (23) represents the choice between taking the termination payoff from the initial state versus continuing. In our case, the choice is between continuing with the initial power generation system or switching to the PFS system, which would represent the left and right terms of the right-hand side of Equation (23), respectively. The optimal conditions for switching will be evaluated for this problem by evaluating Equation (23), the Bellman equation, at every period. While there are different strategies for solving the Bellman equation, this thesis implements value function iteration as the basis for its analysis.

3.7.2 Value Function Iteration

The parts necessary for solving the dynamic optimization problem are the value function, the vector of possible states, and a transition matrix determining the probability of switching states. The value function is taken from Equation (23), the modified Bellman Equation. The vector of possible states, in this case, is the vector of NPVs, calculated from the simulated electricity price realizations. The transition matrix is constructed in a relatively simplifier manner, using Monte Carlo Sampling and Sample Average Approximation Method, assigning an equal probability to each state, equal to $l = 1/J$, with J being the number of simulation iterations. More advanced probability estimation methods are outside the scope of this thesis.

The value function iteration, as described by Judd (1998) works as follows. First, a grid of possible values of the state, the electricity price, $p_{o,t}$, is created, with N elements. Next, an initial guess for the value function, $V^0(p_{o,t})$, is made, a N x 1 vector, representing each possible state. $V^1(p_{o,t})$ can be computing, substituting V^0 into the value function. After finding $V^1(p_{o,t})$, it is compared with $V^0(p_{o,t})$. If the two values are not sufficiently close enough, the iteration process is repeated, substituting $V^1(p_{o,t})$ into the value function for $V^2(p_{o,t})$. On the n^{th} iteration, both $V^n(p_{o,t})$ and $V^{n-1}(p_{o,t})$ will be known. For a large enough n, the values should be sufficiently close. This results in a value function over the electricity prices, which allows one to investigate the trigger prices for switching power generation solutions.

4. Model

4.1 Data Collection

The required data for this analysis is a historical time series of wholesale electricity prices, properties for production profile estimation, estimated initial capital expenditures for the project, estimates for annual operating expenditures for both solutions, total annual carbon emission fee for gas turbine solution (both the Norwegian government and the EU ETS), estimated annual emissions for gas turbine solution, the expected electricity price for the PFS solution, the expected power requirement for the PFS solution, the switch cost, and the discount rate. The wholesale electricity prices are monthly electricity prices in Euro from January 1, 2000 to April 1, 2014, obtained from NordPool Spot. Since the dataset is originally in Euro per megawatt-hour, it is converted into Norwegian kroner using average monthly exchange rates from the Norwegian Central Bank, starting in January 2000. Figure 4-1 below shows the historical price path of the electricity prices in NOK over the 13-year sample.

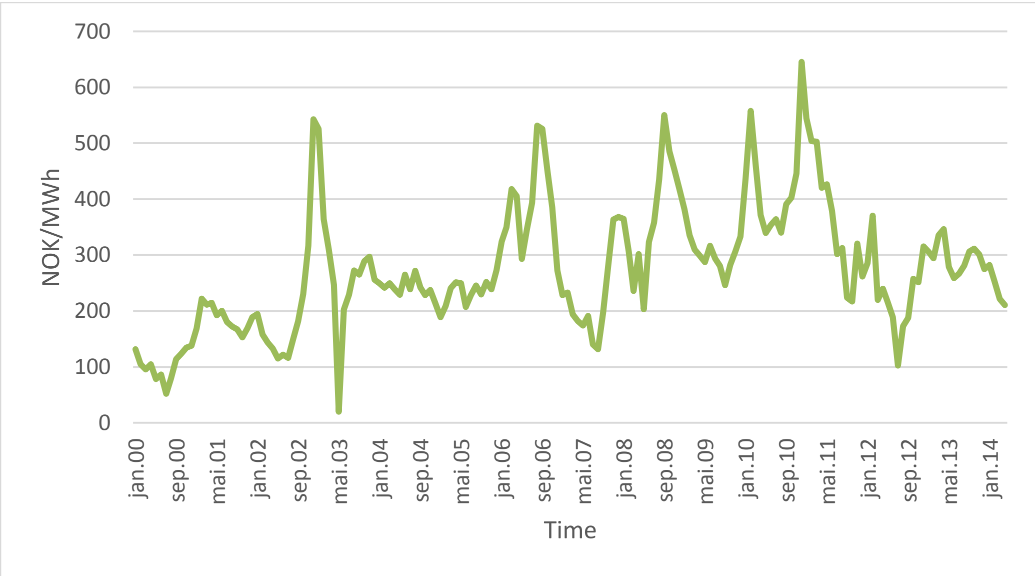

Figure 4-1: Monthly Wholesale Electricity Prices, converted to NOK, using average monthly exchange rates. Source: Nord Pool Spot (2013).

Before moving on to the other data required, it is important to state the uncertain nature of these values. Most cost and operation information surrounding projects under development is highly uncertain and what the operators/developers know is proprietary information, to which this thesis did not have access. That being said, there are a few reports published through NPD and the MPE and other consultancies, namely, the Report on Electrification of the Middle North Sea from 2012, which give an insight into what baseline values should be considered.

The production profile of a yet to be developed field is unknown, however, an approximate production profile is estimated for Edvard Grieg using the Hubbert Curve on a similar field in the North Sea, Oseberg Øst. Oseberg Øst has been in production since 1999 and had similar original reserves of barrels of oil equivalent to those estimated for Edvard Grieg. Edvard Grieg is estimated to have 185.8 million barrels oil equivalent, while Oseberg Øst started originally with 167.7 million (Norwegian Ministry of Petroleum and Energy, 2013). The discrepancy between the exact amounts could lead to an underestimation of the production rate. The annual production information for Oseberg Øst from 1999 to 2014 (using 1999 as the base year) is used to estimate the approximate values of r and K needed to estimate Q_t. Because the approximate initial recoverable reserves are known for Edvard Grieg, this value is substituted for the estimated K, in the attempt to mitigate some of the under-estimation. With these parameters, Edvard Grieg's production profile can be estimated over its expected 30-year lifetime, shown below in Figure 4-2. The full production profile estimated can be found in Appendix 2**.**

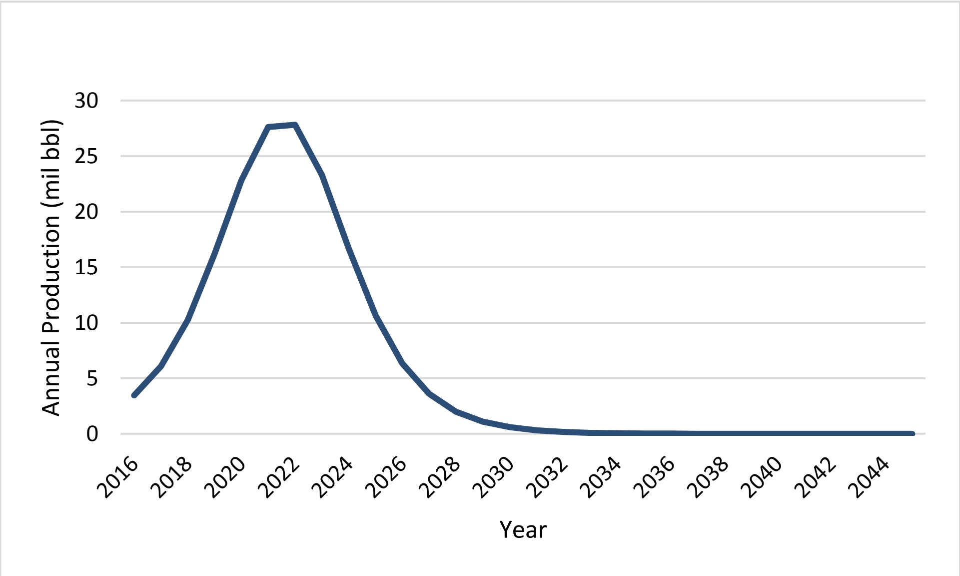

Figure 4-2: Edvard Grieg Production Profile, estimated from Oseberg Øst production data. Source: own calculations, data: Oljedirektoratet (2013).

The estimated capital expenditures are taken from the Edvard Grieg operator, Lundin, who reported an estimated CAPEX or 24 billion NOK. The annual operating costs of each solution are estimated based on the opinions of industry experts and published reports.

The data specific to the gas turbine solution are the annual carbon emission fees and annual carbon emissions. The annual carbon emission fee is the combination of what must be paid to the Norwegian government as well as the EU ETS. These fee amounts are sourced from the Norwegian Petroleum Directorate and Point Carbon and are 410 NOK per ton of CO_2 emitted and approximately 50 NOK per ton CO_2 under the ETS for Norway and the ETS, respectively. This comes to a total fee of 460 NOK per ton CO_2. The annual estimated emissions from the gas turbines are calculated using the heat rate and efficiency for the specific generators used on the Edvard Grieg platform, the GE LM2500+, as well as the average annual power requirement. The LM2500+ technical specifications are sourced from the GE data sheet, yielding a thermal efficiency of 38%, which indicates a heat rate of 8,856 btu/Kwh or 242,906 sm^3/GWh. The energy requirement for the Edvard Grieg platform and connected Ivar Åsen field is estimated to 50 MW, implying an annual power demand of 438 GWh (add energy, 2012). Using the heat rate and annual power demand, as well as a CO_2 factor of 2.4 kilograms/sm^3, the estimated annual carbon emissions in is 255 million kilograms or 283,715 tons CO_2.

The data specific to the PFS solution is the annual power requirement and the electricity price paid by the operator for on-shore electricity from the grid. Operators, being large power consumers, are eligible for wholesale prices. As mentioned in the background, operators typically implement a portfolio of spot prices and long-term contracts for electricity procurement. However, for simplification of the model, the average wholesale electricity price of 290 NOK/MWh, as reported by the Norwegian Statistical Bureau, is used. Since the main units in this analysis are GWh, the converted price is 260,000 NOK/GWh. Taking the annual power requirement used in the gas turbine data, 438 GWh, this yields an annual electricity cost of approximately 127 million NOK. Additionally, the PFS solution, if chosen, requires a one-time CAPEX cost of 200 million NOK for the procurement and installation of the subsea cable from Edvard Grieg field to the Johan Sverdrup field (add energy, 2012).

4.2 Parameter Estimation

Using the mean-reverting Ornstein-Uhlenbeck process chosen from the Statistical Analysis section previously, the parameters estimated for the price process are as follows:

Level, $\bar{P}$	322.07
Speed, η	0.0179
Sigma, σ	0.248

With these parameters, the estimated process for the future crude electricity price realizations is $\frac{P_{EL,t}-P_{EL,t-1}}{P_{EL,t-1}} = 0.0179(322.07 - P_{EL,t})\Delta t + 0.248\varepsilon_t\sqrt{\Delta t}$. This process is used to simulate the future path for the crude electricity price in this analysis. Figure 4-3 below displays a visual representation of 1000 price path simulations in the period, from 2015 to 2046.

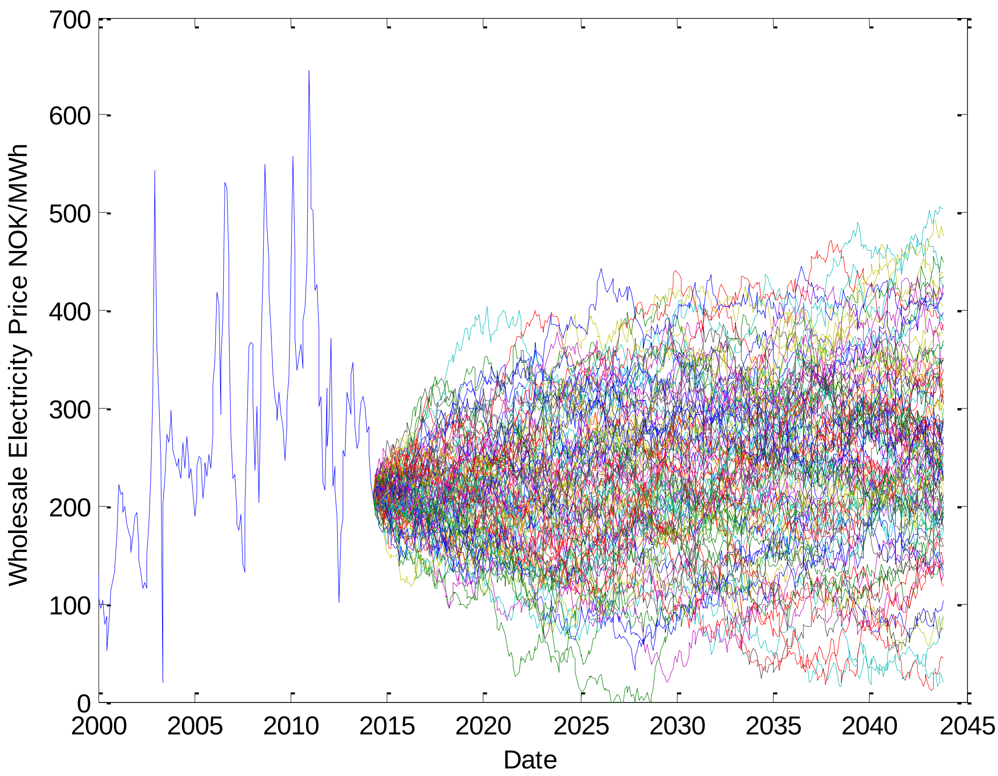

Figure 4-3: 1000 Wholesale Electricity Price Realizations

As can be seen in Figure 4-3 above, the simulated price paths have a high volatility, ranging roughly from 0 to 550 NOK/MWh, but there is a clear tendency to revert to the estimated mean price level around 322 NOK/MWh. These price simulations are used later in calculating the expected terminal NPV values for the different solutions. Something to note from the simulated prices is the apparent smoothing that occurs through the simulation. The historical prices seen on left-hand side of the plotted line exhibit consistent spikes in the prices, with very short intervals between the high peaks and the low peaks. Conversely, the simulated prices on the right-hand side of the plotted line do not follow this same nature. This most likely occurs from the one-factor stochastic model, which focuses primarily on the long-term mean level and the overall volatility. Also, since the spikes do not seem to endure any significant period of time (i.e. longer than one year), such spikes would not have the greatest weight in terms of long-term decision making.

4.3 NPV Calculation

Before moving on to the dynamic optimization, first, the standard NPV for each solution is calculated. This calculation is relatively simple and executed in Excel (see Appendix 1 for Excel sheet). For the gas turbine solution, the NPV at the end of the field lifetime, 23 years, is NOK 4.369 billion. The NPV at the end of the field lifetime for the PFS solution, with an immediate switch to PFS in 2021, is NOK 4.34 billion. At first glance, it is clear that switching to the PFS solution, although profitable, still loses out to the traditional gas turbine solution. Below, Table 4-1 summarizes the changes in the NPV of the different solutions, both in the baseline case and in varying parameter value cases.

Table 4-1: Traditional NPV calculations under differing key parameter values

Scenario	NPV – Gas Turbines	NPV – PFS
Baseline	4.369 billion NOK	4.343 billion NOK
15% Decrease Oil Price	2.463 billion NOK	2.436 billion NOK
15% Increase Oil Price	6.276 billion NOK	6.249 billion NOK
15% Decrease Electricity Price	4.369 billion NOK	4.373 billion NOK
15% Increase Electricity Price	4.369 billion NOK	4.312 billion NOK
15% Decrease Carbon Tax	4.423 billion NOK	4.366 billion NOK
15% Increase Carbon Tax	4.316 billion NOK	4.319 billion NOK

One important thing to note when examining Table 4-1 is how the NPV changes due to a change in a parameter. Concerning the oil price, the optimal solution does not change, simply the amount of money changes. This is logical because in this thesis' case, cost minimization is most important, and oil prices affect only the revenues, which is identical in the two cases. The final two parameters examined are the electricity price and the carbon tax, which are critical to this cost-minimization analysis. As can be seen, a 15% decrease in the electricity price results in the PFS solution becoming the optimal solution, whereas the 15% increase keeps the gas turbine solution optimal. The opposite goes for changes in the carbon price, which affects primarily the gas turbine solution, becoming more profitable when the carbon price decreases and less profitable and no longer optimal, when the carbon price increases. One difference, however, is that the carbon price does affect the PFS NPV as well, since the first years of the PFS case does involve a gas turbine. These NPV calculations serve as the basis for the Monte Carlo simulation for the terminal values used in the dynamic optimization.

4.4 Dynamic Programming Results

4.4.1 Baseline Model

The baseline model implements the parameters set forth in the preceding calculations and estimations. As mentioned previously, the baseline case, over a 23-year time horizon, has a set oil price of 500 NOK/bbl, a simulated wholesale electricity price, a set annual OPEX of 400 million NOK, and an annual carbon tax of 460 NOK/ton. Under these baseline conditions, the dynamic programming model strives to find the optimal conditions for the implementation of a PFS solution over a gas turbine solution. Given the rigidity of the MATLAB model used, a finite discrete dynamic programming solver from the CompEcon Toolbox, created by Paul Fackler and Mario Miranda (2011), some parameters, such as the oil price and production, were held constant. Figure 4-4 displays the estimated optimal project values with the corresponding wholesale electricity prices.

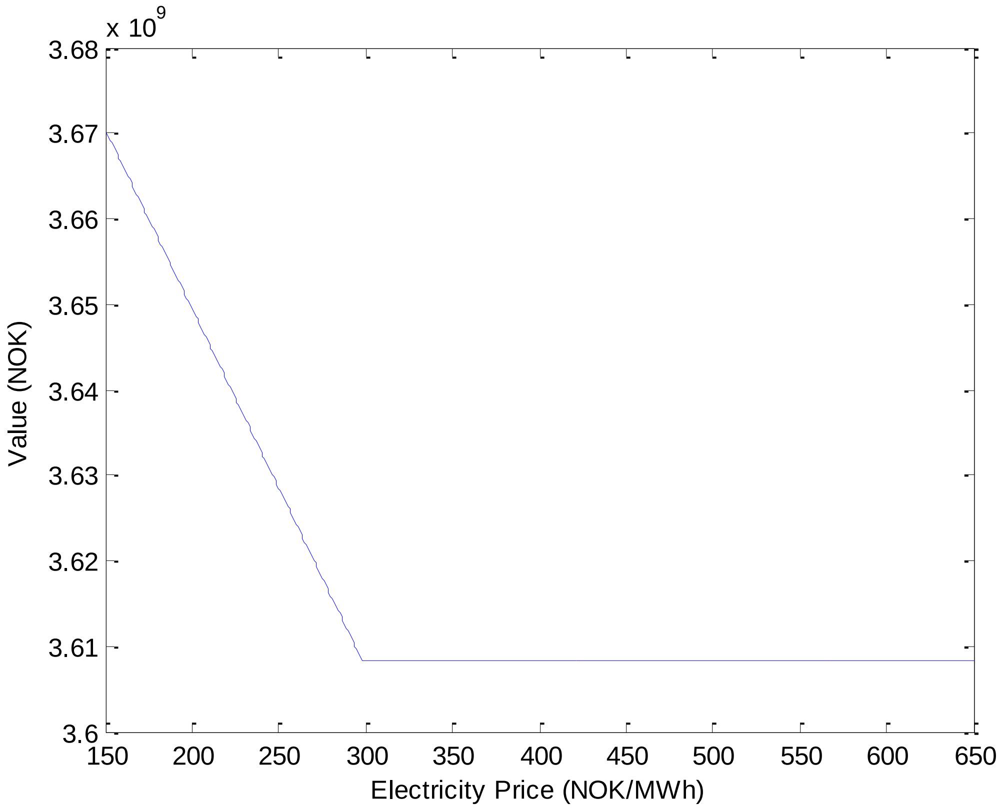

Figure 4-4: Optimal Project Value Function

As can be seen, with increasing electricity prices, the project value decreases steadily, until the point where the electricity price reaches around 295 NOK/MWh. This breakpoint, where the project value levels off at roughly 3.6 billion NOK, indicates the threshold point where it is optimal rather to stay with gas turbine generators instead of switching to PFS. This can also be illustrated with the plot of the optimal policy function, Figure 4-5 below, which is even more telling. In the optimal policy function, y = 2 dictates that the PFS solution is the optimal solution, whereas, y = 1 is to stay with traditional gas turbines. Again, it is clear that the critical electricity price is at 295 NOK/MWh, as seen in the optimal value function above.

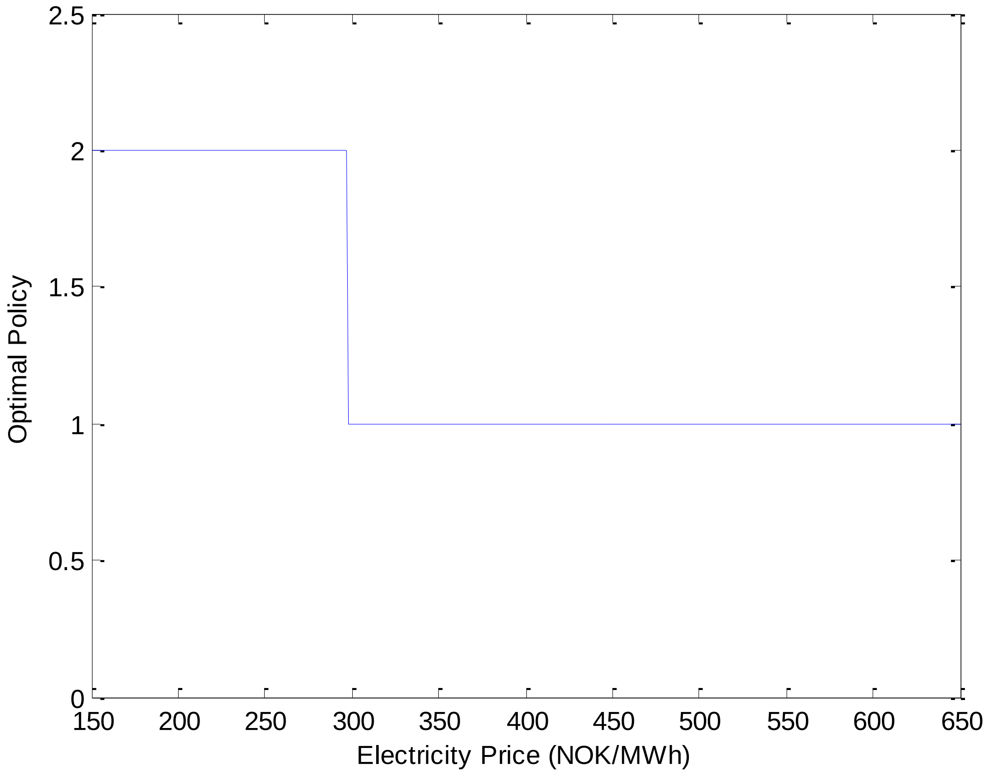

Figure 4-5: Optimal Policy Function Illustration

Figures 4-4 and 4-5 depict that the critical or breakeven electricity price is 295 NOK/MWh. This would be the point at which the manager should be indifferent between staying with the gas turbine and switching to PFS. Looking back at the simulated prices earlier in this section, this price is below the long-term average of 322 NOK/MWh, which could call into question the feasibility of reaching a stable point where this electricity price is available long-term. This low threshold electricity price mirrors the sentiment in the industry that PFS can be too expensive over the lifetime, especially if electricity prices are as volatile as seen. It is important to reiterate that this is the optimal policy in the case when just the electricity price is examined. That being said, the next section examines the sensitivity of the baseline model with respect to its key parameters (oil price and OPEX), and takes an in-depth look at the particular effect of carbon taxes.

4.4.2 Sensitivity Analysis

Upon receiving the results from the baseline model, it is important to examine how these results change due to changes in some of the model parameters. The parameters changed in the sensitivity analysis are the oil price and the annual OPEX. Figure 4-6 illustrates the changes that occur to the baseline model given a 15% increase or decrease to either the oil price or the annual OPEX, holding all other parameters constant.

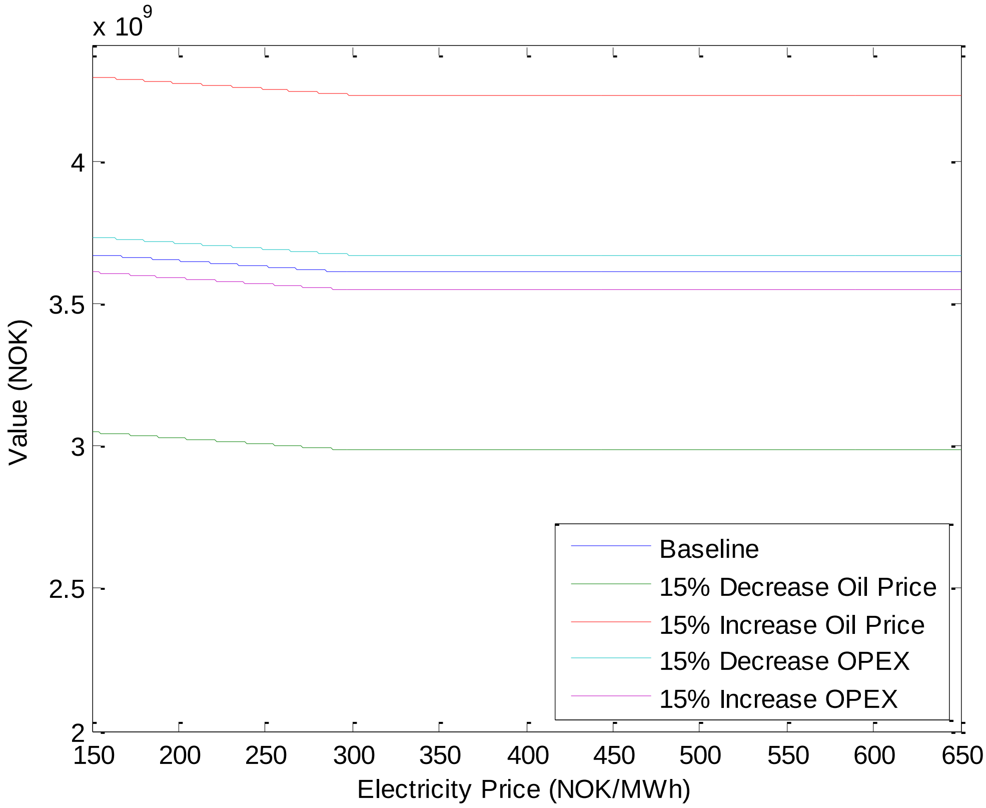

Figure 4-6: Results of Sensitivity Analysis to Baseline Model

As Figure 4-6 shows, changes in either the oil price or annual OPEX do not result in a change to the threshold wholesale electricity prices, but rather a change in the range of expected project values, as indicated by the y-axis. What is interesting to note, is the relative insensitivity of the project value to changes in the annual OPEX, as opposed to changes in the oil price. Either a 15% decrease or increase in the oil price results in a value difference of around half a billion NOK, whereas the change in OPEX results only in a value difference of 10 million or so.

It is expected that this sensitivity analysis does not change the threshold electricity price because these two parameters do not affect the two major components of this problem, cost of electricity for PFS and carbon tax payouts for gas-powered turbines. The next section addresses the effects of future carbon tax levels on the threshold wholesale electricity price.

4.4.3 Carbon Emission Tax

As an extension of the previous sensitivity analysis, the effects of changes in the carbon tax are examined. The baseline total carbon tax is 460 NOK/ton emitted CO_2 and this sensitivity analysis will examine 10% and 25% increases in this total tax and the corresponding effects on the estimated project value. Additionally, the "critical" carbon tax will be found, the tax high enough such that it eliminates the incentive to use gas turbine power generation. This thesis looks at carbon emission taxes separately from the general sensitivity analysis because the carbon emission tax is a critical factor in this analysis, alongside the wholesale electricity prices. Only increases in the carbon emission tax are examined because of the political and social climate calling for increases to carbon taxes to incentivize polluters to use more environmentally friendly technologies. Lastly, a 15% and 25% increase in the carbon prices is examined due to carbon price estimates from an Ernst and Young report, *The future of global carbon markets* (2012), citing that prices in Phase 3 could range from €10 – €25 (NOK 82 – NOK 205), citing roughly a 15% and 25% increase in total carbon prices (both Norwegian and EU ETS), respectively (Ernst & Young, 2012).

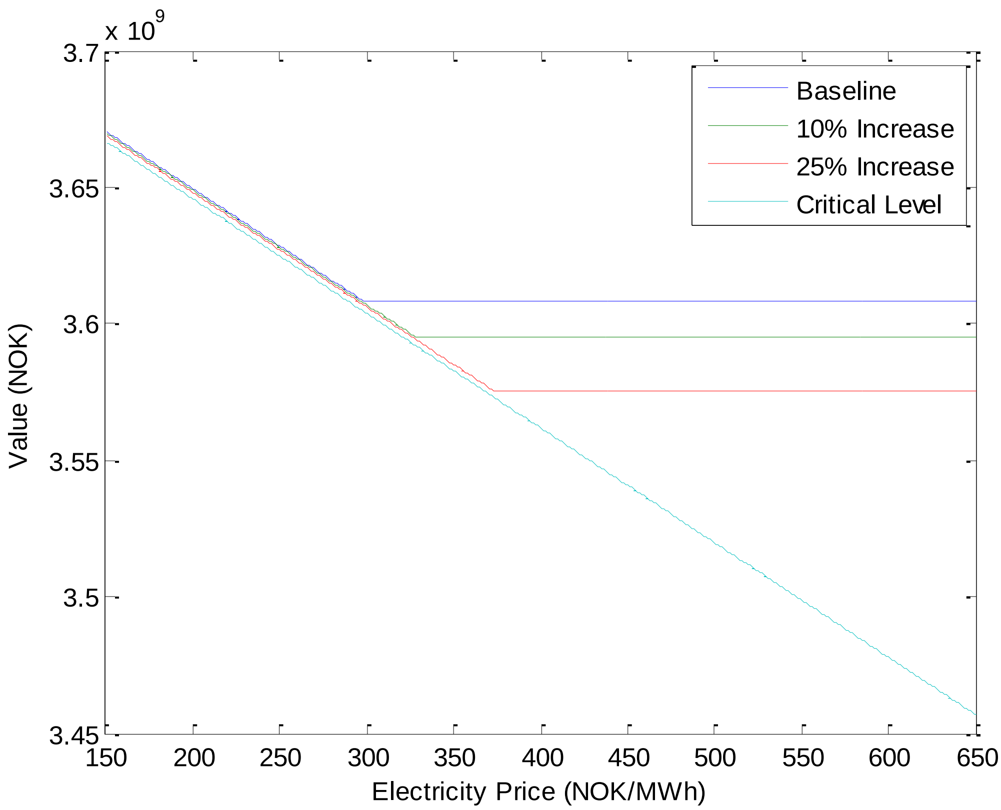

Figure 4-7: Optimal Value Functions Under the Differing Carbon Prices

10% Increase

A 10% increase in the total carbon tax would bring the tax to 506 NOK/ton CO_2. With a 10% increase in the carbon tax, the critical electricity price increases to roughly 320 NOK/MWh, as seen above in Figure 4-7. This increase in the threshold price is to be expected since the increased carbon tax only increases the costs to the gas turbine solution, allowing for a wider

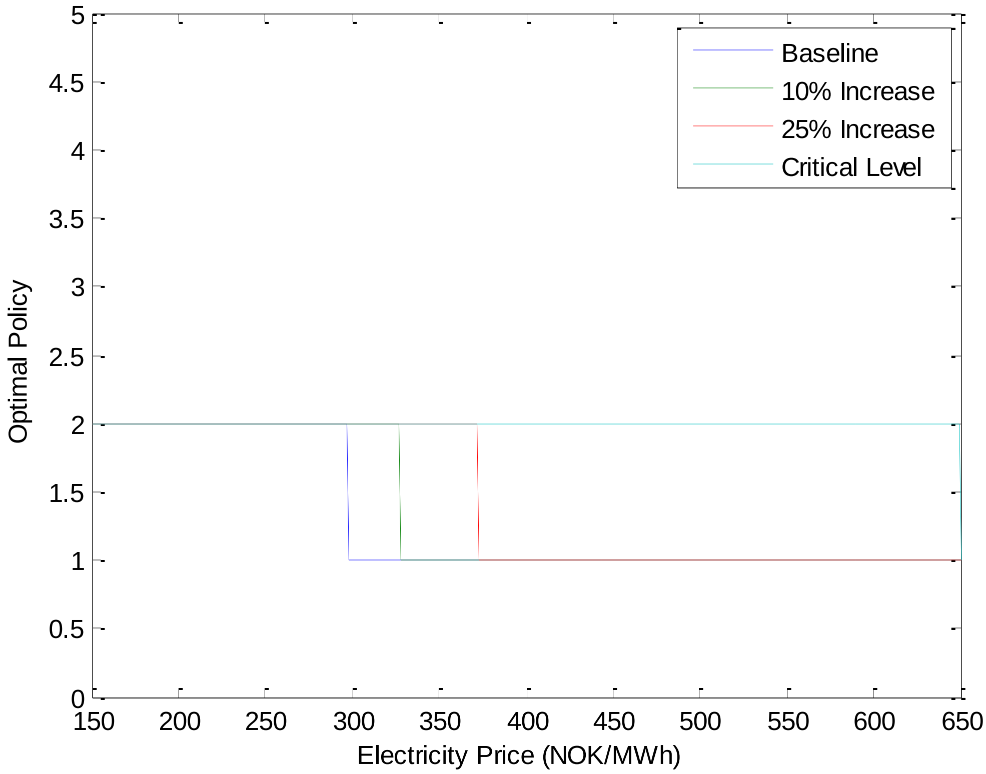

Figure 4-8: Optimal Policy Function under the differing Carbon Prices

range for which the PFS solution has lower OPEX costs. This threshold price, in comparison to the baseline model results, is 25 NOK higher and much closer to the long-term mean level found in the electricity price model. Another interesting change is the range of estimated project values. When comparing the value ranges in Figure 4-7, both the baseline and the 10% carbon increase have the same maximum value at 3.67 billion NOK, but the 10% carbon increase line bottoms out around 3.595 billion NOK, as opposed to around 3.61 billion NOK for the baseline case. This again is a reasonable effect, since the carbon tax increase affects only the gas turbine solution, which represents the lower bound of the optimal value function.

25% Increase

With a 25% increase in the total carbon price, equaling a total carbon price of 575 NOK/ton, the effects are much the same as the 10% increase, however with a much larger effect. As seen above in Figure 4-7, the critical electricity price increases further to around 360 NOK/MWh, reaching a point higher than the modeled long-term mean electricity price. This would indicate that with carbon prices at this level, there could be long-term economic potential for a PFS solution. Once again, the lower bound on the value function drops, this time to a level of 3.57 billion NOK.

Critical Carbon Tax

The critical carbon tax is the tax in this analysis, which eliminates the gas turbine option from the optimal solution. As shown by the light blue line in Figure 4-7 there is no threshold point at which gas turbines would be optimal over PFS. In the previous cases, each of the value functions bottomed out once the threshold price was reached, however, within this set of electricity prices, that point is not reached. In this case, the critical carbon tax is found to be approximately 1,003 NOK/ton of CO_2. To reiterate, this is the total critical carbon tax, meaning the tax for the operator from both the Norwegian government and the ETS. If the recently increased Norwegian carbon tax were to stay the same over this period, that would mean the ETS permit price would have to increase from 50 NOK/ton to 593 NOK/ton, and increase of approximately 1100%, which in the current climate is not likely.

5. Discussion

The results from both the baseline model and the carbon tax scenarios confirm some expected consequences and uncover some difficulties for the feasibility of a PFS solution for the Edvard Grieg field, as well as some general insights for any upcoming field on the NCS. The initial findings for the Edvard Grieg field indicate that a PFS solution is possible within the indicated threshold electricity prices for the different scenarios. Furthermore, these threshold prices become increasingly more favorable towards PFS when coupled with increasing carbon taxes, either from the Norwegian state or the ETS. However, there are many current issues connected to the Norwegian wholesale electricity prices and carbon taxes, outside the scope of this thesis, which play a large role in shaping the optimal conditions for implementation of PFS at Edvard Grieg and generally on the NCS.

First and foremost, the results from the standard NPV calculation and the dynamic programming are quite different. That is not completely unexpected, given the simplifications made to the model in order to implement the chosen dynamic programming technique. That being said, the real option approach presents its user more than an “invest or do not invest” answer but rather a set of conditions, from which one can make better informed decisions based on new information or intuition. From the NPV calculations for the two solutions, the gas turbine solution has the higher NPV, which would motivate its user to shelve the idea of switching to PFS. Conversely, the real options analysis creates boundaries for the optimal policy, depending on realized electricity prices and carbon taxes in the future, providing the user with a more comprehensive picture of the project’s potential value.

The rough threshold electricity prices found for implementing a PFS solution at Edvard Grieg range from 295 NOK/MWh to 360 NOK/MWh, depending on the carbon tax level. Considering a current wholesale electricity price of 290 NOK/MWh, as mentioned in the background, it is reasonable to conclude that a PFS solution could be profitably executed at Edvard Grieg. In this thesis, the electricity price simulations yielded realizations from zero to 600 NOK/MWh. As can be seen from the historical and simulated wholesale electricity prices, it is incredibly difficult to forecast accurately what future electricity prices will be; however, there are some factors, which can help determine the general trend in the short to medium run. As mentioned in the Background, all electricity for Edvard Grieg is to be sourced from the on-shore grid in Southwest Norway, an area that is already struggling with mounting security of supply issues. Although it is outside of the scope of this thesis to examine the growth of electricity demand for both onshore and offshore consumers, a more rigorous investigation of this problem could look into the growth of supply and demand, alongside the priorities assigned to each by the responsible parties. For example, with the grid in Rogaland facing supply issues, and increasing household demand and industrial demand offshore, who is the consumer of first choice and how will that affect the wholesale prices and even availability of electricity to the offshore platforms? Additionally, the electricity price is, in this thesis, modelled by a one-factor mean-reverting stochastic process, which forces mean reversion in the medium to long run. Further investigations into this topic could benefit from implementing a more sophisticated approach to modelling the prices to attempt to capture more of the behavior than achieved in this particular case.

In addition to the wholesale electricity prices, carbon taxes play, as expected, a major role in the viability of a PFS solution, or rather the non-viability of the traditional gas turbine approach. As seen in the changes from the baseline to the increased carbon tax scenarios, there are significant gains for PFS with increasing carbon taxes. However, even though there are significant gains for PFS with a 10-25% increase in carbon taxes, in this case, the critical total carbon tax of 1003 NOK/ton is more than 218% higher than the current total carbon tax of 460 NOK/ton. Currently, Norwegian carbon taxes comprise 410 NOK/ton of the total, with the ETS comprising only 50 NOK/ton. Unlike Norwegian electricity prices, the total carbon tax is a bit easier to forecast accurately, since it is determined through a combination of policy and market forces. Norway already leads the world with regards to its high standards for carbon taxation, so it is unreasonable to propose that major changes in the total carbon tax should come from the ETS. However, given the depressed state of the ETS carbon permit market, any significant increases in the short to medium term seem unlikely. That being said, the current framework for the ETS system runs only through 2020, only four years into this analysis. Although the fate of the ETS after Phase 3 has not been widely discussed, it can be expected that further freezes on permit auctions as well as cap cuts will help push carbon prices to much more effective levels. Further research can be done could be done to better quantify the value of decreased emissions, either from the societal view, by increased environmental quality and amenity or from the operator view, by positive reputational benefits.

In addition to the two major factors, the electricity price and carbon taxes, looking forward, there are other concerns for the practicality of these findings. In this analysis, there is a single type of gas turbine generator considered, the LTE-2500+, which is installed on the Edvard Grieg platform. This particular generator operates at a thermal efficiency of only 38%, translating to high emissions levels. This allows a PFS solution with no emissions and low losses (up to 10%), to compete on OPEX costs, depending on the cost of electricity. With increasing technological advances, particularly within the areas of turbine fuel efficiency, the value of being able to switch to PFS could be diminished, especially if one of the main cost drivers for the gas turbine solution, carbon taxes, could be decreased significantly compared to the main cost driver for PFS, electricity price.

Alongside the economic concerns against implementing PFS, there are also claims that PFS will have little positive effect on the climate. As mentioned previously, electrifying offshore oil installations puts large demands on the onshore grid, which may not have the capacity to supply such demands. This would require electricity import from mainland Europe. One of the major incentives of PFS in Norway is that the power would be supplied through clean hydropower. However, if electricity needs to be imported from Europe, that electricity would come from dirtier power generation methods, such as coal power plants (Ramsdal, 2014). In this case, PFS would improve the carbon footprint on the NCS and in Norway, but globally, there would be little improvement.

Working within the limited scope of this thesis, there does appear to be a margin, albeit thin, for the implementation of PFS at the Edvard Grieg field, given the produced wholesale electricity threshold prices and the current state of the oil industry. However, the thin margin coupled with the already large uncertainty inherent in the industry makes one believe that concrete long-term changes, potentially in the form of a more stable electricity supply or effectively higher carbon taxes, are necessary for PFS to actually be implemented at Edvard Grieg or in future NCS field developments.

6. Conclusion

The Norwegian government and the oil operators have been at odds over the electrification of the Utsira High since the discovery of Johan Sverdrup in 2010. The electrification of the area would stand to save Norway over a million tons of carbon emissions per year, however, the operators are hit with the high cost of supplying the platforms with electrical power from shore. Despite the efforts made by the Norwegian government to discourage carbon emissions offshore, mainly through their above average carbon emission tax, the traditional gas turbine solution is preferred by operators, due to its ease and relatively lower CAPEX.

However, the findings in this thesis can show that there is the possibility for a PFS solution at the Edvard Grieg field. When looking at the main cost differentials between the two solutions: the electricity prices for PFS and the carbon taxes for gas turbines, there are conditions, which allow for a PFS solution. With current carbon taxes, the approximate threshold electricity price for PFS is 295 NOK/MWh, five NOK higher than current contract prices. Furthermore, the threshold prices increase substantially with additional help from higher carbon taxes, through either the Norwegian government or the ETS. This indicates that there is hope in implementing a PFS solution at Edvard Grieg and possibly at other field developments on the NCS.

These findings, however, must be taken with caution given the nature of the industry and the limitations of the model implemented. The petroleum industry is wrought with uncertainty, which requires all to take these findings as merely relative terms and not the absolute truths. Given the complexity of the problem and the limitations of the author, the model was forced to hold many parameters, such as the revenues, constant, impairing the ability of the model to capture the entirety of the problem. However, this work does set the stage for further research regarding the optimal conditions for PFS implementation, making use of more sophisticated techniques to include more of the parameter dynamics that were not dealt with here.

Despite these shortcomings, the findings in this thesis do provide an illustration of the ability of PFS to be a viable power generation option for the Edvard Grieg field. There are many additional factors, such as commodity prices, domestic policy, energy demand, geopolitical conflict, etc., which may arise in the future and have a profound effect on the viability of either power generation option. Nevertheless, by incorporating flexibility their perspective, the operator will have a clearer picture of the options, which await them.

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Appendix 1

Corporate Tax	0,28	Uplift	0,055	CAPEX (NOK)	-24 000 000 000,00
Special Tax	0,5	Oil Price (NOK/bbl)	500,00		
Discount Factor	1,07	OPEX	400 000 000,00	Exchange Rate	1,00

NPV - Gas Turbines (no switch)		2015	2016	2017	2018
	Year	0	1	2	3
Initial Investment (CAPEX)		-24 000 000 000,00			
Oil/Gas production		-	3 441 463,19	6 067 234,82	10 257 139,10
Oil Price		-	500,00	500,00	500,00
Revenue		-24 000 000 000,00	1 720 731 597,37	3 033 617 409,86	5 128 569 549,93
Less:	Operating cost	-	400 000 000,00	400 000 000,00	400 000 000,00
	carbon fees	-	130 508 706,61	130 508 706,61	130 508 706,61
Total OPEX			530 508 706,61	530 508 706,61	530 508 706,61
Operating Profit pre-tax		-24 000 000 000,00	1 190 222 890,75	2 503 108 703,25	4 598 060 843,32
Less:	Depreciation	-	-4 000 000 000,00	-4 000 000 000,00	-4 000 000 000,00
Corporate Tax Base		-	-2 809 777 109,25	-1 496 891 296,75	598 060 843,32
Less:	Uplift	-	-1 320 000 000,00	-1 320 000 000,00	-1 320 000 000,00
Special Tax Base		-	-4 129 777 109,25	-2 816 891 296,75	-721 939 156,68
Total Tax		-	-2 851 626 145,21	-1 827 575 211,46	-193 512 542,21
Total OPEX/Tax			-2 321 117 438,60	-1 297 066 504,85	336 996 164,40
Operating profit post-tax		-24 000 000 000,00	4 041 849 035,97	4 330 683 914,72	4 791 573 385,53
Undiscounted CF		-24 000 000 000,00	4 041 849 035,97	4 330 683 914,72	4 791 573 385,53
Discount Factor			0,9346	0,8734	0,8163
Cash Flow NPV		-24 000 000 000,00	3 777 429 005,58	3 782 587 051,02	3 911 351 181,57
Cumulative Cash Flow		-24 000 000 000,00	-20 222 570 994,42	-16 439 983 943,40	-12 528 632 761,83
NPV		4 369 986 501,17			

		2019	2020	2021	2022	2023	2024
	Year	4	5	6	7	8	9
Initial Investment (CAPEX)							
Oil/Gas production		16 161 874,68	22 817 339,54	27 633 953,86	27 835 411,80	23 290 120,18	16 665 689,19
Oil Price		500,00	500,00	500,00	500,00	500,00	500,00
Revenue		8 080 937 340,10	11 408 669 770,14	13 816 976 932,40	13 917 705 902,35	11 645 060 092,11	8 332 844 596,29
Less:	Operating cost	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
	carbon fees	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61
Total OPEX		530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61
Operating Profit pre-tax		7 550 428 633,49	10 878 161 063,53	13 286 468 225,79	13 387 197 195,74	11 114 551 385,50	7 802 335 889,68
Less:	Depreciation	-4 000 000 000,00	-4 000 000 000,00	-4 000 000 000,00	-	-	-
Corporate Tax Base		3 550 428 633,49	6 878 161 063,53	9 286 468 225,79	13 387 197 195,74	11 114 551 385,50	7 802 335 889,68
Less:	Uplift	-1 320 000 000,00	-	-	-	-	-
Special Tax Base		2 230 428 633,49	6 878 161 063,53	9 286 468 225,79	13 387 197 195,74	11 114 551 385,50	7 802 335 889,68
Total Tax		2 109 334 334,12	5 364 965 629,56	7 243 445 216,12	10 442 013 812,67	8 669 350 080,69	6 085 821 993,95
Total OPEX/Tax		2 639 843 040,73	5 895 474 336,17	7 773 953 922,73	10 972 522 519,29	9 199 858 787,30	6 616 330 700,56
Operating profit post-tax		5 441 094 299,37	5 513 195 433,98	6 043 023 009,67	2 945 183 383,06	2 445 201 304,81	1 716 513 895,73
Undiscounted CF		5 441 094 299,37	5 513 195 433,98	6 043 023 009,67	2 945 183 383,06	2 445 201 304,81	1 716 513 895,73
Discount Factor		0,7629	0,7130	0,6663	0,6227	0,5820	0,5439
Cash Flow NPV		4 150 984 789,29	3 930 832 149,22	4 026 721 390,84	1 834 112 191,60	1 423 129 421,89	933 669 827,50
Cumulative Cash Flow		-8 377 647 972,54	-4 446 815 823,32	-420 094 432,48	1 414 017 759,12	2 837 147 181,02	3 770 817 008,52

2025	2026	2027	2028	2029	2030	2031
10	11	12	13	14	15	16
10 649 695,21	6 326 045,03	3 597 051,82	1 994 884,18	1 091 084,35	592 236,99	320 138,63
500,00	500,00	500,00	500,00	500,00	500,00	500,00
5 324 847 607,23	3 163 022 513,86	1 798 525 908,78	997 442 088,79	545 542 174,05	296 118 496,91	160 069 316,54
400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61
530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61
4 794 338 900,61	2 632 513 807,25	1 268 017 202,17	466 933 382,17	15 033 467,44	-234 390 209,70	-370 439 390,07
-	-	-	-	-	-	-
4 794 338 900,61	2 632 513 807,25	1 268 017 202,17	466 933 382,17	15 033 467,44	-234 390 209,70	-370 439 390,07
-	-	-	-	-	-	-
4 794 338 900,61	2 632 513 807,25	1 268 017 202,17	466 933 382,17	15 033 467,44	-234 390 209,70	-370 439 390,07
3 739 584 342,48	2 053 360 769,65	989 053 417,69	364 208 038,10	11 726 104,60	-182 824 363,57	-288 942 724,26
4 270 093 049,09	2 583 869 476,26	1 519 562 124,30	894 716 744,71	542 234 811,22	347 684 343,05	241 565 982,36
1 054 754 558,13	579 153 037,59	278 963 784,48	102 725 344,08	3 307 362,84	-51 565 846,13	-81 496 665,82
1 054 754 558,13	579 153 037,59	278 963 784,48	102 725 344,08	3 307 362,84	-51 565 846,13	-81 496 665,82
0,5083	0,4751	0,4440	0,4150	0,3878	0,3624	0,3387
536 183 733,00	275 151 436,17	123 863 256,50	42 627 365,69	1 282 652,33	-18 689 835,68	-27 605 740,32
4 307 000 741,52	4 582 152 177,69	4 706 015 434,19	4 748 642 799,88	4 749 925 452,21	4 731 235 616,53	4 703 629 876,21

2032	2033	2034	2035	2036	2037	2038
17	18	19	20	21	22	23
172 667,29	93 016,17	50 075,43	26 948,78	14 500,12	7 801,18	4 196,87
500,00	500,00	500,00	500,00	500,00	500,00	500,00
86 333 643,69	46 508 082,58	25 037 714,76	13 474 388,13	7 250 061,25	3 900 590,10	2 098 433,88
400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61
530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61
-444 175 062,93	-484 000 624,03	-505 470 991,85	-517 034 318,48	-523 258 645,36	-526 608 116,51	-528 410 272,74
-	-	-	-	-	-	-
-444 175 062,93	-484 000 624,03	-505 470 991,85	-517 034 318,48	-523 258 645,36	-526 608 116,51	-528 410 272,74
-	-	-	-	-	-	-
-444 175 062,93	-484 000 624,03	-505 470 991,85	-517 034 318,48	-523 258 645,36	-526 608 116,51	-528 410 272,74
-346 456 549,08	-377 520 486,74	-394 267 373,64	-403 286 768,41	-408 141 743,38	-410 754 330,88	-412 160 012,73
184 052 157,53	152 988 219,87	136 241 332,97	127 221 938,20	122 366 963,23	119 754 375,73	118 348 693,88
-97 718 513,84	-106 480 137,29	-111 203 618,21	-113 747 550,06	-115 116 901,98	-115 853 785,63	-116 250 260,00
-97 718 513,84	-106 480 137,29	-111 203 618,21	-113 747 550,06	-115 116 901,98	-115 853 785,63	-116 250 260,00
0,3166	0,2959	0,2765	0,2584	0,2415	0,2257	0,2109
-30 935 178,96	-31 503 630,43	-30 748 727,10	-29 394 528,46	-27 802 238,33	-26 149 724,65	-24 522 630,04
4 672 694 697,26	4 641 191 066,83	4 610 442 339,73	4 581 047 811,27	4 553 245 572,94	4 527 095 848,29	4 502 573 218,25

2039	2040	2041	2042	2043	2044	2045
24	25	26	27	28	29	30
2 257,76	1 214,57	653,38	351,48	189,08	101,71	54,72
500,00	500,00	500,00	500,00	500,00	500,00	500,00
1 128 879,36	607 285,52	326 689,10	175 741,52	94 539,44	50 857,04	27 358,29
400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61
530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61
-529 379 827,25	-529 901 421,09	-530 182 017,52	-530 332 965,10	-530 414 167,17	-530 457 849,57	-530 481 348,32
-	-	-	-	-	-	-
-529 379 827,25	-529 901 421,09	-530 182 017,52	-530 332 965,10	-530 414 167,17	-530 457 849,57	-530 481 348,32
-	-	-	-	-	-	-
-529 379 827,25	-529 901 421,09	-530 182 017,52	-530 332 965,10	-530 414 167,17	-530 457 849,57	-530 481 348,32
-412 916 265,26	-413 323 108,45	-413 541 973,66	-413 659 712,78	-413 723 050,39	-413 757 122,66	-413 775 451,69
117 592 441,35	117 185 598,16	116 966 732,95	116 848 993,84	116 785 656,22	116 751 583,95	116 733 254,92
-116 463 562,00	-116 578 312,64	-116 640 043,85	-116 673 252,32	-116 691 116,78	-116 700 726,90	-116 705 896,63
-116 463 562,00	-116 578 312,64	-116 640 043,85	-116 673 252,32	-116 691 116,78	-116 700 726,90	-116 705 896,63
0,1971	0,1842	0,1722	0,1609	0,1504	0,1406	0,1314
-22 960 397,59	-21 479 458,22	-20 084 889,86	-18 776 269,35	-17 550 602,13	-16 403 782,73	-15 331 317,20
4 479 612 820,66	4 458 133 362,44	4 438 048 472,58	4 419 272 203,23	4 401 721 601,10	4 385 317 818,37	4 369 986 501,17

NPV - Power from Shore (immediate switch)

Year	2015 0	2016 1	2017 2	2018 3
Initial Investment (CAPEX)	-24 000 000 000,00			
Oil/Gas production	-	3 441 463,19	6 067 234,82	10 257 139,10
Oil Price	-	500,00	500,00	500,00
Revenue	-24 000 000 000,00	1 720 731 597,37	3 033 617 409,86	5 128 569 549,93
Less: Operating cost	-	400 000 000,00	400 000 000,00	400 000 000,00
Carbon /Electricity	-	130 508 706,61	130 508 706,61	130 508 706,61
Switch Cost	-	-	-	-
Total OPEX		530 508 706,61	530 508 706,61	530 508 706,61
Operating Profit pre-tax	-24 000 000 000,00	1 190 222 890,75	2 503 108 703,25	4 598 060 843,32
Less: Depreciation	-	-4 000 000 000,00	-4 000 000 000,00	-4 000 000 000,00
Corporate Tax Base	-	-2 809 777 109,25	-1 496 891 296,75	598 060 843,32
Less: Uplift	-	-1 320 000 000,00	-1 320 000 000,00	-1 320 000 000,00
Special Tax Base	-	-4 129 777 109,25	-2 816 891 296,75	-721 939 156,68
Total Tax	-	-2 851 626 145,21	-1 827 575 211,46	-193 512 542,21
Total OPEX/Tax		-2 321 117 438,60	-1 297 066 504,85	336 996 164,40
Operating profit post-tax	-24 000 000 000,00	4 041 849 035,97	4 330 683 914,72	4 791 573 385,53
Undiscounted CF	-24 000 000 000,00	4 041 849 035,97	4 330 683 914,72	4 791 573 385,53
Discount Factor		0,93	0,87	0,82
Cash Flow NPV	-24 000 000 000,00	3 777 429 005,58	3 782 587 051,02	3 911 351 181,57
Cumulative Cash Flow	-24 000 000 000,00	-20 222 570 994,42	-16 439 983 943,40	-12 528 632 761,83
NPV	4 343 001 635,73			

Year	2019 4	2020 5	2021 6	2022 7	2023 8	2024 9
Initial Investment (CAPEX)						
Oil/Gas production	16 161 874,68	22 817 339,54	27 633 953,86	27 835 411,80	23 290 120,18	16 665 689,19
Oil Price	500,00	500,00	500,00	500,00	500,00	500,00
Revenue	8 080 937 340,10	11 408 669 770,14	13 816 976 932,40	13 917 705 902,35	11 645 060 092,11	8 332 844 596,29
Less: Operating cost	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
Carbon /Electricity	130 508 706,61	130 508 706,61	130 508 706,61	130 508 706,61	131 400 000,00	131 400 000,00
Switch Cost	-	-	-	-	-200 000 000,00	-
Total OPEX	530 508 706,61	530 508 706,61	530 508 706,61	530 508 706,61	531 400 000,00	531 400 000,00
Operating Profit pre-tax	7 550 428 633,49	10 878 161 063,53	13 286 468 225,79	13 387 197 195,74	10 913 660 092,11	7 801 444 596,29
Less: Depreciation	-4 000 000 000,00	-4 000 000 000,00	-4 000 000 000,00	-	-	-
Corporate Tax Base	3 550 428 633,49	6 878 161 063,53	9 286 468 225,79	13 387 197 195,74	10 913 660 092,11	7 801 444 596,29
Less: Uplift	-1 320 000 000,00	-	-	-	-	-
Special Tax Base	2 230 428 633,49	6 878 161 063,53	9 286 468 225,79	13 387 197 195,74	10 913 660 092,11	7 801 444 596,29
Total Tax	2 109 334 334,12	5 364 965 629,56	7 243 445 216,12	10 442 013 812,67	8 512 654 871,85	6 085 126 785,11
Total OPEX/Tax	2 639 843 040,73	5 895 474 336,17	7 773 953 922,73	10 972 522 519,29	9 044 054 871,85	6 616 526 785,11
Operating profit post-tax	5 441 094 299,37	5 513 195 433,98	6 043 023 009,67	2 945 183 383,06	2 401 005 220,26	1 716 317 811,18
Undiscounted CF	5 441 094 299,37	5 513 195 433,98	6 043 023 009,67	2 945 183 383,06	2 401 005 220,26	1 716 317 811,18
Discount Factor	0,76	0,71	0,67	0,62	0,58	0,54
Cash Flow NPV	4 150 984 789,29	3 930 832 149,22	4 026 721 390,84	1 834 112 191,60	1 397 406 898,30	933 563 170,50
Cumulative Cash Flow	-8 377 647 972,54	-4 446 815 823,32	-420 094 432,48	1 414 017 759,12	2 811 424 657,42	3 744 987 827,93

Year	2025 10	2026 11	2027 12	2028 13	2029 14	2030 15
Initial Investment (CAPEX)						
Oil/Gas production	10 649 695,21	6 326 045,03	3 597 051,82	1 994 884,18	1 091 084,35	592 236,99
Oil Price	500,00	500,00	500,00	500,00	500,00	500,00
Revenue	5 324 847 607,23	3 163 022 513,86	1 798 525 908,78	997 442 088,79	545 542 174,05	296 118 496,91
Less: Operating cost	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
Carbon /Electricity	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00
Switch Cost	-	-	-	-	-	-
Total OPEX	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00
Operating Profit pre-tax	4 793 447 607,23	2 631 622 513,86	1 267 125 908,78	466 042 088,79	14 142 174,05	-235 281 503,09
Less: Depreciation	-	-	-	-	-	-
Corporate Tax Base	4 793 447 607,23	2 631 622 513,86	1 267 125 908,78	466 042 088,79	14 142 174,05	-235 281 503,09
Less: Uplift	-	-	-	-	-	-
Special Tax Base	4 793 447 607,23	2 631 622 513,86	1 267 125 908,78	466 042 088,79	14 142 174,05	-235 281 503,09
Total Tax	3 738 889 133,64	2 052 665 560,81	988 358 208,85	363 512 829,25	11 030 895,76	-183 519 572,41
Total OPEX/Tax	4 270 289 133,64	2 584 065 560,81	1 519 758 208,85	894 912 829,25	542 430 895,76	347 880 427,59
Operating profit post-tax	1 054 558 473,59	578 956 953,05	278 767 699,93	102 529 259,53	3 111 278,29	-51 761 930,68
Undiscounted CF	1 054 558 473,59	578 956 953,05	278 767 699,93	102 529 259,53	3 111 278,29	-51 761 930,68
Discount Factor	0,51	0,48	0,44	0,41	0,39	0,36
Cash Flow NPV	536 084 053,56	275 058 277,81	123 776 192,62	42 545 997,57	1 206 607,36	-18 760 905,74
Cumulative Cash Flow	4 281 071 881,49	4 556 130 159,30	4 679 906 351,92	4 722 452 349,50	4 723 658 956,86	4 704 898 051,12

2031	2032	2033	2034	2035	2036
16	17	18	19	20	21
320 138,63	172 667,29	93 016,17	50 075,43	26 948,78	14 500,12
500,00	500,00	500,00	500,00	500,00	500,00
160 069 316,54	86 333 643,69	46 508 082,58	25 037 714,76	13 474 388,13	7 250 061,25
400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00
-	-	-	-	-	-
531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00
-371 330 683,46	-445 066 356,31	-484 891 917,42	-506 362 285,24	-517 925 611,87	-524 149 938,75
-	-	-	-	-	-
-371 330 683,46	-445 066 356,31	-484 891 917,42	-506 362 285,24	-517 925 611,87	-524 149 938,75
-	-	-	-	-	-
-371 330 683,46	-445 066 356,31	-484 891 917,42	-506 362 285,24	-517 925 611,87	-524 149 938,75
-289 637 933,10	-347 151 757,92	-378 215 695,59	-394 962 582,49	-403 981 977,26	-408 836 952,22
241 762 066,90	184 248 242,08	153 184 304,41	136 437 417,51	127 418 022,74	122 563 047,78
-81 692 750,36	-97 914 598,39	-106 676 221,83	-111 399 702,75	-113 943 634,61	-115 312 986,52
-81 692 750,36	-97 914 598,39	-106 676 221,83	-111 399 702,75	-113 943 634,61	-115 312 986,52
0,34	0,32	0,30	0,28	0,26	0,24
-27 672 160,94	-30 997 254,30	-31 561 644,77	-30 802 946,11	-29 445 200,43	-27 849 595,32
4 677 225 890,18	4 646 228 635,88	4 614 666 991,11	4 583 864 045,00	4 554 418 844,57	4 526 569 249,25

2037	2038	2039	2040	2041	2042
22	23	24	25	26	27
7 801,18	4 196,87	2 257,76	1 214,57	653,38	351,48
500,00	500,00	500,00	500,00	500,00	500,00
3 900 590,10	2 098 433,88	1 128 879,36	607 285,52	326 689,10	175 741,52
400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00	400 000 000,00
131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00	131 400 000,00
-	-	-	-	-	-
531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00	531 400 000,00
-527 499 409,90	-529 301 566,12	-530 271 120,64	-530 792 714,48	-531 073 310,90	-531 224 258,48
-	-	-	-	-	-
-527 499 409,90	-529 301 566,12	-530 271 120,64	-530 792 714,48	-531 073 310,90	-531 224 258,48
-	-	-	-	-	-
-527 499 409,90	-529 301 566,12	-530 271 120,64	-530 792 714,48	-531 073 310,90	-531 224 258,48
-411 449 539,72	-412 855 221,58	-413 611 474,10	-414 018 317,29	-414 237 182,51	-414 354 921,62
119 950 460,28	118 544 778,42	117 788 525,90	117 381 682,71	117 162 817,49	117 045 078,38
-116 049 870,18	-116 446 344,55	-116 659 646,54	-116 774 397,19	-116 836 128,40	-116 869 336,87
-116 049 870,18	-116 446 344,55	-116 659 646,54	-116 774 397,19	-116 836 128,40	-116 869 336,87
0,23	0,21	0,20	0,18	0,17	0,16
-26 193 983,52	-24 563 993,46	-22 999 055,00	-21 515 586,64	-20 118 654,73	-18 807 825,31
4 500 375 265,73	4 475 811 272,28	4 452 812 217,28	4 431 296 630,64	4 411 177 975,91	4 392 370 150,60

2043	2044	2045
28	29	30
189,08	101,71	54,72
500,00	500,00	500,00
94 539,44	50 857,04	27 358,29
400 000 000,00	400 000 000,00	400 000 000,00
131 400 000,00	131 400 000,00	131 400 000,00
-	-	-
531 400 000,00	531 400 000,00	531 400 000,00
-531 305 460,56	-531 349 142,96	-531 372 641,71
-	-	-
-531 305 460,56	-531 349 142,96	-531 372 641,71
-	-	-
-531 305 460,56	-531 349 142,96	-531 372 641,71
-414 418 259,24	-414 452 331,51	-414 470 660,54
116 981 740,76	116 947 668,49	116 929 339,46
-116 887 201,32	-116 896 811,45	-116 901 981,18
-116 887 201,32	-116 896 811,45	-116 901 981,18
0,15	0,14	0,13
-17 580 093,68	-16 431 344,92	-15 357 076,26
4 374 790 056,92	4 358 358 711,99	4 343 001 635,73

Appendix 2

Oseberg Øst Profile

Year	q	Q
1999	910 949	910 949
2000	2 553 555	3 464 504
2001	3 812 851	7 277 355
2002	3 143 268	10 420 623
2003	2 270 137	12 690 760
2004	1 864 399	14 555 159
2005	1 098 949	15 654 108
2006	687 219	16 341 327
2007	558 403	16 899 730
2008	446 381	17 346 111
2009	356 812	17 702 923
2010	355 463	18 058 386
2011	526 216	18 584 602
2012	463 654	19 048 256
2013	388 948	19 437 204
2014	82 824	19 520 028
2015	27 451	29 095 657
2016	14 788	29 116 129
2017	7 961	29 127 154
2018	4 284	29 133 088
2019	2 305	29 136 281
2020	1 240	29 137 999
2021	667	29 138 924
2022	359	29 139 421
2023	193	29 139 689
2024	104	29 139 832
2025	56	29 139 910
2026	30	29 139 952
2027	16	29 139 974
2028	9	29 139 986

Hubbert Curve Parameters

Estimate: q/Q = r-(r/K)Q

r	0,62	
K	29 140 000	sm^3
e^c0	0,032270	

Estimation					
Base Year		2016			6,29
Year	q		q (barrels)	q (in millions)	Q
	2016	547 132,46	3 441 463,19	3,44	910 949
	2017	964 584,23	6 067 234,82	6,07	1 649 108
	2018	1 630 705,74	10 257 139,10	10,26	2 923 467
	2019	2 569 455,43	16 161 874,68	16,16	5 003 366
	2020	3 627 557,96	22 817 339,54	22,82	8 105 507
	2021	4 393 315,40	27 633 953,86	27,63	12 161 873
	2022	4 425 343,69	27 835 411,80	27,84	16 642 136
	2023	3 702 721,81	23 290 120,18	23,29	20 755 222
	2024	2 649 553,13	16 665 689,19	16,67	23 937 812
	2025	1 693 115,30	10 649 695,21	10,65	26 089 917
	2026	1 005 730,53	6 326 045,03	6,33	27 415 838
	2027	571 868,33	3 597 051,82	3,60	28 186 427
	2028	317 151,70	1 994 884,18	1,99	28 619 155
	2029	173 463,33	1 091 084,35	1,09	28 857 481
	2030	94 155,32	592 236,99	0,59	28 987 337
	2031	50 896,44	320 138,63	0,32	29 057 676
	2032	27 451,08	172 667,29	0,17	29 095 657
	2033	14 787,94	93 016,17	0,09	29 116 129
	2034	7 961,12	50 075,43	0,05	29 127 154
	2035	4 284,38	26 948,78	0,03	29 133 088
	2036	2 305,27	14 500,12	0,01	29 136 281
	2037	1 240,25	7 801,18	0,01	29 137 999
	2038	667,23	4 196,87	0,00	29 138 924
	2039	358,94	2 257,76	0,00	29 139 421
	2040	193,10	1 214,57	0,00	29 139 689
	2041	103,88	653,38	0,00	29 139 832
	2042	55,88	351,48	0,00	29 139 910
	2043	30,06	189,08	0,00	29 139 952
	2044	16,17	101,71	0,00	29 139 974
	2045	8,70	54,72	0,00	29 139 986
			179 115 391,12		